Eskom
National Transmission Company South Africa ™

Ancillary Services Technical Requirements

Specification of Ancillary Services Technical Requirements for 2025/26 – 2029/30

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ANCILLARY SERVICES TECHNICAL REQUIREMENTS FOR 2025/26 – 2029/30

1. INTRODUCTION

This document specifies the technical requirements for ancillary services for the financial year period 2025/26 till 2029/30. Its purpose is to make known the technical requirements of the System Operator with respect to ancillary services. The technical requirements as specified in this document will be used to develop a medium-term view of requirements for ancillary services for the forthcoming 5-year horizon.

The following requirements are defined as ancillary services:

- Reserves
- Black-Start
- Self-Start
- Unit Islanding
- Reactive Power Supply and Voltage Control
- Constrained Generation

2. METHODOLOGY

The ancillary services technical requirements are determined based on approved methodologies developed by the System Operator.

3. RESERVES

3.1 INTRODUCTION

The definitions of the five reserve categories included in ancillary services are defined in the South African Grid Code [1]. The minimum requirement for each reserve category is revised annually. Each reserve category has its own requirement and is exclusive, that is capacity reserved for one category cannot be used for another category.

3.2 INSTANTANEOUS RESERVE

3.2.1 Description

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

3.2.2 Technical Requirements

The Instantaneous reserve requirement was determined through a dynamic simulation study by establishing the effect of governing on system frequency. The study considered various scenarios, which included various levels of generation and demand side capacity. Renewables (RE) were included in the study as per 2019 IRP [2]. Their impact was assessed during off peak periods, i.e. when demand was at its lowest, representing a low inertia scenario. RE impact is noticeable during off peak but overall the impact on reserves requirements was not significant. The minimum requirements, which are based on only generators providing instantaneous reserves, are shown in Table 1.

Table 1: Instantaneous reserve requirements

Season	Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Summer/ Winter	Peak	650	650	650	650	650
	Off peak	850	850	850	850	850

Generators that are contracted for Instantaneous Reserve shall provide capacity to respond to low and high frequencies as required by the grid code. The study has indicated that less instantaneous reserve is required over peak periods, due to higher system inertia during peak compared to off peak periods. Instantaneous reserve can also be provided by loads i.e. demand response. Previous studies have indicated the optimum split between generators and loads as follows:

Table 2: Optimal split between generators and demand response

Peak periods		Off peak periods		Reserve provider
Generators MW	Demand Response MW	Generators MW	Demand Response MW	
650	0	850	0	Generators only
600	200	800	200	Generators and loads
550	400	750	400	Generators and loads
500	600	700	600	Generators and loads
450	800	650	800	Generators and loads
400	1000	600	1000	Generators and loads

3.3 REGULATING RESERVE

3.3.1 Description

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

3.3.2 Technical Requirements

The IPS needs sufficient regulating range up and down every hour of the day to keep the frequency and SAPP tie line flows within schedule while meeting the peak load within the peak hour. The optimum regulating up and down reserve requirement is based on catering for variability of load and renewables for 90% of the time and compliance with SAPP CPS performance requirements.

A) Variability study

The purpose of this study was to determine the minimum regulating reserve capacity to ensure that load and renewables variability do not compromise frequency control requirements. A production simulation study was undertaken to determine the optimum reserve capacity. Various demand and generation performance scenarios were considered i.e. Low demand low performance and high demand high performance. Figure 1 below depicts simulation results for 2025 and 2029.

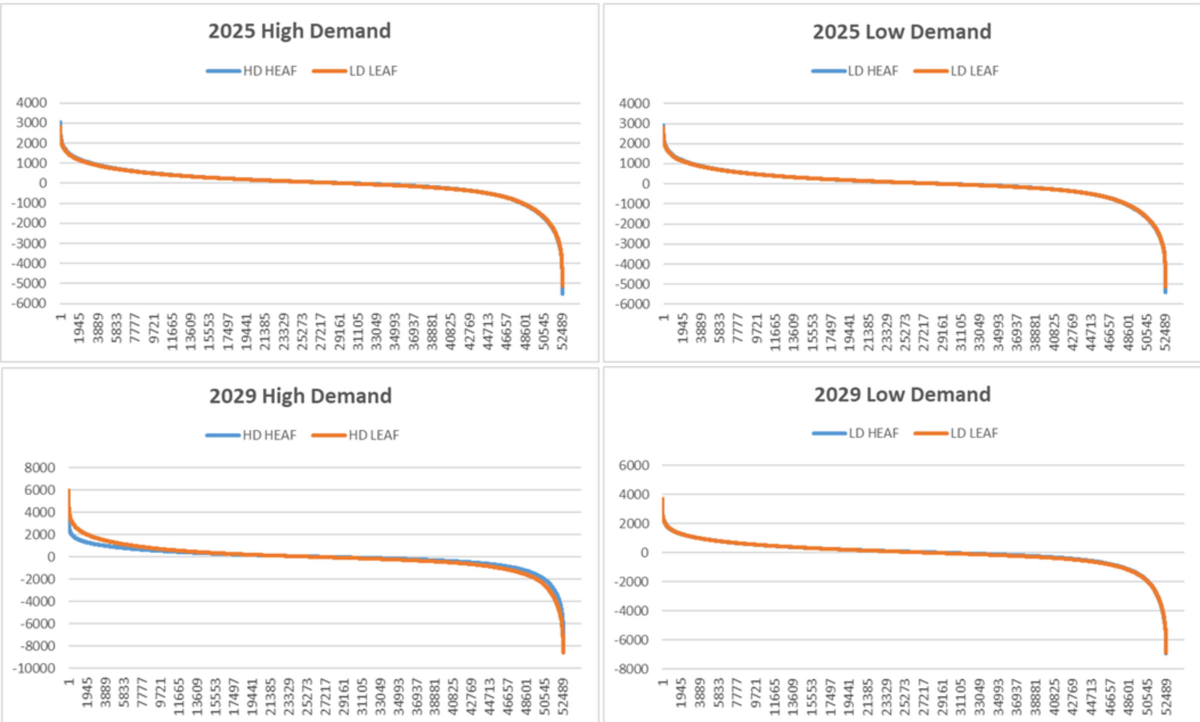

Figure 1: 2025 and 2029 variability study results

Using Figure 1 above, recommended regulating up/down reserve requirements are 750 MW in 2025 and 870 MW in 2029.

The minimum Regulating Reserve requirements, taking load variation and renewable energy unpredictability into consideration, are given in Table 3 below:

Table 3: Regulating up and down reserve requirements

Reserve	Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Regulating up	Summer (Pk/off pk)	750	780	810	840	870
	Winter (Pk/off pk)	750	780	810	840	870
Regulating down	Summer (Pk/off pk)	750	780	810	840	870
	Winter (Pk/off pk)	750	780	810	840	870

Regulating reserve capacity (regulating up + regulating down) is determined by AGC high and low limits set by the service provider to enable regulating up and down.

3.4 TEN-MINUTE RESERVE

3.4.1 Description

Ten-minute reserve is generating capacity or demand side managed load that can respond within 10 minutes when called upon. It may consist of offline quick start generating plant (e.g., hydro, or pumped storage) or demand side load that can be dispatched within 10 minutes. The purpose of this reserve is to restore Instantaneous and Regulating reserve to the required levels after an incident. Ancillary Services requires Ten-minute reserve resources which may be used for up to 600 hours per year (assuming a usage over 50 weeks, 4 days, and 3 hours per day). In addition, if the cost of any potential Ten-minute reserve resource is close to or higher than gas turbines, it must be used as an emergency reserve resource. Any new Ten-minute reserve resource must have no onerous energy restrictions since this reserve may be required to be used every day.

3.4.2 Technical Requirements

A) Credible multiple contingency requirement

A credible multiple unit contingency trip is defined in the SA grid code as a typical loss of three coal fired units. To ensure reliability it was assumed that the total operating reserve should be sufficient to replace the loss of the three biggest coal fired units. Thus, from 2025/26 to 2029/30, the biggest three units have a capacity of 3 x 720 = 2160 MW. The Ten-minute reserve requirement = Total Operating – Instantaneous – Regulating

B) SAPP Requirement

SAPP Operating Guidelines state that a minimum of 931 MW of total operating reserve is currently required from the Eskom control area.

The credible multiple contingency criteria yield a higher requirement for Ten-minute reserves. The Ten-minute reserve requirements are shown in Table 4 below:

Table 4: Ten-minute reserve requirements

Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Peak (Summer/ Winter)	800	770	740	710	680
Off-Peak (Summer/ Winter)	600	570	540	510	480

3.5 EMERGENCY RESERVE

3.5.1 Description

Emergency reserves should be fully activated within 10 minutes [1]. Emergency reserves include interruptible loads, generator emergency capacity (EL1), and gas turbine capacity. Emergency reserve capacity is required less often than Ten-minute reserve. The reserve must also be under the direct control of National Control. These requirements arise from the need to take quick action when any abnormality arises on the system.

3.5.2 Technical requirements

The technical requirement is based on the average loss of coal fired power station capacity greater than 3000 MW, which was calculated to be approximately 3800 MW. This capacity should be replaced by the sum of operating, emergency, and supplemental reserve capacity. Thus, Supplemental + Emergency capacity = Total Power Station capacity – Operating reserve = 3800 MW – 2200 MW = 1600. The emergency reserve is allocated 75% of the 1600 MW and hence the requirements are as given in Table 5:

Table 5: Emergency reserve requirements

Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Winter Peak/ Off peak	1200	1200	1200	1200	1200
Summer Peak/ Off peak	1200	1200	1200	1200	1200

3.6 SUPPLEMENTAL RESERVE

3.6.1 Description

Supplemental reserve is generating or demand side load that can respond in 6 hours or less to restore operating reserves. This reserve must be available for at least 2 hours [1]. This capacity is used to ensure an acceptable day-ahead risk.

3.6.2 Technical requirements

The technical requirement is based on the average loss of coal fired power station capacity greater than 3000MW, which was calculated to be approximately 3800 MW. This capacity should be replaced by the sum of operating, emergency, and supplemental reserve capacity. Thus, Supplemental capacity + Emergency reserve = Total Power Station capacity – Operating reserve = 3800 MW – 2200 MW = 1600. The supplemental reserve is allocated 25% of the 1600 MW and hence the requirements are as given in Table 6:

Table 6: Supplemental reserve requirements

Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Winter Peak/ Off peak	400	400	400	400	400
Summer Peak/ Off peak	400	400	400	400	400

3.7 RESERVE REQUIREMENTS SUMMARY

The overall reserve requirements may be summarised as in Table 7:

Table 7: Summary of reserve requirements

Reserve	Season	Period	2025/26 MW	2026/27 MW	2027/28 MW	2028/29 MW	2029/30 MW
Instantaneous	Summer	Peak	650	650	650	650	650
		Off peak	850	850	850	850	850
	Winter	Peak	650	650	650	650	650
		Off peak	850	850	850	850	850
Regulating	Summer	Peak	750	780	810	840	870
		Off peak	750	780	810	840	870
	Winter	Peak	750	780	810	840	870
		Off peak	750	780	810	840	870
Ten-minute	Summer	Peak	800	770	740	710	680
		Off peak	600	570	540	510	480
	Winter	Peak	800	770	740	710	680
		Off peak	600	570	540	510	480
Operating	**Summer / Winter**	**Peak/ Off peak**	2200	2200	2200	2200	2200
Emergency			1200	1200	1200	1200	1200
Supplemental			400	400	400	400	400
Total			**3800**	**3800**	**3800**	**3800**	**3800**

4. SYSTEM RESTORATION SERVICES

System restoration services are those services that are required in the unlikely event of a failure of the multiple system defence barriers protecting the IPS from a blackout. These services form part of the national system restoration plan, which is a highly confidential document that details the sequence(s) required to restore the IPS for a range of blackout scenarios for the current network topology.

Three system restoration services are defined for the IPS:

1. Black-start (GCR8) [3]
2. Unit islanding (GCR2) [3]

3. Self-start (GCR10)[1] [3]

Provision of these services assumes the absence of an established grid, with the entire IPS being completely de-energised (i.e., all generators and all customers offline) being an extreme possibility that must be planned for from a response perspective.

For black-start, the capability is defined as the provision of generating capacity that, following a total system collapse (black out), is able to start without an outside electrical supply and energise a defined portion of the transmission system so that it can act as a start-up supply for other capacity to be synchronised as part of a process of re-energising the transmission system.

For unit islanding, the capability is defined the ability of a unit, loaded to any load up to MCR, to suddenly disconnect from the transmission system by opening the HV circuit breaker and to control all necessary critical parameters to a sufficient degree to maintain the alternator at speed and excited, supply its own auxiliaries for at least two hours, allowing the unit to re-synchronise to the transmission system. In a blackout scenario, islanded units are expected to restore load and act as a start-up supply for other capacity to be synchronised as part of a process of restoring the transmission system.

For self-start, the capability is defined as the ability of a power station to start-up without an off-site supply, energise a portion of the transmission system and to supply load. In a blackout scenario, it is also envisioned that self-start facilities will be able to enable the reconnection of local inverter-based resources by provision of the requisite voltage and frequency reference for inverters to connect to.

Based on the need to start-up generation and supply load, location is a key consideration for all three services. To be considered as a system restoration option within the current time horizon, a potential service provider would need to be able to provide their capability in the proximity of:

1. Areas with existing conventional, synchronous generation
2. Areas with a high concentration of inverter-based resources such that a sustainable island can be formed
3. Areas in line with #1 and/or #2 above that also are near a major load centre(s)

Consider the following geographical representation of generation resources:

Legend
Shaded areas = Existing generation (incl. IPP peaking)

[1] Amendments to the Grid Code approved by NERSA in February 2023. To be included in next major revision of the Grid Code

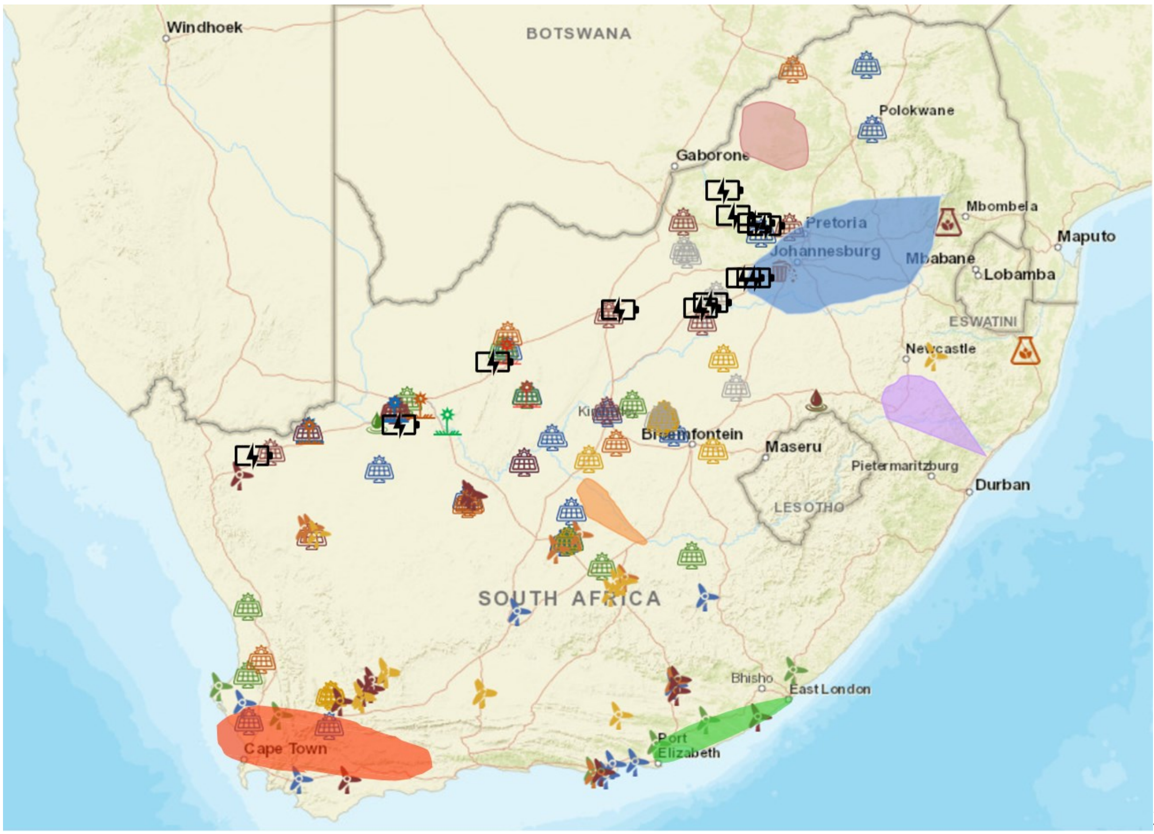

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Figure 2: Locations of independent power producer procurement programme

Given the locational requirements stated above, this implies that consideration will only be given to potential service providers in one of the shaded areas with existing generation and/or one of the areas with a significant concentration of icons denoting existing or forthcoming REIPPPP and BESS projects.

Outside of these specific areas, the reactive power generated by energising long, lightly-loaded transmission lines connected to major load centres and/or non-black-start generators will likely make voltage control extremely unstable. Therefore, such options are suboptimal and will not be considered at this time.

The full testing requirements and process for system restoration service providers are detailed in [3]. However, the aim of this section is to present the high-level requirements that a potential service provider would need to consider before approaching the System Operator for future certification.

2 Original image sourced from IPP Office (https://www.ipp-projects.co.za/ProjectDatabase/Map)

4.1 BLACK-START SERVICE PROVIDER REQUIREMENTS

First and foremost, all black-start service providers must meet the requirements specified in the Grid Code [1] [3]. However, potential service providers should be aware of the following selection criteria and specific System Operator requirements that are necessary for consideration as a black-start facility:

1. Service providers shall be power stations or power plants comprised of synchronous generators with on-site self-starting capability.
2. Peaking facilities may only be considered for black-start if there is capability to provide start-up power for a base-load generator that can then provide power continuously throughout the restoration.
3. Black-start capability shall take precedence over self-start capability and both services may not be contracted for from the same power station or power plant at the same time.
4. New black-start projects shall be considered primarily on proximity to non-black-start generators and proximity to sufficient load (residential and/or other resistive loads will be advantageous).
5. Selection priority may be given to projects in areas of the network with significant generation, but minimal system restoration capability present.
6. Selection priority may be given to projects that have the capacity to start-up multiple generators within an achievable radius.
7. Selection priority may be given to projects in areas with existing network infrastructure or requiring minimal network upgrades to accommodate the new facility.
8. All ratings above 50 MVA may be considered but selection priority shall be given to those facilities with generators or generating units that are rated 100 MVA or larger.
9. Due to the increased importance of voltage control during system restoration, it will be advantageous for generating units at black-start facilities to be capable of operating at power factors outside of the Grid Code requirements, or to have synchronous condenser capability, or other means of additional reactive power control.
10. Renewables and battery energy storage shall not be considered for black-start until such time that the grid-forming inverter technology reaches maturity in a restoration context in South Africa.
11. Each contracted black-start facility shall be operationally available to black-start for at least 90% of the year (and month)
12. Base-load black-start facilities shall be capable of starting at least one on-site base-load generator within 4 hours, following a system blackout.
13. Peaking black-start facilities shall be capable of starting a minimum of one on-site peaking generator in Generating mode within 2 hours following a system blackout. If additional on-site peaking or mid-merit generators are required, the additional unit(s) shall be dedicated in SCO

mode (or other similar reactive power compensation modes). In cases where SCO or other operating modes are not applicable, then any additional voltage control mechanisms that are contracted as part of the facility (e.g., FACTS devices, synchronous condensers, etc.) shall be kept available for the same purpose (one unit in Generating mode, others in SCO/voltage control mode). These facilities shall then be capable of energising a defined portion of the TS and enabling the start-up of a black-start support station from blackout conditions within 4 hours.

14. Base-load black-start facilities and black-start support stations shall be capable of picking up instantaneous load blocks of up to 50 MW and/or ramping within their defined range.

15. Peaking black-start facilities shall be capable of picking up instantaneous load blocks of up to 15 MW and/or ramping within their defined range.

16. All black-start facilities shall be capable of controlling frequency within the continuous operating range (49.0 – 51.0Hz) and shall be capable of controlling voltage within acceptable limits (± 5% of nominal) during the grid reconnection and load pick-up process using the AVR and/or on-load tap change on the generator transformer. SCO capability to be made available as per [3]

17. All black-start facilities shall have redundancy of emergency start-up equipment.

18. Emergency start-up equipment at all black-start facilities shall be capable of supplying the inrush current of any transformers or motors required to be energised as part of the system restoration.

19. The barring, lubrication, jacking and hydrogen seal oil facilities on the generating units shall be independent from the main supply during a system blackout condition and these facilities must be able to operate for an extended period (i.e., at least two hours) after loss of the external supply to ensure the safe run-down of the turbo-generators from nominal to barring speed.

20. After starting up independently and initiating the black-start process, the facility shall be capable of remaining synchronised and available long enough for subsequent base-load units to be started up and synchronised as part of the larger system restoration.

21. Black-start facilities shall be capable of attempting at least three consecutive start-ups. This implies that the facility shall always maintain adequate emergency fuel/power for emergency start-up equipment (75% of full capacity) to enable three consecutive start-up attempts to provide start-up power for other generators.

22. OEM recommended critical spares (agreed between SO and the black-start facility) shall be maintained at all facilities to ensure that required maintenance or refurbishment can be completed as soon as possible such that black-start capability is not compromised.

23. For base-load black-start facilities and black-start support stations, sufficient material supply (e.g., coal, diesel, fuel oil, propane gas, demineralised and potable water, hydrogen, etc.) shall be maintained or catered for in contingency planning by the facility for the entire restoration process. This shall include plans for emergency procurement in the event of a national blackout.

24. Capability testing to be completed as per GCR8. [3]

4.2 UNIT ISLANDING SERVICE PROVIDER REQUIREMENTS

As with black-start, all unit islanding service providers shall meet the requirements specified in the Grid Code [1] [3]. Potential service providers should be aware of the following selection criteria and specific System Operator requirements that are necessary for consideration for unit islanding certification:

1. All unit islanding units shall have a fully commissioned and operational AVR.
2. Apart from monitoring equipment, no special modifications to commercially operational plant shall be made for the purpose of islanding, i.e., all plant and equipment shall be part of the standard equipment and capability of the facility.
3. All unit islanding units shall be capable of energising a dead HV busbar on site.
4. Generators that are rated 200 MVA or larger shall provide unit islanding capability except for generators located at power stations that provide black-start or self-start capability. This does not preclude black-start or self-start service providers from electing to provide unit islanding capability.
5. Only 100 MVA non-hydro generators and larger may be considered for islanding certification.
6. Peaking generators (load factor < 10%) rated between 100-200 MVA shall not be considered for unit islanding certification.
7. Renewable energy sources shall not be considered for unit islanding certification without grid forming capability.
8. Battery energy storage shall not be considered for unit islanding certification.
9. Only remote generators with insufficient local load shall be automatically disregarded for unit islanding certification based on location i.e., all adequately-sized generators of the appropriate technology and usage philosophy shall be considered.
10. Capability testing to be completed as per GCR2. [3]

4.3 SELF-START SERVICE PROVIDER REQUIREMENTS

Following from black-start and unit islanding, all self-start service providers must meet the requirements specified in the Grid Code [1] [3]. However, potential service providers should be aware of the following selection criteria and specific System Operator requirements that are necessary for consideration as a self-start facility:

1. Service providers shall be power stations or power plants comprised of synchronous generators with on-site self-starting capability.
2. Self-start capability shall only be considered for contracting if black-start capability is not viable.
3. Selection shall be based primarily on proximity to sufficient load (residential and/or other resistive loads will be advantageous) and/or proximity to non-synchronous generation (e.g., renewables, BESS).

4. Selection priority may be given to projects in areas of the network with a large customer base.

5. Selection priority may be given to projects in areas with existing network infrastructure or requiring relatively minimal network upgrades to accommodate the new facility.

6. All ratings above 50 MVA may be considered but selection priority will be given to those facilities with generators or generating units that are rated at 100 MVA or larger.

7. Due to the increased importance of voltage control during system restoration, it will be advantageous for generating units at self-start facilities to be capable of operating at power factors outside of the Grid Code requirements, or to have synchronous condenser capability, or other means of additional reactive power control.

8. Each contracted self-start facility shall be operationally available to self-start for at least 90% of a month (and year).

9. Self-start facilities shall be capable of starting a minimum of two or more on-site generating units (one unit in Generating mode, others in SCO mode or similar reactive power compensation mode) within 2 hours.

10. For facilities without SCO capability or other means of reactive power compensation from the generating units, additional voltage control mechanisms that are contracted as part of the self-start capability of the facility shall be operationally available for at least 90% of the year (where required).

11. Facilities shall be capable of controlling frequency within the continuous operating range (49.0 – 51.0Hz) and shall be capable of controlling voltage within acceptable limits (± 5% of nominal) during the grid reconnection and load pick-up process using the AVR and/or on-load tap change on the generator transformer. SCO capability to be made available as per [3].

12. Units at the facility shall be capable of picking up discrete block loads of up to 15 MW as will be required during system restoration.

13. Facilities shall have redundancy of emergency start-up equipment.

14. Emergency start-up equipment shall be capable of supplying the inrush current of any on-site transformers or motors required to be energised as part of the system restoration.

15. Facilities shall always maintain adequate emergency fuel/power (75% of full capacity) for emergency start-up equipment to enable multiple consecutive start-up attempts.

16. A minimum level of primary fuel storage (12 unit generating hours), maintained by the System Operator, shall be required to be retained for system restoration purposes.

17. OEM recommended critical spares (agreed between SO and the self-start facility) shall be maintained at all facilities to ensure that required maintenance or refurbishment can be completed as soon as possible such that self-start capability is not compromised.

18. Sufficient material supply shall be maintained (or catered for in contingency planning) by the facility for the entire restoration process. This shall include plans for emergency procurement in the event of a national blackout.

19. Capability testing to be completed as per GCR10. [3]

4.4 SYSTEM RESTORATION SYSTEM REQUIREMENTS

In addition to the requirements for potential system restoration facilities to be considered for service provision, as listed above, the System Operator also has requirements to ensure that a safe and flexible system restoration process can be completed as swiftly as possible, at any given time. Ideally, all power stations on the network should be capable of all system restoration services, where possible. This would enable the most robust response to any variation on the considered blackout scenarios, regardless of location or root cause. However, this would be impractical as well as financially imprudent based on the level of provision vs. proportionate value to the power system. For this reason, it is important that service providers are procured at a level which reduces customer impact/restoration time in a blackout, without being excessive or surplus to system requirements.

Unit islanding is not a capability that is offered by all generators, and while it is the primary response mechanism to a blackout, it is not guaranteed that islanding will be successful or sustained by all certified islanding units. Considering this, having a significant base-level of certified islanding units increases the likelihood of having some level of successful islanding across the network. For this reason, the System Operator will consider any potential unit islanding facilities, provided they meet all requirements listed in 4.2 above. With unit islanding provision projected to decrease over time, there is no upper (or lower) limit imposed on procuring new unit islanding service providers at this time. Considering the current network topology as well as the latest IRP, Table 8 summarises the location requirements and procurement target for unit islanding:

Table 8: Unit islanding location requirements and procurement target

Potential Service Providers	Locational Requirements	Areas for consideration	Procurement Target
Existing coal, new gas/G2P	Areas with existing conventional non-black-start generation **or** areas with non-synchronous generation	1 - eMalahleni 2 - Middelburg 3 - Lephalale 4 - Northern KZN 5 - Eastern Cape 6 - Western Cape 7 - Northern Cape	Any new qualifying gas/ G2P realised in this period

Unlike unit islanding, both black-start and self-start can be reattempted in the event of failure. As such, these represent the most important response options to a blackout, and thus, the location of these specialised capabilities is key. Considering the current network topology and the latest IRP, Table 9 summarises the black-start and self-start location requirements:

Table 9: Black-start and self-start location requirements

Service	Potential Service Providers	Locational Criteria	Areas for consideration
Black-start	G2P, gas, pumped storage, existing coal	Areas with moderate-to-high concentration of generation **and** sufficient load	1 - eMalahleni 2 - Middelburg 3 - Vaal 4 - Lephalale
Self-start	G2P, gas, pumped storage	Areas with major cities/ large metropolitan municipalities containing significant load **and/or** non-synchronous generation	1 - Cape Town 2 - East London 3 - Mossel Bay/George 4 - Nelson Mandela Bay 5 - Johannesburg 6 - eThekwini 7 - Tshwane 8 - Ekurhuleni 9 - Bloemfontein

International benchmarking with the likes of India, China and Italy gives an indication of the rate at which other grid operators procure black-start services. Analysis performed in this respect indicates that there is ample scope for considering new service providers that fall within the geographical areas indicated in Table 9. Thus, to reduce the burden on existing facilities and introduce further resilience and flexibility to system restoration planning, black-start and self-start provision shall be sought at an increased level such that South Africa moves positively towards parity with other comparable countries/grid operators with respect to system restoration capability. This approach will reduce customer impact by reducing the overall restoration time of the national demand following a blackout. Considering that the peak national demand for 2024/25 was 33 485 MW, Table 10 summarises the combined black-start and self-start procurement targets to ensure an adequate restoration process of the national demand for the current time horizon:

Table 10: Black-start and self-start system requirements

	Grid Code Minimum	Current Status	Minimum Procurement Target	Moderate Procurement Target	Aggressive Procurement Target
No. of facilities	2	3	3 + BS + SS = 5	3 + BS + SS = 8	3 + BS + SS = 13
Time Frame	-	-	2025-2029	2025-2034	2025-2039
Where BS = new black-start facilities // SS = new self-start facilities					

5. REACTIVE POWER AND VOLTAGE CONTROL

Voltage control refers to the process of regulating the voltage in an electrical power system.

Reactive power is the dissipated power resulting from inductive and capacitive loads measured in volt-amperes reactive (VAR).

A synchronous condenser Operation (SCO) is when a generator operates as a DC (direct current) – excited synchronous motor which can compensate either a leading or lagging power factor, by absorbing or supplying reactive power to the network.

The generators when operated in SCO, shall ensure that they are fitted with a system capable of supplying and absorbing reactive power when required.

5.1 TECHNICAL REQUIREMENTS

The technical requirements for reactive power and voltage control include requirements from the Grid Code, Renewables Grid Code and System Operator.

A) Reactive Power Technical Requirements

The reactive power ASTR was derived from the annual Ops appraisal study which identifies regional voltage sensitive areas that require reactive power support under normal and contingency conditions. The Technical Development Plans (TDP) study determines the optimal solution to the identified voltage sensitive areas.

Table 11 shows the reactive power shortages from 2025/26 to 2029/30 and the years when the requirement would fall away after the implementation of the TDP.

Table 11: Reactive Power System Requirements (Mvar)

Grid	Regional Reactive Power Requirements				
	2025/26	2026/27	2027/28	2028/29	2029/30
Central	72	72	72	72	72
Northern Grid	144	144	0	0	0
Northern Cape	400	400	0	0	0
North West	744	744	744	744	0

B) Synchronous Condenser Operation (SCO) Technical Requirements

The SCO ASTR was derived from the Operations Planning study that determines the regional SCO requirements. The study results show the number of SCO units to be run under system healthy as well as under single contingencies.

Table 12: Regional number of units to operate in SCO mode

Grid	No. of Stations Capable of SCO	Total SCO Station Units	ASTR – Single Contingency Requirement
Eastern	2	8	4
Southern Cape	1	3	3
Western Cape	3	9	6

Table 13 below is derived from Table 12 by converting units reactive power capabilities to show how much reactive power is required per area/region.

Eskom currently has enough SCO Units to cater for the required reactive power support in those specific areas, however, the condition is expected to change around 2026/27.

Table 13: Regional SCO Reactive Power System Requirements (Mvar)

Grid	Regional SCO Reactive Power Requirements				
	2024/25	2025/26	2026/27	2027/28	2028/29
East Grid	1016	1016	1016	1016	1016
Southern Cape	105	105	105	105	105
Western Cape	665	665	665	665	665

Table 14 below shows the future reactive power requirement that can be sourced from synchronous condensers or renewable that can offer dynamic reactive power support.

Table 14: Future Reactive Power Requirement (Mvar)

Grid	2025/26	2026/27	2027/28	2028/29	2029/30
East Grid	0	0	880	880	880
Northern Cape	0	0	3960	3960	3960
North East	0	0	0	0	400
Southern Cape	0	0	880	880	880

Table 15 below shows the total combined regional reactive power requirements (based on Table 11, Table 13, and Table 14) which can be sourced from the reactive power equipment, synchronous condensers and even renewables that can offer dynamic reactive power support.

Table 15: System Reactive Power Requirements (Mvar)

Grid	System Regional Reactive Power Requirements				
	2025/26	2026/27	2027/28	2028/29	2029/30
Central Grid	72	72	72	72	72
East Grid	0	0	880	880	880
Northern Grid	144	144	0	0	0
Northern Cape	400	400	3960	3960	3960
North East	0	0	0	0	400
North West	744	744	744	744	0
Southern Cape	0	0	880	880	880

C) Grid Code Requirements for Conventional Generation

1. As required by the Grid Code, Network Code [3], all units greater than 100 MW shall be capable of supplying rated power output (MW) at any point between the limits of 0.85 power factor lagging and 0.95 power factor leading at the HV side of the generator transformer.

2. Reactive power output shall be fully variable between these limits under AVR, manual or other controls.

3. SO shall control power station export/import of reactive power through TEMSE or telephone.

4. When a unit is in pumping or generating, reactive power supply is mandatory in full operating range.

5. Voltages shall not deviate by more than ±5% from declared voltages under normal operating conditions.

6. Gas Turbine units built after the implementation of the Grid Code shall be capable of operating in SCO.

7. Generators shall conduct prototype and routine tests to demonstrate reactive capability.

All units built after the implementation of the South African Grid Code shall be equipped with power system stabilisers. Reactive output shall be fully variable to achieve acceptable levels of voltage (± 5%) under automatic or manual control.

D) Grid Code Requirements for Renewables Power Plants (RPP)

1. During start-up / energising, the Renewables Power Plants (RPP) may only consume or export not more than 5% of rated reactive power from the transmission system.
2. Different power factor categories (A – C) depending on the output power are specified in the RPP Code.
3. The RPP shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the IPP at the point of connection (POC) as well as a voltage control function capable of controlling the voltage at the POC via orders using set points.
4. The RPP shall ensure that they can function/operate under any of the three different modes mentioned below. Furthermore, the reactive power and voltage control functions are mutually exclusive, which means that only one of the three functions mentioned below can be activated at a time:
   a. Q-control
   b. Power Factor–control
   c. Voltage-control
5. The applied parameter settings for reactive power and voltage control functions shall be determined before commissioning by the Network Service Provider (NSP) in collaboration with the SO.

E) System Operator (SO) Requirements

1. SO shall use peaking stations (pump storage and OCGTs) in SCO for voltage control.
2. All installed thermal and peaking stations will be used for voltage control at the discretion of the SO.
3. All generators shall have automatic voltage regulators (AVR)/converters in an automatic voltage control mode.
4. All generators shall inform/update SO of any restriction that might affect the reactive power support.
5. All generators capable of voltage control shall be required to do reactive capability tests as stipulated in the Grid code.

6. CONSTRAINED GENERATION

6.1 INTRODUCTION

The Grid Code [3] specifies that the System Operator manage real-time system constraints within safe operating limits, using constrained generation as one of the ancillary services as required. To ensure that the operation of the system protects against cascading outages, it requires multiple outages of a credible nature be studied in particular, wherever practical. It also requires that the System Operator identify those system constraints that limit the capacity to meet demand, and draw conclusions on the need for this service over the forthcoming 5-year horizon. For this part of the process, constraints with duration beyond a few hours that have a significant impact and high probability are material. This requirement excludes long duration planned transmission maintenance outages that coincide with full generation at the corresponding power station from the list of system constraints, for example, as such combintations can be avoided.

Favourable weather conditions in the Cape, significant and load shedding from generation capacity shortages in the recent past sees a shift from constrained generation addressing regional demand shortfall and reduction of cheap baseload plant sent out generation required due to local network capacity constraints to include curtailment of variable renewable energy (VRE) generation resources due to lack of transmission network capacity in the region. Given the urgency with which generation needs to be added, the Eastern and Western Cape is being used as a test case for adding such generation. It is anticipated that this is likely to lead to inclusion of the need for curtailment due to network congestion as an ancillary service under constrained generation. This will allow this curtailment service to be ringfenced and tracked, as well as allowing the SO to manage it and for it to serve as an input for other processes, including new TDP transmission investment projects, and wheeling tariffs, to consider these costs. It is anticipated that all IPP providers of this service irrespective of whether such providers have a PPA with the SBO/CPA will be paid for the service. The details of how this will work is still to be established. The SO and NTCSA will not pay any provider until the proposed details have been agreed, with the status quo as detailed in the energy contracts remaining in force until then. The intention is for the cost of curtailment to be transparent and separate, and that this cost be managed as an ancillary service by the SO and NTCSA that will be contained in the long-term interest of the country. At the time of compiling this ASTR, NERSA approval of the service was still pending.

6.2 NATIONAL SYSTEM CONSTRAINTS

The SA Grid Code System Ops Code, section 4.3 specifies that any power stations run out of schedule to respect operational limits be compensated for the resulting financial loss so suffered from the lack of IPS capacity and related market rules, as part of constrained generation.

6.2.1 Cape Constraint

Consistent with the System Operator's obligations to operate the IPS in a safe, reliable, and economic manner, the risk to meeting local demand while refuelling Koeberg Nuclear Power

Station (KNPS) was assessed. A production simulation study, using the renewable generation expansion plan outlined in IRP2019 and latest production data, was used to establish the associated additional cost for peaking generation in the Cape resulting from regional transmission constraints, particularly affecting the capacity to meet the local demand during refuelling events at KNPS. From this, the following OCGT constrained generation requirements in Table 16 were determined:

Table 16: Summary of OCGT energy requirements for refuelling of KNPS

Financial year	Study category	Max units required	OCGT energy needed (GWh)
2025/26	Planned operation (N-0)	0	0
	Non-refuel (N-1)	0	0
	Refuel (N-1-1)	0	0
2026/27	Planned operation (N-0)	0	0
	Non-refuel (N-1)	0	0
	Refuel (N-1-1)	0	0
2027/28	Planned operation (N-0)	0	0
	Non-refuel (N-1)	0	0
	Refuel (N-1-1)	0	0
2028/29	Planned operation (N-0)	0	0
	Non-refuel (N-1)	0	0
	Refuel (N-1-1)	0	0
2029/30	Planned operation (N-0)	0	0
	Non-refuel (N-1)	0	0
	Refuel (N-1-1)	0	0

Based on these results, the System Operator chooses to continue to impose no restrictions on when KNPS may be refuelled.

Regarding the operation of Palmiet Pumped Storage Scheme, the System Operator retains the minimum top dam level at 5 unit generating hours (UGH). The restriction on Palmiet not being on planned maintenance during refuelling outages at KNPS also remains.

7. ACCEPTANCE

This document has been seen and accepted by:

Name	Designation
Andre Scholtz	Power System Manager
Bonginkosi Sibeko	National Operations, Chief Engineer
Carl Burricks	Power System Manager
Martin Kopa	System Operations, Acting Technical Operations Senior Manager
Eben Fischer	Power System Manager
Ernest Mpshe	National Control Support Services Manager
Gav Hurford	National Control Manager
Isabel Fick	System Operator General Manager
Raj Pandaram	Acting Integrated Power System Reliability Services Manager
Louis du Plessis	National Operations Manager
Martin Kopa	Operations Planning Manager
Norman van der Merwe	Power System Manager
Paul Davel	National Operations, Chief Engineer
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Thomas Mugagadeli	Power System Manager

8. REVISIONS

Date	Rev.	Compiler	Remarks
December 2024	1.0	VG Smith	New document

9. DEVELOPMENT TEAM

The following people were involved in the development of this document:

- Ike Tshwagong
- Lyle Naidoo
- Marathon Ntusi
- Musa Gumede
- Vaughan Smith

10. SUPPORTING CLAUSES

10.1 Scope

This document specifies the technical requirements for ancillary services for financial years 2025/26 to 2029/30. The purpose of the document is to make the System Operator's requirements known to ensure a reliable network and provide optimal usage of ancillary services for the next five financial years. All suppliers of ancillary services need to meet all aspects of the South African Grid Code relating to these services.

10.2 Abbreviations and Definitions

ASTR: Ancillary services technical requirement(s), or reference to the document defining the complete set

CPA: Central purchasing agent

CPS: Control Performance Standard

GX: Eskom generation group

IRP: Integrated Resource Plan (for electricity)

IPS: Interconnected Power System

KNPS: Koeberg Nuclear Power Station

NTCSA: National Transmission Company of South Africa

OCGT: Open cycle gas turbine

OP: Operating Procedure

OS: Operating Standard

Peak and Off-peak: Peak periods are considered only during weekdays. There are two peak periods in the daily system load profile, morning peak and evening peak, occurring at different times of the day during winter and summer months. Public holidays are treated the same as weekends with no peak periods. In winter, identified as May to August, the morning peak occurs from 06:00 to 09:00 and the evening peak occurs from 17:00 to 20:00. In summer, covering the remainder of the year outside winter, the morning peak occurs from 09:00 to 12:00 and the evening peak from 18:00 to 21:00. Thus, the peak periods occur for six hours of the day every weekday.

Residual load: That portion of the load not met by renewable generation.

RE: Renewable energy (generation)

SAPP: Southern African Power Pool

SBO: Single Buyer's Office

SO: System Operator

SOG: System Operator Guideline

TDP: Transmission development plan (document)

UGH: Unit generating hours

VRE: Variable renewable energy (generation)

10.3 Roles and Responsibilities

The provision of these requirements is monitored regularly via the monthly performance reports.

10.4 REFERENCES

1. "The South African Grid Code: System Operator Code", Rev 10.1 January 2022
2. Integrated Resource Plan for Electricity 2019, Government Gazette, no. 42784, 18 October 2019
3. "The South African Grid Code: Network Code", Rev 10.1 January 2022
4. "Certification and Performance Monitoring Standard for System Restoration Services", Rev 1, March 2024