Eskom
National Transmission
Company South Africa ™

Multi-Year Price Determination (MYPD) 6
Revenue Application for FY2026 – FY2028
National Transmission Company South Africa SOC Ltd
(Transmission)

August 2024

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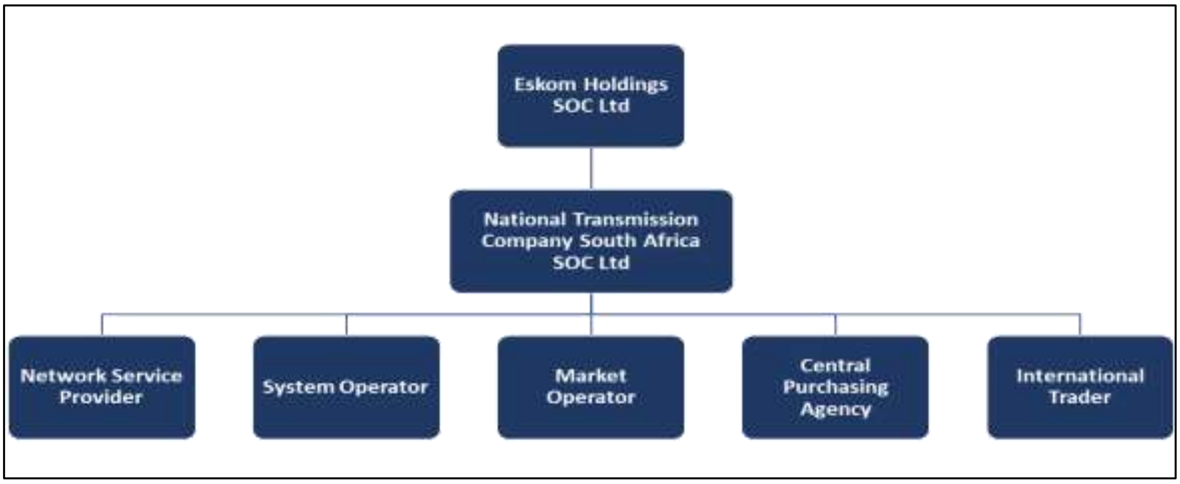
1 Executive Summary

1.1 Introduction

The National Transmission Company South Africa SOC Ltd (hereafter referred to as "NTCSA") is a wholly owned Eskom Holdings SOC Ltd subsidiary. The creation of the NTCSA as a separate transmission company is central to the Government's strategic objective to establish a more competitive, efficient, and sustainable electricity supply industry. The 1998 White Paper on Energy Policy proposed an introduction of competition in the energy sector, beginning with the restructuring of Eskom by splitting it into three independent entities for electricity generation, transmission and distribution. This proposal was later articulated and refined in the 2019 Department of Public Enterprises (DPE) Eskom Roadmap which outlined the future of Eskom, starting by the creation of NTCSA which is fully regulated and wholly owned by Eskom and will act as a network, system and market operator to set the electricity industry on a new path. In terms of the MYPD Methodology the Transmission role is represented by the NTCSA with combined roles related to Independent Power Producers (IPP) and International Purchases.

The NTCSA was operationalised on 1 July 2024 as a wholly owned regulated subsidiary of Eskom.

FIGURE 1: THE NTCSA HIGH LEVEL ORGANOGRAM



The National Energy Regulator of South Africa (NERSA) has awarded NTCSA three licenses, namely, to operate electricity transmission infrastructure, to facilitate energy imports and exports, and to engage in electricity trading within South Africa's borders.

This document details the revenue application for the licensed activities of the NTCSA (Transmission) for the MYPD 6 period FY2026 to FY2028 and sets out key challenges and motivation for revenue requirement. The NTCSA revenue requirements includes the activities of the Transmission network service provider, system planner, system operator and grid code secretariat functions as well as those that relate to the purchase of energy from IPPs (including from Section 34 IPP's) as well as imports from Southern African Power Pool (SAPP) and regional trading partners.

As an operator of transmission facilities, NTCSA invests, operates, and maintains the electricity network assets to transport electricity from Eskom and IPP generation facilities to the Distribution network or, in the case of large energy users such as mines and municipalities, directly to the customers themselves and therefore act as an intermediary link between the electricity generators and the distributors or large energy users. As a system operator the NTCSA is responsible for safely managing and maintaining the Integrated Power System (IPS) which includes the crucial tasks of dispatching electricity generators and ensuring that the power system always remains in balance to prevent blackouts. The NTCSA will also perform the functions of a trader by purchasing energy from Eskom power stations, IPPs and from the ring-fenced International Trader. This energy will then be sold at an aggregated wholesale energy tariff to Eskom Distribution and to the international customers.

For the year ending 31 March 2023, the transmission system infrastructure comprised of approximately 33 194 km of lines as well as 171 high voltage / extra high voltage (HV/EHV) substations with an installed transformation capacity of 155 820 megavolt-ampere (MVA).

1.2 The Basis of Application

1.2.1 Multi-Year Price Determination (MYPD) methodology

NTCSA will submit a ring-fenced revenue application for its licensed activities as part of Eskom's overall submission for the FY2026 to FY2028 in accordance with the MYPD methodology as published by NERSA during October 2016. The methodology provides for the regulator to make ring-fenced revenue determinations, and it is envisaged that NERSA will do so.

1.2.2 Licensing

The revenue application is in accordance with provisions of the licenses that have been awarded to NTCSA namely the licence to operate transmission facilities, to import and export energy and to trade electricity within the borders of South Africa.

1.2.3 Government Support Framework Agreement (GSFA)

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

1.3 Electricity Regulation Act (ERA) Amendment

NTCSA is cognisant that this application is being made when the industry is undergoing transition. The Electricity Regulation Act (ERA) Amendment Bill has been passed by both houses of parliament and is awaiting the approval of the President of South Africa to be enacted. The amendment aims to establish the Transmission System Operator (TSO) and introduce a competitive multi-market structure for the electricity sector. Once enacted, the NTCSA will transition into the TSO. The Act will also grant the NERSA the authority to implement transitional arrangements that will guide the electricity industry.

1.4 Revenue Requirement Summary

For the period FY 2026 to FY 2028, the NTCSA submits this revenue application of R101bn, R115bn and R155bn for the FY2026, FY2027 and FY2028 respectively. The allowable revenue requirement includes the return on assets, the operating costs, depreciation as well as the Regulatory Clearing Account (RCA) and court order(s). Transmission system reliability costs and expenses associated with energy procured from the IPPs as well as costs related to imports and exports of energy are detailed in this application.

NTCSA has taken steps to contain its cost base and limit its impact on electricity price increases. Table below provides an overview of the NTCSA Licensee revenue requirements.

TABLE 1: NTCSA: REVENUE REQUIREMENT

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

1.5 Return on Assets

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

The opening RAB balance for FY2026 is based on the independent asset valuation as at 31 March 2020 adjusted for subsequent movements in capital expenditure. The MYPD 6 RAB values are based on the adjusted values as well as the planned capital expenditure as detailed in the table below.

The RAB value increases over the MYPD 6 period as planned projects investments are incurred. NTCSA capital investment requirements for the FY2026 – FY2028 are included in the table below. These investments are required to strengthen and expand the grid to connect new customers and generation sources in terms of the Transmission Development plan. In addition, investments to replace assets which have reached the end of their technical life are required to sustain a reliable supply of electricity.

TDP2022 states that over the 10 years to 2032, NTCSA is required to build 14 218km of new transmission lines by 2032 and install 105 865MVA of transformer capacity, equivalent to c.42% of the current power line infrastructure. The aim is to connect 53GW of new generation capacity. To this end NTCSA plans to roll out approximately 3 470km and 30 360MVA capacity over the MYPD 6 period to ensure continued stability and access of energy supply. This is a significant ramp up from the historic 300km per year to an average of approximately 1 150km per year in the next three years. Refer more detail on chapter 8.

TABLE 2: NTCSA: PLANNED CAPITAL INVESTMENTS

NTCSA: Total Capital Expenditure (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Strengthening and Expansion	1 899	3 100	5 967	14 263	30 039	31 554	41 143	35 790
Asset Replacement	1 407	1 407	2 055	3 796	5 270	6 269	6 923	6 530
EIA and Servitudes	64	352	589	1 704	1 178	720	769	200
Production Equipment	173	887	543	299	499	503	512	508
Total	**3 543**	**5 745**	**9 154**	**20 063**	**36 987**	**39 046**	**49 347**	**43 027**

1.6 Independent Power Producers (IPPs)

As the country pushes towards the Just Energy Transition, energy sourced from the IPPs increases substantially throughout the revenue application period. The IPP initiatives are included up to Bid Window 8 and includes the risk mitigation programme, emergency generation, Standard Offer programme and battery storage.

The energy sourced from the IPPs increases substantially throughout the revenue application period. The IPP initiatives are included up to Bid Window 8 and includes risk mitigation programme, emergency generation, standard offer programme and battery storage.

The primary driver of the increase is the surge in renewable energy sources. Total energy obtained from IPPs is projected to rise from 24 TWh in FY2025 to approximately 57 TWh by FY2028. Renewable energy makes up a large portion of this total with almost 21 TWh in FY2025 and 50 TWh in FY2028. IPPs' non-renewable energy programme is projected to grow from 1.4 TWh in FY2025 to approximately 3.5 TWh by FY2028. Apart from the Section 34 IPPs, NTCSA is projecting an increase in its short-term programmes, which encompasses emergency generation and standard offer programmes, from 1.6 TWh in FY2025 to 3.9 TWh by FY2028. These translate into an overall cost for the three years of R67bn, R78bn, and R110bn, for FY2026, FY2027 and FY2028 respectively.

TABLE 3: IPP ENERGY COSTS & VOLUMES

NTCSA: IPP Cost and Energy	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Total IPP Purchases (R'm)	43 534	57 662	56 236	66 633	77 640	109 820	135 510	140 943
Total IPP Energy (Gwh)	17 957	22 972	23 856	31 364	35 214	57 259	71 610	70 952

1.7 International Purchases

Eskom imports power from several neighbouring countries to stabilize its electricity supply. These imports are sourced mainly from Hidroeléctrica de Cahora Bassa (HCB) in Mozambique and from various countries through the SAPP short-term markets.

TABLE 4: INTERNATIONAL PURCHASES

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

1.8 Operating Expenditure

Operating expenditure includes all costs involved with the day-to-day running of the business. NTCSA's operating expenditure includes employee costs, maintenance, other expenses, and corporate overheads. It should be noted that these costs are nett of capitalisation and considers other income derived from operations. The NTCSA operating expenditure for the revenue requirement is detailed in the table below.

TABLE 5: NTCSA: OPERATING EXPENDITURE

NTCSA: Operating Expenditure	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	% of Revenue	Application FY2027	% of Revenue	Application FY2028	% of Revenue	Post Application FY2029	Post Applicaton FY2030
Employee Expenses	2 721	3 544	4 161	4 423	4%	4 634	4%	4 822	3%	5 023	5 253
Network Business	2 699	3 523	4 118	4 377		4 586		4 772		4 971	5 199
International Trader	23	21	43	46		48		50		52	54
Other Operating Expenses	1 083	1 035	1 066	1 037	1%	1 001	1%	1 026	1%	1 089	1 154
Network Business	901	1 004	1 056	1 026		990		1 014		1 076	1 141
International Trader	182	30	10	11		11		12		13	13
Maintenance	1 087	1 124	1 564	1 675	2%	1 857	2%	1 968	1%	2 039	2 114
Corporate Overheads	639	821	739	843	1%	818	1%	947	1%	1 002	1 062
Other Income	-150	-72	-46	-48		-50		-52		-54	-57
Total Operating Expenditure	**5 380**	**6 452**	**7 484**	**7 930**	7%	**8 260**	7%	**8 710**	5%	**9 099**	**9 527**
Corporate Overheads: portion excluded from revenue requirement				-162		-191		-218		-228	-239
Total Operating Expenditure in the Revenue Requirement	**5 380**	**6 452**	**7 484**	**7 768**	8%	**8 070**	7%	**8 492**	5%	**8 871**	**9 288**

1.8.1 Employee expenses

Employee expenses are inclusive of cost to company remuneration and other employee related expenditures such as the skills levy, workman's compensation contributions, training, professional fees, overtime, contingency and travel costs. These expenses are nett of capitalisation and represent the costs that are directly recoverable.

NTCSA's employee benefit costs are primarily driven by the staff complement and the rate of remuneration as agreed through the collective bargaining process. The NTCSA workforce is planned to increase to 4 094 by end of FY2025 as the business is capacitated and ramps up for the acceleration of the TDP implementation; thereafter it is projected to remain constant throughout the MYPD 6 period. The growth is required to close the gap created by increased workload from the implementation of the Integrated Resource Plan, the TDP, establishment of new functional areas such as market operator and customer services, as well as the replacement of lost skills.

TABLE 6: NTCSA: EMPLOYEE EXPENSES AND EMPLOYEE NUMBERS

NTCSA: Employee Expenses and Headcount	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Employee Expenses (R'm)	**2 721**	**3 544**	**4 161**	**4 423**	**4 634**	**4 822**	**5 023**	**10 453**
Network Business	2 699	3 523	4 118	4 423	4 586	4 772	4 971	5 253
International Trader	23	21	43	46	48	50	52	5 199
Employee Numbers	**3 196**	**3 801**	**4 094**	**4 094**	**4 094**	**4 094**	**4 094**	**4 094**
Network Business	3 179	3 768	4 061	4 061	4 061	4 061	4 061	4 061
International Trader	17	33	33	33	33	33	33	33

1.8.2 Maintenance costs

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

TABLE 7: NTCSA: MAINTENANCE COSTS

NTCSA: Maintenance Costs	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Servitude Maintenance	192	204	274	301	336	347	360	373
Line Maintenance	236	255	358	383	429	462	479	496
Primary Plant Maintenance	221	233	309	335	365	388	402	417
Secondary Plant Maintenance	47	50	77	87	113	142	147	153
Equipment & Spares	17	20	36	38	50	52	54	56
ERI (Transformer & Logistics)	344	337	465	485	514	528	547	567
Other	30	26	45	46	49	49	51	53
Total Maintenance	**1 087**	**1 124**	**1 564**	**1 675**	**1 857**	**1 968**	**2 039**	**2 114**
As % of Revenue Requirement				*1.7%*	*1.6%*	*1.3%*	*1.1%*	*1.1%*

1.8.3 Other operating expenses

Other operating expenses include insurance, travel costs, security services, IT, telecommunications, safety equipment and general office expenses.

NTCSA's other operating costs are primarily driven by an expanding asset base, growing workforce, and the restructuring and legal separation. This results in increased costs for IT, consulting, security, travel, facilities, and insurance services. Other operating costs remain constant throughout the MYPD 6 period.

TABLE 8: OTHER OPERATING EXPENSES

NTCSA: Other Operating Expenses (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Insurance Premiums and repairs	198	359	319	334	350	367	383	401
Security Expenses	216	167	187	193	242	172	180	188
IT Expenses	41	145	138	145	151	158	165	172
Telecommunications	66	74	84	88	92	96	96	96
Travel Expenses	71	77	93	97	100	103	108	113
Consulting and Legal Costs	52	127	153	141	148	194	203	212
Facilities	29	80	106	111	116	121	127	133
Leases	20	26	28	30	31	33	34	36
Internal Electricity Costs	31	38	53	70	77	83	87	90
Impairment Loss	178	20	-	-	-	-	-	-
Abnormal Costs	364	-	-	-	-	-	-	-
Other	-184	-80	-96	-172	-306	-302	-295	-287
Total	**1 083**	**1 035**	**1 066**	**1 037**	**1 001**	**1 026**	**1 089**	**1 154**

1.8.4 Corporate overhead costs

Corporate overheads expenses are primarily costs that are charged out based on a pre-determined three (3) factor formula. These costs are shared amongst the Eskom's line divisions/subsidiaries in proportion to employee complement, asset values and operational costs. Corporate functions provide indirect services such as treasury, communications, legal, business planning, etc. to support NTCSA.

1.8.5 Other income

This includes income derived from leasing of telecommunication optic fibres, site sharing of telecommunication infrastructure as well as other recoverable projects such as maintenance services provided to third parties.

1.9 Depreciation

Depreciation allows the Licensee to incrementally recover the principal portion of the capital invested in its assets over their useful life. The depreciation reflected in the table below was calculated based on the revalued asset base as at 31 March 2020 as well as considering new asset investments planned for transfer to commercial operation.

TABLE 9: NTCSA REGULATORY ASSET BASE AND DEPRECIATION

NTCSA: Regulatory Asset Base and Depreciation (R'm)	MYPD 5 Decision FY2024	MYPD 5 Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Regulatory Asset Base	113 993	101 895	131 438	161 211	191 175	231 680	264 464
Depreciation	6 596	6 885	6 461	6 949	7 816	9 096	10 447

1.10 Ancillary Services and Power Alert

As part of its responsibilities to maintain power system reliability, the System Operator is required to ensure the provision of appropriate ancillary services. The extent of these services and the way they are to be provided is defined in the South African Grid Code. The ancillary services currently defined in the Grid Code includes:

- Reserves including Demand Response providers,
- System Restoration (Black Start, Self-Start and Islanding products),
- Energy Imbalance (Constrained generation), Reactive Power, and Voltage Control.

TABLE 10: ANCILLARY SERVICES & POWER ALERT

NTCSA: Ancillary Services & Power Alert (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Reserves	-	1 435	1 445	1 580	1 651	-	-
Reactive Power and Voltage Control	-	-	468	436	475	594	637
System Restoration	-	-	376	785	1 689	2 672	3 741
Demand Response	295	380	521	604	693	789	892
Reliability of Services System Costs	35	37	58	61	67	64	62
Power Alert	40	78	78	78	78	78	78
Ancillary Services in the Revenue Requirement	**370**	**1 929**	**2 946**	**3 544**	**4 653**	**4 197**	**5 410**

1.11 Energy Losses

Transmission losses are incurred when energy is transferred from generators to loads. As electricity flows through the transmission network, energy is lost due to electrical resistance and the heating of conductors. Transmission losses are determined by the difference between energy injected onto the transmission grid and energy off-take at main transmission substations including interconnection points. Energy losses of 2.5% are forecasted based on historical trends, simulations, and multiple regression analysis.

1.12 Arrear Debt

Due to severe macroeconomic headwinds, arrear debt particularly municipal debt has grown to unsustainable levels at Eskom. As at end of March 2023, arrear municipal debt was at R58.5 billion, a substantial 31% year-on-year increase from March 2022. The top 10 defaulting municipalities account for about 63% of total arrear municipal debt. While Eskom continues to make efforts to address the arrear debt, however these have not yielded the desired outcome as the debt continued to escalate. A high-level intervention and continuous, coordinated multistakeholder approach is required. Eskom hopes that the Municipal Debt Relief programme facilitated by the National Treasury to support municipalities deal with their historical debt challenges. This remains a significant risk to the sustainability of NTCSA.

1.13 Assumptions

The following assumptions were made in the preparation of the application for the Transmission licensee:

- Implementation of the DPE Roadmap on Eskom as per the amendments in the Energy Regulation Act will proceed during the MYPD 6 period.
- The wholesaler and single-buyer operational costs including IPPs (primary energy) are ring-fenced within the NTCSA costs.
- The International trading costs will form part of the ring fenced NTCSA.

- Existing international interconnectors, including Apollo Converter Station, remain within NTCSA and will not be treated differently to other assets.
- The expansion plan considered the approved 10-year Transmission Development Plan (TDP) for 2023 to 2032.
- The transmission demand forecast not only takes the energy forecast into account, but also the expected typical transmission capacity demand for different sectors of development. This is done to accommodate the long lead times for transmission infrastructure projects and overcome short-term fluctuations in demand caused by external factors.
- The IRP 2019 will form the basis for new generation capacity to be connected to the grid over the MYPD 6 period subject to any subsequent revisions.
- That a ring-fenced revenue determination per Licensee will be made by NERSA.

2 Independent Power Producers

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

2.1 Overview

The South African Government's policy, in accordance with the Integrated Resource Plan (IRP) of 2019, aims to significantly increase the contribution of energy sourced from IPPs. The objectives of this policy are to enhance energy security, promote sustainable development, and stimulate economic growth by leveraging the capabilities and investments of IPPs.

In accordance with the sections 3.1.4(e) of the GSFA, Eskom is required to consult with and seek approval from the DMRE together with the DPE and National Treasury with regards to the proposed amounts for IPP purchase costs and payment obligations to be included in the MYPD 6 application for the period from FY 2026 to FY 2028.

Eskom has undertaken this process and has received feedback from all three relevant government departments, that all concur with the projections on IPP projects to be included in Eskom's MYPD 6 revenue application.

TABLE 11: IPP ENERGY- COSTS

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

TABLE 12: IPP ENERGY PURCHASES - VOLUMES

NTCSA: IPP Energy (GWh)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Eskom short term programmes	-	1 849	1 605	3 215	3 898	3 909	527	-
MTPPP (Emergency Gen)	-	889	1 430	2 269	2 321	2 328	-	-
Short term (Standard Offer)	-	960	175	946	1 577	1 581	527	-
Section 34 programmes (non RE)	1 098	2 374	1 382	1 770	3 445	3 514	10 513	10 513
DoE Peaking	1 098	2 104	528	528	528	530	528	528
Risk Mitigation Programme	-	270	854	1 241	3 039	3 300	3 291	3 291
Gas programme	-	-	-	-	-	-	7 008	7 008
Storage	-	-	-	-	-123	-316	-315	-315
Renewable IPP	16 859	18 748	20 868	26 380	27 872	49 836	60 571	60 439
Renewable IPPs Round 1	3 398	3 683	3 763	3 753	3 747	3 748	3 721	3 723
Renewable IPPs Round 2	2 790	2 959	3 055	3 047	3 043	3 036	3 031	3 024
Renewable IPPs Round 3	4 011	4 290	4 619	4 617	4 612	4 618	4 603	4 600
Renewable IPPs Round 3.5	300	362	761	855	854	856	853	848
Renewable IPPs Round 4	3 490	3 952	4 068	4 063	4 058	4 062	4 048	4 043
Renewable IPPs Round 4+	2 869	3 502	3 504	3 498	3 491	3 493	3 479	3 472
Renewable IPPs Round 5	-	-	1 099	4 770	4 784	4 788	4 765	4 755
Renewable IPPs Round 6	-	-	-	1 776	3 229	3 215	3 183	3 160
Renewable IPPs Round 7	-	-	-	-	54	16 457	16 380	16 349
Renewable IPPs Round 8	-	-	-	-	-	5 563	16 508	16 465
Total IPP	**17 957**	**22 972**	**23 856**	**31 364**	**35 214**	**57 259**	**71 610**	**70 952**

2.2 Section 34 Energy Procurement

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

2.2.1 Renewable Energy IPP Programme

All prices are indexed to the assumed inflation of 6%, except for certain bid window (BW 2 and BW 3 options that are only partially indexed). Bid Windows 1 through 4 included as per the energy expectations in the power purchase agreement (PPA) and prices as per the PPA.

The expected commercial operation dates for projects under Bid Windows 5 to 8 have been provided by the DMRE through the GSFA consultation process. Of the original twenty-five preferred bidders in Bid Window 5 only twelve reached financial close with a total 1 234 MW. These projects are expected to enter commercial operation between September 2024 and June 2025. Under Bid Window 6 six photo-voltaic projects with a total 1000 MW of capacity were announced as preferred bidders. These projects are expected to enter commercial operation between March 2026 and May 2026.

Bid Window 7 is expected to result in 3 200 MW of wind capacity and 1 800 MW of photo-voltaic capacity (with commercial operation in February 2027). Bid Window 8 is expected to result in the same levels of capacity for wind and photo-voltaic generation with commercial operation in October 2028.

2.2.1.1 Peaker programme

The two IPP peaker power stations are commercially operating and assumed to be operating at a minimum load factor of 6% per annum for the entire revenue application cycle. Projected costs are split between the "fixed" capital component and variable energy component.

2.2.2 Risk Mitigation programme

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

2.2.3 Gas programme

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

2.2.4 Section 34 - Storage

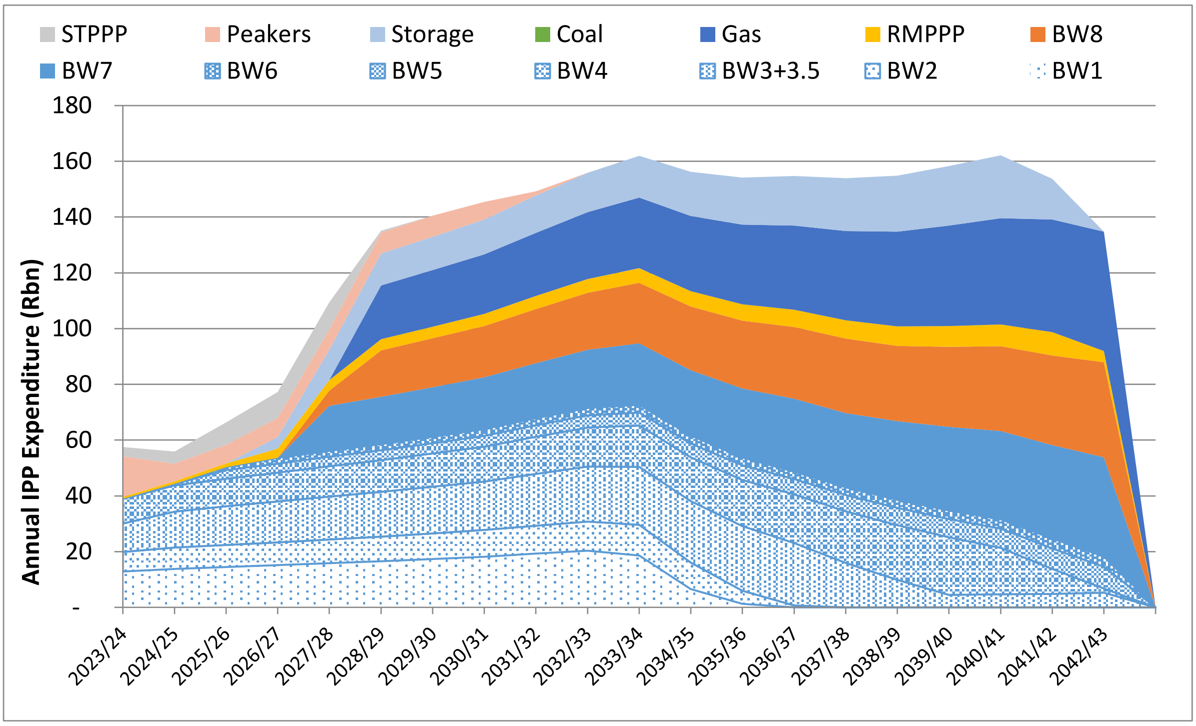
The IRP provides for 513 MW of battery storage. It is expected this will operate from June 2026 with 4 hours storage capability, 89% cycle efficiency and one cycle per day for the duration of the contract. This means that each day will see 4.5 hours of charging and 4 hours of generation, thus daily net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

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

2.3 Eskom short-term programmes

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

FIGURE 2 : SUMMARY OF IPP COSTS OVER LIFE OF CONTRACTS



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

3 International Trader

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

3.1 Introduction

International imports and exports of electricity are presently undertaken by Eskom Holdings SOC Ltd as a licensed activity and based on its membership of the SAPP and various intergovernmental agreements. NTCSA will facilitate cross border energy purchases and sales with countries that are interconnected to the Southern African Grid. Imports and exports are transacted based on power purchase agreements (PPAs) and power sales agreements entered with cross-border utilities, cross-border generators, as well as via the SAPP competitive markets. All cross-border trading transactions including enroute transactions (external transactions that do not cross the RSA Borders) are included in the MYPD 6 application.

3.2 International Trader

The International Trader is a business unit within NTCSA which has been mandated to carry out the cross-border activities on behalf of Eskom.

The International Trader concludes Power Supply Agreements (PSAs) and PPAs with trading partners where contracts are either on a firm or non-firm basis. Firm PSAs are subject to the load curtailment reduction that is in proportion to the load shedding stages that are determined by the relevant codes, whilst non-firm PSAs are suspended in the event of increased demand in South Africa including use of Open Cycle Gas Turbines (OCGT) (diesel) and load shedding.

International Trader through the Transmission Network Service Provider facilitates the provision of wheeling paths for Trading Partners as per the SAPP rules and SAPP prices. These transactions are scheduled on a month-ahead, day-ahead, or hour-ahead basis.

International Trader supplies emergency energy, upon request by Trading Partners, depending on the availability of power as provided for in terms of the SAPP rules. The emergency energy is priced in line with Eskom's declared emergency rates to SAPP and this is based on the marginal unit to be utilised to supply emergency energy.

3.3 International Energy Purchases

Eskom imports power from several neighbouring countries to stabilize its electricity supply. These imports are sourced mainly from Hidroeléctrica de Cahora Bassa (HCB) in Mozambique, the Lesotho Electricity Company (LEC) in Lesotho, and various countries through the SAPP short-term markets. International energy purchases comprise of energy imports that flows into South Africa (imports) and energy sold in the southern Africa (SADC) region and not brought into South Africa (En-Route purchases).

Purchases from HCB show a material increase in the last year of the MYPD 6 period, due to a major refurbishment at the plant in the first two years and will ramp up towards normal production only by FY2028.

TABLE 13: INTERNATIONAL PURCHASES

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

3.4 International Energy Sales

International Energy Sales are classified as export sales (energy bought from Eskom and sold to international customers) or enroute sales (energy sold in SADC, but not produced by Eskom).

Wheeling Transactions comprise external SAPP wheeling, and internal Eskom wheeling on behalf of SAPP members, where a third partie’s network is used to transport energy on behalf of two other contracting parties. The established principle is for the buyer of the energy to pay for the wheeling costs.

All nett wheeling revenue earned by the International Trader for use of the NTCSA Network in South Africa, is paid across to NTCSA monthly. This alleviates the requirement for the International Trader to reserve a fixed network capacity for these highly variable energy flows.

TABLE 14: INTERNATIONAL SALES

NTCSA: International Sales (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
International Sales	10 587	9 401	10 951	13 703	22 105	24 393	26 771	29 458

3.5 Negotiated Price Agreements

The International Trader has one Negotiated Price Agreement (NPA) with the Mozambique Transmission Company (Motraco) which supplies the Mozal aluminium smelter in Mozambique via a pass-through arrangement. The rest of the customers have individually determined tariffs (based on their usage, Time of Use (TOU) profiles, demand requirements etc.).

3.6 Operating Costs

Operating costs which include employee costs and other expenses.

TABLE 15: INTERNATIONAL TRADER OPERATING EXPENSES

International Trader: Operating Expenses (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Employee Expenses	23	21	43	46	48	50	52	54
Impairment Loss	178	20	-	-	-	-	-	-
Other Operating Expenses	3	10	10	11	11	12	13	13
Corporate Overheads	12	20	-	-	-	-	-	-
Total Operating Expenditure	**217**	**71**	**54**	**56**	**59**	**62**	**64**	**67**

3.6.1 Employee Expenses

Employee expenses pertain to the effective and efficient execution of the International Trader mandate. The staff complement is expected to remain unchanged over the MYPD 6 control period. Expenses include cost-to-company remuneration and other employee-related costs such as the skills levy, workers' compensation contributions, training, professional fees, overtime, contingency travel costs, and labour recoveries for capital projects.

3.6.2 Other Operating Costs

Other operating costs includes travel, business development projects and other sundry expenses.

- **Travel and Subsistence expenses**

  Travel expenses encompass both local and international business trips made by employees for operations. The travel expenses is based on scheduled SAPP meetings, expected regional meetings with trading partners, and relationship-building activities.

- **Business development projects**

  To increase regional trading, new transmission interconnectors need to be developed with regional stakeholders. The Business Development department is responsible for advancing priority projects from concept to execution. Their expenses cover project development costs, including consulting fees, legal expenses, and other professional services.

- **Other sundry expenses**

  Other sundry expenses include insurance premiums, sponsorships, telecommunication, stationery and office expenses.

4 Structure and Role of the Network Business

4.1 NTCSA Transmission System License

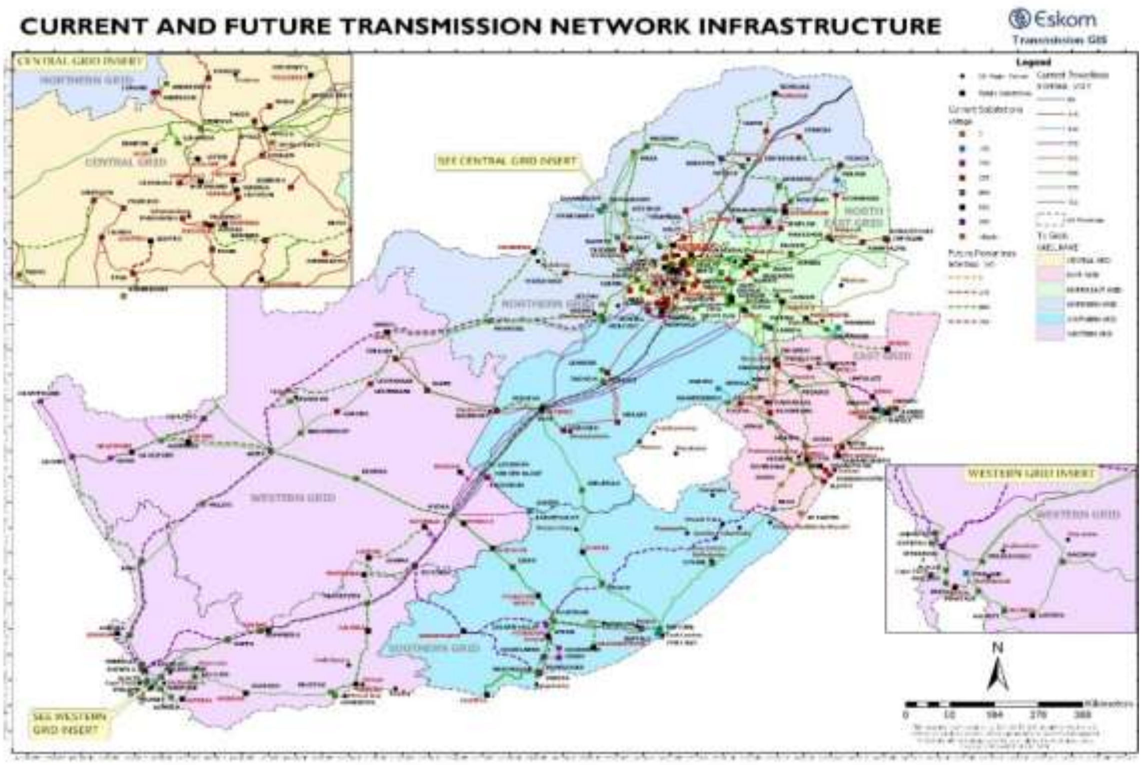
4.1.1 Overview

This section describes the role of the NTCSA which is to operate the national Transmission system, reliably transport electricity from generators to distributors, bulk-end customers and international customers and undertakes the following key integrated functions, namely:

- The Transmission Network Service Provider (TNSP);
- The Transmission System Planner (TSP);
- The System Operator (SO); and
- The Grid Code Secretariat.

The Transmission system comprises of a High Voltage / Extra-High Voltage (HV/EHV) electrical network at voltage levels ranging from 88 kilovolts (kV) to 765kV as well as a 533kV high-voltage direct current link. As at 31 March 2023, the Transmission system assets consist of 171 substations and 155 820 MVA transformers, connected by 33 194 km transmission lines across South Africa as per the figure below.

FIGURE 3: THE CURRENT TRANSMISSION NETWORK MAP



4.1.2 Transmission Network Service Provider (TNSP) Role and Functions

The key functions of the TNSP are to ensure that all transmission system assets used in the delivery process are:

- Correctly specified, designed, constructed and commissioned;
- Managed, operated, maintained in good working order as well as renewed; and
- Performing reliably.

These key functions are performed through a series of activities that include asset management, asset design, asset creation and disposal, network maintenance, network performance monitoring and enhancement.

A further aspect that must be managed by the TNSP is the quality of the electricity being delivered to its customers. This includes waveform quality (such as voltage regulation, unbalance and harmonic content) as well as disturbances (such as interruptions and voltage dips).

Other inherent business responsibilities include management of quality & assurance, safety & security risks and environmental impacts.

4.1.3 Asset Management and Engineering

Amongst other, Asset Management and Engineering includes the following activities:

- **Research:** This involves research into emerging technologies and related international practices. The activities help NTCSA pursue appropriate technologies and ensure continuous improvement through innovation and maintenance strategies.
- **Asset Investment Planning:** This entails the development of an asset investment plan to realise the maximum value from assets while balancing cost, risk, and performance.
- **Asset life cycle management (LCM):** This involves the compilation and maintenance of LCM plans per asset class for long-term sustainability based on appropriate maintenance and renewal strategies. Suitable spares management plans are developed for each technology.
- **Specification and standards:** This involves the compilation per technology type detailing required performance aspects and network application requirements. International standards are specified as appropriate.

- **Establishment of supply contracts:** This involves the provision of technical specifications to the procurement function to acquire the engineering and supply of standard technical solutions, including:
  - Technical tender adjudication.
  - The evaluation and motivation of the technical accreditation of supplier factories to supply the products/services required.
  - Technical contract management including the evaluation and approval of standard products and design solutions during the engineering phase.
  - The oversight and approval of final equipment testing before factory release.
  - The management of the operational relationship with suppliers over the lifetime of respective technologies to ensure long-term product support.
- **Maintenance strategy:** This involves the compilation and review of maintenance philosophies, standards and procedures. Appropriate condition monitoring techniques and test equipment are evaluated and introduced for use on the transmission network to optimize maintenance expenditures and best practices.
- **Operational engineering and consultation:** This involves the review of performance trends, investigation of equipment failures to identify causes, conducting trend analysis and developing corrective actions. Specialist operational support, training courses and coaching are also provided for operating and maintenance staff as required.
- **Technical instructions:** This involves the formulation of appropriate technical instructions to address modifications to plant or process. These are used for implementing design modifications or for giving once-off instructions regarding equipment or maintenance.

4.1.4 Asset Creation

Asset creation is executed in accordance with the relevant standards and procedures. Project development and execution is performed as per the project life cycle model which includes concept, definition, execution and finalisation stages. As a summary, activities include project scoping to meet requirements, evaluation of alternatives, cost estimation, investment justification, securing legal and environmental rights, project management, procurement, construction, supervision, quality control, safety and environmental control, commissioning, handover and finalisation.

The role and function of engineering in this process include:

- **Scope definition:** For new infrastructure, alternative technical solutions are defined to meet system planning or customer requirements. These are prioritised in terms of the estimated costs, performance constraints, implementation constraints and maintenance. Emphasis is placed on innovation, reliability and performance. For asset replacement, work scope is defined and projects are prioritised based on the criteria defined in the life cycle management plans.
- **Detailed designs**: Engineering produces the substation, secondary plant and powerline detailed / application designs for projects.
- **Commissioning and configuration management**: Engineering resources also provide support in the final commissioning of assets in collaboration with Grid staff.

4.1.5 Operations and maintenance

The Grid is managed on a regional basis to perform operating and maintenance functions for substation plant, protection and control systems as well as line and servitude assets. This includes work planning, safety, and environmental risk management as well as security support functions.

The regional Grid business units are responsible for operating and maintaining the transmission plant in a safe and effective manner, restoring the network following fault incidents, sustaining the required quality of supply, interfacing with customers, and ensuring that business objectives are achieved.

Outputs of these regional Grid Business Units include:

- **Operating:** Perform switching to connect or disconnect plant from service (in conjunction with relevant Control Centres) for maintenance, project execution as well as customer requests. Operating is executed as per statutory safety standards.
- **Maintenance planning:** A long-term maintenance plan for all assets is captured and updated on the company's maintenance management system. The maintenance scope per asset is defined in accordance with approved standards and procedures.

  Outage planning: Develop an integrated outage plan to meet the maintenance plan requirements. It includes risk assessment, scheduling, management of constraints and optimization.

- **Maintenance execution:** Perform maintenance as per established procedures and in accordance with system, manufacturer and statutory requirements. Appointment and supervision of contractors for specialized and ad-hoc maintenance activities.
- **Inspections and condition monitoring:** Conduct asset inspections to identify defects and establish condition of plant. Amongst other, this includes oil sampling, gas monitoring, infra-red scanning and diagnostic testing of apparatus.
- **Breakdown maintenance and restoration:** Provide an effective response service to incidents on the power system. Interface with Control Centres and various stakeholders during restoration following network incidents. Repair / normalization and recovery of the power system following plant failures.
- **Live line services:** Conduct live line work maintenance on transmission lines to minimize planned line outage requirements and reduce the risk for interruptions. As required, conductor repairs and insulator replacement is performed under live (energised) conditions using approved tools and techniques.
- **Asset creation:** Produce the commissioning program and commission plant in line with prescribed standards and procedures. Conduct quality inspections during the construction of the new assets.
- **Spares management:** Replenish spares for strategic and operational purposes. This includes storage management and maintenance of spares.
- **Fault investigations:** Investigate and determine root cause for asset failures / incidents. Identify problem areas relating to plant performance and provide recommendations. Define corrective action plans and monitor finding close-outs.
- **Emergency Preparedness and Contingency Planning:** Prepare, evaluate and test Emergency Preparedness and Contingency Plans. Communicate plan to all stakeholders.

The above outputs are performed in accordance with NTCSA record keeping requirements as well as quality standards. Safety and environmental risk management are integrated with work planning and execution.

Line maintenance practices are dependent on specialized helicopter services to execute inspections as well as live line work. NTCSA owns and operates a fleet of helicopters to provide a specialized aerial service for power line inspections, maintenance, construction activities, fibre optic stringing as well as emergency response / repairs. The helicopters are managed in compliance with the South African Civil Aviation Regulations and Technical Standards.

4.1.6 Customer Services

A customer services function for NTCSA provides overall co-ordination, consistency of customer practices, customer experience and provides non-discriminatory grid access for load and generation customers. Customer Services offers leadership and direction on service best practices for the business.

NTCSA is a customer-orientated business that will manage the customer value chain which includes grid access, customer connections, contracting, bulk power supply, network service provision, billing, revenue management as well as customer relationship management with the provision of reliable and cost-effective solutions.

4.1.7 Performance management

NTCSA uses a basket of measures to report and monitor system reliability and performance. These range from system-based performance measures for stakeholder reporting and leading measures to manage underlying performance drivers. They fall into the three broad technical performance categories: reliability, availability, and quality of supply.

A comprehensive performance management process and information management system has been developed to measure and report on performance in these areas. Although these systems are partially automated, data capturing, interpretation and classification of events are labour intensive. Some of the key systems are:

- **Transmission Integrated Plant Performance System (TIPPS)**, which records the availability and reliability of the system as a whole and the performance of individual components within the system including cause classifications.
- **National quality of supply measurement system**, which measures the quality of the electricity supplied by NTCSA at its points of delivery. Measurements include harmonics, voltage regulation, unbalance and voltage dips. These are generally assessed against international, national or agreed standards and limits.

These systems provide measures that are used at various levels in NTCSA, from executive management to equipment specialists, to assist in managing and improving the network performance and its associated processes. NTCSA also has several independent assurance processes in place, such as technical audits, business management system audits, fault investigations and data integrity audits to keep management and key stakeholders informed of the state of the network and the integrity of reported figures.

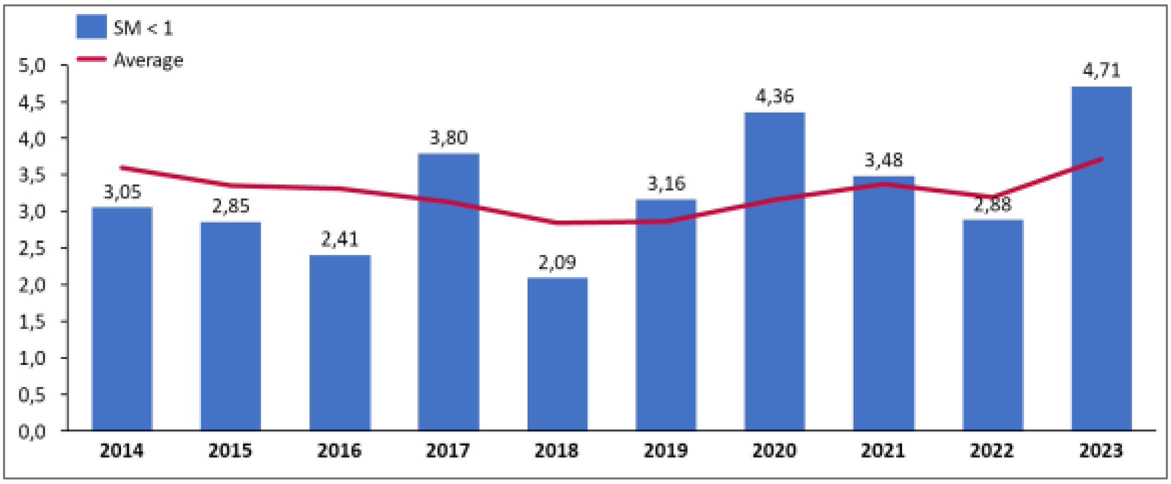
4.1.8 Reliability

Reliability of both the network and the associated plant is one of the key outputs that any transmission utility must provide to its stakeholders to ensure that system-wide measures are tracked, targeted and reported externally:

- **System minutes <1:** One system minute is equivalent to an interruption of the total system load for one minute at the time of the annual system peak. By looking at both load interrupted and duration of the interruptions, this measure reflects the severity of interruptions. SM<1 measures the total system minutes lost during the year from incidents that individually were less than one system minute (i.e. it excludes major incidents).

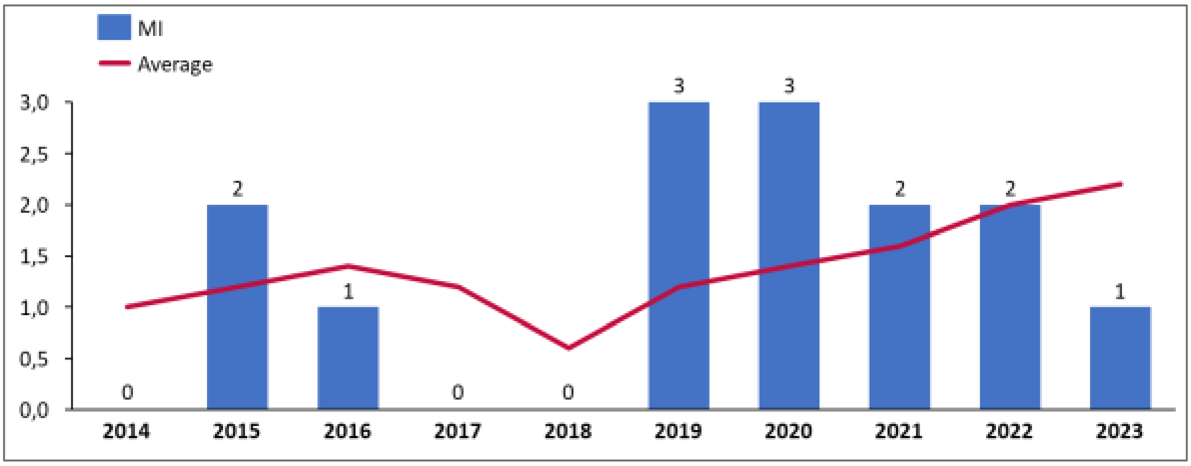
  Following an improvement trend over the last decade, performance deteriorated in FY2023 as reflected in the figure below. This is mainly attributed to increased risks associated with ageing assets resulting in plant failures, switchgear failure incidents as a result of an increased duty cycle due to load shedding as well as theft incidents impacting asset availability.

FIGURE 4: SYSTEM MINUTES <1 PERFORMANCE – 10YR HISTORY



- **Major Incidents:** A major incident is defined as an interruption incident that results in the loss of one or more system minutes. These incidents represent events that are so significant that they would otherwise swamp the underlying interruption performance measure (SM <1). The figure below reflects the number of major incidents over the last decade together with the five-year average trend line. Although a performance improvement was achieved during the earlier period, risks due to ageing assets eroded performance in the latter years. The focus is to address these risks by increasing the amount of network renewal going forward.

FIGURE 5: NUMBER OF MAJOR INCIDENTS – 10YR HISTORY



- **Number of interruptions:** Measures the number of times Transmission interrupts or is unable to supply the full load at any one of its supply points. This measure provides an indication of the frequency of interruptions on the transmission system.

4.1.9 Quality of supply

NTCSA (Transmission) has been involved in the measurement of the quality of supply (QOS) delivered to its customers for many years and was involved in the development of the national standard for QOS, namely NRS 048-2, which has been adopted by NERSA. QOS measures or key performance indicators (KPIs) can be grouped into the following high-level categories: waveform (harmonic, unbalance, and voltage regulation) and disturbance (voltage dips and surges).

NTCSA monitors and reports on dips seen by its customers, it also tracks and manages the number of line faults that cause these dips and annually reports QOS performance to NERSA.

4.2 Transmission System Planner

4.2.1 Overview

The Transmission System Planner (TSP) is responsible for planning the augmentation of the transmission system in accordance with the South African Grid Code. It is reliant on the IRP for the future generation and demand country forecasts as well as industry insights to determine the NTCSA system infrastructure requirements. This ultimately culminates in the publication of the Transmission 10-year Development Plan which informs the capex requirement.

4.2.2 Role / Functions

4.2.2.1 Network planning and project development

The network planning activities are performed in accordance with Grid Code requirements and can be summarized as follows:

- Analysis of the network to identify needs for reinforcement and appropriate solutions to address existing and future violations of the planning criteria as prescribed by the Grid Code.
- Analysis and “interpretation” of the IRP to determine the long-term projected demand growth at a regional / substation level and the associated network reinforcement requirements.
- Analysis and “interpretation” of the IRP in conjunction with the DMRE’s IPP procurement programmes to determine the network reinforcements required to integrate capacity to the power system.
- The study of customer applications for new / modified connections, identification of network reinforcements and issuing of customer quotations.
- Preparation of business cases for expansion projects and obtaining approvals from relevant capital governance committees.
- Compilation of investment documents in accordance with Grid Code requirements.
- Provide expansion planning input for the capital expenditure plan and serve as an interface with other licensees and customers. Ensure that a common view exists between stakeholders for alignment of expansion and asset replacement plans.
- Offer support to the DMRE IPP Office as well as to the renewable energy associations to “unlock” network capacity to connect potential future generation capacity.

4.2.2.2 Transmission Development Plan

The TSP is responsible for publishing a 10-year TDP annually as per the Grid Code requirement to allow members of the public an opportunity to influence it. Although it falls outside the Grid Code requirement, the TSP also compiles a 20-year strategic transmission development plan with an associated load forecast and base case system study file. This is done to:

- Enable an adequate assessment of the effects of new generation capacity;
- Identify strategic power corridors; and
- Enable the assessment of proposed technologies and development plans.

The 10-year TDP consists of a list of all projects expected to be completed over that period, starting the year after its publication. It includes land & rights (EIA and servitude or site acquisition), expansion and replacement of plant. It does not include production assets (viz. vehicles, computer equipment, furniture, tools, etc.).

In compiling the 10-year development plan, consideration is given to the IRP Generation Capacity Plans to ensure that the transmission system is capable to integrate new generation.

The TSP also represents NTCSA in the evaluation of new or increased capacity cross-border interconnectors. These interconnectors make it possible to purchase energy from other members of the SAPP and sell surplus energy.

An assessment was conducted to determine the required internal and external resource capacity to ensure the successful delivery of the TDP 2023-2032. Amongst other, the external resource assessment considered plant and major contractors required for development and execution of projects. In summary, the assessment results revealed the following:

- Additional human resources will be required to successfully deliver the TDP 2023-2032.
- The need for an enhanced enabling internal environment with associated processes, tools and procedures to deliver on the planned large-scale projects.
- Supplier development initiatives are required to increase material supply with both local and international manufacturers.
- NTCSA must be financially sustainable to be able to support the planned infrastructure development.

4.2.2.3 Demand forecasting

The demand forecast is required to evaluate the network capacity to meet the needs of existing and new loads connected to the network. These needs are long term in nature (more than 20 years), extending beyond the expected commissioning dates of new generating capacity.

The IRP is the basis for the demand forecast and generation pattern at a national level for the country, however, it does not provide a spatial view on the demand growth, nor the new generators expected to connect to the system. Hence, the TSP is responsible to “disaggregate” both the demand forecast and generation pattern spatially / geographically across the network. This information is then used by the TSP to evaluate network expansion requirements to meet the country’s anticipated electricity demand and generation connection requirements. Generation and demand forecasts are utilized in developing and maintaining the power system studies database for use in simulation studies.

4.2.2.4 Issuing quotations for new and modified connections

NTCSA (Transmission) is required by the Grid Code to issue quotations to customers for new or modified connections to its network. In terms of the Grid Code and license, the network customer base consists of distributors, end-use customers and generators connected directly to its network.

Customer Services manages the interface with large end-users, generators, municipalities / metros and users who are connected directly to the transmission system. The pricing policy regarding the preparation of quotes is dependent on the nature of the quotation required.

A quote for network service only with indicative capital costs, without obligation for connection service, is provided at a nominal charge. NTCSA’s costs for such quotes are limited to man-hours expended on engineering studies to define project scope and rudimentary desktop design work. When only a network service quote is needed, a load flow and fault level study are all that is required to confirm that the customer’s new requirements are within the delivery capability of the existing network.

A budget quote for a connection service, however, requires detailed design work, site visits, geotechnical surveys etc. to accurately define the scope of work. Since this incurs significant additional expenses, a fee is levied (whether the quotation is accepted or not) to ensure that these costs are not borne by other customers. If the quote is accepted, the costs are capitalised against the project and factored into the connection charge levied to the respective generator, distributor, or customer. Irrespective of whether the customer accepts the quote, these costs are financed outside the regulatory allowed revenue for operational expenses.

4.3 System Operator

As part of its responsibilities to maintain power system reliability, the System Operator (SO) is required to ensure the provision of appropriate ancillary services. The extent of these services and the way they are to be provided is defined in the South African Grid Code. The ancillary services as defined currently are:

- Reserves;
- System Restoration (Black-Start, Self-Start and Islanding);
- Reactive Power and Voltage Control; and
- Energy Imbalance.

The detailed requirements of each service are described in the Ancillary Services Technical Requirements document and the related revenue requirement is as detailed in chapter 6.

4.3.1 Reserves

The SO procures the required reserves from the selected generators connected to the grid as well as from the loads that forms part of the demand response program. It is important to note that Demand Response as highlighted here, is purely for system reliability purposes and should not be confused with energy efficiency programs such as Demand-Side Management (DSM). The reserves cost also cater for service provision from new technologies including battery energy storage as well as IPPs. The different supply side reserves categories are described as follows.

a) Instantaneous Reserve

Instantaneous reserve is generating capacity or demand side managed load that must be fully available within 10 seconds to arrest a frequency excursion outside the frequency dead-band. This reserve response must be sustained for at least 10 minutes. It is needed to arrest the frequency at an acceptable level following a contingency, such as a generator trip, or a sudden surge in load. Generators contracted for instantaneous reserve are also expected to respond to high frequencies (above 50.15 Hz) as stipulated in the South African Grid Code.

b) Regulating Reserve

Regulating reserve is generating capacity or demand side managed load that is available to respond within 10 seconds and is fully activated within 10 minutes. The purpose of this reserve is to make enough capacity available to maintain the frequency close to the scheduled frequency and keep tie line flows between SAPP control areas within schedule.

c) Ten-minute Reserve

Ten-minute reserve is generating capacity or demand side managed load that can respond within 10 minutes when called upon. It may consist of offline quick start generating plant (e.g., hydro, or pumped storage) or demand side load that can be dispatched within 10 minutes. The purpose of this reserve is to restore Instantaneous and Regulating reserve to the required levels after an incident.

d) Emergency Reserve

Emergency reserves should be fully activated within 10 minutes. Emergency reserves include interruptible loads, generator emergency capacity (EL1), and gas turbine capacity. Emergency reserve capacity is required less often than Ten-minute reserve. The reserve must also be under the direct control of National Control. These requirements arise from the need to take quick action when any abnormality arises on the system.

e) Supplemental Reserve

Supplemental reserve is generating or demand side load that can respond in 6 hours or less to restore operating reserves. This reserve must be available for at least 2 hours. This capacity is used to ensure an acceptable day-ahead risk.

The following reserves are obtained from demand response:

a) Instantaneous Reserve

Instantaneous Reserve from demand response (IDR) is consumer load contracted to respond to a fall in frequency. The purpose of Instantaneous Reserve is to arrest the frequency at acceptable limits following a contingency, for example a generator trip. It must respond fully within 10 seconds and must be sustained for at least 10 minutes.

b) Supplemental Reserves

Supplemental demand response (SDR) reserve is a load capacity used to ensure an acceptable day-ahead risk and to allow time for cold reserve plant to be called up. This reserve is available for at least two hours. Contracted customer loads are required to respond within a notice period of 30 minutes to six hours to restore other reserves. This reserve remains utilised until it can be replaced by other capacity or for a maximum duration agreed with the supplier. It is contracted annually with the supplier and bid available day-ahead.

The table below outlines objectives, typical time of use and trigger conditions for demand response services required by SO.

TABLE 16: NTCSA: DEMAND RESPONSE PRODUCTS

PRODUCT	SERVICE	OBJECTIVE	TYPICAL TIME OF USE	TRIGGER CONDITION
Instantaneous DR	Reserve	Arrest rapid frequency decays	24 hours	Under frequency / Over frequency
Supplemental DR	Reserve	To cater for generation capacity losses in the short term (hours to a day)	Summer/ Winter System Peak Hours	Capacity shortage to meet demand and operating reserve requirements

The demand response resource is one of the tools that the System Operator uses to ensure power system reliability. The funding for demand response should be viewed independently from DSM requirements.

4.3.2 Black-Start, Self-Start and Islanding

Black-Start capability is the provision of generating capacity that, following a system collapse (black out), is able to start without an outside electrical supply, energize a defined portion of the transmission system so that it can act as a start-up supply for other capacity to be synchronized as part of a process of re-energising the transmission system.
Self-start is the ability of a power station to start up without an off-site supply, energise a portion of the transmission system to supply load.

The SO procures black-start capability from selected power stations/facilities connected to the power system – at present there are three contracted black-start facilities on the transmission system. Self-start is a new ancillary service and will be procured from selected power stations/facilities connected to the power system.

The SO has determined that with the increase of generation over the coming years, along with the change in generation technology mix, it will be important to procure further black-start and self-start facilities in strategic areas. This will enhance the existing system restoration capability by reducing overall restoration time with additional facilities.

Unit Islanding is the capability of a generating unit to disconnect from the Transmission system by the opening of the High Voltage (HV) breaker and to automatically control all the necessary critical parameters sufficiently to maintain the turbine-generator at the desired speed and excitation, hence supplying its auxiliary load without external supply for a specified amount of time. The SO procures unit islanding capability from selected generating units connected to the power system.

4.3.3 Reactive Power and Voltage Control

In addition to supplying real power, service provider facilities provide reactive power and voltage control to the transmission system. Generators routinely supply or absorb reactive power as necessary to maintain voltage and stability on the transmission grid. Generators can provide this service when generating power (normal operation) and supply reactive power when not generating, that is during Synchronous Condenser Operation (SCO) mode. Pump storage facilities are also capable of providing reactive power and voltage control support when operated in pumping mode.

4.3.4 Energy Imbalance (Constrained generation)

The South African Grid Code defines the Constrained Generation Ancillary Service (CGAS) as follows:

"Constrained generation is the service supplied by a power station to the National Transmission Company (NTC) by constraining its power output below (alternatively above) the unconstrained schedule level. The service is required to ensure the interconnected power system (IPS) remains between appropriate operational limits (e.g. thermal, voltage or stability limits). In providing the service, the power station experiences a financial loss, for which it shall be compensated by the NTC, based on the additional cost incurred by the Service Provider."

4.3.5 Power Alert

Power Alert is a voluntary residential demand reduction project broadcast on selected communication channels, during the evening peak period (between 17:00 and 21:00). The Power Alerts inform the public about the real-time electricity network status and requests electricity users to switch off appliances when the system is constrained. The SO schedules Power Alert before Eskom's emergency reserves. The Power Alert project is seen as a cost-saving tool (economic dispatch) as it reduces the need to use expensive peaking stations.

4.4 Risks and Challenges

The following factors have the potential to affect operational costs and capital expenditure over the 5-year period:

- Ageing network
- Security risks and theft
- Economic growth and reliability requirements
- Market forces and commodity price volatility
- Exchange rate volatility
- Bad debts
- New equipment and technology
- Servitude acquisitions; and
- Future Ancillary Services requirements

4.4.1 Ageing network

Transmission assets are ageing and thereby raising the probability of increased equipment failure due to deteriorating asset condition. This requires increased asset condition monitoring and assessment to manage the risk for unplanned failures. This results in increased unplanned maintenance and restoration workload, the costs of acquiring and holding spares as well as the extent of network asset replacement. NTCSA uses asset management processes to manage its ageing asset base and prioritise asset replacement expenditure.

4.4.2 Security risks and theft

The physical security of assets is a considerable challenge in an environment where there is an escalation of conductor / material theft incidents as well as malicious damage to property. In addition, increased risks to staff and contractor safety have necessitated the introduction of improved security measures.

Additional investment will be made to upgrade prioritized substation security systems nationally. This will include investments for the upgrade of perimeter fencing, installation of surveillance cameras, the upgrading of security control centres supported by the placement of additional security personnel at key substations and armed response services for security incidents.

4.4.3 Economic growth and reliability requirements

Notwithstanding the economic downturn and subsequent reduction in electricity demand, network studies have indicated that parts of the network still require strengthening to meet Grid Code reliability requirements. Investments in infrastructure will consider long term demand forecasting.

4.4.4 Market forces and commodity price volatility

Delivery of the Transmission Development Plan can be impacted by higher commodity prices and increased international demand trend for high-value transmission technical plant resulting in higher asset creation costs and project execution delays.

4.4.5 Exchange rate volatility

Most of the equipment and spares used in the transmission network are imported and therefore subject to the effect of exchange rate fluctuations. Exchange rate volatility has a material impact on the cost of capital projects.

4.4.6 Bad debts

The EDM debt remains a challenge in the International Trader business operations. The matter has been escalated to the Ministry of Energy and Electricity with a request for assistance to address the matter with their counterparts in the government of Mozambique. In this current application there is an allowance of 2% bad debt which is included in the overall Eskom allowable revenue (including NTCSA). The NTCSA will make every effort to ensure that the recovery of any outstanding debt is made from both local and international customers.

4.4.7 New equipment and technology

Newer technologies change the way maintenance is performed and often reduce the level and frequency of required maintenance. The change, however, often drives up initial operating costs: maintenance staff must be trained, new maintenance techniques developed, and new maintenance tools and instruments need to be acquired. As technology evolves, supplier’s ability to support older technologies reduces and this impacts the price of spares.

4.4.8 Environmental requirements - Timelines

NTCSA is required to conduct EIAs on all line and substation projects unless an exemption is granted. It is not possible to predict in advance how long an EIA process will take or what its outcome will be. The outcome of the EIA study, public review and appeal process may therefore affect the timeline and scope of a project materially.

4.4.9 Safety requirements

The safety of staff is non-negotiable. Work in the transmission sector poses inherent safety risks and appropriate investment must be made in safety training and equipment. Measures have been put in place to mitigate known high risks. These include the provision of specialised equipment such as live line tools, fall arrest systems etc. The evolving regulation requirements for construction activities impact skills requirements and associated project execution costs.

4.4.10 Servitude acquisitions

Even after a Record of Decision for EIAs has been obtained, servitude acquisition negotiations are challenging as the line route may pose impacts for the landowners, traverse, or encroach on sensitive areas such as national and private game parks, heritage sites and burial grounds. In some instances, expropriation of land may be required if landowners refuse to grant access. Where appropriate, NTCSA pursues strategic servitude acquisitions in order to reduce timeframes.

4.4.11 Future Ancillary Services requirements

The increased penetration of non-synchronous generation like wind, solar and Battery Energy Storage, coupled with the displacement of large conventional power generating sources by variable renewable energy, introduces different challenges to the power grid. As a result of this, voltage control, inertia and short circuit power will be impacted, and the power grid could potentially become weaker. Restoring the future power system in the unlikely event of a blackout is also anticipated to introduce new challenges that will need to be mitigated by updated strategies for system restoration. There will be a profound impact on frequency control as well. Other significant changes to the Electricity Supply Industry (ESI) such as the unbundling of Eskom, the increase in IPPs, and the introduction of the market code as part of the transition to an energy and ancillary services market will also have a direct impact on the flexibility of the power system, and ancillary services required to ensure reliability. The SO will closely monitor these developments whilst continuing to research international developments and best practices. This may lead to the introduction of new ancillary services products and/or new costing methodologies which could impact both the current and future revenue applications.

5 Network Revenue Requirement Components

5.1 Regulated Asset Base, Depreciation and Return

This section covers the regulated asset base (RAB) and components of the RAB (return on assets and depreciation) as included in the allowable revenue formula:

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

5.1.1 Regulatory Asset Base (RAB)

The Regulatory Asset Base (RAB) is defined as assets of the regulated business that are 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 a 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, NTCSA 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.

The summarized NTCSA RAB application is included in the table below.

TABLE 17: NETWORK BUSINESS: REGULATORY ASSET BASE

Network Business: Regulatory Asset Base (R'm)	MYPD 5 Decision FY2024	MYPD 5 Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Depreciated Replacement Costs (DRC)	86 535	80 850	75 385	70 026	64 844	59 831	55 050
Assets Transferred to CO	14 618	8 656	29 475	52 229	87 626	131 491	171 621
Work Under Construction (WUC)	11 920	11 278	24 327	36 689	37 450	38 614	35 635
Net Working Capital	1 361	1 545	1 515	1 250	-17	237	440
Assets Purchases	21	20	1 231	1 384	1 510	1 617	1 700
Assets funded upfront by cust.	-462	-454	-494	-366	-238	-110	18
Closing RAB	**113 993**	**101 895**	**131 438**	**161 211**	**191 175**	**231 680**	**264 464**
Average RAB		**107 945**	**116 667**	**146 325**	**176 193**	**211 428**	**248 072**

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 transmission 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 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.

5.1.2 Depreciated replacement costs

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

TABLE 18: NETWORK BUSINESS: FIXED ASSETS – DRC VALUES

Network Business: Fixed Assets - DRC Values (R'm)	MYPD 5 Decision FY2024	MYPD 5 Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Opening balance	92 372	86 536	80 850	75 385	70 025	64 844	59 831
Inflation on opening balance	-	-	-	-	-	-	-
Transfers from Work Under Construction (WUC)	-	-	-	-	-		
Depreciation	-5 837	-5 686	-5 465	-5 360	-5 181	-5 014	-4 781
Closing Fixed Assets Values (DRC)	**86 536**	**80 850**	**75 385**	**70 025**	**64 844**	**59 831**	**55 050**

5.1.3 Work under construction (WUC) and Assets Transferred to Commercial Operation (CO)

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.

5.1.4 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. The Table below reflects the revenue related to depreciation for the MYPD 6 period.

TABLE 19: NETWORK BUSINESS: DEPRECIATION

Network Business: Depreciation (R'm)	MYPD 5 Decision FY2024	MYPD 5 Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Existing Fixed Assets	5 837	5 686	5 465	5 360	5 181	5 014	4 781
Fixed Assets - Transfers to CO	777	1 217	816	1 372	2 385	3 806	5 369
Asset Purchases	5	5	308	346	377	404	425
Assets funded upfront by customers	-23	-23	-128	-128	-128	-128	-128
Total Depreciation	**6 596**	**6 885**	**6 461**	**6 949**	**7 816**	**9 096**	**10 447**

5.1.5 Assets excluded from RAB

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

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

5.1.6 Return on Assets

The return on asset included in the MYPD6 application is shown in the table below. NTCSA is applying for 4%, 5% and 6% ROA for 2026, 2027 and 2028 respectively. 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 is the phasing that NTCSA has to make to allow 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.

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.

TABLE 20: NETWORK BUSINESS: RETURN ON ASSETS

Network Business: Return on Asset	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Average RAB (R'm)	116 667	146 325	176 193	211 428	248 072
Real pretax WACC %	11.4%	11.4%	11.4%	11.4%	11.4%
Cost Reflective RoA (R'm)	13 300	16 681	20 086	24 103	28 280
RoA Applied for RoA %	4.00%	5.00%	6.00%	7.47%	9.69%
RoA Applied for (R'm)	**4 667**	**7 316**	**10 572**	**15 802**	**24 048**

Credit rating scores are a crucial indicator of an entity's capacity to fulfil its debt service commitments, a major factor in determining the cost of borrowing and the necessity of credit enhancement or guarantees, and a crucial tool for capital-intensive businesses that depend on debt raising to fund capital development. As NTCSA embarks on a network expansion programme it must ensure that its credit ratings are improved to investment grade so that the market will be willing to lend money and therefore avoid the need for government guarantees.

5.2 Operating Costs

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

Operating costs include all costs involved with the day-to-day running of the business. This includes employee costs, maintenance, other expenses, and corporate overheads. It should be noted that these costs are net of capitalisation and therefore represent the costs that are directly recoverable. The costs of operating and maintaining new assets are included in the operating costs. The table below reflects the business operating costs.

TABLE 21: NETWORK BUSINESS: OPERATING EXPENDITURE

Network Business: Operating Expenditure (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Employee Expenses	2 699	3 523	4 118	4 377	4 586	4 772	4 971	5 199
Maintenance	1 087	1 124	1 564	1 675	1 857	1 968	2 039	2 114
Other Operating Expenses	901	1 004	1 056	1 026	990	1 014	1 076	1 141
Corporate Overheads	627	801	739	843	818	947	1 002	1 062
Other Income	-150	-72	-46	-48	-50	-52	-54	-57
Total Operating Expenditure	**5 164**	**6 380**	**7 430**	**7 873**	**8 201**	**8 648**	**9 035**	**9 460**

The projection for the operating costs has considered the importance of driving cost curtailment in line with the turnaround plan to reduce the cost base as well the need to ensure that operational requirements are met. However, It is expected that NTCSA will see an increase in operating and maintenance costs as it begins its build programme as per TDP 2022 which states that over the 10 years to 2032, NTCSA is required to build 14 218km of new transmission lines by 2032 and install 105 865MVA of transformer capacity, equivalent to c.42% of the current power line infrastructure. **The aim is to connect 53GW of new generation capacity.** To this end NTCSA plans to roll out 2 200km and 24 400MVA capacity over the MYPD 6 period to ensure continued stability and access of energy supply.

5.2.1 Employee expenses

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

NTCSA's employee benefit costs are primarily driven by the following factors:

- **Employee number (Volume) -** The NTCSA staff complement is planned to remain static over the MYPD 6 period.
- **Remuneration (Price)** - Eskom reached a three-year collective agreement with its recognised trade unions for annual increase of 7% salary and housing allowance adjustment. The agreement is applicable to all bargaining employees (but excludes all managerial level employees) and must be effected from FY2024 to FY2026
- The NTCSA workforce comprises a significant number of highly skilled professionals, necessitating a retention cost premium. Transmission operations demand specialized expertise in fields such as SO, Grid Planning, Engineering, and the forthcoming establishment of the Market Operator during the MYPD 6 revenue cycle.
- **Cost Saving initiative** – Ongoing operational savings are implemented to reduce employee costs.

5.2.1.1 Employee number

NTCSA's Network business workforce is planned to increase from 3 179 heads in FY2023 to 4 061 by end of FY2025 and projected to remain constant throughout the MYPD 6 control period. The growth is required to close the gap created by increased workload from the implementation of the IRP2019, TDP, modern technologies (especially in the telecoms environment) as well as development of new functional areas within the business such as including market operator and customer services. and the replacement of lost skills. The table below provides a summary of employee benefit expenses and employee numbers.

TABLE 22: NETWORK BUSINESS: EMPLOYEE EXPENSES AND EMPLOYEE NUMBERS

Network Business: Employee Expenses and Headcount	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Employee Expenses (R'm)	2 699	3 523	4 118	4 377	4 586	4 772	4 971	5 199
Employee numbers	3 179	3 768	4 061	4 061	4 061	4 061	4 061	4 061

Following its legal separation, the NTCSA must independently resource itself across various functional and service areas to fulfil its new and expanded mandate. These include:

- Increasing resources within Grid, projects, and engineering functions to deliver on the revised TDP 2023-2032 objectives, which necessitate an accelerated execution of grid expansion projects. The increased asset creation in support of the IRP 2019 and asset replacement to sustain network demands underscores the need for a skilled and well-equipped workforce.
- Establishing and allocating resources to Customer Service unit to enhance the customer experience and ensure equitable and non-discriminatory grid access for both load and generation customers
- A fully resourced Energy Market Services department will be essential to offer novel services tailored to the evolving electricity supply industry. This includes establishing business units like the Market Operator (MO), a Central Purchasing Agency (CPA), and expanding energy planning initiatives
- Appropriate resourcing of the security function is imperative to safeguard Transmission assets and ensure the safety of the workforce.
- Adequately resourcing support functions like Legal Services, Finance, Human Resources, and Procurement will be pivotal to ensure smooth and efficient operations

To ensure that Transmission is sufficiently staffed and meets the necessary skill requirements, both external recruitment and the learner pipeline will be utilized to fill vacancies. These efforts will prioritize sourcing critical skills such as engineers, artisans, technical officials, technicians, and operators.

5.2.1.2 Remuneration adjustment

Eskom’s remuneration philosophy

Eskom’s general approach to remuneration and benefits is designed to attract and retain skilled, high-performing employees. This is done by providing market-related remuneration structures, benefits, and conditions of service, within the guidelines set by the shareholder in order to remain competitive. Furthermore, Eskom must adhere to the conditions outlined in the government's debt relief programme, which stipulates that Eskom should refrain from implementing remuneration adjustments that could have a detrimental impact on its overall financial position and sustainability.

Trade Union Agreement

In June 2023, Eskom reached a three-year collective agreement with its recognised trade unions. The agreement was implemented from 1 July 2023 and ends on 30 June 2026 for all permanent bargaining unit employees. The agreement excludes managerial/professional and senior management level employees which make up ~40% of NTCSA workforce. The three-year collective agreement is as follows:

- Salaries - Eskom shall increase salaries of all bargaining unit employees by 7% across the board for the FY2023, FY2024 and FY 2025
- Housing allowance – 7% increase on monthly housing allowance of all bargaining unit employees for the FY2023, FY2024 and FY 2025
- A once off taxable payment of R10 000 shall be made to all bargaining unit employees, in FY2023 and FY2024

This agreement is anticipated to provide room for all stakeholders to stabilize the business and concentrate on the recovery of Eskom's operations. Transmission remains committed to optimizing employee numbers by ensuring reasonable employee benefit costs while driving productivity enhancements in operations. The goal is to retain critical and core skills, fostering a motivated and high-performing workforce capable of addressing both current and future operational requirements. For subsequent years the salary increase is assumed for all employees to be CPI.

Specialised Skill Profile and Retention

Eskom jobs are categorised according to five skill levels namely, basic, discretionary, specialised, tactical strategic, professional and the remuneration will also be differentiated according to the skill level. The NTCSA workforce profile differs from other areas within the Eskom value chain, with 92% of its workforce operating at skilled levels. This suggests that the average cost to company per employee will be relatively higher within Transmission.

5.2.1.3 Cost Saving Initiatives

NTCSA acknowledges the necessity of implementing diverse operational strategies to aid in delivering affordable and sustainable electricity supply. To this end, efficiency opportunities are pursued to mitigate the financial impact of increasing employee numbers. Savings initiatives such as overtime reduction, implementation of in-house training programmes and the utilisation of virtual training platforms are being pursued. These initiatives collectively contribute to the reduction of employee expenditure.

5.2.2 Maintenance

5.2.2.1 Background and maintenance costs

NTCSA performs maintenance on its network assets with the primary objective of ensuring high levels of network availability, enhancing asset reliability, extending the life of assets, improving the quality of supply to customers, complying with regulations, prioritizing safety for both people and the environment, and ultimately contributing to the long-term sustainability of NTCSA.

Maintenance is planned and executed in accordance with maintenance processes, standards and procedures, giving due consideration to environmental management and Occupational Health and Safety Act requirements. The maintenance planning, scheduling, execution and control activities are performed using the SAP Plant Maintenance system. Maintenance outages are scheduled by evaluating network risks and identifying opportunities for outage optimisation. The bulk of maintenance tasks are executed by NTCSA employees, whilst some work is contracted out to service providers or original equipment manufacturers (OEMs), considering efficiencies or the specialised nature of the work. The table below summarises the breakdown of NTCSA's maintenance costs.

TABLE 23: NETWORK BUSINESS: MAINTENANCE COSTS

NTCSA: Maintenance Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Servitude Maintenance	192	204	274	301	336	347	360	373
Line Maintenance	236	255	358	383	429	462	479	496
Primary Plant Maintenance	221	233	309	335	365	388	402	417
Secondary Plant Maintenance	47	50	77	87	113	142	147	153
Equipment & Spares	17	20	36	38	50	52	54	56
ERI (Transformer & Logistics)	344	337	465	485	514	528	547	567
Other	30	26	45	46	49	49	51	53
Total Maintenance	**1 087**	**1 124**	**1 564**	**1 675**	**1 857**	**1 968**	**2 039**	**2 114**

5.2.2.2 Maintenance strategy

NTCSA follows a reliability and risk-based proactive maintenance approach, aiming to minimise the risk of asset failures. The maintenance approach predominantly results in time-based condition monitoring tasks, such as inspections and tests to assess asset conditions and to initiate further maintenance actions for restoring the asset conditions. Other resulting maintenance tasks are preventative maintenance tasks based on time. Consideration is given to the asset health, operational information, performance information, statutory requirements, and the safety of the people, the environment, and the assets.

The maintenance strategies are documented as maintenance standards with associated procedures. The maintenance workload is influenced by the size of the network and the condition, age of assets. Recommendations from incident investigations requiring modifications to existing standards and procedures, serve as additional input during the revision of the standards.

Live line maintenance is utilized to overcome planned outage constraints or during emergencies. This requires specialized skills and equipment which has an impact on maintenance costs.

5.2.2.3 Maintenance cost drivers

Constraining maintenance expenditure will lead to cost savings in the short term but could adversely impact sustainability of the Transmission system over the medium to long term. Risks of constrained maintenance expenditure include the escalation of equipment failures and reduced network reliability.

The following maintenance cost drivers were considered in the compilation of the Transmission plant maintenance plan:

a) Increased Transmission System Asset Base

Over the past five years, the assets of the transmission system (kilometres of lines and substation plan) have grown. This expansion has led to increased maintenance workload, such as:

- Additional operating workload at new substations or substations extensions
- Additional inspection and maintenance tasks for lines (both aerial and ground-based)
- Additional primary plant inspections and maintenance tasks

b) Age Profile of Transmission System Assets

A high percentage of NTCSA assets are beyond mid-life requiring increased major maintenance; Refer to the figure below for more information on the asset age profiles.

c) Improving and Sustaining System Reliability

Challenges have been experienced in recent years with the execution of line servitude vegetation management due to procurement delays. This resulted in variances as well as the undesired increased number of line faults due to veld fires. The objective is to normalize vegetation management practices to achieve line fault performance improvement. This will result in increased line maintenance expenditure going forward.

A high level of maintenance execution is required to ensure plant availability and technical sustainability.

5.2.2.4 Maintenance cost escalation

Apart from addressing major maintenance work, which was hindered by the challenges mentioned above, the increased expenditure is also required:

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

5.2.2.5 Maintenance plan

A detailed technical maintenance plan is prepared for every activity in each major equipment category. The activities are carried out in terms of the prescribed maintenance standards and procedures, as summarized in the table below.

TABLE 24: NETWORK BUSINESS: HIGH LEVEL MAINTENANCE ACTIVITIES PER MAJOR EQUIPMENT CATEGORY

Equipment Category	Maintenance Activities
Transmission lines	Line ground patrol; line air patrol & line maintenance
Servitudes	Servitude inspection & servitude maintenance
Transformers & reactors	Monthly inspection; oil sampling; defect repairs & tap changer maintenance
Compensation equipment	Maintenance of shunt & series capacitors & static VAR compensators; (These include series cap platform & system check; shunt cap infrared scanning & SVC bay maintenance & inspection)
HVDC	Apollo radiator cleaning; Apollo fan maintenance; Apollo motor MOT; Apollo oil level checks; etc.
Circuit breakers	Breaker preventative maintenance & major overhaul
Disconnectors / bus equipment	Maintenance of isolators; earth switches; instrument transformers surge arresters & other busbar hardware. (These include bay maintenance; isolator major overhaul; isolator preventative maintenance; silicone treatment; surge arrester greasing; CT care & bay maintenance).
Protection equipment	This includes the functional testing of protection schemes
Metering & measurement equipment	Maintenance of metering & measurement equipment
Control equipment	This includes the functional testing of control equipment (i.e. station ERTU; the IDF; RTU, Station MMI; etc.)
Teleprotection equipment	This includes work on teleprotection (i.e. power line carrier equipment & digital radio links)
Security system	Maintenance of security fence; fence electrifies & security gates
Auxiliary supplies	Battery charger maintenance; battery inspection & battery maintenance
Substation auxiliay equipment	Air conditioner inspection & maintenance; air pressure vessels maintenance, air supply system inspection & compressor inspection & maintenance
Substation general	This includes all maintenance work that is carried out but cannot be logically tied to the above groups of plant (i.e. building maintenance, earth mat continuity check; fire fighting equipment check; link stick calibration & maintenance; substation label maintenance; etc.)

5.2.2.6 Major operating projects expenditure (non-repetitive)

Non-repetitive maintenance includes recovery work following major incidents or plant failures as well as major maintenance or repair activities that do not form part of routine maintenance plans. Unlike routine maintenance, it is difficult to predict when these incidents will occur and, therefore, funds have to be put aside to cater for them. A risk assessment is performed annually on major categories of equipment to gauge the possibility of failure and identify how to mitigate the risks. Examples of non-repetitive maintenance activities include:

- Repairing of major transformer oil leaks
- Replacement of transformer oil, which includes drawing of vacuum and filtering
- Replacement of corroded components, and corrosion repairs and treatment

5.2.3 Other operating costs

The escalation of other operating costs is primarily driven by projected growth in NTCSA's asset base and number of employees as well as the ongoing legal separation. These cost drivers have a direct impact on IT, security, travelling, lease expense, insurance as well as electricity consumption. Other operating costs will remain constant throughout the MYPD 6 period, even with the anticipated restructuring and separation process and the associated costs, as the Transmission division transitions into the NTCSA.

Other operating costs are summarized in the table below. Details per category are included in the following sections.

TABLE 25: NETWORK BUSINESS: OTHER OPERATING EXPENSES

Network Business: Other Operating Expenses (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Insurance Premiums and repairs	198	359	319	334	350	367	383	401
Security Expenses	216	167	187	193	242	172	180	188
IT Expenses	41	145	138	145	151	158	165	172
Telecommunications	66	74	84	88	92	96	96	96
Travel Expenses	71	77	93	97	100	103	108	113
Consulting and Legal Costs	52	127	153	141	148	194	203	212
Facilities	29	80	106	111	116	121	127	133
Leases	20	26	28	30	31	33	34	36
Internal Electricity Costs	31	38	53	70	77	83	87	90
Abnormal Costs	364	-	-	-	-	-	-	-
Other	-187	-90	-106	-183	-318	-314	-307	-300
Total	**901**	**1 004**	**1 056**	**1 026**	**990**	**1 014**	**1 076**	**1 141**

5.2.3.1 Insurance

The increase in asset base and staff has a causal effect on the escalation of the insurance premiums. Factors that influence insurance cover and pricing include:

- Increased transmission system asset base as well as telecommunications network asset transfer
- Insurance claim trends or loss ratio performance
- Value of the insurance excess
- 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

The transmission network expansion program proposed in the 2023 TDP will increase the size of the plant, leading to higher insurance premiums due to the increased value of assets. Current insurance policies for NTCSA cover various areas, including all asset risk, terrorism, motor and mobile plant fleet, aviation-related risks, supply interruption, environmental liability, and general and public liability.

5.2.3.2 Travel and fleet costs

Travel expenses include both the local and international business travel undertaken by employees in the operational course of business or to attend training and meetings on behalf of NTCSA. Fleet include both vehicles, plant and the aviation assets. The cost structure is reflective of the real cost of service incurred which includes:

- Repairs and Maintenance of the fleet
- Fuel cost
- Licensing
- Administration fees

Both fleet repairs and fuel costs comprises a major portion of the total fleet costs.

5.2.3.3 Telecommunication

Telecommunication costs are projected to remain stable throughout the MYPD 6 period. The following services are covered:

- Operational SCADA information for circuit visibility / controllability in the control room
- Control room communication services
- Enabling remote interrogation of digital fault recorders
- Enabling remote downloading of revenue meters at Transmission boundaries
- Enabling communication with Wide area monitoring devices.

The Telecommunication business unit provides the telecommunications circuits that integrates the energy management system (EMS) with remote terminal units (RTU) at sites. The power network in Eskom spans large geographical areas and RTUs are located in multiple remote locations. This leads to the need to use wide area network (WAN) technologies for communications exchanges between RTU's and the EMS at the control centres.

A reliable telecommunication network is of outmost importance to enable visibility and controllability of the power system to the SO. The future implementation of Wide Area Monitoring and Substation Automation will increase the required telecommunication capacities going forward. The increase of NTCSA connected IPP's and embedded generation within Distribution as well as municipal networks will increase the telecommunication requirements going forward.

5.2.3.4 Security Expenses

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

NTCSA has experienced an increase in the number and severity of security incidents necessitating an increase in security expenses to safeguard assets and employees. To address the severity of security incidents within NTCSA, a Security Action Plan was developed. The key objectives of this action plan include the following:

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

In addition to the Security Action Plan, NTCSA is involved in a project that explores technology-based security solutions. This project includes the installation of all-in-one motion sensors that trigger lights and audible alarms. Due to their success, more units have been procured for installation at selected high-risk substations.

Furthermore, NTCSA is upgrading security arrangements at telecommunication network sites owned by Telecommunication. These upgrades aim to safeguard assets and ensure reliable network operation, especially in remote, inaccessible areas where security reaction units are unavailable. NTCSA's security expenses cover a range of services and measures to ensure the protection of assets and personnel:

- **Guarding, Access Control, and Patrols:** Security guards manage access control and patrol sites, including national key points
- **Crime Prevention and Armed Response:** Services for alarm activation responses and overall crime prevention at sites and substations

- **Line Patrols:** Regular patrols of high-risk transmission lines, especially where vandalism occurs or during outages
- **Repairs and Servicing:** Maintenance of control room equipment like screens, monitors, computers, and radios
- **Licensing of Equipment:** Managing licensing, though it does not significantly increase costs
- **Employee Protection and Escorting:** Ensuring the safety of employees performing tower repairs in high-risk areas and escorting staff to respond to plant failures.
- **Tactical Response Teams:** Deploying teams in areas with community protests or volatile situations for enhanced security and stability

NTCSA uses a combination of security guards and technology to protect against copper theft and maintain asset integrity and supply continuity. The high demand for non-ferrous metals has increased the vulnerability of Eskom facilities to vandalism and theft, making this hybrid security approach essential.

The provision of security personnel mitigates the following risks:

- **National Key Points:** Compliance with the National Key Point Act 102 of 1980, requiring security guards at these sites
- **Isolated and High-Risk Locations:** Protection against copper theft, civil unrest, and armed robbery at substations located in isolated or residential areas
- **Energy Supply Continuity:** Ensuring the uninterrupted supply of energy

Consideration is given to both the frequency and impact of security incidents, as a single incident can cause significant damage and supply interruptions. To reduce costs associated with security contractors, NTCSA is adopting a technology-centric approach which includes installing pre-detection cameras, alarm systems, security lighting, and non-lethal electric fences at remote sites.

5.2.3.5 Information Technology (IT)

IT costs are mainly driven by the number of licenses, number of users and the applications used as well as number of laptop/desktop/devices registered in the Configuration Management Database (CMDB). The following services forms part of direct charges:

- Amortization of software and infrastructure
- Vendor support and maintenance fees
- Internal labour costs
- Technical services (which includes infrastructure support, security (information & cyber), service performance management, and end user computing)
- Software annual licencing and support

Charges associated with infrastructure services; end user computing and help desk services are based on the monthly quantities of the various service items included in the contracts.

Software annual licencing and support costs are proportionally charged based on the number of personal computer users. The proportional charges are limited to applications used by NTCSA.

5.2.3.6 Consulting and legal costs

The increase in the provision for consulting and legal expenses during the MYPD 6 period is in anticipation of an upsurge in the need to consult with various professional service providers during the implementation phase of Transmission division legal separation. It must however be noted that external service providers are only appointed in circumstances where such skills are not available within the organisation or where it is prudent to elicit advice/services of an independent body. Consulting and legal costs includes.

- Legal services and support that is required for servitude acquisition negotiations and disputes that arise with the landowners as well as registrations of acquired servitudes.
- Legal services for IPP programme contract establishment, advising on legal disputes and arbitrations (such as arising from curtailment or deemed energy claims).
- Independent professional service providers when acquiring property/servitude rights. This includes Geotech studies, town planning assessments, visual/social impact assessments, property valuation and land surveying. Consultants are also required to assist in planning studies, load forecast studies and an independent review of NTCSA’s planning model.
- Designing services fees to assist with Protection Telecoms Measurement and Control (PTM&C) and engineering designs.

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

5.2.3.7 Facilities

NTCSA manages an expanded property portfolio that spans nationally and includes regional offices and depots within NTCSA Grids. Most of these offices and storage buildings are old and require continuous repairs and maintenance of the buildings and the equipment attached to them.

Facilities expenditure includes cost to service and maintain both owned and leased buildings and facilities. The expenditure incurred are for rates and taxes, municipal services, repairs and maintenance as well as cleaning, hygiene, pest control waste management and horticultural services. Repairs and maintenance represent nearly half of the total facility expenditure.

Repairs and maintenance expenses increase significantly from FY2024 onwards due to the need to undertake major building maintenance which has not been performed due to ongoing financial constraints and delays in concluding technical maintenance service contracts. The major building maintenance includes provision of electrical, air-conditioning, fire systems, fire equipment as well as plumbing repairs. Failure to do this poses a health, safety and security risk for both staff and assets including the strategic spares located in the store yards.
Space planning projects which include creating open plan spaces, and some minor maintenance works must also be undertaken.

5.2.3.8 Leases

Leases are primarily for the rental of offices, storage facilities and Customer Load Network (CLN) buildings where NTCSA does not own sufficient accommodations to support its operations in a particular area.

Aviation operates a fleet of helicopters in support of both NTCSA's and Distribution's Lines teams. Part of Eskom Aviation's mandate is to also provide a fixed wing charter service on an ad-hoc basis. Fixed wing services require an airport with both air traffic control and a controlled runway, compliant with the South African Civil Aviation regulations. These facilities are not practicably owned by NTCSA, but rather sourced from the market.

Leasing costs also incorporate the site sharing expenses for NTCSA telecommunication infrastructure as per the ICASA regulations. The annual rental increases are contractually defined as per the lease agreements and are based on market related escalations.

5.2.3.9 Other

Other costs are inclusive of environmental expenses, safety equipment, stationery, other sundry office expenses as well as both Telecommunication and Aviation cost recoveries from other line divisions.

5.2.4 Corporate overheads

Corporate overheads are costs incurred for services obtained for strategic support and shared services. Corporate functions provide services such as treasury, communications, legal, business planning, etc. to support NTCSA.

5.2.4.1 Direct/Specific Overhead Charge

Direct overhead costs are allocated to the core business using specific, relevant cost drivers for each service provided. These overheads include:

- Shared Services - accounts payable services, payroll, and other HR shared service support functions.
- Information Management
- Eskom Real Estate
- Finance and Other Support Services

Each of these services uses appropriate cost drivers such as employee number, number of invoices processed, or number of purchase orders processed, depending on the nature and relevance of the service being provided. This method ensures that costs are allocated accurately and fairly to the Eskom divisions/subsidiaries.

5.2.4.2 Indirect/General Overhead Charge

Indirect overhead costs, which cannot be directly allocated to a specific division using a distinct cost driver, are shared among the line divisions/subsidiaries using a three-factor formula. The three factor formula (where costs cannot be directly attributable to a specific licensee) is made up of the following:

- Proportion of asset base
- Proportion of headcount
- Operating cost excluding decommissioning provisions.

These overhead costs cover services provided at the group level to optimize resources, leverage synergies, and minimize effort duplication. Services included are corporate advisory, business support, administration, and strategic functions within Eskom's business.

Corporate overheads expenses are grouped into direct corporate overheads and indirect corporate overheads as reflected in the table below.

TABLE 26: NETWORK BUSINESS: CORPORATE OVERHEAD COSTS

Network Business: Corporate Overheads (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Direct Overheads	396	471	539	600	647	689	707	727
Indirect Overheads	231	330	200	242	171	258	295	335
Corporate Overheads	**627**	**801**	**739**	**843**	**818**	**947**	**1 002**	**1 062**

5.2.5 Other income

This includes income derived from leases as well as recoverable projects such as maintenance services provided to third parties. The lease income primarily arises from the site sharing of telecommunication infrastructure as per the ICASA regulations, whereas the sundry income mainly represents the income from providing the usage of telecommunication fibre network.

TABLE 27: NETWORK BUSINESS: OTHER INCOME

Network Business: Other Income (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Insurance proceeds/recovery	(97)	(46)	-	-	-	-	-	-
Operating lease income	(39)	(19)	(31)	(33)	(34)	(36)	(37)	(39)
Sundry income	(13)	(7)	(14)	(15)	(16)	(16)	(17)	(18)
Total Other Income	**(150)**	**(72)**	**(46)**	**(48)**	**(50)**	**(52)**	**(54)**	**(57)**

6 Ancillary Services & Power Alert

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

6.1 Overview

In terms of the MYPD Methodology, the NTCSA System Operator should submit the methodology and models for calculating costs of the Ancillary Services (AS) and Power Alert programmes for consideration by the Energy Regulator.

The SO is responsible for maintaining and managing power system reliability, and therefore, it is required to ensure the provision of appropriate ancillary services. The extent of these services and the way they are to be provided is defined in the South African Grid Code.

The ancillary services currently defined include:

- Reserves (from Eskom Generation, IPP's & Demand Response providers),
- System Restoration (Black-Start, Self-Start and Unit Islanding products),
- Energy Imbalance (Constrained Generation) as well as
- Reactive Power and Voltage Control.

The SO also applies a Power Alert programme which is used during system constraints for consumers to reduce demand during peak hours.The AS and Power Alert costs are summarized in the table below and are based on the volumes as per the Ancillary Services Technical Requirements defined in the Grid Code.

Note that the table below refers to all ancillary services required by NTCSA which includes services provided by IPPs (within the DMRE/EMS programmes and outside the programme) as well as AS provided by Eskom Generation. However, in this application, the Regulator is required to make a separate revenue requirement decision on ancillary services which exclude DMRE/EMS (Energy Market Services) programmes and Eskom Generation as they are catered in the IPP costs and Eskom Generation costs respectively. Kindly refer to Chapter 1 for the revenue requirement.

TABLE 28: ANCILIARY SERVICES REQUIREMENTS

NTCSA: Ancillary Services and Power Alert (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Reserves	337	1 901	2 080	2 303	2 468	919	1 028
Eskom Generation	41	86	90	94	99	103	108
Eskom BESF			24	25	26	27	28
IPP - System Operator Programme	-	1 435	1 445	1 580	1 651	-	-
Demand Response	295	380	521	604	693	789	892
Reactive Power and Voltage Control	278	345	869	874	954	1 343	1 622
Eskom Generation	278	345	401	438	479	525	575
IPPs - System Operator programmes	-	-	468	436	475	594	637
SC (IPPs - DMRE/EMS programmes)	-	-	-	-	-	224	410
System Restoration (Eskom Gx)	57	59	58	61	62	63	65
Energy Imbalance	-	-	376	785	1 689	2 672	3 741
Reliability Services System Costs	35	37	58	61	67	64	62
Power Alert	40	78	78	78	78	78	78
Ancillary Services excluding DMRE/EMS IPP programmes	**746**	**2 419**	**3 519**	**4 162**	**5 319**	**5 139**	**6 596**
IPPs (DMRE/EMS programmes)	-	419	2 084	2 551	2 688	4 746	5 981
Total	**746**	**2 838**	**5 603**	**6 714**	**8 006**	**9 886**	**12 576**

6.1.1 DMRE Section 34 IPP and SO initiated IPP ancillary services programmes

The table above shows the full AS requirements including those that will be procured via the DMRE Section 34 IPP programmes which forms part of the GSFA process. The balance of the IPP ancillary services will be procured as part of SO initiatives which are independent of the DMRE Section 34 process and EMS programmes.

6.2 Assumptions

The following are the assumptions relating to the AS:

- Requirements were based on the latest Ancillary Services Technical Requirements and Eskom Generation Production plan.
- Parameters such as CPI are based on the Eskom Economic evaluation parameters directive.
- Various IPPs that will also be providing ancillary services are expected to come online during the MYPD 6 control period. Related costs are based on latest estimates.
- Synchronous Condenser Operation (SCO) costs are based on the approved FY2024 Wholesale Integrated Selling Price (WISP) rates that have been escalated by 12% in subsequent years, as recommended by the NTCSA Market Operator.
- The costing methodology that will be used in MYPD 6 revenue application is largely the same as the methodology used in MYPD 5 application. Any proposed changes have been explained in the sections to follow.

The SO must be prudent in planning and budgeting for unforeseen events and contingencies that can impact on system reliability. As the SO continues to research local and international developments and best practices, new AS products and new costing methodologies may be introduced, and this could impact the MYPD 6 application. The rationalisation and breakdown of the above costs are provided in the sections to follow.

6.3 Reserves

TABLE 29: ANCILIARY SERVICES RESERVES

NTCSA: Ancillary Services Reserves (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Eskom Generation	41	86	90	94	99	103	108
Eskom BESF	-	-	24	25	26	27	28
IPP - System Operator Programme	-	1 435	1 445	1 580	1 651	-	-
Demand Response	295	380	521	604	693	789	892
Total Reserves	**337**	**1 901**	**2 080**	**2 303**	**2 468**	**919**	**1 028**

To improve the reliability of the power system, the SO has included a provision for an increased quantity of reserves required from Demand Response as well as the procurement of additional reserves from the IPP's and BESF. This has resulted in a significant increase of the reserves from FY2025 onwards.

6.3.1 Reserves from Eskom Generation

TABLE 30: ESKOM GENERATION RESERVES REVENUE REQUIREMENT

Eskom Generation Reserves(R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Instantaneous Reserves	9	10	10	10	11	11	12
Regulating Reserves	11	13	13	14	15	15	16
Ten-minute Reserves	9	10	10	10	11	11	12
Emergency Reserves	13	54	57	59	62	65	68
Total Gx Ancillary Services	**41**	**86**	**90**	**94**	**99**	**103**	**108**

The types of Reserves obtained from Eskom Generation (Gx) are Instantaneous reserves (IR), Regulating reserves (RR), Ten-minute reserves (TMR) and Emergency reserves (EL1).

The costing methodology for IR, RR, TMR reserves from Eskom Gx will be based on the existing costing methodology that has been CPI adjusted. Emergency reserves from Eskom Gx is also based on the existing costing methodology which is performance based and linked to the stations energy charge rate whereby providers are reimbursed for EL1 Energy Sent-out. The associated EL1 costs has increased above CPI based on the increased actual expenditure trends in the FY2024, which are embedded in the Eskom Generation costs.

6.3.2 Reserves from IPP's and BESF

The reliability of the power system has been compromised due to a lack of sufficient reserves. The existing reserves provision is insufficient to meet the quantities defined in the ancillary service's technical requirements due primarily to the ageing Eskom Generation power plants and various technical issues. Therefore, there is a need to obtain additional reserves from new providers such as IPPs and BESF. The SO intends to procure ancillary services from these resources to improve system reliability.

The application is based on cost reflective estimates derived from previous experience with other potential IPPs. It is likely that the estimated rates could change once the actual rates become available from these providers. The application of these estimated cost reflective rates has resulted in a significant increase in the reserves cost for MYPD 6.

Most of the reserves from IPPs will be via the DMRE section 34 programmes. However, the SO has also initiated a programme for the procurement of additional reserves (Ancillary Services Standard Offer Pilot Programme) independent of the DMRE section 34 programmes. The SO is piloting an AS Standard Offer (AS_SO) programme nationally to procure AS reserves (Instantaneous and Regulating Reserves) at standard rates. Qualifying providers that meet the AS technical criteria to provide instantaneous and regulating reserves will be compensated as contracted when dispatched via the SO. The standard offer approach allows the SO to purchase reserves at an established instantaneous and regulating reserves standard rate.

6.3.3 Reserves from Demand Response

Demand response services costs include both energy and capacity payments to customers, as well as the administration charge which covers the costs of providing metering, performance monitoring, payments, project related work, and other equipment needed for service provision as well as administration costs.

The Demand Response (DR) costing methodology for MYPD 6 remains unchanged and it already includes performance-based payments. The DR admin component has been moved from the demand response product category to a new category called "Reliability Services System Costs" (refer to next section for further details). The Instantaneous DR and Supplemental DR costs categories have been adjusted by CPI. However, the overall demand response plan is above CPI due to the need for additional quantities of reserves from demand response providers to help make up for historically low reserve supply. Provision has been made for extra reserves under the "Additional DR Products" category as shown in the table below. Note that the planned costs could be impacted by changes to the terms and conditions of the NPAs held between Eskom Distribution and customers that provide DR. MYPD 6 costs for demand response is shown in the table below.

TABLE 31: DEMAND RESPONSE RESERVES

NTCSA: Demand Response Reserves (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Instantaneous DR	121	156	164	171	179	187	195
Supplemental DR	174	223	244	255	266	278	291
Additional DR Products	-	-	114	178	248	324	406
Administration	-	-	-	-	-	-	-
Total	**295**	**380**	**521**	**604**	**693**	**789**	**892**

6.4 Reliability Services System Costs

Historically, there was an administration component line item under the DR category. This has been CPI adjusted and moved to a new category called reliability services system costs. Apart from the DR admin, an additional provision has been made to develop and manage tools and systems relating to fast frequency response (FFR), load shedding monitoring tool and renewable dispatching under this new category.

TABLE 32: RELIABILITY SERVICES SYSTEM COSTS

NTCSA: Reliability Services System Costs (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
DRAS (formerly DR Admin)	35	28	37	40	42	44	46
FFR	-	3	7	7	12	7	3
Load shedding monitoring tool	-	5	10	10	10	10	10
Renewable dispatching	-	2	4	4	4	4	4
Total	**35**	**37**	**58**	**61**	**67**	**64**	**62**

6.5 System restoration costing

System Restoration Services comprises of Unit Islanding, Black-Start and Self-Start. The SO makes both capacity and variable payments to every station that is contracted to provide Unit Islanding. The cost for Unit Islanding is highly dependent on the performance of the generators. The costs of self-start, which is a new service, are based on the black-start methodology and is dependent on the associated testing plan to be implemented during the MYPD 6 window. The costs for system restoration is shown in the table below.

TABLE 33: SYSTEM RESTORATION

NTCSA: System Restoration (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Black-start (Eskom Gx)	50	51	52	54	56	56	59
Islanding (Eskom Gx)	6	8	7	7	6	6	6
Total	**57**	**59**	**58**	**61**	**62**	**63**	**65**

6.6 Reactive power and voltage control costing

The SO will continue to dispatch SCO units and make use of reactive power provision as required by the system for voltage control and compensate stations accordingly. A provision for reactive power and SCO variable costs from existing providers (Eskom Generation) based on the existing applied costing methodologies has been included in MYPD 6 revenue requirement. The SCO costing methodology is currently under review and could lead to changes such as the introduction of an SCO fixed cost component in future.

Grid planning studies have indicated that there are areas that require additional voltage control support in the form of synchronous condensers (SC) that could be owned by Eskom Gx, IPPs or NTCSA. According to the study, Eskom need to install synchronous condensers by 2026 to ensure system stability. There are two categories of synchronous condenser from IPPs, namely the IPPs which form part of DMRE programmes and those which are part of SO initiated programmes. This has led to a step-increase in the voltage control costs requirements in MYPD 6. The MYPD 6 reactive power and voltage control costsare shown in the table below.

TABLE 34: REACTIVE POWER AND VOLTAGE CONTROL

NTCSA: Reactive Power and Voltage Control (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Reactive Power (Eskom Gx)	137	128	158	167	175	184	193
SC (Eskom Gx)	141	217	243	272	304	341	382
SC (IPPs - SO programmes)	-	-	468	436	475	594	637
SC (IPPs - DMRE/EMS programmes)	-	-		-	-	224	410
Total	**278**	**345**	**869**	**874**	**954**	**1 343**	**1 622**

6.7 Energy Imbalance (Constrained Generation)

The South African Grid Code defines the Constrained Generation Ancillary Service (CGAS) as follows:

"*Constrained generation is the service supplied by a power station to the National Transmission Company (NTC) by constraining its power output below (alternatively above) the unconstrained schedule level. The service is required to ensure the interconnected power system (IPS) remains between appropriate operational limits (e.g. thermal, voltage or stability limits). In providing the service, the power station experiences a financial loss, for which it shall be compensated by the NTC, based on the additional cost incurred by the Service Provider.*"

Various network studies were carried out to determine the constrained generation costs for MYPD 6. The result of these studies is that no constrained generation costs is required for MYPD 6 relating to Eskom Generation.

To reduce the level of unserved energy while still being aligned with climate change objectives, renewable generation will be added to the network beyond regional network limits. While meeting these objectives, this initiative will result in some level of congestion curtailment and possible cost for traditional constrained generation required from the resulting generation redispatch where such redispatch is possible. A provision relating to the compensation of providers that are impacted by congestion curtailment by the SO due to grid constraints has been included in the MYPD 6 application. Congestion curtailment is currently being further investigated and could result in an increased associated AS costs in the near future. The MYPD 6 energy imbalance requirements are shown in the table below.

TABLE 35: ENERGY IMBALANCE

NTCSA: Energy Imbalance (R'm)	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Curtailment (IPPs)	-	-	376	785	1 689	2 672	3 741
Total	**-**	**-**	**376**	**785**	**1 689**	**2 672**	**3 741**

6.8 Power Alert Programme

The SO is responsible for the reliability and security of the South African national electricity grid by monitoring, controlling, and operating it in a safe, economical, and reliable manner. One of the Demand Reduction Programmes available to the SO during system emergencies is the Power Alert Programme. Power Alert is a voluntary residential demand reduction project broadcast on selected communication channels, during the evening peak period (between 17:00 and 21:00). The Power Alerts inform the public about the real-time electricity network status and requests electricity users to switch off appliances, when the system is constrained, thereby reducing their electricity demand during evening peak period.

The Power Alert is typically scheduled and dispatched by the SO before Eskom's emergency reserves are implemented. By placing Power Alert in this merit order, Power Alert is a cost-saving tool (economic dispatch) as it reduces the need to use Eskom's peaking stations (gas turbines).

Historically Power Alert was successful and delivered between 150 and 350 MW peak demand savings, linked to seasonality. This programme predominantly saw support from the residential segment which forms a large portion of Eskom's weekday peak consumption. A projected cost of R78m per year is required to successfully implement this project as reflected in table below.

TABLE 36: POWER ALERT

NTCSA: Power Alert (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Power Alert	40	78	78	78	78	78	78	78
Total	**40**	**78**	**78**	**78**	**78**	**78**	**78**	**78**

7 Energy Losses

7.1 Transmission Technical Losses Overview

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).

Energy loss is an inherent risk in the electricity business and utilities globally are addressing this issue. This energy lost, is approximately equal to the difference between the energy supplied and the energy consumed.

Transmission losses are energy losses incurred when energy is transferred from the generators to the loads. As electricity flows through the transmission network, energy is lost due to electrical resistance and the heating of conductors. The Transmission energy losses (GWh) forecasted for the MYPD 6 period is reflected in the table below.

TABLE 37: FORECASTED ENERGY LOSSES VOLUME

NTCSA: Forecast Energy Losses Volume	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Losses (%)	2.33%	2.20%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Losses (GWh)	4 728	5 163	5 562	5 449	5 364	5 362	5 317	5 284

7.2 Losses forecasting model

The level of transmission losses is influenced significantly by the generation dispatch as well as location and may therefore vary year on year. The following key factors that could have influenced the FY2024 transmission losses trend were considered in the investigation: Load shedding, load changes, network operations and configuration, distributed renewable IPP generation, network strengthening, geographic and generation patterns.

Power flow and statistical studies have shown that there is strong correlation between generation location and transmission losses. The generators in the Mpumalanga and Limpopo regions contribute significantly to losses, while those in the Cape and Karoo regions have a mitigating effect. A forecasting model based on multilinear/multiple regression analysis has been used.

7.3 Transmission Technical Losses Costs

In the process of transporting energy from generators to consumers, the transmission network experiences loss in energy due to heat dissipation. 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. The cost of losses is determined by three key factors: the unit cost of energy, the load profile, and the magnitude of losses incurred. These factors collectively contribute to the overall cost associated with transmission losses.

For information used to derive the above forecasts, refer to the detailed description for Transmission Energy losses as contained in the "*Energy Wheel, Production Plan and Energy Losses*" document.

8 Revenue Related Information - Capital Expenditure

Transmission network needs to be strengthened and expanded to connect new loads and generation to the network to enable country growth. In addition, investments for asset replacement are required for assets which have reached their end of life in order sustain a reliable supply of electricity.

NTCSA (Transmission) requires R 96bn for capital investment over the MYPD 6 period as summarized in TABLE 38 table below. It should be noted that there is an increase in the required investment compared to the previous MYPD control period, which can be attributed to accelerated transformer projects and synchronous condensers and new corridors required to integrate new generation.

TABLE 38: NETWORK BUSINESS: TOTAL CAPITAL EXPENDITURE PER CATEGORY

Network Business: Capital Expenditure (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Strengthening and Expansion	1 899	2 353	5 967	14 263	30 039	31 554	41 143	35 790
Asset Replacement	1 407	1 234	2 055	3 796	5 270	6 269	6 923	6 530
EIA and Servitudes	64	230	589	1 704	1 178	720	769	200
Production Equipment	173	847	543	299	499	503	512	508
Total	**3 543**	**4 663**	**9 154**	**20 063**	**36 987**	**39 046**	**49 347**	**43 027**

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

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

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

NERSA has published rules in the Grid Code governing investment in the transmission network. NTCSA plans the network according to the Grid Code and subject to funding & other resource constraints, builds the network in alignment with the Transmission Development

Plan (TDP). Where insufficient funds are available for required network investments, a consistent set of rules is applied to prioritise projects and allocate funding in such a way that the maximum benefit is gained for customers.

8.1 Transmission Development Plan (TDP)

NTCSA is mandated by NERSA through the Grid Code to annually publish a five-year-ahead transmission system development plan. This plan addresses the need for a stable and sustainable transmission network, integrating new generation capacity and meeting load requirements while maintaining reliability standards.

In 2023, NTCSA was exempted from publishing the TDP due to the ongoing finalization of the new Integrated Resource Plan (IRP) by the Department of Mineral Resources and Energy (DMRE). The TDP 2022, published in October 2022, remains valid, projecting the need for 53GW of new generation capacity by 2032, primarily from renewable sources like solar and wind.

TDP2022 states that over the 10 years to 2032, NTCSA is required to build 14 218km of new transmission lines by 2032 and install 105 865MVA of transformer capacity, equivalent to c.42% of the current power line infrastructure. To this end NTCSA plans to roll out approximately 3 470km and 30 360MVA capacity over the MYPD 6 period to ensure continued stability and access of energy supply. This is a significant ramp up from the historic 300km per year to an average of approximately 1 150km per year in the next three years.

The TDP is crucial for planning capital expansion investments, replacement of aging assets, and other support infrastructure such as telecommunications and production equipment. These investments ensure the transmission network's reliability, efficiency, and capacity to meet future demands. Failure to deliver on TDP will have severe consequences, including difficulties in integrating renewable energy in areas with limited network capacity, inability to meet new generation capacity requirements and postponement of essential asset replacements. These issues will ultimately compromise the stability, reliability, and sustainability of the transmission network.

NTCSA is committed to ensure that TDP is delivered in an efficient and cost-effective manner.

8.2 System Strengthening and Expansion

With reference to the table above this section describes the details regarding the planned strengthening and expansion investment of approximately R76bn over the MYPD 6 period.

The TSP is responsible for planning the expansion of the Transmission System (TS) in accordance with the South African Grid Code published by NERSA. Fundamental to this is the provision of non-discriminatory access to the grid for both load customers as well as generators. In determining the future expansion needs of the TS, due consideration is given to the IRP in determining the demand forecast and generation pattern for the country. The key drivers for augmentation of the TS therefore include:

- Planned new customer connections (load customers and generators)
- Reliability investments (N-1) to resolve existing / anticipated future network constraints
- Mitigation of existing and future fault level exceedances
- Resolution of quality of supply excursions
- Legal / Statutory Compliance (regulatory, safety, environmental etc.)

The TSP annually publishes a 10-year TDP which provides a list of identified projects and associated costs. The 2022 TDP, covering the period 2023 – 2032, will be used as the foundation for NTCSA’s capacity expansion plans over the MYPD 6 period. The following new infrastructure has been added to the TS in recent years:

- Harrismith Strengthening Phase 1
- 400 kV Line Deviations over Landau Colliery Sinkholes
- Benburg Substation 3rd 250 MVA 275/132kV Transformer

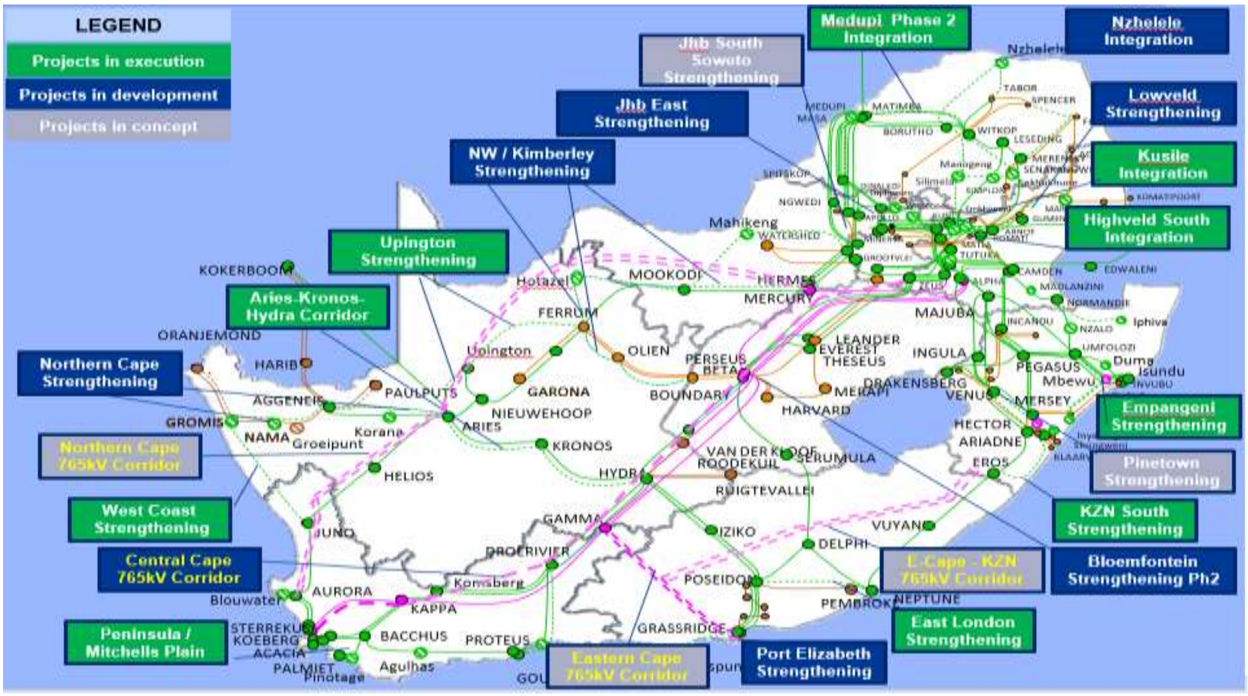
Over the next 5-year period, a substantial amount of NTCSA infrastructure is planned for construction across the country as illustrated in the figure below. Some of the major projects include:

- Medupi and Kusile integration: completion of the NTCSA infrastructure to fully integrate these power stations
- Lowveld and Highveld strengthening projects: completion of the 400 kV network strengthening towards Marble Hall, Middelburg, Nelspruit and Secunda
- Tshwane network strengthening: increasing the power transfer capacity to meet the growing demand of the Metropolitan municipality
- Johannesburg South and East strengthening: increasing the power transfer capacity by introduction of additional 400kV networks into the Germiston and Lenasia / Soweto areas

- KZN strengthening: phase 2 of the introduction of 765kV from Mpumalanga to Empangeni
- South Coast Strengthening: strengthening of the existing 400 kV corridor on the south coast of KZN
- Makalu Strengthening: This project involves establishing Igesi 275/88 kV substation to deload Makalu substation. It will also assist in reducing the network fault levels around Makalu substation
- Northern Cape strengthening (Kimberley and Upington): phase 2 of the 400 kV integration into the region to provide capacity for the potential RE generation in the area.
- West Coast strengthening: integration of the 400 kV network between the Western Cape and Northern Cape provinces from Vredendal to Oranjemond
- Cape Peninsula strengthening: introduction of 400 kV into the Mitchells Plain area

In addition to the above-mentioned schemes, a large number of corridor and transformer projects are being developed and expedited to go into execution in the next five to ten years and some of these are shown in the figure below.

FIGURE 6: PLANNED MAJOR PROJECTS



8.2.1 Planned strengthening and expansion projects

This section includes an overview of projects planned for execution over the MYPD 6 period as per the following program categories:

- Generation integration projects

- Load Customer connection projects
- Strengthening and reliability (N-1) projects and
- Safety and statutory projects

TABLE 39: PLANNED STRENGTHENING AND EXPANSION PROJECTSLION)

Network Business: Planned Strengthening and Expansion Projects	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Strengthening	12 401	25 738	27 707	32 591	29 825
Customer Connections	844	1 557	1 162	1 682	849
Generation integration projects	102	116	128	936	1 353
Reliability (N-1) Compliance	665	1 411	1 876	5 597	3 343
Safety & Stautory	253	1 217	682	337	420
Total	**14 263**	**30 039**	**31 554**	**41 143**	**35 790**

8.2.1.1 Generation integration projects

The MYPD 6 application will be based on the TDP 2022, which was adjusted in November 2023. The primary change from TDP 2021 involves the new generation capacity assumptions. While TDP 2021 mainly relied on the IRP 2019, TDP 2022 includes additional applications received through various DMRE procurement processes, consultations with renewable energy (RE) association as well as the applications received from non-DMRE programmes. These additions make the TDP 2022 more comprehensive and reflective of the current energy landscape.

Considering the abovementioned programmes, an estimated 53GW of new generation capacity will be required by 2032. Failure to deliver will lead to an increased risk to the security of electricity supply for the country. This will require an acceleration of investments in NTCSA infrastructure by development of new corridors, substations and strengthening at existing substations over the period 2023 – 2032, to address both the new generation capacity as well as the network strengthening requirements across the country for security of supply.

Investments were made to connect various IPPs to the system as per the DMRE IPP programmes encompassing Bid Windows 1 to 5 and RMIPPP. As indicated in the table below 95 projects (6 203 MW) associated with these programmes have been successfully integrated onto the Eskom power system. A further 25 projects are in execution and expected to be completed. The 22 projects are in Bid Windows 3, 5 and RMIPPP.

The network capacity for the greater cape regions is severely constrained and will require large investment in the expansion of the transmission system in the form of new corridors and transformation capacity.

Progress on the DMRE IPP programme as of September 2023 is summarised in the table below. There are 6 preferred bidder projects from Bid Window 6, all PV, with a contribution capacity of 1000 MW. These projects are currently at Budget Quotation stage and are expected to be completed in FY2026.

There are also non-DMRE/ private RE IPP projects, consisting of 16 projects that will contribute 578 MW. These are currently in execution stage and expected to be completed by 2025.

The Battery Energy Storage Independent Power Producer Procurement Programme (BES IPPPP) Bid Window 1 is part of DMRE's programme, designed to procure 513 MW of Capacity and AS in the Northern Cape. The BES IPP Procurement Programme Bid Submission Date must be capable of achieving the Commercial Operation date within a period of 24 months after Commercial Close.

TABLE 40: CONNECTION STATUS OF DOE IPP PROGRAMME

Name of Programme	MW Contribution	Current Status
RE-IPP Window 1 (28 Projects)	1 425	All 28 Projects are connected and in operation
RE-IPP Window 2 (19 Projects)	1 040	All 19 Projects are connected and in operation
RE-IPP Window 3 and 3.5 (23 Projects)	1 633	All 22 Projects are connected and in operation. 1 project in execution.
RE-IPP Window 4 and 4B (26	2 205	All 26 Projects are connected and in operation
RMIPPP (5 projects)	353	5 project in execution.
RE-IPP Window 5 (19 Projects)	1 759	19 project in execution.

Refer to the Annexure for details of the list of planned generation integration projects.

8.2.1.2 Load Customer connection projects

Based on the applications processed for customer connections (i.e., new load or increase in capacity), provisions have been made for in the MYPD 6 period for customer connections that would require "deep system strengthening" (shared costs) of the Transmission system. Refer to the list of planned customer connection projects as detailed in the Annexure.

8.2.1.3 Strengthening and reliability (N-1) projects

To ensure the sustainability of the TS in terms of reliability and security of supply, strengthening projects are planned to alleviate network congestions and safeguard the operations of the existing infrastructure considering future generation and demand growth. Refer to the list of planned strengthening projects as detailed in the Annexure.

The design of the network is based on a set of reliability criteria that has been entrenched in the South African Grid Code and is a licence requirement. In 2008 the Grid Code reliability criteria (N-1) changed from probabilistic to deterministic resulting in 128 projects being identified to attain N-1 reliability compliance. Initially, exemption was approved up to end 2016 to attain compliance. Due to challenges mainly associated with servitude acquisitions and Eskom's liquidity position, a subsequent revised exemption application to attain compliance by 2027 was approved by NERSA. The projects planned over the MYPD 6 period are summarised in the Annexure.

FIGURE 7: RELIABILITY PROJECTS (N-1)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Opening balance (Corridors)	49	42	33	31	26	21	19	15	14	14	14	11	7	6	1
Opening balance (Substations)	49	46	41	35	30	21	20	19	15	13	13	10	4	2	0
Total Projects	98	88	74	66	56	42	39	34	29	27	27	21	11	8	1

8.2.1.4 Safety and statutory projects

Safety and Statutory projects address safety risks as well as statutory compliance related requirements. These projects are typically to address risks associated with underrated equipment and to ensure the safety of personnel as well as plant and equipment. Refer to the list of projects in the Annexure for additional details.

8.2.2 Expansion capital plan prudency assessment

This section provides a high-level assessment of the system strengthening and expansion investment of R76bn over the MYPD 6 period for planned projects as detailed in section 8.2.1. A simplified methodology is proposed for the prudency assessment of the applied capital funding as it would be impractical to fully unpack all elements of the project portfolio. In principle, Transmission assets are being created to transport electricity from generators to load centres via lines and to transform extra high voltages to the required customer voltage levels. It is proposed to review the project portfolio efficiency based on prudent installation costs for the following primary assets categories as planned for construction:

- km of line
- Transformation MVA

An independent asset valuation study which was conducted with a base date of 31 March 2020 was utilized to determine average asset creation costs per category. As part of this study, asset creation costs were assessed considering NTCSA's line and substation design specifications.

The asset valuation established the Replacement Cost New (RCN) values for the NTCSA installed base of transformation (MVA) as well as for line assets (km). A replacement cost per MVA and per km of line was derived by dividing the RCN values from the study with the NTCSA installed base as of 31 March 2020. This was escalated at 5% per annum to derive the average asset construction costs for a base date of 31 March 2025. The asset valuation construction costs per Transformation MVA and km of Line are summarized in the table below.

TABLE 41: AVERAGE ASSET CREATION COSTS (AS PER ASSET VALUATION – BASE DATE OF 31 MARCH 2025)

Total Transmission Assets	Independent Valuation RCN (R'm)			
Total Transmission Assets	297 402		Base Date 31 March 2020	Base Date 31 March 2025
Substation and Auxiliary Plant Assets	Independent Valuation RCN (R'm)	Installed Transf (MVA)	RCN (R'm / MVA)	RCN (R'm / MVA)
Transformation (MVA)	148 774	153 135	0.972	1.303
Line Assets	Independent Valuation RCN (R'm)	Installed Line Assets (km)	RCN (R'm / km)	RCN (R'm / km)
All lines	148 627	33 067	4.495	6.024

The prudency assessment needs to verify if the planned system expansion capex expenditure of R76bn to create 3 468 km of line and 30 360 MVA of substation transformation over the MYPD 6 period is reasonable. The planned system expansion capex expenditure as well as the assets planned to be constructed per year is summarized in the table below.

TABLE 42: MYPD6 ASSET CREATION COST – PRUDENCY ASSESSMENT

Expansion Capex		MYPD6 Application FY2026	MYPD6 Application FY2027	MYPD6 Application FY2028	Totals
Strengthening & Expansion (Rm)	A	14 263	30 039	31 554	**75 857**
Assets Planned to be Constructed					
Line Assets (km)		770	894	1 804	3 468
Transformation Assets (MVA)		4 500	10 760	15 100	30 360
Average Asset Creation Unit Cost					
Average Cost per km of line (Rm)		6.024	6.325	6.641	
Average Cost per MVA (Rm)		1.303	1.368	1.436	
Total Average Asset Creation Costs					
Line Asset Creation Cost (Rm)		4 638	5 657	11 981	**22 276**
Transformation Asset Creation Cost (Rm)		5 862	14 716	21 685	**42 263**
Total Justified Capex (Rm)	**B**	**10 500**	**20 373**	**33 666**	**64 539**
Variance (Rm)	**A-B**	**3 764**	**9 666**	**-2 111**	**11 318**

The variance of R11.3 bn over the MYPD 6 period is mainly ascribed to the following:

- The expansion capex includes R13bn to build Synchronous Condenser facilities as well as R2.1bn statutory investments for under rated plant and safety.
- The project phasing of capital expenditure spans multiple years resulting in financial expenditure prior to physical asset creation and commercial operation.

In conclusion, the assessment demonstrates that the planned capital investment of R76bn over the MYPD6 project portfolio for system expansion and strengthening is reasonable and prudent. Notwithstanding, it is recognized that the assessment is a simplified methodology that utilizes average replacement costs and that it does have some limitations.

8.2.3 Capex execution plan/strategy

In the past, Transmission has faced difficulties in fully executing the TDP due to Eskom's capital reprioritization process, which aimed at managing the limited funding resources between projects across its divisions. Alongside funding challenges, bottlenecks in the supply chain have led to lower capital expenditure than assumed by the regulator.

Grid capacity constraints poses serious challenges to the integration of new generation sources, essential for addressing ongoing electricity system problems and in meeting the diversified energy mix objectives outlined in the IRP. Connecting new generation capacity is urgent, while maintaining sustainable grid capacity and ensuring a secure power supply. The TDP, released in 2022, highlights the necessity for over 14,000 kilometres of powerlines and 106 000 MVA of transformation by 2032.

NTCSA is studying different strategies to accelerate the execution and delivery of the capital plan. This is done in addition to the current approach of Engineering, Procurement, and Construction Management (EPCM) which involves many contracts, each reporting directly to the project owner, and therefore retaining more control over the project as well as assuming major risks associated with construction.

8.2.3.1 Engineer, Procure and Construct (EPC)

This is a strategy of maximizing on an EPC approach by reducing the number of contracts (which can potentially be in their tens) to single digit. This is done by eliminating the contracting for final design, construction, and equipment purchases either by contracting in an OE and EPC or developing the project internally and appoint an EPC only. The use of OE and EPC reduces the project management effort from internal resources to external resources.

8.2.3.2 Private Sector Participation (PSP)

The PSP involves awarding responsibility to build identified assets to private sector under different models, type of the model to be applied will vary from one project to another. The following models will be considered.

- Independent Transmission Project (ITP)

  ITP is an external project delivery model were a private entity in the form of a special purpose vehicle (SPV) sources concessional financing and executes the infrastructure in exchange for annual payments over a period of typically between 25-45 years. These arrangements may include responsibility for maintenance and operating.

- Limited PSP with BOOT

  This option involves limited application of PSP via Build, Own, Operate and Transfer (BOOT) through a 25–45-year concession. The model will be implemented to limited projects identified by NTCSA asset management unit.

- Design, Build, Finance (without maintain and operate)

This option accepts PSP but restricts participation in maintenance and operation.

8.2.3.3 Independent Transmission Parties (ITPs)

Though the ITPs might be an option to execute a portion of the capital plan, this will not negate the need for an industry-wide cost reflective tariffs required to meet the obligations to ITP’s. NERSA must ensure fair and equitable treatment of all participants in the industry.

8.3 Asset Replacement

8.3.1 Regulatory treatment for refurbishment investments

The South African Grid Code requires NTCSA to replace assets which are no longer reliable or safe to operate. It further defines that the revenue required for such investments should be recovered from the rate base via the Transmission Use of System Charges. The following extract from South African Grid Code (Transmission Tariff Code) refers:

A1.5.2 Connection charge

(i) Refurbishment costs

Costs for the refurbishment of connection assets shall be evaluated using the least life cycle cost criteria as described in the South African Grid Code.

<u>The refurbishment of connection assets shall occur when the equipment is no longer reliable or safe for operation.</u> The NTC shall justify the need for refurbishment.

<u>The cost of refurbishment of standard connection assets</u>, excluding premium assets, <u>will be covered in the rate base through TUOS charges</u>.

In accordance with the MYPD Methodology, refurbishment cost is to be capitalized and should not be included as part of operating and maintenance revenue requirements. Section 10.4.1 refers as follows:

10 Expenses – Operating and Maintenance

*10.4.1 Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs include normal operating expenditures, maintenance (**excluding refurbishment costs that must be capitalised**), manpower or labour costs, and overheads (centrally administrative and general expenses allocated) that are normally recovered within one financial year.*

Therefore, refurbishment expenditures should be included as part of the RAB once the refurbished asset is "used and usable" after having been placed in Commercial Operation (CO). It is noted that the MYPD Methodology includes an exception to this rule relating to capital expenditure of an expansionary nature which is included as WUC once the investment has been incurred. The following clauses in the MYPD Methodology refers:

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

> *9.1.8.1 <u>Fixed assets must be used and useable</u>, which means that assets should be in a condition that makes it possible to supply demand in the short-term (within 12 months).*
>
> *9.1.8.2 Fixed and other assets that are not used and/or in a useable form will therefore not be included in the RAB.*

9.1.8.3 The exception to the criteria is that the capital expenditure of expansionary nature, to create additional capacity (i.e. which is not used and usable) should be capitalised and included in the RAB as and when construction costs are incurred for return purposes. Such capitalisation will however exclude interest during construction.

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

Historic refurbishment investments are inherently included in the MEAV valuation as the replaced assets were given a “new life” following CO. However, the MEAV Asset valuation is only determined at the commencement of the regulatory period and it does not provide for refurbished assets placed in CO during the MYPD period. Asset refurbishment investments made during the regulatory period should therefore be included as part of the RAB in the year they are planned to be placed in CO. Once in CO, such investments should receive both return on asset as well as depreciation.

Certain assets have been forecasted for replacement due to obsolescence and lack of support from the OEMs for previous generation equipment. Grid code compliance remains a concern especially on the secondary plant equipment. NTCSA has launched an initiative to renew protection schemes as ageing and obsolete plant that could contribute to a sudden and drastic decline in the various performance indexes and will compromise the reliability and sustainability of the transmission network.

NTCSA is currently in process to replace all asbestos structures to adhere to statutory requirements. Supply chain constraint due to the market being overwhelmed with the construction requests as well as long equipment lead times and slow delivery have a negative effect on the equipment replacement timelines contributing to under expenditure. Construction companies are facing labour and skills shortages, rising material costs and additional environmental and safety requirement.

Theft, vandalism and security of staff during construction is also a contributor to the delayed delivery of projects. To ensure that NTCSA will utilise the planned capital applied for, certain projects will also be completed via the EPC route to accelerate timeous delivery. With reference to the capex table above, a total capital amount of R15.3bn is planned for asset replacement investment over the MYPD 6 period. The table below reflects the planned asset renewal investment as well as the values planned to be placed into Commercial Operation (CO) per year.

TABLE 43: PLANNED REFURBISHMENT & COMMERCIAL OPERATION

Commercial Operation Transfers	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Applicaton FY2030
Refurbishment - Annual Investments	3 796	5 270	6 269	6 923	6 530
Refurbishment - Planned for CO	3 734	5 194	6 236	6 951	6 684

8.3.2 Asset replacement planning

NTCSA follows a sustainability framework where maintenance sustains plant over their useful life, contingency plans and availability of spares reduces the impact of interruptions and asset replacement provides for long term network sustainability.

Asset replacement planning is therefore focused on ensuring sustainability of the existing network infrastructure at desired performance levels as well as safety requirements. Planned refurbishment investments are detailed in the Transmission Renewal Plan (TRP) which is shared with the public as part of the TDP consultation process.

Deteriorating asset health is an emerging risk which requires increased asset replacement investment to sustain future Transmission system performance. The current asset health report is summarised in the figures below.

FIGURE 8: NTCSA SUBSTATIONS - ASSET HEALTH INDEX SUMMARY

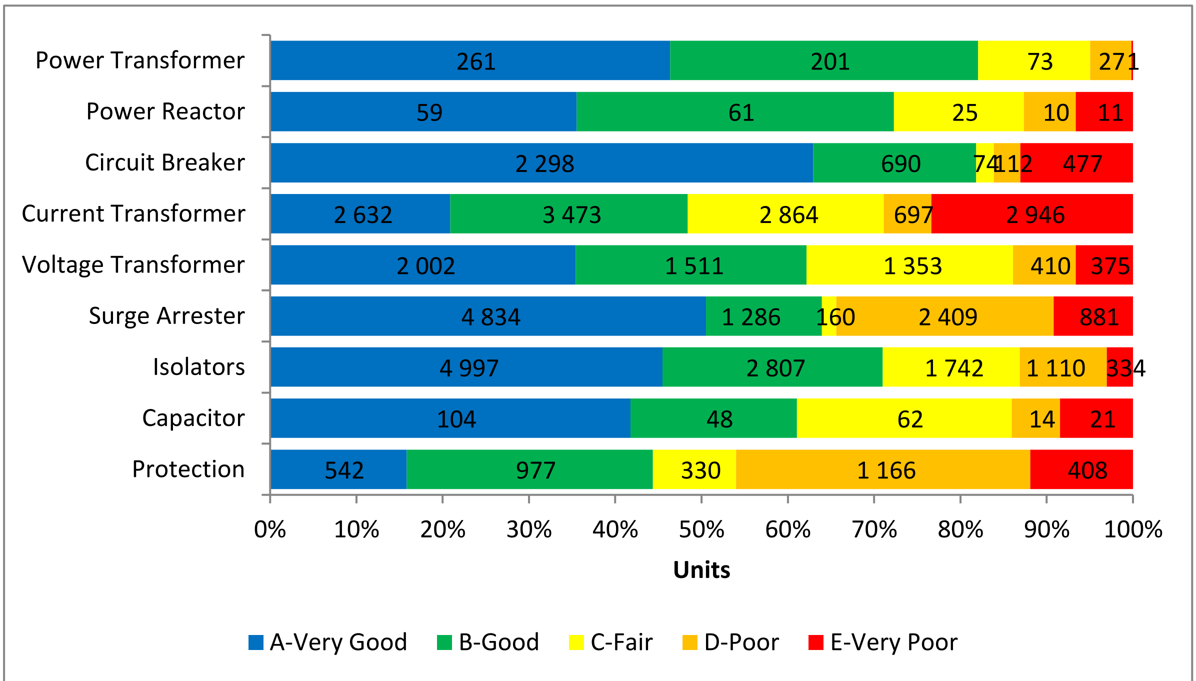
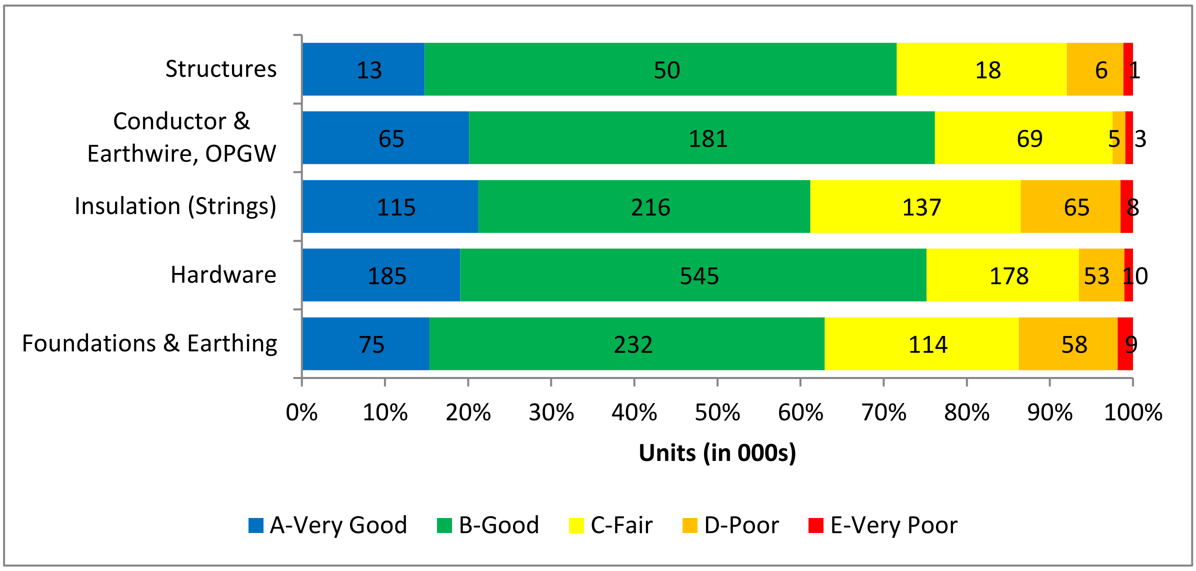


FIGURE 9: NTCSA LINES - ASSET HEALTH INDEX SUMMARY



An asset management approach is followed where asset condition is assessed and the criticality of the assets in terms of continuity of supply and risk to the network are evaluated in order to ensure an optimal prioritized asset renewal plan. It further facilitates balancing the network performance, network risks and capital constraints, providing a long-term focus.

Assets have an expected service life based on the asset design, duty cycle (frequency of use), maintenance strategies and 'life enhancement' strategies. This means that different asset classes will deteriorate at different rates during their service life, depending on the life cycle trajectory followed.

Although age is not a direct criterion for asset replacement, it is a relevant factor to consider in conjunction with asset condition in the long-term planning of asset replacement projects. The following asset age profiles can be considered in terms of the economic and design life cycle as well as the end-of-life risk profile (refer to the figure below).

FIGURE 100: NTCSA SUBSTATION AND LINE - ASSET AGE PROFILES

The Transmission Asset Replacement Plan is not developed in isolation but instead aligns with the following requirements and synergies:

- Alignment to the TDP (or 10-year network Master plan - see Section 8.1)
- Finding an optimum balance in decision-making between costs, network performance and network risks
- Asset life cycle plans
- Complying with relevant legislation, policies, regulatory and statutory requirements in executing asset management activities
- Focus on Customer requirements and approaches in managing NTCSA assets.
- Striving for appropriate international best practices

An investment plan has been compiled by integrating and clustering project scope with a substation level focus considering asset health, compliance, and performance improvement initiatives. The projects are ranked based on prioritisation criteria such as load at risk and statutory requirements. The final constrained execution plan considers project factors such as outages, resourcing, and risks. Further, the constrained execution plan may be adapted because of emergent risks, which are of a statutory or strategic nature, requiring urgent interventions. The required asset replacement capital plan will enable the replacement of identified poor condition assets on a prioritized basis over the next 10 years. Emphasis will be placed on addressing the risk by replacement of high-risk transformers, reactors, capacitor banks, protection scheme replacements as well as transmission line refurbishment.

The transmission asset management program is continually enhanced to align with international standards such as ISO 55001. Currently, NTCSA has a regimented process of appraising assets from all necessary aspects of demand growth, integration of new generation sources, operations flexibility, end of life, statutory compliance as well as operating and maintenance. The Transmission Asset Management Policy indicate a clear shift towards structured risk appraisal and project identification leading to value-based investments.

A Strategic Asset Management Plan (SAMP), outlining how each network appraisal process implements the policy was published. In addition, Eskom continuously enhances the Capital Project Portfolio Management (CPPM) initiative that emphasizes on adherence to project processes, consistent project justification and ranking based on value delivery, development of a single project portfolio development and monitoring and reporting of the investment portfolio.

The Annexure provides a summary of planned projects for the MYPD 6 period and beyond.

8.3.3 Asset Refurbishment Prudency Assessment

With respect to the planned investment value of R15.3bn (i.e. an average of +/- R5.1bn annually), it should be noted that the replacement cost for the total Transmission lines and substation asset base replacement cost has been valued at R297bn (reference: Eskom Regulatory Asset Base Valuation report – MANI Industries, May 2021). It can be concluded that an annual investment of R5.1bn is conservative and reasonable as it only represents +/- 2% of the installed asset base replacement cost. NTCSA continues to accelerate the asset replacement investments considering the ageing asset base and associated condition. Furthermore, it can be noted that substation audits conducted by NERSA included several findings on ageing assets highlighting the need for increased asset replacement.

8.4 EIA's and Servitudes

Environmental Impact Assessment (EIA) cost considerations:

- In terms of the National Environmental Management Act (NEMA) Act 107 of 1998 activities identified in Listing Notice 1 of General Notice Regulations (GN R.) 983 and Listing Notice 3 of GN R. 985 triggers either an Environmental Impact Assessment (EIA) or a Basic Assessment (BA).
- The voltage level of the line will determine which of the two assessments is to be undertaken.
- The EIA scope is determined by the Department of Environmental Affairs or the relevant provincial authority as well as issues arising from the public consultation process. As the applicant, NTCSA has to fund these studies as per the instructed scope using independent consultants or specialists.
- The cost of EIA's is estimated by using historical projects, projected line distances and number of sites required.
- The number of communities that need to be notified as well as the locations for the public meetings also impact costs.

Servitude Acquisition cost considerations:

- Historical costs and estimates are used to determine the servitude costs including a determination by an external registered land valuator, as Eskom compensates the landowner at 100% of the land value as well as any diminution to the remainder.
- Land use factors that are considered includes categories such as grazing, dry cultivated lands, irrigation lands, forestry, orchards, eco-tourism property, vineyards, urban properties, industrial properties, mining etc.

- Compensation is based on land value and in line with Sections 12a (i) and (ii) of the Expropriation Act No. 63 of 1975.
- Additional factors such as compensation for fixed assets within the servitude area (buildings, windmills, commercial trees, graves, fencing etc.) are also considered and included as relevant.
- On procurement, the legal right for the servitude is registered with the Deeds Office with associated legal costs.
- Servitude width: Servitude width will vary per line voltage level with typical values of 765kV=80m, 400kV=55m, 275kV=47m and 132kV=31m. These values consider safety considerations and possible encroachment into the power line from adjacent buildings, structures or vegetation. These restrictions increase in width through commercial forestry areas.
- The lead time to conclude EIA's and acquire servitudes has historically impacted project schedules negatively. To enable long-term project execution planning, strategic investments are being made to secure strategic servitude corridors in advance. Provision has been made for acquisition of the required servitudes over the planning period.
- It is however acknowledged that as a result of the ongoing support and co-operation between various government departments, the lead time to conclude EIA's and servitude acquisition has significantly reduced from between 3/4 years to less than 120 days.

8.5 Production Equipment

Although production equipment assets which are used and usable might not be deemed to be transmitting plant, they are vital in ensuring that NTCSA is able to provide its regulated service. These assets include assets related to transportation facilities related machinery, equipment, appliances, containers and tools, furniture, IT assets, test equipment (including mobile units), specialized line equipment and special purpose vehicles.

The Electricity Regulation Act allows for an efficient licensee "*to recover the <u>full cost of its licensed activities</u>*". Furthermore, the NERSA MYPD Methodology states the following:

"*9.1.1 The Regulatory Asset Base (RAB) must represent <u>assets used and usable to provide regulated service</u> by each of Eskom business operations*."

"*9.1.3 The <u>RAB must consist of existing Fixed Assets</u> in use, <u>New Investments</u>, Works Under Construction (WUC) excluding interest during construction, as well as making allowance for Net Working Capital to allow the respective operations of Eskom to meet short-term obligations*."

The production equipment assets that are planned to be purchased would form part of "New Investments" into Fixed Assets that will be used to provide NTCSA's regulated service.

The MYPD Methodology is furthermore clear that the treatment of such production equipment may not be included as part of the Operational costs. It states the following:

The MYPD Methodology also requires that;

"10.4.1 Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs include normal operating expenditures, maintenance (excluding refurbishment costs that must be capitalised), manpower or labour costs, and overheads (centrally administrative and general expenses allocated) that are <u>normally recovered within one financial year</u>."

Production equipment typically is recovered over a period longer than a year and thus it would be in conflict with the methodology to include such costs as operational costs.

The inclusion of the production equipment as part of the RAB would mean that there would be less of an impact on the overall revenue requirement from the customer as these assets will have their return smoothed over a multi-year period thus aligning with the MYPD methodology principle of "tariff smoothing".

"10.4.5 For any expenses incurred under abnormal or extraordinary circumstances, consideration shall be given to <u>spreading such expenses over a number of years</u>. This consideration may also apply to particular types of expenditure within management's control only for purposes of <u>tariff smoothing</u> and once the Energy Regulator is satisfied that those expenses have been prudently and efficiently incurred."

In conclusion, based on the guidance of the MYPD methodology, these investments should as part of the RAB in the year that they are planned to be purchased and put into use.

9 Conclusion

In conclusion, the revenue application presented by the National Transmission Company South Africa (Transmission) for the financial years FY2026 to FY2028 outlines a strategic approach to ensuring the efficiency, reliability, and sustainability of South Africa's electricity transmission infrastructure. NTCSA is required to build 14 218km of new transmission lines by 2032 and install 105 565MVA of transformer capacity, equivalent to c.42% of the current power line infrastructure. **The aim is to connect 53GW of new generation capacity.**

The required revenues will enable NTCSA to execute its mandate and obligations as a licensed operator while meeting the evolving demands of the energy sector. Key components of the revenue application include investments in infrastructure expansion and modernization, procurement of energy from independent power producers (IPPs), and management of international energy imports. Additionally, NTCSA emphasizes cost containment measures and efficiency improvements to mitigate the impact on electricity prices. By addressing the challenges of maintaining grid reliability, integrating renewable energy sources, and optimizing operational efficiency, NTCSA aims to contribute to the long-term sustainability of South Africa's electricity supply industry.

Overall, the revenue application reflects NTCSA's dedication to fulfilling its mandate while supporting the broader objectives of national energy policy and regulatory frameworks. As South Africa continues its transition towards a more diversified and resilient energy landscape, NTCSA stands poised to play a pivotal role in shaping the future of the electricity sector.

10 Annexure – Project list

TABLE 44: NETWORK BUSINESS: GENERATION INTEGRATION PROJECTS

Generation Integration Projects (Eskom/IPP) (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Kusile TX Integration	-	-	-	135
Medupi TX Integration	-	-	-	151
Richards Bay 3GW Gas Integration - IPP	-	1	110	1 991
Castle WEF 89 MW IPP	1	-	-	-
Gamma MTS 3 x Emoyeni 140 MW WEF Integration	2	1	18	-
IPP Garob &Copperton Windfarm	94	81	-	11
IPP Brandvalley 140 MW WF and Rietkloof	2	18	-	-
IPP Koruson MTS Establishment & Integra	3	16	-	-
Total	**102**	**116**	**128**	**2 288**

TABLE 45: NETWORK BUSINESS: CUSTOMER CONNECTION PROJECTS

Customer Connection Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
ARIES TRFR UPGR TRANSNET OREX LOAD	0	-	-	-
Erica MTS + Phillipi-Erica 400kV Line	10	203	453	575
GARONA TRFR UPG TRANSNET OREX LOAD	6	-	-	-
HEILOS TRFR UPGR TRANSNET OREX LOAD	9	-	-	-
IPP Highveld South Phase 2 Wonderkrag	401	610	95	588
IPP Tshwane Reinforcement - Phoebus Pha	73	-	-	-
JUNO TRFR UPG TRANSNET OREX LOAD	11	-	-	-
KOEBERG 2X 132 kV FEEDER BAY TO SUPPLY DA	3	-	-	-
Koeberg Atlantic 132kv Cable	3	-	-	-
Komati - Haasfontein 88kV uprating (ERA)	1	-	-	-
NamPower	119	124	-	-
Pieterboth - 100MVA EMM Load	147	241	-	-
Transnet Freight Coal Line Upgrade	58	375	615	1 369
Transnet Freigt Rail -Coal Line Upgrade	2	4	-	-
Warmbad 132kV Prot Upgd - Bela Bela Mun	-	-	-	-
Total	**844**	**1 557**	**1 162**	**2 532**

TABLE 46: NETWORK BUSINESS: RELIABILITY (N-1) COMPLIANCE PROJECTS

N-1 Compliance Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Emkhiweni 400/132kV S/S Integr Ph 1A	572	350	94	317
Erica MTS-Pinotage Stikland Loop in	-	-	6	635
JHB East Strengthening Phase 2: North Ra	0	33	253	702
JHB East: Jupiter B Integration Ph1	-	8	270	3 395
JHB North: Apollo-Lepini 275kV	-	-	4	704
Kyalami 400/132kV S/S Integration	-	-	-	85
Limpopo East: Foskor 400MVA 400/275kV trfr	-	1	17	569
Marathon 400 kV Integration	92	925	312	99
Nzhelele 2X500MVA 400/132kV MTS Intg	1	95	920	2 434
Total	**665**	**1 411**	**1 876**	**8 940**

TABLE 47: NETWORK BUSINESS: STRENGTHENING PROJECTS

Network Strengthening Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
KZN Str Empangeni: Mbewu Substation	18	50	424	1 645
Acacia Koeberg 2nd 400kV line	36	49	-	-
Acornhoek 3rd 125 MVA 275/132 kV transf	1	42	10	-
Aggeneis – Groeipunt 400 kV line 2	-	1	48	413
Aggeneis 2nd 66kV Feeder bay - Gamsberg	1	-	-	-
AGGENEIS-PAULPUTS 220KV LINE	225	754	109	-
Agulhas 400/132kV 500MVA Trfr 3	-	-	1	201
Agulhas 400/132kV S/S Integration	174	559	203	-
Alpha 765/400kV 2000MVA Trfr 4	-	-	0	989
Ariadne Eros 2nd 132/400kV line	433	-	-	-
Aries 400/132kV 500MVA trf - IPP	89	135	173	-
Aries 400MVAR Power Compensator	106	439	343	-
Aries–Aggeneis 400 kV line 2	-	1	46	1 325
Artemis 3rd 500 MVA 400/132 kV Trfr	18	584	-	-
Artemis 4th 500 MVA 400/132 kV Trfr	-	0	452	339
Asteria 400/132kV 500MVA Trfr 3	-	-	1	201
Asteria 400/132kV S/S integration	107	379	210	-
Aurora - Juno 400 kV Line 2	0	2	288	831
Beta 765/400kV 2000MVA Trfr 3	-	-	1	255
Bokkom 400/132 kV Substation Integration (Phase 1)	1	3	250	378
Brenner Ph2:Lesokwana 275/88kV S/S	-	17	244	804
Brenner Ph2A: Matla-Jupiter loop-ins	0	9	171	-
Camden-I MTS Int	-	-	1	1 401
Camden-Sol Lines 1 and 2 Loop into Zeus	-	-	0	364
Cape 765 ph4 Gamma-Kappa 765kV no. 2	29	496	641	3 892
Cape Corridor Ph 4: Kappa-Sterrekus 2nd 765kV Line	-	1	33	1 455
Cape Corridor Ph 6 : 2nd Mercury to Sterrekus 765kv line	-	-	-	0
Cape Corridor Phase 4: 1st Perseus – Zeus 765 kV line	680	1 867	3 093	1 092
Cape Corridor Phase 4: 2nd Gamma – Perseus 765 kV	-	1	48	1 412

Network Strengthening Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Cape Ph 5A: 765 kV (400kV Operation) - IPP	-	-	-	1
Carmel 3rd 275/132kV 250MVA transformer	1	153	305	-
Coega Gas Integration ph1 - IPP	-	-	-	1
Dedisa Ext 3rd 500MVA 400/132kV transfor	163	460	-	-
Delphi 3rd 120MVA 400/132kV transformer	103	206	-	-
Dorper 400/132kV S/S Integr - IPP	-	1	158	618
Droerivier 400/132 kV Trfrs 1&2 Upgr	-	-	15	305
Droerivier 500MVA 400/132kV trfr 3 - IPP	73	179	41	-
Droerivier B 400/132 kV MTS - IPP	18	584	-	-
Droerivier-Narina-Gourikwa 400kV	-	-	0	116
EL Voltage Support: 100 MVar Shunt Cap Banks	-	-	-	44
Emkhiweni 400/132kV S/S Integr Ph 1B	21	598	176	66
Erica 400/132kV 500MVA Trfr 3	-	-	2	301
Erica MTS Boundary Wall	5	-	-	-
eThekwini Strengthening - Inyaninga	-	-	-	262
eThekwini Strengthening - Shongweni	-	-	1	772
Etna 3rd 275/88kV 315MVA Transformer (TDP 2019)	3	57	251	47
Everest 275/132kV 500MVA Trf 3	-	-	-	73
Foskor-Merensky 275kV Line 2	-	1	656	432
Galenia 400/132kV 500MVA Trfrs 3&4	-	-	0	622
Galenia Ext 2nd 500 MVA 400/132 kV Trfr	0	15	154	-
Gamma 2nd 2000 MVA 765/400 kV Trfr	-	-	36	681
Gamma Str : 2nd 500 MVA 400/132 kV transformation - IPP	0	70	72	-
Gamma Str: Gamma 765/400 kV trfr - IPP	1	118	583	8
Gamma-Nuweveld 400 kV Line 2	-	-	-	1
GARIEP NETWORK STRENGTHENING	4	-	-	-
Garona 275/132kV Trfr Upgrade	-	-	0	266
Garona 400/132kV Establishment	-	-	0	496
Grahamstown 400/132kV MTS - IPP	-	-	-	11
Grassridge 500MVA 400/132kV Trfr 4	-	-	1	381
Grassridge Ext 3rd 400/132kV 500MVA tran	98	170	-	-
Greater East London Strength Ph 4	1	114	875	494
Greater East London Strengtheing Ph3	43	-	-	-
Groeipunt 400/132kV Establishment - IPP	-	0	46	897
Gromis 400/132kV 500 MVA trfr - IPP	3	96	213	4
Gumeni 2nd 400/132 kV Trfr	43	133	5	26
Harvard 275/132kV 500MVA Trfr 3	-	-	0	266
Helios Strengthening ph 2 - IPP	30	124	-	-
Hendrina 3rd 400/132 kV Trfr	1	79	150	3
Hermes - Mercury 400kV line 2	-	-	0	88
Highveld NW Lowveld North Str Ph2	87	-	-	72
Hlaziya 400/132 kV MTS Integr - IPP	-	3	126	2 719
Hydra 2nd 2000 MVA 765/400 kV Trfr	1	381	404	117
Hydra B 400/132kV S/S Ph1 - IPP	1	6	783	446
Hydra B 400/132kV S/S Ph3 - IPP	-	-	1	262
Hydra Substation 2 x 400/132 kV Trfr Upgrade	1	105	300	142
Hydra-Kronos-Aries 400kV line 2 - IPP	367	1 718	221	-
IPP Deep Strengthening (Phase 4 C)	-	1	14	146
Juno 3rd 400/132 kV Transformer	91	103	52	-
Kappa 3rd 500 MVA 400/132 kV Trfr	-	-	-	217
Kappa 500 MVA 400/132kV trfr 2 - IPP	90	119	4	-
Kimberley Ph 3 : Hermes - Mookodi - Ferum 400kV line	1	172	1 632	1 790
Kimberley Ph 3 : Umtu 400/132kV S/S Est	-	-	-	26
Kimberley Ph 4: Boundary 400kV ph2	48	571	480	-
Kimberley Ph 4B: Boundary 400kV Str	1	58	775	1 056

Network Strengthening Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Kimberley Str Ph5: Beta - Boundary 2nd 400 kV line	-	-	2	440
Kimberley Str Ph5: Boundary - Ferrum 2nd 400 kV line	-	-	5	905
Komsberg 400/132kV 500MVA Trfr 4	-	-	1	494
Komsberg Ext 3rd 500 MVA 400/132kV Transformers - IPP	12	335	-	-
Korana 400/132kV 500MVA Trfr 2	-	-	4	150
Korana Int Ph1: Korana 400/132 kV S/S - IPP	3	54	227	261
Koring 400/132 kV MTS Integr - IPP	53	263	269	-
Koring 400/132kV 500MVA Trfrs 3&4	-	1	96	744
Koring Ext 2nd 500 MVA 400/132 kV Trfr	1	107	71	-
Kronos IPP Transformation Ph 3	113	179	-	-
KZN Str Empangeni: 400kV lines	-	60	40	27
KZN Str Empangeni: Mbewu Invubu and fdr	6	287	281	60
KZN Str Empangeni: Umfolozi Mbewu line	5	592	324	483
Leander 400/132kV MVA Trfr 3	-	-	-	1
Leseding 3rd 500 MVA 400/132 kV transf	0	15	35	197
Lewensaar 400/132 kV S/S Int	-	-	1	400
Limpopo East: Foskor-Merensky 400kV	-	0	28	46
Limpopo East: Foskor-Spencer 400kV	-	4	38	749
Limpopo East: Spencer 500MVA 400/132kV trfr	-	1	23	197
Mahikeng Integration ph1	-	1	12	911
Mahikeng Integration Ph2	-	-	-	21
Majuba 400/132 kV Ext	1	1	273	336
Majuba 400/88 kV Trfr Upgrade	1	1	109	135
Manogeng- Sekhukhune 400kV line 1	0	47	430	84
Medupi Stability Integration 400kV	196	-	-	-
Mercury 1st 2000 MVA 765/400 kV Trfr	105	503	472	-
Mercury 3rd 500 MVA 400/132 kV Trfr	144	109	21	-
Mercury 400/132kV 500MVA Trfr 4	-	-	-	215
Mookodi 1x 500MVA 400/132KV Transformer - IPP	57	353	175	-
Mookodi Dynamic Device	0	1	79	599
Nama Mts Transformers Upgrade -250 MVA 66\22kV	10	-	-	-
Namaqualand Str for IPPs : Gromis-Nama 400kV line	0	45	704	643
Namaqualand Strengthening PH 2 Juno Grom	61	72	-	-
Narina (Blanco) MTS Integration	-	-	-	16
Nieuwehoop 400/132kV 500MVA Trfr 3	-	-	-	-
North KZN: Iphiva 400/132 kV S/S Ph1	-	-	1	1 327
Northern KZN Ph2 - 400/132kV Sub, TFR 2	-	-	-	1
Paulputs 400 kV Str Ph 2 - IPP	-	4	53	552
Paulputs 400/132kV 500MVA Trfr 2	-	-	-	1
Phillipi 3rd 400/132kv 500MVA	65	316	223	174
Pinotage (Firgrove) MTS	5	3	2	-
Pinotage 3rd 500MVA 400/132kV Trfr	-	3	153	182
Poseidon North 400/132kV S/S - IPP	-	-	-	1
Poseidon South 400/132kV S/S - IPP	-	-	-	525
Prairie 275/132kV trfr upgrades	0	63	331	-
Ruigtevallei 3rd 132/66kV 20MVA	10	68	36	-
Rustenburg Phase 2-Marang Extension	-	-	-	1
Rustenburg Str Phase 1 - Bighorn	-	-	-	1
Sekhukhune 800MVA 400/275 kV trfr 1	1	59	121	376
Sekhukhune SS integation ph 1	1	51	477	565
Sekhukhune-Senakangwedi 275kV line 1	-	1	43	152
Sekhukhune-Witkop 400kV line 1	-	-	-	0
Sesiu 400/88kV S/S Integration	9	347	688	235

Network Strengthening Projects (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
SGS PH3: GAMMA-GRASSRIDGE 765KV LINE 1	2	391	2 284	13 946
Sisimuka Phase 1B 275/88kV & lines	1	98	222	84
Siyoneza Substation 3rd 500 MVA 400/132 kV Trfr	-	-	-	2
Sorata Substation Strengthening	-	0	147	827
Soweto Ph 2 - Quattro 275/132kV	-	-	1	470
Soweto Ph1: Quattro 275/88kV Integr	-	1	102	691
Spencer 2x36MVar Cap Banks	0	1	42	52
Stikland Ext 3rd 500MVA 400/132kV transformer	-	3	188	174
Syncon Aggeneis Ph1	1 198	1 031	-	-
Syncon Ferrum Ph1	1 153	1 046	-	-
Syncon Gamma Ph1	1 198	1 031	-	-
Syncon Grassridge Ph1	1 198	1 031	-	-
Syncon Gromis Ph1	1 198	1 031	-	-
Syncon Koruson Ph1	1 198	1 031	-	-
Tabor 2x36MVar Cap Banks	0	1	50	62
Theseus 3rd 500 MVA 400/132 kV Trfr	72	173	-	-
Thuso 3rd 400/132kV 250 MVA	-	1	99	291
Tshwane Metro - Wildebees ph1	-	279	393	-
Tutuka 400/132 kV IPP Substation Int	31	369	58	-
Upington Str: 500MVA 400/132kV trfr 2 - IPP	106	55	-	-
Upington Str: 500MVA 400/132kV trfr 3 - IPP	-	-	2	593
Upington Str: Aries-Upington 400kV line 1 - IPP	97	423	497	91
Upington Str: Ferrum-Upington 400kV line 1 - IPP	687	790	104	-
Vaal Strengthening Ph2B Glockner Etna	1	180	450	270
Waterberg Stbl: Borutho-Silimela 400kV	3	407	643	1
West Rand Ph2A: West Rand Cap Banks	2	55	129	31
West Rand Ph2C:Taunus 400kV Int	0	100	623	225
West Rand Strength - Westgate 400kV	184	481	454	4
West Rand Strengthening - Westgate 400kV	0	2	2	212
Zeus 765/400 kV 2000MVA Trfr 3	-	1	47	910
Total	**12 401**	**25 738**	**27 707**	**62 416**

TABLE 48: NETWORK BUSINESS: SAFETY AND STATUTORY PROJECTS

Safety / Statutory Projects	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Ankerlig TX Koeberg Second Supply	13	-	-	-
FS Terminal Equipment Upgrades	-	-	-	93
Igesi (Makalu B) 275/88kV S/S Integr	107	770	45	-
KOEBERG 400KV BUSBAR RECONFIG & TRANS	56	447	637	593
Mpumalanga Underrated Equip Upgrade	68	-	-	70
Waterberg GX Fault Level Plan Hermes	9	-	-	-
Total	**253**	**1 217**	**682**	**756**

TABLE 49: NETWORK BUSINESS: ASSET REPLACEMENT PROJECTS

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Pembroke SS Refurbishment	35	32	29	12
Kriel SS Refurbishment : HV Yard (ERA)	-	-	25	53
High Risk TRFRS PH2 – Matla No1 400/275kV	15	10	-	100
High Risk TRFRS PH2 – Chivelston No1 400/275kV	24	7	3	-
High Risk TRFRS PH2 – Impala No1&3 400/132kV	10	17	-	-
High Risk TRFRS PH2 – Impala No3 275/132kV	53	23	10	-
High Risk TRFRS PH3 – Prairie No11&12 132/33kV	1	41	42	-
High Risk TRFRS PH3 – Sol No12 132/22kV	1	29	-	-
Phased Replacement of High Risk TRFRS PH 3 - NC	-	60	53	70
Phased Replacement of High Risk TRFRS PH 3 - CG	1	70	49	84
Makalu SS Refurbishment	3	47	160	108
Apollo CS Replace problematic bypass Bre	38	38	38	102
Buffalo Port Rex 2 132kV Towers	-	-	-	3
Drakensberg Ref Phs 2 GIS Fdr bay & Duct	-	-	-	63
Drakensberg SS Refurbishment P2: Fdr Duct (Cable)	26	62	51	77
Drakensburg SS Refurb P2: OPGW on Venus	-	-	-	20
Muldersvlei SS Rfb Phase III (400 kV Ya	2	29	43	40
Arnot SS Refurbishment: 275kV HV Yard	-	-	-	65
Problematic Protection Ref. P2 - South	-	-	-	40
Problmtc Protection PH2 - Free State	1	12	42	15
FS Problematic Protection Ref. P2 - Everest	-	-	-	16
FS Problematic Protection Ref. P2 - Harvard	-	-	-	19
FS Problematic Protection Ref. P2 - Merapi	-	-	-	5
CG Problematic Protection Ref. P2 - Jupiter	-	-	-	4
Problematic Protection Ref. P2 - East	30	28	30	30
NG Problematic Protection Ref. P2 - Tabor	-	29	-	-
NG Problematic Protection Ref. P2 - Witkop	22	-	-	-
Problematic Protection Ref. P2 - N East	2	2	16	13
NW Problematic Protection Refurb P2 - Ararat	-	-	-	4
NW Problematic Protection Refurb P2 - Hermes	-	-	-	3
NW Problematic Protection Refurb P2 - Midas	-	-	-	16
NW Problematic Protection Refurb P2 - Trident	-	-	-	11
Problmtc Protection PH2 - Northern Cape	8	8	10	30

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
WG Protection Refurb P2 - Droerivier	24	-	-	-
WG Protection Refurb P2 - Proteus	23	-	-	-
Replc of the 275kV Bushings on all TRFR	-	-	-	103
Zeus, Auxilliary Supply & Auto Chop Over	-	-	-	0
Muldersvlei SS Refurbishment Phase II (I	25	23	50	50
Normandie SS Refurbishment : 400kV HV Ya	-	-	-	0
NE DC Ref 2019/20 - Komatipoort	93	36	6	72
Acacia SS Refurb Phase A - 11 & 66kV	-	-	-	25
Acacia SS Refurbishment Phase III (132 k	-	-	-	30
Replace Genwest 400kv Surge Aresters	-	-	-	0
Arnot SS Refurbishment: 400kV HV Yard	-	-	-	40
Croydon SS 44kV Feeder Prot (ERA)	-	-	-	2
Grassridge 132kV yard Refurb	21	27	29	29
Ingagane SS Refurbishment: 275kV Yard	7	13	-	7
Matla Underrated Equipment	-	-	-	15
Vulcan SS refurb - Phase 1 (400kV Yard)	58	69	-	34
Vulcan SS refurb - Phase 2 (132 kV Yard)	81	59	-	10
Vulcan SS Refurb Phase 3: (132kV Yard)	29	35	53	137
Vulcan – Kwaguqa 132 kV Feeder Bay Prote	-	-	-	1
Acacia SS Refurbishment Phase II (33 kV	31	51	-	1
Buffalo SS Refurbishment	11	16	15	4
Rockdale SS Refurbishment	-	-	-	59
Minerva SS Refurb (FL mitigation)	82	292	43	35
Grassridge - Neptune Corridor Guy Anchor	-	-	-	5
Athene 400kV Lines Guyed Anchors (Phase2	-	-	-	7
FORDSBURG S/S RFB	-	-	-	4
Fordsburg SS Refurbishment _ Primary Plant (Dev)	20	-	-	-
Bloedrivier SS Ref P1: 275kV Yd & Infras	-	-	-	33
Bloedrivier SS Refurb P2: 88kV Yard	-	-	-	21
Bloedrivier SS Refurb P3: Transformers	-	-	-	70
Aries/Kronos 1 400kV LineReplacement of Optic&Adlash with OPGW (ERA)	16	20	64	-
Oranjemond SS Refurbishment (ERA)	19	16	16	51
Poseidon SS Refurbishment : 66kV Yard (ERA)	22	15	-	-
Ankerling-Aurora 400kv lin OPGW Repla	16	14	-	-
Kruispunt SS Refurbishment	27	5	-	16
Apollo CS: HVDC Refurbishment Phs 2: Bridge 2 Transformers (ERA)	55	20	20	39
Apollo CS: HVDC Refurbishment Phs 2: Bridge 4 Transformers (ERA)	55	20	20	39
Prairie SS Refurbishment Phase 1: 132 kV	7	20	-	27
Matla Kruispunt No1 275kV Line Refurb - 10km	0	20	-	-
Arnot Kruispunt 275kV Line Refurb - 94km	0	-	27	59
Esselen SS Refurbishment	-	-	-	0
Gromis SS Refurbishment (ERA)	18	16	16	59
Ferrum SS Refurbishment	30	40	31	160
Hydra Ruigtevallei No2 220kV LineReconductoring of section of line (twr 90 to 140)	23	0	-	-
Georgedale SS Refurb Phase 4: 275kV Yard	20	20	-	110
Hydra Roodekuil No1 132kV refurb of sele	22	-	-	27
Hendrina Proctn Upgrd- 132KV Feeders ERA	-	-	-	3
Lepini SS Refurbishment (Lepini FL mitig	-	40	27	28
Craighall Reliability Improvement	50	60	-	-
Aurora SS refurbishment	16	38	-	-
APOLLO CS LN DIVIDER REPLACE & RELOCA	32	-	-	-

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Pieterboth SS Refurbishment	-	-	24	137
Zeus SS Refurbishment	-	-	29	68
Simplon SS Refurbishment	-	-	-	75
GEORGEDALE SS: RFB PHASE 2	-	-	-	11
Imprv Internally-Fused Shunt Cap Bank	-	-	-	43
Ref Internally Fused Cap Banks - Ararat	5	64	64	-
Ref Internally Fused Cap Banks - Witkop	-	-	24	-
Perseus SS Refurbishment	-	-	-	0
Watershed SS Refurbishment (ERA)	43	45	35	36
Bacchus - Muldersvlei L1, 400kVAdlash to be replaced with OPGW or other fibre.	10	5	86	-
STABNAC ICCP at Duvha SOC	-	-	-	4
Brenner SS Refurbishment (ERA)	43	45	46	-
Georgedale SS Rfurb Phse 5:275/132kV Trf	-	-	-	1
Eiger SS Refurbishment	41	84	100	100
Bacchus SS Refurbishment	34	52	80	95
NEG Protection Refurbishment Phase 2	-	-	-	5
Impala SS Refurbishment	-	5	50	215
Komatipoort SS refurb Phase 1 (ERA)	26	24	-	23
Illovo SS Refurbishment	-	-	-	2
Nevis SS Refurbishment (Partial)	-	-	-	3
Nevis SS Refurbishment P2	3	92	111	63
Scafell SS Refurbishment	10	12	5	3
Scafell SS Refurbishment P2: Transformers (ERA)	53	153	35	-
Leaches Bay/ Port Rex 132kV line:Towers	-	-	-	0
Spitskop SS Refurbishment	-	-	-	3
Chivelston SS Refurbishment	-	40	18	26
Bighorn SS Refurbishment	-	-	-	3
Tugela SS Refurbishment Scope Def	-	-	-	18
Verdun SS (Secondary plant and Fibre)	-	-	-	4
National Junction Boxes PH2	-	-	-	2
National Junction Boxes PH3	-	-	-	5
National Junction Boxes PH4	-	-	-	5
Marathon SS Refurbishment	-	16	5	32
Pembroke/Poseidon 1-220kV line:Towers to	-	-	-	0
Buffalo-Port Rex 132kV Line Refurbishment (Hardware & Insulators)	-	-	-	6
Buffalo/Leaches Bay 132kV:Replacing all	-	-	-	6
Arnot 275 kV Transfer By-pass	-	-	-	2
Apollo Install new earth Electrodes	-	-	-	8
Grassridge/Poseidon 1-400kV line:Towers	25	30	-	-
Hydra/Poseidon 1-400kV line:Towers to be	-	-	-	0
WAM P2 Central - Jupiter	-	-	-	2
WAM P2 N East – Arnot	-	-	-	1
WAM P2 N East – Camden	-	-	-	2
WAM P2 N East – Duvha	-	-	-	2
WAM P2 N East – Marathon	-	-	-	2
WAMS P2 North – Medupi	-	-	-	1
WAM P2 N Cape - Aries	-	-	-	2
Georgedale Illovo 275kV Rplc Earthwire	-	-	-	1
Buffalo/Neptune 1-132kV :Retro fitting c	-	-	-	0
Buffalo/Neptune 2-132kV :Retro fitting c	-	-	-	0
Georgedale Illovo 275kV Line Silicon	-	-	-	1
NEG Waterlogged Towers : AconhK - Mart 2	-	-	-	2
NEG Waterlogged Towers : Duvha - Matla	-	-	-	3

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
NEG Waterlogged Towers : Duvha - Vulcan	-	-	-	10
NEG Waterlogged Tower : Hendrina - Kriel	-	-	-	5
NEG Waterlogge Tower : Hendrina-Vulcan 1	-	-	-	2
NEG Waterlogge Tower : Hendrina-Vulcan 2	-	-	-	8
NEG Waterlogged Towers : Kendal -Tutuka	-	-	-	4
CG Tower Strct in Water Esselen-Jupiter2	-	-	-	2
CG Tower Strct in Water Croydon - Apollo	-	-	-	4
Impala SS Refurbishment of Steelwork (ERA)	19	9	-	-
Avon SS Refurbishment of Steelwork (ERA)	-	-	-	11
Illovo SS Refurbishment of Steelwork (ERA)	-	-	-	20
GIS- MARSHALLING KIOSK RFB	-	-	-	7
BIRD FAULTS POOR PERFORMING NORTH EAST	-	-	-	1
BIRD FAULTS POOR PERFORMING WEST	-	-	-	13
FSG Bird Guards BG3 Hydra-Perseus 3 ERA	-	-	-	3
FSG Bird Guards BG3 Hydra-Perseus 2 ER	-	-	-	3
FSG Bird Guards BG3 Grootvlei-Theseus 1	-	-	-	2
FSG Bird Guards BG3 Beta-Hydra 1 ERA	-	-	-	2
CG Bird Guards BG3 Brenner-Eiger 1	-	-	-	5
CG Bird Guards BG3 Matla-Esselen 1	-	-	-	5
NEG Bird Guards BG3 Grootvlei-Matla 1	-	-	-	5
Mercury SS: Ref of Cap Bank 1 and 2	-	-	-	13
Rplc Capacitor units @ Beta, Perseus,Hyd	-	-	-	20
Yard stone replacement - Ariadne	-	-	-	1
EG Aviation Spheres - Nat. Rd Crossings	-	-	-	8
GEN - TRAN METERING	-	-	-	2
Pluto Shunt Capacitor Bank	-	-	-	2
Athene & Impala Re-design 132kV Capbank	-	-	-	13
Eiger SS: Install TWS Units	-	-	-	1
Kriel SS: Install TWS Units	-	-	-	4
Matla SS: Install TWS Units	-	-	-	3
Tutuka SS: Install TWS Units	-	-	-	1
Water Drainage Problems (Hyd,Ruit,Roode)	-	-	-	3
HYDRA CONTROL KIOSKS FIRE DETECTION SYST	-	-	-	2
Tshwane CLN HV Yard fencing refurbishme	-	-	-	4
NEG Yard Lighting Upgrade - Arnot	-	-	-	5
NEG Yard Lighting Upgrade - Duvha	-	-	-	3
NEG Yard Lighting Upgrade - Majuba	-	-	-	4
NEG Yard Lighting Upgrade - Matla	-	-	-	2
NEG Yard Lighting Upgrade - Tutuka	-	-	-	1
Lulamisa patrol path & security building	-	-	-	4
TEMSE workstation replacement EXE	-	-	-	40
Upgrade Access Road- Rg,Vn,Tns,Bn,Sn EXE	20	30	30	-
Juno MTS Trfm upgrade project	6	70	77	50
Majuba SS Refurbishment	-	-	-	3
Matla SS Refurbishment : 400kV HV Yard	-	-	42	61
NEG: Problematic Equipment Phase 2	-	-	-	13
Apollo CS Problematic Equipment Phase 2	-	-	-	11
Bloukrans SS Problematic Equipment D&E	-	-	-	18
Pegasus SS Problematic Equipment D&E	-	-	-	14
Rabbit SS Refurb: Poor Assets	-	-	-	17
Luckhoff CS problematic equipment ERA	50	-	50	-
LINES Projects Provision for D&E Asset H	-	-	-	20
Relocation of Duvha SOC to Eskom Park(S	-	-	-	59

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Relocation of Duvha SOC (ERA) (Sys Ops part only not Eskom realestate portion)	-	-	100	350
TPSCM - System Implementation (ERA)	126	-	-	35
TPSCM - Telecoms Infrastructure (ERA)	11	19	1	-
TPSCM - Duvha SOC building works (ERA)	-	44	50	-
Geomagnetically Induced Currents (GIC)	-	-	-	2
North 10Yr Total Provision for D&E	-	-	-	110
North West 10Yr Total Provision for D&E	-	-	-	45
Allocation to Projects	35	35	35	70
KZN SVC Refurbishment - Athene SVC	2	100	71	180
Majuba Problematic Equipm D&E	-	-	-	1
Grootvlei Problematic Equipm D&E	-	-	-	1
Georgedale Illovo 275kV Sediver'93 Insul	-	22	-	-
Hector Illovo No1 275kV Sediver'93 Insul	-	-	-	15
Georgedale Illovo No2 275kV Sediver'93 Insul. rplc	-	-	-	15
Invubu Rabbit No1 275kV Sediver'93 Ins.	-	-	-	24
Invubu Rabbit No2 275kV Sediver'93 Insul. rplc	-	-	-	24
Impala Invubu 275kV Sediver'93 Insul. rp	-	-	-	0
Impala Invubu No2 275kV Sediver'93 Insul. rplc	-	-	-	25
Craighall Refurbishment	5	99	100	55
Koeberg Muldersvlei No1 400kV Line Re-co	-	-	-	17
Free State Lines Servitude Gates Replace	-	-	-	1
Droerivier SS Refurbishment (ERA)	11	10	136	-
Proteus SS Refurbishment (ERA)	10	5	245	31
Ankerlig-Aurora No1 400kV T-Type Spacer	-	-	-	0
Ankerlig-Koeberg No1 400kV T-Type Spacer	-	-	-	0
Grassridge SS : Covered Parking HDV	-	-	-	0
Bacchus M-vlei No1 400kV Line Re-con	-	-	-	10
Installation of DGA's on Transfm & React	-	-	-	103
Instal of Online Oil Dryers for Trnf & R	-	-	-	17
Matimba Substation Tx - Gx Protection Interface (Sync VTs)	13	15	9	24
Matimba SS Refurbishment (P2 - S&S 400kV Breakers & D&Es)	1	2	23	48
Southern Grid: Replace Adlash with OPGW	-	-	-	30
Athene Invubu 400kV Line Refurbishment	-	-	-	30
East Grid S&S HPF Breaker Replacement	-	-	-	20
WC Asbestos Phase Out – Komsberg	-	-	-	5
Ankerlig Defective Concrete Plinths (ER	16	16	14	-
Ankerlig Aurora No2 400kV Line Under Clearance (ERA)	-	-	-	3
EG DC Ref 2019/20 - Venus	-	-	-	1
NW DC Ref 2019/20 - Dinaledi	-	-	-	1
NW DC Ref 2019/20 - Pluto	-	-	-	1
NSP1 Security Build 2a 2c: Perseus (NKP)	-	-	-	2
NSP1 Security Build 2: Pembroke	-	-	-	3
NSP2 Security Build 1 - Bighorn ERA	-	-	-	1
NSP3 Security Build 1 - Zeus ERA	11	10	-	-
NSP3 Security Build 1: Hermes ERA	-	-	-	1
NSP3 Security Build 1: Lepini ERA	8	4	9	-
NSP3 Security Build 1: Alpha ERA	11	7	3	-
NSP4 Security Build 1: Snowdon ERA	7	5	7	-
NSP4 Security Build 3 - Central (Dev)	-	-	-	0
NSP4 Security Build 3 - Pieterboth	-	-	-	12
NSP4 Security Build 3 - Snowdon	-	-	-	14

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
NSP3 Security Build 3 - Glockner	-	-	-	14
NSP5 Security Build 3 - Etna	-	-	-	14
NSP1 Security Build 3 - Esselen	-	-	-	15
NSP4 Security Build 3 - Lulamisa	-	-	-	12
NSP1 Security Build 3 - Minerva	-	-	-	16
NSP1 Security Build 3 - Apollo	-	-	-	17
NSP1 Security Build 3 - Impala	-	-	-	13
NSP3 Security Build 3 - Hermes	-	-	-	14
Roodekuil SS Prot & Pilot Cable Rplc	18	12	-	-
Northern Grid Guy Anchors: Spencer-Witkop 275kV	-	-	-	3
Tx Powerline Training Facility - EAL_Exe	-	-	-	15
Warehouse Initiative project	1	1	100	-
Warehousing Prjt Ph 1: Hume 3 W/H Securi	-	-	-	1
High Priority CT replacements (Dev)	1	15	20	40
Olien SS Refurbishment	-	20	50	60
NW High Risk CT - Watershed SS	-	-	-	2
Hydra SS Refurbishment (ERA)	-	10	20	70
Mersey Bus Zone 275kV Replacement	-	-	-	2
Apollo Storage Plinths MaintBLDG side (ERA)	7	7	7	-
Apollo CS: Replacement of Pole 1 533kV Reactor (ERA)	5	70	65	15
Duvha Refurb Ph1	-	-	-	2
Kendal Refurb Ph1	-	-	-	2
Komati Refurb Ph1	-	-	-	23
Alpha Refurb Ph1	-	-	-	74
Zeus Refurb Ph1	-	-	-	84
Dummy	-	-	-	309
Dummy	-	-	-	158
Capacitor Bank Refurb Ph2	-	-	-	122
Havard SS Problematic Equipment D&E	-	-	-	90
DC Refurbishment P5 - South	-	-	-	2
DC Refurbishment P5 - Free State	-	-	-	2
DC Refurbishment P5 - Central	-	-	-	2
DC Refurbishment P5 - East	-	-	-	2
DC Refurbishment P5 - North	-	-	-	2
DC Refurbishment P5 - NWest	-	-	-	2
DC Refurbishment P5 - North East	-	-	-	2
DC Refurbishment P5 - NCape	-	-	-	2
DC Refurbishment P5 - West	-	-	-	2
Problematic Protection P3 - South	1	15	45	-
Problematic Protection P3 - Free State	1	38	67	165
Problematic Protection P3 - Central	1	108	126	135
Problematic Protection P3 - East	1	38	67	165
Problematic Protection P3 - North	1	52	95	117
Problematic Protection P3 - North East	1	44	63	73
Problematic Protection P4 - Central	1	35	82	150
WG Anti-Climb Replacement ERA	38	-	-	-
Apollo - Cahora Bassa No1&2 Quad spacers	-	76	64	-
Athene-Hillside Lines Hardware Refurb	-	-	-	0
Athene-Hillside 1 Line Hardware Refurb	-	-	-	3
Athene-Hillside 3 Line Hardware Refurb	-	-	-	6
CG Towers in Water	-	-	-	0
Apollo Croydon 1 (Fdn-E)(Twr-D) Twrs in Water & Corrossion	-	-	-	9

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Esselen Jupiter 1 (Fdn-E) Twrs in Water	-	-	-	6
Ankerlig Koeberg Corrosion Refurb	-	-	-	0
Ankerlig Koeberg 1 (Twr-D) Corrosion Refurb	-	-	-	9
Marathon Prairie Grillage Foundations	-	-	-	0
Bernina Glockner Reinsulation	-	-	-	0
Bernina Glockner 2 (Ins-D) Reinsulation	-	-	-	11
Avon Impala Ins & Hrdw Rplcmt	-	-	-	0
Avon Impala 2 (Ins-E)(Hdw-D) Ins & Hrdw Rplcmt	-	-	-	29
Gingindlovu Impala 1 (Ins-E)(Hdw-D) Ins & Hrdw Rplcmt	-	-	-	30
765kV Lines Rebuild Anchor Crossings	-	-	-	0
Alpha–Beta 1 765kV Guy anchor Ref Phase1	-	-	-	11
Hydra–Perseus 1 765kV Guy anchor Ref Ph1	-	-	-	29
Athene Pegasus Reinsulation	-	-	-	0
Acornhoek Foskor Reinsulation	-	-	-	0
Acornhoek Foskor 1 (Ins-D) Reinsulation	-	-	-	2
Camden Sol Reinsulation	-	-	-	0
Camden Sol 1 (Ins-D) Reinsulation	-	-	-	1
Arnot Lines Reinsulation	-	-	-	0
Arnot Hendrina 1 (Ins-D) Reinsulation	-	-	-	1
Arnot Simplon 1 (Ins-D) Reinsulation	-	-	-	4
Duvha Vulcan Reinsulation	-	-	-	0
Duvha Vulcan 2 (Ins-D) Reinsulation	-	-	-	3
NE Kriel Towers in Water	-	-	-	0
Kriel Tutuka 1 (Fdn-D) Twrs in Water	-	-	-	5
Duvha Kusile 1 (Ins-D) Reinsulation	-	-	-	2
Aggeneis Aries Reinsulation	-	-	-	0
Aggeneis Aries 1 (Ins-D) Reinsulation	-	-	-	16
Hydra Poseidon Reinsulation	-	-	-	0
Hydra Poseidon 1 (Ins-D) Reinsulation	-	-	-	16
Hydra Poseidon 2 (Ins-D) Reinsulation	-	-	-	8
Bacchus Proteus Reinsulation	-	-	-	0
Bacchus Proteus 1 (Ins-D) Reinsulation	-	-	-	55
Muldersvlei Sterrekus Reinsulation	-	-	-	0
Muldersvlei Sterrekus 1 (Ins-D) Reinsulation	-	-	-	5
Marathon Prairie Hrdw Rplcmt	-	-	-	0
Marathon Prairie 1 (Hdw-D) Hrdw Rplcmt	-	-	-	5
Marathon Prairie 2 (Hdw-D) Hrdw Rplcmt	-	-	-	20
Hydra Ruigtevallei Hrdw Rplcmt	-	-	-	0
Matimba Pluto Lines Spacer Damper Rplcmt	-	-	-	0
Matimba Marang 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	23
Matimba Ngwedi 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	10
Midas Ngwedi 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	16
Matimba Spitskop Lines Spacer Damper Rplcmt	-	-	-	0
Matimba Spitskop 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	13
Matimba Witkop 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	19
Droerivier Hydra Spacer Damper Rplcmt	-	-	-	0
Droerivier Hydra 3 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	11
Sasol Twrs in Water	-	-	-	0
Sol Sasol 2 1 (Fdn-D) Twrs in Water	-	-	-	1
Sol Sasol 3 1 (Fdn-D) Twrs in Water	-	-	-	4

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Sol Sasol 3 2 (Fdn-D) Twrs in Water	-	-	-	2
Droerivier Mulsdersvlei Spacer Damper Rplcmt	-	-	-	0
Droerivier Kappa 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	14
Kappa Muldersvlei 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	18
Ankerlig Lines Spacer Damper Rplcmt	-	-	-	0
Ankerlig Koeberg 1 (SpDmp-D) Spacer Damper Rplcmt	-	-	-	1
Makalu Scafell Reinsulation	-	-	-	0
Midas Ngwedi 1 Anchor refurb	-	-	-	0
Makalu Scafell Corroded Stubs	-	-	-	0
Makalu Scafell 1 (Fdn-E) Corroded Stubs	-	-	-	9
Grootvlei Zeus Corroded Stubs	-	-	-	0
Grootvlei Zeus 1 (Fdn-D) Corroded Stubs	-	-	-	6
Grootvlei Zeus 2 (Fdn-D) Corroded Stubs	-	-	-	3
Kusile Minerva Corroded Stubs	-	-	-	0
Kusile Minerva 1 (Fdn-D) Corroded Stubs	-	-	-	1
Avon Impala Lines Corroded Stubs & Twrs	-	-	-	0
Avon Impala 2 (Fdn-D)(Twr-E) Corroded Stubs & Twrs	-	-	-	40
Avon Mandini 3 (Fdn-D)(Twr-E) Corroded Stubs & Twrs	-	-	-	8
Gingindlovu Mandini 1 (Fdn-D)(Twr-E) Corroded Stubs & Twrs	-	-	-	5
Impala Invubu Lines Corroded Stubs & Twrs	-	-	-	0
Impala Invubu 1 (Fdn-D)(Twr-E) Corroded Stubs & Twrs	-	-	-	11
Transmission Security Nerve Centre	-	-	-	60
Bighorn Transformer protection upgrade (ERA)	-	10	50	80
NG Problematic Protection Ref. P2 - Warmbad	22	-	-	-
OT Cyber security alignment (ERA)	-	-	-	20
NSP2 Security Build 3 - Brenner	-	-	-	14
NSP5 Security Build 3 - Eiger	-	-	-	14
NSP5 Security Build 3 - Jupiter	-	-	-	14
NSP4 Security Build 3 - Lepini	-	-	-	14
NSP3 Security Build 3 - Sol	-	-	-	14
NSP1 Security Build 3 – Midas	-	-	-	14
NSP2 Security Build 3 - Pluto	-	-	-	14
Harvard SS Refurbishment (ERA)	-	-	20	80
Harvard - Bloemfontein (20km)	9	43	31	-
FS Radio Link Replacement Phase 1	-	14	15	-
UHF Repeater Network (Dx Telecontrol)	-	-	45	84
MSAP - TX Tele Protection	-	-	49	-
Access Network	7	50	32	129
BME Replacement (IP MPLS)	207	258	715	-
Natioanl Site Security System	-	-	171	203
Refurbishment - Facilities	-	-	124	155
PABX	-	-	55	259
Fibre optic	-	-	110	440
Tower Strengthening	-	46	46	-
CR - Gauteng Tower Strengthening projec	15	20	20	-
CR - Gauteng Tower Strength project 3	2	15	20	-
Video conference upgrade	28	31	-	-
Core, Aggregation, NMS, and test IP/MPLS sites	23	51	-	-
Regional rings IP/MPLS (TX and ET sites)	43	100	33	-

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
GP IP/MPLS access sites	17	30	-	-
WC – OT Voice Network Optimisation Phase 1	9	20	-	-
Belville Stikland Duct Fibr	31	7	-	-
KZ - Tower Refurbishment Group 1	11	18	-	-
KZN IP/MPLS access sites	-	-	23	23
KZN Tower Replacement Group 3	-	-	37	-
Ingula - Majuba (OPGW -166KM)	-	-	-	56
Majuba- Tutuka (OPGW - 57KM)	31	-	-	-
Tutuka - Kriel (OPGW - 100KM)	-	-	-	18
MP IP/MPLS access sites	-	21	-	-
Golden Triangle OTN Mpumalanga	9	30	-	-
Mercury Aries Perseus Ring Optical Transport Network-Direct Current Upgrades	26	-	-	-
Acacia - Belleville Duct Fibre (12km)	50	13	-	-
WC - Microwave Link Upgrades phase 2	-	80	-	-
WC IP/MPLS access sites	-	24	-	-
MPU - Witbank Area SDH Links replacement Phase 1	21	-	-	-
NC OT Voice Project	9	20	-	-
MPU_Site Security Phase 1	13	10	10	-
MPU- Battery & Charger Replacement Pha 3	8	15	-	-
MPU- Battery & Charger Replacement Pha 2	8	15	-	-
KZN - Network Strengthening phase 1	-	39	-	-
EC DC Upgrage Stage 3	-	-	-	9
EC - Router replacement Stages 3	-	-	-	7
NAT-Cisco DNA and FMC provisioning, with EPNM upgrade Project	-	40	-	-
Limpopo Backbone Microwave Replacement	-	25	-	-
Ericsson ADM Replacement KZN	-	-	-	10
KZN_Hector SS - Georgedale SS OPGW fibre	-	-	-	5
KZN Georgedale SS - Mersy SS OPGW fibre	-	-	-	45
KZN Mersy SS - Avon SS OPGW	-	-	-	60
KZN Avon SS - Impala SS OPGW fibre	-	-	-	98
KZN Bloedrivier SS LILO OPGW	-	-	-	9
KZN Ottawa SS - Glendale RS microwave link	-	-	-	13
KZN Ingagane RS - Fort Mistake RS microwave link	-	-	-	7
Switchgear and School of Technology(Refurb)	-	-	-	0
New NTCSA Head Office	0	58	-	-
New Building-Polokwane Office (Construction/Purchase)	-	-	-	1
New Building-Port Elizabeth Office (Construction/Purchase)	-	-	-	6
New Building-East London Office (Construction/Purchase)	-	-	-	1
New Building-Westville Office (Construction/Purchase)	-	-	-	1
Major Refurbishment of VLI Main Building (Hall, Kitchen, Dinning, & Boardrooms)	1	10	11	8
VLI Major Refurbishment Project (allocation for any new equipment in Rooms)	-	-	-	5
Lightning Locator System	11	12	-	-
Transmission Historian	15	15	-	-
Security Project (beyond Central Grid pilot)	-	15	15	-
Phoenix replacement	-	12	30	-
System Changes required for Legal Sep	5	20	25	28
Tx Customer Relationship Management	2	10	8	-

Asset Replacement (R'm)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029 & FY2030
Cyber Security Gap closure for Tx Systems	5	10	13	20
Tender Bulletin Solution	-	20	-	-
Enterprise GIS Solution	18	20	1	-
Transmission Network Information System (phase 2)	-	50	-	-
Tx Operational Dashboard/Analytics	-	5	15	15
Transmission Risk Management System	-	-	20	-
Solar Storm Resilience	20	-	-	16
Meter Data Management System	23	23	10	-
Various projects with Total value < R20 million in FY26-FY28	1 163	706	913	3 586
Total	**3 796**	**5 270**	**6 269**	**13 453**