Energy Research Centre – University of Cape Town

Reliability Investigation of the South African Power Generation System with the Inclusion of Wind Energy

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By

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Declaration

I know the meaning of plagiarism and declare that all the work in the work in the document, save for that which is properly acknowledged, is my own

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TIISETSO MASEELA

Acknowledgement

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Abstract

Renewable energy sources such as wind energy for electric power supply are receiving serious consideration around the world due to global environmental concerns associated with conventional generation and depleted conventional energy resources to meet increasing electricity demand. This is more than evident in South Africa, where the recently launched Renewable Energy Independent Procurement Program (REIPPPP) has a proposed capacity of 3725MW, allocating 1850MW to wind energy.

This dissertation investigates the effects that geographical dispersion and penetration level have on the wind capacity credit and the reliability of the South African power generation system, by estimating the capacity credit. Some of the estimates are tested using a simplified dispatch model, which is also used to estimate other indicators such as the expected energy not served and CO_2 emissions of the system for different wind configurations. The sensitivity of the capacity credit definition is further investigated through two definitions. Several scenarios are used to investigate the capacity credit of wind generation, based on the updated IRP base case scenario.

A gradual decrease in capacity credit is experienced as the penetration level of wind energy is increased in all scenarios investigated. There is also a distinct difference between the calculated capacity credits for the two definitions. It was further found that the capacity credit decreases with decreasing spatial dispersion in agreement with what was reported in the literature. Using the dispatch model it was possible to verify some of the capacity credit estimates, as well as calculate the impact of wind on CO_2 emissions.

Further work can be done on the dispatch model to increase its flexibility and sophistication in the way the dispatch of thermal plants is modelled. Furthermore, the study would be improved if the wind speed data was of better quality and the number of sites was increased.

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Abbreviations

AD	Available Downtime
AE	Available Energy
C_{FIRM}	Firm Capacity
C_{FUEL}	Fuel Cost
C_{TAX}	Carbon Tax
C_{TH}	Thermal Capacity
C_{VAR}	Variable Generation Cost
C_{WIND}	Wind Capacity
$C_{WINDEQUIVALENT}$	Equivalent Wind capacity
CAP	Installed Capacity
CAP_{AV}	Available Capacity
CC_{FIRM}	Firm Capacity Credit
$CC_{THERMALQUIVALENT}$	Thermal Equivalent Capacity Credit
CDF	Cumulative Distribution Function
CF	Capacity Factor
CO_2	Carbon Dioxide
CR	Committed Capacity Requirements
DANCED	Danish Co-operation for Environment and Development
DME	Department of Minerals and Energy
DoE	Department of Energy
EENS	Expected Energy not served
ELCC	Effective Load Carrying Capacity
FD	Forecast Demand
FW	Forecast Wind Generation
FOR	Forced Outage Rate
GW	Giga-Watts
GWEC	Global Wind Energy Council

GWh	Giga-Watt hours
GIZ	Deutsche Gesellschaft fur Internationale Zusammenarbeit
IRP	Integrated Resource Plan
LDC	Load Duration Curve
LOLE	Loss of Loss Expectation
LOLP	Loss of Load Probability
MW	Mega-Watts
MWh	Mega-Watt hours
PDF	Probability Distribution Function
PL	Peak Demand
POR	Planned Outage Rate
RD	Required Downtime
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RR	Required Reserve
RRM	Required Reserve Margin
SAWS	South African Weather Service
SRMC	Short Run Marginal Cost
TWh	Tera-Watt hour
WASA	Wind Atlas for South Africa

Chapter 1

Introduction

1.1 Background

South Africa was until recently one of the lowest cost producers of electricity in the world. The electricity sector is important to the economy comprising 28% of the total final energy consumption in 2006 (Subramoney et al., 2009) but supporting a range of high value add activities and essential services across sectors. With increased demand and a reduced reserve margin, there are various challenges facing South African energy policy makers. One of these challenges is maintaining a secure supply of electricity. The South African electricity generation system is based on low-grade coal fired technology which has been developed to match South African conditions over the past century. It was only in the 1980's that the government decided to diversify their generation mix with the commission of a nuclear power plant (Marquard, 2006).

With depleting fossil fuel reserves combined with global warming, South Africa has to invest in non-conventional generation methods to meet its electricity demand. This was noted in the Energy Policy White Paper (DME, 1998), which pledged to invest in renewable energy technologies. This was further complimented in the Renewable Energy White Paper (DME, 2003), which targeted the provision of 10 000GWh of renewable energy by 2013. In addition, the Integrated Resource Plan (DoE, 2010) allocated 17.8 GW to renewable energy for the generation mix in 2030. Currently the electricity generation mix comprises 91.7% of coal, 4.2% of nuclear, 2.4% of hydro and 1.7% of pumped storage with a total capacity of 43.5 GW (Edkins, Marquard & Winkler, 2012; Maleka, Mashimbye & Goyns, 2010) .

With this current energy mix, there is great opportunity for renewable energy to penetrate the South African electricity market, particularly for wind energy as it is the most mature renewable energy technology. Globally, there is over 300 GW of installed capacity of wind energy with between 40 and 50 GW expected to be installed annually worldwide in the foreseeable future as shown in Figure 1 and Figure 2 (GWEC, 2014).

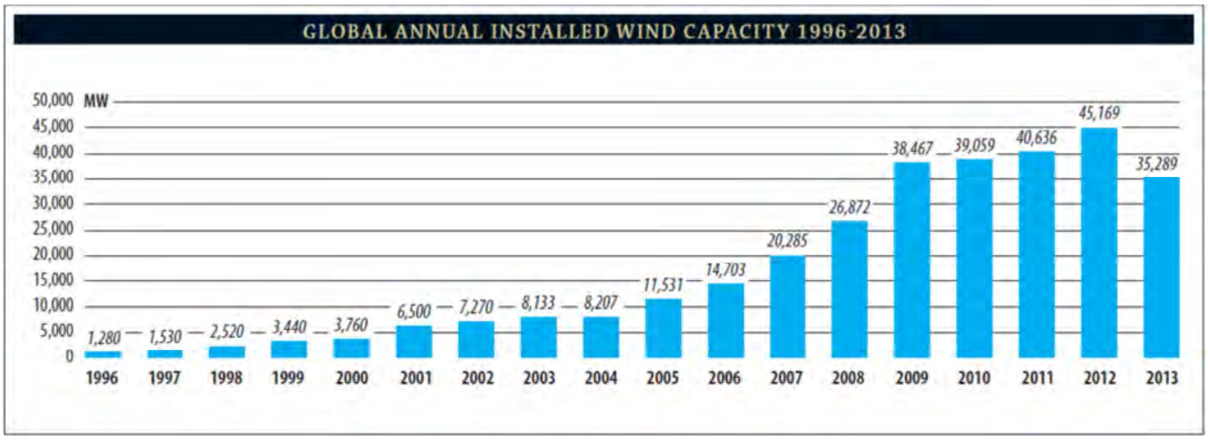

Figure 1 Annual Installed Wind Capacity (GWEC, 2014)

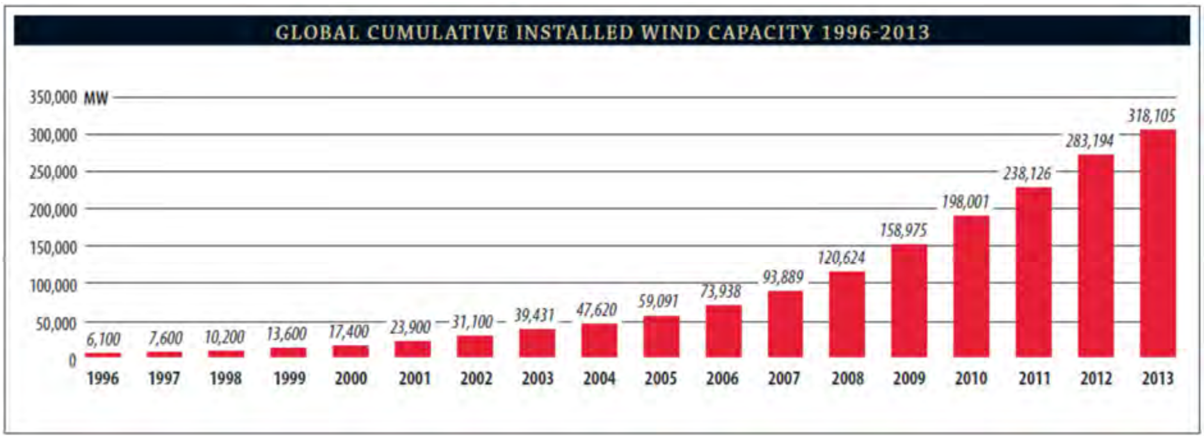

Figure 2 Cumulative Installed Wind Capacity (GWEC, 2014)

Wind energy is quickly becoming one of the leading forms of power generation. There are numerous studies that have analysed the potential of wind power in South Africa, for example the Mesoscale Wind Atlas of South Africa (Hagemann, 2008). This study modelled wind speeds across the country at different heights above the ground in order to determine the availability of the wind resource. It concluded that South Africa has a high wind resource that should be utilised.

Aside from resource availability, the intermittency of the wind resource and the effect that it will have on a power system is a critical issue and needs to be investigated. This dissertation aims to do this for the South African power generation system. At this present moment, the South African power generation system is at a cross-roads with the development of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP). The REIPPPP comprises of 5 phases with a proposed capacity of 3725 MW of renewable energy. Wind Energy has been allocated the majority share of approximately 1850MW. Currently 2 rounds have passed with the allocation of 634MW of wind in round 1 and 563MW in round 2 (Standard Bank, 2012; Whyte & McNair, 2012). Figure 3 shows the sites selected for round 1 and 2.

Figure 3 REIPPPP Wind Projects for Round 1 & 2

1.2 Aim

The aim of this dissertation is to investigate how the reliability of the South African power generation system is affected as more wind capacity is added. The reliability of wind energy is defined in terms of the capacity credit. It can be expressed as the amount of installed conventional generation capacity that can be replaced with wind energy to develop the same system adequacy.

1.2.1 Research Statement

The correlation between wind farms decreases with the increase in distance between wind generation sites. Using this argument, the intermittency of wind generation can be reduced by combining different wind farms from different wind regimes, hence increasing the capacity credit of the wind system. Furthermore, the capacity credit of wind energy decreases as the penetration level of wind energy increases.

1.2.2 Research Objectives

The primary objective of this dissertation is to investigate the effect that the geographical distribution of wind farms has on the capacity credit of the wind system. The geographical distribution can be expressed as the geographical dispersion of the wind farms within the wind system. The secondary objective is to investigate the effect that the wind penetration level has on the capacity credit. The penetration level is the capacity share of installed wind capacity in the power generation system.

This dissertation also investigates the performance indicators of the power generation system through the means of a dispatch model. The performance indicators investigated are the reliability of the system, the energy production of the individual generation technologies in the system, the CO_2 produced by the system and cost associated with the fuel consumption.

A wind generation system needs to be developed for these investigations to be carried out. Therefore, another objective of this dissertation is to develop a wind generation model. This wind generation model is applied to two main scenarios that are investigated in this dissertation. The main scenarios are as following:

- Scenario 1: Year 2011
    - 2 014MW Installed Wind Capacity
    - 43 470MW Installed Conventional Capacity
- Scenario 2: Year 2030
    - 4 360WM Installed Wind Capacity
    - 68 875MW Installed Conventional Capacity

1.3 Significance

The investigations carried out in this dissertation could help during the capacity planning process for determining the required electricity generation investments to meet future demand. With the addition of wind generation, the classical approach based on the consideration of a reserve margin on the basis of typical availability indices of conventional power plants is not adequate. The availability of wind generation will either be overestimated or underestimated due to the intermittency of wind generation. Better accounting of the capacity credit of wind generation improves capacity expansion planning.

Dispersion and penetration level are the two main factors that affect the capacity credit. It is important to establish the extent to which they do.

1.4 Delineations

A power system consists of three different facilities; generation, transmission and distribution. In the investigation of the wind system reliability and its effect on the overall system, generation and transmission failure tend to be more important as they affect a larger section of the system, while distribution failure tend to be more localised. This dissertation only investigates the generation facilities of the power system.

Wind data can be obtained from actual time series data or simulated time series data. There are various studies that have been done on simulated time series, therefore the simulation of time series data is not investigated or performed in this dissertation. Actual time series data is used to develop the wind generation model.

1.5 Overview of Chapters

This dissertation establishes a framework for capacity credit and the corresponding performance indicators for the respective power systems investigated. There are six chapters in this dissertation. The main topics of each chapter are as following:

Chapter 1 introduces the main topics that are going to be investigated in this dissertation. Background information behind the investigation is given, the major research objectives and the scope.

Chapter 2 presents the different concepts and techniques for wind energy modelling, reliability evaluation and capacity credit investigation. Reviews of the available literature on these concepts are also presented.

Chapter 3 presents the methodology used to develop the wind generation model to help investigate the capacity credit and performance indices. The concepts described in chapter 2 are utilised to develop the wind generation model.

Chapter 4 presents the methodology used to investigate the capacity credit for wind generation and the dispatch model developed to investigate the performance indices. The concepts described in chapter 2 and the wind generation model developed in chapter 3 are used to investigate the capacity credit and develop the dispatch model.

Chapter 5 presents the results and the discussions of the various investigations, while chapter 6 summarises the dissertation, highlights the results of the investigations and presents recommendations for future research.

Chapter 2

Literature Review

2.1 Wind Resource Assessment in South Africa

The majority of earlier wind resource assessment in South Africa can be attributed to Diab, who presented various papers for the Department of Minerals and Energy in the late 70s and 80s. However, her most renowned work is the Wind Atlas of South Africa (Diab, 1995). It is a measurement based country wide assessment that contains descriptions of and statistics for numerous long term weather stations around South Africa. It presents mean wind speed, frequency distributions, fitted Weibull parameters for each 30^o sector and overall values as well as the average monthly and daily wind fluctuations in tabular and graphical form.

The wind atlas of South Africa (Diab, 1995) categorises South Africa into *good, moderate and low* wind power potential, with *good* representing areas with average wind speeds above 4ms^{-1}. Diab further developed a national wind resource map as shown in Figure 4 using subjective reasoning.

Her work has been the foundation for many related renewable energy and wind power studies such as Wind Energy in the Western Cape: Grid-connected renewable distribution electricity generation(Schaffler, 2001) and Wind Energy in South Africa (van der Linde, 1996).

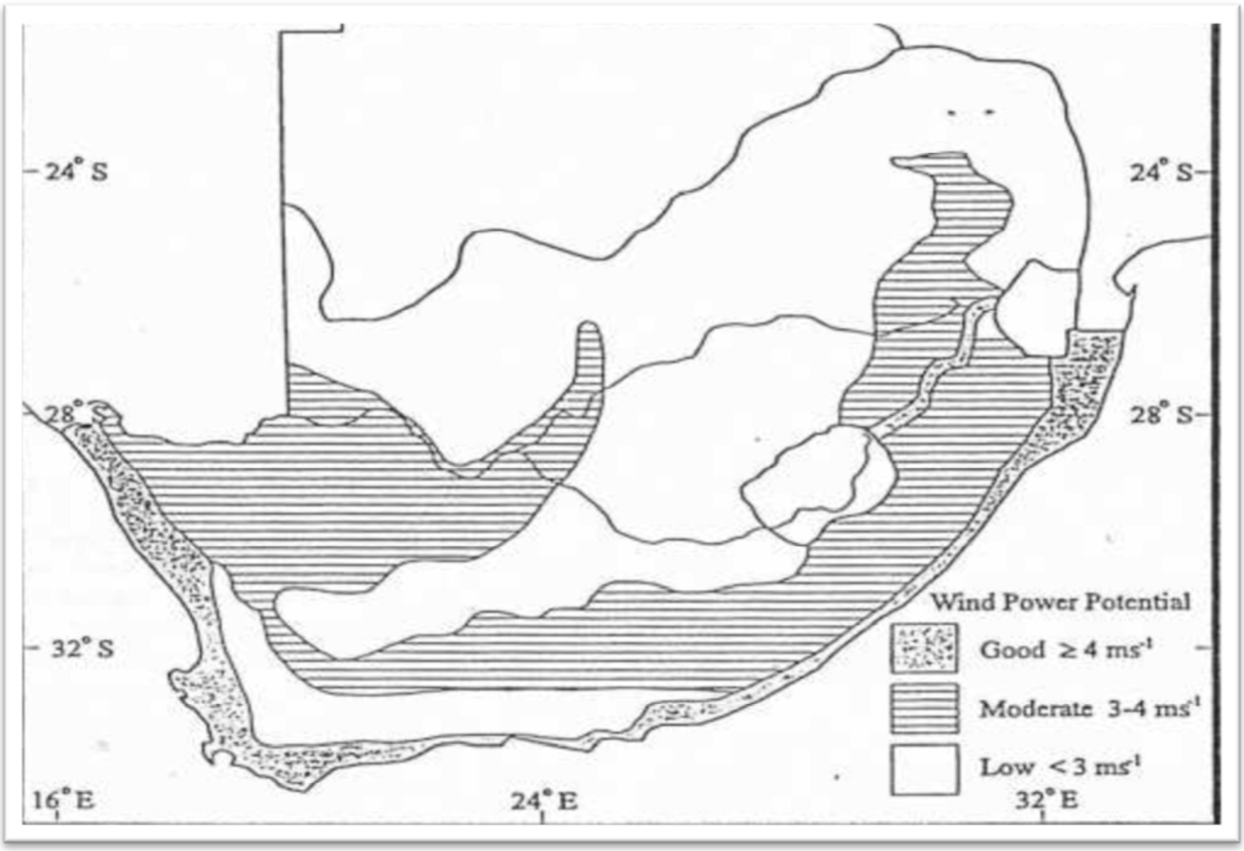

Figure 4 Wind Resource Map of South Africa (Diab, 1995)

As shown in Figure 4, Diab concluded that areas with good wind potential are generally located along the coast with localised areas of very good wind potential elsewhere.

However, due to the nature of the measurements from the weather stations, the reliability and integrity of the wind atlas was deemed to be questionable (Hagemann, 2008). Therefore, with these inaccuracies, Eskom, CSIR, the DME and DANCED, (Danish Co-operation for Environment and Development, now DANIDA) jointly funded a revised wind atlas in 2001. This South African Wind Atlas was supposed to supersede Diab's wind atlas and overcome some of the problems encountered by Diab. Information about this revised wind atlas remains scarce as the results were not published in the public domain. Furthermore, some sources report strong concerns about the data accuracy and correct application of WAsP modelling methodology (EDRC, 2003). The only available details for this wind atlas are published on SABRE-Gen's website[1], and are shown in Figure 5.

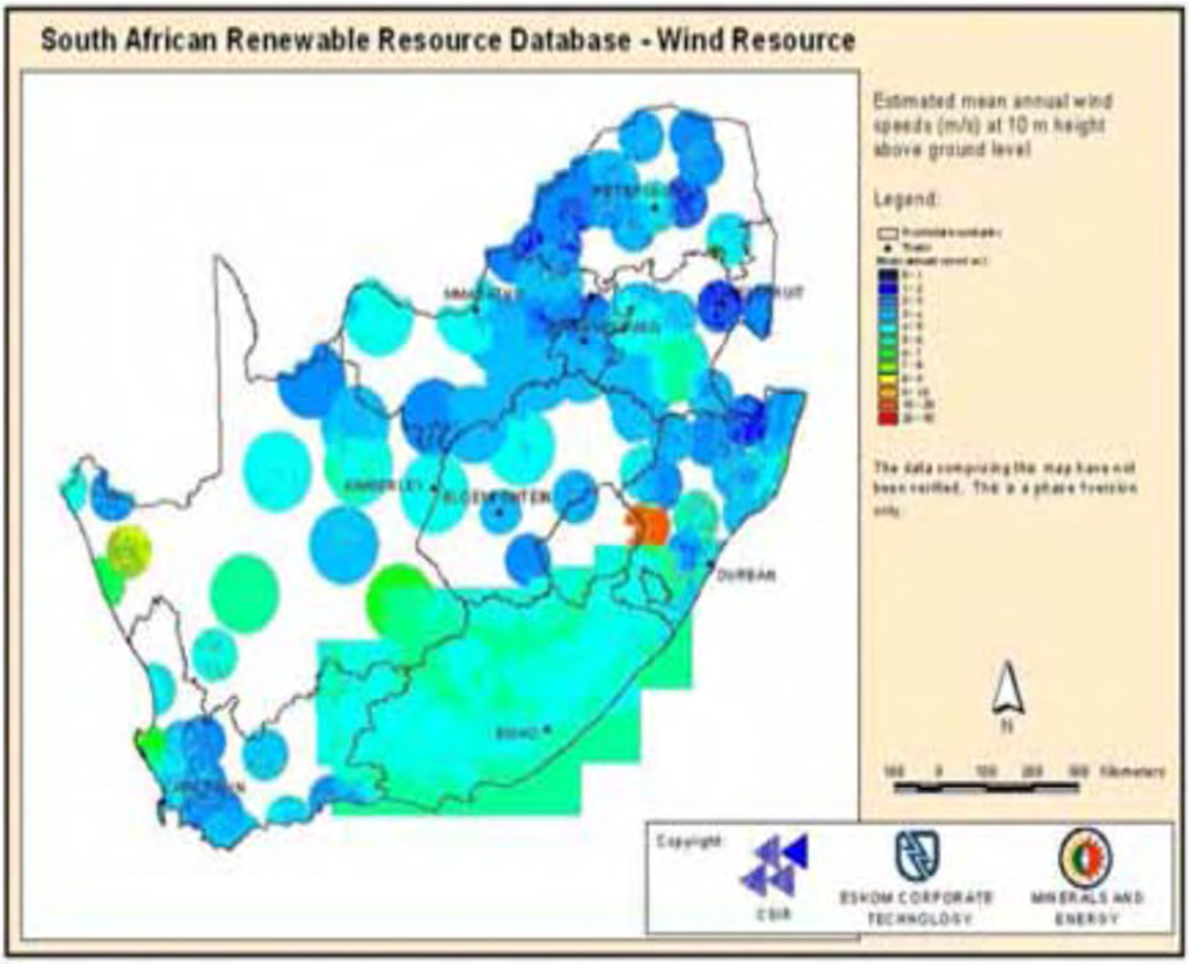

Figure 5 Eskom revised Wind Atlas in 2001 (Sabre-Gen)

After Eskom's revised wind atlas, a mesoscale wind map of South Africa was produced by Hagemann (2008) as part of his PhD research at the University of Cape Town. His thesis explores two objectives, firstly investigating in detail the value of using the regional climate model MM5 to develop high resolution wind climatology of South Africa.

[1] http://www.sabregen.co.za

The second objective was to map and quantify the wind resource of South Africa.

The MM5 model was initially designed to be a regional climate model for short term numerical weather predication and research. It operates at a mesoscale and is driven at the boundaries by global scale data to predict atmospheric circulation (Hagemann, 2008). With this model, it was found that it is possible to generate a valid climatology. Furthermore, a national wind dataset was developed at an 18 X 18km resolution at various heights above the ground. The resulting wind resource maps for annual and seasonal wind speeds revealed previously unknown areas of high wind speeds inland. It also reveals that the wind resource in South Africa is higher than expected in previous studies. Figure 6 illustrates the average annual wind speeds at 10m above ground.

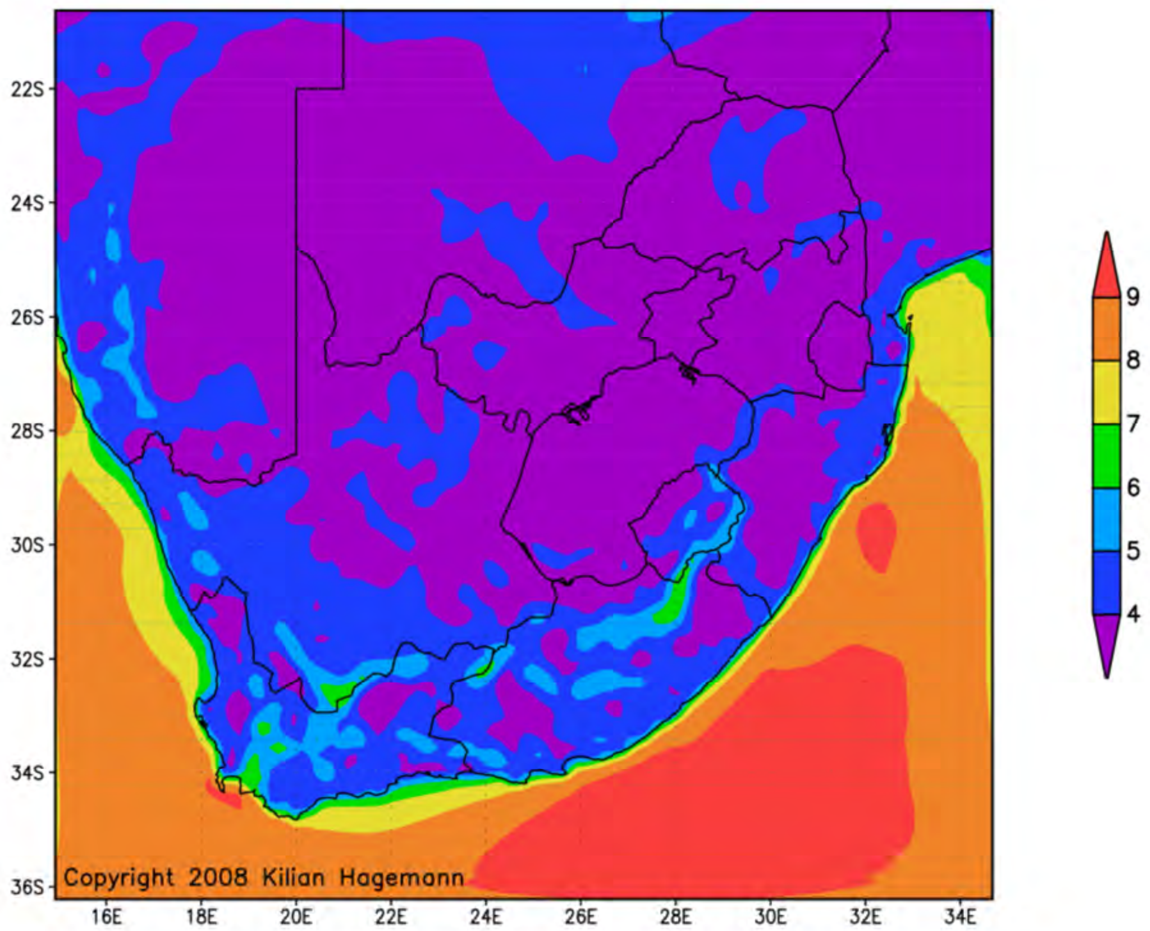

Figure 6 Average Annual Wind Speeds at 10m above ground in ms-1

Hagemann's thesis further stated that the realistic annual electricity generation potential from wind power, outside exclusion zones like nature reserves and reasonably proximate to public infrastructure to be 81TWh corresponding to approximately 35% of 2007s total electrical demand.

Hagemann's wind resource map was a big improvement from the two previous wind resource maps that were developed. In an effort to improve the level of detail and public access, the Department of Energy decided to commission the Wind Atlas for South Africa (WASA) in 2009, jointly funded by the Department of Energy, Eskom and the CSIR (Szewczuk, 2010). The Wind Atlas for South Africa consists of 6 work packages, commencing from June 2009 and ending in March 2014. Table 1 illustrates the work packages with their responsible parties.

To highlight some of the outcomes of WASA, one being a developed numerical wind atlas and database for the Western Cape Province and selected areas of the Northern Cape and Eastern Cape. Another outcome is to develop a micro-scale resource map and database for the modelled areas. A third outcome is to construct 10 high quality wind measurement masts. Figure 7 (Hansen, 2012) illustrates the modelled area and locations of the wind masts (IRENA, 2012).

Table 1 WASA Phase 1 Work Packages

Work Package	Description	Responsible Party
WP1	Meso-scale Modelling	RISO & UCT (CSAG)
WP2	Wind Measurement	RISO & CSIR Stellenbosch
WP3	Micro-scale Modelling	RISO & CSIR Pretoria
WP4	Application	RISO & CSIR Pretoria
WP5	Extreme Wind	RISO & SAWS
WP6	Documentation and Dissemination	SANEDI

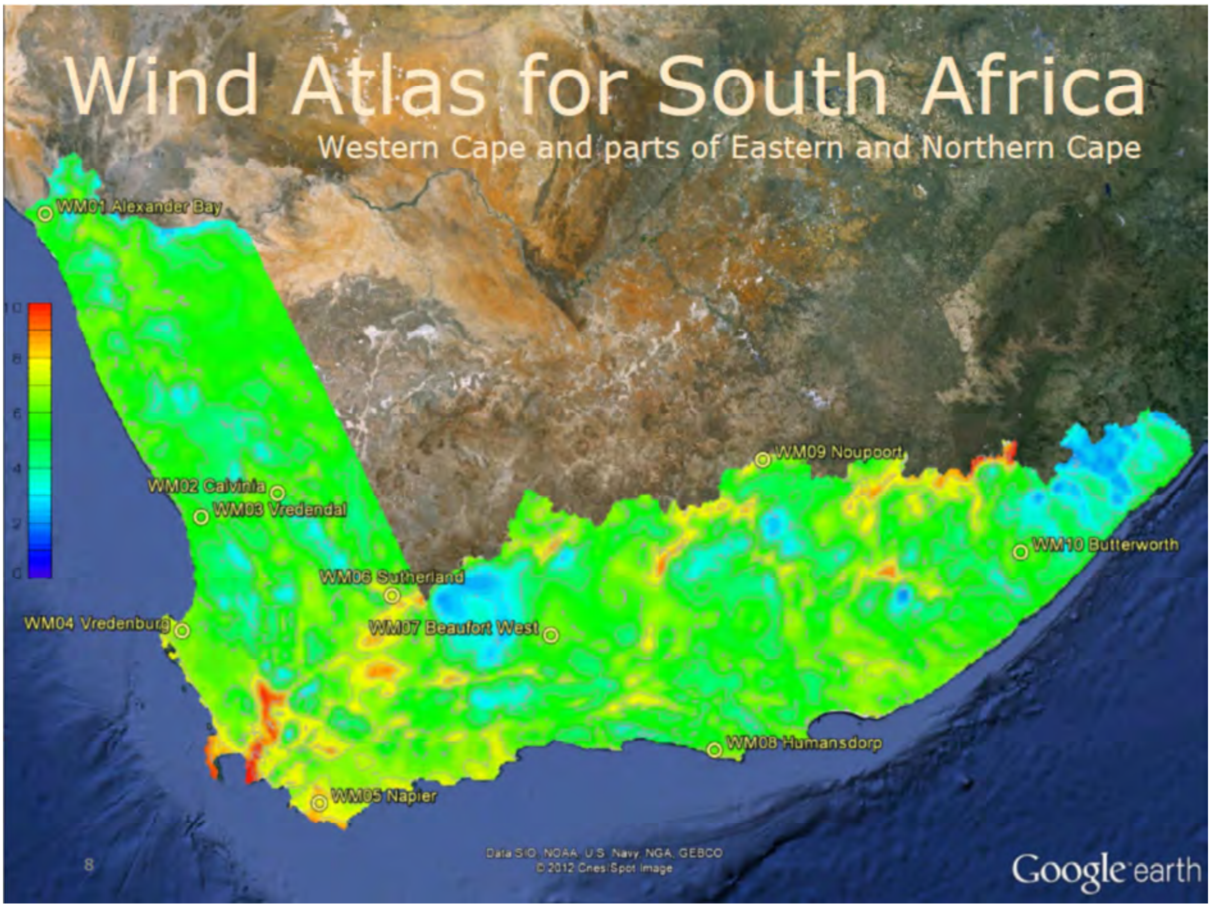

Figure 7 Wind Atlas for South Africa

= Wind Measurement Mast

As shown in Figure 7, the majority of the wind measurement masts are located in the Western Cape. This is quite different from the REIPPPP project sites where the majority of the projects are located in the Eastern Cape as shown in Figure 3. This gives an opportunity to investigate how the reliability will be affected with regards to the dispersion of the wind farms.

Currently, WASA has 10 wind measurement masts installed and operational circled in yellow in Figure 7. Websites have been launched by the Department of Energy at the 2nd Annual wind energy seminar in 2010. Some of these sites include online graphs (www.wasa.csir.co.za), data download capability for the various wind measurement masts (http://wasadata.csir.co.za/wasa1/WASAData), general information on the WASA project (www.wasaproject.info) (Hansen, 2012).

The first Numerical Wind Atlas for South Africa was launched in 2013. The Numerical Wind Atlas Database contains generalized wind climate data sets for every 5 X 5km, approximately 15000 data points, which can be seen as virtual wind measurement masts. The Numerical Wind Atlas Database can be accessed through Google Earth (tadpole) interface (CSIR, 2013).

The wind resource for South Africa has been assessed over many years firstly with Diab's Wind Atlas of South Africa and culminating in the current Wind Atlas for South Africa. Assessing the wind resource is a first step into investigating the effect that wind power will have on the reliability of the South African power generation system, and WASA now makes it possible to do so. The next step takes this wind resource analysis into a power system model. The next section provides a review of wind energy modelling.

2.2 Wind Energy Modelling

Wind energy is an indirect form of solar energy. Winds result from unequal heating of different parts of the earth's surface, causing cooler, dense air to circulate and replace warmer, lighter air. This procedure is intermittent and varies randomly with time. Wind is therefore, highly variable, and it is both site specific and terrain specific. It has seasonal, diurnal and hourly variations. Therefore the wind profile for a specific site cannot be simply determined from the average wind speed resource maps.

Wind speeds need to be simulated where measured data is unavailable in order to more accurately model the wind energy generation. It is beyond the scope of this dissertation to investigate the simulation of wind speed; however, extensive work has been done, for example, past and can be seen in "Simulation of hourly wind speed and array wind power" (1981), "Generation of auto-correlated wind speeds for wind energy conversion system studies" (1984) and "Time-series models for reliability evaluation of power systems including wind energy" (1996).

Furthermore, it has been found that the wind speed distribution for a given location can be well described by the Weibull distribution, given by (Kumaraswamy, Keshavan & Ravikiran, 2011):

$$f(x) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} e^{\left(-\left(\frac{v}{c}\right)^{k}\right)},$$

Equation 1 Weibull Distribution

where, k is the shape parameter, c is the scalar parameter and v is the wind speed. The shape parameter and scalar parameter of the Weibull distribution are given by Equation 2 and Equation 3 respectively (Kumaraswamy, Keshavan & Ravikiran, 2011):

$$k = \left(\frac{\sigma}{v_m}\right)^{-1.086},$$

Equation 2 Shape Parameter

$$c = \frac{v_m}{\Gamma(1+\frac{1}{k})},$$

Equation 3 Scalar Parameter

where v_m is the average wind speed, σ is the standard deviation of the wind speed, and Γ is the gamma function which is defined by the following integral (Kumaraswamy, Keshavan & Ravikiran, 2011):

$$\Gamma(x) = \int_o^\infty t^{x-1}e^{-t}dt.$$

Equation 4 Gamma function

The Weibull distribution is commonly used to describe the wind speed distribution for a given location for certain periods, usually a month or a year

However, when measured wind speed data is available, there are three basic parameters that are needed to quantify the energy potential of the given site. These parameters are the wind speed and direction, topographic characteristics of the study area and the air density. The importance of these parameters is due to the fact that the power in airflow follows a cubic relationship with the free wind speed as shown in Equation 5 (Cheng, Hou & Wu, 2011):

$$P_{air} = \frac{1}{2}\rho v^3,$$

Equation 5 Available Airflow Power

where P_{air} is the power in the airflow, ρ is air density and v is the wind speed.

From Equation 5, the power density for a given location can then be determined given in Watts per square meter (W/m^2). This can be achieved by applying Equation 5 to the wind speed data, whether it has been measured or simulated. The elevation above sea level and the temperature of the wind are used to adjust the density of the air in Equation 5. This is illustrated in the Numerical Wind Atlas by WASA as each point provides a Weibull distribution for the location with the average power density. However, in reality, not all the power is utilised by the wind turbine. This is due to the power loss during the conversion of mechanical energy to electrical energy.

Therefore, the power coefficient can be described as the ratio between the airflow power and the turbine power output, as shown in Equation 6 (Cheng, Hou & Wu, 2011):

$$c_p = \frac{P_{WT}}{P_{air}},$$

Equation 6 Power coefficient

where c_p is power coefficient and P_{WT} is the power output of the wind Turbine

It has been observed that there is a maximum value for power coefficient c_p, known as the Betz limit which is approximately 60%. Power coefficient for wind turbines is a nonlinear function of the tip speed ratio ϒ and is defined by Equation 7 (Cheng, Hou & Wu, 2011):

$$\gamma = \frac{\omega r}{v},$$

Equation 7 Tip Speed Ratio

where ω is the angular velocity of the rotor and r is the radius of the blade. Therefore the Turbine power can be given by:

$$P_{WT} = \frac{1}{2} c_p \rho A v^3,$$

Equation 8 Turbine Power

where A is the swept area of the turbine blades

In order to develop an accurate wind energy model, the correct type of turbine class has to be provided for the correct wind region. The IEC has developed an international standard wind turbine classification called the IEC 61400-1 for wind turbine design for different wind classes (IEC, 2008). From the IEC 61400-1 (IEC, 2008), wind classes are mainly defined by the average annual wind speed and the speed of extreme gusts in the area. There are three wind classes, namely: low; medium; and high, with average annual wind speeds of $7.5ms^{-1}$ $8.5ms^{-1}$ and $10ms^{-1}$ respectively.

Equation 8 is rarely used to determine the wind turbine power output. This is due to the fact in the real world; the wind turbine does not produce electrical output at low wind speeds. This is due the fact there is not enough power in the wind to produce enough thrust on the turbine blades, and hence sustain rotation. Wind turbine power output can be expressed in terms of the cut-in wind speed, the rated wind speed, the cut-out wind speed and the power rating of the wind turbine. The power function of generic wind turbine can be expressed by (Bagen, 2005):

$$P_t = \begin{cases} 0 & 0 \le v \le v_{ci} \\ (A + Bv + Cv^2)P_r & v_{ci} \le v \le v_r \\ P_r & v_r \le v \le v_{co} \\ 0 & v \ge v_{co} \end{cases},$$

Equation 9 Power Function

where P_t, P_r, v_{ci}, v_r, v_{co} are the actual power output, rated power output, the cut-in wind speed, the rated wind speed and the cut-out wind speed of the wind turbine respectively. The constants A, B and C depend on v_{ci} and v_r, as expressed by Equation 10 (Bagen, 2005):

$$A = \frac{1}{(v_{ci}-v_r)^2}\left[v_{ci}(v_{ci}+v_r) - 4v_{ci}v_r\left(\frac{v_{ci}+v_r}{2v_r}\right)^3\right],$$

$$B = \frac{1}{(v_{ci}-v_r)^2}\left[4(v_{ci}+v_r)\left(\frac{v_{ci}+v_r}{2v_r}\right)^3 - (3v_{ci}+v_r\right],$$

$$C = \frac{1}{(v_{ci}-v_r)^2}\left[2 - 4\left(\frac{v_{ci}+v_r}{2v_r}\right)^3\right].$$

Equation 10 Constant for Power Function

With an accurate wind resource described and a realistic turbine power function defined, a wind energy model can be developed. There are various studies that have been conducted, which model the wind energy output of a certain location. One of these studies is “Probabilistic wind power generation model: Derivation and applications” (Cheng, Hou & Wu, 2011), which develops a model for probabilistic power generation. In addition, it derives a fourth order power density function. This is achieved by dividing the wind turbine power function in multiple smaller linear functions. The model also incorporates wind farms, scaling of the wake effect caused by other turbines. The work also extends the modelling of the wind power output up to regional scale, which is often overlooked. The model is verified through Monte Carlo Simulations and compared to empirical and analytical wind power density functions. It was found that model is reasonably matched with the empirical and analytical data.

Another paper that models wind energy output is “Wind Turbine Condition Assessment through Power Curve Copula Modelling” (Gill, Stephen & Galloway, 2012) where a copula power curve was estimated and applied to two empirical data from two operational wind turbines.

It was found that the copula approach has the ability to measure and identify changes in dependency between measured wind speed and power.

A third paper that looks at wind energy modelling is “A framework to determine the Probability Density Function for the output power of Wind farms” (Dhople & Dominguez-Garcia, 2012). It proposes a numerical framework to propagate wind speed uncertainty through the power output of a wind farm. Inputs to this framework include the wind speed probability distribution function (pdf), essentially the Weibull distribution and a statistical availability model for the wind turbine in the wind farm. These inputs are transmitted through a mathematical model that describes the power produced by the wind farm to obtain the pdf of the wind farm power output. The framework is validated through comparison with empirical data.

These papers are amongst the vast number of studies that have been carried out in wind energy modelling. They either incorporate wind speed simulation or use actual time series data to develop wind energy models for analysis. In relation to the objectives of the thesis, developing a wind energy model would be the first step and one of the most important steps in investigating the reliability of a power generation system. This dissertation will use time series data to develop a wind turbine power output model. The next section discusses the reliability of a power generation system with and without wind energy.

2.3 Reliability

A power system consists of facilities necessary to generate, transmit and distribute electrical energy to its consumers. The basic function of an electrical power system is to supply consumers with electricity as economically as possible with an acceptable level of reliability as shown in Figure 8. From Figure 8, the lower the consumer cost, the lower the reliability cost. Therefore the utility needs to find a balance between the consumer cost and the appropriate reliability of the system.

The reliability associated in this description is a measure of the system's overall ability to perform its basic function. Generation and transmission failure tend to be more important as they affect a larger section of the system, while distribution failure tend to be more localised (Wilson & Adams, 2006). Therefore, as stated in chapter one, this dissertation will investigate the reliability of the generation power system and disregard transmission and distribution reliability.

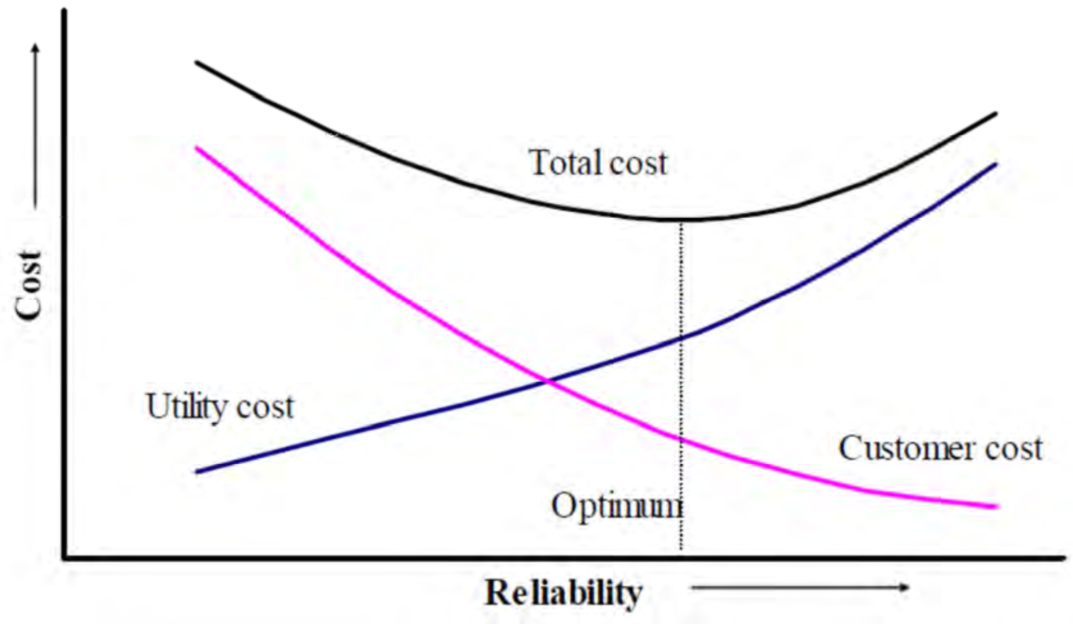

Figure 8 Reliability Cost Components (Bagen, 2005)

System reliability can be subdivided into two distinct categories, system adequacy and system security. System adequacy is generally considered to be the existence of sufficient facilities within the system to meet the consumer demand (Bagen, 2005).

System security is generally considered to be the ability of the system to respond to disturbances. In this case, system adequacy would be the existence of sufficient generation capacity to meet the consumer demand and system security would relate to the versatility of the generation mix to respond to unplanned outages or extreme weather conditions. There is very little published material on system security. On the other hand, there are numerous studies that have investigated system adequacy and will be discussed in more detail later.

Generation adequacy is assessed by determining the probability of there being insufficient generation to meet demand. This is done by calculating the risk of supply shortages. Furthermore, installed capacity must exceed demand to allow loss of generation whether it is for planned or unplanned outages. This additional capacity is known as the reserve capacity.

The ratio between the reserve capacity (IC-PD) and the peak demand (PD) is known as the reserve margin (RM) defined by Equation 11:

$$RM = \frac{IC-PD}{PD} \times 100\%.$$

Equation 11 Reserve Margin

There are two basic reliability assessment techniques. These techniques are either probabilistic or deterministic (Wilson & Adams, 2006). Deterministic techniques are based on an examination of a number of constraining situations, usually the most serious event. In deterministic techniques, it is assumed that if the system can be assured for those cases, then it will be secure for all situations. Deterministic techniques do not reflect the fact that a given level of reliability needs to be satisfied. It also does not consider the underlying factors influencing the ability to meet demand.

Probabilistic techniques involve the calculation of reliability indices such as loss of load probability (LOLP), loss of load expectation (LOLE) or Expected Energy not Served (EENS). These calculations are based on planned and unplanned outage rates for the different plants within the generation mix; hence they include the underlying factors that influence the system's ability to meet demand.

LOLP is defined as the probability that the load will exceed the available capacity. As stated in the definition, it provides the likelihood of encountering difficulty on the system. It however does not indicate the severity of the difficulty, either in terms of capacity or energy shortage. Therefore, LOLE and EENS are better reliability indices. LOLE is a variant of LOLP and is defined as the average number of days or hours in a year on which the demand is expected to exceed the available capacity. It also mathematically defined by Equation 12:

$$LOLE = \frac{\sum_{i=1}^{N}(Total\ Hours\ of\ Loss\ of\ Load)_i}{N},$$

where N is the number of simulations

Equation 12 Loss of Load Expectation (Wang & Baran, 2010)

EENS defines the expected energy that the utility will be unable to supply when load exceeds available capacity. It is mathematically defined by Equation 13:

$$EENS = \frac{\sum_{i=1}^{N}(Total\ Energy\ Not\ Served)_i}{N}.$$

Equation 13 Expected Energy Not Served (Wang & Baran, 2010)

These two indices have been used by large number of utilities and are widely used for planning future generation capacity. These two indices are effective in describing a system's adequacy level individually. However, combining them together to describe a system's adequacy level can be considered to be a better description. This is due to the fact that LOLE describes the probability of loss of load, whilst EENS describes the severity of loss of load.

One of the objectives of this dissertation is to investigate how the reliability of the South African power system is affected by the inclusion of wind energy. Due to intermittency of wind energy, a deterministic approach is not sufficient enough to evaluate the reliability indices, therefore a probabilistic approach needs to be utilised.

From previous work, Monte Carlo simulation is utilised in order to develop the reliability indices. This is because Monte Carlo simulation is the only practical technique for systems that have large numbers of time dependant random variables (Bagen, 2005). There are generally two categories within Monte Carlo simulation, which are sequential and non-sequential simulation.

As the names suggest, sequential simulation follow a sequential or chronological process, recognizing the fact the given time point is correlated to the previous one, whereas in non-sequential simulation, each time point is independent.

There are numerous studies that investigate the reliability of power systems. “Reliability Evaluation of Power System” (Billinton & Allan, 1996) has set the benchmark for reliability evaluation techniques. It builds on the ideas developed by the same author’s in a previous edition of the book.

However, in relation to the objectives of this dissertation, the reliability of power systems with the inclusion of wind energy need to be considered. This was investigated by Singh & Lago-Gonzalez (1985).

The method presented in this article divides the power system into two subsystems, one for conventional generation and another for unconventional general. General systems are built for each subsystem. These two subsystems are combined to generate the reliability indices. The results from the method show that reliability indices are sensitive to the penetration levels of wind energy. This is in agreement with the primary objectives and hypothesis of this dissertation as effects that geographical dispersion and penetration levels have on reliability indices are investigated.

The method used by Singh & Lago-Gonzalez (1985) is taken further by Singh & Kim (1988), where states of mean output values for unconventional generation are identified for a given load using clustering procedures. Reliability indices are developed by combining conventional subsystem with the unconventional generation subsystems in each state.

These two methods do not include the failure and repair characteristic of the wind turbine. This factor was included in “Incorporation of wind energy conversion systems in conventional generating capacity adequacy assessment” (Billinton & Chowdhury, 1992), where a load modification technique was used on a load duration curve to develop the reliability indices. Furthermore, a forced outage rating (FOR) was introduced to a multi-state wind turbine in order to model the failure and repair characteristic of the wind turbine. This method was tested on the Institute of Electrical and Electronics Engineers reliability test (IEEE-RTS). It was found that the FOR is directly proportional to EENS. Effectively, as the FOR increases, so does the EENS. Furthermore, penetration levels of wind capacity were also investigated. It was found that penetration levels are inversely proportional EENS. Essentially, as penetration level increase, the EENS of the system decreases.

The results in “Quantifying reserve demands due to increasing wind power penetration” (Doherty & O'Malley, 2003) seem to disagree with the results developed by Billinton & Chowdhury (1992). Doherty & O'Malley (2003) develop a method that quantifies the reserve needs for a system with wind in such a way that it is directly related to a system reliability criterion. It considers both demand and wind forecasts as well as generator outages. Furthermore, it considers two types of reserves, the first being the reserve that is called upon to make up for any shortfall due to unforeseeable events and secondly, the replacement reserve which is the amount of reserve that needs to be put into place to restore reserve levels.

The procedure proposed in this paper links the probability of a loss of capacity to the reserve level. This method was tested on the IEEE-RTS. It was found that as the wind energy penetration increased, the system became less reliable.

Due to the fact that the conclusions of Billinton & Chowdhury (1992) and Doherty & O'Malley (2003) contradict each other, this gives reason for the investigation of effects that the penetration level and geographical dispersion of wind energy have on the system adequacy and security of South African generation system.

The penetration levels of wind energy are further investigated by D'Annunzio & Santoso (2005) in "Wind power generation reliability analysis and modelling".

They investigate the impact of wind energy on a power system at different penetration levels. They further compare the results with the impact of conventional units using a capacity and energy equivalency. The reliability indices for the system with wind energy are developed using the same method used by Billinton & Chowdhury (1992). The results are then compared with the reliability indices developed when conventional units are added instead of wind. It was found that for penetration levels than 5%, the impact of wind energy is comparable to the impact of conventional generation.

However, it was also found that for penetration levels greater than 5%, wind energy become less effective in reducing the reliability indices.

The reliability investigation of power systems with wind energy is taken further in (Wen, Zheng & Donghan, 2009). They present new reliability indices to describe the character of wind power, such as Equivalent Capacity Rate and load carrying capacity benefit ratio. The load carrying capacity benefit ratio is defined as the ratio between the peak load carrying capacity of wind and the wind installed capacity. The equivalent capacity ratio is defined as the ratio between the load carrying capability of wind and the load carrying capacity of a new conventional unit with the same capacity rating.

The Equivalent Capacity Rate by Wen, Zheng & Donghan (2009) is also known as the capacity credit of wind energy and is discussed in detail in the following section.

2.4 Capacity Credit

Capacity credit of wind is a useful metric for expressing the degree to which intermittent power can be accounted for. It expresses the amount of installed conventional power that can be avoided or replaced with wind energy. It is also defined as the capability of wind power to increase the reliability of the power system.

There are a range of different approaches for calculating capacity credit; ranging from sequential probabilistic methods, including Monte Carlo simulations to diverse approximation methods (Amelin, 2009). There are three major probabilistic computational methods. All three of these methods require the determination of reliability indices of the power system before the capacity credit can be determined.

The first method is the equivalent firm capacity. The **equivalent firm capacity** of a generating unit is defined as the capacity of a fictitious 100% reliable unit which has the same effect on the reliability of the power system as the installed wind power capacity (Amelin, 2009; DoE, Eskom & GIZ, 2011). The resulting capacity credit is the ratio of the equivalent firm capacity and the installed wind generation. A graphical representation of the equivalent firm capacity is given in Figure 9 (Amelin, 2009).

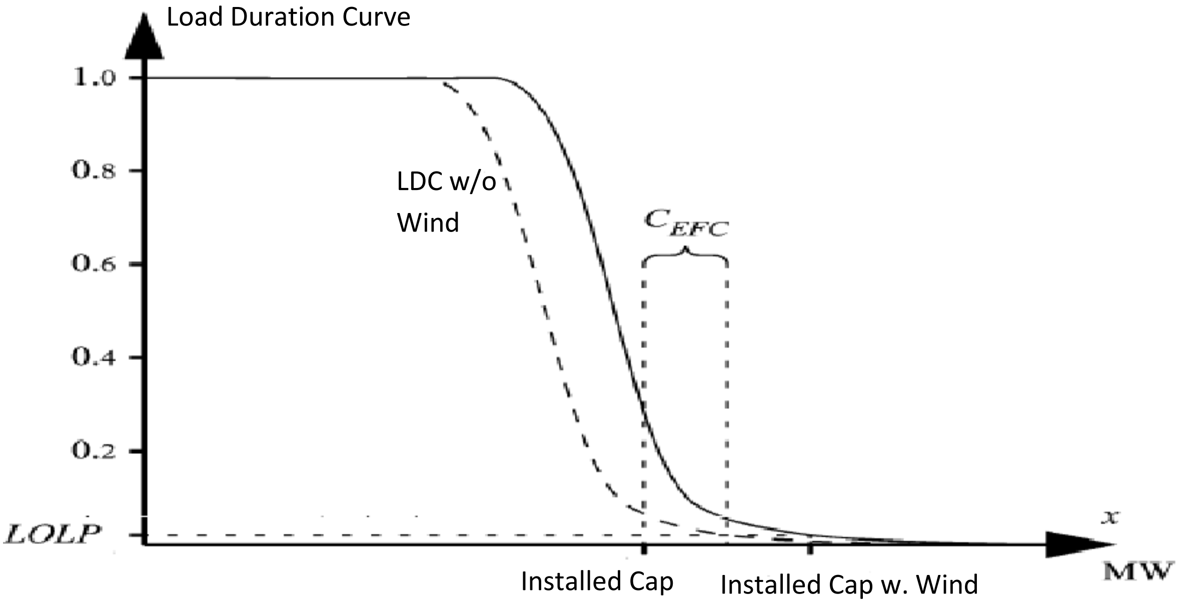

Figure 9 Equivalent Firm Capacity

The second method is the **effective load carrying capability** (ELCC). The ELCC of new generation is defined as the load increase that the system can carry at a specified reliability level (Garver, 1966). It is also easily defined graphically and is shown in Figure 10 (Amelin, 2009). The resulting capacity credit is the ration of the ELCC and the installed wind generation. However, Garver (1966) develops a method that estimates the ELCC for a new unit. The estimation procedure uses a graphical relationship between the ELCC and the characteristics of the unit with system parameter *m*. The parameter *m* is a single number that characterises the annual risk function of the system and is determined from reliability indices.

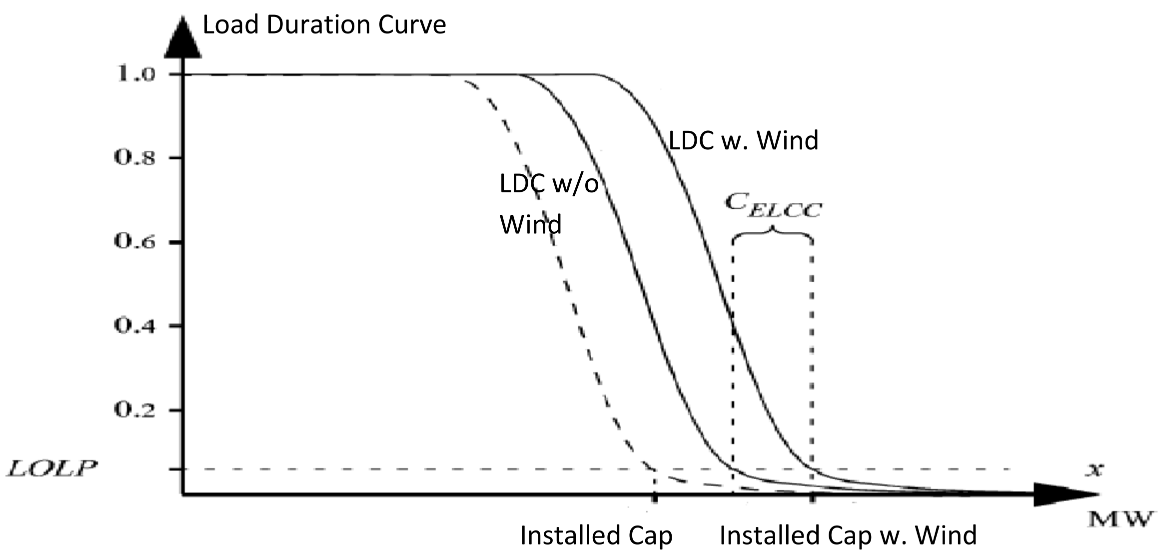

Figure 10 Effective Load Carrying Capability

The third method that involves the reliability indices is the **equivalent conventional power plant**. This method is similar to the equivalent firm capacity method except the fictitious 100% reliable unit is replaced with a reference conventional generation unit (Amelin, 2009).

These three methods are evaluated and compared by Amelin (2009). He found that the variation between the three methods is consistent. He also found that there is a clear correlation between the capacity credit and the reliability indices. The capacity credit of a new unit tends to be higher if it is added to a power system that has low reliability. Another observation is that there is a relationship between the capacity credit and the penetration level of wind generation. It was found that as penetration levels increase, the capacity credit decreases. This relationship will be further investigated in this dissertation, incorporating the effects of geographical dispersion.

Approximation methods for determining capacity credit involve the capacity factor of the wind generation. They generally do not require the direct use of either production cost or reliability modelling or generation data from the conventional generation sources. Milligan & Parsons (1997) evaluates and compares three techniques that approximate the capacity credit using the capacity factor. An effective load carrying capability was determined and used a benchmark for the various methods.

The first technique that is evaluated determines the capacity factor for the top 30% of hourly peak loads. The second method is similar the first except the capacity factors are determined for the hours in which the risk of meeting the load is highest. Essentially, the capacity factors are determined for the hours in which the loss of load probability is highest. The third technique uses the exact same hours that are used in the second. However, this method uses normalised loss of load probability values as weights in order to recognise the hours in which the loss of load probability is most severe. These methods were compared to the benchmark effective load carrying capability by determining the root mean square error between the effective load carrying capability and each technique for every simulation hour. It was found that method 1 and method 2 give the best estimations for the capacity credit.

Another capacity credit estimation technique was developed by Voorspools & D'haeseleer (2006) in "An analytical formula for the capacity credit of wind power". They develop a formula to determine the capacity credit using the capacity factor of the wind resource and the reliability of the system. It is defined by Equation 14 (Voorspools & D'haeseleer, 2006):

$$CC = \alpha \frac{CF_{WIND}}{R_{SYSTEM}} \left(1 + \beta e^{-b(x-1)}\right) \ for\ x > 1\% \,,$$

$$CC = \alpha \frac{CF_{WIND}}{R_{SYSTEM}} (1 + \beta) \ for\ x < 1\%,$$

Equation 14 Analytical formula for Capacity Credit

where CC is the capacity credit (%), x is the penetration level (%), CF_{WIND} is the capacity factor of the wind project (%), R_{SYSTEM} is the reliability of conventional plants (%), α = 37.6, β = 1.843 and b= 0.094.

Furthermore, this technique is sensitive to the penetration level of the wind generation. The formula is extended to cover the dispersion of the wind generation and is given by Equation 15 (Voorspools & D'haeseleer, 2006):

$$CC = \frac{U}{V+\delta}\frac{CF_{WIND}}{R_{SYSTEM}}\left(1 + W\delta e^{-Y(V+\delta)(x-1)}\right) for\ x > 1\%,$$

$$CC = \frac{U}{V+\delta}\frac{CF_{WIND}}{R_{SYSTEM}}(1 + W)\ for\ x < 1\%,$$

Equation 15 Analytical formula for Capacity Credit with Dispersion

where U = 32.8, V = 0.306, W = 3.26 and δ is dispersion coefficient, which is 0 for perfect spread and 1 for no spread.

The capacity credit is an extremely good indicator of how effective wind generation will be on the reliability of a power system. The approximation methods mentioned are effective methods in determining capacity credit as they do not require a lot of simulation effort. Majority of the approximation methods mentioned use the capacity factor of wind energy as an approximation factor. Thus the relationship between the capacity credit and capacity factor has to be investigated. However, the methods that utilise the reliability indices through Monte Carlo simulations are superior.

2.5 Geographical Diversity

The geographical dispersion of wind farms within a wind system has an effect on the capacity credit of the wind system. It can be argued that as the distance between wind farms increases, the wind speed correlation between different wind farms will be begin to fall, having an effect on the capacity credit (DeCarolis & Keith, 2006).

There are various studies that have been performed on the geographical dispersion of wind energy. One of the first comprehensive studies performed on geographical dispersion of wind plants was done by Kahn (1979), who used California's wind and utility data. He found that there is a relationship between geographical dispersion and reliability. Kahn also points out that wind sites that are uncorrelated will generally provide better combined reliability.

Another study that looks at wind energy dispersion is "Reliability benefits of dispersed wind resourced development" (Milligan & Artig, 1998). The aim of this paper is to optimise the dispersion of wind sites based on the reliability of the system. The reliability model used in the study was a load duration curve, "ELFIN", developed by the Environmental Defence Fund. The model used hourly load and generation data to calculate the generation mix required to meet the load. The adequacy indices used in this study are the LOLE and EENS. The paper provides hourly wind power from geographically diverse sites to the electric reliability simulation model. Sites are chosen in such a way as to optimise the dispersion based on reliability. Furthermore, the reliability indices chosen are calculated using two different methods. The first method uses the ELFIN simulation model, whilst the second method used fuzzy logic.

It was found the EENS calculated from fuzzy logic provides the optimal geographical spread of wind farm sites. This is due to the fact EENS is considered to be a more robust measure of reliability. This study does not investigate the effect of geographical dispersion of wind farms, but presents a method in which the geographical dispersion can be optimised, which may be considered in future research.

Levine (2003) investigates how the intermittency of wind energy can be minimised by optimising the geographical dispersion of the wind farms within their data set. A power production model was developed to calculate the mean hourly power production of the wind system with its standard deviation. The wind farm geographical dispersion was then optimised using covariance matrices

This study proved that the intermittency of wind energy can be reduced by optimising the geographical dispersion of wind farms within a wind generation system. It further adds an optimisation method that can be applied to any wind system. Drake & Hubacek (2007) and Traube et al. (2008) also investigate the reduction of wind system intermittency through the optimisation of the geographical dispersion.

2.6 Dispatch Model

The majority of the works that were mentioned in the previous sections all develop a dispatch model in order to investigate the reliability of the power systems they developed, whether it was small or big. However, the development of this dispatch model was not the emphasis of the work and was not reported on. This section presents some of the works that focused on the simulation of the day to day and hour to hour characteristics of a power system with accurate explanations of the developed dispatch models.

Hetzer, Yu & Bhattarai (2008) investigate the effects of wind energy on the classical economical dispatch problem as formulated in Equation 16 through numerical solutions:

$$Minimise\ \sum_i C_{G_i}\ while\ ensuring\ \sum_i P_{G_i} \geq D,$$

Equation 16 Load Balance

where C_{Gi} is the running costs associated with generator i, PGi is the power generation of generator i and D is the electricity demand.

Wind speed functions are characterised using probability density functions. The economical dispatch model is developed so that it is adaptable to all situations. Equation 16 is amended to incorporate various costs. These costs include the cost of conventional generation, the cost of wind generation, the cost of overestimating the wind generation and the cost of underestimating the wind generation. The over and underestimation costs that are included are essentially penalty cost for over and under supplying the system with wind energy.

A Matlab based program with two conventional and two wind energy generators was developed to provide a numerical tool to investigate the effects of wind energy on the economic dispatch problem. It was found that the underestimation cost in the model causes the conventional generators to operate at minimum generation levels until such a point the unit commitment has to be more conservative. At this point, wind generation commitment is decreased, while conventional generation commitment is increase. It was further found that the overestimation cost causes conventional generation to operate at minimum levels, regardless of how high or low the cost it.

This study does not fully investigate the day to day and hour to hour characteristics of a power system.

The four generator model developed does not fully test the load balancing function that is developed. It lacks depth as the convention generation mix is not wide enough to be fully effective. However, it gives a good insight into how the production costs and energy delivery cost may affect a power system.

In “Model predictive dispatch in electric energy systems with intermittent resources” (Le Xie & Ilić, 2008), a model predictive approach is used to allocate the generation resources needed to supply the demand. They explore the potential of using good prediction of renewable energy resources output to solve the economic dispatch problem. The basic concept of a model predictive control is that at each control step, a finite-horizon optimal control problem is solved. This concept is applied to the economic dispatch problem by selecting a moving time horizon and solving the dispatch problem for each time horizon. A time horizon may be set to be a day or the peak hour of demand disaggregated in 5 minute intervals.

The model predictive approach is tested on a 12-bus system with five generator plants of representative types. The five plants are two base load plants, one peaking plant and two renewable energy plants. Each plant is characterised by its short run marginal cost, installed capacity and ramp rate constraints. The developed approach is compared to conventional methods of solving the dispatch problem, one of which is explored in “Risk Assessment of Wind Generation Dispatch Using Monte Carlo Simulation” (Shaaban & Usman, 2013). It was found that the developed approached enables the base load coal plant to operate at higher generation levels, reducing the natural gas generation, while the intermittent energy resources meet the fluctuating load.

The developed approach essentially uses the intermittent resource as a means to follow the demand fluctuations, while base load plants are used to meet the majority of the demand. This approach is effective as it allows less use of expensive peaking plants, which decreases the generation cost to meet demand.

One of conventional methods available to solve the economic dispatch problem is used by Shaaban & Usman (2013) in “Risk Assessment of Wind Generation Dispatch Using Monte Carlo Simulation”.

Monte Carlo simulation is used to produce reliability indices for power systems with wind generation. The reliability indices used in this study are LOLP, EENS and the capacity credit of wind. They utilise a capacity outage distribution table (COPT) to determine the available conventional generation in the system. This table is convolved with an appropriate system load to obtain the reliability indices for a system without wind generation. The wind generation is determined using a multistate wind turbine generator model. The multistate variables are generated using the mean wind speed and its standard deviation of a given location.

The developed Monte Carlo simulation method is tested on Roy Billinton Test System, which consists of 11 conventional generating units with a total installed capacity of 240MW. The annual peak load of the system is 185MW. In determining the reliability indices for the test system with wind generation, a certain amount of capacity of conventional generation is withdrawn from the system and is replaced with an equal amount of wind generation. A capacity credit of 30% is determined. It was further found that as the penetration levels of wind energy increase, the reliability of the system decrease. This compliments previous mentioned works in the preceding chapter and the research statement of this dissertation.

Hargreaves & Hobbs (2012) propose a stochastic dynamic programming approach that use a shorter time step to better capture ramp rates limits and a stochastic process representation of wind output. Two investigation are carried out in this paper, which are firstly what is the upper bound to the value of better wind forecasting and secondly, what is the value of stochastic unit commitment and dispatch relative to decision making based on deterministic models. These investigations are carried by comparing the proposed approach with two other unit commitment models, one of which is similar to the approach used by Shaaban & Usman (2013). These two models are deterministic models solved using Monte Carlo simulation, while the other model uses a heuristic rule for commitment and dispatch decisions.

The proposed stochastic model is a stochastic optimization that identifies an optimal strategy, defined as the immediate decision, for each system operating state at each time stage that minimises expected future costs. Each stage includes electricity demand, wind and conventional generation, commitment status of each unit and the amount of energy that is stored. Demand and wind are assumed to evolve over time according to a Markov process. The developed approach was tested on a Netherlands case study. It was found that the operation cost of the developed approach lie between the deterministic model and the heuristic model, with the deterministic approach producing the cheapest operation costs. However, this is due to the fact that in the deterministic model, the future wind conditions are known, therefore commitment and dispatch can be well planned.

This study does not reach the investigation goals that were set out. The initial goals of the paper are ambiguous as the values of each goal were not defined. However, it gives insight into the effects that wind generation has on the power system operation cost.

Huber (2011) presents a mixed integer quadratic program that models electric grid behaviour with high wind and solar capacities to predict US grid CO_2 emissions reduction and overall generation costs.

The dispatch model within the program mimics a competitive electricity market by dispatching conventional generation units to minimise the hourly operating cost. The dispatch model further incorporates the efficiency corrections of part-load operations, ramping constraints, minimum generation levels, and the cost of cycling for the different generation technologies.

The model is tested on the Arizona-New Mexico-South Nevada electrical grid. Three two week periods were chosen to be modelled, which represent pre-peak demand, peak demand and post peak demand. Furthermore, there are various assumptions made in testing this model, the first being that the grid can freely export power to other grids or curtail wind and solar energy. The second assumption is that the conventional generators do not anticipate future load or renewable energy production.

In relation to the primary objective of Huber's dissertation, there are several conclusions that can be made from the results. One of these is that wind and solar can reduce CO_2 emissions by 50% based on 2008 levels and 35% based on 1990 levels. The cost of achieving these emissions reduction is between 50% and 175% depending on the renewable generation mix. However, the optimum generation mix for lowest cost and max emissions reduction is 50% solar, 25% wind and 25% nuclear.

Wang & Baran (2010) develop and investigate a Monte Carlo based production cost simulation. The developed model simulates realistic processes of system planning and operations and takes wind generation into account. In this paper, the main objective of the model is to investigate the reliability of power generation system integrated with wind energy. However, the model can also be used to investigate the effects wind generation forecasting, system reserve requirement, capacity credit of wind energy and many more power system variables and parameters.

In order to accurately model operational procedures for a power system, unit commitment of conventional generation units are determined through day-ahead modelling based on forecasted demand and wind generation. Forecasted wind generation is determined through using auto-regressive moving average forecasting based on historical values.

Two systems were compared on the same demand profile, one with only conventional generation and the other with wind energy incorporated. The investigation compliments previous works in the previous chapter, where it was found that for low wind energy penetration levels, system reliability is improved, whilst for high wind energy penetration levels, wind energy is not as effective. The investigation also showed the importance of accurate wind forecasting. It was shown that for better quality wind forecasting, the more reliability benefit on the system.

The model developing by Wang and Baran (2010) is extremely effective as it can be applied to investigate the various reliability indices that were discussed in previous sections. Furthermore, this model is used as a basis for the model developed in this dissertation. The model developed and the steps taken to develop it are discussed in detail in later chapters.

2.7 Recent Work

There are various study that incorporate all the aspects that have been discussed in this literature survey. One of these studies is "Capacity credit of wind generation is South Africa" (DoE, Eskom & GIZ, 2011).

This was a project commissioned by the Department of Energy, Eskom and the Deutsche Gesellschaft fur Internationale Zusammenarbeit (GIZ). The aim of this paper is to determine how much conventional generation would be needed in a South African power generation system with high amounts of wind generation. This study presents the simulation results of the investigation carried out to assess the capacity credit of planned wind farms in South Africa. There are three scenarios that are investigated. The first scenario is carried out in the year 2015, with 2000MW installed wind capacity. The second scenario is carried out in 2020, with 4000MW of installed wind capacity and the third scenario is also carried out in 2020, but with 10,000MW of installed wind capacity. The wind generation simulations were performed by Windlab Systems, while the load and conventional generations were performed by Eskom. The capacity credit for these three scenarios was calculated using the equivalent firm capacity technique described earlier through Monte Carlo Simulations.

Scenario 1 produced a capacity credit of 26.8%, scenario 2 produced a capacity of 25.4%, while scenario 3 produced a capacity credit of 22.6%. These results further compliment the findings of previous work, where it was found that the capacity credit of wind generation decreases with increased penetration. The results are further compared with the capacity credit of thermal units.

Essentially they are adopting the equivalent conventional generation capacity that is discussed earlier. The capacity credits determined using the equivalent capacity method are generally 5% higher.

Another study that incorporates majority of the aspects presented in this review is "Planning for large-scale wind and solar power in South Africa: Identifying cost-effective deployment strategies through spatiotemporal modelling" (Ummel, 2013). The main objective of this paper is to demonstrate the potential for new data and modelling techniques to capture the spatiotemporal dynamics critical to power system with high renewable energy. It focuses on South Africa and addresses it in two parts; firstly by generating expected generation efficiency for key renewable technologies at hourly resolutions. Secondly, a power system model is developed to simulate the economic and environmental performance of the renewable technologies in the year 2040.

Renewable energy resource data is obtained over a 10 year period by combining output from NASA's Goddard Earth Observing System (GEOS-5) climate model with solar irradiance data from the Climate Monitoring Satellite Application Facility (CM-SAF) with data produced from WASA. The resource data is run through the National Renewable Energy Laboratory's System Advisor (SAM software) to develop the generating efficiencies. Spatiotemporal patterns are developed by excluding areas that are deemed to be infeasible using screens developed in Ummel's Master's dissertation (Ummel, 2011).

The results presented in this study indicate the majority of wind energy developed in the Northern, Western and Eastern Cape. This may be caused by the inclusion of WASA in the resource data. Furthermore, the penetration levels in Western Cape are slightly higher than the penetration level in the Eastern Cape, which disagrees with REIPPPP round 1 and 2 project sites.

2.8 Conclusion

The modelling of wind energy is one of the most important aspects of this dissertation. Some techniques for modelling wind resource have been presented in this review. Furthermore, there has been extensive work done on reliability evaluation techniques for power system with and without wind generation. However, the past studies that were discussed only apply reliability techniques systems that represent European and U.S markets and systems. With the information obtained from these studies, a solid investigation can be performed for the South African market and power system.

In the South African context, work has been done on the capacity of wind energy with the DoE, Eskom & GIZ (2011) study, along with a dispatch model that optimises WSP deployment in South Africa to minimise generation cost incorporated with CO2 mitigation parameters by Ummel (2013). There is space for further research as the Ummel and DoE, Eskom & GIZ study do not incorporated the effects of geographical dispersion on the capacity credit of wind energy. Furthermore, these studies aim to quantify the capacity credit of wind in South Africa and do investigate the factors that affect the capacity credit.

Thus, it is clear that there is an opportunity to optimise long term energy planning is South Africa. This study will embark on investigating the effects of geographical dispersion and penetration level on the capacity credit of wind energy in South Africa.

Furthermore, these capacity credit factors will be used to investigate their effects on the reliability of a power generation system similar to that of South Africa through the means of a dispatch model. While similar studies have been performed, this study is unique in the sense that it focuses on the South African context, based on the REIPPPP. The methodology behind these analyses will be discussed in detail in the following chapters.

Chapter 3

Methodology – Wind Generation

3.1 Introduction

The performance of renewable power technologies is largely determined by meteorological conditions. The performance of a wind farm is based on the wind resource available at the site. In order to accurately model a wind farm, there are various factors that need to be considered. Some of these major factors are the type of wind turbine that is utilised in the model and the quality of wind data that is analysed as mentioned in the previous chapter. Furthermore, the previous chapter presents numerous studies that focus on wind energy modelling.

The development of an accurate wind energy model is one of the most important steps in analysing the capacity credit of wind energy. The wind model developed in this dissertation is presented in this chapter.

3.2 Data Collection

The first step in wind generation modelling is the collection of data. Due to the proprietary nature of wind data, attaining it proved to be challenging, especially from the project developers that obtained preferred bidder status in round 1 and 2 of the REIPPPP.

The South African Weather Services (SAWS) wind data was obtained at locations closest to the projects. However, due the measurement techniques of SAWS wind masts, the wind data is fairly unreliable. Furthermore, wind analysis is site specific. Actual time series data is needed from the REIPPPP project locations. Therefore, wind data from WASA is utilised. WASA has 10 wind measurement sites as shown in Figure 7. At these 10 sites, there are 60m high measurement masts that measure meteorological data that can be downloaded from http://wasadata.csir.co.za/wasa1/WASAData.

Unfortunately, the data set for wind mast 9 and 10 is not complete and had to be excluded in the analysis. The remaining 8 wind measurement sites do not provide a reasonable amount of geographical dispersion for analysis. Combining the data set from SAWS and WASA would provide a reasonable amount of geographical dispersion, but decrease the reliability of the results. This is considered to be an acceptable loss as one of main aims of this study is to investigate the effect that geographical dispersion has on capacity credit. Figure 11 shows the locations of the WASA sites combined with the REIPPPP project locations, while Table 2 shows the installed capacities of the farms.

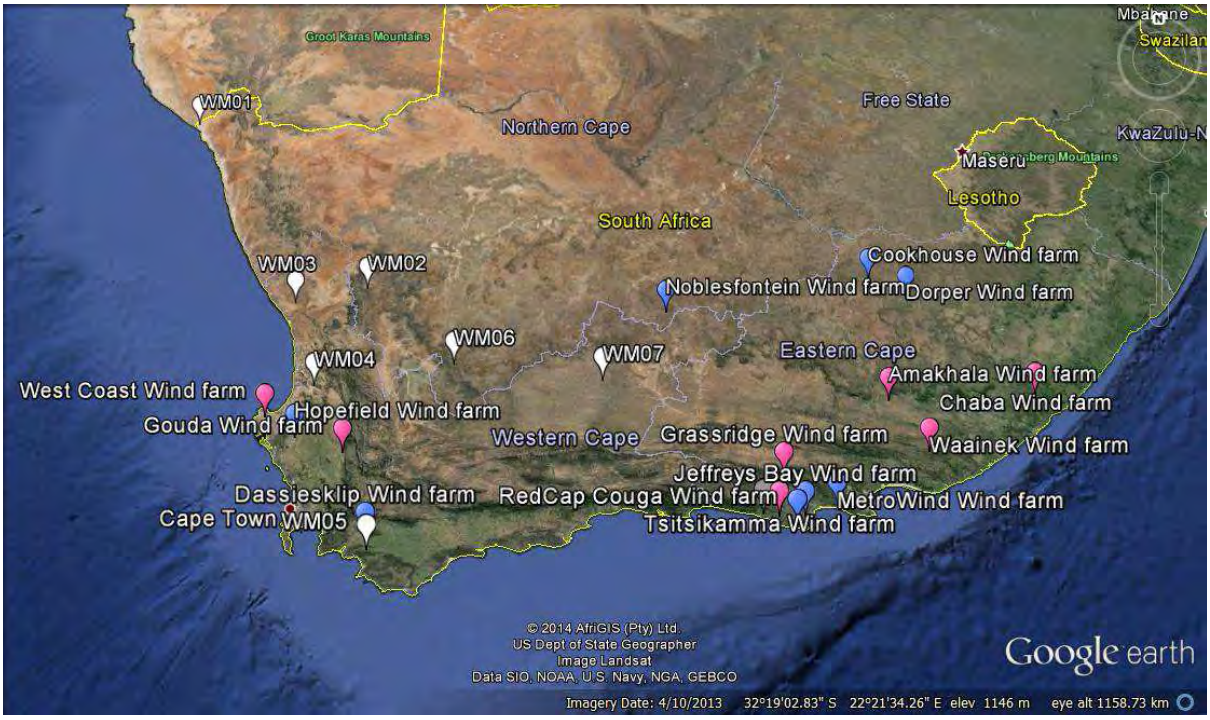

Figure 11 REIPPPP and WASA Farm sites

Table 2 REIPPPP and WASA sites

Source[1]		**Wind Farm**	**Location**	**Capacity [MW]**
WASA		WM01	Northern Cape	89
WASA		WM02	Northern Cape	89
WASA		WM03	Western Cape	66
WASA		WM04	Western Cape	67
WASA		WM05	Western Cape	67
WASA		WM06	Northern Cape	88
WASA		WM07	Western Cape	67
WASA		WM08	Eastern Cape	267
SAWS	REIPPPP round 1	Hopefield Wind	Western Cape	65
SAWS	REIPPPP round 1	Dassiesklip Wind	Western Cape	27
SAWS	REIPPPP round 1	Noblesfontein Wind	Northern Cape	75
SAWS	REIPPPP round 1	Dorper Wind	Eastern Cape	100
SAWS	REIPPPP round 1	MetroWind	Eastern Cape	27
SAWS	REIPPPP round 1	Jeffreys Bay Wind	Eastern Cape	138
SAWS	REIPPPP round 1	Red Cap Couga Wind	Eastern Cape	80
SAWS	REIPPPP round 1	Cookhouse Wind	Eastern Cape	139
SAWS	REIPPPP round 2	West Cost Wind	Western Cape	91
SAWS	REIPPPP round 2	Gouda Wind	Western Cape	135
SAWS	REIPPPP round 2	Tsitsikamma Wind	Eastern Cape	95
SAWS	REIPPPP round 2	Grassridge Wind	Eastern Cape	60
SAWS	REIPPPP round 2	Waainek Wind	Eastern Cape	23
SAWS	REIPPPP round 2	Amakhala Wind	Eastern Cape	138
SAWS	REIPPPP round 2	Chaba Wind	Eastern Cape	21
			Total	**2014**

1 – From Figure 11 place markers, Pink = REIPPPP round 1; Blue = REIPPPP round 2; White = WASA

From Figure 11, a total of 23 sites spread across the Eastern, Western and Northern Capes of South Africa. Hourly wind data for 2011 and is obtained. Hourly wind speed is shown in Figure 12 for one of the wind masts. Detailed analysis of the wind sites is presented in the appendices.

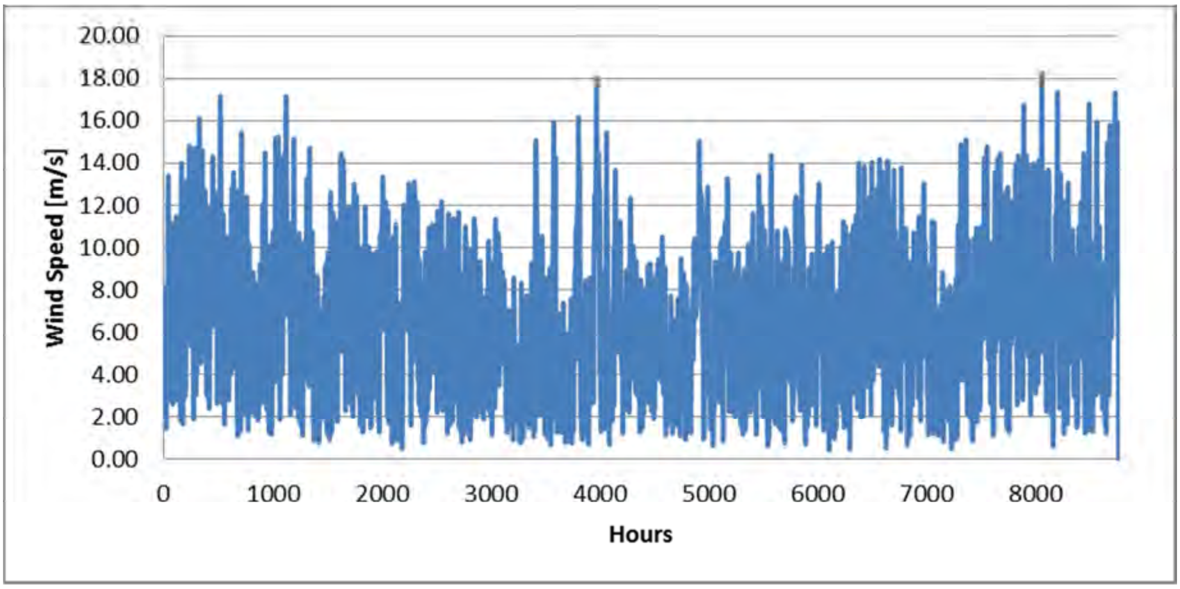

Figure 12 Hourly Wind Speeds

Due to the unreliable data acquired, some of the time series data is discarded, leaving a remaining of 12 wind farms from the original set of 23 as shown in Table 3 and Figure 13.

Table 3 Analysed Wind Farms

Source[1]		Wind Farm	Location	Capacity [MW]
WASA		WM03	Western Cape	168
WASA		WM04	Western Cape	168
WASA		WM05	Western Cape	168
WASA		WM07	Western Cape	168
WASA		WM08	Eastern Cape	168
SAWS	REIPPPP round 1	Hopefield Wind	Western Cape	168
SAWS	REIPPPP round 1	MetroWind	Eastern Cape	168
SAWS	REIPPPP round 1	Jeffreys Bay Wind	Eastern Cape	168
SAWS	REIPPPP round 1	Red Cap Couga Wind	Eastern Cape	167
SAWS	REIPPPP round 2	West Cost Wind	Western Cape	167
SAWS	REIPPPP round 2	Tsitsikamma Wind	Eastern Cape	168
SAWS	REIPPPP round 2	Waainek Wind	Eastern Cape	168
			Total	**2014**

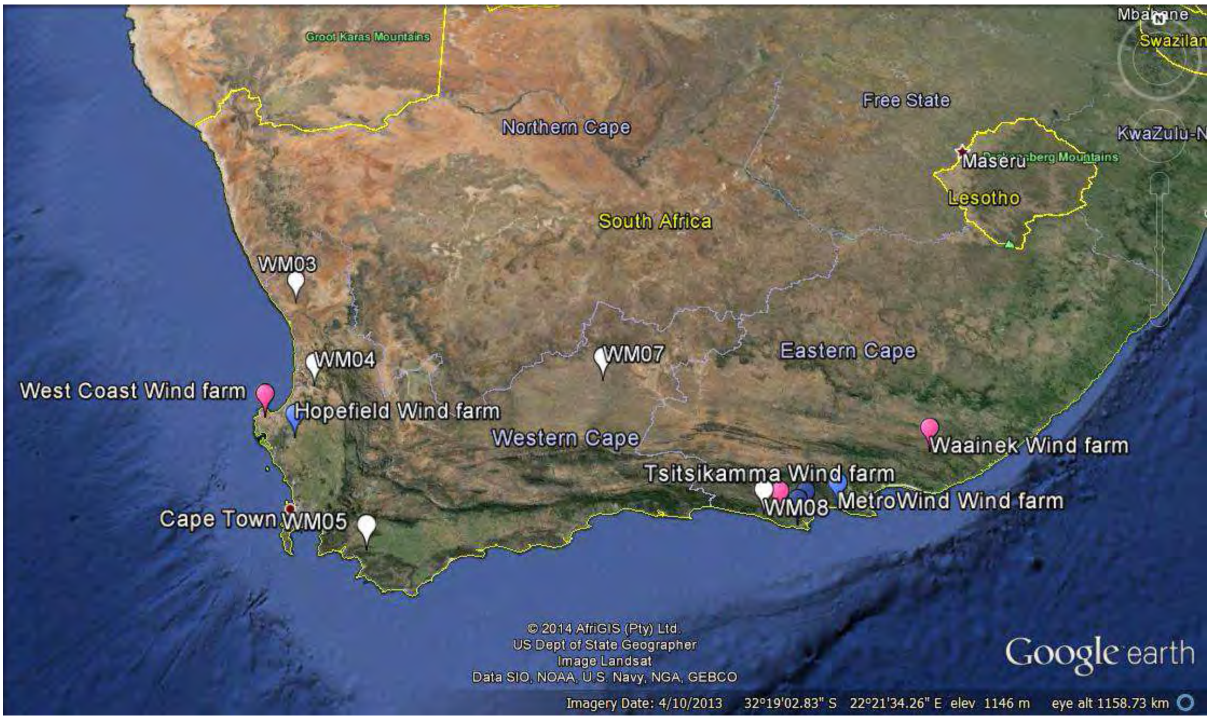

Figure 13 Analysed Wind Farms

These remaining wind farms were used both in the capacity credit and dispatch model investigations. However, the installed wind capacities had to be altered in order to maintain the total installed wind capacity as shown in Table 3.

3.3 Power Production Model

In order to assess the power output of a wind system, the data sets of wind speed have to be converted in power generation from the wind turbines. This can be accomplished through the following steps:

1. Obtain wind speed data
2. Import wind speed data
3. Align the sampling period of the data sets
4. Pick a turbine
5. Power Curve Calculations
6. Adjust the wind speeds to the hub height of the turbine
7. Power Production

In order to simplify the model as much as possible, the power production model is built in Microsoft Excel.

3.3.1 Obtain Wind Speed Data

The previous section describes the process that was used in obtaining wind speed data for analysis. Both organisations mentioned in the data collection section were pivotal in the ability to do this analysis. Actual Time series data is utilized to develop wind generation within the system rather than a multiple-state function. This is due to the fact the diurnal trends of wind generation is better represented with actual time series data.

3.3.2 Import Wind Speed Data

Wind speed data from different organisation is received in the different formats. Depending on the format of the original data set, the import function had to be adjusted in order to capture in a usable format.

3.3.3 Adjust Sampling Periods of data sets

The data that was obtained sampled wind speeds on ten-minute periods and on hourly periods. The analysis of wind speeds in this paper is conducted on an hourly period. All data sets that are sampled on ten-minute periods were converted to an hourly period. This was achieved by taking the hourly mean average of more frequent samples, and reporting the average at the beginning of each hour. Since the model was developed in MS Excel, the offset function was used in conjunction with mean average function to develop these values.

3.3.4 Turbine Selection

In order to simplify the model, one turbine model is utilized to analyse the different measurement sites. This is supported by the fact all wind measurement sites fall within the same wind class of Wind Class II, as described in the previous chapter. Furthermore, wind turbines are designed for the different wind classes. The chosen turbine is a Vestas V90 2MW turbine (Vestas, 2012), with operational data given in Table 4.

Table 4 Vestas V90 2MW Operational Data

Cut in Speed [m/s]	4
Rated Speed [m/s]	12
Cut out Speed [m/s]	25
Hub Height [m]	80
Rotor Diameter [m]	90
Swept Area [m^2]	6 362

The turbine power curve is developed from Equation 10 with the operating data and is shown in Equation 18 and Figure 14. Using Microsoft Excel and the power function described by Equation 9, hourly wind farm power outputs were estimated for each project:

$$A = \frac{1}{(4-12)^2}\left[4(4+12) - 4(4\times 12)\left(\frac{4+12}{24}\right)^3\right],$$

$$B = \frac{1}{(4-12)^2}\left[4(4+12)\left(\frac{4+12}{24}\right)^3 - (3\times 4+12\right],$$

$$C = \frac{1}{(4-12)^2}\left[2 - 4\left(\frac{4+12}{24}\right)^3\right].$$

Equation 17 Power Curve Coefficients (values)

The resultant values of these power curve coefficients of Equation 17 are as following;

A = 0.1111; B = -0.079; C = 0.0127.

This gives a resulting power curve of Equation 18:

$$P_t = \begin{cases} 0 & 0 \leq v \leq 4 \\ (0.1111 - 0.079v + 0.0127v^2)2000 & 4 \leq v \leq 12 \\ 2000 & 12 \leq v \leq 25 \\ 0 & v \geq 25 \end{cases} .$$

Equation 18 Simulation Turbine Power Function

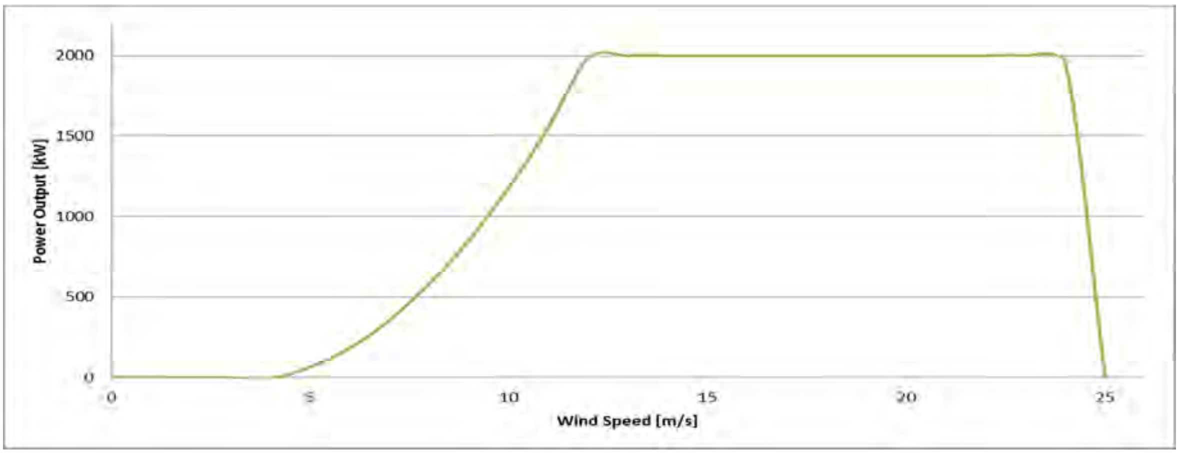

Figure 14 Simulation Turbine Power Function

3.3.5 Adjust Wind Speeds for hub height

Wind speed data from WASA and SAWS were given at heights of 60m and 10m above the ground respectively. The hub height of the chosen turbine is 80m. All measurements had to be scaled up to 80m. The wind speeds were adjusted for height using the one-seventh-power rule, which is expressed in Equation 19 (Masters, 2004):

$$\frac{V}{V_o} = \left(\frac{H}{H_o}\right)^{\alpha},$$

Equation 19 One-Seventh-Power Rule

where V = wind speed at height H; V_o = wind speed at height H_o; and α = the friction coefficient of the terrain.

3.3.6 Power Production

The relation between wind speed and power output is shown in Figure 14. Feeding in the hourly wind speed into Equation 18, the hourly power production for each site can be determined. The analysis of individual sites will be shown in the appendices. However, a summary of this analysis will be presented in the results chapter

3.4 Assumptions

In developing the model presented in the previous section, certain assumptions were made. These assumptions are summarised in this section in Table 5.

Table 5 Wind Generation Assumptions

	Assumption	Rationale
Turbine Selection	One Turbine was utilised for power production	All the selected sites fall within the same wind class. In order to simplify the model, one turbine was selected for power production
Elevation	All wind measurement sites were assumed to be at sea level	Majority of the wind measurement sites are located below 500m above sea level. The difference in air density is considered to negligible.

3.5 Conclusion

The power production model is developed in this chapter. In order to accurately analysis the South African wind energy system, wind data was obtained from SAWS and WASA. Unfortunately the SAWS data is not as reliable as expected reducing the reliability of the results produced by the power production model. In order to overcome this, the unreliable data was excluded from the simulations in order to maintain the integrity of the model. This data is run through the power production model, which is function of the wind data, power function of the chosen turbine, and the hub height of the chosen wind turbine. The chosen wind turbine is the Vestas V90 2MW wind turbine.

The key assumptions made in developing this model are firstly all wind sites are at the same altitude. This assumption is based on the fact that majority of the wind sites are below 500m above sea level. The second key assumption is that the same wind turbine is used at all wind sites. This is based on the fact that all the wind sites are within the same wind class.

There are two models developed in this study that use the output of the power production model. The first model is the capacity credit model, which develops a multi-state function of the wind power output. The second model is the dispatch model, which uses actual wind generation from the model to develop diurnal generation profiles. These two models are further described in the following chapter

CHAPTER 4

Methodology – Dispatch Model and Capacity Credit

4.1 Introduction

The main goal of this dissertation is the investigation of the geographical diversity and penetration of wind farms on the capacity credit of wind in the South African power generation system.

The overall research approach used in this dissertation is stochastic simulation and system analysis of a power system resembling the South African power system with and without wind generators. Stochastic simulation is often used in modelling systems that incorporate random behaviour. It considers the uncertainty within the system through probability theory. Stochastic generation systems are commonly described through probability and cumulative distributions from previously obtained load data.

Due to the random nature of wind generation, stochastic simulation is the only viable approach. Stochastic simulation were used to determine the following outcomes

- The Effective load carrying capacity (ELCC) of the conventional generation system at a predefined reliability level
- Available wind capacity online at the same reliability level at different times of the day
- The capacity credit of wind using the ELCC as a metric to investigate the effects of penetration levels and geographical distribution.

These outcomes were determined with a final goal in mind; which is to graphically illustrate the correlation between the capacity credit and penetration levels, and capacity credit and geographical distribution. The methodologies behind the determination of these outcomes are described in this chapter in detail.

A dispatch model of a resembling the South African power system with and without wind was developed to test the results of the capacity credit estimates and also calculate other relevant other performance indices of the system with and without wind.

4.2 Capacity Credit

The Capacity Credit helps evaluate the value of variable generation to a power system. The capacity credit of a potential wind generation system is investigated by varying the penetration levels and geographical distribution of wind generators. The capacity credit has multiple definitions as stated earlier. In this dissertation, it is defined in two ways:

Definition 1: The capacity of ***equivalent conventional thermal power*** that can be replaced by wind without compromising the system reliability.

Definition 2: The capacity of ***equivalent firm capacity*** that has the same effect as wind on the system reliability.

The parameter that is utilised to show effect on reliability is the ELCC. The ELCC method was first derived by Garver (1966), who used the LOLP to quantify and graphically estimate the load carrying capacity of new generator unit as shown in Figure 15. Garver (1966) initially chose a desired reliability level for the system as a standard for the new system.

The system was then tested to evaluate the reliability of the system at different loads, developing a reliability distribution. A new generator unit is then added to the system and the reliability distribution is developed again. The LCC of the new generator unit is the load increase that the system can carry at the specified reliability level.

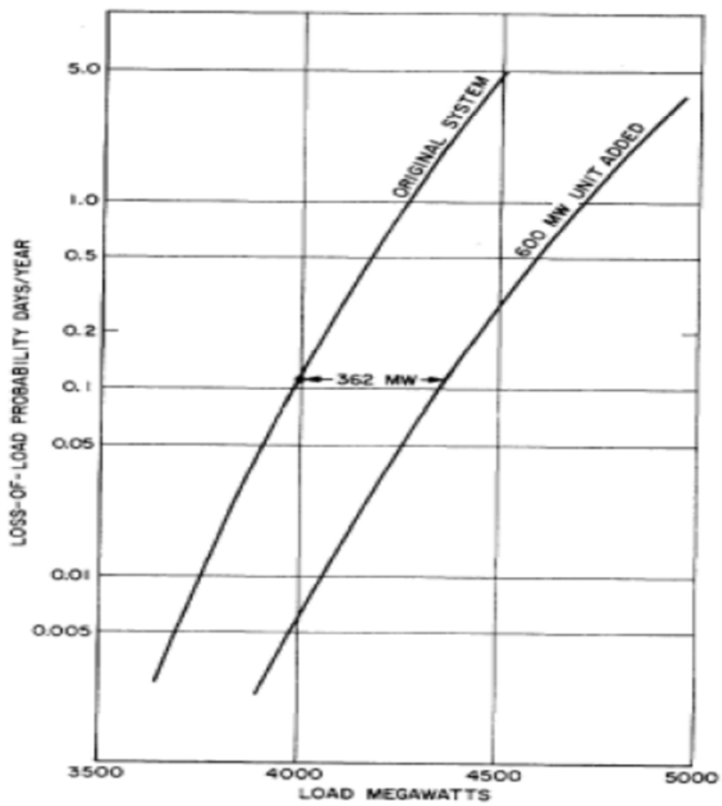

Figure 15 LCC of a new generator unit

The capacity credit calculation method derived in this dissertation is similar to the method developed by Garver (1966). Originally, capacity outage tables based on the FOR of each generation technology were used to evaluate the original system and develop the systems ELCC. In this study, the ELCC is defined as the maximum load or demand that the generation system can confidently carry or meet at a specified reliability target. However, due to the different unit sizes for each generation technology, the loss of load probabilities of the different technologies could not added together at the specified reliability level.

This method overestimated the probabilities of outages. Therefore, in order to counteract this effect, each generation unit within the system needs to be considered. Therefore, the only plausible evaluation methodology available is the method developed by Garver.

Garver's (1966) methods are applied to three systems:

1. The existing system comprising of conventional generation units
2. The existing system with additional wind generation units
3. The existing system with additional equivalent conventional generation units that give the same change in ELCC as the system as wind generation.

4.2.1 Conventional Generation System ELCC

The existing conventional system is evaluated through the comparison of the available online capacity with demand. This was achieved through the usage of an LOLP calculator developed by the University of Cape Town Energy Research Centre.

The LOLP calculator treats each unit as a binary unit to determine its availability. It simulates the outages of discrete units by sampling from a uniform distribution between zero and one. In each simulation, a unit is "out" if the number sampled is less than the respective FOR of each unit, "available" otherwise as shown in equations 6. The FOR's for the various technologies within the system are given in Appendix B:

$$x = rand()$$
$$x < FOR|OFFLINE\ ,$$
$$x > FOR|ONLINE$$

Equation 20 LOLP calculator outages Simulation

where x is a random variable between 0 and 1.

The total system's available capacity is simply the sum of the available units. If the system's available capacity is less than the peak, then loss of load occurs. The LOLP is then the number of failures over the total number of simulations (several thousand simulations). By initially setting the peak demand equal to the capacity and then slowly decreasing it, each time calculating the LOLP, the "reliability distribution function" for the system can be generated. Figure 16 shows the inverse of the reliability distribution function for a system consisting of 43 470 MW of power generation. This curve can be used to identify the maximum load carrying capacity of the system at the desired reliability level.

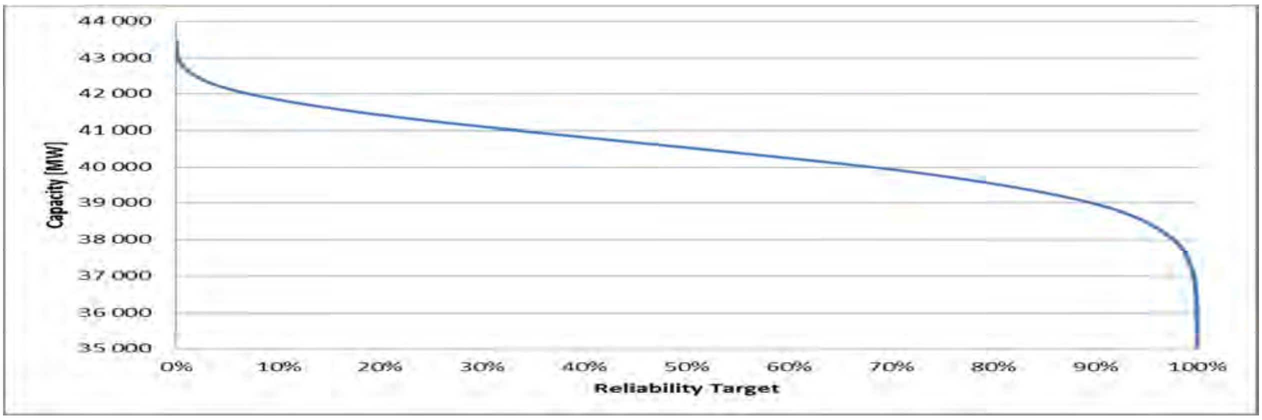

Figure 16 Reliability Distribution

The reliability target set in this dissertation is 90%**.** Therefore, at 90% reliability, the ELCC of the system is 38 970MW as shown in Figure 17 and Table 6.

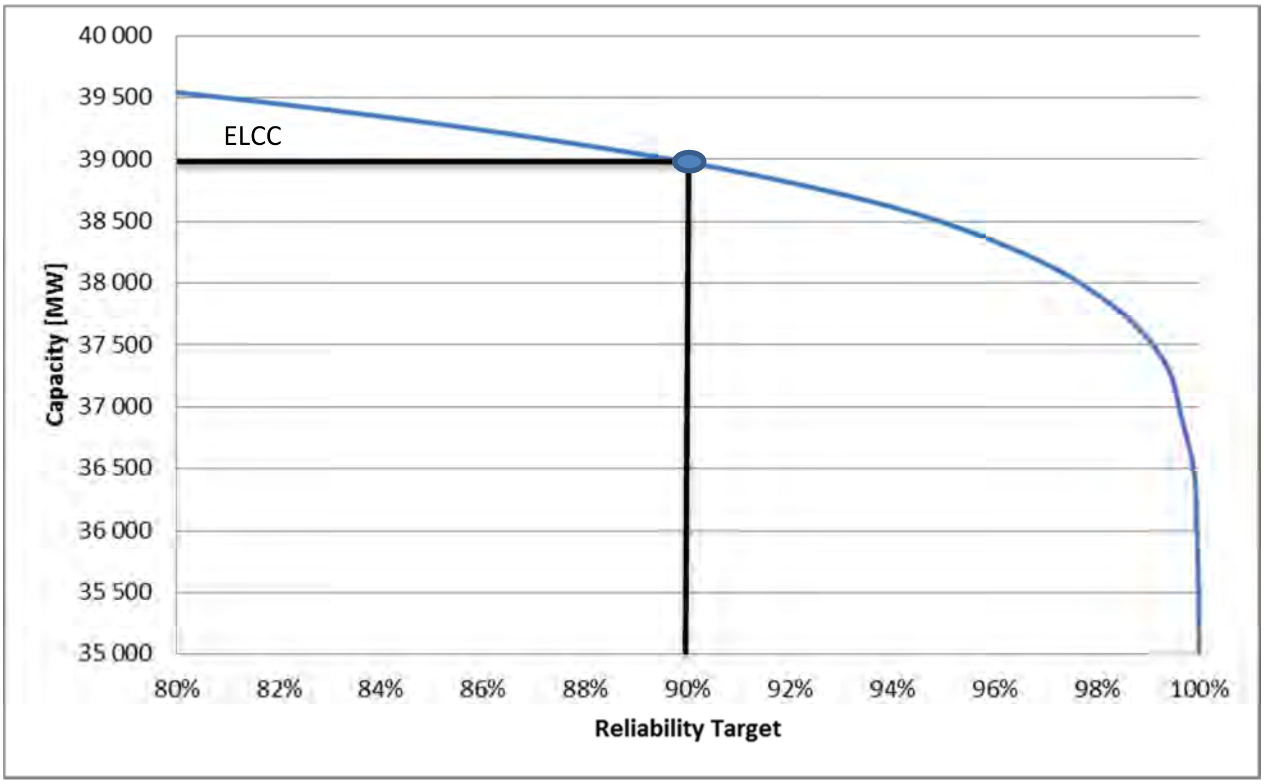

Figure 17 ELCC Determination

Table 6 ELCC Determination

ELCC Existing System	
Total Installed Capacity	43 470 MW
Reliability Target	90%
ELCC	38 970 MW
ELCC %	89.72%

4.2.2 Wind Generation

The method utilised for conventional generation cannot be used for variable generation such as wind. This is due to the fact that wind generation does not have a defined FOR, thus available online capacity cannot be determined. Furthermore, this is also due to the fact that wind generation depends on random meteorological patterns. Therefore, in order to incorporate wind generation into the system, distributions have to be developed from yield data from the previous chapter.

In each simulation a random number is sampled from a uniform distribution between zero and one. The distributions are then used to map the random number to a power output from wind for that simulation. The distributions for wind generation power output are shown in Figure 18 and Figure 19. Furthermore, wind generation is time dependent and varies seasonally. these distributions can be developed for specific time subsets and for the different seasons.

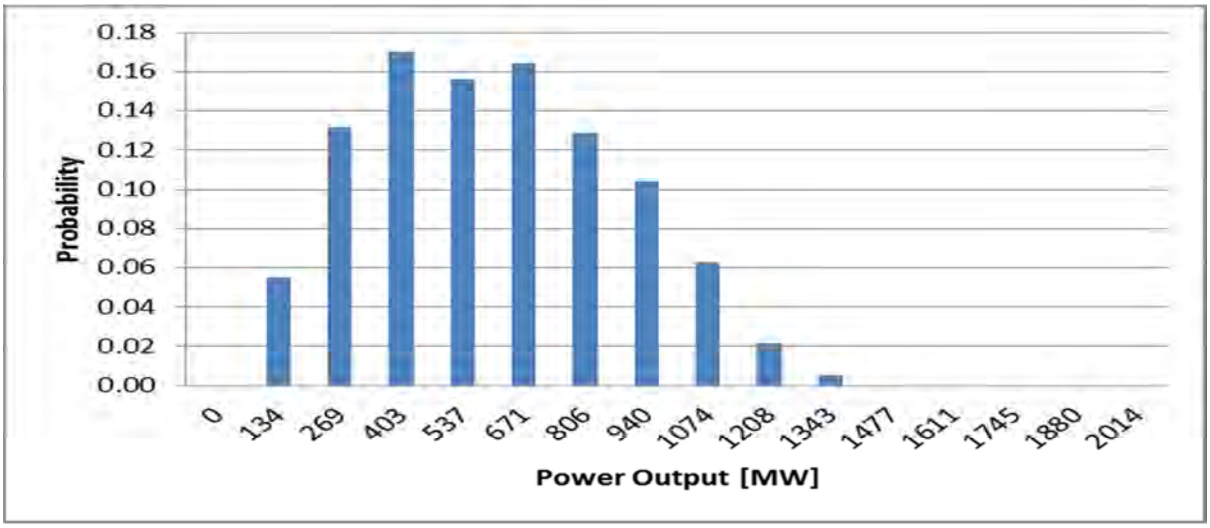

Figure 18 Wind Power Output Histogram

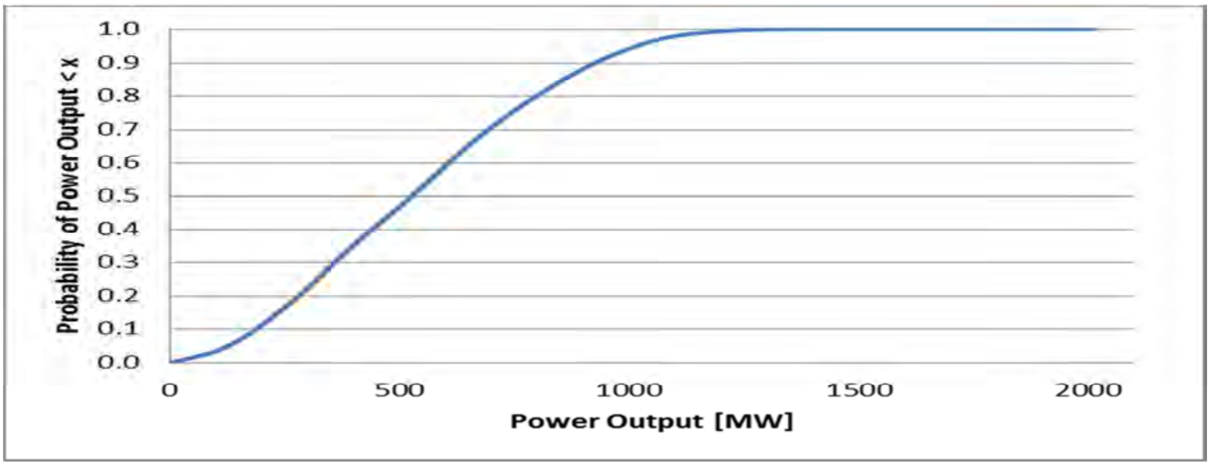

Figure 19 Wind Power Output CDF

While the information provided by the above distributions is valuable, for the purpose of capacity credit calculation, the percentage chance of having more than a particular capacity is more relevant. Therefore, the inverse of the CDF is used as shown in Figure 20. The distribution in Figure 20 is then used to map the random generated numbers to a power output.

The process in section 4.2.1 is repeated for the two systems developed in this dissertation to produce new reliability distributions and ELCCs.

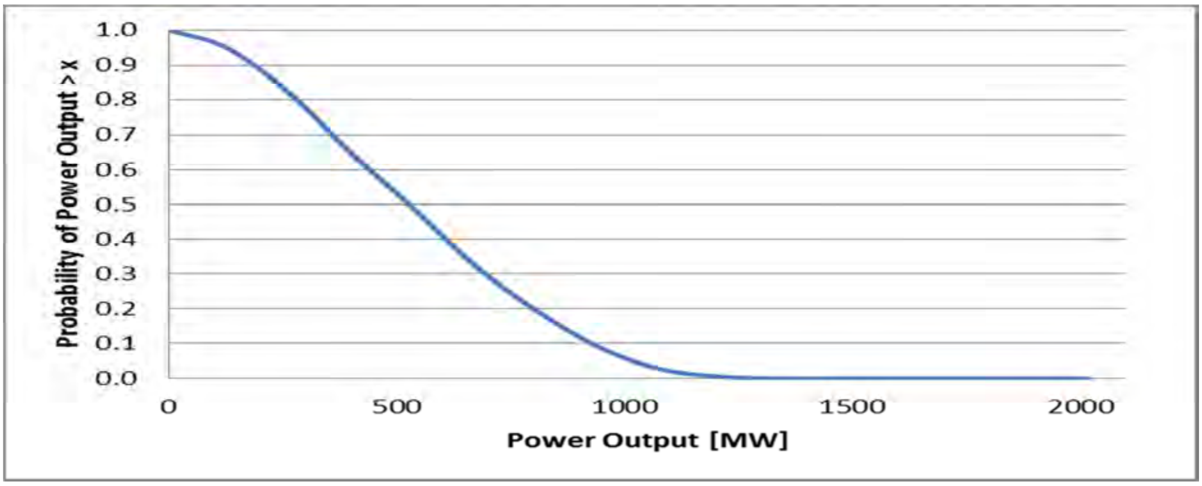

Figure 20 Inverse CDF

4.2.3 Capacity Credit.

The capacity credit defined earlier is illustrated in Figure 21. In Figure 21, the addition of thermal capacity increases the ELCC of the system. The capacity credit of wind generation is the percentage of the wind capacity that increases the ELCC by the same amount as added thermal capacity as shown in Equation 21:

$$ELCC(cc \times C_{WIND}) \equiv ELCC(CF_{THERMAL}),$$

Equation 21 ELCC Balance (Thermal Equivalent)

where cc is Capacity Credit, C_{WIND} is installed wind capacity and $CF_{THERMAL}$ is the added thermal capacity.

In order to be able to compute the ELCC for added $CF_{THERMAL}$, it needs to be equal to a round number of thermal units. The solution to this problem is to find the closest round number of units of firm capacity that matches the change in ELCC. In addition, since the additional units are not 100% reliable and have a FOR, the original C_{WIND} is then scaled up or down to match this change in ELCC, as these units have an effect on the reliability distribution. The capacity credit is then calculated using the following procedure:

1. Determine the conventional generation system $ELCC_{SYSTEM}$.
2. Add C_{WIND} to the conventional system and determine the $ELCC_{WIND}$.
3. Determine difference between $ELCC_{SYSTEM}$ and $ELCC_{WIND:}$ (ΔELCC).
4. Determine thermal capacity rounded to closest round number of units that would provide a similar ΔELCC ($ELCC_{THERMAL}$).
5. Determine $ELCC_{WINDEQUIVALENT}$ by varying C_{WIND} so that $ELCC_{WINDEQUIVALENT}$ is equal to $ELCC_{THERMAL}$.

The equivalent C_{WIND} is then inserted into Equation 22 to determine capacity credit:

$$cc = \frac{C_{THERMAL}}{C_{WINDEQUIVALENT}}.$$

Equation 22 Capacity Credit (Thermal Equivalent)

The above method is used to compute the capacity credit defined by definition 1. Note that although this method gives the result for what is normally understood as being capacity credit, it has the disadvantages of being quite complicated to calculate, and the answer obtained will be a function of the characteristics of the thermal unit that the wind is replacing, i.e. its size and forced outage rate.

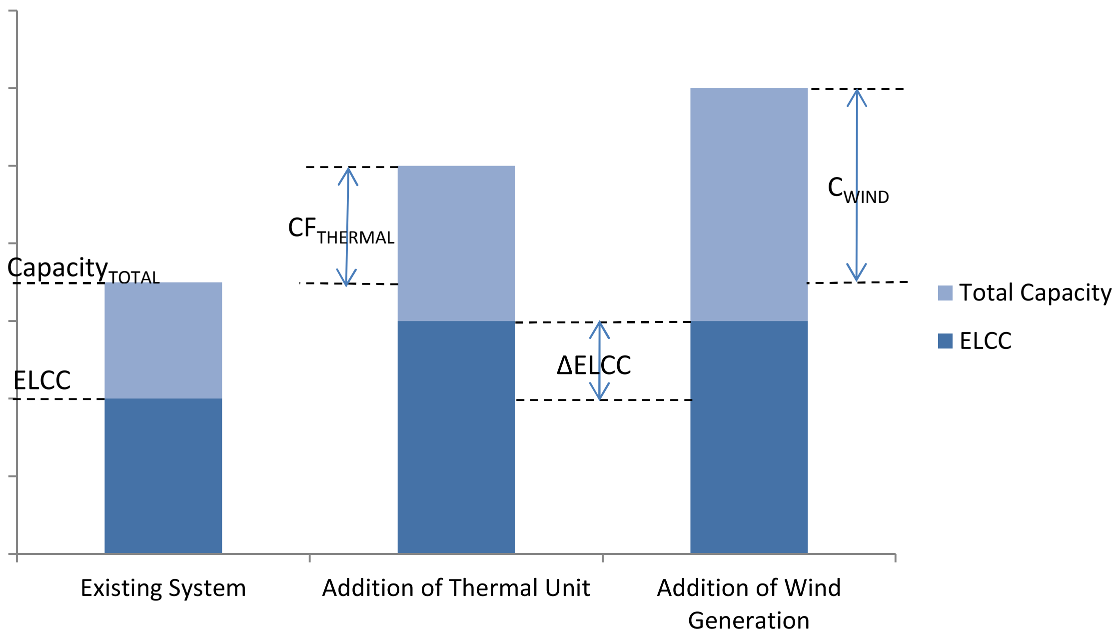

Figure 21 Graphical Aid for Capacity Credit Calculation

In other studies like the "Capacity credit of wind generation is South Africa" (DoE, Eskom & GIZ, 2011), a 100% reliable thermal unit is used as the firm capacity. Capacity credit is then defined by definition 2 and computed by:

$$cc = \frac{\Delta \mathrm{ELCC}}{C_{WIND}}.$$

Equation 23 Capacity Credit (Firm)

The advantage of using this method is that it is a simpler way of determining the capacity credit of wind. However, it assumes a different definition of the capacity credit, namely: what wind capacity is needed to replace a 100% reliable unit.

Other than being simpler, the other advantage of using this definition is that the capacity credit is not a function of the characteristics of an assumed thermal unit. Because the thermal units are not 100% reliable the capacity credit computed in Equation 23 (definition 2 – Firm) will always be lower than that computed using Equation 22 (definition 1 – Equivalent Thermal).

4.2.4 Scenario Analysis

One main goal of this dissertation is to investigate the effects that geographical distribution and penetration levels have on the capacity credit of a potential South African wind generation system. This investigation is carried using a range of scenarios in order to quantify and graphically illustrate the effects of these two parameters.

The scenarios developed in this investigation are based on the Integrated Resource Plan (IRP) for electricity updated report for 2013 (DoE, 2013). The IRP investigates multiple scenarios from a base case scenario to a nuclear cost sensitivity scenario. The scenarios developed in this dissertation are based on the base case scenario of the updated IRP 2013.

The base case scenario of the updated IRP is based on the IRP 2010 (DoE, 2013). Five discrete update steps were used to update the IRP 2010 assumptions. The first step updates was the technology costs, including the fuel, capital, operations and maintenance costs. The second step updates was the demand forecast using the CSIR Green shoots forecasts. The third step updates the performance of the Eskom fleet. Step 4 relates the step 3 as the option of life extension of existing Eskom coal power plants is included. Finally step 5 commits the REIPPPP round 1 and 2 and OCGT peaker programme with other capacity to optimise the model.

The effect that penetration levels and geographical diversity have on the capacity credit on the South African power generation system are analysed in two main scenarios. This is due to the limited supply of wind data available. The developed wind generation system developed in chapter 3 is applied to two generation system: a base case scenario and a future scenario. Within these two scenarios, there are 3 sub-sets that are compared to see how geographical dispersion affects the capacity credit of wind generation.

As wind generation varies seasonally, these investigations are carried at the peak demand hour of the day of 20h00 for the following periods:

- Annual Period
- Summer: December – February
- Autumn: March – May
- Winter: June – August
- Spring: September – November

As shown in Figure 11, there are 6 wind farms in the Western Cape (WC) and 6 farms in the Eastern Cape (EC). The main scenarios are as following:

- Scenario 1: Year 2011: 2014MW of wind generation
- Scenario 2: Year 2030: 4360MW of wind generation

4.2.4.1 Scenario 1: Base Case

The main parameters of scenario 1 are as follows:

Table 7 Base Case Generation Mix

Technology	Installed Capacity [MW]	Unit Size [MW]	Number of Units	FOR
Large Coal	21 090	554	38	6.4%
Large Coal Dry Cooling	9 381	626	15	4.6%
Small Coal	5 049	155	33	12.2%
Cahora Bassa	1 500	300	5	10.0%
Mini Hydro	70	70	1	8.5%
Hydro RSA	600	102	6	6.4%
Open Cycle Gas Turbine (OCGT)	2 400	134	18	5.1%
Nuclear	1 800	900	2	8.7%
Pumped Storage	1 580	216	7	6.8%
TOTAL	**43 470**			
Wind	WC –: 1 007			
	EC –: 1 007			
PEAK LOAD	**37 240**			

The generation mix for the existing system is given by Table 7. Scenario 1 may be seen as the base case for the investigations carried out in this paper.

4.2.4.2 Scenario 2: Future Generation - Year 2030

The main parameters of scenario 2 are as follows:

Table 8 Future Generation Mix

Technology	Installed Capacity [MW]	Unit Size [MW]	Number of Units	FOR
Large Coal Existing	15 960	554	29	6.4%
Large Coal Dry Cooling Existing	19 035	626	30	4.6%
Small Coal	3 610	155	23	12.2%
Large Coal New	2 450	750	3	3.7%
Cahora Bassa	1 500	300	5	10.0%
Mini Hydro	70	70	1	8.5%
Hydro RSA	600	102	6	6.4%
Hydro New	1 500	300	5	5.0%
OCGT Existing	3 120	134	23	5.1%
OCGT New	4 680	115	41	4.6%
CCGT	6 850	237	29	4.6%
Nuclear Existing	1 800	900	2	8.7%
Nuclear New	4 800	1600	3	2.0%
Pumped Storage	2 900	216	13	6.8%
TOTAL	**68 875**			
Wind	WC –: 2 180			
	EC –: 2 180			
PEAK LOAD	**60 509**			

4.2.4.3 Sub-Scenarios

In the order to investigate the effects that geographical diversity has on the capacity credit of wind generation, the total installed wind capacity of each main scenario is varied amongst the two provinces. There are 3 sub-sets in total and are as following:

A. **Full Dispersion**: Total installed capacity is spread evenly as described for the main scenarios
B. **Zero Dispersion**:
   I. Total installed capacity is concentrated in Western Cape
   II. Total installed capacity is concentrated in Eastern Cape

These sub-scenarios are applied to the two main scenarios with the installed capacity changing with each scenario.

4.3 Dispatch Model

The Basic function of an electrical power system is to provide electrical power to its customers as economically as possible with an acceptable level of reliability. Factors involved with the reliability were discussed in the previous chapters. Some of these factors included the EENS and the capacity credit for wind energy.

In order to develop these reliability indices, the system planning and operation process needs to be simulated.

This can be achieved through the means of a dispatch model. A dispatch model is a model that simulates the day to day and hour to hour characteristics of a power generation system by allocating the electrical power output of the various generation units (Hetzer, Yu & Bhattarai, 2008).

In order to minimise the cost, an economic dispatch model is used. In this model, the generation units are dispatched as economically as possible. Essentially this is done by dispatching the cheapest generation technology first. The dispatch problem is formulated by Equation 16, which can be seen as a classic mathematic optimization problem. The aim of the economical dispatch problem is to obtain an optimum allocation of power output among the available generators. This equation can be amended to include various constraints that need to be included into the system. Some of these constraints include minimum and maximum generation levels, unit commitment and ramp rates.

However, the intermittency of wind energy affects all aspects of the traditional processes of power system operation and planning. Therefore, it is crucial to investigate how wind energy will affect the day to day and hour to hour characteristics of the South African power generation system. It is also important to investigate the operation costs and carbon dioxide produced with the inclusion of wind energy in the system.

There has been extensive work done on the reliability of power systems with wind energy. This section presents the models developed in this dissertation.

4.3.1 Model Structure

The model developed in this dissertation tries to simulate how a hypothetical generation system closely resembling the South African system would be dispatched to meet hourly demand while minimising the power system operational cost. It incorporates day-ahead conventional generation unit commitment based on demand forecasting, wind generation forecasting and the reserve requirement. In order to reduce computation time, the simulation year is disaggregated into 12 seasons, one for each month of the year. Within those 12 seasons, a random day is selected to represent the demand profile for that season. Monte Carlo Simulation is used to develop reliability indices as shown by the flow chart in Figure 22.

There are multiple iteration loops within the model, including an annual loop, a seasonal (monthly) loop, daily loop and hourly loop. Within the annual loop, simulations advance from the first season to the last season. Simulation starts by determining the dispatch order of conventional generation based on the short run marginal cost of the different generation technologies within the power system. In order to mimic real operational procedures, planned outages are determined to develop the available capacity for each generation technology in each season.

As stated before, this model incorporates day ahead forecasting to determine conventional unit commitment for the next day. Day ahead forecasting is based on demand forecasting, wind generation forecasting and reserve requirements of conventional generation after planned outages. Demand forecasting and wind generation forecasting are both based on the mean absolute error of historical values.

During real time operations, available capacity based on the day-ahead unit commitment is ready to serve the net load, which is the actual wind generation subtracted from the actual demand.

During real time operations, the system is facing random forced outages and deviations from forecasted demand and wind generation. Emergency actions, such as committing quick start units are taken, if available capacity in insufficient.

After simulating all 12 seasons, the program will reset all variables and repeat the yearly loop again until the maximum number of trails is reached. After all simulations are completed, reliability indices and other statistics such as generation utilisation and generation efficiency are developed. The reliability index used in this dissertation is expected energy not served.

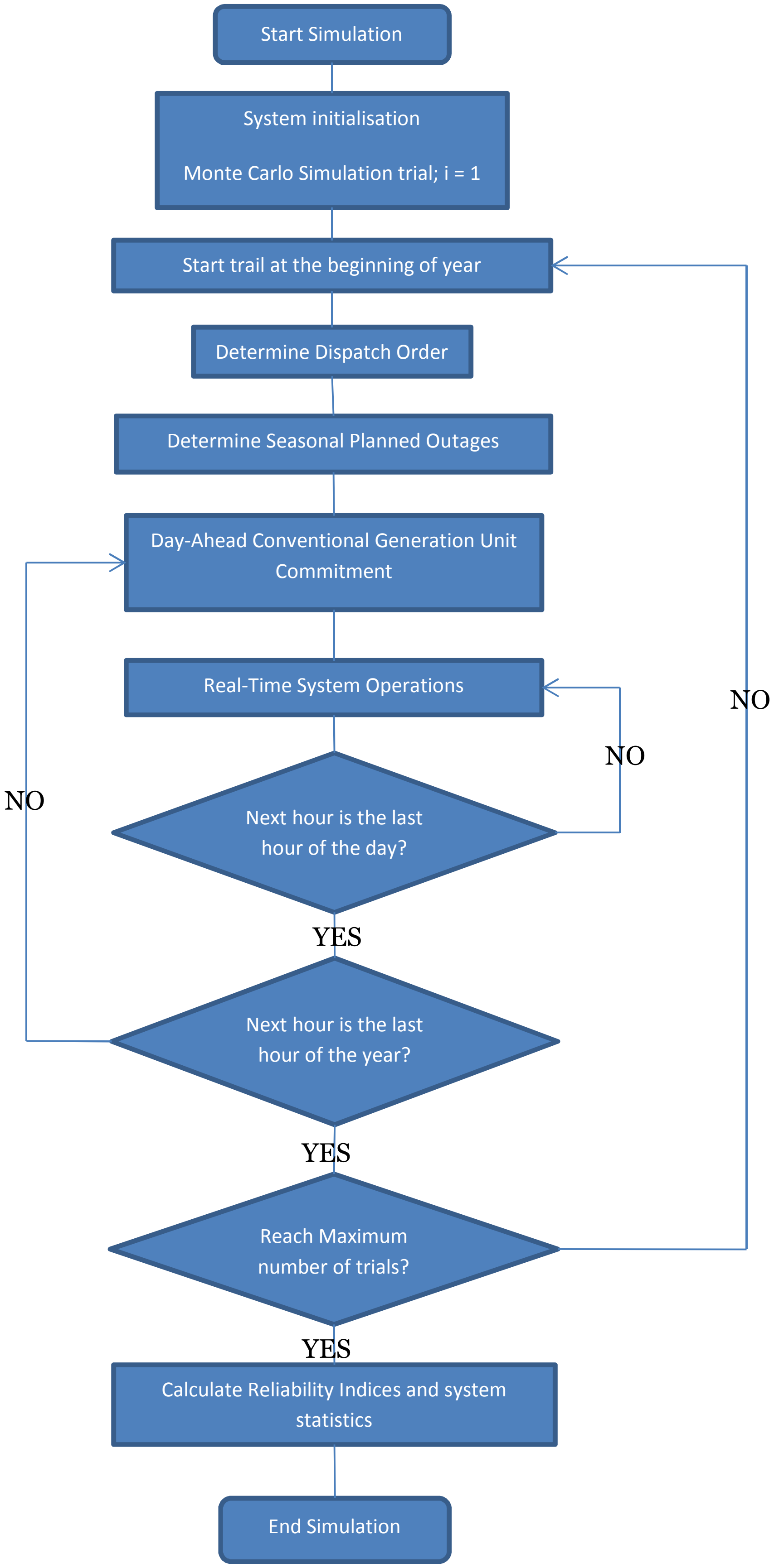

Figure 22 Model Structure

4.3.1.1 Dispatch Order

In order to dispatch the generation units as economically as possible, a dispatch order for the different generation technologies is determined. Generation technologies are dispatched sequentially from lowest to highest according to their short run marginal costs. The short run marginal cost is defined as the overall generation cost of the generation technology. It includes the variable cost, the fuel cost and the fuel/carbon taxes. The short run marginal cost in this dissertation is defined by Equation 24:

$$SRMC_i = (C_{VAR})_i + (C_{FUEL})_i + (C_{TAX})_i + Tiebreaker,$$

Equation 24 Short Run Marginal Cost

where SRMC is the short run marginal cost for technology I, C_{VAR} is the variable cost for technology I, C_{Fuel} is the fuel cost for technology I, C_{TAX} is the carbon tax for technology i

The tie breaker variable in Equation 24 is an arbitrary variable that enables to model to split generation technologies that may have the same short run marginal costs.

4.3.1.2 Maintenance Schedule

The maintenance schedule incorporates all the generating units within the generation system, including the incoming renewable energy technologies. This reserve margin may vary from season to season as peak demand also varies from season to season. However, it is desired that the reserve margin remains constant from season to season. In to order acquire this specification, the reserve margin of the entire system needs to determined and not for the peak season only. The following steps and figures illustrate how this is achieved.

A. The amount of maintenance required by each technology is determined by applying the planned outage rate (POR) on the installed capacity of each technology. The summation of this result represents the total amount of maintenance required in the system, as shown in Equation 25:

$$RD = \sum_i POR_i \times CAP_i \times 8.76,$$

Equation 25 Required Downtime

where RD is the required downtime in GWh, POR is the planned outage rate of technology I, CAP is the installed capacity of technology i.

B. The seasonal available downtime is determined by finding the difference between the total installed capacity and the seasonal peak demand. The summation of this result represents the total available downtime in the system as shown in Equation 26 and Figure 23:

$$AD = \sum_{j=1}^{12} \left(\left(\sum_i CAP_i\right) - PL_j \right) \times d_j \times 8.76,$$

Equation 26 Available Downtime

where AD is the total available downtime, PL is the peak demand in season j and d is the duration of season j.

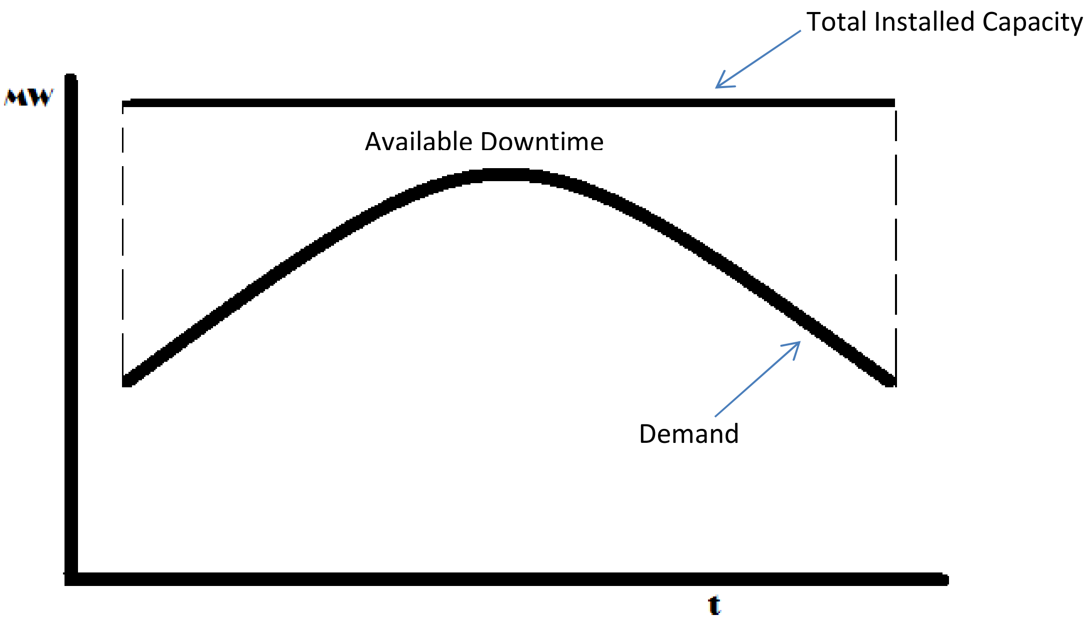

Figure 23 Available Downtime

C. The difference between the available downtime and the required downtime gives the total available amount of electrical energy that can be supplied to the system. This is illustrated in Equation 27 and Figure 24. The ratio between the available energy and the required load is the required reserve margin needed to keep it constant:

$$AE = AD - RD,$$

Equation 27 Available Energy

where AE is the Available Energy. Therefore the required reserve margin is given by Equation 28:

$$RRM = \frac{AE}{(\sum_j PL_j \times d_j \times 8.76)} \times 100\%.$$

Equation 28 Required Reserve Margin

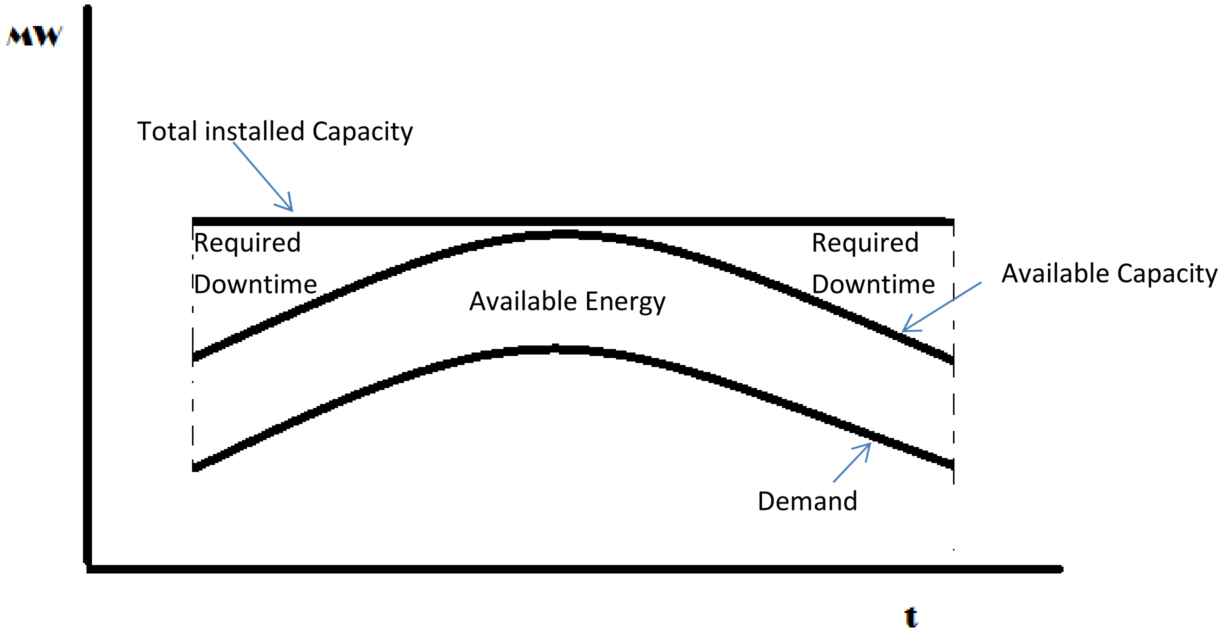

Figure 24 Maintenance Scheduling

Multiplying the seasonal peak demands by the required reserve will produce the available capacity in the system after maintenance. Due to the fact that the peak demand changes seasonally, the available capacity will also change as shown in Figure 24. This seasonal available capacity can then be split within the generation technologies by multiplying them with their respective percentage share of the required downtime. This represents the dispatchable capacity of each technology in each season from Equation 29 and Equation 30:

$$(CAP_{AV})_j = (1 + RRM) \times PL_j,$$

Equation 29 Seasonal Dispatchable Capacity

where CAP_{AV} is the seasonal dispatchable capacity and:

$$(CAP_{AV})_{i,j} = \left(CAP_i/(\textstyle\sum_i CAP_i)\right) \times (CAP_{AV})_j.$$

Equation 30 Technology Dispatchable Capacity

4.3.1.3 Demand

South Africa's demand profile for 2011 is obtained from Eskom (Eskom, 2010). It is divided into 12 seasons to investigate the seasonal correlation in CO_2 produced and production costs. Instead of sampling a generic weekday and weekend for each season, actual days are randomly sampled for each season to incorporate the diurnal trends. Figure 25 illustrates the peak season demand profile for South Africa.

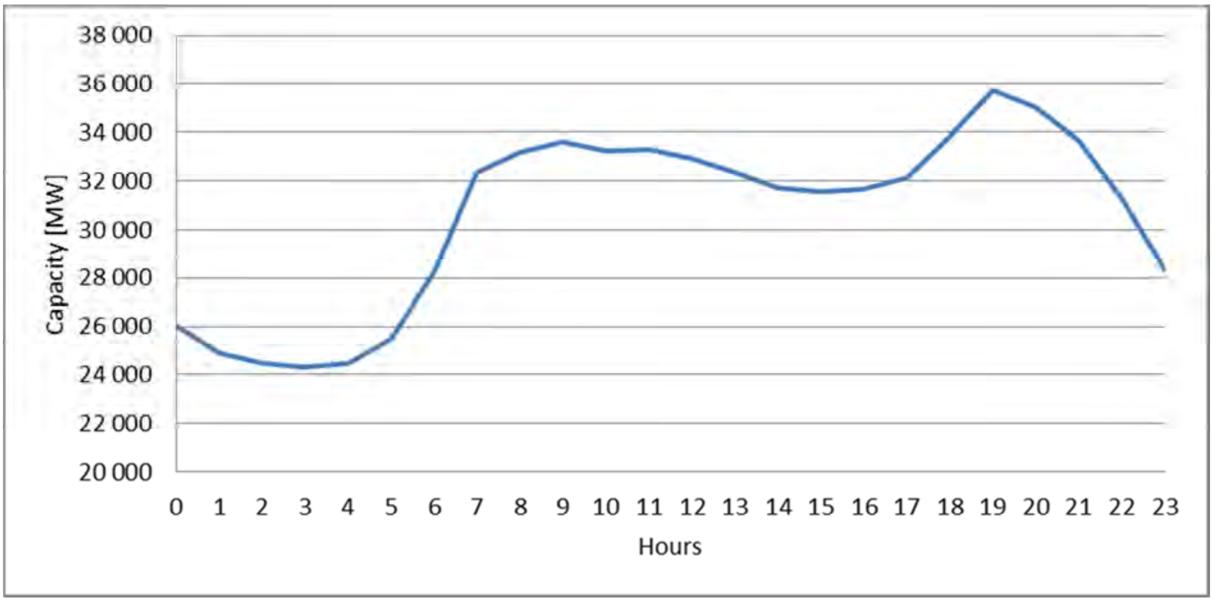

Figure 25 South African Peak Season Demand Profile

4.3.1.4 Wind Generation

Wind Generation is acquired from the analysis carried out in the previous chapter. As stated before, actual hourly power production is used in the dispatch model instead of a multi-state function. It is also sampled in the same manner as the demand profile to ensure that wind generation is sampled for the same day as the demand profile.

4.3.1.5 Conventional Generation

A multi-state function for conventional generation is determined through a binomial distribution, using the forced outage rate (FOR) and number of units within each technology to determine the probability of unit failure. This unit failure distribution is also known as the capacity outage probability table (COPT) as shown in Figure 26. The binomial distribution is given by Equation 31:

$$b(x,n,p) = \begin{cases} \binom{n}{x} p^x (1-p)^{n-x}, & x = 0,1,2,..,n \\ 0 \qquad\qquad\qquad\quad , & otherwise \end{cases},$$

Equation 31 Binomial Distribution

where p is the FOR, x is number of units offline, n is the number of units.

The COPT is also used to determine the probability of online capacity below capacity x as shown in Figure 27. This probability is then used in the real time operation to determine available capacity after outages.

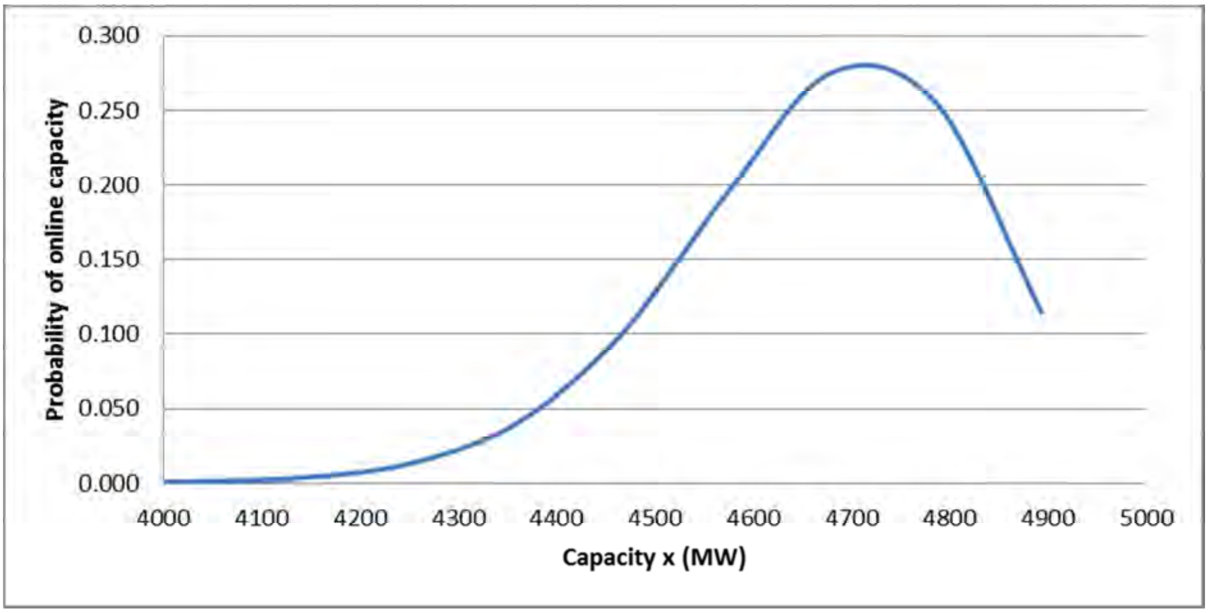

Figure 26 Probability of Online Capacity

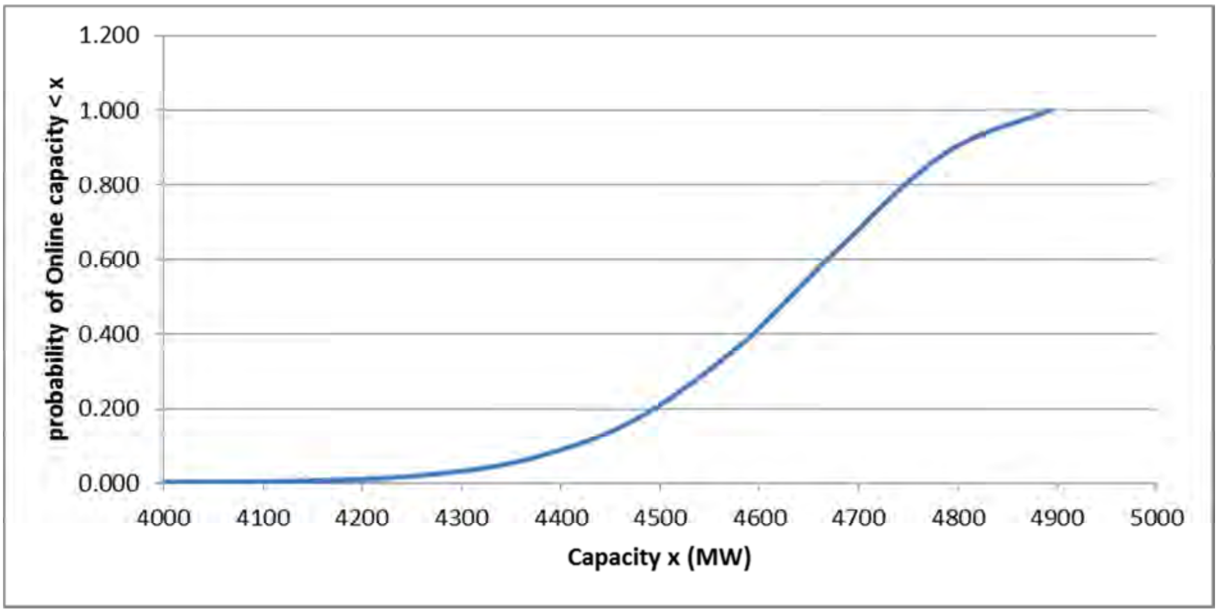

Figure 27 Probability of Online Capacity below Capacity x

The effective load carrying capability (ELCC) represents the maximum load that a system's installed capacity can carry at certain system adequacy. It is essentially the contribution that any given generator makes to overall system adequacy, measured at the specified reliability level of 90%. The ELCC of each thermal technology can be determined from Figure 28. At a certain probability or confidence, the generation technology is most likely to have capacity (x) online as shown in Figure 28 and Table 9 and Table 10.

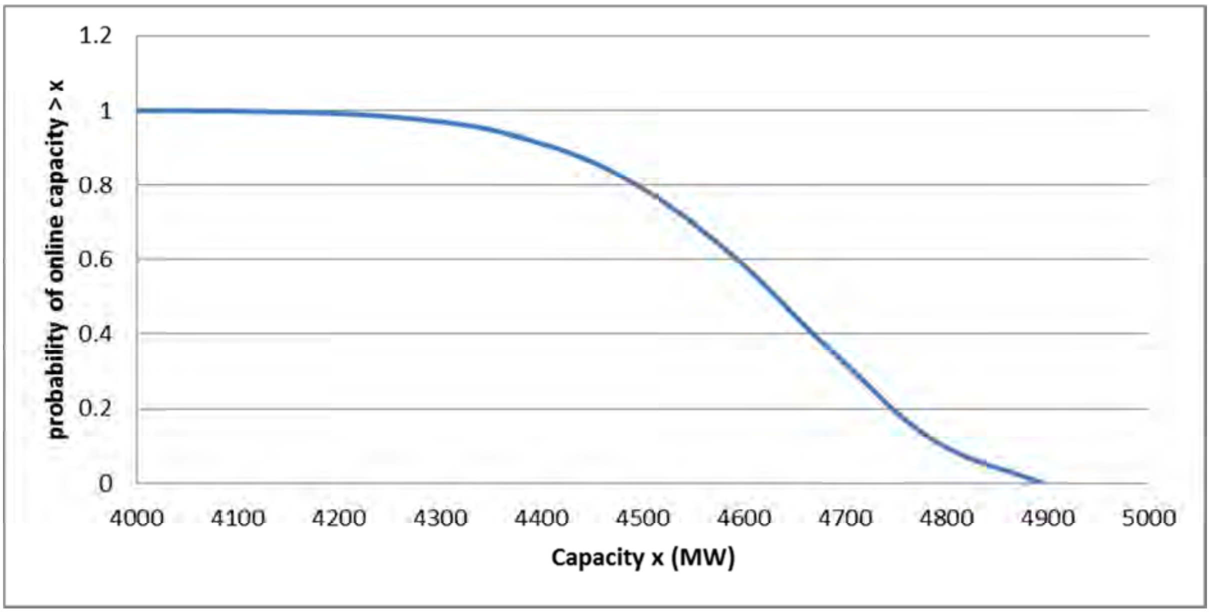

Figure 28 Probability of Online Capacity above Capacity x

Table 9 Probability of Online Capacity

	Small coal			Large Coal			OCGT	
Number of units	Probability	Capacity [MW]		Probability	Capacity [MW]		Probability	Capacity [MW]
5	0.840	4468		0.881	17295		0.779	1861
4	0.941	4361		0.951	16771		0.912	1744
3	0.982	4255		0.983	16246		0.972	1628
2	0.995	4149		0.995	15772		0.993	1512
1	0.999	4042		0.999	15198		0.998	1396
0	1.000	3936		1.000	14674		1.000	1279

Table 10 Conventional ELCC

	Small Coal	Large Coal	OCGT
Installed Capacity	4468	17295	1861
Reliability Target	99%	99%	99%
ELCC	4189	16001	1527
ELCC %	94%	92%	82%

4.3.1.5 Day – Ahead Unit Commitment

In order to realistically simulate power system operations, day-ahead unit commitment needs to be conducted. During day-ahead unit commitment, the actual demand and actual wind generation for the next day are known. The day-ahead forecasted values are used to determine unit commitment for conventional generation. Unit commitment is decided using the forecasted demand and wind values obtained from Lew & Milligan (2011) and the reserve requirements. Reserve requirements are determined through the risk of generation loss. The risk of generation loss is determined from the load carrying capability of conventional generation as shown in Equation 32. The load carrying capability of conventional generation is explained in the previous section.

$$RR_t = ELCC(\%) \times FD_t,$$

Equation 32 Reserve Requirement

where RR is the required reserve for time t, ELCC is the load carrying capability capacity, FD is the forecasted demand for time t.

The day-ahead unit commitment procedure in this dissertation commits capacity for the worst case scenario. Essentially it uses the upper bound of demand forecast and the lower bound of wind forecast. The difference between the forecasted demand and the forecasted wind generation is the net load. As unit commitment is decided daily, the peak net load is used to determine the committed capacity requirement. This ensures that daily peak demand will be met by the system. This peak net load is used in conjunction with the reserve requirements to determine the committed capacity requirements for the next day given by Equation 33 and Equation 34. The committed capacity requirement incorporate the available capacity determined in the maintenance schedule. Technologies are committed according to the set dispatch order, with cheaper technologies being fully committed while more expensive technologies being partially committed as required. This is illustrated in Figure 29.

$$Net\ Load = FD_t - \left(FW_g\right)_t,$$

Equation 33 Net Load

where FW_g is forecasted wind generations for time t.

$$CR_t = Net\ Load + RR_t\ ,$$

Equation 34 Committed Capacity Requirements

where CR is required capacity at time t.

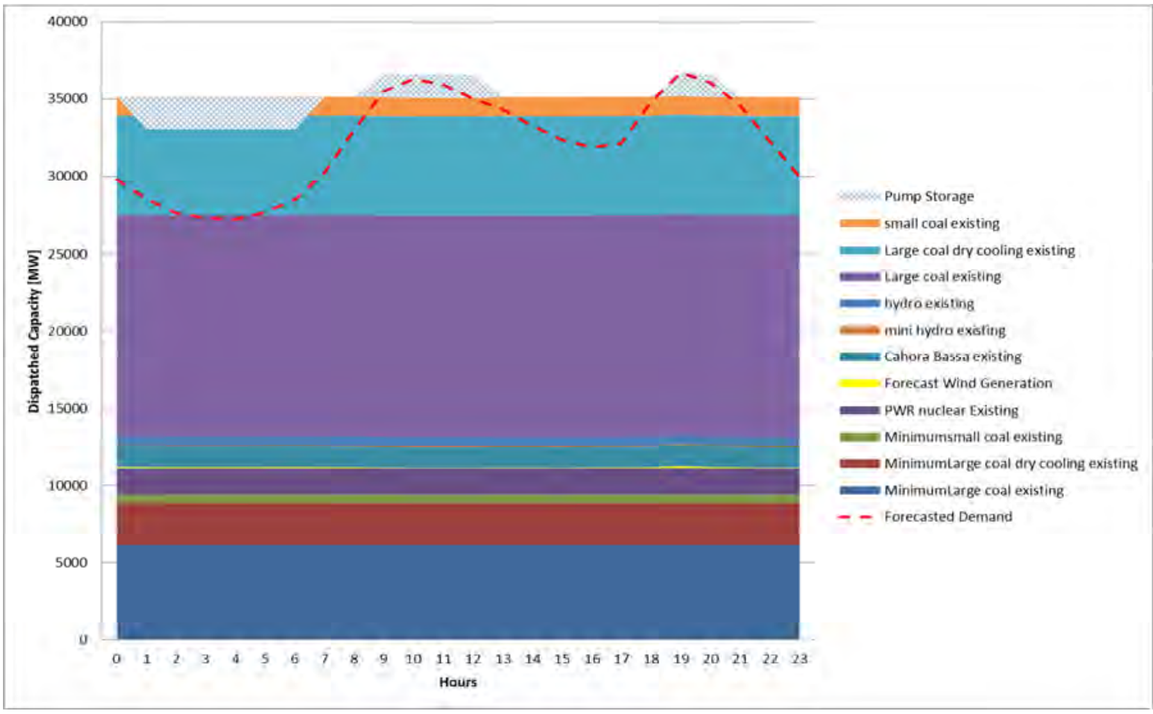

Figure 29 Day - Ahead Simulation

4.3.1.6 Real-Time Operations

Real time operations simulate the hourly operations of the system of the selected random day. The flow chart in Figure 30 shows the main steps of the system operations. Randomly forced outages of committed units are simulated first. This then gives the available committed capacity for that day or season. With this capacity, conventional generation units are dispatched according to the dispatch order in order to meet the required net load as in Equation 16. Quick start generation units are only committed if there is a shortage in capacity. Unserved Energy is then calculated based on the actual demand, actual wind generation and total available committed generation capacity as shown in Equation 35:

$$Unserved\ Energy = D_t - W_{g_t} - \sum_t P_{G_{i_t}},$$

Equation 35 Unserved Energy

where D_t is demand at time t, W_{gt} is wind generation at time t and P_{Gi} is conventional power generation of technology i at time t.

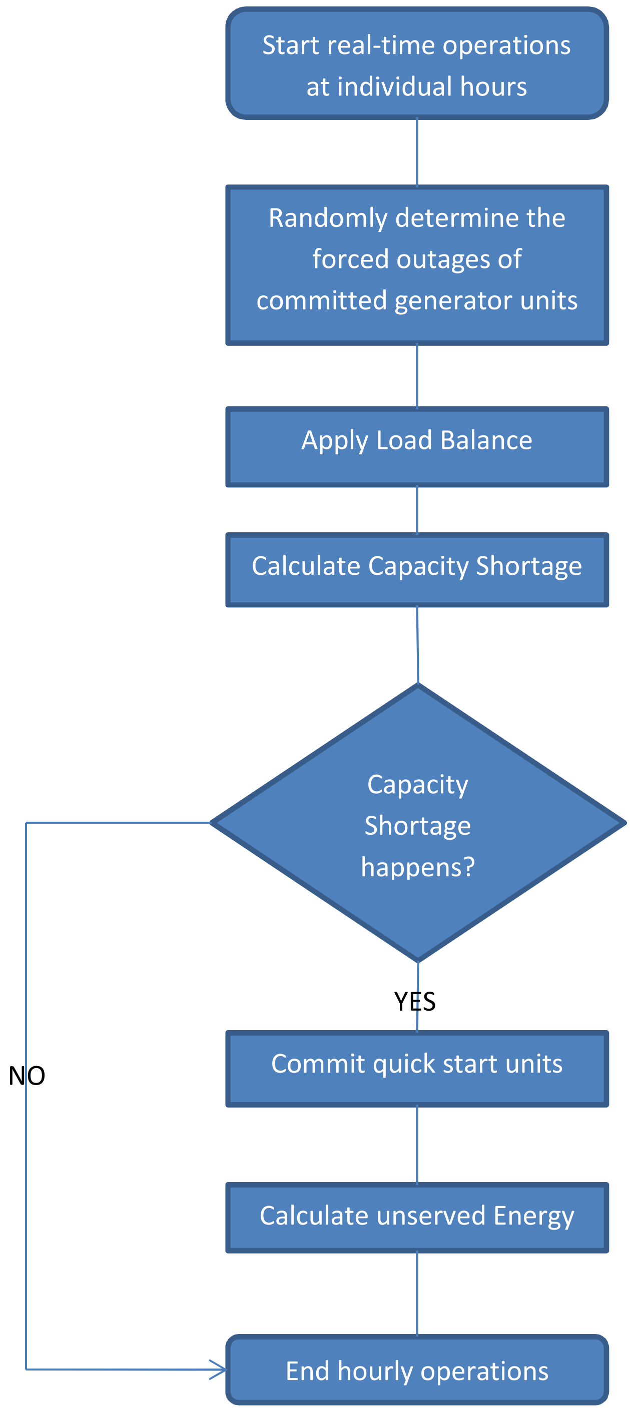

Figure 30 Real-Time Operations flow diagram

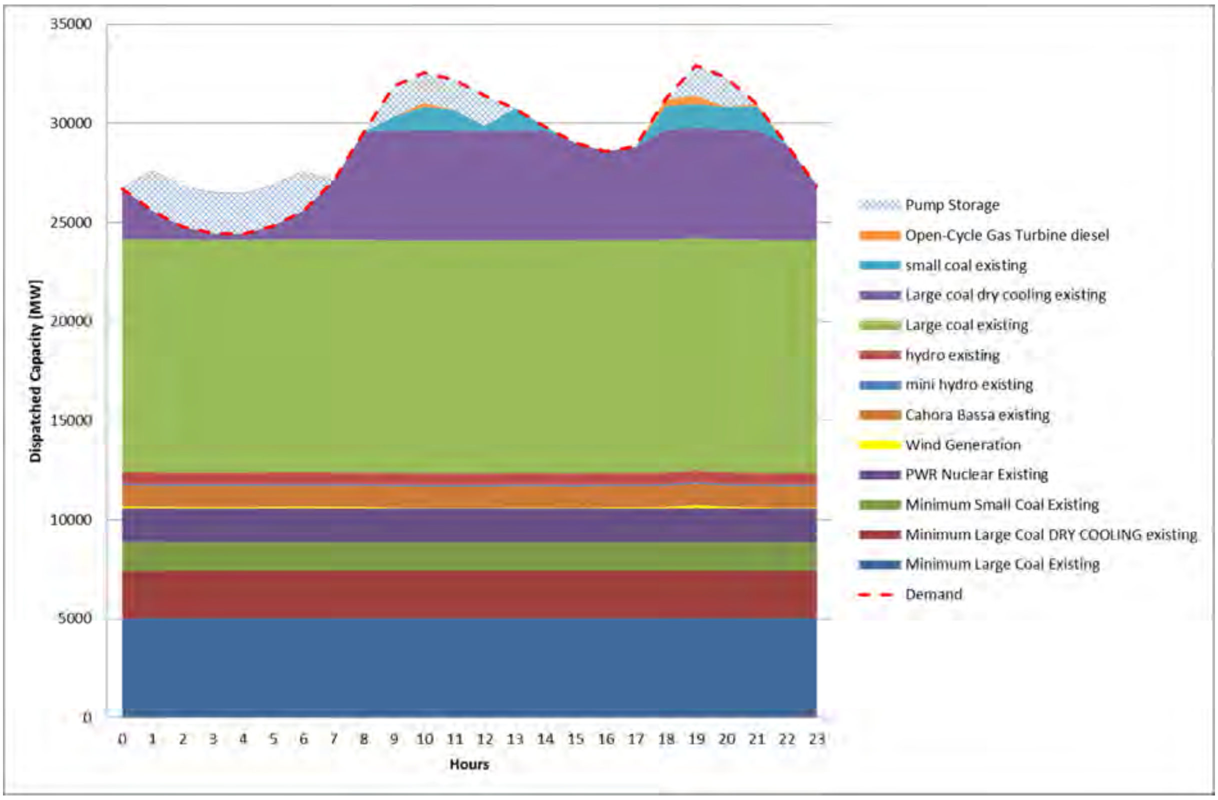

Figure 31 Real-Time simulation

4.3.2 Reliability and Performance Indicators

The main function of the dispatch model is to develop the system's reliability and performance indicators. The system models each hour of the day for each season for each simulation. The average system and performance indicators developed for each hour, which are summed across the 24hours of the day, are then summed across all 12 season to get annual aggregates

The reliability indicator investigated in this study is the EENS, while the performance indicator investigated are the fuel consumption cost and CO_2 emissions produced by the system. These indicators are compared to findings reported in the IRP 2013 (DoE, 2013). These performance indicators are derived from the energy production of each technology. Fuel consumption is only valid for the thermal unit in the system. These thermal units have heat rates that vary with the capacity factor as shown in Figure 32 (International Energy Agency, 2010).

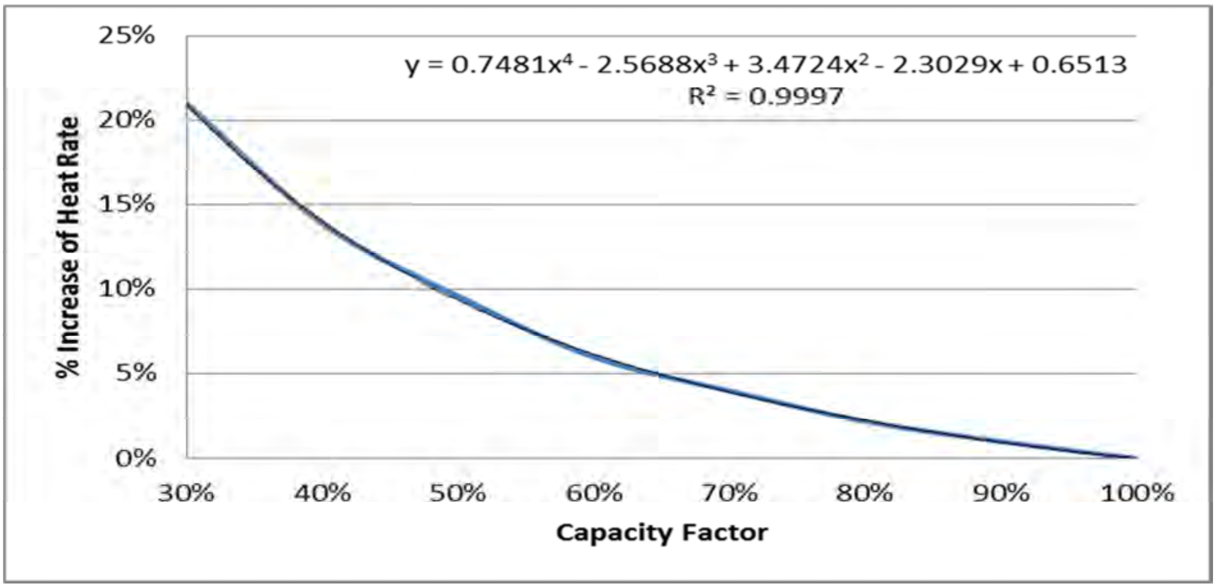

Figure 32 Heat Rate vs Capacity Factor

The resulting heat rate of the unit is used to calculate the efficiency, which in turn is used to calculate the various performance indices of the system. This process is described sequentially by Equation 36 and Equation 37 respectively:

$$\eta = \frac{3600}{HR},$$

Equation 36 Efficiency

where η is the efficiency and HR is the resulting heat rate.

$$Energy\ Value\ of\ Fuel\ Used = \frac{Energy\ Production\ by\ Technology}{\eta}.$$

Equation 37 Energy Value of Fuel Used

The performance indices are then determined by the multiplying the energy value of the fuel used by the corresponding emission or cost factor.

4.3.3 Scenario Analysis

Unlike the capacity credit investigation, performance indicators are developed for one main scenario with 6 sub-scenarios. The main scenario is identical to the 2030 future case used to investigate the capacity credit. The sub-sets investigated within this scenario are used to investigate the effects of penetration levels and geographical dispersion on the generation system. These sub-sets are summarised in Table 11 and Table 12.

Table 11 Geographical Dispersion sub-set scenarios for Dispatch Model Analysis

Scenario	Description	Wind Capacity [MW]	Description
Scenario A	Full Dispersion of Wind	WC –: 1007 EC –: 1007	Simulations are run with wind generation fully dispersed throughout the 2 provinces
Scenario B	WC only	WC –: 2014	Installed wind capacity is concentrated in the Western Cape
Scenario C	EC only	EC –: 2014	Installed wind capacity is concentrated in the Eastern Cape

Table 12 Penetration Level sub-set scenarios for Dispatch Model Analysis

Penetration Level	Wind Capacity [MW]	Description
6%	4 360	Equivalent wind capacity from the capacity credit is compared to the equivalent thermal capacity. (*see Equation 22*)
12%	8 788	Equivalent wind capacity from the capacity credit is compared to the equivalent thermal capacity. (*see Equation 22)*
18%	13 182	Equivalent wind capacity from the capacity credit is compared to the equivalent thermal capacity. (*see Equation 22)*

4.4 Data Collection

In order to simulate the South African power system accurately, the actual power generation mix is needed. The generation mix is obtained from the updated Integrated Resource Plan for South Africa (DoE, 2013). The IRP contains the generation mix from 2013 to 2050. This provides the opportunity to investigate the effect that wind generation has on future generation mix based on the IRP scenarios. These scenarios investigated in the IRP range from base case scenario to a high nuclear percentage share scenario. The scenario chosen for analysis in this dissertation is the base case scenario.

4.5 Assumptions and Limitations

In order to develop the models presented in the previous sections, many assumptions and limitations are applied to reach a solution. The main limitations of this research are that it only considers one year of wind data and that capacity credit results have not ratified using an alternative approach. This is because capacity credit research is fairly immature, especially in South Africa. Furthermore, high quality public wind data is extremely rare to find.

Secondly, the geographical dispersion investigation is constrained by the locations chosen in round 1 and round 2 of REIPPPP. The assumptions made are summarised in Table 13. The main simplifying assumption made in the dispatch model is that the ramp rate for the thermal power plants is assumed to be 100% per hour.

Table 13 Capacity Credit Assumptions

	Assumption	**Rationale**
Firm Capacity Unit size	The thermal capacity unit size for the base case is assumed to be equivalent to small coal power plan unit size.	This is to ensure that the increase in capacity coincides with the IRP 2013
	The thermal capacity unit size for future scenarios is assumed to be equivalent to a closed cycle gas turbine plant unit size	This is to ensure that the increase in capacity coincides with the IRP 2013

4.6 Conclusion

This chapter described a two-step dispatch model for conventional generation as economically as possible. Conventional generation output is simulated using the COPT, FOR and a linear dispatch order. Wind Generation is considered as a negative load and applied to the daily electricity demand to produce a net demand, which needs to be met by other generators in the system. If there are shortages after the dispatch of mid-merit plants, then quick start generation units are committed to counter this generation shortage. Reliability and performance indicators are developed from the dispatch model.

Firm capacity and wind capacity are used to develop ELCC of the power generation system with and without wind generation. The ELCC for conventional generation is developed from the LOLP calculator, which develops an ELCC distribution for each system. Unlike the dispatch model, a multi-state function is used to describe the wind generation.

The Dispatch model structure was first built in Microsoft Excel in order to be debugged before any scenarios were simulated. However, the reliability indices are developed in Matlab. The Matlab code for this model is given in the appendices. The Capacity Credit model is developed and run with Microsoft Excel. The methodology for has resulted in a simple but resilient analysis of the capacity credit for wind generation in South Africa, with a robust power system model.

Chapter 5

Results and Discussion

The effect of geographic dispersion and penetration levels on the capacity credit of utility scale wind generation were tested for the South African power system. This was simulated using the ELCC method, while an energy dispatch model was used to simulate real time operation to estimate average annual avoided CO_2 emissions and dispatch costs.

As a result the following results are explored:

1) Wind Generation
    a. Production Trends
    b. Diurnal Trends
2) Capacity Credit Results
    a. Geographical distribution
    b. Penetration levels
3) Dispatch model outputs

5.1 Wind Generation

5.1.1 Introduction

The development of an accurate wind generation model is the first and one of the most important steps in investigating the capacity credit of wind energy. Furthermore, it is one of the main goals of this dissertation.

As stated previously, obtaining high quality time series wind data was extremely challenging, but with the help of the SAWS and WASA, time series data for 23 wind sites based on round 1 and 2 of REIPPPP was obtained and investigated. These sites were individually investigated and analysed before the entire wind generation system was analysed. The Diurnal trends between wind generation and the demand profile are also investigated.

5.1.2 Production Trends

Given the assumptions made to develop the wind generation model in chapter 3, the simulation results are extremely interesting. Table 14 summarises yearly power production of the individual wind farms based on the model developed in this dissertation.

Table 14 Yearly Production for Base Case

	Wind Farm	Location	Installed Capacity [MW]	Theoretical Production [GWh/yr]	Model Production [GWh/yr]	CF
1	WM01	Northern Cape	89	779.64	193.02	25%
2	WM02	Northern Cape	89	779.64	169.93	22%
3	WM03	Western Cape	66	578.16	191.08	33%
4	WM04	Western Cape	67	586.92	166.71	28%
5	WM05	Western Cape	67	586.92	246.24	42%
6	WM06	Northern Cape	88	770.88	231.88	30%
7	WM07	Western Cape	67	586.92	163.96	28%
8	WM08	Eastern Cape	267	2338.92	772.69	33%
9	Hopefield Wind	Western Cape	65	569.4	102.66	18%
10	Dassiesklip Wind	Western Cape	27	236.52	7.74	3%
11	Noblesfontein Wind	Northern Cape	75	657	96.04	15%
12	Dorper Wind	Eastern Cape	100	876	47.43	5%
13	MetroWind	Eastern Cape	27	236.52	84.16	36%
14	Jeffreys Bay Wind	Eastern Cape	138	1208.88	509.89	42%
15	Red Cap Couga Wind	Eastern Cape	80	700.8	295.59	42%
16	Cookhouse Wind	Eastern Cape	139	1217.64	50.08	4%
17	West Cost Wind	Western Cape	91	797.16	290.12	36%
18	Gouda Wind	Western Cape	135	1182.6	33.37	3%
19	Tsitsikamma Wind	Eastern Cape	95	832.2	351.01	42%
20	Grassridge Wind	Eastern Cape	60	525.6	52.69	10%
21	Waainek Wind	Eastern Cape	23	201.48	39.13	19%
22	Amakhala Wind	Eastern Cape	138	1208.88	49.72	4%
23	Chaba Wind	Eastern Cape	21	183.96	11.62	6%

Samples of the REIPPPP data and results were compared to the quoted yearly production levels by the different Independent Power producers. As stated before, the time series data obtained from SAWS was unreliable. This decreased the accuracy of the power production for some the REIPPPP sites as shown in Table 15.

Table 15 Ratification of Production Results

Wind Farm	Installed Capacity [MW]	Theoretical Production [GWh/yr]	Model Production [GWh/yr]	CF	Quoted Production[1] [GWh/yr]	Quoted CF[1]	% difference
Hopefield Wind	65	569.4	102.66	18%	190.00	33%	-46.0%
Dassiesklip Wind	27	236.52	7.74	3%	88.22	37%	-91.2%
Noblesfontein Wind	75	657	96.04	15%	223.38	34%	-57.0%
Dorper Wind	100	876	47.43	5%	350.40	40%	-86.5%
MetroWind	27	236.52	84.16	36%	80.00	34%	5.2%
Jeffreys Bay Wind	138	1208.88	509.89	42%	447.29	37%	14.0%
Red Cap Couga Wind	80	700.8	295.59	42%	300.00	43%	-1.5%
West Cost Wind	91	797.16	290.12	36%	290.00	36%	0.0%
						Average Deviation (abs)	**32.9%**

1 Quoted yearly production for individual farms: www.nersa.org.za/consultation/presentations/electricity

From Table 15, an average deviation of 32.9% was determined for the selected wind farms. This high deviation is caused by extremely poor data for some of the wind farms. In order to counteract this poor reliability, these wind farms sites were excluded from the analysis in order to maintain the integrity and accuracy of the simulations performed in this dissertation. The remaining wind farms are highlighted in yellow in Table 14 leaving wind system configuration shown in Figure 13 and Table 3. Secondly, looking at the capacity factor from a wind developer's point of view, a project with such a low capacity factor would not be economically viable.

As the entire wind generation system is used in the capacity credit analysis and dispatch model, the overall power production is illustrated and discussed. Figure 33 illustrates the daily yield of the system. From Figure 33, there is a clear difference in yield variation from the summer months to the winter months.

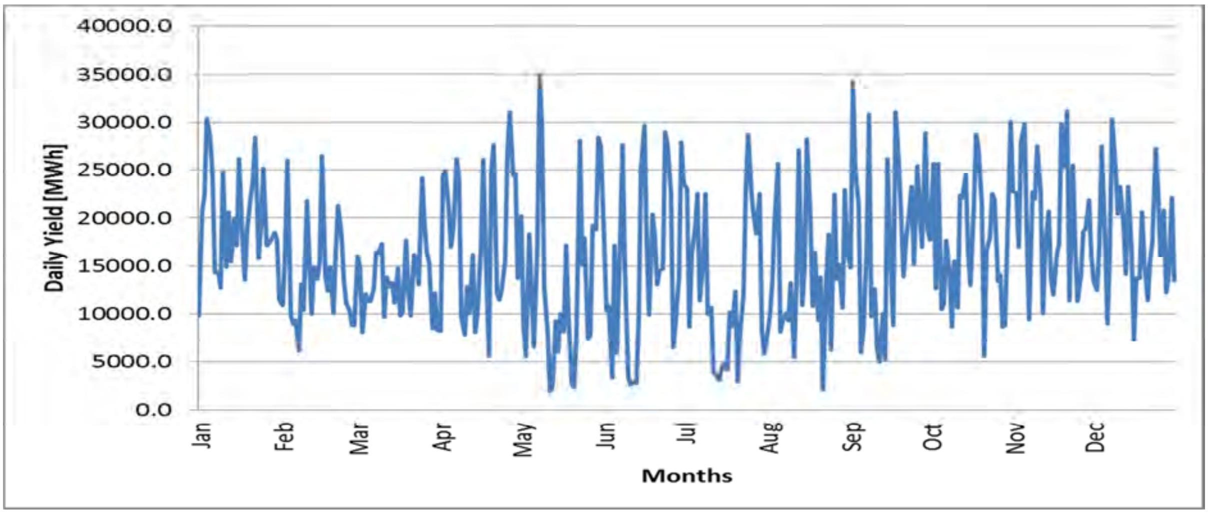

Figure 33 Daily Yield

The degree in variation of wind generation affects the commitment of conventional generation. The greater the degree of variation implies the increased usage of peaking plants to counter act the variation, as the big coal plants cannot change their output as easily. This is further complimented by Figure 34, which shows higher monthly averages for the periods with less variation.

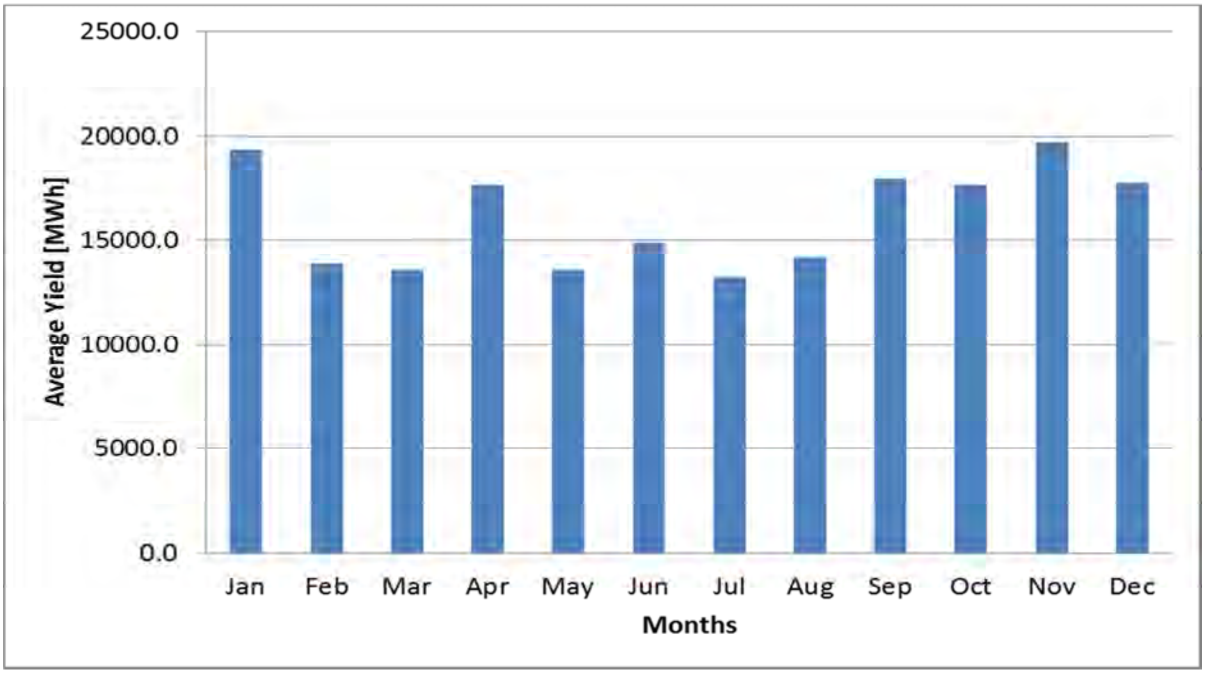

Figure 34 Monthly Yield

Due to the variation in yield output through the year, the yield output and distributions for the different seasons were developed. Furthermore, since Figure 33 illustrates the daily yield, the different seasons were analysed for the peak demand hour of 20h00.

Table 16 and Figure 35 show that the majority of the power produced by the system ranges between 403MW and 806MW. This observation supports the calculated capacity factor of 29.3%. This analysis can be performed for different hours of the day. However, this is outside the scope of this dissertation.

Table 16 Annual Yield Analysis

Power Output [MW]	Probability	Cumulative Probability	Model Yield [MWh]
0	0.000	0.000	0.0
201	0.101	0.101	7451.8
403	0.132	0.233	19334.4
604	0.153	0.386	33835.2
806	0.222	0.608	65253.6
1007	0.126	0.734	46322.0
1208	0.140	0.874	61628.4
1410	0.101	0.975	52162.6
1611	0.016	0.992	9667.2
1813	0.005	0.997	3625.2
2014	0.003	1.000	2014.0

Table 17 Annual Capacity Factor

Theoretical Yield [MWh]	735110.0
Model Yield [MWh]	301294.4
Capacity Factor	41.0 %

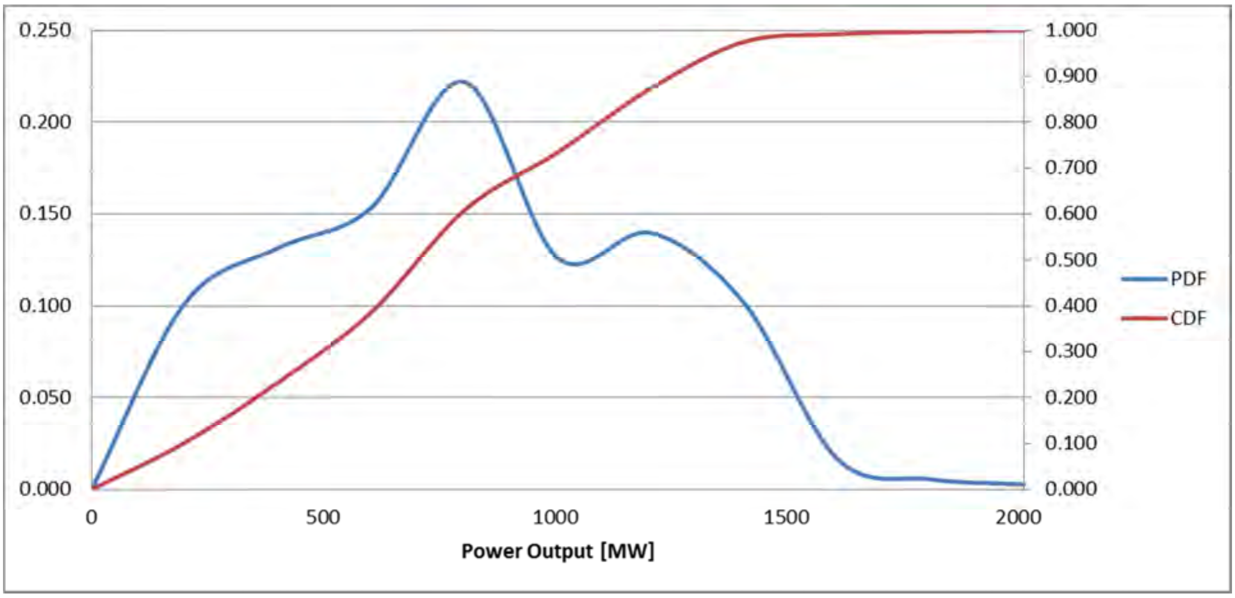

Figure 35 Annual Distributions

Table 18 and Table 19 below summarise the yield analysis for the different seasons of the year. An important result from this analysis is the lower capacity factor of 33.7% for the peak winter season. This implies, that there is less production during this season resulting in the overall power generation system relying more on conventional generation to meet its demand. However, due to the higher capacity factor of 46.7% for the off-peak summer season, this implies that more maintenance can be performed, resulting in more capacity being available for the peak season.

Table 18 Seasonal Yield Analysis

Power Output [MW]	Summer			Autumn			Winter			Spring		
	PDF	*CDF*	*Yield*	*PDF*	*CDF*	*Yield*	*PDF*	*CDF*	*Yield*	*PDF*	*CDF*	*Yield*
0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	0.0
201	0.01	0.01	201.4	0.13	0.13	2416.8	0.24	0.24	4430.8	0.02	0.02	402.8
403	0.06	0.07	2014.0	0.14	0.27	5236.4	0.19	0.42	6847.6	0.14	0.17	5236.4
604	0.17	0.23	9063.0	0.17	0.45	9667.2	0.12	0.54	6646.2	0.15	0.32	8458.8
806	0.27	0.50	19334.4	0.20	0.64	14500.8	0.16	0.71	12084.0	0.26	0.58	19334.4
1007	0.20	0.70	18126.0	0.13	0.77	12084.0	0.11	0.82	10070.0	0.07	0.65	6042.0
1208	0.18	0.88	19334.4	0.09	0.86	9667.2	0.12	0.94	13292.4	0.18	0.83	19334.4
1410	0.09	0.97	11278.4	0.13	0.99	16917.6	0.04	0.98	5639.2	0.14	0.97	18327.4
1611	0.02	0.99	3222.4	0.01	1.00	1611.2	0.01	0.99	1611.2	0.02	0.99	3222.4
1813	0.00	0.99	0.0	0.00	1.00	0.0	0.01	1.00	1812.6	0.01	1.00	1812.6
2014	0.01	1.00	2014.0	0.00	1.00	0.0	0.00	1.00	0.0	0.00	1.00	0.0

Table 19 Seasonal Capacity Factors

	Summer	Autumn	Winter	Spring
Theoretical Yield [MWh]	181250.0	185288.0	185288.0	183274.0
Model Yield [MWh]	84588.0	72101.2	62434.0	82171.2
Capacity Factor	**46.7%**	**38.9%**	**33.7%**	**44.8%**

The variation of wind generation between the different seasons is emphasised in the distributions below. The distribution for the summer season is much smoother. Furthermore, the mode is also much higher than the rest of the curves, reflecting the calculated capacity factors above.

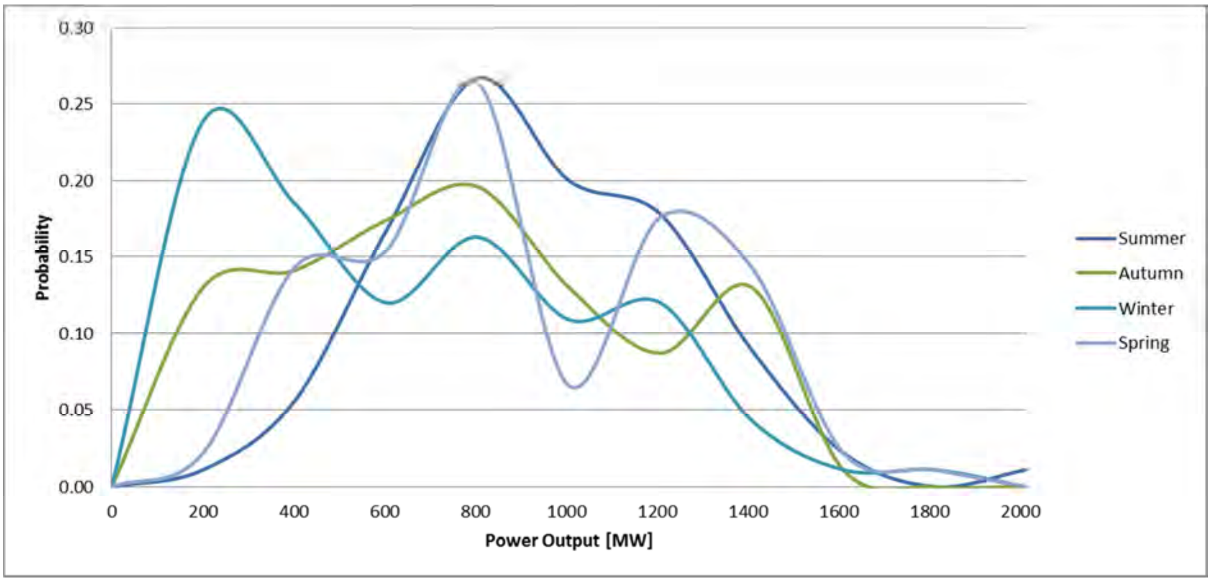

Figure 36 Seasonal PDFs

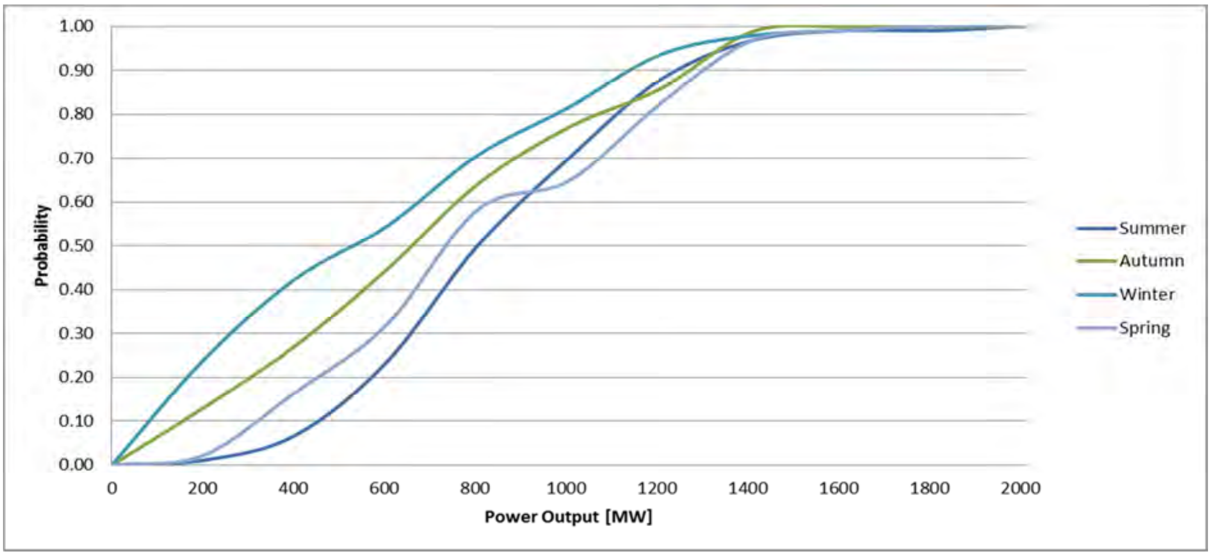

Figure 37 Season CDFs

5.1.3 Diurnal Trends

The generation of wind power varies over the course of a day and seasons. The diurnal behaviour determines the nature of its interactions with load and conventional generations with the power generation system. As with the capacity factor investigations, the diurnal trends of the wind generation system are investigated for the 4 seasons. The winter peak season diurnal trends are presented in this results chapter, with the full set of diurnal trends for each season presented in the appendices.

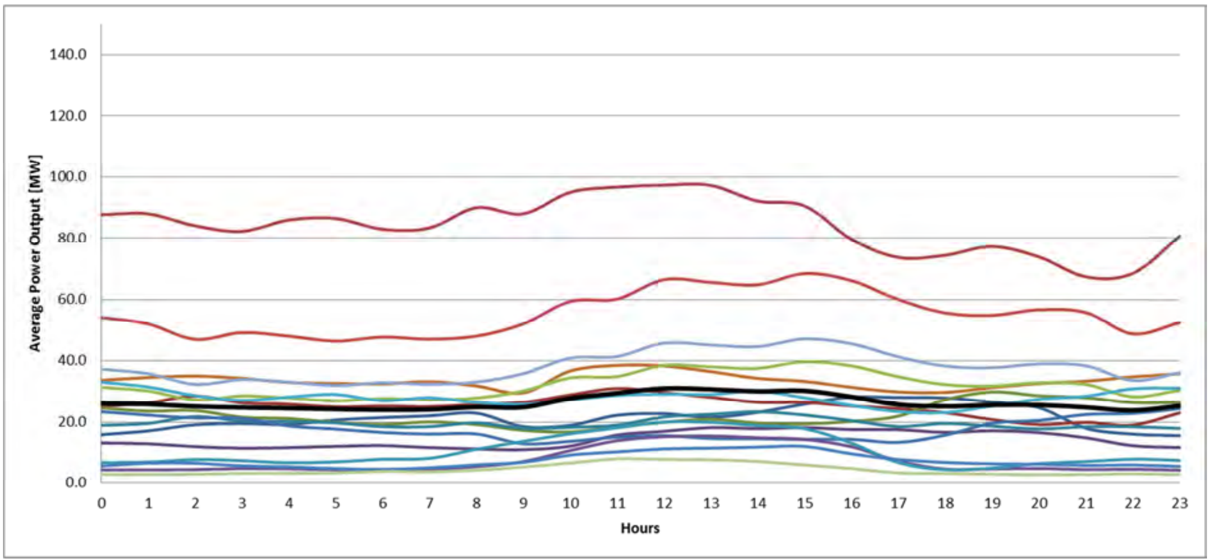

Figure 38 Peak (Winter) Season Diurnal Trends for the Wind Generation System

In Figure 38, the thick black line illustrates the mean diurnal trend of all sites. It is evident that there is a higher daytime power output. This result is in agreement with the finding of Ummel's (2013) findings, as it was also found that there is a higher daytime power output for the peak season.

This implies that less conventional generation needs to be committed during the day, which has an impact of electricity production cost and CO_2 emitted. It is also important to recognise that the mean daytime peak is less pronounced than for the individual sites. This shows less variability in the wind power supply, showing less intermittency and an increased reliability. Looking at the diurnal trends of provincial wind systems illustrated in Figure 39 and Figure 40, it is evident that the day time peak is more pronounced.

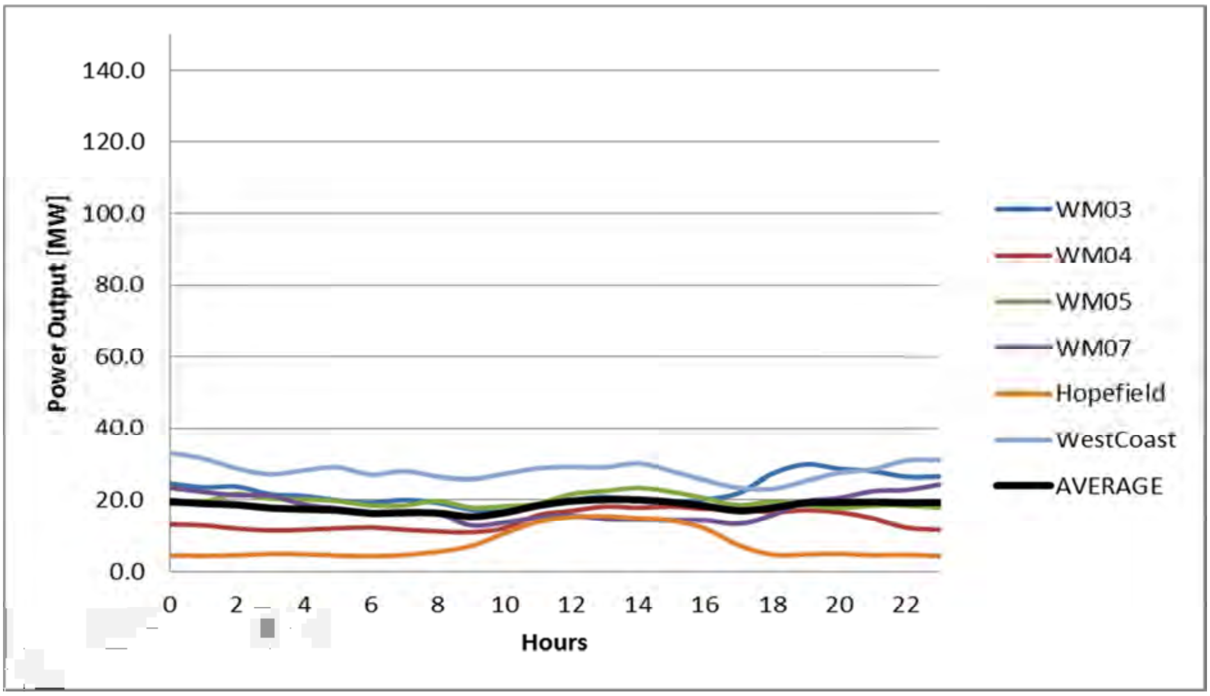

Figure 39 Peak (Winter) Season Diurnal Trends for Western Cape

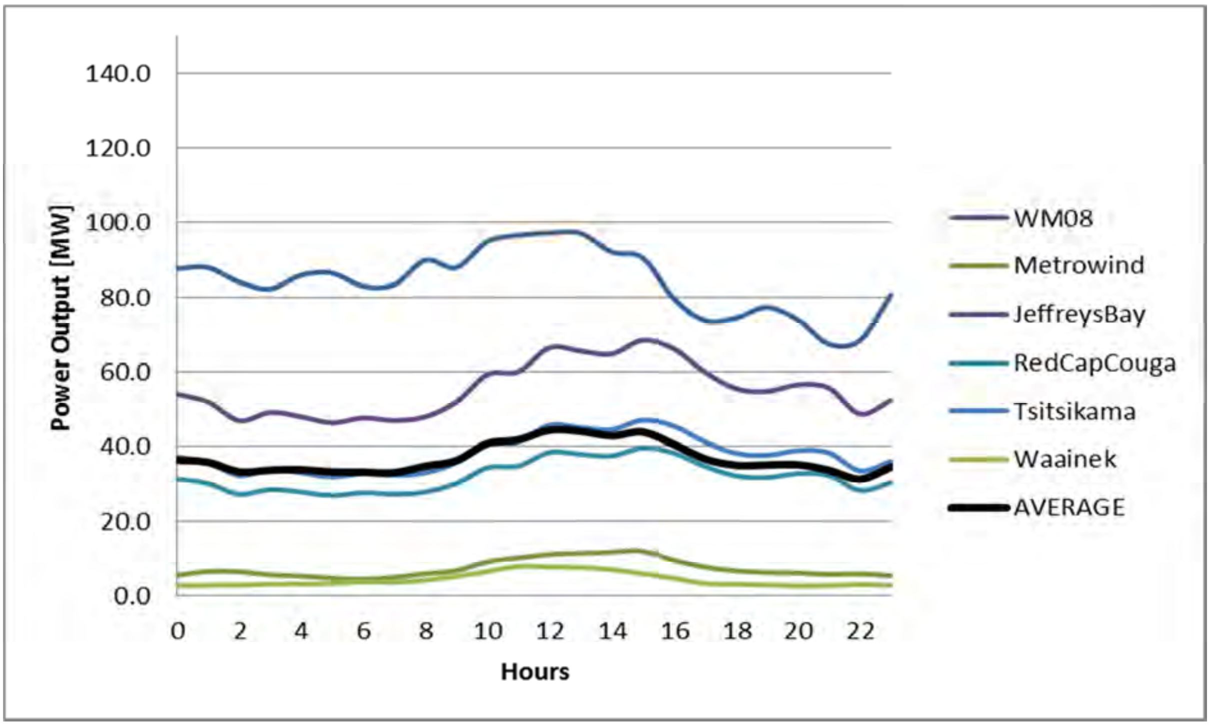

Figure 40 Peak (Winter) Season Diurnal Trends Eastern Cape

The correlation between the individual sites is an important property to analyse as this has a big impact on the capacity credit. Comparing the three figures above, the wind farms in the Eastern Cape have a higher correlation than the wind farms in the other two provinces. Therefore, according to the initial hypothesis of this dissertation, the capacity credit for the wind farms in the Eastern Cape should be less than the capacity credit of the other provinces. However, the diurnal trends only give insight into the capacity credit results.

5.1.4 Conclusion

The wind power production model is one of the most important parts in investigation the capacity of any wind generation system. A wind generation system is developed for the sites that data is available. The wind generation parameters and diurnal trends are investigated.

The outstanding outcomes of this model are firstly the model produces less energy in the peak season than in the other seasons. This outcome compliments previous works on a potential South African wind generation system. As there is less wind generation, this implies less conventional generation can be put offline during the peak season increasing electricity production cost.

Secondly, the diurnal trends show a daytime peak power output. The result of this outcome is that less wind generation is available when it is most needed. Furthermore, the daytime peak is more pronounced as the geographical dispersion the wind sites decreases. Unfortunately this does not give a clear indication to how the geographical dispersion will affect the capacity credit. The capacity credit investigation is presented in the following section.

5.2 Capacity Credit

5.2.1 Introduction

The capacity credit of wind generation system is affect by the penetration level and the geographical dispersion of the wind sites. These two factors are investigated in this dissertation in two main scenarios as described earlier. The results of these investigations are presented in this section.

5.2.2 Scenario 1 - 2011 Base Case

In order to determine the capacity credit of wind generation, the original existing system without additional thermal units or wind capacity was evaluated. The main system parameters for the base case are as following:

Table 20 Existing System ELCC Analysis

Total Installed Capacity	43 470 MW
Peak Demand	37 240 MW
Reliability Target	90%
ELCC	38 970
ELCC %	89.72%

At a confidence level of 90%, the effective load carrying capability of the original existing system is 38970MW. This implies that out of a total installed capacity of 43470MW; only 89.7% of it can be relied upon at a reliability target of 90%. However, as shown in Figure 16 and Figure 17, the ELCC of the system changes with the change in reliability. Figure 41 below shows the effect that additional wind capacity has on the reliability curve at a reliability target of 90%.

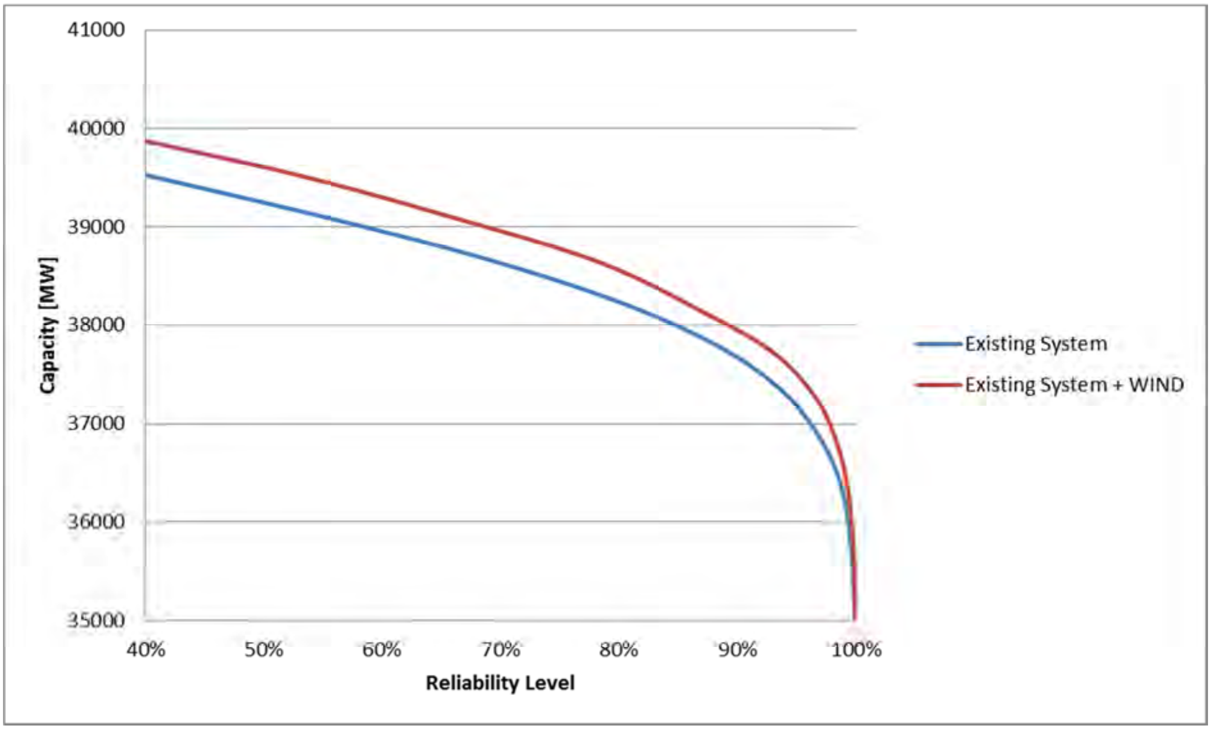

Figure 41 Wind effect on Reliability Distribution

The wind system developed in the base case scenario is based on the REIPPPP round 1 and 2 preferred bidders for wind energy. This is due to the fact that these projects have been committed to the system and should be commissioned in 2014. Due to the structure of the LOLP calculator as mentioned before, the installed wind capacity had to be varied in order the match the effect that the additional thermal units had on the ELCC of the system. These effects were investigated and the results of these investigations are presented in the following sections.

5.2.2.1 Penetration Level

Based on the production trend analysis in section 5.1, effects of penetration levels on the capacity credit were investigated for the different season of the year. Table 21 and Table 22 summarise the results for the base case penetration level investigation, where penetration (%) is defined by Equation 38;

$$Penetration = \frac{C_{WIND}}{Total\ Installed\ Capacity} \times 100\%,$$

Equation 38 Penetration Level

where the Total installed capacity include conventional generators and wind generators.

As stated, the equivalent wind capacity described in section 4.2.3 in Table 21 is the required wind capacity needed to match the effects of the additional thermal units. An interesting result from this methodology is the increasing difference between the originally installed wind capacity and the required equivalent wind capacity with increasing penetration level. This is due to fact that the additional thermal units added are not 100% reliable; therefore as more wind capacity is added, the greater the variation between C_{WIND} and $C_{WINDEQUIVALENT}$.

Table 21 Scenario 1 Annual Penetration Level Analysis

Calculation Procedure Step[1]	**Penetration level**	**4%**	**9%**	**13%**	**17%**
1	Conventional System ELCC [MW]	38 970			
2	C_{WIND} **[MW]**	2 014	4 360	6 521	8 694
	$ELCC_{WIND}$ **[MW]**	39 704	40 415	40 939	41 390
3	ΔELCC	734	1 445	1 969	2 420
	CC_{FIRM}[2]	**36.4%**	**33.1%**	**30.2%**	**27.8%**
4	Thermal Capacity **[MW]**	775	1 394	2 014	2 479
	Number of Units [155MW each][3]	5	9	13	16
6	$C_{WINDEQUIVALENT}$ **[MW]**	1 900	3 900	5 700	7 600
	$ELCC_{WINDEQUIVALENT}$	39 659	40 196	40 733	41 170
	$CC_{THERMALEQUIVALENT}$[4]	**40.8%**	**35.7%**	**35.3%**	**32.6%**

1 See section 4.2.3 and Figure 21

2 CC_{FRIM} = Capacity Credit (FIRM); see Equation 23

3 Unit size equivalent to a small coal power plant unit size (see Table 7*)*

4 $CC_{THERMALEQUIVALENT}$ = Capacity Credit (Thermal Equivalent); See Equation 22

At the chosen reliability level of 90%, we can see from the Table 21 and Figure 43 that the capacity credit decreases with increasing penetration levels of wind energy. These results are in agreement with previous studies performed, where the wind capacity credit decreased with increasing penetration levels. The capacity credit was analysed at the peak demand hour of 20h00. At the initial penetration of 4%, the capacity credit was found to be 40.8%.

As predicted, the CC_{FIRM} is lower than the $CC_{THERMALEQUIVALENT}$. The $CC_{THERMALEQUIVALENT}$ is a function of thermal units added to system. These units are not 100% reliable, thus C_{WIND} needs to be varied to $C_{WINDEQUIVALENT}$ in order to incorporate the uncertainty developed by the FOR of these units.

An interesting result from Table 21 is the degree to which the $CC_{THERMALEQUIVALENT}$ decreases with increment in increasing penetration level. The capacity credit decreases by approximately 5% from the initial penetration level of 4% to 9%. The degree of capacity credit reduction decreases with increasing penetration levels. However, it is important to note the decrease of approximately 3% in CC_{FIRM} with increasing penetration level. From Figure 42, the degree of reduction for CC_{FIRM} is constant, whereas for $CC_{THERMALEQUIVALENT}$ it is not. Furthermore, looking at the overall system and the effects that penetration level has, from Figure 42, the system's ELCC decreases as the penetration level increases.

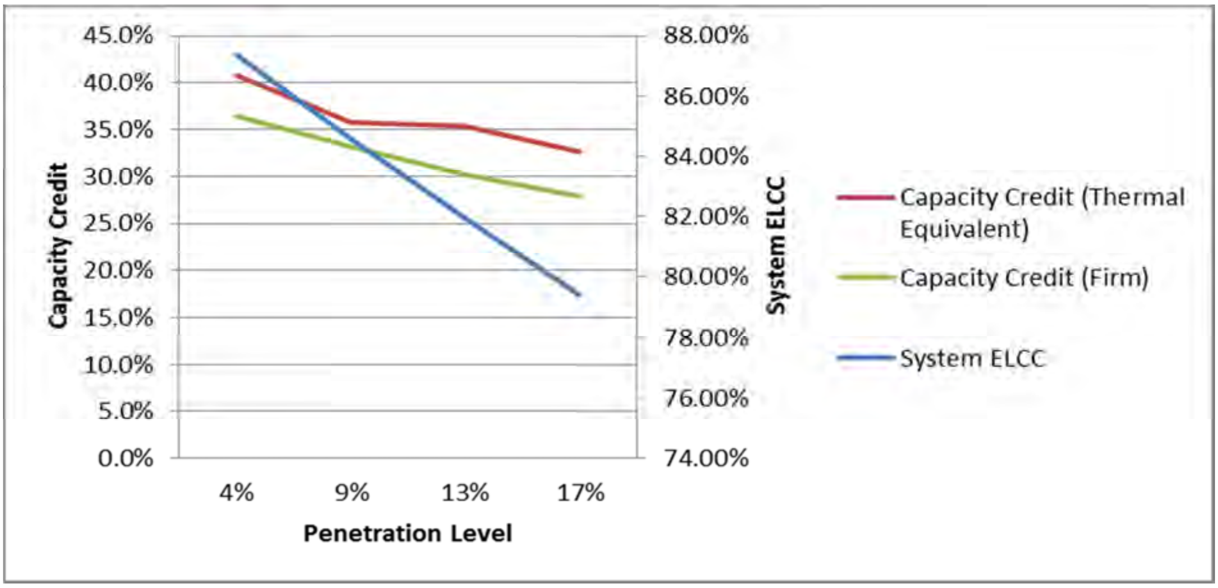

Figure 42 Capacity Credit vs System ELCC

The seasonal penetration level analysis summarised in Table 22 and Figure 43

Table 22 Scenario 1 Season Penetration Level Analysis

Penetration Level	$CC_{THERMALEQUIVALENT}$			
	Spring	Summer	Autumn	Winter
4%	47.0%	45.6%	38.5%	34.4%
9%	43.7%	44.8%	35.7%	30.1%
13%	41.5%	44.3%	33.2%	26.7%
17%	39.8%	42.8%	30.2%	23.8%

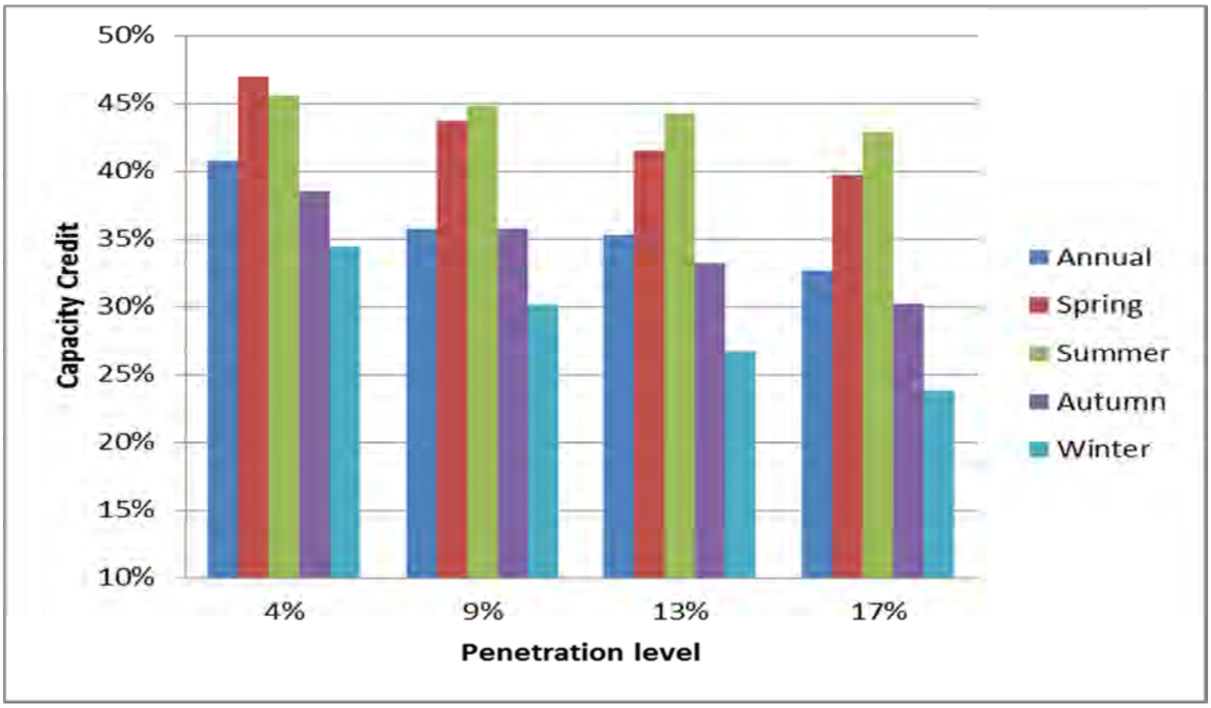

Figure 43 Scenario 1 Seasonal Penetration Level Analysis (Thermal Equivalent)

From Figure 43 above, the degree to which the capacity credit is decreasing reduces with increasing penetration level. Furthermore, the variation between the seasons increases as the penetration level increases. This is a primary results of the fluctuations observed within the different season in section 5.1.2. Interestingly, spring has the best capacity credit at low penetration levels but for higher penetration levels, it is summer that has the best capacity credit. The seasonal capacity credit could be useful from a maintenance scheduling point of view, using the higher capacity credits for summer and spring would allow more scheduled maintenance to take place in those months. Without compromising the system reliability

5.2.2.2 Geographical Dispersion

The effect of geographical dispersion on capacity credit was investigated for four scenarios:

1. Scenario A: Full spread – plants equally spread between the Western and Eastern Cape
2. Scenario B: Total capacity concentrated in the Western Cape
3. Scenario C: Total capacity concentrated in the Eastern Cape

The following table summarises the results of the investigation.

Table 23 Scenario 1 Annual Geographical Dispersion Analysis

Calculation Procedure Step[1]	Scenario	Scenario A	Scenario B	Scenario B
		Full Spread	**WC only**	**EC only**
1	Conventional System ELCC [MW]	38 970		
2	C_{WIND} [MW]	2 014		
	$ELCC_{WIND}$ [MW]	39 704	39 677	39 531
3	ΔELCC	734	707	561
	CC_{FIRM}[2]	**36.4%**	**35.1%**	**27.9%**
4	Firm Capacity [MW]	775	775	620
	Number of Units [155MW each][3]	5	5	4
6	$C_{WINDEQUIVALENT}$ [MW]	1 900	2014	2014
	$ELCC_{WINDEQUIVALENT}$	39 659	39677	39 531
	$CC_{THERMALEQUIVALENT}$[4]	**40.8%**	**38.5%**	**30.8%**

1 See section 4.2.3 and Figure 21

2 CC_{FRIM} = Capacity Credit (FIRM); see Equation 23

3 Unit size equivalent to a small coal power plant unit size (see Table 7*)*

4 $CC_{THERMALEQUIVALENT}$ = Capacity Credit (Thermal Equivalent); See Equation 22

Table 23 shows that the $CC_{THERMALEQUIVALENT}$ for this scenario only drops slightly from of 40.8% for full dispersion to 38.5%, if all the capacity were in the WC, but if all of it were in the EC it would drop much more dramatically to 30.8%. This observation is compliment by the results for CC_{FIRM}. From 36.4% in sub-scenario A, the CC_{FIRM} drops to 35.1% in sub-scenario B and 27.9% in sub-scenario C

The seasonal thermal equivalent capacity credits were also investigated, with the results summarised in Table 24 and Figure 44.

Table 24 Scenario 1 Seasonal Geographical Dispersion Analysis (Thermal Equivalent)

	Full Spread	WC only	EC only
Annual	40.8%	38.5%	30.8%
Spring	47.0%	44.3%	34.4%
Summer	45.6%	51.7%	30.8%
Autumn	38.5%	30.8%	31.8%
Winter	34.4%	29.1%	25.8%
Seasonal Average	***41.4%***	***39.0%***	***30.7%***

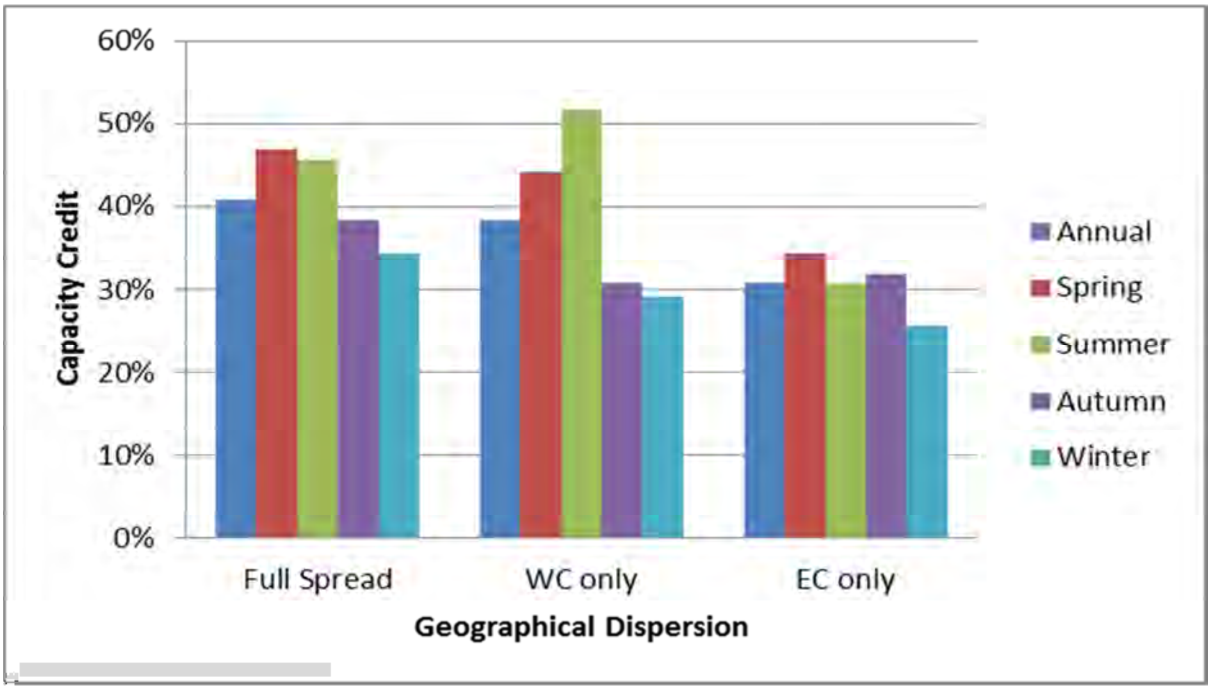

Figure 44 Scenario 1 Seasonal Geographical Dispersion Analysis (Thermal Equivalent)

The results imply that the Western Cape can produce the most reliable wind in the summer season. However, in order to verify this result, wind generation system is investigated on a 2030 future generation mix.

5.2.3 Scenario 2 - 2030 Future Generation Mix

The second scenario for which capacity credit was investigated is a future scenario for the year 2030. The main parameters of scenario 2 are as following:

Table 25 Future System ELCC Analysis

Total Installed Capacity	68 875 MW
Peak Demand	60 509 MW
Reliability Target	90%
ELCC	62 865 MW
ELCC %	91.92%

The results of penetration level and geographical dispersion are presented in the section.

5.2.3.1 Penetration Level

Table 26 summarises the annual penetration level analysis for scenario 2.

Table 26 Scenario 2 Annual Penetration Level Analysis

Penetration level	**6%**	**12%**	**18%**	**24%**
Conventional System ELCC [MW]	62 865			
C_{WIND} [**MW**]	4 360	8 788	13 182	17 576
$ELCC_{WIND}$ [**MW**]	64 349	65 425	66 278	66 969
ΔELCC	1 484	2 560	3 413	4 104
CC_{FIRM}	**34.0%**	**29.1%**	**25.9%**	**23.3%**
Firm Capacity [**MW**]	1 422	2 607	3 318	4 029
Number of Units [237MW each][1]	6	11	14	17
$ELCC_{FIRM}$ [**MW**]	64 221	65 340	65 987	66 670
$C_{WINDEQUIVALENT}$ [**MW**]	4 100	8 600	12 000	15 750
$ELCC_{WINDEQUIVALENT}$	64 271	65 366	66 017	66 682
$CC_{THERMALEQUIVALENT}$	**34.7%**	**30.3%**	**27.7%**	**25.6%**

1 Unit size equivalent to closed cycle gas turbine unit (see Table 8)

The penetration analysis for scenario 2 produces a similar trend for capacity credit to those of scenario 1. $CC_{THERMALEQUIVALENT}$ in scenario 2 is considerably less than first scenario, but CC_{FIRM} is comparable. This is mainly due to the lower forced outage rate (4.6%) of the CCGT plant compared to the 12% used for the small coal units used in scenario 1.

Table 27 Scenario 2 Season Penetration Level Analysis

Penetration Level	**$CC_{THERMALEQUIVALENT}$**			
	Spring	**Summer**	**Autumn**	**Winter**
6%	45.7%	43.5%	32.6%	27.2%
12%	35.8%	39.0%	27.0%	23.7%
18%	33.6%	37.9%	26.2%	20.9%
24%	30.7%	34.1%	23.4%	18.7%

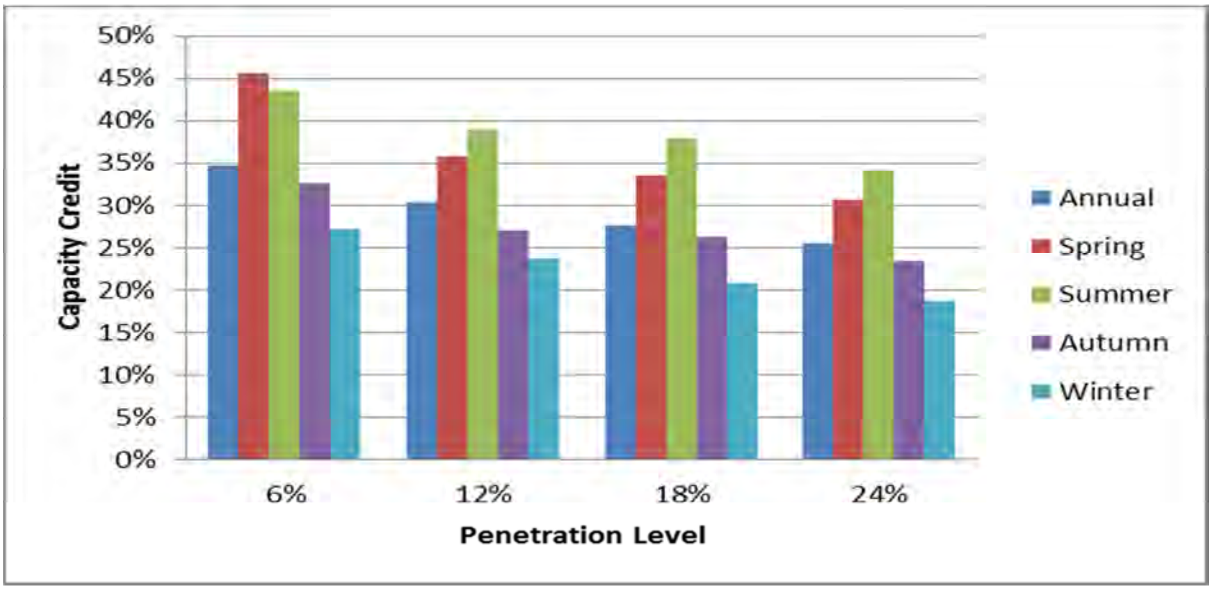

Figure 45 Scenario 2 Seasonal Penetration Level Analysis (Thermal Equivalent)

Table 26 and Figure 45 show the variation of the thermal equivalent capacity credit for different penetration levels for the different seasons. A similar trend to what was seen in the first.

5.2.3.2 Geographical Dispersion

Table 28 summarises the results of the geographical dispersion analysis for scenario 2. The general trend is the same as scenario 1 as the capacity credit decreases with decreasing geographical dispersion. Furthermore, the degree of reduction between sub-scenario A (full dispersion) and B (WC only) is not as pronounced as the degree of reduction between scenario A and C (EC only), with a reduction of approximately 2% and 10% respectively.

In scenario 2, a closed cycle gas turbine unit of 237MW was used as the thermal unit for the $CC_{THERMALEQUIVALENT}$ calculation. Table 28 shows the results of the analysis.

Table 28 Scenario 2 Annual Geographical Dispersion Analysis

Scenario	**Scenario A**	**Scenario B**	**Scenario C**
	Full Spread	**WC only**	**EC only**
Conventional System ELCC [**MW**]	62 865		
C_{WIND} [**MW**]	4360		
$ELCC_{WIND}$ [**MW**]	64 349	64 249	63 876
ΔELCC	1 484	1 404	1011
CC_{FIRM}	**32.6%**	**32.2%**	**21.7%**
Firm Capacity [**MW**]	1 422	1 422	948
Number of Units [237MW each][1]	6	6	4
$ELCC_{FIRM}$ [**MW**]	64 221	64 221	63 744
$C_{WINDEQUIVALENT}$ [**MW**]	4 100	4 360	4 000
$ELCC_{WINDEQUIVALENT}$	64 271	64 249	63 799
$CC_{THERMALEQUIVALENT}$	**34.7%**	**32.6%**	**23.7%**

1 Unit size equivalent to closed cycle gas turbine unit (see Table 8)

Yet again, in order to fully investigate these effects, the seasonal variation was investigated. The results of this investigation are presented in Table 29.

Table 29 Scenario 2 Seasonal Geographical Dispersion Analysis (Thermal Equivalent)

	Full Spread	**WC only**	**EC only**
Annual	34.7%	32.6%	23.7%
Spring	45.7%	39.5%	27.2%
Summer	43.5%	47.4%	27.2%
Autumn	32.6%	28.2%	27.2%
Winter	27.2%	24.0%	20.3%
Average	***37.3%***	***34.8%***	***25.5%***

From Table 29 and Figure 46, there is very little reduction in capacity credit between the Full Spread and the WC only configurations, owing mainly to the very good wind quality of WC in the summer with decreasing dispersion. However, this is not for the other seasons, showing the significance of this investigation as the intermittency of wind generation is well illustrated. Furthermore the capacity credit during the off peak seasons are on average 2% higher than the peak season.

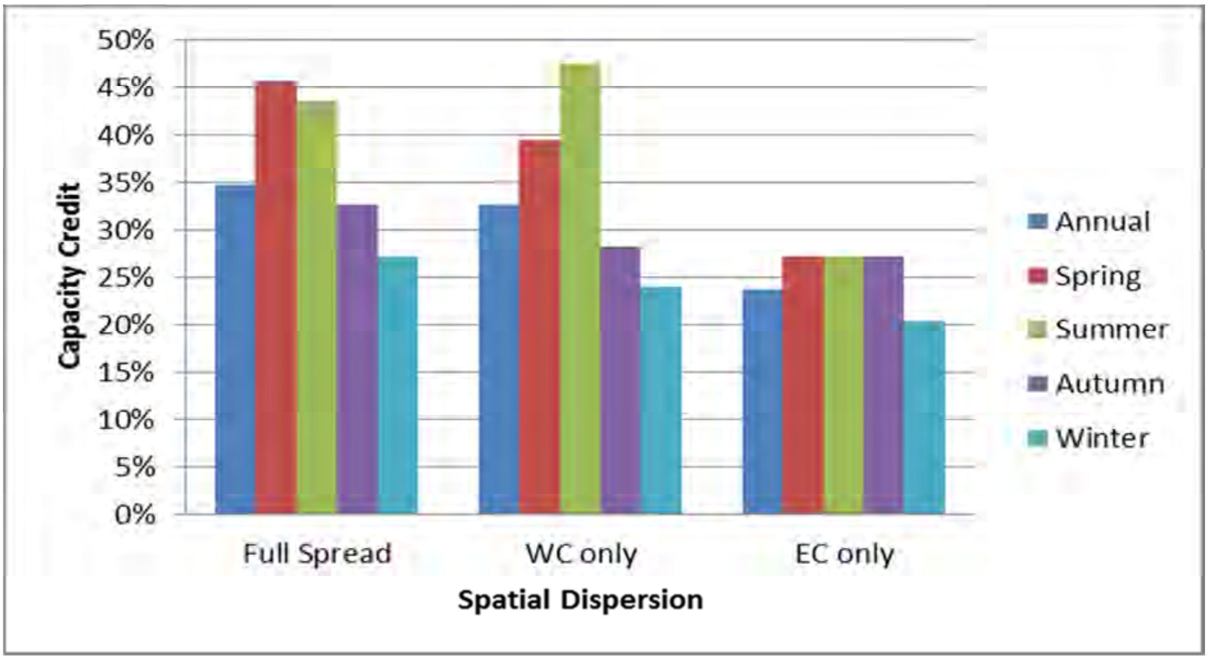

Figure 46 Scenario 2 Seasonal Geographical Dispersion Analysis (Thermal Equivalent)

5.3 Dispatch Model

5.3.1 Introduction

The dispatch model presented in this dissertation simulates the operation of a power plant mix in such a way so as to minimises power system operational cost, whilst meeting the hourly electricity demand. Monte Carlo simulations are used to develop performance and reliability indices (see Appendix D), taking into account uncertainty in unit availability. The performance indicators that are investigated are the electricity production per technology, the CO_2 produced by the system, and the cost involved with fuel consumption per technology.

Simulations were performed for one main scenario, a future 2030 scenario. 6 sub sets are investigated in order to study the effects of geographical dispersion and penetration level on the day to day characteristics of the generation system.

The subsets for the geographical dispersion investigation are as follows:

- Scenario A: Full Spread –Plants equally spread between the Western and Eastern Cape
- Scenario B: WC only – Wind Capacity is concentrated in the Western Cape
- Scenario C: EC only – Wind Capacity is concentrated in the Eastern Cape

The subsets for the penetration level investigation are as follows:

- 6% penetration level – Equivalent wind capacity is compared to the corresponding thermal capacity from Table 26
- 12% penetration level – Equivalent wind capacity is compared to the corresponding thermal capacity from Table 26
- 18% penetration level – Equivalent wind capacity is compared to the corresponding thermal capacity from Table 26

In order to ratify the dispatch model developed, the calculated performance indices developed in this dissertation are compared to those developed by the IRP. In the updated IRP (DoE, 2013), it was reported that for current situations, the electricity system would send out approximately 250 TWh of electricity. The system developed in this model sends out a total 252 TWh. Another important outcome of this simulation are the CO_2 emissions. The emissions produced by this simulation are comparable to those reported in the updated IRP with approximately 218 million tonnes of CO_2 emissions. The EENS of the system is 1.98 GWh. The IRP does not give an indication of the EENS for 2011.

However, it is far less than the threshold amount of 20 GWh stipulated in the IRP. With the base case scenario falling within the bounds of the IRP and sending the same amount of electricity, the 2030 future case and the effects of the wind energy on the day to day operation were investigated

5.3.2 2030 Future Generation Mix

Table 30 and Table 32 summarise the simulation results for 2030 future generation mix. The system developed in this model sends out a total of 405 TWh. From Table 30, the EENS of the system is 2.67 GWh.

Table 30 Average Annual Simulation Results

<table>
<tr><td colspan="3">Expected Energy not Served [GWh]</td><td>0.28</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="2">Technology Group</td><td>Installed Capacity [MW]</td><td>Production by Technology [TWh]</td></tr>
<tr><td colspan="2">Hydro Import Existing</td><td>1500</td><td>8.87</td></tr>
<tr><td colspan="2">Hydro RSA</td><td>670</td><td>5.26</td></tr>
<tr><td colspan="2">Hydro Import New</td><td>1500</td><td>11.83</td></tr>
<tr><td colspan="2">Nuclear new</td><td>4800</td><td>30.32</td></tr>
<tr><td colspan="2">Nuclear Existing</td><td>1800</td><td>19.02</td></tr>
<tr><td colspan="2">Coal New</td><td>2450</td><td>18.01</td></tr>
<tr><td colspan="2">Coal Existing</td><td>38605</td><td>207.41</td></tr>
<tr><td colspan="2">CCGT</td><td>6850</td><td>87.86</td></tr>
<tr><td colspan="2">OCGT New</td><td>4680</td><td>7.69</td></tr>
<tr><td colspan="2">OCGT Existing</td><td>3120</td><td>0.40</td></tr>
<tr><td rowspan="2">Wind</td><td>Western Cape</td><td>2180 (CF: 27.1%)</td><td rowspan="2">11.12</td></tr>
<tr><td>Eastern Cape</td><td>2180 (CF: 31.3%)</td></tr>
<tr><td colspan="2">Total</td><td>70335</td><td>407.8</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="3">CO_2 emissions [$MtCO_2$]</td><td>290.3</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="3">Production Costs [billion ZAR]</td><td>64.16</td></tr>
</table>

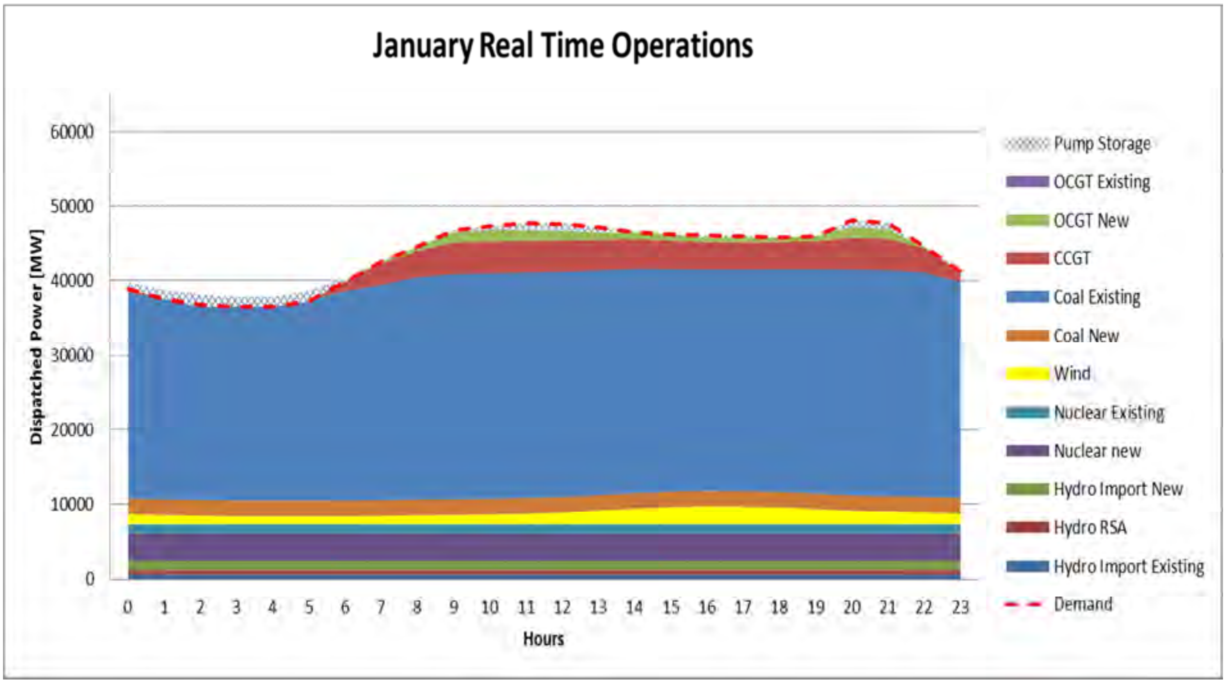

Figure 47 Summer Real Time Operations

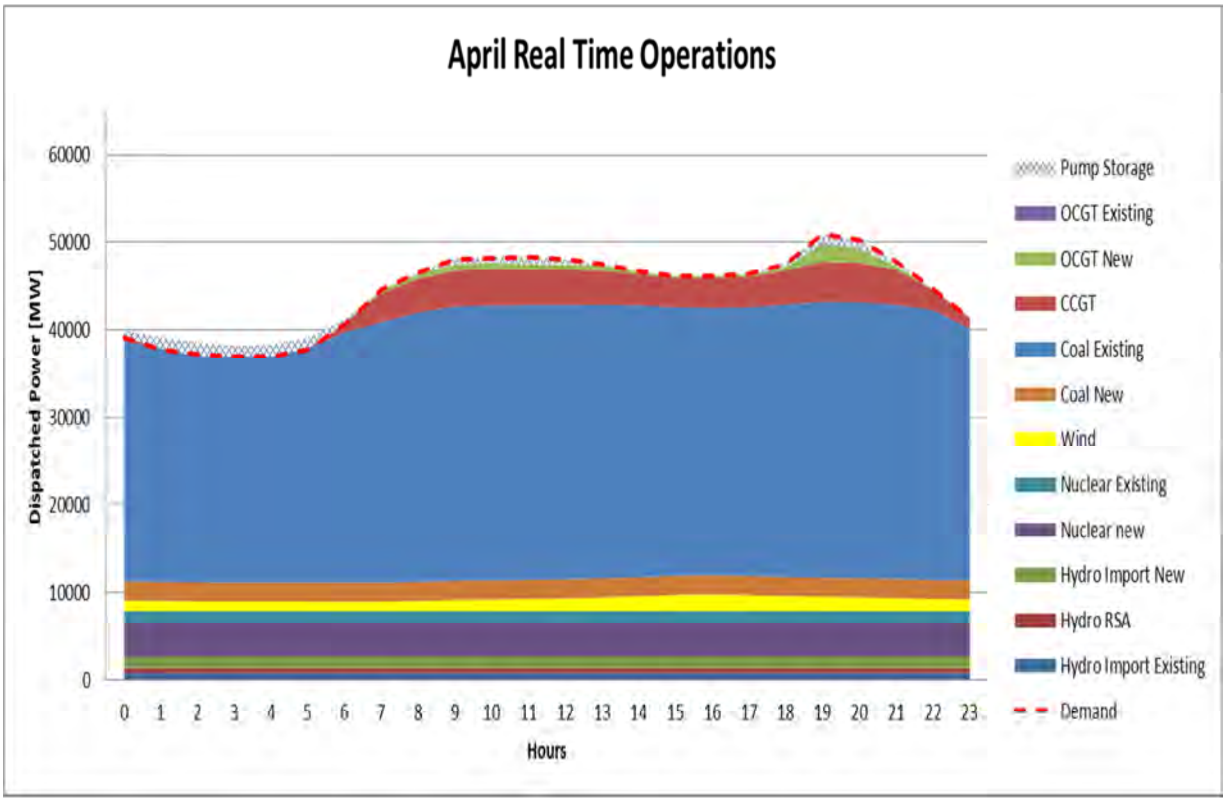

Figure 48 Autumn Real Time Operations

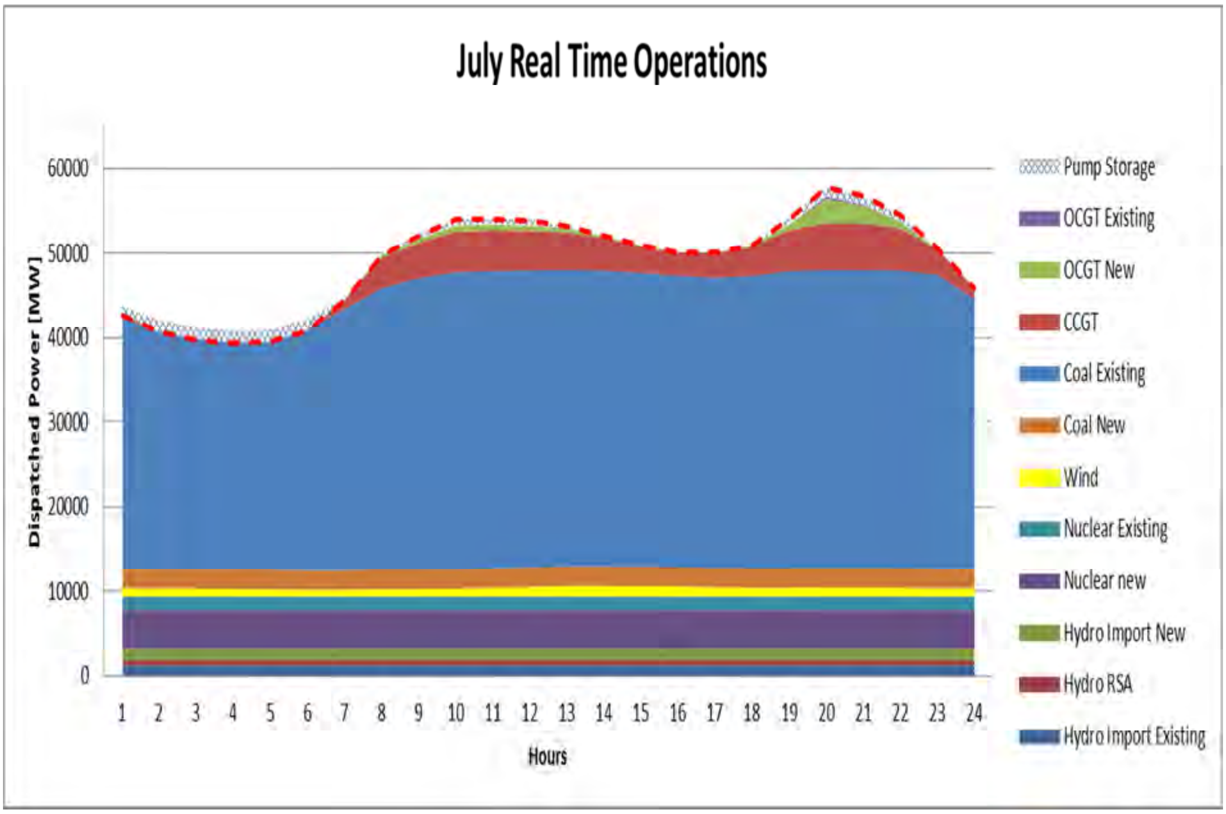

Figure 49 Winter Real Time Operations

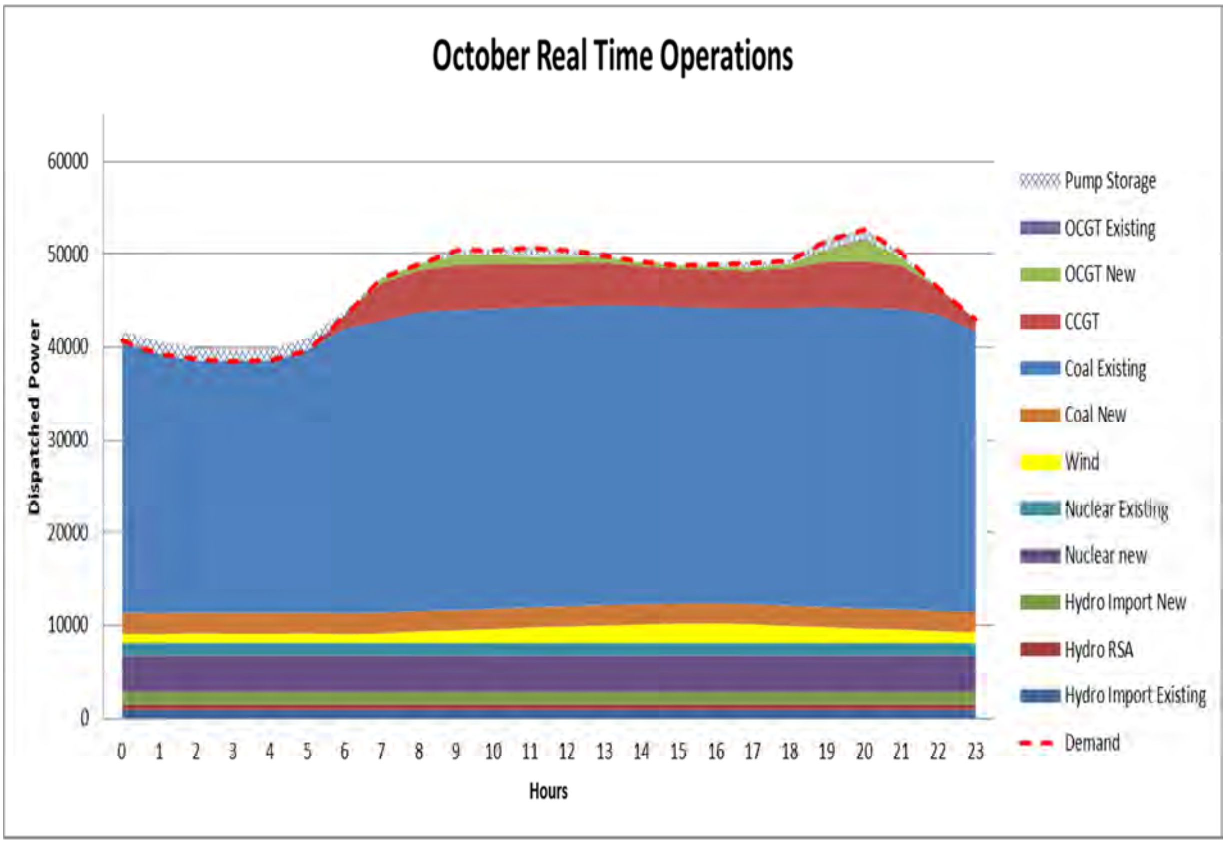

Figure 50 Spring Real Time Operations

The seasonal variation in supply and demand is displayed from Figure 47 to Figure 50 above. A distinct peak can be seen in the winter month of July, with the additional demand being met by small coal. Summer (January) conversely displays no distinct peak as the initial morning peak is similar to the later evening peak. Spring and autumn both display a morning peak and an evening peak.

The dispatch model is used to investigate the effects that penetration levels have on the generation system. It also used to test the capacity credit findings from the previous section by comparing the EENS produced by equivalent wind capacity against the corresponding thermal capacity from Table 26. It was found that the EENS produced by the two different technologies are comparable as illustrated in Table 31. In addition, the decreasing reliability as the penetration level increases compliments the capacity credit investigation findings.

Table 31 Wind Capacity vs Thermal Capacity

	Equivalent Wind Capacity[1]			Equivalent Thermal Capacity[2]		
Additional Capacity [MW]	4 100	8 600	12 000	1 422	2 607	3 318
Dispatched Conventional Power [TWh]	392.9	379.2	369.8	404.8	404.8	404.8
Wind Power Production [TWh]	11.9	25.6	35.1	0.00	0.00	0.00
EENS [GWh]	0.30	0.31	0.34	0.28	0.29	0.57
CO2 Emissions [$MtCO_2$]	63.7	58.96	56.88	66.00	61.03	59.78
Annual Production Cost [billion ZAR]	289.6	280.1	273.2	309.2	299.1	299.1

1 See Table 26

2 See Table 26

The diurnal generation profile gives an insight as to how much energy production there is per technology. These values are summarized in Table 32. The energy production per technology helps calculate the CO_2 emission per technology and associated production costs.

Table 32 Dispatch Model Scenario Analysis

Scenario	**Test Parameter**	**Additional Capacity [MW]**	**Dispatched Conventional Power [TWh]**	**Wind Power Production [TWh]**	**EENS [GWh]**	**CO_2 Emissions [$MtCO_2$]**	**Annual Production Cost [billion ZAR]**
A	Full Dispersion ***(CF: 29.1%)***	WC – 2180 EC – 2180	396.7	11.1	0.28	290.3	64.16
B	WC only ***(CF: 27.1%)***	4360	394.6	10.3	0.32	290.6	64.32
C	EC only ***(CF: 31.3%)***	4360	394.1	11.9	0.66	289.6	63.96

Due to the fact that the same load profile is used in these investigations, similar amounts of energy are dispatched for all scenarios. Approximately 291 Million tonnes of CO_2 emissions are produced in all configurations. This implies about 7MT of reductions in CO_2 emissions for all three scenarios. What is interesting to note is the although more wind power is produced in the EC only scenario, there is also more unserved energy and the same savings in CO_2 emissions, showing that the higher capacity factors of the EC are not necessarily the best from an overall system reliability and emissions point of view.

From Table 32, it is clear that the EENS increases with decreasing geographical dispersion. A small increase between scenario A and B is noted as this is in agreement with the capacity credit investigation. Since these two models were developed independent of each other, and they are in agreement with each other, this further reinforces the results.

Chapter 6

Conclusion and Recommendations

Due to global environmental concerns associated with conventional generation and depleted conventional energy resources to meet increasing electricity demand; renewable energy sources such as wind energy for electric power supply is receiving serious consideration around the world. This is more than evident in South Africa, where the REIPPPP has been implemented with a proposed capacity of 3725MW, allocating 1850MW to wind energy.

Wind energy is an energy source that varies randomly with time. The reliability of the intermittent wind energy is investigated in this dissertation. The reliability index that is used in this paper is the capacity credit, which is normally defined either as the amount of installed conventional generation capacity that can be replaced with wind energy maintaining the same system adequacy. Capacity credit is also sometimes defined as the amount of a 100% reliable generator that can be replaced by wind generators.

There are two important factors that affect the capacity credit of a wind system. These two factors are the geographical distribution of the wind farms and the penetration level of the installed capacity of the wind system as a share of the total system capacity. It can be argued that different wind farms from different wind regions combined together will decrease the intermittency of the overall wind power generation system. This dissertation proposed that this argument is in fact true. This hypothesis was explored through the investigation of the effects that the geographical distribution of the wind farms and the penetration level of the installed capacity have on the capacity credit, given currently available wind data. Time series data was used to simulate yield from 12 wind farms out of 23, which combines WASA wind mast sites and the preferred bidders from round 1 and 2 of the REIPPPP.

Two main scenarios, a 2011 base case scenario and a 2030 future scenario were used in both investigations. Both scenarios are based on the updated IRP base case scenario, which has a proposed generation mix from 2011 to 2050.

The capacity credit analysis was then tested using a simplified dispatch model of the SA generating system developed for this study. The simplified dispatch model also enabled the calculation of other relevant indicators for the power generation system for varying dispersion configurations, such as EENS and CO_2 emissions for 2030.

6.1 Summary of findings and Conclusions

The major findings can be divided into 3 main sections;

- Wind Generation
- Capacity Credit investigation
- Dispatch Model Analysis

6.1.1 Wind Generation

The investigations carried out in this study were based on 12 out of the 23 wind farms (8 WASA wind masts and 15 wind farms from round 1 and 2 of the REIPPPP). Time series data was available for all 23 sites, however only 12 wind farms were evaluated to due inconsistencies in time series data. The resulting wind generation data is summarised in Table 33.

Table 33 Wind Generation Summary

	Annual	Summer	Autumn	Winter	Spring
Theoretical Yield [MWh]	735 110	181 250	185 288	185 288	183 274
Model Yield [MWh]	301 294	84 588	72 101	62 434	82 171
Capacity Factor	**41.0 %**	**46.7%**	**38.9%**	**33.7%**	**44.8%**

The capacity factors presented in Table 33 are in close to the quoted capacity factor by the independent power producers for the different wind projects involved in the REIPPP (see Table 15). The seasonal variation is important, with the summer (off-peak) months producing the highest capacity factor of 46.7%. The lowest capacity factor is produced during the winter (peak) months. However, the capacity factor does not indicate how wind generation will affect the reliability of the system, thus the capacity credit needs to be calculated.

6.1.2 Capacity Credit

The outcomes of the capacity credit investigation in this dissertation are further sub-divided into penetration level analysis and geographical dispersion analysis.

6.1.2.1 Penetration level

For both scenarios in the penetration level analysis, there is a gradual decrease in capacity credit with increasing penetration levels as shown in Figure 51 and Figure 52. This is in agreement with the GIZ study (DoE, Eskom & GIZ, 2011).

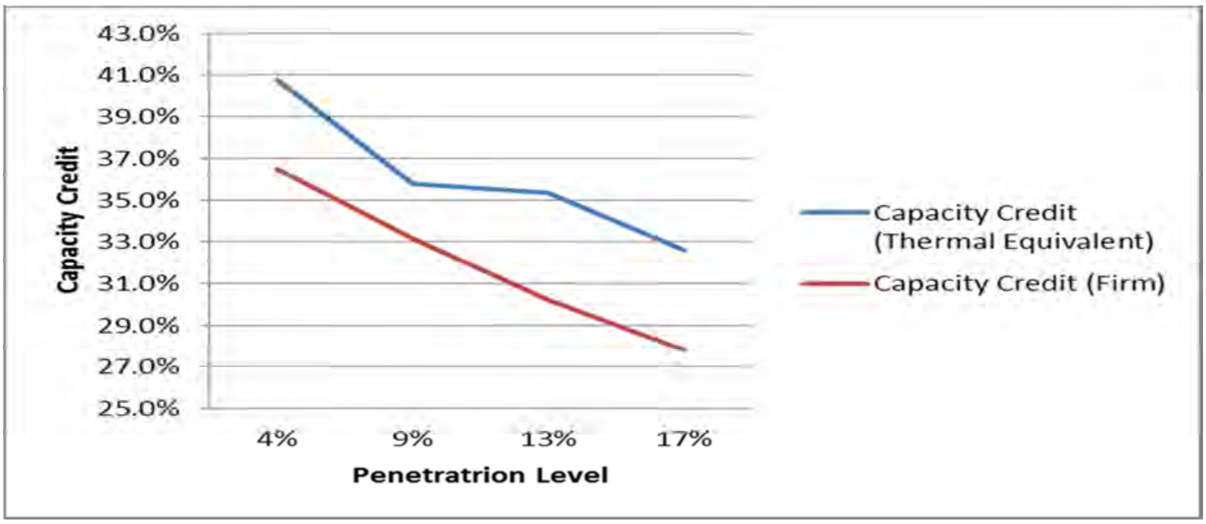

Figure 51 Scenario 1 Penetration level Summary

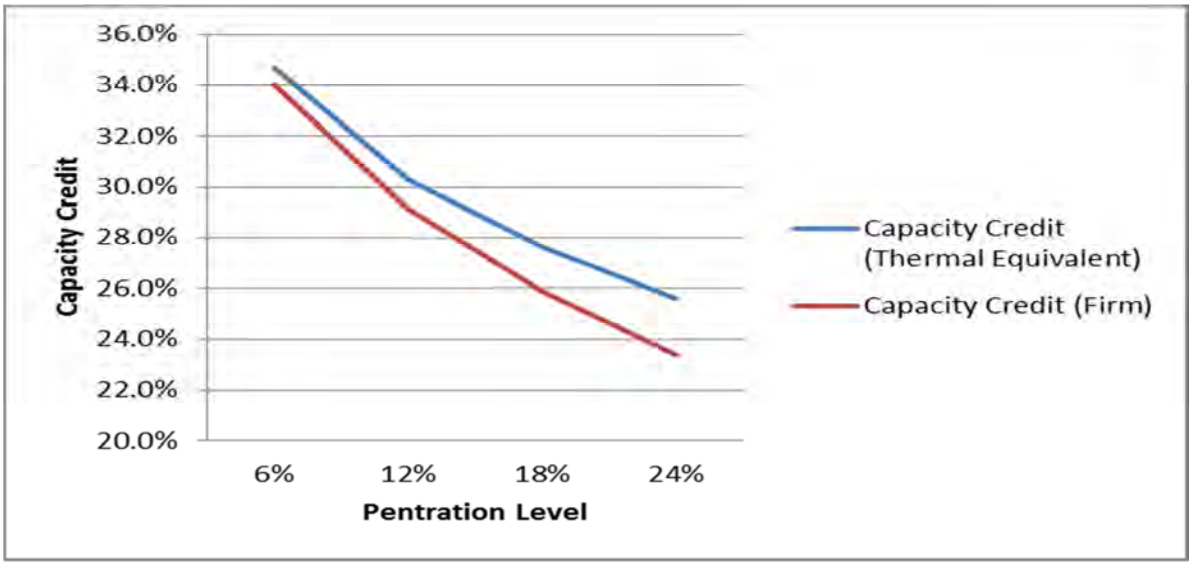

Figure 52 Scenario 2 Penetration level Summary

$CC_{THERMALEQUIVALENT}$ is a function of the characteristics of the assumed thermal units, therefore it will always be higher by CC_{FIRM}. The difference between $CC_{THERMALEQUIVALENT}$ AND CC_{FIRM} decreases from scenario 1 to 2. This is because in the first scenario, the thermal units used were assumed to be equivalent to small coal power plant unit with a FOR of 12.2%, whereas in scenario 2 it was assumed to be equivalent to CCGT unit with a FOR of 4.6%. The reliability of the unit utilised is reduced.

These findings reflect on the chosen methodology to develop and analyse these results. The capacity credit has two definitions in this dissertation, one for equivalent conventional capacity and the other for firm capacity (see section 4.2.3). The difference in the figures produced highlights the importance of the capacity credit definition used when one reports it. Although the calculation method used in CC_{FIRM} is simpler and faster than $CC_{THERMALEQUIVALENT}$, it does not necessarily imply that it is a better definition.

The capacity credit was also estimated for different seasons. For both scenarios, spring produced the best capacity credit at low penetration while at higher penetration levels, it is summer that had the best capacity.

6.1.2.2 Geographical Distribution

It was further found that the capacity credit decreases with decreasing geographical dispersion, which is consistent with literature. This is due to the fact that as geographical dispersion decreases, the correlation between the wind farms in the system increases.

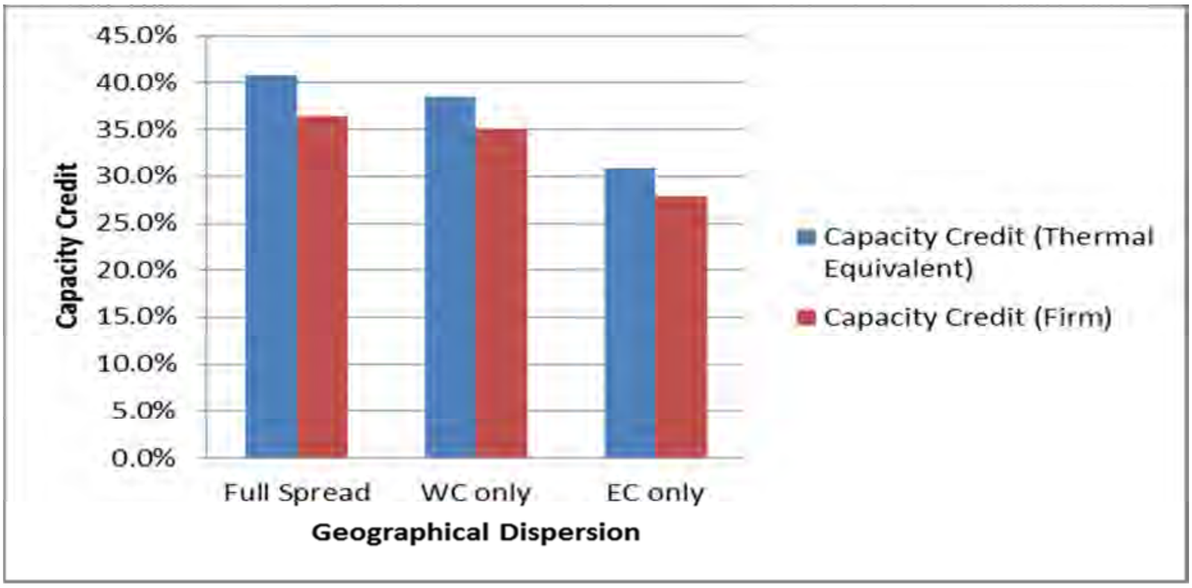

Figure 53 Scenario 1 Geographical Dispersion Summary

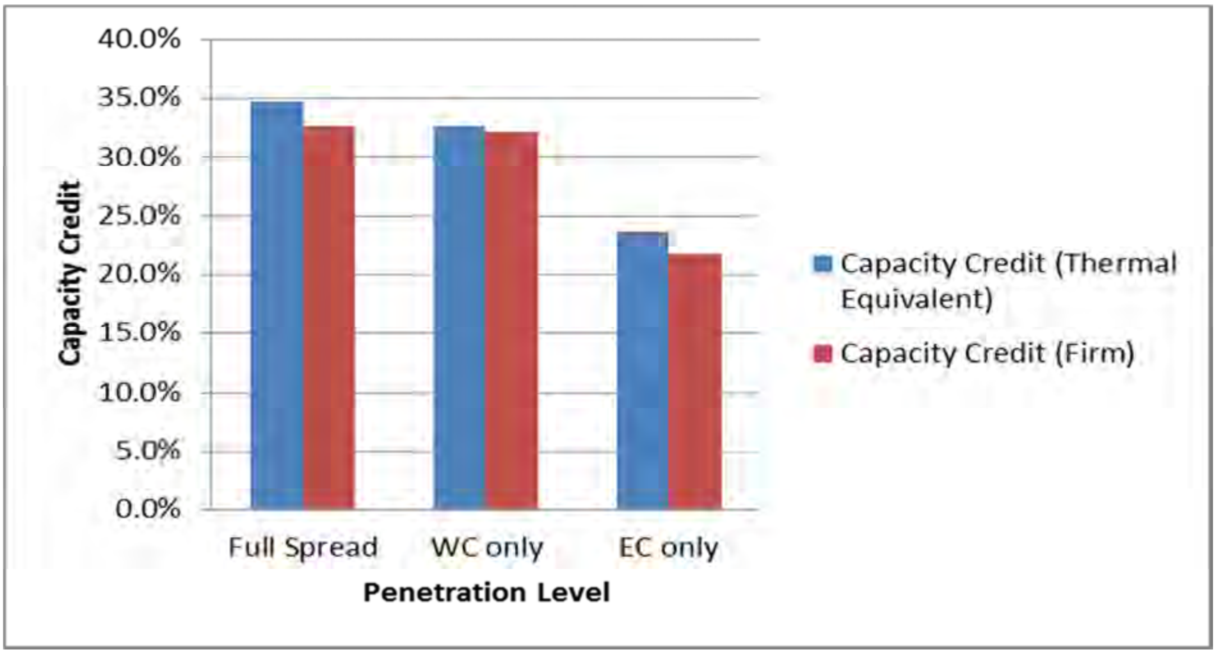

Figure 54 Scenario 2 Geographical Dispersion Summary

There is very little reduction in capacity credit for both definitions between from Full dispersion and WC only. This is driven by good quality wind for Western Cape during summer. However, the reduction between fully spread and EC only is more pronounced.

The seasonal variation also decreases with decreasing dispersion. This result can be better understood by looking at the diurnal trends (see Appendix A.2). The seasonal variation for the wind farms in the EC was not as pronounced as the other provinces, affecting the capacity credit.

Two different scenarios with different assumptions were investigated producing similar results. The difference in results was mainly explained by the different forced outage rate of the equivalent thermal unit chosen for the calculation.

6.1.2 Dispatch Model

There are a number of interesting outcomes observed from the dispatch model, the first being that the performance and reliability indicators developed by the dispatch model for the existing system are in agreement with the findings of the IRP (DoE, 2013).

Table 35 and Table 34 summarise the findings of the dispatch model investigations.

Table 34 Wind vs Thermal

	Equivalent Wind Capacity			Equivalent Thermal Capacity		
Additional Capacity [MW]	4 100	8 600	12 000	1 422	2 607	3 318
Dispatched Conventional Power [TWh]	392.9	379.2	369.8	404.8	404.8	404.8
Wind Power Production [TWh]	11.9	25.6	35.1	0.00	0.00	0.00
EENS [GWh]	0.30	0.31	0.34	0.28	0.29	0.57
CO2 Emissions [MtCO$_2$]	63.7	58.96	56.88	66.00	61.03	59.78
Annual Production Cost [billion ZAR]	289.6	280.1	273.2	309.2	299.1	299.1

From Table 34 above, it is important to note the similarity in the system reliability for the system with equivalent thermal capacity and the system with wind. Furthermore, the decreasing reliability as the penetration level increases compliments the capacity credit investigation findings.

Table 35 Dispatch Model Summary

Scenario	Test Parameter	Additional Capacity [MW]	Dispatched Conventional Power [TWh]	Wind Power Production [TWh]	EENS [GWh]	CO_2 Emissions [MTCO$_2$]	Production Cost [billion ZAR]
A	Full Dispersion ***(CF: 29.1%)***	WC – 2180 EC – 2180	393.7	11.1	2.67	290.8	67.56
B	WC only ***(CF: 27.1%)***	4360	394.5	10.3	2.94	291.3	67.94
C	EC only ***(CF: 31.3)***	4360	392.9	12.0	5.98	290.4	67.57

It was found that the reliability of the system decreases with decreasing geographical dispersion as predicted by the capacity credit analysis. What is interesting to note is that although more wind power is produced in the EC only scenario, there is also more unserved energy, showing that the higher capacity factors of the EC are not necessarily the best from an overall system reliability. This result confirms the fact that the capacity factor alone does not adequately characterise the impact of wind energy in a power system.

6.1.3 Conclusion

This study has provided an estimate of the capacity credit of wind, given available data, which can now be used as an input, to other optimisation/planning models. Additionally, it has introduced into the public domain a simple working dispatch model that could be used to better understand the role of renewables in the South African power system.

The concepts presented and examples illustrated in this dissertation have the potential to help system planners and utility managers to assess the reliability and value that wind can add to the system for different spatiotemporal scenarios and provide useful input into the decision making process.

6.2 Future Work

Academic research should not only add to the body of knowledge of the area researched, but to initiate interest and debate around the topic, aiding future research.

This body of work can be used to further research work in renewable energy interactions with existing power systems. Below are suggestions that will add to research performed in this dissertation and enhance the research area a whole:

- Publicly available time series data is extremely hard to acquire, therefore time should be taken to obtain better quality time series data from regions in South Africa. This would improve the geographical dispersion analysis.
- The capacity credit estimates and the dispatch model could be used to optimise the spatial arrangements of wind farms in South Africa, which can be used as a guideline for allocating future wind projects.
- Further sensitivity analysis can be performed on CO_2 emissions to investigate the actual benefits of wind for the system.
- The dispatch model could be further developed to include other emerging renewable technologies such as solar PV and concentrated solar power into the generation mix. The penetration levels of these renewable technologies can also be optimised to develop a generation mix that has the greatest impact on reliability and CO_2 emissions.
- The dispatch model could be also further developed to include some of the currently missing characteristics of power system management, such as the uncertainty in demand forecasting, the ramp rates constraints and minimum start up and shut down times for thermal plants.

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Appendix A – Wind Generation

A.1 Individual Wind Farm Analysis

The individual wind farm analysis is presented in this section. The approach described in chapter 3 is applied to the individual wind farm analysis. The difference in data quality between WASA and SAWS data is more than evident with the distributions presented in this section of the appendices. The WASA data is Wind Mast 01 to 08 and the SAWS data set is the REIPPPP round 1 and 2 wind farms.

A.1.1 Wind Mast 01

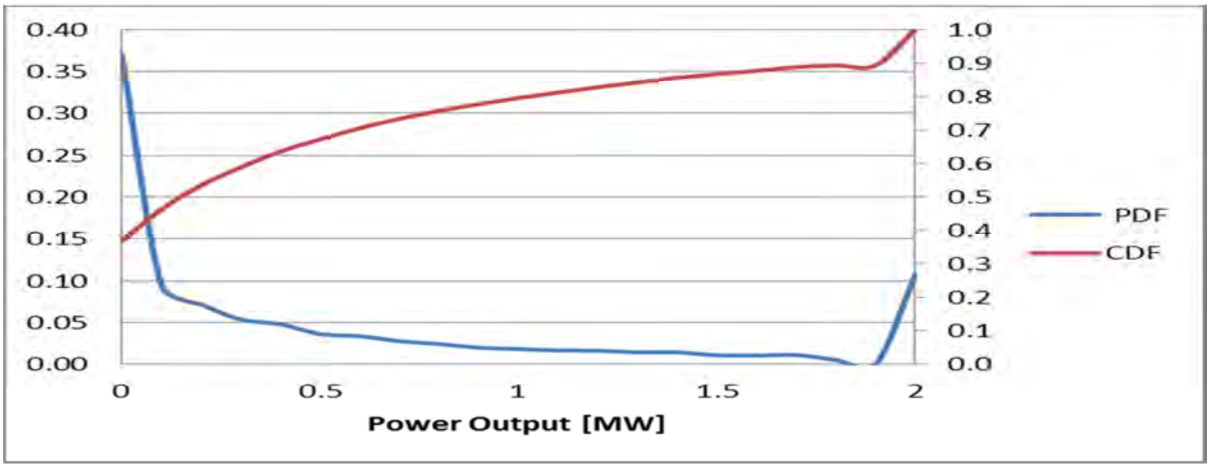

Figure 55 WM 01 Power Output Distributions

A.1.2 Wind Mast 02

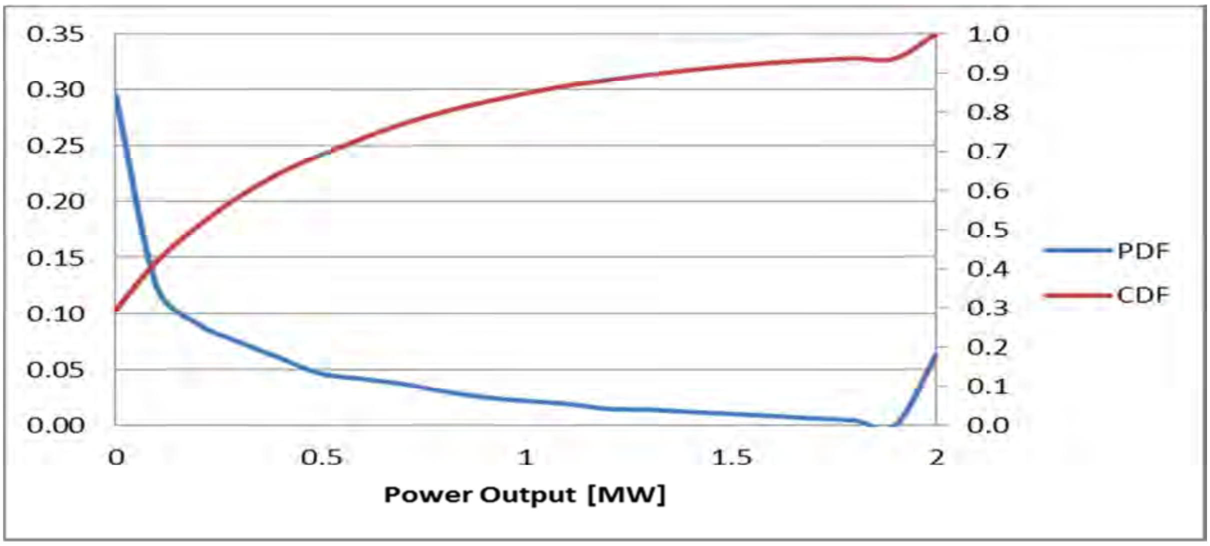

Figure 56 WM02 Power Output Distributions

A.1.3 Wind Mast 03

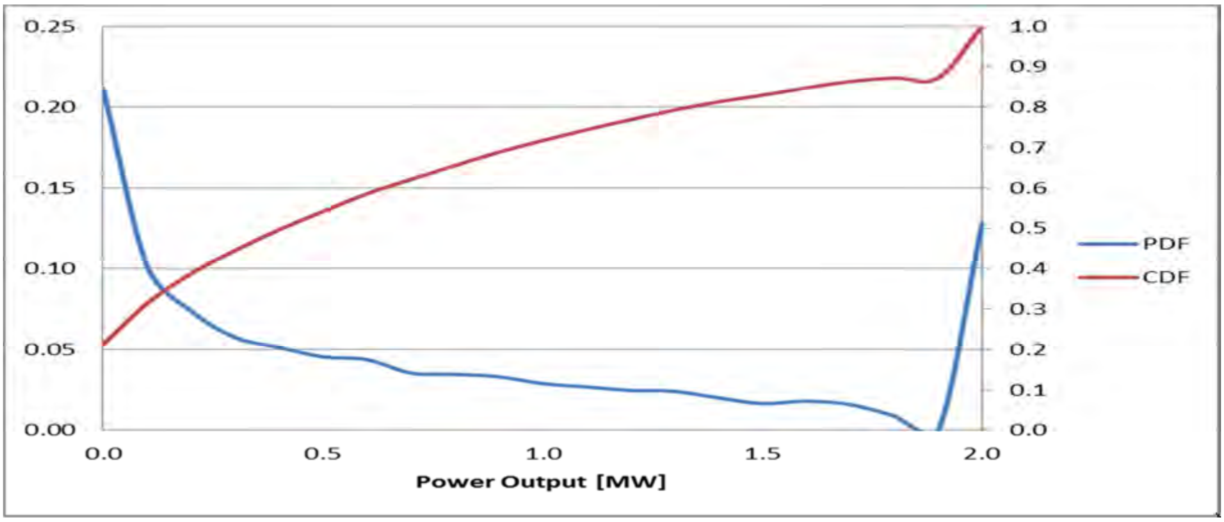

Figure 57 WM 03 Power Output Distributions

A.1.4 Wind Mast 04

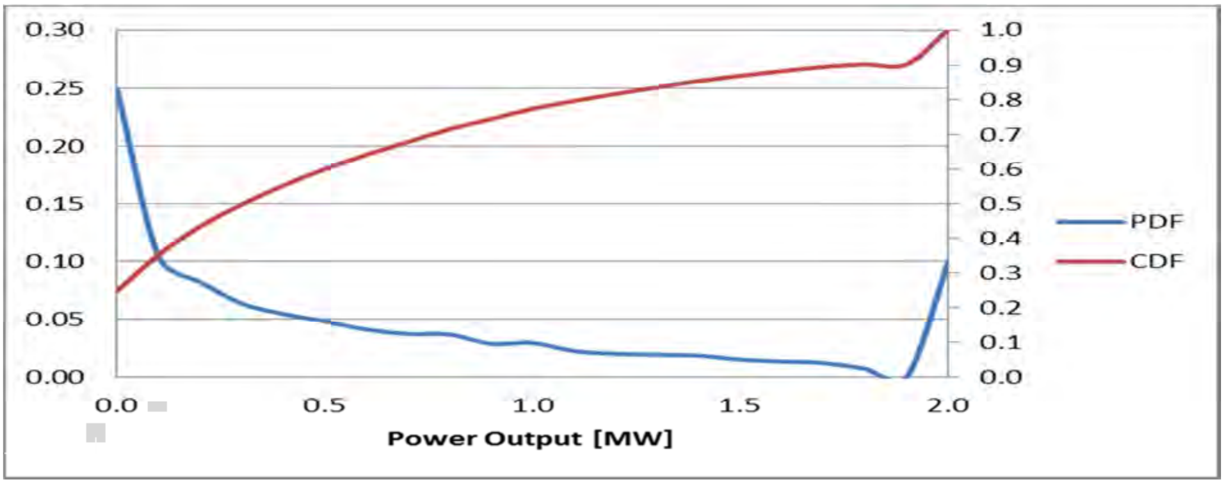

Figure 58 WM 04 Power Output Distributions

A.1.5 Wind Mast 05

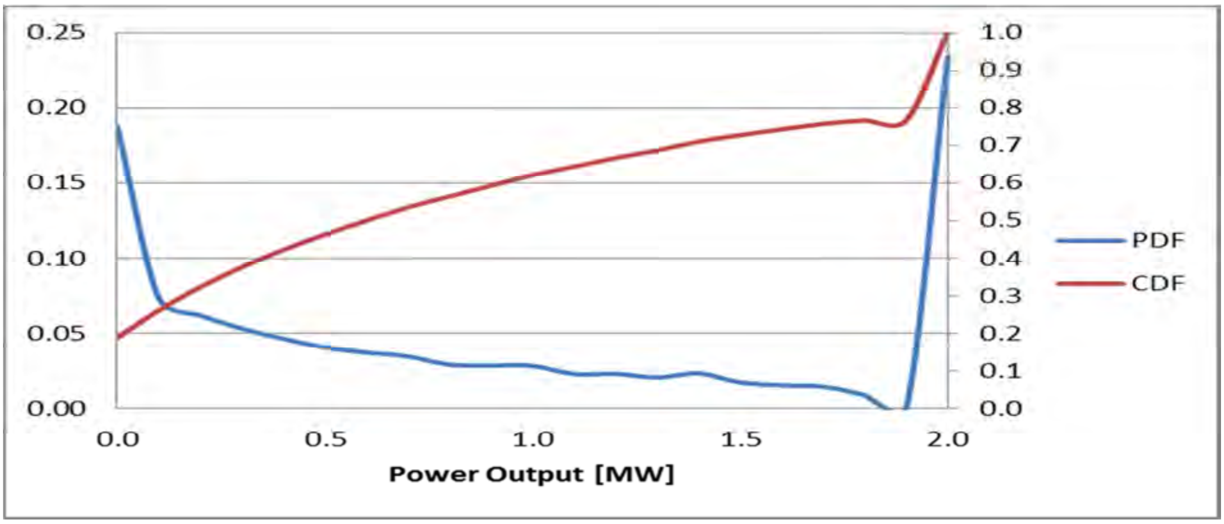

Figure 59 WM 05 Power Output Distributions

A.1.6 Wind Mast 06

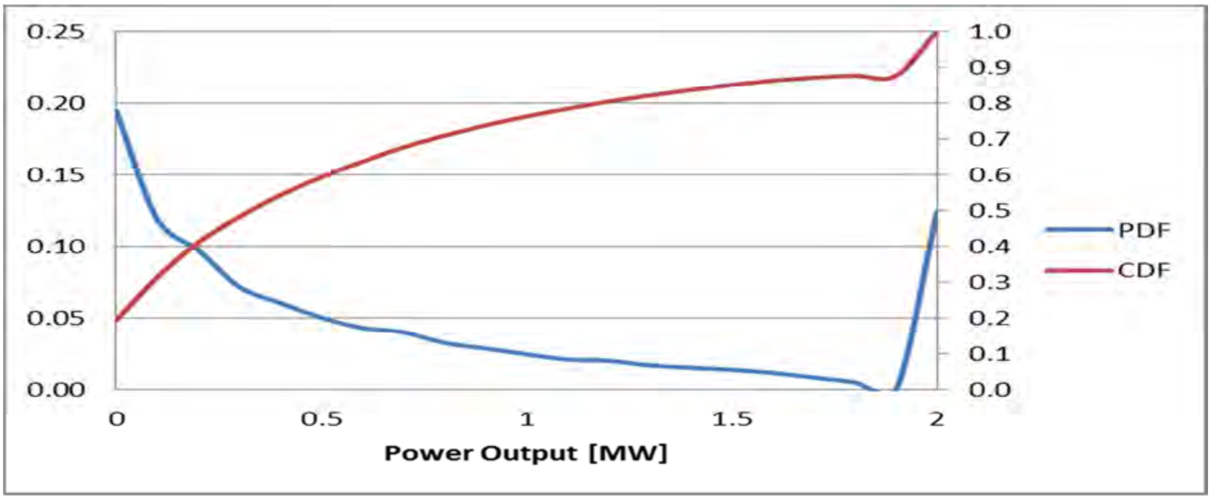

Figure 60 WM 06 Power Output Distributions

A.1.7 Wind Mast 07

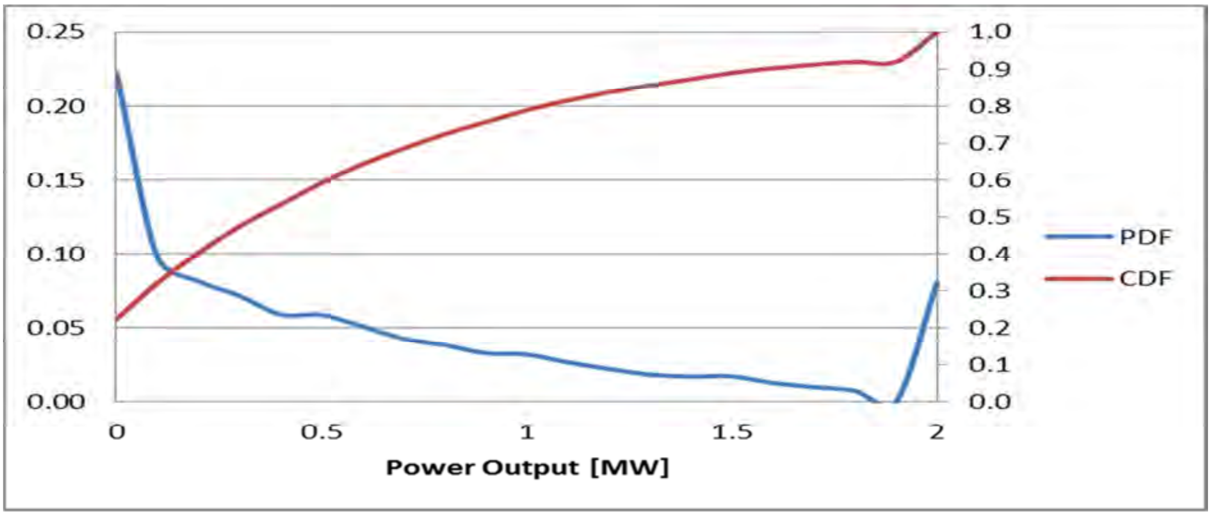

Figure 61 WM07 Power Output Distributions

A.1.8 Wind Mast 08

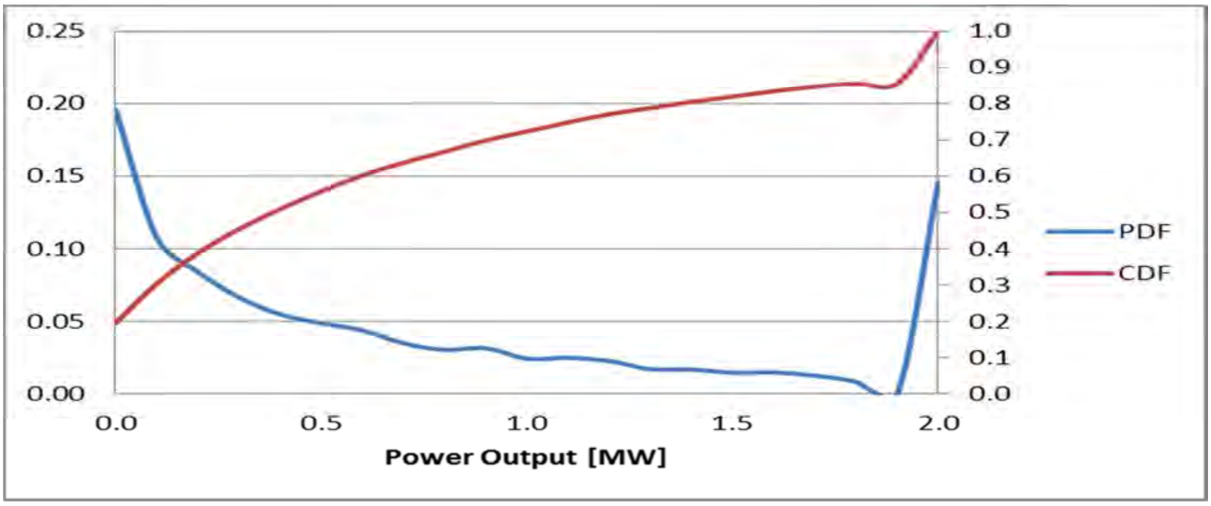

Figure 62 WM08 Power Output Distributions

A.1.9 Hopefield Wind Farm

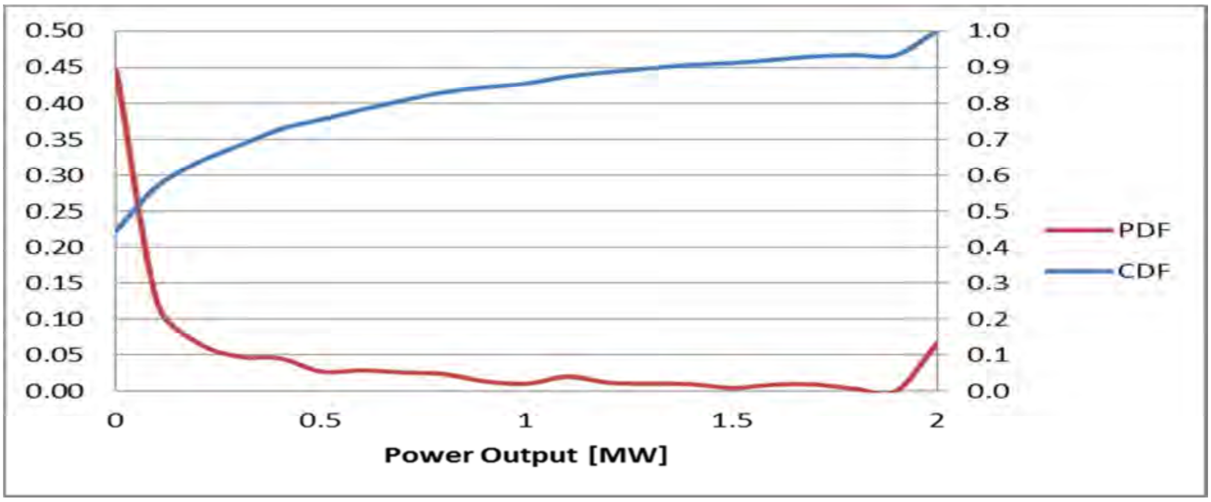

Figure 63 Hopefield Wind Farm Power Output Distributions

A.1.10 Dassiesklip Wind Farm

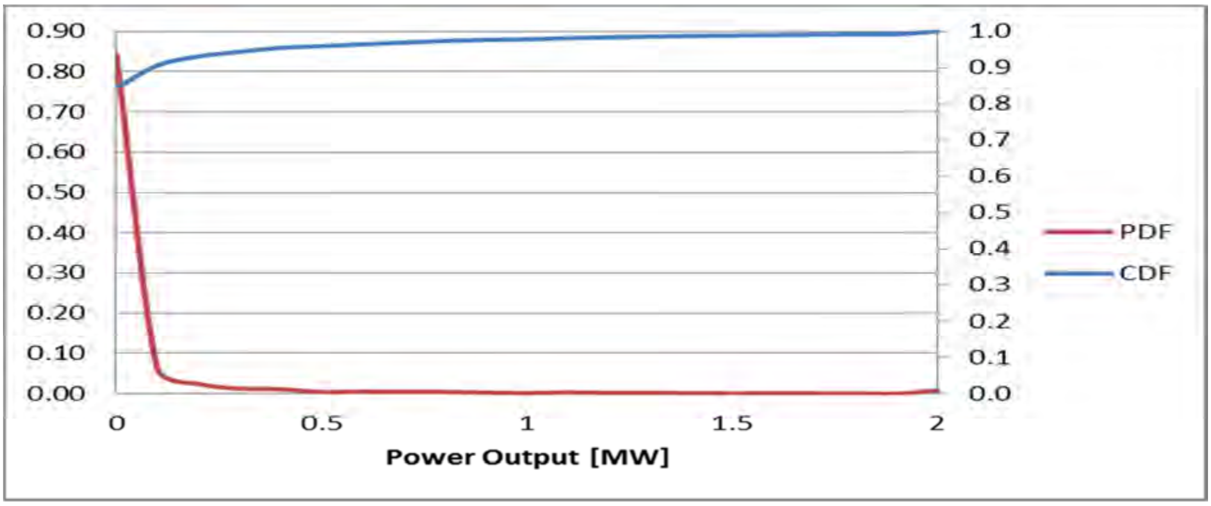

Figure 64 Dassiesklip Wind Farm Power Output Distributions

A.1.11 Noblesfontein Wind Farm

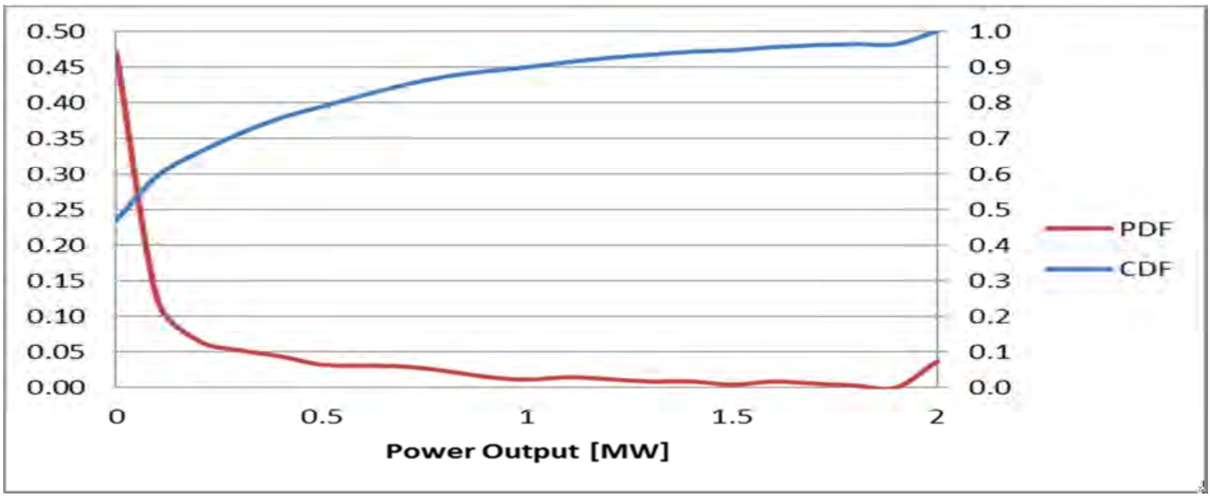

Figure 65 Noblesfontein Wind Farm Power Output Distributions

A.1.12 Dorper Wind Farm

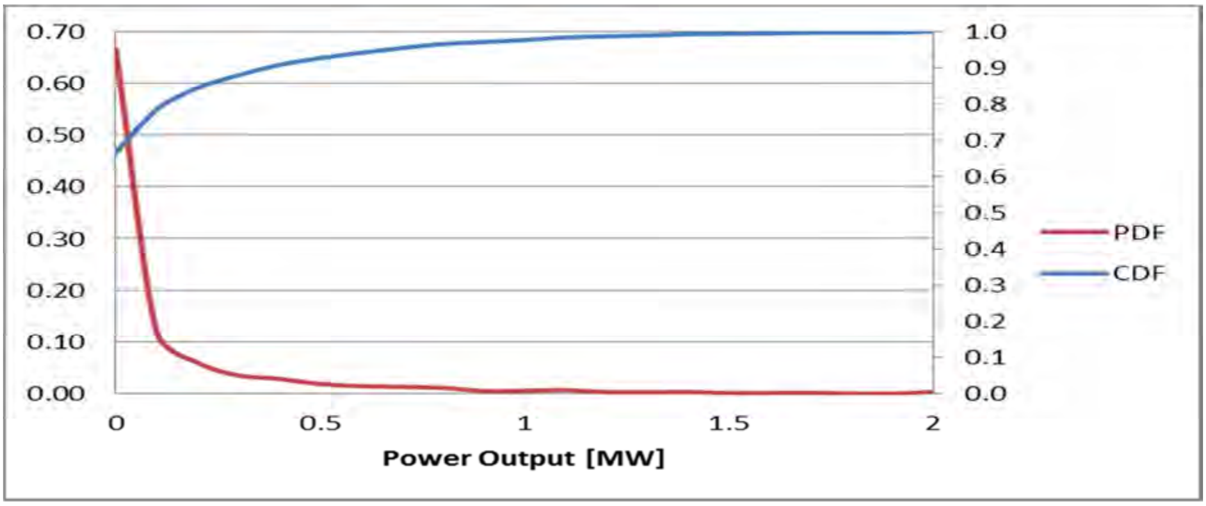

Figure 66 Dorper Wind Farm Power Output Distributions

A.1.13 Metro Wind Farm

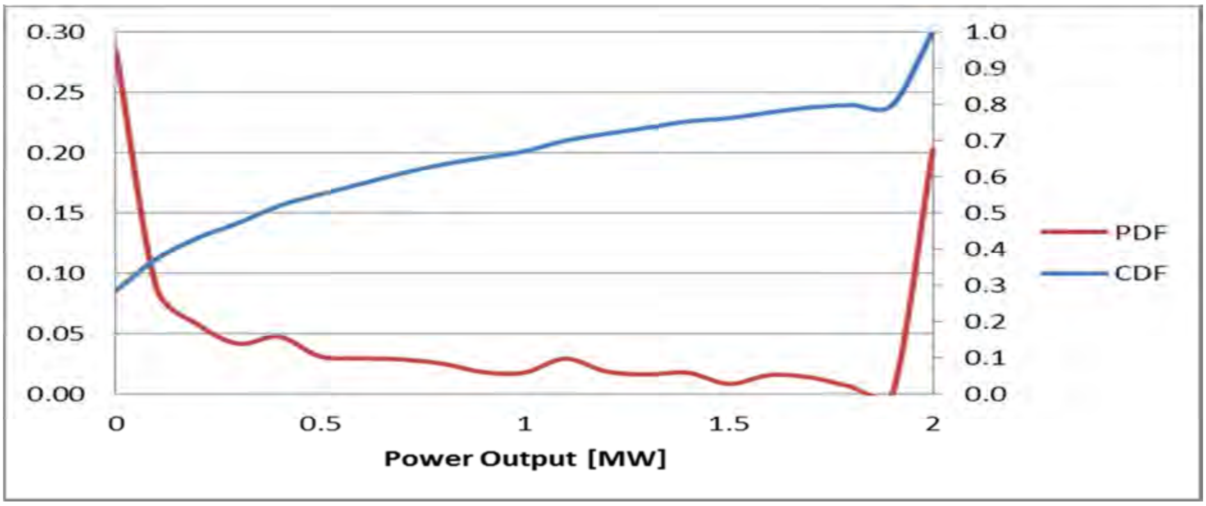

Figure 67 Metro Wind Wind Farm Power Output Distributions

A.1.14 Jeffrey's Bay Wind Farm

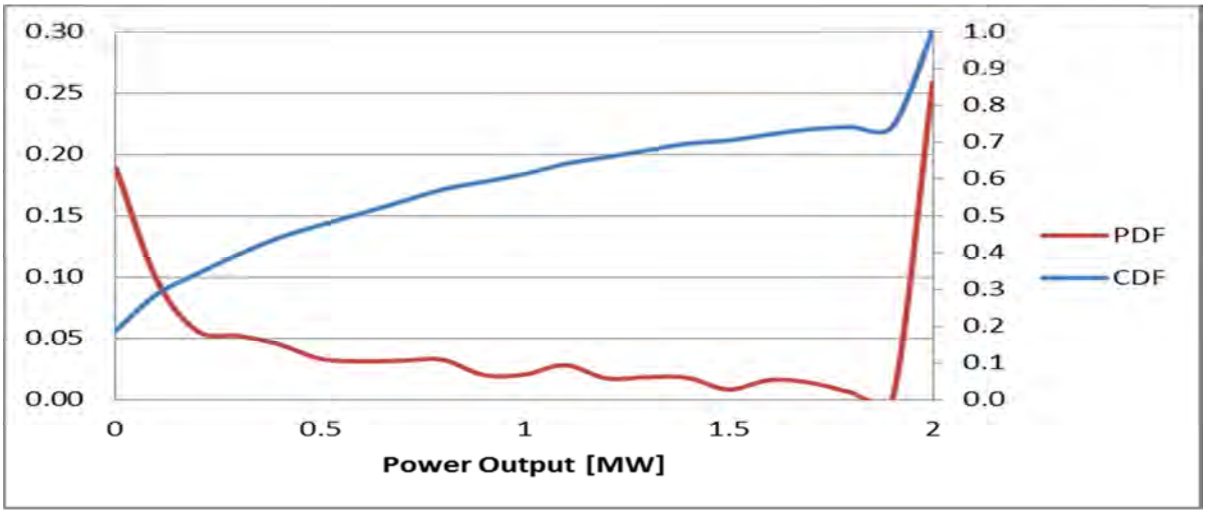

Figure 68 Jeffrey's Bay Wind Farm Power Output Distributions

A.1.15 RedCap Kouga Wind Farm

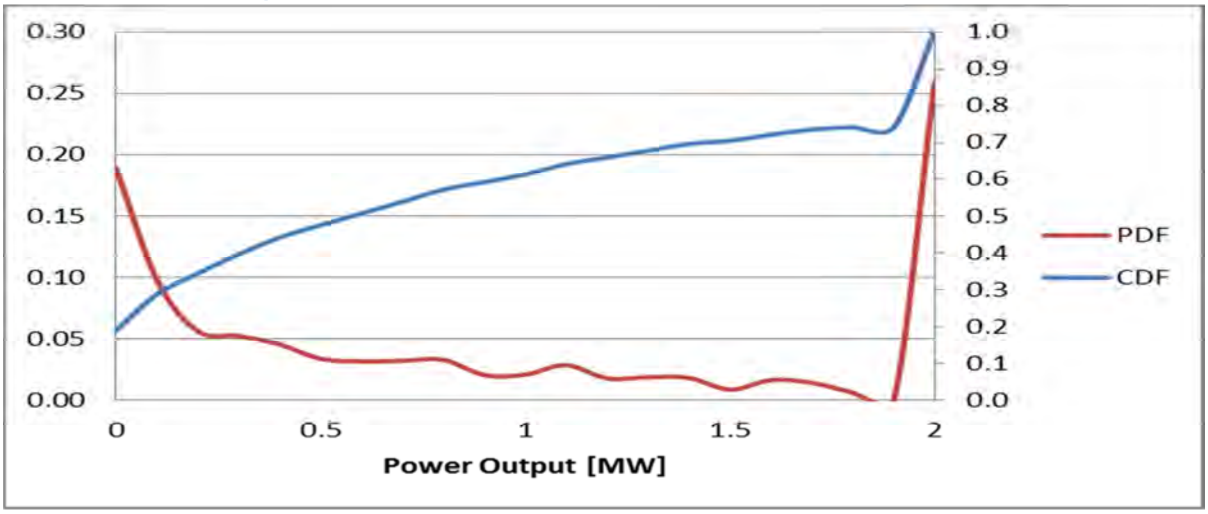

Figure 69 RedCap Kouga Wind Farm Power Output Distributions

A.1.16 Cookhouse Wind Farm

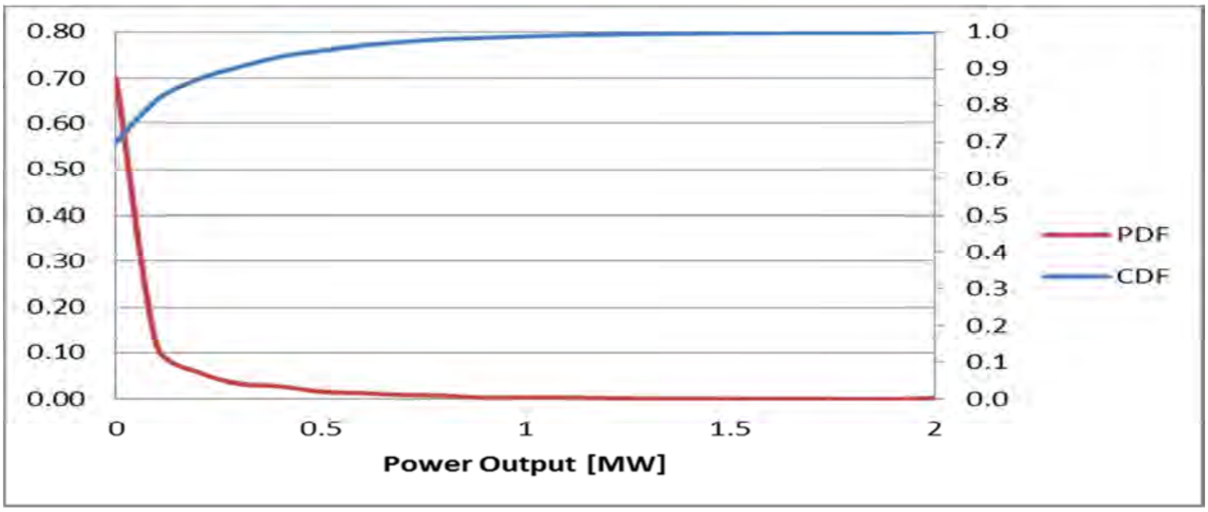

Figure 70 Cookhouse Wind Farm Power Output Distributions

A.1.17 West Coast Wind Farm

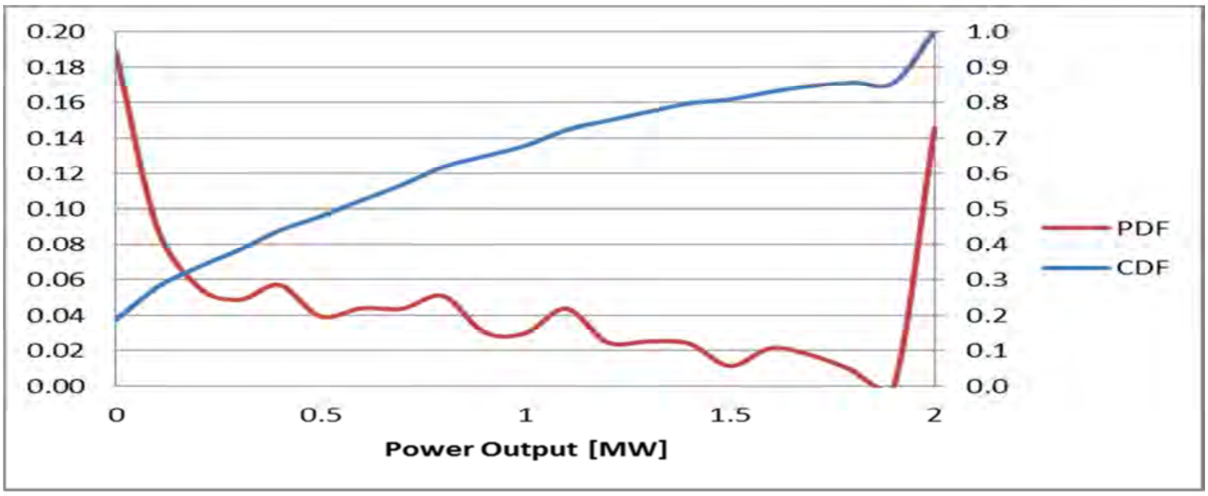

Figure 71 West Coast Wind Farm Power Output Distributions

A.1.18 Gouda Wind Farm

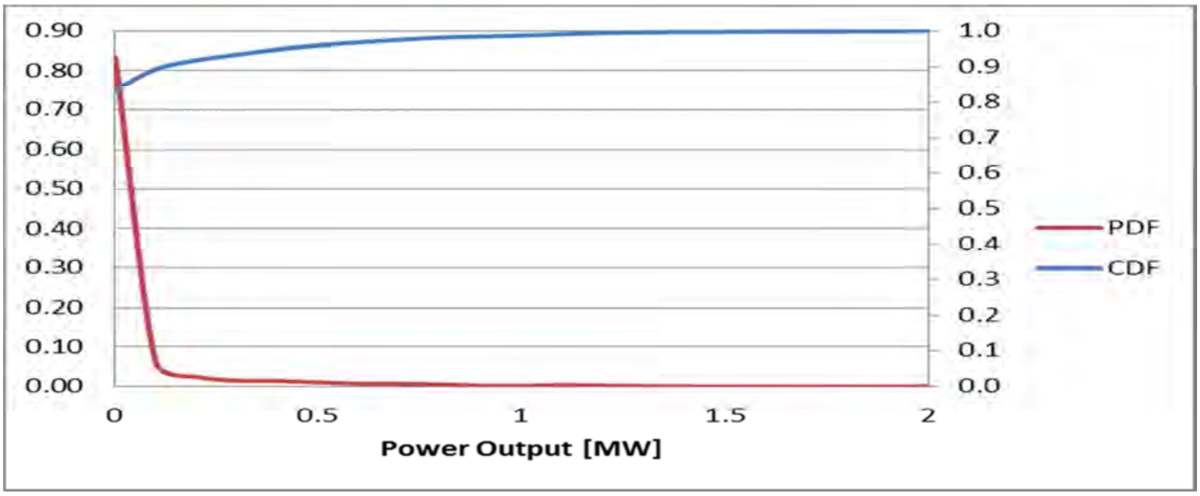

Figure 72 Gouda Wind Farm Power Output Distributions

A.1.19 Tsitsikamma Wind Farm

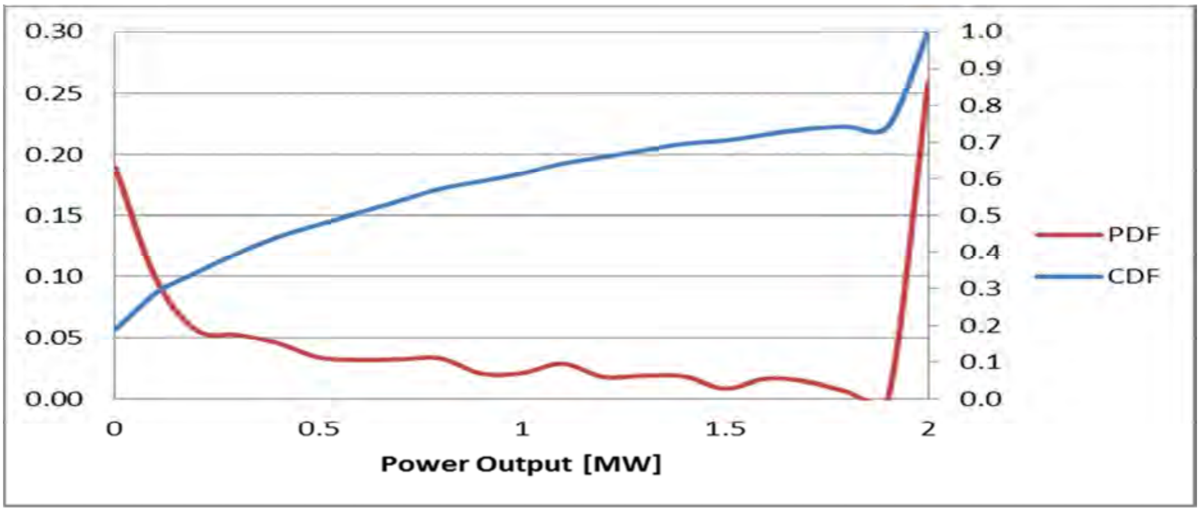

Figure 73 Tsitsikamma Wind Farm Power Output Distributions

A.1.20 Grassridge Wind Farm

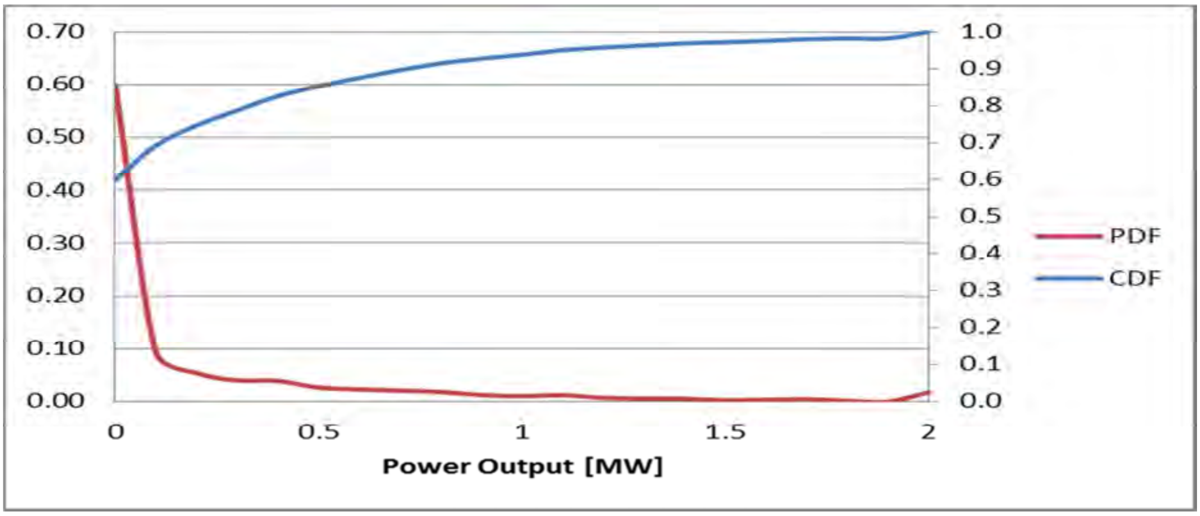

Figure 74 Grassridge Wind Farm Power Output Distributions

A.1.21 Waainek Wind Farm

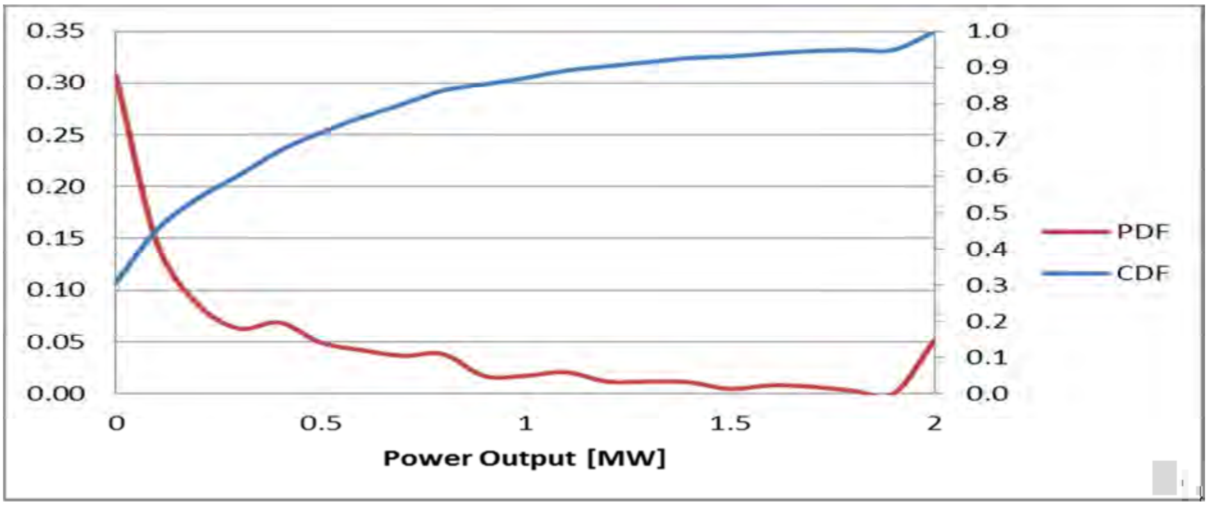

Figure 75Waainek Wind Farm Power Output Distributions

A.1.22 Amakhala Wind Farm

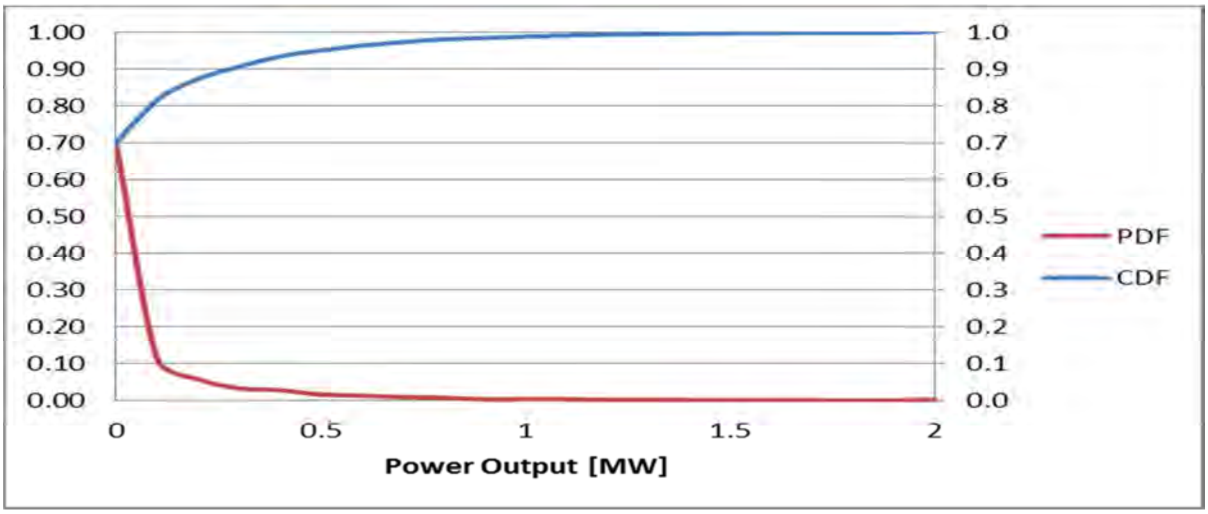

Figure 76 Amakhala Wind Farm Power Output Distributions

A.1.23 Chaba Wind Farm

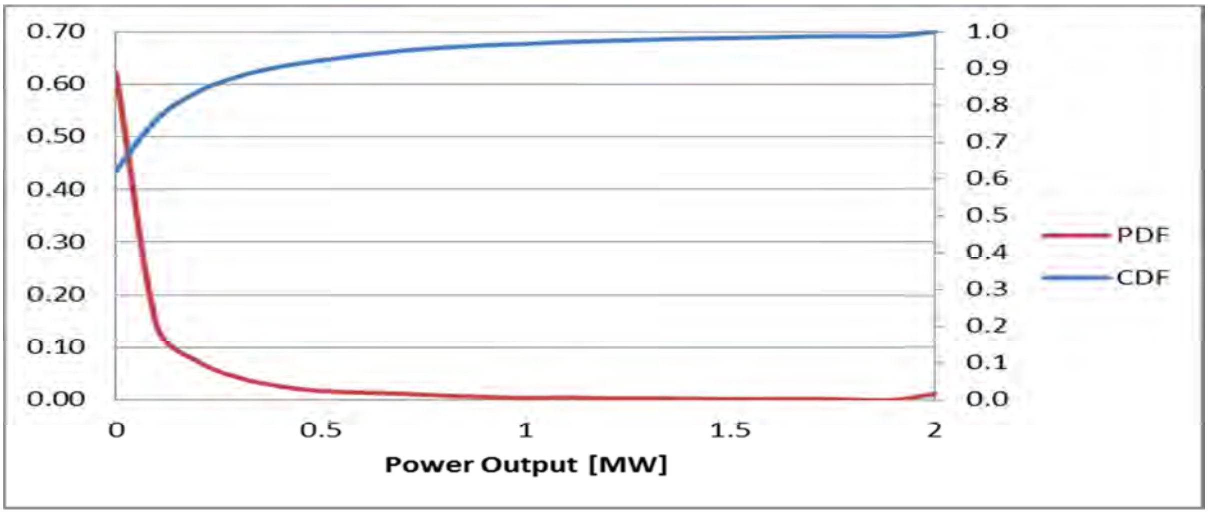

Figure 77 Chaba Wind Farm Power Output Distributions

A.2 Diurnal Trends

A.2.1 Summer Season

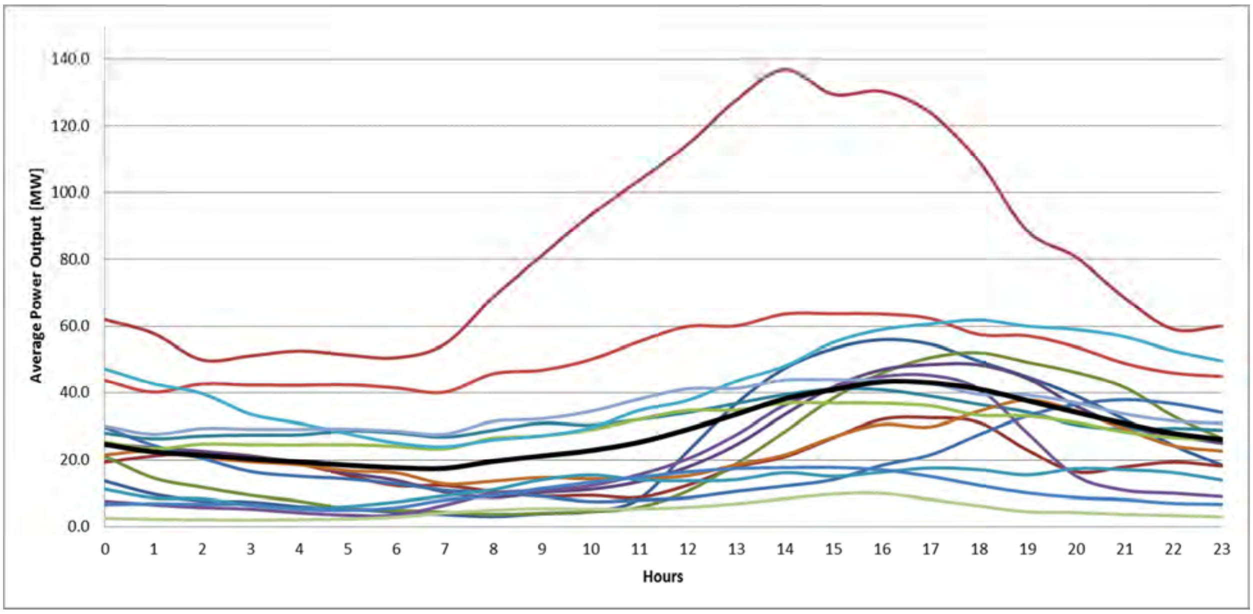

Figure 78 Summer Diurnal Trends

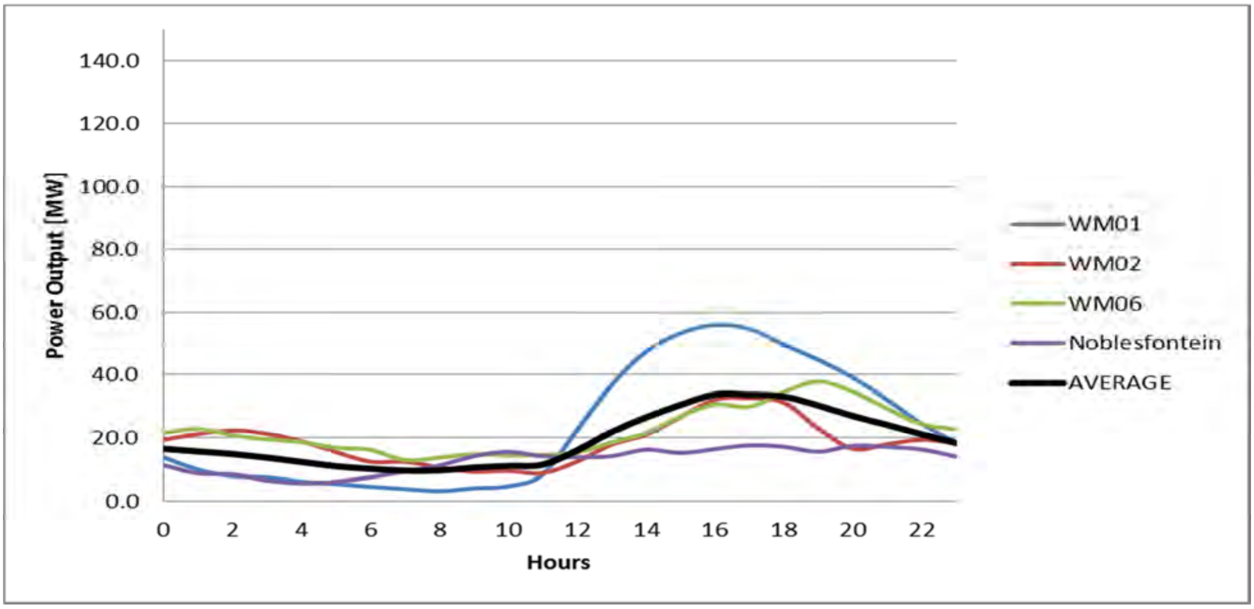

Figure 79 Northern Cape diurnal trend for Summer

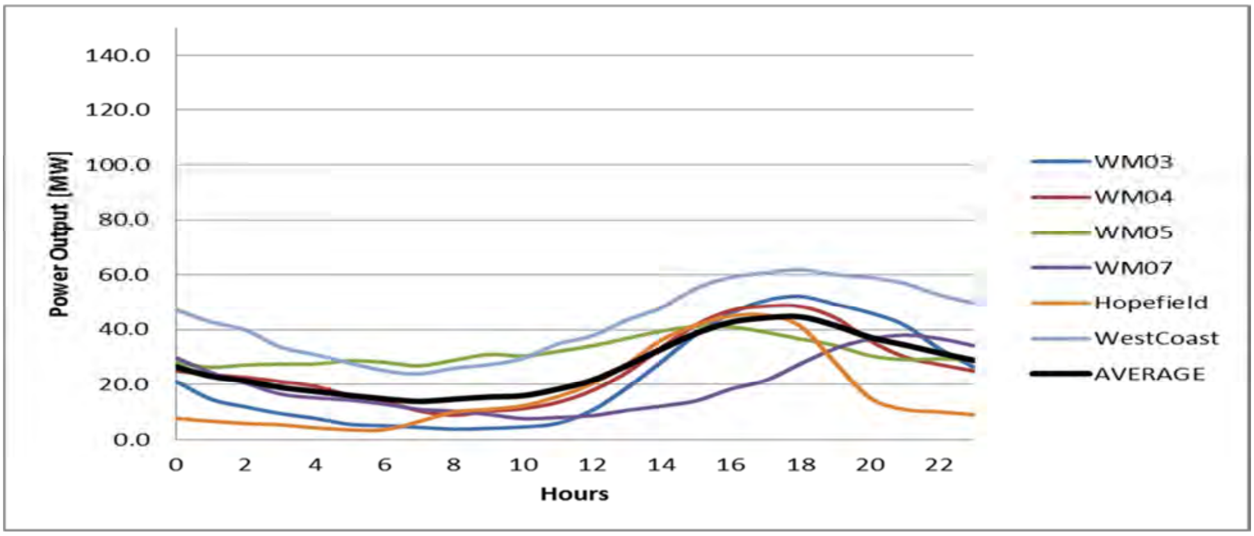

Figure 80 Western Cape diurnal trends for Summer

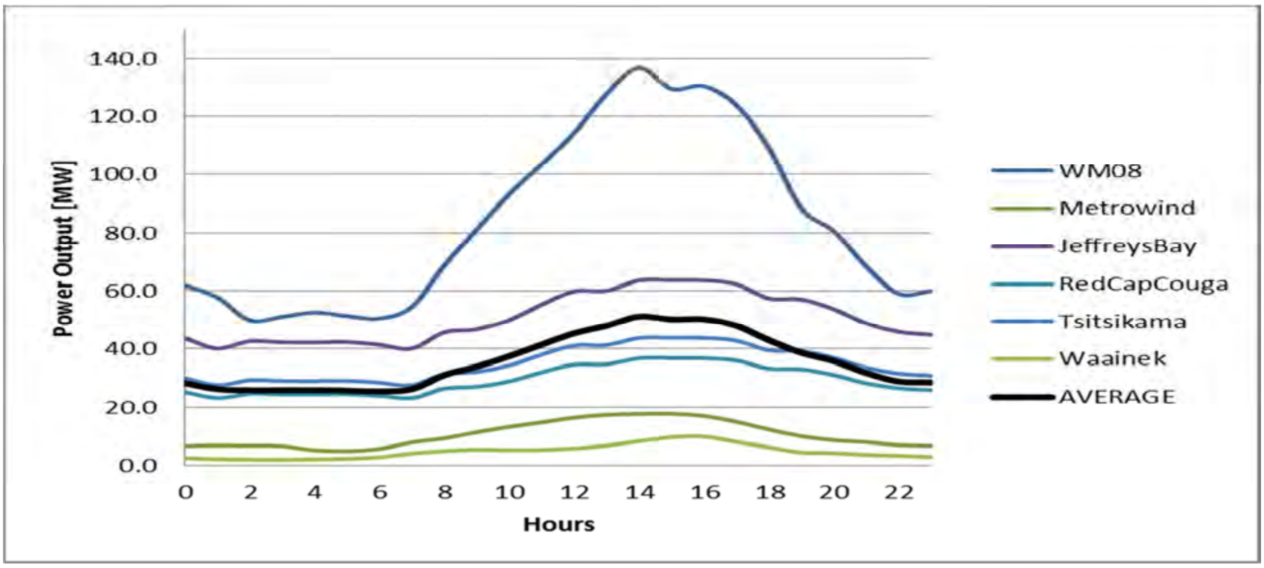

Figure 81 Eastern Cape diurnal trends for Summer

A.2.2 Autumn Season

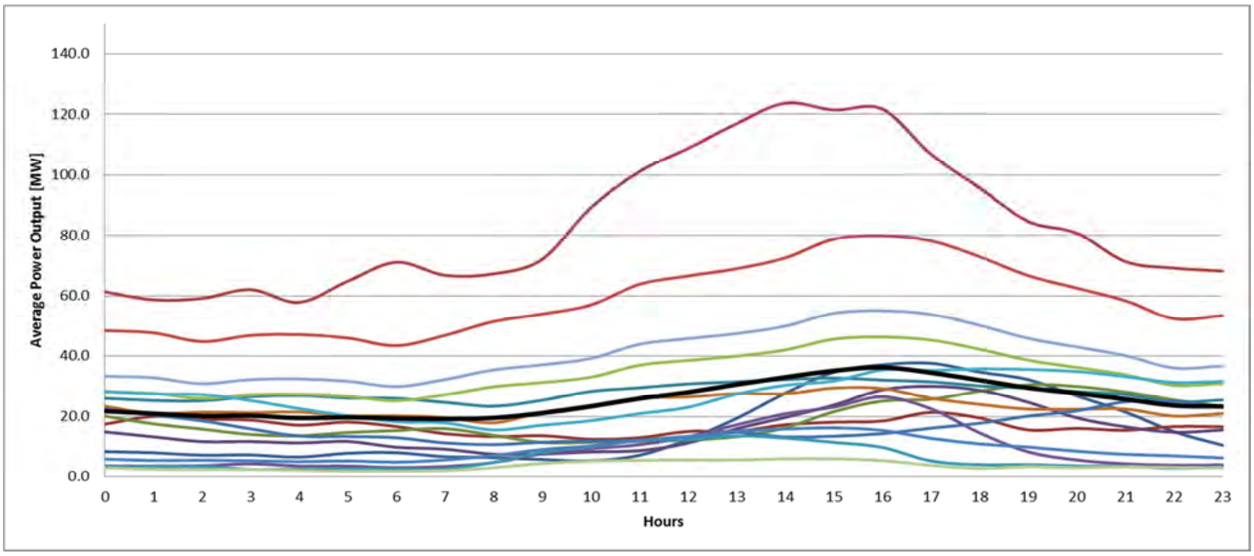

Figure 82 Autumn Season Diurnal Trends

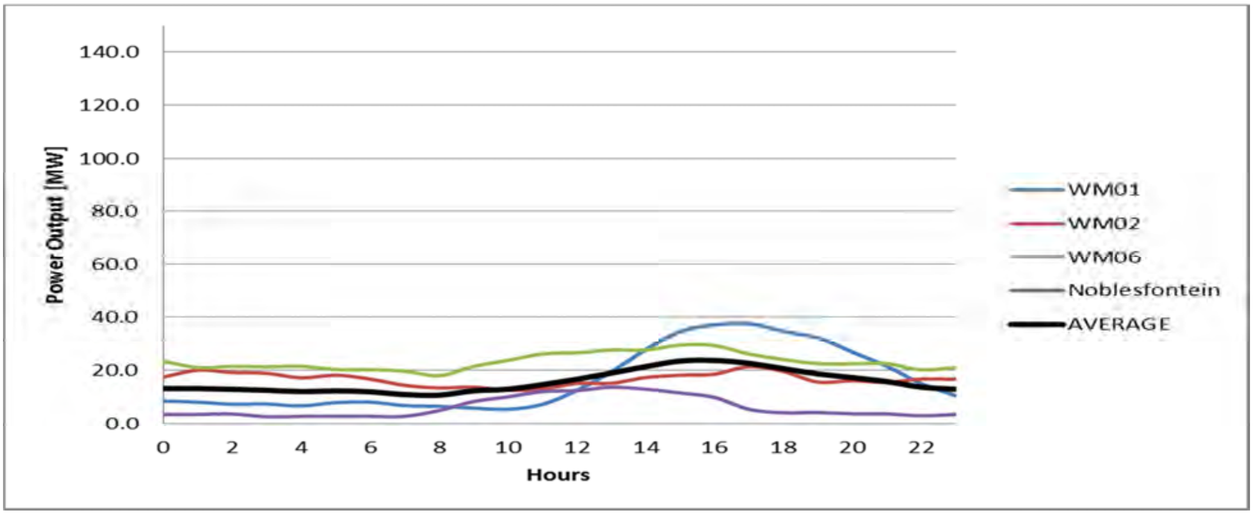

Figure 83 Northern Cape diurnal trends for Autumn

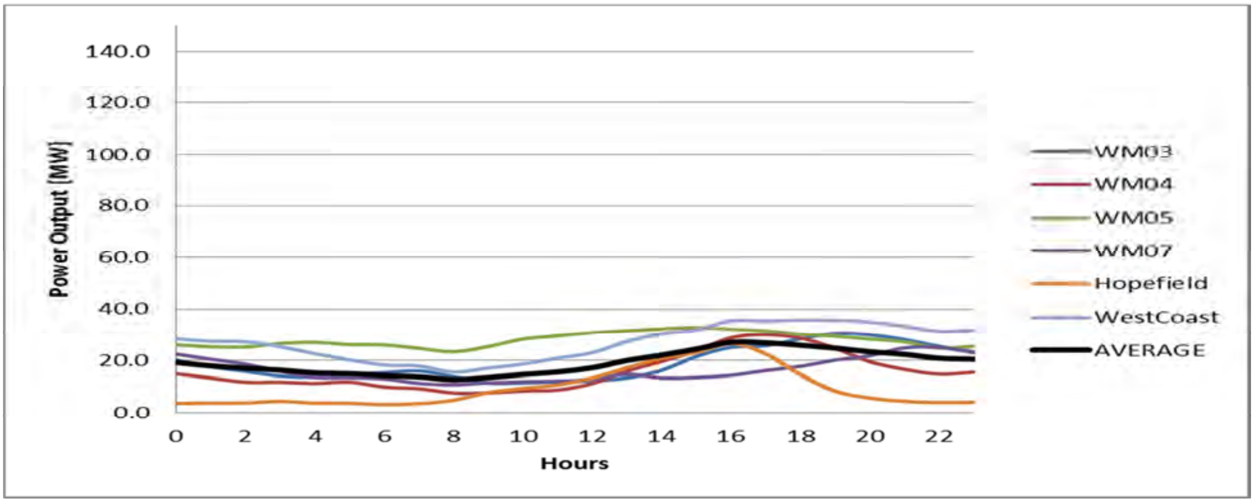

Figure 84 Western Cape diurnal trends for Autumn

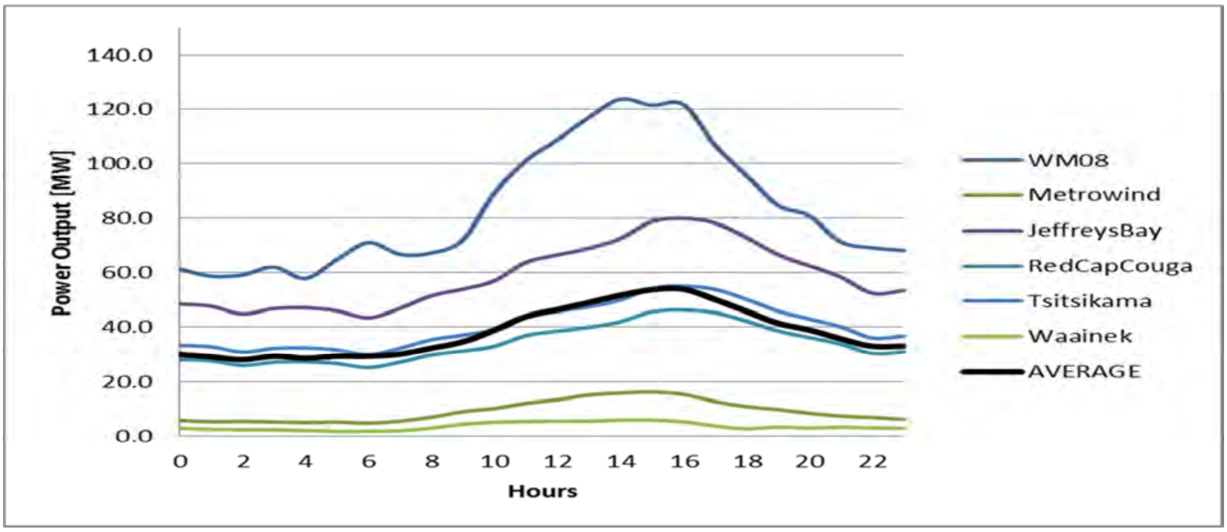

Figure 85 Eastern Cape diurnal trends for Autumn

A.2.3 Spring Season

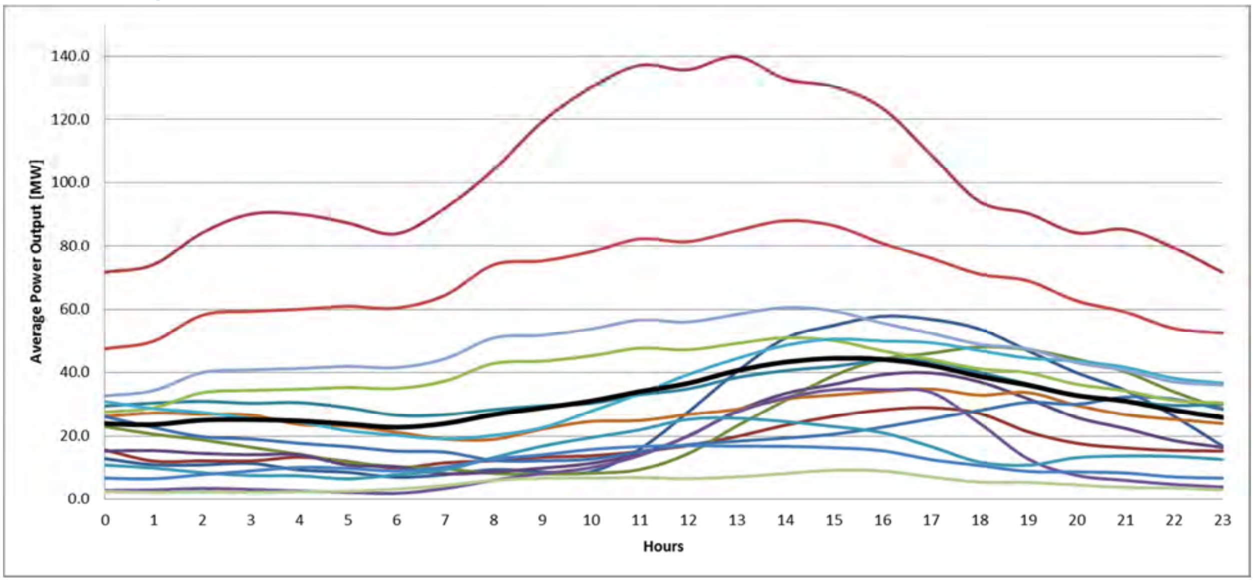

Figure 86 Spring Season Diurnal Trends

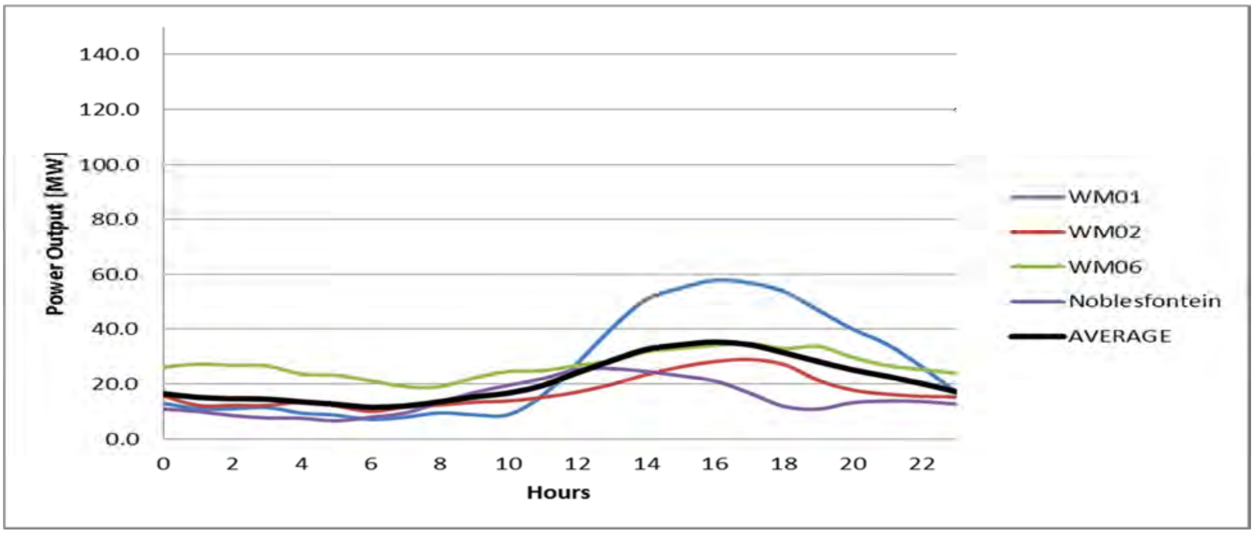

Figure 87 Northern Cape diurnal trends for Spring

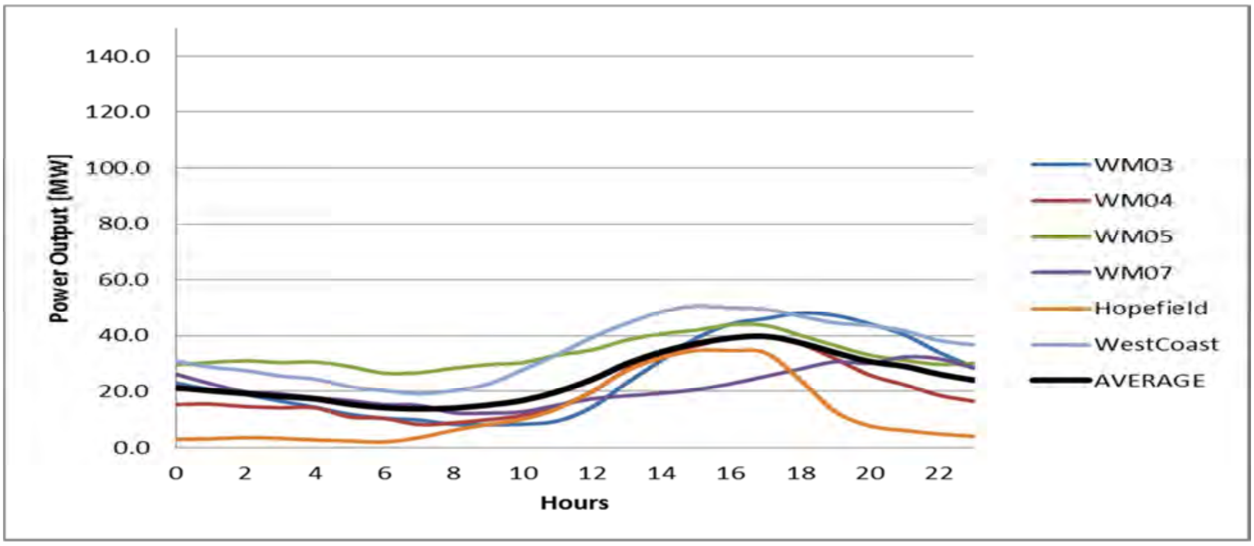

Figure 88 Western Cape diurnal trends for Spring

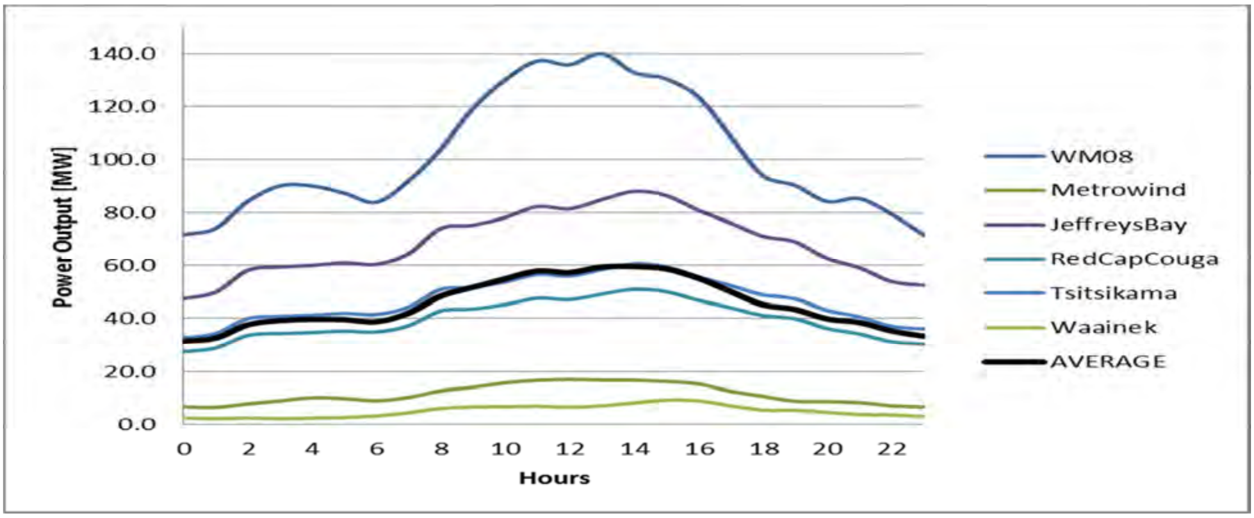

Figure 89 Eastern Cape diurnal trends for Spring

Appendix B – Integrated Resource Plan 2013 (updated)

B.1 Base Case Scenario

The IRP 2010 (reference) is the official government plan for new generation capacity. The updated IRP is intended to provide insight into critical changes for consideration on key decisions in the interim. The updated IRP provides insight into

- The electricity demand and the underlying relationship with economic growth
- New developments in technology and fuel costs
- Scenarios for carbon mitigation strategies and the impact on electricity supply beyond 2030

The update process uses the following approach:

- Developing a new base case scenario from the IRP 2010 by updating the underlying assumptions based on new information.
- Considering different scenarios based on alternative government policies and strategies

The new base case scenario is developed using following steps

1. Technology Options and Costs
    a. The costs of generic technologies used in the IRP 2010 were based on the EPRI report "Power Generation Technology Data for Integrated Resource Plan of South Africa. The EPRI developed an updated report on generic technologies costs based on more recent in April 2012.
2. Expected Demand
    a. The electricity demand over the past 3 years has been lower than what was predicted in IPR 2010, especially for the system operator moderate forecast, which was used as the base case for the IRP. This new electricity demand trend was incorporated into the system operator moderate forecast, which yielded a new demand forecast for the base case scenario.
3. Performance of Eskom Fleet
    a. Due to 2008 electricity crisis, Eskom has delayed maintenance on the generation in order to meet electricity demand. This has resulting in deteriorating performance of the aging fleet worsening the current crisis and hindering the effectiveness of the fleet to meet future demand. In order to relieve the stress on the fleet, Eskom has proposed a new generation maintenance strategy. This new strategy has been incorporated into the new base as the basis for the planned and unplanned maintenance.
4. Potential for extended life of existing fleet
    a. The new maintenance plan developed by Eskom includes addition interventions to improve the efficiency of the existing fleet.
5. Releasing determinations
    a. The new generation capacities called for by the Ministerial Determinations that are not committed are allowed to lapse. This implies that only REIPPPP round 1 and 2 and OCGT peaker programme are committed.

The results of this update process are presented in **Error! Reference source not found.**.

B.2 Technology Parameters

Table 36 Technology Parameters: Coal and Nuclear

	Pulverised coal, with FGD	Pulverised coal, with CCS	Fluidised bed combustion (coal) with FGD	Fluidised bed combustion (coal) with CCS	IGCC	IGCC, with CCS	Nuclear (single unit)	Nuclear fleet
Rated capacity, net (MW)	4500 (6 x 750)	4500 (6 x 750)	250	250	1288 (644 x 2)	1288 (644 x 2)	1600	9600 (6 X 1600)
Life of programme	30	30	30	30	30	30	60	60
Typical load factor (%)	85%	85%	85%	85%	85%	85%	92%	92%
Overnight capital costs (R/kW)	21572	40845	21440	40165	29282	39079	46841	44010
Lead time	9	9	4	4	5	5	6	16
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	2%, 6%, 13%, 17%*, 17%, 16%, 15%, 11%, 3%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	5%, 18%, 35%, 32%*, 10%	5%, 18%, 35%, 32%*, 10%	15%, 15%, 25%, 25%, 10%, 10%	3%, 3%, 7%, 7%, 8%, 8%*, 8%, 8%, 8%, 8%, 8%, 8%, 6%, 6%, 2%, 2%
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	25772	48789	23661	44325	32340	43160	58036	59226
Fixed O&M (R/kW/a)	552	923	543	902	794	951	532	532
Variable O&M (R/MWh)	51.2	81.4	110.8	149.1	42.5	65.4	29.5	29.5
Variable Fuel costs (R/GJ)	17.5	17.5	8.75	8.75	17.5	17.5	6.8	6.8
Fuel Energy Content, HHV, kJ/kg	17850	17850	17850	17850	17850	17850	3.9×10^9	3.9×10^9
Heat Rate, kJ/kWh, avg	9812	14106	10081	15425	9758	12541	10762	10762
Equivalent Avail	91.7	91.7	90.4	90.4	85.7	85.7	94.1	94.1
Maintenance	4.8	4.8	5.7	5.7	4.7	4.7	3	3
Unplanned outages	3.7	3.7	4.1	4.1	10.1	10.1	3	3
Water usage, l/MWh	231	320	33	43	256.7	1027	-	-
Sorbent usage, kg/MWh	15.8	22.8	38	59	0	0		
CO2 emissions (kg/MWh)	947.3	136.2	978	150	930	120		
SOx emissions (kg/MWh)	0.46	0.66	0.47	0.72	0.18	0.23		
NOx emissions (kg/MWh)	1.94	0.42	1.39	2.13	0.01	0.01		
Hg (kg/MWh)								
Particulates (kg/MWh)	0.13	0.18	0.13	0.2	0.04	0.05		
Fly ash (kg/MWh)	168	241.5	172.6	264.1				
Bottom ash (kg/MWh)	3.3	4.8	3.4	5.2				
FGD solids (kg/MWh)	25.2	36.2	61.1	93.4				
Levelised Cost								
Adjusted Capital (R/MWh)	287.10	543.51	263.58	493.78	360.27	480.80	524.14	534.89
O&M (R/MWh)	125.33	205.36	183.73	270.24	149.13	193.12	95.51	95.51
Fuel (R/MWh)	171.71	246.86	88.21	134.97	170.77	219.47	73.18	73.18
Total (R/MWh)	584.14	995.72	535.52	898.99	680.17	893.39	692.83	703.58

Table 37 Technology Parameters: Gas and Renewables

	OCGT	CCGT	CCGT with CCS	Wind	CSP, Parabolic trough, 3 hrs	CSP, Parabolic trough, 6 hrs	CSP, Parabolic trough, 9 hrs	CSP, Central receiver, 3 hrs	CSP, Central receiver, 6 hrs	CSP, Central receiver, 9 hrs	PV, crystalline silicon, Fixed Tilt
Rated capacity, net (MW)	115	711	591	100 (50 x 2)	125	125	125	125	125	125	10
Life of programme	30	30	30	20	30	30	30	30	30	30	25
Typical load factor (%)	10%	50%	50%	30%	30.90%	36.90%	42.80%	31.80%	40.00%	46.80%	19.40%
Overnight capital costs (R/kW)	4357	6406	13223	15394	40438	51090	61176	37577	44866	51604	28910
Lead time	2	3	3	4	4	4	4	4	4	4	2
Phasing in capital spent (% per year) (* indicates commissioning year of 1st unit)	90%, 10%	40%, 50%, 10%	40%, 50%, 10%	5%, 5%, 10%, 80%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 25%, 45%, 20%	10%, 90%
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	4671	7089	14632	15945	44626	56381	67512	41469	49513	56949	29141
Fixed O&M (R/kW/a)	78	163	292	310	582	599	616	537	555	573	208
Variable O&M (R/MWh)	0.2	0.7	0.7	0	1.9	2	2	0	0	0	0
Variable Fuel costs (R/GJ)	92	92	92	0							
Fuel Energy Content, HHV, kJ/kg	39.3†	39.3†	39.3†	0							
Heat Rate, kJ/kWh, avg	11926	7487	9010	0							
Equivalent Avail	88.8	88.8	88.8	94-97	95	95	95	92	92	92	95
Maintenance	6.9	6.9	6.9	6							5
Unplanned outages	4.6	4.6	4.6								
Water usage, l/MWh	19.8	12.7	19.2		299	304	308	310	302	300	
Sorbent usage, kg/MWh											
CO2 emissions (kg/MWh)	618	388	47								
SOx emissions (kg/MWh)	0	0	0								
NOx emissions (kg/MWh)	0.27	0.29	0.35								
Hg (kg/MWh)											
Particulates (kg/MWh)											
Fly ash (kg/MWh)											
Bottom ash (kg/MWh)											
FGD solids (kg/MWh)											
Levelised Cost											
Adjusted Capital (R/MWh)	442.29	134.25	277.10	575.93	1367.51	1446.80	1493.62	1234.81	1172.09	1152.24	1498.70
O&M (R/MWh)	89.24	37.91	67.37	117.96	216.91	187.31	166.30	192.77	158.39	139.77	122.39
Fuel (R/MWh)	1097.19	688.80	828.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total (R/MWh)	1628.73	860.97	1173.39	693.89	1584.42	1634.11	1659.92	1427.58	1330.48	1292.01	1621.09

Table 38 Technology Parameters: Imported Hydro

	Import hydro (Mozambique A)	Import hydro (Mozambique B)	Import hydro (Mozambique C)	Import hydro (Zambia A)	Import hydro (Zambia B)	Import hydro (Zambia C)
	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro
Rated capacity, net (MW)	1500 MW	850 MW	160 MW	120 MW	250 MW	120 MW
Life of programme	60	60	60	60	60	60
Typical load factor (%)	66,7%	38%	42%	64%	46%	38%
Overnight capital costs (R/kW)	17834.37	8339.10	14492	10174	6159	4440
Lead time	9	9	4	3	8	4
Phasing in capital spent (% per year)	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	5%, 5%, 5%, 5%, 10%, 25%, 20%, 20%, 5%	10%, 25%, 45%, 20%	15%, 55%, 30%	5%, 5%, 5%, 5%, 10%, 25%, 25%, 20%	10%, 25%, 45%, 20%
Adjusted overnight capital costs, accounting for capex phasing (R/kW) and discount rate	21116.81	9873.95	17413.74	10876.69	7355.33	4900.49
Fixed O&M (R/kW/a)	344	80,2	80,2	80,2	80,2	80,2
Variable O&M (R/MWh)	0	13,9	13,9	13,9	13,9	13,9
Variable Fuel costs (R/GJ)	N/A	N/A	N/A	N/A	N/A	N/A
Equivalent Avail	90	90	90	90	90	90
Maintenance	7	7	5	5	5	5
Unplanned outages	3	3	5	5	5	5
Levelised Cost						
Adjusted Capital (R/MWh)	273.36	224.36	357.99	146.74	138.06	111.35
O&M (R/MWh)	58.87	38.00	35.71	28.22	33.81	38.00
Fuel (R/MWh)	0	0	0	0.00	0.00	0.00
Total (R/MWh)	332.23	262.38	393.70	174.96	171.88	149.35

B.3 Generation Mix and Demand

Table 39 Base Case Details

Year	Existing/Committed										New											Total Capacity (excl DR)	Total DR	Peak demand	Reserve Margin (Total)	Reserve Margin (Reliable)	CO2 emissions
	Coal	OCGT	Hydro Import	Hydro RSA	PS	Nuclear	PV	CSP	Wind	Other	Coal	CCGT	OCGT	Hydro Import	Hydro RSA	PS	Nuclear	PV	CSP	Wind	Other						
2013	36860	2550	1500	670	1580	1860	0	0	0	3200	0	0	0	0	0	0	0	0	0	0	0	45660	2560	38280	27.8	21.1	264.8
2014	37580	2460	1500	680	1580	1860	910	0	940	3200	0	0	0	0	0	0	0	0	0	0	0	48150	2560	38924	32.4	21.4	257.7
2015	39010	2460	1500	690	2900	1860	1050	200	1300	3450	0	0	0	0	0	0	0	0	0	0	0	51610	2810	39703	39.9	26.8	265.9
2016	41070	3480	1500	690	2900	1860	1070	200	1300	3700	0	0	0	0	0	0	0	0	0	0	0	54710	3060	40608	45.7	31.9	270.1
2017	43210	3480	1500	690	2900	1860	1070	200	1300	3700	0	0	0	0	0	0	0	0	0	0	0	56850	3060	41679	47.2	33.7	277.0
2018	44640	3480	1500	690	2900	1860	1070	200	1300	2700	0	0	0	0	0	0	0	0	0	0	0	58280	2060	42485	44.2	33.6	280.2
2019	45350	3480	1500	690	2900	1860	1070	200	1300	2700	0	0	0	0	0	0	0	0	0	0	0	58990	2060	43713	41.6	31.5	284.5
2020	44970	3480	1500	690	2900	1860	1070	300	1300	2700	0	0	0	0	0	0	0	140	0	0	0	58850	2060	44977	37.1	27.0	289.3
2021	44400	3480	1500	690	2900	1860	1070	300	1300	2700	0	0	0	0	0	0	0	420	0	0	0	58560	2060	46481	31.8	21.6	298.5
2022	43390	3480	1500	690	2900	1860	1070	300	1300	2700	0	0	0	1125	0	0	0	980	0	0	0	59235	2060	47952	29.1	18.0	298.1
2023	42760	3480	1500	690	2900	1860	1070	300	1300	2700	0	0	0	1500	0	0	0	1770	0	0	0	59770	2060	49442	26.1	13.9	304.9
2024	42310	3480	1500	690	2900	1860	1070	300	1300	2700	750	0	0	1500	0	0	0	2700	0	320	0	61320	2060	50895	25.6	11.4	310.9
2025	40420	3480	1500	690	2900	1860	1070	300	1300	2700	1950	2840	0	1500	0	0	1600	3700	0	640	0	66390	2060	52593	31.4	15.2	275.0
2026	39390	3120	1500	690	2900	1860	1070	300	1300	640	1950	2840	840	1500	0	0	1600	4700	0	960	0	67160	0	52995	26.7	12.1	275.0
2027	38090	3120	1500	690	2900	1860	1070	300	1300	640	1950	3550	3240	1500	0	0	1600	5700	0	1600	0	70610	0	54745	29.0	12.2	275.0
2028	36670	3120	1500	690	2900	1860	1070	300	1300	640	1950	3550	4560	1500	0	0	3200	6700	0	1920	0	73430	0	56482	30.0	11.5	275.0
2029	36270	3120	1500	690	2900	1860	1070	300	1300	640	2450	3550	4680	1500	0	0	4800	7700	0	2560	0	76890	0	58547	31.3	11.0	275.0
2030	36230	3120	1500	690	2900	1860	1070	300	1300	640	2450	3550	4680	1500	0	0	4800	8700	3000	3060	0	81350	0	60509	34.4	10.4	275.0
2031	36210	3120	1500	690	2900	1860	1070	300	1300	640	2450	3550	4800	1500	0	0	6400	9700	3000	3700	0	84690	0	62159	36.2	10.5	275.0
2032	35050	3120	1500	690	2900	1860	1070	300	1300	640	3700	3550	5160	1500	0	0	6400	10700	3400	4340	0	87180	0	63463	37.4	9.6	275.0
2033	33890	3120	1500	690	2900	1860	1070	300	1300	640	4450	3550	5160	1500	0	0	6400	11700	5200	4980	0	90210	0	64969	38.9	8.2	275.0
2034	33310	3120	1500	690	2900	1860	1070	300	370	640	5200	3550	6240	1500	0	0	8000	12700	5200	5620	0	93770	0	66210	41.6	10.3	275.0
2035	33310	3120	1500	690	2900	1860	1070	300	0	640	5200	3550	6240	1500	0	0	9600	13700	5200	6260	0	96640	0	67414	43.4	10.9	275.0
2036	32840	3120	1500	690	2900	1860	1070	300	0	280	5950	3550	6840	1500	0	0	9600	14700	5200	6580	0	98480	0	68341	44.1	10.3	275.0
2037	32370	1020	1500	690	2900	1860	1070	300	0	280	6700	3550	9720	1500	0	0	11200	15700	5200	6900	0	102460	0	69621	47.2	12.2	271.8
2038	31900	1020	1500	690	2900	1860	1070	300	0	280	8200	3550	9720	1500	0	0	11200	16700	5200	7220	0	104810	0	70777	48.1	12.0	275.0
2039	30390	1020	1500	690	2900	1860	160	300	0	280	9700	3550	9720	1500	0	0	11200	17700	5200	7860	0	105530	0	71736	47.1	10.7	275.0
2040	28110	1020	1500	690	2900	1860	20	300	0	280	11950	4970	9840	1500	0	0	11200	18700	5200	8500	0	108540	0	72495	49.7	11.9	275.0
2041	26970	1020	1500	690	2900	1860	0	300	0	0	12700	4970	9840	1500	0	0	11200	19700	5200	9020	0	109370	0	73599	48.6	9.5	275.0
2042	26970	1020	1500	690	2900	1860	0	300	0	0	13450	5680	10800	1500	0	0	11200	20700	5200	9480	0	113250	0	74482	52.0	11.7	275.0
2043	26820	1020	1500	690	2900	1860	0	300	0	0	13450	5680	10800	1500	0	0	11200	21700	5800	10120	0	115340	0	75368	53.0	10.8	275.0
2044	26820	1020	1500	690	2900	0	0	200	0	0	13450	5680	10800	1500	0	0	12800	22700	7200	10440	0	117700	0	76112	54.6	10.5	275.0
2045	25650	1020	1500	690	2900	0	0	0	0	0	14950	5680	10800	1500	0	0	12800	23560	7900	10760	0	119710	0	77059	55.3	10.0	275.0
2046	23900	0	1500	690	2900	0	0	0	0	0	16450	6390	12000	1500	0	0	12800	24280	8000	11080	0	121490	0	77841	56.1	9.9	275.0
2047	22100	0	1500	690	2900	0	0	0	0	0	18700	6390	12000	1500	0	0	12800	24720	8000	11080	0	122380	0	78603	55.7	9.5	275.0
2048	19100	0	1500	690	2900	0	0	0	0	0	21700	6390	12000	1500	0	0	12800	24930	8100	11080	0	122690	0	78969	55.4	9.0	275.0
2049	17900	0	1500	690	2900	0	0	0	0	0	23200	6390	12240	1500	0	0	12800	25000	8100	10760	0	122980	0	79640	54.4	8.7	275.0
2050	16120	0	1500	690	2900	0	0	0	0	0	24700	6390	12240	1500	0	0	12800	25000	8100	10520	0	122460	0	80163	52.8	7.5	275.0

Appendix C – Capacity Credit Detailed Results

C.1 2011 Base Case

C.1.1 Penetration Level

Table 40 2011 Annual Penetration Level Analysis

Penetration Level	4%	9%	13%	17%
Wind Capacity [MW]	2 014	4 360	6 521	8 694
$ELCC_{wind}$ [MW]	39 704	40 415	40 939	41 390
ΔELCC [MW]	734	1 445	1 969	2 420
CC_{FIRM}	**36.4%**	**33.1%**	**30.2%**	**27.8%**
Firm Capacity [MW]	775	1 394	2 014	2 479
Wind Equivalent [MW]	1 900	3 900	5 700	7 600
$ELCC_{Firm}$ [MW]	39 642	40 167	40 708	41 138
$ELCC_{windequivalent}$ [MW]	39 659	40 196	40 733	41 170
$CC_{THERMALEQUIVALENT}$	**40.8%**	**35.7%**	**35.3%**	**32.6%**
$ELCC_{wind}$ %	87.36%	84.56%	81.95%	79.40%
$ELCC_{windequivalent}$ %	87.48%	85.46%	82.90%	80.67%

Table 41 2011 Spring Penetration Level Analysis

Penetration Level	4%	9%	13%	17%
Wind Capacity [MW]	2 014	4 347	6 521	8 694
$ELCC_{wind}$ [MW]	39 809	40 625	41 278	41 865
ΔELCC [MW]	839.00	1 655.00	2 308.00	2 895.00
CC_{FIRM}	**41.7%**	**38.1%**	**35.4%**	**33.3%**
Firm Capacity [MW]	775	1704	2324	2943
Wind Equivalent [MW]	1 650	3 900	5 600	7 400
$ELCC_{Firm}$ [MW]	39 642	40 444	41 000	41 534
$ELCC_{windequivalent}$ [MW]	39 661	40 476	40 988	41 568
$CC_{THERMALEQUIVALENT}$	**47.0%**	**43.7%**	**41.5%**	**39.8%**
$ELCC_{wind}$ %	87.69%	85.00%	82.63%	80.31%
$ELCC_{windequivalent}$ %	87.97%	85.51%	83.69%	81.45%

Table 42 2011 Summer Penetration Level Analysis

Penetration Level	**4%**	**9%**	**13%**	**17%**
Wind Capacity [**MW**]	2 014	4 347	6 521	8 694
$ELCC_{wind}$ [**MW**]	39 777	40 692	41 468	42 172
ΔELCC [**MW**]	807.00	1 722.00	2 498.00	3 202.00
CC_{FIRM}	**40.1%**	**39.6%**	**38.3%**	**36.8%**
Firm Capacity [**MW**]	775	1 704	2 479	3 253
Wind Equivalent [**MW**]	1 700	3 800	5 600	7 600
$ELCC_{Firm}$ [**MW**]	39 642	40 444	41 134	41 809
$ELCC_{windequivalent}$ [**MW**]	39 642	40 471	41 170	41 828
$CC_{THERMALEQUIVALENT}$	**45.6%**	**44.8%**	**44.3%**	**42.8%**
$ELCC_{wind}$ %	87.52%	85.15%	83.01%	80.90%
$ELCC_{windequivalent}$ %	87.83%	85.68%	83.96%	81.96%

Table 43 2011 Autumn Penetration Level Analysis

Penetration Level	**4%**	**9%**	**13%**	**17%**
Wind Capacity [**MW**]	2 014	4 347	6 521	8 694
$ELCC_{wind}$ [**MW**]	39 677	40 344	40 814	41 225
ΔELCC [**MW**]	707.00	1 374.00	1 844.00	2 255.00
CC_{FIRM}	**35.1%**	**31.6%**	**28.3%**	**25.9%**
Firm Capacity [**MW**]	775	1 394	1 859	2 324
Wind Equivalent [**MW**]	2 014	3 900	5 600	7 700
$ELCC_{Firm}$ [**MW**]	39 642	40 194	40 592	41 000
$ELCC_{windequivalent}$ [**MW**]	39 677	40 211	40 625	41 032
$CC_{THERMALEQUIVALENT}$	**38.5%**	**35.7%**	**33.2%**	**30.2%**
$ELCC_{wind}$ %	87.30%	84.39%	81.70%	79.14%
$ELCC_{windequivalent}$ %	87.30%	84.95%	82.85%	80.40%

Table 44 2011 Winter Penetration Level Analysis

Penetration Level	4%	9%	13%	17%
Wind Capacity [MW]	2 014	4 347	6 521	8694
$ELCC_{wind}$ [MW]	39 577	40 100	40 489	408 17
ΔELCC [MW]	607.00	1 130.00	1 519.00	1 847.00
CC_{FIRM}	**30.1%**	**26.0%**	**23.3%**	**21.2%**
Firm Capacity [MW]	620	1 084	1 549	1 859
Wind Equivalent [MW]	1 800	3 600	5 800	7 800
$ELCC_{Firm}$ [MW]	39 512	39 916	40 319	40 588
$ELCC_{windequivalent}$ [MW]	39 513	39 947	40 321	40 622
$CC_{THERMALEQUIVALENT}$	**34.4%**	**30.1%**	**26.7%**	**23.8%**
$ELCC_{wind}$ %	87.08%	83.90%	81.05%	78.30%
$ELCC_{windequivalent}$ %	87.35%	84.93%	82.23%	79.91%

C.1.2 Geographical Dispersion

Table 45 2011 Full Dispersion Analysis

	Annual	Summer	Autumn	Winter	Spring
Wind Capacity [MW]	2 014	2 014	2 014	2 014	2 014
$ELCC_{wind}$ [MW]	39 704	39 777	39 677	39 577	39 809
ΔELCC [MW]	734	807.00	707.00	607.00	839.00
CC_{FIRM}	**36.4%**	**40.1%**	**35.1%**	**30.1%**	**41.7%**
Firm Capacity [MW]	775	775	775	620	775
Wind Equivalent [MW]	1 900	1 700	2 014	1 800	1 650
$ELCC_{Firm}$ [MW]	39 642	39 642	39 642	39 512	39 642
$ELCC_{windequivalent}$ [MW]	39 659	39 642	39 677	39 513	39 661
$CC_{THERMALEQUIVALENT}$	**40.8%**	**45.6%**	**38.5%**	**34.4%**	**47.0%**
$ELCC_{wind}$ %	87.36%	87.52%	87.30%	87.08%	87.69%
$ELCC_{windequivalent}$ %	87.48%	87.83%	87.30%	87.35%	87.97%

Table 46 2011 Zero Dispersion Analysis (Western Cape)

	Annual	**Summer**	**Autumn**	**Winter**	**Spring**
Wind Capacity [**MW**]	2 014	2 014	2 014	2 014	2 014
$ELCC_{wind}$ [**MW**]	39 677	39 899	39 590	39 499	39 772
ΔELCC [**MW**]	707.00	929.00	620.00	529.00	802.00
CC_{FIRM}	**35.1%**	**46.1%**	**30.8%**	**26.3%**	**39.8%**
Firm Capacity [**MW**]	775	930	620	465	775
Wind Equivalent [**MW**]	2 014	1 800	2 014	1 600	1 750
$ELCC_{Firm}$ [**MW**]	39642	39790	39512	39378	39642
$ELCC_{windequivalent}$ [**MW**]	39 677	39 797	39 545	39 392	39 668
$CC_{THERMALEQUIVALENT}$	**38.5%**	**51.7%**	**30.8%**	**29.1%**	**44.3%**
$ELCC_{wind}$ %	87.30%	87.79%	87.11%	86.91%	87.51%
$ELCC_{windequivalent}$ %	87.30%	87.98%	87.23%	87.47%	87.79%

Table 47 2011 Zero Dispersion Analysis (Eastern Cape)

	Annual	**Summer**	**Autumn**	**Winter**	**Spring**
Wind Capacity [**MW**]	2 014	2 014	2 014	2 014	2 014
$ELCC_{wind}$ [**MW**]	39 531	39 545	39 577	39 386	39 590
ΔELCC [**MW**]	561.00	575.00	607.00	416.00	620.00
CC_{FIRM}	**27.9%**	**28.6%**	**30.1%**	**20.7%**	**30.8%**
Firm Capacity [**MW**]	620	620	620	465	620
Wind Equivalent [**MW**]	2 014	2 014	1 950	1 800	1 800
$ELCC_{Firm}$ [**MW**]	39 512	39 512	39 512	39 303	39 512
$ELCC_{windequivalent}$ [**MW**]	39 531	39 545	39 553	39 336	39 531
$CC_{THERMALEQUIVALENT}$	**30.8%**	**30.8%**	**31.8%**	**25.8%**	**34.4%**
$ELCC_{wind}$ %	86.98%	87.01%	87.08%	86.66%	87.11%
$ELCC_{windequivalent}$ %	86.98%	87.01%	87.15%	86.96%	87.39%

C.2 2030 Future Case

C.2.1 Penetration Level

Table 48 2030 Annual Penetration Level Analysis

Penetration level	**6%**	**12%**	**18%**	**24%**
Wind Capacity [**MW**]	4 360	8 788	13 182	17 576
$ELCC_{Wind}$ [**MW**]	64 349	65 425	66 278	66 969
ΔELCC	1 484	2 560	3 413	4 104
CC_{FIRM}	**34.0%**	**29.1%**	**25.9%**	**23.3%**
Firm Capacity [**MW**]	1 422	2 607	3 318	4 029
Wind Equivalent [**MW**]	4 100	8 600	12 000	15 750
$ELCC_{Firm}$ [**MW**]	64 221	65 340	65 987	66 670
$ELCC_{windequivalent}$ [**MW**]	64 271	65 366	66 017	66 682
$CC_{THERMALEQUIVALENT}$	**34.7%**	**30.3%**	**27.7%**	**25.6%**
$ELCC_{wind}$ %	88.45%	84.77%	81.25%	77.90%
$ELCC_{windequivalent}$ %	88.66%	84.90%	82.12%	79.25%

Table 49 2030 Spring Penetration Level Analysis

Penetration level	**6%**	**12%**	**18%**	**24%**
Wind Capacity [**MW**]	4 360	8 788	13 182	17 576
$ELCC_{Wind}$ [**MW**]	64 552	65 865	67 004	68 035
ΔELCC	1 687	3 000	4 139	5 170
CC_{FIRM}	**38.7%**	**34.1%**	**31.4%**	**29.4%**
Firm Capacity [**MW**]	1 895	3 081	4 029	5 214
Wind Equivalent [**MW**]	4 150	8 600	12 000	17 000
$ELCC_{Firm}$ [**MW**]	64 446	65 797	66 670	67 820
$ELCC_{windequivalent}$ [**MW**]	64 489	65 812	66 725	67 886
$CC_{THERMALEQUIVALENT}$	**45.7%**	**35.8%**	**33.6%**	**30.7%**
$ELCC_{wind}$ %	88.73%	85.34%	82.14%	79.14%
$ELCC_{windequivalent}$ %	89.36%	85.48%	83.00%	79.50%

Table 50 2030 Summer Penetration Level Analysis

Penetration level	6%	12%	18%	24%
Wind Capacity [**MW**]	4 360	8 788	13 182	17 576
$ELCC_{Wind}$ [**MW**]	64 661	66 143	67 502	68 215
ΔELCC	1 796	3 278	4 637	5 350
CC_{FIRM}	**41.2%**	**37.3%**	**35.2%**	**30.4%**
Firm Capacity [**MW**]	1 896	3 081	4 740	5 451
Wind Equivalent [**MW**]	4 360	7 900	12 500	16 000
$ELCC_{Firm}$ [**MW**]	64 664	65 797	67 281	67 957
$ELCC_{windequivalent}$ [**MW**]	64 661	65 839	67 301	67 935
$CC_{THERMALEQUIVALENT}$	**43.5%**	**39.0%**	**37.9%**	**34.1%**
$ELCC_{wind}$ %	88.88%	85.70%	82.75%	81.24%
$ELCC_{windequivalent}$ %	88.80%	86.30%	83.20%	80.50%

Table 51 2030 Autumn Penetration Level Analysis

Penetration level	6%	12%	18%	24%
Wind Capacity [**MW**]	4 360	8 788	13 182	17 576
$ELCC_{Wind}$ [**MW**]	64 269	65 271	66 034	66 711
ΔELCC	1 404	2 406	3 169	3 846
CC_{FIRM}	**32.2%**	**27.4%**	**24.0%**	**21.9%**
Firm Capacity [**MW**]	1 422	2 370	3 081	3 742
Wind Equivalent [**MW**]	4 360	8 788	11 750	16 000
$ELCC_{Firm}$ [**MW**]	64 228	65 112	65 797	66 474
$ELCC_{windequivalent}$ [**MW**]	64 269	65 125	65 804	66 500
$CC_{THERMALEQUIVALENT}$	**32.6%**	**27.0%**	**26.2%**	**23.4%**
$ELCC_{wind}$ %	88.34%	84.57%	80.95%	77.60%
$ELCC_{windequivalent}$ %	88.34%	85.14%	82.11%	78.80%

Table 52 2030 Winter Penetration level Analysis

Penetration level	6%	12%	18%	24%
Wind Capacity [MW]	4 360	8 788	13 182	17 576
$ELCC_{Wind}$ [MW]	64 043	64 815	65 438	65 998
ΔELCC	1 178	1 950	2 573	3 133
CC_{FIRM}	**27.0%**	**22.2%**	**19.5%**	**17.8%**
Firm Capacity [MW]	1 185	1 896	2 607	3 081
Wind Equivalent [MW]	4 360	8 000	12 500	16 500
$ELCC_{Firm}$ [MW]	63 996	64 664	65 340	65 797
$ELCC_{windequivalent}$ [MW]	63 996	64 688	65 360	65 850
$CC_{THERMALEQUIVALENT}$	**27.2%**	**23.7%**	**20.9%**	**18.7%**
$ELCC_{wind}$ %	88.03%	83.98%	80.22%	76.77%
$ELCC_{windequivalent}$ %	88.03%	84.68%	80.80%	77.58%

C.2.2 Geographical Dispersion

Table 53 2030 Full Dispersion Analysis

	Annual	Summer	Autumn	Winter	Spring
Wind Capacity [MW]	4 360	4 360	4 360	4 360	4 360
$ELCC_{Wind}$ [MW]	64 349	64 661	64 269	64 043	64 552
ΔELCC	1 484	1 796	1 404	1 178	1 687
CC_{FIRM}	**32.6%**	**43.5%**	**32.6%**	**27.2%**	**43.5%**
Firm Capacity [MW]	1 422	1 896	1 422	1 185	1 896
Wind Equivalent [MW]	4 100	4 360	4 360	4 360	4 150
$ELCC_{Firm}$ [MW]	64221	64664	64228	63996	64446
$ELCC_{windequivalent}$ [MW]	64 271	64 661	64 269	63 996	64 489
$CC_{THERMALEQUIVALENT}$	**34.7%**	**43.5%**	**32.6%**	**27.2%**	**45.7%**
$ELCC_{wind}$ %	88.45%	88.88%	88.34%	88.03%	88.73%
$ELCC_{windequivalent}$ %	88.66%	88.80%	88.34%	88.03%	89.36%

Table 54 2030 Zero Dispersion Analysis (Western Cape)

	Annual	Summer	Autumn	Winter	Spring
Wind Capacity [**MW**]	4 360	4 360	4 360	4 360	4 360
$ELCC_{Wind}$ [**MW**]	64 269	64 771	64 094	63 912	64 516
ΔELCC	1 404	1 906	1 229	1 047	1 651
CC_{FIRM}	**32.2%**	**43.5%**	**27.2%**	**21.7%**	**38.1%**
Firm Capacity [**MW**]	1 422	1 896	1 185	948	1 659
Wind Equivalent [**MW**]	4 360	4 000	4 200	3 950	4 200
$ELCC_{Firm}$ [**MW**]	64 221	64 664	63 996	63 758	64 432
$ELCC_{windequivalent}$ [**MW**]	64 269	64 631	64 055	63 812	64 461
$CC_{THERMALEQUIVALENT}$	**32.6%**	**47.4%**	**28.2%**	**24.0%**	**39.5%**
$ELCC_{wind}$ %	88.34%	89.03%	88.10%	87.85%	88.68%
$ELCC_{windequivalent}$ %	88.34%	89.28%	88.24%	88.21%	88.80%

Table 55 2030 Zero Dispersion Analysis (Eastern Cape)

	Annual	Summer	Autumn	Winter	Spring
Wind Capacity [**MW**]	4 360	4 360	4 360	4 360	4 360
$ELCC_{Wind}$ [**MW**]	63 876	63 941	63 956	63 643	63 985
ΔELCC	1 011	1 076	1 091	778	1 120
CC_{FIRM}	**21.7%**	**27.2%**	**27.2%**	**16.3%**	**27.2%**
Firm Capacity [**MW**]	948	1 185	1 185	711	1 185
Wind Equivalent [**MW**]	4 000	4 360	4 360	3 500	4 360
$ELCC_{Firm}$ [**MW**]	63 744	63 996	63 996	63 457	63 996
$ELCC_{windequivalent}$ [**MW**]	63 799	63 941	63 941	6 3516	63 985
$CC_{THERMALEQUIVALENT}$	**23.7%**	**27.2%**	**27.2%**	**20.3%**	**27.2%**
$ELCC_{wind}$ %	87.80%	87.89%	87.91%	87.48%	87.95%
$ELCC_{windequivalent}$ %	88.13%	87.89%	86.04%	88.35%	87.95%

Appendix D – Dispatch Model Results

D.1 2011 Base Case

Table 56 2011 Dispatch Model Results - No Wind

Month	Dispatched Energy [TWh]	EENS [GWh]	Cost of Fuel [Billion R]	CO2 [Mt]
January	20.2	0.00	2.90	18
February	19.0	0.20	2.78	17
March	21.2	0.12	3.08	19
April	19.9	0.03	2.89	18
May	21.4	0.06	3.07	19
June	21.7	0.02	3.10	19
July	22.8	0.03	3.25	20
August	22.1	0.06	3.16	20
September	21.0	0.12	3.04	19
October	21.5	0.03	3.12	19
November	20.8	0.23	3.03	19
December	20.16	0.19	2.94	18
Year	**251.6**	**1.09**	**36.36**	**227**

Table 57 2011 Dispatch Model Results - Full Dispersion

Month	Dispatched Power [TWh]	Wind Energy [TWh]	EENS [GWh]	Cost of Fuel [Billion R]	CO2 [Mt]
January	19.6	0.5	0.01	2.77	17
February	18.7	0.3	0.37	2.69	17
March	20.8	0.4	0.35	3.00	19
April	19.4	0.5	0.06	2.77	17
May	21.0	0.4	0.06	2.97	19
June	21.3	0.4	0.17	3.01	19
July	22.4	0.4	0.10	3.15	20
August	21.7	0.4	0.11	3.06	19
September	20.5	0.5	0.21	2.92	18
October	21.1	0.5	0.15	3.00	19
November	20.3	0.5	0.30	2.91	18
December	19.6	0.5	0.08	2.81	17
Year	**246.5**	**5.1**	**1.98**	**35.09**	**218**

D.2 2030 Future Case

Table 58 2030 Dispatch Model Results – Thermal Capacity (a)

Equivalent Thermal Capacity [MW]			1 422	
Month	**Dispatched Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	32.5	0.00	5.81	24.0
February	30.6	0.01	5.51	22.5
March	34.1	0.03	6.07	25.0
April	32.1	0.03	5.49	23.6
May	34.4	0.01	5.63	25.3
June	34.9	0.03	5.85	25.5
July	36.6	0.03	6.08	26.7
August	35.5	0.03	5.85	26.0
September	33.8	0.07	5.88	24.7
October	34.7	0.03	6.09	25.4
November	33.4	0.02	6.04	24.5
December	32.4	0.00	5.51	24.0
Year	**404.8**	**0.28**	**69.80**	**297.2**

Table 59 Dispatch Model results - Thermal Capacity (b)

Equivalent Thermal Capacity [MW]			2 607	
Month	**Dispatched Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	32.4	0.02	5.82	23.9
February	30.6	0.04	5.54	22.5
March	34.0	0.02	6.08	25.0
April	32.0	0.02	5.52	23.6
May	34.4	0.01	5.67	25.3
June	34.9	0.03	5.89	25.4
July	36.6	0.03	6.14	26.7
August	35.5	0.04	5.89	26.0
September	33.8	0.02	5.91	24.7
October	34.7	0.02	6.12	25.4
November	33.4	0.03	6.06	24.5
December	32.4	0.01	5.56	24.0
Year	**404.8**	**0.29**	**70.22**	**296.9**

Table 60 Dispatch Model Results - Thermal Capacity (c)

Equivalent Thermal Capacity [MW]			3 318	
Month	**Dispatched Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	32.4	0.03	5.81	24.0
February	30.6	0.06	5.51	22.5
March	34.0	0.03	6.07	25.0
April	32.0	0.03	5.49	23.6
May	34.5	0.03	5.63	25.3
June	34.9	0.05	5.85	25.5
July	36.6	0.06	6.08	26.7
August	35.5	0.04	5.85	26.0
September	33.8	0.08	5.88	24.7
October	34.7	0.06	6.09	25.4
November	33.4	0.07	6.04	24.5
December	32.4	0.02	5.51	24.0
Year	**404.8**	**0.57**	**69.80**	**297.2**

Table 61 Dispatch Model Results – 6% Wind Penetration

Equivalent Wind Capacity [MW]				4 100	
Month	**Dispatched Energy [TWh]**	**Wind Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	31.2	1.25	0.01	5.17	23.2
February	29.8	0.80	0.01	5.03	22.0
March	33.2	0.86	0.03	5.59	24.5
April	30.9	1.09	0.03	4.95	22.9
May	33.6	0.83	0.01	5.25	24.7
June	34.0	0.89	0.05	5.45	24.9
July	35.8	0.83	0.03	5.73	26.2
August	34.6	0.90	0.03	5.42	25.4
September	32.6	1.10	0.04	5.32	24.0
October	33.5	1.10	0.03	5.48	24.7
November	32.2	1.20	0.02	5.40	23.8
December	31.3	1.13	0.01	4.94	23.3
Year	**392.9**	**11.98**	**0.30**	**63.73**	**289.6**

Table 62 Dispatch Model Results – 12% Wind Penetration

Equivalent Wind Capacity [MW]				8 600	
Month	**Dispatched Energy [TWh]**	**Wind Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	29.8	2.68	0.03	4.67	22.2
February	28.9	1.72	0.01	4.66	21.4
March	32.2	1.84	0.02	5.18	23.9
April	29.7	2.35	0.00	4.59	22.0
May	32.7	1.77	0.01	4.98	24.0
June	33.0	1.89	0.03	5.09	24.2
July	34.8	1.78	0.07	5.37	25.5
August	33.6	1.92	0.05	5.10	24.7
September	31.4	2.35	0.05	4.88	23.2
October	32.3	2.36	0.02	5.02	23.9
November	30.9	2.57	0.01	4.85	22.9
December	30.0	2.41	0.00	4.57	22.3
Year	**379.2**	**25.64**	**0.31**	**58.96**	**280.1**

Table 63 Dispatch Model Results – 18% Wind Penetration

Equivalent Wind Capacity [MW]				12 000	
Month	**Dispatched Energy [TWh]**	**Wind Energy [TWh]**	**EENS [GWh]**	**Cost of Fuel [Billion R]**	**CO2 [Mt]**
January	28.8	3.63	0.02	4.46	21.5
February	28.2	2.34	0.04	4.48	21.0
March	31.5	2.51	0.03	5.01	23.4
April	28.8	3.19	0.01	4.41	21.3
May	32.0	2.45	0.01	4.88	23.5
June	32.3	2.62	0.03	4.94	23.6
July	34.2	2.44	0.03	5.24	25.0
August	32.9	2.63	0.05	4.96	24.2
September	30.5	3.24	0.02	4.69	22.6
October	31.4	3.21	0.08	4.82	23.3
November	29.9	3.51	0.02	4.61	22.2
December	29.1	3.30	0.01	4.39	21.6
Year	**369.8**	**35.06**	**0.34**	**56.88**	**273.2**

Table 64 2030 Dispatch Model Results - Full Dispersion

Month	Dispatched Energy [TWh]	Wind Energy [TWh]	EENS [GWh]	Cost of Fuel [Billion R]	CO2 [Mt]
January	31.3	1.15	0.01	5.23	23.2
February	29.8	0.74	0.00	5.09	22.0
March	33.2	0.79	0.03	5.62	24.5
April	32.0	1.01	0.01	5.05	23.0
May	33.7	0.79	0.01	5.24	24.8
June	34.1	0.84	0.03	5.43	24.9
July	36.9	0.76	0.04	5.74	26.2
August	34.7	0.84	0.07	5.42	25.5
September	32.7	1.03	0.01	5.33	24.1
October	34.6	1.02	0.03	5.59	24.9
November	32.3	1.12	0.04	5.44	23.8
December	31.4	1.05	0.00	4.97	23.3
Year	**396.7**	**11.12**	**0.28**	**64.16**	**290.3**

Table 65 2030 Dispatch Model Results - Zero Dispersion (Western Cape)

Month	Dispatched Energy [TWh]	Wind Energy [TWh]	EENS [GWh]	Cost of Fuel [Billion R]	CO2 [Mt]
January	31.3	1.14	0.01	5.22	23.2
February	29.8	0.78	0.02	5.09	22.0
March	33.3	0.77	0.04	5.64	24.6
April	31.2	0.86	0.01	5.05	23.0
May	33.8	0.62	0.00	5.30	24.9
June	34.2	0.68	0.04	5.49	25.0
July	35.9	0.68	0.05	5.74	26.2
August	34.7	0.80	0.05	5.43	25.5
September	32.9	0.86	0.07	5.41	24.2
October	33.8	0.87	0.01	5.59	24.9
November	32.3	1.13	0.01	5.43	23.8
December	31.3	1.09	0.01	4.94	23.3
Year	**394.6**	**10.28**	**0.32**	**64.32**	**290.6**

Table 66 2030 Dispatch Model Results - Zero Dispersion (Eastern Cape)

Month	Dispatched Energy [TWh]	Wind Energy [TWh]	EENS [GWh]	Cost of Fuel [Billion R]	CO2 [Mt]
January	31.3	1.16	0.03	5.25	23.2
February	29.4	0.70	0.08	5.13	22.1
March	33.2	0.80	0.10	5.65	24.5
April	30.9	1.14	0.03	4.99	22.9
May	33.5	0.93	0.01	5.19	24.6
June	35.5	0.99	0.04	5.40	24.8
July	35.8	0.84	0.06	5.66	26.1
August	34.7	0.87	0.03	5.41	25.5
September	32.6	1.20	0.13	5.30	24.0
October	33.5	1.19	0.03	5.44	24.7
November	32.3	1.09	0.09	5.50	23.9
December	31.4	1.01	0.04	5.05	23.3
Year	**394.1**	**11.93**	**0.66**	**63.96**	**289.6**

Appendix E – Dispatch Model Code

```
%This model determines the day ahead unit commitment for conventional
%generation thermal units.  it uses the forecasted demand, forecasted
%renewable generation and load carrying capability of the thermal units.
%this model is developed for one season only at the moment.  however, it
will
%be developed to included a loop to model all seasons
%Clear all variables and work space
clc
clear
%A description of the maximum number of days in each season.

s = [31 28 31 30 31 30 31 31 30 31 30 31];
c = [0 31 59 90 120 151 181 212 243 273 304 334];
%Prompt the user for the season.  the seasons are described in the form
%s1,s2,s3,....s12. There are 12 seasons. one for each month

season = input('Select Season for analysis:');
load('Demand.mat'); %loads demand array

n = 10000; %number of samples

Day = round(rand(n,1)*(s(season)-1))+1;
day = c(season)*ones(n,1) + Day;
%The correct demand profile needs to be selected from the demanad metrix

demand = Demand(day,1:24);    %MW

%forecast error for demand based on Mean absolute error

ELCC = 0.8972;
%ForecastDemand = (1+demandMAE)*demand;
ForecastDemand = demand / ELCC;

%Required reserve to contour forced outages.  determined used the load
%carrying capability of thermal systems.
%Call FUNCTION THAT DETERMINES THE LCC FOR THERMAL UNITS with regards to
%required reliability.
%the correct capacity needs to called for the right season.

load('CAPRemaining.mat');   %loads seasonal available capacities for each
technology, wind and solar farm
availablecap = CapacityRemaining(1:9,season);

%the correct wind and solar generation needs to be selected.  the wind and
%solar generation selected is the of the all the wind farms and solar
%farms.

load('Wind2011.mat');
wind = Wind2011(day,1:24);  %MW

%Forecast error for wind and pv based of mean absolute error

REMAE = 0.2;
ForecastWind = (1-REMAE)*wind;

%in order to determine the required capacity, we need to find the net load
%of the system. which is a function of the forecasted demand, reserve
```

```
%requirements, wind generation and pv generation.

ForecastNetDemand = ForecastDemand - ForecastWind;

%non thermal units need to be incorporated into the day ahead unit
%commitment.  these units include hydro and nuclear
%beginning with pump storage

availableCAPps = availablecap(9);   %MW
efficiencyPS = 0.73;
[sorted1 idx] = sort(ForecastNetDemand,2,'descend');
top6 = idx(:,1:6);
top61d = (top6 - 1) * n + [1:n]' * ones(1,6);
bottom6 = idx(:,19:24);
bottom61d = (bottom6 - 1) * n + [1:n]' * ones(1,6);

ForecastNetDemand2 = ForecastNetDemand;
ForecastNetDemand2(top61d(:)) = ForecastNetDemand(top61d(:)) -
availableCAPps;
ForecastNetDemand2(bottom61d(:)) = ForecastNetDemand(bottom61d(:)) +
(availableCAPps/efficiencyPS);

availableCAPnonThermal = CapacityRemaining(5,season) +
CapacityRemaining(6,season) + CapacityRemaining(7,season) +
CapacityRemaining(8,season);
ForecastNetDemand3 = ForecastNetDemand2 - availableCAPnonThermal;

RequiredCAP = max(ForecastNetDemand3,[],2);

%capacity available for thermal units

SmallCoalCAP = ones(n,1) * availablecap(1);
LargeCoalCAP = ones(n,1) * availablecap(2);
LargeCoalDryCAP = ones(n,1) * availablecap(3);

%Online capacity for thermal units according to dispatch order

OnlineLargeCoalCAP = min(LargeCoalCAP,RequiredCAP);
OnlineLargeCoalDryCAP = min(RequiredCAP -
OnlineLargeCoalCAP,LargeCoalDryCAP);
OnlineSmallCoalCAP = min(RequiredCAP - OnlineLargeCoalCAP -
OnlineLargeCoalDryCAP,SmallCoalCAP);
UnitCommitment = OnlineLargeCoalCAP + OnlineLargeCoalDryCAP +
OnlineSmallCoalCAP;

%for real time operations, the same day used in unit commitment is used for
real time operations.
%It uses random numbers to generate forced outages of generation units.
%It also incorporates the minimum stable generation levels of thermal
units.
%generate randon number to generate forced outages
%find the net actual load in the system
%Capacity after forced outages

Units = [46 39 15 20 5 1 6 2 9];
UnitCap = availablecap(1:9) ./ Units';
UnitCAP = ones(n,1) * [ones(1,46) * UnitCap(1) ones(1,39) * UnitCap(2)
ones(1,15) * UnitCap(3) ones(1,20) * UnitCap(4) ones(1,5) * UnitCap(5)
```

```
UnitCap(6) ones(1,6) * UnitCap(7) ones(1,2) * UnitCap(8) ones(1,9) *
UnitCap(9)];
FORate = ones(n,1) * [ones(1,46) * 0.046 ones(1,39) * 0.087 ones(1,15) *
0.064 ones(1,20) * 0.122 ones(1,5) * 0.1 0.085 ones(1,6) * 0.064 ones(1,2)
* 0.065 ones(1,9) * 0.065];
CAPonline = (rand(n,sum(Units)) > FORate) .* UnitCAP;

%Available Capacity for each technology after outages

smallcoalavail = sum(CAPonline(1:n,1:46),2);
largecoalavail = sum(CAPonline(1:n,47:85),2);
largecoaldryavail = sum(CAPonline(1:n,86:100),2);
OCGTavail = sum(CAPonline(1:n,101:120),2);
cahorabassaavail = sum(CAPonline(1:n,121:125),2);
minihydroavail = CAPonline(1:n,126);
hydroexistingavail = sum(CAPonline(1:n,127:132),2);
nuclearavail = sum(CAPonline(1:n,133:134),2);
PSavail = sum(CAPonline(1:n,135:143),2);

averagesmallcoalavail = (sum(smallcoalavail))/n;
averagelargecoalavail = (sum(largecoalavail))/n;
averagelargecoaldryavail = (sum(largecoaldryavail))/n;
averageOCGTavail = (sum(OCGTavail))/n;
averagecahorabassaavail = (sum(cahorabassaavail))/n;
averageminihydroavail = (sum(minihydroavail))/n;
averagehydroexistingavail = (sum(hydroexistingavail))/n;
averagenuclearavail = (sum(nuclearavail))/n;

%percentage of offline capacity is deteremined to find how much online cap
%is still available after outages

percentsmallcoal = (SmallCoalCAP - smallcoalavail) ./ SmallCoalCAP;
percentlargecoal = (LargeCoalCAP-largecoalavail) ./ LargeCoalCAP;
percentlargecoaldry = (LargeCoalDryCAP-largecoaldryavail) ./
LargeCoalDryCAP;

%minimum stable generation level for thermal unitssmal
MSGL = 0.3;
MINsmallcoal = MSGL * smallcoalavail;
MINlargecoal = MSGL * largecoalavail;
MINlargecoaldry = MSGL * largecoaldryavail;

DispatchableSmallcoal = (OnlineSmallCoalCAP - (OnlineSmallCoalCAP * MSGL))
.* (1 - percentsmallcoal);
DispatchableLargecoal = (OnlineLargeCoalCAP - (OnlineLargeCoalCAP * MSGL))
.* (1 - percentlargecoal);
DispatchableLargecoaldry = (OnlineLargeCoalDryCAP - (OnlineLargeCoalDryCAP
* MSGL)) .* (1 - percentlargecoaldry);
%minimum generation and nuclear is dispatched 1st

NetDemand = demand - MINlargecoal * ones(1,24) - MINlargecoaldry *
ones(1,24) - MINsmallcoal * ones(1,24) - nuclearavail * ones(1,24);
NetDemand2 = NetDemand - wind;

PSavail1d = (PSavail - 1) * ones(1,6);
[sorted idx] = sort(NetDemand,2,'descend');
Top6 = idx(:,1:6);
Top61d = (Top6 - 1) * n + [1:n]' * ones(1,6);
Bottom6 = idx(:,19:24);
```

```
Bottom61d = (Bottom6 - 1) * n + [1:n]' * ones(1,6);

NetDemand3 = NetDemand2;
NetDemand3(Top61d(:)) = NetDemand2(Top61d(:)) - PSavail1d(:);
NetDemand3(Bottom61d(:)) = NetDemand2(Bottom61d(:)) + (PSavail1d(:) /
efficiencyPS);

%technologies are then dispatched according to dispatch order

PS = NetDemand2(1:n,:) - NetDemand3(1:n,:);

dispatchedCahoraBassa = min(NetDemand3,cahorabassaavail * ones(1,24));
disptachedMinihydro = min(NetDemand3 - dispatchedCahoraBassa,minihydroavail
* ones(1,24));
dispatchedHydroexisting = min(NetDemand3 - dispatchedCahoraBassa -
disptachedMinihydro,hydroexistingavail * ones(1,24));
dispatchedlargecoal = min(NetDemand - dispatchedCahoraBassa -
disptachedMinihydro - dispatchedHydroexisting,DispatchableLargecoal *
ones(1,24));
dispatchedlargecoaldry = min(NetDemand3 - dispatchedCahoraBassa -
disptachedMinihydro - dispatchedHydroexisting -
dispatchedlargecoal,DispatchableLargecoaldry * ones(1,24));
dispatchedsmallcoal = min(NetDemand3 - dispatchedCahoraBassa -
disptachedMinihydro - dispatchedHydroexisting - dispatchedlargecoal -
dispatchedlargecoaldry,DispatchableSmallcoal * ones(1,24));
dispatchedOCGT = min(NetDemand3 - dispatchedCahoraBassa -
disptachedMinihydro - dispatchedHydroexisting - dispatchedlargecoal -
dispatchedlargecoaldry - dispatchedsmallcoal,OCGTavail * ones(1,24));

%Displaying how power has been dispatched for each technology and a check
%to see if fundamental power balanace has been meet.

DispatchedPower = [nuclearavail * ones(1,24);MINlargecoal *
ones(1,24);MINlargecoaldry * ones(1,24);MINsmallcoal *
ones(1,24);wind;PS;dispatchedCahoraBassa;disptachedMinihydro;dispatchedHydr
oexisting;dispatchedlargecoal;dispatchedlargecoaldry;dispatchedsmallcoal;di
spatchedOCGT];
%disp(DispatchedPower);

TotalDispatchedPower = nuclearavail * ones(1,24) + MINlargecoal *
ones(1,24) + MINlargecoaldry * ones(1,24) + MINsmallcoal * ones(1,24) +
wind + PS + dispatchedCahoraBassa + disptachedMinihydro +
dispatchedHydroexisting + dispatchedlargecoal + dispatchedlargecoaldry +
dispatchedsmallcoal + dispatchedOCGT;
unservedEnergy = demand - TotalDispatchedPower;

AverageDemand = (sum(demand))/n;
AverageUnserved = (sum(unservedEnergy))/n;

AverageWind = (sum(wind))/n;
AveragePS = (sum(PS))/n;

AverageCahoraBassa = (sum(dispatchedCahoraBassa))/n;
AverageMinihydro = (sum(disptachedMinihydro))/n;
AverageHydroexisting = (sum(dispatchedHydroexisting))/n;
AverageNuclear = (sum(nuclearavail))/n;
AverageLargecoal = (sum(dispatchedlargecoal) + sum(MINlargecoal))/n;
AverageLargecoaldry = (sum(dispatchedlargecoaldry) +
sum(MINlargecoaldry))/n;
```

```
AverageSmallcoal = (sum(dispatchedsmallcoal) + sum(MINsmallcoal))/n;
AverageOCGT = (sum(dispatchedOCGT))/n;

%write different indicators into excel for analysis

xlswrite('SIM2011.xls',averagecahorabassaavail,season,'B1:Y1');
xlswrite('SIM2011.xls',averageminihydroavail,season,'B2:Y2');
xlswrite('SIM2011.xls',averagehydroexistingavail,season,'B3:Y3');
xlswrite('SIM2011.xls',averagenuclearavail,season,'B4:Y4');
xlswrite('SIM2011.xls',averagelargecoalavail,season,'B5:Y5');
xlswrite('SIM2011.xls',averagelargecoaldryavail,season,'B6:Y6');
xlswrite('SIM2011.xls',averagesmallcoalavail,season,'B7:Y7');
xlswrite('SIM2011.xls',averageOCGTavail,season,'B8:Y8');

xlswrite('SIM2011.xls',AverageDemand,season,'B10:Y10')
xlswrite('SIM2011.xls',AverageUnserved,season,'B12:Y12');

xlswrite('SIM2011.xls',AverageWind,season,'B14:Y14');
xlswrite('SIM2011.xls',AveragePS,season,'B15:Y15');

xlswrite('SIM2011.xls',AverageCahoraBassa,season,'B17:Y17');
xlswrite('SIM2011.xls',AverageMinihydro,season,'B18:Y18');
xlswrite('SIM2011.xls',AverageHydroexisting,season,'B19:Y19');
xlswrite('SIM2011.xls',AverageNuclear,season,'B20:Y20');
xlswrite('SIM2011.xls',AverageLargecoal,season,'B21:Y21');
xlswrite('SIM2011.xls',AverageLargecoaldry,season,'B22:Y22');
xlswrite('SIM2011.xls',AverageSmallcoal,season,'B23:Y23');
xlswrite('SIM2011.xls',AverageOCGT,season,'B24:Y24');
```

Appendix F – Glossary

Base-load plant: refers to energy plant or power stations that are able to produce energy at a constant, or near constant, rate, i.e. power stations with high capacity factors.

Capacity factor: refers to the expected output of the plant over a specific time period as a ratio of the output if the plant operated at full rated capacity for the same time period.

Capacity Credit: The amount of installed conventional power that can be avoided or replaced with wind energy

Dispatching (economic dispatch): Once a plant has been committed, it can then be operated over a range of possible output levels. The economic dispatch process is a method by which system operators decide how much output should be scheduled from the plants that have been committed, and/or plants that can be started quickly and don't require a lengthy start-up or commitment process.

Expected Energy not Served: The expected energy that will not be delivered when load exceeds capacity

Effective Load Carry Capability: The maximum load that a power system can carry at a given or specified reliability level

Firm Capacity: The capacity of a thermal unit that will produce the same LOLP for a power system as additional wind capacity.

Integrated Resource Plan: refers to the co-ordinated schedule for generation expansion and demand-side intervention programmes, taking into consideration multiple criteria to meet electricity demand.

Integrated Energy Plan refers to the over-arching co-ordinated energy plan combining the constraints and capabilities of alternative energy carriers to meet the country's energy needs.

Load forecasting: Load forecasts are predictions of future demand. For normal operations, daily and weekly forecasts of the hour-by-hour demand are used to help develop generation schedules to ensure that sufficient quantities and types of generation are available when needed

Loss of Load Probability: The % probability that load exceeds the available capacity

Loss of Load Expectation: The expected time duration that the load exceeds the available capacity

Minimum run level: Minimum level of output that can be provided from a generator. Different generators have different minimum run levels based in part on fuel source, plant design, or common use

Peaking plant: refers to energy plant or power stations that have very low capacity factors, i.e. generally produce energy for limited periods, specifically during peak demand periods, with storage that supports energy on demand.

Ramp, ramp rate: Ramp refers to a change in generation output over some unit of time. Ramp rate describes the ability of a generating unit to changes its output, and is often measured in MW/min.
Reserve margin: refers to the excess capacity available to serve load during the annual peak.

Scenario: refers to a particular set of assumptions and set of future circumstances, providing a mechanism to observe outcomes from these circumstances.

Spinning reserve: Generation and responsive load that is on-line, begins responding immediately, and is fully responsive within ten minutes.

Strategy: is used synonymously with Policy, referring to decisions that, if implemented, assume specific objectives will be achieved.

System Security: The ability of a power system to withstand sudden disturbances

System Adequacy: The ability of a power system to satisfy consumer load demand or system operational constraints at all times

Unit: A single generator that may be part of a multiple-generator power plant.

Unit commitment: Is the process of starting up a generator so that boilers reach operating temperature and the plant is synchronized to the grid. This process can take many hours for a steam generator, depending on whether the plant is warm or hot from previous commitment.