

Investing in South Africa's Infrastructure: The Case of the Transmission Development Plan

Authors:

Jabulile Mvubu, Alboricah Tokologo Rathupetsane, Mark Swilling¹



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¹ Mark Swilling is a member of the Board of the National Transmission Company of South Africa. All the information used in this paper is derived entirely from publicly available sources, including public presentations by NTCSCA executives and public documents like Eskom's State of the System, the Transmission Development and Integrated Resource Plan 2025. All the views and opinions expressed in this paper are purely those of the authors based on their academic analysis and do not in any way whatsoever reflect the views of the NTCSCA or any other stakeholder. Mark Swilling has also declared his involvement in this project according to NTCSCA conflict of interest protocols. This discussion paper is the first output of a research collaboration between ASISA, the National Planning Commission, the French Development Bank (AFD) and the South African Research Chair in Urban Innovations at the Centre for Sustainability Transitions, Stellenbosch University. Funding was provided by ASISA.





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Glossary

ABBREVIATION	FULL TERM
AIIM	African Infrastructure Investment Managers (Old Mutual)
ALBI	All Bond Index (reference used in Ninety One's SA Infrastructure Credit Fund)
ASISA	Association for Savings and Investment South Africa
BESS	Battery Energy Storage System(s)
BOOT	Build-Own-Operate-Transfer
BOT	Build-Operate-Transfer
BQ	Budget Quote (Eskom Grid Access Unit)
BW	Bid Window (REIPPPP)
CGV	Credit Guarantee Vehicle
CIS	Collective Investment Scheme
CPA	Capital Projects Appraisal (unit, IFISA Programme Office)
DB	Defined Benefit (pension fund)
DBSA	Development Bank of Southern Africa
DC	Defined Contribution (pension fund)
Dx	Distribution (Eskom division)
EHV	Extra High Voltage
EIA	Environmental Impact Assessment
EPC	Engineering, Procurement and Construction (contractor)
ERAA	Energy Regulation Amendment Act
ESIPPP	Energy Storage Independent Power Producer Procurement Programme
FSCA	Financial Sector Conduct Authority
FY	Financial Year
GASIPP	Gas Independent Power Producer Procurement Programme
GAIN	Growth Acceleration and Inclusion (economic strategy)
GEPF	Government Employees Pension Fund
GFCF	Gross Fixed Capital Formation
GTAC	Government Technical Advisory Centre
GVA / MVA	(Mega/Giga) Volt-Ampere, a measure of transformer capacity
GW / GWh	Gigawatt / Gigawatt-hour
Gx	Generation (Eskom division)
IDC	Industrial Development Corporation
IFISA	Infrastructure Finance and Implementation Support Agency
IPP	Independent Power Producer

ABBREVIATION	FULL TERM
IRP	Integrated Resource Plan
ITP	Independent Transmission Project
ITSO	Independent Transmission System Operator (early term for the TSO)
JET	Just Energy Transition (Skills Forum)
kV	Kilovolt
LCR	Local Content Requirement
LISP	Life-linked Investment Service Provider (also: Linked Investment Service Provider)
MEE	Minister of Energy and Electricity
MTAO	Medium Term Adequacy Outlook (Eskom)
MYPD	Multi-Year Price Determination
NBFI	Non-Bank Financial Institution
NDC	Nationally Determined Contribution
NDPP	Neighbourhood Development Partnership Programme
NERSA	National Energy Regulator of South Africa
NPC	National Planning Commission
NT	National Treasury
NTCSA	National Transmission Company of South Africa
OECD	Organisation for Economic Co-operation and Development
PCC	Presidential Climate Commission
PIC	Public Investment Corporation
PPP	Public-Private Partnership
PV	Photovoltaic (solar)
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RfP / RFP	Request for Proposal
RFQ	Request for Qualification
RMIPPP	Risk Mitigation Independent Power Producer Procurement Programme
RoA	Return on Assets
SANRAL	South African National Roads Agency Limited
SARB	South African Reserve Bank
SA-TIED	Southern Africa - Towards Inclusive Economic Development (National Treasury research programme)
SPV	Special Purpose Vehicle
TDP	Transmission Development Plan
Tx	Transmission (Eskom division)
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital

Introduction

The grid transmission build programme is the largest infrastructure project since 1994. It took nearly a century to build the 33 000 Kms of powerlines that currently connects nearly all South Africans to the electricity grid, and 14 400 Kms need to get built over the next decade. This is, therefore, the most significant infrastructure investment opportunity.

Government has realized that greater collaboration between private and public investments are needed. On 31 March 2026, the Minister of Finance, Mr Enoch Godongwana, officially launched the Infrastructure Finance and Implementation Support Agency (IFISA) Programme Office. The Programme Office is a partnership between the National Treasury, Government Technical Advisory Centre (GTAC) and the Development Bank of Southern Africa (DBSA). IFISA is mandated to mobilise private finance and technical expertise at scale to accelerate infrastructure delivery across the country. The new Programme Office brings together the Public-Private Partnership (PPP) unit, the Capital Projects Appraisal (CPA) unit, the Infrastructure Fund and the Neighbourhood Development Partnership Programme (NDPP) into one coherent, high-impact structure. This provides the ideal institutional framework for engaging institutional investors who want to significantly increase investments in a wide range of infrastructure projects.

The overall objective of this paper is to help pension funds think through how best to take advantage of the emerging infrastructure investment opportunities, specifically focusing on the transmission build programme.

Led by the National Planning Commission, there is a growing realisation within the policy, infrastructure planning and financial community that NBFIs need to increase the levels of investment in Gross Fixed Capital Formation (GFCF) in general, and infrastructure in particular.² The Transmission Development Plan (TDP) is the biggest infrastructure programme since 1994. With the formal establishment of the National Transmission Company of South Africa (NTCSA) in July 2024 and the related approval of the TDP by the National Transmission Company of South Africa (NTCSA), ESKOM and the Cabinet, the declining levels of investment in the transmission grid are being reversed. The pension industry is well-positioned to become a major investor in the rollout of the TDP.³ Transmission assets are large ticket items, have fixed regulated revenue streams and will be continuously funded and built for at least the next decade with thirty-year amortization periods.

With the wider goal to increase NBFI investments in infrastructure in mind, this paper outlines the opportunities and challenges involved in implementing a specific infrastructure programme, namely the TDP and the opportunities and challenges that the pension industry faces as it contemplates how best to invest in the transmission build programme. In doing so, the wider challenge of how to increase NBFI investments in infrastructure will become clearer. How pension funds can increase investments in the TDP should be seen as a case study that sheds light on this wide challenge.

² Swilling, M. and Murau, S. (2025) Transformation of South Africa's Monetary Architecture, 1983-2024. Pretoria: National Planning Commission.

³ Donaldson, A. (2026) Contractual savings and public investment: are our retirement funds misallocated? BER Research Note, 17 April. Stellenbosch: Bureau for Economic Research, Stellenbosch University. Available at: <https://www.ber.ac.za/Documents/Download/b75582ed-227b-4ccd-a629-841277710a07>

Part I: Energy Transition and the Grid

1. The Transmission Development Plan and Unbundling

Two approved policy documents guide national planning for constructing new generation capacity and related grid transmission capacity, namely the Integrated Resource Plan 2025 (IRP2025) and the Transmission Development Plan 2024 (TDP 2024). These planning frameworks need to be aligned so that new generation capacity as envisaged in the IRP2025 is enabled by new transmission capacity as envisaged in TDP2024. If transmission capacity gets built at a slower rate than planned, then newly built generators will not be able to connect to the grid. It also follows that if new generation capacity gets built faster than planned and transmission capacity slower than planned, the problem will get worse.

The IRP2025 was approved by Cabinet in October 2025, one year after the approval of the TDP 2024. The South African Grid Code is provided for in the Energy Regulation Act of 2006 (as amended), and it is the Grid Code that makes provision for the publication of a TDP that must be updated annually. Essentially, the TDP is a forward-looking ten-year plan that specifies which transmission lines and sub-stations will be constructed when, as well as which lines and sub-stations are due for rehabilitation. Partially unbundled out of Eskom and established in 2024, the NTCSA's mandate is to implement the TDP. The NTCSA was granted licenses by NERSA to manage the transition grid within strictly regulated parameters.

The partial unbundling of NTCSA from Eskom Holdings was provided for in the 2019 Eskom Roadmap,⁴ which was a policy framework published by the then Department of Public Enterprises and approved by Cabinet. This policy framework required of Eskom Holdings that a process of unbundling be initiated to create three separate publicly owned entities, namely Generation (Gx), Transmission (Tx), and Distribution (Dx). As of 2026, only Tx has been unbundled, resulting in the establishment of the NTCSA. This is only a partial unbundling because Eskom Holdings remains the shareholder of NTCSA. The original intent of the 2019 Eskom Roadmap was that NTCSA would initially be a wholly owned subsidiary of Eskom Holdings, but after a period of time it would become totally independent of Eskom Holdings.

In 2024, the Energy Regulation Amendment Act (ERAA) was approved for implementation. This Act sets 2030 as the deadline for the establishment of a Transmission System Operator (TSO). It was widely assumed that this meant that the NTCSA would become the TSO. In his State of the Nation speech in February 2026 the President announced that the NTCSA would in fact become the TSO (including ownership of the transmission assets) and set December 2027 as the deadline for its establishment. He set up a Task Team with a three-month deadline to report back to him on how the TSO would get established. This was consistent with a new economic strategy adopted by the Cabinet in December 2025 called the GAIN (Growth Acceleration and Inclusion) strategy.

As of mid-2026, the NTCSA's assets are as follows:

- 33 199 km of high-voltage transmission lines
- 159 384 MVA of three-phase transformer capacity
- 169 transmission sub-stations
- 374 long-distance transmission lines that make up the national grid that all of South Africa depends on for electricity supply

In addition, 332 generation projects underway, that will generate 31 GW that, in turn, will require grid connections by 2030.⁵

⁴ Department of Public Enterprises (2019) Roadmap for Eskom in a Reformed Electricity Supply Industry. Pretoria: Department of Public Enterprises, October. Available at: https://www.gov.za/sites/default/files/gcis_document/201910/roadmap-eskom.pdf

⁵ Eskom (2026) State of the System – 2026 Winter Outlook Briefing. https://www.eskom.co.za/wp-content/uploads/2026/04/State-of-the-System-%E2%80%93-Winter-Outlook-Briefing-2026.pdf?utm_source=chatgpt.com [Accessed: 19 July 2026]

The financial fundamentals of NTCSA as approved by NERSA for the year 2026 were as follows:⁶

- Revenue generated from sale of electricity to Eskom Distribution (who supply the municipalities), major energy users, traders, Southern African utilities, and metropolitan governments: R112 billion, R138 billion and R169 billion respectively for FY2026, FY2027 and FY2028.
- Capex: R20 billion, R36 billion and R39 billion respectively for FY2026, FY2027 and FY2028 to cover strengthening and expansion (R75.8 billion), asset replacement/refurbishment (R15.3 billion), EIAs and servitudes (R3.6 billion), production equipment (R1.3 billion).
- Return on Assets (RoA): R4.4 billion, R6.9 billion, and R10.1 billion respectively for FY2026, FY2027 and FY2028.
- Number of employees: around 4500

As discussed below, the implementation of the TDP is dependent on the successful establishment of the TSO. The challenge is the timing of these developments (discussed later). As already indicated, the President in February gave the Task Team three months to deliver a report. All key public sector stakeholders are represented on the Task Team, including both Eskom and NTCSA.

Although the details of the TDP will be outlined below, it is worth noting that according to the Grid Code, NERSA requires NTCSA to publish a minimum five-year-ahead transmission system development plan annually, indicating the planned major capital investments. This needs to include the acquisition of servitudes for strategic purposes; a list of planned investments, including costs; diagrams displaying the planned changes; an indication of the impact on customers in terms of service quality and cost; and any other information as specified by NERSA from time to time. In other words, the TDP is not just a policy document; it is a detailed technical implementation plan.

The 2024-2034 TDP was the 14th update of the TDP and was launched on 30 October 2024, four months after the NTCSA became operational. It updated the 2022 TDP by considering changing conditions, in particular the high penetration of renewables and the greater need for system stability via gas, synchronous condensers, capacitors, and grid-forming inverters.⁷ A detailed description of the TDP is provided in the next section.

At this stage, the following high level strategic context is what matters: the grid transmission build-program is racing against time. As will be shown below, according to the Cabinet-approved Integrated Resource Plan 2025 (IRP 2025), 14GW of coal-fired power needs to be mothballed by 2030, and another 15 GW must be decommissioned between 2031 and 2042.⁸ To compensate for the loss of this generation capacity (29 GW), a massive quantity of renewables (solar and wind) will be required, plus backup from batteries/gas and stabilization mechanisms. This renewables-based grid is different to the previous coal-based grid with a small number of large controllable generators. To be stable, this kind of renewables-based grid with multiple generators needs a far more substantial set of grid stabilizing mechanisms known as synchronized condensers, capacitors, and grid-forming technologies. They are like shock absorbers in a car – they automatically compensate for sudden glitches or switches in both supply and demand conditions. 31 GW of renewables are already in the pipeline (i.e. wind and solar) and will be available by 2030. Certainty about this figure is derived from the Eskom State of System report that states that there are 332 projects

6 National Energy Regulator of South Africa (2025) In the matter regarding The National Transmission Company South Africa (NTCSA) Multi-Year Price Determination (MYPD6) Revenue Application. <https://www.nersa.org.za/files/files/2025/06/MYPD6DecisionandReasonsforDeision-NTCSA.pdf> [Accessed: 19 July 2026]

7 Each TDP details the plan for the next 10 years, and each successive plan updates the prior plan on a rolling 10-year basis.

8 Power plants are usually mothballed rather than decommission which is very costly and irreversible. Plants can also be put in 'cold reserve' which is about leaving them in a state that allows them to start up again if required – a process that can weeks or even months.

with Budget Quotes (BQs) from Eskom's Grid Access Unit.⁹ BQs are binding contracts that allow solar and wind farms to reach financial close and to be constructed on the assumption they will have a grid connection when ready to be commissioned. However, for this to happen, these projects will need viable grid connections. This, in turn, depends on whether the NTCSA can deliver the TDP on time and, ideally, within or close to budget.

According to the TDP, 14 400 Kms of lines and 271 transformers need to be constructed between 2025 and 2034. This is an annual average of 1400 Kms of lines over the decade. After many years of missing targets, in FY 2023/24 only 74 Kms of lines were built, and in FY 2024/25 293 Kms were built. The target for FY 2025/26 was 423 kms, but only 270.8 Kms were built.¹⁰ The targets for FY 2027/28, FY 2028/29 and FY2029/2030 are 550, 1662 and 2122 respectively. This brings the total by 2030 to 4604.8 Kms,¹¹ which is just below TDP targets. This is what is required to connect the 31 GW of renewables with BQs. However, given that targets were not met in FY2025/26, some analysts have raised questions about whether targets will be met in subsequent years. If they are right, then some of the 31 GW of renewables that will get built by 2030 might find it difficult to get connected to the grid. This, plus the rising cost of keeping the old coal-fired power plants going, increases the chance of loadshedding returning by 2029/30 (discussed further below).

The construction of transformer capacity is on target and may well be achieved: the target for FY 2025/26 was 2540 MVA (Mega-Volt Ampere) and was achieved, as is the target for FY 2026/27 which is 3750 MVA and was achieved.¹² Subject to the availability of transformers mainly from international suppliers in a global market where transformers are in short supply, the targets for FY 2027 through to 2030 may be achievable, i.e. 7000, 9300 and 18735 MVA respectively.¹³ Transformers can be ordered well in advance and in bulk, which is why there should be confidence that the targets can be achieved. Construction is far less complex than in the case of lines because line construction faces the challenge of traversing the complex land dynamics on the ground (from farmers to informal settlements, to new housing developments).

According to a public presentation by NTCSA CEO Monde Bala in October 2025 to an industry workshop hosted by the IDC, the following key strategic TDP initiatives have been identified:

- Powerlines: 5044 Kms of lines are planned for the period 2025-2029, comprising 767 km of 765 kV lines, 4251 kms of 400 kV lines, and 26 km of 275 kV lines. The other 9450 kms will get built in 2030-2034. Several major projects for 2026 and 2027 have already been awarded.
- Transformers: NTCSA intends purchasing 87 transformers in 2025-2029 that will have a combined capacity of 41 325 MVA, and additional 123 in 2030-2034 with combined MVA of 91 325. The smaller transformers (up to Class 3) can be made in South Africa.
- Expedited refurbishment: The programme supports long-term network sustainability, availability, and reliability through the systematic replacement of identified assets, strengthening plant performance, and reducing risk.
- Protection upgrade: Replacing ageing and obsolete protection schemes is critical to improving network performance, reliability, and system resilience.
- Telecommunications upgrade: Pre-identified projects are underway to address key telecommunications constraints supporting the grid, with a focus on improving the reliability, efficiency, and resilience of communications infrastructure for real-time monitoring, control, and maintenance.

⁹ A BQ is a quote issued by Eskom (Grid Access Unit) to the developer of a project (in this instance usually wind or solar, but could also include BESS) for the cost of Eskom building the connection that will allow the project to connect to the grid. The developer pays this amount to Eskom. The quote is valid for a period, and once you have paid the deposit it the quote capacity is then granted to you on the connecting line. This capacity allocation allows you to evacuate the plant's power. It is the capacity allocation that is the critical milestone required in the financial close process. The newly published Grid Capacity Rules should provide certainty around this, but in recent years even after payment of the BQ, Eskom has pulled capacity from projects and granted it elsewhere. This creates significant uncertainty and affects the bankability of projects. It has been a big issue in the funding of projects.

¹⁰ Eskom (2026)

¹¹ Ibid.

¹² Ibid.

¹³ Ibid.

NTCSA has secured most of the capital it needs to fund the first five years of the TDP. In his presentation to Parliament on 5 February 2026, NTCSA's CEO Monde Bala confirmed that "For the first five years, we have secured the capital budget to do that. Our focus is now shifting decisively towards execution." He also confirmed that "Almost of our projects in this 10-year programme are sitting at design stage with a significant portion already in execution."¹⁴ According to the 2026 State of the System report, 7.7 GW of the 31 GW of new generation capacity planned for the period 2025-2030 is already operational, 5.7 GW is being executed, 2.8 GW have Budget Quotes (which means they are approved for execution), and 15.4 GW are what NTCSA refers to as in "BQ Development".¹⁵

Given that the total TDP is costed at R400 billion for 14 500 kms of lines plus 210 transformers and given that around 5000 kms of lines plus 87 transformers are planned for 2025-2029/30 (i.e. one third of the total), it follows that the NTCSA's expected capex for this period should be between R150 and R175 billion, i.e. R30-R35 billion per annum. While, according to Bala, sufficient capital is available until FY2028/29 with, presumably, relatively low debt levels given the terms of the 2023 equity injection of R254 billion by government (which was conditional on no further borrowing),¹⁶ it logically follows that this may not be true for FY2029/30 onwards. Based on the forward planning in the TDP, it is easy to predict that the NTCSA's debt requirement will rise significantly after the expiry of the R254 billion debt relief programme from FY2029/30 onwards. Based on modelling work by DBSA et al. and the substantial increase after 2030 in delivery targets for powerlines and transformers as envisaged in the TDP, it is logical to assume that debt levels could rise from a few billion rand per annum in the 2020s to over R30-R50 billion per annum in the 2030s.¹⁷

To raise large amounts of debt to fund the implementation of the TDP, debt providers will want to ensure that there is a very clear line of sight over a twenty- to thirty-year period with respect to ownership, operational rules and revenue streams. Raising debt now in one entity that becomes another kind of entity later on may reinforce current uncertainties. It is for this reason that the Presidency has insisted on the need for a firm commitment to converting the NTCSA into the TSO (including ownership of the assets) as a crucial precondition for raising the required debt (discussed further below). Eskom, however, has as of mid-2026 continued to argue that transfer of ownership of the transmission assets should be done gradually over time. Eskom and the Presidency are in agreement, however, about the end state, namely that the TSO must own the assets. Either way, loans made to NTCSA and/or ITPs now will need to retain their integrity over the long run.

In sum, while it is conceivable that the required transformers might well be constructed by 2030, analysts have questioned whether the required lines will be ready by 2030 if nothing changes with respect to delivery capacity across the board (within NTCSA, ITPs and EPCs). This has implications for whether or not the renewables (plus storage) in the pipeline can be connected. And if not, the energy generation and storage needed to mitigate the decommissioning of coal-fired power plants might not be available. Eskom's Medium-Term Adequacy Outlook estimates if this scenario materializes, this could trigger loadshedding by 2029/2030.¹⁸ However, as this report makes clear, gas is also a factor.

The IRP2025 does not rely only on renewables to replace coal-fired power. It also assumes that 6 GW of gas at a 50% load factor¹⁹ will be online by 2030. At this load factor, it means gas is seen as not only a backup for variable renewable energy, it also provides the 'baseload' that will be lost when coal-fired power plants are decommissioned. Energy experts agree that it is highly unlikely that 6 GW of gas infrastructure will get built within the next four-and-a-half years. Furthermore, a gas cliff is expected in 2028 when the supply of LP gas from Mozambique starts falling

14 Ntsepha, M. (2026) 'NTCSA secures funding for the first phase of transmission rollout', Energize, 10 February

15 Eskom (2026) State of the System, op. cit.

16 National Treasury (2023) W3:2023 Budget Review Eskom Debt Relief. Pretoria: National Treasury. https://www.treasury.gov.za/documents/national%20budget/2023/review/Annexure%20W3.pdf?utm_source=chatgpt.com [Accessed: 19 July 2026]

17 DBSA et al. (2025), op. cit.

18 Eskom Holdings SOC Ltd. (2023). Medium-Term System Adequacy Outlook 2024-2028. System Operator, National Control Centre. https://www.eskom.co.za/wp-content/uploads/2023/11/Medium_Term_System_Adequacy_Outlook_2024-2028.pdf

19 Load factor refers to the total quantity of the installed capacity that will be utilized. 50% is very high, especially given the cost of gas.

off.²⁰ There is therefore a double whammy of a shortage of LP gas supply, and a lack of LNG-infrastructure. Eskom's Medium Term Adequacy Outlook (MTAO) reveals that even if all the renewables are connected, if 14 GW of coal-fired power is decommissioned and if the planned 6 GW of gas is not grid connected by 2029, South Africa could experience loadshedding again.²¹

Gas can be used for two purposes. It can be used to replace so-called 'baseload' power generation by coal-fired power plants (which is why a 50% load factor would be required), and/or it can be used to backup renewables at load factors of between 5% and 20%. While batteries mitigate the variability of renewables over a period of one to nine hours, gas backup is needed for periods of one to three or four days when wind and solar resources may not be available on a sufficient scale. The IRP envisages that gas will replace some of the current coal-fired power as baseload plus backup for renewables, and the NPC/DBSA report (discussed below) envisages that gas will be used primarily as backup for renewables. A shortage of gas infrastructure affects both, i.e. no baseload replacement for coal-fired power, and limited backup for renewables.

In short, the three primary threats to energy security are (a) slower than planned build-out of the grid to connect the available renewables currently under construction; (b) a faster than planned build-out of renewables generation without grid connections; and (b) failure to build sufficient gas generation capacity to replace the coal-fired power generation that must close down (as per IRP2025) or to back up a large fleet of renewables (as per DBSA/NPC report). This may make it necessary to extend the life of coal-fired power plants beyond their 50-year dead-stop date, which will come at a cost. It will also mean falling foul of the minimum emissions standards promulgated by the Department of Forestry, Fisheries and the Environment. We know the cost of extension because the decision in 2022 to extend the life of the six oldest power stations, for example, has already cost an additional R90 billion for repairs and rehabilitation needed to keep them going.²²

2. Comparing IRP and NPC Reports

Before proceeding to a detailed analysis of the TDP and related implementation challenges, it is worth contrasting the two most significant forward-looking energy models, namely the IRP 2025²³, and the report produced by NPC in partnership with DBSA, NT and PCC²⁴.

The Development Bank of South Africa (DBSA), the Presidential Climate Commission (PCC), the National Planning Commission (NPC), and the National Treasury (NT) (via its research arm, SA-TIED) partnered to determine the investment requirements to achieve energy security and net zero goals by 2050.²⁵ The objective of the study pertains to the need to achieve energy security at least-cost while meeting South Africa's climate targets. The objectives of the study were achieved through a modelling exercise comparing energy mix pathways as scenarios. These scenarios provide investment required, i.e., the capital and operational expenditure per annum, to achieve each stated target.

20 <https://www.parliament.gov.za/press-releases/media-statement-committee-electricity-calls-urgency-addressing-gas-cliff-facing-south-africa>

21 Eskom Holdings SOC Ltd. (2023). Medium-Term System Adequacy Outlook 2024–2028. System Operator, National Control Centre. https://www.eskom.co.za/wp-content/uploads/2023/11/Medium_Term_System_Adequacy_Outlook_2024-2028.pdf

22 Smit, S. (2024). Eskom's decision to keep coal plants running until 2030 could cost R90 billion. Mail & Guardian, 7 June.

23 Department of Mineral Resources and Energy (2025) Integrated Resource Plan 2025. Pretoria: Government of South Africa. Available at: https://www.gov.za/sites/default/files/gcis_document/202510/53596gon6767.pdf

24 DBSA, PCC, NPC and National Treasury (2025) South Africa's Energy Sector Investment Requirements to Achieve Energy Security and Net-Zero by 2050. Midrand: Development Bank of Southern Africa, 5 November. Available at: <https://www.climatecommission.org.za/publications/technical-report-south-africas-energy-sector-investment-requirements-to-achieve-energy-security-and-net-zero-by-2050>.

25 Ibid.

Table 1: Total Energy Investment by Scenario to 2050 (in billion ZAR at 2024 prices)

Scenario	Total Generation Capex	Total Generation Opex	Total Grid Capex	Total investment required	Average annual investment
BAU (C)	1 446	2 490	231	4 166	160
Market (B)	1 229	2 166	262	3 657	141
Green (A)	1 651	1 552	383	3 586	138

Source: ²⁶. Green = Green Industrialisation; Market = Market-based; BAU = Business as usual.

To assess future investment requirements, three scenarios were developed as shown in Table 1. Scenario A (Green Industrialization) assumes full alignment with global climate policies, a 2 GtCO₂e electricity sector carbon budget, air quality compliance mandated by 2030, optimistic technology learning rates, low fossil fuel prices, and a 10% cost of capital premium on new fossil fuel technologies. Scenario B (Market Forces) assumes partial alignment with global climate policies, a 3 GtCO₂e carbon budget, air quality compliance by 2035, moderate learning rates, moderate fuel prices, and a 5% fossil fuel premium. Scenario C (Business-as-Usual) abandons Nationally Determined Contribution (NDC) commitments²⁷ and global climate commitments, imposes no carbon limit, does not mandate air quality compliance, applies pessimistic learning rates, high fuel prices, and no fossil fuel cost premium. As reflected in Table 1, green industrialisation works out cheaper because the opex costs are lower due to the fact that less coal will need to be purchased as coal-fired power stations are decommissioned over the period to 2050.

The technical modelling revealed that a fundamental transformation of South Africa's electricity system architecture is required across all scenarios, though with markedly different trajectories and outcomes. Due to space constraints, only the 'green industrialisation' scenario is elaborated here.

The green industrialization scenario assumed that a real GDP growth rate of 1.0% in 2024 and 2025, 1.5% in 2026 and 2027, and an average of 2% from 2028 to 2050. It was also assumed that nominal national budget spending increase per annum would remain at 4.62%, which is based on the annual average increase in 2024, 2025, and 2026, extended through to 2050. And public spending on energy as a proportion of total government spending would remain flat at 2.88% until 2050. Based on these assumptions, under the Green Industrialization pathway installed generation capacity would expand from the current approximately 60 GW (which includes 48 GW of coal, plus a combination of nuclear, hydro, gas and renewables) to approximately 240 GW by 2050, with variable renewable energy (solar and wind) comprising 61% of total capacity, or 85% when including storage and hydro. This represents not merely a scaling of existing infrastructure but a complete reconfiguration of system design, operation, and market structure.

The modelling identified critical technology deployment milestones that must be achieved to maintain system reliability while transitioning away from coal. By 2030, under the Green Industrialisation scenario South Africa would require 24 GW of solar PV, 18 GW of wind, and 11 GW of battery energy storage systems (BESS). These targets are slightly more ambitious than current procurement programmes, highlighting the importance of sustaining the pace of implementation while also highlighting the limited capacity within South Africa to achieve this. The role of gas emerges as particularly nuanced—while contributing only approximately 5% of energy generation in TWh, gas-fired capacity of 23 GW by 2050 is essential for ensuring system stability and the integration of renewables.

²⁶ DBSA, PCC, NPC and National Treasury (2025) South Africa's Energy Sector Investment Requirements to Achieve Energy Security and Net-Zero by 2050. Midrand: Development Bank of Southern Africa, 5 November. Available at: <https://www.climatecommission.org.za/publications/technical-report-south-africas-energy-sector-investment-requirements-to-achieve-energy-security-and-net-zero-by-2050>

²⁷ NDC commitments refers to commitments made in South Africa's National Determined Contribution as submitted to the UNFCCC.

Transmission infrastructure emerges as a critical requirement across all scenarios. The modelling identifies multiple transmission corridors requiring substantial expansion, with the three main 765 kV corridors — Northern Cape (Western), Eastern Cape (Eastern), and Western Cape via Hydra Central (Central) — requiring the most significant capacity increases. As explained later, the capacity to deliver this will be provided by both the NTCSA (which may become the TSO) and private sector-managed Independent Transmission Projects (ITPs).

The Green Industrialisation scenario achieves cumulative emissions of 2.1 GT CO₂ from 2023 to 2050 (123 Mt/a in 2030), which is generally considered within the current range for the power sector as stipulated in the September 2021 NDC. By 2050, emissions decline to around 8 Mt/a, consistent with net-zero ambitions.

South Africa requires between R3.6-4.2 trillion in 2024 prices in total system investment (i.e. capex and opex) through to 2050 to achieve energy security while meeting climate commitments. The Green Industrialization pathway emerges as the least-cost option at R3.6 trillion (discounted by 8% to 2024 in real terms) and achieves NDC targets for the power sector while delivering modest positive GDP impacts (approximately 0.3% deviation above baseline by 2050) compared to business-as-usual scenarios. Total grid expansion costs to cater for a substantial increase in renewables will be nearly R400 billion by 2050, with distribution collector networks representing 43-53% of these costs.

The estimated least cost and most sustainable option (the so-called 'green industrialisation' scenario) will require a large up-front capital investment that tapers off from 2040 onwards. The capex requirement for this scenario is estimated at R140.1 billion per annum for the 2025-2030 period (total: R700 billion), and R59.7 billion per annum for the period 2031-2050 (total: R1.2 trillion). The total opex requirements for the period 2025 to 2030 is estimated to be R124.5 billion (R24.9 billion per annum), raised primarily from the electricity tariffs. The total opex requirements drop to R40.3 billion for the period 2031-2050 because of the reduced requirement for coal.

Based on a market sounding analysis that shows that R100 billion per annum is available for investment in energy, it was possible to estimate the gap between existing capital expenditure levels and what will be required to achieve the 'green industrialisation' scenario. Assuming the necessary policy and regulatory reforms would be implemented (including cost reflective tariffs), it was found that the gap between the capital expenditure required and capital available in the market was relatively small at R12.5 billion per annum for the period 2025-2027 but growing to R53.5 billion per annum for the period 2028-2030. After 2030, the capital expenditure gap reduces to zero because sufficient private investment will be available if the policy and regulatory regime remains consistent and annual investment levels remain at R100 bn per annum. However, the report makes clear that revenues to cover the estimated operational expenditures will only be possible if NERSA approves a cost-reflective tariff regime.

It therefore follows that there are critical financing gaps if all else remains equal, with funding availability constraints potentially intensifying over the longer term after 2030 without regulatory reform and risk mitigation.

The 2030 and 2040 projections of the DBSA et. al study and IRP2025 are reflected in in Tables 2 and 3. Comparing only Scenario A (Green Industrialisation) with IRP2025, the differences are clear. While the DBSA et. al. study envisages 34 GW of coal-fired power decommissioned by 2030 (i.e. 48 GW minus 34 GW), the IRP2025 envisages 14 GW being decommissioned (i.e. 48 GW minus 14 GW). The DBSA et. al. report therefore envisages more renewables (42.6 GW versus 27.6 GW), and more BESS (11GW versus 4 GW), while IRP2025 envisages far more rooftop solar pv (distributed generation).

Table 2: Comparison of Results from DBSA/NPC/PCC/SA-TIED Report and IRP2025, 2030

Comparison of Dispatchable & VRE Capacity (GW units) by 2030

ENERGY SOURCE	THIS STUDY	IRP 2025 ¹
New Gas	A: 9 B: 7 C: 5	6
BESS	A: 11 B: 2 C: 2	4
Pumped Hydro	3	3
Nuclear	2	2
Coal	A: 14 B: 34 C: 34	34
Total	A: 39 B: 48 C: 46	49

ENERGY SOURCE	THIS STUDY	IRP 2025 ¹
Distributed Generation	7	12
Solar PV	A: 24 B: 14 C: 16	14
Wind	A: 18 B: 11 C: 10	13
Concentrated Solar Power	0.6	0.6
Total	A: 49.6 B: 32.6 C: 33.6	39.6

(Note: A, B and C refers to Scenarios A [Green], B [Market] and C [BAU] as reflected in Table 1. The numbers are the total capacity in GW that will exist by 2030 and by 2040 in the next table. The column called 'This Study' refers to the study by DBSA/NPC et al (2025). The numbers refer to the installed capacity in Gigawatts for each of the 3 scenarios in the DBSA/NPC et al. study and for the IRP2025. The narrative only compares the capacity of Scenario A with the IRP2025, e.g. 24 GW of solar projected to exist by 2030 compared to 14 GW for IRP2025; or 14 GW of coal projected to exist by 2030 for the DBSA/NPC et al. study compared to 34 GW of coal by 2030. BESS = battery energy storage systems, i.e. batteries.)

As per Table 3, the differences between the two studies are much clearer. Most obvious is the IRP2025 assumption that 5GW of new nuclear will be in operation, whereas the DBSA et. al. assumes that no new nuclear can be justified given the high cost. Significantly, if a 50-year life cycle for coal is assumed, the difference between the two reports is not that significant (10 GW with carbon capture and storage versus 19 GW). Whereas wind is similar, the major difference is solar pv (58 GW versus 29 GW).

Table 3: Comparison of Results from DBSA/NPC/PCC/SA-TIED Report and IRP2025, 2040

Comparison of Dispatchable & VRE Capacity (GW units) by 2040

ENERGY SOURCE	THIS STUDY	IRP 2025 ^{1,2}
New Gas	A: 20 B: 18 C: 19	17
BESS	A: 31 B: 26 C: 16	8
Pumped Hydro	5	4
Nuclear	2	7
Coal	A: 10 with CCS B: 10 with CCS C: 15 (no CCS)	50-year life: 19 60-year life: 27
Total	A: 68 B: 61 C: 57	50-year life: 55 60-year life: 63

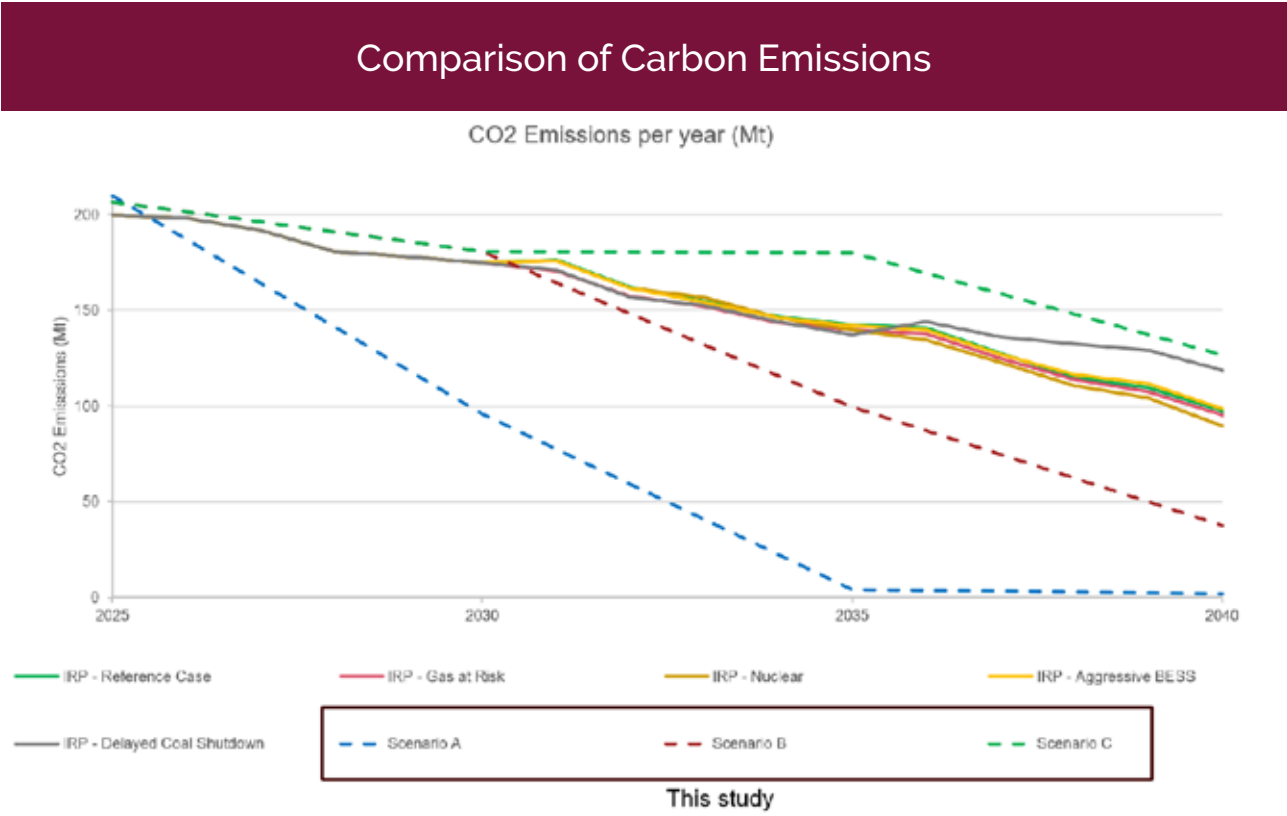
ENERGY SOURCE	THIS STUDY	IRP 2025 ¹
Distributed Generation	9	16
Solar PV	A: 58 B: 39 C: 32	29
Wind	A: 40 B: 24 C: 23	37
Concentrated Solar Power	0.6	0.6
Total	A: 107.6 B: 72.6 C: 64.6	82.6

1. Source: Table 1 Proposed Balanced Plan

2. Source (Coal): Figure 3 Eskom Coal-Fired Station Shutdown Plan Based on a 50-year life

When it comes to emissions, Table 4 reveals the stark difference between the two reports. The five IRP2025 scenarios achieve roughly the same result, except if the decommissioning of coal-fired power plants is delayed once again. The scenarios in the DBSA et. al. report are clearly very different, with only Scenario A ('green industrialisation') achieving the zero-carbon goal.

Table 4: Carbon Emissions for Scenarios in DBSA et. al. and IRP2025 reports



Scenario A in the DBSA/NPC et al. report demonstrates that the accelerated transition towards renewable energy plus backup (batteries, gas and hydro) plus grid stabilization measures (synchronous condensers, capacitors, grid-forming) represents not merely an environmental imperative but the most economically viable pathway for long-term energy security and sustainability, contingent upon strategic capital formation, effective risk mitigation, and comprehensive regulatory reform.

3. Transmission Development Plan: Details

Given that the TDP is directing capex to ensure future demand can be met, it follows that assumptions need to be made about future demand for electricity. This, in turn, is premised on assumptions about future economic growth. To this end, the TDP assumes a "moderate-high" growth scenario averaging annually at 1.6% real GDP growth through to 2034 and an optimistic high growth forecast of 3.2% per annum for the global economy. This will result in peak demand growing from 33.5 GW in 2024 to 43 GW by 2034.²⁸ As a result, the TDP assumes that 56 GW of new generation capacity will be needed by 2034 (to deal with new demand and make up for decommissioning of coal power), broken down as follows: 9.6 GW of PV, 17.5 GW of wind, 3.9 GW of batteries, 15.9 GW of gas, 9 GW of rooftop solar and no additional hydro or nuclear. To enable this, the TDP makes provision for 14 494 km of power lines and 210 transformers (133 GVA). The greatest need is 767 km of high voltage 765 kV long-distance power lines which must be built during 2025–2029. In total, 5044 km of lines (across all voltage levels) must be built during 2025–2029, and 9450 between 2030–2034 (i.e. one third before 2030). If all targets are achieved by 2034, 6957 km of 765 kv lines will have been built, as well as 7477 km of 400 kv lines and 60 km of 275 kv lines. 87 transformers and 15 of the 40 capacitors

²⁸ Peak demand grows faster than economic growth because peak demand is driven by population growth and less by economic growth.

must be constructed during 2025-2029. In addition to these new assets, extensive refurbishment is required, including capacitors, circuit breakers, transformers, DC lines, isolators, protection equipment, reactors, surge arresters and voltage transformers.

As already described based on publicly available information (including the TDP, presentations to Parliament and industry), the expected capex for the transmission build programme is R30-R35 billion per annum or around R150-180 billion for the 6-year period 2025/26 to 2030/31. It is a mistake, however, to assume that the NTCSA will carry this entire burden. Transmission infrastructure (as explained below) is built in two other ways. Firstly, there are ITPs who will raise their own capital to build and operate transmission assets over 30 years. Furthermore, IPPs who build solar and wind farms will also build transmission assets to connect to the grid – known in the industry as 'self-build'. Based on various industry statements and publications, it is reasonable to assume that 20% of the total capex of around R180 billion (i.e. R36 billion per annum) will be implemented via ITPs (clarified further below) and 10% (i.e. R18 bn) will be via IPP 'self-build' projects. This leaves NTCSA with a capex program of R125 – R150 billion of the total grid build programme through to 2030/31 of R180-R210 billion.

As already pointed out, to enable the above capex program, debt levels will inevitably have to increase from FY29 onwards after the debt relief programme ends. Until then, as Monde Bala informed parliament, the Eskom and NTCSA balance sheets are expected to be able to support the capex required for the transmission build programme. As already discussed, it is possible to deduce that from FY29 onwards NTCSA is expected to require additional debt of between R35 and R50 billion for its own build program. The ITPs and IPPs will also be tapping into the debt market for around 80% of the R60 billion they are expected to invest against the revenues they will generate from payments from NTCSA. The NTCSA, ITPs and IPPs will only be able to raise this debt if revenues from the sale of electricity by NTCSA cover the actual operating costs and the weighted average cost of capital. These revenue levels, however, are not determined by NTCSA – they are determined by the regulator, NERSA, on a 3-year cycle basis even though capex projects have 20-30 year life cycles. It remains to be seen whether NERSA will, in fact, approve cost-reflective tariffs. If not, it is logical to conclude that the debt financing of the transmission build programme could be compromised.

NTCSA is a wholesale electricity provider that buys electricity from generators (Eskom, IPPs, Southern African Power Pool), and sells it to Eskom Distribution, large municipalities and large energy users (including foreign countries). Eskom Distribution on-sells to smaller municipalities, and directly to households and businesses. Given that Municipalities now owe Eskom Distribution over R110 bn and given that Eskom Distribution pays NTCSA for the electricity that they distribute, it follows that NTCSA is exposed to municipal debt. Eskom Distribution is implementing various solutions, including Distribution Agency Agreements (DAAs) and prepaid supply models.

The three major financial risks are therefore the following: (a) the ramp up of revenues is premised on the assumption that NERSA will approve cost reflective transmission tariffs – in light of past decisions by the regulator, this outcome cannot be assumed; (b) if the NTCSA is not transformed into the TSO (with the assets), this may make it difficult to raise the required debt against what will remain on the Eskom balance sheet; and (c) NTCSA's ongoing exposure to municipal debt if a solution to the problem is not found.

4. Independent Transmission Projects

As already indicated, it is generally assumed in the energy sector as a whole that around 20% of the TDP will be delivered by ITPs. So, what are ITPs and what does the ITP program look like?

In December 2023, the Cabinet approved a framework for including the private sector into the delivery of transmission assets. This policy initiative was led by the then Minister for Electricity in the Office of the President (who eventually became the Minister of Energy and Electricity in July 2024). The policy framework made provision for the establishment of ITPs as the most appropriate vehicles for enabling private sector participation in the grid transmission build program. When the NTCSA was established in July 2024, the Minister handed over this policy framework to the NTCSA for implementation, working in partnership with a high-level team drawn from the Ministry, National Treasury, the World Bank, and the IPP Office.

In essence, ITPs are similar to IPPs, but with respect to grid transmission assets. They have been implemented in approximately 25 countries around the world. In essence, they are projects that are defined by the (often publicly owned) institution responsible for managing the national grid (in our case, the NTCSA). Invariably, there is an agency that publishes the projects and calls for proposals to implement, often with very detailed technical and financial requirements (in our case, the IPP Office). Private developers that are awarded the contract must raise the finance, construct the assets (lines and/or transformers), and then operate the asset for 20-30 years on a BOT or BOOT basis, after which the asset is transferred back to the grid management entity. The ITP is usually packaged as an SPV, and project finance is raised as debt against the project. Equity/debt ratio is usually 20/80, often with specifications for local ownership requirements. SANRAL's concession toll roads were implemented on this basis in the early 2000s.

The IPP Office issued a Request for Qualification in July, and Request for Proposals in September 2025. The most distinctive feature of the RfP was the requirement that prospective bidders prove prior experience in managing ITPs. Obviously, no SA company qualified because to date private SA companies built transmission assets for Eskom and handed them over to Eskom's transmission division on commissioning. Indeed, SA companies have built the largest grid in Africa this way over the past century. None have managed these assets over an extended period of time. It follows, therefore, that the only bidders that qualify are international companies. However, the RfP requires that the SPV that gets created must have 49% South African ownership by a black-owned company (including, optionally, a 5% share for communities). The steel industry has questioned this by pointing out that this 49% SA shareholder need not prove that they have expertise, which means they can be merely black-owned investors without expertise in the sector. This, indeed, is what materialized. The organized industry associations representing the EPCs that have historically built the grid objected, and many engagements to negotiate an alternative have taken place with uncertain outcomes (explained further below).

On 15 December 2025, the selected bidding consortia were issued draft RfPs to comment on. The selected bidding consortia will obtain the final RfPs in August/September 2026 (delayed from March 2026) and Commercial Operation of the first ITPs will only materialise in 2031. From reports and press statements, the key reason for the delay from March to August/September 2026 is the time required to set up the Credit Guarantee Vehicle (CGV). The CGV is a World Bank initiative aimed at providing investors in ITPs with an alternative guarantee to a sovereign guarantee on a voluntary basis. The equity in the CGV will be taken up by NT, local DFIs, and international DFIs. This, plus guarantee fees, will be the basis for the guarantee issued by the CGV to unlock the debt finance required from the SA capital markets to finance the ITPs. Phase 1 projects are valued at R10 bn and will only be commissioned in 2031.

During FY26, ITP Phase 1 progressed from concept to a market-ready procurement programme, comprising seven priority transmission projects. Key milestones achieved included confirmation of the Phase 1 project portfolio, issuance of the RFQ, pre-qualification of bidders, and release of the draft RFP for consultation. While good progress has been made, programme timelines remain dependent on regulatory alignment, cost recovery arrangements, and Credit Guarantee Vehicle readiness.

The draft RFP was issued to pre-qualified bidders in December 2025 and bidder consultation closed in April 2026. Key programme risks remain unresolved, including uncertainty about whether tariffs will be cost reflective, and the problem of broader balance-sheet exposure to municipal debt.

There are several challenges that have been publicly articulated and need to be addressed:

- **Municipal debt:** Based on direct discussions with World Bank officials, potential investors and the drafters of the Local Government White Paper, it is unclear how the CGV can work considering the NTCSA's exposure to municipal debt (as already explained above). Lenders may well want a clear line of site to the ultimate balance sheets that the NTCSA is dependent on before lending to the NTCSA and ITPs, and those are in part the over-indebted municipal balance sheets.
- **NTCSA balance sheet:** Engineering News reported in December 2024 that the NTCSA is concerned that the CGV is not designed to protect the NTCSA's balance sheet in the case of a default or termination. The same report stated that the NTCSA insists that ITPs should not be reflected on the NTCSA's balance sheet.²⁹

²⁹ Creamer, T. (2024) 'NTCSA says independent transmission projects must not reflect as balance sheet liability', Engineering News, 6th December.

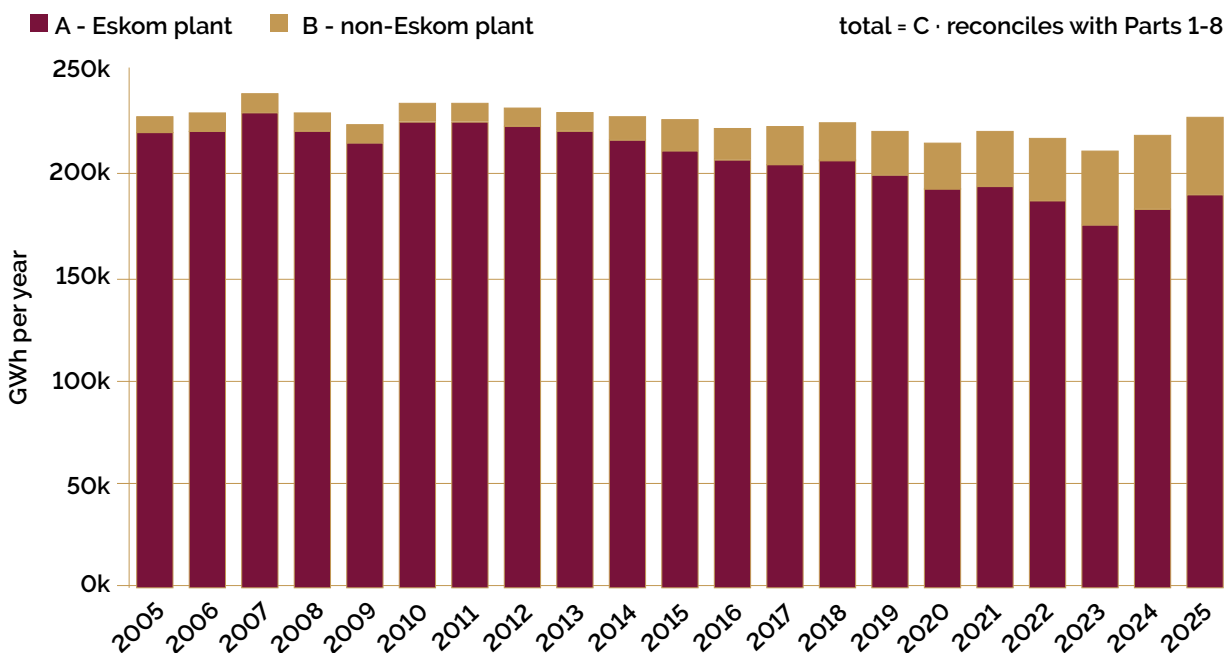
- Localization: the EPC industry remains adamant that the 49% shareholding should specify that local shareholders should have expertise in the transmission sector – this would ensure that they would need to get selected as strategic partners which, in turn, is good from an industrialization perspective because they have a vested interest in re-investing in the expansion of local South African capacity.
- Tariffs: Without Nersa-approved cost-reflective tariffs, the capital raise to ensure that the TDP is implemented over the long run is unlikely to meet expectations.

5. Independent Power Producer Procurement Programmes

As of the latest reporting period, total contracted GW across all programmes stands at 10 GW, with 8,5 GW having achieved commercial operation. REIPPP Bid Windows 1 through 4 are fully operational, with BW5 at just over 1 GW operational out of 2.5 GW approved. REIPPP BW6 and BW7, at 4.2 GW and 5 GW respectively per determination, remain at zero operational GW, as do the ESIPPP (Energy Storage Independent Power Producer Procurement Programme) and GASIPP (Gas Independent Power Producer Procurement Programme) programmes as at end 2025. The RMIPPP programme has 150 MW operational out of 1 996 MW approved.

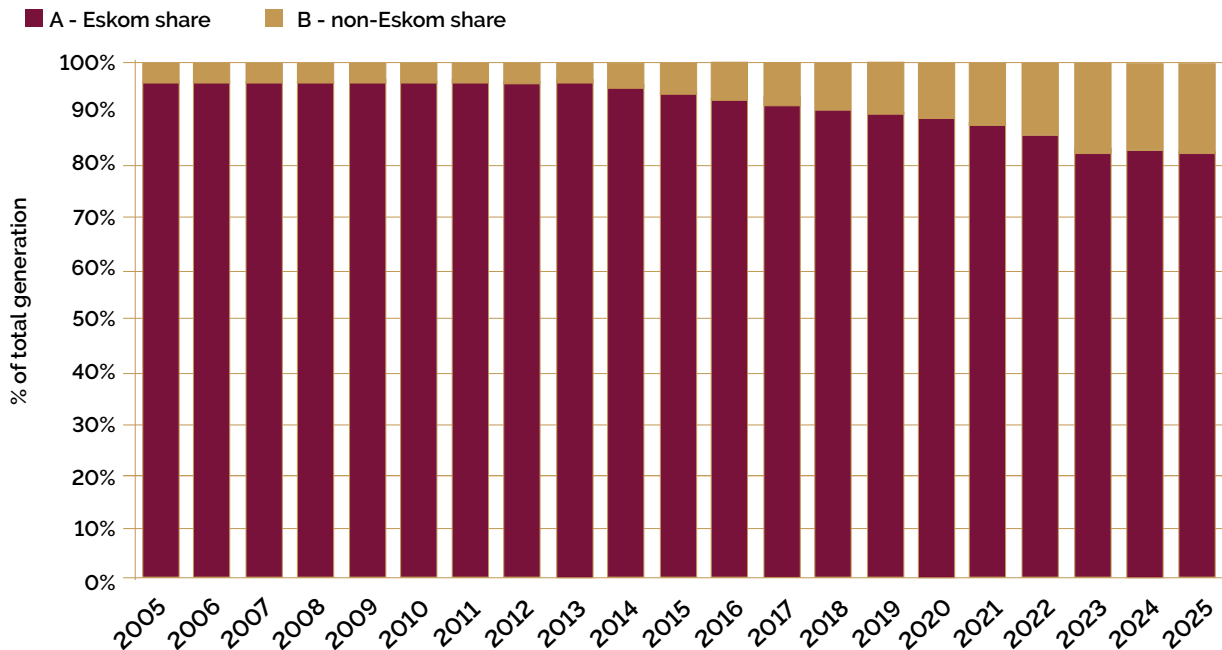
Four factors have resulted in weakening demand for electricity generated by Eskom: the REIPPPP programme, the rooftop solar revolution driven largely by loadshedding, the rising cost of electricity provided by Eskom and weak economic growth. Two trends are evident (see Figures 1 and 2). Firstly, overall electricity generation declined between 2010 and 2023, and is now where it was twenty years ago. Secondly, the amount of electricity generated from non-Eskom plant is steadily growing.

Figure 1: Nett electrical energy generated in SA per year from 2005-2025 – by Eskom and non-Eskom generators – showing the split per year in absolute energy (GWh) terms



(Source: Chris Yelland)

Figure 2: Net Electrical Energy Generated in South Africa, 2005-2025, by Eskom and Non-Eskom Generators (%)



(Source: Chris Yelland, 2026)

(Note: The figures present net electrical energy generated in South Africa and excludes electricity imports (including Cahora Bassa), as well as pumped storage and battery energy storage systems (BESS), which are net consumers of electrical energy over the course of each year.)

6. Unbundling and Tariff Reform

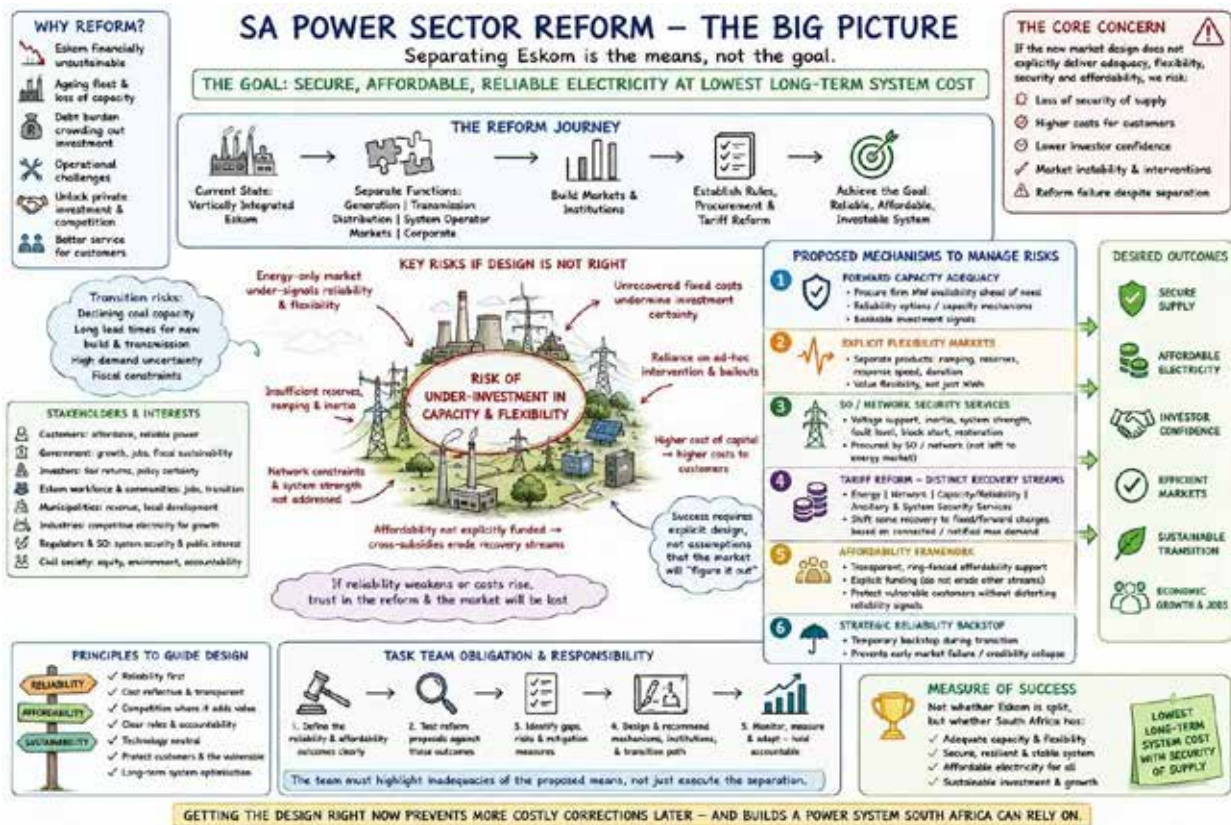
South Africa is going through the most profound transformation of its electricity system since its founding a century ago. It is transitioning from a vertically integrated state-owned natural monopoly to a market-based system that involves a wide range of state and market-based investors, developers and operators. As already mentioned, it is the ERAA that is the cornerstone of this transformation process. According to the ERAA, the soon to be created TSO is supposed to play multiple roles (which are in many other countries separated into separate entities, and this may be advisable over the medium-term). These roles include the following:

- System Operator (i.e. operating the grid, primarily a technical function);
- Market Operator (i.e. operating the newly created electricity market where wholesale buyers and sellers can operate within an open market with transparent rules);
- Transmission System Planning (including TDP updates, MTSAO report, Grid Code etc);
- Central Purchasing Agency (i.e. the buyer and seller of electricity, and ideally separated from the ITSO over the long run).

During the last week of July 2026, the President approved the Eskom Restructuring Task Team report that provided for the establishment of a TSO that is independent of Eskom Holdings, and would fulfil the above roles, plus own the transition assets valued at anything between R85 and R120 billion.

All this has to be configured and fully established by end 2027. Few countries have managed a transition of this nature this quickly, which means it would be unreasonable to assume all will be achieved by end 2027. Figure 3 provides a useful synopsis of the complexities of the transition to a reliable, affordable and investable system:

Figure 3: SA Power Sector Reform Process



(Source: Ronald Marais, NTCSA)

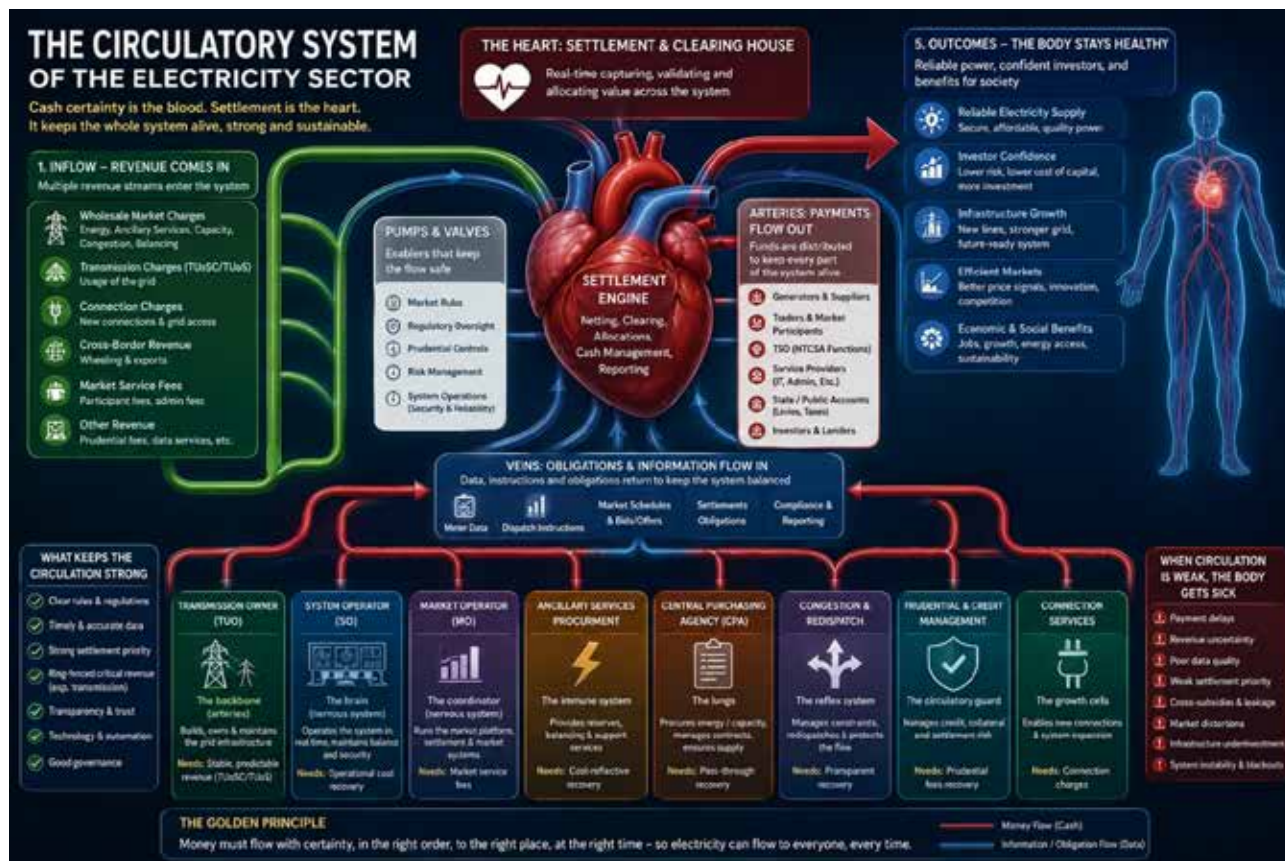
There is a wide consensus that unbundling is necessary because the traditional vertically integrated Eskom model is financially unsustainable, the generation fleet is ageing and some plants need to be decommissioned in the near future, the existing debt burden crowds out new investment, it is necessary to unlock private investment, and service delivery is deteriorating (top left box).

There are many challenges when it comes to unbundling, but one core challenge relates to asset ownership. If the state is the new shareholder of NTCSA (as the TSO) and it is agreed that the NTCSA/TSO must also own the assets, many stakeholders have been asking how will this transaction be executed given that Eskom should not be disadvantaged and the TSO (whether it is the NTCSA or not) should not be overburdened with debt which will compromise its ability to realize the goals of the TDP. Eskom Holdings has argued that NTCSA should remain owned by Eskom Holdings for a transition period, and that a separate entity be established as the TSO for all the non-asset owning functions. Business and many stakeholders strongly agree with the findings of the Eskom Restructuring Task Team Report which recommends the establishment of a TSO that includes ownership of the transmission assets. This, it is argued, will make it possible for the TSO to raise the capital needed to implement the TDP.

The biggest challenge of all is the bundled tariff (signaled as the fourth 'mechanism' in the above diagram). At the moment there is only one tariff that Eskom customers pay. This tariff covers the cost of generation, transmission and distribution and is approved by Nersa. It is collected centrally by Eskom, and then allocated as per NERSA approvals (in principle, but not always in practice) to Gx, Tx and Dx. There seems to be consensus that as long as this continues, it will be challenging to align revenues, operational spending and debt servicing. Without absolute certainty that there is a dedicated revenue stream for the NTCSA/TSO, all sorts of half measures will be introduced (like the CGV) to resolve the problem, and capital raising will be hampered. The solution is tariff unbundling.

Ronald Marais prepared the following diagram (Figure 4) to depict the importance of tariff reform. He argues that reliable and predictable revenue generation is the 'settlement engine' that functions as the beating heart of the entire system:

Figure 4: The Electricity Circulatory System



(Source: Ronald Marais, NTCSA)

On the bottom left in the dark blue box there is a reference to "ring-fenced critical revenue (especially for transmission)". This refers to the revenues from the sources in the green box (top left, box 1) that are not channeled via a bundled tariff through Eskom back to NTCSA/TSO, but accrue directly to NTCSA/TSO at some point in the future. NERSA will have to determine whether, how and when this proposal gets implemented.

7. The Capacity Question

It is common knowledge that for more than a decade leading up to 2024, Eskom diverted funding to Gx that should have been allocated to Tx in response to loadshedding caused by generation problems. As a result, the capacity of the Transmission Division (the core of NTCSA capacity today) was weakened and the EPC industry that actually builds the assets reduced operational capacity. The endorsement of the TDP - and the NT directive that the equity injection of 2023 must be used for transmission - resulted in the urgent need to ramp up capacity very quickly. To put this in perspective: the largest transmission build was in the 1970s/80s during the big electricity build program at that time. The maximum ever built was 1200 Kms per annum, with no EIAs and other constraints. The target of 1400 kms per annum today is therefore higher than anything achieved before, but now with many constraints with respect to EIAs, servitudes, community action, etc. To resolve this, the Ministry of Energy and Electricity initiated and still drives the ITP program to mobilise non-NTCSA capacity, and the NTCSA has published calls for procurement panels for power lines and transformers. However, all indications are that at this early stage in the implementation of the TDP, we are hitting the limits of SA's delivery capacity. Engineering industry estimates suggest that South Africa's current delivery capacity is anything between 500 and 800 kms per annum. Many EPC contractors that were interviewed confirmed that even at this early stage of the build programme, they are at maximum capacity. Some pointed out that they have

to pay double for a mid-level engineer today compared to a year ago. The one good thing about the ITP program is that it brings in international EPC contractors to augment local capacity. The danger is that this displaces South African EPC contractors, rather than boosting their capacity through effective strategic partnerships.

The steel industry argues that a distinction needs to be made between capability and capacity. Capability, they argue, is technical know-how, design skills, project preparation and operational experience. Capacity refers to the quantum of people with the right skills to implement projects on the ground, including skilled artisans, project managers, front-line engineers, etc. They argue that South Africa has the capabilities rooted in over a century of grid building, but capacity has shrunk because of the way funding was redirected from Tx projects to keep the power stations going. Furthermore, they argue, capacity challenges are easier to resolve than capability challenges.

Worth noting that the Minister of Higher Education and Training has established the JET Skills Forum under the auspices of the Human Resource Development Council to address the capacity challenges as the country transitions to a renewables-based economy.

From loadshedding to oversupply of electricity in the midday hours

South Africa experienced load-shedding for 15 years up to mid-2025. While initially there were hopes that the problem would be resolved in the short term, over time demand grew for more reliable and affordable alternatives. As a result, developers and investors collaborated to trigger a massive expansion of renewable energy (solar and wind power). Regulations were relaxed and Eskom approved a large number of projects, both procured via the REIPPPP and - after restrictions were scrapped by the President in 2022 - via large- and small-scale privately owned and operated self-generation (including, but not limited to, rooftop solar).

Most new energy generation plants, however, need to connect to the grid and this, in turn, requires power lines and sub-stations that, in some areas like the Northern Cape, are in short supply. Good energy planning, therefore, should ensure that grid infrastructure is built in time and in sufficient quantity to enable the newly built generators to connect. However, because of the scramble to mitigate the impact of loadshedding, more solar and wind plants are being built than was originally intended by IRP2025 – an unsurprising phenomenon given that it is market dynamics that have been driving the renewable energy revolution rather than the targets of central planners. This, however, has unintended consequences.

This was graphically illustrated by NTCSA's Ronald Marais at an energy conference in Cape Town in June 2026. In Figure 5, he shows that wind and solar generation is getting built at a faster rate than anticipated by the IRP 2025: in particular, 15.25 GW of additional solar will get built by 2030 (on top of the current 12 GW) compared to the IRP2025 target of 14 GW. Wind is less of a challenge: 10GW of wind expected by 2030 compared to the IRP2025 target of 13 GW. To maximize what grid planners call flexibility (i.e. measures to counter-balance the variability of renewable energy and the inflexibility of coal-fired power generation), IRP2050 envisaged 4.4 GW of battery storage, but only 2 GW is expected to be constructed by 2030, further reinforcing the challenge of balancing the grid. By contrast, the DBSA/NPC et al. report proposes 11 GW of battery storage by 2030.



Photo by Viktor Kiryanov on Unsplash

Figure 5: IRP 2025 Projections Compared to Actual

IRP 2025 capacity compared to forward booked NTCSA generation customer connection (BQ)

The current forward booked allocated capacity exceeds the IRP generation .



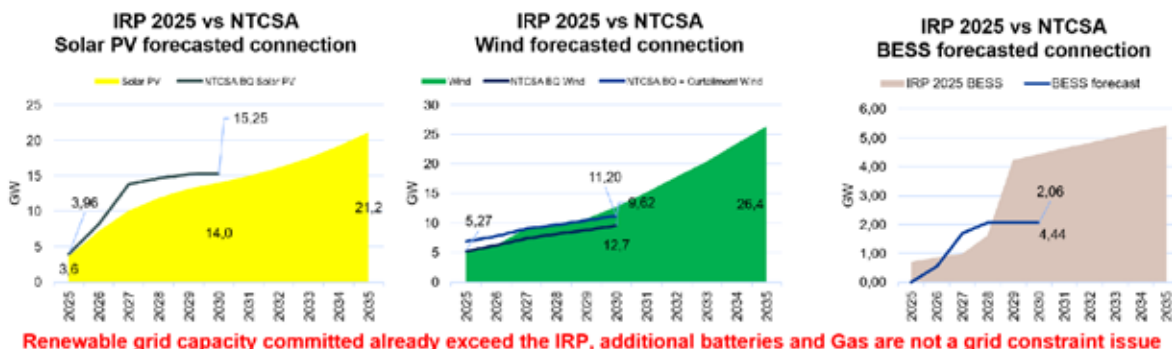
Variability Energy PV and Wind exceeds the IRP 2025

The projected photovoltaic (PV) capacity connection by 2030 is estimated at 15 GW, surpassing the Integrated Resource Plan (IRP) 2025 target of 14 GW.

Wind capacity is expected to reach 10 GW, excluding the 1.58 GW of curtailment capacity released in 2025. The Integrated Resource Plan (IRP) sets a target of 13 GW by 2025.

Flexibility Battery reduced compared to the IRP 2025 projections.

Battery Energy Storage Systems (BESS) is expected to reach 2 GW, while the Integrated Resource Plan (IRP) for 2025 specifies a requirement of 4.4 GW.



Renewable grid capacity committed already exceed the IRP, additional batteries and Gas are not a grid constraint issue

(Source: Ronald Marais, June 2026, Cape Town)

This may look like good news from a sustainability perspective, but it creates serious system stability problems. The reason for this is that South Africa's load profile looks a bit like buffalo horns (see Figure 6): peaks in the morning (6–8 am) at around 25–28 GW and early evening (5–7 pm) at around 28–30 GW, and – because we have a weak industrial base – dips in the middle hours of the day to around 23–25 GW.³⁰ The problem is that solar power (both utility-scale and rooftop) peaks in the middle of the day exactly when demand for electricity is reduced. It helps that electricity is needed to recharge the storage systems (batteries and hydro) thus creating additional demand over and above what consumers use. So, as Figure 6 shows, if you add storage to the actual load, then minus rooftop solar and minus utility-scale wind and solar, the actual load reduces from around 25 GW to as low as 4 GW (on good sun and wind days) – the latter is referred to as the 'residual load'.

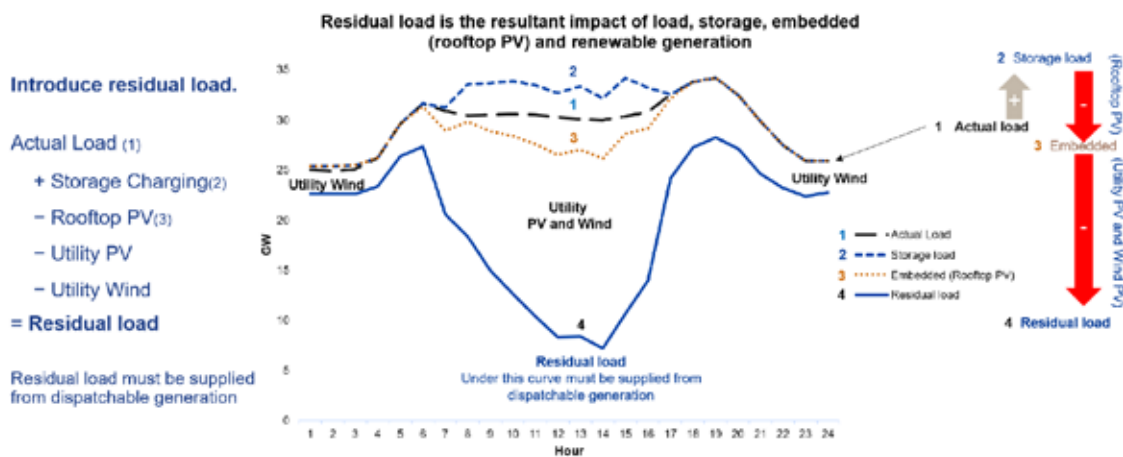
During the middle hours of the day residual demand is as low as 4 GW. However, the coal/nuclear fleet cannot be ramped down to that level. This is when curtailment is necessary. There are gaps during the peaks when there is limited renewable energy and not enough coal/nuclear power. These gaps during the peaks must be filled by dispatchable generators like gas, BESS and pumped storage in addition to coal and nuclear. The problem is that you cannot easily ramp coal-fired and nuclear power stations up and down – that is not how these mechanical systems work. The maximum available from coal-fired power is 22 GW plus 2 GW from nuclear, and the minimum both can go down to is a total 15 GW. This means the evening gap is the difference between 22 GW (when coal and nuclear are at their maximum) and 28 GW that must be filled with batteries, gas and hydro, which is possible. But, as shown in Figures 6 and 7, the real problem is in the middle of the day when you cannot ramp down coal and nuclear below 15 GW and yet only 4 GW is needed when renewables are operating on a good sunny and windy day. If coal and nuclear cannot go down to 4 GW and the renewables remain switched on, supply will be greater than demand causing an imbalance. It is technically impossible to ramp down coal- and nuclear-power plants below the minimum of 15 GW without risking grid stability. Given that it is also technically impossible to switch off the distributed rooftop solar systems, the only solution, therefore, is to switch off the utility-scale renewables in the middle hours of the day – this is what is called 'curtailment'. As reflected in Figure 7, the amount of renewables curtailed in a day equals the difference between what they could generate and what is needed to keep 15 GW of coal and nuclear capacity operational.

³⁰ The load profile of India and China is more like an ostrich egg – because they have an industrial base, the load peaks in the middle of the day exactly when solar power peaks.

Figure 6: Load Curve and Generation over 24 hours

Why the Buffalo Curve Exists

The Buffalo Curve is the combined effect of demand, solar, wind and storage.

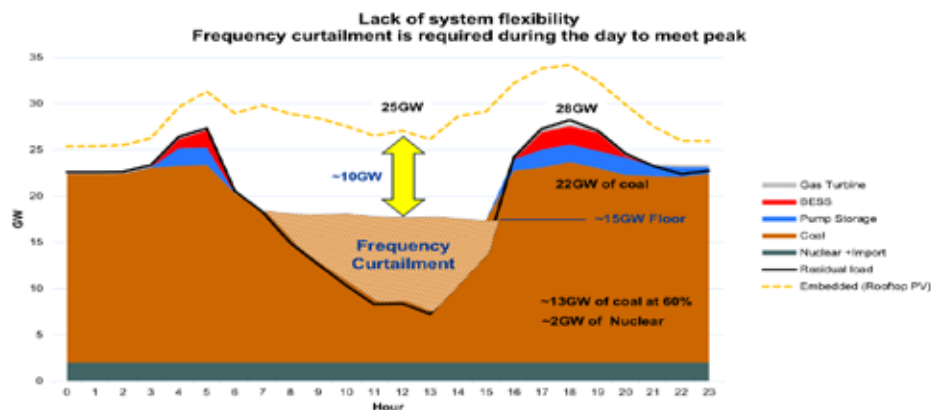


The actual load (1) differs from what system operators monitor. Operators observe the residual load, depicted by the solid black line. This residual load is derived by beginning with the actual load (1), adding the storage load applied during the day (2), then subtracting embedded generation like rooftop PV (3), followed by subtracting utility-scale PV and wind generators. The final profile represents the residual load (4), which is supplied by dispatchable resources such as coal, nuclear, gas, batteries, and others.

(Source: Ronald Marais, June 2026, Cape Town)

Figure 7: Lack of System Flexibility and Curtailment

Let's examine an example involving the ceiling and floor. The ceiling represents a 25GW load after accounting for embedded generation and storage load. The floor is designed to meet an evening peak demand of 28GW; subtracting peaking plants (gas, batteries, and pumped storage), 22GW of coal and nuclear capacity is required. Specifically, the floor consists of 15GW—comprising 2GW from nuclear and 13GW from coal. This means the system can support the difference between ceiling and floor (25GW minus 15GW), allowing for 10GW of utility-scale photovoltaic and wind generation. System frequency serves as an indicator of the balance between load and generation; if generation exceeds demand, frequency rises to unsafe levels. Therefore, system operators must implement frequency management curtailment when additional utility-scale renewable output increases beyond safe limits.



(Source: Ronald Marais, June 2026, Cape Town)

Put more simply: because coal-fired power stations cannot be easily ramped up and down, they must be operated at the same level (within a narrow range of between 22 GW and 13 GW) over a 24/7 period. Their output is lowered a bit in the middle of the day to around 13 GW to accommodate the midday dip in demand. If there is too much solar and coal-fired generation cannot be lowered further, then supply is greater than demand which leaves no option but to switch off some of the solar plants, which is what has been happening with increasing frequency since the start of 2026.³¹ This, of course, is done to protect the coal-fired power plants. However, if there was a lot more battery storage, instead of curtailing renewables in the middle of the day, it would be possible to use up the surplus energy from

31 Creamer, T. (2026) 'NTCSA acknowledges "temporary bottleneck" of R2 bn in curtailment payments to IPPs.' Engineering News, 18th June 2026.

renewables by recharging batteries during the day for release during the peaks and in so doing also prevent too much ramping of the coal plants up and down each day. This is the 'flexibility' that grid planners refer to. But because batteries and other flexibility-enhancing technologies are not being procured quickly enough, this kind of flexibility is not happening while at the same time more and more renewables are coming through the project pipeline.

The other alternative, of course, is the gradual decommissioning of the coal-fired power plants from 2030 onwards (in accordance with IRP2025) which would lower the level of the 'floor' but this would also increase the size of the gaps during peak times. It follows that if decommissioning happens without a substantial increase in storage from batteries and gas plants, there is a risk that there will be insufficient capacity to back up the variable wind and solar systems when required and fill the gaps during the peak periods. In short, flexibility is the problem, and the solution is a lot more storage and related flexibility-enhancing technologies.

The real solution, of course, is to accelerate economic growth to increase demand for the midday surplus electricity, even if this means reducing the price of electricity at these times to incentivize the uptake of these surpluses by consumers who shift their loads and/or expand their economic activities. This is not unusual in other countries, but would require a flexible tariff regime that is very different to the current highly regulated fixed tariff regime.

A word on batteries: they provide a number of ancillary services - they can be brought online instantly for balancing when required, they help 'carry the grid' (grids need sufficient energy to transmit electricity), and they back up renewables when wind and solar are insufficient. In short, the more batteries, the more flexibility. But synchronous condensers, capacitors and grid-forming technologies will also be needed to support voltage stability. These are costly technologies that complement storage because they act like shock absorbers in a car - they smooth out the bumps to ensure stability over a 24/7 cycle while demand and generation conditions change.

8. The Challenge of Localisation

In light of the capacity challenges that South Africa faces, there is a hard choice to be made between prioritising the participation of local industries or simply leveraging global value chains. Although localized execution has many advantages, in light of capacity challenges there are questions about whether it matters who delivers the infrastructure so long as it is built, especially when global markets can offer more efficient near-term solutions.

The answer depends on the practical demands of operating and maintaining the asset over a horizon that covers, at minimum, the investor payback period. If powerlines and substations are imported as fully engineered solutions, the tacit knowledge necessary for maintaining these assets largely remains external to the country. When post-delivery issues emerge, whether from climate-related extreme events, theft, or other physical infrastructure risks, the asset's functionality becomes contingent on access to replacements, which is in turn exposed to global supply chain pressures, international shipping, and currency variability. In the meantime, the asset may operate below optimal capacity while awaiting specialists flown in from abroad, which undermines the reliability of the overall infrastructure.

By using local fabricators, engineers, and construction firms, even if they seem - and maybe are - initially less efficient, greater levels of reparability are embedded into the asset. An existing local technical base can restore asset functionality considerably sooner than mobilising international specialists. Over the longer term, local industries could also offer a more competitive aftermarket, with firms bidding for maintenance cycles and reducing overall dependence on major international suppliers. The infrastructure is thereby made more resilient through continuous access to technical expertise, a key rationale for some level of localization in TDP execution.

One way of operationalising local participation is through local content requirements (LCRs) in the procurement criteria of the TDP. LCRs require a minimum percentage of project costs to be spent on locally produced goods or services.³² LCRs do not, however, automatically secure local industry participation, given that persistently low GFCF and historically erratic transmission demand have progressively diminished manufacturing capacity across the value chain. LCRs

³² Ettmayr, C. & Lloyd, H. (2017) Local content requirements and the impact on the South African renewable energy sector: A survey-based analysis. *South African Journal of Economic and Management Sciences*. 20(1):1.

therefore require parallel investment in value chain restoration and strengthening, meaning identifying where capacity must be grown and where capabilities can be built. Capacity refers to the volume a firm or value chain can produce, while capability denotes the range of products or services it can deliver to the required quality standards.

The manufacturing demand generated in Phase I of the ITP programme is dominated by 400kV transmission lines, and therefore by extra high voltage (EHV) electrical components. Suppliers for 400kV conductors and composite insulators exist locally but are currently too small to meet Phase I volume requirements.³³ Capability exists but capacity is insufficient; investing in capacity building could mean investing in automation, factory line upgrades, and training to increase production output.

Existing power transformer supply, by contrast, sits predominantly at the Class 0–1 transformer levels, with a few suppliers reaching levels 2 and 3.³⁴ The 400kV line projects predominantly require Class 4 transformers, so this is a capability gap rather than a capacity gap. Investment could expand transformer suppliers' capability through technology licensing agreements or partnerships with original international equipment manufacturers. The alternative, simply importing missing capabilities, exposes key infrastructure to supply chain risk: increased global demand for transmission infrastructure, against constrained manufacturing capacity, has seen large transformer lead times double since 2021 while prices have risen by as much as 75%.³⁵ Local transformer suppliers can mitigate this risk. LCRs and accessible capital therefore work in tandem, the former assuring firms of sufficient demand to recoup investment, the latter enabling them to execute work at the quality and pace the TDP requires.

Localisation does not require domestic supply of all materials and services. Rather, it aims to ensure that, where feasible, sufficient demand is met locally to secure the technical expertise needed for long-term asset reliability and infrastructure functionality. Localization functions, in this sense, as risk management: investing in the expertise required to protect assets over the investment recovery period.

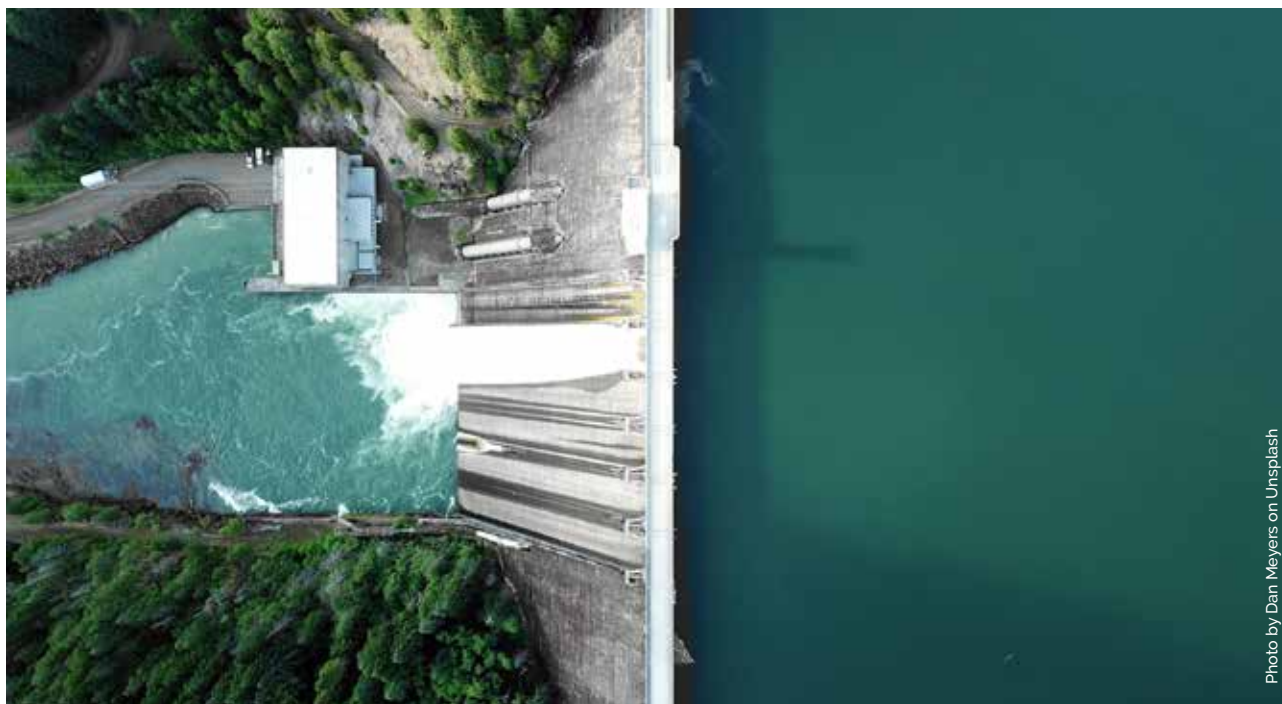


Photo by Dan Meyers on Unsplash

33 GreenCape (2026) South Africa's Independent Transmission Projects (ITP) Programme: investment opportunities for component manufacturers.

34 Vajeth, R. & Tlhatlhetji, P. (2023) Value Chain Mapping of the South African Transmission and Distribution Networks and the Allocation of the South African Manufacturing Capability to the Value Chain Elements. Available at: https://www.lsf-sa.co.za/post/value-chain-mapping_local-manufacturing-capability-in-the-transmission-distribution-sector

35 International Energy Agency (2025) Building the Future Transmission Grid: Strategies to Navigate Supply Chain Challenges. Available at: <https://www.iea.org/reports/building-the-future-transmission-grid>

Part II: Pension Funds and the Infrastructure Opportunity

1. Pension Funds

Pension funds can support South Africa's transmission infrastructure in several ways. The most immediate opportunity is investing in Independent Transmission Projects (ITPs), which are already entering the market. From FY29/30, as the National Transmission Company of South Africa (NTCSA) faces a financing gap, pension funds can also serve as direct debt providers to NTCSA. Both roles are investment-focused and rely on projects that have already reached a bankable standard thus allowing pension capital to be committed. Project preparation, which involves identifying, de-risking, and structuring projects to meet this standard, is a distinct function with different risk-return profiles. Pension funds are not equipped to fund this stage directly, as capital-intensive, pre-revenue, and early-stage work is the responsibility of development finance institutions and dedicated project preparation facilities. The Development Bank of Southern Africa (DBSA) operates a Project Preparation unit for this purpose³⁶, while Infrastructure South Africa (ISA) coordinates project preparation and pipeline development nationally in partnership with National Treasury and the DBSA³⁷. Pension funds can add value by providing strategic input on pipeline challenges and in helping to define the bankability standards required by investors, but they should not be expected to fund project preparation. Viewed in this way, the roles are sequential: DFI-led project preparation creates bankable projects, structured credit enhancement makes them investable at scale, and pension capital is deployed once both conditions are met.

Exposure of South African institutional investors to domestic infrastructure assets sits at 5-7 percent of total assets.³⁸ As investors in ITPs, pension funds would participate directly in the value chains created by the transmission and distribution build programme.³⁹ As a debt provider, they would be financing a build programme that sits within a wider global pattern of scaling up transmission grids to meet demand growth⁴⁰. Enlarging the pipeline available to them is a function of upstream project-preparation capacity at the DBSA and ISA and working credit mitigating structures such as the Credit Guarantee Vehicle that the National Treasury and World Bank have been developing.

To make the investment case, it is necessary to understand where the capital is sitting, why little of it is currently moving into infrastructure, and what is blocking it. It also helps to be clear about what is already happening, since pension fund investment in South African infrastructure already takes place – the objective is to increase the scale. The sections below work through the existing base of investment, the availability of capital more broadly, and the structural and regulatory constraints, before returning to each of the roles above in more detail.

2. Existing pension fund investment in infrastructure

A number of South African asset managers already run dedicated infrastructure and development mandates on behalf of pension funds. Firms such as Prescient Investment Management, Mergence Investment Managers, NinetyOne and Sanlam Investments have each built out infrastructure-focused funds and mandates. Futuregrowth Asset Management and Old Mutual Alternative Investments (including a specialist subsidiary, Old Mutual African

36 DBSA (2026) Project Preparation, accessed 6 August 2026. Webpage: <https://www.dbsa.org/solutions/project-preparation>

37 DBSA (2020) DBSA Signs MOA to Establish and Manage the Infrastructure Fund, 17 August 2020. Press release: <https://www.dbsa.org/press-releases/dbsa-signs-moa-establish-and-manage-infrastructure-fund>

38 World Bank (2026) South Africa's Credit Guarantee Vehicle, 5 March 2026. Factsheet: <https://www.worldbank.org/en/news/factsheet/2026/03/05/south-africa-s-credit-guarantee-vehicle>

39 Vajeth, R. & Tlhatlhetji, P. (2023) Value Chain Mapping of the South African Transmission and Distribution Networks and the Allocation of the South African Manufacturing Capability to the Value Chain Elements. Available at: <https://www.lsf-sa.co.za/post/value-chain-mapping-local-manufacturing-capability-in-the-transmission-distribution-sector>

40 International Energy Agency (2025) Building the Future Transmission Grid: Strategies to Navigate Supply Chain Challenges. Available at: <https://www.iea.org/reports/building-the-future-transmission-grid>

Infrastructure Investment Managers or the OM AIIM) have been particularly prominent, investing in South African infrastructure debt and equity since the early 1990s.⁴¹

The Alexander Forbes Targeted Development Investment Manager Watch survey for the month ending May 2026 shows the scale already achieved. Old Mutual's AIIM IDEAS fund held approximately R29.1 billion under management. Futuregrowth's Power Debt Composite a further R9.8 billion.⁴² Ninety One's SA Infrastructure Credit Fund (ALBI) adds a further R2.2 billion, and Prescient, Mergence and Ninety-One between them run smaller but still substantial segregated and pooled infrastructure credit mandates alongside these.

Futuregrowth's own experience points to where the binding constraint lies. Its allocation to infrastructure tracks the availability of bankable projects, not investor appetite, which lines up with the market structure problems discussed further below. The sector breakdown of its flagship Infrastructure and Development Bond Fund clearly reveals this challenge.⁴³ On 31 March 2025, the Fund's exposure across infrastructure sectors included renewable energy at 14.2% of total investment in infrastructure, transport at 7.67%, various other infrastructures at 3.04%, development finance at 2.93%, and communications at 2.82%.

Figure 9: Futuregrowth Infrastructure & Development Bond Fund, exposure across infrastructure sectors, 31 March 2025.⁴⁴



The large energy portfolio reflects the sub-sector where the greatest number of bankable projects have emerged – projects structured with the revenue certainty, risk allocation, and creditworthiness that institutional investors such as pension funds require before committing capital. Transmission and other sub-sectors have not been short of investable opportunities in principle; rather, fewer of these projects have so far been structured to meet pension funds' bankability requirements. All the managers discussed above share the same perception of risk and potential returns in SA's infrastructure sectors. Projects have to clear risk-adjusted hurdles with structures that are perceived to preserve investment quality over time. Scaling these further needs bankable cash flows from creditworthy counterparties and proven operators, execution certainty backed by a stable political environment, and risk mitigation tools fit for purpose.

3. Availability of capital

In 2025, the National Planning Commission published a report on South Africa's financial architecture that concluded that South Africa is not short of capital.⁴⁵ South Africa has one of the largest pools of institutional capital in

41 Alexander Forbes (2026) Targeted Development Investment Manager Watch Survey, May 2026. Available at: <https://invest.alexforbes.com/za/en/surveys/industry-surveys/assets/targeted-development-investment-manager-watch/final-tdi-survey-may-2026.pdf>

42 Ibid.

43 Futuregrowth Asset Management (2025) Development & Social Impact Bi-annual Report: Futuregrowth Infrastructure & Development Bond Fund, 31 March 2025. Available at: <https://apos-futuregrowth-prod.s3.af-south-1.amazonaws.com/attachments/n46qfmp1eg62lnflggsu46n-futuregrowth-infrastructure-development-bond-fund-impact-report-31-mar-2025.pdf>

44 Ibid.

45 Swilling, M. and Murau, S. (2025) The Transformation of South Africa's Monetary Architecture, 1983–2024: A Report for the National Planning Commission, December. In collaboration with the authors of the background papers and the National Planning Commission's Finance Task Team. Stellenbosch: Centre for Sustainability Transitions. Available at: <https://www.nationalplanningcommission.org.za/assets/Documents/NPC%20FINANCIAL%20ARCHITECTURE%20REPORT%20DEC%202025.pdf>

the developing world, relative to the size of its economy. The problem is that only a fraction of it is finding its way into the domestic infrastructure that the country needs most. As the report noted, the architecture of South African finance has drifted away from long-term productive investment toward short-term portfolio returns, outward flows into foreign assets and liquid equity markets. And that drift has a real cost – for growth, for employment and for the energy transition.

The Transmission Development Plan sets out a capital requirement of R400 billion over a decade, one third of which must be invested by 2031.⁴⁶ This must be delivered by NTCSA and ITPs. NTCSA's own build accounts for an estimated R150–170 billion of that and independent transmission providers are expected to deliver the remainder, around 20% of new capacity. South Africa does not need to raise capital from international funders. Sufficient capital is available from domestic sources. The question is whether the institutional and regulatory environment can be reconfigured to access these domestic funds for the transmission infrastructure.

The scale and urgency of the build programme is already driving up costs, and the financing gap that emerges from FY2029 onwards presents a clear opportunity for pension funds to step in.

4. Pool size and allocation

As at the end of 2024, the combined assets of South Africa's retirement funds, life insurers and collective investment schemes sat at approximately R10.3 trillion, which is 140.9% of GDP.⁴⁷ This pool has been built up over forty years and is among the highest financial intermediation ratios in the developing world. The GEPF alone is managing over R2.5 trillion, roughly 33% of GDP, making it by far the dominant institutional investor in the country. Ninety One is a South African company that has become a global asset manager with nearly R4 trillion under management.

The challenge is not how big the pool is. It is where the money is going. Forty years ago, savings institutions were putting close to 50% of their assets into domestic public sector securities. By 2024 that had fallen to around 20%, which works out to about R2.1 trillion of the R10.3 trillion worth of assets under management.⁴⁸ The rest is sitting in listed equities, property and, increasingly, in foreign assets. Foreign exposure for private retirement funds has grown from under 5% in 2003 to 30% in 2024 of their collective portfolio. This was enabled by the SARB's exchange control regulations that raised the ceiling on foreign investment for institutional investors to 45% in January 2023.

The GEPF's own numbers make this clear. Government bonds now make up about 23.8% of its portfolio, around R630 billion, down from 46.8% in 2003. Equities and collective investment schemes account for over 60% of investments, valued at roughly R1.76 trillion.⁴⁹ What matters for the investment case is not how equities and bonds have historically performed, but whether transmission debt can be structured to a risk level acceptable to retirement funds, at a return the underlying revenue can sustain. Transmission revenue is regulated under the MYPD framework, within limits NERSA will accept as cost-reflective. If the underlying risk in that revenue chain – particularly the Eskom Distribution and municipal collection risk discussed above – is not resolved before the CGV is priced, the return pension funds would reasonably require rises accordingly, and project revenues may be unable to sustain it. The task is to bring that underlying risk down, not to compensate for it with a higher return. This is what would make transmission debt genuinely investable for pension funds.

The shift away from bonds has a direct impact on the bond market: as retirement funds pulled back from government bonds, banks filled the gap, and real long-term yields climbed from an average of 2.6% before 2018 to around 5% between 2018 and 2024. Donaldson describes this as a collective action problem: every fund is doing the individually rational thing by chasing equity returns, but together they are making borrowing more expensive for everyone, including themselves.

⁴⁶ National Transmission Company of South Africa (2024). Transmission Development Plan 2024. Johannesburg: NTCSA. Available at: <https://www.ntcsa.co.za/transmission-development-plan/>

⁴⁷ Donaldson, A.R. (2026) South Africa's retirement funds and their contribution to public sector financing: 1983–2024. Unpublished working paper, 10 February. Based on SARB's 'Whom-To-Whom' database, it is estimated that the total assets of the NBF sector as a whole was at 18.5 trillion in 2024 (see Hadji-Lazzaro, et. al. 2024).

⁴⁸ Ibid.

⁴⁹ Ibid.

In 2024, government issued R339 billion in bonds and treasury bills. The PIC took up around R50 billion of that, about 14.7%. Private retirement funds and insurers together accounted for just 7.1%, which is roughly R24 billion. Banks absorbed 43% of net issuance.⁵⁰ The OECD's 2025 Pensions at a Glance review identifies South Africa as among a minority of economies that carry a greater weighting in equities than bonds, which is unusual for a country whose pension liabilities are long-dated and rand-denominated⁵¹ and where government's need for capital to address such extensive development backlogs is so great.

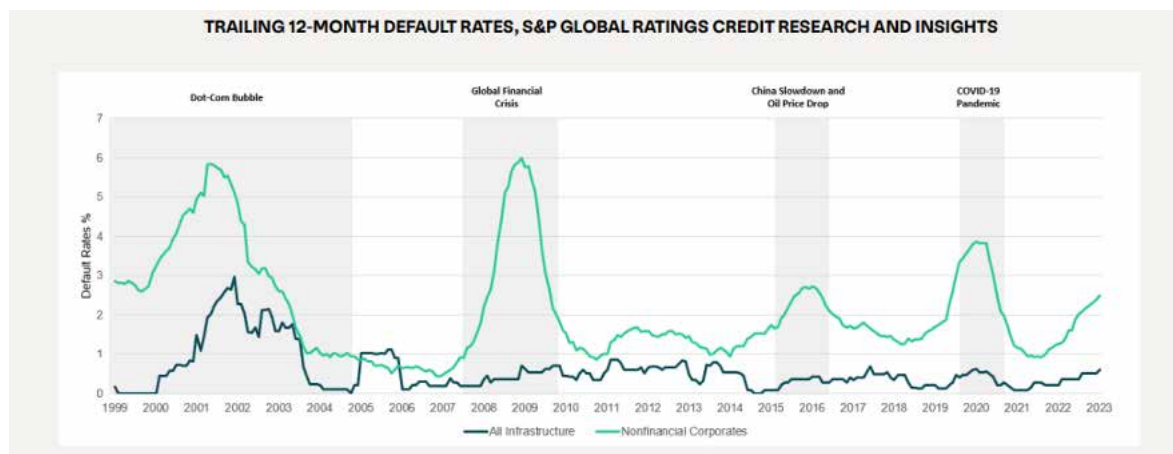
5. Investing in Transmission Infrastructure

As far as transmission infrastructure is concerned, the capital need is large and it is time-sensitive. As already pointed out, one third of R400 billion is required through to 2031/32⁵², with NTCSA's own build accounting for around 80% and the remainder procured via Independent Transmission Projects. Direct fiscal allocation cannot fund this capital need at the scale required. However, capital mobilised through pension funds is still ultimately repaid through returns on investment in public infrastructures that deliver services such as electricity to users who must pay for these services. Like most other infrastructure financing, public finance underwrites the investment in one way or another. The real question is where the upfront capital comes from to fund the projects. Pension funds are, on paper at least, well placed to play this role, in particular if this entails long-dated instruments of 30 years or more. This assumes that these projects will have already moved through the DBSA- and ISA-led project-preparation process described above, so that they reach pension funds in a bankable instrument rather than a development-stage risk.

Pension funds are long-duration investors by nature. They are paying pensions out over decades, so what they actually need is assets that produce stable, predictable cash flows over long periods. In many ways, transmission infrastructure is well suited to this type of investment. Fixed revenue streams regulated by the MYPD (Multi-Year Price Determination) framework make possible asset lives that typically run between 25 and 40 years and returns that historically track inflation.

The data on this equation is consistent. Macquarie Asset Management's analysis of infrastructure debt in 2025 confirmed the S&P's long-run default data on infrastructure, namely unlisted infrastructure defaults at lower rates than equivalent corporate credit and that holds across every major market stress period as is apparent in Figure 8 below.

Figure 8: Trailing 12-month default rates, infrastructure vs non-financial corporates, 1999-2023. Infrastructure debt has consistently defaulted at lower rates than corporate credit across all major market cycles. Source: S&P Global Ratings Credit Research and Insights, reproduced from Raine (2025)⁵³.



⁵⁰ Ibid.

⁵¹ OECD (2025) Pensions at a Glance 2025. Paris: OECD Publishing. Available at: https://www.oecd-ilibrary.org/finance-and-investment/pensions-at-a-glance_19991525

⁵² National Transmission Company of South Africa (2024). Transmission Development Plan 2024. Johannesburg: NTCSA. Available at: <https://www.ntcsa.co.za/transmission-development-plan/>

⁵³ Raine, G. (2025) Inhibitors to pension fund investment in infrastructure in South Africa. Unpublished regulatory constraints analysis.

When defaults do happen, infrastructure debt recovers at a higher rate, with more of the defaulted instruments recovering at par or above compared to non-financial corporates.

There is also the case for diversification. Research from by Latham⁵⁴ and Della Croce⁵⁵ shows that unlisted infrastructure investments behave differently to listed equity markets. Listed infrastructure tends to move with equity markets. Unlisted infrastructure, however, does not – it has a lower correlation with other asset classes. Adding it to a portfolio that is already heavy in equities and foreign assets brings overall volatility down. This diversification and liability-matching rationale, rather than a simple comparison of historical average returns, is the more defensible basis for a fund such as the GEPF to increase its allocation to long-duration infrastructure debt. This can either be achieved via ring-fenced long-dated listed bonds, or direct investments in unlisted assets. As already mentioned, some pension funds have successfully expanded their portfolio of unlisted assets in recent years.

Andrews and Wahba⁵⁶ and Weber, Staub-Bisang and Alfen⁵⁷ both highlight the structural fit between pension fund liabilities and infrastructure asset characteristics, the long maturity profile, the inflation hedging, and the more stable asset values that come with monopolistic or oligopolistic operating environments. Sawant makes the point that infrastructure assets have historically delivered acceptable risk-adjusted returns with stable cash flows, which is exactly what a defined contribution fund with long-term member obligations needs⁵⁸ and what a defined benefit fund needs even more directly given its guaranteed liabilities.

South Africa has a precedent for this. The IPP programme under the REIPPPP showed that institutional capital can be mobilised for energy infrastructure in South Africa when well structured. It worked because there was standardised documentation, a clear procurement framework and a government guarantee. The ITP model for transmission is attempting to do the same. However, government has made it clear that sovereign guarantees will not be available for this. The instrument being developed to substitute for that – a Credit Guarantee Vehicle (CGV) – is, structurally, a monoline: a single vehicle writing backstop guarantees over a portfolio of underlying credits in exchange for a premium. Monoline guarantors have historically only been commercially viable where the underlying transactions were themselves low risk, since a backstop guarantee prices affordably only when the likelihood of it being called is low. A CGV built on a portfolio of uncertain credits does not remove that risk; it relocates it, and prices accordingly. Discussion of the CGV's credit backing tends to focus on NTCSA's balance sheet. That is relevant, but it understates where the underlying risk actually sits: NTCSA's revenue, and the revenue behind the ITPs, ultimately depends on transmission charges being paid by Eskom Distribution and by municipalities as off-takers. Municipal collection performance is the weaker link in that chain – municipal debt stood at over R110 billion at last count, with 95% owed by non-metropolitan municipalities (discussed further below). The CGV cannot be priced as a low-risk monoline while that collection risk remains unresolved. A bankable, cost-reflective tariff framework must be approved by NERSA and the Eskom Distribution and municipal cash flows underpinning NTCSA and the ITPs must be brought to a genuinely low-risk standard. Tariff unbundling will be a crucial precondition for effective revenue collection and ringfencing of risk. Under these conditions, the ITP programme and the NTCSA's build programme could create a pipeline of instruments that pension funds could access through structured debt or blended finance, building on the infrastructure investment capability that already exists in the market.

The NTCSA's own build can be financed directly against the utility's balance sheet, through capital-market bond issuance which is generally the cheaper form of capital, since it draws on the utility's balance sheet rather than a single project's cash flows. ITPs, by contrast, are financed through structured project finance. This means they are

54 Latham, D. (2008) Building the case for direct infrastructure. *Pensions: An International Journal*, 13(1), 83–87. Available at: <https://doi.org/10.1057/pm.2008.8>

55 Della Croce, R. (2012) Trends in Large Pension Fund Investment in Infrastructure. *OECD Working Papers on Finance, Insurance and Private Pensions*, No. 29. Paris: OECD Publishing. Available at: https://www.oecd.org/content/dam/oecd/en/publications/reports/2012/12/trends-in-large-pension-fund-investment-in-infrastructure_g17a21fa/5k8xd1p1p7r3-en.pdf

56 Andrews, A. and Wahba, S. (2007) Investing in Infrastructure: A Primer. *Infrastructure Paper Series No. 2*. New York: Morgan Stanley.

57 Weber, B., Staub-Bisang, M. and Alfen, H.W. (2016) *Infrastructure as an Asset Class: Investment Strategy, Sustainability, Project Finance and PPP*. 2nd edn. Chichester: John Wiley & Sons.

58 Sawant, R.J. (2010) *Infrastructure Investing: Managing Risks and Rewards for Pensions, Insurance Companies and Endowments*. Hoboken: Wiley Finance.

not financed against a single balance sheet but against a project's own cash flows, credit support and risk allocation. That typically is more expensive as there is risk transfer across several balance sheets (sponsors, lenders, guarantors) rather than concentrating it on one balance sheet. Where the balance between these two sets of opportunities should sit, and how it should shift, is not yet settled. It will depend partly on factors outside NTCSA's control, including the challenge of municipal finances. As distribution systems are repaired and collection performance improves, there is potential over time for a share of the underwriting risk to move toward municipalities. This means they will need to build the capacity to take on more of the credit support they currently put at risk. Until that shift happens, the more realistic sequence is utility bonds carrying the lowest-risk, lowest-cost share of the build via NTCSA's own build programme, while structured project finance carries the remainder via ITPs. Pension funds can participate both as bond investors in NTCSA debt, and as structured-debt or blended-finance participants in ITPs once the project-preparation and credit-enhancement work has been executed.

6. Constraints on Pension Fund Investment

Despite the existing base of investment, little pension fund capital is flowing into energy infrastructure at the required scale right now. Raine's regulatory analysis confirms that the core problem is structural. Infrastructure is not recognised as a standalone asset class under Regulation 28 of the Pension Funds Act.⁵⁹ A new infrastructure category was added in 2022 with a 45% overall limit and 25% limit per entity but in practice it has changed very little. As Raine points out, trustees cannot be expected to exercise fiduciary oversight directly over infrastructure projects. The regulatory change created a category, but state entities such as SANRAL, Rand Water, Umgeni, Eskom and Transnet can already issue bonds within Regulation 28's debt security limits. Bond issuance itself is therefore not the constraint, and it is not clear that any additional regulatory "scaffolding" would change that. If a gap exists, it may lie elsewhere, in longer-term offtake agreements that make public infrastructures investable on terms pension funds are willing to hold, rather than in the debt issuance framework itself.

As things stand, most infrastructure allocations have to fit inside either the private equity limit of 15% or the unlisted debt limit of 15% and neither of those was designed with large-scale infrastructure investments in mind. The look-through reporting requirements add another layer. Where infrastructure is held through pooled vehicles, funds have to report underlying exposures every quarter and unlisted infrastructure assets are genuinely difficult to value consistently under mark-to-market requirements.⁶⁰ Raine also flags that the April 2024 Prudential Standard update removed the requirement to report on infrastructure investments specifically, after pushback from industry about the cost. Infrastructure is now not even a clearly tracked category, which makes it that much easier for trustees to treat it as a low priority.

Trustee risk aversion sits on top of all of this, and it is not irrational. Trustees carry personal liability for investment decisions under the Pension Funds Act, so without clear guidelines on how to assess infrastructure risk, the rational thing to do is avoid it. That is especially true for greenfield assets where construction risk and revenue uncertainty are highest. According to Donaldson, the move toward equities and foreign assets has not only been about chasing returns. There is also government and parastatal risk tied to broader questions of South Africa's growth and development trajectory, which matters in the case of transmission given NTCSA's exposure to municipalities with weak collection rates.⁶¹ Municipal debt now stands at over R110 billion, with 95% owned by non-metropolitan governments - the collection risk discussed above in relation to the Credit Guarantee Vehicle.

The market structure remains a significant barrier. Among the regulatory, trustee-level, and market structure constraints, market structure most directly explains the lack of pension capital movement into infrastructure assets. As Ntlai Mosiah of Mazi Infrastructure Fund recently noted, the primary constraint is the project pipeline, not capital or

59 Raine, G. (2025) Inhibitors to pension fund investment in infrastructure in South Africa. Unpublished regulatory constraints analysis.

60 Ibid.

61 Donaldson, A. (2026) Contractual savings and public investment: are our retirement funds misallocated? BER Research Note. 17 April. Stellenbosch: Bureau for Economic Research, Stellenbosch University: Available at: <https://www.ber.ac.za/Documents/Download/b75582ed-227b-4ccd-a629-841277710a07>

regulation.⁶² As Raine notes, there are simply not enough investable vehicles. Many infrastructure projects are not packaged in formats pension funds can actually access. Listed infrastructure funds are few. The unlisted pooled vehicles that do exist often lack the transparency and Regulation 28 compliance certification which funds require does not apply.⁶³ Long-dated infrastructure bonds of the kind that would sit naturally in a pension portfolio are rare in this market.

7. The defined contribution and LISP platform constraint

A further constraint sits in the changing structure of the retirement fund itself that reflects similar challenges with the market structure and Regulation 28 prescriptions described above. The shift from a Defined Benefit to a Defined Contribution approach narrows the pool of capital that can plausibly hold long-dated, illiquid instruments rather than expanding this pool. Global pension asset allocation has shifted from Defined Benefits (DB) toward Defined Contribution (DC) arrangements over the past four decades, across the United States, advanced European economies and emerging markets alike. Pension investors generally have moved away from fixed income securities toward mutual fund shares and other alternative assets over the same period.⁶⁴ DB funds, where the sponsor carries the investment risk and pays a guaranteed benefit, have historically invested in more long-term government and corporate bonds to match the long-dated nature of their liabilities. DC funds, where the individual member carries the investment risk, hold a higher share of equities and mutual fund shares and a correspondingly lower share of bonds, which matters because it is DB-style, liability-matched capital that is best suited for long-dated infrastructure instruments.

South Africa has followed this pattern, with the GEPF standing out as the country's dominant remaining defined benefit fund. Defined contribution capital increasingly sits inside umbrella funds bolted onto collective investment schemes (CIS) as the underlying investment vehicle. Smaller, standalone pension and provident funds have followed a related but distinct path, moving toward life policy-based structures, where the underlying assets sit within an insurer's life fund rather than being held directly by the retirement fund, as a way of managing the governance and administrative burden that a small fund cannot absorb on its own. Alongside these are personal pension products such as retirement annuities, preservation funds and living annuity funds, distributed through life-linked-investment-service-provider (LISP) platforms. On one industry estimate, total LISP platform assets under administration run somewhere between R1.8 trillion and R2.2 trillion. Retirement capital, meaning living annuities, retirement annuities and preservation funds, makes up roughly 65% of that, or R1.5 trillion, with living annuities alone accounting for something in the order of 45% to 50% of retirement capital on LISP platforms, ahead of retirement annuities at 30 to 35% and preservation funds at 15% to 20%.

This narrowing matters for two reasons. First, it reflects a move away from guaranteed annuities, where the insurer carries the longevity and investment risk on behalf of retired members, toward living annuities, where the retired member carries both, and has no equivalent institutional balance sheet to absorb illiquidity risk. Second, it has moved investment decision-making away from the actuarially managed asset liability that matches historically supported long-dated bond and infrastructure allocations in DB funds, toward daily-priced, retail-oriented collective investment schemes designed primarily for liquidity, not for holding long-dated illiquid infrastructure investments.

The result is a regulatory and product-design mismatch, not just an appetite problem. The clearest example is the R1.7 trillion invested through LISPs, which includes over R800 billion held in personal pension products, namely retirement annuities, preservation funds and living annuity funds, that invest predominantly in the collective investment schemes subject to daily dealing requirements. These investors are effectively excluded from participating in high-quality, illiquid infrastructure investments. Liquidity and quality should not be regarded as competing characteristics for eligible assets within a portfolio. However, this is not a pervasive perception in the industry. Addressing this constraint would mean evaluating options that allow capital controlled by retail investors, and by unitised funds more

62 Seima, M. (2026) Pension funds should not be fixing potholes, says Mazi's Ntlai Mosiah, 5 August 2026. Citywire South Africa: <https://citywire.com/za/news/pension-funds-should-not-be-fixing-potholes-says-mazi-s-ntlai-mosiah/a2495460>

63 Raine, G. (2025) Inhibitors to pension fund investment in infrastructure in South Africa. Unpublished regulatory constraints analysis.

64 Ding, Fang, Hardy and Lewis, "Global pension asset allocations and debt markets", BIS Papers No 172, June 2026.

broadly, to access the same private investment universe currently available to institutional investors, alongside the Regulation 28 and look-through reforms discussed above.

Donaldson argues that rather than reducing foreign investment limits, which would create compliance headaches and likely just push funds toward re-characterising assets creatively, the more useful approach is to develop investment guidelines that acknowledge both the tax-privileged status of retirement funds and the macro-financial needs of the domestic economy.⁶⁵ For the GEPP specifically, he argues that guidelines reviewed regularly by an expert committee drawing on National Treasury, SARB and the financial sector would do more than blunt portfolio limits. For transmission infrastructure, what is probably needed is not a new regulatory category but a set of clear guidelines, maybe supported by blended finance instruments or a partial guarantee structure that gives trustees the fiduciary cover to allocate capital without personally exposing themselves.

Another important point to take into account is tax treatment. Section 23M of the Income Tax Act limits interest deductibility where there is a connected-party relationship and the interest recipient is tax-exempt. That creates a specific problem when a pension fund holds both equity and debt in the same infrastructure project. An accelerated depreciation is available for renewable energy projects but not for transmission assets, which makes the tax efficiency of transmission investment less attractive compared to generation.⁶⁶ None of these is impossible to fix but they do add friction and they would need to be worked through as part of an effort to build a pipeline of pension-fund-investable transmission instruments.

8. Unclaimed Benefits

The FSCA's most consequential recent document on the subject is the discussion paper titled *A Framework for Unclaimed Financial Assets in South Africa* (September 2022). It mapped the full landscape of unclaimed assets across the South African financial sector which it estimated at R88.56 billion and proposed 13 policy recommendations to address the problem systematically, including the controversial idea of a *Central Unclaimed Assets Fund*. The paper found that unclaimed retirement benefits constitute 53% of the total (approximately R47 billion at end-2020, held across 1,306 retirement funds on behalf of 4.45 million people), while life insurance and collective investment schemes accounted for 38% (R33.5 billion). The remaining ~9% is distributed across bank deposits, securities, and other instruments.

There has been much discussion about how best to deploy these funds in a way that does not expose any of the financial institutions to unnecessary risk. Obviously, the funds cannot be used for equity or grant funding, which means an appropriate debt instrument and structure will need to be found if these funds are to be used to finance infrastructures with a clear public benefit.

9. Pension Funds' role in the TDP

Given all of the above, the four roles identified at the start can now be grounded in the TDP's actual financing structure and in what pension funds know how to do.

Debt provider: From FY2029, as already described in Part I, it is estimated based on public domain data that the NTCSA might well need to raise R35-50 billion in external debt per annum, and rising in subsequent years. That is exactly the kind of long-dated, fixed-income financing that pension funds are built to provide. The maturities match pension liability horizons; the counterparty is a regulated national entity, and the revenue stream sits behind the MYPD tariff framework. This is not a stretch for funds that already hold government bonds – it is essentially the same risk profile with a more direct link to productive infrastructure.

⁶⁵ Donaldson, A. (2026) Contractual savings and public investment: are our retirement funds misallocated? BER Research Note. 17 April. Stellenbosch: Bureau for Economic Research, Stellenbosch University. Available at: <https://www.ber.ac.za/Documents/Download/b75582ed-227b-4ccd-a629-841277710a07>

⁶⁶ Raine, G. (2025) Inhibitors to pension fund investment in infrastructure in South Africa. Unpublished regulatory constraints analysis.

Investors in ITPs: Around 20% of total TDP capex is expected to flow through independent transmission providers. ITPs are project finance vehicles with a standard equity and debt split, structured similarly – but without sovereign guarantees – to the IPP vehicles that institutional investors have been using under the REIPPPP. Pension funds can participate on either side. On the debt side, revenue certainty from a transmission licence and a defined tariff gives a predictable cash flow. On the equity side, long asset life and a regulated return make it comparable to infrastructure equity that investment funds currently invest in.

Project preparation funding: Getting a project to financial close takes time and money, all of it before a single rand of construction finance is raised. This is usually where pipeline stalls. Pension funds are big enough to provide early-stage capital through dedicated project preparation facilities, either on their own or alongside development finance institutions such as the IFISA arrangement. However, project preparation funding typically has to be committed before a project reaches financial close, without assuming cost recovery. Costs are only recouped as part of project preliminaries if the project proceeds. Given fiduciary duty and return requirements, it is unclear whether pension funds can take on that kind of at-risk commitment without a counterparty providing a guarantee, such as a DFI like the DBSA.

Strategic input on the enabling environment: The guarantee structure, tariff unbundling, and the TSO transition are not going to sort themselves out. They need sustained institutional pressure from people with a real stake in the outcome. Pension funds, given their size and long-term exposure, are exactly the kind of stakeholders who should be in those engagements. This is not lobbying; it is the kind of patient, technically grounded engagement that shifts the conditions under which investment becomes possible.

The second part of this discussion paper draws on Donaldson's macro-financial analysis, Raine's regulatory constraints work, and Moleko's infrastructure investment research to make the argument.⁶⁷ When considered together, the numbers suggest a compelling case. South Africa has R10.3 trillion in institutional savings and the TDP needs R400 through to 2035, one third before 2030. The timelines actually line up, pension fund liabilities are long-dated and so is transmission infrastructure. The money is there, the need is clear, and the roles are well defined. What is still missing is the institutional framework that brings the two together.

Conclusion and Recommendations

The primary conclusion of this discussion paper is that pension funds have an opportunity to significantly increase their investments in infrastructures of various kinds. The case of South Africa's transmission grid build programme was described in detail, including references to a range of investment opportunities. This was followed by a description of the challenges that need to be faced if pension funds are to increase their investments in infrastructure.

The following broad recommendations for the immediate future are worth considering:

1. significantly increase understanding of the infrastructure development landscape and related funding opportunities;
2. instead of waiting for government or DFIs to work out solutions, generate 3 to 5 key regulatory interventions and instruments that could unlock pension fund investments in infrastructure that do not compromise the fiduciary duty of the pension funds;
3. possibly start the ball rolling by focusing on how best to deploy the unclaimed benefits funding as an alternative to the Central Unclaimed Assets Fund.

⁶⁷ Donaldson, A.R. op. cit.; Raine, G. op. cit.; Moleko, N. (2024). 'Pension Funds in SA Economy,' unpublished background paper commissioned by National Planning Commission, Finance Task Team. Pretoria: National Planning Commission; Moleko, N. and Ikhude, S. (2017). 'Pension Funds Evolution, Reform and Trends in South Africa,' International Journal of Economics and Finance Studies 9 (2), 134–151.

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Centre for Sustainability Transitions



The Stables, 19 Jonkershoek Road,
STIAS campus, Stellenbosch



cstenquiries@sun.ac.za



www.sun.ac.za/cst



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