ESKOM'S DEMAND RESPONSE JOURNEY: A STRATEGIC TOOL FOR SYSTEM OPERATOR FLEXIBILITY AND GRID SECURITY

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ABSTRACT

In the early 2000s, South Africa enjoyed a surplus of electricity, but this was to change dramatically over the next few years. Eskom recognised early on that Demand Response (DR) dispatchable load would become an essential tool to strengthen future grid reliability. The DR programme has since grown into a cornerstone of the National Transmission Company South Africa's System Operator (SO) toolkit.

Launched in 2004, the DR programme has evolved into a highly effective and dependable mechanism for supporting system stability, with 1,400 MW of dispatchable DR capacity now available to the SO. Its value was clearly demonstrated during the 2007/2008 electricity supply challenges, when DR provided critical flexibility to help maintain daily operating reserve margins and safeguard power system security.

Today, DR remains a vital component in ensuring a resilient and responsive power grid, helping South Africa navigate both current and future energy demands.

1. INTRODUCTION

Global power systems increasingly rely on Demand Response (DR) programmes to address adverse system events, tight reserve margins, and growing operational uncertainty—and South Africa is no exception. Since 2004, Eskom has made significant strides, expanding from zero DR capability to 1,400 MW of dispatchable DR capacity now available to the National Transmission Company South Africa's System Operator. (NTCSA-SO).

The DR programme is a critical tool for enhancing system reliability, providing the SO with flexible, fast-acting resources to maintain reserve margins during periods of supply constraints or unforeseen system disturbances. Through the DR programme, qualifying electricity consumers were incentivised to voluntarily reduce their consumption during peak demand periods or times of system stress, supporting grid stability.

The DR programme, endorsed by both Eskom and the National Energy Regulator of South Africa (NERSA), was formally approved in December 2004. NERSA mandated that only contracted and verified load providers may be dispatched, and only when the cost of DR is economically competitive with alternative supply-side options. This framework enabled the SO to make informed, real-time decisions—balancing the grid by either ramping up generation or activating contracted DR resources—ensuring both operational efficiency and cost-effectiveness.

1.1. Demand Response journey

The first group of large electricity consumers, all directly supplied by Eskom, were contracted in 2005 to participate in the DR pilot programme, contributing an estimated 383 MW of dispatchable load. The programme initially included the following products:

1.1.1. Instantaneous reserves

Instantaneous reserves served as a buffer to manage sudden drops in system frequency, forming part of the System Operator's operating reserves portfolio. This Instantaneous Demand Response (IDR) product helped stabilise the National Transmission Company South Africa (NTCSA) grid by reducing demand within 6 seconds in response to a frequency-based control signal. This reduction was sustained for up to 10 minutes at a time. Under normal conditions, Eskom manages system frequency between 49.85 Hz and 50.15 Hz using automatic generation control.

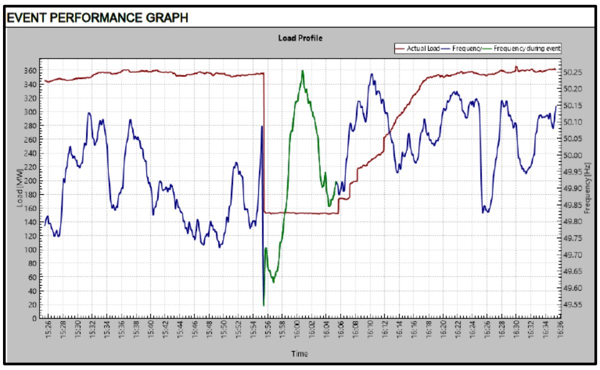

Figure 1: Example of IDR load reduction event

1.1.2. Supplemental reserves

Supplemental reserves help manage peak demand on the national electricity network. Contracted Supplemental Demand Response (SDR) load providers had to respond to load reduction requests within 30 minutes upon instruction from NTCSA. The load reduction had to be maintained for two hours, limited to once per day and up to 300 hours annually. Eskom collected metering data for payment and performance verification.

SDR load reduction requests were managed by NTCSA's National Control, which was feasible during the pilot phase due to the small number of load providers and the relatively limited constraint periods.

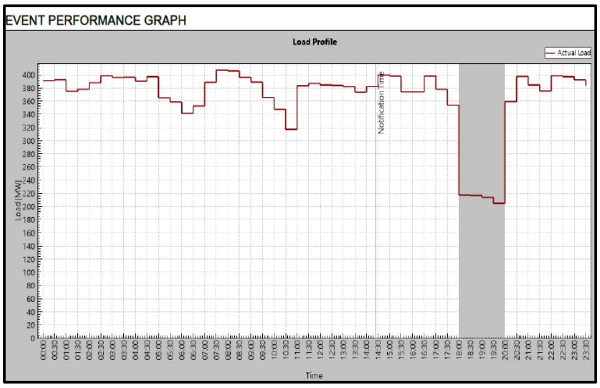

Figure 2: Example of SDR load reduction event

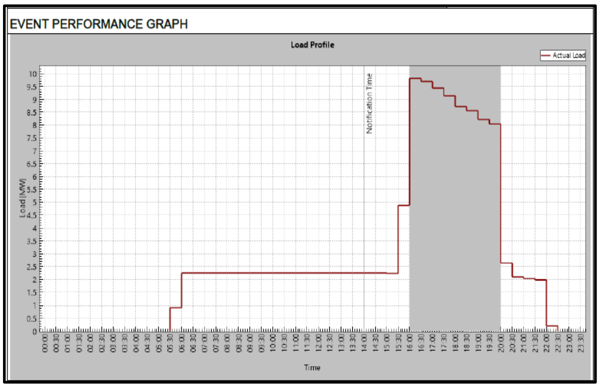

Figure 3: Example of a self-generation event

In 2006, Eskom faced supply constraints in the Western Cape due to the Koeberg Nuclear Power Plant being off and the transmission network only able to supply about 75% of the power requirements. This prompted the extension of the DR programme to municipal and smaller distribution customers. During this time, Eskom also explored leveraging customers' standby generators as emergency reserves. Upon Eskom's request, customers would supply their own electricity to reduce load on the grid. This was not very successful as potential load providers didn't have sufficient diesel storage capacity. This led to the creation of a DR aggregator, which consolidated smaller load providers' loads into a single block presented to the System Operator. The aggregator dispatched these smaller customers based on instructions from National Control.

In 2006, the IDR standby rate was **R10**/MW/h for scheduled hours and the SDR energy rate at **R800** per MWh for energy not consumed. Towards the end of 2007 and early 2008, Eskom faced severe supply constraints, leading to load shedding. To mitigate this, Demand Response reserves were deployed, and an Emergency DR programme was launched to attract larger loads through short-term, higher-rate agreements. As participation and load reduction requests increased, managing all DR agreements manually became difficult for the System Operator. To address this, a pilot Virtual Power Station (VPS) system was developed to aggregate DR loads and present them as a single entity. The VPS streamlined DR performance management, availability planning, dispatch, and reporting.

Since 2011, Eskom's Demand Response programme has evolved significantly, with more customers participating in the programme. A self-generation DR product was introduced, measuring generator output against prior usage.

A dynamic seasonal customer baseline load (CBL) was implemented to address consumption variability, along with enhanced performance metrics and validation. Automated phone and SMS dispatch replaced manual notifications, and financial settlements were processed automatically. Real-time DR usage was displayed on the NTCSA National Control's dashboard.

In 2015, Eskom had 931 MW of certified instantaneous Demand Response reserves available to manage sudden frequency drops, with load providers dispatched on average 17 days per month. Supplemental DR load providers contributed 82.7 GWh in energy reductions during system constraints; however, their availability was lower during peak winter months, as they responded to high time-of-use tariffs.

Additionally, 15 MW of generation capacity participated in the Self-Generation DR programme, with successful load providers using coal, gas, or water as fuel sources. Participation during winter declined due to low dam levels and the use of generators to offset high electricity costs.

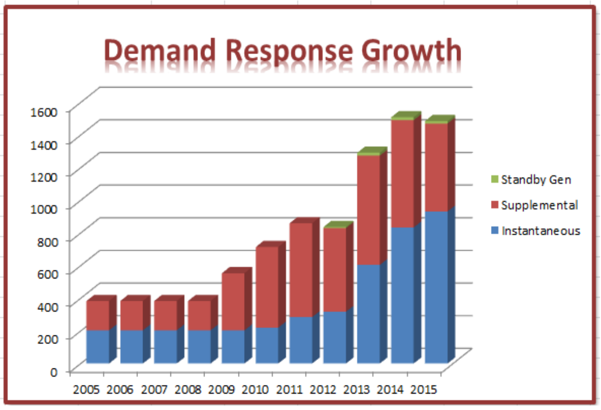

Figure 4: Demand Response Growth (2005–2015)

2. HOW DOES A "WELL-OILED DR MACHINE" FUNCTION EFFICIENTLY?

Demand Response load providers will be excluded from the nationally mandated load curtailment Stages 1 and 2, provided that the electrical infrastructure and network configuration allow for it, they meet the product performance criteria, and they comply with the rules outlined in the Load Reduction Practices as published in NRS 048-9:2023 Edition 3 ('Electricity Supply – Quality of Supply Part 9: Load Reduction Practices, System Restoration Practices, and Critical Load and Essential Load Requirements Under System Emergencies'). It is clear from Figure 4 that the intangible benefit from being excluded from certain curtailment stages is very valuable to load providers, as it assists them in planning their electricity consumption.

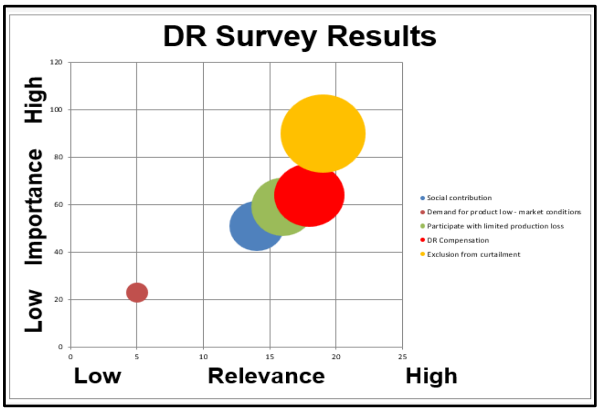

Figure 4: Demand Response Survey

2.1. Virtual Power Station (VPS)

The platform is built on the latest Microsoft® technologies and tailored to Eskom's unique requirements. It supports a range of Demand Response (DR) programmes, including Instantaneous DR, Supplemental DR, Standby Generation, Emergency Curtailment, and Critical Peak Day initiatives.

The VPS manages the entire Demand Response lifecycle—from contract capture to load scheduling and dispatch, as well as measurement and reporting. It delivers comprehensive insights through reports on event performance, monthly outcomes, and settlement summaries.

The VPS interfaces with metering and dispatch equipment—installed at Eskom's expense—at load provider sites. These devices automatically issue shed and restore signals when predefined criteria are met. A real-time dashboard provides visibility into site statuses and key data measurements.

2.2. Certification of participating loads

To participate in Demand Response, the load provider must be certified by Eskom for their load under normal plant conditions. Upon satisfactory verification, Eskom will notify the load provider via email of the certified capacity, which represents the load available for participation. All testing will be conducted at the load provider's own expense. (Loss of production).

SDR Certification requires the load provider to demonstrate successful load reduction, either twice for 30 minutes each, with at least 2 hours between events, or once for 60 minutes.

IDR Certification requires the load provider to demonstrate successful load reduction on two separate occasions, each triggered by the Demand Response installation. The provider must reduce load within 6 seconds and sustain the reduction for up to 10 minutes per event.

2.3. Bid, schedule and dispatch

Load providers are required to submit their dispatchable load offers (bids) to the VPS by 09:00. The VPS then consolidates these load offers and submits the total aggregate dispatchable load to the NTCSA-SO by 10:00. Based on this information, the SO informs the VPS by 12:00 whether the loads should be scheduled or not. Once confirmation is received, the VPS proceeds to schedule the de-aggregated loads by 15:00. (Figure 5)

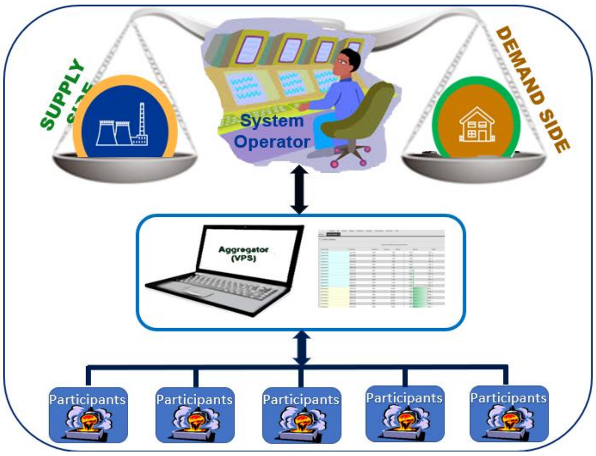

Figure 5: Bidding and scheduling

The **SDR load provider** must ensure that the scheduled capacity is available during the scheduled hours and that the required load reduction is achieved within 120 minutes from the time a dispatch instruction is given via phone call by the VPS. Once the load is reduced, it must be maintained for a duration of two hours. Load reduction events will be limited to a maximum of one event per day and 150 on-target events per financial year (April – March).

The **IDR load provider** must ensure that the scheduled capacity is reduced within six (6) seconds of receiving a load reduction dispatch signal from the DR installation. This signal will be triggered when the system frequency drops below the predefined trip frequency threshold. Load reduction events for IDR will be limited to a maximum of three (3) events per scheduled day, with a mandatory minimum rest period of 60 minutes between consecutive events. Load reductions will be limited to a maximum of 200 on target events per financial year (April – March).

2.4. Load reduction and payment

2.4.1. SDR load reduction calculation methodology

Load reduction shall be calculated per 30-minute integration period, subtracting the actual load from the scaled CBL (reference load) and summated for the duration of the load reduction request.

Formula
LR = sum [(CBL (n) – Actual Load (n)) (CBL (m) – Actual Load (m))]

Where:
n = first Integration Period of the Load Reduction request
m = last Integration Period of the Load Reduction request

If the actual load exceeds the CBL, the said difference shall be a negative variance, and if the actual load is less than the CBL, the said difference shall be a positive variance. For each load reduction event, the positive variances and the negative variances shall be summated, and should the resultant load reduction amount be negative, it shall be deemed to be zero.

The CBL shall consist of average half-hourly weekday and weekend day profiles. These profiles shall exclude curtailment days, planned and unplanned maintenance days and are replaced with a subsequent day for CBL calculations.

For each event, the CBL shall be scaled up or down to match the actual load in proportion to the difference between the average of the CBL and the average actual load during the first two integration periods X(z) of a moving 3 (three) completed integration periods immediately before the event.

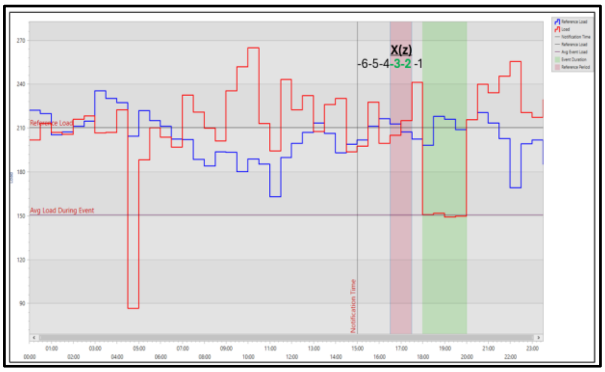

Figure 6: CBL scaling

The reference point X(z) may be moved to a mutually agreed period of regular consumption up to point -6, as indicated in Figure 4, if such a reduction follows a period of abnormal consumption. The allowed options for such a movement shall be limited to points (-1 & -2), (-3 &-4), (-4 &-5) or (-5 &-6). (Figure 6)

2.4.2. **IDR load reduction calculation methodology**
Load reduction will be calculated as the average of two components: (Figure 7)

- The **initial load reduction**, measured as the average reduction recorded in four-second intervals during the first 12 seconds following the load reduction instruction, relative to the pre-shed baseline.
- The **sustained load reduction**, measured as the average reduction maintained after the initial 12 seconds, until either a restore signal is sent by the DR installation or 10 minutes have elapsed, whichever comes first.

Formula
Actual Load Reduction (n) = Average of *Initial Reduction (n)* and *Sustained Reduction (n)*

Where:
n = Applicable incident/event
Initial Reduction (n) = X(a) – X(b)
Sustained Reduction (n) = X(a) – Avg. [X(c…d)]

Definitions:
X = Actual metered four-second integrated demand
(a) = The last completed four-second integration period immediately before the instruction to reduce load (indicated as time "1" in Figure 6)
(b) = The completed four-second integration period within the first 12 seconds after the load reduction instruction, corresponding to the lowest demand recorded during this period (between time "1" and "2")
(c…d) = All completed four-second integration periods starting 12 seconds after the load reduction instruction (time "2") and ending either when a restore signal is issued or after 10 minutes from the instruction time (time "3"), whichever occurs first

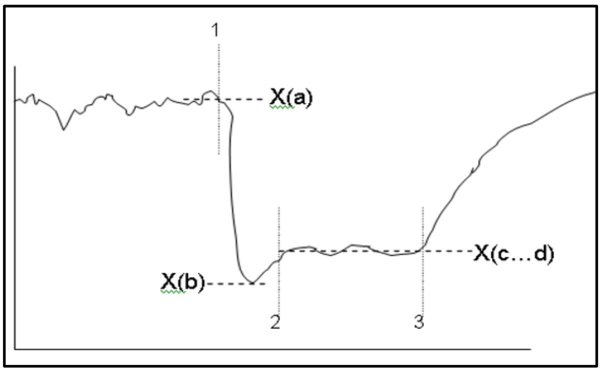

Figure 7: IDR load reduction

DR rates (2025-2026 financial year)
SDR load providers will receive a capacity and energy payment. Capacity payments are based on system peak and off-peak standby hours. The applicable rates are **R41.57 per MW per hour** during system peak hours and **R17.42 per MW per hour** during off-peak hours, provided the resource is scheduled to be on standby.

System peak hours are defined as follows:

- **Summer months** (September to April): Weekdays from 09:00 to 12:00 and from 18:00 to 21:00.
- **Winter months** (May, June, July, and August): Weekdays from 06:00 to 09:00 and from 17:00 to 20:00.

Additionally, an energy payment of R1,944 per MWh will be made for load reduction events where performance exceeds 30%, with a cap at 120%, based on metered energy in MWh.
IDR load providers will receive a capacity payment of **R31.98 per MW per hour** for hours scheduled to be on standby.

3. SETTLEMENTS

Load providers will receive settlement reports by the 5th business day of the following month for any load reduction events that occurred during the previous month. If all parties agree on the amount payable, the load provider must submit an invoice to Eskom by the 10th business day of the month.

3.1. Discussion/Analysis

The largest and smallest single Instantaneous Demand Response (IDR) participating loads are 130 MW and 6 MW, respectively, primarily consisting of smelters with furnace-based loads. Eskom has installed dedicated DR equipment at these sites to manage and control the load response effectively. For Supplemental Demand Response (SDR), the largest and smallest single loads are 97 MW and 2 MW, respectively. These loads are typically associated with smelters, furnace operations, the cement industry, and steel processing facilities.

3.1.1. Advantages and disadvantages for the load provider

Advantages
Load providers benefit from financial incentives designed to potentially reduce their energy and demand costs. By participating, they contribute to grid stability during periods of supply constraints, supporting national energy security. Furthermore, participating load providers may be excluded from certain load curtailment stages, providing additional operational advantages. DR participation is entirely voluntary, with agreements allowing either party to terminate with a 30-day notice period. In the case of SDR, load providers are notified 120 minutes before a load reduction event. SDR events occur only during the evening peak period, are limited to weekdays, and load providers are generally scheduled for no more than three events per week.

Disadvantages
Certain industrial processes are inflexible or sensitive to interruptions. These disruptions can result in the breakage of furnace electrodes or negatively impact product quality. In some cases, the financial incentives offered may not adequately compensate for production losses, particularly where products are linked to volatile market or currency conditions. Additionally, participating more frequently than anticipated can increase maintenance requirements and related operational costs.

3.1.2. Advantages and disadvantages for the NTCSA -SO

Advantages
The SDR programme offers 530 MW of dispatchable load, providing the System Operator with a flexible tool to balance supply and demand, especially during peak periods, generation shortfalls, or unforeseen system events. The IDR programme provides an additional 866 MW of load that can respond within seconds to frequency deviations, significantly enhancing real-time system balancing capabilities. DR also offers a lower-cost alternative to conventional operating reserves and expensive peaking generators, such as open-cycle gas turbines (OCGTs).

Disadvantages
Winter time-of-use (ToU) peak tariffs can reduce SDR availability, as load providers may already be limiting consumption during high-tariff periods, making additional reductions impractical. Furthermore, market or currency fluctuations that influence the profitability of large industrial load providers can directly affect reserve availability. A sudden, significant increase in IDR load following an event can place severe stress on electrical infrastructure, including network equipment centres (NECs), which in extreme cases may overheat, fail, or ignite. Additionally, some supply authorities, particularly municipalities, resist the participation of their customers in DR programmes. Despite Eskom funding all incentives, municipalities perceive this as lost revenue, thereby limiting broader DR adoption.

4. RELATED PROGRAMMES

Locally, the Demand Response programmes include both incentive-based and price-based approaches. Active incentive-based programmes consist of Supplemental Demand Response and Instantaneous Demand Response, as well as Distribution Demand Management Programmes (DDMP). DDMP focus on actions like energy efficiency, load shifting, load clipping, load limiting, and residential load management (ripple control).

On the price-based side, active programs include time-of-use tariffs and long-term interruptible agreements with large consumers. Some price-based initiatives, such as real-time pricing, critical peak pricing, and short-term energy buyback agreements with large consumers, are currently not active. Together, these programs aim to encourage load reduction and flexibility through both financial incentives and pricing strategies.

Globally, Demand Response (DR) programmes vary by region. In the U.S., utilities and system operators like PJM, CAISO, and ERCOT offer incentive- and price-based DR programmes. Europe uses time-of-use tariffs and aggregator-led DR, with the UK's National Grid running services like the demand flexibility service, balancing mechanism, and frequency response services.

Australia focuses on automated DR and renewable integration through mechanisms like wholesale Demand Response, reliability and emergency reserve trader, and virtual power plants for residential systems. In Japan, following the Fukushima disaster, DR expanded to include emergency, price-based, and incentive-based programmes, supporting grid stability and renewable integration. DR is widely used across industrial, commercial, and growing residential sectors.

5. CONCLUSION

South Africa's Demand Response programme has developed significantly since its introduction in 2004, growing into a vital resource that enhances national grid stability, operational flexibility, and energy security.
The Demand Response framework, driven by the Instantaneous Demand Response and Supplemental Demand Response mechanisms, provides 1,400 MW of dispatchable DR capacity to the National Transmission Company South Africa (NTCSA) System Operator. Notably, the introduction of the Virtual Power Station has modernised DR operations by streamlining scheduling, dispatch, and performance verification processes.

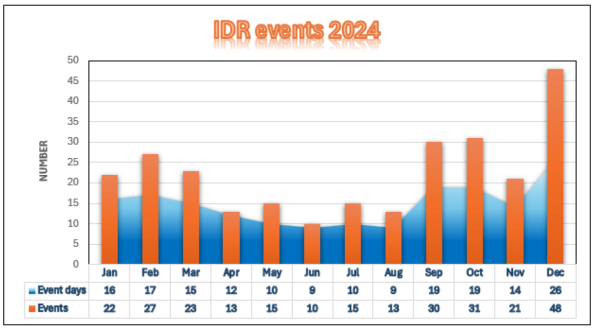

Figure 8: Number of IDR events and event days in 2024

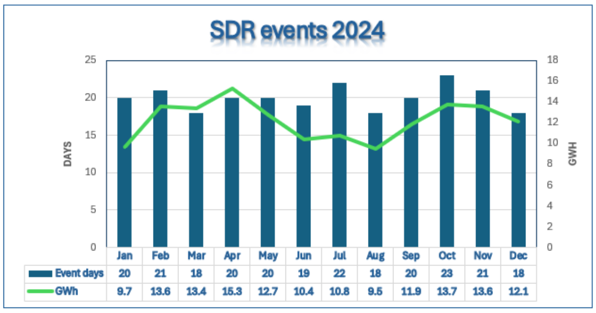

Figure 9: Number of SDR events and total energy not consumed in 2024

The programme delivers considerable benefits for both the System Operator and participating load providers. Load providers receive financial incentives and may be excluded from certain load curtailment stages, offering operational and economic advantages. For the System Operator, DR provides a cost-effective alternative to peaking generators, enhances frequency stability, and supports real-time system balancing during periods of supply constraints or unexpected disturbances.

Despite these successes, key challenges persist. Winter peak tariffs often reduce DR availability, as many large consumers already minimise consumption during these periods. Additionally, resistance from municipalities and some distributors, who fear revenue loss, limits broader programme participation. Looking ahead, integrating DR with variable renewable energy sources is critical as South Africa transitions towards a more sustainable power system. Expansion beyond large industrial users to include smaller commercial, agricultural, and residential loads—enabled by aggregators, smart metering, and dynamic pricing—will be essential. Overcoming regulatory, technical, and economic barriers will require collaboration, innovation, and targeted reforms to fully unlock the DR's potential.

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