**PROJECT DESIGN DOCUMENT FORM
FOR CDM PROJECT ACTIVITIES (F-CDM-PDD)
Version 04.1**

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	TWE Golden Valley Wind Power Project
Version number of the PDD	01
Completion date of the PDD	29/05/2012
Project participant(s)	Terra Wind Energy – Golden Valley (Pty) Limited
Host Party(ies)	South Africa
Sectoral scope and selected methodology(ies)	Sectoral Scope 1 ACM0002 (version 13.0.0)
Estimated amount of annual average GHG emission reductions	481,997 tCO_2e

SECTION A. Description of project activity
A.1. Purpose and general description of project activity

The purpose of the TWE Golden Valley Wind Power Project is the construction of a 147.6 MW wind power plant in the Eastern Cape Province of South Africa.

The wind park will consist of 82 Vestas V100-1.8 MW turbines. It is estimated that the project activity will supply 509,303 MWh of clean electricity to the South African national electricity grid per year resulting in a net load factor of 39.39%.

The project activity is the installation of a new grid-connected renewable power plant. Therefore, according to ACM0002 (version 13.0.0), the baseline scenario is:

"Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system"

The baseline scenario is the same as the scenario existing prior to the start of the implementation of the project activity.

As per 31 March 2011, the total installed capacity of grid-connected power plants in South Africa was 47,463 MW. Ninety-three per cent (93%) of the installed capacity is owned by the national utility, ESKOM. The remaining 7% is owned by municipalities and Independent Power Producers (IPPs), i.e. 4% and 3% respectively. As of 31 March 2012, there were only two grid-connected wind power plants with a total installed capacity of 8.2 MW.[1] This constitutes less than 0.02% of the total installed capacity and is negligible compared to the 85%, 6%, and 4% that coal-based, gas, and nuclear power plants contribute respectively.[2]

The Integrated Resource Plan 2010-2030, published by the Department of Energy (DOE) and the National Energy Regulator of South Africa (NERSA), predicts that by 2030 the power generation capacity of South Africa will double to 89,532MW to meet the rising energy demand. It is expected that wind energy technologies will constitute 10.3% of the future capacity, i.e. approximately 9,200 MW.

Further information regarding the existing and planned power plants is given in section B.4 below.

The project activity will achieve CO2 emission reductions by replacing electricity generated by fossil fuel powered plants connected to the national grid. The project is expected to achieve annual emission reductions of about 481,997 tCO2/year.

The implementation of this project is expected to contribute to sustainable development in South Africa in various ways, including:

- The project is expected to support the national policy goal of achieving 10% penetration for wind technology as a share of total installed capacity in 2020, and 20% in 2030.[3]

[1] Both wind power projects are considered demonstration projects. The first one, Klipheuwel Wind farm of 3 MW is owned by Eskom. The second project, the Darling National Demonstration Wind Farm of 5.2 MW, is owned by an Independent Power Producer (IPP).
[2] 2012 01 19 Graphs Baseline
[3] Integrated Resource Plan for Electricity 2010-2030, Department of Energy, Electricity Regulation Act No.4 of 2006, 6 May 2006

- The project is expected to provide local employment opportunities during the construction and operation phase.
- The project is expected to contribute to South Africa's fiscal revenues through payment of taxes, and attract foreign direct investment.
- The project will have a positive impact on the transfer of wind energy technology to South Africa, as well as know-how skills for local workers. The transfer of technology and know-how will be directly replicable to other future wind energy projects.
- The project will reduce South Africa's CO2 footprint and increase the electricity generation capacity of the country.

A.2. Location of project activity
A.2.1. Host Party(ies)

South Africa

A.2.2. Region/State/Province etc.

Eastern Cape Province

A.2.3. City/Town/Community etc.

Blue Crane Route Local Municipality

A.2.4. Physical/Geographical location

The project is situated 15 km Southeast of Cookhouse in the Eastern Cape province, South Africa. The site belongs to the Bedford Magisterial District. It is bordered on the west by the Great Fish River and the national road R335 from Cradock to Port Elizabeth, and on the northern side by the Cookhouse-Bedford gravel road that passes near the major ESKOM Poseidon substation.

The coordinates and boundaries as well as the map of the project area are given in the figure and table below:

Figure 1: Project Boundary

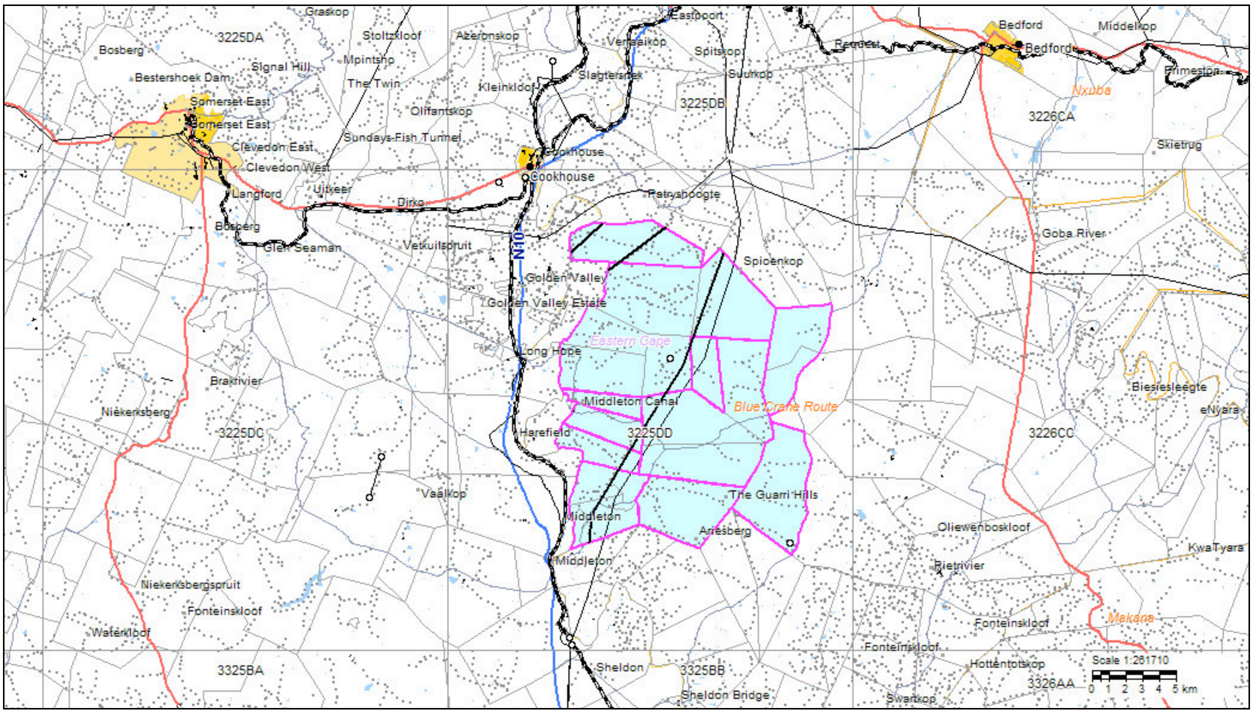

Table 1: Geo-Coordinates Golden Valley Wind Power Plant

	Latitude	Longitude
Golden Valley – Northwest point	32°46'59.85"S	25°49'42.58"E
Golden Valley – Northeast point	32°49'11.64"S	25°58'55.70"E
Golden Valley – Southwest point	32°56'48.49"S	25°49'40.68"E
Golden Valley – Southeast point	32°57'2.72"S	25°57'49.14"E

A.3. Technologies and/or measures

1. Turbine technology

Based on onsite wind measurements and analysis the Vestas V100 1.8 MW wind turbine generator was selected as the most appropriate turbine technology. The turbine has a nominal capacity of 1.8 MW. A total of 82 wind turbine generators (WTGs) will be installed. Further details regarding the technical specifications of the Vestas V100-1.8 MW are given in the table below.

Table 2: Technical specifications of wind turbine technology

Parameter	**Value**
Manufacturer	Vestas Wind Systems A/S
Rotor diameter	100 m
Area swept	7.850 m²
Number of blades	3
Hub height	80 m
Cut-in wind speed	3 m/s
Cut-out wind speed	20 m/s

Rotor speed range	9.3-16.6 rpm
Nominal output	1.8 MW
Lifetime	20 years

2. Grid connection

The project will inject the energy generated into the Transmission System at the Point of Utility Connection at a voltage level of 132 KV.

3. Metering System

A main and back-up metering system will be installed as part of the project in line with the metering code and NRS 057 code.

Transfer of environmentally safe and sound technology will take place through the introduction of state-of-the-art wind turbine technology. Transfer of know-how will take place through the training of local engineers and other technical staff by the Operations and Maintenance contractor with the support of the turbine manufacturer. The turbine manufactures as well as assuring performance standards for the wind farm will also provide oversight of the maintenance and operation of the turbines during its lifetime

The scenario existing prior to the implementation of the project activity is that no other or previous technology for power generation has been employed at this project site.

As further explained in section B.4, the baseline is: "Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the *Tool to calculate the emission factor for an electricity system."*

In the absence of the project activity, electricity would be delivered to the grid by a mix of power plants using different types of technologies. Table 3 provides a list of electricity generating technologies that were supplying electricity to the South African national grid as per 31st March 2011.

Table 3: Installed Capacity (MW) in South Africa

Technology	***Total Installed Capacity (MW)***	***Percentage %***
Coal	40,407	85.13%
Gas	2,760	5.82%
Hydro	675	1.42%
Nuclear	1,910	4.02%
PSHSP	1,589	3.35%
Wind	8.2	0.02%
Bagasse	105	0.22%
Biogas (Waste Water)	4.248	0.01%
Landfill	5	0.01%
Total	***47,463.45***	***100.00%***

According to the 2010-2030 Integrated Resource plan, the current installed capacity is expected to double by 2030 in order to meet the rising electricity demand which is expected to peak at about 80,272 MW by then. In order to meet this demand candidate generation sources include coal, nuclear, concentrated solar power (CSP), solar photovoltaic (PV) and gas turbines (both open cycle and combined cycle types).

According to ACM0002 (version 13.0.0), the emissions sources and greenhouse gases involved, include CO2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The TWE Golden Valley Wind Power Project, with a capacity factor of 39.39 %, is expected to produce approximately 509,303 MWh of clean energy a year thereby displacing 481,997 tCO2 emission from grid connected fossil fired plants per year.

A.4. Parties and project participants

Party involved (host) indicates a host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
South Africa (host)	Terra Wind Energy – Golden Valley (Pty) Limited	No

A.5. Public funding of project activity

The project activity has not received public funding from Parties included in Annex I.

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

The approved consolidated baseline and monitoring methodology ACM0002 "*Consolidated baseline methodology for grid-connected electricity generation from renewable sources*" (version 13.0.0) is applicable and used by the project activity.

In line with ACM0002, the project activity also refers to the latest approved version of the following tools:

- *Tool to calculate the emission factor for an electricity system* (version 02.2.1);
- *Tool for the demonstration and assessment of additionality* (version 06.0.0);
- *Combined tool to identify the baseline scenario and demonstrate additionality* (version 04.0.0);
- *Tool to calculate project or leakage CO2 emissions from fossil fuel combustion* (version 02)

B.2. Applicability of methodology

The proposed project activity meets the applicability criteria listed in the approved consolidated baseline and monitoring methodology ACM0002 version 13.0.0 as shown below:

Applicability criteria	Comments
This methodology is applicable to grid-connected renewable power generation project activities that: (a) Install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) Involve a capacity addition; (c) Involve a retrofit of (an) existing plant(s); or (d) Involve a replacement of (an) existing plant(s).	The proposed project activity meets the applicability criteria (a). It is a grid-connected wind power generation project activity that will install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant)
The project activity is the installation, capacity	The project activity is the installation of a wind

addition, retrofit or replacement of a power plant/unit of one of the following types: hydropower plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit.	power plant. Therefore it meets this applicability criterion.
In the case of capacity additions, retrofits or replacements (except for wind, solar, wave or tidal power capacity addition projects which use Option 2: on page 10 to calculate the parameter *EGPJ,y*): the existing plant started commercial operation prior to the start of a minimum historical reference period of five years, used for the calculation of baseline emissions and defined in the baseline emission section, and no capacity expansion or retrofit of the plant has been undertaken between the start of this minimum historical reference period and the implementation of the project activity.	N/a. The project activity is the installation of a new wind power plant.
In case of hydro power plants: One of the following conditions must apply: • The project activity is implemented in an existing single or multiple reservoirs, with no change in the volume of any of reservoir or • The project activity is implemented in an existing single or multiple reservoirs, where the volume of any of reservoirs is increased and the power density of each reservoir, as per the definitions given in the project emissions section, is greater than 4 W/m^2; or • The project activity results in new single or multiple reservoirs and the power density of each reservoir, as per the definitions given in the project emissions section, is greater than 4 W/m^2.	N/a. The project activity is the installation of a new wind power plant.
In case of hydro power plants using multiple reservoirs where the power density of any of the reservoirs is lower than 4 W/m^2 all the following conditions must apply: • The power density calculated for the entire project activity using equation 5 is greater than 4 W/m^2; • Multiple reservoirs and hydro power plants located at the same river and where are designed together to function as an integrated project1 that collectively	N/a. The project activity is the installation of a new wind power plant.

constitute the generation capacity of the combined power plant; • Water flow between multiple reservoirs is not used by any other hydropower unit which is not a part of the project activity; • Total installed capacity of the power units, which are driven using water from the reservoirs with power density lower than 4 W/m^2, is lower than 15 MW; • Total installed capacity of the power units, which are driven using water from reservoirs with power density lower than 4 W/m^2, is less than 10% of the total installed capacity of the project activity from multiple reservoirs.	
The methodology is not applicable to the following: • Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site; • Biomass fired power plants; • A hydro power plant that results in the creation of a new single reservoir or in the increase in an existing single reservoir where the power density of the reservoir is less than 4 W/m^2.	N/a. The project activity is a grid-connected wind power generation project.
In the case of retrofits, replacements, or capacity additions, this methodology is only applicable if the most plausible baseline scenario, as a result of the identification of baseline scenario, is "the continuation of the current situation, i.e. to use the power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance".	N/a. The project activity is a greenfield plant.

In addition, the project meets the applicability criteria of the *Tool to calculate the emission factor for an electricity system* (version 02.2.1) as follows:

This tool may be applied to estimate the OM, BM and/or CM when calculating baseline emissions for a project activity that substitutes grid electricity, i.e. where a project activity supplies electricity to a grid or a project activity that results in savings of electricity that would have been provided by the grid (e.g. demand side energy efficiency projects).	This tool is applicable since the proposed project activity involves the generation of electricity from wind energy and its supply to the South African National Grid-system.

The tool is not applicable if the project electricity system is located partially or totally in an Annex I country.	The project electricity system is the South African National Grid-system. South Africa is not an Annex I country.

B.3. Project boundary

	Source	GHGs	Included?	Justification/Explanation
Baseline scenario	CO2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity.	CO_2	Yes	Main emission source according to ACM0002
		CH_4	No	Minor emission source according to ACM0002
		N_2O	No	Minor emission source according to ACM0002
Project scenario	Project Activity	CO_2	No	Zero emissions according to ACM0002
		CH_4	No	
		N_2O	No	

Figure 2 below provides a flow chart of the equipment and systems, emissions sources and gases included in the project boundary as well as the monitoring variables in the project boundary:

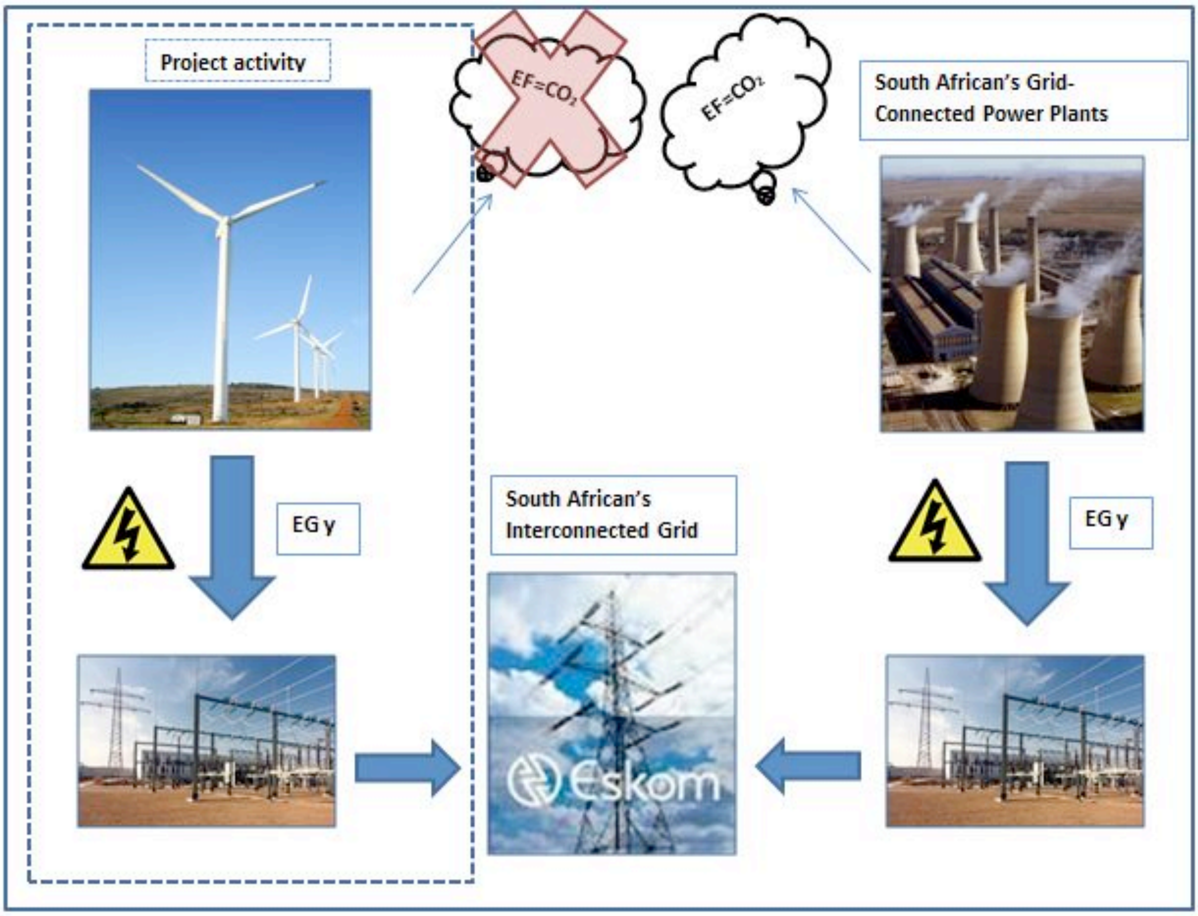

Figure 2: Flow Diagram of the Project Boundary

The wind park will consist of 82 VESTAS V100-1.8 MW wind turbines each with a rated capacity of 1.815 MW. More details on the project activity can be found in section A.3 above.

It is estimated that the project activity will annually supply 509,303 MWh of clean electricity to the South African national electricity operated by ESKOM. The project activity will therefore displace electricity generated by South Africa's fossil fuel grid connected power plants and will therefore lead to annual emission reductions of 481,997 tCO2.

In order to determine the annual emission reductions, the project proponent will monitor the amount of electricity generated, as described in section B.7.1.

B.4. Establishment and description of baseline scenario

The proposed project activity is the installation of a new wind power plant project (greenfield plant) that delivers electricity to the National Electricity Grid of South Africa. Therefore, the baseline scenario is "the electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources into the grid".

Structure of the South African Power Sector

The South African Department of Energy (DoE) is the legislative entity responsible for the South African energy sector. The energy sector is determined by the *National Energy Act of 2008 (No.34 of 2008)*[4].

Specifically for the electricity sector of South Africa, the *Electricity Regulation Act of 2006 (No. 4 of 2006)*[5] determines the framework of the electricity sector. In May 2011, the Department of Energy, acting as the legislative entity, put into force the *Electricity Regulations on New Generation Capacity*[6] under the *Electricity Regulation Act of 2006.* According to the current regulation, 70% of the new generation capacity must be implemented by the state-owned utility company Eskom, and 30% by Independent Power Producers (IPPs).[7] The Department of Energy has the mandate to decide which planned capacity addition will be implemented by Eskom, and which will be determined by a bidding process between IPPs. However, all IPPs are mandated to sell the generated electricity to Eskom (Single-Buyer-Model) through the signing of long-term Power Purchase Agreements (PPAs) with Eskom.

The Department of Energy determines the needed capacity additions after consultation with the regulator NERSA. The DoE regularly develops an "*Integrated Resource Plan for Electricity*" which is updated every two years, the latest one being the *"Integrated Resource Plan 2010-2030 for Electricity"*[8] under the *Electricity Regulation Act No. 4 of 2006.* In its current version, from the year 2010, the Integrated Resource Plan determines the proposed specific amount of each technology in the electricity generation from 2010 to 2030.

Apart from the Department of Energy (DoE) and the National Energy Regulator of South Africa (NERSA), Eskom is the main player in the South African power sector. From 2002, Eskom became a public, limited liability company wholly owned by the government. Eskom owns and operates the

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[4] Department of Energy (2008), National Energy Act of 2oo8 http://www.info.gov.za/view/DownloadFileAction?id=92826, accessed on 30.12.2011

[5] Department of Energy (2006), Electricity Regulation Act of 2006, http://www.info.gov.za/view/DownloadFileAction?id=67855, accessed on 30.12.2011

[6] Department of Energy (2010), Electricity Regulations on New Generation Capacity, http://www.info.gov.za/view/DownloadFileAction?id=136320, accessed on 30.12.2011

[7] Department of Energy, http://www.energy.gov.za/files/electricity_frame.html, accessed on 30.12.2011

[8] Department of Energy (2011), Electricity Regulations on the Integrated Resource Plan 2010-2030, http://www.info.gov.za/view/DownloadFileAction?id=146082, accessed on 30.12.2011

National Electricity Grid and parts of the distribution network, and also owns 93% of the installed generation capacity.

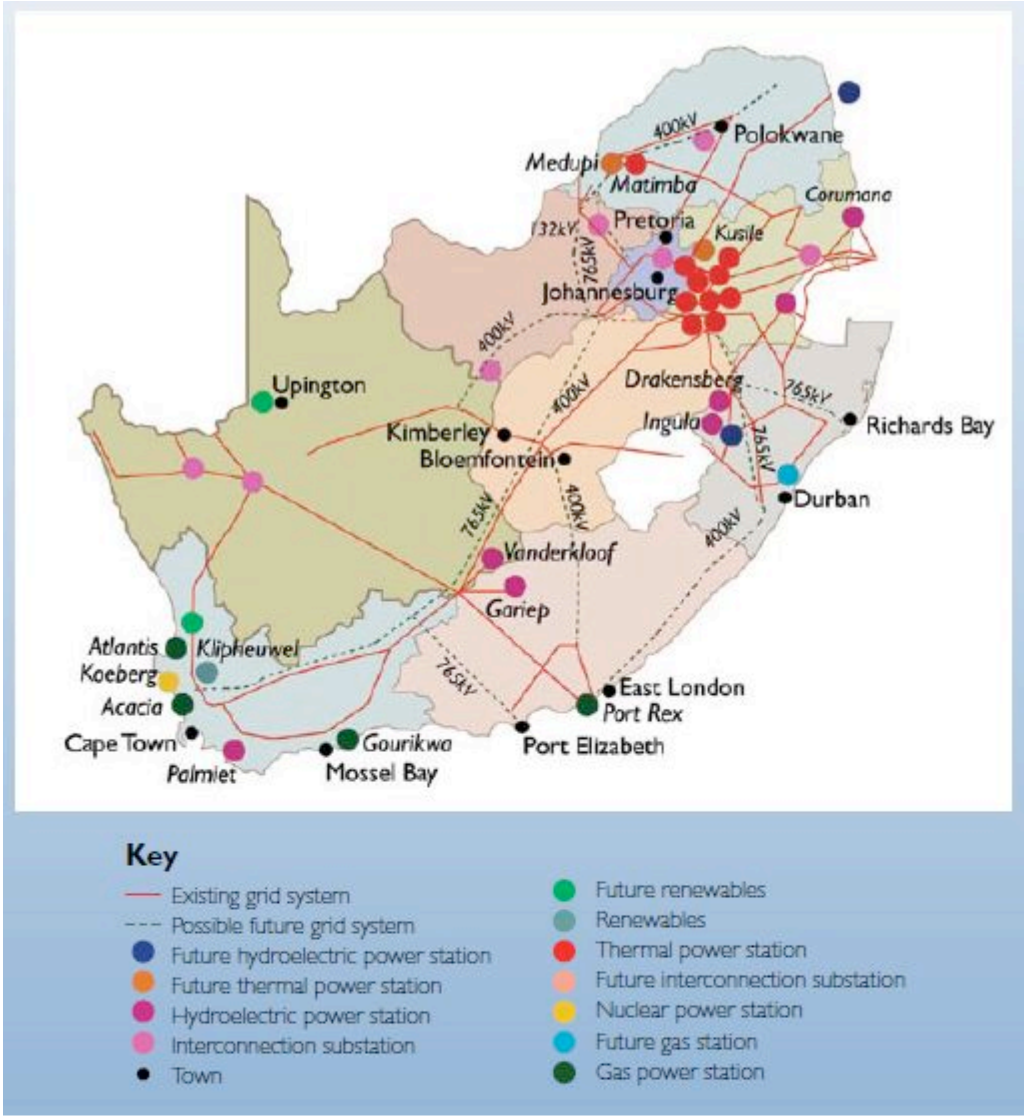

Figure 3: South African Power Sector

<u>Generation</u>

Electricity generation in South Africa is dominated by Eskom, which owns 93% of the installed capacity and supplies about 95% of South Africa's electricity. Municipal owned power plants and IPPs supply the remaining 5% of electricity. Approximately 90% of the total generated electricity is based on coal.[9]

Detailed description of the installed capacity for each technology is presented in the following tables. Data from Eskom's power plants is dated from 2011.[10] The latest published data for IPPs and municipal generation is from 2006[11].

[9] NERSA (2006), 2006 Electricity Supply Statistics for South Africa, http://www.nersa.org.za/Admin/Document/Editor/file/News%20and%20Publications/Publications/Current%20Issues/Electricity%20Supply%20Statistics/Electricity%20supply%20statistics%202006.pdf , accessed on 30.12.2011

[15] ESKOM (2011), Integrated Report 2011, http://financialresults.co.za/2011/eskom_ar2011/index.php, accessed on 30.12.2011

Table 4. ESKOM Electricity Generation Capacity (2011)

Installed ESKOM capacity by source	Nominal Capacity (MW)	Net maximum capacity (MW)
Coal	37,745	35,052
Gas	2,426	2,409
Hydro	661	600
Nuclear	1,910	1,830
PSHSP	1,400	1,400
Wind	3	3

Table 5. Municipalities Electricity Generation Capacity (2006)

Installed municipal capacity by source	Nominal Capacity (MW)	Net maximum capacity (MW)
Coal	1,323	240
Gas	334	122
Hydro	4	-
PSHSP	189	174

Table 6. IPP Electricity Generation Capacity (2006)

Installed private capacity by source	Nominal Capacity (MW)	Net maximum capacity (MW)
Coal	1,339	933
Bagasse / Coal Fired Stations	105	66
Hydro	10	-
Wind	5.2	5.2
Waste Water / Biogas	4.25	4.25
Landfill	5	5

Municipal power plants are mostly coal thermal power plants and gas power plants which generate electricity for the direct supply in their municipal distribution area. Many municipalities have their own distribution networks, and some of them add generation capacity to their distribution lines by adding their own power plants on top of the electricity purchased from the national grid. Power plants operated by IPPs are commonly based on coal/bagasse. Some of the IPP owned power plants generate electricity for on-site consumption (large industrial consumers) and only feed electricity into the grid in the case of excess generation.

Currently, there are only two wind power plants connected to the grid. The 3 MW Klipheuwel Wind Farm which is owned by ESKOM, and the 5.2 MW Darling Wind Farm which is an IPP owned by private investors. These plants are considred demonstration projects.

In terms of installed capacity, coal power plants' share is about 85% followed by electricity generation based on gas (6%), nuclear (4%) and pumped storage hydro power plants (3%). %). Pumped storage plants are net consumers of electricity which pump water during off-peak periods to a reservoir so that electricity can be generated during peak periods. Other energy sources like hydro, biogas etc. are negligible.

[11] NERSA (2006), 2006 Electricity Supply Statistics for South Africa, http://www.nersa.org.za/Admin/Document/Editor/file/News%20and%20Publications/Publications/Current%20Issues/Electricity%20Supply%20Statistics/Electricity%20supply%20statistics%202006.pdf accessed on 30.12.2011

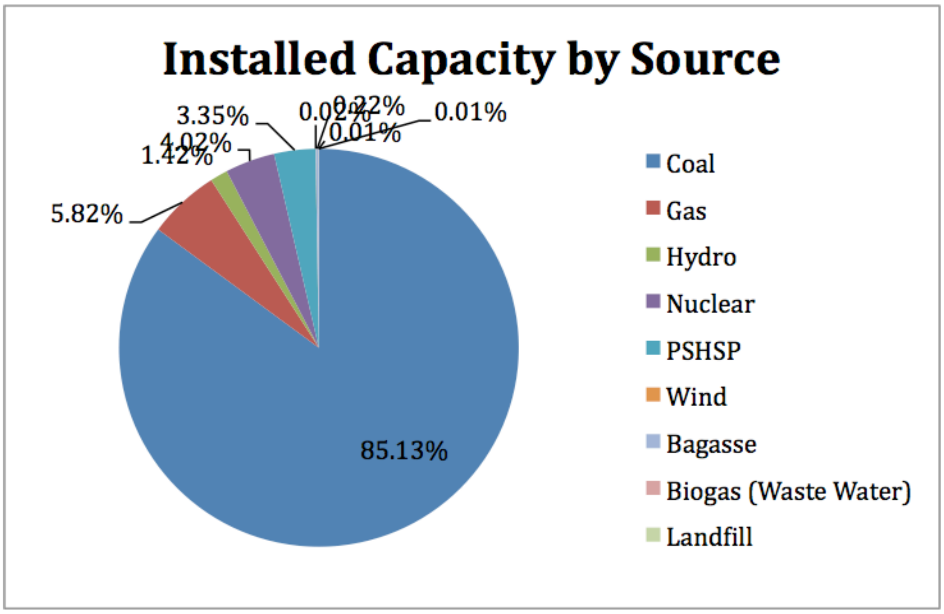

Figure 4: Installed Capacity by Source in South Africa

The *Integrated Resource Plan 2010-2030 for Electricity,* which determines the needed capacity and share of technologies in the future proposes the following capacity additions until 2030: [12]

Table 7. Summary of capacity additions 2010-2030

	Total Capacity		Capacity added (including committed) from 2010 to 2030		New (uncommitted) capacity options from 2010 to 2030	
	MW	**%**	**MW**	**%**	**MW**	**%**
Coal	41,071	45.9	16,383	29.0	6,250	14.7
OCGT	7,330	8.2	4,930	8.7	3,910	9.2
CCGT	2,370	2.6	2,370	4.2	2,370	5.6
Pumped Storage	2,912	3.3	1,332	2.4	0	0.0
Nuclear	11,400	12.7	9,600	17.0	9,600	22.6
Hydro	4,759	5.3	2,659	4.7	2,609	6.1
Wind	9,200	10.3	9,200	16.3	8,400	19.7
CSP	1,200	1.3	1,200	2.1	1,000	2.4
PV	8,400	9.4	8,400	14.9	8,400	19.7
Other	890	1.0	465	0.8	0	0.0
Total	**89,532**		**56,539**		**42,539**	

The current installed capacity of 47,463 MW is therefore expected to double to 89,532 MW by the year 2030. Peak demand in 2030 is expected to reach 80,272 MW. Apart from the domestic generation, the *Integrated Resource Plan 2010-2030 for Electricity* forecasts an increase in imports of electricity generated from hydro power plants located in Zambia and Mozambique from 2022 onwards. However, the *Integrated Resource Plan for Electricity* also mentions that in order to reach this objective, cross-border negotiations and an upgrade in transnational transmission infrastructure will be necessary. Additional risks regarding imports are construction delays and persisting droughts.

The *Integrated Resource Plan for Electricity* also forecasts the continuation of the current power shortage until the year 2016 when newly installed power plants in line with *Integrated Resource Plan 2010-2030*

[12] Department of Energy (2011), Electricity Regulations on the Integrated Resource Plan 2010-2030, http://www.info.gov.za/view/DownloadFileAction?id=146082, accessed on 30.12.2011

for Electricity as shown in Annex 3 will start operation. By the year 2012 a supply shortfall of 9 TWh is expected whereas for the year 2013 the shortfall is expected to be only 3 TWh.

Transmission and Distribution

Eskom operates the integrated national high-voltage transmission system and supplies electricity directly to large consumers such as mines and other large industries, to commercial farmers and also, through the Integrated National Electrification Programme (INEP), to a large number of residential consumers. Eskom provides electricity directly to about 45% of all end-users in South Africa. The other 55% of end-users have their electricity distributed by redistributors (including municipalities).[13] Eskom sells in bulk to certain municipalities, which distribute to the consumers within their boundaries. Those municipalities, own the distribution lines in their areas, and some also own their own generation power plants. There are also a few private entities that have the licence to distribute electricity as shown below: [14]

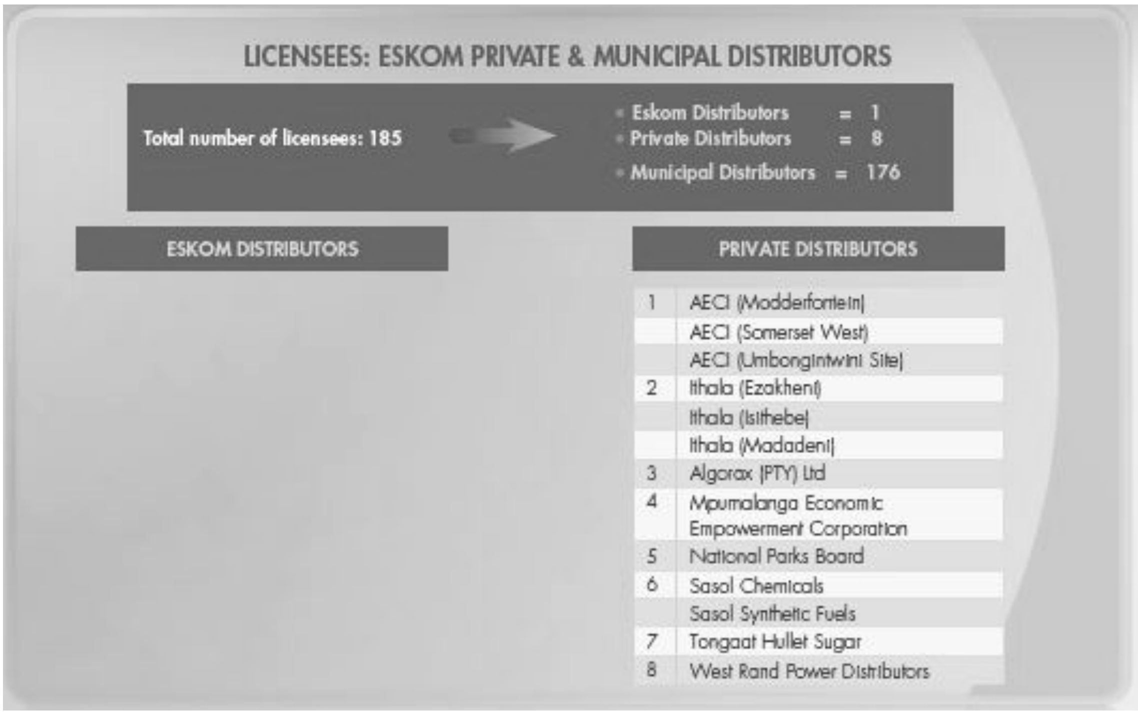

Figure 5. Distribution licenses

The government's policy on the Electricity Distribution Industry (EDI) requires the division to be separated from Eskom and merged with the electricity departments of municipalities to form a number of financially viable regional electricity distributors (REDs)[15]. An interim body, called EDI Holdings Company, was intended to oversee the transition period. This plan would have required Eskom to transfer its distribution assets and business to these entities. The restructuring proposal was formally revoked on 8 December 2010 by the government[16]. Therefore transmission lines are still owned and operated by Eskom.

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[13] ESKOM (2011), Integrated Report 2011, http://financialresults.co.za/2011/eskom_ar2011/index.php, accessed on 30.12.2011

[14] NERSA (2006), 2006 Electricity Supply Statistics for South Africa, http://www.nersa.org.za/Admin/Document/Editor/file/News%20and%20Publications/Publications/Current%20Issues/Electricity%20Supply%20Statistics/Electricity%20supply%20statistics%202006.pdf , accessed on 30.12.2011

[15] Department of Energy, http://www.energy.gov.za/files/electricity_frame.html, accessed on 30.12.2011

[16] ESKOM (2011), Integrated Report 2011, http://financialresults.co.za/2011/eskom_ar2011/index.php, accessed on 30.12.2011

As for transmission of the electricity, to meet the forecasted additional generation capacity in the *Integrated Resource Plan*, the *"Transmission Ten-Year Development Plan 2012-2021"*[17] published by the Transmission Division of ESKOM determines the required additional transmission capacity as depicted in Figure 6:

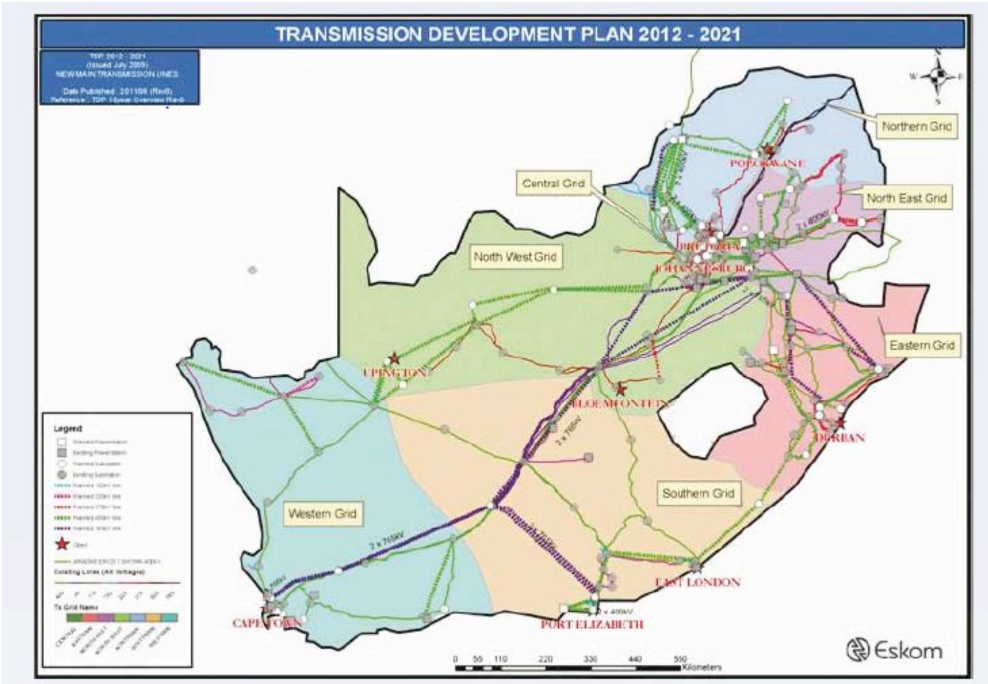

Figure 6. Transmission Development Plan 2012-2021

Significant lengths of new transmission lines are being added to the system: over 4,000 km of 765-kV and over 7,800 km of 400-kV lines have either been approved or proposed over the 10-year *Transmission Development Plan* period. This addition is mainly due to the major network reinforcements required for the supply to the Cape (South and West Grids) and KwaZulu-Natal (East Grid). The integration of the new Medupi Power Station in the developing Limpopo West Power Pool (Medupi is close to Matimba) also requires significant lengths of transmission lines as it is a long distance away from the main load centres. The large length of 400-kV transmission lines is also the result of the development of a more meshed transmission 400-kV network to provide greater reliability and thus improve the levels of network security.

The addition of over 73,000 MVA of transformer capacity to the transmission system is an indication of the increase in load demand and in the capacity requirements of the customers. This figure also includes the transformation capacity required to integrate renewable energy generation. Approximately 2,000 MVars of capacitive support are required to support areas of the network under contingency conditions to ensure that the required voltage levels are maintained. They also improve system efficiency by reducing network losses.

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[17] Eskom (2011), Transmission Ten-Year Development Plan 2012-2021, http://www.eskom.co.za/content/TDP%20051011%20lowres.pdf, accessed on 30.12.2011

TDP New Assets	Total
HVDC Lines (km)	0
765kV Lines (km)	4,430
400kV Lines (km)	7,830
275kV Lines (km)	501
Transformers 250MVA+	119
Transformers <250MVA	25
Total installed MVA	73,985
Capacitors	19
Total installed MVAr	2,094
Reactors	55
Total installed MVAr	12,603

Figure 7. New grid assets 2022

B.5. Demonstration of additionality

Demonstration and Assessment of Prior Consideration of the CDM

In line with version 01 of the *CDM Project Standard* (EB 65, Annex 05), the project participant has informed the host party DNA and the UNFCCC Secretariat in writing of its intention to seek CDM status for the proposed project activity. The UNFCCC Secretariat received the prior consideration form on 23 June 2010. As evidenced by the timeline below, the submission of the Prior Consideration form took place before the start date of the project activity, which is expected to take place on 31/05/2013 when the contracts for the supply of equipment are expected to be signed.

Table 8: Project Milestones

Date	Milestone
26/03/2009	NERSA publishes Feed-in-Tariffs for wind, small-hydro, landfill gas and concentrated solar power
05/02/2010	Joint Development Agreement between Terra Power Solutions and GE
27/05/2010	Installation of wind measurement mast
23/06/2010	CDM prior consideration
March 2011	NERSA consultation paper on review of Feed-in-Tariffs
05/04/2011	Record of Decision (RoD), i.e. EIA approval
03/08/2011	Request for Qualifications and Proposals under the Renewable Energy Independent Producer (IPP) Programme.
12/10/2011	Wind Resource Assessment Report
08/12/2011	Contract with CDM consultant
30/01/2012	CDM stakeholder consultation
16/05/2012	Project is acquired by Biotherm Energy and the investment decision is taken
31/05/2013	Expected date on which contract will be signed with turbine supplier
12/07/2013	Expected date for financial close
31/07/2013	Expected date for start of construction

31/07/2015	Expected commissioning date

In line with ACM0002 (version 13.0.0), the *Tool for the demonstration and assessment of additionality* (version 06.0.0) was used to demonstrate that the project is additional. The following steps were undertaken:

Step 1: Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a: Define alternatives to the project activity:

The following are identified the alternatives to the project activity:

Alternative 1: The project activity not undertaken as a CDM project activity

Alternative 2: A coal power plant producing electricity with comparable quality, properties and application areas. This alternative is considered credible because coal power plants have already been implemented in South Africa by Independent Power Producers (e.g. Kelvin, Sasol Chemical Industry) and coal power plants in general constitute 85% of the total capacity generation of the country. The implementation of coal power plants is highly attractive because South Africa is the 6th largest producer of coal in the world with one of the lowest coal prices in the world.

The Integrated Resource Plan for Electricity, which determines the planned capacity additions until 2030, forecasts the implementation of additional 16,383 MW coal-fired power plant capacities.

Alternative 3: A power plant using another source of renewable energy and producing electricity with comparable quality, properties and application areas (e.g. hydro). This alternative is considered credible because hydro power plants have already been implemented by Independent Power Producers in South Africa (Friedenheim, Bethlelem). Solar power plants are not considered as a credible alternative given the high investment costs involved.

Alternative 4: Electricity generated by the operation of grid-connected power plants and by the addition of new generating sources. This, in fact, is the continuation of the current situation and is the identified baseline for the installation of a new grid-connected renewable power plant according to ACM0002 (version 13.0.0).

Sub-step 1b: Consistency with mandatory laws and regulations:

All the above alternatives are consistent with mandatory and regulatory requirements, especially the *Electricity Regulation Act No.4 of 2006 – Electricity Regulations on New Generation Capacity* from 4 May 2011 that establish that 30% of the additional capacity to supply electricity to the national grid must be implemented by Independent Power Producers through tendering procedures. There are no restrictions on types of power plants; hence, both coal power plants and renewable energy power plants are allowed to deliver electricity to the grid.

As the four alternatives identified are in compliance with all applicable laws and regulations and are also realistic and credible alternatives available to the project participants, the project is additional under step 1.

Step 2: Investment analysis

Taking into account the *Guidelines on the assessment of investment analysis* (version 05), the following steps were taken.

Sub-step 2a: Determine appropriate analysis method

The *Tool for the demonstration and assessment of additionality* provides three methods for carrying out investment analysis:

1. Simple cost analysis (Option I),
2. Investment comparison analysis (Option II)
3. Benchmark analysis (Option III).

The proposed project activity will generate financial and economic benefits other than CDM related income therefore the simple cost analysis (Option I) cannot be applied.

In line with ACM0002 (version 13.0.0), the baseline scenario for the project activity is the supply of electricity from a grid. Therefore, the baseline scenario does not necessarily require investment and is outside the control of the project developer. Option III, benchmark analysis is therefore, selected as the appropriate analysis method for the project activity.

Sub-step 2b: Option III. Apply benchmark analysis

In line with paragraph 30 of the *Guidelines on the assessment of investment analysis* (version 05), the WACC was used as the appropriate benchmark for comparison with the Project IRR. All input values used in the investment analysis were valid and applicable at the time the investment decision was taken, i.e. 16/05/2012. The benchmark as well as the financial assessment are carried out post tax and shown in nominal terms.

The WACC was calculated using the formula below:

$$WACC = w_d K_d(1-T) + w_e K_e$$

Where:

WACC = Weighted Average Cost of Capital
w_d = Percentage of debt financing
w_e = Percentage of equity financing
K_d = Average cost of debt financing
K_e = Average cost of equity financing
T = Applicable corporate tax rate

The following parameter values were used in calculation of the WACC:

Table 9: Benchmark calculation

Parameter	Value	Unit	Source
w_d	70	%	Financial Model
w_e	30	%	Financial Model
K_d	13	%	Commercial Lending Rate
K_e	15.6	%	UNFCCC default value + IMF inflation forecast
T	28	%	South African Revenue Authority

Based on the above parameter values, the Weighted Average Cost of Capital (WACC) is calculated as follows:

WACC = 70 x 13 x (1-28) + 30 x 15.6
= 11.23%

Sub-step 2c: Calculation and comparison of financial indicators:

Basic parameters and assumptions used for the calculation of the Project IRR are given in the tables below:

Table 10: Project Parameter

Project Parameter	*Value*	*Unit*
Wind Turbines	VESTAS V100-1.8	
Number of Turbines	82	
Turbine Capacity	1.8	MW
Gross Capacity	147.6	MW
Net Energy Production	509,303	MWh
Plant Load Factor	39.39	%
Tariff Price	1,050	ZAR\MWh
Exchange rate ZAR/USD	7.9364	ZAR/USD
Exchange rate EUR/USD	10.3459	ZAR/EUR
Corporate Tax	28%	%

Table 11: Financing Parameter

Financing	Value	Unit
Debt/Equity Ratio	70/30	
Interest rate	13	%
Construction loan interest rate	10	%

Table 12: CAPEX Parameter

CAPEX Item	Cost (ZAR)
Project development, management and legal cost	28,244,307
Equipment Cost	2,239,680,432
Contingencies (10%) of EPC	223,968,043
Interest During Construction (IDC)	309,323,496
Working Capital	77,987,022
Debt reserve	168,451,967
Financing fee	59,297,432
Development fee available for distribution	75,000,000
Total	*3,181,952,699*

Table 13: OPEX Parameter

OPEX Item	Cost/year (ZAR
Land lease (2% of revenue)	10,695,363
Service and maintenance	36,900,000
Retrofit and decommissioning reserve	4,000,000
Administration	25,000,000
Insurance (0.6% of EPC)	13,438,083
Community trust fund (2.1% of revenue)	11,230,131

Table 14: Revenue Parameter

Revenues	Value	Unit
Sales of Electricity	509,303	MWh/year

Tariff	1,050	ZAR/MWh
Total Revenue from Electricity Sales	534,768,150	ZAR/year
Number of CERs per year	481,997	CERs/year
Price per CER	15	EUR/CER
CER Revenue per year	76,578,803	ZAR/year

Table 15: Inflation Parameter

Parameter	Value	Unit
Inflation factor	4.7	%
Tariff escalation	4.7% on 50% of the generated electricity	

A 20-year cash flow was used to calculate the Project IRR.

The table below shows the post-tax, nominal Project IRR calculated for the project with and without CDM. As can be seen from the table, the CDM project activity without CER revenues has a less favourable IRR than the benchmark.

Table 16: Benchmark vs. Project IRR

Project IRR without CDM Revenues	9.02 %
Project IRR with CDM Revenues	11.59 %
Benchmark	11.23 %

Sub-step 2d. Sensitivity analysis

In order to show that the conclusion regarding the financial/economic attractiveness is robust to reasonable variations in the critical assumptions, a -10%/+10% sensitivity analysis was carried out on the following parameters:

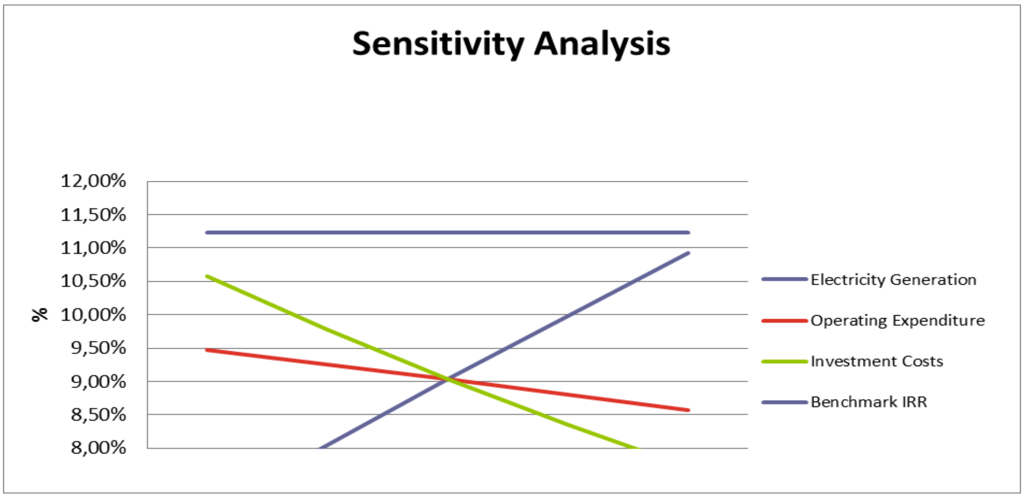
- Electricity generation
- Equipment Costs
- Operating Costs

The table and graph below give an overview of the resulting Project IRRs.

Table 17: Sensitivity analysis (-10%/+10%)

	-10.00%	-5.00%	0.00%	5.00%	10.00%
Electricity Generation	7.04%	8.04%	9.02%	9.98%	10.92%
Equipment Cost	9.46%	9.24%	9.02%	8.79%	8.56%
Operating Costs	10.57%	9.76%	9.02%	8.33%	7.70%

Figure 8: Sensitivity Analysis



The sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be financially/economically attractive without the revenues from the carbon credits.

Outcome of Step 2: The Benchmark Analysis and Sensitivity Analysis show that the project activity is not financially attractive without the CER revenue. Therefore, the project activity is additional under step 2.

Step 4: Common practice analysis
Sub-step 4a: Analyze other activities similar to the proposed project activity:
The following steps were undertaken to prove that the project activity is not common practice analysis:

STEP 1: The installed capacity of the project activity is 147.6 MW. Therefore, the applicable output range equals 73.8-221.4 MW (+/-50% of the project capacity).

STEP 2: The applicable geographical area is South Africa. The number (N_{all}) that deliver the same capacity, within the range calculated in step 1, as the project activity and have started commercial operations before the start date of the project activity (31/05/2013) equals twelve (8).

Table 18: Common Practice Analysis

Name	Type	Owner	Installed Capacity (MW)
Acacia	Gas	ESKOM	171
Port Rex	Gas	ESKOM	171
Athlone	Coal	Municipal	180
Bloemfontein	Coal	Municipal	103
Pretoria West	Coal	Municipal	170
Johannesburg	Gas	Municipal	176
Steenbras	PSS	Municipal	189
Sasol Chemical Industry	Coal	IPP	139

STEP 3: The total number of plants (N_{diff}) identified under Step 2 that apply a different technology from the project activity equals twelve (8).

STEP 4: $F = 1 - N_{diff}/N_{all} = 1 - 8/8 = 0$

Similar activities cannot be observed because $F < 0.2$ and $N_{all} - N_{diff}$ is smaller than 3. Therefore, it can be concluded that the project activity is also additional under step 4 (Common Practice Analysis).

B.6. Emission reductions
B.6.1. Explanation of methodological choices
>>
Project emissions (PE_y)

The project activity involves the implementation of a wind power project. Therefore, PE_y=0.

Baseline emissions (BE_y)

Baseline emissions are calculated using equation 6:

$$BE_y = EG_{PJ,y} * EF_{Grid,CM,y}$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO2/yr)
$EG_{PJ,y}$	=	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr)
$EF_{Grid,CM,y}$	=	Combined margin CO2 emission factor for grid connected power generation in year *y* calculated using the latest version of the “Tool to calculate the emission factor for an electricity system” (tCO2/MWh)

The project activity is the installation of a new grid-connected renewable power plant at a site where no renewable power plant was operated prior to the implementation of the project activity. Therefore equation (7) applies:

$$EG_{PJ,y} = EG_{faciliaty,y}$$

Where:

$EG_{PJ,y}$	=	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr)
$EG_{faciliaty,y}$	=	Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y* (MWh/yr)

$EF_{Grid,CM,y}$ was calculated according to the following steps.

Step 1. Identify the relevant electric power system

For calculating the grid emission factor, the project activity has identified the South African national grid as the relevant project electricity system. The identification of the South African national grid as the relevant project electricity system is based on the following arguments:

- The South African DNA has not published a delineation of the project electricity system and connected electricity system.
- There is no proof of the existence of significant transmission constraints by means of the application criteria, therefore the application criteria does not result in a clear grid boundary.

- Finally, South Africa does not have a layered dispatch system and the country has only one grid system that serves the entire country. Therefore, and in line with version 02.2.1 of the *Tool to calculate the emission factor for an electricity system*, the national grid definition is used by default.

Step 2. Choose whether to include off-grid power plants in the project electricity system (optional)

The project activity has selected Option I and only grid power plants were included in the calculation.

The *Tool to calculate the emission factor for an electricity system* provides for the following methods to determine the operating margin (OM):

a) Simple OM
b) Simple adjusted OM
c) Dispatch data analysis OM
d) Average OM

In South Africa, low-cost/must-run resources constitute more than 50% of total grid generation. Besides hydro, wind, and nuclear power plants, most coal-fired power plants have to be considered as low-cost/must-run because of the following reasons:

- Coal used in South African power plants is a cheap resource compared to other technologies e.g. natural gas/kerosene because South Africa is the 6th largest producer of coal in the world with one of the lowest coal prices in the world.[18]
- Coal power plants in South Africa have an average capacity factor higher than 75%. In line with international common practice, power plants with a capacity factor higher than 75% are considered as base-load power plants that are usually dispatched independently of the daily or seasonal load. In addition, Eskom Holdings Annual Report 2011 defines most of the coal power plants as base load plants.

Because low-cost/must-run resources constitute more than 50% of total grid generation, the simple OM method cannot be used. Therefore, the project activity has selected the average OM method for calculating the operating margin.

In terms of data vintage, the project will use the *ex ante* option, and the emission factor is determined once at the validation stage based on a 3-year generation weighted average based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation.

Step 4. Calculate the operating margin emission factor according to the selected method

The average OM emission factor ($EF_{grid,OM-ave,y}$), is calculated as the average emission rate of all power plants serving the grid, using the methodological guidance as described under (a) for the simple OM, but also including the low-cost/must-run power plants in all equations.
The average OM emission factor is calculated using equation 1

$$EF_{grid,OM-ave,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

[18] The future of South African coal; Market Investment and Policy changes –Anton Eberhard

$EF_{grid,OM-ave,y}$ = Average operating margin CO2 emission factor in year y (tCO2/MWh)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

$EF_{EL,m,y}$ = CO2 emission factor of power unit m in year y (tCO2/MWh)

m = All grid power units serving the grid in year y

y = The relevant year as per the data vintage chosen in Step 3

Determination of $EG_{m,y}$

For grid power plants, $EG_{m,y}$ is based on published records from ESKOM and CDM monitoring reports for the CDM power plants. Together, the ESKOM power plants and CDM project represent 95% of the total electricity generated. Electricity generated from Independent Power Producers and Municipality owned power plants is not available, therefore it could not be included in this calculation. However it only represents less than 5% of the total electricity generated. Furthermore, the electricity generated from the pumped storage power plants are not factored in since they are net consumers of electricity.

Table 19: Electricity Generation

		Generation Data (MWh)		
Name	**Type**	**2008-2009**	**2009-2010**	**2010-2011**
Amot	Coal	11,987,281	13,227,864	12,194,878
Camden	Coal	6,509,079	7,472,070	7,490,836
Duvha	Coal	21,769,489	22,581,228	20,267,508
Grootvlei	Coal	1,249,556	2,656,230	3,546,952
Hendrina	Coal	12,296,687	12,143,292	11,938,206
Kendal	Coal	23,841,401	23,307,031	25,648,258
Komati	Coal	-	1,016,023	2,060,141
Kriel	Coal	18,156,686	15,906,816	18,204,910
Lethabo	Coal	23,580,232	25,522,698	25,500,366
Majuba	Coal	22,676,924	22,340,081	24,632,585
Matimba	Coal	26,256,068	27,964,141	28,163,040
Matla	Coal	21,863,400	21,954,536	21,504,422
Tutuka	Coal	21,504,122	19,847,894	19,067,501
Acacia	Gas (Jet kerosene)	-	971.00	992.00
Port Rex	Gas (Jet kerosene)	-	322.00	5,507.00
Ankerlig	Gas/Diesel Oil	-	6,303.00	-
Gourikwa	Gas/Diesel Oil	-	5,817.00	-
Gariep	Hydropower	-	-	-
Vanderkloof	Hydropower	-	-	-
Colleywobbles	Hydropower	-	-	-
First Falls	Hydropower	-	-	-
Second Falls	Hydropower	-	-	-
Ncora	Hydropower	-	-	-
Koeberg	Nuclear	13,004,000	12,806,000	12,099,000
Klipheuwel	Wind	2,000	1,000	2,000
PetroSA biogas to	CDM	23,286	23,286	23,286

energy				
Bethlehem Hydroelectric project	CDM	8,983	8,983	8,983
Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	CDM	3,744	3,744	3,744
Durban landfill gas Bisasar Road project	CDM	31,723	31,723	31,723
Total		**224,764,661**	**228,828,053**	**232,394,838**

Determination of $EF_{EL,m,y}$

Because data on fuel consumption and electricity generation of the grid-connected units is available, Option A1 is used to determine the emission factors of the grid power units. However, for Acacia, Port Rex, Ankerlig, Gourikwa only data on electricity generation and fuel type is available during year 2009-2010, thus Option A2 is used instead for those.

Option A1 (equation 2):

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

Where:

$EF_{EL,m,y}$	=	CO2 emission factor of power unit *m* in year *y* (tCO2/MWh)
$FC_{i,m,y}$	=	Amount of fossil fuel type *i* consumed by power unit *m* in year *y* (Mass or volume unit)
$NCV_{i,y}$	=	Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit)
$EF_{CO2,i,y}$	=	CO2 emission factor of fossil fuel type *i* in year *y* (tCO2/GJ)
$EG_{m,y}$	=	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)
m	=	All grid power units serving the grid in year *y*
i	=	All fossil fuel types combusted in power unit *m* in year *y*
y	=	The relevant year as per the data vintage chosen in Step 3

Option A2 (equation 3):

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

Where:

$EF_{EL,m,y}$	=	CO2 emission factor of power unit *m* in year *y* (tCO2/MWh)
$EF_{CO2,m,i,y}$	=	Average CO2 emission factor of fossil fuel type *i* in power unit *m* in year *y* (tCO2/GJ)
$\eta_{m,y}$	=	Average net energy conversion efficiency of power unit *m* in year *y* (ratio)
m	=	All power units serving the grid in year *y*
y	=	The relevant year as per the data vintage chosen in Step 3

The following tables summarize the published data on fuel consumption from the power plants:

Table 20: Fuel consumption for grid-connected power plants (kg/year)

		$FC_{i,m,y}$ (*kg/year*)		
Name	**Type**	**2008-2009**	**2009-2010**	**2010-2011**
Amot	Coal	6,395,805,000	6,794,134,000	6,525,670,000
Camden	Coal	3,876,211,000	4,732,163,000	4,629,763,000
Duvha	Coal	11,393,553,000	11,744,606,000	10,639,393,000
Grootvlei	Coal	674,538,000	1,637,371,000	2,132,979,000
Hendrina	Coal	7,122,918,000	6,905,917,000	7,139,198,000
Kendal	Coal	15,356,595,000	13,866,514,000	15,174,501,000
Komati	Coal	0	664,497,000	1,271,010,000
Kriel	Coal	9,420,764,000	8,504,715,000	9,527,185,000
Lethabo	Coal	16,715,323,000	18,170,227,000	17,774,699,000
Majuba	Coal	12,554,406,000	12,261,833,000	13,020,512,000
Matimba	Coal	13,991,453,000	14,637,481,000	14,596,842,000
Matla	Coal	12,689,387,000	12,438,391,000	12,155,421,000
Tutuka	Coal	11,231,583,000	10,602,839,000	10,191,709,000
Acacia	Gas (Jet kerosene)	0	0	347,066.46
Port Rex	Gas (Jet kerosene)	0	0	219,913.98
Ankerlig	Gas/Diesel Oil	0	0	0
Gourikwa	Gas/Diesel Oil	0	0	0

For the Acacia and Port Rex power stations, data on fuel consumption published was in litre units. In order to make the conversion to kg/year, the values were multiplied by the density of the fuel as shown in Table 21 below.

Table 21: Fuel consumption Acacia and Port Rex (kg/year)

Plant Name	**Fuel *(litres/year)***			**Density *(kg/l)***	**Fuel *(kg/year)***		
	2008-2009	***2009-2010***	***2010-2011***		***2008-2009***	***2009-2010***	***2010-2011***

Acacia	0	0	444,957	0.78	0	0	347,066.46
Port Rex	0	0	281,941	0.78	0	0	219,913.98
Ankerlig	0	0	0	0.82	0	0	0
Gourikwa	0	0	0	0.82	0	0	0

For the calculation of the individual power plants emission factors, the following net calorific values and average emission factors for the fuels have been considered:

Table 22: Net Calorific Value and Emission Factors for fuel types

Type	*NCV (GJ/kg)*	$EF_{co2,i,y}$ *(tCO2/GJ)*
Coal (Other bituminous coal)	0.0199	0.0895
Gas (Jet kerosene)	0.042	0.0697
Gas/Diesel Oil	0.0414	0.0726

Finally, for the Option A2 power plants for year 2009-2010, the following data are used:

Table 23: Power plants using option 2

	$EF_{CO2,m,i,y}$	$\eta_{m,y}$	$EF_{el,m,y}$
Acacia	0.0697	39.5%	0.64
Port Rex	0.0697	39.5%	0.64
Ankerlig	0.0726	39.5%	0.66
Gourikwa	0.0726	39.5%	0.66

The default value for open cycle gas turbines that began generation after the year 2000 in Annex 1 in the *Tool to calculate the emission factor for an electricity system* has been used for the four power stations.

Step 5: Calculate the build margin (BM) emission factor

For the calculation of the build margin (BM) emission factor, Option 1 data vintage has been chosen. Hence, for the first crediting period, the build margin emission factor will be calculated *ex ante* based on the most recent information available on units already built for sample group *m* at the time of CDM-PDD submission to the DOE for validation. For the second crediting period, the build margin emission factor will be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period will be used.

The build margin emission factor is thus calculated using **equation 12** of the *Tool to calculate the emission factor for an electricity system*, as shown below:

$$EF_{grid,BM,y} = \frac{\sum_{m} EG_{m,y} \times EF_{EL,m,y}}{\sum_{m} EG_{m,y}}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO2 emission factor in year *y* (tCO2/MWh)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)

$EF_{EL,m,y}$ = CO2 emission factor of power unit *m* in year *y* (tCO2/MWh)

m = Power units included in the build margin

y = Most recent historical year for which power generation data is available

Table 24 below provides an overview of the power plants connected to the South African electricity system.

Table 24: Power plants and their commissioning dates

Number	Project Name	Type	Commissioning Date
1	Bethlehem hydroelectric project	Hydro	11/11/09
2	Durban landfill gas Bisasar Road project	Land Fill Project	3/1/08
3	PetroSA biogas to energy	Waste water	1/10/08
4	Gourikwa	Gas fuel	3/30/07
5	Ankerlig	Gas fuel	3/29/07
6	Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	Land Fill Project	1/7/06
7	Klipheuwel	Wind	Aug-02
8	Majuba	Coal	4/1/96
9	Kendal	Coal	10/1/88
10	Palmiet	Pumped storage	4/18/88
11	Matimba	Coal	12/4/87
12	Lethabo	Coal	12/22/85
13	Tutuka	Coal	6/1/85
14	Colleywobbles	Hydropower	1/1/85
15	Koeberg	Nuclear	7/21/84
16	Ncora	Hydropower	3/1/83
17	Drakensberg	Pumped storage	6/17/81
18	Duvha	Coal	1/18/80
19	Matla	Coal	9/29/79
20	Second Falls	Hydropower	4/1/79
21	First Falls	Hydropower	2/1/79
22	Vanderkloof	Hydropower	1/1/77
23	Port Rex	Gas fuel	9/30/76
24	Acacia	Gas fuel	5/13/76
25	Kriel	Coal	5/6/76
26	Amot	Coal	9/21/71
27	Gariep	Hydropower	9/8/71
28	Hendrina	Coal	5/12/70
29	Grootvlei	Coal	6/30/69

30	Camden	Coal	12/21/66
31	Komati	Coal	11/6/61

In order to identify the power units *m* included in the build margin and in accordance with the *Tool to calculate the grid emission factor for an electricity system*, $SET_{5\text{-units}}$ and $SET_{\geq 20\%}$ were identified. Both $SET_{5\text{-units}}$ and $SET_{\geq 20\%}$ comprise the same power plants, thus both are SET_{sample}.

Table 25: BM Set 5 units

	Name	Technology	Year of Commissioning	Cumulative %	*EGm,y (MWh/y)*
1	Gourikwa	Gas fuel	3/30/07	0%	0
2	Ankerlig	Gas fuel	3/29/07	0%	0
3	Klipheuwel	Wind	8/1/02	0%	2,000
4	Majuba	Coal	4/1/96	11%	24,632,585
5	Kendal	Coal	10/1/88	22%	25,648,258
	Total				**50,282,843**

As some of the power plants in the SET_{sample}, Majuba and Kendal, started to supply electricity to the grid more than 10 years ago, step (d) was considered and $SET_{sample\text{-}CDM}$ was calculated.

Table 26:BM Set sample-CDM

	Name	Technology	Year of Commissioning	Cumulative %	*EGm,y (MWh/y)*
1	Gourikwa	Gas fuel	3/30/07	0.000%	0.00
2	Ankerlig	Gas fuel	3/29/07	0.000%	0.00
3	Klipheuwel	Wind	8/1/02	0.001%	2,000
CDM	Bethlehem hydroelectric project	Hydro	11/11/09	0.005%	8,983
CDM	Durban landfill gas Bisasar Road project	Land Fill Project	3/1/08	0.018%	31,723
CDM	PetroSA biogas to energy	Waste water	1/10/08	0.028%	23,286
CDM	Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	Land Fill Project	1/7/06	0.030%	3,744
	Total	***AEG $SET_{sample\text{-}CDM}$***			***69,736***

AEG $SET_{sample\text{-}CDM}$ was around 0.03%, much lower than 20% required by the *Tool to calculate the emission factor for an electricity system*. Therefore, step (e) was considered and power units that started to supply electricity to the grid more than 10 years ago were added until the electricity generation of the new set comprised 20% of the annual electricity generation. The final set of power plants included in the calculation of the Build Margin ($SET_{sample\text{-}CDM>10years}$) was as follows:

Table 27:Power plants included in the BM

Number	Name	Technology	Year of Commissioning	Cumulative %	*EGm,y (MWh/y)*

1	Gourikwa	Gas fuel	3/30/07	0.0%	-
2	Ankerlig	Gas fuel	3/29/07	0.0%	-
3	Klipheuwel	Wind	8/1/02	0.0%	2,000.00
	Bethlehem hydroelectric project	Hydro	11/11/09	0.0%	8,983.13
	Durban landfill gas Bisasar Road project	Land Fill Project	3/1/08	0.0%	31,723.20
	PetroSA biogas to energy	Waste water	1/10/08	0.0%	23,285.54
	Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	Land Fill Project	1/7/06	0.0%	3,744.00
4	Majuba	Coal	4/1/96	10.6%	24,632,585
5	Kendal	Coal	10/1/88	21.7%	25,648,258
	Total	***AEG*** ***SETsample-CDM>10years***			***50,350,579***

The CO_2 emission factor of each power unit *m* ($EF_{EL,m,y}$) is determined as per the guidance in step 4 (a) for the simple OM, using **equation (3)** under option A2 following guidelines in the tool that stipulates as follows "*If the power units included in the build margin m correspond to the sample group* $SET_{sample\text{-}CDM\text{->}10yrs}$, *then, as a conservative approach, only option A2 from guidance in Step 4 (a) can be used and the default values provided in Annex 1 shall be used to determine the parameter* $\eta_{m,y}$*.*"
Equation 3, option A2 is shown below:

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

Where:

$EF_{EL,m,y}$	=	CO2 emission factor of power unit *m* in year *y* (tCO2/MWh)
$EF_{CO2,m,i,,y}$	=	Average CO_2 emission factor of fuel type *i* used in power plant *m* in year *y* (tCO2/GJ)
$\eta_{m,y}$	=	Average net energy conversion efficiency of power unit *m* in year *y* (ratio)
m	=	The power *units* included in the build margin
y	=	The relevant year as per the data vintage chosen in Step 5

The following data was used in the calculation of $EF_{EF,m,y}$ for the plants in *group* $SET_{sample\text{-}CDM\text{->}10yrs}$

Name	***Technology***	***EFCO2,m,i,y (tCO2/GJ)***	***ηm,y***	***EFEL,m,y***
Gourikwa	Gas fuel	0.0726	39.5%	0.66
Ankerlig	Gas fuel	0.0726	39.5%	0.66
Klipheuwel	Wind	0.0000	-	-

Bethlehem hydroelectric project	Hydro	0.0000	-	-
Durban landfill gas Bisasar Road project	Land fill	0.0000	-	-
PetroSA biogas to energy	Waste water	0.0000	-	-
Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	Land fill	0.0000	-	-
Majuba	Coal	0.0895	35.5%	0.91
Kendal	Coal	0.0895	35.5%	0.91
	AEG SETsample-CDM>10years			

The table below shows the values and power units applied in the calculation of the build margin.

Name	***Technology***	***EFel,m,y (tCO2/MWh)***	***EGm,y (MWh/y)***
Gourikwa	Gas fuel	0.66	-
Ankerlig	Gas fuel	0.66	-
Klipheuwel	Wind	-	2,000.00
Bethlehem hydroelectric project	Hydro	-	8983
Durban landfill gas Bisasar Road project	Land fill	-	31723
PetroSA biogas to energy	Waste water	-	23286
Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	Land fill	-	3744
Majuba	Coal	0.91	24,632,585
Kendal	Coal	0.91	25,648,258
Total	***AEG SETsample-CDM>10years***		***50,350,579***

For *y* the most recent historical year for which grid power generation data is available, in this case 2010-2011 was used and for *m,* the power *units* included in the build margin were used.

Step 6: Calculate the Combined Margin

Option A i.e. the weighted average combined margin is used.

The combined margin emissions factor is calculated as follows per equation 13:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO2 emission factor in year *y* (tCO2/MWh)
$EF_{grid,OM,y}$	=	Operating margin CO2 emission factor in year *y* (tCO2/MWh)
w_{OM}	=	Weighting of operating margin emissions factor (%)
w_{BM}	=	Weighting of build margin emissions factor (%)

The following default values are used for w_{OM} and w_{BM}:

Wind and solar power generation project activities: $w_{OM} = 0.75$ and $w_{BM} = 0.25$ (owing to their intermittent and non-dispatchable nature) for the first crediting period and subsequent crediting periods;

Leakage:

In line with ACM0002 version 13.0.0, no leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction, processing, transport). These emissions sources are neglected**.**

Emission reductions
In line with ACM0002 (version 13.0.0) the emission reductions are calculated using **(equation 11)** as follows:

$$ER_y = BE_y - PE_y$$

Where:

ER_y	=	Emission reductions in year *y* (t CO2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO2e/yr)
PE_y	=	Project emissions in year *y* (t CO2/yr)

B.6.2. Data and parameters fixed ex ante

Data / Parameter	$EG_{m,y}$
Unit	MWh
Description	Net electricity generated by power plant/unit *m* in year *y*
Source of data	ESKOM published data and CDM Monitoring Reports for the CDM project activities
Value(s) applied	See Annex 4
Choice of data or Measurement methods and procedures	Data on electricity generation has been obtained from ESKOM, the main utility company in South Africa and owner of the power plants. For the CDM power plants, that are not owned by ESKOM, generation data had to be estimated from the CDM Monitoring Reports.
Purpose of data	Calculation of baseline emissions
Additional comment	N/a

Data / Parameter	$FC_{i,m,y}$
Unit	kg/year
Description	Amount of fossil fuel type *i* consumed by power plant / unit *m* in year *y*
Source of data	ESKOM published data and government records
Value(s) applied	See Annex 4
Choice of data or Measurement methods and procedures	Data on fuel consumption has been obtained from Eskom, the main utility company in South Africa and owner of the power plants. The values provided for the coal plants are in tonnes. These values were converted to kg by multiplying by 1000. The values provided for the gas turbines i.e. Acacia, Port Rex, Ankerling and Gourikwa are in litres. These were converted to kg units by multiplying by the fuel type density given in (kg/l). For jet gasoline, the density value used was 0.78 kg/l while 0.82 kg/l was used for diesel oil.
Purpose of data	Calculation of baseline emissions
Additional comment	N/a

Data / Parameter	**$NCV_{i,y}$**
Unit	GJ/mass or volume unit
Description	Net calorific value (energy content) of fossil fuel type i in year y
Source of data	IPCC default values at the lower limit of the uncertainty at a 95% confidence interval have been used.
Value(s) applied	Fuel Type: NCV (GJ/kg) — Coal (other bituminous coal): 0.0199; Gas/Jet kerosene: 0.042; Gas/Diesel Oil: 0.0414
Choice of data or Measurement methods and procedures	IPCC default values are used as there is no specific data from the fuel suppliers of the power plants and also no regional default values.
Purpose of data	Calculation of baseline emissions
Additional comment	N/a

Fuel Type	NCV (GJ/kg)
Coal (other bituminous coal)	0.0199
Gas/Jet kerosene	0.042
Gas/Diesel Oil	0.0414

Data / Parameter	**$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$**
Unit	tCO2/GJ
Description	CO2 emission factor of fossil fuel type *i* used in power unit *m* in year *y*
Source of data	IPCC default values at the lower limit of the uncertainty at a 95% confidence interval have been used.
Value(s) applied	Fuel Type: EFCO2 (tCO2/GJ) — Coal (other bituminous coal): 0.0895; Gas/Jet kerosene: 0.0697; Gas/Diesel Oil: 0.0726
Choice of data or Measurement methods and procedures	IPCC default values are used as there is no specific data from the fuel suppliers of the power plants and also no regional default values.
Purpose of data	Calculation of baseline emissions
Additional comment	N/a

Fuel Type	EFCO2 (tCO2/GJ)
Coal (other bituminous coal)	0.0895
Gas/Jet kerosene	0.0697
Gas/Diesel Oil	0.0726

Data / Parameter	$\eta_{m,y}$
Unit	%
Description	Average net conversion efficiency of power unit *m* in year *y*
Source of data	Default value for open cycle gas turbines built after 2000 and Fluidised Bed System (FBS) coal generation technology for units built before and in 2000 is used as per Annex 1 of the *Tool to calculate the emission factor for an electricity system.*
Value(s) applied	Open cycle gas turbines built after 2000: 39.5% (FBS) coal generation technology for units built before and in 2000: 35.5%
Choice of data or Measurement methods and procedures	There is no data published on the efficiency of Eskom's gas power plants, therefore default values as provided in Annex 1 of the *Tool to calculate the emission factor for an electricity system* shall be used.
Purpose of data	Calculation of baseline emissions
Additional comment	-

B.6.3. Ex ante calculation of emission reductions

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In order to calculate the emission reductions from the project activity, three-year historic generation data for grid connected power plants were used. This data was obtained from ESKOM. The estimated emission reductions are calculated as follows:

The emission reductions of the project activity are calculated as follows:

$$BE_y = EG_{PJ,y} * EF_{grid,CM,y}$$

Calculation of $EG_{PJ,y}$

The project will install a grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity, therefore $EG_{PJ,y}$ is calculated as per option (a).

$$EG_{PJ,y} = EG_{facility,y}$$

Parameter	Value	Unit	Source
$EG_{facility,y}$	509,303	MWh	Financial Model

Calculation of $EF_{grid,CM,y}$

The combined margin emission factor for the grid is calculated using the following formula:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$

Values to determine $EF_{grid,CM,y}$ for wind are:

Parameter	Value	Unit	Source
$EF_{grid,BM,y}$	0.91	tCO2/MWh	GEF calculations
W_{BM}	0.25		

$EF_{grid,OM-DD,y}$	0.96	tCO2/MWh	GEF calculations
W_{OM}	0.75		

Therefore:

$EF_{grid,CM,y}$ = 0.95 tCO2/MWh

BE_y = 509,303 * 0.95= 481,997 tCO2/year

Leakage emissions

No leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction, processing, transport). These emissions sources are neglected.

Emission reductions

$$ER_y = BE_y - PE_y$$

Therefore, emission reductions equal:

481,997 tCO2 - 0 = 481,997 tCO2

More detailed and transparent calculations can be found in the Excel spreadsheet attached to this PDD.

B.6.4. Summary of ex ante estimates of emission reductions

Year	Baseline emissions (t CO_2e)	Project emissions (t CO_2e)	Leakage (t CO_2e)	Emission reductions (t CO_2e)
Year 1	481,997	0	0	481,997
Year 2	481,997	0	0	481,997
Year 3	481,997	0	0	481,997
Year 4	481,997	0	0	481,997
Year 5	481,997	0	0	481,997
Year 6	481,997	0	0	481,997
Year 7	481,997	0	0	481,997
Total	3,373,982	0	0	3,373,982
Total number of crediting years	7			
Annual average over the crediting period	481,997	0	0	481,997

B.7. Monitoring plan
B.7.1. Data and parameters to be monitored

Data / Parameter	**$EG_{facility,y}$**
Unit	MWh
Description	Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y*
Source of data	Main metering equipment installed at project activity site
Value(s) applied	509,303
Measurement methods and procedures	The following parameters will be measured: (i) The quantity of electricity supplied by the project plant/unit to the grid; and (ii) The quantity of electricity delivered to the project plant/unit from the grid The electricity supplied to the grid and delivered to the project plant/unit from the grid will be measured continuously by a main and back-up meter owned by ESKOM. The meters are installed at the point of connection with the grid as agreed by the grid operator. High-precision equipment will be used to achieve high level of accuracy of the measurements. The equipment will be calibrated and tested according to recognized standards as agreed with the grid operator.
Monitoring frequency	The net quantity of electricity supplied to the grid will be measured continuously and recorded monthly. The Metering System shall be read monthly by the National Transmission Company on the last day of each month (or such other day as may be agreed upon by the parties) for the purpose of determining the Net Electrical Output of the Plant since the preceding reading. The National Transmission Company shall read the Metering System by reading the log in the SCADA system and taking the kWh meter position on the first day of the calendar month at 0:00 midnight. The National Transmission Company shall transmit the data to the project proponent who is responsible to storage the collected data.
QA/QC procedures	The metering requirements of the South African Metering Code will be met as well as NRS 057, which specifies requirements for commissioning, maintenance, auditing and testing of these metering equipment. The accuracy of the meter shall be in accordance with the minimum requirements of NRS 057. In cases where electronic access to the meter is not possible or the metered data is not available, the metering code allows for the following options to solve the problem, Manual meter data downloading, Estimation or substitution subject to mutual agreement between the affected parties, Profiling or Reading of the meter at scheduled intervals. If estimation of the data must be done the following shall apply: • The *NTC (National Transmission Company)* shall produce a monthly report for all estimations made. • No estimation shall be made on three or more consecutive time slots, and if such estimation has to be made, the *NTC* shall ensure that the meters are downloaded for the billing cycle. All downloaded metering information shall be archived in such a manner

	that it cannot be altered without leaving a detailed audit trail, and that a copy of the raw meter data is kept by the electricity supply authority or independent meter operator for a minimum period of five years. This raw meter data shall be available on request. The distributor licensee or independent meter operator shall ensure that procedures are in place to minimize the possibility of such raw meter data being accessed by unauthorized personnel, and to ensure that the raw meter data cannot be modified in any way. The means of storage of the raw meter data shall be such that any access to it is recorded. Validity checks for raw data is to be done at regular intervals or at a frequency that will allow a further interrogation of the meter (or both) before the data is overwritten within the meter and before this data can be used for any purpose. Time intervals for the validity checks are indicated in the NRS 057 and depend on the meter load. The metering code further gives instructions on various approaches that can be taken in case data is not available due to electronic access to the meters not being possible, an emergency bypass or other scheme having no metering system, or if metering data not available. In such cases the National Transmission Company (NTC) in this case Eskom would have to resolve to manual meter data downloading, estimation or substitution subject to mutual agreement between the affected parties, profiling or reading of the meter at scheduled intervals When estimation needs to be done, the metering code stipulates that the *NTC* shall produce a monthly report for all estimations made. No estimation shall be made on three or more consecutive time slots, and if such estimation has to be made, the *NTC* shall ensure that the meters are downloaded for the billing cycle. The metering code further directs that not more than ten slots may be estimated per meter per month. In terms of verification of data, the metering code stipulates that the NTC shall compare meter readings (advances) with the metering database at least once a year.
Purpose of data	Calculation of baseline emissions
Additional comment	N/A

B.7.2. Sampling plan

N/a

B.7.3. Other elements of monitoring plan

In order to enable verification of emission reductions the project activity must maintain credible, transparent and adequate data measurement, collection, estimation, and tracking systems. The following monitoring procedures and responsibilities will apply:

All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period.

All measurements should be conducted with the calibrated measurement equipment according to relevant industry standards.

Terra Wind Energy – Golden Valley will be responsible for monitoring the data included in section B.7.1, including:

- Calibration of metering equipment as per the manufacturer's requirement
- Monthly recording
- QA/QC
- Long-term storage and archiving of metering data
- Training

Monitoring period

The monitoring period will start from the date of commissioning of the project activity. An annual monitoring report will be produced.

Parameters monitored

Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y*

Metering

Metering for electricity generation will be conducted with calibrated measurement equipment according to relevant industry standards. The South African National Standard has published the *Code of practice of electricity metering* NRS 057:2009. This code of practice specifies the procedures and standards to be adhered to by electricity licensees and their agents in operating and servicing new and existing metering installations which are to be used for billing purposes. The code of practice is applicable to metering installations in their entirety, including all measuring transformers, wiring, cabling, metering panel construction, active and reactive meters, data loggers, and associated test facilities.

ESKOM Distribution as the National Transmission Company will be responsible for:

- Calibration and maintenance of equipment
- Physical reading and day-to-day handling
- Quality Control and Quality assurance measures

ESKOM will provide a Main Metering System and Back-Up Metering System on-site. The metering equipment will be installed at the point of supply which defines the commercial boundary between the licensee and the customer.

ESKOM shall be responsible for managing and collecting metering information. ESKOM shall also transmit the data to the project proponent who is responsible to storage the collected data in line with the monitoring plan.

QA/QC

The type of metering installation at each metering point shall comply with NRS 057 metering specifications as modified by this code and other relevant standards issued by SABS (South African Standards Division).

The meter(s) readings will be crosschecked with actual invoices sent by project owners to the grid company or with the registries provided to the project owners by the grid company of the energy delivered by the project to the interconnection substation.

The meter(s) readings will be readily accessible for the Designated Operational Entity (DOE) carrying out the verification of monitoring data.

Training

A training session for TWE and ESKOM will be conducted by the carbon consultant before the project is implemented in order to ensure a common understanding of the CDM monitoring procedures and requirements. The training will include the following contents:

- CDM project cycle and the significance of monitoring
- Management structure and work scope
- Components of the monitoring plan
- QA/QC procedures
- Monitoring report template
- Preparation for verification
- Questions and answers

Furthermore a training session for monitoring staff will be conducted before the start of operation by the EPC consultant regarding the operating, metering, calibration and maintenance practices.

SECTION C. Duration and crediting period
C.1. Duration of project activity
C.1.1. Start date of project activity

According to version 6 of the CDM glossary of terms, the start date of a project activity is defined as "the earliest date at which either implementation or construction or real action of a CDM project activity begins.

The project participant is expected to sign a contract on 31/05/2013 for the supply of equipment or construction/operation services. This marks the start date of the project activity since real action has taken place and the project participant makes a commitment toward implementing the project.

C.1.2. Expected operational lifetime of project activity

20 years

C.2. Crediting period of project activity
C.2.1. Type of crediting period

Renewable crediting period

C.2.2. Start date of crediting period

31/07/2015

C.2.3. Length of crediting period

7 years (84 months)

SECTION D. Environmental impacts
D.1. Analysis of environmental impacts

As part of the EIA process, the project carried out a number of studies to analyse the environmental impacts of the projects. The environmental impacts are detailed in a number of studies, including:

- Final Scoping Report: Proposed Cookhouse Wind Energy Project , Blue Crane Route Local Municipality" (CES, December 2009)
- Proposed Terra Wind Energy Golden Valley Project: Specialist Reports (CES, October 2010)
    - Ecological Specialist Report
    - Avifauna Specialist Report
    - Visual Specialist Report
    - Noise Specialist Report
    - Heritage Specialist Report
    - Palaeontological Specialist Report
- Environmental Impact Assessment Report (CES, October 2010)
- Environmental Management Plan (CES, October 2010)

The expected environmental impacts, both during construction and operation, are summarized in the Environmental Impact Assessment Report as follows:

Construction Phase
The visual impact on sensitive viewers and viewpoints due to the construction phase of the Terra Wind Energy-Golden Valley Project is expected to be high due to the size of the project and the increase in highly visible activity in a rural/agricultural landscape. This is mainly because the height of the features that will be built and the siting will expose construction activities against the skyline. Additionally, an increase in activity, vehicles and workers in an otherwise quiet area will affect views. Traffic may be disrupted while large turbine components are moved along public roads. Activity at night is also probable since transport of large turbine components may occur after work hours to minimise disruption of traffic on main roads. Even with the incorporation of mitigation measures, this impact will remain high.

However, it is also worth noting that the visual impact of the construction phase may likely to be positive, especially during assembly of the turbine towers. The construction engineering feat of lifting and attaching components weighing more than 50 tons in a highly visible area is bound to be spectacular (see for example, Degraw 2009). Further, most of the sensitive viewers living in close proximity to the turbines have agreed to have turbines on their properties and are presumably informed on the effect of the construction phase on their views (*pers.comm.* CES).

The noise specialist study revealed that there will be a short-term increase in noise in the vicinity of the site during the construction phase (rated as low) as the ambient level will be exceeded. The impact during the construction phase will difficult to mitigate. The noise level at four noise sensitive areas during the operational phase will be unacceptable. These four areas are: (1) Ou Smoor Drift Farm House (NSA 2) – The wind turbine generator is too close to the dwelling (WTG 117 – 462m). This is resulting in the noise exceeding the recommended limit from 9m/s. (2) Matjesfontein Farm House (NSA 3) – The wind turbine generator is too close to the dwelling (WTG 190 – 385m). This is resulting in the noise exceeding the recommended limit from 9m/s. (3) Jagersfontein Farm House (NSA 4) – The wind turbine generator is too close to the dwelling (WTG 19 – 269m). This is resulting in the noise exceeding the recommended limit from 6m/s. (4) Rietfontein Farm House (NSA 6) – The wind turbine generator is too close to the dwelling (WTG 147 – 245m). This is resulting in the noise exceeding the recommended limit from 5m/s. The following recommendations are made for the construction phase: All construction operations should only occur during daylight hours if possible. No construction piling should occur at night. Piling should only occur during the hottest part of the day to take advantage of unstable atmospheric conditions. Ensure that construction staff receives "noise sensitivity" training.

In terms of ecological impacts, most impacts in the construction phase with mitigation are low, with only the loss of plant species of special concern scoring a moderate negative overall significance. Construction of the wind farm will result in a small amount of loss of the limited areas of Thicket, Bedford Dry Grassland, Karroid Thicket, Albany Broken Veld on the site. This loss will occur as a result of trampling of the vegetation as well as extra clearing needed for construction. Mitigation measures can be used in order to reduce the trampling and rehabilitate the vegetation respectively.

The Loss of plant Species of Special Concern (SSC) including *Pachypodium bispinosum, Pelargonium sidoides, Crassula perfoliata, Euphorbia globosa, Euphorbia meloformis, Aloe tenuior, Anacampestros* sp, *Euphorbia meloformis, Tritonia* sp, *Watsonia* sp, *Drosanthemum* sp, *Psilocaulon* sp and *Trichodiadema* sp. during the construction phase of the proposed Terra Wind Energy-Golden Valley Project is of concern.

The majority of the other impacts associated with the proposed project during the construction phase before mitigation are of moderate – low significance, and the significance of all of these impacts with the exception of the loss of ecological habitat and loss of plant SSC during the construction phase – after the incorporation of appropriate mitigation measures, can be reduced to Low. In terms of noise, the no-go option of *not* proceeding with the project is not recommended for the following reasons:

- The impacts associated with the project can be mitigated by applying set back distances as well as relocating turbines, albeit in locations that may be less efficient for electricity generation.
- There are a number of the farm owners whose property the turbines are on and who are enthusiastic about contributing to the environment in a positive way.
- The economic and environmental benefits of the project outweigh the cost of mitigation measures that are needed to ensure that the sensitive noise receptors are not adversely affected.

The heritage specialist assessment states that not implementing the proposed project will result in no impacts to heritage, apart from those impacts caused by natural forces such as erosion. The Ecological Study lists mostly moderate and high impacts for the no-go option due to the introduction and infestation of alien plant species. After mitigation these impacts are reduced to low or N/A.

Significant impacts on palaeontological heritage normally occur during the construction phase and not in the operational phase of any development. Excavations made during the course of installing the proposed turbines and associated developments (*e.g.* roads, powerlines) may well expose, damage, disturb or permanently seal-in scientifically valuable fossil heritage that is currently buried beneath the land surface or mantled by dense vegetation.

The fossil record and inferred palaeontological sensitivity of the three main rock units represented in the study region are summarized in Table 9-1 (based on Almond *et al*., 2008). Bedrock excavations made during construction of the proposed wind energy facility east of Cookhouse will primarily affect continental sediments of the Middleton Formations of the Late Permian Beaufort Group. These sediments underlie the great majority of the study area and are renowned for their rich fossil heritage of terrestrial vertebrates (most notably mammal-like reptiles or therapsids), as well as fish, amphibians, molluscs, trace fossils (*e.g.* trackways) and plants (*e.g.* petrified wood). Caenozoic surface sediments in the study area (*e.g.* alluvium, colluvium) are generally of low palaeontological sensitivity, while the Karoo dolerite intrusions do not contain fossil remains at all. Although the direct impact of the proposed project will be local, fossils within the Beaufort Group are of importance to national as well as international research projects on the fossil biota of the ancient Karoo and the end-Permian mass extinction.

Operational Phase

During the operational phase, the proposed Terra Wind Energy-Golden Valley Project will have a high visual impact. Most of the viewers/viewpoints identified by the visual specialist are highly sensitive to changes in their views. However, the region has a low population density and the proposed site is far removed from visually sensitive areas such as pristine wilderness sites and protected areas. A large network of high voltage power lines radiates across most of the study area and pylons are visible from most viewpoints. The wind farm will alter a number of views due to its size (spatial extent and the height of the turbines) and visibility (located on ridges). There are a few visual receptors (viewers and viewpoints) for which the visual intrusion will be very high (residents living on or close to the wind farm area), although many of these have agreed to have turbines on their properties. Regardless of the incorporation of mitigation measures, this impact will remain high.

As discussed above, bat fatalities as a result of the proposed project will be of moderate negative significance without mitigation and with the incorporation of appropriate mitigation measures, this impact remains moderate negative. It is important to note, however, that there is currently no information available on bat fatalities, and their causes at windfarms in South Africa, therefore this EIA assumed the worst-case scenario.

Ecological impacts are higher for the operation phase of the development, with most scoring a moderate negative overall significance. Four of these moderate ecological impacts relate to the effect of the wind turbines on bats and it is recommended that the impact on bats is carefully monitored during the operation phase of the development. It is also recommended that continuous monitoring and removal of alien plant species be done, as well as careful monitoring of the state of the landscape with the ECBCP land use planning principles in mind.

The introduction of alien species will also be of high negative significance with the proposed project as well as the No-Go option. However, if alien invader species are consistently managed over the entire operation phase of the project, and an alien eradication program implemented (in terms of the No-Go option), the significance of this impact can be reduced to low.

The impact of noise on the noise sensitive areas (NSA) is high in terms of the operational phase where four individual turbines are located within 500m of household residences. Should the four individual turbines be relocated to a distance of more than 500m from the household residences, the rating will fall to low for the operational phase. The impact of low frequency noise and infra sound will be negligible as there is no evidence to suggest that adverse health effects will occur as the sound power levels generated in the low frequency range are not high enough (i.e. are well below 90 dB) to cause physiological effects. The majority of the other impacts associated with the proposed project during the operational phase before mitigation were regarded as being of moderate significance, and the significance of all of these impacts with the exception of the following (whose significance remains moderate for all alternatives even after the incorporation of appropriate mitigation measures) can, after the incorporation of appropriate mitigation measures can be reduced to Low:-

- Change in the rural landscape.
- Intrusion of turbines on sensitive viewers
- Heritage impact
- Disturbance displacement of birds.
- Bird mortalities from colliding with turbine blades, tower, and/or associated infrastructure.
- Loss of bird habitat
- Loss of Bedford Grassland
- Loss of Karroid Thicket
- Loss of Scrub Grassland
- Disturbance and loss of bat habitat; and
- Bat mortalities.

The findings of the heritage study for the operational phase are high. Impacts to intangible heritage are expected to occur relating to changes to the feel, atmosphere and identity of a place or landscape. The point at which a wind turbine may be perceived as being “intrusive” from a given visual reference point is a subjective judgment. However, it can be anticipated that the presence of such facilities close to (for example) wilderness and heritage areas will destroy many of the intangible and aesthetic qualities for which an area is valued. Due to the sheer size of the turbines, shadow flicker, visual impact of road cuttings into the sides of slopes and residual impacts after the cessation of operations, e.g. the large

concrete base will remain buried in the ground indefinitely; bankruptcy of or neglect by a wind energy company can result in turbines standing derelict for years creating a long-term eyesore.
Significant impacts on palaeontological heritage normally occur during the construction phase and not in the operational phase of any development.

D.2. Environmental impact assessment

In accordance with the requirements of the National Environmental Management Act (Act No 107 of 1998) (NEMA), and relevant EIA regulations made in terms of this Act and promulgated in April 2006 (Government Notice No 385), and listed activities under (Government Notice Nos 386 and 387), the proposed project requires a full Scoping and Environmental Impact Assessment (EIA).[19]

Coastal & Environmental Services (CES) were contracted to conduct the EIA.

The EIA process was carried out in two phases: (1) a Scoping Phase, during which the most important environmental issues and project alternatives that must be assessed in the subsequent EIA phase are identified and (2) the Environmental Impact Assessment phase, which included a comprehensive study of the impacts of the proposed projects on the the natural and social environment and an assessment of the significance of the various impacts.. During the latter phase, recommendations are also made on how negative impacts may be mitigated and benefits enhanced.

The Scoping Phase for the proposed project took place between September and December 2009. The Draft Scoping Report (DSR) was distributed to Interested and Affected Parties (I&APs) for comment for a period of one month between 30 October and 30 November 2009. Comments and the appropriate responses were included into the Final Scoping Report (FSR) which was submitted together with a Plan of Study (PoS) for the detailed EIA phase to the National Department of Environmental Affairs (DEA), formerly the Department of Environmental Affairs and Tourism (DEAT), for review and comments on 15 January 2010.

DEA issued their approval of the FSR, following their review on the 12th Febuary 2010 and instructed the Environmental Assessment Practitioner (EAP) to proceed with the EIA Process.

The final EIA report was completed after having taken into account comments from various Interested and Affected Parties and relevant local authorities. It was then submitted to the Department of Environmental Affiars in October 2010. The project obtained approval from the Department of Environmental Affairs on the 5th of April 2011 as stated in the Record of Decision (RoD).[20]

SECTION E. Local stakeholder consultation
E.1. Solicitation of comments from local stakeholders

Based on the definition of Stakeholders as given in version 06 of the Glossary of CDM Terms the project identified the following relevant stakeholders:

- Local landowners in the project area
- Members from the wider project area
- Government departments and agencies (local, district and national)
- Members of the general public

Local community and landowners:

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[19] TWE - Golden Valley Final EIA Report
[20] TWE - Golden Valley ROD

The local community and landowners are considered as stakeholders because they will be directly affected by the project in several ways e.g. environmental and social impacts and economic benefits.

Members from the wider project area:
This included neighbouring farmers as well as members who had identified themselves as Interested and Affected Parties (I&APs) based on the Environmental Impact Assessment process.

Government representatives:
Local, provincial and national government departments and agencies are considered stakeholders as they will be responsible for ensuring that the project fits within government policies, planning, requirements and regulations, will issue project approvals and will monitor project implementation and operations.

General public
The general public is a stakeholder due to the large-scale nature of the project and because the public will be the main end-user of electricity generated. In addition, the general public may also have an interest in the project in terms of potential for technology transfer and replication, employment opportunities and wider environmental and economic effects.

How stakeholder comments were invited:

The project developers organized a stakeholder consultation meeting on 30th of January 2012 at Middleton Manor, Blue Crane Route Municipality, Eastern Cape Province, South Africa. Key stakeholders were invited to participate through personal invitation letters distributed in advance via email. Members of the public were also informed of the meeting through an announcement in the Herald, a newspaper with regional circulation in Port Elizabeth. The article was published on 26th January 2012.

Comments from stakeholders unable to attend the meeting were also invited by email and phone. In addition, stakeholders present at the meeting were asked to brief their colleagues who were unable to attend in case of further comments. As part of the Environment Impact Assessment (EIA) processes, further stakeholder consultations had been held. Their comments are reflected in the scoping and EIA reports.

E.2. Summary of comments received

During the stakeholder consultations a number of issues were raised and comments provided. The below provides an overview of the most important topics that were discussed.

- Land procurement and EIA process
  Stakeholders were interested in the land procurement process as well as the EIA process and effects of the wind park on neighbouring farms.

- Carbon credit benefits
  The stakeholders were interested in finding out more about the CDM and the ownership of the carbon credits as well as the revenues obtained through them.

- Noise and Visual Impacts
  Stakeholders expressed concern regarding the visual and noise impact of the project.

E.3. Report on consideration of comments received

Land procurement and EIA process

Land will be leased directly from landowners involved in the project. The agreement is such that once the turbines have been erected, only the parcel in which the turbine rests will be leased from the landowners. Therefore, landowners will be free to continue with their activities on the land.

Regarding the the EIA process, Interested and Affected Parties had been invited to give their comments on the project during an open and transparent process. A comprehensive study of the projects environmental impacts was conducted by specialists as indicated in the final EIA report submitted to the Department of Environmental Affairs. After the completion of the EIA process, the project proponent has also continued and will continue to interect with relevant I&AP to ensure that comments are properly taken into consideration.

Noise and Visual Impacts

The potential noise and visual impacts of the project were taken into account as part of the EIA process. Specialist studies were conducted and documented in the specialist study report as well as the final EIA report.

In terms of noise control during construction phase, various mitigation measures are provided which include restricting construction to the daytime, turning off noise making equipment when not in use and ensuring the equipment is properly maintained.[21] During the operational phase, the EMP states that the project developers shall ensure that the turbine infrastructure is maintained such that noise levels in identified noise sensitive areas associated with the project will not exceed the legally acceptable level of 45 dB for affected communities or households.

As for visual impacts, the final EIA report states that though impacts during construction phase are expected to be high, this may not necessarily be negative as the assembly of turbines may be a fascinating spectacle due to the size of the components being assembled.

During operations, visual impact on sensitive viewers and viewpoints is expected to be high due to the dimensions of the turbines and their potential visibility in the region. However since opinions on the aesthetics of wind farms differ radically, it cannot be perceived whether the effects would be positive or negative.

Carbon credit benefits

Renewable energy projects often need the carbon credit revenue to make the projects financially viable. Therefore, the carbon credits are typically owned by the project developer and revenues will typically go the project developer.

SECTION F. Approval and authorization

The Letter of Approval from South Africa is not available at the time of submitting the PDD to the validating DOE.

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Appendix 1: Contact information of project participants

Organization name	Terra Wind Energy – Golden Valley (Pty) Limited
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Appendix 2: Affirmation regarding public funding

Not additional information

Appendix 3: Applicability of selected methodology

Not additional information

Appendix 4: Further background information on ex ante calculation of emission reductions

Net electricity generated by power plant/unit *m* in year *y* ($EG_{m,y}$)

		Generation Data (MWh)		
Name	**Type**	**2008-2009**	**2009-2010**	**2010-2011**
Amot	Coal	11,987,281	13,227,864	12,194,878
Camden	Coal	6,509,079	7,472,070	7,490,836
Duvha	Coal	21,769,489	22,581,228	20,267,508
Grootvlei	Coal	1,249,556	2,656,230	3,546,952

Hendrina	Coal	12,296,687	12,143,292	11,938,206
Kendal	Coal	23,841,401	23,307,031	25,648,258
Komati	Coal	-	1,016,023	2,060,141
Kriel	Coal	18,156,686	15,906,816	18,204,910
Lethabo	Coal	23,580,232	25,522,698	25,500,366
Majuba	Coal	22,676,924	22,340,081	24,632,585
Matimba	Coal	26,256,068	27,964,141	28,163,040
Matla	Coal	21,863,400	21,954,536	21,504,422
Tutuka	Coal	21,504,122	19,847,894	19,067,501
Acacia	Gas (Jet kerosene)	-	971.00	992.00
Port Rex	Gas (Jet kerosene)	-	322.00	5,507.00
Ankerlig	Gas/Diesel Oil	-	6,303.00	-
Gourikwa	Gas/Diesel Oil	-	5,817.00	-
Gariep	Hydropower	-	-	-
Vanderkloof	Hydropower	-	-	-
Colleywobbles	Hydropower	-	-	-
First Falls	Hydropower	-	-	-
Second Falls	Hydropower	-	-	-
Ncora	Hydropower	-	-	-
Koeberg	Nuclear	13,004,000	12,806,000	12,099,000
Klipheuwel	Wind	2,000	1,000	2,000
PetroSA biogas to energy	CDM	23,286	23,286	23,286
Bethlehem Hydroelectric project	CDM	8,983	8,983	8,983
Durban Landfill-gas-to-electricity project – Mariannhill and La Mercy Landfills	CDM	3,744	3,744	3,744
Durban landfill gas Bisasar Road project	CDM	31,723	31,723	31,723
Total		**224,764,661**	**228,828,053**	**232,394,838**

Amount of fossil fuel type *i* consumed by power plant/unit *m* in year *y*

		$FC_{i,m,y}$ (kg/year)		
Name	**Type**	**2008-2009**	**2009-2010**	**2010-2011**
Amot	Coal	6,395,805,000	6,794,134,000	6,525,670,000
Camden	Coal	3,876,211,000	4,732,163,000	4,629,763,000
Duvha	Coal	11,393,553,000	11,744,606,000	10,639,393,000
Grootvlei	Coal	674,538,000	1,637,371,000	2,132,979,000
Hendrina	Coal	7,122,918,000	6,905,917,000	7,139,198,000
Kendal	Coal	15,356,595,000	13,866,514,000	15,174,501,000
Komati	Coal	0	664,497,000	1,271,010,000
Kriel	Coal	9,420,764,000	8,504,715,000	9,527,185,000
Lethabo	Coal	16,715,323,000	18,170,227,000	17,774,699,000

Majuba	Coal	12,554,406,000	12,261,833,000	13,020,512,000
Matimba	Coal	13,991,453,000	14,637,481,000	14,596,842,000
Matla	Coal	12,689,387,000	12,438,391,000	12,155,421,000
Tutuka	Coal	11,231,583,000	10,602,839,000	10,191,709,000
Acacia	Gas (Jet kerosene)	0	-	347,066.46
Port Rex	Gas (Jet kerosene)	0	-	219,913.98
Ankerlig	Gas/Diesel Oil	0	-	0
Gourikwa	Gas/Diesel Oil	0	-	0

Appendix 5: Further background information on monitoring plan

No additional information

Appendix 6: Summary of post registration changes

No additional information

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History of the document

Version	Date	Nature of revision
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	EB 66 13 March 2012	Revision required to ensure consistency with the “Guidelines for completing the project design document form for CDM project activities” (EB 66, Annex 8).
03	EB 25, Annex 15 26 July 2006	
02	EB 14, Annex 06b 14 June 2004	
01	EB 05, Paragraph 12 03 August 2002	Initial adoption.
Decision Class: Regulatory **Document Type:** Form **Business Function:** Registration		