CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

SECTION A. General description of project activity

A.1. Title of the project activity:

>>
The Capture and Utilisation of Methane at the GFI Mining South Africa' owned Beatrix Mine in South Africa
Version 10
Date: 07 April 2010

A.2. Description of the project activity:

>>
Purpose:

The Beatrix Mine (referred to as Beatrix from here on) is a gold mine that is owned by GFI Mining South Africa; of which Gold Fields is the holding company. Beatrix is located in the Free State Province of South Africa. The proposed project activity involves the destruction and utilisation of methane at this mine. The project can be divided into two distinct activities:

- The first being the destruction and utilisation of mine methane; which originates in the main Beatrix mine from intersecting geological faults whilst mining. The mining activity releases underground methane. The origin of this methane is unknown. Methane is highly explosive and a safety hazard. Currently, the underground mine methane is diluted with ventilation air to below its explosion limits and released into the atmosphere through ventilation shafts. This section of the project is referred to as "Mine methane" from here on.
- The second being the destruction of non-mine methane; which is methane emitting from boreholes drilled for exploration purposes by the Beatrix mine. Methane is released from numerous exploration boreholes. Since the start of the drilling program in the 1950s, a number of boreholes have intersected methane-carrying geological structures. During the development of this project, 488 holes were identified in the GFI Mining South Africa mining area. Only five of these boreholes, geographically far apart from each other, are venting methane at rates that justify the implementation of greenhouse gas reduction projects. This is section of the project is referred to as "Non-mine methane" from here on.

Mine Methane:

The proposed project will pipe the underground mine methane up the main shaft at Beatrix (Number 1 Shaft) and to the surface where it will be flared and used to generate electricity. The project will be implemented in two phases:

1. The first phase will be the installation of a flaring system. At this stage, all the mine methane will be flared. The first phase, or flaring of all the mine methane, is expected to begin in November 2010.
2. The second phase will be the installation of the power plant; which is expected to begin in Jan 2011. In phase two, the mine methane will be used to generate electricity and any excess methane that the engines cannot handle will be flared.

This phased approach is adopted due to the various delivery and lead times of the equipment.

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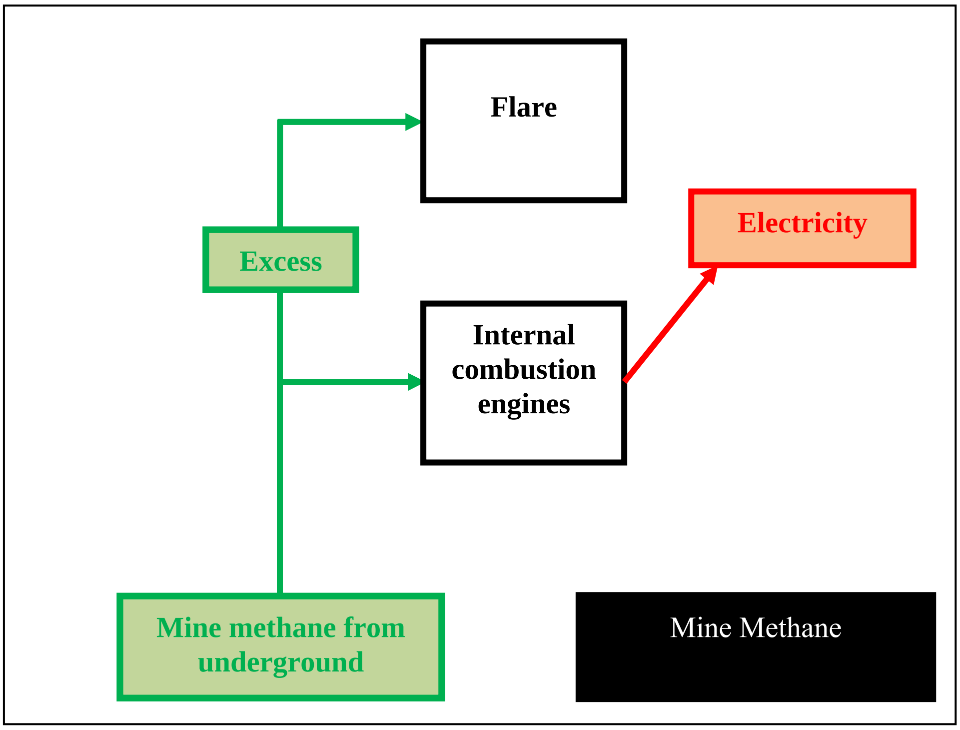

Figure 1: Proposed mine methane project activity

In the project activity, electricity will be generated by combusting the mine methane in internal combustion engines. Currently, the plan is to install 4 engines with an installed capacity/electricity output of 1.345 MW el. each[1]. The specification of the engines will be made available to the validators and will be used for the ex-ante calculation of the emission reductions. However, this project is not yet in detailed design stage and hence the installed capacity of the engines and the manufacturer is subject to change.

The electricity generated in the project activity will displace grid electricity as Beatrix does not generate electricity on site. Beatrix does have stand-by emergency generators, which it uses to bring the miners to surface when there is no grid electricity. The generators are only used as emergency power. Under normal circumstances, Beatrix sources all of its electricity from the South African national grid.

The excess methane that cannot be handled by the engines will be flared. The engines have a certain installed capacity and cannot handle a gas flowrate above 380 Nm^3/hr each[2]. If the methane flowrate increases above what can be handled by the engines then it will be routed directly to the flare. This is necessary owing to the variable gas flowrate.

[1] Please see engine specification document entitled “ts_HardRock_66kV”

[2] Please see engine specification document entitled “ts_HardRock_66kV.” Again, this is the current plan, but the project is not yet in detailed design stage and, as such, is subject to change. The variability in mine methane might change the size and number of the engines.

Non-Mine Methane:

The non-mine methane released from five exploration boreholes, geographically far apart from each other, will be flared as part of the project activity.

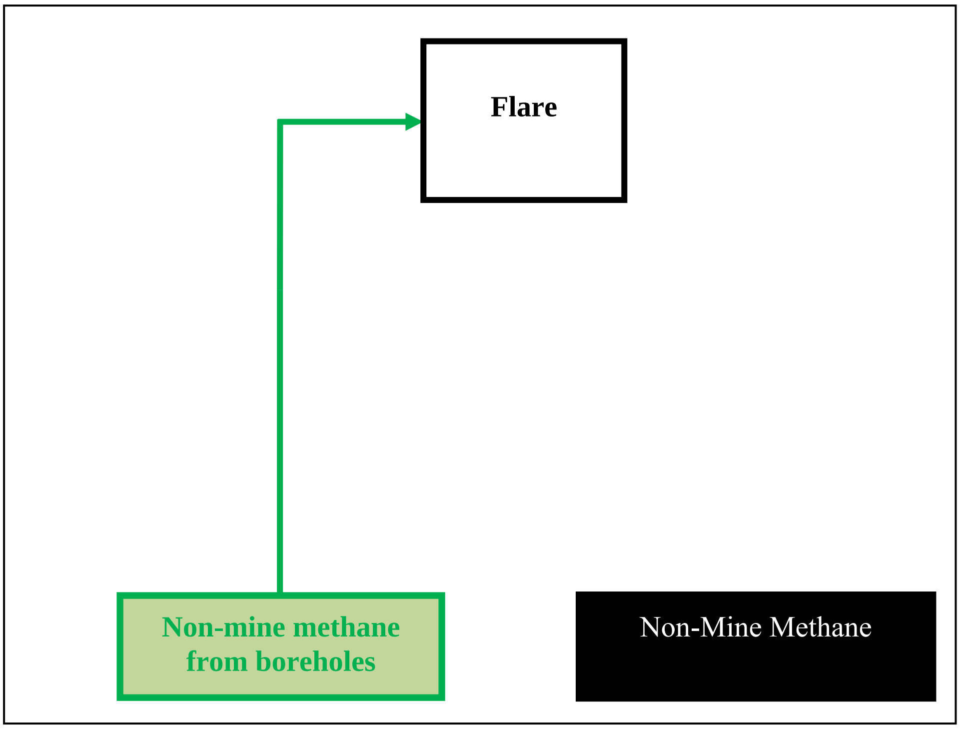

Figure 2: Proposed non-mine methane project activity

GHG Reduction:

The use of this underground mine methane will reduce the amount of electricity Beatrix needs to import from the national grid. The South African grid electricity is generated predominantly from low grade coal. The use of coal and, more specifically, low grade coal means that the production of grid electricity is emissions-intensive.

The proposed project will destroy both the underground mine methane and the non-mine methane released from the boreholes. The destruction of this methane will result in the elimination of methane released directly into the atmosphere. Since methane has 21 times the global warming potential of carbon dioxide, the project will result in a reduction of GHG emissions.

Contribution to Sustainable Development:

The project makes positive contributions to sustainable development. The South African Designated National Authority (DNA) evaluates sustainability in three categories: Economic, environmental and social. The contribution of the project towards sustainable development is discussed in terms of these three categories:

- **Economic:** The project will contribute to foreign reserve earnings for South Africa via the carbon credit sales revenue.

- **Environmental:** At a regional level, the project will have a positive impact on the environment. This positive impact relates to a reduction in the generation of coal-based electricity and its associated environmental consequences. These consequences include: the impact of coal mining, the utilisation of scarce water resources, SO_2 emissions and the impacts associated with the disposal of coal ash.

The project will result in a reduction of greenhouse gas emissions by eliminating the release of methane; which has a global warming potential of 21 times that of carbon dioxide.

- **Social:** The project will create jobs in both the construction and operations phase.

  The project will destroy the underground mine methane and the methane released from boreholes. Methane has always been a huge safety risk since it is a highly explosive gas. The destruction of the methane will result in a safer working environment for the personnel at Beatrix.

  GFI Mining South Africa have committed to contributing a percentage (R0.20 per ton of CO_2e and 0.5% of pre-tax profit) of their carbon credit revenue to The Gold Fields Foundation. This is similar to the contribution GFI Mining South Africa makes out of gold mining revenue in terms of its social sustainable development obligations as dictated by the South African mining legislative framework relating to sustainable development.

  The Gold Fields Foundation is involved in a number of projects aimed at the social upliftment of the local communities. These projects target local economic development with a positive environmental impact. Examples of these projects include:

  - Golden Oils – a community based, indigenous plant essential oil project
  - Bulk water supply to the Lejweleputswa District
  - Land and housing project in Masilonyana
  - Beatrix day-care facilities

A.3. Project participants:

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Name of Party involved (*) ((host) indicates a host Party)	**Private and/or public entity(ies) project participants (*) (as applicable)**	**Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)**
Republic of South Africa (host)	GFI Mining South Africa (Pty) Ltd	No
	Promethium Carbon (Pty) Ltd	
Switzerland	Mercuria Energy Trading SA	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		
Note: *When the PDD is filled in support of a proposed new methodology (forms CDM-NBM and CDM-NMM),* at least the host Party(ies) and any known project participant (e.g. those proposing a new methodology) shall be identified.		

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:
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A.4.1.1. Host Party(ies):
>>
The host party is the Republic of South Africa.

A.4.1.2. Region/State/Province etc.:
>>
The project is located in the Free State Province.

A.4.1.3. City/Town/Community etc.:
>>
Beatrix mine is situated south of Virginia in an area known as the "Welkom Gold Fields." Beatrix mine is in the Theunissen district of the Free State. Beatrix falls under Masilonyana Local Municipality and Lejweleputswa District Municipality.

A.4.1.4. Details of physical location, including information allowing the unique identification of this project activity (maximum one page):
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The proposed project will be located on Leeuwbult 52, which is a farm in the district of Theunissen near Virginia. The location of the project is represented below.

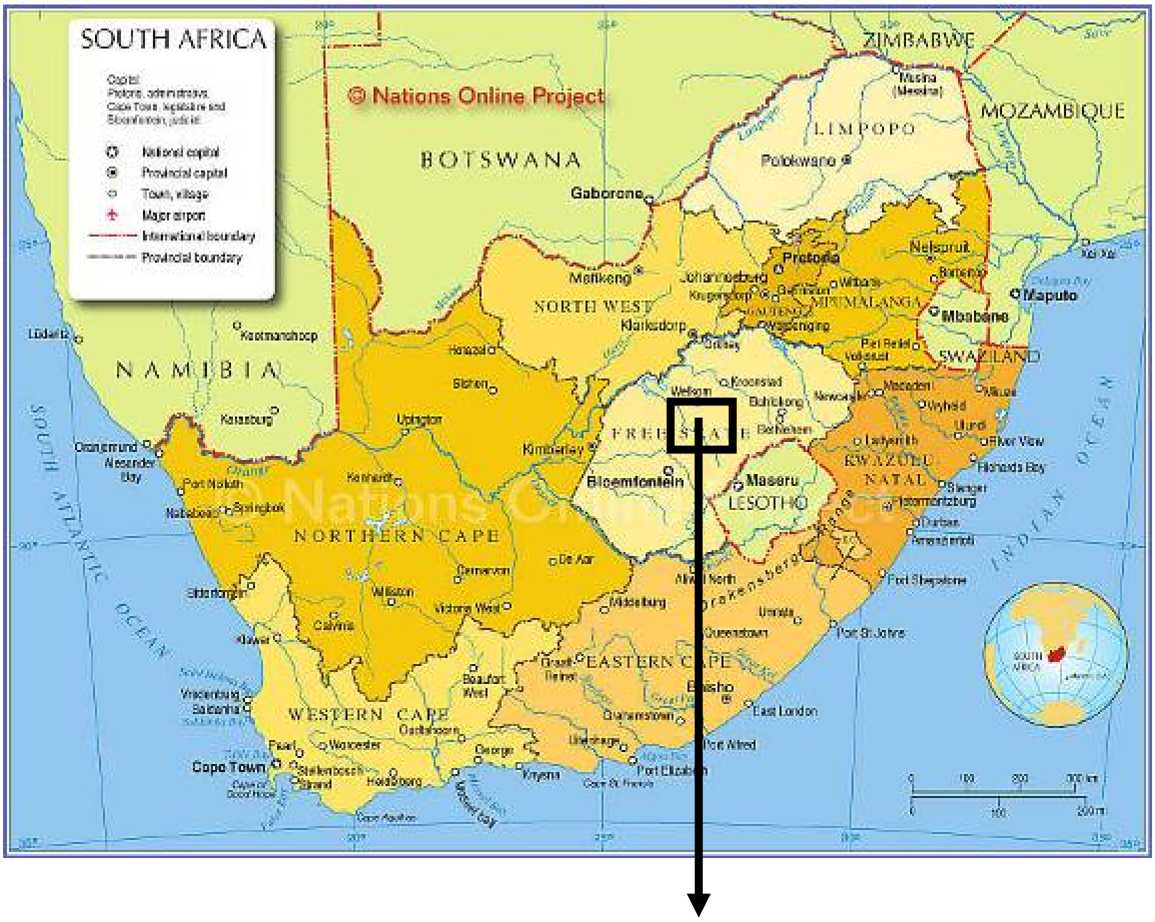

Figure 3: Map of southern Africa[3]

Project Location

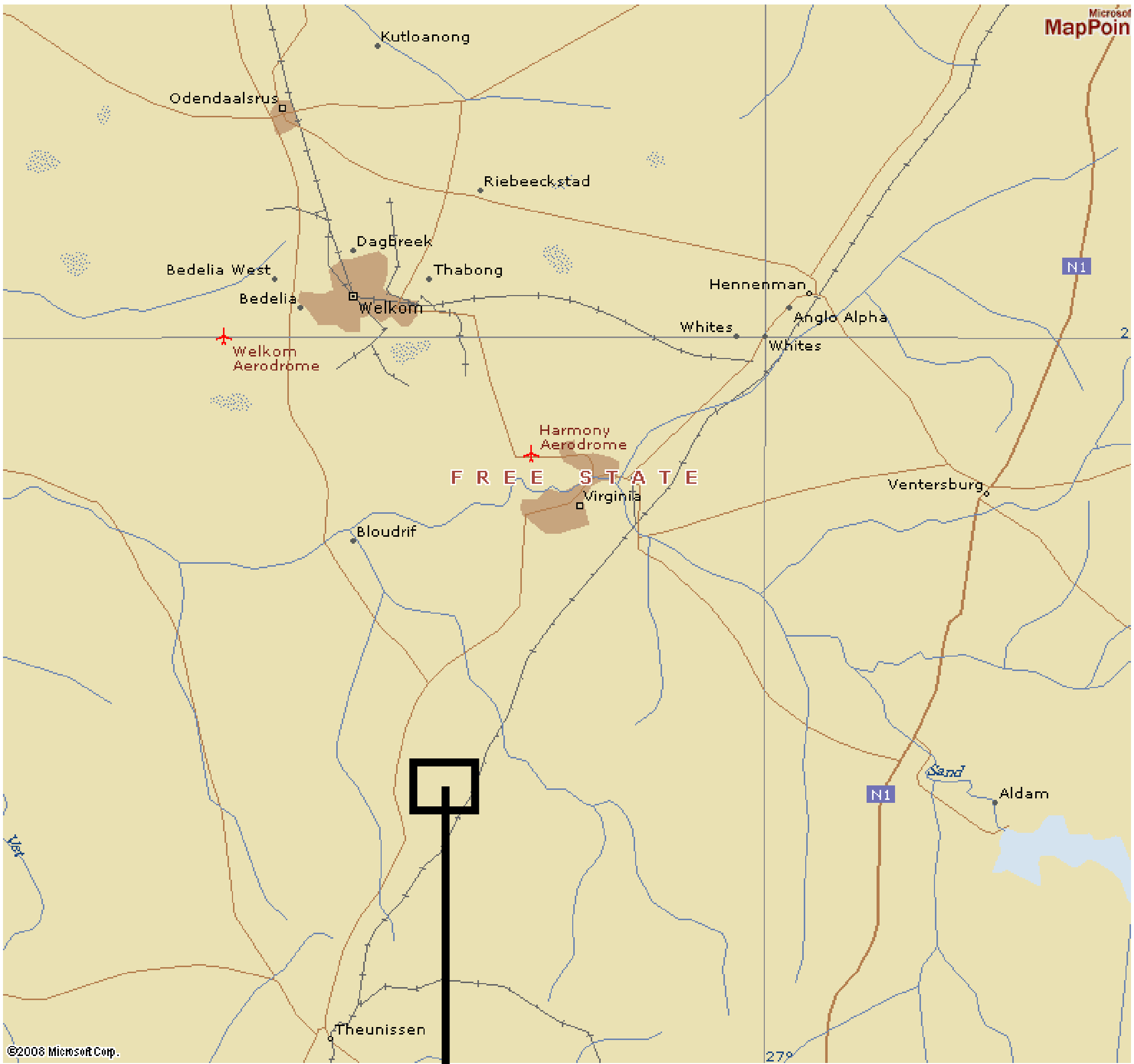

Figure 4: Map of the Free State[4]

Project Location

Mine Methane

[3] This map was extracted from www.nationsonline.org website. [Accessed 1 October 2008]

[4] This map was extracted from http://encarta.msn.com/map_701512555/free_state.html. [Accessed 1 October 2008]

The plant that will use and destroy the underground mine methane will be located at Beatrix mine close to Number 1 shaft. The GPS coordinates are:
S 28°15'44"
E 26°47'06"

Non-Mine Methane
The project will flare the non-mine methane released from five boreholes. These boreholes are located at the following co-ordinates:

Name	GPS Coordinates
DBE1	S 28º11'066" E 26º45'488"
EX1	S28º16'334" E 26º44'612"
ST23	S28º11'995" E 26º44'312"
1400	S28º13'323" E 26º44'.607"
2264	S28º13'908" E 26º47'078"

Figure 5: Indication of Beatrix main shaft and the five boreholes[5]

A.4.2. Category(ies) of project activity:

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The project category is:
Sectoral Scope 10: Fugitive emissions from fuels (solid, oil and gas)

A.4.3. Technology to be employed by the project activity:

>>
Background on the Occurrence of both Mine and Non-Mine Methane

[5] Google Earth Imagery. [Accessed 1 October 2008]

The methane is found in geological faults and liberated when the fault is encountered during the mining activity or exploration drilling. The origin of the methane in these faults is unknown. Scientific research indicates that is comes from a deep-seated source and that it may be of biological origin. More information on the research done into the source of the methane can be found in Annex 3. Annex 3 describes the location of the geological faults in greater detail.

Methane from gold mines is different to methane from coal mines. The methane from gold mines is not released homogeneously whereas the methane from coal mines is released homogeneously. Coal mine methane is a direct result of coal mining (i.e. if more coal is mined then more methane is released). This is not the case with gold mine methane. Hence, it is difficult to determine how much methane will be released and how long that methane source will continue to release methane. This presents many challenges for projects proposing to use the gold mine methane.

The project details for the mine methane and non-mine methane are discussed below:

1. <u>The Use and Destruction of the Mine Methane</u>

The mine methane will be captured by:
1. Sealing off an area into which the methane is released and piping the methane from that area to the surface, and/or
2. Piping the methane from underground boreholes to the surface.

These methane capturing methods are within the applicability criteria as described in AM0064; Version 02; EB42. These capturing methods will only be done in cases where the mine methane can safely and practically be captured.
Currently, the methane is diluted by piping compressed air into the rock face at the geological faults where methane is released. In the project, these same pipes will be used to extract the methane from the faults. The extracted methane will then be piped approximately 3.5km underground. The methane will be brought up the main shaft.

The mine methane will be piped to surface. The initial installation will consist of 5 monitoring stations underground, which will be installed to measure the flowrate of the methane. A diagram of the underground mine methane extraction system based on where methane is currently emitted in the mine can be seen below. This system will be modified and adjusted as required by the rates of actual methane release during the crediting period.

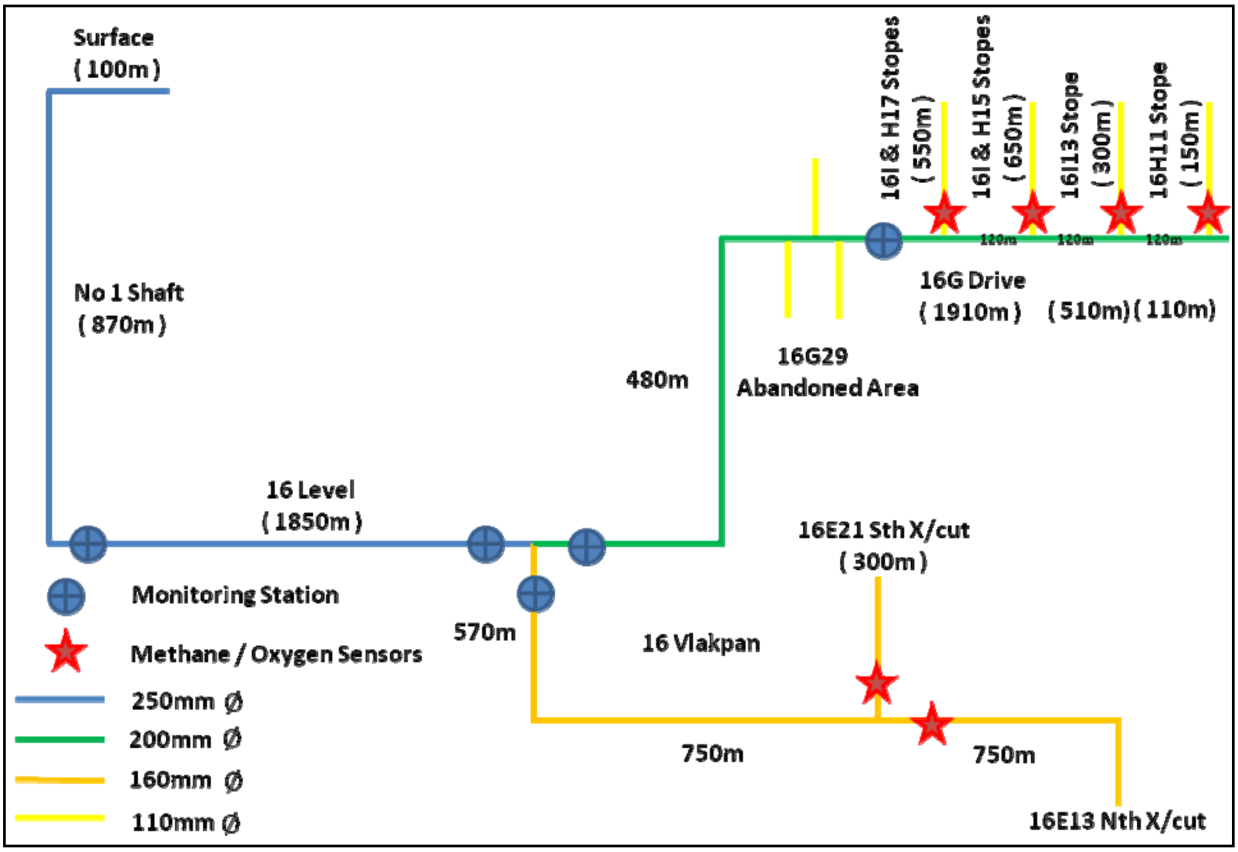

Figure 6: The underground piping and monitoring system for mine methane extraction.

GFI Mining South Africa have been monitoring and measuring the amount of methane being extracted for many years. Due to the nature of the methane source, it is not possible to capture all of the methane originating in the mine. However, based on experience, GFI Mining South Africa are comfortable that they will be able to deliver around 400 - 450l/s of methane from the mine. Once the extraction piping and flaring facility are complete, accurate measurements can be taken and there will be more certainty of the amount of gas available. For the purposes of the ex-ante calculation of the emission reductions, a flowrate of 429l/s was used when the engines are running. When the engines are down, the blower is turned down and the flowrate is 400l/s. The reason for selecting this conservative flowrate is discussed further on.

The composition of the gas being piped from underground is expected to be:

Sample description	Hydrogen (%)*	Oxygen (%)	Nitrogen (%)	Carbon monoxide (%)*	Carbon dioxide (%)	Methane (%)	Ethane (%)	Propane (%)*	Butane (%)*
16G29 STH X/C T/WAY	< 0.005	2.95	16.14	< 0.005	0.07	80.62	0.21	0.02	< 0.005
16G29 NTH X/CUT	< 0.005	4.03	27.89	< 0.005	0.56	67.37	0.16	< 0.005	< 0.005
16G 15 X/C VALVE D/DRILL	< 0.005	1.93	12.48	< 0.005	0.05	85.30	0.22	0.01	< 0.005
16E21 X/CS PIPE DISCHAGE VLAKPAN	< 0.005	1.65	11.30	< 0.005	0.05	86.78	0.22	< 0.005	< 0.005
16E13 X/CW PIPE DISCHARGE VLAKPAN	< 0.005	1.19	9.81	< 0.005	0.05	88.75	0.21	< 0.005	< 0.005

* = Not detected. Estimated detection limit used.

Figure 7: The gas composition from the South African Nuclear Energy Corporation (NECSA)[6]

[6] Please see document entitled PAL-2008-REP-0077. The gas composition is subject to change, but it will be monitored in accordance with the baseline and monitoring methodology.

Obviously, the gas composition is subject to change. A gas composition of 85.36 volume % was assumed for the ex-ante calculation of the emission reductions (the average of the four samples above 80% methane concentration[7]).

The captured underground mine methane will be used for:

Electricity generation from mine methane:
The captured mine methane will be combusted in internal combustion engines to generate electricity.

The current plan is to generate 5.38 MW el. of electricity in four internal combustion engines each with an electrical generation capacity of 1.345 MW el[8]. Owing to the variability in the methane flowrate and the possibility that some old sources will dry out and other sources will start emitting mine methane, more engines may be installed at a later stage.

Although electricity will always be generated in internal combustion engines, the number of engines and the installed capacity of the engines are subject to change as the project has not yet entered detailed design phase.

Flaring of mine methane:
The mine methane that cannot be handled by the installed engines due to the capacity limit will be flared in an enclosed flare. This is necessitated by the fact that the flowrate of mine methane varies. None of the captured methane will be released back into the atmosphere. The flare will only used to burn excess gas (gas over and above 422l/s maximum demand from the engines). The flare will have a minimum flowrate of 7l/s. It will be desirable to keep the flare running at a very low capacity even when the engines are running at full load. This will ensure that the flare is alight and will be able to immediately burn any additional gas should an engine trip.

When the internal combustion engines and/or absorption chillers are offline for maintenance or unforeseen circumstances, all the captured methane will be flared.

The current plan is to install a single flare near the Number 1 Shaft. The flare has the capacity to handle a maximum gas flowrate of 1,450 Nm3/hr (400 l/s) and a turndown ratio of 1:50[9]. Instruments will be installed to monitor both the inlet and outlet gas conditions in order to determine the combustion efficiency of the flare.
When the engines are down for maintenance, the gas will be routed to the flare. However, the flare can only handle 400l/s. The blower comes equipped with the variable speed drive and must be turned down so that only 400l/s of gas is sent to the flare. A second flare can be installed at a later stage if the gas flowrate is significantly higher than expected.

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[7] The sample with the methane concentration of 67.37% was excluded from the calculated average as it fell below the 90% confidence level and, as such, was considered to be a dud sample. It is likely that there was air ingress in this sample as the oxygen content and the nitrogen content are higher than the other samples.

[8] Please see engine specification document entitled "ts_HardRock_66kV." The project has not yet entered the detailed design phase and, as such, the manufacturer of the engines, the number of the engines and the installed capacity of the engines is subject to change.

[9] Please see the flare specifications bearing in mind that this is the current plan. The project has not entered the detailed design phase as of yet and, as such, the manufacturer and specific specifications of the flare is subject to change.

The project will be implemented in two phases owing to the various lead times of the equipment. The phases are as follows:

The first phase will be the installation of a flaring system. At this stage, all the mine methane will be flared. The first phase, or flaring of all the mine methane, is expected to occur in March 2010. In order to be conservative, the ex-ante calculations of the emission reductions for phase 1 have been done on a gas flowrate of 429l/s[10].

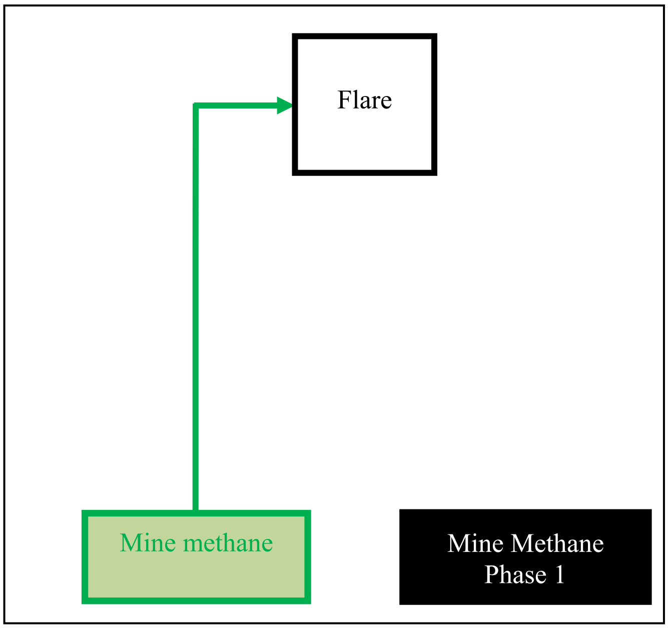

Figure 8: Phase 1

[10] This is based on an estimated flowrate from Beatrix of between 400 and 450l/s. A gas flowrate of 429l/s was selected for the purpose of sending 422l/s to the engines and 7l/s to the flare in phase 2. A flowrate of 422l/s is the maximum gas flowrate required by the engines in accordance with manufacturer's specifications. A flowrate of 7l/s is the minimum flowrate required to keep the flare operating in accordance with manufacturer's specifications. The technology used for the ex-ante calculation of the emission reductions is the current plan, but the project has not entered detailed design yet and there may be minor changes at a later stage.

The second phase will be the installation of the electricity generation plant. In phase two, the mine methane will be used to generate electricity and any methane that cannot be handled by the engines will be flared. Phase two is projected to occur in November 2010. In order to be conservative, the ex-ante calculations of the emission reductions for phase 2 have been done on a gas flowrate of 422l/s sent to the engines and 7l/s sent to the flare[11].

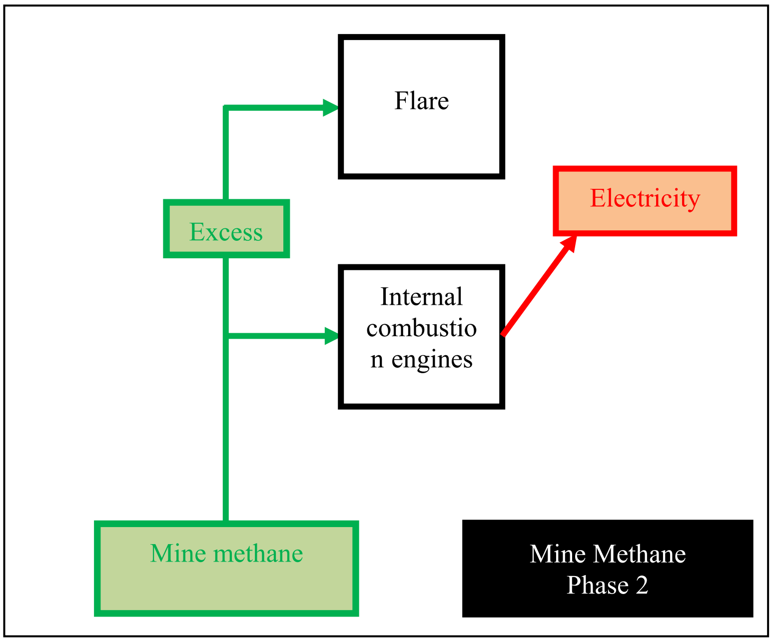

Figure 9: Phase 2

The reason for this two phased approach is that the lead time for the internal combustion engines is longer than the lead time for the flares.

2. The Destruction of the Non-Mine Methane Released from the Boreholes

The methane released from five exploration boreholes, geographically far apart from each other, will be flared. The boreholes are simply holes in the ground that were drilled for exploration purposes. All the boreholes considered in this project activity were drilled before 2001. Pictures of the boreholes included in this project can be seen below:

[11] A gas flowrate of 422l/s is the maximum gas flowrate that can be handled by the internal combustion engines. This is available in the manufacturer's specification for the engines. However, the project is not yet in detailed design stage and, as such, the manufacturer, the number of engines and the installed capacity of the engines is subject to change. In addition, owing to the variability in the flowrate of the mine methane, it may allow for another engine to be installed at a later stage. A gas flowrate of 7l/s to the flare is taken from the manufacturer's specification and is the minimum flowrate of gas to keep the flare running continuously. Obviously, depending on the gas flowrate, the amount of methane flared can vary.

EX1

ST23

1400

DBE1

2264

Figure 10: Pictures of the non-mine methane boreholes

The flowrate and composition of the gas released from each of these boreholes is:

Borehole Name	Average Gas Flowrate (l/s)	Methane Concentration (vol %)
DBE1	13.16	100
EX1	70.12	99.72
ST23	97.29	99.03
1400	25.71	99.44
2264	11.47	100

The flowrate and composition of the gas from the boreholes is subject to change.

A diagram of the destruction of the non-mine methane is presented below:

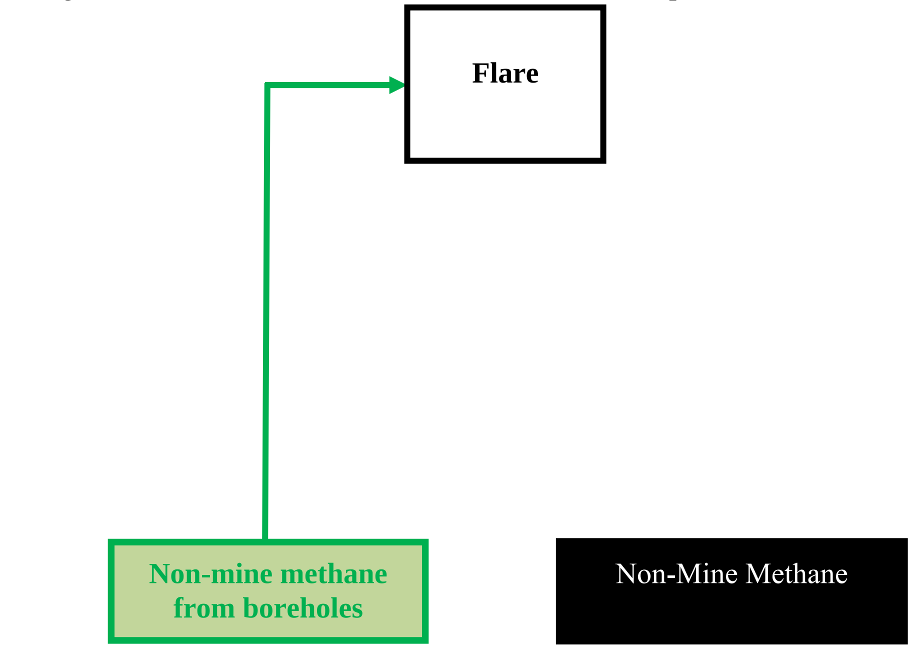

Figure 11: The destruction of non-mine methane from the boreholes

A single enclosed flare will be installed at each of the five boreholes.

The current plan is to install flares that will have the monitoring equipment required to claim the default flare efficiency of 90% in accordance with the "Tool to determine project emissions from flaring gases containing methane." The flares installed at EX1 and ST23, the two biggest emitters, will allow for the potential to install instruments at a later stage that monitor both the inlet and outlet gas conditions in order to calculate the actual combustion efficiency in accordance with the tool. The flares installed at the other three boreholes will not have the ability to be retrofitted in order to calculate the actual flare efficiency. Hence, the default flare efficiency will be claimed for DBE1, 1400 and 2264 throughout the project crediting period. The ex-ante calculations of the emission reductions are modelled to reflect the situation at installation (all borehole flares assume default flare efficiency). The specifications of the borehole flares are included in Annex 5.

The non-mine methane is not used to generate electricity owing to the low flowrates, but more importantly to the remote locations of the boreholes. The location of the boreholes means that piping the methane to the mine methane electricity generation plant is impractical and generating electricity at the borehole would mean having to transmit the electricity to the Beatrix mine for use. The infrastructure required and the losses incurred during transporting this small amount of electricity makes generating electricity at the boreholes impractical. There are also safety concerns.

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

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The estimated amount of emission reduction over the chosen crediting period is represented below:

Table 1: Summary of emission reductions

Years	Annual estimation of emission reductions in tonnes of CO2e*
11 Mar 2010 – 31 Dec 2010	139,135
1 Jan 2011 – 31 Dec 2011	252,101
1 Jan 2012 – 31 Dec 2012	252,101

1 Jan 2013 – 31 Dec 2013	252,101
1 Jan 2014 – 31 Dec 2014	252,101
1 Jan 2015 – 31 Dec 2015	252,101
1 Jan 2016 – 31 Dec 2016	252,101
1 Jan 2017 – 10 Mar 2017	50,094
Total estimated reductions (tonnes of CO2e)	**1,701,838**
Total number of crediting years	**7 (renewable twice)**
Annual average over the crediting period of estimated reductions (tonnes of CO2e)	**212,730**

*The emission reductions are less in 2010 than in subsequent years because of the project implementation plan. The project will be implemented in two phases as discussed in Section A.4.3. The calculations were done in such a way as to reflect the phased implementation plan.

Due to the variation of mine methane, the emission reduction figures in the table above were calculated based on measurements taken during the development of the project. There is no guarantee that the underground methane emission rate will stay constant. The methane emission rate may increase or decrease, depending on changing geological conditions. Should this happen, the emission reduction by the project will vary accordingly.

A.4.5. Public funding of the project activity:

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No public funding has been used or will be used in the development and implementation of this project.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

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This PDD is compiled using the approved baseline and monitoring methodology AM0064:

"Methodology for methane capture and utilization or destruction in underground, hard rock, precious and base metal mines"

Version 02, EB 42

This PDD refers to the following tools:

- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" Version 01;
- "Combined tool to identify the baseline scenario and demonstrate additionality" Version 02.2;
- "Tool to determine project emissions from flaring gases containing methane" Annex 13, EB28;
- "Tool to calculate the emission factor for an electricity system" Version 02.

No fossil fuel is used to capture, transport or use the mine or non-mine methane. Hence, the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" Version 02 is not used in the PDD.

B.2. Justification of the choice of the methodology and why it is applicable to the project activity:

>>
AM0064 was developed by Promethium Carbon (Pty) Ltd specifically for the Beatrix mine methane capture and destruction project.

A discussion of the applicability of AM0064 as applied to the Beatrix Underground Methane Capture Project follows:

Table 2: Discussion of the applicability of AM0064 for mine methane

Discussion of the Applicability conditions of AM0064 for mine methane capture and utilization or destruction as applied to the Beatrix Underground Methane Capture Project		
Applicability criteria as in AM0064	**Project activity at Beatrix mine**	**Was the Applicability condition of AM0064 met?**
The applicability conditions apply to project activities that involve capture, utilisation or destruction of methane from any operating mine, excluding mines where coal is extracted.	Methane will be captured, utilized and destroyed. Beatrix is not a coal mine.	Yes
Mine methane can be captured from the following: *• Underground boreholes in the mine, where mine methane can be captured from:* *- Development ends including shafts, access drives, ore passes or other developments;* *- Existing infrastructure such as shafts, access drives, raises and winzes;* *- Working areas including working stopes and worked out stopes; or* *- Any other area opened up for the development of the mine or the extraction of ore;* *• Surface wells drilled into sealed off areas where the mine methane is accumulated;* *• Gas drainage galleries or other infrastructure using mine methane capture techniques, including capture of gas from sealed areas;* *• Ventilation air.*	Methane will be captured from underground boreholes, gas drainage galleries and sealed areas as described in AM0064. Surface well drainage from sealed off areas where mine methane is accumulated could be considered if future methane sources are identified due to continued mining. Ventilation air methane will not be used.	Yes
The mine methane can be removed from the mine, in which the project activity is implemented, in two ways: *1. By sealing off an area into which the methane is released and piping it from that area, and/or* *2. By piping the methane from underground boreholes.*	Both these removal methods will be used in the Beatrix project.	Yes
For the purposes of this component, drainage to surface boreholes is only allowed in the following cases: *• Where a hole is drilled from the surface to an underground mining area where mine methane is allowed to accumulate. For safety reasons, such an area will be isolated (sealed off) from the rest of*	Depending on future mine development, methane may be drained to surface through boreholes drilled into underground mining areas where methane is allowed to accumulate as	Yes

the workings by walls. Methane will be drained into these areas with the purpose of taking it to the surface via the borehole. *• Where a hole is drilled from the surface to an underground mining area and a pipe into which mine methane has been collected is connected to the opening of the borehole where it intersects the mining area. In this case the borehole is used to convey mine methane to surface rather than to install a pipe column in the shaft.*	required by AM0064. Methane extraction, from surface boreholes, that does not comply with the requirements of AM0064 will not be done.	
The methodology is applicable under the following conditions: *• The captured mine methane is utilised to produce electricity, motive power and/or thermal energy and/or destroyed through flaring;* *•Prior to the start of the project activity all mine methane was released into the atmosphere or partially used for heat generation;* *• The methodology applies to both new and existing mining activities;* *• Project participants must be able to supply the necessary data for ex-ante projections of methane demand in the case where part of mine methane was used for the heat generation prior to the start of the project activity.*	Captured methane will be used for electricity generation. No prior use of the methane exists and all methane is diluted in the ventilation air. Beatrix is an existing mining operation.	Yes
This component of the methodology does not apply to project activities that: *• Operate in coal mines;* *• Operate in open cast mines;* *• Capture methane from abandoned or decommissioned mines;* *• Capture/use methane from surface boreholes that do not intersect mining areas/developments underground;* *• Use CO2 or any other fluid/gas to enhance methane drainage.*	Beatrix mine is not a coal mine and is not an open cast mine. Beatrix is, furthermore, an operating mine and not an abandoned or decommissioned mine. Future surface borehole methane extraction will only be done for mining areas/developments underground. No CO_2 will be used for enhanced methane drainage.	Yes
In addition, the applicability conditions included in the tools referred to above apply.	All tools that AM0064 refers to were adhered to.	Yes
Finally, for mine methane capture and utilization or destruction, this methodology is only applicable to project activities where the identified baseline scenario is a partial or total atmospheric release of mine methane. In case of a partial atmospheric release, some mine methane is flared and/or used for the heat generation only.	The baseline selection section will illustrate that atmospheric methane release is the baseline scenario.	Yes

Table 3: Discussion of the applicability of AM0064 for non-mine methane

Discussion of the Applicability condition of AM0064 for non-mine methane capture and destruction as applied to the Beatrix Underground Methane Capture Project		
Applicability criteria as in AM0064	**Project activity at Beatrix mine**	**Was the Applicability condition of AM0064 met?**
These conditions below are applicable to project activities that capture and destroy methane released from geological structures, e.g. methane released directly from holes bored to geological formations specifically for mineral exploration and prospecting activities.	Methane will be captured, and destroyed. The methane released is the result of a geological structure.	Yes
Abandoned or decommissioned mines, as well as open cast mines are excluded. Coal extraction mines or oil shale, as well as boreholes or wells opened for gas/oil exploration or extraction do not qualify under this methodology.	Beatrix is an operating mine. Beatrix is not a coal mine and is in no way involved in gas/oil exploration.	Yes
Project participants are able to demonstrate that the methane captured would have been emitted to the atmosphere in the absence of the project activity using historic records kept on exploration and prospecting activities, current safety procedures and ventilation design diagrams. The exploration plans shall be available as required evidence.	The methane would have been vented to the atmosphere. This is demonstrated by safety procedures and ventilation design diagrams	Yes
Only methane emitted from structures (mineral exploration and prospecting activities, adits, boreholes, etc.) designed and installed solely for prospecting of minerals qualifies; pre mining drainage related to minerals for which the mine was developed and is being operated does not qualify. Dedicated methane or natural gas extraction is excluded.	The boreholes were drilled solely for the prospecting of gold and not as pre-mining drainage. Information regarding the exploration borehole in terms of the descriptive log and detailed geological analysis is available.	Yes
This methodology is applicable to the following cases: *(i) Structures installed, or boreholes drilled before 2001: or* *(ii) Structures installed, or boreholes drilled after 2001 with a minimum of 5 years prior to project registration, where it could be demonstrated that the structures or the boreholes where part of a exploration plan.*	The boreholes were all drilled before 2001.	Yes
Project activities shall capture and destroy methane within the project boundary. That means, there will be no transportation, distribution or selling of methane or natural gas to	The methane will be destroyed on site and will not be transported or distributed outside the	Yes

users outside the mining site.	mining property. The small volumes of methane and remote locations do not justify any piping installation or other use of the gas.	
The measures that would increase the amount of methane emissions from the boreholes beyond the natural release as would occur in the baseline are excluded. This means forced extraction by pumping or the use of CO2 or any other fluid/gas to enhance methane drainage is excluded. If a flare is used, the lowest possible fan capacity should be established under which flare can properly operate.	No measures to increase the amount of methane emissions will be used. In cases where the methane pressure in the borehole is sufficient (at least 45-50mbar), no fan will be installed on the flare at that borehole. If a fan is required, the suction pressure of the fan will not be less than atmospheric pressure.	Yes
The methodology is not applicable to project activities generating non-mine methane if a combustion facility is used for heat and/or electricity generation.	The unpredictability of the gas flow rate, the low estimated flow rates, as well as the distance to any consumer does not justify the generation of heat or electricity from this borehole. If at any stage power generation using the non-mine methane becomes viable, a deviation will be applied for.	Yes
In addition, the applicability conditions included in the tools referred to above apply.	All tools that AM0064 refers to were adhered to.	Yes
Finally, for non-mine methane capture and destruction, the methodology is only applicable if the identified baseline scenario is a total atmospheric release of methane.	The baseline scenario is a total atmospheric release of methane.	Yes

B.3. Description of the sources and gases included in the project boundary:

>>

The *spatial extent* of the project boundary comprises:

- All equipment installed and used as part of the project activity for the extraction of the methane at the project site.
- Flaring and captive power facilities installed and used as part of the project activity.
- Power plants connected to the electricity grid, where the project activity exports or imports power from the grid, as per the definition of an electricity system in the latest approved version of the "Tool to calculate the emissions factor for an electricity system."

Mine Methane

The boundary for the capture of mine methane includes:

- Piping of the methane to the surface
- Underground monitoring stations for the methane

A diagram of the boundary for the capture of mine methane can be seen below:

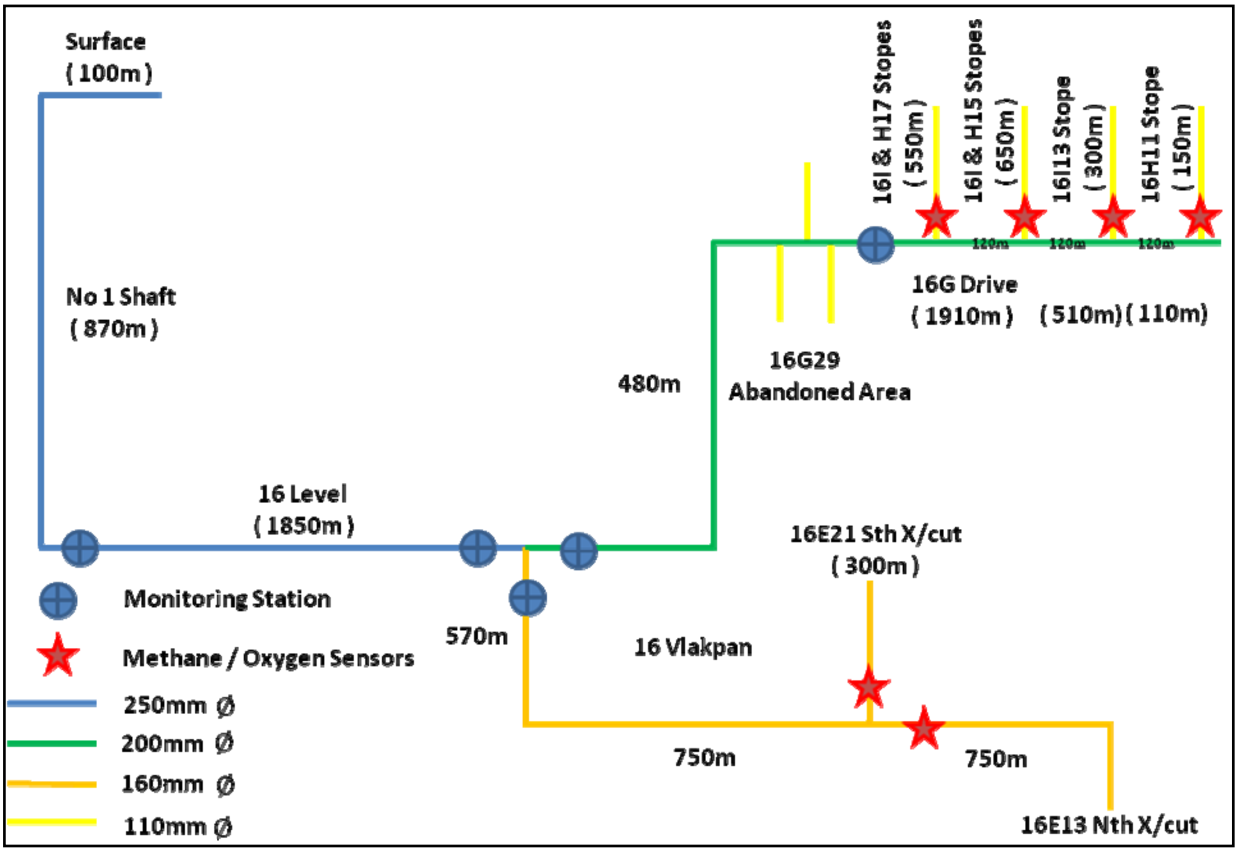

Figure 12: Underground mine methane capture

The boundary for the destruction and utilisation of mine methane includes:

- The piping of methane on the surface to the flare and internal combustion engines
- The fan on the surface used to increase the pressure of the methane
- The flare
- The internal combustion engines
- The instrumentation on the surface, which is in place for monitoring

A diagram of the boundary for the destruction and utilisation of mine methane can be seen below:

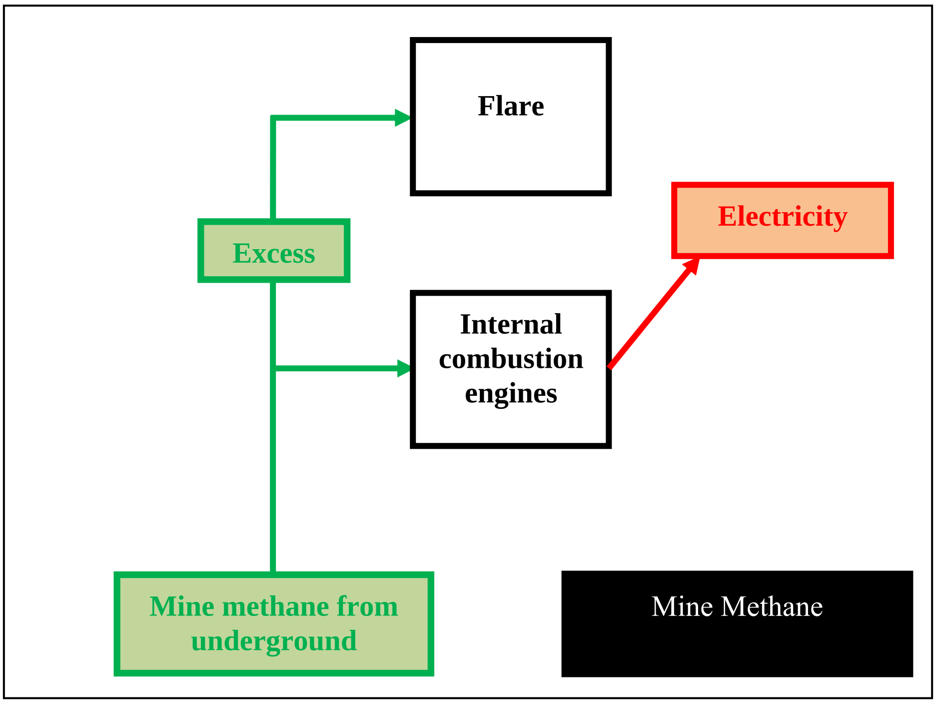

Figure 13: Destruction and utilisation of mine methane

Table 4 illustrates which emissions sources are included and which are excluded from the project boundary for determination of both baseline and project emissions.

Table 4: Overview on emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Venting of methane	CO_2	No	Excluded.
		CH_4	Yes	Emissions from the venting of mine and non-mine methane are included in the project boundary.
		N_2O	No	Excluded. There is no N_2O in the gas.
	Emissions from use or destruction of methane in the baseline	CO_2	Yes	Emissions from any flaring or use for heat generation in the baseline scenario are included in the project boundary. However, no methane was flared or used in the baseline.
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. There is no N_2O in the gas.
	Emissions from electricity generation in the grid	CO_2	Yes	Included in the project boundary as the project will generate electricity from the mine methane through engines.
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
	Emissions from captive power and/or heat generation, and vehicle fuel use	CO_2	Yes	Included in the project boundary as the project activity includes power generation from the mine methane.
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
	On-site fuel consumption due to the project activity, including transport of the gas	CO_2	Yes	The electricity used by the equipment in the project activity will be included in the project boundary. Apart from electricity, no other fossil fuels are used in the project activity.
		CH_4	No	Excluded for simplification. This emission source is assumed to be negligible.
		N_2O	No	Excluded for simplification. This emission source is assumed to be negligible.
	Emissions from methane combustion	CO_2	Yes	Emissions from the combustion of mine and non-mine methane in flares and engines will be included in the project boundary.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
a c	Emissions from NMHC	CO_2	Yes	If NMHC accounts for more than 1% by volume of extracted mine methane then the emissions from the combustion of NMHC in flares and engines must be included in the project boundary. The NMHC content of the gas will be monitored in the project activity.

	destruction	CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
	Fugitive emissions of unburned methane	CO_2	No	Excluded.
		CH_4	Yes	Small amounts of methane will remain unburned in flares and power generation. This methane will be accounted for and included in the project boundary.
		N_2O	No	Excluded.
	Fugitive methane emissions from on-site equipment	CO_2	No	Excluded for simplification. This emission source is assumed to be very small.
		CH_4	No	
		N_2O	No	
	Fugitive methane emissions from gas supply pipeline or in relation to use in vehicles	CO_2	No	Excluded for simplification. However other leakage effects are taken into account in the project.
		CH_4	No	
		N_2O	No	
	Accidental methane release	CO_2	No	Excluded for simplification. This emission source is assumed to be very small.
		CH_4	No	
		N_2O	No	

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

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The "Combined tool to identify the baseline scenario and demonstration of additionality" (version 02.2) was used to identify the baseline scenario in the following manner:

Step 1: Identification of alternative scenarios

Sub-Step 1a: Define alternative scenarios to the proposed CDM project activity

Alternative Scenarios for Mine Methane

The identified alternative baseline scenarios are:

A. Diluting the methane to safe and acceptable levels with ventilation air is technically feasible. The ventilation air methane (VAM) can then be:
   i. Vented to atmosphere as VAM;
   ii. Destroyed or used in technology that can use VAM rather than venting it;

B. Capturing of methane and extraction from underground boreholes or sealed off areas. The captured methane can then be:
   i. Captured and vented above ground in a safe location
   ii. Flared above ground
   iii. Used for additional grid or captive power generation
   iv. Used for the generation of thermal heat, such as hot and/or chilled water and/or steam
   v. Fed into gas pipeline (to be used as fuel for vehicles or heat/power generation);

vi. Used for electricity generation with the excess flared
vii. Used for electricity generation with the excess flared without being registered as a CDM project activity. This is the proposed project activity for the destruction and utilisation of mine methane without CDM.

The baseline scenario alternatives include all possible options to generate electricity:

C. For the generation of electricity:
i. Electricity can be imported from the national grid
ii. Electricity can be generated from fossil fuels other than mine methane
iii. Electricity can be generated from methane
Electricity can be generated from renewable energies

Alternative Scenarios for Non-Mine Methane

The baseline scenario alternatives for non-mine methane capture and destruction include all possible options that are technically feasible to handle non mine methane to comply with safety regulations. These options are:

D. Technically feasible options for the handling of the non-mine methane:
i. Vented to atmosphere;
ii. Destroyed or used in technology that can use methane rather than venting it;
iii. Flared;
iv. Used for additional grid or captive power generation;
v. Used for the generation of thermal heat, such as hot and/or chilled water and/or steam
vi. Fed into gas pipeline (to be used as fuel for vehicles or heat/power generation);
vii. Flaring without being registered as a CDM project activity. This is the proposed project activity for the destruction of non-mine methane without CDM.

Sub-Step 1b: Consistency with mandatory applicable laws and regulations:

All options comply with the mandatory applicable laws and regulations.

National and Sectoral Policies and Regulations Relevant to Determining the Baseline Scenario

There are no policies that require Beatrix mine to use the mine methane that is currently being diluted and vented as VAM. More relevant to the project activity is the Power Conservation Project (PCP), which, at the time of writing the PDD, is in the process of being developed by Eskom, in concert with Municipalities, Government, and customers.

The PCP is a demand side project aimed at stabilising the supply/demand balances in the system. According to Eskom, the details of the PCP are still being refined, but one of the criteria used in designing the PCP is to signal efficient use of electricity. Once this PCP is legislated, it will require the Beatrix mine to commit to reducing their grid electricity consumption. The relevance of this PCP, in the selection of the baseline scenario, is discussed below:

In EB 22 Annex 3, the Board differentiates between two types of national and/or sectoral policies that need to be taken into account when establishing the baseline scenario (paragraph 6). The second type is relevant to the PCP since it concerns energy efficiency:

Paragraph 6 (b): *National and/or sectoral policies or regulations that give comparative advantages to less emissions-intensive technologies over more emissions-intensive technologies (e.g. public subsidies to promote the diffusion of renewable energy or to finance energy efficiency programs). These policies are E- type policies that decrease GHG emissions.*

The Board then goes on to state that policies applicable under paragraph 6 (b) need not be taken into account when establishing the baseline scenario if they have been implemented since the adoption by the COP of the CDM M&P (decision 17/CP.7, 11 November 2001).

The PCP is still in development, but will, more than likely, be legislated before project implementation. However, this is after the 11 November 2001 and, as such, the PCP need not be taken into account when establishing the baseline scenario for the Beatrix mine.

To date (April 2010), the PCP has not been implemented.
STEP 2: Barrier analysis

Sub-step 2a: Identify barriers that would prevent the implementation of alternative scenarios:

A list of the alternative scenarios and the investment, technological barriers and barriers due to prevailing practice that they face is presented below:

<u>**Alternative Scenarios for the Mine Methane**</u>

Scenario Ai: The VAM can be vented to atmosphere
The mine currently dilutes the methane with ventilation air and releases it into the atmosphere. This is common practice for mine methane from gold mines. According to Hugo (1963) when referring to methane in the Orange Free State Gold-Field, *"...as much gas as possible is allowed to escape through surface bore-holes or via the exhaust ventilation systems in order to reduce the methane hazard in the mines[12]."*

This is illustrated in more detail in a report by Cook (1998), *"The normal means of dealing with accumulations and emissions are well documented (various including Greig, 1989; Eschenburg, 1980), although a part of this is based on the assumptions that gases separate depending on relative densities. The methods include ventilation, cementing or plastering fissures, water infusion of fissures, drainage and compressed air[13]."*

And, *"It is generally considered that the relatively small methane volumes can be controlled by good ventilation practice and proper detection procedures (Jackson, 1957; Kidd ,1997), and that other procedures are additional for particular circumstances[14]."*

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[12] Hugo, J.P., 1963. *Helium in the Orange Free State Gold-Field*. Geological Survey for the Department of Mines.
[13] Cook, A.P., October 1998. *The occurrence, emission and ignition of combustible strata gases in Witwatersrand gold mines and Bushveld platinum mines, and means of ameliorating related ignition and explosion hazards.* Available online from http://deepbio.princeton.edu/samp/simpros.pdf. [Accessed 11 August 2009].
[14] Cook, A.P., October 1998. *The occurrence, emission and ignition of combustible strata gases in Witwatersrand gold mines and Bushveld platinum mines, and means of ameliorating related ignition and explosion hazards.* Available online from http://deepbio.princeton.edu/samp/simpros.pdf. [Accessed 11 August 2009].

Hence, there are no barriers to this scenario and it can be considered a possible baseline scenario for the mine methane.

Scenario Aii: The VAM can be destroyed or used in technology that can use VAM rather than venting it
Using the VAM is not common practice as stated by Cook (1998), "*In general it is considered that the normal ventilation practices currently used are more than adequate to prevent any accumulation or sudden outburst of flammable gases in a working place*" and *"Good ventilation is considered to be the reason why methane intersections are kept under control. Ventilation volumes are said to be above standard and any methane appearances are dealt with effectively.*[15]*"*

The low concentration of methane in the VAM and the variability in this concentration make it difficult to use the VAM. Hence, this can be eliminated as a plausible baseline scenario.

Scenario Bi: The mine methane can be captured and vented above ground in a safe location
The mine methane is vented as VAM. Venting the mine methane not as VAM would require capturing the mine methane in its concentrated form then piping it up the shaft and finding a safe location in which to vent it. Firstly, the capturing and piping of concentrated methane would pose a safety risk to the mine. In addition, it is difficult to think of a close safe location away from the mine and farms in the area in which to vent this gas with a methane concentration above 85 volume %.

The dangers of methane are elaborated: "*Methane can be dangerous because the mixture of methane and air in a confined area can create explosive conditions! If the amount of methane in the air reaches 5 to 15 percent, an explosion can occur. If the amount of methane in the air increases even more, it can be flammable...Higher concentrations of methane in the air can also be dangerous because there is not enough oxygen for people to breathe*[16]."

Methane poses a huge safety risk to the mine and this option would increase the risk to safety at the mine. Finding a location to vent the methane is not an option as there is still a safety risk associated with the methane unless it is diluted below its explosion limits in air. This scenario is not an alternative baseline scenario.

Scenario Bii: The captured mine methane can be flared above ground
The captured mine methane can be flared above ground. This would require capturing the concentrated methane before it is diluted with ventilation air. This is not current practice in the mine. The capturing of the mine methane and piping it to surface increases the safety risk associated with the methane. It is much safer to dilute the methane at source to below its explosion limits in air and transport the VAM; which is current practice. The methane is diluted with ventilation air in the baseline. The methane is not captured and flared above ground.

Scenario Biii: The mine methane can be used for additional grid or captive power generation
The variability and unpredictability of the mine methane make it difficult to be used for additional grid or captive power generation. The mine needs a reliable power source in order to keep the miners safe underground. The variability and unpredictability of the methane is cited by Cook

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[15] Cook, A.P., October 1998. *The occurrence, emission and ignition of combustible strata gases in Witwatersrand gold mines and Bushveld platinum mines, and means of ameliorating related ignition and explosion hazards.* Available online from http://deepbio.princeton.edu/samp/simpros.pdf. [Accessed 11 August 2009].

[16] Study Hall Webmaster. 21/6/2004. *Methane Background Information*. Available online from http://education.arm.gov/studyhall/globalwarming/methane.stm. [Accessed 11 August 2009].

(1998), *"Uncertainty as to the origins and transport mechanisms of gas within the strata make emissions difficult to predict, so although the ventilation is adequate to control the normal situation, sudden emissions do create problems"* and *"The distribution of gas is across almost all mines, but to variable degrees. There is no distinct correlation between reefs, mines, depths or regions, making prediction difficult to generalise. Many individual mines and people have their own opinions where the chances of gas emissions are greater.*[17]*"*

The use of methane poses a safety risk to personnel and will require adequate training on the risks associated with methane gas. According to Cook (1998), "*There is a general lack of awareness of the hazards of methane on mines, with only four mines considering combustible gases to be a problem*" and *"Methane ignitions have long been acknowledged as a hazard in South African gold and platinum mines, but the origins and transport mechanisms of the gas have not been well understood. This lack of understanding has contributed to the hazard, making gas emissions difficult to predict and prepare for."*

Owing to the unpredictability of the mine methane flow and the hazardous nature of mine methane, this can be eliminated as a potential baseline scenario.

In addition, the generation of electricity for export to the grid would require a connection licence from Eskom. According to Eskom, *"Generators that wish to connect to the Distribution Network will be required to apply and pay for a connection and sign a connection and use-of-system agreement....Embedded generators irrespective of who the owner is, will be given non-discriminatory access to the network. This is in line with the Distribution Code and the Electricity Regulation Act. Loads and generators will be treated on a consistent basis i.e. both will be charged for dedicated and a contribution to upstream costs.*[18]*"*

The environmental management plan of the mine would need to altered in order to allow for the generation of electricity on site. This is legislated by the Mineral and Petroleum Resources Development Act, 2002[19].

Scenario Biv: The mine methane can be used for the generation of thermal heat, such as hot and/or chilled water and/or steam

Like Scenario Biii above, the use of mine methane for the generation of thermal heat is not a plausible baseline alternative owing to the unpredictability of the mine methane flow and the hazardous nature of the mine methane. Hence, this option can be eliminated as an alternative scenario.

Scenario Bv: The mine methane can be fed into a gas pipeline

The closest natural gas pipeline is 178 km in a straight line away from the site (Sasolburg)[20]. The distance over which this methane would need to be transported eliminates this scenario as a

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[17] Cook, A.P., October 1998. *The occurrence, emission and ignition of combustible strata gases in Witwatersrand gold mines and Bushveld platinum mines, and means of ameliorating related ignition and explosion hazards.* Available online from http://deepbio.princeton.edu/samp/simpros.pdf. [Accessed 11 August 2009].

[18] Eskom. *Embedded Generators*. Available online from http://www.eskom.co.za/live/content.php?Item_ID=7381&Revision=en/0. [Accessed 11 August 2009].

[19] The Mineral and Petroleum Resources Development Act, 2002. Available from http://www.dme.gov.za/pdfs/minerals/MPRDA_ACT_28_0F_2002.pdf. [Accessed on 11 August 2009].

[20] This distance was calculated online using http://distancecalculator.globefeed.com/South_Africa_Distance_Result.asp?fromplace=Sasolburg%20(Free

possible baseline scenario. The location of the natural gas pipeline from Mozambique can be seen below:

Figure 15: The route of the natural gas pipeline from Mozambique[21]

Scenario Bvi: The mine methane can be used for electricity generation with the excess flared
Scenario Biii describes the difficulty with using the mine methane for electricity generation. Please see Biii to see why this scenario can be eliminated as a plausible baseline alternative.

In addition, the generation of electricity and the flaring of mine methane will require that the environmental management plan be amended in accordance with Mineral and Petroleum Resources Development Act, 2002, *"No person may prospect for or remove, mine, conduct technical co-operation operations, reconnaissance operations, explore for and produce any mineral or petroleum or commence with any work incidental thereto on any area without— (a) an approved environmental management programme or approved environmental management plan; which is a plan to manage and rehabilitate the environmental impact as a result of prospecting, reconnaissance, exploration or mining operations conducted under the authority of a reconnaissance permission, prospecting right, reconnaissance permit, exploration right or mining permit...*[22]*"*

The generation of electricity in equipment such as an internal combustion engine would require training of personnel to operate and maintain the equipment. A service level agreement would need

%20State)&toplace=Virginia%20(Free%20State)&fromlat=-26.8135767809105&tolat=-28.1166667&fromlng=27.8169536590576&tolng=26.9. [Accessed 11 August 2009].

[21] Available from http://w3.sasol.com/natural_gas/content/images/route.jpg. [Accessed 11 August 2009].

[22] The Mineral and Petroleum Resources Development Act, 2002. Available from http://www.dme.gov.za/pdfs/minerals/MPRDA_ACT_28_0F_2002.pdf. [Accessed on 11 August 2009].

to be signed with the manufacturer of the engine to ensure that the engines were properly serviced[23].

Scenario Bvii: The mine methane can be used for electricity generation with the excess flared without being registered as a CDM project activity. This is the proposed project activity for the destruction and utilisation of mine methane without CDM.
Owing to the unpredictability and uncertainty of the methane resource, this can be eliminated as a plausible baseline scenario. Please see Scenario Biii; which discusses the uncertainty of the methane resource and safety issues related to the use of mine methane.

Scenario Ci: The electricity can be imported from the national grid
The mine already receives all of its electricity from the national grid and only has emergency generators on site. Sourcing all the electricity from the national grid is common practice and, hence, this option is a plausible baseline scenario. The mine already has all equipment in place to receive electricity from the grid. In addition, historically, grid electricity has always been cheap as demonstrated in the investment analysis for the project in the section below.

Scenario Cii: The electricity can be generated from fossil fuels other than mine methane
The possible fossil fuel options would be gas, coal, diesel and HFO.

Gas is not a feasible option as the nearest gas pipeline is about 178km away from the mine (see Scenario Bv for justification). Generating electricity from coal, diesel and HFO would require a long-term fuel-supply agreement as it is important that the mine have a constant electricity supply in order to ensure the safety of the workers underground. This fuel-supply agreement introduces risk to the project.

In addition, electricity generation using fossil fuels would require equipment like engines, boilers and generators. This equipment is costly as can be seen by the cost of the internal combustion engines that will be used in the project activity.

Hence, this option can be excluded as a possible baseline scenario.

Scenario Ciii: The electricity can be generated from methane
The variability of the mine methane eliminates this as a plausible baseline scenario. According to Cook (1998), *"Uncertainty as to the origins and transport mechanisms of gas within the strata make emissions difficult to predict, so although the ventilation is adequate to control the normal situation, sudden emissions do create problems"* and *"The distribution of gas is across almost all mines, but to variable degrees. There is no distinct correlation between reefs, mines, depths or regions, making prediction difficult to generalise. Many individual mines and people have their own opinions where the chances of gas emissions are greater.*[24]*"*

Scenario Civ: The electricity can be generated from renewable energies
The electricity could be generated from wind or solar power. However, the mine has no experience in the generation of electricity from renewable energy. All electricity is sourced from the national grid.

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[23] Please see the Service Level Agreement with General Electric Jenbacher. This would apply with other engines like MAN engines.

[24] Cook, A.P., October 1998. *The occurrence, emission and ignition of combustible strata gases in Witwatersrand gold mines and Bushveld platinum mines, and means of ameliorating related ignition and explosion hazards.* Available online from http://deepbio.princeton.edu/samp/simpros.pdf. [Accessed 11 August 2009].

In addition, there are no solar power plants in South Africa. Eskom are looking in to developing a 100MW solar power plant; which could be built in two years. If the plant is built, it will be the first solar power plant in South Africa and it will be built in Uppington; which has the best solar resource[25]. Hence, solar power is not a feasible alternative for the mine.

Wind is also not a feasible option for the mine as the wind power potential in the area is rated as low.

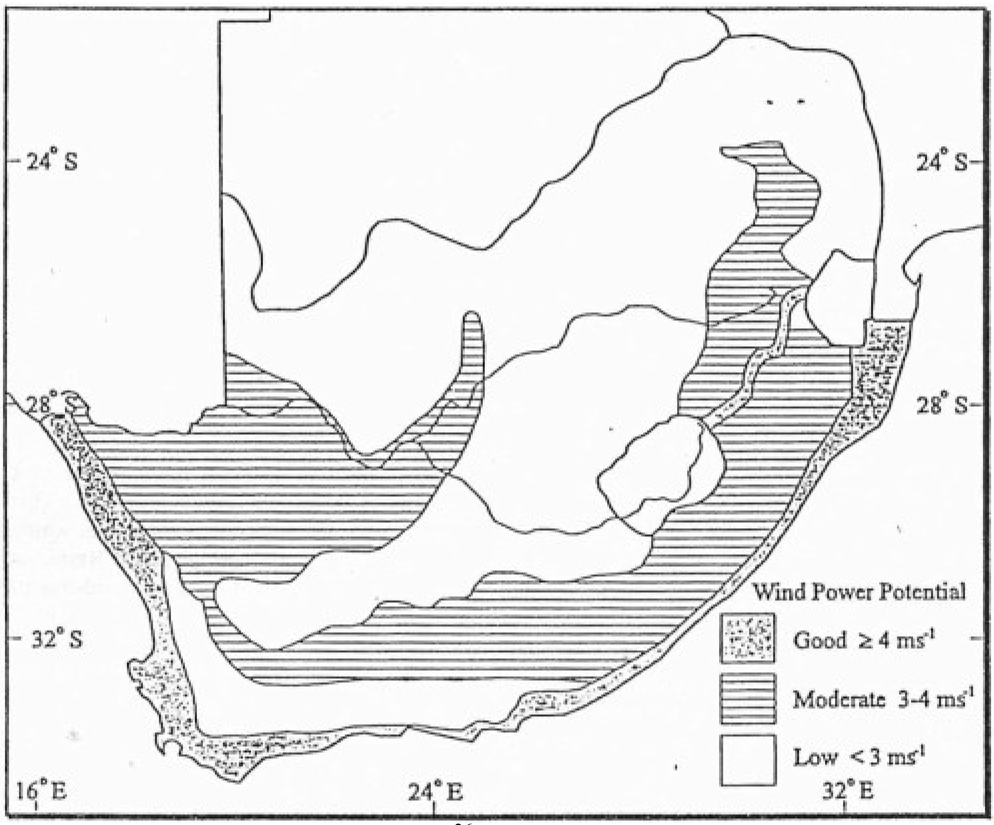

Figure 16: Wind Atlas of South Africa[26]

Generating electricity is not the core business of the mine and building and operating a renewable energy plant would require sourcing people with the right expertise. Generating electricity from renewable energy would not reduce the methane emissions from the mine. This alternative is not a plausible baseline scenario.

<u>**Alternative Scenarios for the Non-Mine Methane**</u>

Scenario Di: The non-mine methane can be vented to atmosphere

This is the current practice. The non-mine methane is released from the boreholes into the atmosphere. This scenario has no barriers and can be considered a plausible baseline scenario.

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[25] Treevolution. 6 March 2009. *Eskom decision on solar power plant imminent*. Available from http://www.treevolution.co.za/?p=2621. [Accessed on 11 August 2009].

[26] Diab, R. (1995). *Wind Atlas of South Africa.* Department of Mineral and Energy Affairs, Pretoria, 136 pp.

Scenario Dii: The non-mine methane can be destroyed or used in technology that can use methane rather than venting it

The boreholes are geographically far apart from each other and from the main shaft. If electricity and/or heat were generated from the methane then it would need to be transported to the mine. The location of the boreholes versus the location of the main shaft can be seen below:

Figure 17: Plot of the boreholes and the main shaft on Google Earth from the GPS co-ordinates

The distance between the closest borehole (2264) and the main shaft is 3 km[27]. This distance makes is difficult to transport the energy produced from the non-mine methane to the main shaft. 2264 is also one of the smaller boreholes and, hence, possible energy generation from this non-mine methane is small.

In addition, the non-mine methane flowrate varies and this makes the generation of electricity and heat from the methane unfeasible. The safety risk associated with transporting and using this methane is a considerable barrier to this alternative scenario. Hence, this can be eliminated as a plausible baseline scenario.

Scenario Diii: The non-mine methane can be flared

This is not current practice at the mine. The boreholes have been venting methane for a number of years without this methane being destroyed by the mine. The methane released from the boreholes is not a risk to the mine and its operations as a result of the distance of the boreholes from the main shaft. Hence, the mine has had no reason to flare the non-mine methane. Hence, this option can be eliminated as a possible baseline scenario.

Scenario Div: The non-mine methane can be used for additional grid or captive power generation

[27] Google Earth – Distance in a straight line

The generation of electricity from non-mine methane is not the core business of the mine. Hence, training and the sourcing of personnel with expertise in this area would be essential. The variability in the flowrate of the non-mine methane and the generally low flowrates of methane from the boreholes make it difficult to generate electricity from this non-mine methane. The distance between the boreholes and the main shaft are also a barrier to the project as either the methane or the electricity would need to be transported a fair distance. Hence, this can be eliminated as a possible baseline scenario.

Scenario Dv: The non-mine methane can be used for the generation of thermal heat, such as hot and/or chilled water and/or steam
This alternative is prohibited by the distance between the boreholes and the main shaft. The mine methane or the thermal energy would need to be transported a fair distance before reaching the user. This can also be eliminated as a potential baseline option.

Scenario Dvi: The non-mine methane can be fed into a gas pipeline
As with Scenario Bv, the closest natural gas pipeline is 178 km in a straight line away from the site (Sasolburg)[28]. This option is then prohibited by the distance over which the mine methane would need to be transported.

Scenario Dvii: The non-mine methane can be flared without being registered as a CDM project activity.
Flaring of the non-mine methane is not current practice at the mine. The boreholes have been venting methane for a number of years without this methane being destroyed by the mine. The methane released from the boreholes is not a risk to the mine and its operations as a result of the distance of the boreholes from the main shaft. Hence, the mine has had no reason to flare the non-mine methane. Hence, this option can be eliminated as a possible baseline scenario.

Sub-step 2b: Eliminate alternative scenarios which are prevented by the identified barriers:

This has been done in the analysis of the scenarios above. The only scenarios that are not eliminated as a result of the barriers are:

A i. The mine methane is vented to the atmosphere as VAM
C i. Electricity can be imported from the national grid
D i. The non-mine methane is vented to atmosphere.

The alternative scenario that does not face any barriers is the baseline scenario. Hence, the baseline scenario for Beatrix is the continuation of the current practice, which is to dilute and vent the mine methane and import electricity from the grid. The non-mine methane is released into the atmosphere.

Simply continuing with this practice has the following advantages:

- It conforms to all legal requirements provided that the mine methane is diluted sufficiently;
- No technological barriers exists as this is the accepted industry practice;
- No capital expenditure is required since the ventilation system currently in use at the Beatrix mine adequately dilutes the methane to an acceptable level; and,

[28] This distance was calculated online using http://distancecalculator.globefeed.com/South_Africa_Distance_Result.asp?fromplace=Sasolburg%20(Free%20State)&toplace=Virginia%20(Free%20State)&fromlat=-26.8135767809105&tolat=-28.1166667&fromlng=27.8169536590576&tolng=26.9. [Accessed 11 August 2009].

- It is common practice to source electricity from the national grid.

Step 3: Investment Analysis

An investment analysis was performed on the proposed project activity to determine if the project is finacially viable. The financial parameters used in the investment analysis were from October 2008 as that was the date at which validation was conducted and the investment decision was made.

Mine Methane

A financial model was built for the mine methane project. The inputs into the model are:

Parameter	**Value applied**	**Unit**	**Source of Information**	**Comments**
Index: Rand/Euro	11.17	Ratio: ZAR/€	http://www.resbank.co.za/sarbdata/rates/newmrd.asp?type=MRDIE as on 5 Dec 2009	
Index: South African Inflation in 2008	0.115	%	http://www.statssa.gov.za/keyindicators/CPI/CPIHistory_rebased.pdf	The South African Reserve Bank has set a target for the SA Consumer Price Index (CPI, "inflation rate") of between 3% and 6% per annum. The model was based on a forecast of 5%.
Index: South African Inflation - CPI as in 2009 H2	0.059	%	www.sarb.co.za as on 5 Dec 2009	
Index: South African Inflation forecast- CPI	0.05	%	www.sarb.co.za as on 5 Dec 2009	
Index: South African Inflation - PPI as in 2008	0.142	%	http://www.statssa.gov.za/publications/P01421/P01421October2009.pdf as on 5 Dec 2009	The long term producer price index was taken as being in the same order as the long term Consumer price index.
Index: South African Inflation - PPI as in H2 2009	-0.033	%	www.sarb.co.za as on 5 Dec 2009	
Index: South African Inflation - PPI	0.05	%	www.sarb.co.za as on 5 Dec 2010	
Index: Euro Inflation	0.031	%	http://www.ecb.int/stats/prices/hicp/html/inflation.en.html as on 5 Dec 2009 for the year 2008	
Index: €/CER	0	€ per ton CO2e		(taken as zero to prove additionality)

Parameter	**Value applied**	**Unit**	**Source of Information**	**Comments**
Index: Engine oil costs	20.27	R/litre	Quotation from Mobil/Engen	
Index: Eskom price	22.5	Rc/kWh	http://www.eskom.co.za/annreport09/ar_2009/info_sheets/pricing_03.htm as on 5 Dec 2009	
Index: Eskom price increase	varies per year	%	http://www.eskom.co.za/content/NERSA%20consultation%20paper%20price%20increase%20~1.pdf Para 2.4, Page 13 http://www.engineeringnews.co.za/print-version/nersa-grants-eskom-275-tariff-increase-2008-06-18	The price of electricity is taken as the price at which it can be bought from the grid. This is in turn based on the latest published prices by the National Energy Regulator of South Africa (NERSA)
Technical: Unit size of power generation plant	1.345	MW	GE Jenbacher documentation	
Technical: Number of Units	4	Number	Plant design documentation	
Technical: Parasitic load	0.024	MW per Unit	GE Jenbacher documentation	
Technical: Oil consumption	0.52	liter per MWhr	GE Jenbacher documentation	
Technical: Availability Factor	0.95	%	GE Jenbacher documentation	
Operating Cost: Spares contract	9.8	Euro per operating hour	GE Jenbacher CSA contract	
Operating Cost: Head Office Operating Indirects	1,192,933	Rands per year	Beatrix Operating Cost spreadsheet	
Operating Cost: Site Operating Indirect Costs	1,903,486	Rands per year	Beatrix Operating Cost spreadsheet	
Fixed O&M cost: Direct Operating Consumables	71,327	Rands per year	Beatrix Operating Cost spreadsheet	

Parameter	Value applied	Unit	Source of Information	Comments
Fixed O&M cost: Maintenance Costs	46,000	Rands per year	Beatrix Operating Cost spreadsheet	
Fixed O&M cost: Inspections and Testing	313,186	Rands per year	Beatrix Operating Cost spreadsheet	
Capex: Total Project Costs	72,537,060	Rands	Capital cost spreadsheet	
Capex: Rebuild cost	4,552,074	Rands	Cost of rebuild engine exchange – quotation from from GE Jenbacher	The engines must recieve a major rebuild after 60,000 hours. The value of the plant after 60,000 hours operation and before the rebuild is taken as zero.
Cost of Capital: WACC	0.12	% - Real	NATIONAL ENERGY REGULATOR OF SOUTH AFRICA In the matter regarding RENEWABLE ENERGY FEED – IN TARIFFS PHASE II by the National Energy Regulator of South Africa, page 12, (http://www.nersa.org.za/UploadedFiles/ElectricityDocuments/REFIT%20Guidelines.pdf as accessed on 5 Dec 2009)	The Weighted Average Cost of Capital as benchmark was taken from the document from NERSA as they have established objectively that this is the return required by Independant Power Producers to justify power generation projects.
Cost of Capital: Commercial Lending rates in October 2008	0.155	%	http://www.reservebank.co.za/internet/Historicdata.nsf/Mainpage?OpenPage&Click=42256DA4002CFF0E.29d44b91ee5b4df442256d860053d613/$Body/0.DF0 as accessed on 5 December 2009	The project was also benchmarked against the cost of capital taken at commercial lending rates. This is seen as a concervative aproach as the cost of capital is higher than the cost of debt.

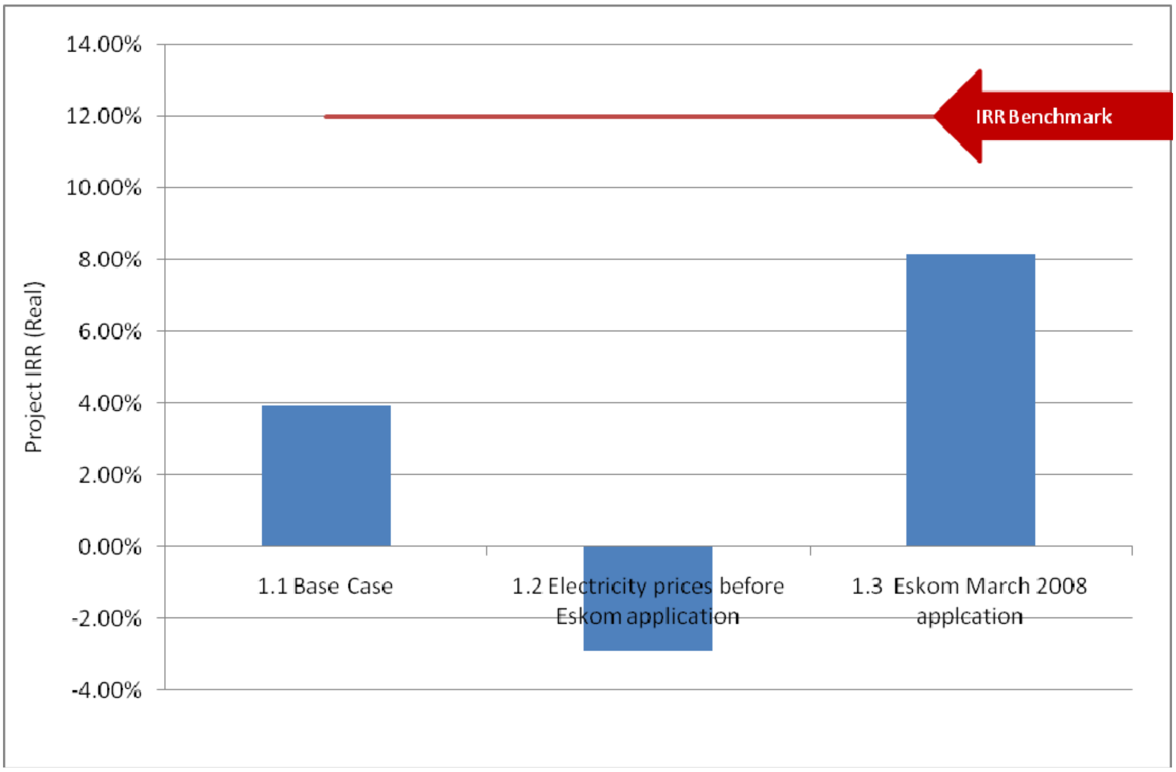
The outcome of the model is that the project returns a real IRR of 3.9% agains a real WACC of 12%. If the nominal cash flows are used and benchmarked against the commercial lending rates, the IRR is 9.5% against a benchmark of 15.5%.

Sensitivity analysis:

Electricity Price Escalation:

There has been a number of attempts by Eskom to increase the price of power. These have been used to run sensitivities on the project.

Scenario	Comments	Price increases		Source	Real IRR as compared to the real WACC of 12%
1.1 Base Case	The base case is the last official price publication by the National Energy Regulator of South Africa at the time of the validation of the project	2009	34.2%	http://www.nersa.org.za/UploadedFiles/RegulatorsDecisions/Reasons%20for%20Decision%20Eskom%20Price%20Increase%2018%20June%202008.pdf, page 2 as accessed on 5 Dec 2009	3.92%
		2010	13%		
		2011	5%		
		etc	5%		
1.2 Electricity prices before Eskom application	This is the case on which the planning of the project was based up to 17 March 2008 when Eskom applied for a 60% increase in the price of electricity	2009	14%	http://www.nersa.org.za/documents/Aide%20Memoir%20MYPD%20Rule%20Change%2020%20Dec%202007.pdf, page 2 as accessed on 5 Dec 2009	-2.9%
		2010	13%		
		2011	5%		
		etc	5%		
1.3 Eskom March 2008 applcation	This case represents the application by Eskom for a 60% price increase in April 2008. This increase was not granted – see Case 1.1 above	2009	60%	http://www.eskom.co.za/content/Eskom%20Draft%20Application~1.pdf	8.18%
		2010	13%		
		2011	5%		
		etc	5%		



Capital Cost:

A sensitivity analysis was run to see what capital cost reduction would be required to make the project viable without carbon credit revenue. The outcome is that a capital cost reduction from R72.5 million to R44 million (39% reduction) is required to increase the IRR to the benchmark real WACC of 12% .

<u>Non-Mine Methane</u>

The capital cost of the borehole flares has been made available to the validators. The only revenue from the non-mine methane is the CERs. Hence, the carbon credits are needed to make this project financially viable. This makes the project additional.

Step 4: Common practice analysis

Globally, various projects are at different stages of development to utilize coal mine methane (CMM) for power generation. These projects are being developed as CDM projects. At least six of these projects are being executed in China. The proposed Beatrix project is a deviation from these projects since Beatrix is a gold mine and the methane released is not related to the amount of gold mined.

Beatrix will be the first gold mine to use the methane for electricity generation in South Africa. All methane from South African gold mines is simply diluted and vented. This is referenced in a letter from the Chamber of Mines of South Africa. This letter can be seen in Annex 5.

The internal combustion engines that will be used in the project activity have been used at only two other CDM registered projects in South Africa. These projects are:

- PetroSA Biogas to Energy Project (Project 0446); and
- Durban Landfill Gas-to-Electricity Project – Mariannhill and La Mercy (Project 0545).

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality):

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The "Combined tool to identify the baseline scenario and demonstration of additionality" (version 02.2) was used to demonstrate that the proposed project activity is additional.

Section B.4. lists the alternatives scenarios and the barriers that these scenarios face. Apart from the identified baseline, the alternatives scenarios, including the proposed project activity, face barriers. Therefore, all the other alternative scenarios, including the proposed project activity, are additional.

The additionality of the proposed project activity is further illustrated by the barriers listed below:

A complete list of barriers that would prevent the proposed project activity from occurring are listed below:

Investment barriers *inter alia*:

- Codes such as the mineral resource quantification code of the JSE Securities Exchange (where Gold Fields is listed as GFI Mining South Africa (Pty) Ltd) or other international codes such as JORC are required by the investment community. When considering these codes, it is clear that the investment of capital in the available methane resources is not justifiable. This is because of the unpredictable nature of the methane occurrence. The proposed project, which involves the use of methane, therefore, is very difficult to fund in terms of conventional mining finance.
- The unquantifiable and unpredictable nature of the mine methane makes debt funding of the proposed project extremely difficult.
- Return on investment for a methane utilization project is low, particularly on a perceived risk-adjusted basis, in comparison with the alternative uses of this available capital.
- Financial projections for the proposed project suggest that, even under optimistic assumptions, the cost to generate electricity will be higher than the average cost of electricity from the national provider (Eskom).
- The proposed project will require capital expenditure that would not be required in the continuation of the baseline.
- An investment analysis was performed in Section B.4.

Technological barriers, *inter alia*:

- The unpredictability of methane supply is a barrier to the project activity. The flowrate of the methane is expected to vary and the continuation of the release of methane is not a certainty. This poses risks in terms of plant capacity and investment. According to Head and Kissell, "*Unlike coal mines, methane emission rates in metal/non-metal mines are not consistent. This irregularity often makes an accumulation of methane an unexpected event, and an unexpected event by definition is difficult to anticipate.*[29]"
- The internal combustion engines require specialist labour and infrastructure

[29] See document entitled cap 13 available at http://www.bvsde.paho.org/bvsacd/cd67/2006-127/cap13.pdf

Barriers due to prevailing practice, *inter alia*:

- The project activity is the "first of its kind" in South Africa. This is demonstrated by the letter from the Chamber of Mines that is in Section B.4.
- Generating electricity is not part of the normal skill set of a mining activity.
- Largely because of the low cost of electricity and technological barriers, most mine operators in South Africa have not really considered the possibility of generating electricity from mine methane. Due to the delocalization of the methane sources and the unpredictability of the methane supply, it is not ideal for use as a fuel source and has not, to date, been used as fuel source.
- There is no legislative pressure to use the energy content from the methane. South African laws only make provision for safety issues regarding methane venting. Even where utilization has been identified as a priority, current legal policies offer little or no incentive for using mine methane to generate electricity.
- There is no policy or regulations preventing the release of methane in South Africa. In terms of the Mines Health and Safety Act employers and employees are obliged to identify hazards and eliminate, control or minimise the risk to health and safety. Operational experience on Beatrix has led the management to believe that the sealing off of surface holes forces methane that would have escaped on surface to escape into working areas. This increases the risk of workers in these working areas. The sealing of surface holes is therefore not allowed by management.

Registering the proposed project activity as a CDM project will alleviate the identified barriers in the following ways:

Alleviating the Investment barriers *inter alia*:
The carbon credit revenue will lower the financial risks associated with the project and, therefore, aid in overcoming the identified investment barriers.

The only financial benefit that this project will have, without carbon credit revenue, is the displacement of electricity by using mine methane. As was stated earlier, the relatively cheap price of South African grid electricity does not make the use of mine methane attractive. The carbon credit revenue will make the use of mine methane feasible.

Alleviating the Technological barriers, *inter alia*:
The technological barriers are linked to the operators of the technology. The additional revenue can also be used to cover the costs associated with the training of staff required to operate the specialised equipment.

Alleviating the Barriers due to prevailing practice, *inter alia*:
As was stated, this project is the "first of its kind" in South Africa. The additional carbon credit revenue will make the project attractive to investors despite this risk.

<u>Additionality of project activity</u>
The proposed project activity is additional. This is demonstrated by the barrier analysis. Investment, technological and common practice barriers were identified. These barriers are overcome by the registration of the project as a CDM project. Therefore, the proposed capture and use of the Beatrix mine methane and the destruction of the Beatrix non-mine methane satisfies the CDM additionality criteria.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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The emission reduction (ER), baseline emission (BE), project emission (PE) and leakage emissions (LE) are calculated as set out below:

<u>Baseline emissions for mine methane capture and utilization or destruction</u>

$$BE_y = BE_{MD,y} + BE_{MR,y} + BE_{Use,y} \quad \textbf{(1)}$$

Where:

BE_y	Baseline emissions in year y (tCO_2e/yr)
$BE_{MD,y}$	Baseline emissions from the destruction of methane in the baseline scenario in year y (tCO_2e/yr)
$BE_{MR,y}$	Baseline emissions from the release of methane into the atmosphere in year y that is avoided by the project activity (tCO_2e/yr)
$BE_{Use,y}$	Baseline emissions from the production of power and/or heat displaced by the project activity in year y (tCO_2e/yr)

In the baseline, no methane is used for any heat or electricity generation. Methane destruction in the baseline only occurs if the gas is ignited by accident. This accidental methane destruction is not desirable and is stopped as soon as possible for safety reasons. (This leads to $BE_{MD,y} = 0$.)

In the baseline, all methane was simply vented to atmosphere as ventilation air methane. The baseline emissions due to the ventilation of the methane will be captured in the $BE_{MR,y}$.

In the proposed project activity, the methane will be used to generate electricity. Excess methane will be flared. The generation of electricity will displace grid electricity used in the baseline. This will be captured in the $BE_{Use,y}$ term.

Equation 1 becomes:

$$BE_y = BE_{MR,y} + BE_{Use,y} \quad \textbf{(1.1)}$$

<u>Baseline emissions from the release of methane into the atmosphere:</u>

Baseline emissions from the venting of methane were calculated as follows:

$$BE_{MR,y} = GWP_{CH4} \times \sum_i \left[\left(MM_{PR,i,y} - MM_{BL,i,y}\right) + \left(VAM_{PR,i,y} - VAM_{BL,i,y}\right)\right] \quad \textbf{(6)}$$

Where:

$BE_{MR,y}$	Baseline emissions from the release of methane into the atmosphere in year y that is avoided by the project activity (tCO_2e/yr)
GWP_{CH4}	Global Warming Potential of methane
$MM_{PR,i,y}$	Mine methane captured, sent to and destroyed by use i in the project activity in year y (tCH_4/yr)
$MM_{BL,i,y}$	Mine methane that would have been captured, sent to and destroyed by use i in the baseline scenario in year y (tCH_4/yr)
$VAM_{PR,i,y}$	VAM captured, sent to and destroyed by use i in the project activity in year y (tCH_4)

$VAM_{BL,i,y}$ VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in year y (tCH_4)

No ventilation air methane (VAM) is used in the baseline (BL) or in the project case (PR). The result is that:

$VAM_{PR,i,y} = 0$
$VAM_{BL,i,y} = 0$

No mine methane (MM) is captured and used in the baseline (BL). The result is:

$MM_{BL,i,y} = 0$

Combustion engines and flaring of excess methane will take place in the project case (PR). Therefore, including the uses of methane, Equation 6 simplifies to equation 6.1:

$$BE_{MR,y} = GWP_{CH4} \times \left(MM_{PR,engine,y} + MM_{PR,flare,y} \right) \quad \textbf{(6.1)}$$

Where:
$MM_{PR,engine,y}$ Mine methane captured, sent to and destroyed by internal combustion engines in the project activity in year y (tCH_4/yr)
$MM_{PR,flare,y}$ Mine methane captured, sent to and destroyed by flare in the project activity in year y (tCO_2e/yr)

Baseline emissions from power generation by project activity:

The proposed project activity will generate electricity. The electricity generated will displace electricity that was sourced from the national grid in the baseline. No captive power generation occurred in the baseline. Equation 7 originally stated:

$$BE_{Use,y} = GEN_y \times EF_{ELEC,y} + HEAT_y \times EF_{HEAT,y} + VFUEL_y \times EF_{V,y} + ABS_y \times \frac{COP_{ABS}}{COP_{ELEC}} \times EF_{ELEC,y}$$

(7)

Where:
$BE_{Use,y}$ Baseline emissions from the production of power or heat replaced by the project activity in year y (tCO_2e/yr)
GEN_y Electricity generated by the project activity in year y (MWh)
$EF_{ELEC,y}$ Emission factor for electricity generation (grid, captive or a combination) replaced by the project activity (tCO_2/MWh)
$HEAT_y$ Heat generation by project activity in year y (GJ)
$EF_{HEAT,y}$ Emission factor for heat generation replaced by the project activity (tCO_2/GJ)
$VFUEL_y$ Vehicle fuel provided by the project activity in year y (GJ)
$EF_{V,y}$ Emission factor for vehicle operation replaced by the project activity (tCO_2/GJ)
ABS_y Chilling produced in project activity by absorption chillers in year y (MWh)
COP_{ABS} Coefficient of performance of the absorption chiller (MW thermal input / MW thermal output)
COP_{ELEC} Coefficient of performance of the electrical chillers used in the baseline Chillers (MW electrical input / MW thermal output)

4Only electricity is generated, equation 7 simplifies to:

$$BE_{Use,y} = GEN_y \times EF_{ELEC,y} \tag{7.1}$$

The project activity will displace grid electricity.

The emission factor for the grid electricity was calculated in accordance with the latest approved version of the "Tool for calculation of emission factor for electricity systems," Version 02. The steps applied to determine the emission factor for the grid were as follows:

Step 1: Identify the relevant electric power system
The project electricity system includes the power plants that are physically connected through transmission and distribution lines to the project activity and that can be displaced without significant transmission constraints. South Africa is the host country for the project activity and the national boundary of the country is also the grid boundary. The project activity sources electricity from the South African national electricity grid.

Step 2: Chose whether to include off-grid power plants in the project electricity system (optional)
The grid emission factor is calculated from only grid power plants (Option I). Off-grid power plants are not included in the calculations.

Step 3: Select an operating margin method
The OM is calculated using the simple OM method (Option (a)). The simple OM method can be used provided that the low-cost/must-run resources constitute less than 50% of the total grid generation in average of the five most recent years.

If adding the Eskom and non-Eskom low-cost/must-run resources, the total percentage amount to 6.16% of the total grid generation in average of the five most recent years. Therefore, Option (a) is applicable to the situation in South Africa.

In terms of data vintages, the *ex ante* option were chosen to calculate the simple OM. In this option a 3 year generation-weighted average are used for the grid power plants. Using this option also means that the emission factor is determined only once at the validation stage, thus no monitoring and recalculation is required during the crediting period.

The data used in OM calculations are for the 3 year period of 1 April 2006 – 31 March 2009 (Eskom financial year is from 1 April – 31 March).

Step 4: Calculation of the operating margin emission factor
Option B is used for calculating the simple OM. The calculations in this option are based on the total net electricity generation of all power plants serving the system and the fuel types and fuel consumption of the project electricity system. Option B is used seeing that:

a) The necessary data for Option A (electricity generation and emission factor for each power unit) is not available; and
b) Only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is know; and

Off-grid power plants are not included in the calculation.

Equation 7 (in the methodological tool) is used to calculate the simple OM:

$$EF_{grid,OMsimple,y} = \frac{\sum_i \left(FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y}\right)}{EG_y}$$ **(GEF Tool[30] Eq. 7)**

Where:

$EF_{grid, OMsimple,y}$	=	CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$FC_{i,y}$	=	Amount of fossil fuel type i consumed by power plant/unit m in year y (mass or volume unit)
$NCV_{i,y}$	=	Net calorific value (energy content) fossil fuel type i in year y (GJ/mass or volume)
$EF_{CO2,i,y}$	=	CO_2 emission factor of fossil fuel type i in year y (tCO_2/GJ)
EG_y	=	Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units, in year y (MWh)
i	=	All fossil fuel types combusted in power sources in the project electricity system in year y
y	=	The relevant year as per data vintage chosen in Step 3.

Step 5: Identify the cohort of power units to be included in the build margin
The sample of power units *m* used to calculate the build margin consists of either:

(a) The set of five power units that have been built most recently, or
(b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and have been built most recently.

The set of power plants that comprise the larger annual generation should be used.

Option (b) is not viable seeing that non-Eskom data is not available for any vintage after 2006. All the commissioning dates of the power plants are available; therefore Option (a) is used.

In order to determine the vintage of data, one of the following options must be selected:

Option 1: For the first crediting period, calculate the build margin emission factor *ex ante* based on the most recent information available at the time of CDM-PDD submission to the DOE for validation.
Option 2: For the first crediting period, the build margin emission factor shall be updated annually, *ex post*, including those units built up to the year of registration of the project activity.

Option 1 is used for this project due to the lack consistent data from the same vintage for the Eskom and non-Eskom power plants.

Step 6: Calculate the build margin emission factor

[30] UNFCCC methodological tool for the grid emission factor (GEF), “Tool for calculation of emission factor for electricity systems,” Version 02.

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units *m* during the most recent year *y* for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$ **(GEF Tool Eq. 13)**

Where:

$EF_{grid,BM,y}$	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)
$EF_{EL,m,y}$	CO_2 emission factor of power unit *m* in year *y* (tCO_2/GJ)
M	Power units included in the build margin
y	The relevant year as per data vintage chosen in Step 3.

The CO_2 emission factor of each power unit m ($EL_{EL,m,y}$) should be determined as per the guidance in step 3(a) for the simple OM, using option A1 using for y the most recent historical year for which power generation data is available, and using for m the power units included in the build margin.

If for a power unit *m* data on fuel consumption and electricity generation is available the emission factor ($FE_{EL,m,y}$) should be determined as follows:

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_m EG_{m,y}}$$ **(GEF Tool Eq. 2)**

Where:

$EF_{EL,m,y}$	CO_2 emission factor of power unit *m* in year *y* (tCO_2/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) fossil fuel type *i* in year y (GJ/mass or volume)
$EF_{CO2,i,y}$	CO_2 emission factor of fossil fuel type *i* in year y (tCO_2/GJ)
$EG_{m,y}$	Net electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)
m	All power plants/units serving the grid in year y except low-cost/must-run power plants/units
i	All fossil fuel types combusted in power plant/unit m in year y
y	The relevant year as per data vintage chosen in Step 3.

Step 7: Calculate the combined margin emission factor
The combined margin factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM}$$ **(GEF Tool Eq. 14)**

Where:

$EF_{grid,BM,y}$	Build Margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$	Operating margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM}	Weighting of operating margin emissions factor (%)
w_{BM}	Weighting of build margin emissions factor (%)

Please see the document entitled '*Calculation of the Emission Factor for the South African Grid*' for a detailed calculation of the grid emission factor.

Equation 9 is presented below:

$$EF_{ELEC,y} = s_{grid,y} \times EF_{grid,y} + s_{captive} \times EF_{captive,y}$$ **(9)**

Where:

$EF_{ELEC,y}$	CO_2 baseline emission factor for the electricity displaced due to the project activity during the year y (tCO_2/MWh)
$EF_{grid,y}$	CO_2 baseline emission factor for the grid electricity displaced due to the project activity during the year y (tCO_2/MWh)
$EF_{captive,y}$	CO_2 baseline emission factor for the captive electricity displaced due to the project activity during the year y (tCO_2/MWh)
s_{grid}	Share of the electricity demand supplied by the grid imports over the last 3 years (%)
$s_{captive}$	Share of facility electricity demand supplied by captive power over the last 3 years (%)

Taking in consideration that all electricity in the baseline is sourced from the grid:

S_{grid} = 100%
$S_{captive}$ = 0%

The project activity will not replace any new or existing captive generation electricity generation. The result is that:

$EF_{captive,y} = 0$

This implies that Equation 9 can be simplified to Equation 7.2:

$$EF_{ELEC,y} = EF_{grid,y}$$ **(7.2)**

Where:

$EF_{ELEC,y}$	Emission factor for electricity generation (grid, captive or a combination) replaced by the project activity (tCO_2/MWh)
$EF_{grid,y}$	CO_2 baseline emission factor for the grid electricity displaced due to the project activity during the year y (tCO_2/MWh)

Baseline emissions for non-mine methane capture and destruction:

Historically, all methane from exploration boreholes was emitted to atmosphere.

$$BE_y = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000} \quad \textbf{(12)}$$

BE_y	Baseline emissions in year y (tCO2e)
GWP_{CH4}	Global warming potential for methane (value of 21)
$TM_{RG,h}$	Mass flow rate of methane in the residual gas (in the “*Tool to determine project emissions from flaring gases containing methane”* it is defined as the gas stream flowing to the flare) in the hour h (kg/h)
1/1000	Factor to convert kg/year to ton/year

The “*Tool to determine project emissions from flaring gases containing methane*” was used to calculate the mass flowrate of methane in the residual gas.

Project emissions due to project activities recovering mine methane

Project emissions are defined by the following equation:

$$PE_y = PE_{ME,y} + PE_{MD,y} + PE_{UM,y} \quad \textbf{(13)}$$

Where:

PE_y	Project emissions in year y (tCO_2e/yr)
$PE_{ME,y}$	Project emissions from energy use to capture and use methane in year y(tCO_2e/yr)
$PE_{MD,y}$	Project emissions from methane destroyed in year y (tCO_2e/yr)
$PE_{UM,y}$	Project emissions from un-combusted methane in year y (tCO_2e/yr)

Project emissions from the use of additional energy required for MM/VAM capture and utilisation

Additional energy was required to capture, transport and compress, use or destruct the mine methane. Project emissions from the use of this energy were calculated as follows:

$$PE_{ME,y} = PE_{ELEC,y} + PE_{FF,y} \quad \textbf{(14)}$$

Where:

$PE_{ELEC,y}$	Project emissions from the use of electricity for capture, transportation, compression and utilisation or destruction of MM/VAM in year y (tCO_2e/yr). Calculated in accordance with the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption"
$PE_{FF,y}$	Project emissions from the combustion of fossil fuels for capture, transportation, compression and utilisation or destruction of MM/VAM in year y (tCO_2e/yr). Calculated in accordance with the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"

No fossil fuel will be used for the capture, transportation, compression, utilisation or destruction of MM/VAM in the project activity. Hence, $PE_{FF,y} = 0$.

The mine methane captured will be pumped to surface. The pumping will be done by using an electrical blower. To calculate $PE_{ELEC,y}$, AM0064 states that the *"Tool to calculate baseline, project and/or leakage emissions from electricity consumption"* (Version 01) must be used. The application of this tool can be seen in Annex 4.

Project emissions from the combustion of MM/VAM

AM0064 states that when the captured mine methane is burned in a flare, heat or power plant, or oxidized in a catalytic oxidation unit, emissions from combustion are released. (In addition, if non methane hydro carbons (NMHC) account for more than 1% by volume of the extracted MM or more than 0.1% by volume of the extracted VAM, combustion emissions from these gases should also be included.) The project emissions (PE) from mine methane destruction (MD) are then accounted for as follows:

$$PE_{MD,y} = \left(MD_{FL,y} + MD_{OX,y} + MD_{ELEC,y} + MD_{HEAT,y} + MD_{GAS,y}\right) \times \left(CEF_{CH4} + r \times CEF_{NMHC}\right) \quad \textbf{(15)}$$

Where:

$PE_{MD,y}$	Project emissions from MM/VAM destroyed in year y (tCO_2e/yr)
$MD_{FL,y}$	Amount of methane destroyed through flaring in year y (tCH_4/yr)
$MD_{OX,y}$	Amount of methane destroyed through catalytic oxidation in year y (tCH_4/yr)
$MD_{ELEC,y}$	Amount of methane destroyed through power generation in year y (tCO_2e/yr)
$MD_{HEAT,y}$	Amount of methane destroyed through heat generation in year y (tCO_2e/yr)
$MD_{GAS,y}$	Amount of methane destroyed after being supplied to gas grid or for vehicle use in year y (tCH_4)
CEF_{CH4}	Carbon emission factor for combusted methane (2.75 tCO_2/tCH_4)
CEF_{NMHC}	Carbon emission factor for combusted non methane hydrocarbons (the concentration varies and, therefore, to be obtained through periodical analysis of captured methane) ($tCO_2/tNMHC$)
r	Relative proportion of NMHC compared to methane $r=PC_{NMHC}/PC_{CH4}$
PC_{CH4}	Concentration (in mass) of methane in extracted gas (%), measured on wet basis
PC_{NMHC}	NMHC concentration (in mass) in extracted gas (%)

No mine methane will be:

- Destroyed through catalytic oxidation ($MD_{OX,y} = 0$)
- Supplied to a gas grid or used as vehicle fuel ($MD_{GAS,y} = 0$)
- Destroyed through heat generation ($MD_{HEAT,y} = 0$)

Equation 15 then simplifies to Equation 15.1:

$$PE_{MD,y} = \left(MD_{FL,y} + MD_{ELEC,y}\right) \times \left(CEF_{CH4} + r \times CEF_{NMHC}\right) \quad \textbf{(15.1)}$$

Furthermore, gas analysis indicated that non-methane hydrocarbons (NMHCs) accounts for 0.22% of the composition. Therefore, the NMHCs are below the 1% threshold for the ex-ante calculation of the emission reductions and are assumed negligible. Therefore, they are excluded. However, they will be monitored in the project activity. Equation 14.1 is simplified further to Equation 14.2:

$$PE_{MD,y} = \left(MD_{FL,y} + MD_{ELEC,y}\right) \times \left(CEF_{CH4}\right) \quad \textbf{(15.2)}$$

AM0064 states that the amount of methane destroyed by each application depends on the efficiency of combustion in that application.

Firstly, the mine methane destroyed by the flare is determined:

$$MD_{FL,y} = MMES_{FL,y} - \frac{PE_{flare,y}}{GWP_{CH4}} \quad \textbf{(16)}$$

Where:

$MD_{FL,y}$	Amount of methane destroyed through flaring in year y (tCH_4)
$MMES_{FL,y}$	Amount of methane measured sent to flare in year y (tCH_4)
$PE_{flare,y}$	Project emissions of non-combusted CH_4, expressed in terms of tCO_2e, from flaring of the residual gas stream in year y (tCO_2e)
GWP_{CH4}	Global warming potential of methane (21 tCO_2/tCH_4)

The project emissions of non-combusted CH_4 expressed in terms of CO_2e from flaring of the residual gas stream ($PE_{flare,y}$) was calculated following the procedures described in the "*Tool to determine project emissions from flaring gases containing methane*" (Version: not stated. Origin: EB 28, Annex 13). The calculations of the project emissions of non-combusted CH_4 can be found in Annex 4.

Secondly, the mine methane destroyed through electricity generation is determined:

$$MD_{ELEC,y} = MMES_{ELEC,y} \times Eff_{ELEC} \quad \textbf{(20)}$$

Where:

$MMES_{ELEC,y}$	Amount of methane measured sent to power plant in year y (tCH_4)
Eff_{ELEC}	Efficiency of methane destruction/oxidation in power plant

Project emissions from un-combusted methane

$$PE_{UM,y} = \left[GWP_{CH4} \times \sum_i MMES_{i,y} \times \left(1 - Eff_i\right) \right] + PE_{flare,y} + PE_{OX,y} \times GWP_{CH4} \quad \textbf{(23)}$$

Where:

$PE_{UM,y}$	Project emissions from un-combusted methane in year y (tCO_2e)
GWP_{CH4}	Global warming potential of methane (21 tCO_2e/tCH_4)
$MMES_{i,y}$	Methane measured sent to use i in year y (tCH4)
Eff_i	Efficiency of methane destruction in use i (%)
$PE_{flare,y}$	Project emissions of non-combusted CH_4, expressed in terms of tCO_2e, from the residual gas stream (tCO_2e)
$PE_{OX,y}$	Project emissions of non oxidized CH4 from catalytic oxidation of the VAM stream in year y (tCH_4)

As applied to this project, Equation 23 becomes:

$$PE_{UM,y} = \left[GWP_{CH4} \times MMES_{ELEC} \times \left(1 - Eff_{ELEC}\right) \right] + PE_{flare,y} \quad \textbf{(23.1)}$$

Where:

$MMES_{ELEC,y}$	Amount of methane measured sent to power plant in year y (tCH_4)
Eff_{ELEC}	Efficiency of methane destruction/oxidation in power plant

<u>Project emissions due to project activities recovering non-mine methane:</u>

Project emissions are defined by the following equation:

$$PE_y = PE_{ME,y} + PE_{MD,y} + PE_{UM,y} \tag{24}$$

Where:

PE_y	Project emissions in year y (tCO_2e/yr)
$PE_{ME,y}$	Project emissions from energy use to capture and use methane in year y(tCO_2e/yr)
$PE_{MD,y}$	Project emissions from methane destroyed in year y (tCO_2e/yr)
$PE_{UM,y}$	Project emissions from un-combusted methane in year y (tCO_2e/yr)

$$PE_{ME,y} = PE_{ELEC,y} + PE_{FF,y} \tag{25}$$

Where:

$PE_{ELEC,y}$	Project emissions from the use of electricity for the operation of the facilities installed by the project in year y calculated in accordance with the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" (tCO_2)
$PE_{FF,y}$	Project emissions from the combustion of fossil fuels for the operation of the facilities installed by the project in year y (tCO_2e/yr). Calculated in accordance with the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" (tCO_2e)

There is no electricity used for the operation of the borehole flares and instrumentation. Each of the flares is equipped with a solar panel. There is no fossil fuel consumption for the operation of the non-mine methane facilities. Hence,

$$PE_{ME,y} = 0$$

Project emissions from methane destroyed (combusted methane) in year *y* ($PE_{MD,y}$) was determined as follows:

$$PE_{MD,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \left(\eta_{flare,h}\right) \times \frac{CEF_{CH4}}{1000} \tag{26}$$

CEF_{CH4}	Carbon emission factor for combusted methane (2.75 tCO_2/tCH_4)
η_{flare}	Flare efficiency in hour h, according to the "Tool to determine project emissions from flaring gases containing methane"
$TM_{RG,h}$	Mass flow rate of methane in the residual gas (in the tool it is defined as the gas stream flowing to the flare) in the hour h (kg/h)

1/1000 Factor to convert kg/year to ton/year

A default flare efficiency according to the "Tool to determine project emissions from flaring gases containing methane" was used for all of the borehole flares.

Project emissions in year y from un-combusted methane in accordance with the "Tool to determine project emission from flaring gases containing methane." were determined as follows:

$$PE_{UM,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \left(1 - \eta_{flare,h}\right) \times \frac{GWP_{CH4}}{1000} \qquad (27)$$

GWP_{CH4}	Global warming potential for methane (value of 21)
η_{flare}	Flare efficiency in hour h, according to the "Tool to determine project emissions from flaring gases containing methane"
$TM_{RG,h}$	Mass flow rate of methane in the residual gas (in the tool it is defined as the gas stream flowing to the flare) in the hour h (kg/h)
1/1000	Factor to convert kg/year to ton/year

Leakage due to project activities recovering mine methane

AM0064 states that ***"Leakage may occur if the project activity prevents MM/VAM from being used to meet the baseline thermal energy demand, whether as a result of physical constraints on delivery, or price changes."*** No mine methane (MM) was used in the baseline.

Such displacement resulting in leakage does not occur and the project activity does not ***"cause increased emissions outside the project boundary associated with meeting thermal energy demand with other fuels."***

AM0064 states that ***"because of likely day-to-day fluctuations in MM/VAM extraction rates, to ensure a conservative result, CERs should not be calculated solely from annual data. Any CERs generated from methane destruction should be calculated using daily logs, or monthly logs if daily data are not available, of project-case demand for MM/VAM for nonthermal uses compared against estimates of the baseline MM/VAM demand for thermal uses. For each day (or month) of the crediting period, this form of leakage must be calculated if:"***

$$ME_k - \left(MMES_{ELEC,k} + MMES_{HEAT,k}\right) < TH_k \qquad (28)$$

Where:

ME_k	Methane extracted on day k (tCH_4)
$MMES_{HEAT,k}$	Methane measured sent to new heat generation uses on day k in the project scenario that would not have been sent in the baseline scenario on day k (tCH_4)
$MMES_{ELEC,k}$	Methane measured sent to power plant on day k (tCH_4)
TH_k	Methane used to serve thermal energy demand in the baseline for day k (tCH_4)

No mine methane is used in the baseline ($TH_k = 0$) and

It is furthermore not possible for the sum of methane sent to heat generation equipment ($MMES_{HEAT,k}$) and the methane sent to electricity generation equipment ($MMES_{ELEC,k}$) to be more than the methane extracted (ME_k). The result is that:

$$ME_k - \left(MMES_{ELEC,k} + MMES_{HEAT,k}\right) \geq 0 \quad \textbf{(28.1)}$$

Taking into consideration that $TH_k = 0$, the implication is that no leakage occurs in this project activity.

$$LE_y = Q_{AF} \times NCV_{AF} \times EF_{AF} \times OXID \quad \textbf{(32)}$$

Where:

LE_y	Leakage emissions in year y (tCO_2e/yr)
$Q_{AF,y}$	Quantity of alternative fuels displaced by the project activity in year y (tonnes or m^3)
NCV_{AF}	Net calorific value for alternative fuels (GJ/tonne or m3)
EF_{AF}	Emissions factor for alternative fuel (tCO_2/GJ) sourced from IPCC
OXID	Oxidation efficiency of combustion (%), sourced from IPCC

Since $Q_{AF,y}$ is zero. The result is that:

$$LE_y = 0 \quad \textbf{(32.1)}$$

Leakage due to project activities recovering non-mine methane:

No leakage is considered as in accordance with AM0064 version 02.

Emission reductions

The emission reduction ER_y by the project activity during a given year y is the difference between the baseline emissions (BE_y) and project emissions (PE_y). The leakage emissions (LE_y) in this project activity are zero as no activity which uses methane occurred in the baseline. No baseline methane application was thus displaced. The emission reduction is calculated as below:

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(33)}$$

Where:

ER_y	Emission reductions in year y (tCO_2e/yr)
BE_y	Baseline emissions in year y (tCO_2e/yr)
PE_y	Project emissions in year y (tCO_2e/yr)
LE_y	Leakage emissions in year y (tCO_2e/yr)

B.6.2. Data and parameters that are available at validation:

The following table with values is reproduced from the flaring tool:

Parameter	SI Unit	Description	Value
MM_{CH4}	kg/kmol	Molecular mass of methane	16.04
MM_{CO}	kg/kmol	Molecular mass of carbon monoxide	28.01
MM_{CO2}	kg/kmol	Molecular mass of carbon dioxide	44.01
MM_{O2}	kg/kmol	Molecular mass of oxygen	32
MM_{H2}	kg/kmol	Molecular mass of hydrogen	2.02
MM_{N2}	kg/kmol	Molecular mass of nitrogen	28.02
AM_c	kg/kmol (g/mol)	Atomic mass of carbon	12
AM_h	kg/kmol (g/mol)	Atomic mass of hydrogen	1.01
AM_o	kg/kmol (g/mol)	Atomic mass of oxygen	16
AM_n	kg/kmol (g/mol)	Atomic mass of nitrogen	14.01
P_n	Pa	Atmospheric pressure at normal conditions	101 325
R_u	$Pa.m^3/kmol.K$	Universal ideal gas constant	8 314.472
T_n	K	Temperature at normal conditions	273.15
MF_{O2}	Dimensionless	O2 volumetric fraction of air	0.21
GWP_{CH4}	t_{CO2}/t_{CH4}	Global warming potential of methane	21
MV_n	$m^3/Kmol$	Volume of one mole of any ideal gas at normal	22.414

Data / Parameter:	s_{grid}
Data unit:	percentage
Description:	Percentage of the electricity demand supplied by the grid imports for the 3 years preceding the implementation of the project.
Source of data used:	Current and historical mining operations at Beatrix mine.
Value applied:	100%
Justification of the choice of data or description of measurement methods and procedures actually applied :	No captive electricity generation occurs in the baseline. Historically, all electricity is sourced from the national grid.
Any comment:	

Data / Parameter:	$s_{captive}$
Data unit:	percentage
Description:	Percentage of the electricity demand supplied by captive electricity generation for the 3 years preceding the implementation of the project.
Source of data used:	Current and historical mining operations at Beatrix mine.
Value applied:	0%
Justification of the choice of data or description of	No captive electricity generation occurs in the baseline. Historically, all electricity is sourced from the national grid.

measurement methods and procedures actually applied :	
Any comment:	

Data / Parameter:	CEF_{CH4}
Data unit:	tCO_2/tCH_4
Description:	Carbon emission factor for combusted methane
Source of data used:	As stated in AM0064
Value applied:	2.75
Justification of the choice of data or description of measurement methods and procedures actually applied :	Ex ante value stated in AM0064
Any comment:	44/16 = 2.75 tCO_2e/tCH_4

Data / Parameter:	Eff_{ELEC}
Data unit:	Percentage
Description:	Efficiency of methane destruction/oxidation in power plant
Source of data used:	IPCC default value as stated in AM0064
Value applied:	99.5%
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value as stated in AM0064
Any comment:	

Data / Parameter:	TH_{BL}
Data unit:	tCH_4
Description:	Average annual thermal demand over the past 5 years (tCH_4)
Source of data used:	Current and historical mining operations at Beatrix mine
Value applied:	0
Justification of the choice of data or description of measurement methods and procedures actually applied :	Historically the baseline scenario had no thermal demand.
Any comment:	

B.6.3. Ex-ante calculation of emission reductions:

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The calculations presented in this section were based on:

Mine Methane

- A project start date (i.e. implementation of the flare) of 11 March 2010 as per the project plan;
- Flaring occurs in the first phase of the project, which runs from March to November 2010;
- Electricity generation and flaring occur in the second phase of the project, which runs from 1 November 2010 to the end of the crediting period.
- The main flare will have all the monitoring equipment necessary to calculate the actual combustion efficiency as per the "Tool to determine project emissions from flaring gases containing methane." This per the quote obtained for the flare[31].

- **Non-Mine Methane**The borehole flares will be installed and commissioned by the 11 March 2010 as per the project plan.
- The flares will be enclosed flares and have a default flare efficiency of 90% as per the "Tool to determine project emissions from flaring gases containing methane." The flares for ST23 and EX1 will have the capability of being retrofitted at a later stage with monitoring equipment to monitor the actual combustion efficiency of the flares. For the purpose of the ex-ante calculation of the emission reductions, the borehole flares will assume a 90% default flare efficiency. Refer to Annex 5 for the flare specifications.

Baseline emissions for mine methane capture and utilization or destruction

Equation 1:

$$BE_y = BE_{MD,y} + BE_{MR,y} + BE_{Use,y}$$

Year	BE_y	$BE_{MD,y}$	$BE_{MR,y}$	$BE_{Use,y}$
11 Mar 2010 – 31 Dec 2010	126,958.61	0	123,352.29	3,606.32
1 Jan 2011 – 31 Dec 2011	203,623.29	0	161,940.23	41,683.07
1 Jan 2012 – 31 Dec 2012	203,623.29	0	161,940.23	41,683.07
1 Jan 2013 – 31 Dec 2013	203,623.29	0	161,940.23	41,683.07
1 Jan 2014 – 31 Dec 2014	203,623.29	0	161,940.23	41,683.07
1 Jan 2015 – 31 Dec 2015	203,623.29	0	161,940.23	41,683.07
1 Jan 2016 – 31 Dec 2016	203,623.29	0	161,940.23	41,683.07
1 Jan 2017 – 10 Mar 2017	41,004.47	0	32,589.72	8,414.75

Equation 3:

$$r = \frac{PC_{NMHC}}{PC_{CH4}}$$

Year	r	PC_{NMHC}	PC_{CH4}
11 Mar 2010 – 31 Dec 2010	0.00503	0.38%	75%

[31] The manufacturer and technical specifications of the flare is subject to change as the project has not yet entered detailed design. It is likely that the quote obtained for the mine methane flare will be accepted and the flare ordered, but this has not happened to date.

1 Jan 2011 – 31 Dec 2011	0.00503	0.38%	75%
1 Jan 2012 – 31 Dec 2012	0.00503	0.38%	75%
1 Jan 2013 – 31 Dec 2013	0.00503	0.38%	75%
1 Jan 2014 – 31 Dec 2014	0.00503	0.38%	75%
1 Jan 2015 – 31 Dec 2015	0.00503	0.38%	75%
1 Jan 2016 – 31 Dec 2016	0.00503	0.38%	75%
1 Jan 2017 – 10 Mar 2017	0.00503	0.38%	75%

Equation 6:

$$BE_{MR,y} = GWP_{CH4} \times \left(MM_{PR,engine,y} + MM_{PR,flare,y}\right)$$

Year	$BE_{MR,y}$	GWP_{CH4}	$MM_{PR,engine,y}$	$MM_{PR,flare,y}$
11 Mar 2010 – 31 Dec 2010	123,352.29	21	625.59	5,248.33
1 Jan 2011 – 31 Dec 2011	161,940.23	21	7,230.77	480.67
1 Jan 2012 – 31 Dec 2012	161,940.23	21	7,230.77	480.67
1 Jan 2013 – 31 Dec 2013	161,940.23	21	7,230.77	480.67
1 Jan 2014 – 31 Dec 2014	161,940.23	21	7,230.77	480.67
1 Jan 2015 – 31 Dec 2015	161,940.23	21	7,230.77	480.67
1 Jan 2016 – 31 Dec 2016	161,940.23	21	7,230.77	480.67
1 Jan 2017 – 10 Mar 2017	32,589.72	21	1,459.71	92.18

Equation 7:

$$BE_{Use,y} = GEN_{y} \times EF_{ELEC,y}$$

Year	$BE_{Use,y}$	GEN_{y}	$EF_{ELEC,y}$
11 Mar 2010 – 31 Dec 2010	3,606.32	3,679.92	0.98
1 Jan 2011 – 31 Dec 2011	41,683.07	42,533.74	0.98
1 Jan 2012 – 31 Dec 2012	41,683.07	42,533.74	0.98
1 Jan 2013 – 31 Dec 2013	41,683.07	42,533.74	0.98
1 Jan 2014 – 31 Dec 2014	41,683.07	42,533.74	0.98
1 Jan 2015 – 31 Dec 2015	41,683.07	42,533.74	0.98
1 Jan 2016 – 31 Dec 2016	41,683.07	42,533.74	0.98
1 Jan 2017 – 10 Mar 2017	8,414.75	8,586.48	0.98

Equation 9:

$$EF_{ELEC,y} = s_{grid} \times EF_{grid,y} + s_{captive} \times EF_{captive,y}$$

Year	$EF_{ELEC,y}$	s_{grid}	$EF_{grid,y}$	$s_{captive}$	$EF_{captive,y}$
11 Mar 2010 – 31 Dec 2010	0.98	1	0.98	0	0
1 Jan 2011 – 31 Dec 2011	0.98	1	0.98	0	0
1 Jan 2012 – 31 Dec 2012	0.98	1	0.98	0	0
1 Jan 2013 – 31 Dec 2013	0.98	1	0.98	0	0

1 Jan 2014 – 31 Dec 2014	0.98	1	0.98	0	0
1 Jan 2015 – 31 Dec 2015	0.98	1	0.98	0	0
1 Jan 2016 – 31 Dec 2016	0.98	1	0.98	0	0
1 Jan 2017 – 10 Mar 2017	0.98	1	0.98	0	0

Baseline emissions for non-mine methane capture and destruction:

$$BE_y = BE_{EX1,y} + BE_{ST23,y} + BE_{2264,y} + BE_{DBE1,y} + BE_{1400,y}$$

Year	BE_y	$BE_{EX1,y}$	$BE_{ST23,y}$	$BE_{2264,y}$
11 Mar 2010 – 31 Dec 2010	77,629.12	25,075.94	34,552.87	4,113.33
1 Jan 2011 – 31 Dec 2011	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2012 – 31 Dec 2012	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2013 – 31 Dec 2013	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2014 – 31 Dec 2014	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2015 – 31 Dec 2015	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2016 – 31 Dec 2016	96,049.59	31,026.16	42,751.86	5,089.37
1 Jan 2017 – 10 Mar 2017	18,420.47	5,950.22	8,198.99	976.04

Year	$BE_{1400,y}$	$BE_{DBE1,y}$
11 Mar 2010 – 31 Dec 2010	9,167.60	4,719.39
1 Jan 2011 – 31 Dec 2011	11,342.96	5,839.24
1 Jan 2012 – 31 Dec 2012	11,342.96	5,839.24
1 Jan 2013 – 31 Dec 2013	11,342.96	5,839.24
1 Jan 2014 – 31 Dec 2014	11,342.96	5,839.24
1 Jan 2015 – 31 Dec 2015	11,342.96	5,839.24
1 Jan 2016 – 31 Dec 2016	11,342.96	5,839.24
1 Jan 2017 – 10 Mar 2017	2,175.36	1,119.85

Equation 12a: Borehole EX1

$$BE_{EX1,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000}$$

Year	$BE_{EX1,y}$	$TM_{RG,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	25,075.94	168.66	21

1 Jan 2011 – 31 Dec 2011	31,026.16	168.66	21
1 Jan 2012 – 31 Dec 2012	31,026.16	168.66	21
1 Jan 2013 – 31 Dec 2013	31,026.16	168.66	21
1 Jan 2014 – 31 Dec 2014	31,026.16	168.66	21
1 Jan 2015 – 31 Dec 2015	31,026.16	168.66	21
1 Jan 2016 – 31 Dec 2016	31,026.16	168.66	21
1 Jan 2017 – 10 Mar 2017	5,950.22	168.66	21

Equation 12b: Borehole ST23

$$BE_{ST23,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000}$$

Year	$BE_{ST23,y}$	$TM_{RG,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	34,552.87	232.40	21
1 Jan 2011 – 31 Dec 2011	42,751.86	232.40	21
1 Jan 2012 – 31 Dec 2012	42,751.86	232.40	21
1 Jan 2013 – 31 Dec 2013	42,751.86	232.40	21
1 Jan 2014 – 31 Dec 2014	42,751.86	232.40	21
1 Jan 2015 – 31 Dec 2015	42,751.86	232.40	21
1 Jan 2016 – 31 Dec 2016	42,751.86	232.40	21
1 Jan 2017 – 10 Mar 2017	8,198.99	232.40	21

Equation 12c: Borehole DBE1

$$BE_{DBE1,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000}$$

Year	$BE_{DBE1,y}$	$TM_{RG,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	4,719.39	31.74	21
1 Jan 2011 – 31 Dec 2011	5,839.24	31.74	21
1 Jan 2012 – 31 Dec 2012	5,839.24	31.74	21
1 Jan 2013 – 31 Dec 2013	5,839.24	31.74	21
1 Jan 2014 – 31 Dec 2014	5,839.24	31.74	21
1 Jan 2015 – 31 Dec 2015	5,839.24	31.74	21
1 Jan 2016 – 31 Dec 2016	5,839.24	31.74	21
1 Jan 2017 – 10 Mar 2017	1,119.85	31.74	21

Equation 12d: Borehole 2264

$$BE_{2264,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000}$$

Year	$BE_{2264,y}$	$TM_{RG,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	4,113.33	27.67	21
1 Jan 2011 – 31 Dec 2011	5,089.37	27.67	21

1 Jan 2012 – 31 Dec 2012	5,089.37	27.67	21
1 Jan 2013 – 31 Dec 2013	5,089.37	27.67	21
1 Jan 2014 – 31 Dec 2014	5,089.37	27.67	21
1 Jan 2015 – 31 Dec 2015	5,089.37	27.67	21
1 Jan 2016 – 31 Dec 2016	5,089.37	27.67	21
1 Jan 2017 – 10 Mar 2017	976.04	27.67	21

Equation 12e: Borehole 1400

$$BE_{1400,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \frac{GWP_{CH4}}{1000}$$

Year	$BE_{1400,y}$	$TM_{RG,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	9,167.60	61.66	21
1 Jan 2011 – 31 Dec 2011	11,342.96	61.66	21
1 Jan 2012 – 31 Dec 2012	11,342.96	61.66	21
1 Jan 2013 – 31 Dec 2013	11,342.96	61.66	21
1 Jan 2014 – 31 Dec 2014	11,342.96	61.66	21
1 Jan 2015 – 31 Dec 2015	11,342.96	61.66	21
1 Jan 2016 – 31 Dec 2016	11,342.96	61.66	21
1 Jan 2017 – 10 Mar 2017	2,175.36	61.66	21

<u>Project emissions due to project activities recovering mine methane</u>

Equation 13:

$$PE_y = PE_{ME,y} + PE_{MD,y} + PE_{UM,y}$$

Year	PE_y	$PE_{ME,y}$	$PE_{MD,y}$	$PE_{UM,y}$
11 Mar 2010 – 31 Dec 2010	48,540.82	866.57	11,403.54	36,270.71
1 Jan 2011 – 31 Dec 2011	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2012 – 31 Dec 2012	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2013 – 31 Dec 2013	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2014 – 31 Dec 2014	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2015 – 31 Dec 2015	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2016 – 31 Dec 2016	26,646.36	1,581.59	20,625.07	4,439.70
1 Jan 2017 – 10 Mar 2017	5,317.63	303.32	4,155.20	859.11

Equation 14:

$$PE_{ME,y} = PE_{ELEC,y} + PE_{FF,y}$$

Year	$PE_{ME,y}$	$PE_{ELEC,y}$	$PE_{FF,y}$
11 Mar 2010 – 31 Dec 2010	866.57	866.57	0
1 Jan 2011 – 31 Dec 2011	1,581.59	1,581.59	0
1 Jan 2012 – 31 Dec 2012	1,581.59	1,581.59	0

1 Jan 2013 – 31 Dec 2013	1,581.59	1,581.59	0
1 Jan 2014 – 31 Dec 2014	1,581.59	1,581.59	0
1 Jan 2015 – 31 Dec 2015	1,581.59	1,581.59	0
1 Jan 2016 – 31 Dec 2016	1,581.59	1,581.59	0
1 Jan 2017 – 10 Mar 2017	303.32	303.32	0

Equation 15:

$$PE_{MD,y} = \left(MD_{FL,y} + MD_{ELEC,y}\right) \times \left(CEF_{CH4} + r \times CEF_{NMHC}\right)$$

Year	$PE_{MD,y}$	$MD_{FL,y}$	$MD_{ELEC,y}$	CEF_{CH4}
11 Mar 2010 – 31 Dec 2010	11,403.54	3,524.28	622.46	2.75
1 Jan 2011 – 31 Dec 2011	20,625.07	305.41	7,194.62	2.75
1 Jan 2012 – 31 Dec 2012	20,625.07	305.41	7,194.62	2.75
1 Jan 2013 – 31 Dec 2013	20,625.07	305.41	7,194.62	2.75
1 Jan 2014 – 31 Dec 2014	20,625.07	305.41	7,194.62	2.75
1 Jan 2015 – 31 Dec 2015	20,625.07	305.41	7,194.62	2.75
1 Jan 2016 – 31 Dec 2016	20,625.07	305.41	7,194.62	2.75
1 Jan 2017 – 10 Mar 2017	4,155.20	58.57	1,452.41	2.75

Equation 16:

$$MD_{FL,y} = MMES_{FL,y} - \frac{PE_{flare,y}}{GWP_{CH4}}$$

Year	$MD_{FL,y}$	$MMES_{FL,y}$	$PE_{flare,y}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	3,524.28	5,248.33	36,205.02	21
1 Jan 2011 – 31 Dec 2011	305.41	480.67	3,680.47	21
1 Jan 2012 – 31 Dec 2012	305.41	480.67	3,680.47	21
1 Jan 2013 – 31 Dec 2013	305.41	480.67	3,680.47	21
1 Jan 2014 – 31 Dec 2014	305.41	480.67	3,680.47	21
1 Jan 2015 – 31 Dec 2015	305.41	480.67	3,680.47	21
1 Jan 2016 – 31 Dec 2016	305.41	480.67	3,680.47	21
1 Jan 2017 – 10 Mar 2017	58.57	92.18	705.84	21

Equation 20:

$$MD_{ELEC,y} = MMES_{ELEC,y} \times Eff_{ELEC}$$

Year	$MD_{ELEC,y}$	$MMES_{ELEC,y}$	Eff_{ELEC}
11 Mar 2010 – 31 Dec 2010	622.46	625.59	99.5%
1 Jan 2011 – 31 Dec 2011	7,194.62	7,230.77	99.5%
1 Jan 2012 – 31 Dec 2012	7,194.62	7,230.77	99.5%
1 Jan 2013 – 31 Dec 2013	7,194.62	7,230.77	99.5%
1 Jan 2014 – 31 Dec 2014	7,194.62	7,230.77	99.5%
1 Jan 2015 – 31 Dec 2015	7,194.62	7,230.77	99.5%

1 Jan 2016 – 31 Dec 2016	7,194.62	7,230.77	99.5%
1 Jan 2017 – 10 Mar 2017	1,452.41	1,459.71	99.5%

Equation 23:

$$PE_{UM,y} = \left[GWP_{CH4} \times MMES_{ELEC} \times \left(1 - Eff_{ELEC}\right)\right] + PE_{flare,y}$$

Year	$PE_{UM,y}$	$MMES_{ELEC,y}$	Eff_{ELEC}	$PE_{flare,y}$
11 Mar 2010 – 31 Dec 2010	36,270.71	625.59	99.5%	36,205.02
1 Jan 2011 – 31 Dec 2011	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2012 – 31 Dec 2012	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2013 – 31 Dec 2013	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2014 – 31 Dec 2014	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2015 – 31 Dec 2015	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2016 – 31 Dec 2016	4,439.70	7,230.77	99.5%	3,680.47
1 Jan 2017 – 10 Mar 2017	859.11	1,459.71	99.5%	705.84

Year	$PE_{OX,y}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	0	21
1 Jan 2011 – 31 Dec 2011	0	21
1 Jan 2012 – 31 Dec 2012	0	21
1 Jan 2013 – 31 Dec 2013	0	21
1 Jan 2014 – 31 Dec 2014	0	21
1 Jan 2015 – 31 Dec 2015	0	21
1 Jan 2016 – 31 Dec 2016	0	21
1 Jan 2017 – 10 Mar 2017	0	21

<u>Project emissions due to project activities recovering non-mine methane:</u>

Equation 24:

$$PE_y = PE_{ME,y} + PE_{MD,y} + PE_{UM,y}$$

Year	PE_y	$PE_{ME,y}$	$PE_{MD,y}$	$PE_{UM,y}$
11 Mar 2010 – 31 Dec 2010	16,912.06	0	9,149	7,762.91
1 Jan 2011 – 31 Dec 2011	20,925.09	0	11,320	9,604.96
1 Jan 2012 – 31 Dec 2012	20,925.09	0	11,320	9,604.96
1 Jan 2013 – 31 Dec 2013	20,925.09	0	11,320	9,604.96
1 Jan 2014 – 31 Dec 2014	20,925.09	0	11,320	9,604.96
1 Jan 2015 – 31 Dec 2015	20,925.09	0	11,320	9,604.96
1 Jan 2016 – 31 Dec 2016	20,925.09	0	11,320	9,604.96
1 Jan 2017 – 10 Mar 2017	4,013.03	0	2,171	1,842.05

Equation 25:

$$PE_{ME,y} = PE_{ELEC,y} + PE_{FF,y}$$

Year	$PE_{ME,y}$	$PE_{ELEC,y}$	$PE_{FF,y}$
11 Mar 2010 – 31 Dec 2010	0	0	0
1 Jan 2011 – 31 Dec 2011	0	0	0
1 Jan 2012 – 31 Dec 2012	0	0	0
1 Jan 2013 – 31 Dec 2013	0	0	0
1 Jan 2014 – 31 Dec 2014	0	0	0
1 Jan 2015 – 31 Dec 2015	0	0	0
1 Jan 2016 – 31 Dec 2016	0	0	0
1 Jan 2017 – 10 Mar 2017	0	0	0

Equation 26:

$$PE_{MD,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \left(\eta_{flare,h}\right) \times \frac{CEF_{CH4}}{1000}$$

Year	$PE_{MD,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	CEF_{CH4}
11 Mar 2010 – 31 Dec 2010	9,149	522.12	0.90	2.75
1 Jan 2011 – 31 Dec 2011	11,320	522.12	0.90	2.75
1 Jan 2012 – 31 Dec 2012	11,320	522.12	0.90	2.75
1 Jan 2013 – 31 Dec 2013	11,320	522.12	0.90	2.75
1 Jan 2014 – 31 Dec 2014	11,320	522.12	0.90	2.75
1 Jan 2015 – 31 Dec 2015	11,320	522.12	0.90	2.75
1 Jan 2016 – 31 Dec 2016	11,320	522.12	0.90	2.75
1 Jan 2017 – 10 Mar 2017	2,171	522.12	0.90	2.75

Equation 27:

$$PE_{UM,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \left(1 - \eta_{flare,h}\right) \times \frac{GWP_{CH4}}{1000}$$

Year	$PE_{UM,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	7,762.91	522.12	0.90	21
1 Jan 2011 – 31 Dec 2011	9,604.96	522.12	0.90	21
1 Jan 2012 – 31 Dec 2012	9,604.96	522.12	0.90	21
1 Jan 2013 – 31 Dec 2013	9,604.96	522.12	0.90	21
1 Jan 2014 – 31 Dec 2014	9,604.96	522.12	0.90	21
1 Jan 2015 – 31 Dec 2015	9,604.96	522.12	0.90	21
1 Jan 2016 – 31 Dec 2016	9,604.96	522.12	0.90	21
1 Jan 2017 – 10 Mar 2017	1,842.05	522.12	0.90	21

<u>Leakage due to project activities recovering mine methane</u>

Equation 28:

$$ME_k - \left(MMES_{ELEC,k} + MMES_{HEAT,k}\right) < TH_k$$

Year	ME_k	$MMES_{ELEC,k}$	$MMES_{HEAT,k}$	TH_k
11 Mar 2010 – 31 Dec 2010	19.77	-	0	0
1 Jan 2011 – 31 Dec 2011	21.20	20.85	0	0
1 Jan 2012 – 31 Dec 2012	21.20	20.85	0	0
1 Jan 2013 – 31 Dec 2013	21.20	20.85	0	0
1 Jan 2014 – 31 Dec 2014	21.20	20.85	0	0
1 Jan 2015 – 31 Dec 2015	21.20	20.85	0	0
1 Jan 2016 – 31 Dec 2016	21.20	20.85	0	0
1 Jan 2017 – 10 Mar 2017	21.20	20.85	0	0

Emission reductions

Equation 33:

$$ER_y = BE_y - PE_y - LE_y$$

Year	ER_y	BE_y	PE_y	LE_y
11 Mar 2010 – 31 Dec 2010	139,135	204,588	65,453	0
1 Jan 2011 – 31 Dec 2011	252,101	299,673	47,571	0
1 Jan 2012 – 31 Dec 2012	252,101	299,673	47,571	0
1 Jan 2013 – 31 Dec 2013	252,101	299,673	47,571	0
1 Jan 2014 – 31 Dec 2014	252,101	299,673	47,571	0
1 Jan 2015 – 31 Dec 2015	252,101	299,673	47,571	0
1 Jan 2016 – 31 Dec 2016	252,101	299,673	47,571	0
1 Jan 2017 – 10 Mar 2017	50,094	59,425	9,331	0

B.6.4 Summary of the ex-ante estimation of emission reductions:

>>

Year	**Estimation of project activity emissions (tonnes of CO_2 e)**	**Estimation of baseline emissions (tonnes of CO_2 e)**	**Estimation of leakage (tonnes of CO_2 e)**	**Estimation of overall emission reductions (tonnes of CO_2 e)**
11 Mar 2010 – 31 Dec 2010	65,453	204,588	0	139,135
1 Jan 2011 – 31 Dec 2011	47,571	299,673	0	252,101
1 Jan 2012 – 31 Dec 2012	47,571	299,673	0	252,101
1 Jan 2013 – 31 Dec 2013	47,571	299,673	0	252,101
1 Jan 2014 – 31 Dec	47,571	299,673	0	252,101

2014				
1 Jan 2015 – 31 Dec 2015	47,571	299,673	0	252,101
1 Jan 2016 – 31 Dec 2016	47,571	299,673	0	252,101
1 Jan 2017 – 10 Mar 2017	9,331	59,425	0	50,094
Total (tonnes of CO_2 e)	**360,212**	**2,062,050**	**0**	**1,701,838**

B.7. Application of the monitoring methodology and description of the monitoring plan:

The monitoring plan will ensure that project emission reductions are accurately monitored, recorded and reported. The onsite monitoring as well as calibration/verification of measurement equipment will be the responsibility of the operations manager. The data will be collected on site and archived both on site and off site. Promethium Carbon, the CDM project developer, will be responsible for calculating the emission reductions and drafting of the monitoring report.

The monitoring plan below is divided into two sections: mine methane and non-mine methane monitoring.

Mine Methane Monitoring Plan

1. **Data to be monitored.**

The monitoring equipment and the placing of the equipment in the project are shown in the diagram below. The following parameters will be monitored as per the applied monitoring methodology:

- The flowrate of the gas sent to the engines and the flare
- The methane concentration in the extracted gas
- The NMHC concentration in the extracted gas
- The composition of the gas going to the flare
- The oxygen and methane concentration of the exhaust gas from the flare
- The temperature of the flare
- The electricity produced by the engines
- The electricity consumption of the plant

The monitoring equipment is depicted in the diagram below:

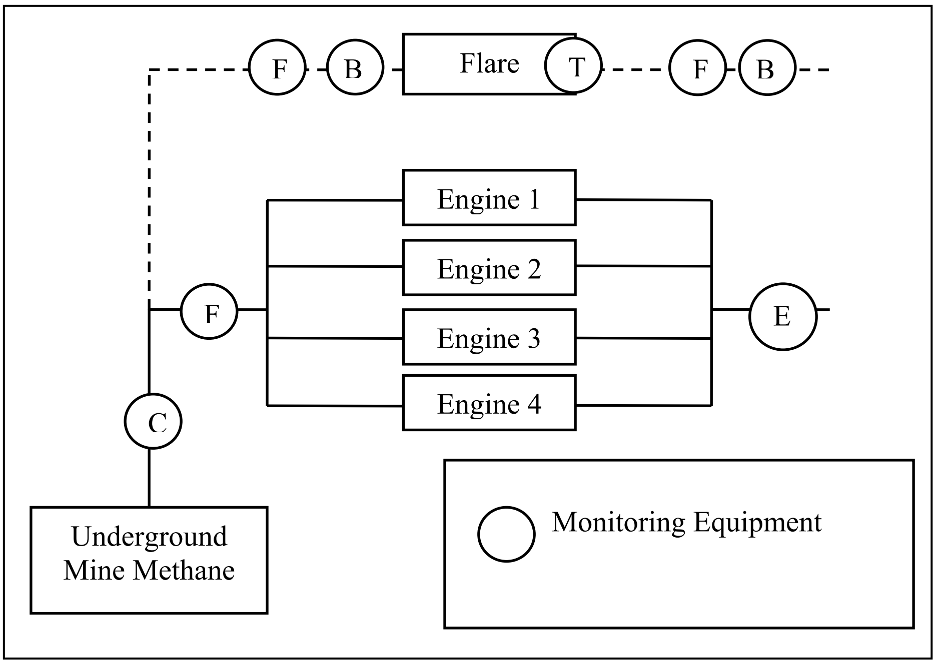


Figure 14: Mine Methane Monitoring System

In addition, the electricity consumption of the plant will be monitored continuously.

A description of the symbols appears below:

Symbol	Description	Function
B	Methane and Oxygen Concentration Meter	Measure CH_4 and O_2 concentration of gas
F	Gas Flow Meter	Measure gas flowrate sent to generators and flares
T	Thermocouple	Measures the temperature of the flare to ensure correct operation
E	Electricity Meter	Measure electricity generated by the engines
C	Gas composition	Measuring the composition of the gas (CH_4, NMHC). The gas will be sampled every 3 months and tested for the NMHC concentration.

The below ground monitoring stations for the collection of the underground mine methane are shown in figure 15 below. These stations are to ensure the safety of the underground workers.

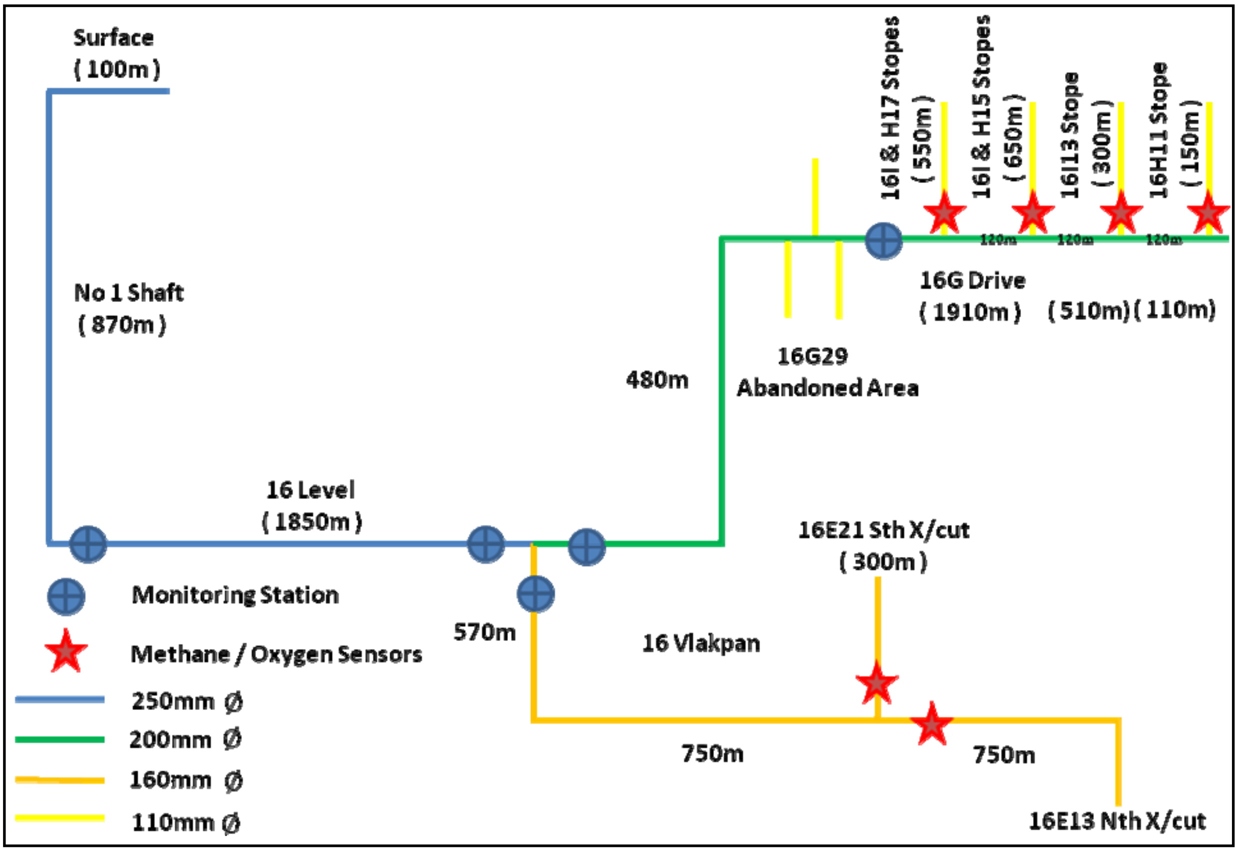


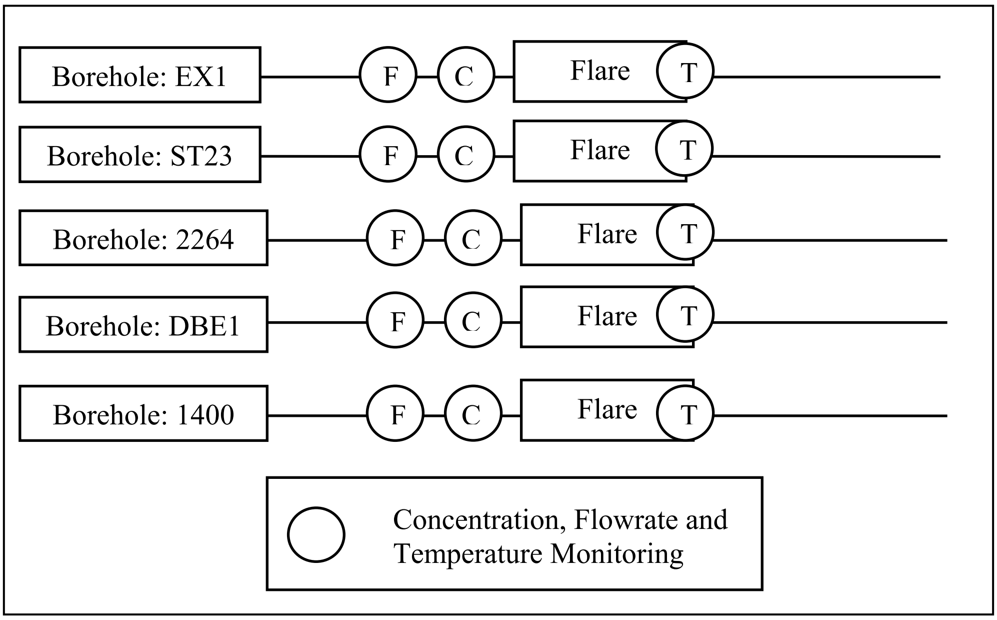
Figure 15: The underground piping and monitoring system for methane extraction.

The monitoring stations underground measure both gas flowrate and methane concentration.

Non-mine Methane Monitoring Plan

2. **Data to be monitored.**

Enclosed flares will be installed at the boreholes. The enclosed flares will have temperature sensors to monitor that the combustion temperature remains above 500ºC. The flares will come equipped with inlet flowrate and composition meters. A default combustion efficiency of 90% will be used in accordance with the tool. This is reflected in the diagram below:



The flares at the two bigger boreholes (EX1 and ST23) will have the ability to be retrofitted with the monitoring equipment necessary to claim actual combustion efficiency. However, this monitoring equipment will only be installed at a later stage.

Symbol	Description	Function
C	Concentration Meter	Measure CH_4 concentration of the gas
F	Gas Flow Meter	Measure methane sent to flare
T	Thermocouple	Measures the temperature of the flare to ensure correct operation

3. **Responsibility for data monitoring, recording and management.**

The operations manager will be responsible for ensuring that the data is monitored and recorded and that the instruments are all in working order.

4. **Calibration of meters and metering**

The following procedures will be implemented by the project to ensure accurate measurement and therefore accurate knowledge of GHG emission reductions.

- The metering equipment will be calibrated in accordance with manufacturer's specifications.
- The metering equipment will be calibrated and checked for accuracy in accordance with manufacturer's specifications.
- The instrumentation has not been finally selected yet. However, the instrumentation must have an accuracy of at least 95%. This can be checked at the first verification.

5. **Verification Procedure**

Verification will be done annually.

- The project participants will provide the data and calculated emission reductions to the DOE during verification.
- The operations personnel and the project participants will cooperate with the DOE during the verification process. The personnel working on this project will be available for consultation during the entire verification and will provide correct data to substantiate all queries.

B.7.1 Data and parameters monitored:

Mine methane capture and utilization or destruction

Data / Parameter:	$MM_{PR,engine,y}$ or $MMES_{ELEC,y}$
Data unit:	tCH_4/yr
Description:	Mine methane captured, sent to and destroyed by internal combustion engines in the project activity in year y
Source of data to be used:	Engine specifications were used for the purpose of the ex-ante calculations. The flowrate will be measured in the project activity. The methane concentration of the gas will be metered at the flare. Since the methane concentration of the gas sent to the flare and the gas sent to the engines does not differ, the concentration of the gas at the flare can be used to give the concentration of the gas sent to the engines.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	7,230.77 tCH_4/year
Description of measurement methods and procedures to be applied:	The flowrate of the gas will be monitored continuously, integrated hourly and logged electronically. The methane concentration will be measured continuously at the flare.
QA/QC procedures to be applied:	The flowmeter and concentration meter will be calibrated according to manufacturer's specifications.
Any comment:	

Data / Parameter:	$MM_{PR,flare,y}$ or $MMES_{FL,y}$

Data unit:	tCH_4/yr
Description:	Mine methane captured, sent to and destroyed by flare in the project activity in year y
Source of data to be used:	A flow meter and concentration meter will be installed to measure the flowrate of methane sent to the flare.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	506.82tCH_4/year
Description of measurement methods and procedures to be applied:	The flow meter will measure the flowrate of gas. The flow meter has temperature and pressure compensation. The methane value of that gas will be monitored and used to calculate the flowrate of methane.
QA/QC procedures to be applied:	The flowmeter and methane concentration meter will be calibrated in accordance with manufacturer's specifications.
Any comment:	

Data / Parameter:	GEN_y
Data unit:	MWh
Description:	Electricity generated by the project activity in year y
Source of data to be used:	The electrical output will be measured by an electricity meter installed at the engines.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	44,772.36MWh
Description of measurement methods and procedures to be applied:	The electricity output will be measured at the engines. This meter will be installed in phase 2. The electricity generated will be monitored continuously, integrated hourly and logged electronically.
QA/QC procedures to be applied:	The meter will be calibrated according to manufacturer's specifications.
Any comment:	

Data / Parameter:	PC_{CH4}
Data unit:	%
Description:	Concentration (in mass) of methane in extracted gas (%), measured on wet basis
Source of data to be used:	The concentration of methane will be monitored continuously at the underground monitoring stations. The methane concentration of the gas is then monitored again at the flare.
Value of data applied for the purpose of calculating expected emission reductions in	75%

section B.5	
Description of measurement methods and procedures to be applied:	The concentration will be monitored continuously, integrated hourly and logged electronically. The methane concentration will be measured in volume percent. Using the flowrate of the gas, the volumetric concentrations of the components in the gas and molar masses; the volume percent will be converted into a mass percent. The concentration will be monitored on a wet basis and this value will be reported on a wet basis. The concentration is metered by a gas analysis device. This device will first, cool the gas to a temperature of 5 degree (condensate will be evacuated), logically the gas is now 100% wet since it is very close to the dew point. Afterwards, the gas will move to the measuring cells in this status. So the gas is wet.
QA/QC procedures to be applied:	Maintenance of concentration meters will be done according to manufacturer's specification; which comply with manufacturer's specifications.
Any comment:	

Data / Parameter:	PC_{NMHC}
Data unit:	%
Description:	NMHC concentration (in mass) in extracted gas
Source of data to be used:	The gas will be sampled every 3 months initially and tested for the NMHC concentration. The frequency of this will be reduced to twice a year after the first year of operation of the plant. The methane concentration will be monitored continuously. If the methane concentration falls below the 75% indicated by the analysis taken prior to the project activity or the average concentration in that year then the gas will be sampled again and the new NMHC concentration will be used.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.38%
Description of measurement methods and procedures to be applied:	The gas is sampled and the samples are sent to a laboratory for testing.
QA/QC procedures to be applied:	
Any comment:	

Data / Parameter:	$EC_{PJ,,y}$
Data unit:	MWh/y
Description:	Quantity of electricity consumed by the project electricity consumption source in year *y*
Source of data to be used:	The electricity consumed by the plant will be measured.
Value of data applied for the purpose of calculating expected	825.19MWh/year

emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	The electricity consumption of the electricity generating equipment and auxiliaries will be measured. The continuous monitored data will be logged electronically.
QA/QC procedures to be applied:	The measuring equipment will be calibrated according to manufacturer's specifications.
Any comment:	

Data / Parameter:	TDL_y
Data unit:	-
Description:	Average technical transmission and distribution losses for providing electricity to source in year y
Source of data to be used:	A default value of 3% was used because the scenario presented below was found to be applicable to the project (verbatim text in italics): *(b) project and leakage electricity consumption sources if the electricity consumption by all project and leakage electricity consumption sources to which scenario A or scenario C (cases C.I or C.III) applies is smaller than the electricity consumption of all baseline electricity consumption sources to which scenario A or scenario C (cases C.I or C.III) applies.*
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Default 3% as stated in "*Tool to calculate baseline, project and/or leakage emissions from electricity consumption*"
Description of measurement methods and procedures to be applied:	The tool will be checked annually for updates and new default values.
QA/QC procedures to be applied:	Default values, as stated in the tool, will be used.
Any comment:	

Data / Parameter:	$FV_{RG,h}$
Data unit:	m^3/h
Description:	Volumetric flow rate of the residual gas in dry basis at normal conditions in the hour *h*
Source of data to be used:	Measurements will be taken using a flow meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	101.16 m^3/h
Description of measurement methods and procedures to be applied:	A flowmeter will be installed to measure the flowrate of gas sent to the flare. The volumetric flowrate will be measured on a dry basis; ensuring that all the moisture is removed prior to the analysis. This will be the same for the density of methane and the fraction of methane in the residual gas.

	The flowrate will be measured after the dewatering unit and after the pressure increase of the blowers (here, there is also a significant gas temperature increase). At this time, there is no condensate and the relative humidity is not zero but approximately 20-30%. So, the gas is dry.
QA/QC procedures to be applied:	Flow meters are to be periodically calibrated according to the manufacturer's recommendation.
Any comment:	

Data / Parameter:	$fv_{i,h}$
Data unit:	-
Description:	Volumetric fraction of component i in the residual gas in the hour *h* Where i is CH_4,CO,CO_2,O_2,H_2,N_2
Source of data to be used:	Initial gas analyses before project start was used for the ex-ante calculations. Thereafter, the volumetric fraction of CH4 will be measured and remainder will be considered to be N_2.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	$fv_{CH4,h}$ = 0.85 (value from initial measurement) $fv_{N2,h}$ = 0.15 (value from initial measurement)
Description of measurement methods and procedures to be applied:	. The volumetric fraction of CH_4 will be measured continuously. The remainder will be considered as N_2. The volumetric fraction of methane will be measured on a dry basis; ensuring that all the moisture is removed prior to the analysis. This will be in line with the measurement of the gas flowrate and the density of methane.
QA/QC procedures to be applied:	The instrument measuring the volumetric fraction of CH_4 as well as O_2 and CO_2 will be calibrated according to the manufacturer's specifications; which correspond with international standards. The instrument measures CH_4, O_2 and CO_2. However, only the CH_4 measurement will be used in the calculations as the remainder will be assumed to be N_2.
Any comment:	

Data / Parameter:	$fv_{CH4,FG,h}$
Data unit:	mg/m^3
Description:	Concentration of methane in the exhaust gas of the flare in dry basis at normal conditions in the hour h
Source of data to be used:	Measurements at the flare as part of the flare package
Value of data applied for the purpose of calculating expected emission reductions in section B.5	11,414.62mg/m^3
Description of measurement methods and procedures to be applied:	The volumetric fraction of the methane in the exhaust gas will be measured. This measurement will be converted to mg/m^3. The concentration of methane will be

	measured on a dry basis; ensuring that all the moisture is removed prior to the analysis. This will be in line with the measurement of the gas flowrate and the density of methane.
QA/QC procedures to be applied:	The instrument will be calibrated in accordance with manufacturer's specifications.
Any comment:	

Data / Parameter:	$t_{O2,h}$
Data unit:	-
Description:	Volumetric fraction of O_2 in the exhaust gas of the flare in the hour h
Source of data to be used:	Measured using a continuous gas analyser (electrochemical)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.02
Description of measurement methods and procedures to be applied:	The concentration of oxygen will be monitored using a flue gas analyser. The concentration of oxygen will be measured on a dry basis; ensuring that all the moisture is removed prior to the analysis.
QA/QC procedures to be applied:	The analyser will be periodically calibrated according to the manufacturer's recommendation. The accuracy of the instrument is +/- 1%.
Any comment:	

Data / Parameter:	T_{flare}
Data unit:	°C
Description:	Temperature in the exhaust gas of the flare
Source of data to be used:	Measurements by project participants
Value of data applied for the purpose of calculating expected emission reductions in section B.5	600 °C
Description of measurement methods and procedures to be applied:	Measure the temperature of the exhaust gas stream in the flare by a Type N thermocouple. A temperature above 500 ºC indicates that a significant amount of gases are still being burnt and that the flare is operating. The temperature should be measured continuously.
QA/QC procedures to be applied:	Thermocouples should be replaced or calibrated every year.
Any comment:	An excessively high temperature at the sampling point (above 700 ºC) may be an indication that the flare is not being adequately operated or that its capacity is not adequate to the actual flow.

Non-mine methane capture and destruction

Data / Parameter:	$FV_{RG,h}$

Data unit:	m^3/h
Description:	Volumetric flow rate of the residual gas in dry basis at normal conditions in the hour *h*
Source of data to be used:	Measurements will be taken using a flow meter at each borehole
Value of data applied for the purpose of calculating expected emission reductions in section B.5	EX1 = 252.43 ST23 = 350.26 2264 = 41.29 1400 = 92.55 DBE1 = 47.38
Description of measurement methods and procedures to be applied:	A flowmeter will be installed to measure the flowrate of gas sent to the flare at each borehole. The flowmeter will have temperature and pressure compensation and reports the flowrate in Nm^3/hr. The analysis will be done on a dry basis ensuring that the moisture is extracted before the measurement is taken.
QA/QC procedures to be applied:	Flow meters are to be periodically calibrated according to manufacturer's specifications.
Any comment:	

Data / Parameter:	$fv_{i,h}$
Data unit:	-
Description:	Volumetric fraction of component i in the residual gas in the hour *h* Where i is CH_4,CO,CO_2,O_2,H_2,N_2
Source of data to be used:	The methane concentration of the residual gas will be measured and the remainder will be considered as N_2
Value of data applied for the purpose of calculating expected emission reductions in section B.5	**EX1** $fv_{CH4,h} = 1.00$ $fv_{N2,h} = 0$ **ST23** $fv_{CH4,h} = 0.99$ $fv_{N2,h} = 0.01$ **2264** $fv_{CH4,h} = 1.00$ $fv_{N2,h} = 0$ **1400** $fv_{CH4,h} = 0.99$ $fv_{N2,h} = 0.01$ **DBE1** $fv_{CH4,h} = 1.00$ $fv_{N2,h} = 0$
Description of measurement methods and procedures to be applied:	The methane concentration of the gas will be monitored continuously, integrated hourly and logged electronically. The remainder will be considered as N_2.
QA/QC procedures to be applied:	The instrument measuring the concentration of methane will be calibrated according to manufacturer's specifications.
Any comment:	

Data / Parameter:	Tflare
Data unit:	°C
Description:	Temperature in the exhaust gas of the flare
Source of data to be used:	Measurements by project participants
Value of data applied for the purpose of calculating expected emission reductions in section B.5	600 °C
Description of measurement methods and procedures to be applied:	Measure the temperature of the exhaust gas stream in the flare by a Type N thermocouple. A temperature above 500 ºC indicates that a significant amount of gases are still being burnt and that the flare is operating. The temperature should be measured continuously.
QA/QC procedures to be applied:	Thermocouples should be replaced or calibrated every year.
Any comment:	An excessively high temperature at the sampling point (above 700 ºC) may be an indication that the flare is not being adequately operated or that its capacity is not adequate to the actual flow.

B.7.2. Description of the monitoring plan:

>>

The onsite monitoring as well as calibration/verification of measurement equipment will be the responsibility of the operations manager. The data will be collected on site and archived both on site and off site. Promethium Carbon will be responsible for calculating the emission reductions and drafting of the monitoring report. Further detail on the monitoring of the project can be seen in the monitoring plan.

B.8. Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies):

>>

Both the baseline study and the monitoring methodology were developed by Promethium Carbon (Pty) Ltd and completed in October 2008.

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

>>

The starting date of the project activity is 21 September 2009. This is the date that the mine methane and non-mine methane flares are ordered in accordance with the project plan. This is in accordance with EB 41 where the starting date can be the date on which contracts have been signed for equipment or construction/operation services required for the project activity.

C.1.2. Expected operational lifetime of the project activity:

>>

The life time of the mine exceeds the 21 year period of this project activity.

C.2. Choice of the crediting period and related information:

C.2.1. Renewable crediting period:

C.2.1.1. Starting date of the first crediting period:

>>

11/03/2010 or the date of registration, whatever occurs later.

C.2.1.2. Length of the first crediting period:

>>

Seven years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>

Not applicable

C.2.2.2. Length:

>>

Not applicable

SECTION D. Environmental impacts

>>

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

>>

The project does not involve any activity that is listed in terms of the National Environmental Management Act and, as such, does not require an environmental impact assessment or a basic assessment.

Following meetings with the regional director of The Department of Minerals and Energy (DME) for Welkom, the project will need to be included as an addendum to the Environmental Monitoring Programme Report (EMPR). DEAT expects this process to take four months.

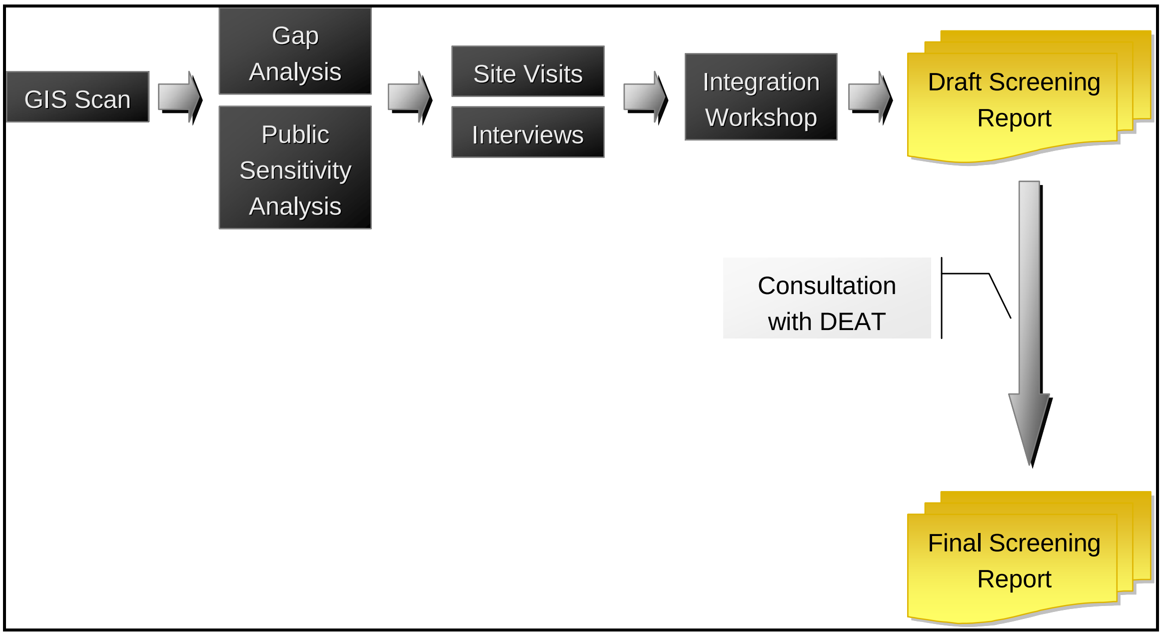
D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

>>

The project participants contracted Strategic Environmental Focus (SEF) to compile a screening report on the project. The objectives of the screening report were:

- To make recommendations on the appropriate environmental authorisation processes to be undertaken for the establishment of the cogeneration plant;
- To provide advanced warning of any potential environmental issues or sensitivities at the existing site, which may influence the outcome of the environmental authorisation processes; and
- To highlight environmental risks, and to briefly discuss these risks with regards to the legislation governing both the current operations as well as the proposed inclusion of the cogeneration operations on site;

The process followed to realise the objectives of the screening report was:



The results of the screening exercise were:

- There do not appear to be any environmental fatal-flaws associated with the establishment of the proposed cogeneration plant on the existing 'brown-fields" site;
- The proposed cogeneration plant will be installed at an existing "brown-fields" site;
- It will not be necessary to apply for a Water Use License in terms of Section 21, 37(1) or 38(1) of the National Water Act, 1998, as no listed water uses are contemplated for the proposed project. This is given that municipal water (Sedibeng) will be used as top-up water for the cogeneration plant; and
- The proposed development will also require an addendum to the mine's existing EMPR in terms of the Minerals and Petroleum Resources Development Act, 2002(Act No. 28 of 2002) [MPRDA)], therefore requiring that an Environmental Management Plan be submitted for approval to the Department of Minerals and Energy (DME).

Following the screening report, the relevant authorities were consulted to confirm the necessary permits required. As discussed above, the project will have to be included as an addendum to the EMPR of the mine. Arcus Gibb, a South African environmental consulting company, has drafted the addendum and it has been submitted to the authorities for comment.

SECTION E. Stakeholders' comments

>>

E.1. Brief description how comments by local stakeholders have been invited and compiled:

>>

An advertisement was placed in a local newspaper in both English and Afrikaans. Afrikaans is the language of the area. The advertisement was placed in the Vista newspaper on the 22nd of August 2008. Comments were invited on the project and the closing date for comments was the 15th of September 2008.

There was also a stakeholder meeting on 22 January 2009 as required by the process for the Addendum to the Environmental Management Programme (EMP). Invitations for this meeting were sent out to the relevant stakeholders. Two meetings were held on 22 January 2009 at the Jongingozi Boardroom of the Beatrix Gold Mine. The first meeting, for the general public, took place in the morning at 10h00 and the second one, for the authorities, was held in the afternoon at 14h00. The main purpose of the meetings was to reflect back to the public and authority representatives in terms of the following:

- To inform the public and authority representatives about the proposed project and the environmental process to be followed;
- To provide the public and authorities with an opportunity to exchange information and to express views and concerns and comment on the draft EMP document;
- To provide the opportunity to register as an interested and affected party (I & AP); and
- To outline the way forward.

Dirk van Greuning of Goldfields gave a presentation regarding the background to the project, and how it fits into the Beatrix Gold Mine during the morning meeting with I&APs and Hennie Pretorius during the afternoon meeting with authority representatives. Reuben Heydenrych of Arcus GIBB presented the addendum to the EMP and information regarding the proposed cogeneration facility as well as methane gas flares.

E.2. Summary of the comments received:

>>

Comments on the Advertisement:

There were two responses to the advertisement:

1. The first was a journalist from a regional paper in Bethlehem in the Eastern Free State, who was only interested in GFI Mining South Africa paying to have the advert placed in his newspaper as well.
2. The second person was a local businessman from Welkom who enquired about the benefit that the Gold Fields Foundation would derive from the project. The businessman is planning to start a Section 21 company. Ultimately, he wanted to know if his proposed company would gain as a result.

In addition, there were some casual observations along the lines: “We saw the Beatrix methane capture advert in the Vista”.

Comments from the stakeholder consultation:

As an example of the comments received, the first five questions were:

1. A query was raised regarding the amount of carbon credits obtained and if it is possible to obtain more than the expected R27.5 million, mentioned in the presentation.
2. Concern was raised regarding any possible animal life around the boreholes.

3. Hennie Hanekom expressed concern regarding an open borehole (unrelated to this project) on his property.
4. A query was raised regarding the expected lifespan of the project.
5. A query was raised regarding the expected commencement of construction for the proposed project.

To see all the comments and questions received, please refer to the Stakeholder Comment Report.

E.3. Report on how due account was taken of any comments received:

>>

The two responses to the advertisement were addressed as follows:

1. Bethlehem is not in the region of Beatrix and would not target any relevant stakeholders for this project. The distance between the project and Bethlehem exceeds 300km.
2. Once the section 21 company is formed, the Gold Fields Foundation will assess its merits as a possible beneficiary of the Foundation.

The comments from the stakeholder meeting were addressed as follows:

1. Robbie Louw from Promethium Carbon responded that once methane is extracted, measurements will be taken to determine if it is possible to obtain more than the expected calculated carbon credits.
2. All five boreholes from which the methane is to be extracted are located on maize lands. One of these is located on a camp which keeps cattle in the area. Apart from that there are no signs of wildlife. The footprints of the flares are relatively small and they are to be fenced off.
3. Hennie Pretorius from Beatrix Mine indicated that Beatrix Mine would investigate and determine whether the borehole could be closed or whether it could be connected to a different borehole so that the methane could exit at another point.
4. Robbie Louw from Promethium Carbon indicated that electricity would be generated for a period of 10 years, corresponding to the current expected remaining life of the mine. Carbon credits could, however, continue to be earned for a total period of 21 years if the mine were to continue to flare methane. The mine could also decide to buy the engines from the Promethium-Exxaro Joint Venture at the end of the 10 year contract if they wanted to continue to generate electricity.
5. Brian van Oerle from Promethium Carbon indicated that the project would be constructed within three months of approval of the EMP by the Department of Minerals and Energy (DME). It is therefore hoped that the DME would be able to approve the EMP within 3 months of submission of the final EMP as this was the commitment given by Mr. Aubrey Tshivandekano of the DME during a meeting with him in November 2008. If this time frame was adhered to, the project could be constructed by August or September.

To see all the comments and questions received, please refer to the Stakeholder Comment Report.

Annex 1

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There is no public funding.

Annex 3

BASELINE INFORMATION

Information about the Occurrence of Methane at a Gold Mine

1. Methane Capturing:

1.1 Methane Occurrence:

The methane in the Beatrix mining area is not liberated homogeneously as is the case in coal beds. Methane is carried in geological faults from unknown reservoir(s) or source(s). Scientific research into the occurrence of the methane indicates that the methane:

(a) seems to come from a deep-seated source, and
(b) may be of biological origin.

Some of the literature sources are listed below:

- Hugo P. J., Helium in the Orange Free State Gold Field, Geological Survey, Republic of South Africa, 1963.
- Takai et al., Archaeal Diversity in Waters from Deep South African Gold Mines, Applied and Environmental Microbiology, December 2001, Vol 67, No 12, pp 5750 – 5760
- England, G L, Rasmussen, B, Krapez, B, Groves, D I, Archaean oil migration in the Witwatersrand Basin of South Africa, Journal of the Geological Society, Mar 2002
- Spangenberg J., Frimmel H. E., Basin-internal derivation of hydrocarbons in the Witwatersrand Basin, South Africa: evidence from bulk and molecular 13C data, Chemical Geology, 2001, 173, 339-355.
- Ward J.A. et al, Microbial hydrocarbon gases in the Witwatersrand Basin, South Africa: Implications for the deep biosphere, Geochimica et Cosmochimica Acta, Vol. 68, No. 15, pp. 3239–3250, 2004.

The conclusion reached by Ward states that: "*... these microbial hydrocarbon gases are the product of in situ methanogenic communities in the deep subsurface of the Witswaterand basin*."

Attempts to reduce the methane hazard in the underground mines, by borehole drainage, were made in the 1960s. These attempts were unsuccessful due to the failure to predict the location of the methane gas in the underground mines. This was documented and made public by the Department of Mines in a geological survey on Helium in the Orange Free State Gold-Field. *The South African Government Printer, Bulletin 39, G.P.-s 3479551-1962-63-1200*

The difficulties in predicting the location of the methane in the Beatrix mine are exacerbated by the lack of detailed major and minor geological fault charts. The major geological fault zones, running through the Beatrix mining area, are depicted in Figure 3. The minor faults are largely uncharted. As the country rock in the area is impermeable, methane is carried exclusively in these discrete faults. The exact location of the methane in these discrete faults is difficult to determine. Hence, the management of methane in the mine can only be done on an *ex post* basis; when the area is mined and the methane is released.

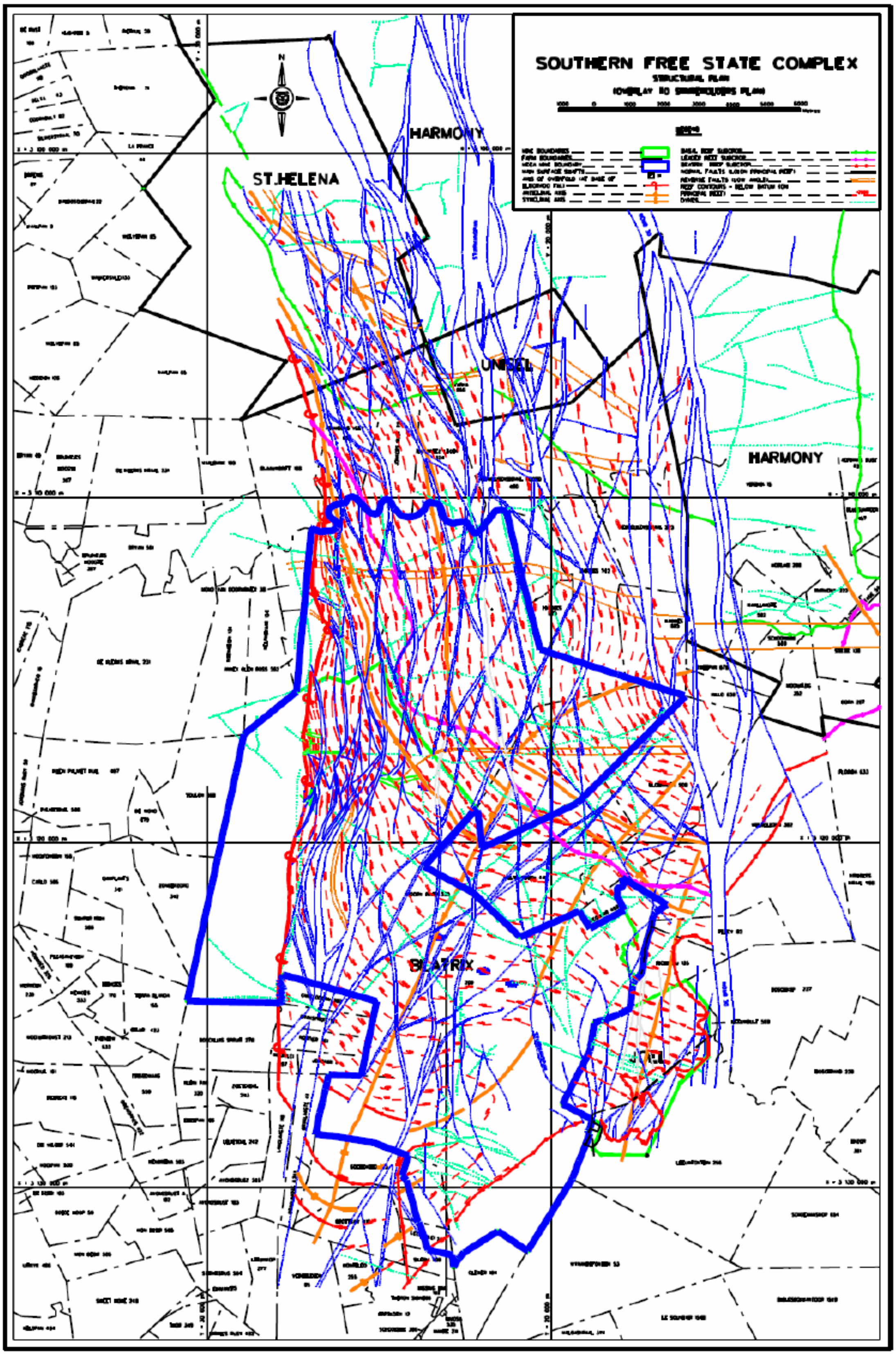

Figure 14: Geological faults in the Beatrix mining area

Historically, methane emissions from mining operations has occurred from the Karoo Supergroup through to the Virginia Formation (refer Figure 15 below) at depths ranging from 300 meters to 3 kilometres.

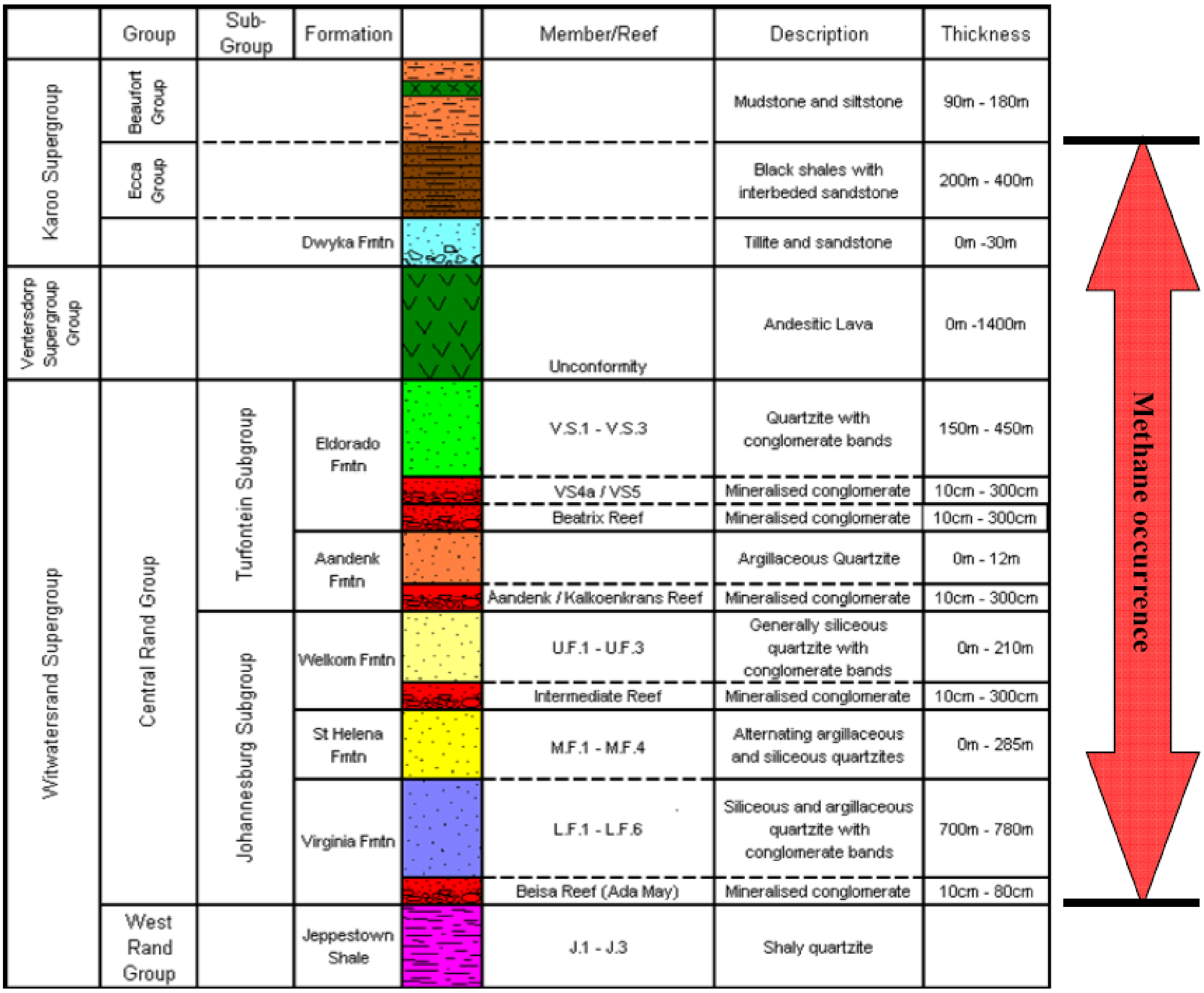

Figure 15: Free State goldfields stratigraphic column

Methane from these geological structures is vented from two main sources: surface boreholes and underground mining areas.

Currently, all of the methane from the underground workings is diluted into the ventilation air and vented to surface through the vent shafts. Examples of these vent shafts can be seen in Figure 16.

The number 1, 2 and 3 Shaft areas of the Beatrix mine are depicted in Figure 16 below. The schematic diagram shows the 3 main shafts, the 2 ventilation shafts and the various levels at which underground mining activity occurs. Clean air travels into the mine through the 1, 2 and 3 Shafts and methane-containing air travels out of the mine through the Vent Shaft and the 2B Vent Shaft.

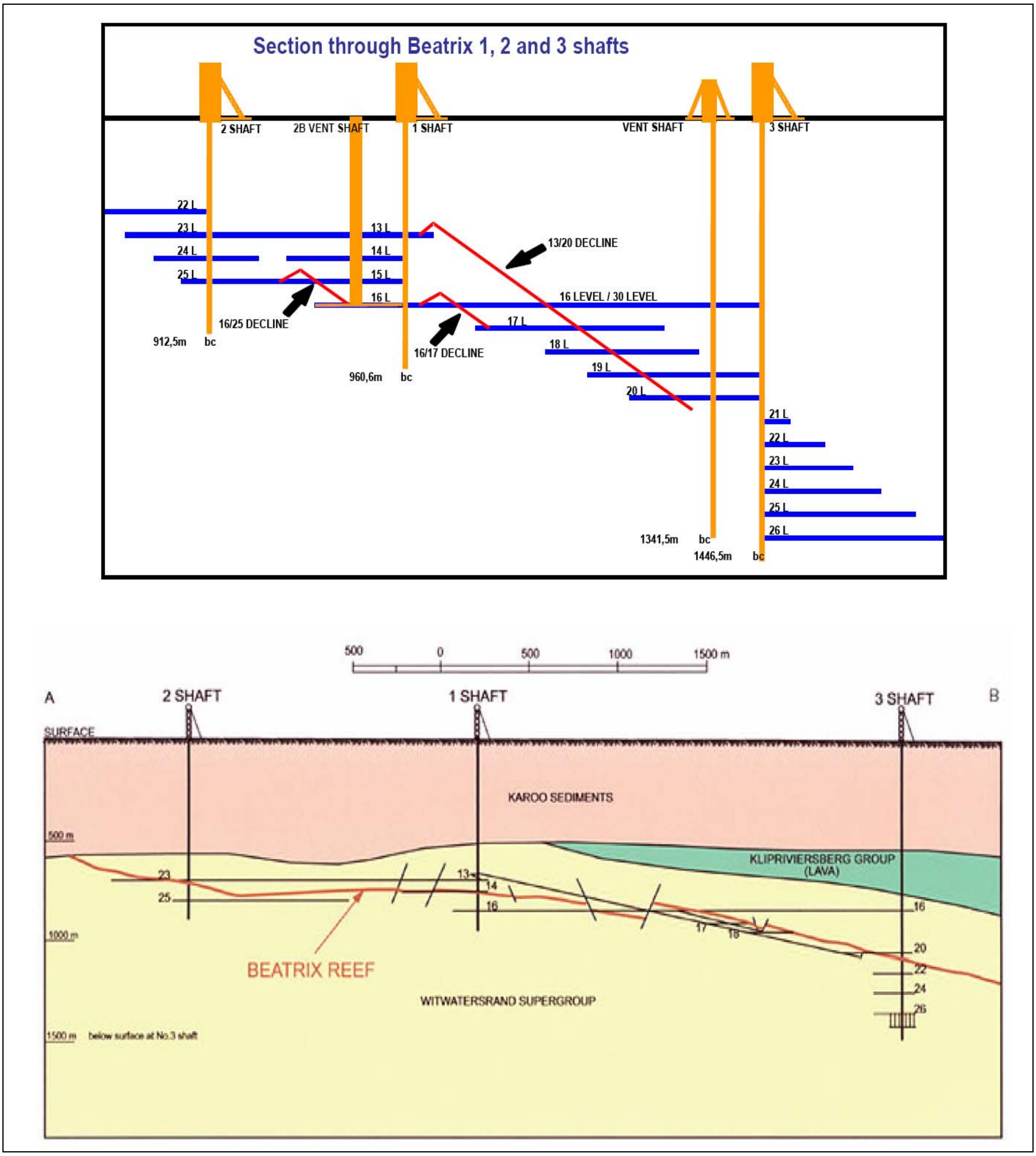

Figure 16: Schematic arrangements of the Beatrix 1, 2 & 3 Shafts ventilation arrangement

Annex 4

MONITORING INFORMATION

From the "Tool to determine project emissions from flaring gases containing methane" (EB 28, Annex 13):

The steps in this tool were carried out to determine the project emissions from flaring the mine methane and the non-mine methane. A single flare will be installed at the Number 1 Shaft to combust the mine methane. A flare will be installed at each of the five boreholes in order to destroy the non-mine methane. Hence, this tool was applied for each of the borehole flares and for the flare at the Number 1 Shaft.

The steps in the tool are as follows:

STEP 1: Determination of the mass flow rate of the residual gas that is flared

This step calculates the residual gas mass flow rate in each hour h, based on the volumetric flow rate and the density of the residual gas. The density of the residual gas is determined based on the volumetric fraction of all components in the gas.

$$FM_{RG,h} = \rho_{RG,n,h} \times FV_{RG,h}$$ *(Flaring Tool[32] 1)*

Where:

$FM_{RG,h}$	*Mass flow rate of residual gas in hour h (kg/h)*
$\rho_{RG,n,h}$	*Density of residual gas at normal conditions in hour h*
$FV_{RG,h}$	*Volumetric flow rate of the residual gas in dry basis at normal conditions in hour h (m^3/h)*

And:

$$\rho_{RG,n,h} = \frac{P_n}{\frac{R_u}{MM_{RG,h}} \times T_n}$$ *(Flaring Tool 2)*

Where:

$\rho_{RG,n,h}$	*Density of residual gas at normal conditions in hour h*
P_n	*Atmospheric pressure at normal conditions (101,325 Pa)*
R_u	*Universal ideal gas constant (8,314 Pa.m^3/kmol.K)'*
$MM_{RG,h}$	*Molecular mass of the residual gas in hour h (kg/kmol)*
T_n	*Temperature at normal conditions (273.15K)*

And:

---

[32] UNFCCC methodological tool, "Tool to determine project emissions from flaring gases containing methane".

$$MM_{RG,h} = \sum_i \left(fv_{i,h} \times MM_i \right) \qquad \textit{(Flaring Tool 3)}$$

Where:

$MM_{RG,h}$	*Molecular mass of the residual gas in hour h (kg/kmol)*
$fv_{i,h}$	*Volumetric fraction of component i in the residual gas in the hour h*
MM_i	*Molecular mass of residual gas component i*
i	*The components CH_4, CO, CO_2, O_2, H_2, N_2*

If Flaring Tool 3 is applied to this project activity it becomes:

$$MM_{RG,h} = (fv_{CH4,h} \times MM_{CH4} + fv_{CO} \times MM_{CO} + fv_{CO2} \times MM_{CO2} + fv_{O2} \times MM_{O2} + fv_{H2} \times MM_{H2} + fv_{N2} \times MM_{N2})$$

(Flaring Tool 3.1)

Where:

$fv_{CH4,h}$	Volumetric fraction of methane in the residual gas in the hour h
$fv_{CO,h}$	Volumetric fraction of CO in the residual gas in the hour h
$fv_{CO2,h}$	Volumetric fraction of CO_2 in the residual gas in the hour h
$fv_{O2,h}$	Volumetric fraction of O_2 in the residual gas in the hour h
$fv_{H2,h}$	Volumetric fraction of H_2 in the residual gas in the hour h
$fv_{N2,h}$	Volumetric fraction of N_2 in the residual gas in the hour h
MM_{CH4}	Molecular mass of methane (kg/kmol)
MM_{CO}	Molecular mass of CO (kg/kmol)
MM_{CO2}	Molecular mass of CO_2 (kg/kmol)
MM_{O2}	Molecular mass of O_2 (kg/kmol)
MM_{H2}	Molecular mass of H_2 (kg/kmol)
MM_{N2}	Molecular mass of N_2 (kg/kmol)

STEP 2: Determination of the mass fraction of carbon, hydrogen, oxygen and nitrogen in the residual gas

The mass fractions of carbon, hydrogen, oxygen and nitrogen in the residual gas, were calculated from the volumetric fraction of each component i in the residual gas, as follows:

$$fm_{j,h} = \frac{\sum_i fv_{i,h} \times AM_j \times NA_{j,i}}{MM_{RG,h}} \qquad \textit{(Flaring Tool 4)}$$

Where:

$fm_{j,h}$	*Mass fraction of element j in the residual gas in hour h*
$fv_{i,h}$	*Volumetric fraction of component i in the residual gas in the hour h*
AM_j	*Atomic mass of element j (kg/kmol)*
$NA_{j,i}$	*Number of atoms of element j in the component i*
$MM_{RG,h}$	*Molecular mass of the residual gas in hour h (kg/kmol)*
j	*The elements carbon, hydrogen, oxygen and nitrogen*
i	*The components CH_4, CO, CO_2, O_2, H_2, N_2*

When applied in this project Flaring Tool equation 4 became:

$$fm_{C,h} = \frac{fv_{CH4,h} \times AM_C \times NA_{C,CH4} + fv_{CO,h} \times AM_C \times NA_{C,CO} + fv_{CO2,h} \times AM_C \times NA_{C,CO2}}{MM_{RG,h}}$$

(Flaring Tool 4.1)

Where:

$fm_{C,h}$	Mass fraction of carbon in the residual gas in hour h
$fv_{CH4,h}$	Volumetric fraction of methane in the residual gas in the hour h
$fv_{CO,h}$	Volumetric fraction of CO in the residual gas in the hour h
$fv_{CO2,h}$	Volumetric fraction of CO_2 in the residual gas in the hour h
AM_C	Atomic mass of carbon (kg/kmol)
$NA_{C,CH4}$	Number of atoms of carbon in methane
$NA_{C,CO}$	Number of atoms of carbon in CO
$NA_{C,CO2}$	Number of atoms of carbon in CO_2

$$fm_{H,h} = \frac{fv_{CH4,h} \times AM_H \times NA_{H,CH4} + fv_{H2,h} \times AM_H \times NA_{H,H2}}{MM_{RG,h}}$$ (Flaring Tool 4.2)

Where:

$fm_{H,h}$	Mass fraction of hydrogen in the residual gas in hour h
$fv_{CH4,h}$	Volumetric fraction of methane in the residual gas in the hour h
$fv_{H2,h}$	Volumetric fraction of H_2 in the residual gas in the hour h
AM_H	Atomic mass of hydrogen (kg/kmol)
$NA_{H,CH4}$	Number of atoms of hydrogen in methane
$NA_{H,H2}$	Number of atoms of hydrogen in H_2
$MM_{RG,h}$	Molecular mass of the residual gas in hour h (kg/kmol)

$$fm_{O,h} = \frac{fv_{CO,h} \times AM_O \times NA_{O,CO} + fv_{CO2h} \times AM_O \times NA_{O,CO2} + fv_{O2,h} \times AM_O \times NA_{O,O2}}{MM_{RG,h}}$$

(Flaring Tool 4.3)

Where:

$fm_{O,h}$	Mass fraction of oxygen in the residual gas in hour h
$fv_{CO,h}$	Volumetric fraction of CO in the residual gas in the hour h
$fv_{CO2,h}$	Volumetric fraction of CO2 in the residual gas in the hour h
$fv_{O2,h}$	Volumetric fraction of O2 in the residual gas in the hour h
AM_O	Atomic mass of oxygen (kg/kmol)
$NA_{O,CO}$	Number of atoms of oxygen in CO
$NA_{O,CO2}$	Number of atoms of oxygen in CO_2
$NA_{O,O2}$	Number of atoms of oxygen inO_2
$MM_{RG,h}$	Molecular mass of the residual gas in hour h (kg/kmol)

$$fm_{N,h} = \frac{fv_{N2,h} \times AM_N \times NA_{N,N2}}{MM_{RG,h}} \qquad \text{(Flaring Tool 4.4)}$$

Where:

$fm_{N,h}$	Mass fraction of nitrogen in the residual gas in hour h
$fv_{N2,h}$	Volumetric fraction of nitrogen in the residual gas in the hour h
AM_N	Atomic mass of hydrogen (kg/kmol)
$NA_{N,N2}$	Number of atoms of hydrogen in nitrogen
$MM_{RG,h}$	Molecular mass of the residual gas in hour h (kg/kmol)

STEP 3*: Determination of the volumetric flow rate of the exhaust gas on a dry basis*

This step is only applicable if the methane combustion efficiency of the flare is continuously monitored.

Determine the average volumetric flow rate of the exhaust gas in each hour h based on a stoichiometric calculation of the combustion process, which depends on the chemical composition of the residual gas, the amount of air supplied to combust it and the composition of the exhaust gas, as follows:

$$TV_{n,FG,h} = V_{n,FG,h} \times FM_{RG,h} \qquad \textit{(Flaring Tool 5)}$$

Where:

$TV_{n,FG,h}$	*Volumetric flow rate of the exhaust gas in basis at normal conditions in hour h (m^3/h)*
$V_{n,FG,h}$	*Volume of the exhaust gas of the flare in dry basis at normal conditions per kg of residual gas in hour h (m^3/h residual gas)*
$FM_{RG,h}$	*Mass flow rate of the residual gas in hour h (kg residual gas/h)*

$$V_{n,FG,h} = V_{n,CO2,h} + V_{n,O2,h} + V_{n,N2,h} \qquad \textit{(Flaring Tool 6)}$$

Where:

$V_{n,FG,h}$	*Volume of the exhaust gas of the flare in dry basis at normal conditions per kg of residual gas in the hour h (m3/kg residual gas)*
$V_{n,CO2,h}$	*Quantity of CO_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*
$V_{n,O2,h}$	*Quantity of O_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*
$V_{n,N2,h}$	*Quantity of N_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*

$$V_{n,O2,h} = n_{O2,h} \times MV_n \qquad \textit{(Flaring Tool 7)}$$

Where:

$V_{n,O2,h}$	*Quantity of O_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*
$n_{O2,h}$	*Quantity of moles O_2 in the exhaust gas of the flare per kg residual gas flared in hour h (kmol/kg residual gas)*

MV_n	*Volume of one mole of any ideal gas at normal temperature and pressure (22.4 L/mol)*

$$V_{n,N2,h} = MV_n \times \left\{ \frac{fm_{N,h}}{200 AM_n} + \left(\frac{1 - MF_{O2}}{MF_{O2}} \right) \times \left[F_h + n_{O2,h} \right] \right\} \qquad \text{(Flaring Tool 8)}$$

Where:

$V_{n,N2,h}$	*Quantity of N_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*
MV_n	*Volume of one mole of any ideal gas at normal temperature and pressure (22.4 L/mol)*
$fm_{N,h}$	*Mass fraction of nitrogen in the residual gas in hour h*
AM_n	*Atomic mass of nitrogen (kg/kmol)*
MF_{O2}	*O_2 volumetric fraction of air*
F_h	*Stoichoimetric quantity of moles O_2 required for complete oxidation of one kg residual gas in hour h*
$n_{O2,h}$	*Quantity of moles of O_2 in the exhaust gas of the flare per kg residual gas flared in hour h*

$$V_{n,CO2,h} = \frac{fm_{C,h}}{AM_c} \times MV_v \qquad \text{(Flaring Tool 9)}$$

Where:

$V_{n,CO2,h}$	*Quantity of CO_2 volume free in the exhaust gas of the flare at normal conditions per kg of residual gas in the hour h (m^3/kg residual gas)*
$fm_{C,h}$	*Mass fraction of carbon in the residual gas in the hour h*
AM_C	*Atomic mass of carbon (kg/kmol)*
MV_n	*Volume of one mole of any ideal gas at normal temperature and pressure (22.4 L/mol)*

$$n_{O2,h} = \frac{t_{O2,h}}{\left(1 - \frac{t_{O2,h}}{MF_{O2}}\right)} \times \left[\frac{fm_{C,h}}{AM_c} + \frac{fm_{N,h}}{2AM_N} + \frac{1 - MF_{O2}}{MF_{O2}} \times F_h \right] \qquad \text{(Flaring Tool 10)}$$

Where:

$n_{O2,h}$	*Quantity of moles O_2 in the exhaust gas of the flare per kg residual flared in hour h (kmol/kg residual gas)*
$t_{O2,h}$	*Volumetric fraction of O_2 in the exhaust gas in the hour h*
MF_{O2}	*Volumetric fraction of O_2 in the air (0.21)*
$fm_{C,h}$	*Mass fraction of C in the residual gas in hour h*
$fm_{N,h}$	*Mass fraction of N in the residual gas in hour h*
F_h	*Stociometric quantity of moles of O_2 required for a complete oxidation of one kg residual gas in hour h (kmol/kg residual gas)*
AM_C	*Atomic mass of C (kg/kmol)*
AM_N	*Atomic mass of N (kg/kmol)*

$$F_h = \frac{fm_{C,h}}{AM_C} + \frac{fm_{H,h}}{4AM_H} - \frac{fm_{o,h}}{2AM_O}$$ *(Flaring Tool 11)*

Where:

F_h	*Stociometric quantity of moles of O_2 required for a complete oxidation of one kg residual gas in hour h (kmol/kg residual gas)*
$fm_{C,h}$	*Mass fraction of C in the residual gas in hour h*
$fm_{H,h}$	*Mass fraction of H in the residual gas in hour h*
$fm_{O,h}$	*Mass fraction of O in the residual gas in hour h*
AM_C	*Atomic mass of C (kg/kmol)*
AM_H	*Atomic mass of H (kg/kmol)*
AM_O	*Atomic mass of O (kg/kmol)*

STEP 4: Determination of methane mass flow rate in the exhaust gas on a dry basis
This step is only applicable if the methane combustion efficiency of the flare is continuously monitored.

The combustion efficiency will be measured continuously in this project for the flare installed at the Number 1 Shaft. Hence, Step 4 applies for the mine methane flare. A default flare efficiency of 90% will be assumed for the borehole flares. The possibility exists that at a later stage monitoring equipment will be installed on the two bigger borehole flares (ST23 and EX1) in order to calculate the actual combustion efficiency. When this monitoring equipment is installed, Step 4 will be applied for both ST23 and EX1 in addition to being applied for the mine methane flare.

The mass flow of methane in the exhaust gas is based on the volumetric flow of the exhaust gas and the measured concentration of methane in the exhaust gas, as follows:

$$TM_{FG,h} = \frac{TV_{n,FG,h} \times fv_{CH4,FG,h}}{1{,}000{,}000}$$ *(Flaring Tool 12)*

Where:

$TM_{FG,h}$	*Mass flow rate of methane in the exhaust gas of the flare in dry basis at normal conditions in the hour h (kg/h)*
$TV_{n,FG,h}$	*Volumetric flow rate of the exhaust gas in dry basis at normal conditions in hour h (m^3/h exhaust gas)*
$fv_{CH4,FG,h}$	*Concentration of methane in the exhaust gas of the flare in dry basis at normal conditions in hour h (mg/ m^3)*

STEP 5: Determination of methane mass flow rate in the residual gas on a dry basis

The quantity of methane in the residual gas flowing into the flare is the product of the volumetric flow rate of the residual gas ($FV_{RG,h}$), the volumetric fraction of methane in the residual gas ($fv_{CH4,RG,h}$) and the density of methane ($\rho_{CH4,n,h}$) in the same reference conditions (normal conditions and dry or wet basis).

It is necessary to refer both measurements (flow rate of the residual gas and volumetric fraction of methane in the residual gas) to the same reference condition that may be dry or wet basis. If the residual gas moisture is significant (temperature greater than 60ºC), the measured flow rate of the residual gas that is usually referred to wet basis should be corrected to dry basis due to the fact *that the measurement of methane is usually undertaken on a dry basis (i.e. water is removed before sample analysis).*

$$TM_{RG,h} = FV_{RG,h} \times fv_{CH4,RG,h} \times \rho_{CH4,n} \qquad \textit{(Flaring Tool 13)}$$

Where:

$TM_{RG,h}$	*Mass flow rate of methane in the residual gas in the hour h (kg/h)*
$FV_{RG,h}$	*Volumetric flow rate of the residual gas in dry basis at normal conditions in hour h (m^3/h)*
$fv_{CH4,RG,h}$	*Volumetric fraction of methane in the residual gas on dry basis in hour h*
$\rho_{CH4,n}$	*Density of methane at normal conditions (0.716 kg/ m^3)*

STEP 6: Determination of the hourly flare efficiency

The determination of the hourly flare efficiency depends on the operation of flare (e.g. temperature), the type of flare used (open or enclosed) and, in case of enclosed flares, the approach selected by project participants to determine the flare efficiency (default value or continuous monitoring)

This project will use an enclosed, continuously monitored flare for the mine methane.

The non-mine methane/borehole flares will initially only have the monitoring equipment necessary to comply with the 90% default flare efficiency.

The tool states that the in case of enclosed flares and continuous monitoring of the flare efficiency, the flare efficiency in the hour h ($\eta_{flare,h}$) is:

- *0% if the temperature of the exhaust gas of the flare (T_{flare}) is below 500 °C during more than 20 minutes during the hour h.*
- *determined as follows in cases where the temperature of the exhaust gas of the flare (T_{flare}) is above 500 °C for more than 40 minutes during the hour h :*

$$\eta_{flare,h} = 1 - \frac{TM_{FG,h}}{TM_{RG,h}} \qquad \textit{(Flaring Tool 14)}$$

Where:

$\eta_{flare,h}$	*Flare efficiency in the hour h*
$TM_{FG,h}$	*Methane mass flow rate in the exhaust gas averaged in a period of time t (kg/h)*
$TM_{RG,h}$	*Mass flow rate of methane in the residual gas in the hour h (kg/h)*

STEP 7: Calculation of annual project emissions from flaring

Project emissions from flaring are calculated as the sum of emissions from each hour h, based on the methane flow rate in the residual gas (TMRG,h) and the flare efficiency during each hour h ($\eta_{flare,h}$), as follows:

$$PE_{flare,y} = \sum_{h=1}^{8760} TM_{RG,h} \times \left(1 - \eta_{flare,h}\right) \times \frac{GWP_{CH4}}{1{,}000} \qquad \textit{(Flaring Tool 15)}$$

Where:

$PE_{flare,y}$	*Project emissions from flaring the residual gas stream in year y (tCO_2e)*
$TM_{RG,h}$	*Mass flow rate of methane in the residual gas in the hour h (kg/h)*
$\eta_{flare,h}$	*Flare efficiency in hour h*
GWP_{CH4}	*Global warming potential of methane valid for the commitment period (tCO_2e/tCH_4)*

<u>Flaring of Mine Methane</u>

Flaring Tool result of Equation 1:

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$
11 Mar 2010 – 31 Oct 2010	831.66	0.79	1,047.55
1 Nov 2010 - 31 Dec 2010	76.17	0.79	95.94
1 Jan 2011 – 31 Dec 2011	76.17	0.79	95.94
1 Jan 2012 – 31 Dec 2012	76.17	0.79	95.94
1 Jan 2013 – 31 Dec 2013	76.17	0.79	95.94
1 Jan 2014 – 31 Dec 2014	76.17	0.79	95.94
1 Jan 2015 – 31 Dec 2015	76.17	0.79	95.94
1 Jan 2016 – 31 Dec 2016	76.17	0.79	95.94
1 Jan 2017 – 10 Mar 2017	76.17	0.79	95.94

Flaring Tool result of Equation 2:

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Oct 2010	0.793905	101,325	8,314	17.79	273.15
1 Nov 2010 - 31 Dec 2010	0.793905	101,325	8,314	17.79	273.15
1 Jan 2011 – 31 Dec 2011	0.793905	101,325	8,314	17.79	273.15
1 Jan 2012 – 31 Dec 2012	0.793905	101,325	8,314	17.79	273.15
1 Jan 2013 – 31 Dec 2013	0.793905	101,325	8,314	17.79	273.15
1 Jan 2014 – 31 Dec 2014	0.793905	101,325	8,314	17.79	273.15
1 Jan 2015 – 31 Dec 2015	0.793905	101,325	8,314	17.79	273.15
1 Jan 2016 – 31 Dec 2016	0.793905	101,325	8,314	17.79	273.15
1 Jan 2017 – 10 Mar 2017	0.793905	101,325	8,314	17.79	273.15

Flaring Tool result of Equation 3:

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$	MM_{CO}	$fv_{CO2,h}$
11 Mar 2010 – 31 Oct 2010	17.79	0.85	16.04	0	28.01	0
1 Nov 2010 - 31 Dec 2010	17.79	0.85	16.04	0	28.01	0
1 Jan 2011 – 31 Dec 2011	17.79	0.85	16.04	0	28.01	0
1 Jan 2012 – 31 Dec 2012	17.79	0.85	16.04	0	28.01	0
1 Jan 2013 – 31 Dec	17.79	0.85	16.04	0	28.01	0

2013						
1 Jan 2014 – 31 Dec 2014	17.79	0.85	16.04	0	28.01	0
1 Jan 2015 – 31 Dec 2015	17.79	0.85	16.04	0	28.01	0
1 Jan 2016 – 31 Dec 2016	17.79	0.85	16.04	0	28.01	0
1 Jan 2017 – 10 Mar 2017	17.79	0.85	16.04	0	28.01	0

Year	MM_{CO2}	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Oct 2010	44.01	0	32	0	2.02	0.15	28.02
1 Nov 2010 - 31 Dec 2010	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2011 – 31 Dec 2011	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2012 – 31 Dec 2012	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2013 – 31 Dec 2013	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2014 – 31 Dec 2014	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2015 – 31 Dec 2015	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2016 – 31 Dec 2016	44.01	0	32	0	2.02	0.15	28.02
1 Jan 2017 – 10 Mar 2017	44.01	0	32	0	2.02	0.15	28.02

Flaring Tool result of Equation 4:

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$	$NA_{C,CO}$	$fv_{CO2,h}$
11 Mar 2010 – 31 Oct 2010	0.58	0.85	12	1	0	1	0
1 Nov 2010 - 31 Dec 2010	0.58	0.85	12	1	0	1	0
1 Jan 2011 – 31 Dec 2011	0.58	0.85	12	1	0	1	0
1 Jan 2012 – 31 Dec 2012	0.58	0.85	12	1	0	1	0
1 Jan 2013 – 31 Dec 2013	0.58	0.85	12	1	0	1	0
1 Jan 2014 – 31 Dec 2014	0.58	0.85	12	1	0	1	0
1 Jan 2015 – 31 Dec 2015	0.58	0.85	12	1	0	1	0
1 Jan 2016 – 31 Dec 2016	0.58	0.85	12	1	0	1	0
1 Jan 2017 – 10 Mar 2017	0.58	0.85	12	1	0	1	0

Year	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	1	17.79
1 Nov 2010 - 31 Dec 2010	1	17.79

1 Jan 2011 – 31 Dec 2011	1	17.79
1 Jan 2012 – 31 Dec 2012	1	17.79
1 Jan 2013 – 31 Dec 2013	1	17.79
1 Jan 2014 – 31 Dec 2014	1	17.79
1 Jan 2015 – 31 Dec 2015	1	17.79
1 Jan 2016 – 31 Dec 2016	1	17.79
1 Jan 2017 – 10 Mar 2017	1	17.79

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$	$fv_{H2,h}$	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	0.1938	0.85	1.01	4	0	2	17.79
1 Nov 2010 - 31 Dec 2010	0.1938	0.85	1.01	4	0	2	17.79
1 Jan 2011 – 31 Dec 2011	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2012 – 31 Dec 2012	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2013 – 31 Dec 2013	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2014 – 31 Dec 2014	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2015 – 31 Dec 2015	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2016 – 31 Dec 2016	0.19	0.85	1.01	4	0	2	17.79
1 Jan 2017 – 10 Mar 2017	0.19	0.85	1.01	4	0	2	17.79

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	0.23	0.15	14.01	2	17.79
1 Nov 2010 - 31 Dec 2010	0.23	0.15	14.01	2	17.79
1 Jan 2011 – 31 Dec 2011	0.23	0.15	14.01	2	17.79
1 Jan 2012 – 31 Dec 2012	0.23	0.15	14.01	2	17.79
1 Jan 2013 – 31 Dec 2013	0.23	0.15	14.01	2	17.79
1 Jan 2014 – 31 Dec 2014	0.23	0.15	14.01	2	17.79
1 Jan 2015 – 31 Dec 2015	0.23	0.15	14.01	2	17.79
1 Jan 2016 – 31 Dec 2016	0.23	0.15	14.01	2	17.79
1 Jan 2017 – 10 Mar 2017	0.23	0.15	14.01	2	17.79

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$	$fv_{CO2,h}$
11 Mar 2010 – 31 Oct 2010	0	0	16	2	0	1	0
1 Nov 2010 - 31 Dec 2010	0	0	16	2	0	1	0
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1	0
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1	0
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1	0
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1	0
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1	0
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1	0
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1	0

Year	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	2	17.79
1 Nov 2010 - 31 Dec 2010	2	17.79
1 Jan 2011 – 31 Dec 2011	2	17.79
1 Jan 2012 – 31 Dec 2012	2	17.79
1 Jan 2013 – 31 Dec 2013	2	17.79
1 Jan 2014 – 31 Dec 2014	2	17.79
1 Jan 2015 – 31 Dec 2015	2	17.79
1 Jan 2016 – 31 Dec 2016	2	17.79
1 Jan 2017 – 10 Mar 2017	2	17.79

Flaring Tool result of Equation 5:

Year	$TV_{n,FG,h}$	$V_{n,FG,h}$	$FM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	18,819.83	23.67	795.07
1 Nov 2010 - 31 Dec 2010	1,723.62	23.67	72.82
1 Jan 2011 – 31 Dec 2011	1,723.62	23.67	72.82
1 Jan 2012 – 31 Dec 2012	1,723.62	23.67	72.82
1 Jan 2013 – 31 Dec 2013	1,723.62	23.67	72.82
1 Jan 2014 – 31 Dec 2014	1,723.62	23.67	72.82
1 Jan 2015 – 31 Dec 2015	1,723.62	23.67	72.82
1 Jan 2016 – 31 Dec 2016	1,723.62	23.67	72.82
1 Jan 2017 – 10 Mar 2017	1,723.62	23.67	72.82

Flaring Tool result of Equation 6:

Year	$V_{n,FG,h}$	$V_{n,CO2,h}$	$V_{n,O2,h}$	$V_{n,N2,h}$
11 Mar 2010 – 31 Oct 2010	23.67	1.05	0.55	22.07
1 Nov 2010 - 31 Dec 2010	23.67	1.05	0.55	22.07
1 Jan 2011 – 31 Dec 2011	23.67	1.05	0.55	22.07
1 Jan 2012 – 31 Dec 2012	23.67	1.05	0.55	22.07
1 Jan 2013 – 31 Dec 2013	23.67	1.05	0.55	22.07
1 Jan 2014 – 31 Dec 2014	23.67	1.05	0.55	22.07
1 Jan 2015 – 31 Dec 2015	23.67	1.05	0.55	22.07
1 Jan 2016 – 31 Dec 2016	23.67	1.05	0.55	22.07
1 Jan 2017 – 10 Mar 2017	23.67	1.05	0.55	22.07

Flaring Tool result of Equation 7:

Year	$V_{n,O2,h}$	$n_{O2,h}$	MV_n
11 Mar 2010 – 31 Oct 2010	0.55	0.02	22.4
1 Nov 2010 - 31 Dec 2010	0.55	0.02	22.4
1 Jan 2011 – 31 Dec 2011	0.55	0.02	22.4
1 Jan 2012 – 31 Dec 2012	0.55	0.02	22.4
1 Jan 2013 – 31 Dec 2013	0.55	0.02	22.4
1 Jan 2014 – 31 Dec 2014	0.55	0.02	22.4
1 Jan 2015 – 31 Dec 2015	0.55	0.02	22.4
1 Jan 2016 – 31 Dec 2016	0.55	0.02	22.4
1 Jan 2017 – 10 Mar 2017	0.55	0.02	22.4

Flaring Tool result of Equation 8:

Year	$V_{n,N2,h}$	MV_n	$fm_{N,h}$	AM_n	MF_{O2}	F_h	$n_{O2,h}$
11 Mar 2010 – 31 Oct 2010	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Nov 2010 - 31 Dec 2010	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2011 – 31 Dec 2011	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2012 – 31 Dec 2012	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2013 – 31 Dec 2013	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2014 – 31 Dec 2014	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2015 – 31 Dec 2015	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2016 – 31 Dec 2016	22.07	22.4	20%	14.01	0.21	0.24	0.02
1 Jan 2017 – 10 Mar 2017	22.07	22.4	20%	14.01	0.21	0.24	0.02

Flaring Tool result of Equation 9:

Year	$V_{n,CO2,h}$	$fm_{C,h}$	AM_C	MV_n
11 Mar 2010 – 31 Oct 2010	1.05	56%	12	22.4
1 Nov 2010 - 31 Dec 2010	1.05	56%	12	22.4
1 Jan 2011 – 31 Dec 2011	1.05	56%	12	22.4
1 Jan 2012 – 31 Dec 2012	1.05	56%	12	22.4
1 Jan 2013 – 31 Dec 2013	1.05	56%	12	22.4
1 Jan 2014 – 31 Dec 2014	1.05	56%	12	22.4
1 Jan 2015 – 31 Dec 2015	1.05	56%	12	22.4
1 Jan 2016 – 31 Dec 2016	1.05	56%	12	22.4
1 Jan 2017 – 10 Mar 2017	1.05	56%	12	22.4

Flaring Tool result of Equation 10:

Year	$n_{O2,h}$	$t_{O2,h}$	$fm_{C,h}$	AM_C	$fm_{N,h}$	AM_N	MF_{O2}	F_h
11 Mar 2010 – 31 Oct 2010	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Nov 2010 - 31 Dec 2010	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2011 – 31 Dec 2011	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2012 – 31 Dec 2012	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2013 – 31 Dec 2013	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2014 – 31 Dec 2014	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2015 – 31 Dec 2015	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2016 – 31 Dec 2016	0.02	2%	56%	12	20.49%	14.01	0.21	0.24
1 Jan 2017 – 10 Mar 2017	0.02	2%	56%	12	20.49%	14.01	0.21	0.24

Flaring Tool result of Equation 11:

Year	F_h	$fm_{C,h}$	AM_C	$fm_{H,h}$	AM_H	$fm_{O,h}$	AM_O
11 Mar 2010 – 31 Oct 2010	0.24	56%	12	18.98%	1.01	4%	16
1 Nov 2010 - 31 Dec 2010	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2011 – 31 Dec 2011	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2012 – 31 Dec 2012	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2013 – 31 Dec 2013	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2014 – 31 Dec 2014	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2015 – 31 Dec 2015	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2016 – 31 Dec 2016	0.24	56%	12	18.98%	1.01	4%	16
1 Jan 2017 – 10 Mar 2017	0.24	56%	12	18.98%	1.01	4%	16

Flaring Tool result of Equation 12:

Year	$TM_{FG,h}$	$TV_{n,FG,h}$	$fv_{CH4,FG,h}$
11 Mar 2010 – 31 Oct 2010	218.45	18,819.83	11,607.51
1 Nov 2010 - 31 Dec 2010	20.01	1,723.62	11,607.51
1 Jan 2011 – 31 Dec 2011	20.01	1,723.62	11,607.51
1 Jan 2012 – 31 Dec 2012	20.01	1,723.62	11,607.51
1 Jan 2013 – 31 Dec 2013	20.01	1,723.62	11,607.51
1 Jan 2014 – 31 Dec 2014	20.01	1,723.62	11,607.51
1 Jan 2015 – 31 Dec 2015	20.01	1,723.62	11,607.51
1 Jan 2016 – 31 Dec 2016	20.01	1,723.62	11,607.51
1 Jan 2017 – 10 Mar 2017	20.01	1,723.62	11,607.51

Flaring Tool result of Equation 13:

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Oct 2010	640.26	1,047.55	85%	0.716
1 Nov 2010 - 31 Dec 2010	58.64	95.94	85%	0.716
1 Jan 2011 – 31 Dec 2011	58.64	95.94	85%	0.716
1 Jan 2012 – 31 Dec 2012	58.64	95.94	85%	0.716
1 Jan 2013 – 31 Dec 2013	58.64	95.94	85%	0.716
1 Jan 2014 – 31 Dec 2014	58.64	95.94	85%	0.716
1 Jan 2015 – 31 Dec 2015	58.64	95.94	85%	0.716
1 Jan 2016 – 31 Dec 2016	58.64	95.94	85%	0.716
1 Jan 2017 – 10 Mar 2017	58.64	95.94	85%	0.716

Flaring Tool result of Equation 14:

Year	$\eta_{flare,h}$	$TM_{FG,h}$	$TM_{RG,h}$
11 Mar 2010 – 31 Oct 2010	0.6588074	218.45	640.26
1 Nov 2010 - 31 Dec 2010	0.6588074	20.01	58.64
1 Jan 2011 – 31 Dec 2011	0.6588074	20.01	58.64
1 Jan 2012 – 31 Dec 2012	0.6588074	20.01	58.64
1 Jan 2013 – 31 Dec 2013	0.6588074	20.01	58.64
1 Jan 2014 – 31 Dec 2014	0.6588074	20.01	58.64
1 Jan 2015 – 31 Dec 2015	0.6588074	20.01	58.64
1 Jan 2016 – 31 Dec 2016	0.6588074	20.01	58.64
1 Jan 2017 – 10 Mar 2017	0.6588074	20.01	58.64

Flaring Tool result of Equation 15:

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Oct 2010	35,892.43	640.26	0.66	21
1 Nov 2010 - 31 Dec 2010	312.59	58.64	0.66	21
1 Jan 2011 – 31 Dec 2011	3,680.47	58.64	0.66	21
1 Jan 2012 – 31 Dec 2012	3,680.47	58.64	0.66	21

1 Jan 2013 – 31 Dec 2013	3,680.47	58.64	0.66	21
1 Jan 2014 – 31 Dec 2014	3,680.47	58.64	0.66	21
1 Jan 2015 – 31 Dec 2015	3,680.47	58.64	0.66	21
1 Jan 2016 – 31 Dec 2016	3,680.47	58.64	0.66	21
1 Jan 2017 – 10 Mar 2017	705.84	58.64	0.66	21

Flaring of Non-Mine Methane

Flaring at EX1

Equation 1

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$
11 Mar 2010 – 31 Dec 2010	181.04	0.7171632	252.43
1 Jan 2011 – 31 Dec 2011	181.04	0.7171632	252.43
1 Jan 2012 – 31 Dec 2012	181.04	0.7171632	252.43
1 Jan 2013 – 31 Dec 2013	181.04	0.7171632	252.43
1 Jan 2014 – 31 Dec 2014	181.04	0.7171632	252.43
1 Jan 2015 – 31 Dec 2015	181.04	0.7171632	252.43
1 Jan 2016 – 31 Dec 2016	181.04	0.7171632	252.43
1 Jan 2017 – 10 Mar 2017	181.04	0.7171632	252.43

Equation 2

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Dec 2010	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2011 – 31 Dec 2011	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2012 – 31 Dec 2012	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2013 – 31 Dec 2013	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2014 – 31 Dec 2014	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2015 – 31 Dec 2015	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2016 – 31 Dec 2016	0.717163225	101,325	8,314	16.07	273.15
1 Jan 2017 – 10 Mar 2017	0.717163225	101,325	8,314	16.07	273.15

Equation 3

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$	MM_{CO}	$fv_{CO2,h}$
11 Mar 2010 – 31 Dec 2010	16.07	1.00	16.04	0	28.01	0
1 Jan 2011 – 31 Dec 2011	16.07	1.00	16.04	0	28.01	0
1 Jan 2012 – 31 Dec 2012	16.07	1.00	16.04	0	28.01	0
1 Jan 2013 – 31 Dec 2013	16.07	1.00	16.04	0	28.01	0
1 Jan 2014 – 31 Dec 2014	16.07	1.00	16.04	0	28.01	0
1 Jan 2015 – 31 Dec 2015	16.07	1.00	16.04	0	28.01	0
1 Jan 2016 – 31 Dec 2016	16.07	1.00	16.04	0	28.01	0
1 Jan 2017 – 10 Mar 2017	16.07	1.00	16.04	0	28.01	0

Year	MM_{CO2}	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Dec 2010	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2011 – 31 Dec 2011	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2012 – 31 Dec 2012	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2013 – 31 Dec 2013	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2014 – 31 Dec 2014	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2015 – 31 Dec 2015	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2016 – 31 Dec 2016	44.01	0	32	0	2.02	0.00	28.02
1 Jan 2017 – 10 Mar 2017	44.01	0	32	0	2.02	0.00	28.02

Equation 4

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	0.74	1.00	12	1	0
1 Jan 2011 – 31 Dec 2011	0.74	1.00	12	1	0
1 Jan 2012 – 31 Dec 2012	0.74	1.00	12	1	0
1 Jan 2013 – 31 Dec 2013	0.74	1.00	12	1	0
1 Jan 2014 – 31 Dec 2014	0.74	1.00	12	1	0
1 Jan 2015 – 31 Dec 2015	0.74	1.00	12	1	0
1 Jan 2016 – 31 Dec 2016	0.74	1.00	12	1	0
1 Jan 2017 – 10 Mar 2017	0.74	1.00	12	1	0

Year	$NA_{C,CO}$	$fv_{CO2,h}$	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	1	0	1	16.07
1 Jan 2011 – 31 Dec 2011	1	0	1	16.07
1 Jan 2012 – 31 Dec 2012	1	0	1	16.07
1 Jan 2013 – 31 Dec 2013	1	0	1	16.07
1 Jan 2014 – 31 Dec 2014	1	0	1	16.07
1 Jan 2015 – 31 Dec 2015	1	0	1	16.07
1 Jan 2016 – 31 Dec 2016	1	0	1	16.07
1 Jan 2017 – 10 Mar 2017	1	0	1	16.07

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$	$fv_{H2,h}$
11 Mar 2010 – 31 Dec 2010	0.25	1.00	1.01	4	0
1 Jan 2011 – 31 Dec 2011	0.25	1.00	1.01	4	0
1 Jan 2012 – 31 Dec 2012	0.25	1.00	1.01	4	0

1 Jan 2013 – 31 Dec 2013	0.25	1.00	1.01	4	0
1 Jan 2014 – 31 Dec 2014	0.25	1.00	1.01	4	0
1 Jan 2015 – 31 Dec 2015	0.25	1.00	1.01	4	0
1 Jan 2016 – 31 Dec 2016	0.25	1.00	1.01	4	0
1 Jan 2017 – 10 Mar 2017	0.25	1.00	1.01	4	0

Year	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	2	16.07
1 Jan 2011 – 31 Dec 2011	2	16.07
1 Jan 2012 – 31 Dec 2012	2	16.07
1 Jan 2013 – 31 Dec 2013	2	16.07
1 Jan 2014 – 31 Dec 2014	2	16.07
1 Jan 2015 – 31 Dec 2015	2	16.07
1 Jan 2016 – 31 Dec 2016	2	16.07
1 Jan 2017 – 10 Mar 2017	2	16.07

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0.00	0.00	14.01	2	16.07
1 Jan 2011 – 31 Dec 2011	0.00	0.00	14.01	2	16.07
1 Jan 2012 – 31 Dec 2012	0.00	0.00	14.01	2	16.07
1 Jan 2013 – 31 Dec 2013	0.00	0.00	14.01	2	16.07
1 Jan 2014 – 31 Dec 2014	0.00	0.00	14.01	2	16.07
1 Jan 2015 – 31 Dec 2015	0.00	0.00	14.01	2	16.07
1 Jan 2016 – 31 Dec 2016	0.00	0.00	14.01	2	16.07
1 Jan 2017 – 10 Mar 2017	0.00	0.00	14.01	2	16.07

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$
11 Mar 2010 – 31 Dec 2010	0	0	16	2	0	1
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1

Year	$fv_{CO2,h}$	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.07
1 Jan 2011 – 31 Dec 2011	0	2	16.07
1 Jan 2012 – 31 Dec 2012	0	2	16.07
1 Jan 2013 – 31 Dec 2013	0	2	16.07

1 Jan 2014 – 31 Dec 2014	0	2	16.07
1 Jan 2015 – 31 Dec 2015	0	2	16.07
1 Jan 2016 – 31 Dec 2016	0	2	16.07
1 Jan 2017 – 10 Mar 2017	0	2	16.07

Equation 13

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Dec 2010	168.66	252.43	99.72%	0.67
1 Jan 2011 – 31 Dec 2011	168.66	252.43	99.72%	0.67
1 Jan 2012 – 31 Dec 2012	168.66	252.43	99.72%	0.67
1 Jan 2013 – 31 Dec 2013	168.66	252.43	99.72%	0.67
1 Jan 2014 – 31 Dec 2014	168.66	252.43	99.72%	0.67
1 Jan 2015 – 31 Dec 2015	168.66	252.43	99.72%	0.67
1 Jan 2016 – 31 Dec 2016	168.66	252.43	99.72%	0.67
1 Jan 2017 – 10 Mar 2017	168.66	252.43	99.72%	0.67

Equation 14

Year	$\eta_{flare,h}$
11 Mar 2010 – 31 Dec 2010	0.9
1 Jan 2011 – 31 Dec 2011	0.9
1 Jan 2012 – 31 Dec 2012	0.9
1 Jan 2013 – 31 Dec 2013	0.9
1 Jan 2014 – 31 Dec 2014	0.9
1 Jan 2015 – 31 Dec 2015	0.9
1 Jan 2016 – 31 Dec 2016	0.9
1 Jan 2017 – 10 Mar 2017	0.9

Equation 15

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	2,507.59	168.66	0.90	21
1 Jan 2011 – 31 Dec 2011	3,102.62	168.66	0.90	21
1 Jan 2012 – 31 Dec 2012	3,102.62	168.66	0.90	21
1 Jan 2013 – 31 Dec 2013	3,102.62	168.66	0.90	21
1 Jan 2014 – 31 Dec 2014	3,102.62	168.66	0.90	21
1 Jan 2015 – 31 Dec 2015	3,102.62	168.66	0.90	21
1 Jan 2016 – 31 Dec 2016	3,102.62	168.66	0.90	21
1 Jan 2017 – 10 Mar 2017	595.02	168.66	0.90	21

Flaring at ST23

Equation 1

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$

11 Mar 2010 – 31 Dec 2010	252.48	0.7208482	350.26
1 Jan 2011 – 31 Dec 2011	252.48	0.7208482	350.26
1 Jan 2012 – 31 Dec 2012	252.48	0.7208482	350.26
1 Jan 2013 – 31 Dec 2013	252.48	0.7208482	350.26
1 Jan 2014 – 31 Dec 2014	252.48	0.7208482	350.26
1 Jan 2015 – 31 Dec 2015	252.48	0.7208482	350.26
1 Jan 2016 – 31 Dec 2016	252.48	0.7208482	350.26
1 Jan 2017 – 10 Mar 2017	252.48	0.7208482	350.26

Equation 2

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Dec 2010	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2011 – 31 Dec 2011	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2012 – 31 Dec 2012	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2013 – 31 Dec 2013	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2014 – 31 Dec 2014	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2015 – 31 Dec 2015	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2016 – 31 Dec 2016	0.720848159	101,325	8,314	16.16	273.15
1 Jan 2017 – 10 Mar 2017	0.720848159	101,325	8,314	16.16	273.15

Equation 3

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$	MM_{CO}
11 Mar 2010 – 31 Dec 2010	16.16	0.99	16.04	0	28.01
1 Jan 2011 – 31 Dec 2011	16.16	0.99	16.04	0	28.01
1 Jan 2012 – 31 Dec 2012	16.16	0.99	16.04	0	28.01
1 Jan 2013 – 31 Dec 2013	16.16	0.99	16.04	0	28.01
1 Jan 2014 – 31 Dec 2014	16.16	0.99	16.04	0	28.01
1 Jan 2015 – 31 Dec 2015	16.16	0.99	16.04	0	28.01
1 Jan 2016 – 31 Dec 2016	16.16	0.99	16.04	0	28.01
1 Jan 2017 – 10 Mar 2017	16.16	0.99	16.04	0	28.01

Year	$fv_{CO2,h}$	MM_{CO2}
11 Mar 2010 – 31 Dec 2010	0	44.01
1 Jan 2011 – 31 Dec 2011	0	44.01
1 Jan 2012 – 31 Dec 2012	0	44.01
1 Jan 2013 – 31 Dec 2013	0	44.01
1 Jan 2014 – 31 Dec 2014	0	44.01
1 Jan 2015 – 31 Dec 2015	0	44.01
1 Jan 2016 – 31 Dec 2016	0	44.01
1 Jan 2017 – 10 Mar 2017	0	44.01

Year	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Dec 2010	0	32	0	2.02	0.01	28.02
1 Jan 2011 – 31 Dec 2011	0	32	0	2.02	0.01	28.02
1 Jan 2012 – 31 Dec 2012	0	32	0	2.02	0.01	28.02
1 Jan 2013 – 31 Dec 2013	0	32	0	2.02	0.01	28.02
1 Jan 2014 – 31 Dec 2014	0	32	0	2.02	0.01	28.02
1 Jan 2015 – 31 Dec 2015	0	32	0	2.02	0.01	28.02
1 Jan 2016 – 31 Dec 2016	0	32	0	2.02	0.01	28.02
1 Jan 2017 – 10 Mar 2017	0	32	0	2.02	0.01	28.02

Equation 4

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	0.74	0.99	12	1	0
1 Jan 2011 – 31 Dec 2011	0.74	0.99	12	1	0
1 Jan 2012 – 31 Dec 2012	0.74	0.99	12	1	0
1 Jan 2013 – 31 Dec 2013	0.74	0.99	12	1	0
1 Jan 2014 – 31 Dec 2014	0.74	0.99	12	1	0
1 Jan 2015 – 31 Dec 2015	0.74	0.99	12	1	0
1 Jan 2016 – 31 Dec 2016	0.74	0.99	12	1	0
1 Jan 2017 – 10 Mar 2017	0.74	0.99	12	1	0

Year	$NA_{C,CO}$	$fv_{CO2,h}$	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	1	0	1	16.16
1 Jan 2011 – 31 Dec 2011	1	0	1	16.16
1 Jan 2012 – 31 Dec 2012	1	0	1	16.16
1 Jan 2013 – 31 Dec 2013	1	0	1	16.16
1 Jan 2014 – 31 Dec 2014	1	0	1	16.16
1 Jan 2015 – 31 Dec 2015	1	0	1	16.16
1 Jan 2016 – 31 Dec 2016	1	0	1	16.16
1 Jan 2017 – 10 Mar 2017	1	0	1	16.16

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$	$fv_{H2,h}$
11 Mar 2010 – 31 Dec 2010	0.25	0.99	1.01	4	0
1 Jan 2011 – 31 Dec 2011	0.25	0.99	1.01	4	0
1 Jan 2012 – 31 Dec 2012	0.25	0.99	1.01	4	0
1 Jan 2013 – 31 Dec 2013	0.25	0.99	1.01	4	0
1 Jan 2014 – 31 Dec 2014	0.25	0.99	1.01	4	0
1 Jan 2015 – 31 Dec 2015	0.25	0.99	1.01	4	0
1 Jan 2016 – 31 Dec 2016	0.25	0.99	1.01	4	0
1 Jan 2017 – 10 Mar 2017	0.25	0.99	1.01	4	0

Year	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	2	16.16
1 Jan 2011 – 31 Dec 2011	2	16.16
1 Jan 2012 – 31 Dec 2012	2	16.16
1 Jan 2013 – 31 Dec 2013	2	16.16
1 Jan 2014 – 31 Dec 2014	2	16.16
1 Jan 2015 – 31 Dec 2015	2	16.16
1 Jan 2016 – 31 Dec 2016	2	16.16
1 Jan 2017 – 10 Mar 2017	2	16.16

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0.02	0.01	14.01	2	16.16
1 Jan 2011 – 31 Dec 2011	0.02	0.01	14.01	2	16.16
1 Jan 2012 – 31 Dec 2012	0.02	0.01	14.01	2	16.16
1 Jan 2013 – 31 Dec 2013	0.02	0.01	14.01	2	16.16
1 Jan 2014 – 31 Dec 2014	0.02	0.01	14.01	2	16.16
1 Jan 2015 – 31 Dec 2015	0.02	0.01	14.01	2	16.16
1 Jan 2016 – 31 Dec 2016	0.02	0.01	14.01	2	16.16
1 Jan 2017 – 10 Mar 2017	0.02	0.01	14.01	2	16.16

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$
11 Mar 2010 – 31 Dec 2010	0	0	16	2	0	1
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1

Year	$fv_{CO2,h}$	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.16
1 Jan 2011 – 31 Dec 2011	0	2	16.16
1 Jan 2012 – 31 Dec 2012	0	2	16.16
1 Jan 2013 – 31 Dec 2013	0	2	16.16
1 Jan 2014 – 31 Dec 2014	0	2	16.16
1 Jan 2015 – 31 Dec 2015	0	2	16.16
1 Jan 2016 – 31 Dec 2016	0	2	16.16
1 Jan 2017 – 10 Mar 2017	0	2	16.16

Equation 13

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Dec 2010	232.40	350.26	99.03%	0.67
1 Jan 2011 – 31 Dec 2011	232.40	350.26	99.03%	0.67
1 Jan 2012 – 31 Dec 2012	232.40	350.26	99.03%	0.67
1 Jan 2013 – 31 Dec 2013	232.40	350.26	99.03%	0.67
1 Jan 2014 – 31 Dec 2014	232.40	350.26	99.03%	0.67
1 Jan 2015 – 31 Dec 2015	232.40	350.26	99.03%	0.67
1 Jan 2016 – 31 Dec 2016	232.40	350.26	99.03%	0.67
1 Jan 2017 – 10 Mar 2017	232.40	350.26	99.03%	0.67

Equation 14

Year	$\eta_{flare,h}$
11 Mar 2010 – 31 Dec 2010	0.9
1 Jan 2011 – 31 Dec 2011	0.9
1 Jan 2012 – 31 Dec 2012	0.9
1 Jan 2013 – 31 Dec 2013	0.9
1 Jan 2014 – 31 Dec 2014	0.9
1 Jan 2015 – 31 Dec 2015	0.9
1 Jan 2016 – 31 Dec 2016	0.9
1 Jan 2017 – 10 Mar 2017	0.9

Equation 15

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	3,455.29	232.40	0.90	21
1 Jan 2011 – 31 Dec 2011	4,275.19	232.40	0.90	21
1 Jan 2012 – 31 Dec 2012	4,275.19	232.40	0.90	21
1 Jan 2013 – 31 Dec 2013	4,275.19	232.40	0.90	21
1 Jan 2014 – 31 Dec 2014	4,275.19	232.40	0.90	21
1 Jan 2015 – 31 Dec 2015	4,275.19	232.40	0.90	21
1 Jan 2016 – 31 Dec 2016	4,275.19	232.40	0.90	21
1 Jan 2017 – 10 Mar 2017	819.90	232.40	0.90	21

Flaring at DBE1

Equation 1

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$
11 Mar 2010 – 31 Dec 2010	33.91	0.715665	47.38
1 Jan 2011 – 31 Dec 2011	33.91	0.715665	47.38
1 Jan 2012 – 31 Dec 2012	33.91	0.715665	47.38
1 Jan 2013 – 31 Dec 2013	33.91	0.715665	47.38
1 Jan 2014 – 31 Dec 2014	33.91	0.715665	47.38

1 Jan 2015 – 31 Dec 2015	33.91	0.715665	47.38
1 Jan 2016 – 31 Dec 2016	33.91	0.715665	47.38
1 Jan 2017 – 10 Mar 2017	33.91	0.715665	47.38

Equation 2

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Dec 2010	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2011 – 31 Dec 2011	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2012 – 31 Dec 2012	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2013 – 31 Dec 2013	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2014 – 31 Dec 2014	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2015 – 31 Dec 2015	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2016 – 31 Dec 2016	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2017 – 10 Mar 2017	0.715664956	101,325	8,314	16.04	273.15

Equation 3

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	16.04	1.00	16.04	0
1 Jan 2011 – 31 Dec 2011	16.04	1.00	16.04	0
1 Jan 2012 – 31 Dec 2012	16.04	1.00	16.04	0
1 Jan 2013 – 31 Dec 2013	16.04	1.00	16.04	0
1 Jan 2014 – 31 Dec 2014	16.04	1.00	16.04	0
1 Jan 2015 – 31 Dec 2015	16.04	1.00	16.04	0
1 Jan 2016 – 31 Dec 2016	16.04	1.00	16.04	0
1 Jan 2017 – 10 Mar 2017	16.04	1.00	16.04	0

Year	MM_{CO}	$fv_{CO2,h}$	MM_{CO2}
11 Mar 2010 – 31 Dec 2010	28.01	0	44.01
1 Jan 2011 – 31 Dec 2011	28.01	0	44.01
1 Jan 2012 – 31 Dec 2012	28.01	0	44.01
1 Jan 2013 – 31 Dec 2013	28.01	0	44.01
1 Jan 2014 – 31 Dec 2014	28.01	0	44.01
1 Jan 2015 – 31 Dec 2015	28.01	0	44.01
1 Jan 2016 – 31 Dec 2016	28.01	0	44.01
1 Jan 2017 – 10 Mar 2017	28.01	0	44.01

Year	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Dec 2010	0	32	0	2.02	0	28.02
1 Jan 2011 – 31 Dec 2011	0	32	0	2.02	0	28.02
1 Jan 2012 – 31 Dec 2012	0	32	0	2.02	0	28.02
1 Jan 2013 – 31 Dec 2013	0	32	0	2.02	0	28.02
1 Jan 2014 – 31 Dec 2014	0	32	0	2.02	0	28.02

1 Jan 2015 – 31 Dec 2015	0	32	0	2.02	0	28.02
1 Jan 2016 – 31 Dec 2016	0	32	0	2.02	0	28.02
1 Jan 2017 – 10 Mar 2017	0	32	0	2.02	0	28.02

Equation 4

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	0.75	1.00	12	1	0
1 Jan 2011 – 31 Dec 2011	0.75	1.00	12	1	0
1 Jan 2012 – 31 Dec 2012	0.75	1.00	12	1	0
1 Jan 2013 – 31 Dec 2013	0.75	1.00	12	1	0
1 Jan 2014 – 31 Dec 2014	0.75	1.00	12	1	0
1 Jan 2015 – 31 Dec 2015	0.75	1.00	12	1	0
1 Jan 2016 – 31 Dec 2016	0.75	1.00	12	1	0
1 Jan 2017 – 10 Mar 2017	0.75	1.00	12	1	0

Year	$NA_{C,CO}$	$fv_{CO2,h}$	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	1	0	1	16.04
1 Jan 2011 – 31 Dec 2011	1	0	1	16.04
1 Jan 2012 – 31 Dec 2012	1	0	1	16.04
1 Jan 2013 – 31 Dec 2013	1	0	1	16.04
1 Jan 2014 – 31 Dec 2014	1	0	1	16.04
1 Jan 2015 – 31 Dec 2015	1	0	1	16.04
1 Jan 2016 – 31 Dec 2016	1	0	1	16.04
1 Jan 2017 – 10 Mar 2017	1	0	1	16.04

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$	$fv_{H2,h}$
11 Mar 2010 – 31 Dec 2010	0.25	1.00	1.01	4	0
1 Jan 2011 – 31 Dec 2011	0.25	1.00	1.01	4	0
1 Jan 2012 – 31 Dec 2012	0.25	1.00	1.01	4	0
1 Jan 2013 – 31 Dec 2013	0.25	1.00	1.01	4	0
1 Jan 2014 – 31 Dec 2014	0.25	1.00	1.01	4	0
1 Jan 2015 – 31 Dec 2015	0.25	1.00	1.01	4	0
1 Jan 2016 – 31 Dec 2016	0.25	1.00	1.01	4	0
1 Jan 2017 – 10 Mar 2017	0.25	1.00	1.01	4	0

Year	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	2	16.04
1 Jan 2011 – 31 Dec 2011	2	16.04
1 Jan 2012 – 31 Dec 2012	2	16.04
1 Jan 2013 – 31 Dec 2013	2	16.04
1 Jan 2014 – 31 Dec 2014	2	16.04
1 Jan 2015 – 31 Dec 2015	2	16.04

1 Jan 2016 – 31 Dec 2016	2	16.04
1 Jan 2017 – 10 Mar 2017	2	16.04

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	-	-	14.01	2	16.04
1 Jan 2011 – 31 Dec 2011	-	-	14.01	2	16.04
1 Jan 2012 – 31 Dec 2012	-	-	14.01	2	16.04
1 Jan 2013 – 31 Dec 2013	-	-	14.01	2	16.04
1 Jan 2014 – 31 Dec 2014	-	-	14.01	2	16.04
1 Jan 2015 – 31 Dec 2015	-	-	14.01	2	16.04
1 Jan 2016 – 31 Dec 2016	-	-	14.01	2	16.04
1 Jan 2017 – 10 Mar 2017	-	-	14.01	2	16.04

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$
11 Mar 2010 – 31 Dec 2010	0	0	16	2	0	1
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1

Year	$fv_{CO2,h}$	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.04
1 Jan 2011 – 31 Dec 2011	0	2	16.04
1 Jan 2012 – 31 Dec 2012	0	2	16.04
1 Jan 2013 – 31 Dec 2013	0	2	16.04
1 Jan 2014 – 31 Dec 2014	0	2	16.04
1 Jan 2015 – 31 Dec 2015	0	2	16.04
1 Jan 2016 – 31 Dec 2016	0	2	16.04
1 Jan 2017 – 10 Mar 2017	0	2	16.04

Equation 13

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Dec 2010	31.74	47.38	100.00%	0.67
1 Jan 2011 – 31 Dec 2011	31.74	47.38	100.00%	0.67
1 Jan 2012 – 31 Dec 2012	31.74	47.38	100.00%	0.67
1 Jan 2013 – 31 Dec 2013	31.74	47.38	100.00%	0.67
1 Jan 2014 – 31 Dec 2014	31.74	47.38	100.00%	0.67
1 Jan 2015 – 31 Dec 2015	31.74	47.38	100.00%	0.67

1 Jan 2016 – 31 Dec 2016	31.74	47.38	100.00%	0.67
1 Jan 2017 – 10 Mar 2017	31.74	47.38	100.00%	0.67

Equation 14

Year	$\eta_{flare,h}$
11 Mar 2010 – 31 Dec 2010	0.9
1 Jan 2011 – 31 Dec 2011	0.9
1 Jan 2012 – 31 Dec 2012	0.9
1 Jan 2013 – 31 Dec 2013	0.9
1 Jan 2014 – 31 Dec 2014	0.9
1 Jan 2015 – 31 Dec 2015	0.9
1 Jan 2016 – 31 Dec 2016	0.9
1 Jan 2017 – 10 Mar 2017	0.9

Equation 15

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	471.94	31.74	0.90	21
1 Jan 2011 – 31 Dec 2011	583.92	31.74	0.90	21
1 Jan 2012 – 31 Dec 2012	583.92	31.74	0.90	21
1 Jan 2013 – 31 Dec 2013	583.92	31.74	0.90	21
1 Jan 2014 – 31 Dec 2014	583.92	31.74	0.90	21
1 Jan 2015 – 31 Dec 2015	583.92	31.74	0.90	21
1 Jan 2016 – 31 Dec 2016	583.92	31.74	0.90	21
1 Jan 2017 – 10 Mar 2017	111.99	31.74	0.90	21

Flaring at 2264

Equation 1

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$
11 Mar 2010 – 31 Dec 2010	29.55	0.715665	41.29
1 Jan 2011 – 31 Dec 2011	29.55	0.715665	41.29
1 Jan 2012 – 31 Dec 2012	29.55	0.715665	41.29
1 Jan 2013 – 31 Dec 2013	29.55	0.715665	41.29
1 Jan 2014 – 31 Dec 2014	29.55	0.715665	41.29
1 Jan 2015 – 31 Dec 2015	29.55	0.715665	41.29
1 Jan 2016 – 31 Dec 2016	29.55	0.715665	41.29
1 Jan 2017 – 10 Mar 2017	29.55	0.715665	41.29

Equation 2

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Dec 2010	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2011 – 31 Dec 2011	0.715664956	101,325	8,314	16.04	273.15

1 Jan 2012 – 31 Dec 2012	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2013 – 31 Dec 2013	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2014 – 31 Dec 2014	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2015 – 31 Dec 2015	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2016 – 31 Dec 2016	0.715664956	101,325	8,314	16.04	273.15
1 Jan 2017 – 10 Mar 2017	0.715664956	101,325	8,314	16.04	273.15

Equation 3

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$	MM_{CO}
11 Mar 2010 – 31 Dec 2010	16.04	1.00	16.04	0	28.01
1 Jan 2011 – 31 Dec 2011	16.04	1.00	16.04	0	28.01
1 Jan 2012 – 31 Dec 2012	16.04	1.00	16.04	0	28.01
1 Jan 2013 – 31 Dec 2013	16.04	1.00	16.04	0	28.01
1 Jan 2014 – 31 Dec 2014	16.04	1.00	16.04	0	28.01
1 Jan 2015 – 31 Dec 2015	16.04	1.00	16.04	0	28.01
1 Jan 2016 – 31 Dec 2016	16.04	1.00	16.04	0	28.01
1 Jan 2017 – 10 Mar 2017	16.04	1.00	16.04	0	28.01

Year	$fv_{CO2,h}$	MM_{CO2}
11 Mar 2010 – 31 Dec 2010	0	44.01
1 Jan 2011 – 31 Dec 2011	0	44.01
1 Jan 2012 – 31 Dec 2012	0	44.01
1 Jan 2013 – 31 Dec 2013	0	44.01
1 Jan 2014 – 31 Dec 2014	0	44.01
1 Jan 2015 – 31 Dec 2015	0	44.01
1 Jan 2016 – 31 Dec 2016	0	44.01
1 Jan 2017 – 10 Mar 2017	0	44.01

Year	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Dec 2010	0	32	0	2.02	0	28.02
1 Jan 2011 – 31 Dec 2011	0	32	0	2.02	0	28.02
1 Jan 2012 – 31 Dec 2012	0	32	0	2.02	0	28.02
1 Jan 2013 – 31 Dec 2013	0	32	0	2.02	0	28.02
1 Jan 2014 – 31 Dec 2014	0	32	0	2.02	0	28.02
1 Jan 2015 – 31 Dec 2015	0	32	0	2.02	0	28.02
1 Jan 2016 – 31 Dec 2016	0	32	0	2.02	0	28.02
1 Jan 2017 – 10 Mar 2017	0	32	0	2.02	0	28.02

Equation 4

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	0.75	1.00	12	1	0
1 Jan 2011 – 31 Dec 2011	0.75	1.00	12	1	0

1 Jan 2012 – 31 Dec 2012	0.75	1.00	12	1	0
1 Jan 2013 – 31 Dec 2013	0.75	1.00	12	1	0
1 Jan 2014 – 31 Dec 2014	0.75	1.00	12	1	0
1 Jan 2015 – 31 Dec 2015	0.75	1.00	12	1	0
1 Jan 2016 – 31 Dec 2016	0.75	1.00	12	1	0
1 Jan 2017 – 10 Mar 2017	0.75	1.00	12	1	0

Year	$NA_{C,CO}$	$fv_{CO2,h}$	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	1	0	1	16.04
1 Jan 2011 – 31 Dec 2011	1	0	1	16.04
1 Jan 2012 – 31 Dec 2012	1	0	1	16.04
1 Jan 2013 – 31 Dec 2013	1	0	1	16.04
1 Jan 2014 – 31 Dec 2014	1	0	1	16.04
1 Jan 2015 – 31 Dec 2015	1	0	1	16.04
1 Jan 2016 – 31 Dec 2016	1	0	1	16.04
1 Jan 2017 – 10 Mar 2017	1	0	1	16.04

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$
11 Mar 2010 – 31 Dec 2010	0.25	1.00	1.01	4
1 Jan 2011 – 31 Dec 2011	0.25	1.00	1.01	4
1 Jan 2012 – 31 Dec 2012	0.25	1.00	1.01	4
1 Jan 2013 – 31 Dec 2013	0.25	1.00	1.01	4
1 Jan 2014 – 31 Dec 2014	0.25	1.00	1.01	4
1 Jan 2015 – 31 Dec 2015	0.25	1.00	1.01	4
1 Jan 2016 – 31 Dec 2016	0.25	1.00	1.01	4
1 Jan 2017 – 10 Mar 2017	0.25	1.00	1.01	4

Year	$fv_{H2,h}$	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.04
1 Jan 2011 – 31 Dec 2011	0	2	16.04
1 Jan 2012 – 31 Dec 2012	0	2	16.04
1 Jan 2013 – 31 Dec 2013	0	2	16.04
1 Jan 2014 – 31 Dec 2014	0	2	16.04
1 Jan 2015 – 31 Dec 2015	0	2	16.04
1 Jan 2016 – 31 Dec 2016	0	2	16.04
1 Jan 2017 – 10 Mar 2017	0	2	16.04

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	-	-	14.01	2	16.04
1 Jan 2011 – 31 Dec 2011	-	-	14.01	2	16.04
1 Jan 2012 – 31 Dec 2012	-	-	14.01	2	16.04

1 Jan 2013 – 31 Dec 2013	-	-	14.01	2	16.04
1 Jan 2014 – 31 Dec 2014	-	-	14.01	2	16.04
1 Jan 2015 – 31 Dec 2015	-	-	14.01	2	16.04
1 Jan 2016 – 31 Dec 2016	-	-	14.01	2	16.04
1 Jan 2017 – 10 Mar 2017	-	-	14.01	2	16.04

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$
11 Mar 2010 – 31 Dec 2010	0	0	16	2	0	1
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1

Year	$fv_{CO2,h}$	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.04
1 Jan 2011 – 31 Dec 2011	0	2	16.04
1 Jan 2012 – 31 Dec 2012	0	2	16.04
1 Jan 2013 – 31 Dec 2013	0	2	16.04
1 Jan 2014 – 31 Dec 2014	0	2	16.04
1 Jan 2015 – 31 Dec 2015	0	2	16.04
1 Jan 2016 – 31 Dec 2016	0	2	16.04
1 Jan 2017 – 10 Mar 2017	0	2	16.04

Equation 13

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Dec 2010	27.67	41.29	100.00%	0.67
1 Jan 2011 – 31 Dec 2011	27.67	41.29	100.00%	0.67
1 Jan 2012 – 31 Dec 2012	27.67	41.29	100.00%	0.67
1 Jan 2013 – 31 Dec 2013	27.67	41.29	100.00%	0.67
1 Jan 2014 – 31 Dec 2014	27.67	41.29	100.00%	0.67
1 Jan 2015 – 31 Dec 2015	27.67	41.29	100.00%	0.67
1 Jan 2016 – 31 Dec 2016	27.67	41.29	100.00%	0.67
1 Jan 2017 – 10 Mar 2017	27.67	41.29	100.00%	0.67

Equation 14

Year	$\eta_{flare,h}$
11 Mar 2010 – 31 Dec 2010	0.9
1 Jan 2011 – 31 Dec 2011	0.9
1 Jan 2012 – 31 Dec 2012	0.9

1 Jan 2013 – 31 Dec 2013	0.9
1 Jan 2014 – 31 Dec 2014	0.9
1 Jan 2015 – 31 Dec 2015	0.9
1 Jan 2016 – 31 Dec 2016	0.9
1 Jan 2017 – 10 Mar 2017	0.9

Equation 15

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	411.33	27.67	0.90	21
1 Jan 2011 – 31 Dec 2011	508.94	27.67	0.90	21
1 Jan 2012 – 31 Dec 2012	508.94	27.67	0.90	21
1 Jan 2013 – 31 Dec 2013	508.94	27.67	0.90	21
1 Jan 2014 – 31 Dec 2014	508.94	27.67	0.90	21
1 Jan 2015 – 31 Dec 2015	508.94	27.67	0.90	21
1 Jan 2016 – 31 Dec 2016	508.94	27.67	0.90	21
1 Jan 2017 – 10 Mar 2017	97.60	27.67	0.90	21

Flaring at 1400

Equation 1

Year	$FM_{RG,h}$	$\rho_{RG,n,h}$	$FV_{RG,h}$
11 Mar 2010 – 31 Dec 2010	66.51	0.7186583	92.55
1 Jan 2011 – 31 Dec 2011	66.51	0.7186583	92.55
1 Jan 2012 – 31 Dec 2012	66.51	0.7186583	92.55
1 Jan 2013 – 31 Dec 2013	66.51	0.7186583	92.55
1 Jan 2014 – 31 Dec 2014	66.51	0.7186583	92.55
1 Jan 2015 – 31 Dec 2015	66.51	0.7186583	92.55
1 Jan 2016 – 31 Dec 2016	66.51	0.7186583	92.55
1 Jan 2017 – 10 Mar 2017	66.51	0.7186583	92.55

Equation 2

Year	$\rho_{RG,n,h}$	P_n	R_u	$MM_{RG,h}$	T_n
11 Mar 2010 – 31 Dec 2010	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2011 – 31 Dec 2011	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2012 – 31 Dec 2012	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2013 – 31 Dec 2013	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2014 – 31 Dec 2014	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2015 – 31 Dec 2015	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2016 – 31 Dec 2016	0.718658255	101,325	8,314	16.11	273.15
1 Jan 2017 – 10 Mar 2017	0.718658255	101,325	8,314	16.11	273.15

Equation 3

Year	$MM_{RG,h}$	$fv_{CH4,h}$	MM_{CH4}	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	16.11	0.99	16.04	0
1 Jan 2011 – 31 Dec 2011	16.11	0.99	16.04	0
1 Jan 2012 – 31 Dec 2012	16.11	0.99	16.04	0
1 Jan 2013 – 31 Dec 2013	16.11	0.99	16.04	0
1 Jan 2014 – 31 Dec 2014	16.11	0.99	16.04	0
1 Jan 2015 – 31 Dec 2015	16.11	0.99	16.04	0
1 Jan 2016 – 31 Dec 2016	16.11	0.99	16.04	0
1 Jan 2017 – 10 Mar 2017	16.11	0.99	16.04	0

Year	MM_{CO}	$fv_{CO2,h}$	MM_{CO2}
11 Mar 2010 – 31 Dec 2010	28.01	0	44.01
1 Jan 2011 – 31 Dec 2011	28.01	0	44.01
1 Jan 2012 – 31 Dec 2012	28.01	0	44.01
1 Jan 2013 – 31 Dec 2013	28.01	0	44.01
1 Jan 2014 – 31 Dec 2014	28.01	0	44.01
1 Jan 2015 – 31 Dec 2015	28.01	0	44.01
1 Jan 2016 – 31 Dec 2016	28.01	0	44.01
1 Jan 2017 – 10 Mar 2017	28.01	0	44.01

Year	$fv_{O2,h}$	MM_{O2}	$fv_{H2,h}$	MM_{H2}	$fv_{N2,h}$	MM_{N2}
11 Mar 2010 – 31 Dec 2010	0	32	0	2.02	0.01	28.02
1 Jan 2011 – 31 Dec 2011	0	32	0	2.02	0.01	28.02
1 Jan 2012 – 31 Dec 2012	0	32	0	2.02	0.01	28.02
1 Jan 2013 – 31 Dec 2013	0	32	0	2.02	0.01	28.02
1 Jan 2014 – 31 Dec 2014	0	32	0	2.02	0.01	28.02
1 Jan 2015 – 31 Dec 2015	0	32	0	2.02	0.01	28.02
1 Jan 2016 – 31 Dec 2016	0	32	0	2.02	0.01	28.02
1 Jan 2017 – 10 Mar 2017	0	32	0	2.02	0.01	28.02

Equation 4

Year	$fm_{C,h}$	$fv_{CH4,h}$	AM_C	$NA_{C,CH4}$	$fv_{CO,h}$
11 Mar 2010 – 31 Dec 2010	0.74	0.99	12	1	0
1 Jan 2011 – 31 Dec 2011	0.74	0.99	12	1	0
1 Jan 2012 – 31 Dec 2012	0.74	0.99	12	1	0
1 Jan 2013 – 31 Dec 2013	0.74	0.99	12	1	0
1 Jan 2014 – 31 Dec 2014	0.74	0.99	12	1	0
1 Jan 2015 – 31 Dec 2015	0.74	0.99	12	1	0
1 Jan 2016 – 31 Dec 2016	0.74	0.99	12	1	0
1 Jan 2017 – 10 Mar 2017	0.74	0.99	12	1	0

Year	$NA_{C,CO}$	$fv_{CO2,h}$	$NA_{C,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	1	0	1	16.11
1 Jan 2011 – 31 Dec 2011	1	0	1	16.11
1 Jan 2012 – 31 Dec 2012	1	0	1	16.11
1 Jan 2013 – 31 Dec 2013	1	0	1	16.11
1 Jan 2014 – 31 Dec 2014	1	0	1	16.11
1 Jan 2015 – 31 Dec 2015	1	0	1	16.11
1 Jan 2016 – 31 Dec 2016	1	0	1	16.11
1 Jan 2017 – 10 Mar 2017	1	0	1	16.11

Year	$fm_{H,h}$	$fv_{CH4,h}$	AM_H	$NA_{H,CH4}$	$fv_{H2,h}$
11 Mar 2010 – 31 Dec 2010	0.25	0.99	1.01	4	0
1 Jan 2011 – 31 Dec 2011	0.25	0.99	1.01	4	0
1 Jan 2012 – 31 Dec 2012	0.25	0.99	1.01	4	0
1 Jan 2013 – 31 Dec 2013	0.25	0.99	1.01	4	0
1 Jan 2014 – 31 Dec 2014	0.25	0.99	1.01	4	0
1 Jan 2015 – 31 Dec 2015	0.25	0.99	1.01	4	0
1 Jan 2016 – 31 Dec 2016	0.25	0.99	1.01	4	0
1 Jan 2017 – 10 Mar 2017	0.25	0.99	1.01	4	0

Year	$NA_{H,H2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	2	16.11
1 Jan 2011 – 31 Dec 2011	2	16.11
1 Jan 2012 – 31 Dec 2012	2	16.11
1 Jan 2013 – 31 Dec 2013	2	16.11
1 Jan 2014 – 31 Dec 2014	2	16.11
1 Jan 2015 – 31 Dec 2015	2	16.11
1 Jan 2016 – 31 Dec 2016	2	16.11
1 Jan 2017 – 10 Mar 2017	2	16.11

Year	$fm_{N,h}$	$fv_{N2,h}$	AM_N	$NA_{N,N2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0.01	0.01	14.01	2	16.11
1 Jan 2011 – 31 Dec 2011	0.01	0.01	14.01	2	16.11
1 Jan 2012 – 31 Dec 2012	0.01	0.01	14.01	2	16.11
1 Jan 2013 – 31 Dec 2013	0.01	0.01	14.01	2	16.11
1 Jan 2014 – 31 Dec 2014	0.01	0.01	14.01	2	16.11
1 Jan 2015 – 31 Dec 2015	0.01	0.01	14.01	2	16.11
1 Jan 2016 – 31 Dec 2016	0.01	0.01	14.01	2	16.11
1 Jan 2017 – 10 Mar 2017	0.01	0.01	14.01	2	16.11

Year	$fm_{O,h}$	$fv_{O2,h}$	AM_O	$NA_{O,O2}$	$fv_{CO,h}$	$NA_{O,CO}$

11 Mar 2010 – 31 Dec 2010	0	0	16	2	0	1
1 Jan 2011 – 31 Dec 2011	0	0	16	2	0	1
1 Jan 2012 – 31 Dec 2012	0	0	16	2	0	1
1 Jan 2013 – 31 Dec 2013	0	0	16	2	0	1
1 Jan 2014 – 31 Dec 2014	0	0	16	2	0	1
1 Jan 2015 – 31 Dec 2015	0	0	16	2	0	1
1 Jan 2016 – 31 Dec 2016	0	0	16	2	0	1
1 Jan 2017 – 10 Mar 2017	0	0	16	2	0	1

Year	$fv_{CO2,h}$	$NA_{O,CO2}$	$MM_{RG,h}$
11 Mar 2010 – 31 Dec 2010	0	2	16.11
1 Jan 2011 – 31 Dec 2011	0	2	16.11
1 Jan 2012 – 31 Dec 2012	0	2	16.11
1 Jan 2013 – 31 Dec 2013	0	2	16.11
1 Jan 2014 – 31 Dec 2014	0	2	16.11
1 Jan 2015 – 31 Dec 2015	0	2	16.11
1 Jan 2016 – 31 Dec 2016	0	2	16.11
1 Jan 2017 – 10 Mar 2017	0	2	16.11

Equation 13

Year	$TM_{RG,h}$	$FV_{RG,h}$	$fv_{CH4,RG,h}$	$\rho_{CH4,n}$
11 Mar 2010 – 31 Dec 2010	61.66	92.55	99.44%	0.67
1 Jan 2011 – 31 Dec 2011	61.66	92.55	99.44%	0.67
1 Jan 2012 – 31 Dec 2012	61.66	92.55	99.44%	0.67
1 Jan 2013 – 31 Dec 2013	61.66	92.55	99.44%	0.67
1 Jan 2014 – 31 Dec 2014	61.66	92.55	99.44%	0.67
1 Jan 2015 – 31 Dec 2015	61.66	92.55	99.44%	0.67
1 Jan 2016 – 31 Dec 2016	61.66	92.55	99.44%	0.67
1 Jan 2017 – 10 Mar 2017	61.66	92.55	99.44%	0.67

Equation 14

Year	$\eta_{flare,h}$
11 Mar 2010 – 31 Dec 2010	0.9
1 Jan 2011 – 31 Dec 2011	0.9
1 Jan 2012 – 31 Dec 2012	0.9
1 Jan 2013 – 31 Dec 2013	0.9
1 Jan 2014 – 31 Dec 2014	0.9
1 Jan 2015 – 31 Dec 2015	0.9
1 Jan 2016 – 31 Dec 2016	0.9
1 Jan 2017 – 10 Mar 2017	0.9

Equation 15

Year	$PE_{flare,y}$	$TM_{RG,h}$	$\eta_{flare,h}$	GWP_{CH4}
11 Mar 2010 – 31 Dec 2010	916.76	61.66	0.90	21
1 Jan 2011 – 31 Dec 2011	1,134.30	61.66	0.90	21
1 Jan 2012 – 31 Dec 2012	1,134.30	61.66	0.90	21
1 Jan 2013 – 31 Dec 2013	1,134.30	61.66	0.90	21
1 Jan 2014 – 31 Dec 2014	1,134.30	61.66	0.90	21
1 Jan 2015 – 31 Dec 2015	1,134.30	61.66	0.90	21
1 Jan 2016 – 31 Dec 2016	1,134.30	61.66	0.90	21
1 Jan 2017 – 10 Mar 2017	217.54	61.66	0.90	21

The "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" (EB 39, Annex 7, Version 01)

The destruction and utilisation of mine methane will use electricity whereas the destruction of non-mine methane will not use electricity. The equipment for the destruction and utilisation of mine methane will use electricity from the South African National Grid. The flares for the destruction of non-mine methane will use solar power[33].

Project Emissions from Electricity Consumption for Mine Methane

During the project case, grid electricity and captive electricity (electricity generated by the project) will be required for the capture, transportation, compression and utilisation or destruction of the mine methane ($PE_{ELEC,y}$). In order to calculate $PE_{ELEC,y}$, the "*Tool to calculate baseline, project and/or leakage emissions from electricity consumption*" must be applied. This tool provides the procedure to estimate the project emissions associated with the consumption of electricity.

Applying this tool:

Scenario C applies to the proposed project activity. Scenario C is presented below (verbatim text is in ***italics***):

"Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s).

One or more fossil fuel fired captive power plants operate at the site of the electricity consumption source. The captive power plant(s) can provide electricity to the electricity consumption source. The captive power plant(s) is/are also connected to the electricity grid.

Hence, the electricity consumption source can be provided with electricity from the captive power plant(s) and the grid".

Scenario C was selected as the electricity consumed by the proposed project activity will be sourced either from the grid or from the captive power plant (the project).This captive power plant will be connected to the grid. Hence, it will not be possible to determine how much of the electricity consumed in the project case is sourced from the captive power plant and how much is purchased from the grid.

Furthermore, Case C.I applies (*italic* text is verbatim from the tool):

"Case C.I: Grid electricity. The implementation of the project activity only affects the quantity of electricity that is supplied from the grid and not the operation of the captive power plant. This applies, for example,

- *If at all times during the monitored period the total electricity demand at the site of the captive power plant(s) is, both with the project activity and in the absence of the project activity, larger than the electricity generation capacity of the captive power plant(s); or*
- *If the captive power plant is operated continuously (apart from maintenance) and feeds any excess electricity into the grid, because the revenues for feeding electricity into the grid are above the plant operation costs; or*

[33] Please see quote for solar panels

- *If the captive power plant is centrally dispatched and the dispatch of the captive power plant is thus outside the control of the project participants."*

Case C.I. applies since the implementation of the project activity will only affect the quantity of electricity that the Beatrix mine imports from the grid and not the operation of the captive power plant. The total electricity demand at the Beatrix mine, which is the site of the captive power plant, is always larger than the electricity generation capacity of the plant.

- The total electricity demand of Beatrix is approximately 864,000MWh/year.
- The total captive generation ability is 5.38 installed MW electrical.

The captive power plant will be operated continuously (apart from maintenance) and the electricity generated by the plant will be dispatched centrally. The dispatch of the electricity will be outside the control of the GFI Mining South Africa' Beatrix mine.

Since, Scenario C.I applies to the project activity; the electricity emission factor can be calculated using either Option A1 or Option A2.

Option A1 was selected in order to calculate the electricity emission factor. Option A1 states (verbatim test in italics):

"Option A1: Calculate the combined margin emission factor of the applicable electricity system, using the procedures in the latest approved version of the "Tool to calculate the emission factor for an electricity system" ($EF_{EL,j/k/l,y} = EF_{grid,CM,y}$)."

The identified term, $EF_{grid,CM,y}$, refers to Step 7 of the "Tool to calculate the emission factor for an electricity system" (version 02), which states (verbatim text in *italics*):

"Step 7. Calculate the combined margin emissions factor

The combined margin emissions factor is calculated as follows:

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

(Equation 13 in the "Tool to calculate the emission factor for an electricity system")

$EF_{grid,BM,y}$	=	*Build margin CO_2 emission factor in year y (tCO_2/MWh)*
$EF_{grid,OM,y}$	=	*Operating margin CO_2 emission factor in year y (tCO_2/MWh)*
w_{OM}	=	*Weighting of operating margin emissions factor (%)*
w_{BM}	=	*Weighting of build margin emissions factor (%)*

- *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 for subsequent crediting periods.*

- *All other projects: w_{OM} = 0.5 and w_{BM} = 0.5 for the first crediting period, and w_{OM} = 0.25 and w_{BM} = 0.75 for the second and third crediting period, unless otherwise specified in the approved methodology which refers to this tool."*

The default value of w_{OM} = 0.5 and w_{BM} = 0.5 will be used.

The electricity emission factor is then used to determine the project emissions due to electricity consumption by the proposed project activity. These emissions can be determined by applying Equation 1 from the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption," version 01:

$$PE_{EC,y} = \sum_j EC_{PJ,j,y} \times EF_{EL,j,y} \times \left(1 + TDL_{j,y}\right)$$

(Equation 1 from the "Tool to calculate, project and/or leakage emissions from electricity consumption)

Where:

$PE_{EC,y}$	Project emissions from electricity consumption in year y (tCO_2/yr)
$EC_{PJj,y}$	Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/year)
$EF_{EL,j,y}$	Emission factor for electricity generation for source j in year y (tCO_2/MWh)
$TDL_{j,y}$	Average technical transmission and distribution losses for providing electricity to source l in year y
j	Sources of electricity consumption in the project
l	Leakage sources of electricity consumption

This equation could then be applied to this project taking into account that the sources of electricity (j) will only be the national grid.

There will be one source of electricity consumption in the project. Hence, 'j' will be one. Applied to this project, Equation 1 becomes:

$$PE_{EC,y} = EC_{PJ,y} \times EF_{EL,y} \times (1 + TDL_y)$$

A default of 3% was used for the average technical transmission and distribution losses for providing electricity ($TDL_{j,y}$). A default was chosen as there is no recent, accurate and reliable data available within South Africa. The 3% was used since the electricity consumption by the proposed project activity is smaller than the electricity consumption of all the baseline electricity consumption sources.

From "Tool to calculate baseline, project and/or leakage emissions from electricity consumption":

Equation 1:

Year	$PE_{EC,y}$	$EC_{PJ,j,y}$	$EF_{EL,j,y}$	$TDL_{j,y}$
11 Mar 2010 – 31 Dec 2010	866.57	858.50	0.98	3%
1 Jan 2011 – 31 Dec 2011	1,581.59	1,566.86	0.98	3%
1 Jan 2012 – 31 Dec 2012	1,581.59	1,566.86	0.98	3%
1 Jan 2013 – 31 Dec 2013	1,581.59	1,566.86	0.98	3%
1 Jan 2014 – 31 Dec 2014	1,581.59	1,566.86	0.98	3%
1 Jan 2015 – 31 Dec 2015	1,581.59	1,566.86	0.98	3%
1 Jan 2016 – 31 Dec 2016	1,581.59	1,566.86	0.98	3%

1 Jan 2017 – 10 Mar 2017	303.32	300.49	0.98	3%

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Annex 5

LETTER FROM CHAMBER OF MINES OF SOUTH AFRICA

CHAMBER OF MINES OF SOUTH AFRICA

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20 October 2009

THE CAPTURE AND EXTRACTION OF UNDERGROUND METHANE AT BEATRIX GOLD MINE FOR THE GENERATION OF ELECTRICAL POWER

Beatrix Gold Mine is a deep level gold mine in the Free State province of South Africa and has the highest methane emission rate compared to any other gold mine in the country.

Methane is emitted from underground sources intersected during mining operations and released into the atmosphere through the mine's upcast ventilation shafts. The mine will capture approximate 400l/s of methane at source and pipe it to surface along an extraction column. Electricity will be generated by using gas engines to generate approximately 4MW of electrical power which will be made available for use by the mine. The excess methane will be destroyed by flaring it.

Beatrix Gold Mine is the only hard rock mine in South Africa at present to employ the process of generating electricity from methane extracted from its underground workings. This project has a number of benefits for the mine being the mitigation of the global warming impact as well as the removal of approximately 49% of the total volume of methane gas from the general body of the air in the geographical areas of the mine where the methane gas is emitted into the atmosphere, thus reducing the risk of methane related incidents. The mine will furthermore reduce its carbon footprint by approximately 25%.

Dries Labuschagne
Chamber of Mines