mitigation REPORT

SOUTH AFRICA'S GREENHOUSE GAS MITIGATION POTENTIAL ANALYSIS

TECHNICAL APPENDIX C – ENERGY SECTOR

environmental affairs
Department:
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On behalf of:
Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety
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The suite of reports that make up South Africa's Greenhouse Gas (GHG) Mitigation Potential Analysis include the following:

Technical Summary

Main Report

Technical Appendices:

Appendix A: Approach and Methodology

Appendix B: Macroeconomic Modelling

Appendix C: Energy Sector

Appendix D: Industry Sector

Appendix E: Transport Sector

Appendix F: Waste Sector

Appendix G: Agriculture, Forestry and Other Land Use Sector

List of Acronyms

Acronym	Definition
AFOLU	agriculture, forestry and other land use
BAT	best available technologies
BTU	British thermal unit (= ~ 1055 joules)
Capex	capital investment cost
CCGT	closed cycle gas turbine
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSP	concentrated solar power
CTL	coal to liquid
DEA	Department of Environmental Affairs
DME	Department of Minerals and Energy
DoE	Department of Energy
EAC	equivalent annual cost
EF	emission factor
ERC	Energy Research Centre, University of Cape Town
FCC	fluid catalytic cracking
FCCU	fluid catalytic cracking unit
GDP	gross domestic product
GHG	Greenhouse Gas
GHGI	Greenhouse Gas Inventory for South Africa
GTL	gas to liquid
GVA	gross value added
GW	gigawatt
GWh	gigawatt hour
GWP	global warming potential
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kW	kilowatt
kWh	kilowatt hour
$KtCO_2e$	kilotonnes of carbon dioxide equivalent
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas

Acronym	Definition
LTMS	Long-Term Mitigation Scenarios
MAC	marginal abatement cost
MACC	marginal abatement cost curve
MCA	multi-criteria (decision) analysis
MW	Megawatt
MWe	megawatt electrical
MWh	megawatt hour
Mt	million tonnes
$MtCO_2e$	million tonnes of carbon dioxide equivalent
N_2O	nitrous oxide
NAC	net annual cost
NCCRP	National Climate Change Response Policy
NCV	net calorific value
NDP	National Development Plan
NERSA	National Energy Regulator of South Africa
NGP	New Growth Path
NPC	National Planning Commission
NPV	net present value
NT	National Treasury
OECD	Organisation for Economic Co-operation and Development
OCGT	open cycle gas turbine
Opex	(annual) operation and maintenance cost
PWR	pressurised water reactor (nuclear)
RFG	refinery fuel gas
SATIM	South African TIMES model
StatsSA	Statistics South Africa
TWG-M	Technical Working Group on Mitigation
UNFCCC	United Nations Framework Convention on Climate Change
VSD	variable speed drive
WAM	'with additional measures' scenario
WEM	'with existing measures' scenario
WOM	'without measures' scenario
WTO	World Trade Organization
ZAR/R	South African Rand

Acknowledgements

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Chapter I: Introduction

1. Introduction

This chapter identifies the GHG emissions mitigation potential for the South African energy sector. The mitigation potential is presented in the form of marginal abatement cost curves (MACCs) for the years 2020, 2030, and 2050, ranking available mitigation options in terms of their marginal abatement costs. The mitigation potential presented is considered to be technically achievable assuming that all identified mitigation technologies have been technically proven or will be proven prior to becoming available. An overview of the reference emissions projection and a list of the potential future abatement opportunities for the energy key sector are presented in this chapter, before the sector and subsector MACCs are described.

The energy sector comprises exploration and exploitation of primary energy sources, conversion of primary energy sources into more useable energy forms in refineries and power plants and the transmission and distribution of fuels. This includes IPCC emissions sectors 1A fuel combustion activities, 1A1 energy industries and 1B fugitive emissions from fuels. The energy sectors examined and sources of emissions (as classified by the IPCC categories) are listed in Table 1 below.

Table 1: Energy subsectors (with IPCC emissions source classifications) included in the mitigation analysis.

Energy sector	Subsector	IPCC emissions category	
		Fuel combustion (1A)	Fugitive emissions (1B)
Power	Electricity and heat production	1A1a	
Non-Power	Petroleum refining	1A1b	1B2aiii4
	Coal mining and handling	1A1ci	1B1a
	Oil and natural gas	1A1cii	1B2
	Other energy industries	1A1cii	1B3

GHG emissions projections and mitigation opportunities for energy sector emissions that are presented in this section focus on four separate sources of emissions, described below.

- Combustion emissions from the use of fuels in stationary combustion. Fuel combustion may be defined as the intentional oxidation of materials within an apparatus that is designed to provide heat or mechanical work to a process, or for use away from the apparatus.
- Fugitive emissions, which escape without combustion (e.g. leakage of natural gas and the emissions of methane during coal mining and flaring during oil/gas extraction and refining).
- Process emissions, from production processes, from the use of greenhouse gases in products, and from non-energy uses of fossil fuel.
- Indirect emissions from the consumption of electricity.

The most important sector is power generation, which accounted for 65% of all energy-related emissions in 2009. Fugitive emissions from the energy sector accounted for around 8% in 2009.

Reference case projections and assessments of mitigation potential are presented separately in the chapters which follow as an aid to clarity for the reader. The structure of the appendix is as follows:

- Chapter II: Power Sector Reference Case Projections
- Chapter III: Non-Power Sector Reference Case Projections
- Chapter IV: Power Sector Mitigation Potential
- Chapter V: Non-Power Sector Mitigation Potential
- Chapter VI: Summary

Chapter II: Power Sector Reference Case Projections

2. Approach and Assumptions

2.1 Approach

The emissions projections for the power sector were assessed using an MS Excel™-based scenario tool, which modelled the potential uptake of different electricity generation technologies over time. The tool allowed different scenarios to be explored, representing the different potential mix of technologies which could be deployed to meet a given level of exogenous electricity demand.

The tool was also used to assess the abatement potential, and associated cost, of the different technologies – both individually and as part of a given projection or scenario.

2.1.1 Scenario tool metrics

The main outputs from the tool are emission projections and system cost estimates (which include the additional costs of any mitigation measures) for the 2010–2050 time horizon (plus 2000–2010 historical data). The output metrics include:

- plant capacity and generation
- plant and system levelised costs of generation[1]
- total sector costs (annually and on a net present value (NPV) basis)
- fuel consumption
- total sector emissions
- marginal abatement costs (MACs) for reductions in carbon dioxide (CO_2) emissions

2.1.2 Matching generation and demand

A key component of the scenario modelling is the matching of electricity supply and demand. Within the tool, the operation of a given plant type can be characterised by a minimum load factor (meaning specific plant capacity has to operate at a certain level if built) and maximum load factor (to determine flexible generation). Some plants may not have to run at all, such as open cycle gas turbine (OCGT) power generation plants, while others have to run at maximum availability. In order to meet demand, available plants are despatched based on their merit order, and allowing for the operational constraints of the different plant types.

2.2 Assumptions

2.2.1 Demand

Electricity demand is an exogenous input to the scenario tool. The electricity demand projections were derived from the bottom-up modelling of the electricity requirements in each of the end-use sectors. The modelling approach for each of these sectors is described in the relevant sections of this report.

Based on this end-use demand, the total domestic generation output required was calculated. In doing so, energy sector use was added in, along with distribution and transmission system losses and net exports. Assumptions on the values of these parameters are compiled in Table 2.

Table 2: Assumptions for electricity generation projections

Parameter	Value	Notes	Sources
Energy sector electricity use	2%	Assumed to be a constant proportion of final electricity demand, value held as observed in the latest energy balance	DoE energy balances
Distribution and transmission system losses	6% and 3.3% respectively up to 2030, 5% and 3.3% from 2031 onwards	Eskom target values	Eskom (2010)
Imports and exports	13,754 GWh/pa (imports) 13,227 GWh/pa (exports)	Assumed that exports and imports do not increase in proportion with overall demand, but stay constant over the entire time horizon. 2010 Eskom values used.	Eskom (2010)

1. The levelised cost of energy (LCOE) is the price at which electricity must be generated for a specific source to break even over the lifetime of a project.

To assess the mitigation measures in the power sector the demand forecast of the reference projection was used to enable direct comparison of power sector supply scenarios. On the other hand, when assessing the impact of mitigation measures which will reduce electricity demand in the end-use sectors, this forecast can be adjusted to ensure that the lower sector demand is correctly represented by subsequently lower power sector emissions. For example, to assess the impact of existing measures in the end-use sectors, the electricity supply projection 'with existing measures' (WEM) used the corresponding end-use sector demand forecast, while the 'without measures' (WOM) supply projection used the 'without measures' end-use demand. These are shown in Figure 1.

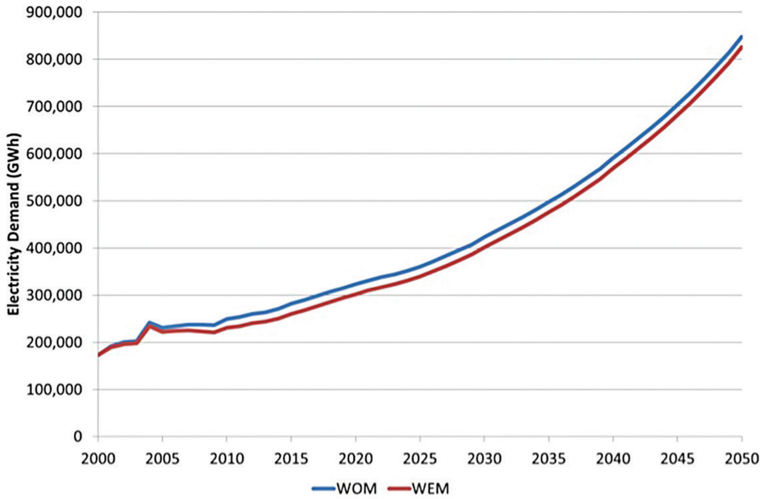

Figure 1: Electricity demand in end-use sectors, WOM and WEM projections (GWh)

The end-use electricity demand projections for the WEM projection split by sector are shown in Figure 2.

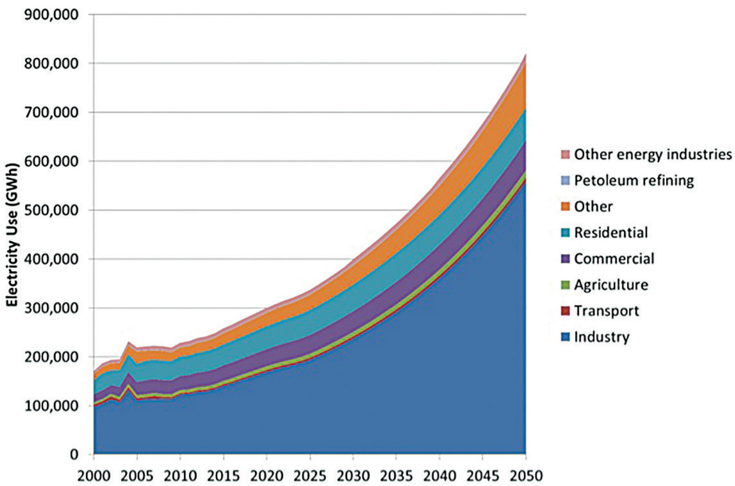

Figure 2: Electricity use from individual WEM projections (GWh)

2.2.2 Fuel parameters

Emissions factors for CO_2, nitrous oxide (N_2O) and methane (CH_4) emissions from different plants were taken from the draft Greenhouse Gas Inventory for South Africa (GHGI) (DEA, 2013), supplemented for new technologies not currently included in the GHGI with IPCC recommended emission factors. The one exception is energy from waste plant for which the emission factors were sourced from the waste sector projection (current study). Carbon capture and storage (CCS) applied to coal plant was assumed to have 85% CO_2 capture efficiency (OECD/IEA, 2008; assuming a steam cycle, chemical absorption technology).

Most fuel prices were obtained from the Integrated Resource Plan (IRP) (DoE, 2011), with the exception of waste (Table 3). Costs for waste fuel are negative because these represent cost savings for not having to dispose of the waste (landfill gate fees). These costs remain constant throughout the time horizon with the exception of gas, which increases according to the trends given in EPRI (2010).

Table 3: Fuel cost assumptions

Fuel	Price, R/MWh	
	2010	2030
Coal – pulverised coal (PC)	54.00	54.00
Coal – fluidised bed combustion (FBC)	27.00	27.00
Gas	288.00	385.00
Forest residue	70.20	70.20
Waste	-4.30	-4.30
Nuclear fuel	22.50	22.50

Sources: Ricardo-AEA waste sector projections for waste, IRP, 2010 for others

2.2.3 Existing system

Eskom data (Eskom, 2012; and Eskom website) was used to define the existing system parameters, including current plant capacity, past generation levels, and derived load and efficiency factors for current plants.[2]

Aside from the national electricity supplier, a few independent suppliers and municipalities own other power plants. The generation capacity of these auto-producers is taken from the IRP. Most of this generation capacity is coal-based, and the national GHGI only reports on coal use for auto-producers. These power stations are mostly old and have low load factors (DoE, 2010). For these reasons auto-generation was considered as a separate single type of plant in the power model.

2.2.4 Technology parameters

Most parameters that describe specific technologies (excluding existing system) were assigned values from the IRP. This includes capital and operating costs, lifetime, efficiencies and load factors. The waste and landfill generation values were produced using the waste sector projections. Capital costs for CCS were based on the assumption that they are 50% higher than those of a plant without CCS (OECD/IEA, 2008). Finally, nuclear plant investment costs were increased in line with the Energy Task Team comments and are set at the higher value given in the IRP (this adjusts for previous underestimation of waste management and decommissioning costs, and is 40% higher than prior estimates).

A discount rate of 11.3% per year was used when calculating present values.

Learning rates for wind power, solar power technologies, and biomass used in the tool are taken from the IRP 2010 report. The CCS learning rate is obtained based on data from an OECD/IEA report on CO_2 capture and storage (OECD/IEA, 2008).

2. Note that historical fuel consumption values (for 2000 to 2010) differ from those used in the GHGI to estimate emissions from the power sector, as they are based on a net calorific value (NCV) for coal consumed provided by Eskom which are based on measurement, rather than the NCV assumed in the GHGI which is based on older data from the DoE.

3. Reference Case Projection

South Africa's Integrated Resource Plan for Electricity 2010–2030 (DoE, 2011) was used to inform the electricity supply side scenarios of this work. The latest available iteration of the IRP was conducted in late 2010/early 2011, and the time horizon included in the scenarios is 2010–2030.

Due to the timing of its preparation, the base case scenario from the IRP was deemed to be suitable for use as a foundation for the WEM projection in the current study.

The definition of scenarios in the power sector is based on planned capacity additions to meet demand. Therefore the WOM and WEM projections are defined as follows:

- The WOM projection is represented by coal generation. It assumes that all base-load capacity comes from coal with mainly gas turbines (using diesel) providing peaking capacity. Some pumped storage hydro is also included, but there is no wind, solar, or waste generation.
- The WEM projection is represented by the IRP 2010 Base Case to 2030. Post 2030, the relative shares of the plant capacity observed in 2030 are held at consistent proportions to 2050.

3.1 Results

The resulting GHG emissions for the WOM and WEM projections calculated by the power tool are shown in Figure 3. The year 2010 emissions were calibrated to the most recent energy activity data. Up to 2020, the difference is small, but as older plants retire, the new capacity has more effect, and therefore the difference in emissions grows substantially.

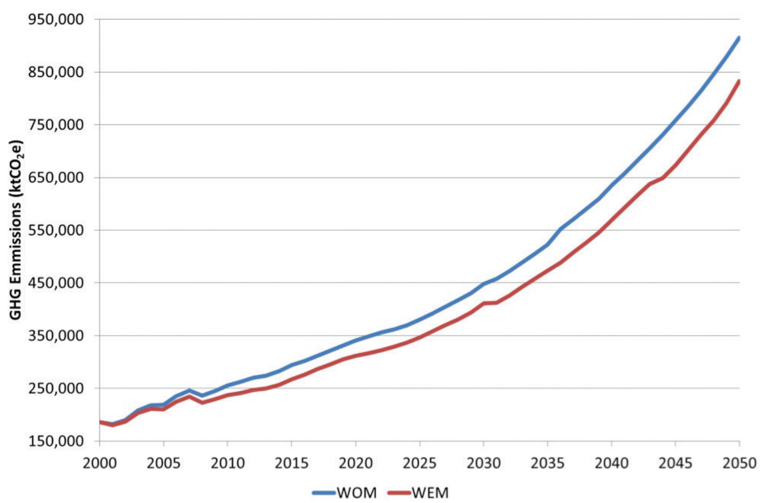

Figure 3: WOM and WEM scenario emissions for the power sector

The levelised cost of electricity generation, as calculated in the tool, is shown in Figure 4. The source of data for electricity generation costs is the IRP 2010 document. Reserve margins are calculated as an output of the power sector tool.

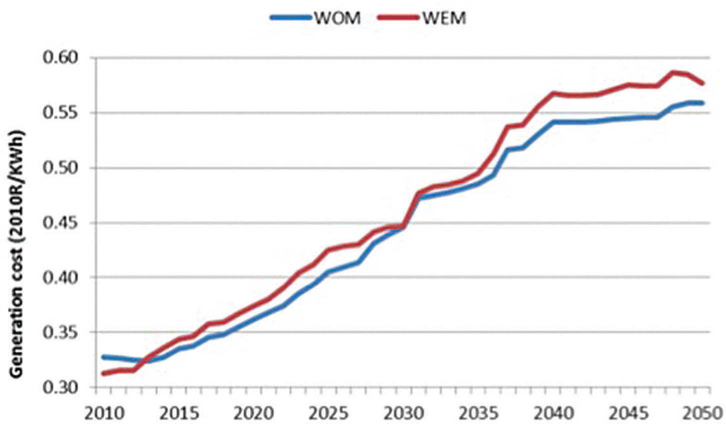

Figure 4: WOM and WEM scenario generation costs for the power sector

These costs only represent the levelised cost of electricity generation, and do not show the investment profile for new capacity. Moreover, they do not include any transmission and distribution costs. Hence the reported values are lower and have a slightly different trend than the electricity prices in the IRP 2010. These wider costs associated with the electricity system are important, and significant investment in the electricity grid is likely to be required alongside any additional investment in new generation capacity. These wider system costs therefore need to be taken into account in future infrastructure planning decisions, but have not been assessed as part of the current study which is focused on mitigation measures.

Electricity demand is projected to grow rapidly in the latter part of the time horizon. In modelling the response of the power generation sector to this demand, the reserve margins were not allowed to decrease below 15% for both the WEM and WOM scenarios, as shown in Figure 5. In practice, a larger reserve margin might be preferred to provide greater resilience, particularly if more intermittent renewable energy technologies are being taken up. Increasing the reserve margin will require increased capacity from flexible generation plant, which will increase the overall system cost of electricity generation. For WEM, the higher reserve margins prior to 2030 reflect the inclusion of demand side measures in the projection. For WOM, peak demand capacity was updated in line with the WOM electricity demand thus resulting in a lower reserve margin.

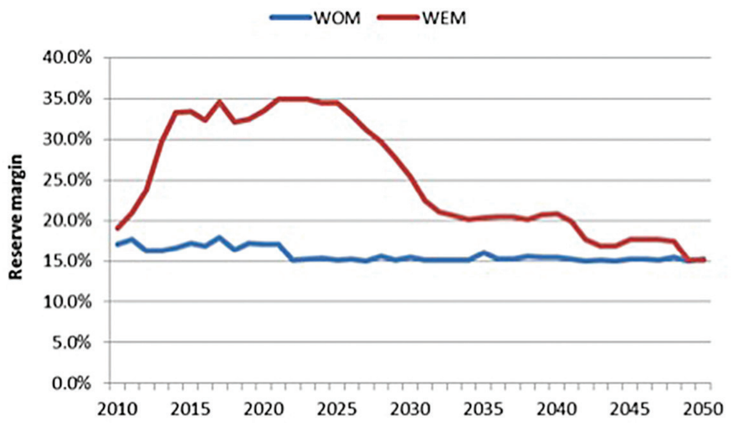

Figure 5: WOM and WEM scenario reserve margin for the power sector

Figure 6 shows the proportion of renewable capacity in the total mix for both WOM and WEM projections. This includes hydro options, as well as waste, wind and solar capacity. For WOM, this is thus mainly small, large and pumped storage hydro-electric power. It should be noted though that pumped storage might rely on coal generation.

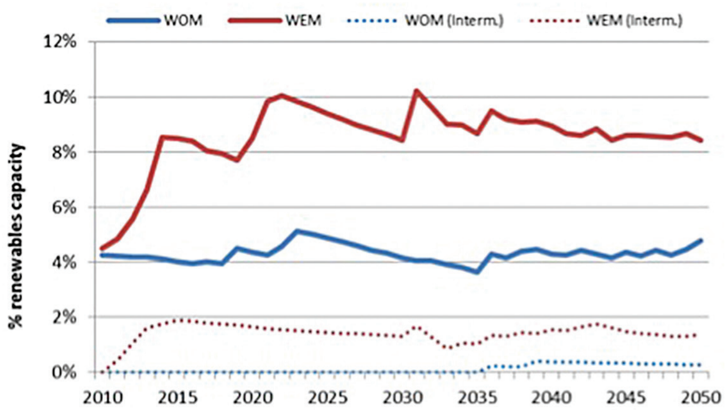

Figure 6: Renewable energy capacity for the WOM and WEM scenario in the power sector

Intermittent renewable lines show the capacity proportion of those renewables that are not continuously available.

Chapter III: Non-Power Sector Reference Case Projections

4. Approach and Assumptions

Two projections have been produced for the non-power energy sectors.

- A reference case projection: this is a projection of emissions from 2000 to 2050 assuming that no climate change mitigation actions have taken place since 2000. Thus for the period from 2000 to 2010, it does not follow the actual observed path of emissions but the path that emissions would have taken if none of the climate change mitigation actions implemented in this period had taken place. The UNFCCC refers to this as a 'without measures' (WOM) scenario.
- A 'with existing measures' (WEM) projection: this projection incorporates the impacts of climate change mitigation actions and climate change policies and measures implemented to date. For the period 2000 to 2010 the projections follow the actual path of observed emissions.

The projections were produced using a bottom-up methodology, with each sector modelled separately. For energy related emissions, the overall approach was to take current fuel consumption and to project future fuel consumption based on expected growth rates in the sector, and an allowance for autonomous energy efficiency improvements i.e. improvements to energy consumption in the sector which will occur anyway (without any further policy interventions) simply as a result of replacing retired equipment with new, more efficient equipment. For petroleum refining and upstream oil and gas activities, current and historic fuel use and electricity use, and fugitive emissions were taken from information supplied by industry. For the other energy industries sector information was provided on both fuel use, and fuel and process related emissions, together with information on emissions factors specific to that industry. Fuel use and electricity use for coal mining and handling were based on data provided by industry.[3] Emissions from auto producers are included in the power sector projection. For oil refining a rate of 0.1% p.a. Is used for autonomous energy efficiency improvements

For oil refining and other energy industries (which includes the production of liquid fuels from coal and gas), the growth in capacity was modelled by examining, in consultation with industry, how the production of synthetic liquid fuels and petroleum refining would need to expand given:

- the forecast demand for liquid fuels derived from the sectoral projections
- the aim stated in South Africa's Energy Security Master Plan to meet 30% of liquid fuel demand from domestic sources
- the minimum size for new plant i.e. additional demand must rise to a level that supports the building of new plant

This leads to the introduction of new 80,000 bbl/day coal-to-liquid plants in 2030, 2040 and 2050 and new 250,000 bbl/day refineries in 2030 and 2050. Any shortfall in liquid fuel production is assumed to be met by the import of finished products. It was assumed that any new plant introduced would be state of the art, i.e. The new plant would include in their design any relevant mitigation options (excluding carbon capture and storage). The new plant therefore has been modelled with a better specific energy consumption and emissions profile than the existing plant.

Fuel-related emissions and fugitive emissions from upstream oil and gas activities were projected forward on the basis of expected activity in the relevant gas field until 2020. For fuel related and fugitive emissions from coal mining and refining, growth in emissions is projected on the basis of growth in the sector as determined in the macroeconomic modelling. Emissions factors for fugitive emissions i.e. CH_4 released per tonne of coal mined and per tonne of oil refined are assumed to remain constant. Current emissions for these sectors are taken from the GHGI.

The above methodology takes as its starting point actual historic energy consumption and fugitive emissions. It includes the actual observed impact of any climate change mitigation

3. The data supplied did not cover the whole of the sector so was used to calculate a specific energy consumption per tonne mined which was then multiplied by total production to give a value for the sector as a whole.

measures implemented in those years and is thus a 'with existing measures' (WEM) projection. To create a 'without measures' (WOM) scenario, the reductions achieved by climate change mitigation actions implemented between 2000 and 2010 need to be added to the emissions under WEM.

The assessment of implementation of mitigation measures was completed in consultation with industry. The process identified that mitigation options had been implemented in the oil refining, coal mining and other energy industries sectors. For oil refining and coal mining, estimates were made and agreed with industry of the level of uptake in 2010 of the relevant mitigation options. This is shown in Table 4. The level of uptake is defined as the percentage of installations or processes to which the measure is applicable, that are assumed to have implemented the measure by 2010. For example if improved process control has been implemented in half of the production processes to which it is applicable, then uptake is 50%. In the case of other energy industries, details of measures implemented and an assessment of mitigation potential were provided directly by industry.

The emissions reductions that result from the assumed level of uptake are summarised in Table 5. These are calculated using the assumed uptake rates, and the same assumptions as in the MACC curves (see Chapter V) regarding the reductions which measures achieve and the applicability of the measure (i.e. The proportion of emissions in the sector which are affected by the mitigation option). Implementation of measures (and hence emissions savings) were assumed to be linear between 2000 and 2010. Fuel and electricity savings from 2010 onwards are assumed to be constant. Emissions reductions resulting from electricity-related measures are calculated on a year-on-year basis using the electricity emissions factor calculated for the 'without measures' power sector projection.

Table 4: Mitigation options assumed implemented between 2000 and 2010

Sector	Mitigation option implemented	Level of uptake in 2010
Oil refining	Improve process heater efficiency	80%
Oil refining	Use refinery fuel gas (RFG) instead of heavy fuel oil	80%
Oil refining	Waste heat boiler and expander applied to flue gas from the fluid catalytic cracking (FCC) regenerator	80%
Oil refining	Improve process control	80%
Coal mining	Improve energy efficiency of mine haul and transport operations	50%
Coal mining	Process, demand & energy management system	50%
Coal mining	Energy-efficient lighting	50%
Coal mining	Install energy efficient electric motor systems	50%
Coal mining	Optimise existing electric motor systems (controls and variable speed drives)	50%
Coal mining	Onsite clean power generation	20%
Other energy industries	Conversion of feedstock from coal to natural gas	Fully implemented
Other energy industries	Total feed compressor upgrade	Fully implemented
Other energy industries	Open cycle gas turbine	Fully implemented*

** Installation of the OCGT was completed in 2010, but the turbine was only operational for 6 months of that year*

Table 5: Estimate of emissions reductions achieved in 2010 through measures implemented between 2000 and 2010 (ktCO_2e per year)

Sector	Process related	Fuel related	Electricity related	Total
Oil refining	0.3	219	16	235
Coal mining	0	73	557	631
Other energy industries*	4,930	1,621	1,072	7,623
Total	4,930	1,913	1,645	8,489

** For OEI fuel-related emissions savings are net of the increase in fuel consumption due to use of the OCGT. Emissions savings in OEI were 400 ktCO_2e higher in 2011 and 2012 as OCGT was operational for the full year.*

5. Reference Case Projection

Projected emissions from energy industries other than power generation are shown in Figure 7 and Table 6 for the reference 'without measures' case and in Figure 8 and Table 7 for the WEM case. The most significant source of emissions is the other energy industries sector, which in 2010 accounted for 86% of emissions from the non-power energy sectors. The increase in emissions from this sector as new plants are introduced can be clearly seen in the figures, and emissions from this sector in the WEM scenario rise by 97% between 2010 and 2050. Emissions from other sectors also rise strongly over this period, with emissions from coal mining more than doubling due to the projected growth in this sector, and emissions from oil refining increasing by 56%. Emissions from upstream oil and gas cease after 2020 when planned production from the field ceases. Overall emissions from all energy sectors (excluding power generation) rise by 89% between 2010 and 2050.

Mitigation measures implemented to 2010 mean that emissions are estimated to have been reduced by about 8,489 kt-CO_2e in 2010; emissions savings in subsequent years are higher (by 400 ktCO_2e) as measures implemented in 2010 become fully operational. The main emissions savings arise from measures implemented in the other energy industries sector.

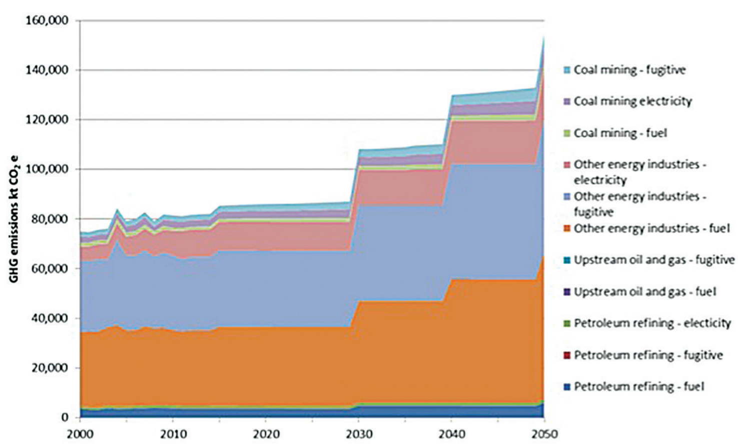

Figure 7: Energy (non-power sector) reference case 'without measures' (WOM) emissions projection

Table 6: Energy (non-power sector) reference case 'without measures' (WOM): total of all GHGs

Emissions ($ktCO_2e$)	2000	2010	2020	2030	2040	2050
Petroleum refining – fuel	3,640	3,829	3,607	4,845	4,799	6,000
Petroleum refining – fugitive	9	15	56	63	63	70
Petroleum refining – electricity	957	995	973	1,211	1,219	1,455
Upstream oil and gas – fuel	36	56	35	0	0	0
Upstream oil and gas – fugitive	11	20	9	0	0	0
Other energy industries – fuel	29,913	30,408	31,912	40,898	49,884	58,870
Other energy industries – fugitive	28,855	30,078	30,770	38,549	46,328	54,107
Other energy industries –electricity	5,616	9,887	11,592	14,345	17,296	20,123
Coal mining – fuel	1,598	1,220	1,376	1,613	2,013	2,667
Coal mining – electricity	2,435	2,785	3,048	3,521	4,354	5,654
Coal mining – fugitive	2,002	2,266	2,758	3,260	4,106	5,490
Total WOM	**75,072**	**81,560**	**86,138**	**108,306**	**130,063**	**154,436**

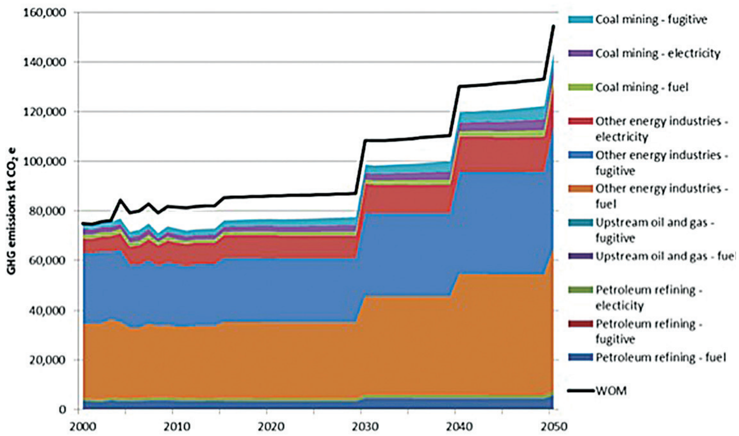

Figure 8: Energy (non-power sector) 'with existing measures' (WEM) emissions projection

Table 7: Energy (non-power sector) 'with existing measures' (WEM) case: total of all GHGs

Emissions ($ktCO_2e$)	2000	2010	2020	2030	2040	2050
Petroleum refining – fuel	3,640	3,610	3,389	4,627	4,581	5,781
Petroleum refining – fugitive	9	14	56	63	63	70
Petroleum refining – electricity	957	979	937	1,153	1,117	1,341
Upstream oil and gas – fuel	36	56	35	0	0	0
Upstream oil and gas – fugitive	11	20	9	0	0	0
Other energy industries – fuel	29,913	28,787	30,783	39,769	48,755	57,740
Other energy industries – fugitive	28,855	25,148	25,840	33,619	41,398	49,177
Other energy industries –electricity	5,616	8,817	9,400	11,907	14,181	16,863
Coal mining – fuel	1,598	1,146	1,303	1,540	1,940	2,593
Coal mining – electricity	2,435	2,229	2,425	2,842	3,504	4,727
Coal mining – fugitive	2,002	2,266	2,758	3,260	4,106	5,490
Total WEM	**75,072**	**73,074**	**76,935**	**98,779**	**119,644**	**143,783**

Chapter IV: Power Sector Mitigation Potential

6. Identification of Mitigation Opportunities

6.1 List of Mitigation Opportunities

A list of all mitigation opportunities identified in the electricity production sector (IPCC sector 1A1a: electricity and heat production) is provided in Table 8. The options specified in Table 8 are consistent with the options specified under the IRP 2010 Policy-Adjusted Scenario (DoE, 2011).

The project team was requested to seek consistency with the IRP scenarios. Therefore the choice was influenced by the technologies defined in the IRP. Most of the options analysed are advanced generation technologies, and energy generation from renewable sources. The final set thus excludes options such as conversion or efficiency improvements of existing power plant fleet.

Table 8: List of mitigation opportunities analysed in the electricity production sector.

Abatement measure category	Abatement measure / mitigation opportunity	Description
Renewable energy	Hydro (small scale)	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Hydro pumped storage	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Biomass generation	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Waste to energy generation	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Onshore wind	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Concentrated solar power (parabolic trough)	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Solar PV	Replace fossil fuel combustion electricity and heat production with renewable energy
Renewable energy	Landfill gas (combustion of landfill gas methane for electricity generation)	Replace fossil fuel combustion electricity and heat production with renewable energy
CCS		Fossil fuel thermal power plant with carbon capture and storage (CCS)
Nuclear PWR		Nuclear PWR (AREVA EPR)
Natural gas power	CCGT	Developing grid connected electricity generation plants using natural gas – gas combined cycle gas turbine (CCGT)
Natural gas power	OCGT	Developing grid connected electricity generation plants using natural gas – gas open cycle gas turbine (OCGT)
Natural gas power	Moving from single to combined cycle gas-fired turbines (CCGT)	Developing grid connected electricity generation plants using natural gas – moving from single to combined cycle gas-fired turbines (CCGT)
Improved combustion of coal and lignite	IGCC	Developing grid connected electricity generation plants using an integrated gasification combined cycle (IGCC) technology

Two of these options (pumped storage and OCGT) have been included in the tool, but excluded from the mitigation analysis while hydropower was assumed to come from imports.

Pumped storage can play a very useful role in maintaining system balance and allowing very rapid additional power generation to meet peaks in demand. It can be a useful complement to intermittent renewables, potentially allowing storage of excess power produced when demands are low. However it is not a generation technology per se, as electricity is expended to pump water into a storage reservoir before it is re-released to generate power, consequently its use is unlikely to directly lead to carbon savings. It is therefore not considered as a mitigation option.

Similarly, OCGT plants are very useful peaking plants as they can be started up very quickly. They are not used for base load however, due to their low efficiencies compared to CCGT plants, and would not deliver significant savings. They are therefore not considered as a mitigation option.

6.2 Costing and Mitigation Potential of Mitigation Measures

The assumptions used for making mitigation projections and costing the intervention in each case are given in Table 9 below.

Table 9: Assumptions used to quantify mitigation potential for the electricity production sector

Mitigation option	Key data elements	Key data sources
Imported hydro	Investment costs, fixed operating costs, lifetime, efficiency, load factor	DoE (2011)
Biomass	Investment costs, fixed operating costs, variable O&M costs, fuel costs, lifetime, efficiency, load factor, learning rate	DoE (2011)
IGCC	Investment costs, fixed operating costs, fuel costs variable O&M costs, lifetime, efficiency, load factor	DoE (2011)
Coal CCS	Investment costs, fixed operating costs, variable O&M costs, fuel costs, lifetime, efficiency, load factor, learning rate, CO_2 capture efficiency. Investment costs are based on a mark-up over conventional coal plant cost.	OECD/IEA (2008) With regular plant costs from DoE (2011).
Wind, solar PV and CSP	Investment costs, fixed operating costs, lifetime, efficiency, load factor, learning rate	DoE (2011)
Gas CCGT	Investment costs, fixed operating costs, lifetime, efficiency, load factor, gas prices	DoE (2011), EPRI (2010)
Nuclear power	Investment costs, variable O&M costs, fuel costs, lifetime, efficiency, load factor. The higher of the given values for nuclear investment costs was used, assuming an additional 40% increase in capital costs according to the IRP 2010–2030 plan (as approved by the TWG).	DoE (2011)
Energy from waste and landfill gas	Investment costs, variable O&M costs, fuel costs, lifetime, efficiency, load factor	Current study waste projections

7. Marginal Abatement Cost Curves

The marginal abatement cost curves (MACCs) show the costs and emissions abatement potential from different measures as a static snapshot for a single year. The potential for total abatement in each target year is calculated with reference to the WEM scenario, taking into account the uptake of measures in this scenario.

In 2020, as shown in Figure 9, there are no measures that display a negative marginal abatement cost. The least expensive option, which is also the option with the highest abatement potential, is wind power. Further along the line, landfill gas (LFG), concentrated solar power and biomass provide small but still relatively inexpensive contributions to emissions savings (all under R450/tCO_2e). Gas CCGT could save a further 3,000 ktCO_2e in 2020, while more expensive concentrated solar PV can deliver further significant emissions savings.

In 2030, we see the appearance of three new technologies which together could deliver savings of more than 60,000 ktCO_2e (Figure 10). Imported hydropower could deliver abatement of 1,700 ktCO_2e[4] at a negative marginal abatement cost, while nuclear power would provide abatement of a further 53,000 ktCO_2e, and coal power plants with carbon capture and storage (CCS) could deliver 8,000 ktCO_2e[5]. The remaining technologies would deliver a similar abatement profile as in 2020, each technology delivering more savings than before, with potential total savings of 137 MtCO_2e.

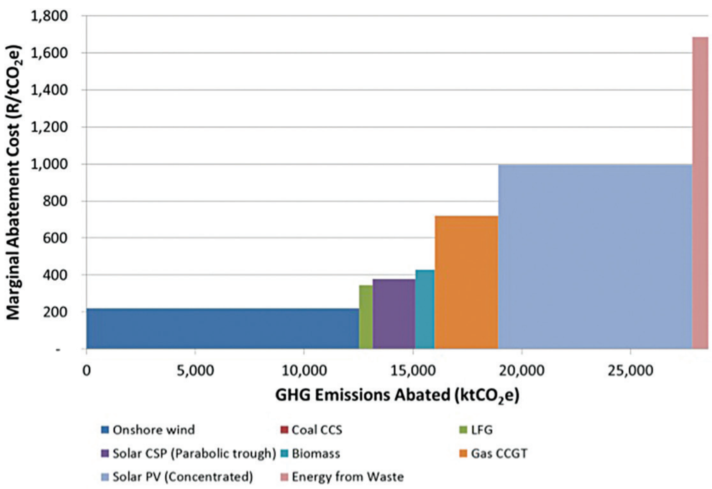

Figure 9: Power sector MACC for 2020

4. The price assumptions and timing of imported hydro power are optimistic. These costs are subject to negotiation, and might in reality be substantially higher.

5. The current marginal abatement cost estimates for nuclear power do not include fuel costs.

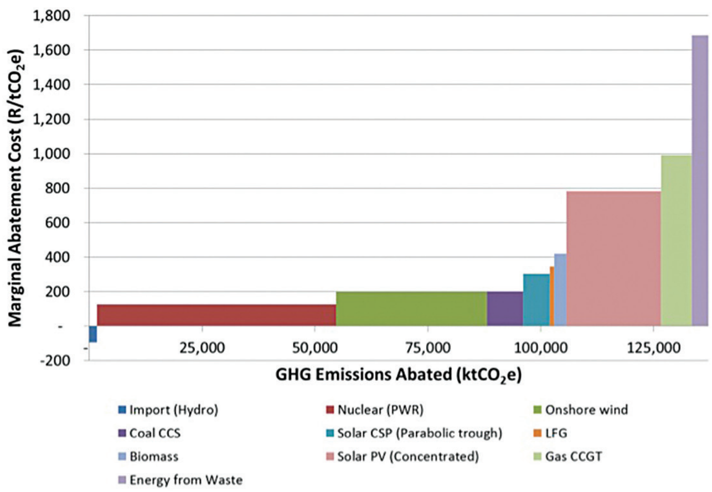

Figure 10: Power sector MACC for 2030

Finally, in 2050 the total potential savings for the WEM projection exceed 400 $MtCO_2e$ (Figure 11). The largest part of this is delivered by nuclear energy, followed by CCS and onshore wind. Imported hydro is the only cost-effective option, and is expected to deliver GHG savings of almost 9,000 $ktCO_2e$.

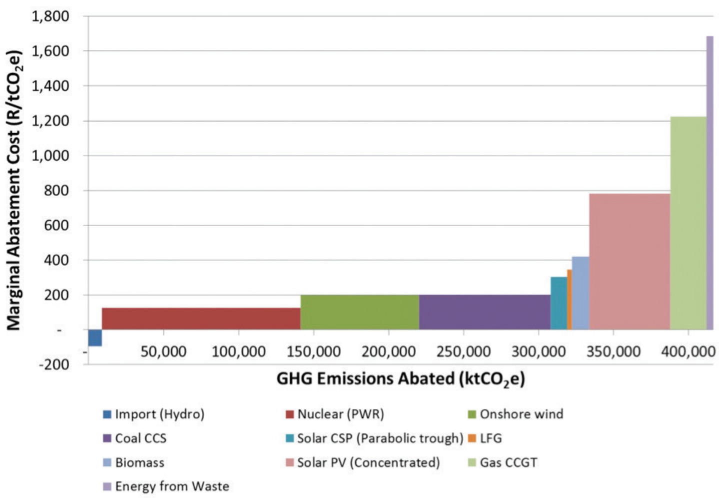

Figure 11: Power sector MACC for 2050

8. Total Mitigation Potential

The mitigation options are selected by the power tool in the order of merit, until the required level of generation is reached. This means that the generation mix first includes the available capacity of the cheaper options (in terms of R/kWh), and only then moves on to the next one. The available capacity is limited by the build rates in the IRP. The current analysis shows that if all technically available mitigation potential in the power sector was implemented, then GHG emissions could be reduced by 28,585 ktCO_2e in 2020, 137,149 ktCO_2e in 2030 and 416,555 ktCO_2e in 2050. This represents a total potential reduction of 9%, 33% and 50% (respectively) of reference emissions under the WEM projection (Table 10).

Table 10: Total mitigation potential for the energy (power) sector, assuming all measures are implemented (ktCO_2e)

Measure	2020	2030	2050
Gas closed cycle gas turbine (CCGT)	2,913	6,797	24,016
Biomass	900	2,699	11,471
Concentrated solar power (parabolic trough)	1,966	5,897	11,009
Coal carbon capture and storage (CCS)	-	8,039	87,852
Onshore wind	12,524	33,396	78,794
Nuclear power	-	52,973	132,433
Landfill gas	619	964	3,166
Import (hydro)	-	1,695	8,947
Solar photovoltaics (concentrated)	8,921	20,977	54,227
Energy from waste	742	3,712	4,640
TOTAL	**28,585**	**137,149**	**416,555**
TOTAL % reduction relative to WEM	**9%**	**33%**	**50%**

Associated installed capacities of each measure needed to achieve the above abatement potential are shown in Table 11.

Table 11: Installed capacity for each mitigation measure for the energy (power) sector (MW).

Measure	2020	2030	2050
Gas closed cycle gas turbine (CCGT)	2,844	9,954	21,330
Biomass	250	750	1,500
Concentrated solar power (parabolic trough)	700	1,700	3,000
Coal carbon capture and storage (CCS)	-	1,500	14,250
Onshore wind	5,600	13,600	32,000
Nuclear power	-	6,400	19,200
Landfill gas	96	141	414
Import (hydro)	-	3,489	3,489
Solar photovoltaics (concentrated)	3,700	8,700	22,500
Energy from waste	168	840	1,050
TOTAL	13,358	47,074	118,733

Chapter V: Non-Power Sector Mitigation Potential

9. Identification of Mitigation Options

For the purposes of the energy sector analysis, mitigation opportunities are defined as physical actions that can be implemented to reduce GHG emissions from the exploration and exploitation, conversion, and transmission and distribution of energy. These include technical measures such as replacing fossil fuelled thermal electricity generation with renewable sources, implementing better production techniques and technologies, energy efficiency technologies, and end-of-pipe technologies which directly abate emissions. Both new-build projects and retrofit projects are considered. The types of mitigation opportunities identified are categorised below.

- Renewable and low carbon power generation technologies, which replace conventional fossil fuel-fired power plants.
- Energy efficiency measures, which reduce distribution and transmission losses (e.g. improved power flow management), reduce end-use energy consumption and so reduce direct emissions from stationary fuel combustion (e.g. recovery and use of waste gas) or reduce indirect emission from electricity use on-site (e.g. improved energy-efficient utility systems such as lighting, compressors and cooling systems).
- Improved efficiency of onsite heat and power generation techniques, which again reduce overall energy consumption and associated emissions from fuel combustion (e.g. energy-efficient boiler systems, including replacement of old boilers with new) or reduce imported grid electricity and associated indirect emissions (e.g. implementation of waste gas energy recovery and use for cogeneration).
- Fuel switch, which replaces fossil fuels with less carbon-intensive fuels such as natural gas or 'zero-carbon' fuels such as biomass.
- GHG abatement technologies, which directly capture and dispose of emissions such as carbon capture and storage (CCS).

GHG emissions mitigation opportunities for the energy sector have been identified based upon international best practice and under the guidance of the Technical Working Group (TWG) sector experts. The potential to reduce or prevent GHG emissions and cost effectiveness have been quantified.

Mitigation opportunities have been identified and quantified following the process described below:

- Development of a long list: based upon desktop research of international GHG mitigation best practice and best available technology (BAT) for production, a long list of GHG emissions abatement measures was prepared for each industrial subsector.
- Refinement of a short list: the long list was disseminated to the TWG-M and feedback was gathered on the applicability and potential of each measure. A short list of mitigation opportunities was then selected based upon this feedback for each subsector.
- Further quantitative data gathering: the data parameters required to construct the marginal abatement cost curves (MACCs), including the abatement potential and costs, were then gathered using international benchmarks and BAT literature. Questionnaires for each industry subsector were disseminated to the TWG-M members, including all of the quantified measures, to verify the parameters based upon sector expertise from South Africa, and to allow the TWG-M members to provide quantitative information on additional mitigation activities.
- Final list of measures: the final list of data was then prepared based upon the TWG-M final feedback.

The extent to which these mitigation technologies can reduce or prevent emissions and their costs have been quantified based on a set of data parameters gathered for each measure.

9.1 Data Parameters

For each measure, the data parameters required to calculate the GHG abatement potential (in tonnes of CO_2e) and the marginal abatement cost (MAC, in cost per tonne of CO_2 abated) over the 2010–2050 period, have been gathered based upon benchmark documentation and through dialogue with TWG sector experts. The summary list of data parameters gathered is described in Table 12. Marginal abatement cost curves (MACCs) for the key focus years (2020, 2030 and 2050) were then constructed using these principal indicators of mitigation performance applying the approach described in Section 10.

Table 12: List of mitigation measure data parameters

Parameter		Unit	Description
A	**GHG emissions reduction potential (process, fugitive, fuel and/or indirect emissions)**		
A.1	Reference emissions	$ktCO_2e$	Reference emissions in $ktCO_2e$ (in 2010)
A.2	Emissions abatement potential	$ktCO_2e$	Reduction in emissions compared to the reference emissions in $ktCO_2e$
A.3	Emissions abatement potential	%	Potential percentage (%) reduction in emissions compared to reference emissions.
A.4	Applicability	%	% of total emissions that abatement measures can be applied to (e.g. if 100% of emissions come from process electricity consumption, then a process control improvement measure would be 100% applicable).
B	**Energy saving**		
B.1.1	Reference thermal energy consumption	GJ/tonne product	Reference thermal energy consumption in GJ/tonne product (e.g. crude steel).
B.1.2	Thermal energy saving potential	GJ/t product	Reduction in thermal energy consumption compared to the reference energy consumption.
B.1.3	Thermal energy saving potential	%	% thermal energy saving potential compared to reference thermal energy consumption (e.g. if 65% of thermal energy is consumed by the steam reforming step, then a steam reforming process improvement would be 65% applicable).
B.1.4	Applicability	%	% of total thermal energy consumption that abatement measure can be applied to.
B.2.1.	Reference electricity consumption	GJ/tonne product	The reference electricity consumption in GJ/tonne product.
B.2.2	Electricity saving potential	GJ/t product	Reduction in electricity consumption compared to the reference consumption.
B.2.3	Electricity saving potential	%	% electricity saving potential compared to reference electricity consumption (e.g. if 22% of energy consumption is from preparation equipment, then a preparation process control improvement would be 22% applicable).
B.2.4	Applicability	%	% of total electricity consumption that abatement measure can be applied to.
C	**Costs**		
C.1.1	Capital cost	R/site or R/sector	Typical capital investment for measure in 2010.
C.1.2	Additional annual costs	R/year	Additional annual costs e.g. operational and maintenance costs in R/year (not including additional energy cost).
C.1.3	Site production capacity	Tonnes product/ year	Typical site production capacity (tonnes product/year) for reference.
C.2.1	Capital cost	R/t	Typical capital investment for measure now. Please specify specific cost in R/t product
C.2.2	Additional annual costs	R/t	Additional annual costs e.g. operational and maintenance costs. Please specify specific cost in R/t product (not including additional energy cost).
C.3	Abatement cost	R/ tCO_2e	Abatement cost for measure in R/tCO_2e (in certain cases only the abatement cost was available, e.g. CCS measures)
D	**Availability**	%	When the technology is likely to become technically available (2010, 2020, 2030, 2040 and 2050).
E	**Reference sector uptake %**	%	The likely % uptake of the technology across the sector that will happen anyway under current policy, existing measures, technology development status and economics.
F	Lifetime	years	Expected lifetime of mitigation technology/equipment/ plant.

9.2 Data Sources and References

The technical, effectiveness and cost data gathered for each mitigation option are based on a variety of sources. In order of priority, these are as follows.

1. Personal communication with sector experts from South Africa during the TWG-M and via direct email and telephone communication.
2. International benchmarks – examples of best practice and best available techniques (BAT).
3. Best estimates based upon the experience of the project team.

In all cases, the sources of information are clearly referenced. Also, the team has taken every step possible within the scope and available resources to verify the validity of assumptions and data with the TWG-M experts to ensure applicability and accuracy of GHG emissions mitigation potential.

9.3 Mitigation Options per Sector

The final lists of sector specific mitigation opportunities that have been selected during the mitigation analysis and deemed to have good mitigation potential are presented below for each energy subsector. The current implementation status in South Africa is described (where this has been identified by the sector task team).

9.3.1 Petroleum Refining

Table 13: List of mitigation measures for the Petroleum Refining sector

No	Abatement measure	Description	Implementation status in South Africa	Type
1	Improve steam generating boiler efficiency	Approximately 30 to 40 percent of onsite energy use at domestic refineries is used in the form of steam generated by boilers, cogeneration, or waste heat recovery from process units. Implement measures including systems approach to steam generation, boiler feed water pre-treatment, improved process control, improving insulation on the distribution pipes, maintenance programme., recover steam from blowdown, reduce standby losses, improve and maintain steam traps and install steam condensate return lines.	Technology is already commonly applied in South Africa. The potential for improving boiler efficiency is estimated to be in the range of 3 – 4%.	Improved onsite site energy generation
2	Improve process heater efficiency	Improve process heater efficiency by implementing draft control (e.g. maintain excess air at 1% rather than the previous 3-4%) and combustion air pre-heating (e.g. every 20°C drop in exit flue gas temperature increases the thermal efficiency of the furnace by 1%. The resulting fuel savings can range from 8–18%).	Technology is already commonly applied in South Africa. The remaining potential for improving process heater efficiency is estimated to be less than 5% and really only covers operational actions (getting the O_2 right and maintaining burners) given the constraints of retrofitting existing refineries.	Energy efficiency measure
3	Waste heat recovery and utilisation	Recovery and use of waste heat in refinery: using waste heat boilers to reduce the use of fuel for the production of steam. Flue gases throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economiser to preheat the boiler feed water. The most likely candidate for energy recovery at a refinery is the fluid catalytic cracking unit (FCCU), although recovery may also be obtained from the hydrocracker and any other process that operates at elevated pressure or temperature.	Technology is already commonly applied in South Africa. Available waste heat on refineries is low-level given the plot-space and configuration constraints that existing refineries face.	Energy efficiency measure
4	Minimise flaring and utilise flare gas as fuel	Minimise flaring. Use flaring of refinery fuel gas (RFG) only during start-up/ shutdown/ upset/ emergency conditions to reduce emissions. Install flare gas recovery compressor system to recover flare gas to the fuel gas system.	Not widely implemented. Potential for improvement.	Improved onsite site energy generation, GHG abatement and EE measure
5	Efficient energy production (CCGT and CHP)	Efficient energy production using combined cycle power generation and co-generation plants (CCGT/CHP). Use internally generated fuels or natural gas for power (electricity) production using gas turbine and generate steam from waste heat of combustion exhaust to achieve greater energy efficiencies. Can generate all power needs and export excess power to the grid reducing grid imports.	Technology is commonly applied internationally (in new refineries) but has not yet been tested in South Africa. Uptake of this option is zero due to high capital costs and the difficulty of retrofitting on existing plants	Improved onsite site energy generation

No	Abatement measure	Description	Implementation status in South Africa	Type
6	Waste heat boiler and expander applied to flue gas from the FCC regenerator	Heat recovery from the regenerator flue gas is conducted in a waste heat boiler or in a CO boiler. Heat recovery from the reactor vapour is conducted in the main fractionator by heat integration with the unsaturated gas plant as well as generation of steam with the residual heat from product rundown streams and pump around streams. The steam produced in the CO boiler normally balances the steam consumed. Installing an expander in the flue gas stream from the regenerator can further increase the energy efficiency.	This option has been implemented by most refiners in SA. Limited potential.	Energy efficiency measure
7	CCS – existing refineries	Carbon capture and storage (CCS) – Removal of CO_2 from flue gas streams, capture and disposal of CO_2. Three techniques are available: oxy-combustion, post-combustion solvent capture and stripping, and post-combustion membrane.	Technology is entirely untested. The crude refiners are not considering CCS as an option for GHG mitigation due to cost issues around extracting CO_2 from flue gas, scale issues (transportation) and capital constraints.	CCS
8	Energy monitoring and management system	Computer-aided management system for process operations, energy systems and energy consumption. Identify energy saving opportunities and improve overall operational energy efficiency. Benchmark GHG performance and implement energy management systems to improve energy efficiency.	Technology is already commonly applied in South Africa. Potential for further improvement.	Energy efficiency measure
9	Improved process control	Optimise control of the production process with effective monitoring, control and process automation equipment. Improve equipment lifetime, energy efficiency, reduce waste, improve production yield and reduce pollutants and GHG emissions.	Technology is already commonly applied in South Africa. Potential for further improvement.	Energy efficiency measure
10	Improved heat exchanger efficiencies	Improved heat system (e.g. preheating of air and fuel charged to boilers, reduced heat losses, improved heat exchanger efficiencies, improved process integration etc.).	Technology is already commonly applied in South Africa. Potential for further improvement.	Energy efficiency measure
11	Improved electric motor system controls and variable speed drives (VSDs)	Improved electric motor system controls and variable speed drives (e.g. compressors, pumps and fans).	Technology is already commonly applied in South Africa. Potential for further improvement.	Energy efficiency measure
12	Energy-efficient utility systems	Energy-efficient utility systems (e.g. lighting, refrigeration, compressed air).	Technology is already commonly applied in South Africa. Potential for further improvement.	Energy efficiency measure
13	CCS – New Refineries	Carbon capture and storage (CCS) – Removal of CO_2 from flue gas streams, capture and disposal of CO_2 installed on new refineries.	Technology is entirely untested.	CCS

9.3.2 Other Energy Industries

Table 14: List of mitigation measures for the other energy industries sector

No	Abatement measure	Description	Implementation status in South Africa	Type
1	Upgrade feed compressors	Upgrading primary electric motor driven equipment can achieve significant electricity savings.	Measure implemented prior to 2010; future potential will be captured in improved electric motor system controls and VSDs.	Energy efficiency measure
2	Increase onsite gas-fired power generation using internal combustion engines	Installation of most efficient gas turbine power generation equipment onsite to reduce imports of carbon intensive grid electricity. Uptake limited by access to gas fuel.	Implemented in SA after 2010. There is limited potential for further implementation.	Improved onsite site energy generation
3	Waste heat recovery power generation	Recovery of waste process heat and use for onsite electric power generation replacing consumption of carbon intensive grid electricity purchases from Eskom	Already implemented in SA. Further implementation is technically possible.	Improved onsite site energy generation
4	Waste gas recovery and use	Recovery of waste process gas (e.g. rectisol methane) and use for thermal/heat demand on site.	Already implemented in SA. The potential for further implementation is unclear.	GHG abatement, improved onsite site energy generation
5	CCS – process emissions from existing plants (storage onshore)	CO_2 capture and compression is the first stage of carbon capture and storage (CCS). CCS can capture, compress, transport and store up to 99% of CO_2 emissions. Coal to liquid/gas to liquid (CTL/GTL) industry can separate and recover CO_2 relatively easily due to high purity steams of CO_2 in the production process and therefore prevent process CO_2 emissions at much lower abatement costs (compared to CO_2 flue gas capture technologies). CCS costs estimates vary from US\$60–100/tCO_2 (ETSAP, 2010b), including capex, compression, transport and storage. CTL/GTL cost could be a low as US\$11/tCO_2. CO_2 could also be captured from flue gas emission; however this will be much more expensive to implement. CO_2 transport and storage is the second stage of CCS. Mitigation potential is physically limited to national geological storage capacity in South Africa. It is likely that CO_2 storage capacity will be filled by recovered process CO_2 (before flue gas CO_2 is recovered).	Technology has been tested internationally but not yet commonly applied. Not yet tested in South Africa. A realistic upper limit for the geological storage of CO_2 from a large point source would be 6mtpa – such a project would be double the size of the current largest project under construction (Gorgon). It should be noted that compression and conditioning of this volume of CO_2 would consume ~ 9300 GWh/annum reducing the effective CO_2 mitigation to ~ 5 mtpa. The earliest opportunity to start injection would be 2025 provided storage is proven by 2020.	CCS

No	Abatement measure	Description	Implementation status in South Africa	Type
6	Energy monitoring and management system	Computer-aided management system of process operations, energy systems and energy consumption. Identify energy saving opportunities and improve overall operational energy efficiency. Benchmark GHG performance and implement energy management systems to improve energy efficiency.	Already implemented in SA. Further implementation is technically possible.	Energy efficiency measure
7	Improved process control	Optimise control of the production process with effective monitoring, control and process automation equipment. Improve equipment lifetime, energy efficiency, reduce waste, improve production yield and reduce pollutants and GHG emissions.		Energy efficiency measure
8	Improved electric motor system controls and VSDs	Improved electric motor system controls and variable speed drives (e.g. compressors, pumps and fans)		Energy efficiency measure
9	Energy-efficient utility systems	Energy-efficient utility systems (e.g. lighting, refrigeration, compressed air)		Energy efficiency measure
10	Improved heat systems	Improved heat system, including exchanger efficiencies		Energy efficiency measure
11	CCS – process emissions from existing plants (storage offshore)	As above. Except captured CO_2 transported and stored offshore so costs increases, but capacity not limited as much.	Technology has been tested internationally but not yet commonly applied. Not yet tested in South Africa. As above.	CCS
12	CCS – process emissions from new plants	As for CCS for existing facilities (storage onshore) above. Except captured CO_2 transported and stored offshore so costs increases, but capacity not limited as much. Capture capex costs are assumed to be 75% of existing plant,	Technology has been tested internationally but not yet commonly applied. Not yet tested in South Africa. As above.	CCS

Coal Mining and Handling

Table 15: List of mitigation measures for the coal mining and handling sector

No	Abatement measure	Description	Implementation status in South Africa	Type
1	Methane destruction by flaring	Coal mine methane release reduced through capture and destruction by flaring in cases where site conditions result in methane concentrations high enough to allow for use of this technology	One project in SA. Further implementation dependent on depth of mining and specific site conditions	GHG abatement
2	Methane capture and use for power and heat production	Coal bed methane capture and use for power (electrical or motive) and heat (instead of venting and flaring). Benefits include reducing greenhouse gas emissions by destroying methane, replacing electricity generated from the grid thereby displacing coal fired generation, providing motive power for mine vehicles again replacing other fossil fuels that are less efficient, replacing heat generated by coal-fired boilers and/or compressing gas to be piped off site for general use providing a source of natural gas.	One bulk yield test in SA. Further implementation may be technically possible.	GHG abatement
3	Use of biodiesel	Use of biodiesel for open pit mobile machinery. Reduce fossil fuel combustion.	Not implemented.	Fuel switch
4	Improve coal mine energy efficiency	Improve energy efficiency by adopting an energy management system, pump optimisation through frequency drives, convert to energy-efficient electric motors, optimise lighting efficiencies, solar hot water, computerised fleet management system, optimise dragline operations and ventilation fans.	Already implemented in SA. Further implementation is technically possible	Energy-efficiency measure
5	Energy monitoring and management system	Computer-aided management system of process operations, energy systems and energy consumption. Identify energy saving opportunities and improve overall operational energy efficiency.	Already implemented in SA. Further implementation is technically possible	Energy-efficiency measure
6	Improved electric motor system controls and VSDs	Improved electric motor system controls and variable speed drives (e.g. compressors, pumps and fans).	Already implemented in SA. Further implementation is technically possible	Energy-efficiency measure
7	Energy-efficient utility systems	Energy-efficient utility systems(e.g. ventilation, lighting, compressed air)		Energy-efficiency measure

Oil and Natural Gas

Table 16: List of mitigation measures for the oil and natural gas sector

No	Abatement measure	Description	Implementation status in South Africa	Type
1	Eliminate flaring of vented natural gas from oil and gas fields	Eliminate gas flaring at oil/gas fields by capturing and processing natural gas that is currently and in the future would be flared. Example projects (e.g. Ovade-Ogharefe oil field) treat captured gas and inject it into existing gas transmission lines for sale to an independent power plant (IPP) while the extracted natural gas liquids (NGLs) are transported and sold into the national and international market. Can reduce flaring by approximately 98%.	Emissions are flared	GHG abatement
2	Eliminate gas venting by capturing and utilising waste natural gas from oil and gas fields	Eliminate gas venting at oil/gas fields by capturing and processing associated natural gas that is currently and in the future would be vented. Example projects (e.g. Ovade-Ogharefe oil field) treat captured gas and injected into existing gas transmission line for sale to an independent power plant while the extracted NGLs be transported and sold into the national and international market. Can reduce flaring by approximately 98%.	Waste natural gas emissions are vented.	GHG abatement, improved onsite energy generation
3	CO_2 EOR and CO_2 Storage	Carbon dioxide enhanced oil recovery (CO_2 EOR) and CO_2 storage using waste CO_2 (captured from energy or industrial sources) in the oil extraction process to increase the recovery rate of oil and securely store CO_2. The recovery factor varies widely as a function of the reservoir characteristics. Over the past decades, technology improvements have meant increasing recovery factors. Currently, a typical recovery factor for oil fields ranges from 30-50% while for natural gas it is typically higher, ranging from 70-80%. However, extracting more than 40% of the oil in places may require enhanced oil recovery (EOR) techniques and additional costs, as well as in-depth analysis to ensure the economic affordability of the process.	EOR is not yet implemented in South Africa.	GHG abatement

10. Approach to Development of Marginal Abatement Cost Curves

Marginal abatement cost curves (MACCs) have been developed for the non-power energy key sector and subsectors for 2020, 2030 and 2050, presenting the annual technical mitigation potential relative to the reference WEM emissions projection.

Marginal abatement cost curves show the cost and emissions reduction potential for a group of mitigation measures or technologies. Relative to the reference WEM emissions projection, the MACC shows the GHG mitigation potential for each abatement technology along the horizontal x-axis (in tonnes of CO_2e abated) and the cost of implementing the measures along the vertical y-axis (in R per tonne of CO_2e abated). The mitigation measures are ranked from left to right along the x-axis from cheapest to most expensive.

A sectoral bottom-up approach has been taken in developing the MACCs and determining the non-power energy sector-level technical mitigation potential. Generally, the sectoral mitigation potential (for each year between 2010 and 2050) for each measure has been estimated compared to the reference WEM emissions projection for the non-power energy subsector (and specified subsectors), based upon an assessment of three key percentage factors.

- Emissions reductions potential – percentage of fugitive, process, direct fuel and/or indirect electricity emissions.
- Applicability – the percentage of the total reference sector emissions that the mitigation measure's reduction potential can be applied to.
- Sector uptake/penetration – the percentage of the sector that implements the measure.

The sector-wide mitigation potential is then simply estimated by multiplying the reference emissions by the three factors above for each measure and then adding the mitigation potential of all measures identified for the sector.

The approach taken and methodology applied in developing the MACCs for the non-power energy sectors is described in detail in Technical Appendix A: Approach and Methodology. The MACCs have been constructed using a computer-based Microsoft Excel™ spreadsheet. A summary of the key methodological assumptions affecting GHG mitigation potential and the marginal abatement cost made are described below.

10.1 Estimating Mitigation Potential

The GHG mitigation abatement potential for each abatement technology is displayed along the horizontal x-axis of the MACC (in tonnes of CO_2e abated).

The annual mitigation potential for each measure is calculated on a sectoral basis in each year of analysis (e.g. 2020, 2030 and 2050). The mitigation potential is based upon the WEM reference emissions projection (for process, direct fuel emissions and indirect electricity related emissions), the data parameters gathered for each mitigation measure identified (including direct emissions reduction potential and applicability, process emissions reduction potential and applicability, and fuel saving potential and applicability, and electrical saving potential and applicability, as described in Table 12 in Section 9.1), and the selected sector uptake. The mitigation potential is then calculated applying the following formulas:

Sector mitigation potential ($tCO_2e/year$)

= fugitive emissions reduction ($tCO_2e/year$) +

process emissions reduction ($tCO_2e/year$) +

direct fuel emissions reduction ($tCO_2e/year$) +

indirect electricity emissions reduction ($tCO_2e/year$)

The fugitive emissions reduction potential for a given mitigation measure is calculated using the following formula:

Fugitive emissions reduction ($tCO_2e/year$)

= reference fugitive emissions ($tCO_2e/year$) ×

fugitive emissions reduction potential (%) ×

applicability (%) × sector uptake (%)

The process emissions reduction potential for a given mitigation measure is calculated using the following formula:

Process emissions reduction ($tCO_2e/year$)

= reference process emissions ($tCO_2e/year$) ×

process emissions reduction potential (%) ×

applicability (%) × sector uptake (%)

The fuel emissions reduction potential for a given mitigation measure is calculated using the following formula:

Direct fuel emissions reduction ($tCO_2e/year$)

= reference direct fuel emissions ($tCO_2e/year$) ×

fuel energy saving potential (%) ×

applicability (%) × sector uptake (%)

Finally, the indirect electricity emissions reduction potential of a given mitigation measure is calculated using the following formula:

Indirect emissions reduction (tCO_2e/year)

= reference indirect electricity emissions (tCO_2e/year) ×

electricity saving potential (%) ×

applicability (%) × sector uptake (%)

The emissions reduction potential and applicability, fuel saving potential and applicability, and electrical saving potential and applicability for each measure have been selected based upon benchmark information and/or in consultation with the TWG sector experts. The selected parameters for all mitigation measures identified in each non-power energy sector are presented in the following sections together with relevant assumptions.

Importantly, the selected level of sector uptake for each measure determines the extent to which a measure is available and implemented across the sector and impacts the overall mitigation potential.

10.1.1 Mitigation Measures Availability

A MACC may include a wider range of abatement measures, including established existing technologies, and less well established emerging technologies. Certain emerging technologies might not be available for application until some point in the future. This is reflected in the assumptions that are made about the availability of technology at a given point in time.

Drawing upon published research the availability of each of the technologies over the assessment period has been defined. For each technology the availability has been allocated to the beginning of one of the following 10 year periods: 2010, 2020, 2030 and 2050.

10.1.2 Sector Uptake and Market Penetration

The extent to which a specific abatement measure can be implemented at a given point in time in the future is influenced by its availability and market penetration rate. The penetration rate essentially describes the rate at which the measure could realistically penetrate the market. It therefore provides a limit on the abatement potential that can be delivered by a specific measure. For new technologies, this rate is typically assumed to follow existing investment cycles.

In the energy (excluding electricity generation) sectors and industrial sectors, for example, the selected level of implementation of a mitigation measure in a given year is defined by three parameters outlined below.

- Starting point: when additional mitigation action is implemented.
- Penetration rate: at what rate a measure is implemented over the 2010–2050 time period (i.e. The penetration rate).
- Uptake: the extent to which a measure is implemented and deployed across the sector at a point in time (e.g. 25%, 50% or 100% by 2050).

To determine the starting point, penetration rate and uptake of each measure, a pragmatic approach is applied guided by the principle of what is technically possible (and not limited by economic and other non-technical limitations). These parameters have been decided based on two factors:

- Availability of technology: as defined above, the availability of each measure is allocated to the beginning of one of the following 10 year periods: 2010, 2020, 2030, 2040 or 2050.
- Marginal abatement cost: The overall cost per tonne of CO_2e abated.

Additionally, the following assumptions have been made:

- Measures are implemented between 2010 and 2050, from 0% to 100% additional uptake.
- Measures are implemented starting from when they are deemed to be technically available.
- Measures are typically implemented sector-wide at a rate from 0 to 100% over a period of 10 years, if a measure is a smaller retrofit project (i.e. lifetime of between 10 and 15 years). If measures are deemed to be locked-in technology (i.e. lifetime of between 25 and 40 years), then it is assumed that they are implemented over 20 years.
- Where a set of measures is mutually exclusive, then it is assumed that they will be implemented equally and the total summed uptake of these measures cannot exceed 100% (e.g. post-combustion and oxyfuel CCS).

Where a measure is deemed to be too costly in comparison to other options or not feasible due to the prior implementation of another measure, then the uptake has been set to zero and the measure has been removed from the MACC.

The selected levels of uptake for each measure are presented in the following sections for each non-power energy sector. These levels of uptake have been selected in consultation with the TWG industry experts.

The above approach and selected abatement, marginal abatement cost and technically possible levels of uptake result in the creation of the 'with additional measures' (WAM) emissions projection.

10.2 Estimating the Marginal Abatement Cost

The marginal abatement cost (MAC) is an indicator of the cost required to implement a given technical measure to abate a unit of CO_2e. The MAC describes the net cost of implementing a measure by comparing the capital and operational costs against potential energy cost savings (or additional energy overheads) per tonne of abatement. The MAC is shown along the vertical y-axis of the MACC (in cost per tonne of CO_2e abated). The marginal abatement costs for a measure in a given year are defined as follows:

MAC (R/tCO_2e) = net annual cost (R/year)/
total emissions reduction (tCO_2e/year)

The net annual cost (NAC) for a measure in a given year is the sum of the equivalent annual cost (EAC) and the annual operation and maintenance cost (Opex) minus the energy cost saving. The NAC is defined as follows:

NAC (R/year) = equivalent annual cost (R/year) +

annual operation & maintenance cost (R/year) –

energy cost saving (R/year)

The EAC for a given measure is defined as the capital investment cost (Capex) of the technical measure annualised over the measure's lifetime applying a discount rate. This can be calculated in MS Excel™ by taking the negative value returned by the PMT function.

The Capex is annualised because the measures within the MACC may have different lifetimes. Annualising the Capex allows the marginal abatement costs of different measures to be compared and ranked. The Capex is based on the estimated overnight[6] capital cost for the measure in 2010. The Capex, Opex and lifetime have mostly been based on benchmark information, then cross-checked with the sector task team representatives. In cases where more accurate costing information has been made available by the TWG, this has been used instead. The selected Capex, Opex and lifetimes for all of the mitigation measures identified in each non-power energy sector are displayed in the following sections. The discount rate is assumed to be 11.3% (as set by the TWG).

A capital discount rate of 11.3% is unlikely to be available for private sector investment in the interventions which have been identified. One consequence of this is that mitigation options that lie below the line (a negative marginal abatement cost) may not necessarily be as attractive when private sector discount rates are used.

10.2.1 Other Cost Assumptions

The energy cost saving (R/year) for a given measure in a given year is based upon the estimated annual fuel and/or electricity saving (GJ/year) multiplied by the assumed price for that year (in R/GJ). The assumed fuel and electricity prices for the period 2010 to 2050 are presented and explained in Box 1.

Box 1: Energy Price Assumptions

The assumed fuel prices for 2010, 2020, 2030 and 2050 used in the mitigation analysis and the development of the non-power energy, industry and transport sector MACCs are presented in Table 17. The prices are based upon the supply costs of various indigenous production of primary fossil and renewable energy and on import prices from "Appendix I. Primary Energy Supply Sector – Reference Case Assumptions" of version 3.2 of the SATIM Energy Model Methodology Appendices (ERC, 2013) provided in R/GJ (with the exception of metallurgical coke, petcoke and refinery fuel gas which are not specified in the SATIM model). This source was considered to be the most comprehensive, up-to-date and consistent data source for South African fuel prices on which to base the fuel price assumptions. The assumed prices are net prices and do not include tax or additional local distribution charges.

6. The lump sum cost disregarding interest for a construction project.

Box 1: Energy Price Assumptions – Continued

Exceptionally, the 2010 base year price for metallurgical coke and petcoke is based upon average market price information (Resource-Net, 2011). The refinery fuel gas (RFG) production cost is based on the SATIM energy model crude oil cost and the assumption that 5% of feed crude stock is converted into RFG and RFG production costs are 2.5% of total refinery product energy. The 2020, 2030 and 2050 prices are all extrapolated based upon the SATIM growth trend for crude oil.

In reality, the fuel prices paid by different businesses and industry subsectors may vary depending on several factors (e.g. amount of fuel purchased, supply contract terms etc.). As no other single and consistent information source was available for fuel prices paid in the non-power energy and industry subsectors, the SATIM energy model and DoE energy prices were applied.

The electricity price for 2010 and projection up to 2050 is based upon the anticipated average electricity price path included in the Integrated Resource Plan (IRP) For Electricity 2010–2030 (DoE, 2011, Figure 4). This was considered to be the most appropriate data source on which to base the electricity price assumption and projection and is consistent with the power sector mitigation analysis assumptions.

Table 17: Assumed energy prices for 2010 base year and projected prices up to 2050

Item	Units	Source	Note	2010	2020	2030	2040	2050
Coking coal	R/GJ	(ERC, 2013)DoE	Imports of coking coal	55	60	66	70	75
Bituminous coal	R/GJ	(ERC, 2013)	Extraction of coal	27	30	33	35	37
Metallurgical coke	R/GJ	(Resource-Net, 2011)	Projection linked to coal trend, SATIM Model 2013	112	123	134	143	152
Petcoke	R/GJ	(Resource-Net, 2011)	Projection linked to crude oil trend, SATIM Model 2013	111	137	170	192	213
Natural gas	R/GJ	(ERC, 2013)	Imports of gas southern Mozambique piped	44	55	68	77	85
Crude oil	R/GJ	(ERC, 2013)	Imports of crude oil	97	121	150	168	187
Liquid natural gas (LNG)	R/GJ	(ERC, 2013)	Imports of gas, LNG	72	88	108	121	133
Liquid petroleum gas (LPG)	R/GJ	(ERC, 2013)	Imports of oil, LPG	276	300	329	348	367
Motor gasoline	R/GJ	(ERC, 2013)	Imports of oil, gasoline	124	153	188	211	234
Gas diesel oil	R/GJ	(ERC, 2013)	Imports of oil, diesel	117	145	180	203	226
Heavy fuel oil (HFO)	R/GJ	(ERC, 2013)	Imports of oil, HFO	97	121	150	168	187
Kerosene	R/GJ	(ERC, 2013)	Imports of oil ,kerosene	127	154	189	211	232
Biomass bagasse	R/GJ	(ERC, 2013)	Renewable resource: biomass bagasse	20	20	20	20	20
Biomass wood	R/GJ	(ERC, 2013)	Renewable resource: biomass wood	20	20	20	20	20
Biodiesel	R/GJ	(ERC, 2013)	Imports of biodiesel	123	152	189	213	237
Electricity	R/GJ	(DoE, 2011)	IRP projection (Figure 4) breakdown of anticipated average electricity price path	117	264	264	264	264
Bioethanol	R/GJ	(ERC, 2013)	Imports of bioethanol	131	160	198	222	246
Refinery fuel gas	R/GJ	Specific assumption	Linked to imported crude oil projection	8	10	13	14	16

While a specific set of energy prices were assumed for the study, it is recognised that when developing sector specific feasible mitigation options, prices that are applicable to the specific activity will need to be applied.

11. Mitigation Potential for the Non-Power Energy Sector

The non-power energy sector includes four subsectors comprising petroleum refining, coal mining and handling, oil and natural gas production and other energy industries. A summary of abatement potential and marginal abatement costs for all measures is shown in Table 32. Summary MACCs for the non-power sector are shown below. MACCs have also been developed for each of the four subsectors for 2020, 2030 and 2050 and are presented in the sections which follow.

11.1 Marginal Abatement Cost Curves for the Non-Power Sector

Marginal abatement cost curve summaries for 2020, 2030 and 2050 are shown in Figure 12, Figure 13 and Figure 14 below. Please refer to Table 32 for details on each measure.

Identification numbers shown in the legends of all of the MACC figures below may be used to look up details in Table 32.

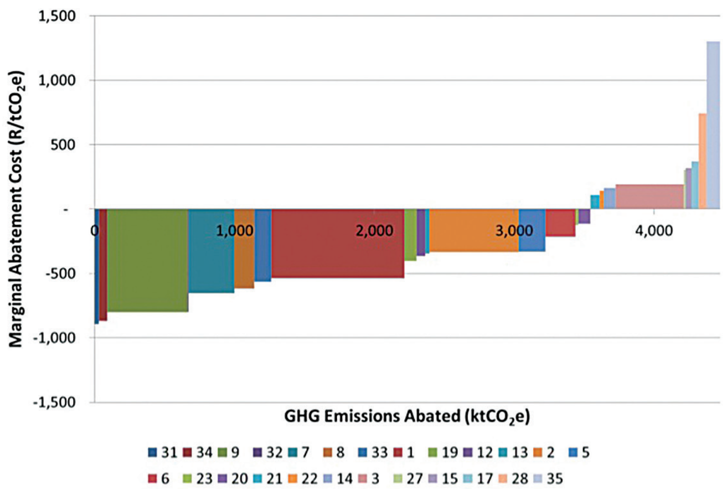

Figure 12: Marginal abatement cost curve for the non-power energy sector in 2020

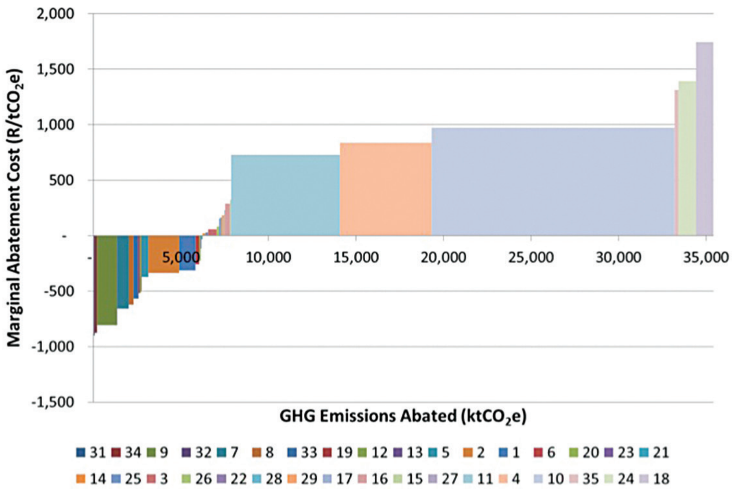

Figure 13: Marginal abatement cost curve for the non-power energy sector in 2030

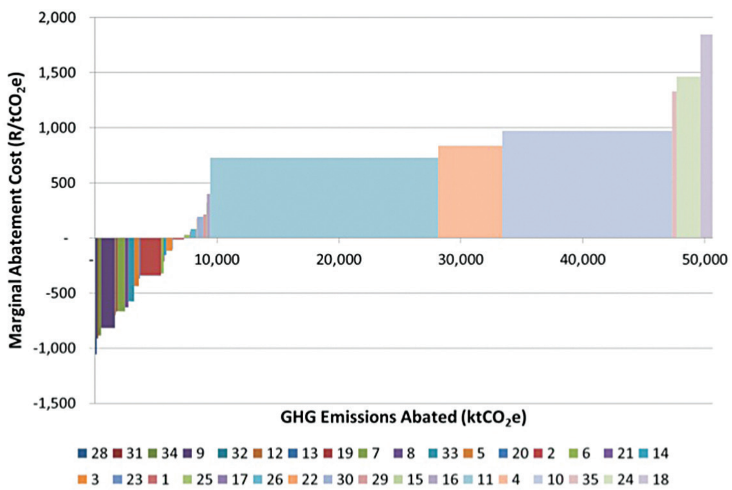

Figure 14: Marginal abatement cost curve for the non-power energy sector in 2050

11.2 Petroleum Refining

The MACCs for petroleum refining operations in South Africa, including conventional oil refining, are presented below for 2020, 2030 and 2050. The key assumptions made in the analysis are summarised below.

11.2.1 Key Assumptions

The MACC analysis for petroleum refining makes the following general assumptions.

Production, energy and GHG emissions projections are split for existing and new production capacity. New capacity is assumed to be added in 2030 and 2050.

The measure of crude oil refined by existing refineries is based on the "sources of crude oil for SAPIA members" provided in the 2010 SAPIA Annual Report (SAPIA, 2011). It is noted that this may not be an entirely accurate measure of oil refined due to changes in crude stock levels.

Sector growth is based upon supply estimates necessary to meet forecasted national liquid fuel demand in line with South African Government energy security targets, provided by TWG members and SAPIA members. New facilities with capacity of 250,000 barrels per day (bbl/day) of liquid fuel are assumed to be added in 2030 and 2050, adding an additional 500,000 bbl/day by 2050 (SAPIA, 2013).

It is also important to recognise that mitigation actions taken within the transport sector will have important feedbacks in other sectors of the economy, particularly the energy sector. For example, abatement measures that influence the level of fuel demand will feedback in terms of the level of liquid fuel that needs to be produced in South Africa to meet transport demand, and therefore the associated emissions from the sector. Likewise, the large-scale take up of biofuels, if supplied from indigenous sources, will have an influence on future land use scenarios, and the associated direct emissions from this sector.

The bottom-up approach that has been used in the current study does not assess each of these sectoral interactions automatically, and to do so fully would require additional modeling effort which is beyond the scope of the current study. However, the use of emission factors, which include an estimate of the impacts of measures on indirect emissions such as those associated with fuel production, allows the scale of some of these interactions to be understood.

With the aim of reducing emissions, the MACCs assume that 50% of refining facilities implement efficient onsite power energy production equipment by 2030 (e.g. combined cycle gas turbines and combined heat and power) capable of meeting at least 60% of a refinery's electricity demand and reducing equivalent indirect emissions from imported power.

New refineries added in 2030 and 2050 are assumed to have lower emissions factors and be more energy efficient compared to existing plants in 2010, reflecting the more modern design and adoption of best available technologies. Overall energy efficiency is assumed to improve by 20% compared to existing operations in 2010. These improvements are based on the assumption that all identified measures except CCS would be implemented in new facilities.

CCS capital and operational costs for capture, transport and storage of CO_2 are based upon IEA benchmark costs (ETSAP, 2010b). The additional annual costs of onshore storage assume US$5/t$CO_2$e transport and US$10/tCO_2e onshore storage cost. Storage offshore assumes US$10/t$CO_2$e for transport and US$20/tCO_2e for offshore storage cost. For CCS transport costs 100km is selected as the default transport distance for CO_2 storage onshore within coal fields, and 400km is selected for CO_2 storage in offshore geological formations. It is noted that some sources may be located closer or further than the selected distances. To compensate for this uncertainty, the high IEA cost estimate for CO_2 transport is selected as above.

CO_2 storage capacity is not considered to be limited to the levels of CO_2e storage proposed by the MACCs based upon assessments of onshore and offshore storage resources in South Africa. The estimated capacity of geological storage in South Africa is at least 150 Gt (150,000 Mt) of CO_2, for example. The storage potential lies mainly in the capacity of saline formations associated with the oil- and gas-bearing sequences in the Outeniqua, Orange and Durban/Zululand basins (Council for Geoscience, 2010). It should be emphasised that the estimated geological storage volume is theoretical. Through extensive basin exploration and site characterisation activities, effective (actual) storage capacity can be established and may be lower than initial theoretical estimates.

For storage of CO_2 from existing plants, injection into either coal fields or saline formations can begin from 2025 and two (out of the four) refineries can be retrofitted. New refineries which come online in 2030 and 2050 have CCS installed (at 75% of the assumed benchmark capital cost for existing plants). The MACCs assume injection of CO_2 into saline reservoirs in offshore basins can begin as early as 2030.

The cost of refinery fuel gas (RFG) is based on the assumption that 5% of feed crude stock is converted into RFG and production costs are 2.5% of total refinery product energy consumption giving an RFG production cost of approximately R8/GJ in 2010.

The assumed fugitive emissions for an existing refinery are based upon data on flaring of RFG submitted to the GHGI by one oil refinery equivalent to 666 GJ/day in 2012.

The equivalent sector fugitive GHG emissions assume the same emissions for all four existing conventional oil refineries (approximately 1% of total emissions). The assumptions and sector estimate for years 2009 to 2012 are shown in Table 18. The "minimise flaring and utilise flare gas as fuel" mitigation measure aims to abate these fugitive emissions and assumes that a 75% reduction in emissions is technically possible for existing refineries. For new refineries it is assumed that a 75% reduction reflecting improved design is built in.

Table 18: Assumptions behind refinery fuel gas flaring activity and equivalent fugitive emissions

Item	Unit	2009	2010	2011	2012	Assumption
Refinery flaring (data submitted by one refinery)	GJ/day	702	170	566	666	1 BTU = 1,055.06
Flaring (assuming continuous operation)	GJ/year	256,088	62,000	206,411	242,995	
Flaring (assuming IPCC NCV for refinery gas of 49.5 GJ/ tonne)	tonnes/year	5,174	1,253	4,170	4,909	49.5 GJ/tonne
Sector flaring (assuming all 4 oil refineries in operation in SA have similar flaring activity)	tonnes/year	20,694	5,010	16,680	19,636	
	TJ/year	1,024	248	826	972	
CO_2 emissions (assuming IPCC refinery gas emission factor (EF) of 57,600 $kgCO_2/TJ$)	$ktCO_2$/year	59	14	48	56	57600 $kgCO_2/TJ$
CH_4 emissions (assuming refinery gas EF of 1 $kgCH_4/TJ$)	$ktCH_4$/year	0.001	0.000	0.001	0.001	1 $kgCH_4/TJ$
	$ktCO_2e$/year	0.024	0.006	0.019	0.022	23 GWP
N_2O emissions (assuming refinery gas EF of 0.1 kgN_2O/TJ)	ktN_2O/year	0.0001	0.0000	0.0001	0.0001	0.1 kgN_2O/TJ
	$ktCO_2e$/year	0.030	0.007	0.024	0.029	296 GWP
Total GHG emissions	$ktCO_2e$/year	59	14	48	56	

The assumed emissions reduction and energy saving potential for each mitigation measure included in the petroleum refining production MACC, together with references, are presented in Table 19. The assumed cost, technology availability and lifetime are listed in Table 20. The assumed technology uptake in 2010, 2020, 2030 and 2050 and other key assumptions are shown in Table 21.

Table 19: Emissions reduction potential and energy saving potential of mitigation measures and references in petroleum refining

	Abatement measure	Emissions abatement potential	Applicability	Fuel/energy saving potential	Applicability	Electricity saving potential	Applicability	Reference
		%	%	%	%	%	%	
1	Improve steam generating boiler efficiency			5%	38%			(EC, 2013c) (USEPA, 2010) (SAPIA, 2013)
2	Improve process heater efficiency			5%	18%			
3	Waste heat recovery and utilisation			5%	100%			
4	Minimise flaring and utilise flare gas as fuel	75%	100%					
5	Efficient energy production (CCGT and CHP)					60%	100%	
6	Waste heat boiler and expander applied to flue gas from the FCC re generator			15%	20%			

Abatement measure		Emissions abatement potential	Applicability	Fuel/energy saving potential	Applicability	Electricity saving potential	Applicability	Reference
		%	%	%	%	%	%	
7	CCS – existing refineries	70%	100%	-40%	100%	-10%	100%	(SAPIA, 2013) (ETSAP, 2010)
8	Energy monitoring and management system			2%	100%	2%	100%	(EC, 2009a, p45, 83) (EC, 2013c)
9	Improved process control			2%	100%	2%	100%	(EC, 2009a p76)
10	Improved heat exchanger efficiencies			10%	40%			(EC, 2009a, p94, 164)
11	Improved electric motor system controls and VSDs					10%	60%	(EC, 2009a, p199, 214, 289)
12	Energy-efficient utility systems					10%	40%	(EC, 2009, p206, 228, 235, 246)
13	CCS – New Refineries	80%	100%	-30%	100%	-10%	100%	(SAPIA, 2013) (ETSAP, 2010)

Table 20: Costs, availability and lifetime of petroleum refining mitigation

Abatement measure		Capital cost	Additional annual costs	Site production capacity	Abatement cost	Availability	Lifetime
		Million R/site	Million R/year	Million tonnes/year	R/tCO_2	Year	Years
1	Improve steam generating boiler efficiency	20	1	3.2		2010	15
2	Improve process heater efficiency	10	1	3.2		2010	15
3	Waste heat recovery and use	180	9	3.2		2010	25
4	Minimise flaring and use flare gas as fuel	18	1	3.2		2010	25
5	Efficient energy production (CCGT and CHP)	648	32	3.2		2010	40
6	Waste heat boiler and expander applied to flue gas from the FCC regenerator	135	7	3.2		2010	25
7	CCS – existing refineries				1,215	2025	40
8	Energy monitoring and management system	30	2	3.2		2010	15
9	Improved process control	60	3	3.2		2010	15
10	Improved heat exchanger efficiencies	120	6	3.2		2010	15
11	Improved electric motor system controls and VSDs	72	4	3.2		2010	15
12	Energy-efficient utility systems	36	2	3.2		2010	15
13	CCS – New Refineries				1,080	2030	40

Table 21 Mitigation technology sector uptake and other assumptions in petroleum refining

Abatement measure		% Total sector uptake				Other Assumptions
		2010	2020	2030	2050	
1	Improve steam generating boiler efficiency	0%	100%	100%	100%	Assumed Capex of R20million. Boiler feed water (BFW) preparation example project – initial investment of the membrane system was $350,000 and annual savings of $200,000. Standby loses example – these measures were applied to a small 40 tonnes/hr steam boiler at an ammonia plant, resulting in energy savings of 54 TBtu/yr* with a capital investment of about $270,000 (1999$).
2	Improve process heater efficiency	80%	100%	100%	100%	Assumed Capex of R10million. One refinery in the United Kingdom installed a combustion air preheater on a vacuum distillation unit (VDU) and reduced energy costs by $109,000/yr. The payback period was 2.2 years.
3	Waste heat recovery and use	0%	50%	100%	100%	Assumes typical 120,000 bbL/day site thermal energy use of 9,000 TJ, of which 20% wasted through heat losses and 25% of this loss is recoverable (5% in total) for utilisation within process to reduce fuel use. Cost/site assumes R180 million Capex and Opex of 5% of Capex.
4	Minimise flaring and use flare gas as fuel	0%	100%	100%	100%	Assumes a reduction of 75% of flaring is technically possible. Assumes approximate cost of US$2 million for flare gas recovery compressor system.
5	Efficient energy production (CCGT and CHP)	0%	0%	50%	50%	Assumes 40 MW thermal input CCGT & CHP uses gas turbine with recovery steam boilers with back pressure steam turbine with efficiency of 80% (electrical 35%/heat 45% output, 20% loss) capable of generating 14MW electrical power output and approx. 60% of 120,000 bbL/day site power needs. Assumes counterfactual technology assumed to be heat generation equipment and grid electric. Selected cost/site assumes 50MW at US$1,800/kW Capex and Opex of 5% of Capex. Reduce imported power and possible export. Assume cost saving from a reduction in imported power by14 MWe or approx. 60%. Assumes fuel demand met by excess RFG onsite. However, additional fuel source may be needed if RFG on site cannot meet fuel demand. (Building new CHP plant combined with CCS would be more cost effective than separate CHP and CCS projects).
6	Waste heat boiler and expander applied to flue gas from the FCC regenerator	50%	100%	100%	100%	The waste heat boiler recovers the heat from the flue gas and the expander can recover part of the pressure to be used in the compression of the air needed in the regenerator. An example of the application of an expander saved 15MWe of the flue gas generated by a FCC of a capacity of 5Mt/yr. Selected cost/site assumes 15MWe at US$1,000/kW Capex and Opex of 5% of Capex. Assumes energy balance.

	Abatement measure	% Total sector uptake				Other Assumptions
		2010	2020	2030	2050	
7	CCS – existing refineries	0%	0%	50%	50%	In the oil industry, between 5% and 10% of crude oil is used for the refining process and the CO_2 concentration in the refinery gas streams ranges from 3% to 13%. More than 600 refineries worldwide produce globally some 800 $MtCO_2$/yr. Some 45 refineries emit more than 3Mt CO_2/yr. Modern plants converting heavier crudes into light products produce even more emissions. Most important processes are distillation, reforming, hydrogenation and cracking. While distillation requires low temperature heat, hydrogenation requires hydrogen, and cracking produces heat and CO_2 from heavy oil residues. Reformers, catalytic crackers and vacuum distillation units account for 30-40% of the energy use, which could be supplied by CHP units with CCS. Heaters could be equipped with post-combustion CO_2 capture systems. A study on the UK refinery plants suggests that the CO_2 capture would require 6.2 GJ of natural gas per tCO_2 captured. This is much more than the energy needed for CO_2 capture in power plants. The total cost would exceed \$200/tCO_2 in total (Capex, compression, transport, storage). • Assumes \$120/tCO_2e Capex for exiting plant (assuming Capex is 60% of minimum IEA price). • 6.2GJ additional annual costs for fuel consumption per tCO_2 captured and -10% power overhead for CO_2 compression. • Assumes additional annual costs of US\$5/tCO_2e transport (pipeline 100km) and US\$10/tCO_2e onshore storage cost.
8	Energy monitoring and management system	0%	100%	100%	100%	Saving, cost and uptake estimated and cross-checked with TWG members
9	Improved process control	80%	100%	100%	100%	
10	Improved heat exchanger efficiencies	0%	50%	50%	50%	
11	Improved electric motor system controls and VSDs	0%	50%	100%	100%	
12	Energy-efficient utility systems	0%	50%	100%	100%	
13	CCS – new refineries	0%	0%	100%	100%	• Assume costs and overheads are 75% for new plant. • 4.55 GJ fuel consumption additional fuel consumption per tCO_2 captured for new plant. • Assumes additional annual costs of US\$10/tCO_2e transport (pipeline 400km) and US\$20/tCO_2e offshore storage cost.

* Trillion British thermal units

11.2.2 *Marginal Abatement Cost Curve*

The technical mitigation potential for the South African petroleum refining sector in 2020 is estimated at over 558 ktCO_2e/year compared to the WEM reference projection or 13% of total emissions. The MACC for 2020 is shown in Figure 15 and indicates that the options with the lowest marginal abatement costs are the installation of advanced energy management and monitoring systems, improvement of existing steam generating boiler efficiencies and the improvement of process heater efficiencies. These all have negative marginal abatement costs of less than -R100/tCO_2e. Improved process control, improved heat exchanger efficiencies and recovery and use of waste heat within the process all offer good abatement potential at varying levels of cost. Minimising flaring activity and use of flare gas as fuel is the only option proposed to abate fugitive emissions and has a positive abatement cost of over R300/tCO_2e.

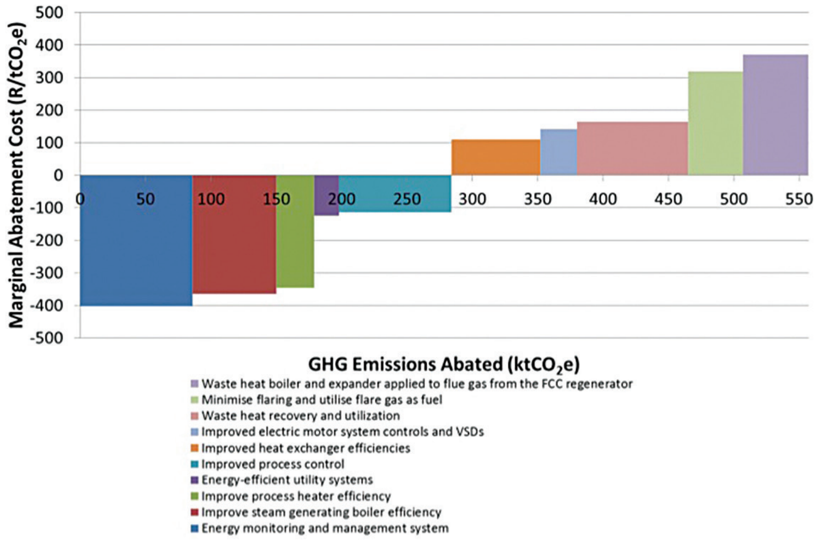

Figure 15: Petroleum Refining MACC for 2020

Assuming the availability and uptake of CCS technology in 2030, the annual abatement potential increases significantly to 2,950 ktCO_2e/year compared to the WEM reference projection or 51% of total emissions. The 2030 MACC is shown in Figure 16. Implementing CCS on existing refineries is capable of mitigating 998 ktCO_2e/year or 17% of total sector emissions. The cost of retrofitting existing refineries with CCS is estimated at almost R1,750/tCO_2e. This is considerably more expensive compared to the cost of CCS in other sectors due to the complicated process, many sources of CO_2 (e.g. process emissions and flue gas emissions) and higher energy overhead required to capture the CO_2 (e.g. as much as 6.2 GJ of energy per tCO_2 captured). This is much more than the energy needed for CO_2 capture in power plants. Despite this high cost, implementing new refining capacity with CCS is capable of mitigating another 17% of sector emissions. The marginal abatement cost of including CCS in new refineries is estimated at R1,392/tCO_2e. Implementing efficient energy generation techniques, including CCGT and CHP, mitigates an additional 5% of total sector emissions at a cost of R289/tCO_2e.

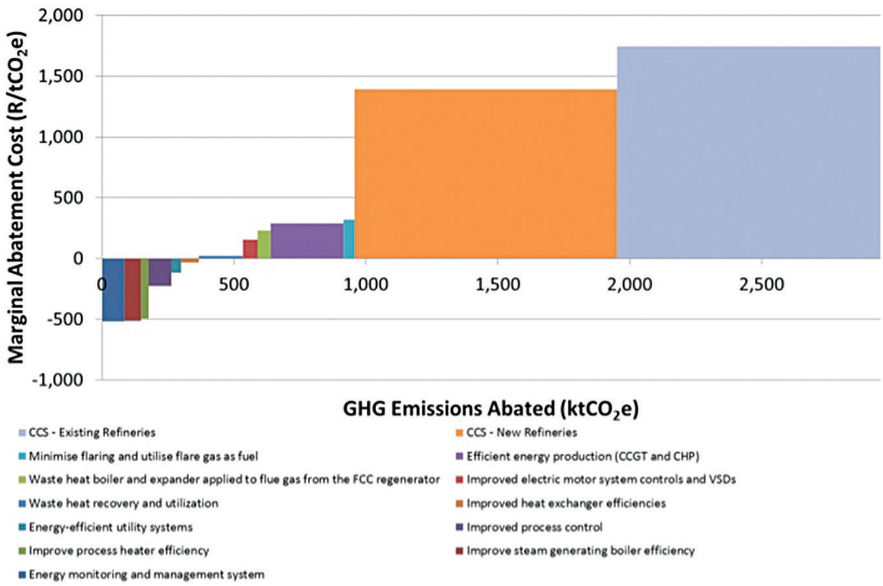

Figure 16: Petroleum Refining MACC for 2030

The rank order of mitigation measures remains the same in 2050 with the bulk of mitigation action achievable only at positive costs (i.e. above the x-axis in the MACC) as shown by Figure 17. Efficient onsite energy generation continues to show good mitigation potential. However, CCS remains the dominant mitigation option. The wider uptake of CCS in new refining capacity increases overall sector mitigation to 3,885 ktCO_2e/year or 54% of the reference emissions.

The total mitigation potential from 2010 up to and including 2050 is estimated at 74 million tonnes CO_2e compared to the WEM reference projection equivalent to 35% of total emissions.

Possibly one of the largest and most significant mitigation actions available to the South African energy sector would be to meet the forecasted rise in liquid fuel demand by increasing imported crude oil and building additional conventional oil refining capacity instead of constructing more coal-to-liquid (CTL) synthetic liquid fuel production capacity. Liquid fuel demand could be met by either increasing the size of the two new refineries to 350,000 bbl/day to be added in 2030 and 2050 or by constructing a third new refinery of 250,000 bbl/day in 2040, for example. Although this would not meet energy security objectives, it would significantly reduce emissions where the reference case is assumed to increase CTL capacity.

This potentially major mitigation opportunity has not been included in the petroleum refining MACC as it was identified too late in the MACC development process and requires further study to quantify mitigation potential and marginal abatement costs. However, it should be examined further and considered as a significant option in future mitigation policy.

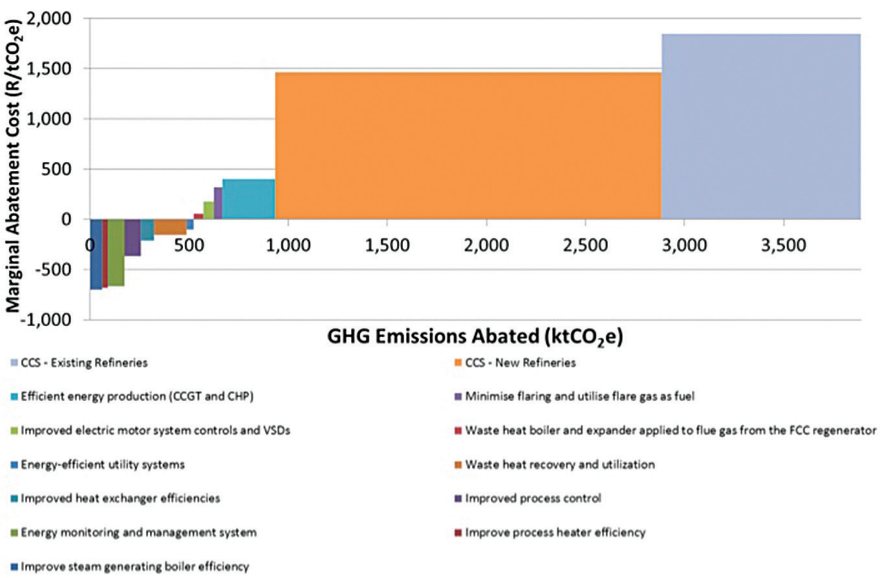

Figure 17: Petroleum refining MACC for 2050

11.3 Coal Mining and Handling

The MACCs for coal mining and handling, including surface and underground mining operations are presented below for 2020, 2030 and 2050. The assumptions made in the analysis are also summarised.

11.3.1 Key Assumptions

For the purpose of GHG mitigation, the MACCs assume that 2.5% of total coal mining operations in South Africa can be equipped for coal mine methane recovery and use for power and/or heat generation by 2030, increasing to 5% by 2040. The analysis also assumes that 5% of total coal mining operations in South Africa can be equipped for coal mine methane recovery and destruction by flaring, increasing to 10% by 2040. It is noted that the TWG sector experts stated that this technology is limited to mining operations in excess of 200 metres deep due to a low inherent methane concentration in coal seams in South Africa, resulting in sporadic volumes and fluctuating concentration of methane released. In many cases methane recovery is not considered economically or technically feasible under these specific site conditions.

For the implementation of biodiesel mitigation measures, the MACCs assume that a maximum of 50% of the mining fleet can be fueled by biodiesel. This assumes that first generation 5% biodiesel is available from 2010 and second generation biodiesel is available from 2020. In both cases, it is assumed that the infrastructure and regulatory regime is in place to ensure 50% of the fleet can be supplied.

Sector growth ranges from 2.2% per annum on average from 2010 to 2050, in line with the emissions projection assumptions and the underlying macroeconomic model.

The assumed emissions reduction and energy saving potential for each mitigation measure included in the coal mining and handling MACC, together with references, are presented in Table 22. The emissions reduction potential, energy saving potential and costs for measures 3 and 5 to 11 are based on mitigation data and feedback submitted by TWG sector members. Measures 1, 2 and 4 are based upon benchmark information.

Where cost information is not available, estimates have been made and presented to the TWG-M for comment. The assumed costs, technology availability and lifetime are listed in Table 23. The assumed technology uptake in 2010, 2020, 2030 and 2050 and other key assumptions are shown in Table 24.

It is noted that the sector-wide abatement potential and applicability estimates provided in Table 24 will not apply for all sites. According to industry experts, this technology might only be possible with mining operations in excess of 200 metres and only with certain specific site conditions due to a low inherent methane concentration in coal seams in South Africa, resulting in sporadic volumes and fluctuating concentration released. The actual decision to implement mitigation measures and the assessment of both technical and financial feasibility will always be site-specific.

Table 22: Emissions reduction potential and energy saving potential of coal mining and handling mitigation measures and references

	Abatement measure	Emissions abatement potential	Applicability	Source	Energy saving potential	Applicability	Energy saving potential	Applicability	Reference
		%	%		%	%	%	%	
1	Coal mine methane recovery and use for power and/or heat generation	90%	100%				100%	100%	(UNFCCC, ACM0008, 2010) (Coal Mining TWG, 2013)
2	Coal mine methane recovery and destruction by flaring	90%	100%	Fugitive					CDM Executive Board, UNFCCC, 2010) (Coal Mining TWG, 2013)
3	Use of 1st generation biodiesel (B5) for transport and handling equipment	5%	100%	Fuel emissions from transport					(DRET, 2013) (Coal Mining TWG, 2013)
4	Improve energy efficiency of mine haul and transport operations				15%	100%			(DRET, 2013) (Coal Mining TWG, 2013)
5	Use of 2nd generation biodiesel (B50) for transport and handling equipment	50%	100%	Fuel emissions from transport					(Coal Mining TWG, 2013)
6	Use of 2nd generation biodiesel (B100) for transport and handling equipment	100%	100%	Fuel emissions from transport					(Coal Mining TWG, 2013)
7	Process, demand & energy management system						5%	100%	(DRET, 2010) (Coal Mining TWG, 2013)
8	Energy-efficient lighting						1%	100%	(DRET, 2010) (Coal Mining TWG, 2013)
9	Install energy-efficient electric motor systems						20%	100%	(DRET, 2010) (Coal Mining TWG, 2013)
10	Optimise existing electric motor systems (controls and VSDs)						10%	100%	(DRET, 2010) (Coal Mining TWG, 2013)
11	Onsite clean power generation						10%	100%	(DRET, 2010) (Coal Mining TWG, 2013)

Table 23: Costs, availability and lifetime of coal mining and handling mitigation measures

	Abatement measure	Capex/unit electricity saved/year	Additional Opex/ unit electricity saved/year	Capex/unit fuel energy saved/ year	Additional Opex/ unit fuel energy saved/year	Capex/unit CO_2e abated/ year	Additional Opex/ unit CO_2e abated/year	Availability	Lifetime
		R/TJ	R/TJ	R/TJ	R/TJ	R/ktCO_2	R/ktCO_2	Year	Years
1	Coal mine methane recovery and use for power and/or heat generation	1,110,223	138,778					2010	20
2	Coal mine methane recovery and destruction by flaring					465,839	23,292	2010	20
3	Use of 1st generation biodiesel (B5) for transport and handling equipment					424,623	21,231	2010	15
4	Improve energy efficiency of mine haul and transport operations			283,925	141,963			2010	15
5	Use of 2nd generation biodiesel (B50) for transport and handling equipment					127,387	6,369	2020	15
6	Use of 2nd generation biodiesel (B100) for transport and handling equipment					84,925	4,246	2030	15
7	Process, demand & energy management system	43,554	2,178					2010	15
8	Energy efficient lighting	217,771	4,355					2010	15
9	Install energy-efficient electric motor systems	536,800	26,840					2010	15
10	Optimise existing electric motor systems (controls and VSDs)	80,520	4,026					2010	15
11	Onsite clean power generation	3,856,048	192,802					2010	25

Table 24 Coal mining and handling mitigation technology sector uptake and other assumptions

	Abatement measure	% Total sector uptake 2010	2020	2030	2050	Other Assumptions
1	Coal mine methane (CMM) recovery and use for power and/or heat generation	0%	0%	2.5%	5%	Assumes R400 million overnight investment and R50m O&M cost and generating ~100 GWh/year (based on benchmark CDM CMM projects). Assumes 90% CMM capture and destruction efficiency and all electricity consumption emissions are self-supplied.
2	Coal mine methane recovery and destruction by flaring	0%	0.0%	5%	10%	The recovery project is a flaring project at Anglo American Thermal Coal's New Denmark colliery near Standerton. The operation involves the incorporation of two enclosed Swiss-designed mobile flares into the mine's methane drainage system. A small diesel blower delivers the methane to four flaring nozzles, where the gas is mixed with air to a concentration that enables it to be safely burnt. The process can be monitored remotely via the flare's solar-powered communication system. The project reportedly cost US$1.2 million and the project developers are pursuing carbon credits under the Clean Development Mechanism (CDM). Assumes an emission reduction of 90% in venting and flaring is technically possible. Assumes conservative cost of approximately US$5.5 million for flare gas recovery compressor system and flaring system per mining unit.
3	Use of 1st generation biodiesel (B5) for transport and handling equipment	0%	25%	25%	0%	Abatement potential assumes 100% of fleet converted to 5% biodiesel (B5) and is applicable to 100% of fleet fuel emissions. Assumes biodiesel is 100% zero emissions and R50 million is the conversion cost. Based on mitigation data submitted by TWG member.
4	Improve energy efficiency of mine haul and transport operations	50%	100%	100%	100%	Technology and energy saving potential based on Australian benchmark data. No available benchmark Capex and Opex information, therefore this has been estimated. The cost difference between diesel and bio fuels is calculated in the EAC and NAC calculation below.
5	Use of 2nd generation biodiesel (B50) for transport and handling equipment	0%	0%	25%	25%	Abatement potential assumes 100% of fleet converted to 10% biodiesel (B10) and is applicable to 100% of fleet emissions. Assumes biodiesel is 100% zero emissions and R100million is the conversion costs.
6	Use of 2nd generation biodiesel (B100) for transport and handling equipment	0%	0%	0%	25%	Abatement potential assumes 100% of fleet converted to 10% biodiesel (B10) and is applicable to 100% of fleet emissions. Assumes biodiesel is 100% zero emissions and R100 million is the conversion costs.
7	Process, demand & energy management system	50%	75%	100%	100%	Based on mitigation data submitted by TWG members.
8	Energy efficient lighting	50%	75%	100%	100%	Based on mitigation data submitted by TWG members.
9	Install energy-efficient electric motor systems	50%	75%	100%	100%	Based on mitigation data submitted by TWG members.
10	Optimise existing electric motor systems (controls and VSDs)	50%	75%	100%	100%	Based on mitigation data submitted by TWG members.
11	Onsite clean power generation	20%	60%	100%	100%	Based on mitigation data submitted by TWG members. Assumes PV installed onsite. Cost based on PV costs of US$2,000/kW for equipment and US$500/kW other costs (e.g. design, construction, erection) and a capacity factor of 10%.

11.3.2 Marginal Abatement Cost Curve

The technical mitigation potential for the coal mining and handling sector in 2020 is estimated at 385 $ktCO_2e$/year or 6% of the reference WEM emissions projection. The 2020 MACC displayed in Figure 18 shows that there are several energy-efficiency measures available with negative abatement costs, including the implementation of process, demand and energy management systems, optimisation of existing electric motor systems (controls and VSDs), installation of energy-efficient lighting, installation of energy-efficient electric motor systems (replacing old inefficient units) and the improvement of mine haul and transport energy efficiency (via training, behaviour change and improved transport management and operation). There is also potential for the use of first generation biodiesel (B5) for transport and handling equipment to reduce emissions from transport albeit at a higher positive abatement cost.

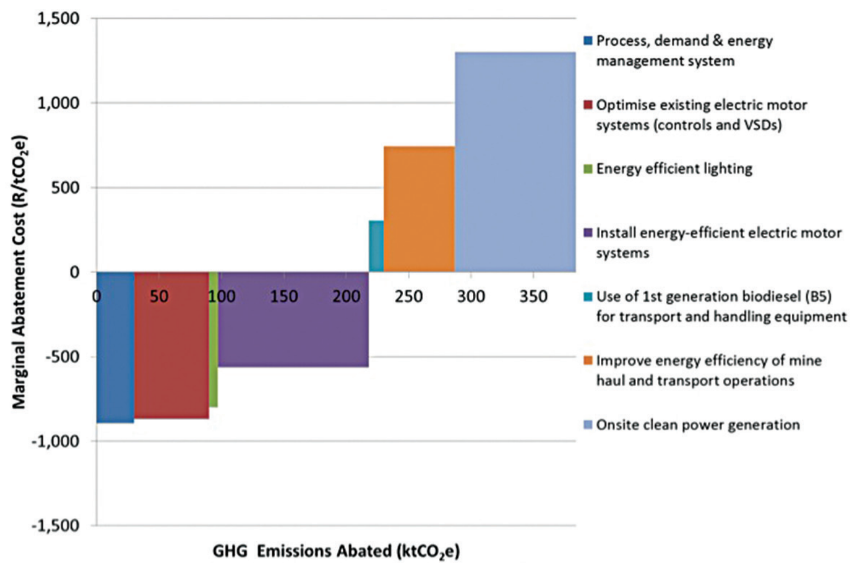

Figure 18: Coal Mining and Handling MACC for 2020

In 2030, the mitigation potential increases to 1,284 $ktCO_2e$/year equivalent to 17% of the WEM reference emissions projection for the coal mining sector, driven largely by energy-efficiency measures with negative marginal abatement costs. The 2030 MACC displayed in Figure 19, shows that energy-efficiency measures with negative marginal abatement costs continue to show the greatest potential for mitigation, capable of abating 11% of total emissions when combined. A proportion of fugitive emissions (equal to 5% of sector total emissions) can be abated by the assumed implementation of coal mine methane recovery and destruction by flaring and coal mine methane recovery and utilisation use for power and/or heat generation at relatively low marginal abatement cost of R30- and R83 R/tCO_2e, respectively. The development of onsite clean power generation also contributes to GHG mitigation (e.g. solar PV) by replacing imported power and reducing indirect emissions. However, this measure has a high marginal abatement cost of over R1,300/tCO_2e.

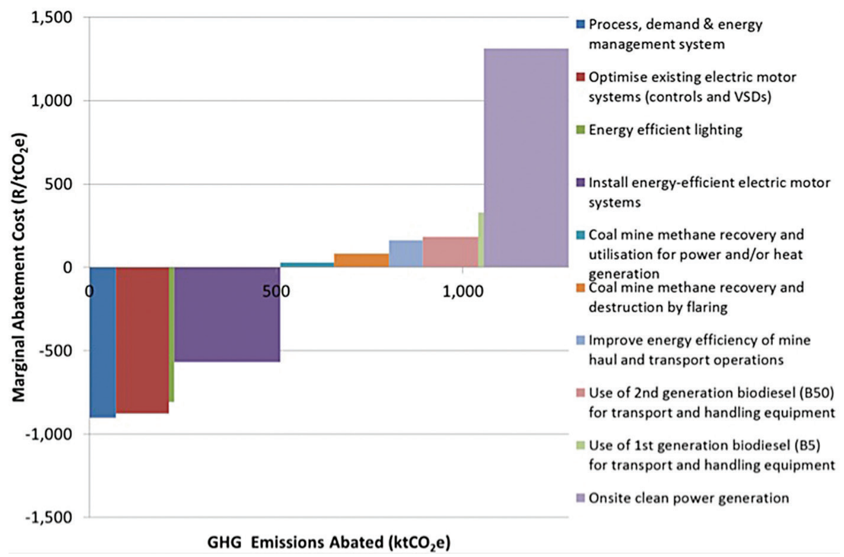

Figure 19: Coal Mining and Handling MACC for 2030

Figure 20 displays the coal mining MACC for 2050. This estimates the annual abatement potential at over 3,112 $ktCO_2e$/year in 2050 when compared to the WEM reference projection or 24% of total emissions. The notably significant mitigation options with negative marginal abatement costs, are the implementation of process, demand and energy management systems, optimisation of existing electric motor systems (with improved controls and VSDs where suitable) and installation of energy-efficient electric motors (replacing old, inefficient units). These are all energy-efficiency measures which reduce electricity consumption and associated indirect emissions. The availability of 2nd generation biodiesel and supply of 50% of the coal mining fleet can cut total fleet emissions by half and reduce sector wide emissions by 6% at a modest positive abatement cost.

The total mitigation potential which is deemed to be technically possible is 56 million tonnes of CO_2e in absolute terms over the 2010 to 2050 period or 14% of the reference WEM emissions projection.

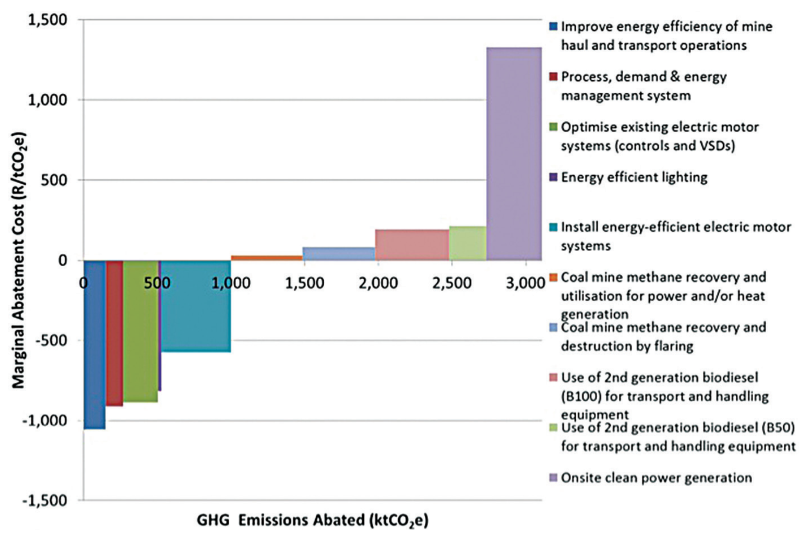

Figure 20: Coal Mining and Handling MACC for 2050

11.4 Oil and Natural Gas

The MACC for oil and natural gas production is presented in Figure 21; see below a summary of the key assumptions made in the analysis.

11.4.1 Key Assumptions

The assumed emissions reduction and energy saving potential for each mitigation measure included in the oil and natural gas production MACC, together with references, are presented in Table 25. The assumed costs, technology availability and lifetime are listed in Table 26. The assumed technology uptake in 2010, and other key assumptions are shown in Table 27.

Based upon forecasted growth from the TWG sector member, existing gas exploration and production is expected to cease in 2020. No production is planned beyond 2020 so only one MACC for 2020 is presented. The marginal abatement costs for the mitigation measure identified for this sector are high, in comparison to other sectors, due to the very short technology lifetime of a maximum of seven years (over which to annualise the investment cost) and the relatively low absolute mitigation potential.

Table 25: Emissions reduction potential and energy saving potential of mitigation measures and references in oil and natural gas production

Abatement measure		Emissions abatement potential	Applicability		Energy saving potential	Applicability		Reference
		%	%	Source	%	%	Energy	
1	Eliminate gas venting by destruction by flaring of vented natural gas from oil and gas fields	75%	100%	Fugitive emissions from venting				(ETSAP, 2010e) (CDM PDD, 2008) (CDM PDD, 2009)
2	Eliminate gas venting by capturing and using waste natural gas from oil and gas fields	75%	100%	Fugitive emissions from flaring	3%	100%	Fuel combustion for onsite electricity consumption	(ETSAP, 2010e) (CDM PDD, 2008) (CDM PDD, 2009)
3	Energy monitoring and management system				2%	100%		(EC, 2009a, p45, 83), (EC, 2003)
4	Improved electric motor system controls and VSDs				5%	80%		(EC, 2009a, p199, 214, 289)
5	Energy-efficient utility systems				20%	20%		(EC, 2009a p206, 228, 235, 246)
6	Waste heat recovery and use in process				20%	100%		(EC, 2009a p163)

Table 26 Costs, availability and lifetime of oil and natural gas production mitigation measures

	Abatement measure	Capital cost	Additional annual costs	Site production capacity	Availability	Lifetime
		Million R/site	Million R/year	Mt/year	Year	Years
1	Eliminate gas venting by flaring of vented natural gas from oil and gas fields	100	5.00	1,349	2010	7
2	Eliminate gas venting by capturing and using waste natural gas from oil and gas fields	220	11.00	1,349	2010	7
3	Energy monitoring and management system	6	0.30	1,349	2010	7
4	Improved electric motor system controls and VSDs	30	1.50	1,349	2010	7
5	Energy-efficient utility systems	27	1.35	1,349	2010	7
6	Waste heat recovery and use in process	68	3.38	1,349	2010	7

Table 27 Mitigation technology sector uptake and other assumptions in oil and natural gas production

	Abatement measure	% Total sector uptake		Other Assumptions
		2010	2020	
1	Eliminate gas venting by flaring of vented natural gas from oil and gas fields	0%	50%	Flaring destroys methane (98%) and converts into CO_2. Abatement potential equals annual tCO_2e vented from 2000-2011 (source: GHGI) multiplied by % methane (assumed 80%) divided by GWP of methane (assumed 23) and 98% effectiveness. Cost assumed to be half the cost of capture and use.
2	Eliminate gas venting by capturing and using waste natural gas from oil and gas fields	0%	50%	Abatement potential multiplied by average annual gas vented from 2000-2011. Cost of R2 million/tCO_2e provided by respondent deemed to be too cheap.
3	Energy monitoring and management system	0%	100%	Estimated energy saving and cost per site
4	Improved electric motor system controls and VSDs	0%	100%	
5	Energy-efficient utility systems	0%	100%	
6	Waste heat recovery and utilisation in process	0%	100%	

11.4.2 Marginal Abatement Cost Curve

The technical mitigation potential for the exploitation and extraction of oil and natural gas resources in South Africa in 2020 is estimated at 18 $ktCO_2e$/year or 41% of the reference WEM emissions projection. The 2020 MACC for fuel combustion and fugitive emissions is displayed in Figure 21. This shows that most mitigation measures identified have positive abatement costs which are much higher compared to the marginal abatement costs in other sectors. This is due to the short technology lifetime of seven years and the relatively low absolute mitigation potential. As sector production activity is forecasted to cease by the end of 2020 and projected emissions are low in comparison to other sectors, the mitigation activity in this subsector is not significant.

The total mitigation potential from 2010 up to and including 2050 is estimated at 207 $ktCO_2e$ compared to the WEM reference projection, equivalent to 16% of total emissions.

Due to the low abatement potential and high marginal abatement costs, the oil and natural gas mitigation measures are not included in the MCA analysis.

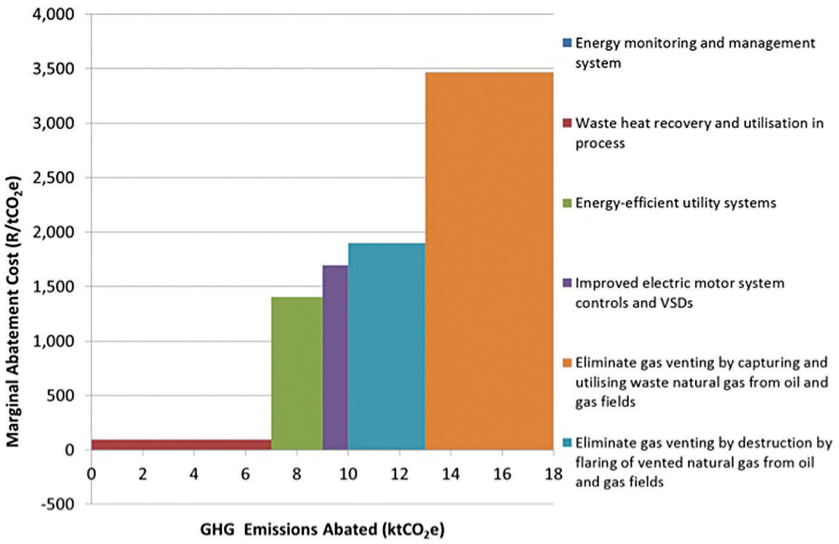

Figure 21: Oil and natural gas MACC for 2020

11.5 Other Energy Industries

The MACCs for other energy industries in South Africa, including operations that manufacture synthetic liquid fuels from solid and gaseous fossil fuels, for 2020, 2030 and 2050 are presented in Figure 22, Figure 23 and Figure 24 respectively. The key assumptions made in the analysis for emissions reduction and energy saving potential; costs, availability and lifetime of mitigation measures; and other assumptions including sector uptake are shown in Tables 28, 29 and 30, respectively.

11.5.1 Key Assumptions

The MACC analysis for other energy industries makes the following assumptions.

Production, energy and GHG emissions projections are split for existing and new production capacity (added in 2030, 2040 and 2050).

The underlying production, energy consumption and emissions data is based upon data submitted by industry stakeholders to the GHGI and data submitted directly by stakeholders from the other energy industries sector.

Sector growth is based upon energy supply estimates required to meet forecasted national liquid fuel demand in line with South African's Energy Security Master Plan targets, provided by TWG members and SAPIA members. New facilities with capacity of 80,000 barrels per day (bpd) of liquid fuel are assumed to be added in 2030, 2040 and 2050, adding an additional 240,000 bpd by 2050 (SAPIA, 2013).

New facilities added in 2030, 2040 and 2050 are assumed to have lower emissions factors and to be more energy efficient, reflecting a more modern design and adoption of best available technologies. Overall carbon intensity is assumed to decrease by 30% compared to existing operations in 2010. The improvement has been allocated proportionally to fugitive, fuel/energy emissions and electricity emissions. These improvements are based on the assumption that all identified measures would be implemented in a new facility (except CCS).

CCS capital and operational costs for capture, transport and storage of CO_2 are based upon IEA benchmark costs (ETSAP, CCS, 2010). The additional annual costs of onshore storage assume US$5/t$CO_2$e transport and US$10/tCO_2e onshore storage cost. Storage offshore is assumed to be possible by 2030 and assumes additional annual costs of US$10/t$CO_2$e for transport and US$20/tCO_2e for offshore storage cost. For CCS transport costs, 100km is selected as the default transport distance for CO_2 storage onshore within coal fields and 400km is selected for CO_2 storage in offshore geological formations. It is noted that some sources may be located closer or further than the selected distances. To compensate for this uncertainty, the high IEA cost estimate for CO_2 transport is selected.

Table 28: Emissions reduction potential and energy saving potential of mitigation measures and references in the other energies industries sector

	Abatement measure	Fugitive/process emissions abatement potential	Applicability	Fuel/energy saving potential	Applicability	Electricity saving potential	Applicability	Reference
		%	%	%	%	%	%	
1	Upgrade feed compressors	0%	0%			0%	100%	(Industry)
2	Increase onsite gas-fired power generation – using internal combustion engines	0%	0%	-5%	100%	23%	100%	(Industry) (ETSAP, 2010c)
3	Waste heat recovery power generation					21%	100%	(Industry)
4	Waste gas recovery and utilisation	50%	100%					(Industry)
5	CCS – process emissions from existing plants (storage onshore)	25%	100%			-12%	100%	(ETSAP, 2010b) (ETSAP, 2010d) (Industry)
6	Energy monitoring and management system			2.5%	100%		100%	(EC, 2009a, p45, 83)
7	Improved process control			2.5%	28%			(EC, 2009a, p76) (Industry)
8	Improved electric motor system controls and VSDs					10%	70%	(EC, 2009a, p199, 214, 289) (Industry)
9	Energy efficient utility systems					10%	30%	(EC, 2009a, p206, 228, 235, 246) (Industry)
10	Improved heat systems	2%	22%			12%	100%	(EC, 2009a p94, 164) (Industry)
11	CCS – process emissions from existing plants (storage offshore)	66%	100%			-32%	100%	(ETSAP, 2010b) (ETSAP, 2010d) (Industry)
12	CCS – process emissions from new plants	90%	100%			-37%	100%	

Table 29: Costs, availability and lifetime of mitigation measures in the other energies industries sector

	Abatement measure	Sector capital cost	Sector additional annual costs	Abatement cost	Availability	Lifetime
		R Million/site	R Million/year	R/tCO_2	Year	Years
1	Upgrade feed compressors	150	7.50		2007	15
2	Increase onsite gas-fired power generation – using internal combustion engines	1,445	-		2013	25
3	Waste heat recovery power generation	6,420	128		2010	25
4	Waste gas recovery and use	2,160	108		2010	25
5	CCS – process emissions from existing plants (storage onshore)	3,240	972.00	675	2025	40
6	Energy monitoring and management system	180	9		2010	15
7	Improved process control	180	9		2010	15
8	Improved electric motor system controls and VSDs	720	36		2010	15
9	Energy efficient utility systems	360	18		2010	15
10	Improved heat systems	360	18		2010	15
11	CCS – process emissions from existing plants (storage offshore)	8,586	4,722.30	810	2030	40
12	CCS – process emissions from new plants	4,178	2,108.24	594	2030	40

Table 30 Mitigation technology sector uptake and other assumptions in the other energies industries sector

	Abatement measure	% Total sector uptake				Other Assumptions
		2010	2020	2030	2050	
1	Upgrade feed compressors	0%	100%	100%	100%	Measure implemented prior to 2010; future potential will be captured in 'improved electric motor system controls and VSDs' below.
2	Increase onsite gas-fired power generation – using internal combustion engines	0%	100%	100%	100%	Current generation efficiencies for ICE power generation systems range from 33% to 41% lower heating value (LHV) (Zogg et al., 2007). 41% assumed.
3	Waste heat recovery power generation	0%	36%	100%	100%	
4	Waste gas recovery and use	0%	100%	100%	100%	

	Abatement measure	% Total sector uptake				Other Assumptions
		2010	2020	2030	2050	
5	CCS – process emissions from existing plants (storage onshore)	0%	0%	100%	100%	• A realistic upper limit for the geological storage of CO_2 from a large point source would be 6mtpa – such a project would be double the size of the current largest project under construction (Gorgon). • It should be noted that compression and conditioning of this volume of CO_2 would consume ~ 930 GWh/annum reducing the effective CO_2 mitigation to ~ 5 mtpa. • The earliest opportunity to start injection would be 2025 provided storage is proven by 2020. • Assumes investment cost of high pure CO_2 stream capture and compression is US\$60/tCO_2 for existing plant. This is at the high end of the IEA benchmark for total cost range for Synfuel production (US\$60-100) including Capex, transport, storage etc. Assumes 60% investment costs. • Assumes additional annual costs of US\$5/tCO_2e transport (pipeline 100km) and US\$10/tCO_2e onshore storage cost. • Assumes onshore injection of CO_2 can begin in 2025
6	Energy monitoring and management system	0%	25%	50%	50%	
7	Improved process control	0%	100%	100%	100%	
8	Improved electric motor system controls and VSDs	0%	50%	100%	100%	
9	Energy efficient utility systems	0%	50%	100%	100%	
10	Improved heat systems	0%	50%	100%	100%	
11	CCS – process emissions from existing plants (storage offshore)	0%	0%	100%	100%	• Storage potential is based upon original estimates of ~21,900 ktpa minus the 6,000 ktpa already stored onshore (under the "CCS – existing plant (storage onshore" measure) to give 15,900 ktCO_2 per year, or 66% of reference 2010 sector process emissions (24,218 ktCO_2e). • Assume injection begins in 2030 to account for greater difficulty and cost going offshore. • Assumes injection begins in 2030 to account for greater difficulty going offshore. Also includes greater costs. • Assumes additional annual costs of US\$10/tCO_2e transport (pipeline 400km distance) and US\$20/tCO_2e offshore storage cost.

Abatement measure		% Total sector uptake				Other Assumptions
		2010	2020	2030	2050	
12	CCS – process emissions from new plants	0%	0%	100%	100%	• CO_2e storage potential for new facilties based upon numbers above 21,900/24,218 = 86% of 100% of process emissions. Again assumes injection begins in 2030 to account for greater difficulty going offshore. Also includes greater costs. • Assumes investment cost of high pure CO_2 stream capture and compression is US$40/ tCO_2 for existing plant. This is at the lower end of the IEA benchmark total cost range for Synfuel production (US$60-100 of which 60% is assumed as Capex) reflecting the new build cost savings. • Storage additional annual costs of US$10/$tCO_2e$ transport (pipeline 400km distance) and US$20/$tCO_2e$ offshore storage cost. • The electricity overhead is also assumed to reduce to 80% of the existing plant cost by using high efficiency motors and controls/VSDs etc.

Carbon dioxide storage capacity is not considered to be limited to the levels of storage proposed by the MACCs based upon assessments of onshore and offshore storages resources in South Africa. The estimated capacity of geological storage in South Africa is at least 150 Gt (150,000 Mt) of CO_2. The storage potential lies mainly in the capacity of saline formations associated with the oil- and gas-bearing sequences in the Outeniqua, Orange and Durban/Zululand basins. Offshore storage assumes storing in the Zululand Basin with an estimated effective capacity of 460 million tonnes and located within 400 km from South Africa's major emissions sources (Council for Geoscience, 2010). Injection of process CO2 emissions from existing plants into onshore coal fields can begin from 2025. New plants which come online in 2030, 2040 and 2050 have CCS installed (at a cost of 60% of the assumed benchmark cost for existing plants). The MACCs assume injection of CO_2 for new facilities into saline reservoirs in offshore basins can begin as early as 2030.

11.5.2 Marginal Abatement Cost Curve

The technical mitigation potential for other energies industries in South Africa in 2020 is estimated at over 3.5 $MtCO_2e$ compared to the WEM reference emissions projection or 5% of total emissions. The MACC for 2020 displayed in Figure 22 shows the wide portfolio of mitigation measures that are available and are already planned to be implemented by the sector from 2010 to 2020. All but one of the identified measures is deemed to have negative marginal abatement costs. For example, improved heat systems (using waste heat for maximising existing onsite steam turbine electricity generation capacities), improved existing electric motor system controls and VSDs (matching motor revolutions with load requirements and thus minimising their electricity use) and installing energy efficient utility motor systems (e.g. lighting, compressed air and refrigeration) all have costs of less than -R600/tCO_2e. Waste gas recovery has a positive cost due to the much higher capital cost and lower potential for uptake relative to other energy efficiency measures proposed.

The annual mitigation potential is transformed in 2030 to just over 31 $MtCO_2e$ compared to the WEM reference emissions projection, or 37% of total emissions, due to the assumed uptake of CCS technologies to capture and store process CO_2 emissions in existing and new production facilities. The mitigation potential of CCS dwarfs the potential of the other energy efficiency options available. The 2030 MACC displayed in Figure 23, shows that CCS for process emissions from existing plants has the largest mitigation potential capable of mitigating over 19 $MtCO_2e$ in 2030 or 22% of total sector reference emissions, at a marginal abatement cost of R838 and R973/tCO_2 for storage of CO_2 in coal fields onshore and offshore saline formations, respectively. The lower marginal abatement cost option for implementing CCS in new facilities has a lower cost of R729 /tCO_2 (assuming transport and storage costs for offshore storage) and can mitigate an estimated at 6.2 $MtCO_2e$ in 2030 or 7% of total sector reference emissions.

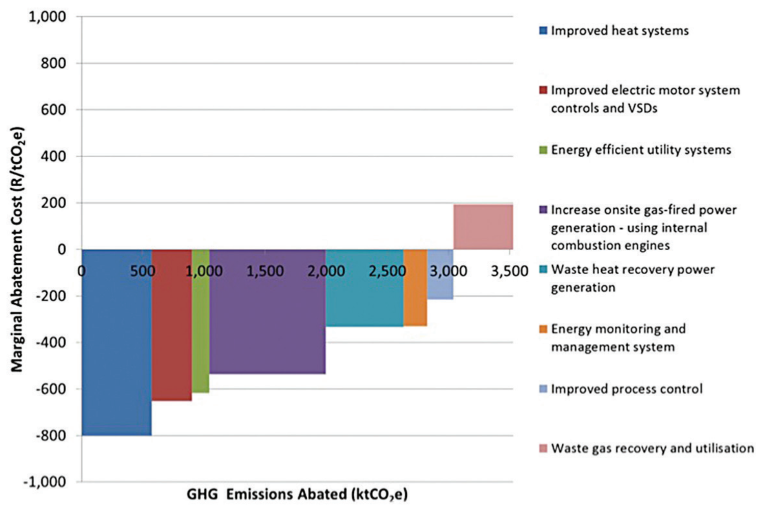

Figure 22: Other energy industries MACC for 2020

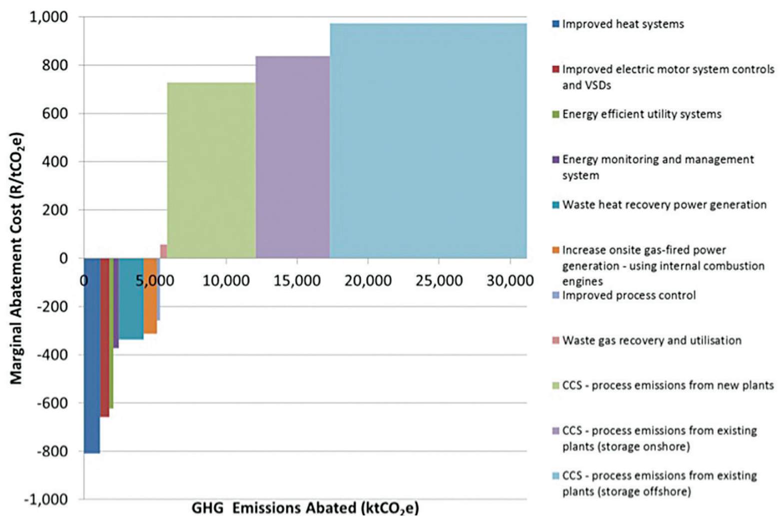

Figure 23: Other energy industries MACC for 2030

The technical mitigation potential for other energies industries in 2050 is estimated at over 43 $MtCO_2e$ compared to the WEM reference emissions projection, or 35% of total emissions. The 2050 MACC featured in Figure 24 shows that as the production of synthetic fuel increases from new facilities built after 2030, so does the uptake of CCS resulting in the mitigation of 18.7 million $MtCO_2e$ of process emissions, equivalent to 15% of total emissions. Combined, CCS technologies mitigate 38 $MtCO_2e$ compared to the WEM reference emissions projection or 31% of total emissions, whilst other measures contribute 4% of the identified total mitigation potential. The marginal abatement costs of the CCS measures remain constant compared to 2030, whilst the energy efficiency measures have lower marginal abatement costs as assumed underlying energy prices and cost savings increase over time.

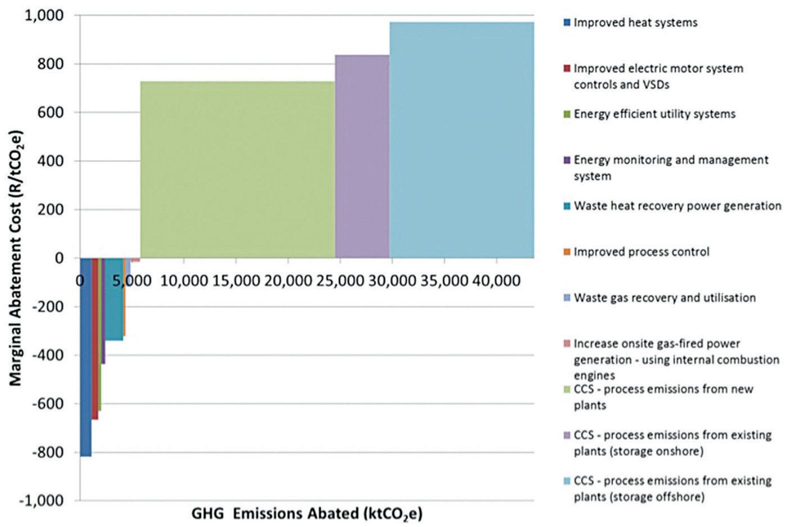

Figure 24: Other energy industries MACC for 2050

The total technical mitigation potential from 2010 up to and including 2050 for other energies energy industries in South Africa is estimated at just over 812 $MtCO_2e$ compared to the WEM emissions projection, or 24% of reference emissions. Capture and storage of process emissions constitutes the majority of the estimated mitigation potential, equivalent to 19% of total reference emissions mitigated. To increase the mitigation potential further, the capture and storage of CO_2 emissions in flue gas emissions could be considered (although the cost to capture and compress of CO_2e would be much higher than the cost of CCS for process emissions due to the lower CO_2e concentrations in the flue gas).

As identified already, possibly one of the largest and most significant mitigation opportunities available to the South African energy sector would be to meet the forecasted rise in liquid fuel demand by increasing imported crude oil and building additional conventional oil refining capacity instead of coal-to-liquid (CTL) synthetic liquid fuel refineries. Demand could be met by either increasing the size of the two new refineries to 350,000 bbl/day to be added in 2030 and 2050 or by constructing a third new refinery of 250,000 bbl/day in 2040, for example. Although this would not meet energy security objectives, it would significantly reduce emissions, compared to a reference case that builds additional CTL capacity.

This potentially major mitigation opportunity has not been included in the other energy industries MACC as it was identified too late in the MACC development process and requires further assessment to quantify the abatement potential and costs. However, it should be examined and considered as an option in future mitigation policy.

Chapter VI: Summary

12. Marginal Abatement Cost Curves for the Energy Sector

Summary MACCs for 2020, 2030 and 2050 for the energy sector are shown in Figure 25, Figure 26 and Figure 27, respectively. Please refer to Table 32 for details of the abatement potential and marginal abatement costs illustrated below.

The results shown in the MACCs below are for measures which can be carried out in the energy sector. They do not account for emissions savings in the other energy industries and refining sectors that can be expected if abatement measures in the transport sector reduce demand for liquid fuels and hence for refining capacity. This is discussed further below.

In 2020 (and excluding transport-related savings), a total of 33 $MtCO_2e$ of abatement potential has been identified in the energy sector (Figure 25). The MACC curve illustrates that only 11% of the available mitigation potential (3.5 $MtCO_2e$) can be achieved through measures which have negative marginal abatement costs.

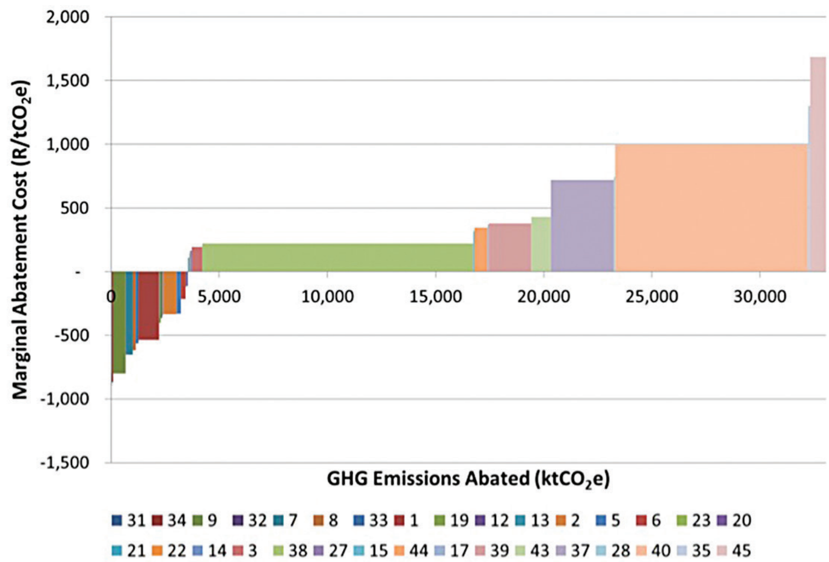

Figure 25: Marginal abatement cost curve for the energy sector in 2020

In 2030, a total of 172.6 $MtCO_2e$ of abatement potential has been identified in the energy sector (Figure 26). The MACC curve illustrates that only 5% of the available mitigation potential (7.9 Mt CO_2e) can be achieved through measures which have negative marginal abatement costs.

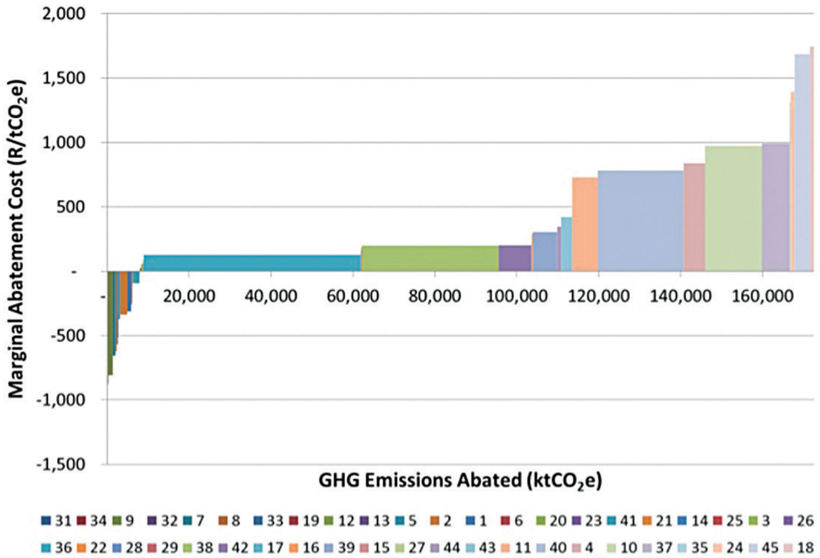

Figure 26: Marginal abatement cost curve for the energy sector in 2030

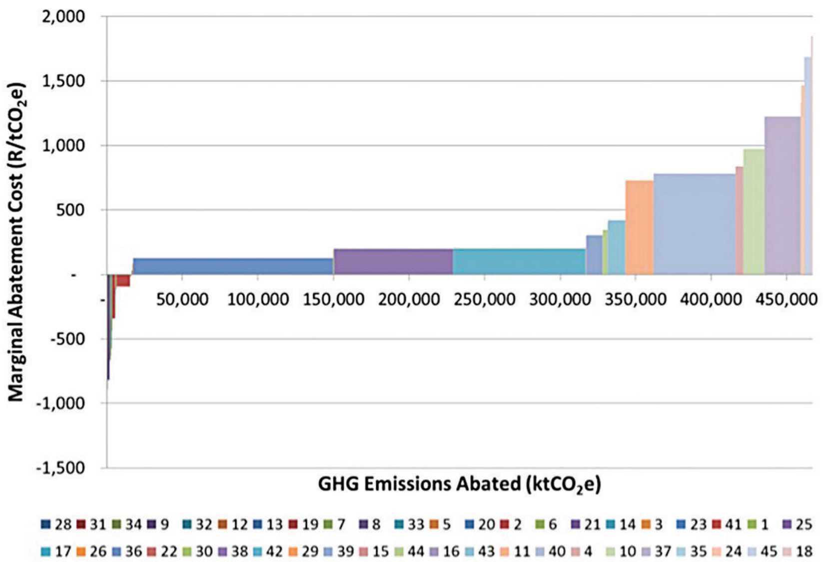

Figure 27: Marginal abatement cost curve for the Energy sector in 2050

In 2050, a total of 467 $MtCO_2e$ of abatement potential has been identified in the energy sector (Figure 27). The MACC curve illustrates that only 3.5% of the available mitigation potential (16.2 $MtCO_2e$) can be achieved through measures which have negative marginal abatement costs.

13. Technical Mitigation Potential

A summary of technical mitigation potential in 2020, 2030 and 2050 for all sectors and subsectors covered in the assessment of the energy sector is shown in Table 31 below.

Estimates of mitigation potential for the non-power energy sector have been calculated independently of changes in other sectors. Estimates for the other energy industries and petroleum refining sectors only show the impact of measures which can be implemented in the sector. They do not show savings which might occur due to a reduced need for new capacity in the sector if successful implementation of mitigation options in the transport sector reduces demand for liquid fuel. If all transport mitigation options were successfully implemented then emissions in the energy sector could be reduced by a further 20.3 $MtCO_2$ in 2050. This interaction between the transport and energy sector is accounted for in the national level analysis carried out in the main report (Section 18).

In summary, abatement options from the power sector dominate abatement potential for the energy sector, accounting for between 79% and 89% of total mitigation potential. The second largest contributor is the other energy industries sector, representing 28,585, 137,189 and 416,555 $ktCO_2e$ in 2020, 2030 and 2050 respectively.

Table 31: Summary of technical mitigation potential for the energy sector, including a breakdown by sector and subsector and showing results for 2020, 2030 and 2050 ($ktCO_2e$)

Sector	Subsector	2020	2030	2050
Power		28,585	137,149	416,555
% Total		86.47%	79.48%	89.16%
Non-Power	Coal mining	385	1,284	3,112
	Oil and gas	0	0	0
	Other energy industries	3,529	31,181	43,630
	Petroleum refining	558	2,951	3,891
Subtotal		**4,472**	**35,415**	**50,632**
% Total		13.53%	27.52%	10.84%
Total		33,057	172,565	467,186

14. 'With Additional Measures' Projection

Assuming that all available mitigation measures are implemented, the resulting 'with additional measures' abatement projection for the energy sector is shown in Figure 28. A similar graphic showing a breakdown between subsectors within the non-power sector is shown in Figure 29. Note that emissions from the power sector have been reallocated to end-users and electricity-related emissions savings have been adjusted for the progressive reduction of carbon intensity of the electricity supply over time.

For the power sector, the total projected emissions savings in 2020, 2030 and 2050 (28,585, 137,189 and 416,555 $ktCO_2e$) represent a reduction of the reference WEM emissions for the sector of 9%, 33% and 50%, respectively.

For the non-power sector, the total projected emissions savings in 2020, 2030 and 2050 (4,472, 35,415 and 50,632 $ktCO_2e$) represent a reduction of the sector reference WEM emissions of 7%, 43% and 42%, respectively.

For the energy sector as whole, the total projected emissions savings in 2020, 2030 and 2050 (33,057, 172,565 and 467,186 $ktCO_2e$) represent a reduction of the reference WEM emissions of 9%, 35% and 49%, respectively.

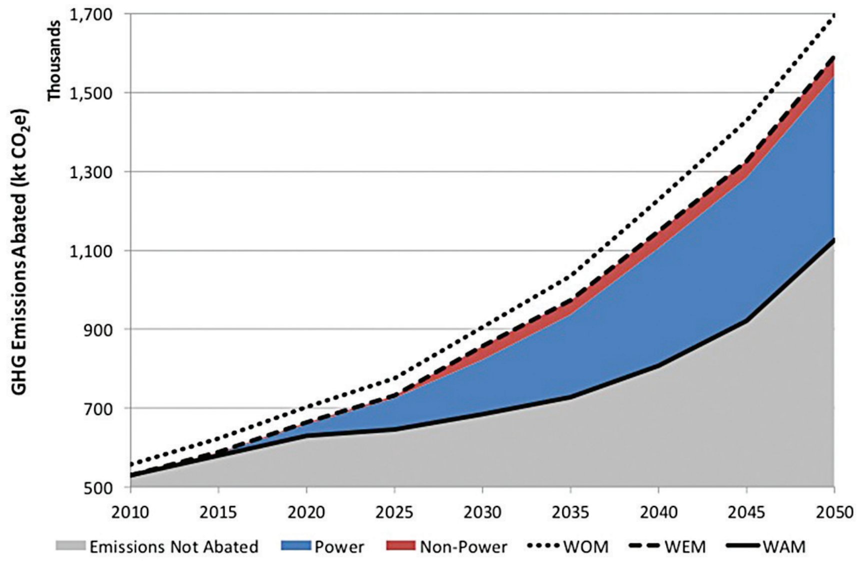

Figure 28: 'With additional measures' (WAM) scenario for the energy sector, showing a breakdown between the power and non-power sectors. Emissions from the power sector have been reallocated to end-users and electricity-related emissions savings have been adjusted accordingly. Reference case WOM and WEM emission projections are also shown.

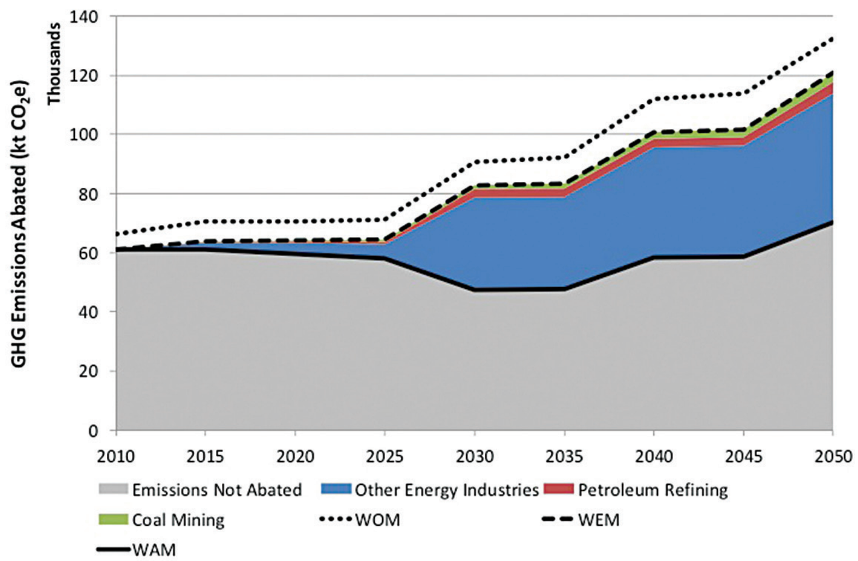

Figure 29: 'With additional measures' scenario for the non-power sector, showing a breakdown between subsectors. Emissions from the power sector have been reallocated to end-users and electricity-related emissions savings have been adjusted accordingly. Reference case WOM and WEM emission projections are also shown.

15. Impact Assessment of Individual Mitigation Measures

The impact assessment is undertaken using the multi-criteria analysis (MCA) approach described in the main body of the report.

15.1 Scoring of Each Measure in Relation to Agreed Criteria

The criteria for assessing each measure are applied consistently across all sectors with the scoring and weighting options described in the main body of the report. Two methods have been applied for scoring.

- A quantitative assessment using the costs estimated for each measure and the economic models which provide figures for gross value added (the economic criterion) and jobs (part of the social criterion).
- A qualitative assessment based on scoring by the Sector Task Team.

Taking both quantitative and qualitative scores into consideration for each criterion, points are allocated to each measure with the results for the 'balanced weighting' scenario shown in Table 33 below (zero is the worst result and 100 the best).

Mitigation measures of various type and different sectors and subsectors are well mixed across the MCA scoring spectrum. Broadly speaking, a mixture of energy efficiency, efficient (and relatively clean) gas-fuelled electricity generation technologies and renewable power technologies score highest. This is due either to the high abatement potential (e.g. gas fired/renewable measures) or to the low cost of implementation compared to the high GHG abatement potential giving a negative marginal abatement cost (e.g. For energy saving measures). Other reasons are the high positive economic and social impact, the non-GHG environmental benefits and the relative ease of implementability compared to other more complex technologies. These measures are followed for the most part by cross-sector energy efficiency measures and renewables.

Generally, those measures with a high positive marginal abatement cost and a low score of implementability score worst under the MCA scoring criteria (e.g. CCS measures and cost intensive waste heat/gas power generation equipment). This could be due to the uncertainty surrounding future technologies which are unproven at commercial-level in South Africa, their perceived level of installation and operational complexity and their expected high cost. As many proposed mitigation technologies are being led by research and development programmes elsewhere in Europe, Asia or North America, they might appear to score low in terms of social benefit as these mitigation technologies and skills are expected to be imported.

15.2 Net Benefit Curve

The concept of net benefit is described in the main body of the report. In the case of the balanced weighting scenario the net benefit curve is shown in Figure 30 below.

The amount of CO_2e which can be mitigated for each measure, for the full period from 2010 to 2050, is shown on the horizontal axis. According to the graph, slightly more than 7.7 $GtCO_2e$ of abatement potential is available from the energy sector over the next 40 years. In order to maximise the net benefit (as determined by the MCA analysis), the measures should be implemented in order from left to right as they appear in Figure 30. Please refer to Table 33 for details on each measure. The measures are listed in the table in their order of priority, according to the overall scores assigned under the balanced weighting option.

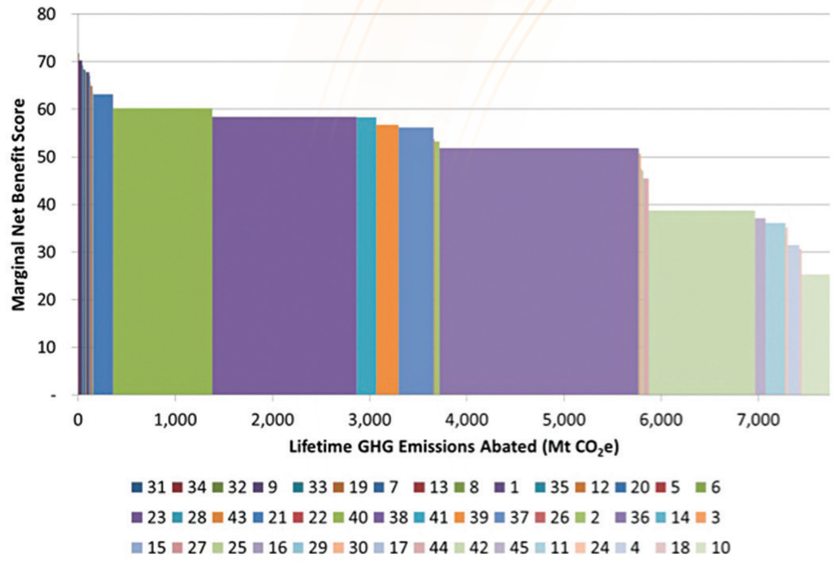

Figure 30: Net benefit curve for the balanced weighting scenario for the energy sector.

Table 32: Abatement ($ktCO_2e$) and marginal abatement cost (MAC, R/tCO_2e) for all measures in the Energy sector in 2020, 2030 and 2050

ID	Key Sector	Sector	Subsector	Measure	2020		2030		2050	
					Abatement	MAC	Abatement	MAC	Abatement	MAC
1	Energy	Non-Power	Other Energy Industries	Increase onsite gas-fired power generation – using internal combustion engines	952	-536	937	-313	914	-16
2	Energy	Non-Power	Other Energy Industries	Waste heat recovery power generation	637	-334	1,754	-337	1,732	-341
3	Energy	Non-Power	Other Energy Industries	Waste gas recovery and utilisation	488	194	488	57	488	-118
4	Energy	Non-Power	Other Energy Industries	CCS– process emissions from existing plants (storage onshore)	0	0	5,236	838	5,248	838
5	Energy	Non-Power	Other Energy Industries	Energy monitoring and management system	192	-331	385	-373	385	-437
6	Energy	Non-Power	Other Energy Industries	Improved process control	215	-216	215	-258	215	-322
7	Energy	Non-Power	Other Energy Industries	Improved electric motor system controls and VSDs	329	-652	653	-658	644	-666
8	Energy	Non-Power	Other Energy Industries	Energy efficient utility systems	141	-617	280	-623	276	-630
9	Energy	Non-Power	Other Energy Industries	Improved heat systems	574	-802	1,139	-808	1,125	-819
10	Energy	Non-Power	Other Energy Industries	CCS– process emissions from existing plants (storage offshore)	0	0	13,875	973	13,908	973
11	Energy	Non-Power	Other Energy Industries	CCS– process emissions from new plants	0	0	6,220	729	18,694	728
12	Energy	Non-Power	Petroleum Refining	Improve steam generating boiler efficiency	64	-365	63	-513	62	-702
13	Energy	Non-Power	Petroleum Refining	Improve process heater efficiency	30	-346	29	-494	29	-682
14	Energy	Non-Power	Petroleum Refining	Waste heat recovery and utilization	85	165	168	21	164	-157
15	Energy	Non-Power	Petroleum Refining	Minimise flaring and utilise flare gas as fuel	42	319	42	319	42	319
16	Energy	Non-Power	Petroleum Refining	Efficient energy production (CCGT and CHP)	0	0	276	289	267	401
17	Energy	Non-Power	Petroleum Refining	Waste heat boiler and expander applied to flue gas from the FCC regenerator	50	371	50	229	49	56
18	Energy	Non-Power	Petroleum Refining	CCS– Existing Refineries	0	0	998	1,745	1,007	1,848
19	Energy	Non-Power	Petroleum Refining	Energy monitoring and management system	87	-402	85	-519	84	-667
20	Energy	Non-Power	Petroleum Refining	Improved process control	87	-114	85	-227	84	-368
21	Energy	Non-Power	Petroleum Refining	Improved heat exchanger efficiencies	68	110	67	-34	66	-213
22	Energy	Non-Power	Petroleum Refining	Improved electric motor system controls and VSDs	28	142	55	154	53	178

ID	Key Sector	Sector	Subsector	Measure	2020		2030		2050	
					Abatement	MAC	Abatement	MAC	Abatement	MAC
23	Energy	Non-Power	Petroleum Refining	Energy-efficient utility systems	19	-124	37	-117	36	-102
24	Energy	Non-Power	Petroleum Refining	CCS– New Refineries	0	0	994	1,392	1,949	1,465
25	Energy	Non-Power	Coal Mining	Coal mine methane recovery and utilisation for power and/or heat generation	0	0	144	30	483	30
26	Energy	Non-Power	Coal Mining	Coal mine methane recovery and destruction by flaring	0	0	147	83	494	83
27	Energy	Non-Power	Coal Mining	Use of 1st generation biodiesel (B5) for transport and handling equipment	13	305	15	329	0	0
28	Energy	Non-Power	Coal Mining	Improve energy efficiency of mine haul and transport operations	57	744	90	163	151	-1,057
29	Energy	Non-Power	Coal Mining	Use of 2nd generation biodiesel (B50) for transport and handling equipment	0	0	149	184	252	214
30	Energy	Non-Power	Coal Mining	Use of 2nd generation biodiesel (B100) for transport and handling equipment	0	0	0	0	503	193
31	Energy	Non-Power	Coal Mining	Process, demand & energy management system	30	-894	71	-901	118	-913
32	Energy	Non-Power	Coal Mining	Energy efficient lighting	6	-800	14	-807	24	-817
33	Energy	Non-Power	Coal Mining	Install energy-efficient electric motor systems	121	-564	284	-568	473	-575
34	Energy	Non-Power	Coal Mining	Optimise existing electric motor systems (controls and VSDs)	61	-869	142	-876	236	-887
35	Energy	Non-Power	Coal Mining	Onsite clean power generation	97	1,302	227	1,313	378	1,330
36	Energy	Power	Electricity and Heating	Nuclear (PWR)	0	126	52,973	126	132,433	126
37	Energy	Power	Electricity and Heating	Gas CCGT	2,913	721	6,797	992	24,016	1,224
38	Energy	Power	Electricity and Heating	Onshore wind	12,524	220	33,396	199	78,794	199
39	Energy	Power	Electricity and Heating	Solar CSP (Parabolic trough)	1,966	379	5,897	304	11,009	304
40	Energy	Power	Electricity and Heating	Solar PV (Concentrated)	8,921	995	20,977	782	54,227	782
41	Energy	Power	Electricity and Heating	Import (Hydro)	0	-95	1,695	-95	8,947	-95
42	Energy	Power	Electricity and Heating	Coal CCS	0	244	8,039	202	87,852	202
43	Energy	Power	Electricity and Heating	Biomass	900	429	2,699	420	11,471	420
44	Energy	Power	Electricity and Heating	LFG	619	346	964	346	3,166	346
45	Energy	Power	Electricity and Heating	Energy from Waste	742	1,686	3,712	1,686	4,640	1,686

Table 33: Quantitative data informing the scoring of options for the energy sector scoring as well as score for main criteria and overall weighted score

ID	Key sector	Sector	Subsector	Measure	Score	Total emissions abated ($ktCO_2e$)	NPV of costs per $ktCO_2e$ mitigated	GVA impact per $ktCO_2e$ mitigated	Jobs created per $ktCO_2e$ mitigated	Ratio of unskilled to total	Cost	Economic impact	Social impact	Non-GHG environmental impact	Imple-mentability
1	Energy	Non-Power	Other Energy Industries	Increase onsite gas-fired power generation – using internal combustion engines	68	32,661	-63.41	11.07	0.08	0.34	81	71	34	75	85
2	Energy	Non-Power	Other Energy Industries	Waste heat recovery power generation	53	52,908	-29.00	7.42	0.04	0.31	73	65	32	75	25
3	Energy	Non-Power	Other Energy Industries	Waste gas recovery and utilisation	51	16,836	32.09	-0.80	-0.02	0.42	59	51	28	75	43
4	Energy	Non-Power	Other Energy Industries	CCS – process emissions from existing plants (storage onshore)	31	120,930	77.15	-9.88	-0.08	0.35	49	36	24	30	18
5	Energy	Non-Power	Other Energy Industries	Energy monitoring and management system	65	11,727	-34.20	5.66	0.04	0.34	74	62	32	70	93
6	Energy	Non-Power	Other Energy Industries	Improved process control	65	7,639	-32.45	5.95	0.04	0.34	74	63	32	70	93
7	Energy	Non-Power	Other Energy Industries	Improved electric motor system controls and VSDs	68	19,563	-64.98	11.18	0.08	0.34	81	71	34	70	93
8	Energy	Non-Power	Other Energy Industries	Energy efficient utility systems	68	8,384	-60.31	10.63	0.07	0.34	80	70	34	70	93
9	Energy	Non-Power	Other Energy Industries	Improved heat systems	70	34,139	-84.95	13.57	0.10	0.34	85	75	35	70	93
10	Energy	Non-Power	Other Energy Industries	CCS – process emissions from existing plants (storage offshore)	25	292,698	141.09	-17.81	-0.15	0.35	34	23	20	30	18

ID	Key sector	Sector	Subsector	Measure	Score	Total emissions abated ($ktCO_2e$)	NPV of costs per $ktCO_2e$ mitigated	GVA impact per $ktCO_2e$ mitigated	Jobs created per $ktCO_2e$ mitigated	Ratio of unskilled to total	Cost	Economic impact	Social impact	Non-GHG environmental impact	Imple-mentability
11	Energy	Non-Power	Other Energy Industries	CCS – process emissions from new plants	36	205,956	29.38	-3.86	-0.03	0.35	60	46	28	30	18
12	Energy	Non-Power	Petroleum Refining	Improve steam generating boiler efficiency	66	2,227	-65.15	0.00	0.08	0.34	81	53	34	70	93
13	Energy	Non-Power	Petroleum Refining	Improve process heater efficiency	68	1,039	-62.99	11.18	0.08	0.34	81	71	34	70	93
14	Energy	Non-Power	Petroleum Refining	Waste heat recovery and utilization	52	5,092	2.58	2.70	0.01	0.14	66	57	28	70	40
15	Energy	Non-Power	Petroleum Refining	Minimise flaring and utilise flare gas as fuel	50	1,491	40.56	-4.67	-0.04	0.36	57	45	37	70	40
16	Energy	Non-Power	Petroleum Refining	Efficient energy production (CCGT and CHP)	47	6,843	17.05	-0.90	-0.01	0.40	62	51	29	70	25
17	Energy	Non-Power	Petroleum Refining	Waste heat boiler and expander applied to flue gas from the FCC regenerator	47	1,767	33.08	0.11	-0.02	0.46	59	53	29	70	25
18	Energy	Non-Power	Petroleum Refining	CCS – Existing Refineries	31	22,725	59.35	-8.34	-0.07	0.35	53	39	15	30	18
19	Energy	Non-Power	Petroleum Refining	Energy monitoring and management system	69	3,018	-68.89	11.96	0.08	0.34	82	73	34	70	93
20	Energy	Non-Power	Petroleum Refining	Improved process control	66	3,018	-35.49	8.15	0.05	0.32	74	66	32	70	93
21	Energy	Non-Power	Petroleum Refining	Improved heat exchanger efficiencies	63	2,376	-10.46	5.13	0.02	0.28	69	61	30	70	93
22	Energy	Non-Power	Petroleum Refining	Improved electric motor system controls and VSDs	62	1,648	-2.50	4.22	0.02	0.23	67	60	30	70	93
23	Energy	Non-Power	Petroleum Refining	Energy-efficient utility systems	65	1,099	-27.06	7.10	0.04	0.31	72	65	32	70	93

ID	Key sector	Sector	Subsector	Measure	Score	Total emissions abated ($ktCO_2e$)	NPV of costs per $ktCO_2e$ mitigated	GVA impact per $ktCO_2e$ mitigated	Jobs created per $ktCO_2e$ mitigated	Ratio of unskilled to total	Cost	Economic impact	Social impact	Non-GHG environmental impact	Imple-mentability
24	Energy	Non-Power	Petroleum Refining	CCS – New Refineries	35	21,654	38.50	-5.31	-0.04	0.35	58	44	27	30	18
25	Energy	Non-Power	Coal Mining	Coal mine methane recovery and utilisation for power and/or heat generation	48	7,505	0.37	0.63	0.00	0.16	66	54	28	50	43
26	Energy	Non-Power	Coal Mining	Coal mine methane recovery and destruction by flaring	54	7,704	3.95	-0.51	-0.00	0.35	65	52	19	70	68
27	Energy	Non-Power	Coal Mining	Use of 1st generation biodiesel (B5) for transport and handling equipment	49	276	62.14	-8.24	-0.07	0.35	52	39	35	50	68
28	Energy	Non-Power	Coal Mining	Improve energy efficiency of mine haul and transport operations	64	3,433	26.15	10.51	-0.00	3.89	60	70	29	70	100
29	Energy	Non-Power	Coal Mining	Use of 2nd generation biodiesel (B50) for transport and handling equipment	47	4,679	11.08	-1.64	-0.01	0.35	64	50	49	45	25
30	Energy	Non-Power	Coal Mining	Use of 2nd generation biodiesel (B100) for transport and handling equipment	47	6,347	5.85	-0.89	-0.01	0.35	65	51	59	30	25
31	Energy	Non-Power	Coal Mining	Process, demand & energy management system	72	2,478	-87.96	13.82	0.10	0.34	86	76	36	70	100

ID	Key sector	Sector	Subsector	Measure	Score	Total emissions abated ($ktCO_2e$)	NPV of costs per $ktCO_2e$ mitigated	GVA impact per $ktCO_2e$ mitigated	Jobs created per $ktCO_2e$ mitigated	Ratio of unskilled to total	Cost	Economic impact	Social impact	Non-GHG environmental impact	Imple-mentability
32	Energy	Non-Power	Coal Mining	Energy efficient lighting	71	496	-80.58	12.89	0.09	0.34	85	74	35	70	100
33	Energy	Non-Power	Coal Mining	Install energy-efficient electric motor systems	69	9,911	-60.54	10.34	0.07	0.34	80	70	34	70	100
34	Energy	Non-Power	Coal Mining	Optimise existing electric motor systems (controls and VSDs)	72	4,956	-85.90	13.56	0.10	0.34	86	75	35	70	100
35	Energy	Non-Power	Coal Mining	Onsite clean power generation	67	7,929	-24.86	10.34	0.05	0.29	72	70	32	85	85
36	Energy	Power	Electricity and Heating	Nuclear (PWR)	52	2,052,714	8.47	-1.17	-0.01	0.36	64	51	29	65	53
37	Energy	Power	Electricity and Heating	Gas CCGT	56	359,763	141.73	-16.76	-0.15	0.36	34	25	40	95	85
38	Energy	Power	Electricity and Heating	Onshore wind	58	1,485,869	22.46	-2.72	-0.02	0.36	61	48	28	90	68
39	Energy	Power	Electricity and Heating	Solar CSP (Parabolic trough)	57	228,033	45.63	-5.37	-0.05	0.36	56	44	47	85	50
40	Energy	Power	Electricity and Heating	Solar PV (Concentrated)	60	1,018,444	75.36	-9.00	-0.08	0.36	49	38	45	100	68
41	Energy	Power	Electricity and Heating	Import (Hydro)	58	202,632	23.52	-2.83	-0.02	0.37	61	48	28	90	68
42	Energy	Power	Electricity and Heating	Coal CCS	39	1,092,115	9.17	-1.17	-0.01	0.36	64	51	19	45	18
43	Energy	Power	Electricity and Heating	Biomass	63	204,122	36.74	-4.41	-0.04	0.36	58	45	47	80	85
44	Energy	Power	Electricity and Heating	LFG	45	53,202	26.43	-3.15	-0.03	0.36	60	47	28	70	23
45	Energy	Power	Electricity and Heating	Energy from Waste	37	108,951	114.04	-13.90	-0.12	0.36	41	30	22	70	23

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