

Renewable energy and reliability of electricity supply

Analyses of the impact of the expanding
renewable energy in the South African
electricity system

October 2016



Ea Energy Analyses



Published by:

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Introduction

The project “Strategy about System Adequacy and Reserve Margin with Increasing Levels of Variable Generation” assesses the effects of increasing levels of penetration of renewables on the system adequacy and reserve margins of the South African grid. It is supported by the South African-Danish program for renewable energy.

The project is led by Ea Energy Analyses and supported by the Danish Technical University, EOH EnerWeb, the Danish Energy Agency as well as the Danish TSO, Energinet.dk (in an advisory capacity).

Throughout the project we have collaborated closely with the Steering Committee and the User Group. SANEDI, DoE and Eskom have been represented in these groups. Detailed data about the South African system has been supplied by Eskom for use in this project.

1 Executive summary

Electricity systems must be in balance at all times. Reliability can be analysed as *adequacy* (the static analysis indicating that generation capacity exist to cover electricity demand at all times) and as *security* (the dynamic analysis indicating that the system is able to withstand a sudden change, e.g. the tripping of a power line or a power plant).

In South Africa significant expansion of renewable energy generation is planned. More than 7,000 MW wind power and 6,000 MW solar power is expected to come online before year 2025. This will generate 5-10% of the total electricity demand. This amount of variable, renewable energy is not alarming, and analyses indicate that this generational can be efficiently integrated – mainly by developing good procedures in the planning and operation of the electricity system.

The South African electricity system has been very stressed the latest years. Curtailment of demand has taken place, because generation capacity was mission e.g. to allow for the maintenance of the fleet of aging generators.

Variable generation from wind and solar can help alleviate the capacity shortage in a stressed system (e.g. see cases with high demand, in table 1). However, the impact is only marginal in a less stressed system.

1.1 Reserve dimensioning and international experiences

The reserve categories and reserve allocation methods used by Eskom align with those used in ENTSO-E and NERC. Eskom is using statistical approaches to reserve dimensioning and are following the same trend as being observed internationally. As the variable generation penetration increases, more statistical and probabilistic methods are being employed in NERC and ENTSO-E to reflect and dimension for the increase in net load variability.

The wind integration studies conclude that the effect of increased variable generation is in the slower reserve categories with the secondary reserve being modestly affected and the tertiary reserves larger impacts, due to net load forecast errors.

Balancing costs increase as a function of wind penetration, and the level of increase is related to the usage of interconnectors, wind aggregation over large geographic areas and scheduling power close to the delivery hour.

In order to cater for the increase due to variable generation penetration, TSO's are incorporating wind variability into their reserve sizing, using improved operating procedures and continuous nett load forecasting to pro-actively activate tertiary reserves.

1.2 Variability and predictability

Danish Technical University's CorWind software is applied to simulate real and forecasted wind power in 3 simulation cases: the past (2014), planned (2020) and future (2025). For the 2014 and the 2020 scenarios, the exact positions of the wind turbines are known. For the additional WPPs in the 2025 scenario, the provided locations of the main transformer stations are used, as illustrated by Figure 1.

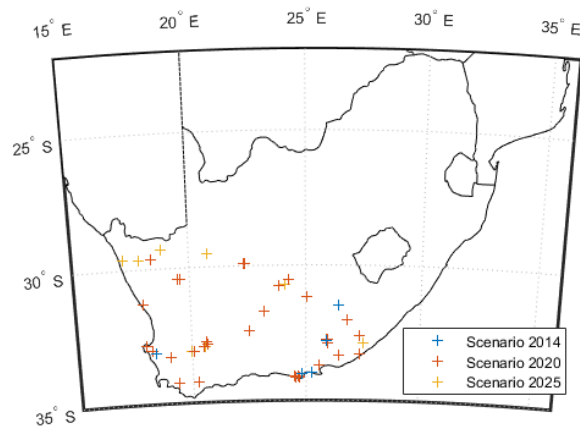


Figure 1: Locations of wind power plants

CorWind has been used to simulate time series of real wind power and of hour-ahead and online prognoses with 5-min temporal resolution and day-ahead forecasts with 1-hour resolution corresponding to the typical resolutions of forecast systems. The simulations are done using all 25 years of WRF reanalysis time series. For each year, different random seeds are used to make the stochastic simulations in CorWind. This approach ensures a good coverage of annual as well as seasonal and diurnal variations.

High resolution (5 min) real and forecasted wind power time series are aggregated to the system level to study the impact on use of fast reserves. For comparison (and for application in the SisyfosR model), the time series are

normalised with the assumed installed capacities 457 MW in 2014, 3,800 MW in 2020 and 7,400 MW in 2025.

A PV model is applied to simulate normalised PV power time series with hourly resolution within the borders of South Africa. The PV power time series are provided with 10 km x 10 km resolution in the first place, and subsequently aggregated to main transmission system level for the SisyfosR studies. The results for year 2014 are presented in Figure 2.

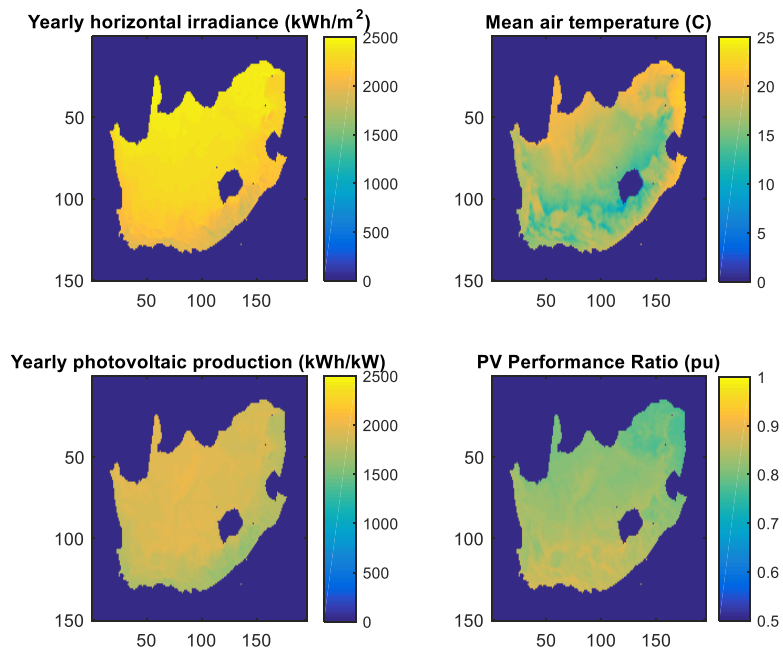


Figure 2: Overview results for year 2014. Top left plot: yearly horizontal irradiance (kWh/kW); top right plot: mean air temperature (C); bottom left plot: yearly photovoltaic production (kWh/kw); bottom right plot: PV performance ratio (pu).

According to South Africa's Ancillary Services Technical Requirements, regulating reserves should be sufficient to cover the genuine load variations within the hour. In order to quantify the load variations, the ten-minute load pickup and load drop off are calculated. In order not to include the steepest deterministic (and therefore predictable) diurnal variations, the approximately 5 % largest load variations are removed and the load variation is determined as the maximum of the remaining approximately 95%.

The corresponding 95 % percentile of wind power fluctuations is therefore relevant to quantify the impact of wind power variability on need for regulating reserves. Table 1 shows the 95% quantiles of the 10 min wind

power ramp rates calculated from the real wind power time series simulated with CorWind. The 95% percentiles are greater than the mean absolute wind power forecast errors.

Case year	2014	2020	2025
95% percentile [p.u.]	-0.062	-0.028	-0.021
95% percentile [MW]	-29	-107	-155

Table 1. 95% quantiles of the 10 min ramp rates of the wind power time series simulated with CorWind. Values are in p.u. of installed wind power capacity.

Table 2 shows the impact of wind power on the total need for reserves in years 2015/16 and 2019/20. The total variations are calculated assuming that consumption and wind ramp rates are independent. The increase due to wind is calculated as the difference between the total variations and the consumption variations. It is seen that the increased need for reserves is 9 MW, corresponding to 1.6% of the reserves without considering wind power.

Period	2015/16	2019/20
Consumption variations [MW]	450	550
Wind variations [MW]	48	100
Total variations [MW]	453	559
Increase due to wind [MW]	3	9
Increase due to wind [%]	0.7	1.6

Table 2. Calculation of total need for reserves including wind variations in year 2015/16 and 2019/20. The values apply to the summer half-year.

The main conclusions of the work are

- The normalized wind power ramp rates of the real wind power are reduced significantly from 2014 to 2020 and further reduced in 2025 because of the spatial smoothening.
- The normalized day-ahead, hour-ahead and online wind power forecast errors are reduced significantly from 2014 to 2020 and further reduced in 2025 because of the spatial smoothening.
- Wind power variability will not impact the use of instantaneous reserves because of the moderate rate of change of wind power combined with the frequency deadband.
- Wind power variability is estimated to increase the use of regulating reserves with 1.4 % in 2019/20

1.3 Stochastic analyses

In this study a stochastic method of analysing system adequacy has been used using the SisyfosR model. Stochastic methods can improve the N-1 method, since failure of all units is considered. The strengths of stochastic methods are multiple, including the results being presented in real security of supply units (Energy Not Supplied, ENS), and the fact that the complex nature of a given system can be represented. Especially new power sources with varying generation, like wind and solar, can be included in the analyses and their contribution to security of supply investigated.

The SisyfosR model has been populated with detailed data about the South African electricity system. Information about all power plants and a detailed representation of the transmission grid has been entered into the model. Hourly demand profiles for each node in the transmission grid have been used, as well as hourly node-specific generation profiles for wind and solar power (time series of 8,760 hours for each profile). Energy Not Served (ENS) has been calculated for 2014, 2020 and 2025 for a selected number of alternative scenarios. The parameter variations explored in the scenarios are:

- Demand (Low 1% p.a., Moderate 2% p.a., High 3% p.a.)
- Plant outage levels (on average: Low 8%, High 13%, Very High 17%)
- Renewable energy development pathways (All RE, Half RE, Half_Half¹ RE)

The results of all of the scenarios modelled are presented in Table 3:

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	RE development	Low	High	Very High	Low	High	Very High	Low	High	Very High
2014	Actual	655								
2020	Half_Half RE	9	9	9	19	42	293	136	1 636	5 435
2020	All RE	9	9	9	19	55	355	174	1 746	5 440
2020	Half RE	9	9	9	19	83	569	256	2 636	7 776
2025	Half_Half RE	9	9	9	16	16	16	47	344	1 389
2025	All RE	9	9	9	16	16	17	66	493	1 699
2025	Half RE	9	9	9	16	16	21	104	926	3 134

Table 3: Annual average ENS for all SisyfosR modelled scenarios across 1000 runs per scenario. Unit: GWh per annum

¹ Scenarios where only half of the planned RE expansion takes place, whereas the other half (in expected yearly power generation) is substituted through conventional generation capacity

A 'Reference' case representing year 2014 has been simulated in order to provide a validation for the model, as well as a within-model benchmark for the future scenarios. For year 2014, the SisyfosR-modelled ENS of 655 GWh compares relatively well to the real-life reported ENS of 512 GWh (provided that e.g. Demand Response capabilities have not been represented in the SisyfosR model).

The SisyfosR scenario analysis suggests that the demand projections are a critical factor with regard to the resulting modelled system adequacy, as expressed by the average annual Energy Not Served (ENS). E.g. with the current generation fleet expansion plans materializing on schedule and the demand growth continuing at a rate of 1% per annum (Demand: Low), the system adequacy should be able to reach satisfactory levels, even in the absence of improvement in the existing generation fleet availability rates. Should the demand growth rate reaches 2% per annum throughout the projection period (Demand: Moderate), the modelling results suggest that system adequacy outcomes would be more dependent on the developments in other key factors, e.g. the availability rates of the existing generation fleet and realization of the RE development plans (the factors tested), especially towards 2020. Finally, if the demand development reaches the levels as projected by IRP 2010 (i.e. demand growth rate reaches 3.1% per annum throughout the projection period; Demand: High scenarios), the modelled outcomes in terms of average annual ENS reach critical levels even under the assumption of most favourable outcomes in terms of other key factors.

The results also indicate that a delay in the RE expansion will result in severe implications for system adequacy if demand is high. Similar effects can be observed in the case of 2020 with moderate demand and outage levels above low.

The analysis further suggests that dispatchable capacity does indeed provide higher contribution to security of supply; however, the absolute scale of difference (i.e. fairly slight) would though indicate that also RE generation can contribute very significantly to system adequacy. Finally, it can be observed that the difference in the modelled ENS is almost negligible in the most critical system condition scenarios (i.e. high demand and high outage rate), which is fairly intuitive considering that in critical situations any additional power generation capacity can likely help alleviate the pressure.

With 2014 as test case it is found that it would have been optimal to have additional firm capacity in South Africa of 3,500 MW. This result is influenced by the fact that 2014 was a year with high outage rates on many power plants.

The analysis supports the idea of having a goal for ENS. In the IRP 20 GWh is described as the maximum acceptable level of ENS. This seem to be in line with the analyses of optimal amount of ENS – all results have values between 10 and 20 GWh after optimal investment in new generation capacity. To reduce ENS below these value would lead to generation capacity that is used less than 16 hours per year.

2 Reserve dimensioning and international experiences

Over and above the capacity to match the peak demand, power systems require additional capacity to deal with failures, unbalances, planned and unplanned events.

The first two types of capacities are called system reserves and more details on their dimensioning are provided in sections 2.1 and 2.2, respectively:

- Capacity to cope with a major, sudden failures (N-1) – short term perspective (seconds). Automatic and manual reserves.
- Capacity to cope with unbalances – medium term perspective (minutes to hours). Unbalances can come from demand, outage of traditional generation and transmission lines – or can be unbalances from renewable energy (wind and solar)

Section 2.3 reviews the results of a number of international integration studies to assess the impact of increased variable generation on reserve levels.

Increasing amounts of variable generation has impacted the dimensioning techniques and the approach to reserve dimensioning. The response by TSO's to increases in variable generation is described in section 2.4.

2.1 Reserve allocation in South Africa

The South African Grid Code [1] details the requirements for different reserve categories and specifies five categories of reserves, as follows:

- 1) **Instantaneous reserves** – Used to arrest the frequency at acceptable limits following a contingency.
- 2) **Regulating reserves** – Used for second-by-second balancing of supply and demand, and under AGC control.
- 3) **10-minute reserves** – To balance supply and demand for changes between the Day-ahead market and real-time, such as load forecast errors and unit unreliability.
- 4) **Emergency reserves** – Used when the interconnected power system (IPS) is not in a normal condition, and to return the IPS to a normal condition while slower reserves are being activated.
- 5) **Supplemental reserves** – Used to ensure an acceptable day-ahead risk.

The operating reserve comprises the instantaneous, regulating and 10 minute reserves.

During and after an event, the different categories of reserves are utilised with specific time to activation and duration of usage. Figure 3 shows how the different reserve categories are used during an under-frequency event.

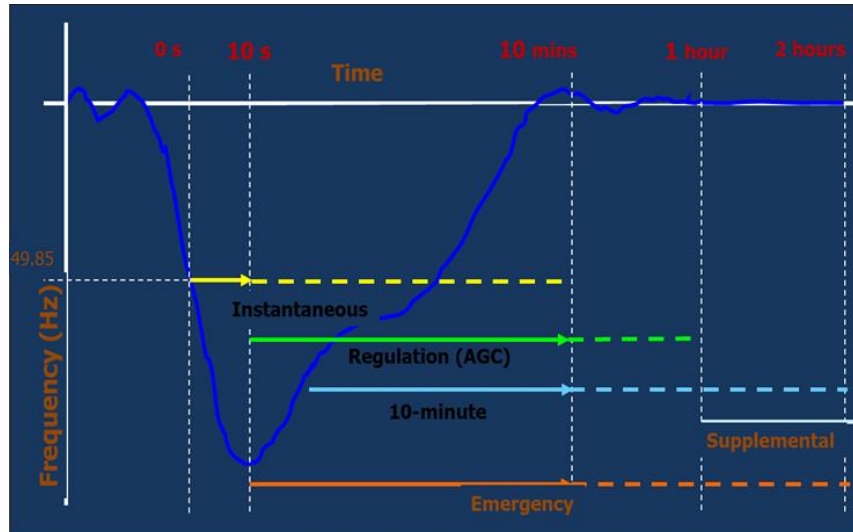


Figure 3: Different reserve categories as used after a frequency event or contingency

Most reserve categories are dimensioned based on the sizes of contingencies in the system:

- Operating reserve - credible multiple contingency event
- Instantaneous – system dynamics based on credible single contingency (>49.5Hz) and multiple contingency (>49 Hz) events [2]
- Emergency – worst contingency in the system, i.e. the loss of the largest power station

Regulating reserves are sized based on the 10-minute variation in nett load (load minus variable generation). Variable generation would include solar and wind generation [3].

The supplemental reserve level is based on an economic comparison between running the most expensive generator and reserves provided by demand response through the Virtual Power Station.

2.2 International review of reserve allocation

In literature, the following three international organisations are often referred to in conjunction with reserve levels and level setting:

- National American Electric Reliability Corporation (NERC);
- European Network of Transmission System Operators for Electricity (ENTSO-E);
- Union for the Coordination of Transmission of Electricity (UCTE).

Today UCTE is the region ‘Central Europe’ in ENTSO-E.

Despite the differences in terminology, the categories for reserve level setting in ENTSO-E (and UCTE) maps closely to those used by Eskom. NERC however, treats normal operating reserves (regulating and load following) separate to reserves allocated to contingencies (frequency, spinning, non-spinning and replacement).

Figure 4 shows a mapping between the categories in use by the different organizations.

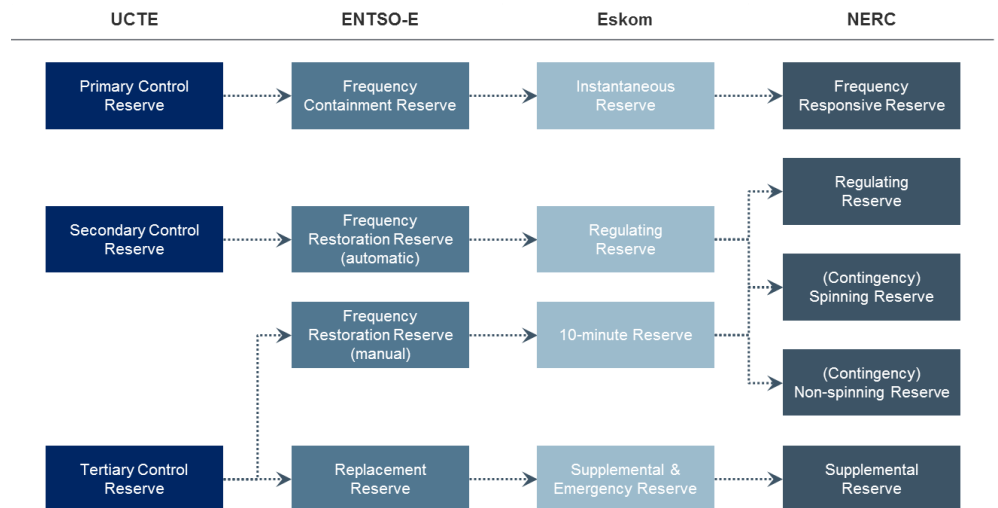


Figure 4: Mapping between UCTE, ENTSO-E, Eskom and NERC reserve categories

ENTSO-E uses the largest contingency criteria for the dimensioning of reserves [4]:

- Frequency containment reserve: N-1 and N-2 (for the region Central Europe)
- Frequency Restoration Reserves – in conjunction with variation of nett load (see below)
- Replacement reserves – the largest expected loss of power (generation unit, power infeed, DC-link or load) in the control area.

With increasing penetration of variable generation, probabilistic methods based on the variation in nett load (load minus variable generation) were developed and used in the dimensioning of Frequency Restoration Reserves and Replacement Reserves, respectively. The reference incident is often used as a minimum requirement.

Similarly, NERC [5] uses the largest contingency criteria for dimensioning their contingency reserves (spinning and non-spinning). ERCOT [6] (the ISO in Texas), has adopted a probabilistic approach based on variations in nett load, for the dimensioning of the regulating reserves and non-spinning contingency reserves.

Dynamic dimensioning of reserves is a practice employed in, for example, Australia and ERCOT [6][7]. The reserve levels are regularly evaluated and adjusted if necessary, based on performance. ERCOT integrated this approach into their probabilistic assessment.

2.3 Integration studies on impact of increased variable generation

Impact on reserve dimensioning

A number of wind integration studies were reviewed [1]-[5] to obtain insights into the impact of increases in variable generation on reserve levels. In the integration studies reviewed, most of the impact on system capacity reserves are on dimensioning of the tertiary reserves, e.g. load following, replacement reserves etc. and not the faster response categories.

Moderate increases are reported in regulating reserves and larger increases in the reserve requirements for load following and replacement. These studies assume that the operating procedures are unchanged when estimating these impacts.

For wind generation, the secondary reserves are impacted modestly and adjustment approaches using geometric addition of wind variability were proposed [2].

The impact on tertiary reserves are due to increase in nett load forecasting errors, which is a function of geographic distribution and forecast horizon, as shown in these figures from [2] and [3]:

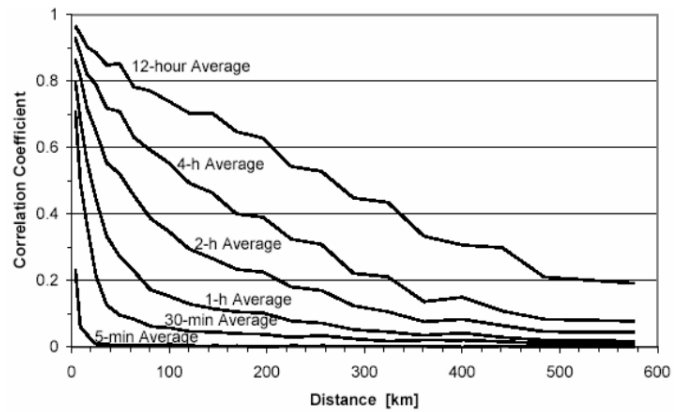


Figure 5 Geographic diversity measured as correlation coefficient as a function of distance and wind aggregation time frames

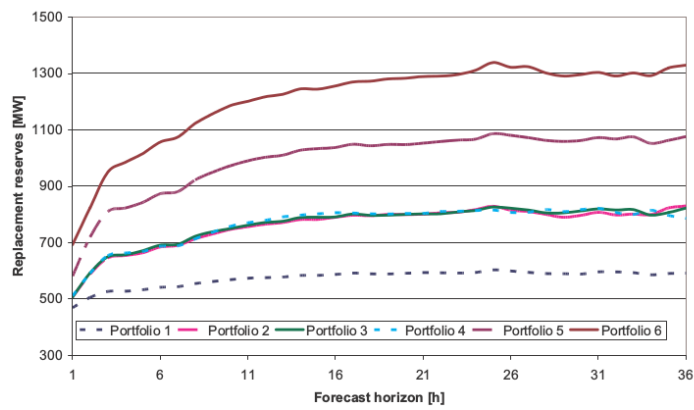


Figure 6 Replacement reserve for the different portfolios (wind penetration) and forecast horizons.

Seasonal and inter-decade variation of energy availability has a significant impact on the effective available capacity of wind generating plant and impacts longer term system adequacy assessment.

Impact on balancing costs

The impact on balancing costs were discussed in [14] and the following figure shows this impact based on experience and wind integration studies:

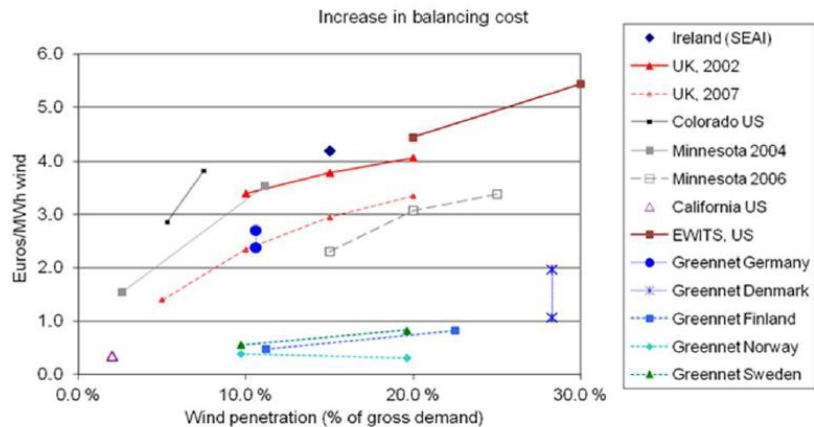


Figure 7 Increase in balancing cost as a function of wind penetration

In most cases, balancing costs increase with an increase in wind penetration – the study notes that: “a general conclusion is that if interconnection capacity is allowed to be used for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used”.

Further that other important factor for reducing costs were:

- Wind aggregation over large geographic areas
- Scheduling the power system closer to the delivery hour

2.4 Experience with increase in variable generation

The negative impacts due to the nett load variability associated with high variable generation penetration may be countered through [13][14]:

- Incorporating wind generation into reserve sizing,
- Better forecasting tools
- Development of reserve market ramping products
- Improved operating procedures (i.e. sub-hourly markets),
- Continuous wind power forecasting with dispatch adjustments,
- Flexibility (and smoothing) which is derived from geographic diversity and other flexible sources.

Where these measures and operational procedures are applied, system operators generally experience null to very modest impact on the dimensioning, allocation and costs of system reserves.

For example, in the case of Energinet.dk, the national TSO of Denmark, a system was developed to predict system imbalances based on weather forecast, demand forecast, wind power and solar power prognosis. Based on

a 12 hour-ahead predicted imbalance curve, tertiary reserves may be activated or imbalances swapped with neighbours (if possible).

The traditional procedures for activating reserves can be called reactive, while the Energinet.dk's approach can be called proactive. In popular terms the new procedure can be described as "driving looking through the front window" in contrast to "driving looking in the rear view mirror".

Experiences of other European countries with significant wind power shares in the system include [14]:

- Ireland – no additional reserves were required during periods of high wind variability. However, due to frequency and voltage stability constraints, a number of conventional stations are required to remain online
- Spain – the impact on automatic reserves has been minimal, but significant impacts on the manual reserves have been experienced. Spain is building experience and confidence in using probabilistic methods for dimensioning manual reserves.
- Portugal – existing reserve allocation has been increased by 10% of predicted wind power. The additional reserves are supplied through hydro generation and tie-line balancing with Spain.

2.5 References for chapter 2

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3 Variability and predictability of renewable energy

This chapter describes the analyses of variability and predictability of renewable energy in the South African power system. The analyses include wind power as well as solar power, based on a common weather reanalysis.

3.1 Weather reanalysis

This section describes the WRF time series used in the wind and solar variability analyses. The meteorological time series are based on the weather model, which was applied in the Wind Atlas of South Africa (WASA), but minor modifications have been made to include all of South Africa and to include the solar data.

The meteorological data was produced using a mesoscale reanalysis method, which is often used for obtaining high-resolution climate or climate change information from relatively coarse-resolution global general circulation models or reanalysis. The mesoscale reanalysis uses a limited-area, high-resolution model driven by boundary conditions from the reanalysis. The strength in using the models to fill the observation gaps is that the fields are dynamically consistent and they are defined on a regular grid. Additionally, the models respond to local forcing that adds information beyond what can be represented by the observations.

The mesoscale reanalysis used to generate the meteorological time series uses the National Center for Atmospheric Research (NCAR) Advanced Research Weather Research and Forecasting (ARW-WRF) model [1]. The version used is v3.5.1 that was released 23 September 2013. The model forecasts use 41 vertical levels from the surface to the top of the model located at 50 hPa; 12 of these levels are placed within 1000 m of the surface. The model setup uses standard physical parameterizations including the Mellor-Yamada (MYJ) PBL scheme [2].

The model was integrated within the domain shown in Figure 1. The outer domain (1) has a horizontal spacing of 30 km x 30 km. The inner domain (2) model grid has a horizontal spacing of 10 km x 10 km, on a Lambert projection with center at 29°N, 25°E. The domain has dimensions of 195 × 150 points. The simulation from which the meteorological time series are derived covers 25 years (1990–2014). Individual runs are re-initialized every 11 days. Each run overlaps the previous one by 24 h, to avoid using the time during which

the model is spinning up mesoscale processes. A similar method was used and verified in [3], [4], [5]. Initial, boundary, and grids for nudging are supplied by the ERA Interim Reanalysis [6].

Sea surface temperatures (SSTs) that evolve with time, which are derived from satellite and in situ measurements are also used in the simulation. These fields are at a horizontal resolution of $0.25^\circ \times 0.25^\circ$ latitude vs. longitude [7]. They replace the coarse resolution SSTs available from the reanalysis ($0.7^\circ \times 0.7^\circ$) and should adequately represent the horizontal structure and time evolution of the SSTs in this area.

New output fields not available in the standard model were added to the simulation. These include: hourly-averaged wind speed, hourly-averaged kinetic energy flux, and hourly-integrated solar insolation.

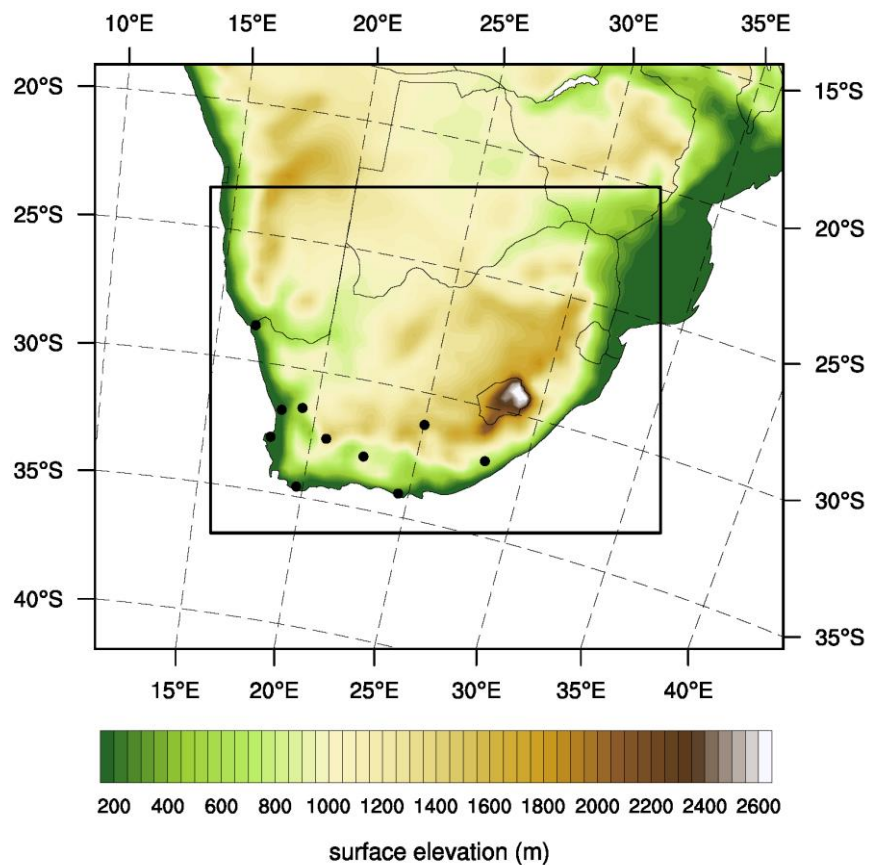


Figure 8: Domain configuration and terrain elevation used in the simulations. The circles show the location of the WASA measurement masts.

3.2 Wind power

Three simulation cases have been defined in agreement with ESKOM and DOE. Those cases are:

- 2014 being the reference (Past) case including the WPPs installed in the beginning of the year.
- 2020 being the (Planned) development case.
- 2025 being a not too far future case to be considered in the grid development plans.

The locations of the wind power plants (WPPs) are shown in Figure 9. For the 2014 and the 2020 scenarios, the exact positions of the WPPs are known. For the additional WPPs in the 2025 scenario, the provided locations of the main transformer stations are used.

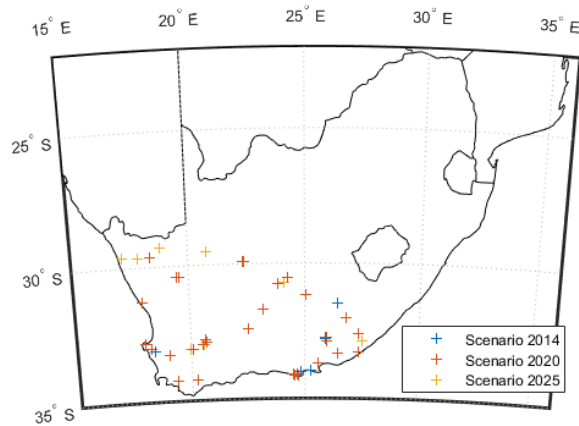


Figure 9: Locations of wind power plants

Table 4 shows the mean absolute wind power forecast errors (MAE) and ramp rate in p.u. of installed wind power capacity for each of the three scenarios. The forecast errors and ramp rates are provided using DTU Wind Energy's CorWind software to simulate time series of real wind power and of hour-ahead and online prognoses with 5-min temporal resolution and day-ahead forecasts with 1-hour resolution corresponding to the typical resolutions of forecast systems. The simulations are done using all 25 years of WRF reanalysis time series. For each year, different random seeds are used to make the stochastic simulations in CorWind. This approach ensures a good coverage of annual as well as seasonal and diurnal variations.

Case year	2014	2020	2025
Wind power capacity [MW]	457	3,800	7,400
Day-ahead error [p.u.]	0.075	0.047	0.043
Hour-ahead error [p.u.]	0.054	0.031	0.027
Online (10 min) error [p.u.]	0.040	0.021	0.017
Mean absolute ramp rate [p.u./10 min]	0.028	0.013	0.010

Table 4. Mean absolute forecast errors (MAE) and ramp rate of the wind power time series simulated with CorWind. Values are in p.u. of installed wind power capacity.

The specific power of a wind turbine (WT) is defined as the ratio between the rated power and the rotor area of the WT. The specific power has a significant influence on WT power curves, which is affecting the WPP power curves in a similar way.

Figure 10 shows the duration curves for the simulated 2025 scenario using the power curves for different specific power of new WPPs. The following three values were chosen:

- 259 W/m² which being the weighted average of present WTs in South Africa.
- 229 W/m² being the minimum specific power of present WTs in South Africa.
- 196 W/m² being a very low but existing WT specific power, corresponding to 2.0 MW rated power with 114m diameter rotor.

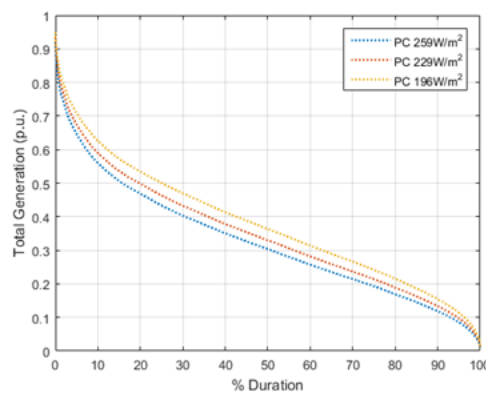


Figure 10: Duration curves for 2025 scenario using different specific power of new WPPs.

The corresponding capacity factors are shown in Table 5. The values confirm that the specific power has a significant influence on the capacity factor, and thus on the energy production from the WTs.

Specific power [W/m ²]	259	229	196
Capacity factor	0.32	0.35	0.38

Table 5. Capacity factors for 2025 scenario using different specific power of new WPPs.

According to South Africa’s Ancillary Services Technical Requirements [8], regulating reserves should be sufficient to cover the genuine load variations within the hour. In order to quantify the load variations, the ten-minute load pickup and load drop off are calculated. In order not to include the steepest deterministic (and therefore predictable) diurnal variations, the approximately 5 % largest load variations are removed and the load variation is determined as the maximum of the remaining approximately 95%.

The corresponding 95 % percentile of wind power fluctuations is therefore relevant to quantify the impact of wind power variability on need for regulating reserves. Table 6 shows the 95% quantiles of the 10 min wind power ramp rates calculated from the real wind power time series simulated with CorWind. As expected, the 95% percentiles are greater than the MAEs in Table 4.

Case year	2014	2020	2025
95% percentile [p.u.]	-0.062	-0.028	-0.021
95% percentile [MW]	-29	-107	-155

Table 6. 95% quantiles of the 10 min ramp rates of the wind power time series simulated with CorWind. Values are in p.u. of installed wind power capacity.

Table 7 shows the impact of wind power on the total need for reserves in years 2015/16 and 2019/20. The first row shows the latest calculations of the reserves needed to cover the consumption variations in the summer half year according to South Africa’s ancillary services requirements [8]. The next line is the wind variations for each of the years, interpolating between the absolute value of the wind power quantiles from Table 6 in 2014 and 2020. Next, the total variations are calculated assuming that consumption and wind ramp rates are independent. Finally, the increase due to wind is calculated as the difference between the total variations and the consumption variations. It is seen that the increased need for reserves is 9 MW, corresponding to 1.6% of the reserves without considering wind power.

Period	2015/16	2019/20
Consumption variations [MW]	450	550
Wind variations [MW]	48	100
Total variations [MW]	453	559
Increase due to wind [MW]	3	9
Increase due to wind [%]	0.7	1.6

Table 7. Calculation of total need for reserves including wind variations in year 2015/16 and 2019/20. The values apply to the summer half-year.

3.3 Solar power

The PV power estimations are based on the WRF time series on hourly basis of selected meteorological parameters for the selected historical period for each 10 km x 10 km areas (MetCells or Tile) of the entire South Africa area. Out of the $195 \times 150 = 29250$ met cells in the inner WRF domain (see Figure 8), normalised PV generation time series are simulated for each of the 11,883 MetCells covering the South Africa area. Subsequently, those time series are aggregated into 176 nodes corresponding to each of the main transmission system in South Africa.

Figure 11 shows a snapshot of the results for 2014. The yearly horizontal irradiance is the integral over the year of the hourly irradiance (i.e. cumulated energy received on the ground) and is the main input of the model. The yearly photovoltaic production is the integral over the year of the computed normalized PV production. Values are expressed in kWh per kW nominal power, which is basically the capacity factor.

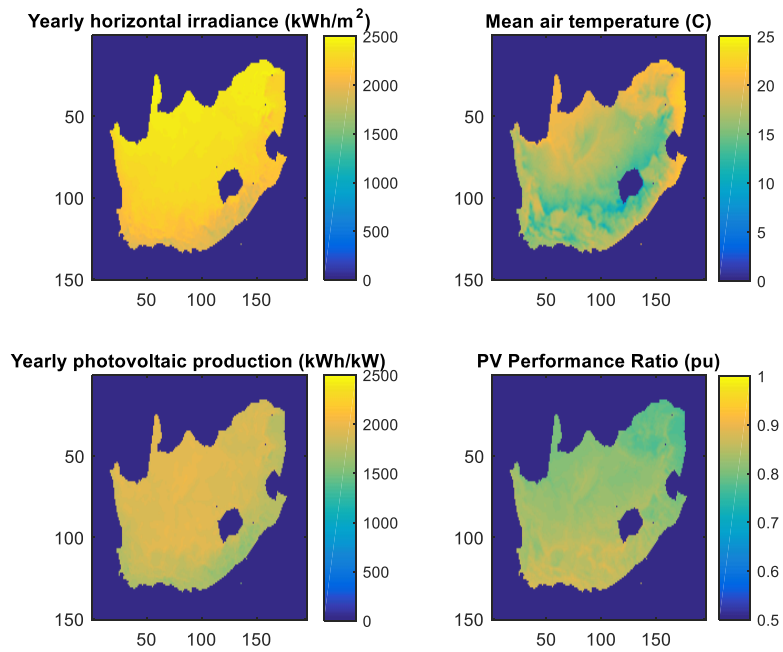


Figure 11: Overview results for year 2014. Top left plot: yearly horizontal irradiance (kWh/kW); top right plot: mean air temperature (C); bottom left plot: yearly photovoltaic production (kWh/kw); bottom right plot: PV performance ratio (pu).

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4 Stochastic analyses of the South African system

This chapter documents the Stochastic Analysis and System Adequacy study – and explores scenarios for the South African power system assessing how system adequacy and the need for reserves may develop in the future, addressing the geographical distribution of the renewables, the load, and the transmission grid using the SisyfosR modelling framework. It also provides input to the analysis of costs of ensuring system adequacy.

4.1 SisyfosR

SisyfosR is a simulation model for investigation of power system adequacy based on the SISYFOS model developed by the Danish Energy Agency². The SisyfosR model applies a numerical approach based on the Monte Carlo principle (with a large number of runs with random outcome of unplanned outage). The outcome of a Monte Carlo simulation is the probability distribution of the expected values of reliability indices.

The model uses stochastic methods of power generation and grid outages to determine Energy Not Supplied (ENS). ENS is computed per hour and per node across many runs. Figure 12 illustrates the computational process of SisyfosR.

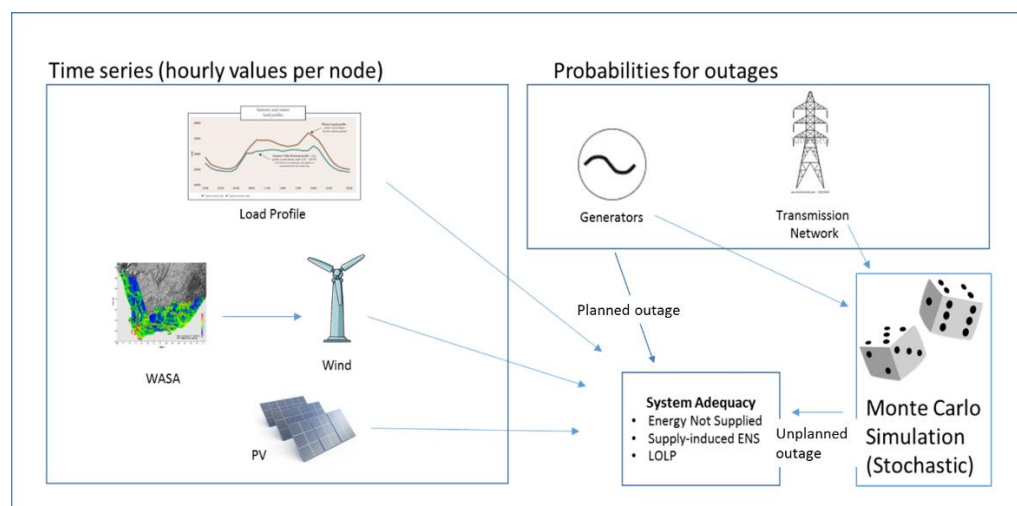


Figure 12. Outline of the computation in SisyfosR.

Key inputs to the model are:

- Generation: Capacity (MW) and planned and unplanned outage (%)

² The rights of the SisyfosR model are shared between the Danish Energy Agency and Ea Energy Analyses

- Wind, solar and pumped hydro are represented by hourly variation profiles for a year
- Lines: Capacity (MW) and unplanned outage (%)³
- Demand: Hourly demand per node for a year

The high-voltage network is included in the modelling, and the model evaluates whether it is the network or the production capacity that is the key cause of power system adequacy issues.

4.2 Data

The system adequacy model SisyfosR has been populated with detailed data about the South African electricity system. Information about all power plants and a detailed representation of the transmission grid has been entered into the model. Power demand projections is another fundamental input to the model, and Figure 13 presents the increasing discrepancy between the projected and the realized power demand developments in South Africa. This has been addressed through scenario analysis in the current study.

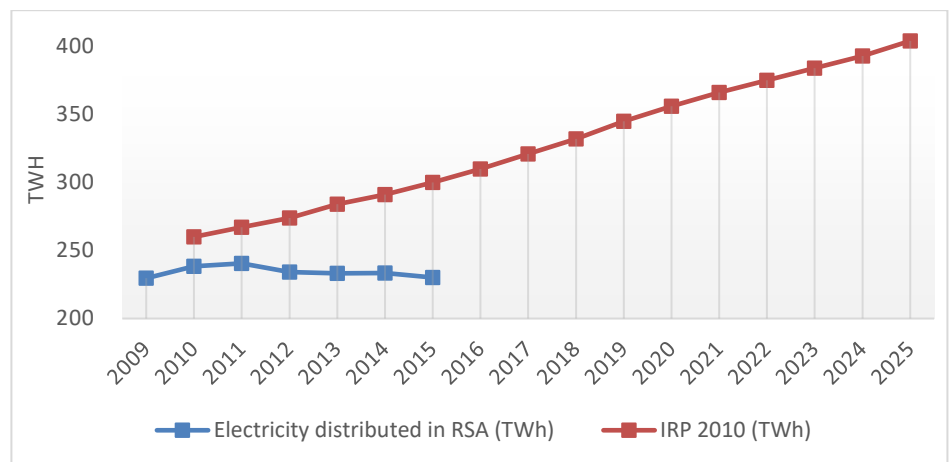


Figure 13: Realized vs. Projected electricity demand in South Africa. Sources: (Statistics South Africa, 2014), (Department of Energy of South Africa, 2011), (Statistics South Africa, 2016)

The expansion of generation capacity towards 2025 represented in the model is shown in Table 8.

³ Typical, actual transfer capacity should be used. Practical operation may dictate that this can be smaller than the technical line rating.

Generation type (MW)	2014	2020	2025
Coal	35,940	45,596	45,626
Oil	2,460	2,460	2,460
Hydro	2,100	2,000	4,563
Nuclear	1,860	1,860	6,660
Pumped storage	1,400	2,732	2,732
CCGT		474	711
OCGT		1,029	2,643
Wind	457	3,846	7,446
Solar PV		2,697	4,897
CSP		700	1,200
Other		79	79
Total Capacity (MW)	44,217	63,472	79,016

Table 8. Generation expansion based on the data from 2015 TD – 2020 CF Post Peak Rev 2.

Hourly demand profiles for each node in the transmission grid have been used, as well as hourly node-specific generation profiles for wind and solar power (time series of 8,760 hours for each profile). Figure 14 illustrates the yearly average wind generation across the hour of the day across the different wind sites in South Africa, as well as the regional smoothening effect (black thick line).

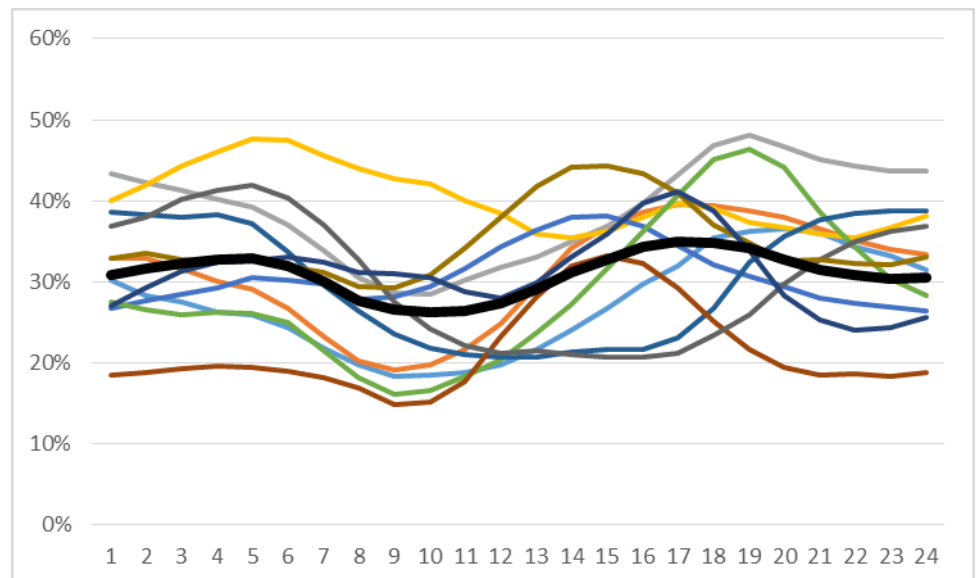


Figure 14. Yearly average wind generation across the hour of the day. Percentage of installed capacity. The black thick line is capacity-weighted average. The other lines are node-specific data.

Figure 15 presents the examples of solar profiles of a selected day across the 27 different nodes represented in the model in 2020.

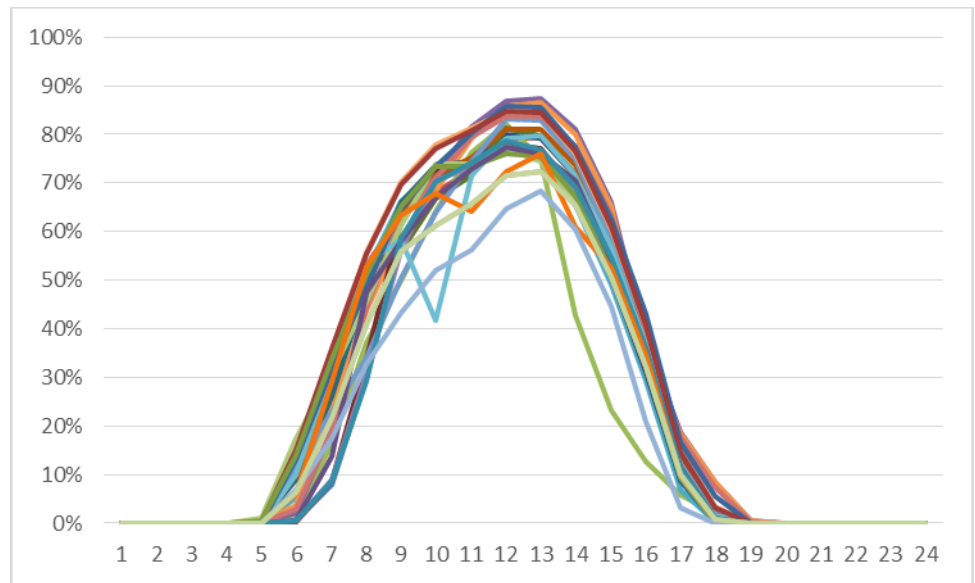


Figure 15. Examples of solar profiles for a specific day: 1 January. 27 nodes with PV capacity in 2020.

Figure 16 illustrates the capacity-weighted generation fleet-wide outage rates in South Africa over time.

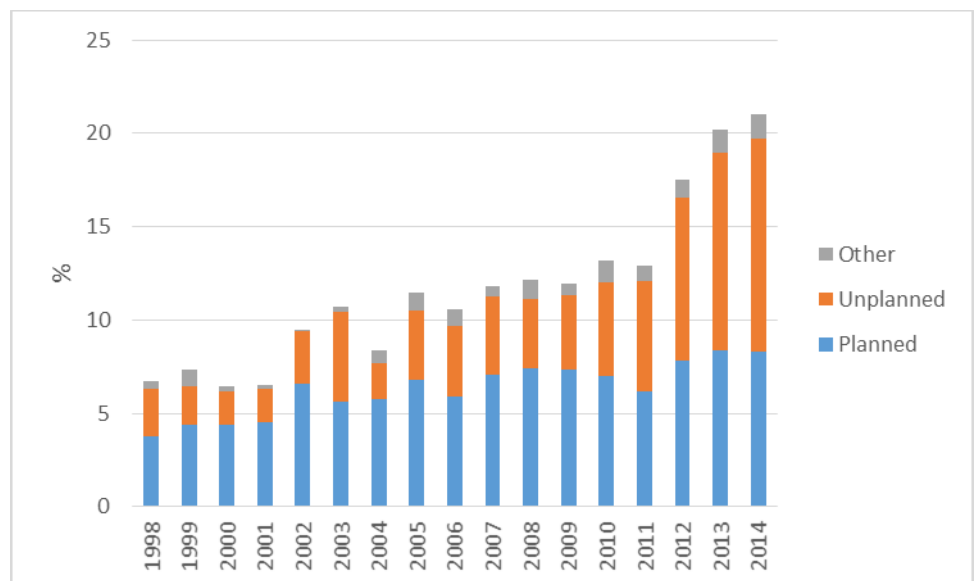


Figure 16. Outage statistics. 1998-2014. Capacity weighted.

Finally, Table 9 presents the assumptions regarding the planned and unplanned outage rates of new generation units applied in the model.

Plant type	Planned maintenance	Unplanned maintenance
Coal	4.8%	3.7%
Hydro	0.8%	0.2%
Storage	5.0%	1.0%
Nuclear	6.0%	2.0%
CCGT	6.9%	4.6%
OCGT	6.9%	4.6%
Other	4.0%	6.0%

Table 9: Planned and unplanned maintenance assumptions for new generation plants based on IRP 2010

4.3 Scenarios

In the current study, a number of scenarios have been investigated in the SisyfosR model. A 'Reference' case representing year 2014 has been simulated in order to provide a validation for the model, as well as a within-model benchmark for the future scenarios. Simulations are also made for years 2020 and 2025, respectively. In order to account for the uncertainty regarding future developments, a number of key parameter variations are explored:

- Demand (Low 1% p.a., Moderate 2% p.a., High 3% p.a.)
- Plant outage levels (on average: Low 8%, High 13%, Very High 17%)
- Renewable energy development pathways (All RE, Half RE, Half_Half⁴ RE)

Table 10 provides an overview of the scenarios, total of 55, investigated in the current study.

Parameter / Year	2014	2020	2025
Demand	Actual	High	High
		Moderate	Moderate
		Low	Low
Plant outage*	Actual (Very High)	Very High	Very High
		High	High
		Low	Low
Renewable energy	Actual	All	All
		Half	Half
		Half_Half	Half_Half
Number of scenarios	1	27	27

Table 10. Overview of the scenarios tested in the study.

* Only applies to the existing units. All new units are assigned outage rates as per IRP 2010.

⁴ Scenarios where only half of the planned RE expansion takes place, whereas the other half (in expected power generation equivalent) is substituted through conventional generation capacity

4.4 Results

This section of the report presents the results of the SisyfosR modelled scenarios. The results of each scenario modelled in the current analysis have been based on a sequence of 1 000 annual runs (i.e. 1 000 stochastic simulations of each year represented by 8 760 hours).

2014 Reference

The South African power system as of year 2014 has been represented using the actual measured demand data, the node-specific load profiles and the actual planned maintenance schedule of the existing generation fleet. Figure 17 illustrates the capacity surplus situation (only accounting for the planned outages) in the South African power system in 2014 as represented in SisyfosR.

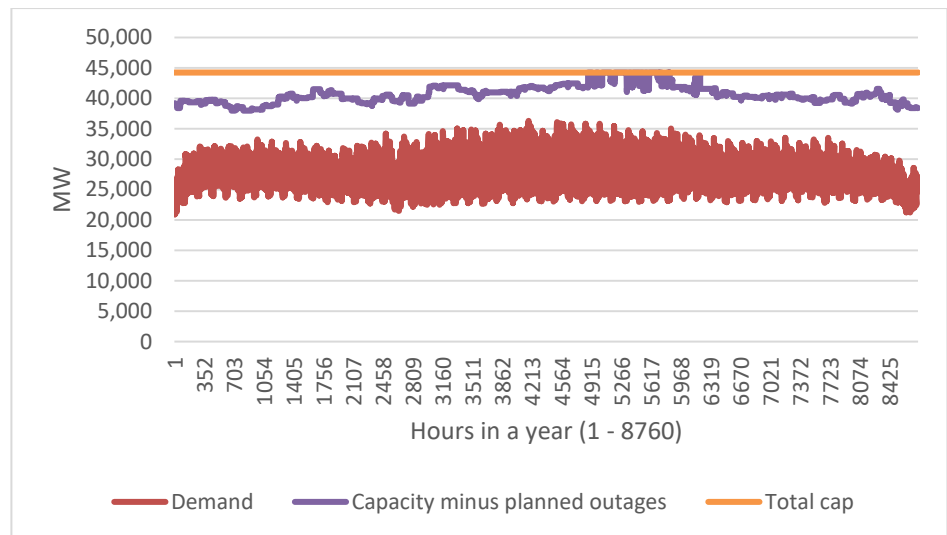


Figure 17: Demand, total generation capacity and capacity minus planned outages for the SisyfosR modelled year 2014

Using the above as inputs, the unplanned outages on generation units and transmission lines have been stochastically simulated in the SisyfosR model. Modelling results indicate that the highest frequency of ENS instances is not to be found during hours with the highest demand; it is in fact the load levels of 30,000 – 32,000 MW that exhibit the highest frequencies of ENS instances in the modelled results of the 2014 system, as illustrated by Figure 18.

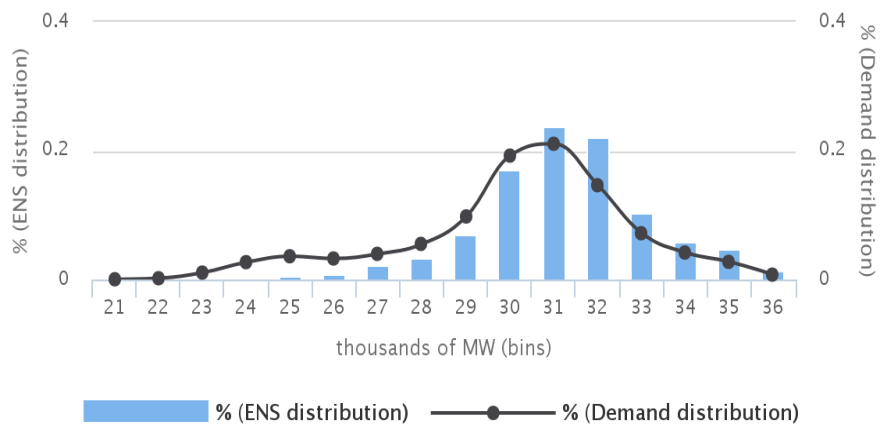


Figure 18: ENS distribution per demand ranges (bins) for the SisyfosR modelled year 2014 over 1000 runs

Figure 19 presents the capacity surplus histogram in relation to the number of instances and ENS incidents, as well as the average ENS across the 1 000 runs in SisyfosR. As the graph illustrates, the vast majority of ENS takes place at times of capacity deficit (the remaining ENS instances being attributable to grid issues).

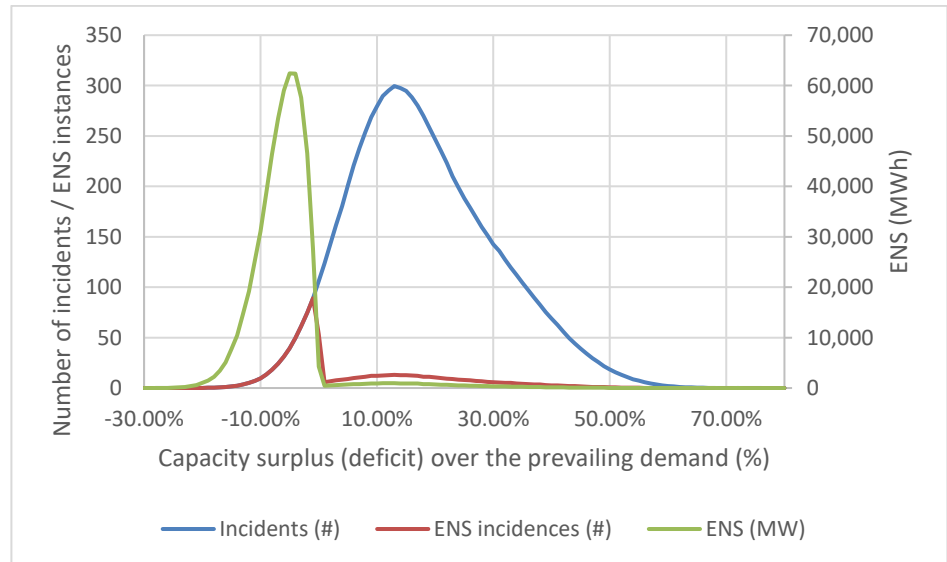


Figure 19: Histogram of average number of Incidents and ENS instances, as well as average ENS, over capacity surplus bins over the prevailing demand across the 1000 runs in SisyfosR for modelled year 2014

All scenario results

Table 11 provides an overview of the results of all of the scenarios investigated in the SisyfosR model, expressed in terms of average Energy Not Served (ENS) in GWh per annum across 1 000 model runs for each scenario.

		Demand: Low			Demand: Moderate			Demand: High		
		Outage level								
Year	RE development	Low	High	Very High	Low	High	Very High	Low	High	Very High
2014	Actual			655						
2020	Half_Half RE	9	9	9	19	42	293	136	1 636	5 435
2020	All RE	9	9	9	19	55	355	174	1 746	5 440
2020	Half RE	9	9	9	19	83	569	256	2 636	7 776
2025	Half_Half RE	9	9	9	16	16	16	47	344	1 389
2025	All RE	9	9	9	16	16	17	66	493	1 699
2025	Half RE	9	9	9	16	16	21	104	926	3 134

Table 11: Annual average ENS for all SisyfosR modelled scenarios across 1000 runs per scenario. Unit: GWh per annum

The power system adequacy in South Africa in 2014 was deemed highly problematic, yielding reported ENS of 512 GWh. This compares reasonably well to the SisyfosR modelled average annual ENS for 2014 of 655 GWh, taking into account that e.g. demand response capabilities were not represented in the model in the current study. As such, a proportion of the modelled ENS in 2014 would have in reality been alleviated by the activation of demand response.

The 'Low Demand' (1% annual growth rate) scenarios all show a very small amount of ENS regardless of the other parameter variations, well below the adequacy metric of Unserved Energy of 20 GWh per annum indicated in the IRP 2010 (2013 update). The system has enough spare capacity even if plant outage and RE generation capacity developments are less than satisfactory.

The 'Moderate Demand' (2 % annual growth rate) scenarios are all below the 20 GWh metric in 2025, except for the Half RE and High outage case, which is only slightly exceeding the limit (21 GWh). 2020 is more critical, and the resulting system adequacy is more dependent on the other parameter variations. Particularly the outages levels affect the resulting level of ENS. Only low outage levels result in acceptable modelled values of ENS. For higher levels of outages, the modelled ENS is exceeding the threshold. Here the impact of delayed RE-development ('Half RE') also shows, resulting in significantly higher ENS.

The 'High Demand' (3.1 % annual growth rate) scenarios all result in critical ENS levels, with 2020 being more stressed than 2025. The results also suggest

that the outage level variations have a higher impact than the RE-development pathways tested. In the scenarios featuring the generation plant outage levels consistent with those observed in 2014 ('Very High'), the modelling results suggest extreme levels of ENS.

The 'Half_Half RE' scenarios investigate the possibility of half of the planned RE expansion taking place, whereas the other half (in expected power generation equivalent) being substituted through conventional generation capacity, i.e. coal- and gas-fired. There are only slight differences in the resulting modelled ENS between the 'Half_Half RE' and 'All RE' scenarios. The direction of the differences (i.e. higher resulting ENS for 'Half_Half RE' scenarios compared to 'All RE' scenarios) does indicate that dispatchable capacity provides higher contribution to security of supply; the absolute scale of difference (i.e. fairly slight) would though indicate that also RE generation can contribute very significantly to system adequacy. Finally, it can be observed that the difference in the modelled ENS is almost negligible in the most critical system condition scenarios (i.e. high demand and high outage rate), which is fairly intuitive considering that in critical situations any additional power generation capacity can likely help alleviate the pressure. It should be noted, however, that these results are subject to the underlying assumptions (e.g. expression of expected RE generation into conventional generation capacity and its allocation in the transmission system, as well as the specific RE generation profiles).

Economically optimal amount of ENS

In this section we will demonstrate how the probabilistic method (in principle, subject to the values of the input parameters) can be used to find an economically optimal amount of ENS.

In this exercise it is assumed that the cost of ENS is US \$ 6,000 per MWh (25% more than the 75,000 R/MWh used in the IRP). It should though be noted that estimation of the value of ENS is associated with high degree of uncertainty.

Furthermore, it is assumed that additional peak generation capacity can be established at US\$ 95,000 per MW/year. This is meant to illustrate the costs of a single cycle gas turbine. With these values it is not economical to invest in extra generation capacity, if the marginal capacity is used less than 16 hours per year.

2014 is used as an example. It is possible to plan planned outage and still have surplus capacity in all hours. However, unplanned outage results in situations

with ENS. SisyfosR is used to compute a duration curve for the ENS, presented in Figure 20.

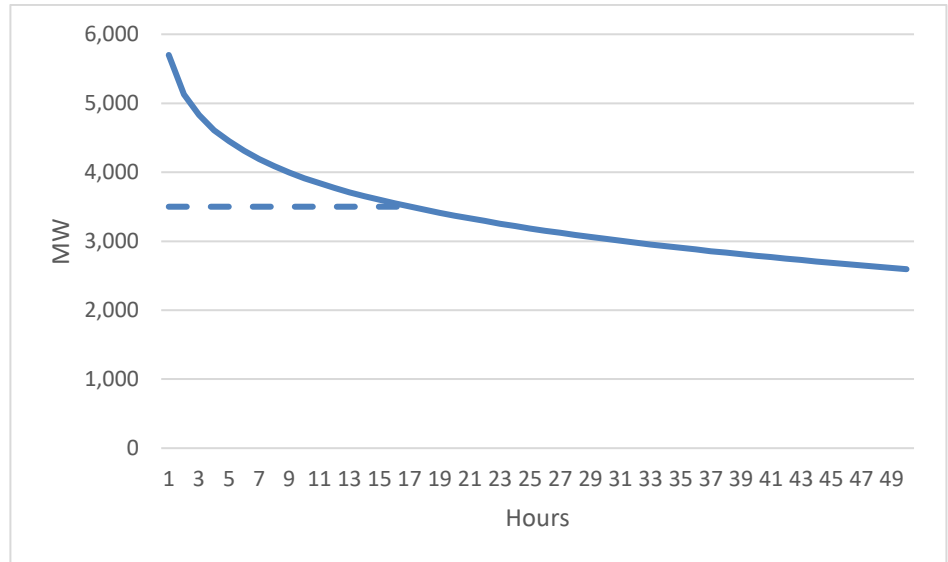


Figure 20: Duration curve for ENS. Data for 2014, with 1,000 MW capacity reserved for N-1 incidences. Assuming additional 3,500 MW, the area below the dashed line will be avoided as ENS, However, the area above the line will still be ENS.

Based on the duration curve, total costs can be estimated, using the value ENS and capacity costs as inputs, respectively. The total cost estimates are presented in Figure 21.

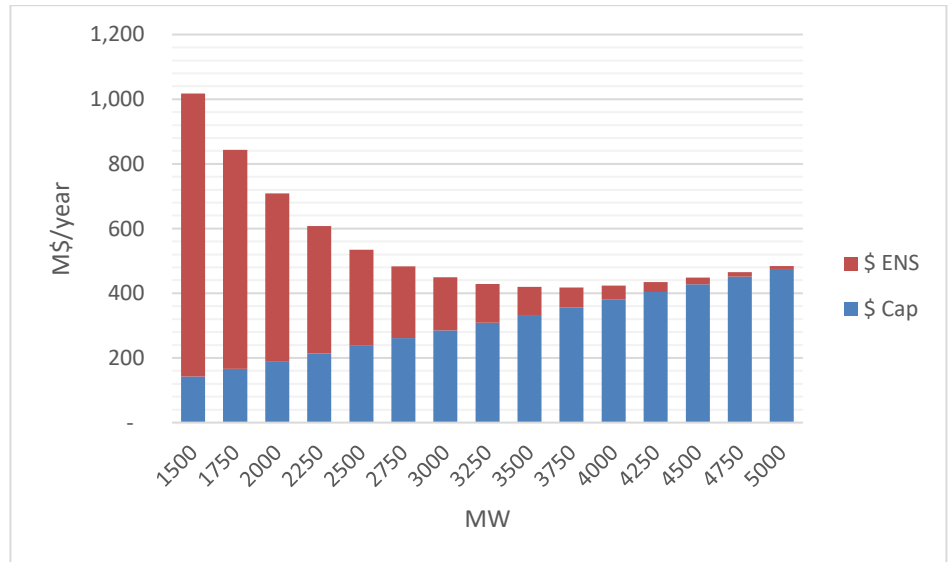


Figure 21. Total cost for ENS and new capacity. Minimum total costs can be found at 3,500 MW new capacity.

The resulting optimal amount of extra capacity (based on the current assumptions) is ca. 3,500 MW. This would significantly reduce the amount of

ENS. There will be 11 GWh ENS after adding the capacity. However, adding capacity beyond the 3,500 MW would increase the total costs. The marginal capacity would have less than 16 hours of run time per year.

For the future, more capacity can be added, or investments can be done to reduce the outage frequency of the existing plants. An economic analysis can show what is cheapest.

5 Renewable energy and the reliability

The main conclusions of the work are

- The normalized wind power ramp rates of the wind power in South Africa is reduced significantly from 2014 to 2020 and further reduced in 2025 because of the spatial smoothing.
- Wind power variability will not impact the use of instantaneous reserves because of the moderate rate of change of wind power combined with the frequency dead band.
- Wind power variability is estimated to increase the use of regulating reserves marginally, with max 1.8% in 2020 and max 2.4% in 2025. Those numbers are less than the 50 MW resolution used in the South African technical requirements to ancillary services.
- The use of 10-minute reserves is expected to increase to balance the day-ahead wind (and PV) power forecast errors. The wind power forecast errors have been quantified, but the total need for 10-minute reserves has not been studied in the present work.
- High rate of unplanned outage has results in a stressed system with frequently curtailment of demand. The needed capacity to obtain an acceptable adequacy are clearly influenced by the rate of outage.
- Use of stochastic methods, like the Sisyfos-R model, is a way to study how different measures can reduce energy-not-served (ENS).

5.1 Recommendations

The main recommendations of the work are:

- Include wind and PV in future updates of load variation study determining the need for regulating reserves in the technical requirements to ancillary services.
- Consider hour-ahead planning to reduce need for regulating reserves. The cost benefits of HA planning should be assessed taking into account the investment and operation cost of regulating and 10 minute reserves respectively and the possible reduction in forecast errors which are found in the present work.
- Improved hour ahead planning could be realised by adding real time (partly up-scaled) measurements for demand, wind and solar generation.

Supporting reports

Annex 1: System Reserves in the South African Power System and International Utilities (WP1)

Annex 2: Strategy about system adequacy and reserve margin with increasing levels of variable generation (WP2)

Annex 3: Stochastic analyses of adequacy (WP3)