Transmission Licensee (Tx)

Multi-Year Price Determination (MYPD) 5 Revenue Application for FY2023 – FY2025

Submission to NERSA

June 2021

Contents

LIST OF TABLES:

LIST OF FIGURES:

1 Executive Summary

1.1 Introduction

This document details the Transmission Licensee revenue application for FY2023 to FY2025 and sets out key challenges and revenue requirements.

The summary and additional detailed information as well as the completed MIRTA templates and relevant appendices form an integral part of the Licensee application.

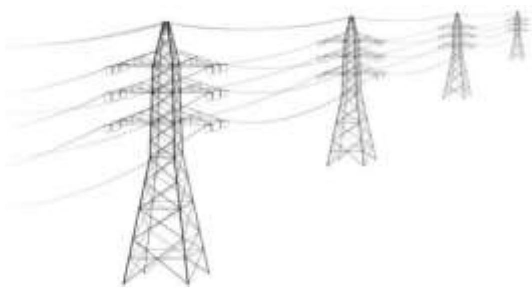
The Transmission revenue requirement includes the activities of the Transmission network service provider, system planner, system operator and grid code secretariat functions which are performed by the Transmission Group. In addition the revenue requirement also includes strategic and shared services which form a part of the Eskom corporate overheads allocated to the Transmission Licensee.

The Transmission licensee provides the infrastructure and operations to transmit electricity from Eskom and IPP generation infrastructure to the Distribution network or, in the case of large energy users such as mines and municipalities, directly to the customers themselves. As such, Transmission is the intermediary link between the generation licensees and the distribution licensees or large energy users.

In the year ending March 2021, the Transmission infrastructure comprised of approximately 33 158 km of lines, 169 high voltage / extra high voltage (HV/EHV) substations with an installed transformation capacity of 154 500 megavolt-ampere (MVA).

1.2 Revenue Requirement Summary

This document provides information on the Transmission Licensee revenue requirement including the return on assets, the operating costs and depreciation. The Transmission costs for ancillary services, demand reduction and technical losses costs are also detailed with this application.



Transmission has taken steps to contain its cost base and limit its impact on electricity price increases. Table 1 provides an overview of the Transmission Licensee's revenue requirements.

TABLE 1: TRANSMISSION: FY2023 - FY2025 REVENUE REQUIREMENTS (R'M)

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		126 225	133 217	139 777	147 568	159 405
WACC %	ROA	X	-1.99%	0.69%	0.87%	1.65%	3.04%
Returns			- 2 513	922	1 220	2 427	4 838
Primary energy	PE	+					
International purchases	PE	+					
IPPs	PE	+					
Environmental levy	L&T	+					
Carbon tax	L&T	+					
Arrear debt	E	+					
Operating costs	E	+	5 349	5 678	5 741	6 071	6 441
Research and Development	R&D	+					
Depreciation	D	+	6 334	6 634	6 919	7 059	7 398
MYPD5 Allowable revenue			**9 170**	**13 234**	**13 880**	**15 557**	**18 677**
Approved RCA's for liquidation	RCA		609	-	-	-	-
MYPD5 Allowable revenue including RCAs	R'm		**9 779**	**13 234**	**13 880**	**15 557**	**18 677**

Note: Research and Development costs are included in operating costs

1.3 Return on Assets

The 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, the Transmission Licensee is allowed to earn a return on the installed Regulatory Asset Base (RAB) as well as on relevant capital works that are under construction.

An independent asset valuation study was used to calculate the value of the Transmission RAB. The MYPD5 RAB values as contained in Table 1 are based on this asset valuation study as well as the planned capital expenditure as detailed in Table 2.

As summarised in Table 1, the RAB value increases over the MYPD5 period as new assets are brought into commercial operation and planned projects investments are incurred.

Transmission capital investment requirements for FY2023 – FY2025 are included in Table 2. These investments are required to strengthen and expand the grid to connect new loads and generation sources. In addition, investments to replace assets which have reached the end of their technical life are required to sustain a reliable supply of electricity.

TABLE 2: TRANSMISSION: PLANNED CAPITAL INVESTMENTS (R'M)

Transmission : Total Capital Expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Strengthening and Expansion	1 392	1 322	2 718	10 410	11 782	10 988	11 479	16 046
Asset Replacement	710	547	619	1 127	1 604	2 040	3 307	3 443
EIA and Servitudes	94	86	201	132	112	265	983	682
Production Equipment	13	112	25	47	26	25	84	154
Total	**2 208**	**2 067**	**3 562**	**11 716**	**13 523**	**13 318**	**15 853**	**20 326**

1.4 Operating Expenditure

Operating expenditure includes all costs involved with the day-to-day running of the business. Transmission's operating expenditure includes employee costs, maintenance, other expenses and corporate overheads. It should be noted that these costs are nett of capitalisation and also considers other income derived from operations. The Transmission operating expenditure for the revenue requirement is detailed in Table 3.

TABLE 3: TRANSMISSION: OPERATING EXPENDITURE (R'M)

Transmission: Operating Expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee Expenses	1 729	2 374	2 586	2 708	2 870	3 063	3 203	3 383
Maintenance	638	816	934	982	1 054	1 117	1 160	1 218
Other Operating Expenses	810	569	680	750	797	895	931	985
Corporate Overheads	1 414	1 283	1 213	1 262	1 340	1 076	1 176	1 254
Other Income	(126)	(150)	(101)	(107)	(113)	(120)	(127)	(127)
Total Operating Expenditure	**4 464**	**4 892**	**5 311**	**5 594**	**5 948**	**6 030**	**6 343**	**6 713**
Corporate Overheads: portion excluded from revenue	-	57	(266)	(245)	(270)	(289)	(272)	(272)
Total Operating Expenditure for Revenue Requirement	**4 464**	**4 949**	**5 046**	**5 349**	**5 678**	**5 741**	**6 071**	**6 441**

1.4.1 Employee expenses

The need for fundamental operational changes is recognised in order to provide affordable, sustainable electricity supply to all South Africans.

In alignment with the Department of Public Enterprises Roadmap, functional unbundling of Eskom was completed by end March 2021 and has resulted in staff servicing Transmission being transferred from Eskom corporate and centralised functions to the Transmission Division. This resulted in an increase in the Transmission staff complement relative to the MYPD4 application. Efficiency opportunities have also been pursued to ensure that headcount is contained over the planning period as outlined in Table 4.

Transmission staff complement is planned to grow during the MYPD5 period to deliver on the increased capital expenditure programme to enable the Integrated Resource Plan (IRP 2019), increasing asset renewal as well as the advancement of energy market services.

Workforce optimisation was identified as a major component to drive internal efficiencies, increase productivity and lower the operating cost across Eskom.

The employee expenses are inclusive of cost to company remuneration and other staff related expenditures such as training, professional fees, overtime and contingency travel costs. These expenses are nett of capitalisation and represent the costs that are directly recoverable.

TABLE 4: TRANSMISSION: EMPLOYEE EXPENSES

Transmission: Employee Expenses and Headcount	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee Expenses (R'm)	1 729	2 374	2 586	2 708	2 870	3 063	3 203	3 383
Headcount	2 084	2 839	3 092	3 154	3 152	3 226	3 225	3 225

1.4.2 Maintenance costs

Transmission'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 specialised skills and equipment to perform live line maintenance has an impact on maintenance costs. The maintenance revenue requirement further considers the increase in the asset base, inflation as well as deriving efficiency improvements.

The execution of some maintenance work in FY2020 was abnormally low due to challenges with procurement processes. This is projected to normalise in FY21 to ensure network sustainability.

TABLE 5: TRANSMISSION: MAINTENANCE COSTS (R'M)

Transmission: Maintenance Costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Servitude Maintenance	46	118	168	171	183	195	202	212
Line Maintenance	107	167	185	191	204	215	223	234
Primary Plant Maintenance	177	189	201	207	218	229	238	250
Secondary Plant Maintenance	38	49	54	57	60	65	67	71
Equipment & Spares	16	30	32	34	38	40	41	43
ERI (Transformer & Logistics)	233	241	274	303	329	351	365	383
Other	21	22	19	19	22	23	22	23
Total Maintenance	**638**	**816**	**934**	**982**	**1 054**	**1 117**	**1 160**	**1 218**

1.4.3 Other operating expenses

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

TABLE 6: TRANSMISSION: OTHER OPERATING EXPENSES (R'M)

Transmission: Other Operating Expenses (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance Premiums and repairs	202	246	260	269	283	301	317	333
Security Expenses	94	125	147	152	162	170	177	186
IT Expenses	22	62	87	92	93	98	108	113
Telecommunications	69	86	90	96	98	102	107	112
Travel Expenses	47	65	81	94	99	107	110	113
Consulting and Legal Costs	3	44	47	48	49	52	53	55
Facilities	25	47	48	53	59	64	68	72
Leases	10	22	28	30	32	36	39	41
Internal Electricity Costs	14	22	24	26	29	31	34	35
Abnornal Costs	314	-	-	-	-	-	-	-
Other	11	(150)	(131)	(112)	(108)	(66)	(82)	(76)
Total	**810**	**569**	**680**	**750**	**797**	**895**	**931**	**985**

1.4.4 Corporate overhead costs

Corporate overheads expenses are primarily costs that cannot be specifically allocated to a Division and these are charged out based on a pre-determined formula and are shared amongst the three licensees in proportion to employee complement, asset values and other operating costs. Corporate functions provide indirect services such as treasury, communications, legal, business planning, etc. to support the Transmission licensee.

1.4.5 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.

1.5 Depreciation

Depreciation allows the Licensee to incrementally recover the principal of the capital invested in its assets over their useful life. The depreciation for the Transmission system assets is based on an asset valuation study compiled by an independent entity. The study considered modern equivalent replacement costs of the transmission assets, remaining useful asset life and depreciated values for the respective asset classes. The depreciation reflected in Table 7 below was calculated based on the asset valuation study conclusions as well as considering new asset investments planned for transfer to commercial operation.

TABLE 7: TRANSMISSION REGULATORY ASSET BASE AND DEPRECIATION (R'M)

Transmission: Regulatory Asset Base & Depreciation (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulatory Asset Base	106 898	108 566	126 225	133 217	139 777	147 568	159 405
Depreciation	7 700	8 414	6 334	6 634	6 919	7 059	7 398

1.6 Ancillary Services and Demand Reduction

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 manner in which they are to be provided is defined in the South African Grid Code. The ancillary services includes Reserves (Generation & Demand Response), Black Start and Islanding, Energy Imbalance, Reactive Power and Voltage Control. The motivations for ancillary services and demand reduction programmes are included in the Transmission script whilst the revenue requirement application has been included with the Generation Licensee revenue application.

1.7 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.

1.8 Assumptions

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

- Implementation of the DPE Roadmap will proceed during the MYPD5 period.
- The wholesaler and single-buyer operational costs (excluding primary energy costs) are ring-fenced but remain part of the Transmission Licensee costs.
- Existing international interconnectors, including Apollo Converter Station, remain within Transmission and will not be treated differently to other transmission assets.
- The expansion plan considered the approved 10-year Transmission Development Plan (TDP) for 2021 to 2030.
- 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 MYPD5 period.
- That a ring-fenced revenue determination per Licensee will be made by NERSA.

2 Structure and Role of the Transmission Licensee

This section describes the role of the Transmission Licensee, providing detail on the following responsibilities:

- The Transmission Network Service Provider (TNSP);
- The Transmission System Planner (TSP);
- The System Operator (SO);
- The Grid Code Secretariat (role performed by the System Operator);
- Integrated resource planning.

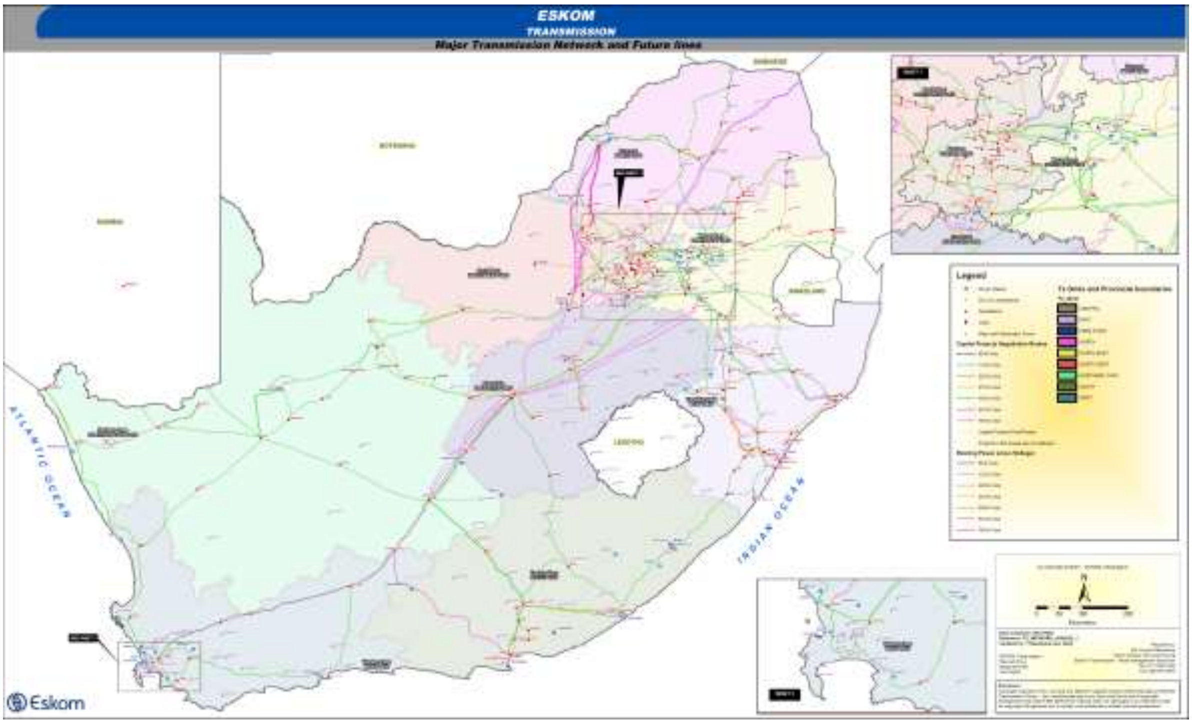
2.1 Transmission Network Service Provider

2.1.1 Overview

The TNSP provides, maintains, operates and manages the network assets to reliably transport electricity from generators to redistributors, bulk-end customers and international customers.

Transmission operates 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 (HVDC) link. Transmission's assets consist of 169 substations and 154 500 MVA transformers, connected by 33 158 km transmission lines across South Africa (as at March 2021) as per Figure 1.

FIGURE 1: THE CURRENT TRANSMISSION NETWORK MAP



2.1.2 Role / Functions

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

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

These assets include:

- High-voltage and extra-high-voltage lines ranging from 88kV to 765kV
- Transmission substations including assets such as:
  - Transformers ranging from 1 to 2 000MVA;
  - Switchgear (e.g. circuit breakers, isolators and earth switches);
  - Instrument transformers (e.g. CVTs, VTs, CTs);
  - Secondary plant equipment used to measure, protect, communicate and control the electricity being transported.

These key functions are performed through a series of activities that include technology management and 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.

2.1.3 Engineering and technology management

Engineering and technology management is required for the following Transmission assets:

- High voltage substation plant;
- Transmission lines;
- Protection, tele-protection, metering and control (PTM&C) systems;
- Telecommunications network.

Engineering / Technology management includes the following activities:

- **Research:** This involves research into emerging technologies and related international practices. The activities help Transmission pursue appropriate technologies and ensure continuous improvement through innovation and maintenance strategies.
- **Specification and standards:** This involves the compilation per technology type detailing required performance aspects and network application requirements. International standards, such as IEC, 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 for Commercial department and the motivation of the technical portion of the contract to the respective procurement committees.
    - 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 as well as 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 optimise maintenance expenditures and best practices.
- **Technology life cycle management (LCM):** This involves the compilation and maintenance of LCM plans per technology type for long-term sustainability based on appropriate maintenance and renewal strategies. The LCM plan includes minimum performance levels and the respective prioritisation criteria. LCM plans generate either asset replacement projects or specific asset management actions. Suitable spares management plans are required for each technology for implementation on a national basis.
- **Operational engineering and consultation:** This involves the investigation of equipment failures to identify the causes and corrective actions as well as to ensure that findings and recommendations are documented. It includes the review of performance trends, conducting of technical audits, failure cause analysis, development and the implementation of corrective action plans. Specialist operational support, consultation, 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.

2.1.4 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 resources 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**: Standard products / designs are selected as "building blocks" for the majority of project application designs. Engineering departments produce the substation, secondary plant (PTM&C) and powerline detailed / application designs for all projects.
- **Commissioning and configuration management**: Engineering resources also provide support in the final commissioning of assets in collaboration with Transmission Grid staff.

2.1.5 Asset replacement investment planning

This involves identifying, ranking and consolidating capital investment projects into robust asset investment plans and includes the following functions:

- **Risk assessment:** Risk opportunity screening of all potential investments against the business strategic objectives, condition assessments and life cycle management plans.
- **Investment and project formalisation:** Selection of the best solution from formulated alternatives with accompanying costs, business case and project documentation.
- **Prioritisation:** Ranking of projects in accordance with asset condition, network criticality and risk criteria.
- **Investment portfolio optimisation:** Optimising the investment portfolio in terms of financial / non-financial resources and constraints.

2.1.6 Operations and maintenance

The Grid is managed on a regional basis to perform operating and maintenance functions for substation plant, protection & 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 transmission assets is captured and updated on the transmission 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 optimisation.
- **Maintenance execution:** Perform maintenance as per established procedures and in accordance with system, manufacturer and statutory requirements. Appointment and supervision of contractors for specialised 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 24 hour response service to incidents on the power system. Interface with Control Centres and various stakeholders during restoration following network incidents. Repair / normalisation and recovery of the power system following plant failures.
- **Live line services:** Conduct live line work maintenance on transmission lines to minimise 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 Transmission record keeping requirements as well as national quality standards. Safety and environmental risk management are integrated with work planning and execution.

Line maintenance practices are dependent on specialised helicopter services to execute inspections as well as live line work. Transmission owns and operates a fleet of helicopters to provide a specialised 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.

2.1.7 Performance management

Transmission uses a basket of measures to report and monitor system reliability and performance. These range from system based performance measures for stakeholder reporting to detailed plant-specific 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 measures the availability and reliability of the system as a whole and the performance of individual components within the system. Measures range from system minutes down to failures of individual plant items (such as capacitor banks) and generally include a cause analysis.
- **National quality of supply measurement system**, which measures the quality of the electricity supplied by Transmission 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.

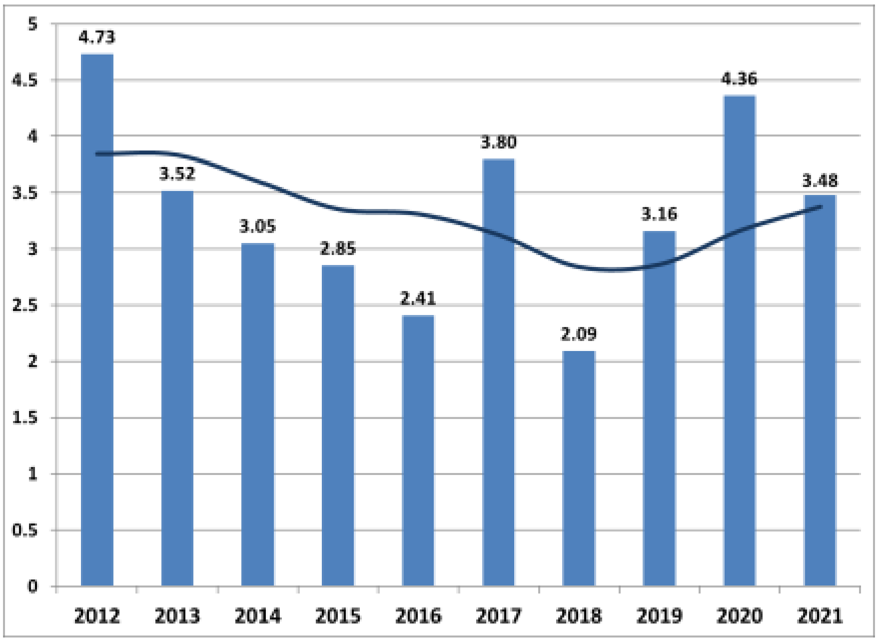
These systems provide measures that are used at various levels in Transmission, from executive management to equipment specialists, in order to assist in managing and improving the network performance and its associated processes. Transmission also has a number of independent assurance processes in place, 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.

2.1.8 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:

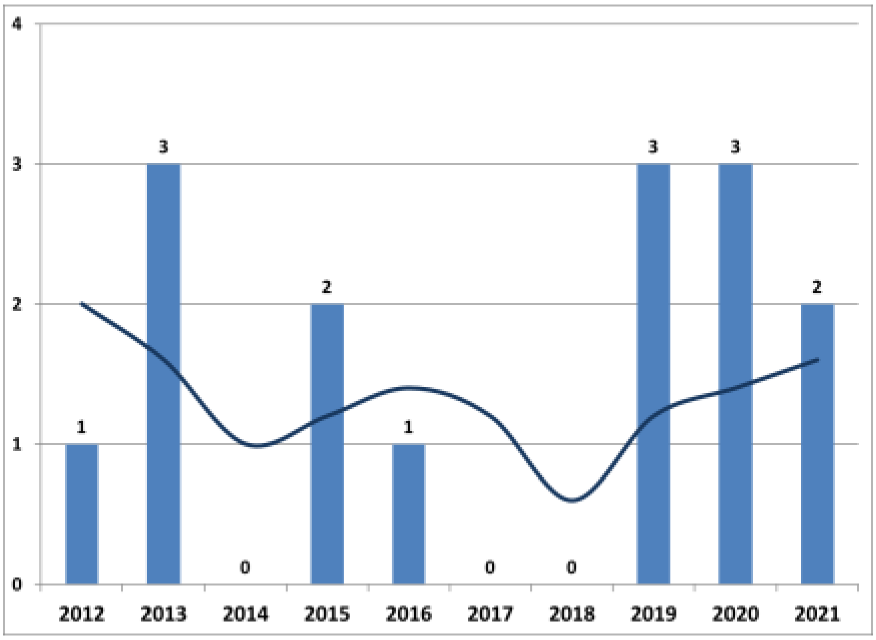
- **System minutes <1:** Measures the total system minutes lost during the year from incidents that individually were less than one system minute (i.e. it excludes major incidents). One system minute is equivalent to an interruption of the total system load for one minute at the time of the annual system peak. By looking at both load interrupted and duration of the interruptions, this measure reflects the severity of interruptions. Following an improvement trend over the last decade, performance has deteriorated partially in recent years as reflected in Figure 2. This is mainly attributed to increased risks associated with ageing assets and unplanned plant failures.

FIGURE 2: SYSTEM MINUTES <1 PERFORMANCE



- **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). Figure 3 reflects the number of major incidents for 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 impacted performance in the latter years.

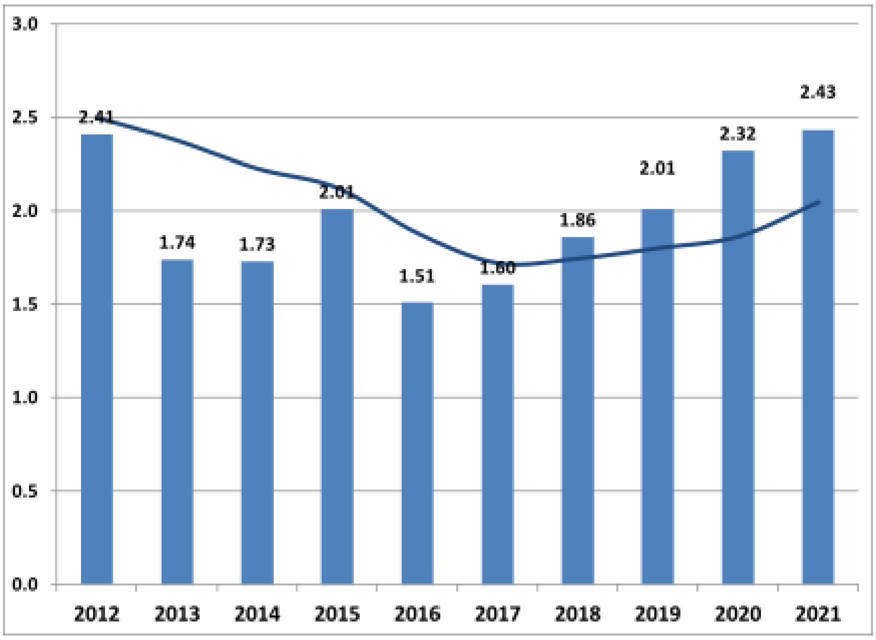
FIGURE 3: NUMBER OF MAJOR INCIDENTS



- **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.
- **Line faults per 100km:** Measures the total number of line faults over a 12-month period per 100km of installed transmission line. A line fault is defined as an incident where the transmission line trips because of an event on the line itself (caused by lightning, veld fire, birds, insulation failure etc.).

Line fault performance has been below expectations due to challenges with increased environmental factors such as bird caused faults. The line fault per 100 km performance trend is reflected in Figure 4.

FIGURE 4: TRANSMISSION LINE FAULTS PER 100KM



2.1.9 Plant availability

Ideally the network or plant should be available at all times. In practice, however, this availability is affected by the disconnection of plant from the system for both planned events (generally for maintenance) and unplanned events (such as plant failures). Although planned outage optimisation is essential and will improve plant availability, maintenance should not be compromised as it ensures the sustainability of the network.

2.1.10 Quality of supply

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).

Transmission 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.

2.1.11 Customer Services

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

Transmission business is customer-focused to provide reliable and least-cost solutions. Transmission shall be a customer-orientated business that will manage the customer value chain which includes grid access, customer connections, contracting, bulk power supply, service provision, billing, revenue and debt management, customer relationship management for customers and market participants.

2.2 Transmission System Planner

2.2.1 Overview

The Transmission System Planner (TSP) is responsible for planning the augmentation of the transmission system in accordance to 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 Transmission system infrastructure requirements. This ultimately culminates in the publication of the Transmission 10 year Development Plan which informs the Transmission Capex revenue requirement.

2.2.2 Role / Functions

2.2.2.1 Network planning and project development

The network planning activities are performed in accordance with Grid Code requirements and can be summarised 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 Integrated Resource Plan (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 DOE'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.

2.2.2.2 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;

- 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 Transmission in the evaluation of new or increased capacity cross-border interconnectors. These interconnectors make it possible to purchase energy from other members of the Southern African Power Pool (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 2021-2030. 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 2021-2030.
- 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.
- Transmission must be financially sustainable to be able to support the planned infrastructure development.

2.2.2.3 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 (in excess of 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 utilised in developing and maintaining the power system studies database for use in simulation studies.

2.2.2.4 Issuing quotations for new and modified connections

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. The terminology used here is the same as used in section 2 (2) of the Network Code.

A quote for network service only with indicative capital costs, without obligation for connection service, is provided at a nominal charge. Transmission'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.

2.3 System Operator

2.3.1 Overview

The System Operator (SO) is responsible for the safe and efficient operation of the Interconnected Power System (IPS). The mandate of the System Operator is "to control the operation of and be responsible for the short-term reliability of the Interconnected Power System" as defined in the South African Grid Code.

In order to carry out its mandate, the SO is required to employ a highly skilled workforce. In addition, the workforce is dependent on various power-system and information and communication technology tools that assist in making pertinent decisions during various stages of the system operations processes.The workforce requirements coupled with the technology requirements, accounts for a major component of the financial needs of the System Operator.

The Grid Code secretariat is housed within the System Operator as mandated by the National Energy Regulator of South Africa (NERSA). This has to be financially ring fenced and treated as a pass-through, for revenue application purposes.

Moreover the Grid Code requires the SO to carry sufficient ancillary services in order to ensure that reliability of the power system is always maintained. The required quantities are purchased from various providers and are accounted for in the ancillary services budget.

2.3.2 Role / Functions

In terms of the Transmission License and the South African Grid Code, the SO is responsible for the security of the South African national electricity grid by monitoring, controlling and operating it in a safe, economical and reliable manner. This ensures Quality of Supply to all customers.

The primary focus of the System Operator is to ensure continuing reliability and quality of supply in support of Transmission's objectives. Key objectives of the SO include:

- Ensuring system reliability, safety and security;
- Dispatching generation;
- Setting operational procedures;
- Controlling the operations of the Interconnected Power System;
- Acquiring and managing ancillary services;
- Providing operational information to key stakeholders;
- Managing compliance to the South African Grid Code.

The introduction of Independent Power Producers (IPPs) has improved the system outlook for South Africa. This has however brought certain challenges to the System Operator environment. Various systems will need to be updated and new ones identified that will assist the SO to carry out its mandate.

Another challenge as volumes increase would be that of the variability that is inherent in renewable energy outputs. The SO is required to cater for such eventualities through more detailed planning and by having relevant systems in place to cater for and deal with such variability.

2.3.3 Ancillary services and Demand Reduction Programme

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 manner in which they are to be provided is defined in the South African Grid Code. The ancillary services are defined as:

- Reserves;
- Black Start and Islanding;
- Reactive Power and Voltage Control;
- Energy Imbalance.

The detailed requirements of each service are described in the Ancillary Services Technical Requirements document and the subsequent revenue requirement is as per an approved costing methodology.

2.3.3.1 Reserves

The SO procures the required reserves from the 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 reserve costs also cater for service provision from new technologies including battery energy storage as well as independent power producers (IPPs).

The following reserves are obtained from demand response:

a) Instantaneous Reserve

Instantaneous Reserve from demand response 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

This comprises of Supplemental Demand Response as well as Self-generation Demand Response. These are customer loads that can 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. It is required to ensure an acceptable day-ahead risk, and to allow time for cold reserve plant to be called up.

Table 8 outlines objectives, typical time of use and trigger conditions for demand response services required by SO.

TABLE 8: TRANSMISSION: 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.

2.3.3.2 Black Start and Islanding

Black Start capability is the provision of generating equipment that, following a system black out, is able to start without an outside electrical supply (self-start), and to energise a defined portion of the transmission system so that it can act as a start-up supply for other base load generators to be synchronised as part of a process of power system restoration.

At present there are three black start sites on the transmission system. The SO has determined that with the increase of generation over the coming years, it may be desirable to procure further black start facilities in strategic areas.

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 pays a capacity payment and a variable payment to each station which is contracted to provide Islanding. The costs for Islanding are highly dependent on the performance of the generators. Costs could also increase with the arrival of new generation able to provide unit islanding.

2.3.3.3 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 also supply reactive power when not generating, that is during Synchronous Condenser Operation, (SCO) mode.

2.3.3.4 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."

2.3.3.5 Power Alert

Power Alert is a voluntary residential demand reduction project broadcast on selected television 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 System Operator schedules Power Alert before Eskom's emergency reserves. The Power Alert project is regarded as a cost-saving tool (economic dispatch) as it reduces the need to use expensive peaking stations.

2.3.4 Grid Code Secretariat

NERSA has, through the Transmission License, appointed System Operator within the Transmission Division as the Grid Code Secretariat (GCS). The GCS is responsible for administering the development and application of the Grid Code by the users of the Interconnected Power System (IPS), and recommending the appropriate changes and exemptions to the Code for approval by the NERSA Board.

The evolution of the electricity supply industry, largely driven by the introduction of the independent power producers, has increased resource requirement for the GCS. Several parts of the Grid Code require the System Operator to monitor compliance by the generation assets connected to the IPS to the relevant requirements of the Grid Code. This role is also being fulfilled by the GCS.

2.3.4.1 Grid Code Secretariat Governance Activities

The Governance Code provides the detailed responsibilities of the GCS whose core function is to perform administrative activities of the SA Grid Code on behalf of NERSA. According to the Governance Code the GCS key activities include, amongst others, the following:

- Managing activities of the Grid Code Advisory Committee (GCAC);
- Preparation of amendments and exemption proposals for submission to the NERSA Board for approval, following review by the GCAC;
- Ensuring that procedures are developed and published for the review of proposed amendments and exemptions by the Grid Code Advisory committee (GCAC);
- Updating of the Grid Code;
- Publication and management of the Grid Code documentation;
- Grid Code further research and development in line with industry changes.

2.3.4.2 Generation Compliance Monitoring

The advent of government’s Renewable Energy Independent Power Producers (REIPP) programme has brought about several changes to the way the GCS performs its function. Following the approval of the Renewable Energy Grid Connection Code by NERSA in 2012, there has been a significant increase in the workload related to Generation Compliance validation. The number of exemptions and amendments being processed annually has also increased. The Renewable Energy Grid Code provides for SO and NERSA to validate compliance of each renewable energy power plant before commercial operation. The GCS has been tasked by the Grid Code Advisory Committee to lead with this process, which resulted in the establishment of the Renewable Energy Technical Evaluation Committee (RETEC). RETEC’s role involves validation of the Grid Code compliance by Renewable Power Plants before commercial operation as required by the Code. This required additional resources (both manpower and financial resources) due to the number of projects and the different processes applied.

2.3.4.3 Resource Implications

The activities highlighted above have resulted in an increase in the cost of running the GCS function. Operating expenses have also increased due to travelling requirements for compliance site-testing requirement of the respective power plants. It is further understood that the cost of the GCS should be seen as a pass-through.

2.3.5 Telecommunications

Telecommunications supports Transmission's core operations by providing mission critical telecommunication services at various substations, power stations and customer sites on a real time basis to manage, view and operate the power supply. These services include the enablement of the following key functions:

- Real time monitoring and control of a power system, including frequency control, maintaining the supply demand balance, voltage control to ensure compliance with quality of supply requirements;
- Supervisory switching of plant to ensure safety of personnel;
- Voice communication and data exchange; and
- Speedy restoration of customer interruptions of supply.

2.4 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;
- New equipment and technology;
- Legislative and statutory requirements;
- Servitude acquisitions;
- Uncertainty regarding new power generation and their geographical location;
- New customer connections.

2.4.1 Ageing network

Transmission assets are ageing and thereby raising the probability of equipment failure. This requires increased asset condition monitoring and assessment to manage the risk for unplanned failures. This has an impact on the amount of unplanned maintenance required, the costs of acquiring and holding spares as well as the extent of network asset replacement.

Transmission uses asset management processes to manage its ageing asset base and prioritise asset replacement expenditure.

2.4.2 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 new security measures.

Additional investment will be made to upgrade the transmission security system nationally. This will include expenditure on the installation of surveillance cameras and associated equipment, the upgrading of national and other supporting control centres, placement of security personnel at key substations, increased access control and armed response at certain substations.

2.4.3 Economic growth and reliability requirements

Notwithstanding the recent 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.

2.4.4 Market forces and commodity price volatility

Prior to deteriorating global economic conditions, transmission high-value technical plant was affected by the soaring price of resources such as copper, steel and aluminium caused by high international demand. In the last few years, commodity prices have generally stabilised creating improved price certainty for the procurement of technical plant. The recent COVID-19 pandemic resulted in increased volatility of commodity prices. An ongoing shift in global commodity prices can impact on future asset creation costs.

2.4.5 Exchange rate volatility

Exchange rate volatility can have a material impact on the cost of projects. Projects with a high foreign content are most at risk. Most of the equipment and spares used in the transmission network are imported and therefore the effect of exchange rate fluctuations on future costs cannot be underestimated.

2.4.6 New equipment and technology

As technology changes, products inevitably evolve as well. Supplier inability to support older technologies drives up the price of spares resulting in the need to invest in new generation technologies. Cost competition often results in narrower design margins and impacts on product quality. Lower tolerance of equipment to harsh environments increases the risk and rate of early failure.

Newer technologies also change the way maintenance is performed and often reduce the level of maintenance required. 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.

2.4.7 Regulatory and statutory requirements

Transmission is obliged to comply with conditions stipulated in both the South African Grid Code, as well as environmental and safety regulations.

2.4.7.1 Environmental requirements

Increased environmental legislation has a direct impact on capital and operating expenses. Transmission is required to conduct Environmental Impact Assessments (EIAs) on all line and substation projects, unless an exemption is granted. The government can also grant extensions to interested and affected parties wanting to review documentation. The impact of unforeseen events is twofold: implementation delays and deferment of capital expenditure.

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 affect the scope of a project in a material way.

The EIA process has a significant impact on transmission line projects. The scope of work in terms of length, numbers of suspension and strain structures, accessibility and foundation requirements cannot be finalised until the entire EIA process is complete. The cost can also not be accurately estimated until the scope is finalised.

It may also be necessary to recycle an existing power corridor to overcome environmental constraints. This involves dismantling the existing lines and building a dual voltage multi-circuit line to enable the new and existing circuits to occupy the same servitude. This is significantly more expensive than building a conventional line.

2.4.7.2 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.

In order to manage vehicle accident risks, drive-cams and telemetric data systems have been introduced in addition to driver training programs and the management of safety behaviour. The evolvement of regulation requirements for construction activities may impact skills requirements and associated project execution costs.

2.4.8 Servitude acquisitions

Transmission engages in strategic servitude acquisitions to enable the TDP. In some cases these may traverse or encroach on sensitive areas, such as national and private game parks, heritage sites and burial grounds. In the current process, the government gives a five-year authorisation and thereafter, a full EIA submission with new alternatives is required. These strategic acquisitions are critical for network expansion to meet load growth demands within specified timeframes. In some instances, expropriation of land may be required if landowners refuse to grant access. Using the present regulations, an expropriation should take approximately six months however in practice this process takes significantly longer.

2.4.9 Uncertainty on new power stations and their geographical locations

Any new generation capacity, whether built by Eskom or an IPP, must be integrated into the existing transmission system. Uncertainty regarding the timing and location of this generating capacity makes it difficult to forecast capital expenditure, since new stations may be deferred or not materialise at all. In such cases, provision must still be made for system strengthening to supply local load from sources located elsewhere in the network.

2.4.10 New customer connections

In terms of its licence, Transmission is obliged to provide non-discriminatory access to the grid for all generators and loads irrespective of geographical location.

3 Revenue Requirement Components

3.1 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:

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

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

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

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

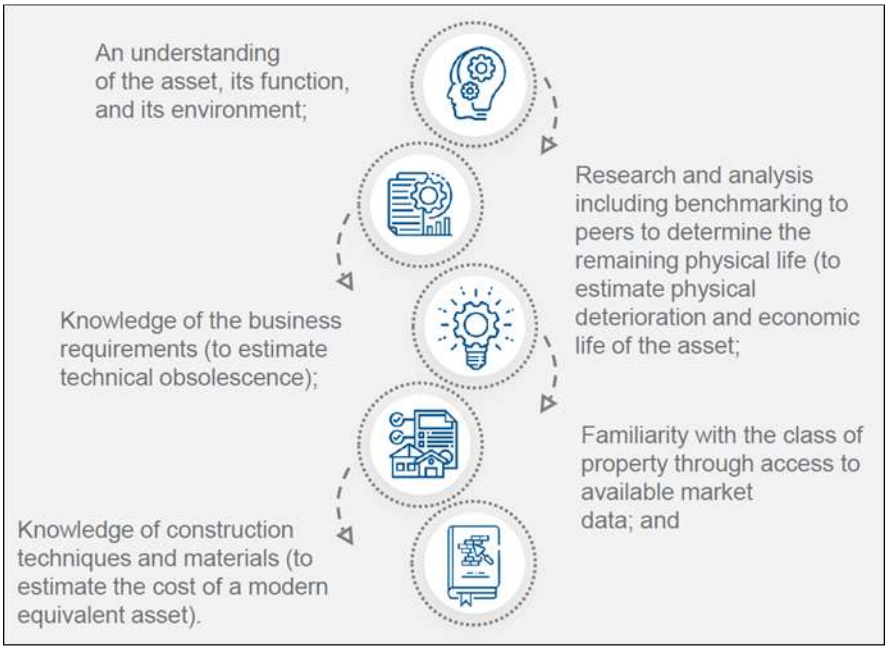
- Depreciation on the commissioned assets, in accordance with the method prescribed by the MYPD methodology. Depreciation is calculated on revalued assets as at 31 March 2020, assets commissioned since 31 March 2020 and asset purchases.
- Return on assets is calculated on all assets including work under construction and working capital, at a rate determined by NERSA.

The ERA and the Electricity Pricing Policy (EPP) require the recovery of efficient costs and earning a fair return on capital. The EPP and the MYPD methodology require that assets be valued at their Modern Equivalent Asset Value (MEAV). In accordance with the MYPD methodology, Eskom has undertaken a revaluation of all completed assets used in the generation, transmission and distribution of energy as at 31 March 2020. It should be noted that the process followed requires an independent assessment of the value of the RAB. Actual capital expenditure on these assets is not considered when this RAB valuation is undertaken. It is viable benchmarks, for the depreciated replacement costs that are considered in arriving at the valuation of RAB as at 31 March 2020.

The RAB valuation was undertaken by an independent entity that has international experience in the realm of asset valuation for large infrastructure companies. As required by the MYPD methodology, the determination of the regulatory asset base value is based on the costs to replace these assets (i.e. Modern Equivalent Assets Valuation (MEAV)) and adjusted for the remaining life and any relevant forms of obsolescence. This valuation has been undertaken in accordance with the guidelines and requirements of the International Valuation Standards. The basis of the valuation was the Eskom fixed asset registers and comparisons were made with market data for actual construction cost of similar assets. This valuation exercise included site visits where samples of the physical assets were performed. The site visits had to be minimised due to the restrictions of the COVID-19 pandemic.

In determining the depreciated replacement cost, the independent consultants ensured that the following key elements were undertaken as per Figure 5.

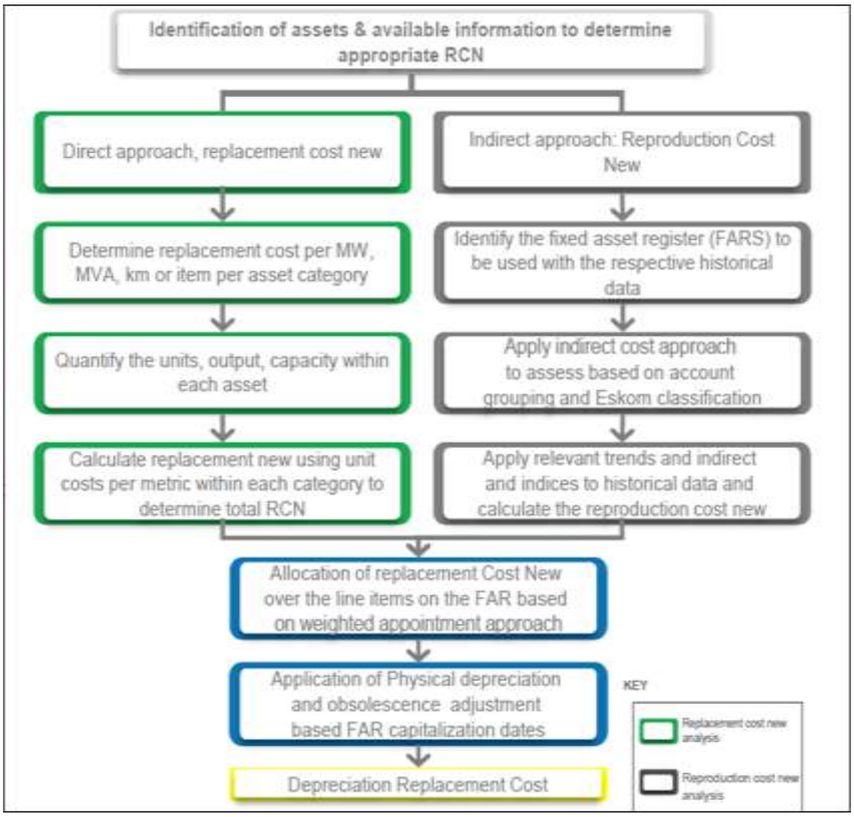
FIGURE 5: VALUATION KEY STEPS



The International Valuation Standards Charter defines a Modern Equivalent Asset as *"An asset which provides similar function and equivalent utility to the asset being valued, but which is of a current design and constructed or made using current materials and techniques."* The MEAV approach is synonymous with the Cost Approach or Depreciated Replacement Cost (DRC) approach. The DRC was determined through the application of the cost approach methodology, which is a recognised approach for the valuation of specialist assets which are not regularly traded. The cost approach methodology includes the identification of the estimated new replacement cost of assets, which is then adjusted to reflect physical, and functional obsolescence.

Refer to Figure 6 which provides an overview of the cost approach valuation methodology.

FIGURE 6: VALUATION METHODOLOGY



The Eskom assets have been valued based on a Depreciated Replacement Cost (DRC) method. The DRC method is a form of cost approach that is defined as:

"The current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation."

The DRC method is based on the economic theory of substitution and it involves comparing the assets being valued with another. However, DRC is normally used in situations where there is no directly comparable alternative. The comparison, has to be made with a hypothetical substitute, also described as the modern equivalent asset (MEA).

The underlying theory is that the potential buyer in the exchange would not pay any more to acquire the asset being valued than the cost of acquiring an equivalent new one. The technique involves assessing all the costs of providing a modern equivalent asset using pricing at the valuation date.

In order to assess the price that the potential buyer would bid for the actual subject asset, valuation depreciation adjustments have to be made to the MEA to reflect the differences between it and the subject assets.

These differences can reflect obsolescence factors such as the physical condition, the remaining economic life, the comparative running costs and the comparative efficiency and functionality of the actual subject assets.

The asset values in the Regulatory Asset Base are therefore not shown at the new cost to replace them but at their depreciated replacement cost. For example, if it would cost R1bn to replace an asset at the end of March 2020 which has two years remaining life out of a total useful life of 25 years, the depreciated replacement cost at the end of March 2020 would be R80m (i.e. R1bn x 2/25).

A key benefit of this methodology is that the DRC is based on an external market related valuation for new and equivalent assets considering remaining life and obsolescence. The DRC is therefore not based on actual expenditures as were incurred by Eskom which could include inefficiencies with the asset creation process or procurement irregularities.

The details with respect to the Transmission Regulatory Asset Base (RAB), Depreciation and Return on Asset for this revenue application are included in the following sections.

3.1.1 Regulatory Asset Base (RAB)

The summarised Transmission RAB application is included in Table 9.

TABLE 9: TRANSMISSION: REGULATORY ASSET BASE SUMMARY (R'M)

Transmission Regulatory Asset Base (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	62 890	56 131	92 372	86 535	80 850	75 385	70 026
Assets Transferred to CO	25 474	29 246	14 429	29 048	37 703	47 297	59 645
Work Under Construction (WUC)	16 269	20 776	18 293	16 395	19 815	24 420	30 249
Net Working Capital	2 074	2 245	1 413	1 531	1 706	719	(356)
Assets Purchases	191	168	187	170	156	192	277
Assets funded upfront by cust.	-	-	(469)	(462)	(454)	(445)	(435)
Closing RAB	**106 898**	**108 566**	**126 225**	**133 217**	**139 777**	**147 568**	**159 405**

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.

3.1.1.1 Depreciated Replacement Cost (March 2020)

The Depreciated Replacement Costs (DRC) as per the valuation report is shown in Table 10. The valuation report excludes interest during construction (IDC) due to the overnight cost being used to determine the MEAV. Overnight cost is defined as the cost of a construction project if no interest is incurred during construction as if the project was completed overnight.

TABLE 10: VALUATION REPORT EXTRACT (R'M)

	Cap Cost	NBV	NBV in Scope	Final RCN	Physical Depreciation	DRC
Transmission (Dx)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)	(ZAR Millions)
Telecommunications (6000)	2.277	1.337	1.337	2.977	(2.187)	799
Transmission Plant (16000)	65.315	44.942	44.942	294.425	(186.586)	107.838
Land (Tx) 1000	281	281	-	-	-	N/A
Buildings (Tx) 4000	929	801	-	-	-	N/A
Sub total	**68.802**	**47.361**	**46.279**	**297.402**	**(188.765)**	**108.637**

The Capital Cost (Cap Cost), Net Book Value (NBV), and Net Book Value in Scope (NBV in Scope) was in accordance with the Eskom's fixed asset registers (FARs). The Modern Equivalent Asset Value (MEAV) was determined using the Overnight Cost methodology and assigned the costs on a "like for like" basis based on the nature of the subject assets to arrive at the Final Replacement Cost New (RCN). The Final RCN was adjusted for physical depreciation as per the age profile of the assets. The Final RCN less Physical Depreciation was then adjusted for Technical Obsolescence based on the performance of the assets in comparison to a defined performance standard, to arrive at the Depreciated Replacement Cost. The Depreciated Replacement Cost being "the current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation.

The Transmission valuation of R 108,6bn excludes land and buildings, working capital, assets purchases, Work under Construction and assets planned for commissioning after end March 2020 since these were not part of the scope of the consultants' valuation project. These components were indexed to the inflation rate for the respective years as well as depreciation adjustments were added in accordance with the MYPD methodology to determine the total RAB value as detailed in Table 9.

3.1.1.2 Work under construction (WUC) and Assets Transferred to 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 transmission 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.

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.

3.1.1.3 Assets excluded from RAB

The DRC valuation for Transmission assets as shown in Table 10 includes assets that are funded via upfront customer contributions. In terms of the MYPD methodology these assets do not earn a return on assets and their depreciation is not to be included in the revenue requirement.

The total assets shown in Table 9 and the depreciation reflected in Table 12 have therefore been reduced by the values as shown in Table 11 below to exclude such assets.

TABLE 11: TRANSMISSION: ASSETS FUNDED VIA UPFRONT CONTRIBUTIONS (R'M)

Assets Funded by Customers Upfront (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening Balance	(1 372)	(1 238)	(476)	(469)	(462)	(454)	(445)
Inflation on Opening Balance			-	-	-	-	-
Transfers to CO			(15)	(15)	(15)	(16)	(16)
Depreciation	134	141	22	23	23	24	25
Closing Asset Values	**(1 238)**	**(1 097)**	**(469)**	**(462)**	**(454)**	**(445)**	**(435)**

The objective of tracking these assets as a separate asset class (as shown in Table 11) is to ensure transparency; therefore both the RAB and the depreciation are reduced accordingly.

3.1.2 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 debt incurred. As is required by the MYPD methodology, the annual depreciation allowance is determined by dividing the cost of the asset by the estimated useful life of that asset.

Table 12 reflects the revenue related to depreciation for the MYPD5 period.

Depreciation on assets as per the FY2020 valuation is computed by dividing the depreciated value of the assets over the remaining life of the respective assets as reflected at the end of March 2020. This depreciation cost is included with the "Existing Fixed Assets" category in Table 12.

All subsequent transfers to commercial operation post 31 March 2020 are depreciated over the asset life but limited to the normal useful life for all Transmission assets. The depreciation costs for these assets are included with 'Transfers to CO' in Table 12.

TABLE 12: TRANSMISSION: DEPRECIATION (R'M)

Transmission Depreciation (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Existing Fixed Assets	5 929	5 837	5 686	5 465	5 360
Fixed Assets - Transfers to CO	380	777	1 217	1 570	1 995
Asset Purchases	47	43	39	48	69
Assets funded upfront by customers	(22)	(23)	(23)	(24)	(25)
Total Depreciation	**6 334**	**6 634**	**6 919**	**7 059**	**7 398**

3.1.3 Return on assets

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 are being phased to allow for the smoothing of the tariff as shown in Table 13. This is the phasing that Eskom 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. This migration is accompanied by risks which need to be managed. It is unfortunate that further burden is required to be applied on the fiscus. In essence the subsidy provided to all consumers is continued to be provided for a longer period.

TABLE 13: TRANSMISSION: RETURN ON ASSETS

Transmission Return on Asset (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	126 225	133 217	139 777	147 568	159 405
Real pretax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost Reflective RoA (R'm)	8 962	9 458	9 924	10 477	11 318
RoA Applied for RoA %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA Applied for (R'm)	**(2 513)**	**922**	**1 220**	**2 427**	**4 838**

3.2 Operating Costs

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. Table 14 reflects the business operating costs.

TABLE 14: TRANSMISSION: OPERATING AND MAINTENANCE COSTS (R'M)

Transmission: Operating Expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee Expenses	1 729	2 374	2 586	2 708	2 870	3 063	3 203	3 383
Maintenance	638	816	934	982	1 054	1 117	1 160	1 218
Other Operating Expenses	810	569	680	750	797	895	931	985
Corporate Overheads	1 414	1 283	1 213	1 262	1 340	1 076	1 176	1 254
Other Income	(126)	(150)	(101)	(107)	(113)	(120)	(127)	(127)
Total Operating Expenditure	**4 464**	**4 892**	**5 311**	**5 594**	**5 948**	**6 030**	**6 343**	**6 713**
Corporate Overheads: portion excluded from revenue	-	57	(266)	(245)	(270)	(289)	(272)	(272)
Total Operating Expenditure for Revenue Requirement	**4 464**	**4 949**	**5 046**	**5 349**	**5 678**	**5 741**	**6 071**	**6 441**

The projection for the operating costs has taken into account the importance of driving cost curtailment in line with the turnaround plan to reduce Eskom's cost base, these initiatives are expected to contribute to the overall Eskom's financial sustainability.

3.2.1 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.

In alignment with the Department of Public Enterprises Roadmap, functional unbundling of Eskom has resulted in staff servicing Transmission being transferred from Eskom Corporate and centralised functions to the Transmission Division. The growth in Transmission employee expenses is therefore due to an increase in headcount as an outcome of the organisational restructuring implemented since FY2020. It should be noted that the Transmission headcount increase was predominantly based on relinking of staff within Eskom. This relinking and resourcing of key functions is planned to be concluded during FY2022.

The need for fundamental operational changes is recognised in order to provide affordable, sustainable electricity supply to all South Africans. Efficiency opportunities have also been pursued to ensure that the headcount increase is contained utilising natural attrition and voluntary separation options to drive internal efficiencies, increase productivity and lower operating costs.

The Transmission staff complement is planned to grow during the MYPD5 period to enable the advancement of energy market services as well as the capacity to execute capital projects for the Integrated Resource Plan (IRP 2019) and increased asset renewal plan. System expansion investments over the MYPD5 period will also increase the asset base and associated operational workload drivers and headcount requirement to maintain and operate these assets. Table 15 provides a summary of employee expenses and headcount.

TABLE 15: TRANSMISSION: EMPLOYEE EXPENSES AND HEADCOUNT

Transmission: Employee Expenses and Headcount	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee Expenses (R'm)	1 729	2 374	2 586	2 708	2 870	3 063	3 203	3 383
Headcount	2 084	2 839	3 092	3 154	3 152	3 226	3 225	3 225

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.

3.2.1.1 Staff Re-linking

As part of Eskom's organisational restructuring and divisionalisation process, employees in service and support functions were re-linked back to line functions. The aim of this process was to:

- Strengthen operations and maximise decision making;
- Improve levels of accountability at the right levels of business;
- Improve operational and financial efficiencies;
- Maximise execution of strategy; and
- Improve productivity and value delivery - shortest sustainable lead time.

Employees from Technology, Telecommunications, Procurement, Finance, Properties, Research and Human Resources divisions were relinked to Transmission since FY2019. Further staffing to acquire the required capacity for some functions is planned to be concluded in FY2022. Table 16 shows the number of staff relinked to Transmission.

TABLE 16: TRANSMISSION: STAFF RELINKING IN RECENT YEARS

Business Areas/Functions	FY 2021	FY 2022	Total
Eskom Telecommunication	376	-	376
Engineering	239	-	239
Land & Rights	41	-	41
Finance	112	1	113
Procurement	61	18	79
HR	33	1	34
Project Development Delivery	-	16	16
Security	20	2	22
Research, Technology & Development	-	12	12
Other (CAD, Eskom Real Estate)	6	-	6
Demand Response	9	-	9
Grid Access Unit relinked out to Distribution	(34)	-	(34)
Total	**863**	**50**	**913**

3.2.1.2 Additional Staff Requirements

Transmission staff complement is expected to increase from 3 092 in FY2022 to 3 226 by FY2025 representing a 4% growth over the MYPD5 period. Legal separation from Eskom requires the new Transmission entity to resource itself in the various functional/service areas in order to deliver on its new and expanded mandate. These areas include:

- Energy Market Services which will be required to provide new services to the changing electricity supply industry;
- Increased asset creation in support of the IRP 2019 and asset replacement for sustainability as detailed in the Transmission Development Plan (TDP);
  - Transmission has conducted an assessment of resourcing requirements to deliver on the TDP 2021-2030 objectives.
  - The results of the internal resource analysis concluded a need to increase staff complement with +/- 175 between the periods 2021 to 2025.
- Legal, compliance & regulatory resources to support Procurement and various contract functions in Energy Markets Services and Grids;
- The need to adequately resource Security functions to protect Transmission assets and workforce.

3.2.1.3 Cost Saving Initiatives

One of the conditions of the Special Appropriation Act of 2019 whose aim was to provide financial assistance to Eskom in order to meet its financial obligations is that no salary adjustments or bonus should paid out to non-bargaining employees in financial year 2021.

Savings initiatives including overtime reduction, structure optimisation by reducing the number of Grid areas as well as voluntary cash separation packages were implemented to reduce employee expenditure.

3.2.2 Maintenance

3.2.2.1 Background and maintenance costs

Maintenance is performed in order to:

- Extend plant life;
- Ensure high levels of plant availability;
- Ensure quality of supply delivery to customers;
- Ensure the safety of people;
- Contribute to the long-term sustainability of Eskom.

Maintenance is planned and executed in accordance with maintenance standards and procedures as well as with due consideration to environmental management and OHS Act requirements. Maintenance planning, scheduling, execution and control are performed utilising the SAP Plant Maintenance system. Maintenance outages are scheduled based on evaluating network risks and outage optimisation opportunities. The bulk of maintenance tasks are executed by Transmission employees whilst some work is contracted out to service providers or OEM's considering efficiencies or the specialised nature of the work. Table 17 summarises the breakdown of Transmission's maintenance costs.

TABLE 17: TRANSMISSION: MAINTENANCE COSTS (R'M)

Transmission: Maintenance Costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Servitude Maintenance	46	118	168	171	183	195	202	212
Line Maintenance	107	167	185	191	204	215	223	234
Primary Plant Maintenance	177	189	201	207	218	229	238	250
Secondary Plant Maintenance	38	49	54	57	60	65	67	71
Equipment & Spares	16	30	32	34	38	40	41	43
ERI (Transformer & Logistics)	233	241	274	303	329	351	365	383
Other	21	22	19	19	22	23	22	23
Total Maintenance	**638**	**816**	**934**	**982**	**1 054**	**1 117**	**1 160**	**1 218**

3.2.2.2 Maintenance strategy

Maintenance workload is driven by the size of the network and the condition / age of assets. Transmission's maintenance strategy includes the compilation and review of maintenance philosophies, standards and procedures. Incident investigation recommendations requiring modifications to existing standards and procedures are used as additional input during the revision of the standards.

The maintenance philosophy is mostly time-based, but also considers the following:

- Operational information (usage);
- On- and off-line condition monitoring;
- Plant performance information;
- Non-intrusive functional testing;
- Statutory requirements;
- Safety of assets and people.

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.

3.2.2.3 Maintenance cost drivers

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

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

a) Increased Transmission System Asset Base:

The Transmission system assets (km of lines and substation plant) increased by +/- 5% over the last 5 years. This has increased the associated maintenance workload, such as:

- Additional operating workload at new substations or substation extensions;
- Additional lines servitude inspection and maintenance tasks (aerial & ground);
- Additional primary plant inspections and maintenance tasks.

b) Age Profile of Transmission System Assets:

A high percentage of transmission assets are beyond mid-life requiring increased major maintenance; Refer to Figure 12 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 under expenditures as well as the undesired increased number of line faults due to veld fires. The objective is to normalize vegetation management practices in order to achieve line fault performance improvement. This will result in increased line maintenance expenditure going forward. High levels of maintenance execution is required to ensure required plant availability and technical sustainability.

3.2.2.4 Maintenance cost escalation

The increase in maintenance expenditure projection is as a result of abnormally low maintenance expenditure in FY2020 owing to the delay in the conclusion of servitude maintenance contracts. This was due to changes in the servitude contract procurement strategy with regards to decentralizing the contract management to regional level as opposed to the previous national contract and also delays in other procurement processes in concluding service contracts, issuing of enquiries and tender evaluations.

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

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

3.2.2.5 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 Table 18.

TABLE 18: TRANSMISSION: 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.)

3.2.2.6 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.

3.2.3 Other operating costs

The escalation of other operating costs is primarily driven by the re-linking of corporate functions to Transmission (represent 48% growth in staff complement) and direct impact on various costs categories such as IT, travelling, lease expense, insurance as well as electricity consumption. The above inflation increases in other operating costs are mostly in FY2021 (beginning of the re-linking process) and FY2022 (consolidation of the re-linking and divisionalisation process), and then stabilise throughout the MYPD5 period.

Other operating costs are summarized in Table 19. Details per category are included in the following sections.

TABLE 19: TRANSMISSION: OTHER OPERATING EXPENSES (R'M)

Transmission: Other Operating Expenses (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance Premiums and repairs	202	246	260	269	283	301	317	333
Security Expenses	94	125	147	152	162	170	177	186
IT Expenses	22	62	87	92	93	98	108	113
Telecommunications	69	86	90	96	98	102	107	112
Travel Expenses	47	65	81	94	99	107	110	113
Consulting and Legal Costs	3	44	47	48	49	52	53	55
Facilities	25	47	48	53	59	64	68	72
Leases	10	22	28	30	32	36	39	41
Internal Electricity Costs	14	22	24	26	29	31	34	35
Abnornal Costs	314	-	-	-	-	-	-	-
Other	11	(150)	(131)	(112)	(108)	(66)	(82)	(76)
Total	**810**	**569**	**680**	**750**	**797**	**895**	**931**	**985**

3.2.3.1 Insurance

The increase in asset base and staff has causal effect on the escalation of the insurance premiums in FY2021 onwards.

Factors that influence 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.

Insurance policies products currently in place for Transmission covers a number areas including but not least all asset risk, terrorism, motor and mobile plant fleet, aviation related risks, interruption of supply, environmental liability as well as general and public liability.

3.2.3.2 Travel and fleet costs

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

Transmission 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 major portion of the total fleet costs.

3.2.3.3 Telecommunication

Telecommunication costs are projected to remain stable throughout the MYPD5 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.

Eskom 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 System Operator business environment. The future implementation of Wide Area Monitoring and Substation Automation will increase the required telecommunication capacities going forward. The increase of Transmission-connected IPP's and embedded generation within the Distribution as well as municipal networks will also have an impact on the telecommunication requirements going forward.

3.2.3.4 Security costs

The growth of security related costs in FY2021 and FY2022 is as a result of inclusion of 527 telecommunications network sites owned and operated by Eskom Telecommunication. Most of these sites are located in remote and not easily accessible areas where security reaction units are not available. Provision is also made to mitigate/upgrade the current security arrangement in the telecommunication sites to safeguard the assets and ensure reliable operation of the network.

Transmission's security expenses are mainly for the following:

- Guarding; Access Control and patrols of sites and substations inclusive of national key points;
- Crime prevention;
- Armed response services for alarm activation at sites and substations;
- Line patrols; of high risk lines where towers are vandalised or during an outage the line will require patrols
- Repairs/servicing of control room equipment (screens, monitors, computers, radios);
- Licensing of equipment; (same does not contribute substantially to the increase)
- Employee's protection while performing tower repairs in high risk areas where they can be victims of crime e.g. hi-jacked or robbed;
- Escorting of staff to high risk sites during late at night/early morning to respond to plant failures.
- Tactical response teams – required in areas where Eskom experiences community protest, and in volatile situations, such a response team is required.

A hybrid of security guards and security technological systems are deployed to mitigate increased risks in copper theft and to preserve the integrity of assets and continuity of supply. The increasing high demand for non-ferrous metals has highlighted the vulnerability of Eskom facilities to vandalism and theft. The security measures are currently inadequate to mitigate the risk. Most of the sites/substations and towers are located in remote areas where security reaction units are not available. Even if security systems are working optimally (i.e.

detecting, deterring, delaying if they are breached), security staff are required to respond to alarms.

The following risks are mitigated by provision of security personnel:

- National Key Points are governed by the National Key Point Act 102 of 1980 which stipulates that security guards must be deployed at these sites;
- Transmission's substations are located in isolated areas or near residential areas with risks of copper theft, civil unrests and armed robbery;
- Contributing to continuity of energy supply.

Consideration cannot only be given to the number of security incidents, but also to the impact an individual security incident may impose on the network reliability (e.g. one incident of a fallen tower can result in millions of rands worth of damage and a sustained interruption of supply).

The roll out of technology will enable Eskom to reduce the cost associated with security contractors. Initially there will be a need to invest in capital expenditure for security technology however it will be offset by the decrease in the number of security guards per site. A technology centric approach will assist in curbing the uncontrolled escalation of guarding cost. The implementation of security technology in the remote sites will include:

- Pre-detection cameras (CCTV);
- Alarms system;
- Security lighting;
- Non-lethal electric fence.

3.2.3.5 Information Technology (IT)

IT costs are mainly driven by the number of users and the number of applications used. The 48% growth in Transmission staff complement from FY2020 to FY2022 (see Table 15) resulted in the increase in the proportional charge of IT costs. The following services forms part of direct charges:

- Infrastructure services;
- End user computing;
- Help desk;
- 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 is limited to applications used by Transmission.

3.2.3.6 Consulting and legal costs

Consulting costs have substantially increased mainly due to the relinking of land & servitude rights management to Transmission. National Environmental Assessments Act (NEMA) requires Eskom to appoint independent professional service providers to undertake certain task as part of acquiring property/servitude rights. The independent service providers perform the following services:

- Geotech studies,
- Town planning assessments,
- Visual impact assessments, social impact assessment etc.
- Property valuation,
- Land Surveying and,
- Negotiations.

Consultants are also required to assist in planning studies, load forecast studies and an independent review of Transmission's planning model.

Legal costs are mainly related to IPP's with regard to contract establishment, advising on legal disputes and arbitrations (such as arising from curtailment or deemed energy claims).

3.2.3.7 Facilities

This includes costs to service and maintain business owned buildings and facilities. The expenditures incurred are for rates and taxes, municipal services, repairs and maintenance as well as cleaning services. Repairs and maintenance represent nearly half of the total facility costs.

Transmission's facility repairs and maintenance expenses increases in FY2021 onwards due to the need to undertake major building maintenance that has not been performed due to ongoing financial constraints coupled with delays in concluding technical maintenance service contracts to cater for electrical, air-conditioning, fire systems, fire equipment and plumbing repairs.

Transmission office and storage buildings are old, and thus require continuous repairs and maintenance of the buildings and the equipment attached to them. 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.

3.2.3.8 Leases

This is primarily for the rental of office space and storage areas where Eskom does not own sufficient facilities, aircraft hangars as well as site sharing expenses for telecommunication infrastructure as per the ICASA regulations. The escalation in leasing expense is determined by the existing provisions in the lease agreements.

3.2.3.9 Abnormal costs

The following costs incurred in FY2020 are considered as unusual and therefore not part of the normal operational costs.

- Customer refunds;
- Scrapping of assets not yet commissioned;
- Scrapping of Capital spares.

3.2.3.10 Other

Other costs are inclusive of environmental expenses, safety equipment, stationery, other sundry office expenses as well as Eskom Telecommunication cost recovery from line divisions.

3.2.4 Corporate overheads

Corporate overheads charges are costs that cannot be allocated directly to a specific line division because the service provided is an overall support to the various divisions in delivering core business activities. Overheads in Eskom are split between direct (specific) and indirect (general) overheads. These costs include the portion of the total Eskom overhead costs which have been allocated to the Transmission licensee.

3.2.4.1 Direct/Specific Overhead Charge

Direct overheads are those costs which are apportioned to the core business by using the most appropriate cost driver that is specific to the service being provided. The following services are charged as direct overheads:

- Shared Services – this includes accounts payables services, payroll and other HR shared service support functions
- Information Management

- Eskom Real Estate
- Finance

3.2.4.2 Indirect/General Overhead Charge

Indirect overhead costs cannot be directly allocated to a specific division using a distinctive cost driver and are shared amongst the three licensees in proportion to employee complement, asset values and other operating costs. The costs relate to services provided at group level mainly to optimize resources, take advantage of synergies and minimize duplication of efforts. This includes corporate advisory services, business support, administration and strategic functions Eskom business.

Corporate overheads expenses are grouped into direct corporate overheads and indirect corporate overheads as reflected in Table 20. These costs include the portion of the total Eskom overhead costs which have been allocated to the Transmission licensee.

TABLE 20: TRANSMISSION: CORPORATE OVERHEAD COSTS (R'M)

Transmission Corporate Overheads (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Overheads	853	579	443	430	459	494	532	550
Indirect Overheads	561	704	770	832	881	582	644	704
Corporate Overheads	**1 414**	**1283**	**1 213**	**1262**	**1 340**	**1076**	**1 176**	**1254**

3.2.5 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 21: TRANSMISSION: OTHER INCOME (R'M)

Transmission Other Income (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance proceeds/recovery	(113)	(53)	-	-	-	-	-	-
Operating lease income	(1)	(42)	(44)	(46)	(49)	(52)	(55)	(55)
Sundry income	(13)	(55)	(58)	(61)	(65)	(68)	(72)	(72)
Total	**(126)**	**(150)**	**(101)**	**(107)**	**(113)**	**(120)**	**(127)**	**(127)**

3.3 Ancilliary Services and Demand Reduction Programmes

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

The Ancillary Services, Demand Response and Power Alert form part of Generation licensee Primary Energy revenue requirement in the Allowable Revenue formula. It can be noted that the AS IPP reserves revenue requirements are embedded in Eskom's overall IPP revenue application to NERSA. Thus the motivation for Ancillary Services (including IPP reserves), Demand Response and Power Alert is included in the Transmission script whilst the revenue application has been included with the Generation Licensee MYPD5 application as per the MYPD Methodology.

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 manner in which they are to be provided is defined in the South African Grid Code.

The ancillary services currently defined include:

- Reserves (Generation, IPP's & Demand Response),
- Black Start and Islanding,
- Energy Imbalance (Constrained Generation) as well as
- Reactive Power and Voltage Control.

The System Operator also applies a Power Alert programme which is used during system constraints for consumers to reduce demand during peak hours.

The following are the assumptions and declarations relating to the MYPD5 revenue requirement proposal:

- The Eskom FY2022 projections and previous expenditure trends was used as reference for the MYPD5 base year.
- Parameters such as CPI are based on the Eskom Economic evaluation parameters directive.
- Requirements were based on the latest Production plan and Ancillary Services Technical Requirements.
- The Risk Mitigation Independent Power Producer Programme (RMIPPP), Eskom Battery Energy Storage Facility (BESF) will come online and start providing ancillary services in FY2023.

- Synchronous Condenser Operation (SCO) revenue requirements are based on the approved FY2021 Wholesale Integrated Selling Price (WISP) rates that have been escalated by 8% over subsequent years.
- There may be other IPP facilities offering ancillary services in the future. At the time of this submission these costs were unknown. However a provision has been made for services from these providers based on previous experience with other potential IPPs.
- The System Operator continues to research international developments and best practices. This may lead to the introduction of new AS products and/or new costing methodologies which could impact future MYPD applications.
- The costing methodology that will be used in MYPD5 revenue application is largely the same as the methodology used in MYPD4 application. Any proposed changes have been explained in the sections to follow.

The revenue requirement for Ancillary Services and Demand Reduction is summarized in Table 22 and are based on the volumes as per the Ancillary Services Technical Requirements defined in the Grid Code. In terms of the NERSA Allowable Revenue formula, the above ancillary services revenue requirements fall under the Primary Energy (PE) component of the Allowable Revenue formula. The AS IPP reserves revenue requirements are also embedded in Eskom's overall IPP revenue application to NERSA.

The System Operator has to be prudent in planning and budgeting for unforeseen events and contingencies that can impact on system reliability. The rationalization and breakdown of the above revenue requirements are provided in the sections to follow.

The reliability of the power system has been compromised in recent years due to a lack of sufficient reserves. To help remedy this during the MYPD5 window, the System Operator has:

- Increased the quantity of reserves required from Demand Response providers;
- Implemented a performance based costing methodology for emergency reserves;
- Made provision for the procurement of additional reserves from IPP's and BESF at cost reflective rates.

This has resulted in a significant increase in the reserves revenue requirement for MYPD5.

TABLE 22: ANCILIARY SERVICES AND DEMAND REDUCTION REVENUE REQUIREMENTS (R'M)

Transmission Ancillary Services (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Reserves Total	333	321	369	895	937	979	1 164	1 218
Eskom Generation	*22*	*26*	*30*	*40*	*42*	*44*	*47*	*49*
Eskom BESF	-	-	-	*59*	*62*	*65*	*68*	*71*
IPP's and External BESF	-	-	-	*415*	*434*	*453*	*615*	*643*
Demand Response	*311*	*295*	*339*	*381*	*399*	*416*	*435*	*455*
Reactive Power and Voltage	169	185	199	112	121	131	142	153
Black Start & Islanding	41	45	52	53	55	55	56	59
Constrained Generation	0	2	12	-	-	-	-	-
Power Alert	-	33	78	78	78	78	78	78
Total	**543**	**586**	**710**	**1 138**	**1 191**	**1 243**	**1 440**	**1 508**

3.3.1 Reserves costing

3.3.1.1 Reserves from Eskom Generation

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

The costing methodology for IR, RR and Ten-min reserves from Eskom Gx will be based on the existing costing methodology that has been CPI adjusted.

With regards to emergency reserves from Eskom Gx, the previous (MYPD4) Emergency Level 1 (EL1) costing methodology was based on fixed components only (manpower, maintenance and efficiency components). A new EL1 costing methodology that is performance based is included in MYPD5. This is linked to the stations energy charge rate whereby providers are reimbursed for EL1 Energy Sent-out.

3.3.1.2 Reserves from IPP's and BESF

The reliability of the power system has been compromised due to a lack of sufficient reserves. The provision of reserves from existing providers has been negatively impacted by the age and technical issues plaguing most existing reserve providers. There is therefore a need to obtain reserves from additional providers. Potential IPP and BESF resources are expected to come online within the MYPD5 period. The SO is planning to procure ancillary services from these resources to further improve system reliability.

An approved costing methodology for the procurement of reserves from IPP's and BESF does not currently exist. However a provision has been made for services from these providers based on previous experience with other potential IPPs resulting in more cost reflective rates being applied. The applied rates are subject to change once the actual rates become available from these providers. The application of these cost reflective rates has resulted in a significant increase in the reserves revenue requirement for MYPD5.

TABLE 23: IPP'S AND BESF RESERVES REVENUE REQUIREMENTS (R'M)

Transmission IPP and BESF Reserves (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
IR (Eskom BESF)	-	-	1	1	1	1	1
RR (Eskom BESF)	-	-	59	61	64	67	70
Sub Total (Eskom BESF)	-	-	59	62	65	68	71
IR (IPP + External BESF)	-	-	5	5	6	8	8
RR (IPP + External BESF)	-	-	410	428	448	607	635
Sub Total (IPP + External BESF)	-	-	415	434	453	615	643
Total IPP and BESF Reserves	**-**	**-**	**474**	**496**	**518**	**683**	**713**

3.3.1.3 Reserves from Demand Response

The costs to provide the demand response services are 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 DR costing methodology for MYPD5 remained unchanged and it already includes payment penalties. Whilst the admin, energy and capacity charge rates applied have been CPI adjusted, the overall increase in the demand response budget is above CPI due to the System Operator's need for additional quantities of reserves from demand response providers to assist in offsetting the historically poor provision of reserves from other providers. A ring-fenced NERSA decision is requested on the Demand Response revenue requirements.

The MYPD5 revenue requirement for demand response reserves is shown in Table 24.

TABLE 24: DEMAND RESPONSE RESERVES REVENUE REQUIREMENTS (R'M)

Transmission: Demand Response Reserves (R'm)	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Instantaneous DR	117	134	140	146	153	160	167
Supplemental DR	151	168	209	218	228	238	249
Administration	27	37	32	35	36	37	40
Total	**295**	**339**	**381**	**399**	**416**	**435**	**455**

3.3.2 System restoration costing

System Restoration Services comprises of:

- Unit Islanding
- Black-start

The costing methodology for both unit islanding and black-start remain unchanged and are dependent on the cost drivers as well as the associated testing plan during the MYPD5 window.

3.3.3 Reactive power and voltage control costing

The System Operator regards reactive power provision from service providers as a mandatory Grid Code requirement. It will therefore not be paying for provision of reactive power within the mandatory range. Hence there is no reactive power revenue requirement in MYPD5.

However (SCO) provision will still be compensated. The System Operator will continue to dispatch SCO units as required by the system for voltage control and compensate stations for the energy consumed on a monthly basis.

3.3.4 Energy Imbalance (Constrained Generation)

Various network studies were carried out to determine the constrained generation revenue requirements for MYPD5. It is therefore envisaged that no constrained generation revenue is required for MYPD5.

3.3.5 Power Alert Programme

The System Operator (SO) is responsible for the reliability and security of the South African national electricity grid by monitoring, controlling and operating it in a safe, economical and reliable manner. One of the Demand Reduction Programmes available to the System Operator during system emergencies is the Power Alert Programme.

Power Alert is a voluntary residential demand reduction project broadcast on selected television 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 project budget of R78m per year is required to successfully implement this project as reflected in Table 22.

3.4 Transmission energy losses volumes

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 MYPD5 period is reflected in Table 25.

TABLE 25: FORECASTED ENERGY LOSSES VOLUME

Transmission: Forecast Energy Losses Volume	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Losses (%)	2.29%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Losses (GWh)	5 110	5 695	5 686	5 648	5 623	5 611	5 611

3.4.1 Losses forecasting model

The level of transmission losses are 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 FY2021 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 area have an increasing contribution to losses whereas those in the Cape and Karoo area have the opposite effect. A forecasting model used is based on multilinear /multiple regression analysis.

Three test cases were evaluated using multiple regression analysis in order to determine the relationship between generation in all the transmission zones (geographical areas) and losses. The difference between the test cases is the formulation of regressors, i.e.: the variables that are made up of geographical zones that the generators are assigned to.

- In the first test case, regressors are made up of the current 6 generation zones.

- In the second test case, the geographical proximity of the power plants is used to aggregate generators into ten transmission zones.
- Lastly, Eskom generation is assigned to 6 zones whereas IPPs are considered as a separate zone.

As shown in Table 26, the resulting forecast of 2.51% is taken as the weighted average from the three test cases and the reported year end energy losses.

TABLE 26: ENERGY LOSSES – WEIGHTED AVERAGE RESULT

Energy Losses - Weighted Average Result	Model 1 (6Z-All)	Model 2 (Geo proxy)	Model 3 (6Z-No IPP)	Model 3 (6Z-IPPIncl)	YE-Values
Losses	3.05%	2.62%	2.79%	2.09%	2.00%
Energy (GWh)	1 399 625	1 399 625	1 399 625	1 399 625	1 399 625
Weighted Average	**2.51%**				

In summary, the transmission forecasting model is based on multiple regression analysis and the results consider that transmission losses are influenced by the location of the dispatched generators and the penetration of IPPs. Based on the high R-square, it can be concluded from the results, that the chosen variables can be used to explain the current levels of losses. The forecast losses are: annual average is 2.51%, with the maximum of 3.05 and the minimum of 2.09%.

4 Revenue Related Information - Capital Expenditure

Transmission's 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.

Transmission requires R38.6bn for capital investment over the MYPD5 period as summarized in Table 27.

TABLE 27: TRANSMISSION: TOTAL CAPITAL EXPENDITURE PER CATEGORY (R'M)

Transmission : Total Capital Expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Strengthening and Expansion	1 392	1 322	2 718	10 410	11 782	10 988	11 479	16 046
Asset Replacement	710	547	619	1 127	1 604	2 040	3 307	3 443
EIA and Servitudes	94	86	201	132	112	265	983	682
Production Equipment	13	112	25	47	26	25	84	154
Total	**2 208**	**2 067**	**3 562**	**11 716**	**13 523**	**13 318**	**15 853**	**20 326**

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

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.

Environmental Impact Assessments (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.

NERSA has published rules in the Grid Code governing investment in the transmission network. Transmission 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.

4.1 System Strengthening and Expansion

With reference to Table 27, this section describes the details with regard to the planned strengthening and expansion investment of R33.2bn over the MYPD5 period.

The Transmission System Planner (TSP) is responsible for planning the expansion of the Transmission System (TS) in accordance to 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 (loads 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 Transmission Development Plan (TDP) which provides a list of identified projects and associated costs. The 2020 TDP, covering the period 2021 – 2030, will be used as the foundation for Transmission's capacity expansion plans over the MYPD5 period.

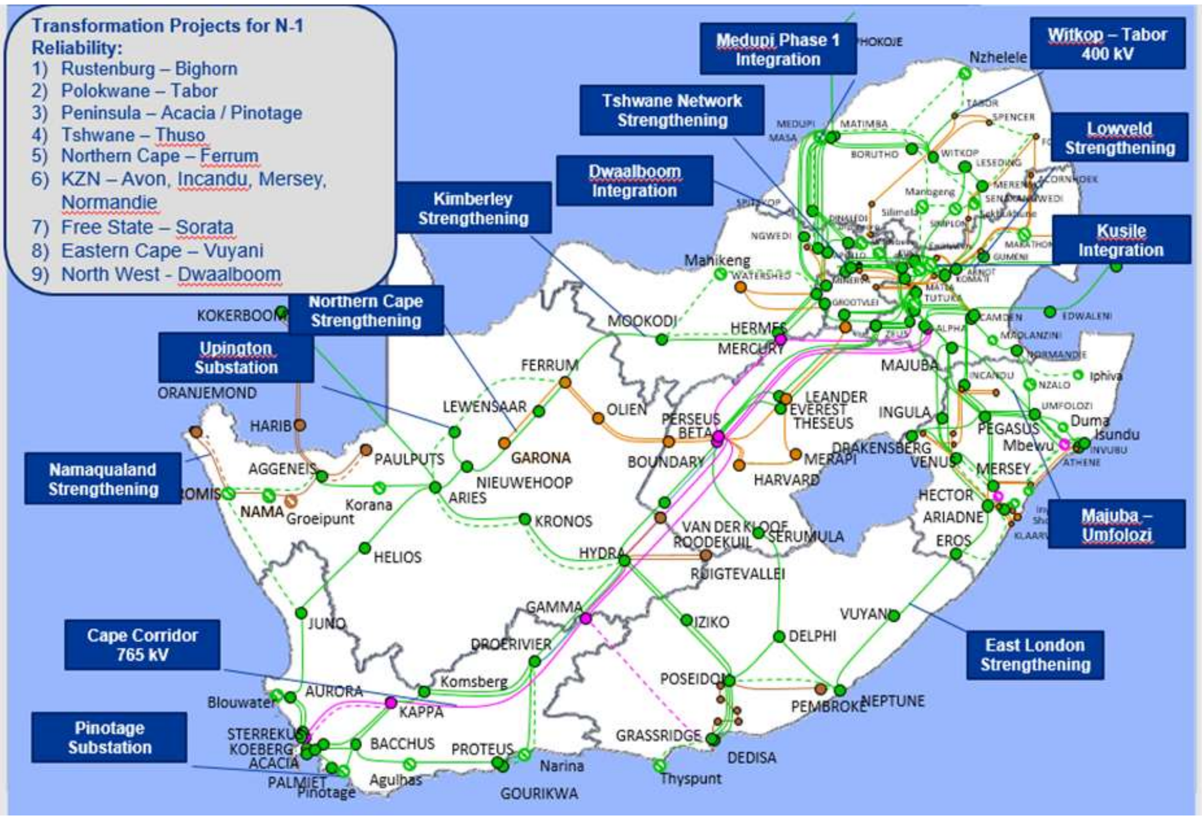
A significant amount of new infrastructure as illustrated in Figure 7 has been added to the TS in recent years mainly associated with the integration of Eskom's new generation (Medupi, Kusile and Ingula). Substantial "backbone" strengthening associated with reliability of supply has also been achieved across the network and includes the following major projects:

- Cape Corridor: 765kV lines from Mpumalanga to the Western Cape
- KZN strengthening: phase 1 of the 765kV from Mpumalanga to Empangeni
- East London strengthening: linking 400kV networks between KZN and Eastern Cape
- Lowveld strengthening: increasing the capacity between Malelane and Komatipoort
- Witkop – Tabor 400kV integration in Limpopo
- Kimberley strengthening: phase 1 of the 400kV "injection" from the North West to the Northern Cape provinces
- Upington strengthening: 400kV lines and substation linking Upington to North West and Western Cape corridors
- Western Cape: integration of the new Pinotage 400 / 132 kV substation in the Peninsula area

- North West: completion of the Dwaalboom switching to provide firm capacity to customers
- Free State: upgraded the Sorata switching station with transformation to provide firm capacity to the Harrismith area

Over and above the major "backbone" strengthening projects, a considerable number of substation transformation projects were accomplished across the country.

FIGURE 7: COMPLETED MAJOR PROJECTS

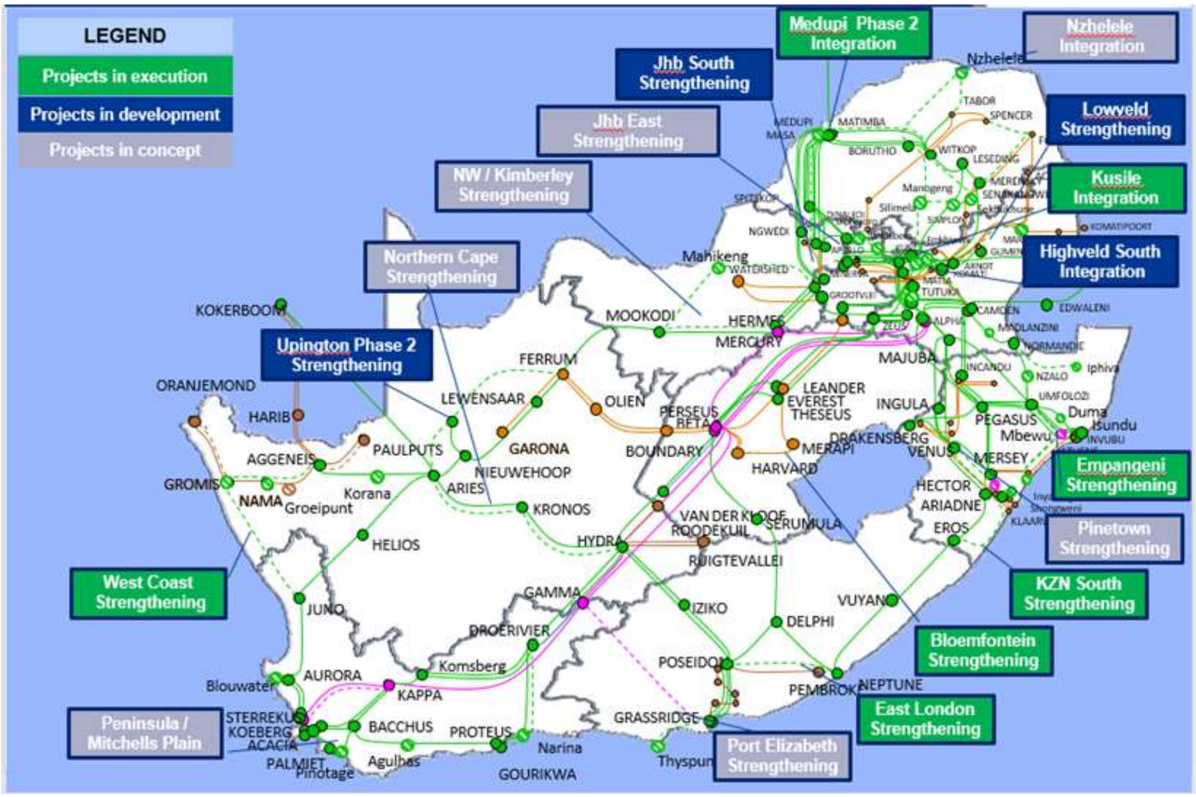


Over the next 5 year period, a substantial amount of transmission infrastructure is planned for construction across the country as illustrated in Figure 8. Some of the major projects include:

- Medupi and Kusile integration: completion of the transmission infrastructure to fully integrate these power stations
- Nzhelele integration: introduction of 400kV into the northern Limpopo province
- Tshwane network strengthening: increasing the power transfer capacity to meet the growing demand of the Municipality
- Lowveld and Highveld strengthening projects: completion of the 400kV network strengthening towards Middleburg, Nelspruit and Secunda

- KZN strengthening: phase 2 of the introduction of 765kV from Mpumalanga to Empangeni
- Bloemfontein strengthening: reliability improvements by introducing 400kV networks
- Johannesburg South and East strengthening: increasing the power transfer capacity by introduction of additional 400kV networks into the Germiston and Lenesia / Soweto areas
- Northern Cape strengthening (Kimberley and Upington): phase 2 of the 400kV integration into the region to provide capacity for the potential RE generation in the area
- West Coast strengthening: integration of the 400kV networks between the Western Cape and Northern Cape provinces from Vredendal to Oranjemond
- Cape Peninsula strengthening: introduction of 400kV into the Mitchells Plain area

FIGURE 8: PLANNED MAJOR PROJECTS



4.1.1 Planned strengthening and expansion projects

This section includes an overview of projects planned for execution over the MYPD5 period as per the following program categories:

- Generation integration projects;
- Load Customer connection projects;
- Strengthening and reliability (N-1) projects;
- Safety and statutory projects.

Expenditures for an additional year prior to and after the MYPD5 period have been included to support the capex prudency assessment (refer to section 4.1.2).

4.1.1.1 Generation integration projects

The MYPD4 application was based on the TDP 2017 that used the Draft IRP 2016 for assumptions on the new generation capacity in the country. Since then the Draft IRP 2018 was released and formed the basis for the TDP 2019. Subsequently, the latest IRP (IRP 2019) gazetted in November 2019, informed the TDP 2020. The IRP 2019 proposes a more "aggressive" role out plan for new generation capacity in the Country when compared to that of the Draft IRP 2016 or Draft IRP 2018. The net impact of the IRP 2019 is that 9.8 GW of new capacity is expected to be connected to the system within the next 5 years (by 2025) followed by 17 GW of additional capacity (of which 11 GW is for RE) to be connected between 2026 and 2030. Based on application processed, the areas of interest with abundant RE resources are limited in available network capacity. Since this additional capacity was not factored into the TDP 2019 nor in the MYPD4 application and in Transmission's capital plan, the success of the IRP 2019 is therefore dependent on an accelerated Transmission generation integration programme. This would require significant investments in Transmission infrastructure in areas with huge potential in RE resources.

Phases 1 and 2 of the Medupi integration project as well as phase 1 of the Kusile integration project were completed during the MYPD3/4 period. With this infrastructure in place it is now possible to dispatch power from 5 units at Medupi and 3 units at Kusile power stations. Over the MYPD4/5 period, Phase 3 of the Medupi integration project and Phase 2 of the Kusile integration project are planned for completion and will provide the transmission capacity to dispatch the full capacity from these power stations to the load centres.

Ongoing investments were made during the MYPD4 period to connect various IPP's to the system as per the DOE IPP programmes encompassing Bid Windows 1 to 4. As indicated in Table 28, 82 projects (4 912 MW) associated with these programmes have been successfully integrated onto the Eskom power system. A further 13 projects are in execution and expected to be completed in FY2022.

The initial available system capacity to integrate IPP's has largely been consumed in areas with high renewable energy potential thereby requiring increased deep system strengthening for future connections.

Progress on the DOE IPP programme as at October 2020 is summarised in Table 28.

TABLE 28: CONNECTION STATUS OF DOE IPP PROGRAMME

Status of current IPP programmes

Name of programme	MW contribution	Current status
RE-IPP Window 1 (28 projects)	1436	All 28 projects connected and in commercial operation
RE-IPP Window 2 (19 projects)	1054	All 19 projects connected and in commercial operation
RE-IPP Window 3 and 3.5 (23 projects)	1656	22 projects connected and in commercial operation. 1 project in execution phase.
RE-IPP Window 4 and 4B (26 projects)	2205	13 projects connected and in commercial operation. 13 projects in execution

82 RE IPP projects connected and contributing 4912 MW underpinned by ~ R3 Billion Eskom investments

Table 29 details the list of planned generation integration projects.

TABLE 29: GENERATION INTEGRATION PROJECTS (R'M)

Generation Integration (Eskom / IPPs) (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026
Waterberg GX Integration: 400kV Stabilit	457	601	345	-
Ngwedi (Mogwase) substation	-	-	-	-
Kusile TX Integration	589	388	107	-
Medupi TX Integration	379	-	-	-
Perdekraal East Wind integration (IPP)	-	-	-	-
Deep Strengthening for IPP (Komsberg)	43	-	-	-
Riverbank IPP Integration at Pembroke	-	-	-	-
Waterloo IPP Integration at Mookodi	-	-	-	-
KonkoonsiesII IPP integration Paulputs	-	-	-	-
Garob IPP Integration at Kronos	-	-	-	-
Redstone IPP Integration at Olien	-	-	-	-
Golden Valley IPP integration at Poseido	-	-	-	-
Excelsior IPP integration at Bacchus	-	-	-	-
Loeriesfontein Orange IPP Integr Helios	-	-	-	-
Kangnas IPP Integration at Aggeneis	-	-	-	-
Waterberg Stbl: Borutho-Silimela 400kV - Ph1	394	44	-	-
Waterberg Stbl: Borutho-Silimela 400kV - Ph2	157	-	-	-
Aggeneis 400/132kV 500MVA trf - IPP	33	118	-	-
Aries 400/132kV 500MVA trf - IPP	153	33	118	-
Boundary 275/132 kV 500MVA trfr -IPP	91	-	-	-
Coega 3000MW Gas Integration - IPP	19	343	583	1 019
Dorper 400/132kV S/S Integration - IPP	-	-	1	152
Garona 400/132kV integration - IPP	172	273	-	-
Groeipunt 400/132kV Establishment - IPP	203	162	-	-
Helios Strengthening ph 2 - IPP	-	3	22	111
Hydra B 2nd LILO (Hydra-Perseus 400 kV line into	-	-	-	5
Hydra B 400/132kV S/S - IPP	231	56	-	-
Khanyisa 450MW Integration - IPP	10	-	-	-
Kimberley Ph 3 : Hermes - Mookodi - Ferum 400kV line	111	963	1 904	153
Korana Int Ph1: Korana 400/132 kV S/S - IPP	-	18	236	216
Korana Int Ph2: 2nd Aggeneis Aries 400kV line - IPP	-	0	67	674
Kronos IPP Transformation Ph 3 - IPP	2	127	3	-
Mookodi 1x 500MVA 400/132KV Transformer - IPP	77	219	44	-
Namaqualand Str for IPPs : Gromis 400/132kV Transform	-	-	12	84
Namaqualand Str for IPPs : Gromis-Nama 400kV line - IPP	528	853	-	-
Paulputs 3rd Transformer : 1st 400/132kV 500 MVA	49	255	127	-
Poseidon North 400/132kV S/S for IPP	-	-	-	42
Poseidon South 400/132kV S/S - IPP	-	3	262	187
Richards Bay 3GW Gas Integration - IPP	50	70	142	1 060
Thyspunt S/S for Wind IPP	-	-	-	-
Upington Str : Aries-Upington 1st 400kV line - IPP	160	390	436	-
Upington Str : Aries-Upington 2nd 400kV line- IPP	-	-	1	115
Upington Str : Ferrum-Upington 1st 400kV line - IPP	318	585	776	-
Upington Str : Upington 2nd 500 MVA 400/132 kV	115	-	-	-
Total	**4 342**	**5 504**	**5 186**	**3 818**

4.1.1.2 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 MYPD5 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 Table 30.

TABLE 30: CUSTOMER CONNECTION PROJECTS (R'M)

Customer Connection Projects (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026
Tshwane Reinforcement Phoebus Phase 1	10	289	133	142
eThekwini Strengthening - Inyaninga	-	-	-	39
Soweto Ph 2 - Quattro 275/132kV	268	13	-	-
Soweto Phase 1 - Quattro 275/88kV	253	107	-	-
Transnet Freight Coal Line Upgrade	258	668	521	211
Tshwane Metro - Wildebees ph1	103	31	-	-
Total	**892**	**1 108**	**654**	**392**

4.1.1.3 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 taking into account future generation and demand growth.

Refer to the list of planned strengthening projects as detailed in Table 31.

TABLE 31: STRENGTHENING PROJECTS (R'M)

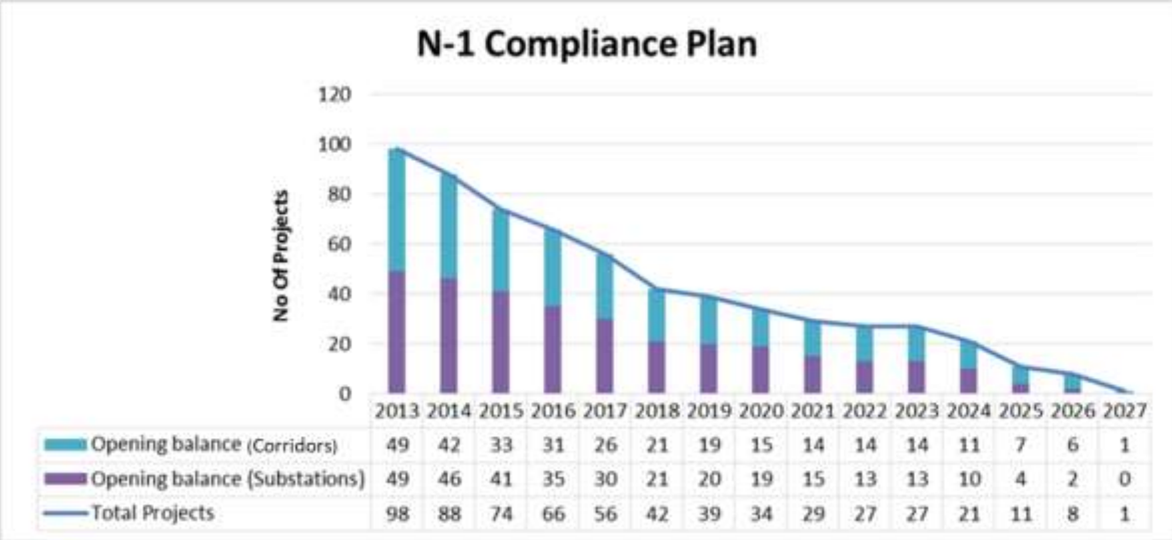
Network Strengthening (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026
KZN Str Empangeni: Mbewu Substation	-	-	35	42
KZN Str Empangeni: Mbewu Invubu and fdr	-	-	18	-
KZN Str Empangeni: Umfolozi Mbewu line	-	-	468	219
KZN Str Empangeni: Mbewu 400kV lines	-	-	6	-
Bloemfontein Strenghtening Ph2	-	-	-	13
Foskor-Merensky 275kV Line 2	104	28	259	-
Gamma Str : 2nd 500 MVA 400/132 kV transformation	-	-	-	2
Gamma Str: 1st 500 MVA 400/132 kV transformation	-	9	218	280
Gamma Str: Gamma 765/400 kV transformation - IPP	-	-	-	5
Greater East London Strength Ph 4	-	-	6	205
Rustenburg Str Phase 1 - Bighorn	-	-	-	39
Sekhukhune SS integation ph 1	-	8	172	1 200
Sekhukhune-Witkop 400kV line 1	-	-	5	590
SGS PH3: GAMMA-GRASSRIDGE 765KV LINE 1	-	-	4	207
SGS PH4: GAMMA-GRASSRIDGE 765KV LINE 2	-	-	-	3
Siluma 275/88 kV S/S (400kV build)	-	7	120	670
Sorata Substation Strengthening	-	-	-	5
AME Strengthening Projects	256	477	257	184
Telecommunications Strenghtening Projects	165	413	168	157
Total	**525**	**941**	**1 737**	**3 819**

The design of the network is based on a set of reliability criteria that has been entrenched in the South Africa 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 MYPD5 period as well as the current status regarding project execution towards the N-1 compliance is summarised in Table 32 and Figure 9 respectively.

TABLE 32: RELIABILITY (N-1) COMPLIANCE PROJECTS (R'M)

N-1 Compliance Projects (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026
Greater East London Strengthening Ph 3	-	87	316	138
Ankerlig Sterrekus 400kV Line	-	-	-	-
Highveld NW Lowveld North Str Ph2	270	204	-	-
Highveld South Reinforcement Ph2 Sol B	151	212	572	551
Ariadne Venus 2nd 400kV line	148	-	-	-
Bloemfontein Strengthening Ph1B	-	-	-	-
Harrismith Strengthening Ph1 Sorata	41	28	-	-
Ariadne Eros 2nd 132/400kV line	427	250	-	-
Simmerpan Strengthening Ph1A (Stage 1)	29	-	-	-
Vaal Strengthening Ph2B Glockner Etna	99	258	240	-
Namaqualand Strengthening Ph2 Juno-Gromis	626	213	-	-
Ankerlig TX Koeberg Second Supply	-	-	-	-
Pinotage (Firgrove) MTS	-	-	-	-
Northern Cape Str: Ferrum Nieuwehoop	-	-	-	-
Aries 400MVAR Power Compensator	4	607	-	-
Philippi substation extension	44	78	385	214
AME N-1 Projects	62	16		
Acacia Koeberg 2nd 400kV line	0	-	-	-
Emkhiweni 400/132kV S/S Integr Ph 1A	429	185	-	-
Emkhiweni 400/132kV S/S Integr Ph 1B	539	83	-	-
Erica 400/132kV MTS & lines	1	333	68	-
JHB East - Jupiter B ph1	-	-	192	678
JHB East - Jupiter ph 3	-	-	-	15
JHB East: Mesong Integration	78	154	180	617
JHB North: Apollo-Lepini 275kV	92	467	-	-
Lowveld ph2B Marathon 400kV Integr	542	-	-	-
Nzhelele 2X500MVA 400/132kV MTS Intg	-	-	28	908
Phillipi-Erica 400kV Line	736	43	-	-
Sisimuka Phase 1B 275/88kV & lines	7	118	133	-
Total	**4 325**	**3 336**	**2 114**	**3 121**

FIGURE 9: RELIABILITY PROJECTS (N-1)



4.1.1.4 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 Table 33 for additional details.

TABLE 33: SAFETY AND STATUTORY PROJECTS (R'M)

Safety / Statutory Projects (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026
Mpumalanga Underrated Equip Upgrade	47	127	-	-
Waterberg GX Fault Level Plan Merensky	-	-	-	-
Waterberg GX Fault Level Plan Witkop	-	-	-	-
Waterberg GX Fault Level Plan Perseus	5	8	5	-
Highveld Sout Reinforce Sol MTS Ph I	21	79	-	-
Waterberg GX Fault Level Plan Apollo	10	15	-	-
Waterberg GX Fault Level Plan Lomond	-	-	-	-
Waterberg GX Fault Level Plan Hermes	26	6	23	-
Waterberg GX Fault Level Plan Midas	-	-	-	-
Waterberg GX Fault Level Plan Pluto	3	-	-	-
Koeberg 400kV busbar reconfiguration	215	410	720	329
Makalu B Strengthening	-	249	549	-
Total	**327**	**894**	**1 297**	**329**

4.1.2 Expansion capital plan prudency assessment

It is recognized that NERSA is required to assess the Transmission capital expenditure from a prudency and efficiency perspective. This section provides a high level assessment of the system strengthening and expansion investment of R33.2bn over the MYPD5 period for planned projects as detailed in section 4.1.1.

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 Transmission's line and substation design specifications.

The asset valuation established the Replacement Cost New (RCN) values for the Transmission 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 Transmission installed base as at 31 March 2020. This was escalated at 5% per annum to derive the average asset construction costs for a base date of 31 March 2022. The asset valuation construction costs per Transformation MVA and km of Line are summarized in Table 34.

TABLE 34: AVERAGE ASSET CREATION COSTS (AS PER ASSET VALUATION – BASE DATE OF 31 MARCH 2020)

Total Transmission Assets	Independent Valuation RCN (R'm)		Base Date 31 March 2020	Base Date 31 March 2022
Total Transmission Assets	297 402			
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	1.125
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	5.203

The prudency assessment needs to verify if the planned system expansion capex expenditure of R 33.2bn to create 2 385 km of line and 13 990 MVA of substation transformation over the MYPD5 period is reasonable.

The planned system expansion capex expenditure as well as the assets planned to be constructed per year is summarized in Table 35.

TABLE 35: MYPD5 ASSET CREATION COST – PRUDENCY ASSESSMENT

Expansion Capex		Application FY2023	Application FY2024	Application FY2025	Totals
Strengthening & Expansion (R'm)	**A**	**10 410**	**11 782**	**10 988**	**33 180**
Assets Planned to be Constructed:					
Line Assets (km)		683	1 124	578	2 385
Transformation Assets (MVA)		4 500	4 130	5 360	13 990
Average Asset Creation Unit Cost:					
Average Cost per km of line (Rm)		5.203	5.463	5.737	
Average Cost per MVA (Rm)		1.125	1.181	1.240	
Total Average Asset Creation Costs:					
Line Asset Creation Cost (Rm)		3 554	6 141	3 316	13 010
Transformation Asset Creation Cost (Rm)		5 061	4 877	6 646	16 584
Total Justified Capex (R'm)	**B**	**8 615**	**11 018**	**9 962**	**29 594**
Variance (R'm)	**A-B**	**1 796**	**764**	**1 027**	**3 586**

The variance of R 3.6bn over the MYPD5 period is mainly ascribed to the following:

- The expansion capex includes for statutory investments of R 2.5bn over the MYPD5 period for under rated plant and safety investments.
- 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 R 33.2bn over the MYPD5 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.

4.2 Asset Replacement

4.2.1 Regulatory treatment for refurbishment investments

The South African Grid Code requires Transmission 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 are 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 <u>capital expenditure of expansionary nature, to create additional capacity</u> (i.e. which is not used and usable) <u>should be capitalised and included in the RAB</u> as and when construction costs are incurred for return purposes. Such capitalisation will however exclude interest during construction.

9.1.8.4 <u>WUC will be excluded</u> from RAB <u>for</u> the purposes of <u>depreciation</u>.

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.

With reference to Table 27, a total capital amount of R 4.8bn is planned for asset replacement investment over the MYPD5 period. Table 36 reflects the planned asset renewal investment as well as the values planned to be placed into Commercial Operation (CO) per year.

TABLE 36: PLANNED REFURBISHMENT & COMMERCIAL OPERATION (R'M)

MYPD5 Commercial Operation Transfers (R'm)	Application FY2023	Application FY2024	Application FY2025	Totals
Refurbishment - Annual Investments	1 127	1 604	2 040	4 489
Refurbishment - Planned for CO	440	704	909	2 053

4.2.2 Asset replacement planning

Transmission 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 Transmission Development Plan 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 Figure 10 and Figure 11.

FIGURE 10: TRANSMISSION SUBSTATIONS - ASSET HEALTH INDEX SUMMARY

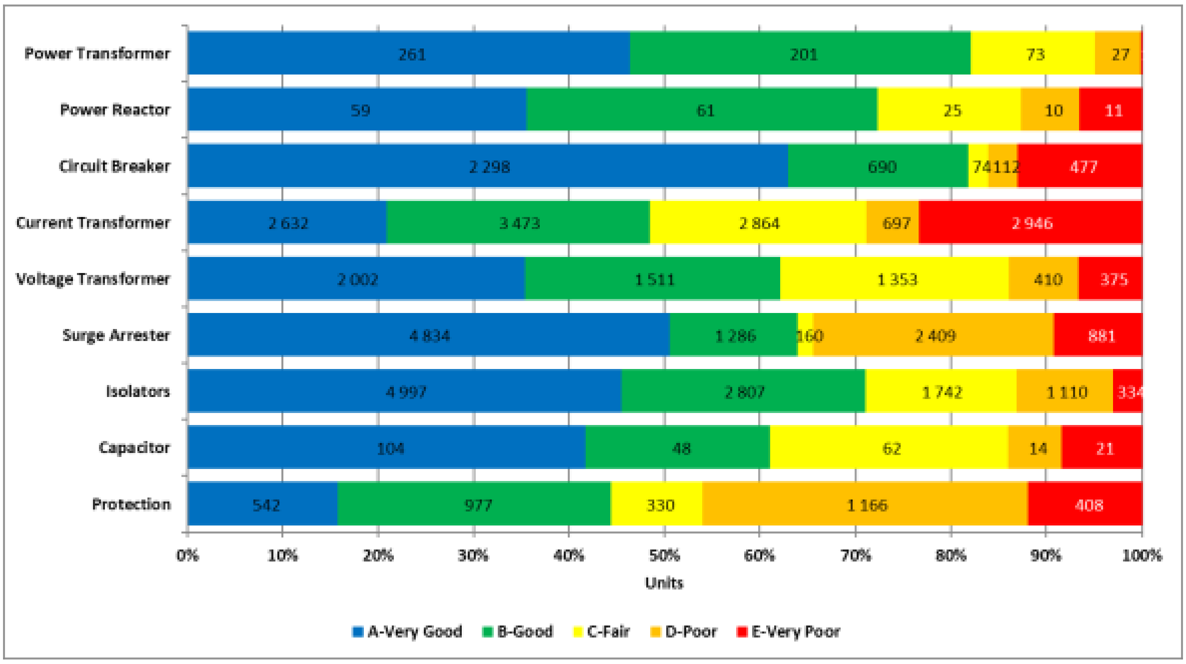
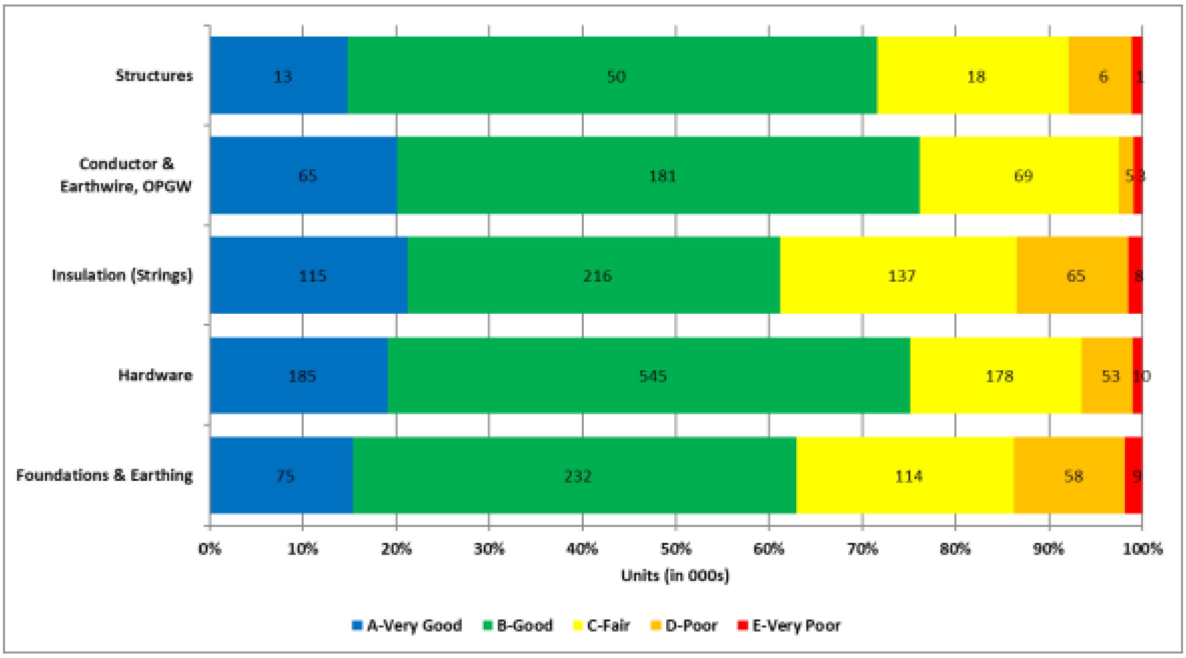


FIGURE 11: TRANSMISSION LINES - ASSET HEALTH INDEX SUMMARY



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 the course of their service life, depending on the life cycle trajectory followed.

Although age is not a direct criteria 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 Figure 12).

FIGURE 12: TRANSMISSION 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 3.1)
- 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 Transmission 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 as a result 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.

Transmission has relaunched a program of formalised asset management and intends to increase the number of areas where it aligns with requirements of international asset management standards, such as ISO 55001. At the moment Transmission 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. An Asset Management Policy has recently been approved with statements of intent that indicate a clear shift towards structured risk appraisal and project identification that will lead to value-based investment decisions. A Strategic Asset Management Plan (SAMP), outlining how each network appraisal process implements the policy, is in the final phases of compilation and will be published shortly. In addition, Eskom has launched a Capital Project Portfolio Management (CPPM) project that emphasizes 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.

Table 37 provides a summary of planned projects for the MYPD5 period.

TABLE 37: TRANSMISSION: ASSET REPLACEMENT PROJECTS (R'M)

Transmission Refurbishment (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Vulcan SS Refurbishment Phase 1: (400kV Yard)	12	76	74	20	-
Vulcan SS Refurbishment Phase 2: (2nd TRFR)	32	50	58	28	-
Grassridge SS Refurbishment :132 kV Yard	11	46	72	25	-
Pembroke SS Refurbishment	11	28	70	43	-
Phased Replacement of High Risk TRFRS PH 2	-	2	90	90	50
Apollo CS: HVDC Refurbishment Phs 2: Bridge 2&4 TRFRS	-	2	90	180	90
Scafell SS Refurbishment	11	6	74	35	-
Acacia SS Refurbishment Phase II (33 kV &132kV Yard)	8	28	53	58	-
Aurora SS Refurbishment	7	44	33	30	13
Komatipoort SS Refurbishment	5	58	20	2	-
Juno Transformation upgrade project	20	39	20	20	-
Craighall SS GIS Bypass (Now Reliability Project)	0	17	50	55	28
Buffalo SS Refurbishment	10	31	26	20	2
Kruispunt SS Refurbishment	10	47	9	12	-
Muldersvlei SS Refurbishment Phase II (132 kV Yard)	9	26	29	18	5
Hydra Roodekuil No1 132kV refurbishment of selected wood poles	5	22	23	25	35
Apollo CS Replace problematic bypass Breakers	10	21	18	-	-
Bird Faults Poor Performing East	31	10	8	-	-
Underrated CBs and assoc. bay equip - Sol	9	19	19	-	-
Helios-Juno 400kV Line Fibre Optic Project	4	23	18	-	-
Eiger SS Refurbishment	-	4	41	91	83
Nevis SS Refurbishment	1	10	33	41	54
Problematic Protection Ref. P2 - Central	0	20	20	20	5
Ankerlig - Aurora No 1 400kV OPGW /Earthwire Replacement	5	33	1	-	-
Gromis Oranjemond Line 1 Reconductor And Replace Earthwire	9	17	12	35	40
Gromis SS Refurbishment	1	20	18	35	36
Landau Colliery sinkholes and lines relocation	-	38	-	28	-
Problematic Protection Ref. P2 - East	0	15	20	20	15
Prairie SS Refurbishment Phase 1: 132 kV Yard	13	17	4	11	8
Apollo CS: Breakers 11kV Replacement	14	8	10	5	-
Apollo CS: Shunt Capacitor Bank Refurbishment	14	13	6	-	-
Makalu SS Refurbishment	1	10	20	40	50
Poseidon SS Refurbishment : 66kV Yard	0	0	30	4	4
NEG Various SS: Yard Lighting Upgrading	20	3	6	-	-
Underrated CBs and assoc. bay equip - Rockdale	13	13	3	-	-
Georgedale SS Refurbishment Phase 3 : 132kV Yard	10	12	7	20	9
Athene Pegasus Stay Clearances	13	11	4	-	-
Brenner SS Refurbishment	1	13	13	16	50
Glockner SS Refurbishment	8	15	3	-	-
National Line Trap Refurbishment	7	18	1	-	-
Phillipi SS: Install TWS Units	9	12	6	-	-
Luckhoff CS problematic equipment	0	26	-	-	-
Problematic Protection Ref. P2 - NEast	1	10	15	15	15
Craighall - Lepini 275kV Line Tower Failure	8	9	7	-	-
Ingagane SS Refurbishment P1: 88kV Yard	-	12	12	-	-
CG DC Ref 2019/20	21	0	3	3	3
Georgedale SS Refurbishment Phase 2 Scope Definition	2	6	16	10	10
Alstom GL312 Breaker Replacement (High Priority)	-	12	12	12	13
Komatipoort SS: Rplc 22kV Kiosk Brk	10	3	10	-	-
Georgedale SS Refurbishment Phase 4 : 275kV Yard	-	3	20	20	20
Esselen SS Refurbishment	0	0	23	45	15
Acacia SS Refurbishment Phase I (66 & 11kV Yard)	10	6	7	7	-
KZN SVC Refurbishment - Athene SVC	3	4	16	90	200
Ferrum SS Refurbishment	2	5	15	20	40
Fordsburg SS Refurbishment	19	0	3	-	-
New EMS Systems for NCC & SOC	-	2	20	60	80
Athene 400kV Lines Guyed Anchors (Phase1)	4	2	15	-	-
Northern Cape Protection Ref - Gromis	10	3	7	-	-
NW DC Ref 2019/20	1	11	8	7	8
Problematic Protection Ref. P2 - NCape	0	10	10	10	10
Balance of Projects (i.e. of 319 projects)					
- Substation Related	377	400	525	1 482	1 578
- Line Related	114	108	102	276	308
- Telecommunications Related	170	59	52	187	471
- Sytem Operations Related	32	13	28	35	96
Total	**1 127**	**1 604**	**2 040**	**3 307**	**3 443**

4.2.3 Asset Refurbishment Prudency Assessment

With respect to the planned investment value of R 4.8bn (i.e. an average of +/- R 1.6bn annually), it should be noted that the replacement cost for the total Transmission lines and substation asset base replacement cost has been valued at R 297bn. It can be concluded that an annual investment of R 1.5bn is conservative and reasonable as it only represents +/- 0.5% of the installed asset base replacement cost. There will be a need to increase asset replacement investments in future years 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.

4.3 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, Eskom Transmission 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 land owner 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 take into account 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.

4.4 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 Transmission is able to provide its regulated service. These assets include; assets related to transportation, 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 full cost of its licensed activities*". Furthermore, the NERSA MYPD Methodology states the following:

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

"*9.1.3 The RAB must consist of existing Fixed Assets in use, New Investments, 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 Transmission'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 normally recovered within one financial year."

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 spreading such expenses over a number of years. This consideration may also apply to particular types of expenditure within management's control only for purposes of tariff smoothing 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.

5 Conclusion

The need for fundamental operational and structural changes to reduce operational costs is recognized in order to provide affordable, sustainable electricity supply to all South Africans.

Good progress has been made towards the planned separation of Transmission which has entailed the relinking of various corporate and centralized functions to the Transmission Division to secure the required resourcing. Steps have also been taken to contain the cost base and limit its impact on electricity price increases. Workforce and structural optimisation was identified as a major component to drive internal efficiencies, increase productivity and contain the overall operating cost.

Over the last five years, Transmission has sustained network reliability performance (SM<1, Major Incidents and Line Faults) thereby limiting the Transmission impact on the severity of interruptions to customers. This performance needs to be sustained requiring investments in maintenance execution and increased replacement of assets which have reached their end of life. Expansion of the Transmission Grid is required to enable the IRP 2019 by connecting new generators and customer loads for country growth.

Failure to invest in line with network condition requirements will lead to deteriorating system reliability, increased maintenance costs and a higher required investment quantum for future years.