# Energy Emissions

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## A modelling input into the **Long Term Mitigation Scenarios** process

**Prepared for:**
**Department of Environment Affairs and Tourism**
**South Africa**

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## LTMS Input Report 1

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The suite of reports that make up the Long Term Mitigation Scenario study include the following:

| | |
|---|---|
| A | Long Term Mitigation Scenarios for South Africa |
| B | Technical Summary |
| C | Technical Report |
| C.1 | Technical Appendix |
| D | Process Report |

The study was supported by the following inputs:

LTMS Input Report 1: Energy emissions

LTMS Input Report 2: Non-energy emissions: Agriculture, Forestry and Waste

LTMS Input Report 3: Non-energy emissions: Industrial Processes

LTMS Input Report 4: Economy-wide modeling

LTMS Input Report 5: Impacts, vulnerability and adaptation in key South African sectors

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# 1. Introduction

Emissions from energy supply and use constitute by far the largest part of South Africa's total greenhouse gas (GHG) emissions. Hence energy modeling is a key analytical basis for the information provided to the long-term mitigation scenarios (LTMS) process.

This report contains the technical information provided by the energy modeling team at the Energy Rserach Centre, led by Alison Hughes, to the Scenario Building Team which developed the LTMS scenarios. The information was integrated into the overall Technical Report (with appendices), its Technical Summary and the Scenario Document.

# 2. Research methodology

The work of the research teams is located within the overall scenario building methodology described above. Research teams feed information about scenarios and mitigation actions to the Scenario Building Team. They provide data needed by the SBT to populate the scenarios.

Some of the information included in the research methodology, together with many key drivers, were included in a document circulated prior to SBT3. The document was revised substantially based on comments at the meeting and interactions afterwards. References in the following text to the 'SBT3 document' refer to the finalized version.[1]

The research teams gathered large amounts of data to conduct energy modeling, analysis of non-energy emissions, macro-economic modeling and assessments of vulnerability and adaptation. It is not possible to list all data comprehensively. Some data is reported here because it is known to be important in determining the overall results and / or there was significant debate about some data.

For all scenarios, key common drivers were identified, such as GDP, population and technological change and other factors detailed in Appendix 4.

In terms of gases, energy modeling will consider the three 'big' greenhouse gases, $CO_2$ , $CH_4$ , $N_20$, as well as other GHGs – carbon monoxide (CO), oxides of nitrogren ($NO_x$), non-methane volatile organic compounds (NMVOCs,) and sulphur dioxide ($SO_2$). The new guidelines for GHG inventories also require reporting on three industrial trace gases (HFCs, PFCs and $SF_6$), but at this stage these are not accounted for in our energy modeling.

Potentially, emission in energy and non-energy sectors are related. For example, non-energy emissions from coal mining would depend on the total coal demand, which in turn is driven in part by demand for electricity. There is not full linkage between energy and non-energy emissions. However, all sectors have made use of the same projections for GDP and population, to ensure consistency. In addition, projected growth in synfuel and coal industry emerging from the energy modeling (GWC case) has been used for extrapolating non-energy industrial process emissions.

Methodologies for macro-economic modeling and analysis of impacts, vulnerability and adaptation studies will be included in future reports.

## 2.1 Energy modeling

Energy models are a powerful way to explore various alternative energy futures quantitatively, but are all subject to specific constraints. In this case, the research team chose to use the MARKAL (short for Market Allocation) model, a model developed by the International Energy Agency. MARKAL is an optimising model, meaning that, subject to available resources, a set of energy supply and use technologies, and a set of required energy services specified by the modelling team, the model determines the optimal configuration of the energy system in terms of an objective function, usually to minimize costs subject to constraints. The model ensures that energy system requirements are met, e.g. that energy demand is equal to supply; that a specified reserve margin is

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[1] 'LTMS inputs & actions FINAL Jan 2007.doc', circulated to stakeholders by Tokiso on 31 January 2007.

maintained; that plants for peak and base-load are distinguished; that technologies have a limited life, etc.

The strength of the MARKAL models lies in answering questions about the most cost-effective technology solutions for energy systems. Both fuel costs and the cost of energy technologies are considered (Howells & Solomon 2002). Constraints, which temper the drive to least cost, can include environmental factors (e.g. emissions), limits on resource availability and dissemination rates of policies and measures. The model is demand-driven, in that it starts from projections of useful energy demand.

The optimisation process is based on an assumption that investment decisions in the energy sector are made by all actors in the energy system on a rational economic basis, and thus without careful design, the least-cost option will take over the entire energy market – something not observed in practice, due to non-economic policy considerations and issues facing policymakers, and other decision-makers, such as energy security concerns, energy poverty, accounting rules, or organizational culture. Model outcomes are thus constrained by bounds – upper and lower limits on investment in specific technologies applied by the modeling team.

MARKAL requires a large set of data, which can be divided into several kinds:

1. Data on energy technologies – conversion (e.g. power plants, refineries), transportation (e.g. pipelines) and end-use (e.g. motors, lights) technologies – which would include efficiency, capital cost, life time, and environmental impacts/emissions.
2. Independent variables such as GDP and population.
3. The structure of the energy system.
4. Historical data on the existing energy system.

MARKAL is typically used to construct a ‘reference case’, against which other scenarios are compared. The reference case is effectively a simulation of the development of the energy system into the future, and is very tightly constrained to represent a ‘business as usual’ scenario, generally continuing existing development trends. For instance, energy efficiency is only increased in line with historical trends. In the case of climate change, constraints can be changed to develop different mitigation scenarios (for instance, requiring a minimum or absolute percentage of climate-friendly technologies, assuming a significant increase in energy efficiency, or placing a limit on emissions); the model then optimises the energy system within the parameters of these new constraints. It is then possible to compare the mitigation scenario in question to the reference scenario in terms of total system cost, and in terms of other factors such as $CO_2$ emissions.

Energy models, including MARKAL, have various limitations which need to be considered when interpreting outputs. First, the structure of the energy system remains static over the modelling period. Second, MARKAL and other models simulate decision-making in a relatively simple way (usually using only a few quantitative criteria). Results are driven by the objective function – minimising costs. More complex criteria (such as public resistance to nuclear power) can be approximated roughly by imposing constraints (for instance, a limit to investment in nuclear power plants). Third, a specific failing of MARKAL is its inability to account satisfactorily for peak load in the electricity sector, since although the model distinguishes between day and night (and summer, winter and intermediate periods), it does not make finer time distinctions. Thus, the model has a tendency to generate less electricity from peak-load plant than would be the case in a real electricity system. Fourth, major drivers of energy demand, such as GDP and population, are not explicitly represented within MARKAL. Energy demands and projections are calculated outside of the model.

The energy model is based on energy demand from key economic sectors. The sectors in this study were agriculture, commercial, industry, residential and transport. The structure and major assumptions for the reference case of each of the following sectors is given below.

The MARKAL model used for the LTMS process was extended to allow analysis beyong the usual energy planning horizon, up to 2050. The thirty-year version of the MARKAL model was internationally reviewed by AEA Energy & Environment. The review found that the SA energy system was reasonably well represented, with the characterisation of upstream, transformation / conversion and end-use sectors (industry, residential, commercial, transport, agriculture); the model was well balanced, with an appropriate amount of characterisation across the different sectors; most technologies have been characterised properly, with use of appropriate cost and technical parameters; tracking of energy and emissions across the system ensures that model outputs can be properly interpreted; and that model development appeared to have been done in a logical manner, with appropriate naming conventions, and documentation of core data and assumptions. Some general recommendations were made to further develop the model, without being critical to its usability. Recommendations focused on technology characteristics (future costs / technical performance), adding novel or emerging technologies; further energy conservation measures; and loosening some constraints (AEAEE 2007). In sum, the MARKAL model has passed international peer review.

The key drivers for energy demand are economic growth, population and technological changes (see discussion of key drivers in Appendix 4). In most sectors, GDP is a primary driver, but in the residential sector, population is important. For transport, GDP would be more important for growth in energy demand for freight services, while population plays a role for passenger transport. More detail on projections of demands are elaborated for each sector in Appendix 5. GDP has been discussed previously and the shape of projected GDP agreed at SBT3. SBT4, however, raised the issue of the *composition* of GDP. Further work was done on this and is reported in Appendix 4, especially a new section 4.2 on GDP composition.

### 2.1.1 Overview of energy demand

The broad patterns of energy demand over time are shown in Table 1, which has projections of the fuel use by sector for the 'growth without constraints' case, to provide an overview. This appendix describes demand in for each sector in a little more detailed, followed by the major supply industries, namely electricity generation and liquid fuel supply.

**Table 1: Fuel use by sector in the GWC case, selected years**

| | *2003* | *2005* | *2015* | *2025* | *2035* | *2045* | *2050* |
|---|---|---|---|---|---|---|---|
| Agriculture | 122 | 124 | 150 | 207 | 285 | 369 | 413 |
| Commerce | 110 | 117 | 175 | 275 | 397 | 519 | 581 |
| Industry | 1,245 | 1,332 | 1,918 | 2,863 | 4,160 | 5,649 | 6,462 |
| Residential | 216 | 222 | 254 | 284 | 300 | 311 | 315 |
| Transport | 672 | 720 | 1,136 | 1,800 | 2,698 | 3,654 | 4,145 |
| total | 2,365 | 2,516 | 3,634 | 5,430 | 7,841 | 10,503 | 11,915 |

More detailed analysis of demand for various sectors are reported in the Appendix.

### 2.1.2 Energy demand by sector

The energy modeling approach (described in the technical report) starts from projections of energy demand. Table 1 shows the fuel use by sector for the 'growth without constraints' case, to provide an overview. This appendix describes demand in for each sector in a little more detailed, followed by the major supply industries, namely electricity generation and liquid fuel supply.

**Table 2: Fuel use by sector in the GWC case, selected years**

| | *2001* | *2005* | *2015* | *2025* | *2035* | *2045* | *2050* |
|---|---|---|---|---|---|---|---|
| Industry | 1 206 | 1 387 | 1 962 | 3 014 | 4 621 | 6 576 | 7 689 |
| Transport | 634 | 720 | 1 112 | 1 783 | 2 693 | 3 677 | 4 188 |
| Agriculture | 73 | 76 | 93 | 129 | 179 | 233 | 262 |
| Commerce | 100 | 112 | 156 | 222 | 301 | 380 | 419 |
| Residential | 197 | 209 | 231 | 249 | 256 | 260 | 260 |
| Total | 2 209 | 2 504 | 3 555 | 5 397 | 8 051 | 11 126 | 12 818 |

#### *2.1.2.1 Agricultural energy demand*

Demands for heat, processing energy, irrigation, tractors, harvesters and other energy needs (all in Peta Joules) are met through various technologies and fuel sources. Technologies using liquid fossil fuels (tractors, harvesters and pumps using diesel or petrol) are able to use a bio-fossil fuel blend. Tractors and harvesters are also able to run on pure bio-ethanol or bio-diesel for a case in which a farmer may be producing his own biofuel for use in farm vehicles. Demand for energy increases in time with respect to the agricultural GDP.

Fuels come from refineries or mines, in the case of coal, and dummy boxes along fuel paths allow for accounting for each specific sector.

#### *2.1.2.2 Commercial sector demand for energy*

The commercial sector is modelled with demands for cooling, lighting, refrigeration, space heating, water heating and 'other' demands that are met by various technologies using a range of energy carriers.

The energy demand in the commercial sector is based on the floor space for a given commercial activity. The increase in energy demand is modelled on an increasing floor space area. Floor space projections are generated using regression analyses with the GDP growth projections for various commercial buildings (warehouses, offices etc). These are then summed up to give the total floor space projection. Table 3 below shows the floor space projections from 2000 to 2030 based on the GDP growth. Figure 1 shows, graphically, the projected floor area growth by commercial building type.

**Table 3: Floor space projections for the commercial sector**

| *Year* | *Floor space (million m$^2$)* | *Year* | *Floor space (million m$^2$)* |
|---|---|---|---|
| 2000 | 75.2 | 2015 | 120.5 |
| 2001 | 77.0 | 2016 | 124.9 |
| 2002 | 79.1 | 2017 | 129.4 |
| 2003 | 81.6 | 2018 | 134.1 |
| 2004 | 84.450 | 2019 | 138.8 |
| 2005 | 86.4 | 2020 | 143.5 |
| 2006 | 88.5 | 2021 | 148.3 |
| 2007 | 91.2 | 2022 | 153.1 |
| 2008 | 94.2 | 2023 | 157.9 |
| 2009 | 97.9 | 2024 | 162.7 |
| 2010 | 102.0 | 2025 | 167.4 |
| 2011 | 104.6 | 2026 | 172.1 |
| 2012 | 106.9 | 2027 | 176.7 |
| 2013 | 110.7 | 2028 | 181.3 |
| 2014 | 115.2 | 2029 | 185.8 |
|  |  | 2030 | 190.3 |

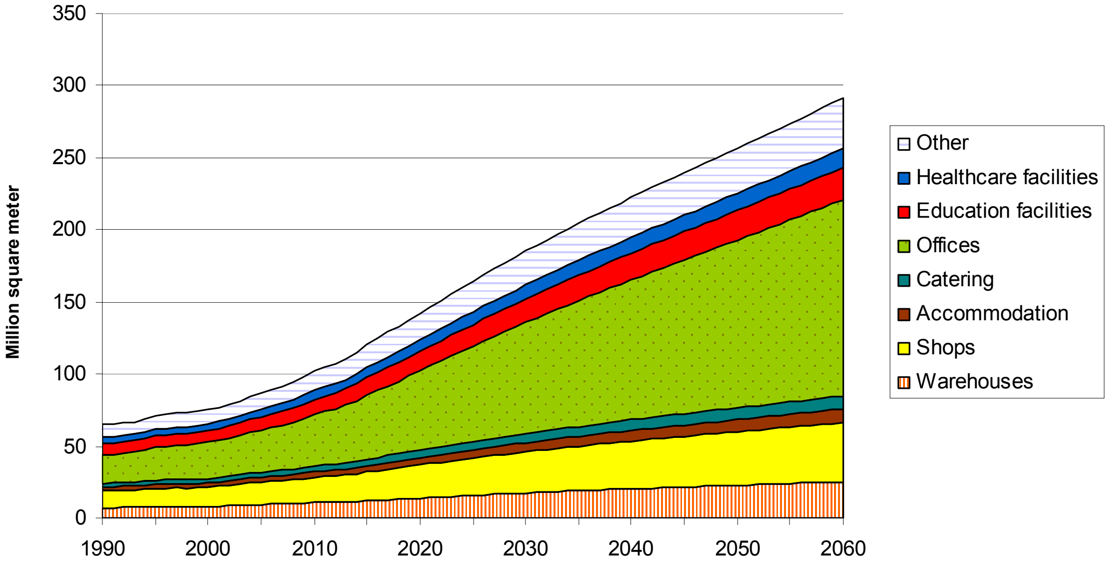

**Figure 1: Floor space growth projection by type**

Since most energy use in the commercial sector takes place during business hours, the time of use is very important for modelling the sector. Much of the energy is used for heating or cooling, thus the seasonal dependence plays an important role in energy demand modelling. The percentage of each demand that occurs in a particular time of use period is shown in Figure 2.

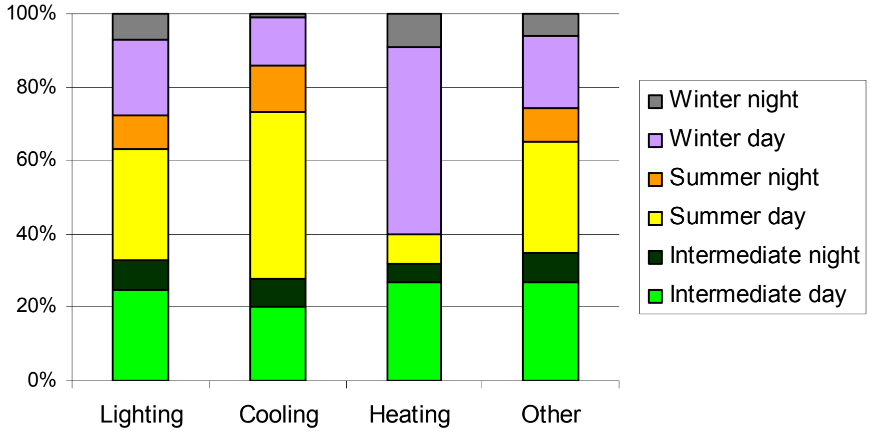

**Figure 2: Time of use for the commercial sector**

#### 2.1.2.3 *Industrial energy demand*

In the model, the industrial sector is disaggregated into three major sectors, gold mining; other mining and the rest of industry. Industry combines iron and steel; non-ferrous metals; non-metallic minerals; pulp and paper; chemical & petro-chemical; food and tobacco; and other)

End use demands are split up into heating (boilers and process heating), cooling, compressed air, HVAC, facility support, lighting, and a few other end use demands. All these demands, besides boiler heat, are met with electricity. Boilers are fed with an assortment of fuels such as coal, bagasse, heavy fuel oil, as well as electricity for electrode boilers.

How fuel use changes in industry over time is shown in Table 4.

**Table 4: Fuels used in industry in GWC scenario, selected years**

| | **2001** | **2005** | **2015** | **2025** | **2035** | **2045** | **2050** |
|---|---|---|---|---|---|---|---|
| Coal | 613.41 | 709.76 | 1022.78 | 1592.15 | 2464.34 | 3529.68 | 4136.91 |
| Diesel | 18.83 | 20.97 | 27.48 | 39.97 | 58.91 | 81.59 | 94.47 |
| Electricity | 412.0358 | 469.7347 | 642.4479 | 961.7504 | 1447.193 | 2032.615 | 2365.092 |
| Gas | 8.29 | 9.6 | 13.87 | 21.62 | 33.5 | 48.01 | 56.28 |
| HFO | 52.1 | 60.31 | 87.01 | 135.53 | 209.87 | 300.7 | 352.47 |
| HRG | 14.62 | 16.9 | 24.18 | 37.46 | 57.78 | 82.56 | 96.68 |
| LPG | 0.11 | 0.12 | 0.17 | 0.25 | 0.38 | 0.54 | 0.63 |
| Paraffin | 0.41 | 0.46 | 0.63 | 0.95 | 1.44 | 2.04 | 2.38 |
| Bagasse | 50.77 | 58.81 | 84.93 | 132.4 | 205.12 | 293.97 | 344.62 |
| Biomass | 35.21 | 40.79 | 58.91 | 91.83 | 142.26 | 203.89 | 239.01 |

#### *2.1.2.4 Residential energy demand*

The vast range of income in South Africa means that the energy demand of households can differ significantly. Higher income households tend to demand more energy through the use of more electric appliances, whereas lower income households use more traditional energy sources via inefficient means. Whether a household is situated in an urban or rural setting also impacts on the energy use and particularly the type of fuel used to meet energy demands. In many rural areas wood is available whereas a similar economic bracket in the city, may be using coal. In order to capture these differences within the model, the residential sector is divided into six different household types. Table 5 below shows the different housing types and the number of households in each type in 2001.

**Table 5: Household type and number of households of that type in 2001**

*Source: (Winkler 2006)*

| *Household* | *Number of households* | *Share of all households* | *Notes and assumptions* |
|---|---|---|---|
| Urban rich electrified (UHE) | 4 074 438 | 36.4% | Virtually 100% of rich urban households are electrified |
| Urban poor electrified (ULE) | 1 255 728 | 11.2% | Remainder of urban electrified households must be poor |
| Urban poor unelectrified (ULN) | 1 349 240 | 12.0% | Rest of urban must be non-electrified |
| Rural rich electrified (RHE) | 1 181 279 | 10.5% | Assume 84% of rich rural households are electrified |
| Rural poor unelectrified (RLE) | 1 095 449 | 9.8% | Remainder of rural electrified must be poor |
| Rural poor unelectrified (RLN) | 2 249 571 | 20.1% | Rest of rural households must be non-electrified; number of households includes the few rich rural not electrified |

In this study, ‘poor’ households, with regard to energy consumption, are considered to be those in the bottom two quintiles of income (an annual per capita income of less than R4 033). Households that fall into a ‘middle class’ have been included in the ‘rich’ category (Winkler 2006).

Energy demand in the residential sector is divided into cooking, lighting, space heating, water heating and other electrical demands. Originally refrigeration and laundry were included as separate demands, however national data is not available for such disaggregation. Data collection in the residential sector is a difficult and expensive task thus most of the information used in the model is calculated from census data. Census 2001 gives numbers of households that use a particular fuel to meet a specific demand. From these numbers of households, an energy use is calculated given a fuel use per household. The factor of fuel use per household is an approximation and leads to some inaccuracies. In areas that figures look highly unlikely, an expert (Eugene Visagie, Energy Research Centre, 2006) was consulted and numbers were adjusted, keeping total fuel use similar to what was reported in the DME National Energy Balance for 2001.

Demand for energy increases as population increases since with population growth there is obviously an increase in the number of households. There is also an increase in energy demand as households become richer and thus own more appliances and require more energy. This factor is taken into account with the shifting of household types as people get richer or more urbanization takes place.

#### *2.1.2.5 Transport energy demand*

The modelling of the transport sector is based on previous work done at the ERC (Vessia 2006). One major difference is that in the older version of the South African national MARKAL model, the demand for transport was given in vehicle-kilometres for specific types of vehicles. This made it very different to simulate change from one mode of transport (for example private cars) to another mode of transport (for example buses or trains). The new model allows for more flexibility by setting the demand to passenger-kilometres for passenger transport and tonne-kilometres for freight. With this method one has to assume an occupancy or tonnage for each type of vehicle. These assumptions are given in Table 6 below.

**Table 6: Assumptions for occupancy and load for passenger and freight vehicles**

| ***Passenger vehicles*** | ***Occupancy (persons/vehicle )*** |
|---|---|
| Diesel buses | 35 |
| Petrol taxis (minibus) | 10 |
| Diesel taxis (minibus) | 10 |
| Petrol cars | 2.1 |
| Diesel cars | 2.1 |
| Hybrid cars (diesel) | 2.1 |
| Hybrid cars (petrol) | 2.1 |
| SUVs diesel | 2.1 |
| SUVs petrol | 2.1 |
| Motorcycles | 1 |

| ***Diesel freight vehicles*** | ***Load (ton/vehicle)*** |
|---|---|
| Light commercial vehicle | 3 |
| Medium commercial vehicle | 10 |
| Heavy commercial vehicle | 15 |
| Petrol freight vehicles | |
| Light commercial vehicle | 3 |

When calculating the efficiency for freight vehicles it is assumed that the vehicle is full for half of the journey (ie half the kilometres) and empty for the other half. Fuel efficiency for diesel vehicles is assumed to be 85% the efficiency of petrol vehicles. New vehicles are assumed to have an efficiency of 90% of the given efficiency to account for city driving versus open-road driving as well as a decrease in efficiency with increased age of a vehicle. This value is confirmed by Kwon 2006 (Kwon 2006). In a study performed in Great Britain, it was concluded that while fuel consumption rates may have improved over time, this was partly offset by an increase in the average engine capacity of vehicles. Thus we use an annual efficiency improvement of 0.9% compared with the potential improvement of 1.1% if there was no change in average engine capacity (Kwon 2006). A recent study in the US showed that households do not consider fuel prices when making decisions about vehicle or gasoline purchases (Turrentine & Kurani in press 2006). The trend of buying vehicles with larger engines and the decoupling of fuel prices from types of vehicles purchased highlights the need for government intervention if energy and emissions savings are to be made in the transport sector.

Another addition to the model is the inclusion of separate categories for sport utility vehicles (SUVs) and hybrid vehicles. The cost for SUVs is averaged from the cost of the following Toyota vehicles for both petrol and diesel: Land Cruiser GX, Land Cruiser Pickup, Land Cruiser Pickup Brutus and Land Cruiser Prado VX. Little data is available for sales of these types of vehicles as they are new to the market. This makes it difficult to predict the growth patterns for these vehicles in the future. Research was done on the penetration rates of SUV and hybrid vehicles into foreign markets to get some idea of future penetration rates in South Africa.

The United States Department of Transport estimated that in 2004 there were 24.3 million SUVs on the road versus 137.6 million ordinary cars. With regards new vehicle sales, an estimated 27% of new vehicle registration in 2002 were SUVs (Plaut 2004). In 2004 hybrid vehicle sales made up 0.52% of the market share and was forecast to 3% in 2011 (de Haan et al 2006).

In South Africa the situation is somewhat different since approximately only 5% of households could afford to buy an SUV or hybrid vehicle[2] (SAARF 2005). If each household has two vehicles, 10% of vehicles are owned by the top income households and could potentially be SUV's or hybrids. Keeping in mind percentage of SUVs and hybrids in new cars sales in the US and the fact that the top 10% of vehicles on the road *could* be SUVs or hybrids, we assumed that or these top 10% of vehicles, by 2035 40% of them will be SUVs and 10% will be hybrids. This equates to 4% of the total fleet of private passenger vehicles consisting of SUVs and 1% of hybrids. These estimates are inline with original estimates.

Demand for transportation is met through these various technologies using an assortment of energy carriers with liquid fuels such as diesel and petrol being the most dominant. The model has the flexibility to include bioethanol and biodiesel into the transportation fuel mix in any ratio specified. While these fuels are not currently used in South Africa on a large scale, with the growing interest in biofuels and the construction of a bioethanol plant underway, this flexibility allows the model to perform more realistic future scenarios. In the base case it is assumed that ethanol and biodiesel will be made available from 2008 and will be blended with petrol and diesel in ratios of 10% and 5% respectively by 2012. Thereafter the biofuels ratios will remain constant.

### 2.1.3 Power plants

All major existing Eskom plants are included explicitly in the model and smaller plants such as the hydro plants Gariep and Van der Kloof are included collectively as Eskom hydro plants. Currently moth-balled Coal-fired plants that have plans to come online before 2030, such as Groot Vlei and Komato, are in the model. New plants that are under construction, such as the New Braamshoek plant and the CCGT plant planned for Coega are also explicitly in the model. Existing municipal plants are collectively included in the model as a single unit.

All new coal plants are assumed to have Flue-gas desulphurization (FGD). Proven technologies such as certain renewable energy technologies, clean coal technologies or Pebble Bed Modular Reactor (PBMR) nuclear technology are also included. For new technologies, a technology learning rate is applied such that over time new technologies decrease in cost due to economies of scale and 'learning by doing'.

Transmission costs are not included in the model for either existing or new plants. However certain types of plants that do not need to be built near a fuel source, for example nuclear power plants and gas turbines, are given a 'transmission benefit' in the form of slightly reduced cost.

Since electricity generation accounts for some 40% of GHG emissions in South Africa (RSA 2004), the mitigation potential in this sector is high. Consequently, the data on costs and other characteristics of new power plants are of interest. The values which stakeholders agreed to use for this process are summarised in Table 7. More detailed descriptions of the energy technologies were provided in Appendix 5 of the SBT3 document.

These values were derived by comparing values in previous work – the first Integrated Energy Plan (DME 2003), the second National Integrated Resource Plan (NER 2004) and previous work done at the ERC (Winkler 2006). The full range of values found are reported in Appendix 2 of the SBT3

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[2] We assume that households with an income of R18 000 per month or higher are able to afford an SUV. These households fit into LSM (Living Standards Measure) 10 as described by the South African Advertising Research Foundation.

document. More detailed explanations of why certain values were chosen is listed in new ‘Notes’ columns in these tables, in which a comparison to ISEP 10 data is now also included.

The values reflected in Table 7 were first circulated to stakeholders prior to SBT3, which was held on 29 November 2006. At that meeting, agreement could not be reached and a small group was set up to discuss the matter further. The intention was to complete these discussions by mid-December 2006. Extensive efforts were made both by stakeholders and the research team to obtain the most accurate data possible. After several interaction, a teleconference on 26 January 2007 reached agreement on a set of numbers with which to proceed. The energy modeling team will now proceed to complete the reference case and start modeling of mitigation actions based on the data reflected here. It is reiterated (as stated at SBT3 and since) that stakeholder retain the right to return to data issues in the process, with evidence from the literature or official plans.

**Table 7: Characteristics of new electricity generation technologies**

| | ***Capex: pv capital expenditure*** ***( R/kW in yr - 2003 R)*** | ***Ffixed O&M costs*** ***(R/ kw / yr - 2003 R)*** | ***Variable o&m costs*** ***(R / MWh / yr, r/mwh for imports - 2003 R)*** | ***Capacity per unit*** ***(MW)*** | ***Expected operating lifetime*** ***(Years)*** | ***Efficiency*** ***(%)*** | ***Lead time*** ***(years - construction lead time)*** | ***Availability factor*** ***(%)*** | ***Capacity factor*** ***( %)*** |
|---|---|---|---|---|---|---|---|---|---|
| PF dry-cooled with FGD | R9 980 | R125 | R7.5 | 642 | 30 | 34.6 | 4 | 88 | |
| Fluidized bed combustion (FBC) greenfield with FGD | R11 511 | R205 | R19.5 | 233 | 30 | 36.7 | 4 | 86 | |
| Supercritical coal with FGD | R11 015 | R227 | R16.9 | 600 | 30 | 40.0 | 4 | 88 | |
| Integrated gasification combined cycle (IGCC) | R10 564 | R141 | R19.1 | 550 | 30 | 46.3 | 5 | 88 | |
| Combined cycle gas turbine (CCGT) (w/out transmission benefits) LNG | R4 171 | R175 | R10.6 | 387 | 25 | 50.0 | 3 | 85 | |
| Open cycle gas turbine (OCGT)1 | R2 753 | R80 | R65.9 | 120 | 25 | 33.0 | 2 | 85 | |
| Imported hydro-electricity (Cahora Bassa) | | | R92.2 | | | n/a | | | n/a |
| Imported hydro-electricity (Mepanda Uncua) | | | R161.3 | | | n/a | | | n/a |
| Imported hydro-electricity (Inga) | | | R126.7 | | | n/a | | | n/a |
| Imported coal-fired electricity (Mmamabula) | | | R- | | | n/a | | | n/a |
| Imported gas-fired electricity (Kudu) | | | R235.4 | | | n/a | | | n/a |
| Central solar receiver ('power tower' with molten salt as HTF) | R22 200 | R178 | R0.1 | 100 | 30 | n/a | 3 | | 51 |
| Parabolic trough (thermal oil as HTF) | R22 500 | R147 | R0.1 | 100 | 30 | n/a | 3 | | 40 |
| Photovoltaic | R49 000 | R69 | | 5 | 30 | n/a | 2 | | 20 |
| Wind turbines | R7 768 | R167 | | 5 | 20 | n/a | 2 | | 20 25 |
| Landfill gas | R4 287 | R156 | R0.4 | 3 | 25 | n/a | 3 | | 89 |
| New biomass co-generation | R23 000 | R154 | R22.9 | 8 | 30 | n/a | 4 | | 68 |
| New small hydro | R10 938 | R202 | | 2 | 25 | n/a | 1 | | 30 |
| PBMR (excl transmission benefits) | R18 707 | R158 | R6.7 | 165 | 40 | 40.5 | 4 | 95 | |
| PBMRlater series multi-module | R10 761 | R158 | R6.7 | 165 | 40 | 40.5 | 4 | 95 | |
| PWR (excl trans benefits) | R15 290 | R507 | R25.0 | 874 | 40 | 31.5 | 4 | 79 | |
| Pumped storage | R4 619 | R37 | R9.0 | 333 | 35 | 76.0 | 7 | 97 | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| (Braamhoek) | | | | | | | | | |
| Pumped storage (generic) | R4 822 | R49 | R9.0 | 333 | 40 | 76.0 | 7 | 97 | |

It should be noted that lead times are construction lead times, and do not include time required for pre-feasibility and EIA process. Lead times including these processes may be longer, and high global demand for power plants may affect timing of actual implementation. Variable O&M costs as inputs to the Markal model do not explicitly include fuel costs, but costs attached to fuels upstream are taken into account by the model. Results therefore do report all variable costs, including fuel. Open-cycle gas turbines may use a variety of fuels (LPG, kerosene, natural gas or syngas), which differ only by fuel costs (NER 2004).

Note that the variable O&M costs for imports are in R/MWh, not per year. This reflects an estimate of the price that would be paid for imported electricity, be it from hydro-electric, gas- or coal-fired stations.

Wind turbines will be made available at two capacity factors 20% and 25% at the same cost. The difference lies in the wind resource. Since the energy model would simply choose the higher capacity factor turbine if unconstrained, an upper limit will be placed on the wind turbines to reflect the number of good sites available. The research team will report these upper bounds in a future report.[3]

The research team will also further specify the kind of biomass co-generation used, which draws on waste products such as bagasse, wood chips, etc.

The capital cost and capacity factors for solar thermal plants (the 'power tower' as well as the trough) are within the quite wide range of capital costs reflected in the literature on solar thermal plants (World Bank 2006, 1999; NREL 1999; Sargent & Lundy 2003; Philibert 2005; De Vries *et al.* 2007; UNEP 2006; IEA & OECD 2006; IEA 2003; EDRC 2003; Banks & Schäffler 2005; Winkler 2006; DME 2004). The values reflected in Table 7 are drawn from a recent study citing data on a plant to be built in South Africa near Upington (World Bank 2006: 90-91). Eskom noted that it agreed to proceed with these numbers with caution, as the plant had not yet been built.[4]

Following queries from stakeholders, it is noted that CCGT costs do not include costs of re-gasification plant; but that such costs are included within in fuel costs, considered upstream in the modeling.

The exchange rate is relevant for imported capital equipment. In the modeling, the investment costs of power plants will be first taken in dollars, then converted by the exchange rate of R7.50 in 2003, increasing at 2% per year (as decided by SBT3).

Several stakeholders suggested that imported coal-fired electricity from Botswana needed to be considered. Available information suggests that two phases of approximately 2230 MW each will be developed, with the first phase starting in 2011. The value of the project is reported to be greater than $4 billion, the life of mine: 40 years and production of 12 million tons of coal per year. A significant part of the power (70%) will be sold to Eskom. What is not known is the price at which electricity will be sold (AEJ 2006b, 2006a; CIC 2006). In the absence of cost information, we assume that the levelised cost (c/kWh) of Mmamabula would be the same as a new coal-fired power station in South Africa. This would at least enable more accurate accounting of emissions within SA and attributable to imports. When information about the actual price becomes public, this could be adjusted.

The efficiency of supercritical coal-fired stations has been queried by several stakeholders. It was given as 40%, which the international literature indicates is possible. There is a range of efficiencies reported, from 36 – 42% (NEA *et al.* 2005). There is also evidence that in developing countries, efficiency may be lower than international values (Chikkatur & Sagar 2006). Given these various factors, our approach is to reduce efficiency of supercritical to 38% for the first new stations built, but to include more efficient stations (at 40%) from 2030 onwards.

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[3] This approach was agreed in a discussion of the small working group on 26 January 2007.

[4] This approach was agreed in a discussion of the small working group on 26 January 2007.

Ultra-supercritical coal is not reflected in the table, as complete information across all the parameters required has not been found by the team, nor provided by stakeholders. The research team will consider inclusion, if further data becomes available. Further information on representing industrial co-generation in generic form in the modeling is being sought by the research team.

The following sections briefly describes the power generation technologies considered in this study. These technologies are currently available or are likely to become commercial available within the projected time period. Further detail describing the various technologies are provided in the Appendix.

### 2.1.4 Power generation technologies

The general characteristics of new power stations were reported in the Technical Report. Further detail describing the various technologies is provided here.

#### *2.1.4.1 Coal-fired pulverized fue*

Conventional pulverized fuel (PF) combustion is common throughout the world and the majority of South Africa's electricity is generated in these types of plants. Finely ground coal particles of coal are blown into the boiler where they are burnt. Heat from combustion is collected through the water-cooled walls of the boiler and a number of heat-exchangers to produce high pressure steam. This steam passes through a steam turbine which in turn drives an electric generator.

Different configurations of steam plant are possible either for electricity-only or cogeneration (combined heat and power) applications. In South Africa most power plants are electricity only, however in the future there may be development of more cogeneration plants.

The temperature and pressure at which the steam is generated is the key design feature of a conventional PF plant. All PF plants in South Africa use sub-critical boilers (the steam pressure is below the critical pressure of water (approximately 218 atmospheres). Supercritical boilers are proven technology that raise pressure above this, thus increasing the efficiency to about 42% from 38-40% efficiency of sub-boilers. Specialised alloys are required to withstand high-pressure steam which increases the cost for components throughout the power plant. In the future most large coal-fired plants will probably have supercritical boilers.

Emissions control is an important cost factor of all PF plants. Current emissions control in South Africa involves basic particulates control but any future coal-plants built will include flue-gas desulphurisation (FGD). We assume all new coal plants include FGD at over 90% efficiency and bag-house filters. The predominant FGD system consists of a reaction vessel in which sulphur dioxide is absorbed from the flue gas stream by a slurry of limestone or other reagent. These systems add cost and reduce generation efficiency of the power plant, however removal efficiencies are some times higher than 95%. NOx control systems relate to the coal combustion itself and involve the flow of air into the combustion zone and the type of burner used.

#### *2.1.4.2 Fluidized-bed combustion (FBC)*

This new technology is proven in many countries, however it has not yet been used in South Africa. Coal is burnt in a 'bed' or dense cloud of aerodynamically suspended particles. The airflow suspending the particles is sufficiently strong that a portion of the particles is entrained out of the boiler and recirculated back into it via cyclones. Water is heated in the same way as a conventional power plant and steam is raised to turn turbines and drive electric generators. FBCs have environmental advantages over other coal-fired plants:

- Combustion temperatures are generally lower than in a typical PF plant thus reducing the production of thermal NOx.
- The need for expensive FGD equipment can be avoided by injecting sorbent (for example limestone) directly into the fluidised bed boiler. This allows for fuel flexibility as lower grade (high sulphur content) coal can be used.

In South Africa the use of FBCs is particularly attractive since 'discard coal' (low grade currently unusable coal) can be used, however when discard coal is used, the emissions from the FBC are worse than from a PF station using higher grade coal. Another disadvantage is that FBC's have a lower efficiency than sub- or super- critical PF plants are have a higher capital cost (Van der Riet et al 2005). This may explain why the technology still seems far away for large-scale generation but is perhaps most appropriate for onsite generation of coal mines. In FBCs coal can be supplemented with different types of biomass.

#### *2.1.4.3 Integrated gasification combined cycle (IGCC)*

Gasification technology increased the coal power-generation cycle efficiency by combining two or more energy cycles: a high-temperature gas turbine cycle and a steam turbine cycle. In most applications coal is partially combusted in an oxygen-blown gasifier to yield a synthetic gas (syngas) which is predominantly carbon monoxide and hydrogen. The syngas is cleaned before being burnt in a high efficiency gas turbine to produce electric power. The exhaust gases from the gas turbine are cooled in a heat-recovery steam generator (HRSG) and the steam is sent to a steam turbine for additional electricity generation.

The choice to use oxygen rather than air as a source of oxygen for gasification means that components can be smaller as the volume of source gas is smaller and the heating value of the gas produced is closer to that of natural gas. The gas turbine therefore requires less modification to burn the syngas produced in an oxygen-consuming gasifier. Nevertheless the need for a dedicated cryogenic oxygen production facility adds to the cost of the system.

IGCC has the following benefits:

- Cleaning of syngas can result in very low stack emissions, comparable with natural gas fired power stations.
- Efficiencies of up to 48% by utilising advances gas turbine technologies and combined cycle processes.
- Sulphur removal rates are very high (98%) thus systems can be designed to handle fuels with very high sulphur content. Removed sulphur can also be used in the chemical industry.
- Produces a sintered glassy ash which locks in most chemical components found in fly ash.
- Offers the potential to remove $CO_2$ from the syngas for carbon sequestration.

#### *2.1.4.4 Gas-fired open-cycle gas-turbine (OGCT)*

An OCGT power plant is basically a simple gas turbine connected to a generator and auxiliary systems such as the fuel supply system, lube cooling system, fire protection system and the control system. In South Africa all current gas turbine power plants are OGCTs run on liquid fuels such as diesel or kerosene. Of the 662MWe of gas turbine capacity in South Africa, about half are owned by Eskom and half are owned by municipalities. These plants are currently used for emergency power or for peaking power.

#### *2.1.4.5 Gas-fired combined-cycle gas-turbine (CCGT)*

A new type of gas turbine plant to be used in South Africa is the CCGT. In a CCGT power plant, the gas turbine is usually run on natural gas and the hot exhaust gases are used to generate steam in a HRSG. The steam is then delivered to a steam turbine for additional power generation. In a CCGT plant, about two-thirds of the electrical power is derived from the gas turbine while the steam turbine contributes the remaining third. The greatest advantage of a CCGT is the very high efficiency (50 - 60%), the low capital costs per kWh and the quick construction time.

The first CCGT in South Africa is under construction in New Castle, KwaZulu-Natal and will produce 15MW electricity and 120 000t/h of industrial steam (Le Roux 2006). The plant is owned and operated by an independent power producer and is scheduled to start production in January. More power plants of this type could prove beneficial to the South African power mix provided that gas supply and gas prices are acceptable.

The type of fuel used by a gas turbine plant determines the emissions. Natural gas has lower emissions than liquid fuels, however both gas and liquid fuels are cleaner fuels than coal. Natural gas has little or no sulphur or particulates.

#### *2.1.4.6 Nuclear power plants: pressure water reactor (PWR)*

South Africa's only nuclear power plant, Koeberg, is situated 30km north of Cape Town and consists of two PWR units. Each unit has a capacity of 920MWe and it cooled by sea water. In this system, water inside a pressurised reactor is heated up by the of uranium fuel in the reactor. High temperature, high pressure water is passed through a heat-exchanger to a secondary water system in which steam is produced. This steam drives turbines that generate electricity. Plans for future plants of this type are underway.

#### *2.1.4.7 Nuclear power plants: pebble-bed modular reactor (PBMR)*

A nuclear technology in which South Africa has invested a great deal, is the PBMR. This is small, simple, inherently safe design using helium as the coolant and graphite as the moderator. The fuel consists of uranium surrounded by multiple barriers and embedded in graphite balls or ‘pebbles’. The first demonstration module (165MWe) will go into production in 2013 provided that legal and political approvals are granted. Thereafter 24 modules of 165MWe each will be implemented.

#### *2.1.4.8 Hydroelectric power and pumped storage*

Hydroelectricity makes use of natural hydrology and topography. Water at a certain height is trapped (usually in a dam) or diverted to pass through turbines that generate electricity. Being a water-stressed country South Africa does not have vast hydroelectricity resources. There are 665MWe of installed hydroelectric power in South Africa of which most is owned by Eskom. Only two of the hydroelectric stations are over 50MWe – Gariep (360MWe) and Vanderkloof (240MWe). While potential for large hydroelectric schemes is limited, there are possibilities for small- and micro-hydro plants.

Pumped storage is not considered a regular power generation facility since it uses electricity at off-peak times to pump water from a lower reservoir into a higher reservoir. This water is then released during peak electricity demand through pump-turbines to generate power. While these stations are net users of electricity, they are important storage systems for load following. The two large Eskom owned pumped storage stations are Drakensberg (1000MWe) and Palmiet (400MWe) while the Cape Town municipality owns the Steenbras station (180MWe). A new pumped storage scheme is planned for Braamhoek on the Free State/KwaZulu-Natal border which will consist of four 333MWe units.

#### *2.1.4.9 Wind*

Wind turbines consist of a rotor, generator, directional system, protection system and tower. Wind spins the rotor blades which drives the generator thus turning mechanical energy into electrical energy. Gearing is some times used to increase the rotation speed for electricity generation. The directional system enables horizontal axis machines to orientate themselves into the wind for maximum power. Modern turbines are usually equipped with protection systems such as variable orientation of blades, mechanical brakes or shut-down mechanisms to prevent damage during excessive wind loads. The tower raises the rotor above the ground to capture the greater windspeeds and avoid turbulence caused by ground-interference.

Until the mid 1980s, wind turbines had typical outputs of less than 100kW and rotor diameters from 10m. In the mid 1990s turbines ranged from 0.5WM – 1.5MW and today commercial prototypes of 3.6MW with greater than 80m rotor diameters are being installed. This increase in size of turbines as well as an economy of scale in many European countries that are installing large on- and offshore wind farms, has led to significant reductions in cost.

Currently in South Africa no electricity on the national grid is generated from wind. Nevertheless wind was important traditionally, and continues to be, for water pumping on farms. An estimated 30 000 systems are currently installed (Banks & Schaffler 2006). There are also about 500 wind turbines on farms that generate direct current electricity, usually at 36V.

In 2003, Eskom installed two 660kWh wind turbines and one 1.7MWe at Klipheuvel in the Western Cape as part of the South African Bulk Renewable Energy Generation (SABRE) programme of demonstration and research. An independent group, Darling Independent Power Producer (Darlipp), is an example of an independent power producer in South Africa. The Darling wind farm project in the Western Cape has a planned initial capacity of 5MW with intentions to expand to 10MW.

#### *2.1.4.10 Concentrating solar power systems*

Concentrating solar power (CSP) can be exploited though three different systems: parabolic trough, parabolic dish and power tower. All CSP systems make use of a concentrator which captures and concentrates direct solar radiation and delivers it to the receiver. The receiver absorbs the concentrated sunlight and transfers the heat to a power-energy conversion system. The parabolic trough uses linear parabolic mirrors to reflect sunlight. The parabolic dish system collects sunlight through a round parabolic solar collector and the power tower employs heliostats (large sun-tracking mirrors) to concentrate solar energy onto a central tower-mounted receiver.

The parabolic trough is the most mature of the technologies however the power tower is looking more attractive with its potentially lower cost and more efficient thermal storage. The dish/engine systems can be used in smaller applications.

CSP systems can also be ‘hybridised’ or operated in combination with conventional fossil fuels. For example parabolic troughs can be combined with gas combined-cycle systems.

In South Africa, as part of the SABRE programme initiated in 1998, a 25kW solar dish with a Stirling engine was installed at the Development Bank of Southern Africa in Midrand in 2002. Eskom is also studying the feasibility of building a 300MWe solar thermal power station near Uppington in the Northern Cape. If built, this station would have three 100MWe units concentrating sunlight via heliostats onto a central power tower in which molten salt would absorb the heat. The salt is able to store heat thus allowing the station to deliver electricity 24 hours a day.

#### *2.1.4.11 Solar photovoltaic systems*

Photovoltaic (PV) technology transforms the energy of solar photons into direct electric current using semiconductor materials. When photons enter the photovoltaic cell, electrons in the semiconductor are freed, generating direct electric current. The process of converting sunlight to electricity has very low efficiency: Laboratory tests achieve up to 32% efficiency but in practice it is much lower than this. There are many different solar cell designs but the most common semiconductor materials are single-crystal silicon, amorphous silicon, polycrystalline silicon, cadmium telluride, copper indium diselenide and gallium arsenide. The most important PV cell technologies are crystalline silicon and thin films, including amorphous silicon (NEA *et al.* 2005).

PV cells are connected to form a PV module or panel. PV modules come in standard sizes ranging from less than a watt to around 100 watts. PV modules can be connected together to form an array. In order to obtain useful electricity from the PV array, a number of other elements such as an inverter, batteries, charge controller are required. PV systems can either be used as stand-alone off-grid systems (often applicable in remote areas when extension of the grid is too expensive or infeasible), grid-connected systems in buildings or large utility-scale systems.

In South Africa no electricity from solar power is generated for the national grid but PV systems are widely used in rural areas. It is estimated that about 70 000 households, 250 clinics and 2 100 schools have PV panels. Programmes are in place to increase the number of these systems (Winkler 2006).

#### *2.1.4.12 Biomass for electricity generation*

Much biomass is used in South Africa for heating, lighting and cooking in low-income households. The industrial use of biomass is small but significant. Annually South Africa’s sugar industry produces about two million tons of sugar from about 20 million tons of cane. Approximately seven million tons of bagasse is burnt in boilers to make steam for electricity generation and process heat.

The paper and pulp mills in South Africa also use biomass to generate electricity with an estimated capacity if 170MWe. The mills burn sawdust and bark to make steam for electricity generation and process heat. In chemical pulp mills, ‘black liquor’ is separated from wood fibres after passing through digesters. This black liquor is burnt in recovery boilers to make steam. The pulp and paper industry is expanding and there is room for expansion of generating capacity both for onsite use and for sale to the national grid.

Biofuels from biomass such as ethanol (both liquid and gel) and biodiesel are receiving considerable attention particularly for use in the transport sector (ethanol and biodiesel) and residential sector (ethanol gel). These energy carriers are most appropriate for direct combustion and not for electricity generation.

#### *2.1.4.13 Municipal waste for electricity generation*

It has been estimated that South Africa’s total domestic and industrial waste disposed in landfill sites has an energy content of about 11 000 GWh per annum. This could be directly combusted or converted into biogas and methane for electricity production.

A project currently underway in the Durban metropolitan municipality consists of enhanced landfill gas capture from three of the city's landfill sites and use of this gas to generate up to 10MW of electricity. This project is supported by the World Bank's Prototype Carbon Fund which will purchase the greenhouse gas reductions of 68 833 metric tonnes $CO_2$ equivalent per annum (DSW & PCF 2006; ENS 2004).

### 2.1.5 Refineries

All existing refineries are included in the model as a single unit of refining capacity, as are the synfuel plants. New crude oil refineries all have a capacity of 300 000 bbl/day. A new coal-to-liquid (CTL) plant is also included as an option, with 80 000 bbl-equivalent / day.

The new bio-ethanol plant under construction in Bothaville in the Free State is also included explicitly in the model. By the end of 2007 it is expected to be producing 473 000 litres of alcohol per day from 1126 tons of maize daily (25 Degrees 2006). Plans are in place for another seven such plants to be constructed in the Free State, North West and Mpumalanga.

**Table 8: Key characteristics of refineries**

| | *Capex: PV capital expenditure (million R / PJ in year 2003 R)* | *Fixed O&M costs (R / GJ / year (2003 R)* | *Variable O&M costs (R / GJ / year (2003 R)* | *Expected operating lifetime (Years)* | *Capacity factor (%)* |
|---|---|---|---|---|---|
| **Crude oil** | | | | | |
| Petrol-intensive 300 000 bbl/day | 66 | 9.4 | 1.9 | 25 | 92% |
| Diesel-intensive 300 000 bbl/day | 66 | 9.4 | 1.9 | 25 | 92% |
| Generic 300 000 bbl/day | 66 | 9.4 | 1.4 | 25 | 92% |
| **Gas-to-liquids** | [2003 R/GJ] | | | | |
| New GTL based on PetroSA | 148.70 | 10.94 | 11.45 | 25 | 0.93 |
| **Coal-to-liquids** | [2003 R/GJ] | | | | |
| New CTL based on Sasol | 272.16 | 9.45 | 3.43 | 25 | 0.96 |
| **Maize-to-ethanol** | 159.83 | 33.360 | 40.773 | 25 | 0.96 |
| **Biodiesel** | | | | | |
| Large biodiesel plant | 52.91 | 6.00 | 9.70 | 25 | 0.96 |
| Small scale biodiesel plant | 234.9 | 18.21 | 29.71 | 25 | 0.82 |

Refineries can be set up to produce outputs in different ratios. The outputs for different refineries are reported in Table 9 by energy output.

**Table 9: Output splits of different existing refineries**

| *Oil refinery* | | *GTL output split* | | *CTL output split* | |
|---|---|---|---|---|---|
| Diesel | 31.5% | Diesel | 24.0% | Diesel | 20.9% |
| Fuel oil | 23.6% | Fuel oil / alchohols | 8.2% | Fuel alchohols | 12.4% |
| Jet fuel | 8.9% | LPG | 6.9% | Jet fuel | 2.2% |
| LPG | 1.7% | Paraffin | 9.9% | LPG | 1.9% |
| Paraffin | 2.9% | Petrol and aviation gas | 51.0% | $CH_4$ rich gas | 2.9% |
| Petrol | 30.7% | | | Paraffin | 2.2% |
| Refinery gas | 0.7% | | | Petrol and aviation gas | 57.5% |

| | | | | | |
|---|---|---|---|---|---|
| | | | | $H_2$ rich gas | 0.0% |

The output splits or product slates for new refineries are assumed to be different to existing ones, as demand for fuels shifts.

**Table 10: Output splits for new refineries**

| | ***Generic new*** | ***Diesel-intensive*** | ***Petrol-intensive*** | ***New CTL*** |
|---|---|---|---|---|
| Avgas | 0.3% | 0.3% | 0.3% | |
| Diesel | 34.9% | 42.6% | 34.5% | 73.0% |
| HFO high sulphur | 21.4% | 11.4% | 11.4% | |
| Jet Fuel | 7.9% | 11.0% | 11.1% | |
| Illuminating paraffin | 3.0% | 3.0% | 3.0% | |
| LPG | 1.8% | 2.4% | 1.9% | 3.4% |
| Petrol | 30.7% | 29.3% | 37.8% | 23.6% |

## 2.2 Mitigation cost methodology

The methodology for calculating mitigation costs is based on the approach developed for the SA Country Study (Clark & Spalding-Fecher 1999). The approach drew on international best practice, notably a report written by the United Nations Environment Programme's Collaborating Centre on Energy and the Environment entitled Economics of Greenhouse Gas Limitation: Technical Guidelines (Halsnaes *et al.* 1998b). Other climate-change related sources include the guidelines developed by the Intergovernmental Panel on Climate Change (IPCC 1996) and costs reported in its assessment reports on mitigation (IPCC 2001, 2007). Further references to the literature on mitigation costs methodology include OECD (2000), Sims (2003) and earlier works listed in Clark & Spalding-Fecher (1999).

The approach can be summarised [5] as follows:

- The life cycle costs of the mitigation options and baseline should be calculated by discounting all of the costs of these options to a present value.
- These life cycle costs should then be levelised, so they are expressed in Rands per year.
- The cost effectiveness analysis should be based on the difference in the levelised life cycle costs of the mitigation option and the baseline option (levelised annual cost), divided by the average annual reduction in emissions.
- The cost-effectiveness analysis should exclude taxes and subsidies, external costs, depreciation and interest payments but include private costs or costs which can easily be quantified. Implementation costs should be included.

For energy modeling, the approach used for LTMS is to replicate this approach, using Markal result parameters. Thus, unlike in the approach above, costs and emissions reductions do not relate to a specific project, but *to the modelled system as a whole*. Thus, a) the cost parameter used from MARKAL is the total system cost, not the cost of a specific part of the energy system, and b) emissions are similarly emissions for the whole system. The life cycle costs are thus replaced by the total system costs.

Thus, the cost effectiveness of a particular mitigation action, or the Mitigation Cost (MC), is the annual Levelised Incremental Cost (LIC) divided by the annual average Emissions Savings (ES), or

$$\mathrm{MC} = \mathrm{LIC} / \mathrm{ES},$$

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[5] Readers seeking more detailed are referred to the full report (Clark & Spalding-Fecher 1999), particularly the Executive Summary and the illustrative example in section 6.2.

where ES is calculated by adding the annual emissions for each case over the period (2003 to 2050) to get the Cumulative Emissions (CE) for the period, then subtracting the cumulative emissions for the mitigation action from those of the baseline. This difference is then divided by the number of years in the period (in this case 48) to get the annual average emissions savings. Thus,

$$ES = (CE_{baseline} - CE_{mitigation\ action})/(\text{end year} - \text{base year}+1).$$

Emissions saved in the mitigation case are thus reported as a positive number. However, costs saved in the mitigation case are reported as a negative number (and thus extra cost incurred in the mitigation case are reported as a positive number).

The MARKAL parameter which is used to derive the discounted system costs is U.ANNADJTOTCOS, an annual real undiscounted cost of the total energy system in the model for a particular year, excluding taxes and subsidies. Thus, to calculate the total discounted system cost, the values for U.ANNADJTOTCOS for the years 2003 to 2050 is discounted using an appropriate discount rate (in this case, for four discount rates: 0%, 3%, 10% and 15%) for the baseline, and for the mitigation action. U.ANNADJTOTCOS does not include taxes and subsidies. Thus, to calculate the LIC, the discounted cost of the baseline and the mitigation action is calculated from U.ANNADJTOTCOS for each case, and then levelised for the total period. LIC is the difference between the levelised costs (LC) of the baseline and the mitigation action, thus,

$$LIC = LC_{mitigation\ action} - LC_{baseline}$$

Non-energy modeling uses the same fundamental methodology, although a significant difference is that each sectoral model compares emissions and costs only within that sub-sector, e.g. emissions in agriculture with and without low tillage. Using Excel, costs are derived by discounting future payments to net present value; these are then levelised (PMT function) to derive annual costs. These are divided by the average annually emissions difference between the baseline and mitigation cases.

## 2.3 Costs as share of GDP or system costs

At SBT4, the approach of expressing mitigation costs as a share of GDP was raised. There is a tradition of expressing mitigation costs in this way (see, for example, Nordhaus 1993; Azar & Schneider 2002; Halsnaes *et al.* 1998a), and generally have found this share to be higher in developing than developed countries. The share of GDP has been used more recently in the Stern Review on the economics of climate change (Stern Review 2006). The Review estimated that ‘the annual costs of stabilisation at 500-550ppm CO2e to be around 1% of GDP by 2050 - a level that is significant but manageable’. It contrasted this with the costs of inaction, suggesting that ‘BAU climate change will reduce welfare by an amount equivalent to a reduction in consumption per head of between 5 and 20%’ (Stern Review 2006: Executive Summary pp. x and xii).

While the impacts study does not provide a comprehensive monetization of the damage costs of climate change, it outlines that there would be some costs (see **Error! Reference source not found.**). The 1% of GDP level can be used as an externally-given threshold to assess whether mitigation costs at an acceptable level. Whether this level should be 1% or some other level would ultimately be a political judgement on what costs are manageable for our country.

The methodology for calculating share of GDP needs to deal with the fact that mitigation costs change over time. The mitigation costs are discounted (at a range of discount rates) in the R / t $CO_2$-eq reported in the energy and non-energy modeling. The approach taken to calculating the share of GDP starts with the difference in total energy system costs, i.e. the incremental costs of the mitigation ‘wedge’ minus the costs of the base case, GWC. These costs are reported by Markal for each year. The incremental costs are divided by the GDP for the same years, giving a share of GDP per year. Since the percentages change over time – as mitigation cost difference and GDP both change – we take the average (mean) of the shares. The averaged share of GDP is what is reported, in percentages.

Using a similar methodology, the aggregate mitigation costs can be compared to the total energy system costs. Since the energy system is smaller than the economy, its costs are smaller and mitigation costs expressed as a share of these smaller numbers will be higher.

# 3. Drivers

The drivers in this section were discussed at SBT3 and revised based on a) the comments made at SBT3, b) further valuable inputs from several of you after the meeting, and c) a small working group discussion specifically on Table 2, dealing with power station costs. The working group eventually reached sufficient consensus on a set of numbers, on the basis of which the research teams now proceeded with their analysis of mitigation actions.

## 3.1 Gross domestic product

### 3.1.1 GDP projections

Together with population, GDP is one of the biggest drivers of energy use. As people become more affluent, their energy consumption changes as they move to cleaner, more convenient fuels (usually electricity), acquire more appliances and demand more energy. In long-term modelling of energy and greenouse gas (GHG) emissions, per capita income is often the major development indicator.

The task of projecting GDP growth is difficult and decisions on growth rates are often politically bias as governments would like to project a continuously high GDP growth when, in fact, this is unlikely to occur. GDP growth is seldom, if ever, exponential over a long time period; however this is the way that most energy models describe GDP growth: a single percentage growth. If one examines other developed regions of the world, it is easy to see that GDP growth increases, reaches a peak and then declines.

The IPCC describes this pattern in five major stages of economic development (IPCC 2000):

- First, the pre-industrial economy, in which most resources must be devoted to agriculture because of the low level of productivity.
- Second, the phase of capacity-building that leads to an economic acceleration.
- Third, the acceleration itself (about two decades).
- Fourth, industrialization and catch-up to the ‘productivity frontiers’ prevailing in the industrialized countries (about six decades).
- Fifth, the period of mass-consumerism and the welfare state.

South Africa is unique in that its apartheid history created a huge disparity between different ethnic groups and the areas in which they live so that today parts of the country represent developed nations while large parts of the country fall into what would be classified as ‘developing’. South African could be described as being an accelerating economy (stage 3).

Another factor when developing a GDP growth projection for South Africa is that the impact of HIV/AIDS could play a significant role in the GDP of the country. If we assume that the population will stabilize and decrease over time, then we cannot believe that the GDP will follow an exponential growth. GDP will, to some extent, follow population trends.

Work was done on long-term GDP growth projections for energy modelling by Øvyind Vessia (Vessia 2006) at the Energy Research Centre at UCT. He looked at historical GDP growth in South Africa, compared it to trends in other countries and developed a time dependent GDP projection (called GDP-E) which initially increases quite steeply but then returns to a stable, lower growth. This is the GDP growth pattern used for this study. The assumptions made are somewhat weak but serve as a first approximation for moving away from modelling GDP as a simple exponential growth trend.

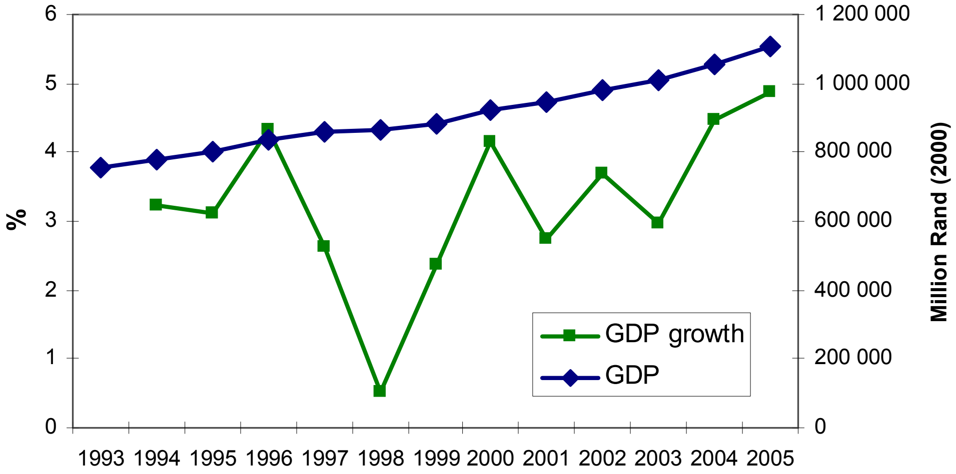

**Figure 3: Annual GDP and growth rate for South Africa 1993 – 2005**
*Source: StatsSA 2006*

Over the past 12 years, GDP growth in South Africa has fluctuated between 0.5% and 5% but has shown as positive trend as illustrated in Figure 3. Targets for GDP growth rates have been set as part of the Accelerated and Shared Growth Initiative for South Africa (AsgiSA 2006; National Treasury 2005). Figure 4 below shows this trend and the GDP growth as well as Vessia's projection of GDP growth to 2060. The current growth trend extends to 2015 and 2016 in which the peak growth at 5.24% is reached, after which growth decreases to a more stable lower level of approximately 2% annual growth.

The literature on GDP growth rates has been assessed *inter alia* by the IPCC (IPCC 2000). The world has witnessed high periodic economic growth in many countries. A per capita GDP growth rate of 3.5% per annum were, for instance, achieved in Western Europe between 1950 and 1980. Similarly, high per capita GDP growth rates were achieved in the developing economies of Asia. Per capita GDP growth rates of individual countries have even been higher – 8 % per annum in Japan over the period 1950-1973, 7 % in Korea between 1965 and 1992, and 6.5 % per year in China since 1980 (IPCC 2000). Based on such analysis, Vessia (2006) suggested that South Africa might be considered to be in and acceleration phase (stage 5). This would be consistent with AsgiSA targets of economic growth increasing from recently relatively low values around 2.5%. In the long-term, GDP growth rates might settle around 3%, consistent with the IPCC's recommendation for discount rates of 3% to be applied for long-term, inter-generational studies (IPCC 2001: 467).

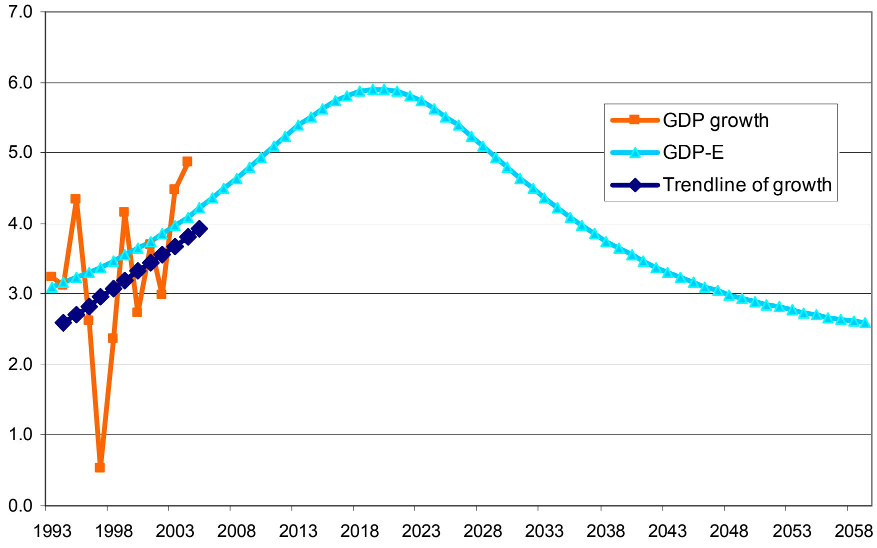

**Figure 4: South Africa's GDP growth, the trend line and projected GDP-E growth**

Hence the GDP growth projections in Figure 4 are adjusted to peak at 6%.[6] In the longer-term future (from 2030 to 2050), the GDP growth rate starts flattening out around 3%. The growth rate in the initial years lies slightly above the trend-line, but note that the actual data points varied substantially between 1993 – 2005.

### 3.1.2 GDP composition

A meeting with economists was held on 12 July 2007 to discuss macro-economic issues and long-term mitigation. Minutes of the meeting were circulated to SBT members, and documentation from the meeting, including a revised document on sectoral growth trends, was placed on the LTMS website. The following information summarises the key implications for modeling in the LTMS process.

The sectoral growth document focused on indices used in modelling the future energy system as a basis for the development of long-term mitigation scenarios. These indices play a fundamental role in linking the basic drivers of the model (GDP projections) with projected growth in energy demand in specific sectors. Understanding sectoral growth trends better would have two outcomes for energy modelling: 1) a more realistic ‘business as usual’ case would result, and 2) policies could be modelled which would shift the GDP to a less energy-intensive basis. These policies promise to be amongst the most significant mitigation policies, with considerable sustainable development co-benefits, but without a better understanding of sectoral growth, it is unclear what impact these would have on the energy system, and the broader economy.

For the purposes of the energy model, the energy system has been divided into five areas: industry, commerce, transport, residential and agriculture. The majority of the economy is represented by the commercial sector, which represents services sectors; however, the most energy-intensive portion of the economy is the industry sector, which for the purposes of the energy model includes the mining sector. Because of the energy-intensive nature of many of the industries within the industry sector, energy demand is disaggregated into a number of categories, and separate sectoral growth indices are applied to each of these categories. The most significant of these are described in more detail below, and form the basis of the discussion to follow. It is thus vital for these growth rates to be as plausible and accurate as possible, since these play a large part in determining the plausibility of the energy model as a whole.

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[6] The original work was done by Vessia (2006), but has been adjusted here based on SBT3 discussions.

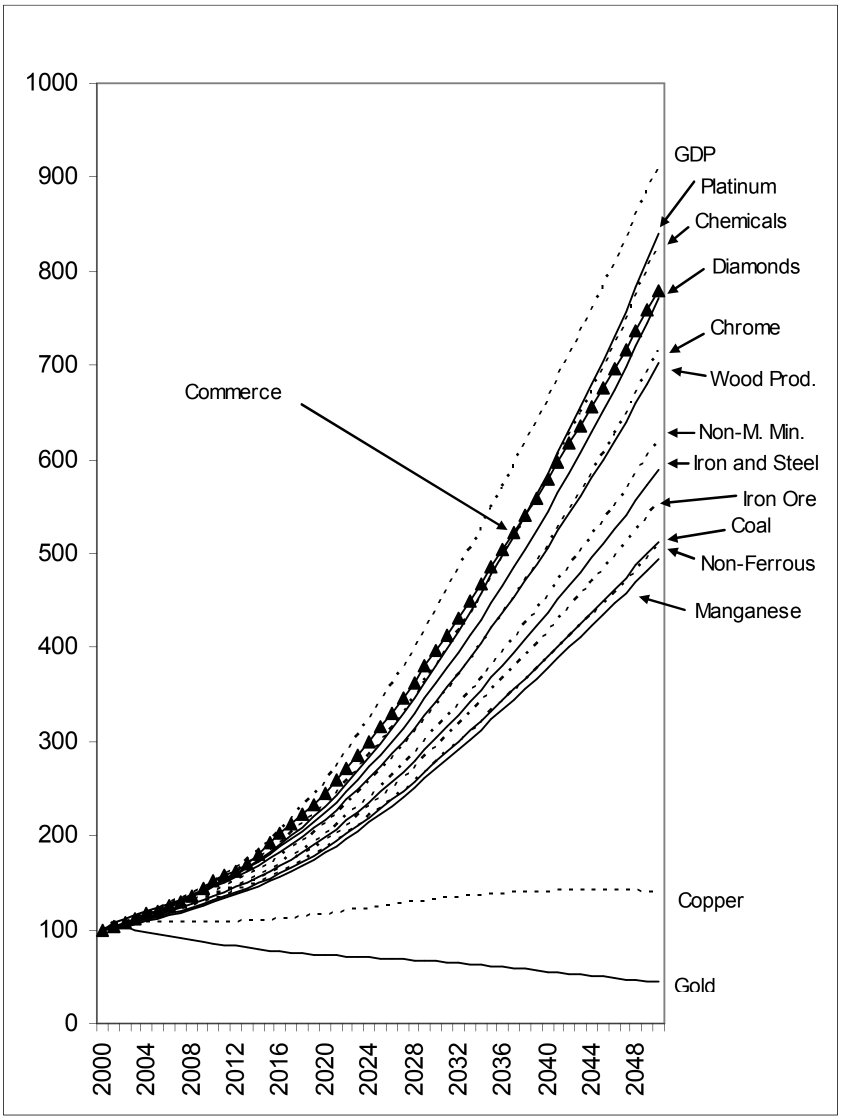

**Figure 5: Growth in GDP by industry and commercial sector, old projections**

The projections of sectoral growth were discussed with economists in the meeting of 12 July 2007. This served to check expectations as to how different sectors might grow in future. There was agreement that the structure of the economy was likely to change over time. Some information was provided for specific sectors, notably mining. Figure 6 shows the revised projections.

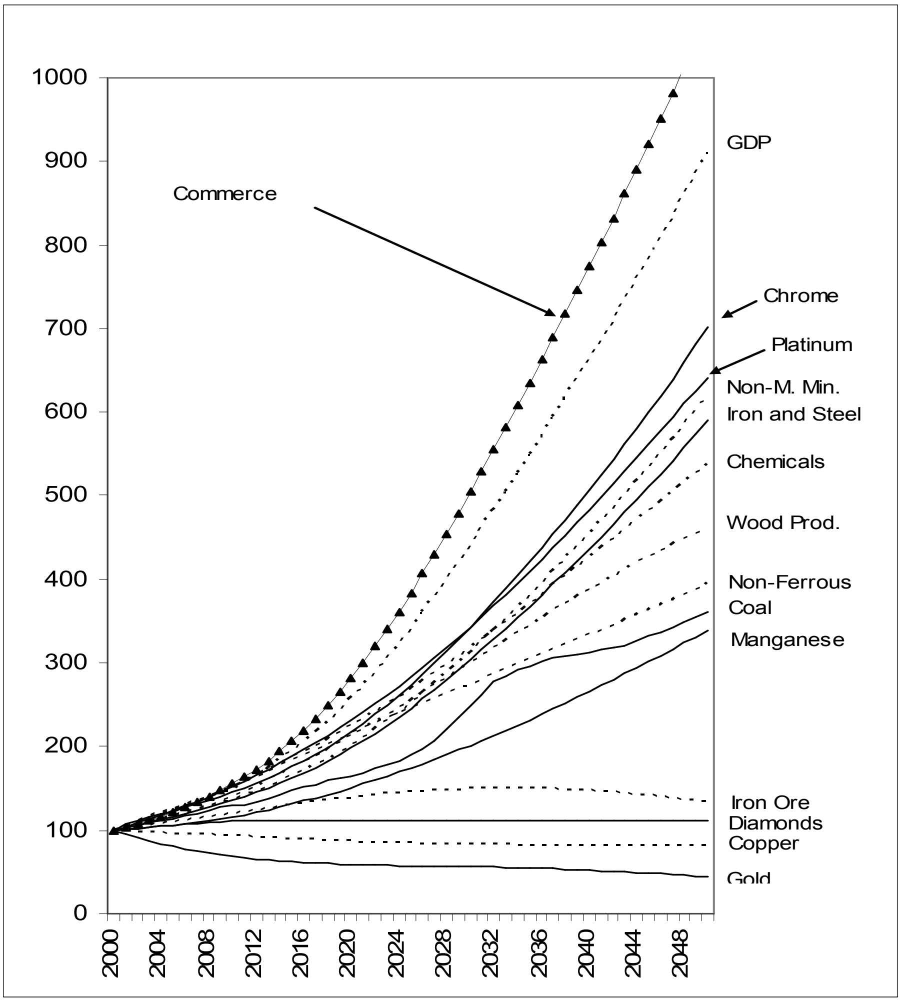

Figure 6: Sectoral growth projections, revised

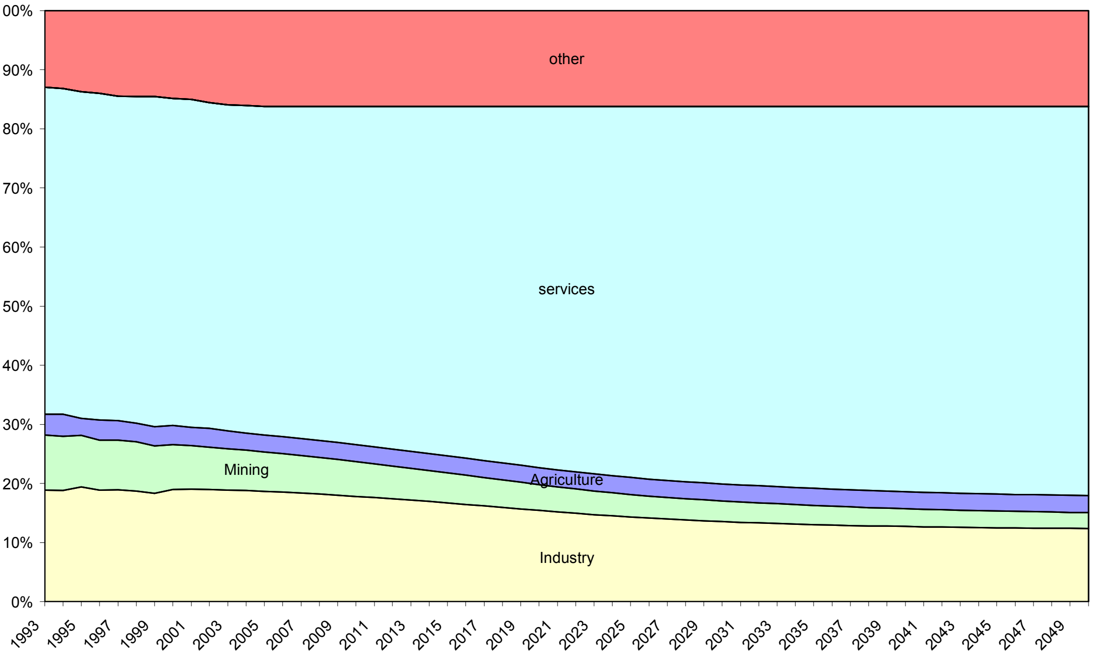

Figure 7: Composition of GDP, all sectors

## 3.2 Population projections

Population projections are a topic of much debate in South Africa given the high rate of HIV infection and how this will impact the growth of the population. Many believe that the population will level off and even decline in the future. No model can perfectly simulate this population growth as there are too many unknown variables. Nevertheless, a study by Professor Dorrington of the University of Cape Town Commerce Faculty for the Actuarial Society of South Africa is well respected for its population projections with the influence of HIV/AIDS (ASSA 2002). This is the model used for this study. Figure 8 below shows the simulated population growth over the study period.

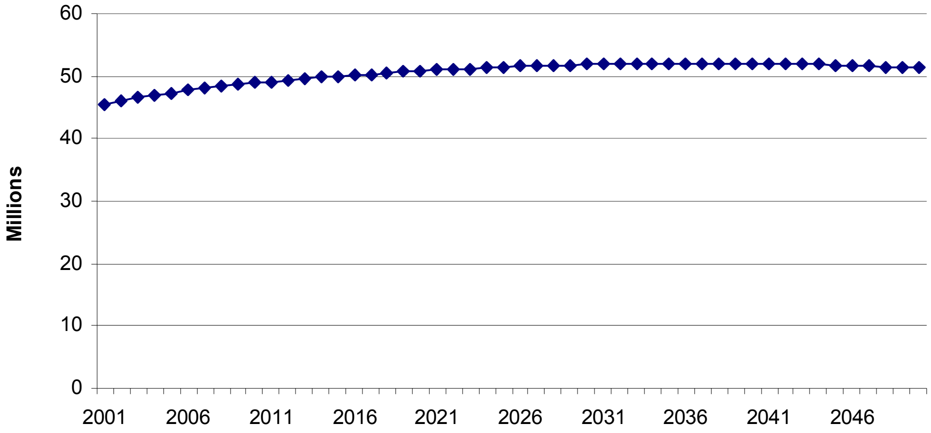

**Figure 8: Population projection from ASSA model: 2001 – 2050**

## 3.3 Discount rate

The discount rate is a critical factor influencing any analysis of economic effects over time. Discount rates effectively express a time preference for money – money right now is preferred to money in the future. Yet in another perspective, high rates literally discount future expenditure, and hence costs to be borne by future generations.

As noted at SBT3, analyses considering the long-term future (as with the LTMS process) should include consideration of a range of discount rates, including lower ones. The IPCC notes that two factors need to be taken into account. ‘For mitigation effects, the country must base its decisions at least partly on discount rates that reflect the opportunity cost of capital. … In developing countries the rate could be as high as 10%–12%’ (IPCC 2001: 466). These rates do not reflect private rates of return, typically between 10% and 25%. The second perspective is based on equity in a long-term context. Weitzman (1998) surveyed 1700 professional economists and found that (a) economists believe that lower rates should be applied to problems with long time horizons, such as that being discussed here, and (b) they distinguish between the immediate and, step by step, the far distant future. The discount rate implied by the analysis falls progressively, from 4% to 0%, as the perspective shifts from the immediate (up to 5 years hence) to the far distant future (beyond 300 years).

Good practice is to consider more than one rate, to provide policymakers with some guidance on how sensitive the results are to the choice of discount rate. ‘A lower rate based on the ethical considerations is, as noted above, around 3%’ (IPCC 2001: 467). For this study, sensitivity analysis will be conducted on discount rates at different levels, e.g. 15%, 10%, 3% and 0%.

## 3.4 Technology learning

Technology is an important driver of energy development, and technology costs change over time. One of the most important factors shaping the results of energy models are the assumptions they make about technology learning (IEA & OECD 2000; Repetto & Austin 1997; Fisher & Grubb

1997; Energy Innovations 1997; IEA & OECD 2006) – the extent to which technologies get cheaper over time.

A range of technology learning rates were proposed at SBT2. After some discussion, it was decided to establish a virtual working group to consider this issue. ERC produced a discussion document, a tele-conference was held on 18 October.[7] Good progress was made at the meeting and further input received from some stakeholders. ERC circulated a revised document to participants and others who had indicated interest at the end of October. A further round of comments was invited, after which the document was produced.

The two central explanatory factors why new technologies get cheaper over time are i) learning-by-doing and ii) economies of scale. Further background, including the mathematical approaches used to represent learning, are explained more fully in the SBT3 document. Empirical data on learning for energy technologies has been gathered (IEA & OECD 2000; World Bank 1999; Laitner 2002; NREL 1999; Papineau 2006; Nemet 2006; Junginger *et al.* 2004). Learning curves show the decline in costs (c/kWh for electricity generation technologies) as cumulative electricity production doubles.

Technologies will grow until they reach a maximum global capacity. Using these maximum global potentials, the growth of technologies can be represented in the form of a logistic equation, i.e. one that does not increase exponentially forever, but slows as it approaches an upper limit and eventually flattens out (see Appendix 1 of SBT3 document). If global cumulative capacity approaches an upper limit, the rate of growth in installed capacity will slow, and consequently learning would slow accordingly. The SBT agreed that where the research teams could not find maximum global potentials in the literature, they would assume an estimate. These potentials are reported in the third column of Table 11, with a more detailed derivation in the Appendix 1 of the SBT3 document. In addition, there is information on the rate of the doubling based on the historical growth rates. These doubling times can be used to cross-check doubling resulting from the logistic equation.

Table 11 shows the learning rates for new electricity generating technologies, based on the process undertaken by the working group as outlined above. Appendix 1 of the SBT3 document compared learning ratios from studies, with the last column reporting the values for this study, which were chosen as being within the range cited in the peer-reviewed literature.

**Table 11: Learning rates for electricity generating technologies**

| ***Energy technology*** | ***Range of learning rates in the literature *(%)*** | ***Maximum level this technology can reach globally (GW)*** | ***Learning rate, this study*** |
|---|---|---|---|
| Wind | 5 - 40% | 2,000 | 19% |
| Solar photovoltaic | 17 – 68% | 500 | 25% |
| | | | 35% |
| Solar thermal, parabolic trough | 5 – 32% | 500 | 15% |
| Solar thermal, power tower | 5 – 20% | 500 | 20% |
| Geothermal | | | |
| Small hydro | 5% | | 5% |
| Tidal | 5% | | 5% |
| Supercritical coal | 3 – 7% | 3,072 | 4% |
| Integrated gasification combined cycle | | | |
| Fluidised bed combustion | | | |
| Natural gas combined cycle | 4 – 7% | 3,773 | 5% |
| Advanced water reactors, nuclear | | | |

* The full range (from the minimum to maximum value we found in the literature) is reported in the second column. See Appendix 1 of the SBT3 document for all the values.

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[7] Participants were Mandy Rhambaros (Eskom), Richard Worthington (SECCP), Jason Schäffler (Nano Energy), Mary Haw, Harald Winkler (ERC).

It will be noted that gaps exist for some new technologies. Information from stakeholder would be welcome, based on peer-review literature and / or rates used in official plans developed with stakeholder participation (e.g. IEP, NIRP, etc).

Carbon capture and storage (CCS) costs can also be expected to benefit from learning. Given our energy economy's dependence on coal, CCS needs to be considered as a mitigation option. However, CCS is not an electricity-generating technology and hence not listed above. The costs of CCS are added to the costs of power plants. Estimates of future costs as assessed by the IPCC from the international literature (IPCC 2005b) will be used in considering CCS as a mitigation option, together with initial work on CCS in South Africa (Engelbrecht *et al.* 2004; Mwakasonda & Winkler 2005). As with any other technology, its impacts on local sustainable development should be carefully assessed.

The approach to learning for the PBMR differs in that production is primarily national (although China is also developing a PBMR-like reactor). The reference plan for NIRP 2 indicated that the first greenfield PBMR (base) would be built 'earliest end 2013' (NER 2004: 6). With a first unit in 2013, the cost reductions might begin in 2014. NIRP 2 explicitly indicates that technology learning is taken into account – 'after several multi-modules have been deployed, a cheaper multi-module' (NER 2004: 26). Appendix 3.7 further indicates that '70% of the potential cost improvement may be realised by the 3rd eight-pack station' (p.22). The costs of the first multi-module (excluding transmission benefits) are given as R 18 707 / per installed kW. Costs for the later 'series' multi-module are given at R 10 761 / kW (NER 2004: 28, Table 8). We further assume that the 32 modules would be built over a period of 12 years, i.e. completed by 2025.

The SBT adopted the approach to technology learning, the rates in Table 11 and the above approach to PBMR costs, on the basis of the work by the working group (see also Figure 5 in Appendix 1 of the SBT3 document). On the PBMR costs, it was accepted that a range of costs need to be considered and therefore a scenario should also look at other costs based on the closest equivalent technology.

## 3.5 Exchange rate forecasting

South Africa's exchange rate has been volatile in the recent past. Appendix 4 of the SBT3 document showed the year-on-year inflation differential between South Africa and the advanced economies, as well as the average annual depreciation or appreciation of the rand (a negative figure indicates an appreciation). South Africa follows a flexible exchange rate regime, which allows exchange rates to be determined by the supply and demand for the currency.

These factors, together with expectations of investors, make it difficult to predict future exchange rates. One approach is to use inflation differentials. The inflation rate of South Africa has been significantly higher than that of the developing world during the past 35 years.

In future, South Africa's inflation rate can therefore reasonably be expected to remain stable at fairly low levels, with many believing that inflation targeting will be successful in maintaining levels of between 4 and 5% per annum. At the same time, however, given the large degree of income inequality and skills shortages in the South African economy we are also unlikely to see the inflation rate dropping to lower levels comparable to that of industrialised countries. The inflation rate in the industrialised or OECD countries is likely to be around 2% per annum in the foreseeable future. This implies an inflation differential of between 2 and 3% in the long run between South Africa and the industrialised countries, many of which are our trading partners (personal communication, George Kershoff, Bureau of Economic Research, University of Stellenbosch). Following historical trends it is therefore likely that the South African exchange rate will continue its steady decline in value, although not at the relatively high rate of around 6.4% seen in the past 35 years. An annual depreciation rate of around 2 to 3% per annum is probably an accurate prediction for the long term future (see Appendix 4 of the SBT3 document for a more detailed discussion).

Based on the literature reviewed by the macro-economic team, the exchange rate will increase at 2% (and following Rod Crompton's suggestion at SBT2, but no need to average). Exchange rate will only apply to imported capital equipment; currently, this is being applied for power plants, refineries and imported fuels, which are quoted in US dollars. It could be applied to major industrial equipment as well, if data were made available by stakeholders, but the intention is not to apply these to small appliances.

The strength or weakness of the South African rand compared to international currencies is another factor that can influence model outputs. Since the investment costs of most power stations as well as imported fuels such as crude oil are quoted in US dollars, the fluctuating rand-dollar exchange rate can have a large influence on the model results and the total costs of certain scenarios. The exchange rate is a highly volatile factor and very difficult to predict. For this study an assumed exchange rate of R7.50 to the US dollar in 2003 was agreed upon. To follow recent trends of increased exchange rates, a 2% increase per year is assumed (Pauw 2006). Table 12 shows the projected exchange rate of the South African rand to the US dollar from 2003 to 2050.

**Table 12: Projected rand-dollar exchange rate over the study period**

| | |
|---|---|
| 2003 | R 7.50 |
| 2005 | R 7.80 |
| 2010 | R 8.62 |
| 2015 | R 9.51 |
| 2020 | R 10.50 |
| 2025 | R 11.59 |
| 2030 | R 12.80 |
| 2035 | R 14.13 |
| 2040 | R 15.61 |
| 2045 | R 17.23 |
| 2050 | R 19.02 |

The energy model is structured in such a way that sensitivity analyses can be run on exchange rate values.

## 3.6 Future energy prices

Predicting future fuel prices is virtually impossible and different theories come up with very different results. The only thing that is certain is that whatever prediction one makes, it will almost definitely not be the real price in future. Yet to model mitigation actions and scenarios, some assumptions must be made.

Prices are reported in R / GJ in Appendix 3 of the SBT3 document.

### 3.6.1 Oil prices

Liquid fuels constitute the largest end use of energy in South Africa. Predicting future prices of these fuels is a key parameter. Background to oil, gas and coal prices are described more fully in Appendix 5 of the SBT3 document. Projections for the crude oil price have been adjusted upward by the IEA, OECD and EIA respectively. The oil price in 2003 was on average $30 per barrel (EIA 2006), but it increased sharply in 2004-5. Even though the oil price for 2030 is lower than current levels, all major projections suggest these levels.

The possibility of a second synthetic fuel plant will be included in the modeling. It can be included either in Current development plans or Growth without constraints.

→ For the reference case, we project oil prices from $30 per barrel in the base year (2003) to $ 97 / bbl in nominal terms ($55 / bbl in real terms) (in 2030), and extrapolated at the same rate beyond.

### 3.6.2 Gas prices

Prices rise from around R28 per GJ in 2003 to R140 per GJ in 2030 (IEA 2006) (R46 / GJ in real terms, or $6.5 / MBtu). After 2030, we assume that the increase continues at the same rate as 2003-2030.

### 3.6.3 Coal prices

As agreed at SBT2, the domestic coal price for electricity generation is higher at R 6 / GJ, than in previous studies (about R 3 / GJ). Domestic coal prices are expected to increase, as it is believed that as resources become more difficult to extract. Hence this assumes a higher coal price for coal than previous work. Beyond that, coal may increase further in prices, according to Ernst Venter of Kumba, as it is likely that during the next few decades, coal could be in much shorter supply.[8]

Prices rise from around R 3 / GJ in 2003 and then rise to R6 per GJ, in 2030 after which they increase further.

## 3.7 Emission factors

The study generally uses IPCC default emission factors. In the energy model, emission factors are placed on the primary energy carriers at the point where the fuel is combusted. For example emissions from petrol are placed on the petrol going into a vehicle and not on the crude oil going into a refinery. Excess emissions from the refining process itself, are placed on the refinery. Coal being burnt in power stations has emissions factors associated with it, but electricity does not have emission factors.

Emission factors are needed to convert energy consumption (in energy units, PJ or GJ) to emissions. The Intergovernmental Panel on Climate Change (IPCC) default emission factors (in tC / TJ, or t $CO_2$ / TJ) were used for emissions of $CO_2$, $CH_4$, $N_2O$, $NO_x$, CO, NMVOC and $SO_2$ (IPCC 1996: Tables 1-2, 1-7, 1-8, 1-9, 1-10, 1-11 and 1-12 respectively). Following IPCC methodology, local emission factors or adjustments to defaults based on local conditions were made.

For carbon dioxide from other bituminous coal, 26.25 tC/TJ was used instead of the IPCC default of 25.8 tC/TJ. This adjustment is based on direct measurements at a South African coal-fired power station (Lloyd & Trikam 2004). The higher emissions are consistent with the lower calorific value of South African sub-bituminous coal at 19.59MJ/kg, whereas the IPCC default value is for 25.09 MJ/kg coal. Further measurements at more stations in future may lead to a submission of a South Africa-specific emission factor to the IPCC. The above list already includes important local air pollutants ($SO_2$, $NO_x$, and NMVOC), but not particulate matter.

At the time of the study, biofuels do not have emissions associated with them in the model since they are regarded as carbon neutral. Taking into account up- and down-stream emissions, biofuel production may show in some cases that biofuels have substantial emissions (Von Blottnitz & Curran in press). This is supported by American studies for ethanol on maize that show a positive-carbon balanc

# 4. Constraints

## 4.1 Constraints in energy modeling

At SBT4, stakeholders requested further information on constraints, noting that constraints were of various kinds. References was made to a number of different *kinds* of constraints – physical constraints, constraints on resource availability (e.g. coal, uranium, helium, water, land and others). The energy modeling team noted that even in ‘Growth without Constraints’, there are constraints reflecting, for example, fuel shares for meeting a particular energy demand, or penetration rates of different technologies.

This section provides further information on constraints in energy modeling. The constraints included are resource constraints, ‘build’ constraints and so-called ‘activity ratios’.

Resource constraints are applied where there is a limit on the availability of a resource. In Markal, these are typically applied as upper, fixed or lower bounds on technologies using a resource (BOUND(BD) in Markalese). The bounds are shown in Table 13.

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[8] Presentation at Fossil Fuel Foundation indaba, October 2006.

**Table 13: Upper, fixed and lower bounds on technologies using energy resources**

| *Unit: GW (total capacity that can be built)* | *Type of bound* | *2003* | *2005* | *2015* | *2025* | *2035* | *2050* |
|---|---|---|---|---|---|---|---|
| Bagasse co-gen station new 1 | UP | 0.1130 | 0.1130 | 0.1130 | 0.1130 | 0.1130 | 0.1130 |
| New CCGT | UP | 3.8700 | 3.8700 | 3.8700 | 3.8700 | 3.8700 | 3.8700 |
| New FBC station | UP | 11.1840 | 11.1840 | 11.1840 | 11.1840 | 11.1840 | 11.1840 |
| New OCGT natural gas | UP | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Interutible supply | UP | 1.5100 | 1.5100 | 0.3840 | 0.3840 | 0.3840 | 0.3840 |
| Landfill gas electricity generation large installations | UP | 0.0040 | 0.0040 | 0.0040 | 0.0040 | 0.0040 | 0.0040 |
| Landfill gas electricity generation medium installations | UP | 0.0270 | 0.0270 | 0.0270 | 0.0270 | 0.0270 | 0.0270 |
| Landfill gas electricity generation micro installations | UP | 0.0230 | 0.0230 | 0.0230 | 0.0230 | 0.0230 | 0.0230 |
| Landfill gas electricity generation small installations | UP | 0.0200 | 0.0200 | 0.0200 | 0.0200 | 0.0200 | 0.0200 |
| New PBMR station | UP | 1.9800 | 1.9800 | 1.9800 | 1.9800 | 1.9800 | 1.9800 |
| New PF station with FGD | UP | 40.0000 | 40.0000 | 40.0000 | 40.0000 | 40.0000 | 40.0000 |
| Camden PF station | UP | 1.5200 | 1.5200 | 1.5200 | 1.5200 | 1.5200 | 0.0000 |
| Grootvlei PF station | UP | 1.1280 | 1.1280 | 1.1280 | 1.1280 | 1.1280 | 0.0000 |
| Komati A PF station | UP | 0.4350 | 0.4350 | 0.4350 | 0.4350 | 0.4350 | 0.0000 |
| Komati B PF station | UP | 0.4560 | 0.4560 | 0.4560 | 0.4560 | 0.4560 | 0.0000 |
| New Braamhoek pumped storage plant | UP | 1.3320 | 1.3320 | 1.3320 | 1.3320 | 1.3320 | 1.3320 |
| New generic pumped storage plant | UP | 0.9990 | 0.9990 | 0.9990 | 0.9990 | 0.9990 | 0.9990 |
| New PWR station | UP | 15.0000 | 15.0000 | 15.0000 | 15.0000 | 15.0000 | 15.0000 |
| Wind turbine 20% load factor | UP | 0.0000 | 0.0000 | 1.9250 | 5.7750 | 7.7000 | 7.7000 |
| Wind turbine 25% load factor | UP | 0.0033 | 0.0033 | 1.9275 | 5.7758 | 7.7000 | 7.7000 |
| New Integrated Gasification Combined Cycle | UP | | | | | | |
| New CCGT at Coega | UP | 3.6000 | 3.6000 | 3.6000 | 3.6000 | 3.6000 | 3.6000 |
| New CCGT at New Castle, KZN | UP | 0.0150 | 0.0150 | 0.0150 | 0.0150 | 0.0150 | 0.0150 |
| New Super Critical coal with FGD | UP | 40.0000 | 40.0000 | 40.0000 | 40.0000 | 40.0000 | 40.0000 |
| OCGT in Atlantis - under construction | FX | 0.0000 | 0.0000 | 0.6160 | 0.6160 | 0.6160 | 0.6160 |
| OCGT in Mossel Bay - under construction | FX | 0.0000 | 0.0000 | 0.4530 | 0.4530 | 0.4530 | 0.4530 |

Build constraints might apply even if the energy resource is available, technology might not be able to be built. International supply constraints on delivering technologies have been mentioned in this regard, or the human and institutional capacity might limit the ability to build more than a certain amount per year. Table 14 shows the constraints for building of power stations applied in GWC.

**Table 14: Build constraints (IBOUND(BD)) on power stations**

| *Unit: GW ( capacity built /yr)* | | *2003* | *2005* | *2015* | *2025* | *2035* | *2050* |
|---|---|---|---|---|---|---|---|
| Camden PF station | UP | 0.3800 | 0.3800 | 0.3800 | 0.3800 | 0.3800 | 0.3800 |
| Grootvlei PF station | UP | 0.5650 | 0.5650 | 0.5650 | 0.5650 | 0.5650 | 0.5650 |
| Komati A PF station | UP | 0.3030 | 0.3030 | 0.3030 | 0.3030 | 0.3030 | 0.3030 |
| Komati B PF station | UP | 0.3030 | 0.3030 | 0.3030 | 0.3030 | 0.3030 | 0.3030 |
| New Braamhoek pumped storage plant | UP | 0.9990 | 0.9990 | 0.9990 | 0.9990 | 0.9990 | 0.9990 |
| Solar thermal parabolic trough | UP | 1 | 1 | 1 | 1 | 1 | 1 |
| Solar thermal power tower | UP | 1 | 1 | 1 | 1 | 1 | 1 |
| New integrated gasification combined cycle | UP | 0 | 0 | 1.13 | 1.88 | 2.25 | 2.25 |
| New super critical coal with FGD | UP | 0.0000 | 0.0000 | 2.2500 | 3.7500 | 4.5000 | 4.5000 |
| New PWR station | UP | 0.0000 | 0.0000 | 0.8500 | 1.5500 | 1.9000 | 1.9000 |

There is a build bound on new CTL plants in GWC, of 26 PJ per year.

The year in which new technologies can start can be thought of as a constraint as well. Starting dates for power plants are entered in the energy model, based on the lead times agreed as part of the table of characteristics of new electricity generation technologies (Table 8 of the appendix). The earliest starting dates for refineries are showing in the following list; the technology may come in later, so years shown are the earliest possible:

- bioethanol refinery - existing/under construction; 2007;
- crude oil refinery, new generic 300 000 b/d; 2012;
- crude oil refinery, new petrol-intensive 300 000 b/d; 2020;
- crude oil refinery, new diesel-intensive 300 000 b/d; 2020;
- LNG regassification plant; 2008;
- new bio-diesel refinery; 2007;
- new bioethanol refinery; 2008;
- new small bio-diesel refinery; 2007;
- Sasol CTL - new; 2014.

A range of other factors are ‘constrained’ in energy modeling. Markal itself solves for the least-cost solution subject to a number of built-in constraints, e.g. energy supply meeting demand, maintaining reserve margin, etc. In addition, the user can define additional constraints, so-called Adratios. The most commonly used of these are RAT_ACTs, which define the relationship of an activity to other specified paramaters. For example, if the energy demand for lighting in residential households can be met by incandescents, CFLs, candles, and paraffin lights, the relevant RAT_ACT is defined to match penetration rates - the share of demand met by different technologies and hence from different energy sources. Observed patterns of fuel use (in this example for different household types) is used as a starting point. These ratios can be kept fixed (if there is no reason to expect that they would change). To allow fuel-switching in policy cases, RAT_ACTs are defined with upper and lower bounds, so that the shares can change over time. The set of RAT_ACTs is too large to reflect in a table here, but a complete dump from the Markal model is available on request.

## 4.2 Availability of water

#### *4.2.1.1 Water constraints on new coal-to-liquid plants*

Sasol currently has two plants receiving water from the Integrated Vaal River System. The Sasol Secunda Complex’s primary source of water is Grootdraai Dam, which will be supported through the Vaal River Eastern Sub-system Augmentation Project in 2008. The Sasol Sasolburg Complex is supplied from Vaal Dam, which is supported from the Thukela-Vaal Transfer Scheme, as well as the Lesotho Highlands Water Project. The water requirements for the two complexes are presented in the following table for the indicated years of the DWAF planning period (DWAF 2006).

**Table 15: Sasol's water requirements**
*Source: (DWAF 2006)*

| | ***Water requirements (million $m^3$ / annum)*** | | | | | |
|---|---|---|---|---|---|---|
| | ***2006*** | ***2010*** | ***2015*** | ***2020*** | ***2025*** | ***2030*** |
| Sasol Secunda Complex | 92.0 | 91.3 | 107.8 | 112.1 | 117.2 | 123.1 |
| Sasol Sasolburg Complex | 26.4 | 28.9 | 32.3 | 35.5 | 38.9 | 42.7 |
| Total | 118.5 | 120.2 | 140.1 | 147.6 | 156.1 | 165.8 |

This projection by DWAF does not include any new plants from SASOL. According to Sasol the water requirement per new CTL of 80 000 bbl / d is approximately 40 million $m^3$ (Fraser 2007). The current allocation of 3000 million $m^3$ of water in the Vaal water system is fully allocated.

Under normal economic and population growth scenarios, the next augmentation to the Vaal water system from the Lesotho Highlands Transfer scheme is planned for around 2020. The feasibility study is due for completion by December 2007. This would be followed by a transfer scheme from the Thukela in 2035. It is envisaged that augmentation from the Umzimvubu would only be required in 2050. This will be a very costly scheme – estimated at two times that of the other two (van Rooyen 2007).

The system can accommodate 2 new CTLs by 2020 by implementing stringent DSM in the Vaal system. A major problem with this however, is that it will bring the system too close to its limits, leaving very little reserve margin. Given that a 12-15 year period from conception to commissioning is required, it is already unlikely that one of the augmentation schemes will be built before 2020 in time for additional Sasol plants (van Rooyen 2007).

In order to accommodate the additional 3 CTL's after 2020, the Thukela and Umzimvubu augmentations would need to be brought forward. This would increase the financial burden to DWAF in terms of their capital costs forecast to the order of tens of billions of Rands.

**Table 16: The present value costs and capacity**

| ***Scheme*** | ***Capacity*** | ***Estimated cost*** |
|---|---|---|
| Lesotho Highlands | ~460 million $m^3$<br>(DWAF 2006) | Study due in Dec 07. Possibly same magnitude as Thukela. |
| Thukela<br>(KZN) | 450 million $m^3$<br>(DWAF 2001) | R 5 billion (1998)<br>(DWAF 2001) |
| Umzimvubu<br>(E-Cape) | 630-1260 million $m^3$ (a portion of this would be needed for agriculture in Transkei) (van Rooyen 2007) | ¬ R17 - 32billion (2006)<br>(Rademeyer 2007) |

Other options to bring new water into Vaal system could include:

- desalination from Richard's Bay, pumped up to Vaal River;
- reallocation of water use, although this is unlikely to happen before the augmentation of the Lesotho Highlands or Thukela options since the Agricultural lobby is unlikely to give up its allocation;
- use of return flows in the Vaal system is already taking place.

DWAF have recently completed the first stage reconciliation strategy for the Vaal River system and are currently working on the second phase study which will incorporate updated water requirements from the bulk users, Eskom and Sasol.

#### *4.2.1.2 Water for coal power stations*

Eskom currently operates 12 coal fired electrical power stations, which receive water from the Integrated Vaal River System. Some of these stations were decommissioned and are now being de-mothballed to increase supply in response to the growing demand for electrical power to fuel the South African economy. There are also plans to develop three new power stations, envisaged to receive water from the Vaal River System. Two are scheduled to receive water from Vaal Dam, and current planning is that the third will be located close to the existing Kendal Power Station and receive water from the Eastern Vaal River Sub-system (a component of the Integrated Vaal River System). The table below provides a summary of the water requirements and lists all the power stations, their primary water source, as well as the projection of water requirements for the indicated years of the DWAF planning period (DWAF 2006).

The DWAF projections do not include any new plants envisaged under the LTMS. Additional plants would have a less significant impact if they are dry cooled, i.e. they would add less than 4 million $m^3$ per annum per new dry-cooled station to the total of about 400 million $m^3$.

**Table 17: Eskom's water requirements**
*Source: (DWAF 2006)*

| ***Power station*** | ***Primary water source*** | ***Water requirements (million $m^3$ / annum)*** | | | | | |
|---|---|---|---|---|---|---|---|
| | | ***2006*** | ***2010*** | ***2015*** | ***2020*** | ***2025*** | ***2030*** |
| Hendrina | Komati sub-system | 31.0 | 32.4 | 33.0 | 32.7 | 32.7 | 32.7 |
| Arnot | | 29.4 | 33.4 | 36.1 | 36.5 | 36.6 | 36.6 |
| Duvha | | 50.8 | 50.4 | 51.6 | 52.2 | 52.2 | 52.2 |
| Komati | | 2.6 | 5.6 | 9.9 | 8.3 | 8.4 | 8.4 |
| Kriel | Usutu sub-system | 38.8 | 40.7 | 43.5 | 43.2 | 43.5 | 43.5 |
| Matla | | 51.5 | 53.6 | 51.6 | 54.3 | 54.3 | 54.3 |
| Kendel | | 3.2 | 3.3 | 3.4 | 3.4 | 3.4 | 3.4 |
| Camden | | 5.5 | 19.2 | 23.2 | 23.2 | 23.2 | 23.2 |
| New coal-fired 1 | | 0.0 | 0.6 | 2.9 | 3.7 | 3.7 | 3.7 |
| Majuba | Zaaihoek sub-system | 19.2 | 25.6 | 25.6 | 24.1 | 24.1 | 24.1 |
| Tutuka | Grootdraai sub-system | 34.5 | 46.2 | 44.3 | 48.8 | 48.8 | 48.8 |
| Grootvlei | Vaal dam | 0.8 | 6.1 | 10.4 | 10.1 | 10.1 | 10.1 |
| Lethabo | | 45.5 | 46.6 | 49.4 | 50.1 | 50.1 | 50.1 |
| New coal-fired 2 | | 0.0 | 0.0 | 0.6 | 3.0 | 3.0 | 3.0 |
| New coal-fired 3 | | 0.0 | 0.0 | 0.0 | 2.6 | 3.0 | 3.0 |
| Total | | 312.9 | 361.7 | 387.5 | 396.3 | 397.2 | 397.2 |

# 5. Description of mitigation actions

Mitigation actions were considered by SBT3 in three categories – energy supply, energy use and non-energy emissions. Each of these includes sub-sectors. Energy modeling considered energy supply (notably electricity generation and liquid fuels), as well as energy use in major economic sectors – industry, transport, commercial, residential and agricultural sectors. The CSIR considered non-energy emissions in agriculture, waste and land use, land use change and forestry (LULUCF). Industrial process emissions were considered by Gerrit Kornelius of AirShed, focusing on synfuels production, coal mining, iron and steel, ferro-alloy production, alumium and cement.

The notion of 'wedges' was developed by Pacala and Socolow (2004) to show that a range of existing technologies could deliver 1 GtC in emission reductions over the next 25 years. The challenge was to scale up technologies, provide policy guidance and channel investment. Wedges in the LTMS context mean emission reductions over time. If the reduction increase over time, the graphs have the shape of a wedge. Mitigation actions and the resultant wedges are used somewhat interchangeably in this report.

**Error! Reference source not found.** provides a brief description of the mitigation actions modelled, including key model parameters, time-frames, goals (e.g. penetration rates, extent of action) for the reference and mitigation cases. Below, we describe in more detail the parameters for each mitigation action. Results for the modelling are described in detail in sections **Error! Reference source not found.** to **Error! Reference source not found.**.

### 5.1.1 Energy efficiency in the commercial sector

In the commercial sector, a number of energy efficient technologies are available to replace older demand technologies or reduce their energy consumption. These technologies include energy efficient HVAC systems, heat pumps, variable speed drives, efficient motors and efficient boilers. In the scenario these technologies are introduced in 2008, i.e in the first year that government is expecting to implement awareness campaigns under the energy strategy. The exception is efficient lighting options such as CFL's which are introduced prior to 2008. This is done because attempts to improve lighting efficiency through the use of CFL's and electronic ballasts have already begun through demand side management campaigns.

There is large scope to improve the energy efficiency of commercial buildings in South Africa, for example the Nedbank building in Cape Town has managed to achieve a reduction in energy intensity of 65% below that of other similar buildings through design.

The standards, retrofits and other management actions implemented to improve the energy efficiency of the commercial sector impact on either the useful energy intensity of demand or the energy efficiency of the technology meeting the demand. Building thermal design, or design measures that reduce lighting demand will have an impact on energy intensity and will reduce the useful energy demand to be met by HVAC systems, heating systems and lighting. These improvements to useful energy intensity by lighting and thermal design standards are restricted to new buildings in the scenario. Retrofits to the lighting systems or HVAC systems in existing buildings and are included as an improvement in energy efficiency.

New technologies are given an investment bound which restricts the investment in new capacity of the technology each year. This is done so that their use is gradually increased during the planning period. In this way a more realistic policy impact is modelled.

Assumptions are made around the payback period for energy efficiency measures and the marginal cost of the electricity saved. From these assumptions, we calculate an investment cost for the efficiency measure.

Another important aspect of commercial efficiency is the thermal performance of buildings. Assumptions are made about the potential improvement in efficiency of new buildings should building standards be introduced. Certain measures can also be applied to older buildings as retrofits.

***HVAC systems***

HVAC retrofits to more efficient HVAC systems and the improvement of the energy efficiency of HVAC systems is allowed in both existing and new buildings. The savings are assumed to result from audits and other awareness campaigns. The efficiency of HVAC systems can be improved through the use of variable speed drives (VSD's) on fans, retrofitting HVAC systems and using alternative HVAC systems such as heat pumps or central air conditioning units that have a higher coefficient of performance (COP).

It is assumed that variable speed drives can improve the efficiency of HVAC systems by 15% and that this efficiency improvement is applicable to 12.5% of building floor space.

HVAC retrofits to HVAC systems in old buildings are allowed in one third of all buildings and can improve energy efficiency by an average of 35%. Generally these improvements are easy to implement and are assumed to have a payback period of five years.

Efficient HVAC systems in new buildings are allowed in one third of buildings in 2015, and the efficiency of the system can improve by an average 42.5%. A payback period of 5 years is assumed for these measures.

Heat pumps and central air conditioners are allowed to meet a greater portion of demand after 2008. The portion of demand that they can meet is increased 5% between 2008 and 2015 and a further 6% by 2030. This assumes that all new buildings will have the option of using either a heat pump or central air conditioner to met their cooling needs.

#### *Thermal design*

It is assumed that building standards aimed at improving the thermal design of buildings could reduce the useful energy demand for cooling by an average 40%. The standards and thus improvement in useful energy demand apply to new buildings only.

It is assumed that the 40% savings in demand for cooling can be achieved in 50% of new buildings each year and a further 30% savings can be achieved in 40% of buildings. The savings are introduced into new buildings from 2008 onwards.

#### Efficient lighting

Retrofits and a move towards CFL's improve the energy efficiency of lighting in existing buildings. Standards reduce the useful energy demand for lighting in new buildings. Eskom DSM campaigns targeting lighting have been very successful and are achieving significant savings. These campaigns include the subsidy of the sale of electronic ballasts which have effectively eliminated the sale of magnetic ballasts. When electronic ballasts replace magnetic ballasts, there is a saving of 20%.

It is assumed that lighting demand in existing buildings can be improved in two ways. Either magnetic ballasts are replaced with electronic ballasts achieving a savings of 20%, or the entire lighting system will be retrofitted achieving a saving of 40%. Again this is a conservative saving, retrofitted commercial buildings such as Plein Street in Cape Town recorded savings as high as 60%.

In existing buildings savings of 20% through the replacing of magnetic with electronic ballasts are allowed in 50% of buildings, a further 40% saving through the complete retrofit is allowed in 20% of buildings by 2015. The assumed payback periods for the lighting retrofit is 4 years, ballasts are replaced with electronic ballasts as they fail at no additional cost.

CFL's are allowed to replace 3.3% of demand for incandescent lighting in 2015 and 6% of demand for incandescent lighting by 2030.

In new buildings it is assumed that improved design will reduce demand by 60% in 40% of buildings and 30% in a further 40% of buildings.

#### Water heating

Water heating efficiency is improved through the increased use of solar water heaters and heat pumps to meet demand. Both technologies can meet up to 10% of demand in new buildings in 2015 and 20% of demand in 2030

#### *Other appliances*

The energy required by new electrical appliances or equipment such as computers and fridges is assumed to reduce over time. These improvements in energy efficiency rely on design improvements to technologies. Other savings are the result of behaviour changes and rely on successful awareness campaigns or training. It is assumed that 25% of appliance demand can increase 15% in efficiency and a further 25% can achieve a 30% increase in efficiency. These measures are assumed to have a one year payback.

### 5.1.2 Energy efficiency in the Industrial sector

The industrial sector is a sector which promises great opportunities for improving energy efficiency. In this sector improvements in energy efficiency are likely through improved lighting efficiency, compressed air efficiency, motor efficiency, thermal efficiency, steam system efficiency and HVAC efficiency. These are standard measures and are all easily implemented.

For each end use demand in industry such as boiler fuels, compressed air, etc, an assumption is made about how much energy can be saved through efficiency measures. These assumptions are based on currently available technology and studies on industrial efficiency potential (Howells et al 2003).

Efficiency measures in the industrial sector are introduced in 2008 and continue to improve until 2030. They are assumed to be driven by awareness campaigns, auditing of industrial facilities, and the implementation of standards within the sector.

Savings for all processes reliant on electrical energy are presented below, in all cases the savings suggested are the average savings that could be achieved across all types of industries in the industrial subsectors.

***Thermal savings***
These savings are realised through savings in the steam system as well as improved efficiency in other areas. Savings in the steam system can be achieved through steam trap maintenance, improved boiler efficiency, isolating steam from unused lines, repairing steam leaks, optimising condensate return, minimising vented steam and a number of other measures. The focus here is on improving the efficiency of the steam system and boiler and not on improving the efficiency of the end use process. It is estimated a 20% improvement in steam system efficiency could be achieved. An average payback period of 1.4 years is assumed for the basket of measures.

***Compressed air savings***
Compressed air savings can be realised at the compressors as well as the ducting system. Fixing leaks in compressed air pipes and closing pipes that are not needed and reducing elbows, all result in savings that can be achieved in the piping system with minimal capital expense. Sequencing compressors to meet demand so that they run at full load or using more compressors of smaller size, as well as using cool intake air and waste heat recovery are all ways in which savings can be made at the compressors at a low cost. Typically these savings have a payback period of less than a year. We estimate the payback period for compressed air savings to be 11 months and that a saving of 20% is achievable.

***Efficient lighting***
Lighting efficiency can be improved by switching to more efficient lamps and fixtures, this includes replacing magnetic ballasts with electronic ballasts and improved lighting design. Experience through DSM lighting programmes in South Africa has shown that between 30 and 60% savings in lighting in factories are achievable. Additional savings can be achieved by making use of daylight through sky lighting, or using sensors to switch lights off in areas where they are not needed continuously. It is estimated that an average 40% savings could be achieved and that the average payback period is 3.6 years.

***Efficient motors***
Motor savings can be achieved through the correct sizing of motors and the use of high efficiency motors. A payback period of 6 years is estimated for these measures along with a saving of 5%.

***Variable speed drives***
Variable speed drives, also called variable frequency drives achieve savings by regulating the speed of the motor. Variable speed drives can achieve savings of between 5 and 10% depending on the application. The largest savings are generally realised for fans and pumps where the input power varies with the cube of the pump or fan speed. The assumed payback period for variable speed drives is 7 years

Industrial measures are allowed a penetration rate of between 2% and 7% each year, ie 2-7% of demand is assumed to improve in efficiency each year. This penetration rate is based on anticipated success of audits and awareness campaigns, but it should be noted that without significant effort on the part of government it is likely that this penetration rate will be achieved (Howells et al, 2003).

### 5.1.3 Energy efficiency in the residential sector

In the residential sector, savings are achieved by allowing households to switch to more efficient appliances and fuels. The target for final energy demand reduction by 2015 in the residential sector is 10%. In order to reach this target, fairly significant changes need to take place in the early part of the time period. The following measures are the most important measures taken in the residential case to achieve the savings.

***Basa Njengo Magogo***

An improved method of using coal braziers known as the 'Basa Njengo Magogo' method shows an increase in efficiency of 37.5%. This method of cooking which is simple and requires no additional or alternative appliances is part of a DME programme to reduce local air pollutants in low-income areas. The combustion of fuel is more efficient in the 'Basa Njengo Magogo' method of cooking as the fire is lit from the top of the Briazier and burns slowly down, in the traditional method of cooking the fire is lit at the bottom of the stove. Major advantages include reduced particulate emission, ease of ignition and reduction of coal required by 17%. This coal saving equates to 1kg per use and, at a cost of approximately R1 per kilogram of coal, this translates to a saving of R30 per month (Le Roux et al 2005).

In the base case (or growth without constraint), it is assumed that the Basa Njenga Magogo method is used in up to 3% of households in 2015 and 7% in 2030. In the reference case it is assumed that in Urban Low-income Electrified and Non-electrified households up to 20% of coal braziers shift to the Basa Njenga Magogo method by 2015 and 40% by 2030 for space heating and cooking. These upper bounds on penetration rates are based on assumptions about the effectiveness of government programs to reach households and convince them to shift to the new method.

***Solar water heaters***

Solar water heaters (SWHs) are gaining popularity with cities such as Cape Town considering policies to make Solar water heaters on new homes a by-law. In the residential reference case, we allow high penetration rates of Solar water heaters, Table 18 shows the assumed penetration rates of solar water heaters into new houses. A much lower rate is assumed for old houses.

**Table 18: Assumed rates of adoption of solar water heaters by household type**

| | ***2008*** | ***2015*** | ***2030*** | ***2050*** |
|---|---|---|---|---|
| ***New houses*** | | | | |
| Rural rich electrified | 1% | 25% | 60% | 65% |
| Rural poor electrified | 1% | 25% | 60% | 65% |
| Rural poor unelectrified | 1% | 5% | 10% | 20% |
| Urban rich electrified | 1% | 50% | 75% | 75% |
| Urban poor electrified | 1% | 55% | 80% | 80% |
| Urban poor unelectrified | 1% | 7% | 15% | 20% |
| ***Old houses*** | | | | |
| Rural rich electrified | 1% | 8% | 10% | 15% |
| Rural poor electrified | 0% | 2% | 5% | 7% |
| Rural poor unelectrified | 0% | 0.5% | 2% | 4% |
| Urban rich electrified | 1% | 5% | 10% | 20% |
| Urban poor electrified | 1% | 2% | 6% | 10% |
| Urban poor unelectrified | 0% | 0% | 0% | 0% |

***Geyser blankets***

Geyser blankets are another efficient water heating technology to be implemented in this scenario. We assume a high penetration rate of approximately 65% of electric geysers are insulated with a geyser blanket (or similarly effective insulation) by 2015 (Howells et al 2003). Geyser blankets achieve a 14.3% improvement in efficiency.

***Thermal efficiency of houses***

Thermal performance of buildings can be improved through addition of insulation, ceilings and general thermal efficiency building standards. In many low income households ceilings are omitted as a cost-saving mechanism however it greatly affects the thermal comfort and space heating requirements of the building. In this scenario we assume a high penetration of thermal efficiency in new buildings and a smaller penetration rate for old buildings where limited retrofit is possible and more costly. In new houses it is assumed that all new houses will have improved insulation. Of those, 50% will have significant winter heating requirement and the improved insulation will result in a 30% reduction in space heating requirements (Howells et al, 2003).

***Ethanol gel***

Ethanol gel fuel is a new replacement to paraffin for use in low-income houses for cooking and lighting. Advantages are mainly in safety (if knocked over, gel fuel stoves will not cause wide-spread fires as paraffin stoves do) and in reduced particulate emissions. The efficiency of these stoves is under investigation and while the calorific value of ethanol gel was thought to be similar to paraffin (23 MJ/kg for gel versus 25 MJ/kg for paraffin), recent studies have shown that the energy intensity of ethanol gel fuel is closer to 16 MJ/kg (Lloyd, 2007). Another drawback is that during tests, a large amount of water vapour collects at the bottom of the pot during cooking. This reduces the efficiency of the stove and lengthens the time required for cooking. The cost of the gel fuel could also prove prohibitive since five litres of gel fuel costs approximately R160 whereas the same amount of paraffin costs R50 (Makgetla, 2006). Nevertheless, users of the gel fuel stoves have commented that the clean burning fuel is more pleasant to use and easier to store and transfer than paraffin. And while costs are high, they claim that an amount of gel fuel that could last up to a month would only last a week if it were paraffin (Makgetla, 2006). It is interesting to note that the efficiencies of gel fuel stoves and paraffin stoves are not very different (0.41 versus 0.4) yet the calorific value of the fuels and resultant energy costs are very different.

Given the algorithms used by the model, gel fuel stoves would prove to be very unfavourable in a least-cost optimising scenario. In reality, it seems that gel fuel may have advantages over paraffin that the model cannot take into account: the safety aspect mentioned above and reduced evaporation rate. In the base case there is little to no penetration of gel fuel into the residential fuel mix, however in the reference case, the bounds on gel fuel are opened up, and the model is free to choose the least-cost option to meet demand.

***Lighting***

Lighting in the residential sector is another area in which significant savings are possible. Eskom has already initiated a massive roll-out of CFLs in the Western Cape to aid with the recent power shortages. In the base case, a very low penetration rate of CFLs is assumed: 5.3% in urban areas and 1.9% in rural areas. In the reference case this is increased dramatically to 40% by 2015 in urban areas and up to 35% in rural areas. The upper bound on penetration continues to increase to 60% and 50% by 2030 in urban and rural areas respectively. These rates remain constant to 2050.

For other water heating, cooking and space heating technologies, the upper and lower bounds are widened in the reference case, so as to give the model the freedom to choose most efficient fuel and technologies to meet demand.

### 5.1.4 Energy efficiency in transport

The overall target for final energy demand reduction in the transport sector by 2015 is 9%. In order to reach this goal a number of stringent policies or measures are introduced. The transport sector energy efficiency case is modelled with less freedom than the other efficiency cases. It is not believed that customers will choose more efficient vehicles without the introduction of policy or that the purchase or use of transport modes amongst the higher income groups is done with consideration to the cost.

In the base case, all new private passenger vehicles and light commercial vehicles increase in efficiency by 0.4% per annum. In the scenario this efficiency improvement is increased to 0.9% per annum, based on savings which have been achieved in the United Kingdom (An & Sauer 2004). In addition to this, vehicle occupancy is assumed to increase from 2.1 passengers per vehicle-km to 2.2 passengers per vehicle-km.

The taxi recapitalization plan is also included in this scenario. In the base case we have assumed a moderate increase in the number of diesel taxis introduced to the taxi fleet, and a significant impact is only made after 2015. The diesel taxis that form part of the programme are larger Midi bus vehicles that seat 19-35 passengers compared with the mini buses that seat 18 passengers or less and are designed for longer distances. In the scenario, the target is introduced sooner so that by 2015, 4.7% of taxis are diesel. This is increased further to 7.4% by 2030.

The number of private diesel cars also increases in comparison to the base case where an increase is only noticed after 2015. It increases further to 15% in 2030. The number of diesel passenger vehicles has increased dramatically over the past few years. While the base case does demonstrate this with an increase from 2.8% in 2001 to 5% in 2030 of private passenger-kilometres, this efficient transport scenario allows the model greater penetration of diesel vehicles. In this scenario diesel cars make up 15-30% of private passenger-kilometres by 2030.

Hybrid vehicles are included as an option for improved vehicle efficiency. Hybrid vehicles can make up 2% of passenger km by 2030. SUV use decreases compared to the base case where it is assumed to increase up to 2%. In the scenario the use of SUV’s is capped at 1% of private passenger-kilometres.

In addition, the use of public transport is allowed to increase. In the base case public transport is 51.2% of demand, in the scenario case public transport is allowed to grow by 25% above this.

The use of rail for freight is also increased. The base case assumes that 28.3% of tonne-km are transported by rail in 2015 and 32.3% in 2030. In this scenario, the use of rail for freight is allowed to increase to 44.6% in 2015 and 45.15% in 2030.

In this scenario the biofuels blends are increased to determine the effect this has on the cost and fuel mix of the country. The blend fractions are increased to 8% ethanol with petrol and 2% biodiesel with diesel in 2013. Thereafter the percentage of ethanol in petrol is taken up to an assumed maximum of 20% and biodiesel to a maximum of 5% in 2030. 20% ethanol is the maximum fuel blend for petrol cars before major modifications are required and the volume of ethanol required to achieve this blend could be produced in South Africa without impacting on food supply based on agricultural trends and land availabilities. It should be noted however that if we also produce biofuels for sale to other foreign countries, this may no longer be true.

Bioethanol is produced locally from maize in the scenario, biodiesel is produced from imported sunflower seeds, or other imported feedstock. The cost of feedstock as well as plant capacity is included in the scenario.

### 5.1.5 Renewable electricity

In this scenario we apply a minimum penetration of renewable technologies for electricity generation. The model parameters specify that 15% of electricity sent out in 2020 must come from renewable sources, and 27% by 2030 (around 443 PJ). Included in the renewable options to meet demand are hydro, wind, solar, biomass and landfill gas technologies. Imported hydro is restricted in this scenario to 15% of supply.

### 5.1.6 Nuclear

In this scenario the contribution of nuclear technologies to the supply of electricity is increased. The technologies considered are the pebble bed modular reactor and new pressurised water reactors similar to the ones in operation at Koeberg. Starting in 2015, nuclear energy supplies 27% of electricity demand by 2030 in this scenario.

### 5.1.7 Tax on $CO_2$

In a carbon restricted environment, in which countries agree to reduce their carbon emissions, carbon dioxide levels may be reduced by placing a tax on carbon dioxide emissions, thus giving a monetary value to ‘clean’ energy processes. In this scenario, an escalating tax is introduced on all $CO_2$ emissions from the energy. See results section 6.3.1 below for details.

# 6. Results for scenarios and mitigation actions

## 6.1 Envelope scenarios

### 6.1.1 Growth without Constraints (GWC)

This is the ‘no-mitigation’ scenario, in which there is growth without constraints (GWC). It would involve no change from current trends, not even implementing existing policy. This scenario is important for the negotiations, as it could represent a ‘maximum position’. By stating this higher-emission case, the substantial mitigation actions required to reach CDP would receive more acknowledgement.

Figure 9 shows upfront the result that emissions under GWC increase dramatically, increasing more than four-fold. Most of the GHG emissions continue to be associated with energy supply and use, with non-energy emissions (industrial processes, waste, agriculture and LULUCF) contributing roughly a fifth. GDP growth drives much of this increase, with more detailed reasons elaborated in the text below.

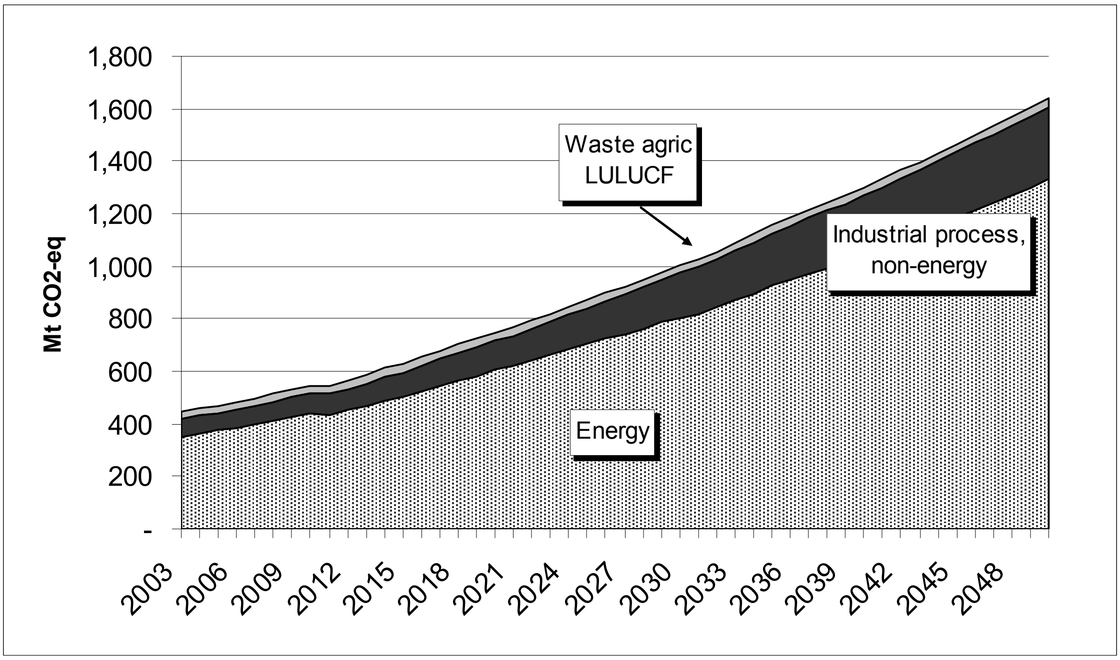


**Figure 9: Energy and non-energy emissions under Growth without Constraints, Mt $CO_2$ –eq**

**In the 'Growth without Constraints' scenario, energy demand grows mainly in the industry and transport sectors.** Total fuel consumption across all sectors increases more than five-fold, from 2365 PJ in 2003 to 11 915 PJ in 2050. Figure 10 shows that the growth in commercial, residential and agricultural fuel use are relatively small in comparison. The predominant fuels differ by sectors. About half of industrial fuel use comes from coal, with another third from electricity. Industrial process emissions grow particularly in synfuels and sectors such as iron & steel, cement and ferro-alloys. In 2050, the commercial sector uses electricity for 65% of its energy needs, with another fifth from coal. Fuel use in transport is dominated by petrol (55% in 2003, but 46% by 2050), diesel (31%; 30%) and jet fuel (12% increasing to 18%). The residential sector is well-known for its multiple fuel use, yet the electrification programme has resulted in 63% of fuel use using electricity as a carrier in 2003. This increases to 88% by 2050. Biomass (mostly fuelwood), paraffin and coal continue to be used, with solar energy not making a major contribution in this scenario.

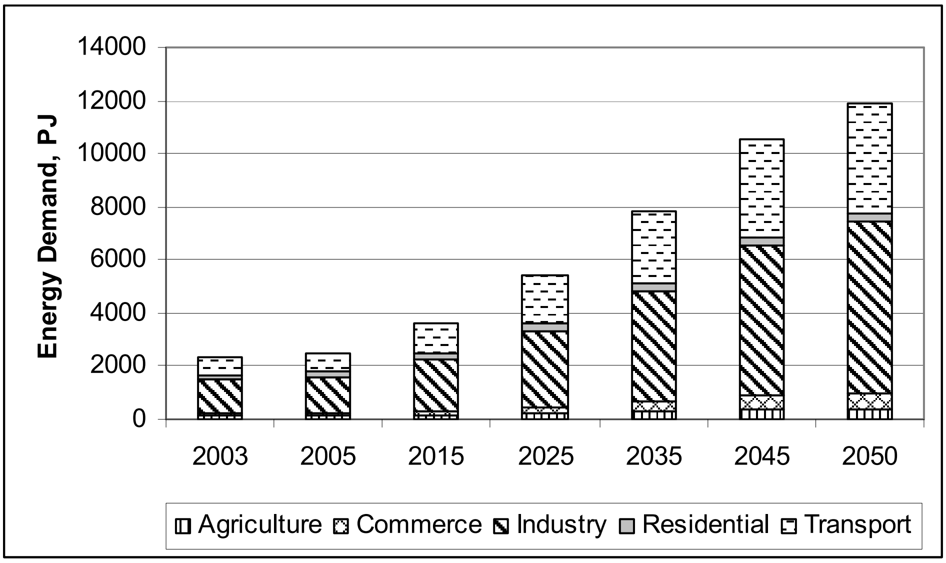


Figure 10: Fuel use by sector, all fuels (PJ)

In Growth without constraints, electricity continues to be generated overwhelmingly from coal and to a lesser extent nuclear power. As existing coal stations come to the end of their life-time, they are replaced with new coal stations. New pulverized fuel coal plants are all super-critical with a higher efficiency of 38% rising to 40% over time – no more sub-critical PF coal plants (34.5% efficiency) are built. IGCC plants are the predominant coal-fired technology, comprising 56% of capacity by 2050.

Figure 11 shows new supercritical coal start coming into the mix from 2016, with IGCC from 2020, together with some combined cycle gas turbines and PWR nuclear. The share of coal-fired electricity generating capacity stays over 75% for the period. The shares of coal and nuclear continues close to 90% until around 2050. CCGT reaches 3% capacity during the period.

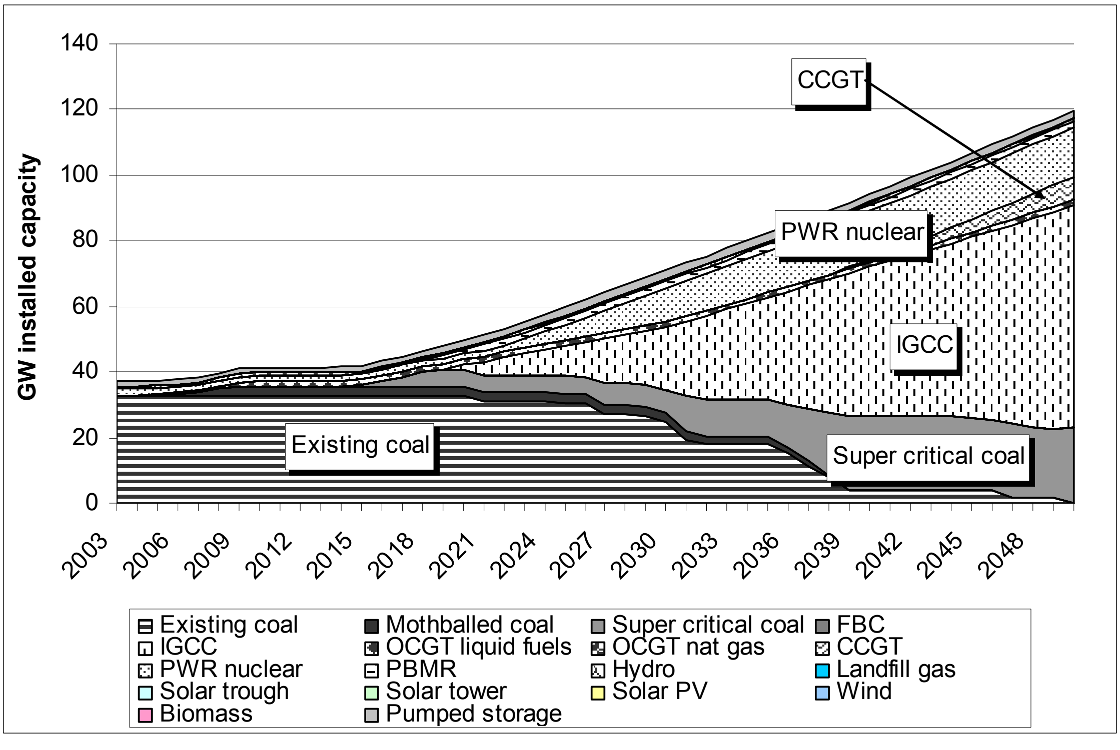


Figure 11: Electricity expansion plan in the GWC case, GW installed capacity 2003-2050

**Renewables remain limited to a small share of capacity, and do not enter the generation mix in a significant way in the GWC scenario.** Renewable energy technologies for electricity generation contribute less than a percent of installed capacity, declining from 2.18% of installed capacity in 2003 to 0.74% in 2050 (see also Table 19), comprising only existing hydro and biomass (mainly bagasse) capacity, and a small amount of added landfill gas capacity. Contribution of renewable sources to electricity sent out is around half this amount, due to lower availability factors.

Electricity production continues to be mainly from coal-fired power stations, which can be run 88% of the time. The gas-fired power stations are suitable for peak generation, and thus do not run as much. Renewable energy technologies will run when the resource is available and thus have smaller shares of electricity generated. However, some designs improve availability factors, such as the use of molten salt in the solar power tower.

**Table 19: Projected electricity generating capacity by type of power plant**

| | ***2003*** | ***2005*** | ***2015*** | ***2025*** | ***2035*** | ***2045*** | ***2050*** |
|---|---|---|---|---|---|---|---|
| Existing coal | 32.8 | 32.8 | 32.8 | 30.6 | 17.8 | 4.0 | 0.0 |
| Mothballed coal | 0 | 0.38 | 2.79 | 2.79 | 2.41 | 0 | 0 |
| Super critical coal | 0 | 0 | 0.31 | 5.38 | 11.17 | 22.26 | 23.16 |
| FBC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC | 0.0 | 0.0 | 0.0 | 9.2 | 31.5 | 54.8 | 67.6 |
| OCGT liquid fuels | 0.17 | 0.17 | 1.69 | 1.69 | 1.52 | 1.52 | 1.52 |
| OCGT nat gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCGT | 0 | 0 | 0 | 0 | 0 | 3.96 | 7.21 |
| PWR nuclear | 1.8 | 1.8 | 1.8 | 4.75 | 12.49 | 15 | 15 |
| PBMR | 0 | 0 | 0 | 1.98 | 1.98 | 1.98 | 1.98 |
| Hydro | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 |
| Landfill gas | 0 | 0 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Solar trough | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Pumped storage | 1.58 | 1.58 | 1.77 | 2.38 | 2.73 | 2.33 | 2.33 |
| Total | 37 | 38 | 42 | 60 | 82 | 107 | 120 |

**The capacity to produce petroleum products from refineries is dominated by crude oil and synfuel refineries in GWC. Five new crude refineries are built within the period as well as five new CTL plants, each with half the capacity of Secunda are built in GWC.**

All new crude refineries are assumed to have a capacity of 300 000 bbl / day. Sasol have indicated that all new coal-to-liquid plants would be low-termperature Fischer-Tropsch, with a product profile of 70% diesel, 25% naphtha (used for petrol) and 5% LPG.

At SBT4, Sasol indicated that only ‘half’ a new CTL (i.e. 80 000 bbl / day for Mafutha, compared to 160 000 bbl at Secunda) might be built, but agreed to discuss this with the Sasol strategy team. Harald Winkler met with the Sasol team at their request on 21 June 2007 to discuss this matter. A letter from Sasol was received on 27 June, reflecting Sasol’s considerations in particular of coal and water constraints on CTL under ‘Growth without carbon Constraints’. It concludes that ‘no single factor will prevent the implementation of CTL facilities as described in the current working document and technical report for SBT4, although the costs of securing a reliable supply may be prohibitive under current economic considerations’. The letter was circulated to SBT members. The research team engaged further with DWAF on the availability of water, which emerged as a key constraint, with ‘significant cost implications’. This issue is reflected, together with other constraints, in section **Error! Reference source not found.**.

Although both sources of liquid fuels expand considerably, the share produced by crude oil refineries begins at around 69% (fraction of total energy) in the base year, declines only slightly to a low of 67% in 2020, rising again to 76% by 2050. After that, increasing demand is met mainly from new crude refineries and imports. Five new 300 000 bbl/day crude refineries are commissioned between 2011 and 2047.

Given such constraints, we assume that a new CTL plant, with a capacity of 80 000 bbl / d (half of Secunda) could be built no faster than one every six years. Five new CTL plants of a capacity of 80 000 bbl /d are commissioned between 2014 and 2038. Synfuel production begins at around 31% of the total domestic fuel production and declining to 21% in 2050. High net exports in 2003 (27% of production) decline to 1% by 2050. Biofuels play an insignificant role, rising from 0.4% of domestic fuels supply in 2011 to just under 2% in 2050.

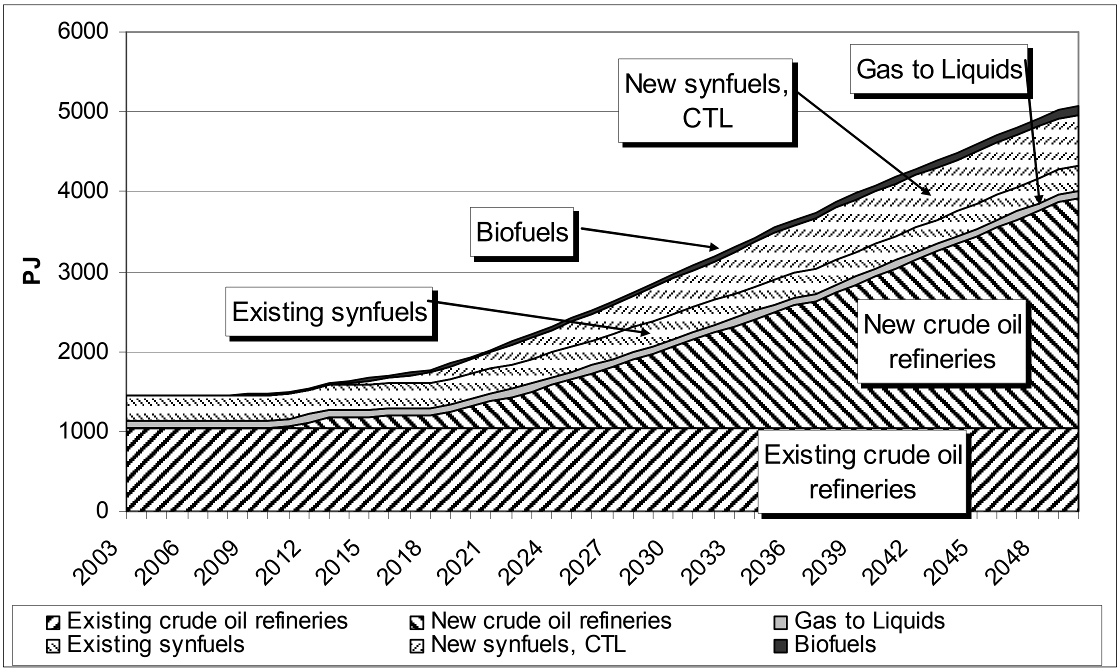


**Figure 12: Growth of refinery capacity in the GWC case, 2003-2050**

**On current energy trends, greenhouse gas emissions will rise dramatically.** Energy-related emissions ($CO_2$, $CH_4$ and $N_20$) increase just under four times from the base year to 2050. Together with increases from synfuels, this drives a similar scale increase in GHGs overall, including non-energy emissions. Without constraints, energy-related emissions grow at an average 2.9% annually. Energy GHG emissions reach 1 330 Mt $CO_2$eq in 2050, an increase of more than 978 Mt. Electricity generation accounts for 56% of energy-related CO2 emissions in 2003 declining to 41% in 2050. The declining share is due to emissions growth in liquid fuels and coal use in industry, with five new coal-to-liquid plants.

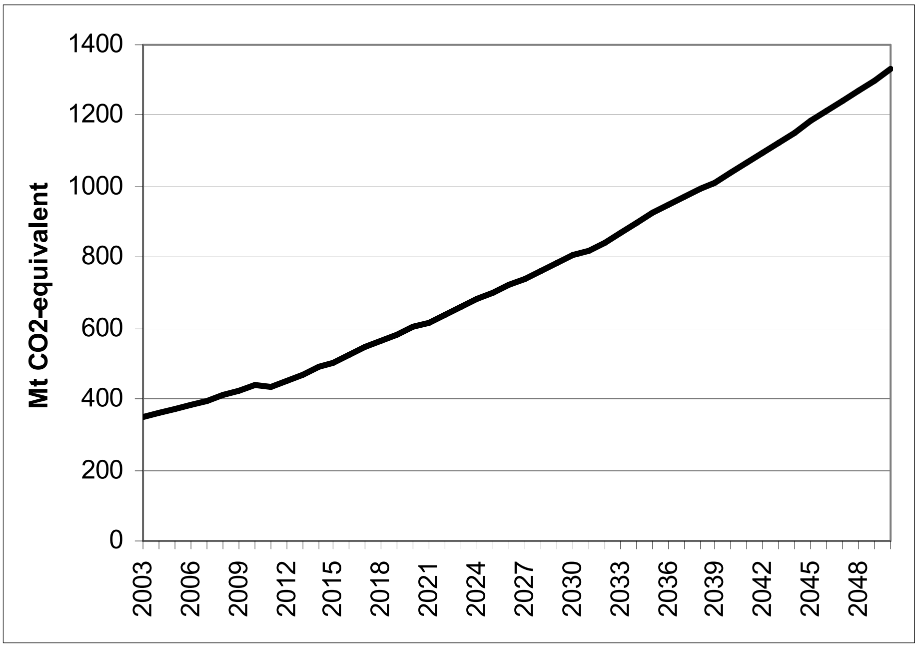


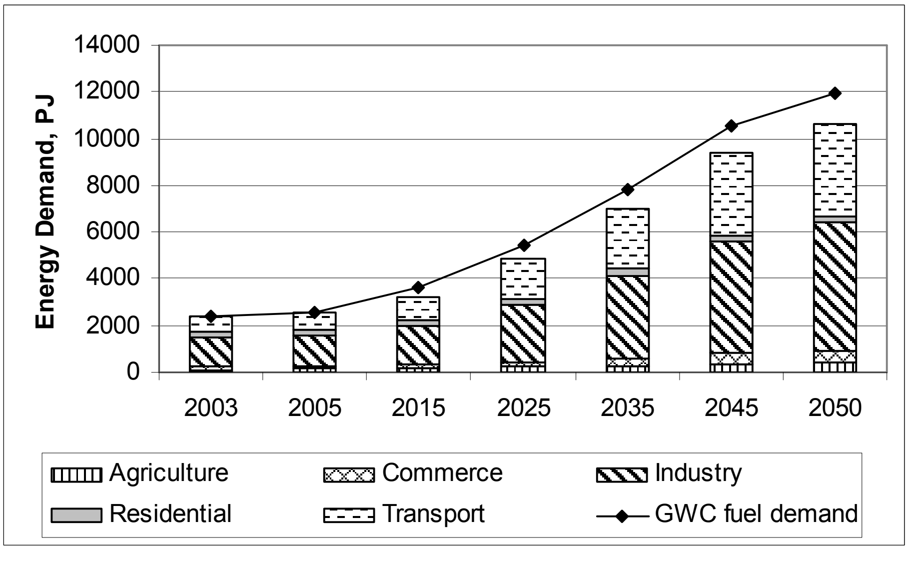
**Figure 13: Projections of GHG emissions from energy supply and use in the GWC case, 2003-2050**

### 6.1.2 Current development plans (CDP)

The Current Development Plans (CDP) scenario assumes that existing government policy is implemented. Notably, the energy efficiency target of reducing final energy demand by 15% below projected levels by 2015, and the renewable energy target of 10 000 GWh by 2013 are assumed to be reached. This was consistent with the base case for the Integrated Energy Planning (IEP) process and National Integrated Resource Plan (NIRP2). The SBT agreed that the CDM would be excluded from the base case, as it will have a negligible impact.

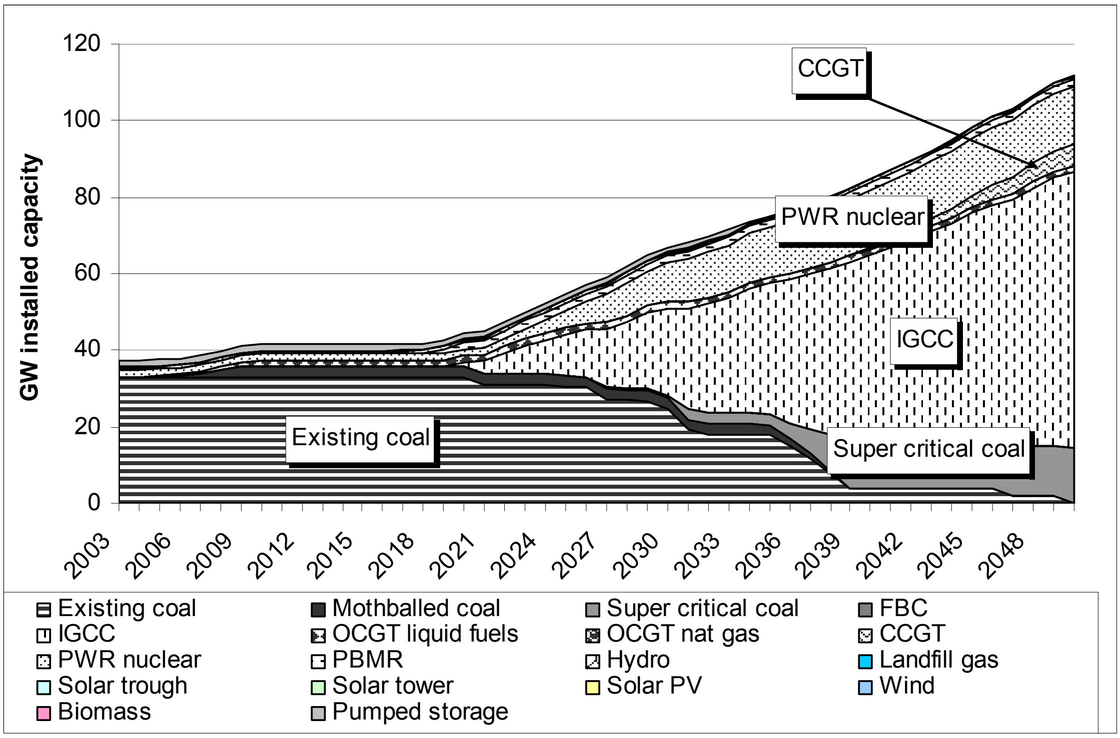
**In the 'Current Development Plans' scenario, energy demand grows mainly in the industry and transport sectors.** Figure 14shows that the growth in commercial, residential and agricultural fuel use are relatively small in comparison. The predominant fuels differ by sectors. In 2050, 59% of industrial fuel use comes from coal, with another third from electricity. The commercial sector uses electricity for 66% of its energy needs, with another fifth from coal. Fuel use in transport is dominated by petrol (55% in 2003, but 32% by 2050), diesel (31%; 31%) and jet fuel (12% increasing to 18%). In the residential sector, electricity use increases but more moderately than in GWC (63% to 68%).

**Figure 14: Fuel use by sector, all fuels (PJ)**



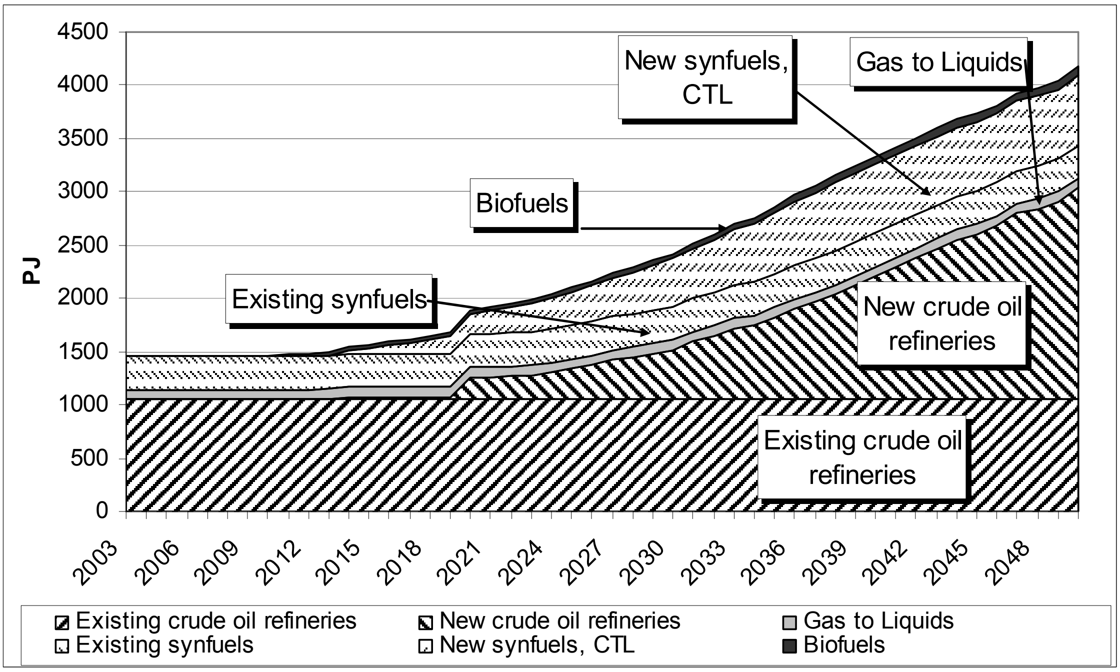
**In 'Current Development Plans', electricity continues to be generated overwhelmingly from coal and to a lesser extent nuclear power.** Electricity generating capacity in CDP is lower - while in GWC, capacity added is about three times the base year capacity, the CDP grid is around 10 GW smaller. The somewhat lower growth is due to reduced demand for electricity, as final energy demand is reduced by 15% in pursuit of the energy efficiency target. GWC sees less new coal stations coming in from the middle of the period, initially with fewer pulverized fuel stations, but increasingly also not building as much super-critical coal as in CDP. Conventional nuclear and CCGT power plants see less investment. As in GWC, there is no significant investment in renewables.

**Figure 15: Electricity expansion plan in the CDP case, GW installed capacity 2003-2050**



**The capacity to produced petroleum products from refineries is dominated by crude oil and synfuel refineries in CDP.** Demand for liquid fuels is considerable lower in CDP than in GWC, resulting in the commissioning of one less refinery.

**Figure 16: Refinery capacity in the CDP case, 2003-2050**

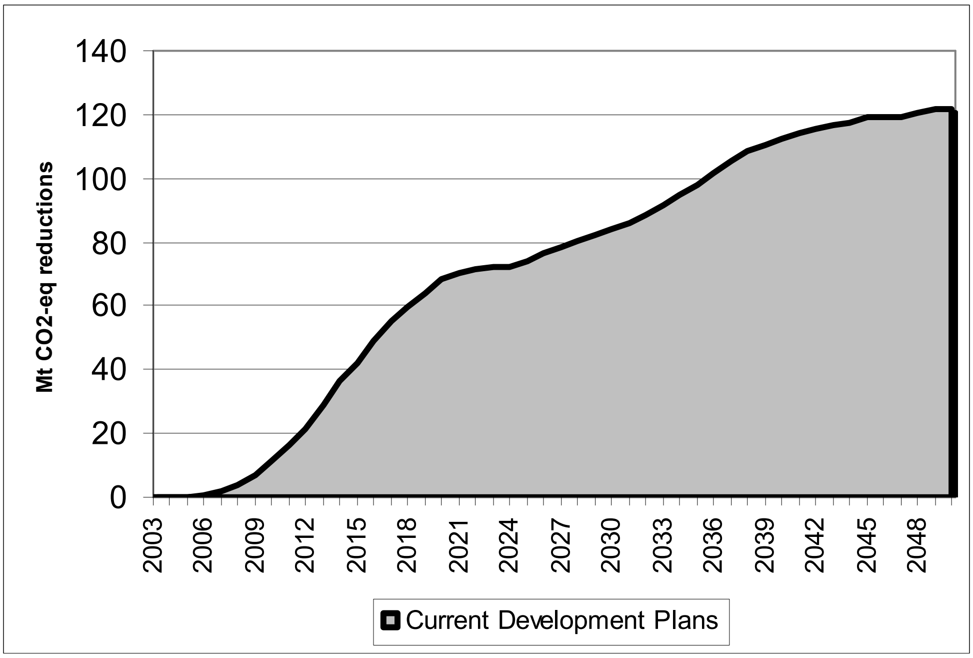


**In CDP, GHG emission still rise dramatically.** Nonetheless, CDP includes a significant effort in reducing emissions measured in millions of tons of $CO_2$ avoided compared to Growth without Constraints.

Figure 53Figure 17 below shows the emission reductions due to the mitigation actions already included in the CDP scenario, notably the energy efficiency targets being met. A total of 3 412 Mt of $CO_2$-eq are avoided during the period, at a saving of –R510 per ton.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -77,364 | -36,270 | -20,836 |
| Annual $CO_2$eq saving (Mt/yr) | 71 | | |
| Cost effectiveness (R/t $CO_2$eq) | -1,088 | -510 | -293 |
| Total CO2eq saving (Mt, 2003-2050) | 3,412 | | |
| % increase on GWC costs | -11.39% | | |
| % of GDP | -2.36% | | |

**Figure 17: Emission reductions due to CDP relative to GWC**



## 6.2 Results for mitigation actions

### 6.2.1 Mitigation actions: Commercial energy efficiency

The commercial energy efficiency interventions results in less electricity, liquid fuels and solid fuels being used overall, but more gaseous fuel and renewables. More specifically, there are substantial reductions in coal for space heating and LPG for water heating. More efficient lighting – fluorescent and CFLs – replace incandescents. Consumption of non-renewable fuels in both cases is approx 1000 PJ lower than in GWC. The main savings are in water heating, followed by lighting and HVAC. The resultant 'wedge' of emission reductions in shown in Figure 19.

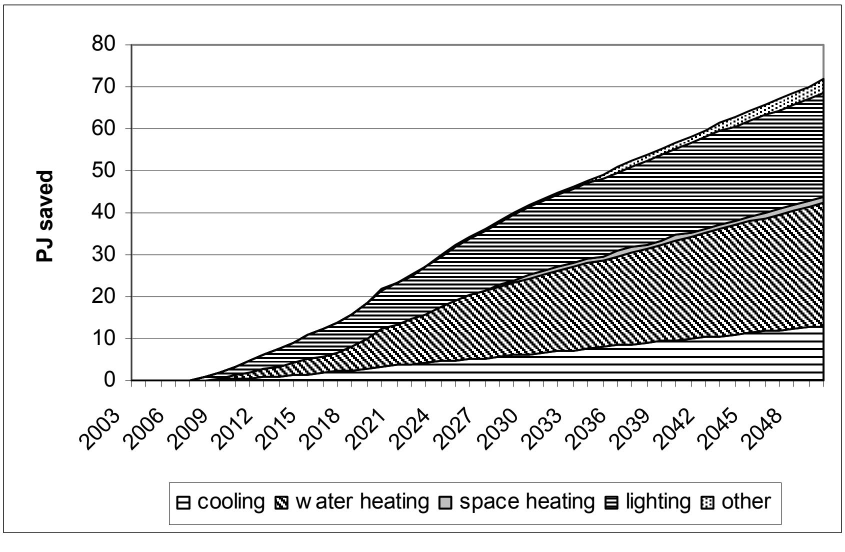


**Figure 18: Fuel use comparison in the commercial sector**

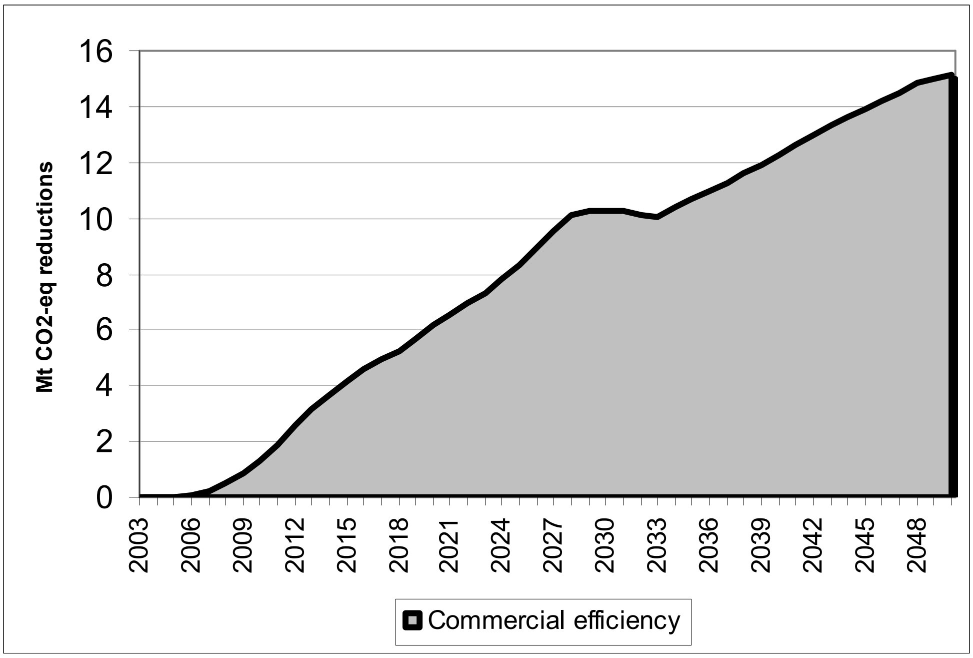


**Figure 19: Emission reductions for commercial energy efficiency**

Commercial energy efficiency can reduce an average of 8 Mt $CO_2$-eq per year, adding up to 381 Mt over the period. At a 10% discount rate, the mitigation costs are –R203 / t $CO_2$-eq. Like other energy efficiency wedges, **the commercial one is a 'net negative cost option', that is, the upfront costs of improving efficiency are more than offset by the energy savings over time.**

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -3,923 | -1,611 | -894 |
| Annual $CO_2$eq saving (Mt/yr) | 8 | | |
| Cost effectiveness (R/t $CO_2$eq) | -494 | -203 | -113 |
| Total CO2eq saving (Mt, 2003-2050) | 381 | | |
| % increase on GWC costs | -0.56% | | |
| % of GDP | -0.12% | | |

### 6.2.2 Mitigation actions: Industrial energy efficiency

At SBT4, this wedge showed the largest cumulative reduction in emissions. Different views were expressed as to whether this was achievable or not. The auditing process included a meeting with industry stakeholders (21 June 2007).[9]

**Table 20: Overall efficiency improvements, distinguishing technological efficiency and systems savings**

| | ***2008*** | ***2015*** | ***2030*** | ***2050*** |
|---|---|---|---|---|
| Boilers and steam systems | 0% | 10, 10% | 16, 16% | 20, 20% |
| Compressed air | 0% | 7.5, 7.5% | 16,16% | 20, 20% |
| Process heat | 0% | 3,-% | 4, -% | 5, -% |
| HVAC | 0% | 12, -% | 18, -% | 25, -% |
| HVAC with waste heat | 0% | 0% | 10% | 30% |

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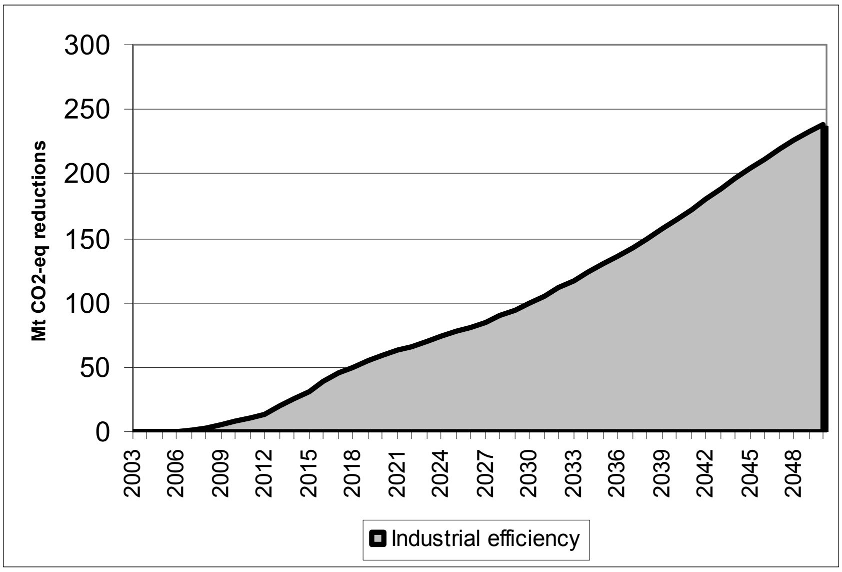
[9] The meeting was chaired by Ian Langridge, chair of the Energy Efficiency Technical Committee.

| | | | | |
|---|---|---|---|---|
| Lighting | 0% | 30,10% | 70,10% | 75,10% |
| Other motive | 0% | 9% | 11% | 15% |
| Pumping, fans (process flow) | 0% | 10% | 25% | 40% |
| Process cooling | 0% | 5% | 7% | 10% |

Table 20 emerged from the discussions at the small meeting on industrial energy efficiency. It shows the revised estimates of overall efficiency improvements achievable in the near-term (2008) and three future years, 2015, 2030 and 2050. Technical efficiency gains may be limited when considering technology in a narrow sense, but further savings are possible when taking the broader system into account. The percentage are additive to give overall savings.

The industrial energy efficiency wedge was not doubled, compared to the wedge shown at SBT4. The industrial energy efficiency wedge has been re-run, based on the adjusted energy savings considered possible at various periods. The size of the industrial energy efficiency 'wedge' shown in Figure 21 is still large, although slightly smaller than that shown at SBT4, now at 4 805 Mt $CO_2$-eq.

**Figure 20: Emission reductions for industrial energy efficiency**



**Industrial energy efficiency is also a net negative cost mitigation action, at -34 / t $CO_2$-eq.** The range of interventions in industrial efficiency cover a range of more energy-intensive activities, leading to larger total reductions.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -9,250 | -3,235 | -1,595 |
| Annual $CO_2$eq saving (Mt/yr) | 95 | | |
| Cost effectiveness (R/t $CO_2$eq) | -97 | -34 | -17 |
| Total CO2eq saving (Mt, 2003-2050) | 4,572 | | |
| % increase on GWC costs | -1.24% | | |
| % of GDP | -0.26% | | |

### 6.2.3 Mitigation actions: Transport

It is important to note two important differences in modelling the transport sector, which differentiate it from others:

1) In the transport sector, the model is tightly constrained, and does not optimise in the way that it does in the rest of the energy system. The rationale for this is that consumers apply a range of other criteria to purchasing transport services in addition to purely economic considerations.
2) The basic units in the transport section are passenger-kilometres[10]; thus, energy consumption is measures in terms of how much energy is required per passenger-km. The advantage of this approach is that modal shifts can be modelled far more easily. Thus, in the case of vehicle efficiency, improvements in engine efficiency are not modelled directly. Instead, the efficiency improvement is in the amount of energy required per passenger-kilometre; however, since the number of passengers in vehicles remains the same, this approach approximates vehicle efficiency improvement.

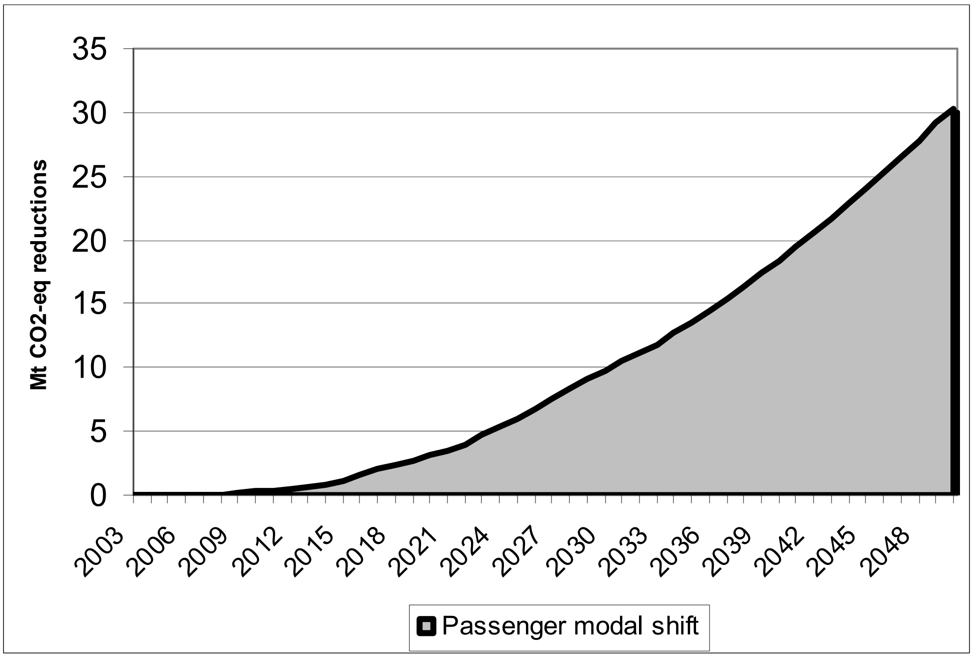
### *6.2.3.1 Modal shifts for passenger transport*

A modal shift in passenger transport means that more passenger-kilometres are produced by the same energy use. The emission reduction are mostly due to reduced use of diesel and petrol (although electricity use increases at the same time).

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -38,439 | -11,048 | -4,685 |
| Annual $CO_2$eq saving (Mt/yr) | 10 | | |
| Cost effectiveness (R/t $CO_2$eq) | -3,936 | -1,131 | -480 |
| Total CO2eq saving (Mt, 2003-2050) | 469 | | |
| % increase on GWC costs | -4.89% | | |
| % of GDP | -1.05% | | |

The costs for this wedge *include* infrastructure costs. The scale of investment required in public transport systems would at least reduce and maybe outweigh the cost savings from more efficient transport. Even with infrastructure costs taken into account, the costs are still net negative, at -R1 131 t / $CO_2$-eq. Total emissions of 469 Mt $CO_2$-eq are saved over the period.

**Figure 21: Emission reductions from modal shift in passenger transport, 2003-2050**



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[10] This is a measure of transport services; thus one passenger-kilometer = transport required to move one passenger one km.

#### *6.2.3.2 Electric vehicles*

Capital costs are higher at R176 000 for an electric vehicle, composed to R100 000 for petrol and R115 000 for diesel cars, although these are expected to decline with technology learning. The 'well-to-wheels' implications for GHG emissions depend, of course, where the electricity comes from. If electricity is generated in a coal-dominated grid – as is the case for both the US and SA – the emission reductions will be less than one in which uses a lot of lower- or zero-carbon fuels for electricity generation. A recent study on electric vehicles in the US by EPRI and NRDC has shown that emission reductions are possible even in coal-dominated grids (EPRI & NRDC 2007). The analysis shown here assumes that electric vehicles make up 60% of the private passenger car market, which displaces only about a quarter of petrol use in the transport sector (the remainder is used by petrol minibus taxis, light commercial vehicles, and the remaining private passenger vehicles). If a GWC-type grid is assumed, take-up of electric vehicles results in mitigation of 450 Mt $CO_2$-eq over the period, even with on a coal-dominated grid, at a relatively high cost of R607 per ton. As vehicle cost reduces, this will become a more affordable mitigation option. In addition to $CO_2$ mitigation, electric vehicles also have other co-benefits, such as the lowering of local air pollution in urban areas.

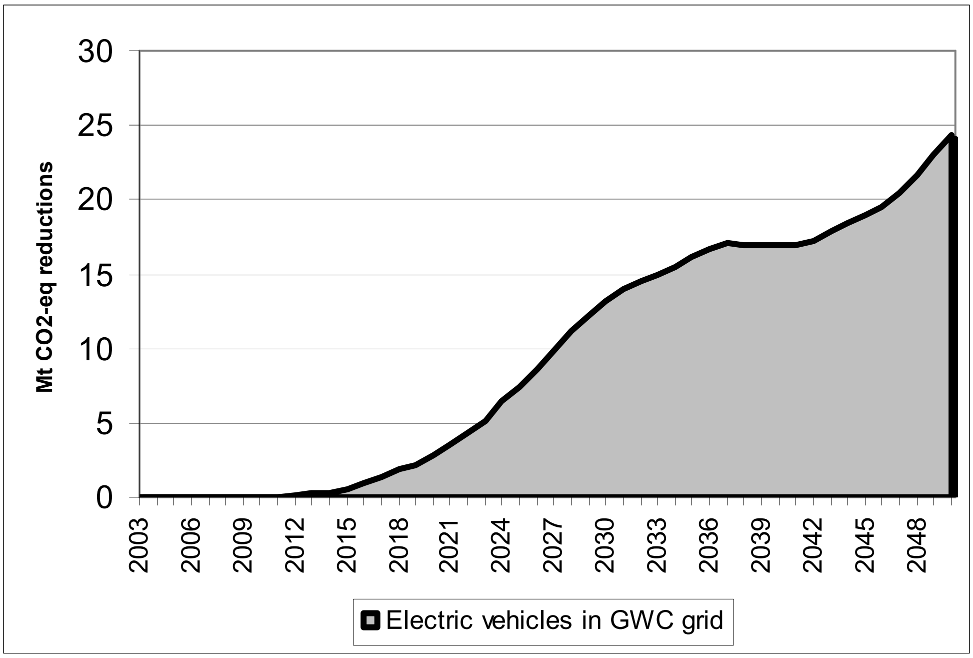
| ***Discount rate*** | ***3%*** | ***10%*** | ***15%*** |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 17,218 | 5,689 | 2,708 |
| Annual $CO_2$eq saving (Mt/yr) | 9 | | |
| Cost effectiveness (R/t $CO_2$eq) | 1,838 | 607 | 289 |
| Total CO2eq saving (Mt, 2003-2050) | 450 | | |
| % increase on GWC costs | 2.27% | | |
| % of GDP | 0.48% | | |

If a grid dominated by nuclear and renewables is assumed, the $CO_2$ savings are somewhat higher, as portrayed in the table below:

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 37,826 | 13,338 | 6,539 |
| Annual $CO_2$eq saving (Mt/yr) | 130.32 | | |
| Cost effectiveness (R/t $CO_2$eq) | 290 | 102 | 50 |
| Total CO2eq saving (Mt, 2003-2050) | 6,255 | | |
| % increase on GWC costs | 5.07% | | |
| % of GDP | 1.08% | | |

However, these costs and savings *include* those of the transformed electricity grid, thus, if one subtracts the effects of the change in the grid, the *net* savings for electric vehicles are 666 Mt $CO_2$-eq.

**Figure 22: Emission reductions from electric vehicles on a GWC grid**



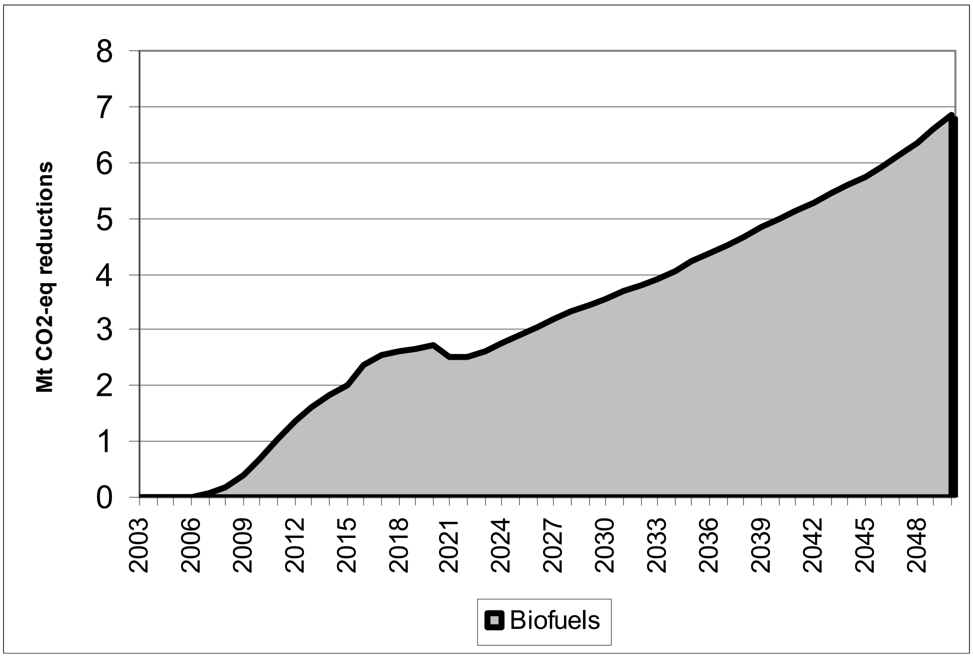
### *6.2.3.3 Biofuels*

Biofuels forms part of a more general renewable energy option, but is here reported separately. In addition, as an economic instrument, a subsidy for biofuels has also been modelled.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 3,267 | 1,679 | 1,109 |
| Annual $CO_2$eq saving (Mt/yr) | 3 | | |
| Cost effectiveness (R/t $CO_2$eq) | 1,019 | 524 | 346 |
| Total CO2eq saving (Mt, 2003-2050) | 154 | | |
| % increase on GWC costs | 0.52% | | |
| % of GDP | 0.10% | | |

The biofuels 'wedge' in Figure 23 is on a scale of less than 10 Mt $CO_2$-eq per annum, with total emission reductions of 154 Mt $CO_2$-eq over the whole period. Average reductions of 3 Mt $CO_2$-eq per year come at a relatively high mitigation cost of R 524 / t $CO_2$-eq. **The moderate scale of reductions reflects the limits on the potential of biofuel in SA**, which needs to take into account issues of food security, availability of arable land and water, and potential impacts on biodiversity.

**Figure 23: Emission reductions from biofuels**

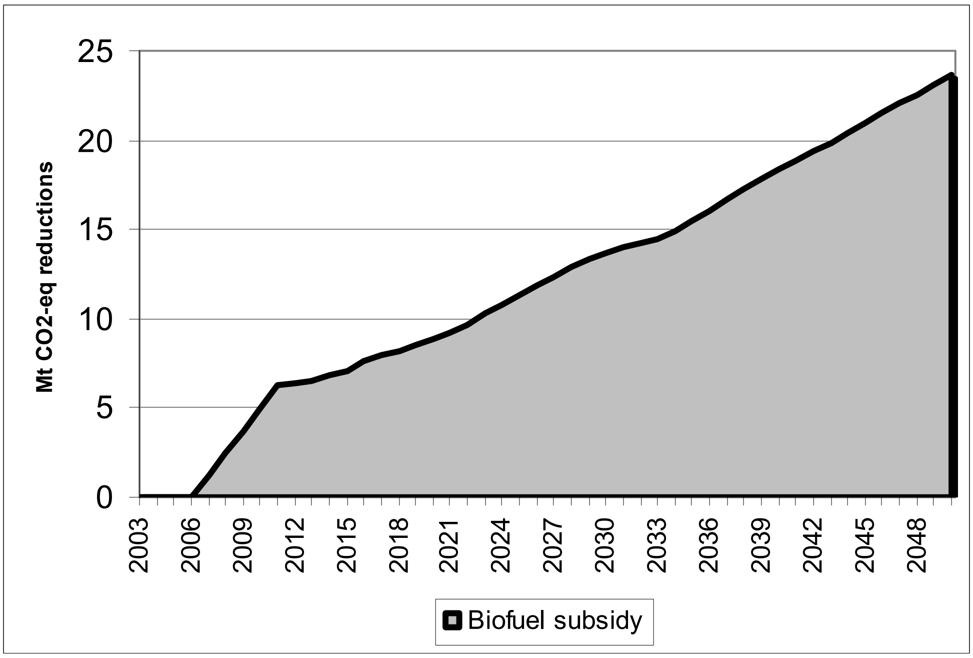


#### 6.2.3.4 *Subsidy for biofuels*

A subsidy was applied to biofuels of R166 per litre, which resulted in biofuels comprising 9% of the domestic fuel by 2050, and mitigation of 573 Mt $CO_2$-eq over the period, at a cost of R697 / ton. Biofuels displace one crude refinery, and thus significantly lower oil imports.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 13,304 | 8,317 | 6,257 |
| Annual $CO_2$eq saving (Mt/yr) | 12 | | |
| Cost effectiveness (R/t $CO_2$eq) | 1,115 | 697 | 524 |
| Total CO2eq saving (Mt, 2003-2050) | 573 | | |
| % increase on GWC costs | 2.34% | | |
| % of GDP | 0.44% | | |

**Figure 24: Emission reductions from biofuels subsidy**



#### 6.2.3.5 *Efficient light vehicles*

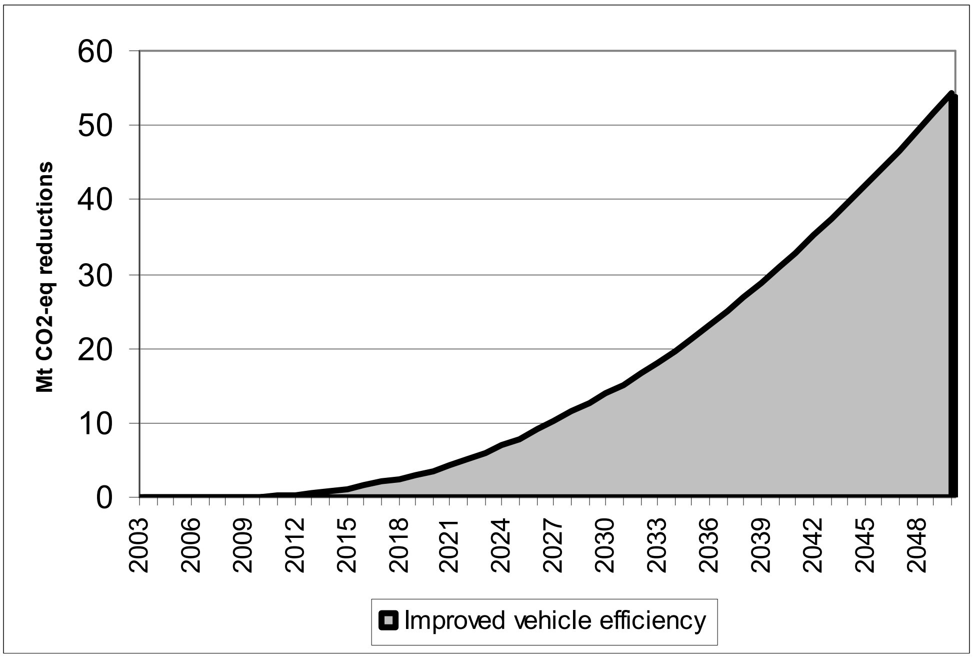
Vehicle efficiency increases 0.5% in GWC, whereas as in CDP, it increases by 0.4% between 2003 and 2007, and 0.9% thereafter. In case reported for SBT 5, vehicle efficiency improves beyond the CDP case, by 1.2% per year, saving a significant amount of petrol. There is a significant reduction in domestic fuel requirements (17%), significantly less refinery capacity is built domestically, and imports increase significantly to balance the domestic product profile.

The two most important factors in reducing costs are first that more efficient vehicles save 14% of petrol consumption over the period (saving 25% in 2050), and saving 12% of diesel (22% in 2050). Second, the construction of new crude refineries is delayed and avoided (only three new refineries are built as opposed to five), reducing system costs.

Greater vehicle efficiency is a negative cost mitigation option. The wedge in Figure 25 is shown on a scale of up to 60 Mt $CO_2$-eq per year, although the annual average is 16 Mt. Between 2003 and 2050, some 758 Mt $CO_2$-eq can be avoided at a cost of –R269 / t $CO_2$. Both the cost-effectiveness and the scale of the reductions suggest that there is significant mitigation potential in proactively promoting a greater increase in the efficiency of South Africa's vehicle fleet.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -14,942 | -4,243 | -1,779 |
| Annual $CO_2$eq saving (Mt/yr) | 16 | | |
| Cost effectiveness (R/t $CO_2$eq) | -946 | -269 | -113 |
| Total CO2eq saving (Mt, 2003-2050) | 758 | | |
| % increase on GWC costs | -1.90% | | |
| % of GDP | -0.41% | | |

**Figure 25: Emission reductions from vehicle efficiency**

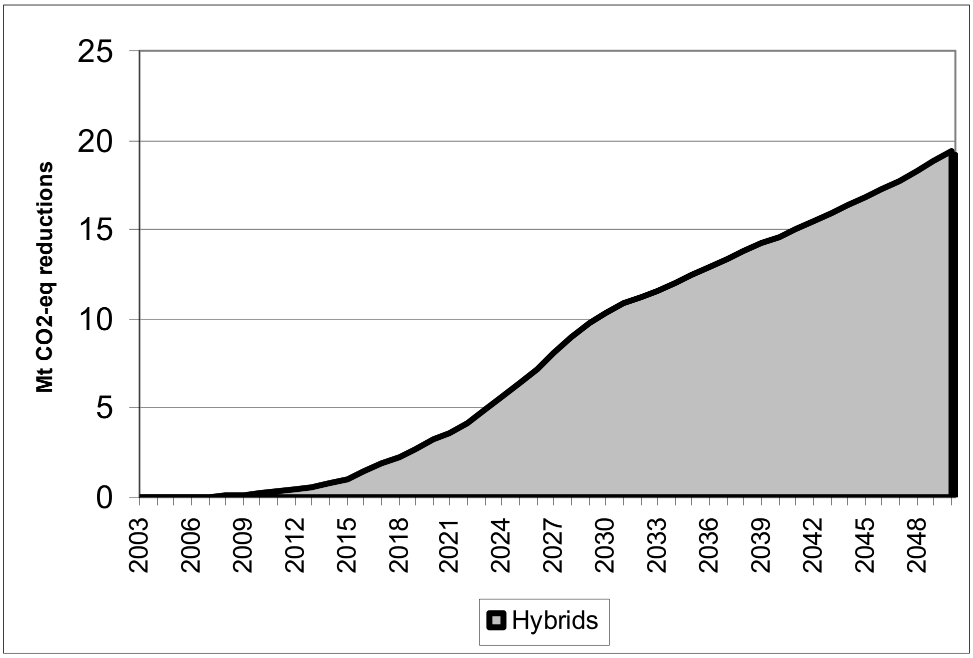


### 6.2.3.6 *Hybrid vehicles*

With 40% of cars being hybrids by 2030 (starting from zero in 2003), costs increase with the price of vehicles being more than double that of regular petrol cars. The increased use of hybrids displaces only petrol-driven private passenger vehicles. The efficiency of hybrids is more than double in passenger-kilometres per fuel use. **Introducing hybrids result in substantial emissions savings over the period of 381 Mt $CO_2$-eq, but at a high cost of R1 987 / t $CO_2$ at a 10% discount rate.** This is a significant cost for reductions that average only 8 Mt $CO_2$-eq per year.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 47,739 | 15,789 | 7,362 |
| Annual $CO_2$eq saving (Mt/yr) | 8 | | |
| Cost effectiveness (R/t $CO_2$eq) | 6,009 | 1,987 | 927 |
| Total CO2eq saving (Mt, 2003-2050) | 381 | | |
| % increase on GWC costs | 6.27% | | |
| % of GDP | 0.52% | | |

**Figure 26: Emission reductions from deployment of hybrid vehicles**



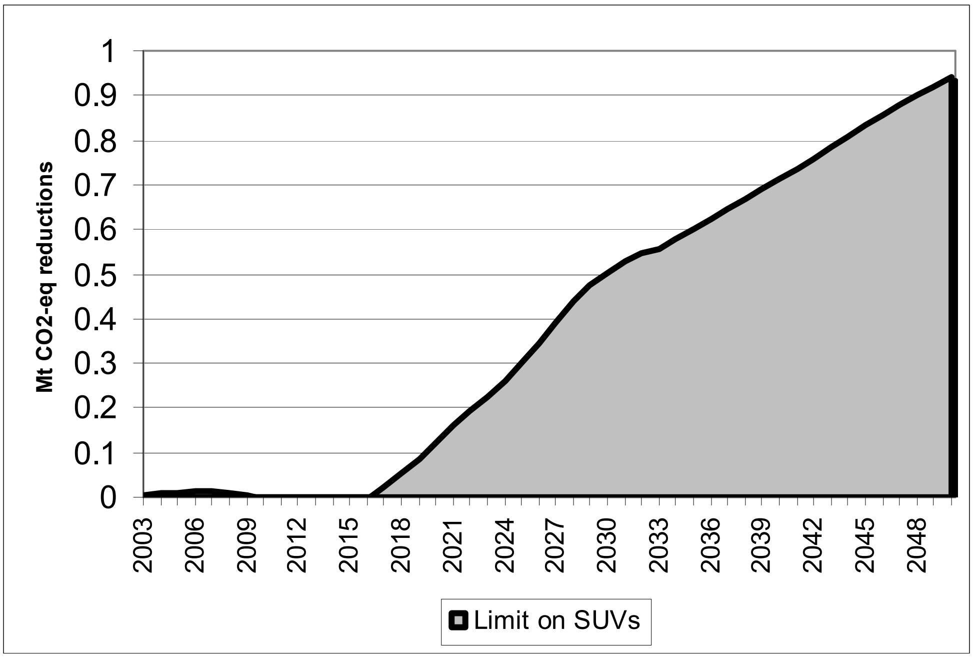
#### 6.2.3.7 *Downsizing/ limiting SUVs*

Limiting the share of larger, more expensive SUVs requires a shift to smaller vehicles. Not only is the capital cost of these vehicles about a third of SUVs, but they deliver more passenger-kilometers per litre of fuel.

A limit on vehicle size is implemented in that only 1% of private passenger-kilometers can come from SUVs, most coming from smaller-engine vehicles. Emission reductions are 18 Mt of $CO_2$-eq over the period, at a cost of –R4 404 per ton (Figure 27). The highly negative costs are realistic, as they reflect a move to vehicles that have a lower capital cost and lower running costs.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -5,450 | -1,660 | -700 |
| Annual $CO_2$eq saving (Mt/yr) | 0.4 | | |
| Cost effectiveness (R/t $CO_2$eq) | -14,457 | -4,404 | -1,856 |
| Total CO2eq saving (Mt, 2003-2050) | 18 | | |
| % increase on GWC costs | -0.70% | | |
| % of GDP | -0.15% | | |

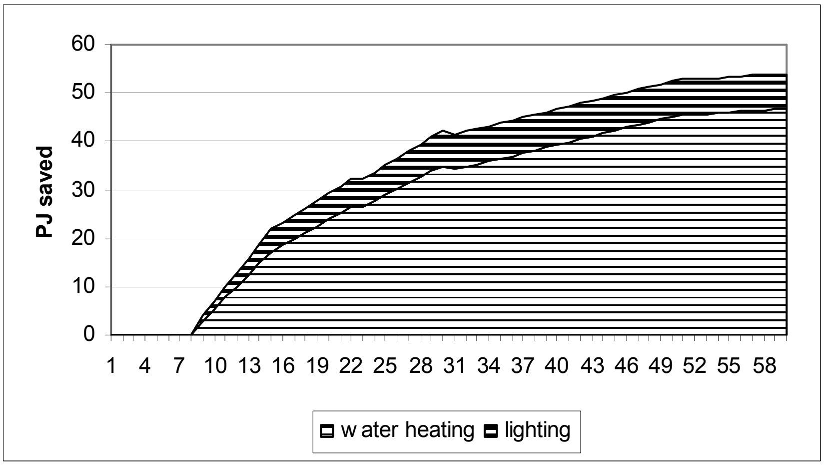
**Figure 27: Emission reductions from limits on SUVs, 1%**



### 6.2.4 Mitigation actions: Residential sector

Residential mitigation actions save a moderate amount of $CO_2$ over the period – 430 Mt $CO_2$-eq. These come at a cost of -R198 / t $CO_2$-eq. Most energy savings derive from water heating, with a smaller saving from lighting.

Figure 28: Savings through energy efficiency measures in the Residential sector



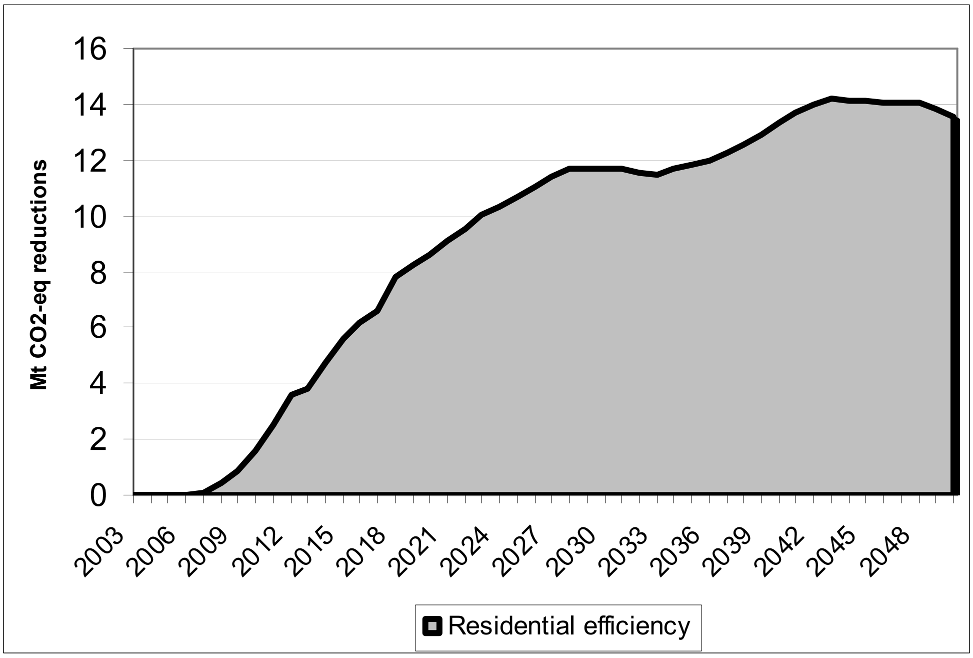
**Residential energy efficiency (including SWH) is a good negative cost mitigation option**. **While individual interventions are small, across a large number of households they add up avoided emissions of over 400 Mt $CO_2$-eq over time. In addition, there are clear socio-economic benefits – increased service of hot water, warmer houses, lower fuel bills.** These factors make this option an important candidate for a portfolio of mitigation actions.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -3,601 | -1,770 | -1,072 |
| Annual $CO_2$eq saving (Mt/yr) | | 9 | |
| Cost effectiveness (R/t $CO_2$eq) | -402 | -198 | -120 |

| | |
|---|---|
| Total CO2eq saving (Mt, 2003-2050) | 430 |
| % increase on GWC costs | -0.55% |
| % of GDP | -0.11% |

The total emission Emphasise that these interventions (CFLs, insulation, SWH, other efficiency) have great local sustainable development benefits.

**Figure 29: Emission reductions from residential energy efficiency**



### 6.2.5 Mitigation actions: Renewable electricity

#### *6.2.5.1 Renewable electricity to 27%*

For this action, 15% of electricity dispatched must come from domestic renewable resources by 2020, from South African hydro, wind, solar thermal, landfill gas, PV, bagasse/pulp and paper. This is extrapolated to 27% by 2030, at which level it remains thereafter. Each of these technologies has an upper limit of capacity that can be built over the period.

This scenario sees the introduction of solar power towers, parabolic trough, wind. The extent to which each is introduced can be seen in Figure 30. The solar power tower comes into the mix from 2014 and reaches its limit of 30 GW in 2045. The trough starts off much smaller, but reaches 16 GW by 2050. Wind comes in gradually, mostly at 25% availability, reaching a peak of 15 GW installed capacity in 2030, but declining to 7 GW by 2050.

**Figure 30: Electricity generating capacity for renewables with learning**

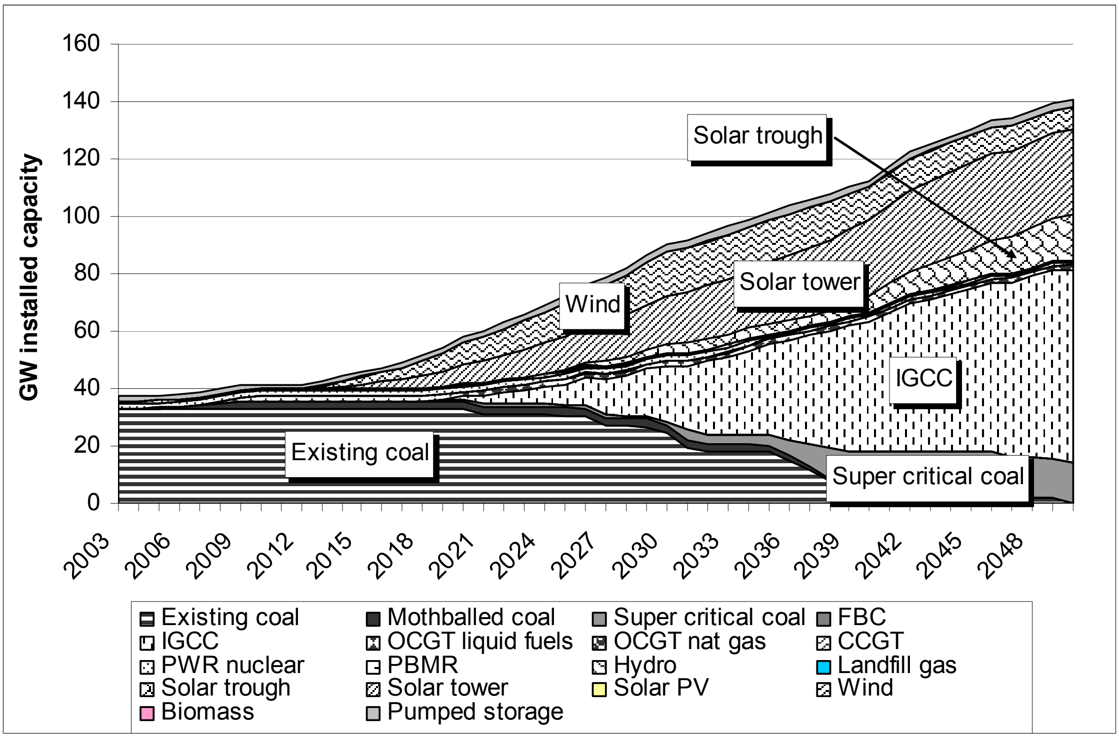


Figure 30 shows installed capacity (GW), not electricity generated (kWh). Since renewable energy technologies generally have lower availability factors (with the exception of the power tower at 60%), more capacity needs to be built for the same electricity output than for a high-availability plant; thus the size of the grid in this case is 140 GW, 20 GW larger than in GWC.

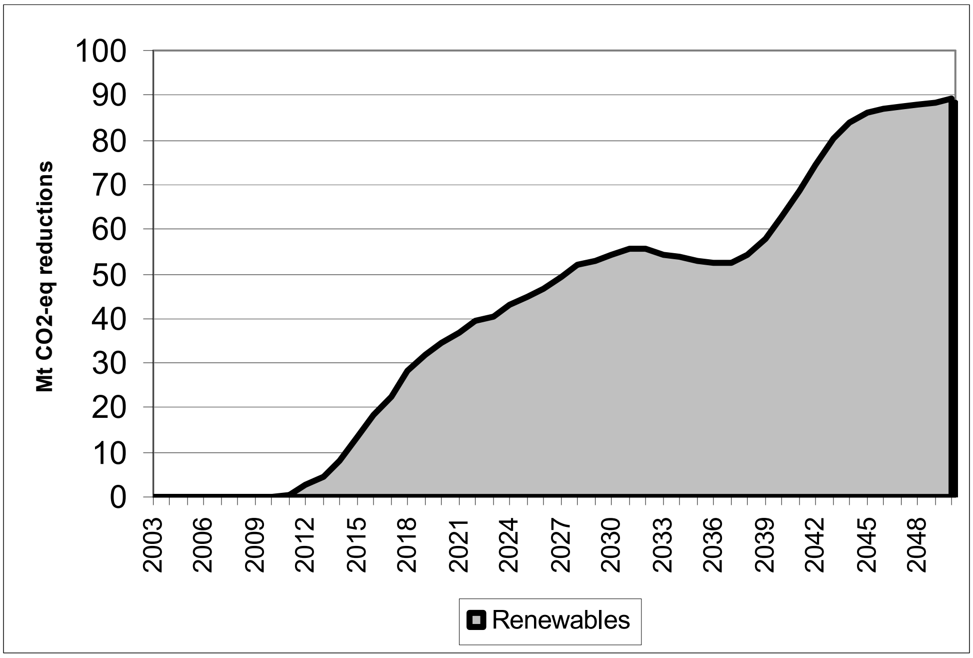
**Table 21: Electricity generating capacity by generation type (GW): Renewable energy scenario**

| | ***2003*** | ***2005*** | ***2015*** | ***2025*** | ***2035*** | ***2045*** | ***2050*** |
|---|---|---|---|---|---|---|---|
| Existing coal | 32.8 | 32.8 | 32.8 | 30.6 | 17.8 | 4.0 | 0.0 |
| Mothballed coal | 0 | 0.38 | 2.79 | 2.79 | 2.41 | 0 | 0 |
| Super critical coal | 0 | 0 | 0 | 0.85 | 3.58 | 14.3 | 13.89 |
| FBC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC | 0.0 | 0.0 | 0.0 | 7.3 | 32.0 | 56.4 | 67.6 |
| OCGT liquid fuels | 0.17 | 0.17 | 1.69 | 1.69 | 1.52 | 1.52 | 1.52 |
| OCGT nat gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCGT | 0 | 0 | 0 | 0.09 | 0.7 | 0.89 | 0.8 |
| PWR nuclear | 1.8 | 1.8 | 1.8 | 1.8 | 0 | 0 | 0 |
| PBMR | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 |
| Landfill gas | 0 | 0 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Solar trough | 0 | 0 | 0 | 0.66 | 3.57 | 10.76 | 15.76 |
| Solar tower | 0 | 0 | 1.53 | 11.53 | 21.53 | 30 | 30 |
| Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 2.78 | 11.56 | 14.55 | 9.62 | 7.7 |
| Biomass | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Pumped storage | 1.58 | 1.58 | 1.67 | 2.28 | 2.73 | 2.33 | 2.33 |
| Total | 37 | 38 | 46 | 72 | 101 | 131 | 140 |

The table below shows that the emission reductions in Figure 31 add up to 2 010 Mt $CO_2$ over the period. The mitigation cost is R52 / ton $CO_2$-eq at a 10% discount rate, reducing emission on average by 42 Mt $CO_2$-eq per year.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 4,177 | 2,165 | 1,241 |
| Annual $CO_2$eq saving (Mt/yr) | 42 | | |
| Cost effectiveness (R/t $CO_2$eq) | 100 | 52 | 30 |
| Total CO2eq saving (Mt, 2003-2050) | 2,010 | | |
| % increase on GWC costs | 0.63% | | |
| % of GDP | 0.13% | | |

**Figure 31: Emission reductions from renewables**

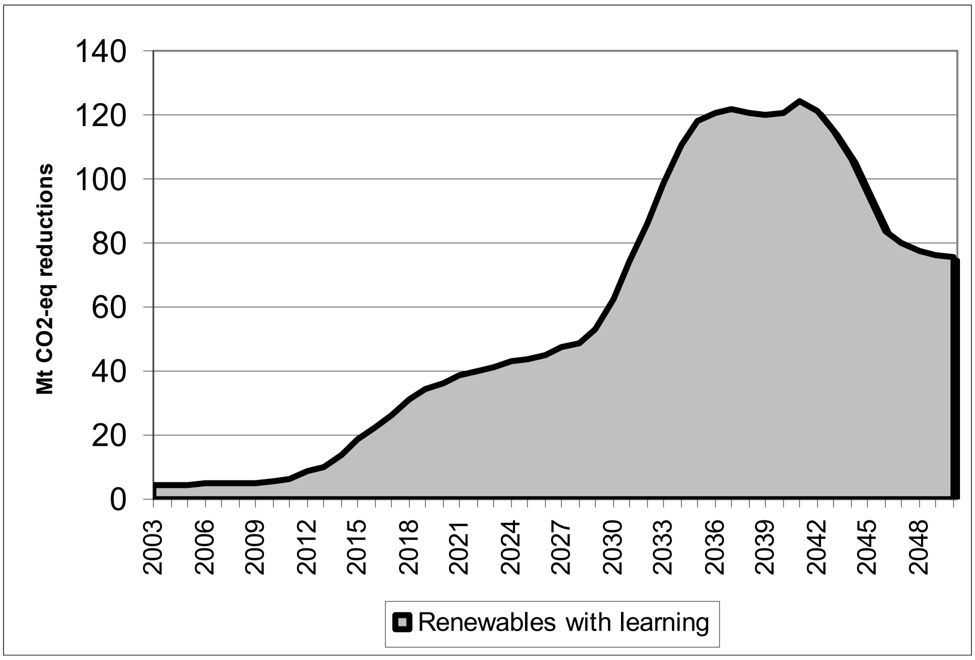


If technology learning is assumed for both GWC and the renewable case, the mitigation costs decline significantly, becoming negative at –R143 / t $CO_2$-eq. The total emission reductions are also increased to 2 757 Mt $CO_2$-eq over the period.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -11,087 | -8,208 | -7,557 |
| Annual $CO_2$eq saving (Mt/yr) | 57 | | |
| Cost effectiveness (R/t $CO_2$eq) | -193 | -143 | -132 |
| Total CO2eq saving (Mt, 2003-2050) | 2,757 | | |
| % increase on GWC costs | -2.13% | | |
| % of GDP | -0.38% | | |

Emission reductions increase with learning, even when compared to the base case with learning (see Figure 32). **Annual emission reductions are 15 Mt $CO_2$-eq higher if technology learning is assumed.**

**Figure 32: Emission reductions from renewables with learning, compared to GWC with learning**



The conclusion is that – if SA found itself in a world in which new technologies got cheaper due to investment globally – emission reductions would be more cost-effective, and still deliver significant reductions.

### *6.2.5.2 Extended wedge: Renewable electricity to 50%*

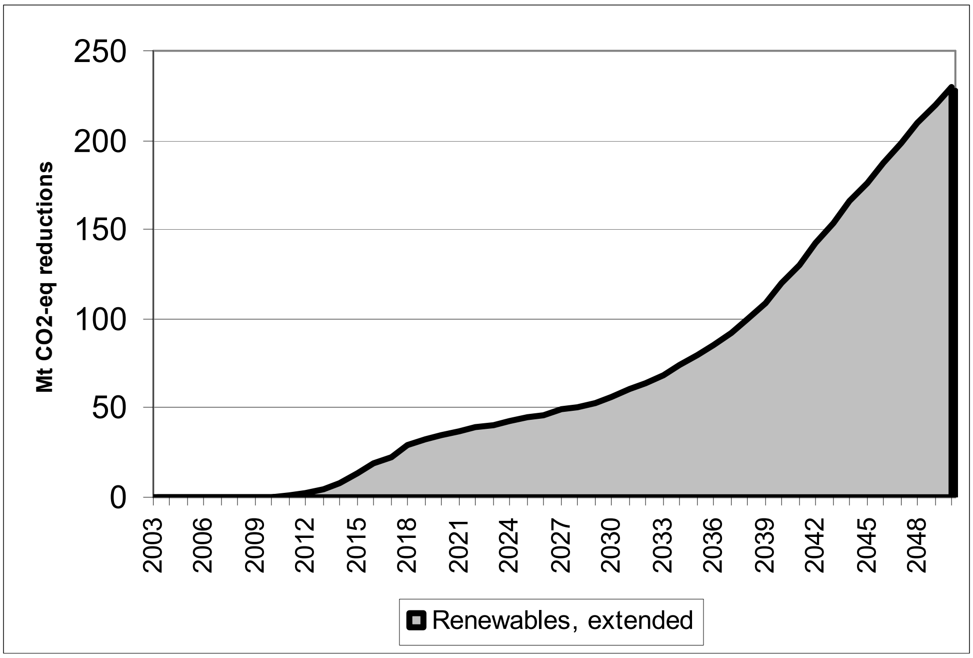
In this case, renewables are extended to 50% by 2050. Total emission reductions increase to 3 285 Mt $CO_2$-eq, but at a higher mitigation costs of R92 / t $CO_2$-eq.

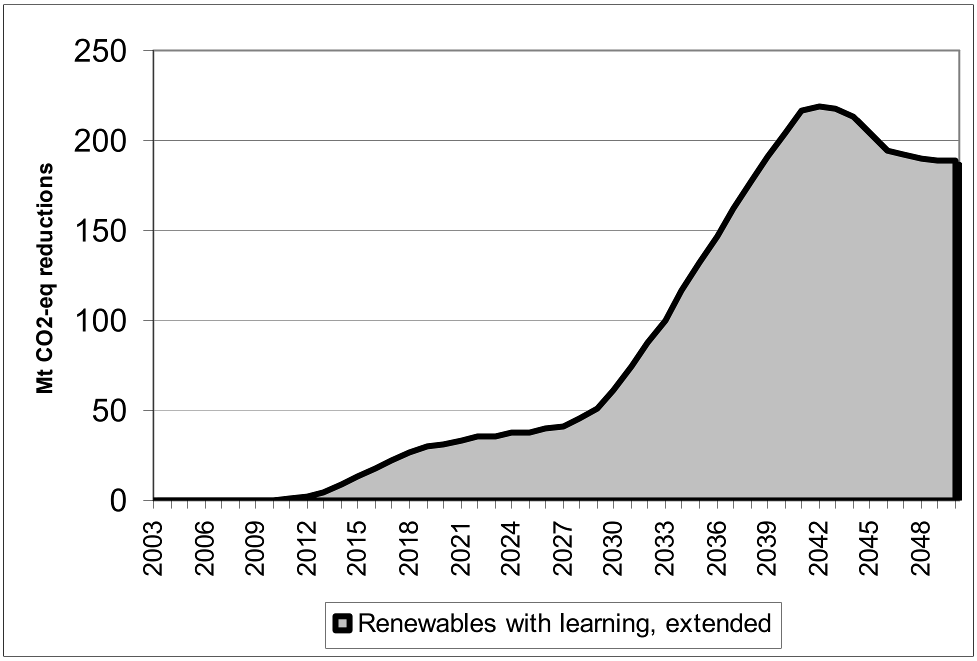
| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 20,276 | 6,310 | 2,872 |
| Annual $CO_2$eq saving (Mt/yr) | | 68 | |
| Cost effectiveness (R/t $CO_2$eq) | 296 | 92 | 42 |
| Total CO2eq saving (Mt, 2003-2050) | | 3,285 | |
| % increase on GWC costs | | 2.64% | |
| % of GDP | | 0.56% | |

When taking learning into consideration, mitigation costs are R 3 / t $CO_2$-eq, with annual emissions reductions of 83 Mt $CO_2$-eq. A total of 3 990 Mt is mitigated over the period.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 527 | 278 | 79 |
| Annual $CO_2$eq saving (Mt/yr) | | 83 | |
| Cost effectiveness (R/t $CO_2$eq) | 6 | 3 | 1 |
| Total CO2eq saving (Mt, 2003-2050) | | 3,990 | |
| % increase on GWC costs | | 0.07% | |
| % of GDP | | 0.02% | |

**Figure 33: Emission reductions from extended renewables, with and without learning**





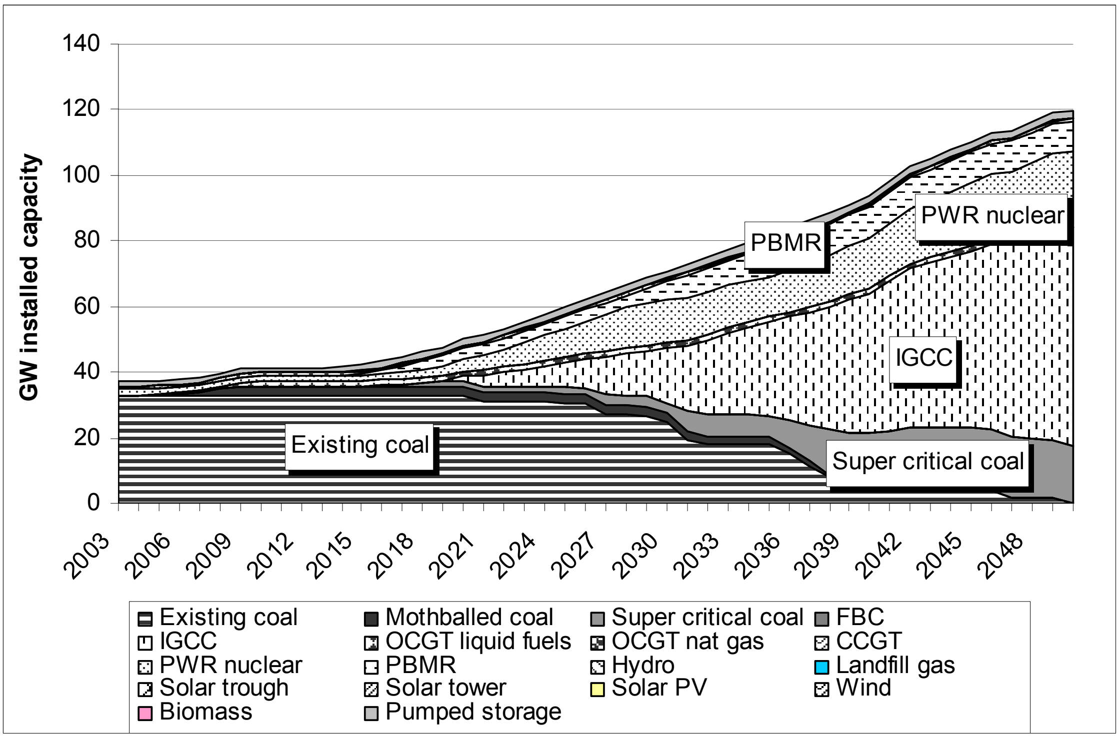
**For the mitigation costs of renewable energy technologies, assumptions about learning are clearly important.**

### 6.2.6 Mitigation actions: Nuclear power

#### *6.2.6.1 Nuclear power to 27%*

In this scenario, either the Pebble Bed Modular Reactor, or new PWR nuclear plants must provide 27% of electricity generated by 2030. No new nuclear capacity can be commissioned before 2013, when the first PBMR can be commissioned, with the PWR in 2015. The upper bounds on capacity are relaxed in the mitigation case (100 GW PWR max; 50 GW PBMR).

**Figure 34: Electricity generating capacity for nuclear mitigation**



The PBMR reaches more than 1% of installed capacity in 2015 and 8% by 2050, a capacity of 9 GW. PWR plants see Koeberg coming to an end of its life by 2035, but total PWR capacity reaches 15% of total installed capacity in 2025, increasing to 19% by the end of the period, nuclear totalling 23 GW of capacity in 2050.

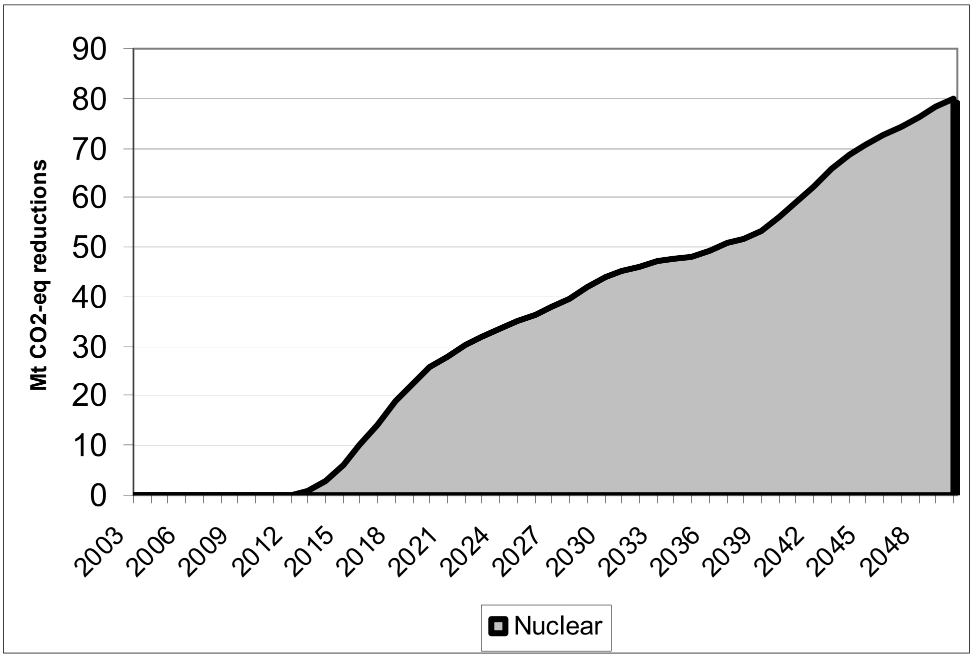
**Table 22: Electricity generating capacity by generation type (GW): Nuclear scenario**

| | *2003* | *2005* | *2015* | *2025* | *2035* | *2045* | *2050* |
|---|---|---|---|---|---|---|---|
| Existing coal | 32.8 | 32.8 | 32.8 | 30.6 | 17.8 | 4.0 | 0.0 |
| Mothballed coal | 0 | 0.38 | 2.79 | 2.79 | 2.41 | 0 | 0 |
| Super critical coal | 0 | 0 | 0 | 1.93 | 6.47 | 19.06 | 17.33 |
| FBC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC | 0.0 | 0.0 | 0.0 | 7.5 | 28.6 | 54.0 | 65.3 |
| OCGT liquid fuels | 0.17 | 0.17 | 1.69 | 1.69 | 1.52 | 1.52 | 1.52 |
| OCGT nat gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCGT | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PWR nuclear | 1.8 | 1.8 | 1.8 | 8.87 | 12.11 | 19.19 | 22.99 |
| PBMR | 0 | 0 | 0.48 | 3.4 | 9.38 | 9.38 | 9.38 |
| Hydro | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 |
| Landfill gas | 0 | 0 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Solar trough | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Pumped storage | 1.58 | 1.58 | 1.77 | 2.17 | 2.46 | 2.33 | 2.33 |
| Total | 37 | 38 | 42 | 60 | 82 | 110 | 120 |

The total emission reductions from building nuclear power are 1 660 Mt $CO_2$-equivalent over the 48 years. The cost of saving is R 18 per t $CO_2$-eq at 10% discount rate. Mitigation costs are lower than for renewables. This result is probably due to two factors – the higher availability factor of nuclear plants, and the relative costs (without technology learning). The annual emission reductions average 35 Mt $CO_2$-eq.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 1,537 | 611 | 309 |
| Annual $CO_2$eq saving (Mt/yr) | 35 | | |
| Cost effectiveness (R/t $CO_2$eq) | 44 | 18 | 9 |
| Total CO2eq saving (Mt, 2003-2050) | 1,660 | | |
| % increase on GWC costs | 0.21% | | |
| % of GDP | 0.05% | | |

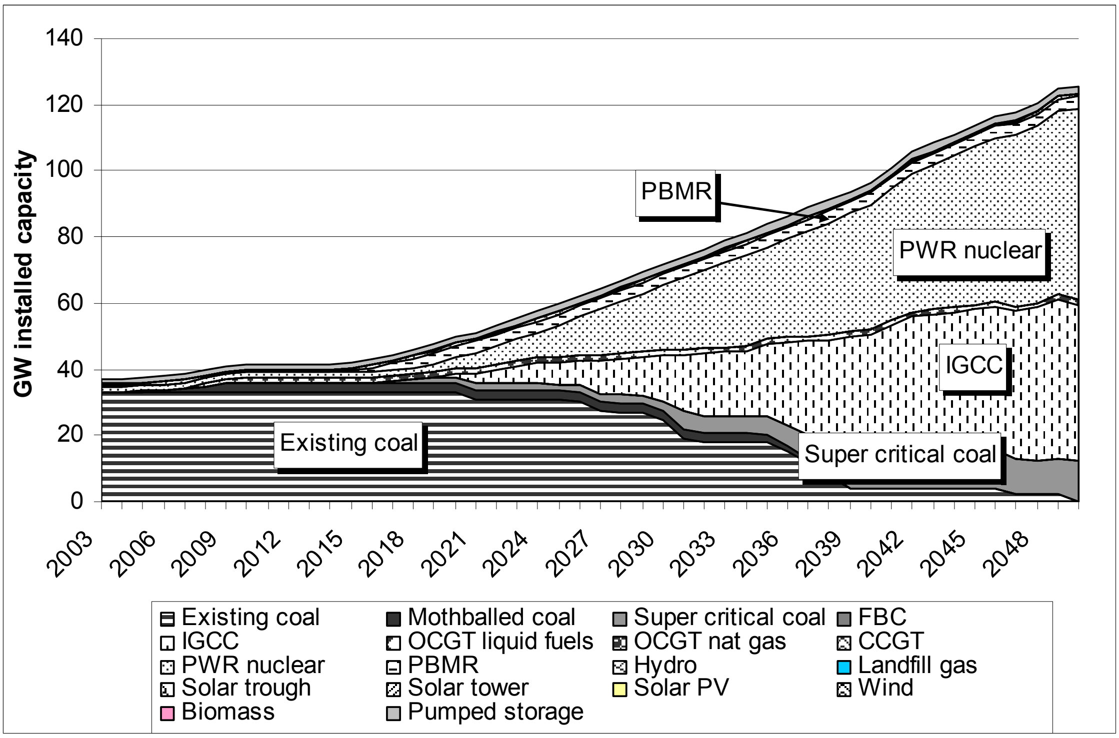
**Figure 35: Emission reductions from nuclear power**



### 6.2.6.2 *Extended wedge: Nuclear power to 50%*

As agreed at SBT4, the nuclear mitigation action was modelled in extended form, reaching 50% of electricity generated in 2050. As can be see in Figure 36, most of the increase in nuclear capacity comes from the PWR.

Figure 36: Electricity generating capacity for nuclear mitigation, extended

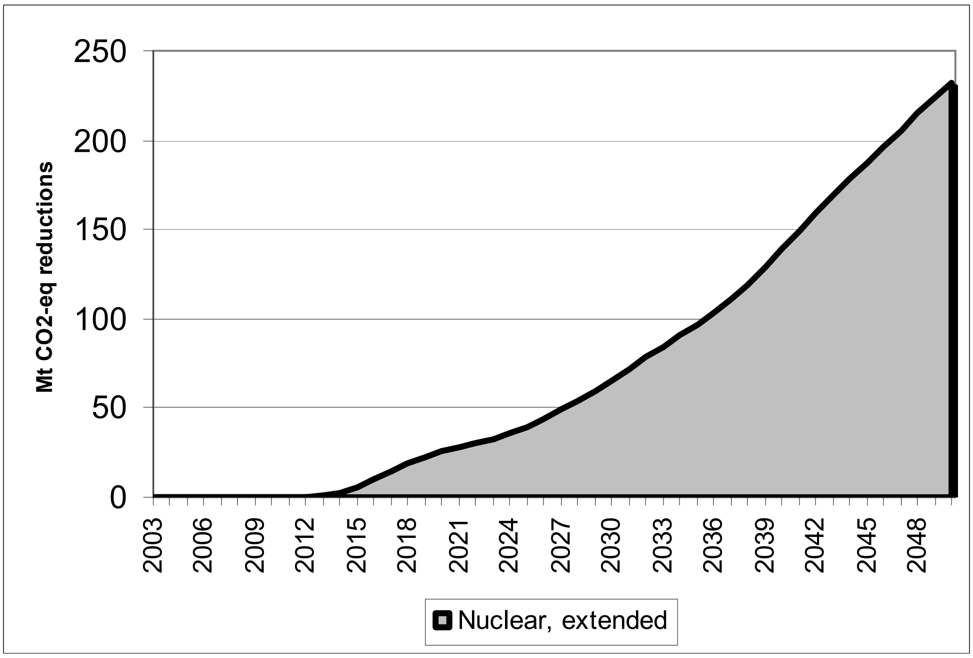


The extended wedge shows substantial emission reductions of 72 Mt $CO_2$-eq per year on average, totalling 3 467 Mt $CO_2$-eq from 2003 to 2050. This is a significant increase over nuclear at 27%, which saved less than 2000 Mt, at a slightly higher mitigation cost – from R 18 to R 20 / t $CO_2$-eq.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 5,445 | 1,433 | 561 |
| Annual $CO_2$eq saving (Mt/yr) | 72 | | |
| Cost effectiveness (R/t $CO_2$eq) | 75 | 20 | 8 |
| Total CO2eq saving (Mt, 2003-2050) | 3,467 | | |
| % increase on GWC costs | 0.68% | | |
| % of GDP | 0.15% | | |

**Note the scale of Figure 37, which almost rises to 250 Mt $CO_2$-eq in 2050. In the South African context, this is a large wedge. Total emission reductions at 3 467 Mt $CO_2$-eq over the period.**

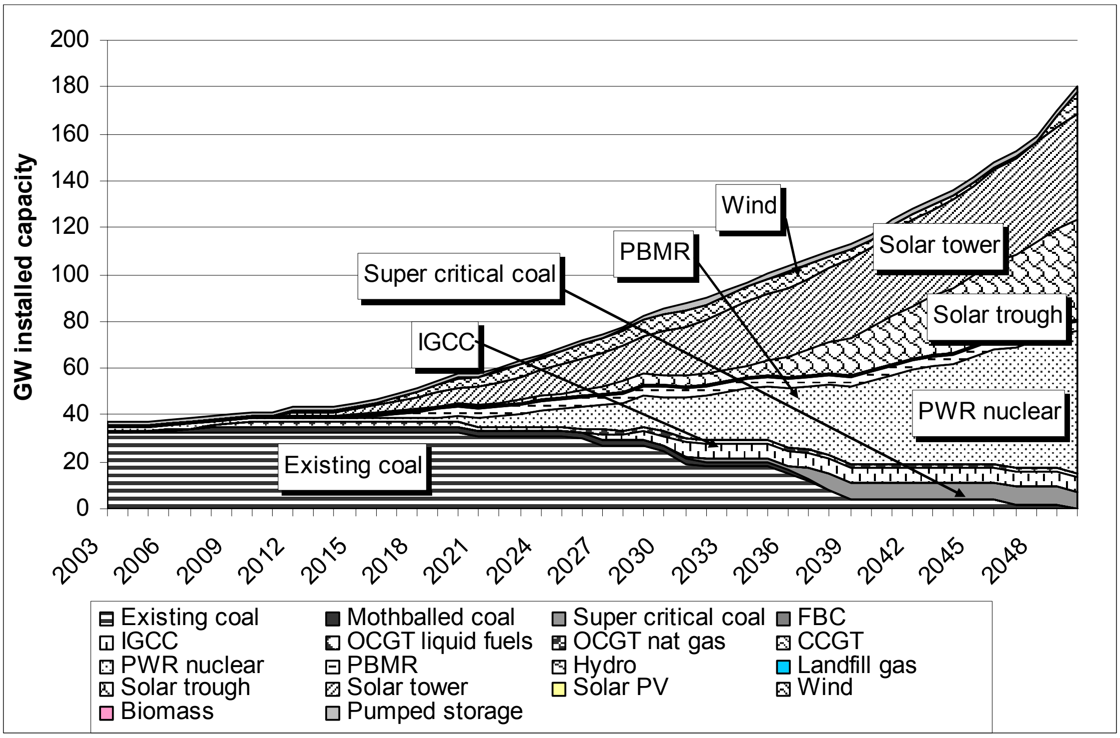
Figure 37: Emission reductions from nuclear power, 50% by 2050



### 6.2.7 Mitigation actions: renewable and nuclear power

To investigate the effect of renewables and nuclear combined., the wedges in this section combine the nuclear and renewable mitigation options at 50% each. The resulting is dominated by PWR nuclear and the solar tower and trough technologies. Note that the total capacity of the grid is 180 GW by 2050, requiring significantly more installed capacity than in other wedges (generally 120-140 GW).

**Figure 38: Electricity generating capacity for nuclear and renewables mitigation**



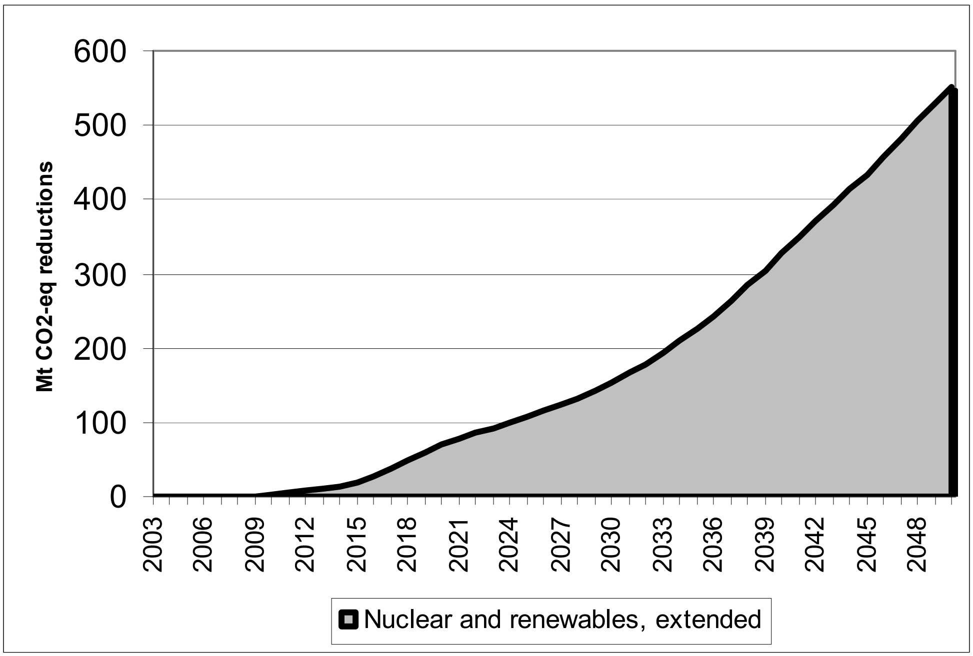
This would be like a commitment to make South Africa's electricity generation zero-carbon by 2050.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 28,963 | 9,007 | 4,160 |

| | | | |
|---|---|---|---|
| Annual $CO_2$eq saving (Mt/yr) | 173 | | |
| Cost effectiveness (R/t $CO_2$eq) | 168 | 52 | 24 |
| Total CO2eq saving (Mt, 2003-2050) | 8,297 | | |
| % increase on GWC costs | 3.78% | | |
| % of GDP | 0.81% | | |

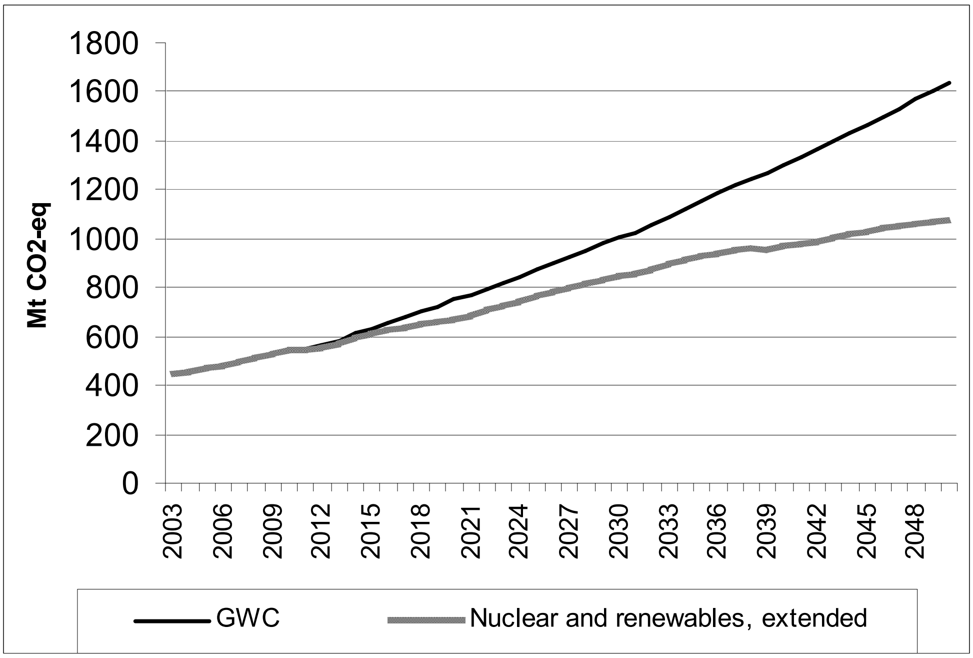
**With close to a zero-carbon electricity sector in 2050, 8 297 Mt $CO_2$-eq can be avoided, 173 Mt on average each year. By the end of the period, emission reductions reach 560 Mt, reducing the gap to RBS to 59%. However, emissions still increase in absolute terms.** Mitigation costs are R 52 / t $CO_2$-eq at a 10% discount rate. This combination of extended wedges stays below 1% of GDP.

**Figure 39: Emission reductions from renewables and nuclear power**



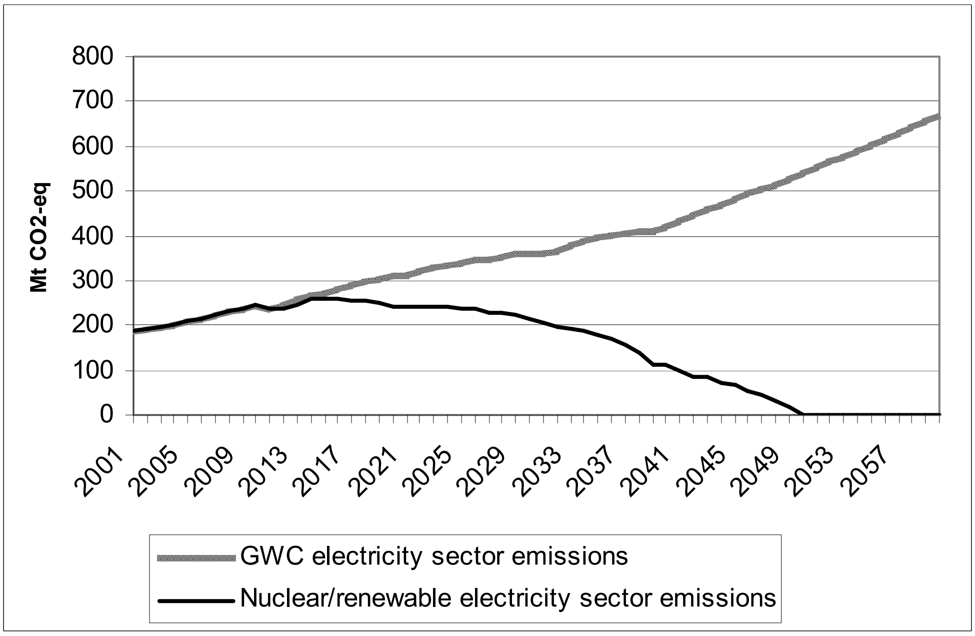
While the wedge shown in Figure 39 is large, total energy emissions in the combined nuclear and renewable case (both 50%) still do not decline over the period. Figure 40 shows total emissions in GWC compared to the combined case.

**Figure 40: Emissions from renewables and nuclear power compared to total emissions in GWC**



In other words, **even very aggressive mitigation in the electricity sector on its own will not prevent growth in absolute emissions. Mitigation action is needed in several sectors to get anywhere near what is Required by Science** – there is no 'silver bullet'. A portfolio of technologies will be needed, as suggested in the IPCC's Fourth Assessment Report. (IPCC 2007) The effect on $CO_2$ emissions in the electricity sector, however, is more dramatic, as see in Figure 41.

**Figure 41: $CO_2$ emissions in the electricity sector for nuclear and renewables each at 50%**



### 6.2.8 Variants: 80% nuclear and renewables

At the request of SBT members, the research team ran two variants of the extended renewable and nuclear wedges. Both were extended so that 80% of electricity would have to be generated from nuclear and renewables respectively in 2050. The remaining 20% could come from any sources.

The modeling team found cumulative emission reductions (2003-2050) of 5095 Mt CO2-eq for the 80% nuclear and 4 780 Mt for 80% renewable variant. However, the modelers expressed low confidence in the results. These reasons were raised at the Working Group meeting of 3 October 2007, and it was agreed that these variants would not be reflected in the Scenario document. They are reported here (and summarised in the Technical Summary). The cost-effectiveness of mitigation in these two cases, at a 10% discount rate, is R12 / t CO2-eq for 80% nuclear and R 65 for 80% renewables. The mitigation costs relative to economy (GDP) and the total energy system costs are reported. The total mitigation costs for 80% renewables would amount to 0.7% of GDP; or raise energy system costs by 3.1 %. Similarly, nuclear would impose costs equivalent on average over the period 2003-2050 of 0.15 % of GDP; or 0.7% more in energy system costs.

The energy modeling team expressed low confidence in the results reported here. The fundamental reason is that the energy system is stretched beyond limits normally considered in modelling. Assumptions that hold at lower penetration rates no longer apply at these levels. More specifically:

**For renewables:** This case uses the same assumptions for the availability of renewable plants as the base case. It is important to note that we have six time-slices in the Markal energy model. These time-slices each contain a demand for a summer day and summer night, winter day and winter night and intermediate day and intermediate night. The time-slice fraction allocated to day within the model is 0.62, and night 0.38. In order to simulate a load profile the demand for electricity by the sectors differs in each time-slice, for instance in the commercial sector demand during the winter day is assumed to be 71% of the daily demand in the season and the seasonal winter demand, 32 percent of the total demand in the year. With these limited parameters it is possible to simulate a very rough load profile.

The renewable options are modelled using an annual plant availability, the option does exist in Markal to use a time-slice availability, but this is largely unknown in the South African context for both wind and solar themal electricity technologies, which make the largest contributors towards renewable energy generation. In the cases where renewable generation contributes to the total electricity generated to a lesser extent the load profile and availability simplifications can be acceptable, however where renewables are included at 80% both the roughness of load profile and the lack of time specific generation data, which could include increased costs for plants that may require large amounts of storage make the results very inaccurate.

**For nuclear power**: The analysis assumes no constraints on the delivery of plants, or parts of the system that would have to be imported. At lower levels of penetration, this might be a plausible assumption. But if South Africa order large numbers of nuclear plants (at the same time as other countries might do the same), this constraint becomes significant.

South Africa currently imports its nuclear fuel in processed form. Similar arguments might apply to the fuel, or alternatively, a full nuclear fuel cycle might be developed domestically. The costs of developing a nuclear fuel cycle are not included in the modeling, which would need to be added to the costs assumed.

Given large amounts of nuclear power, the stand-by capacity for cooling may be larger. This has not been modelled. Again, this is a simplification that modelers find acceptable at lower penetration rates, but that become a significant issue at higher levels.

### 6.2.9 Mitigation actions: Cleaner coal - IGCC

The cleaner coal mitigation action comprises an increase in IGCC, with a much more optimistic penetration rate for the technology. In 2018, supercritical coal constitutes more than 9% of installed capacity. It reaches 10GW of installed capacity by 2050. IGCC is 16% of the mix mid-way through (2025) and 67% by 2050. There is no extended cleaner coal wedge, since super-critical coal plants, which were part of the wedge presented at SBT4, are now in GWC by definition – no more sub-critical plants are to be built, as can be seen in Figure 42, with some CCGT and PWR nuclear coming in. Cleaner coal is sometimes understood to include CCS from electricity generation as well, see wedge in Figure 44.

**Figure 42: Electricity generating capacity for cleaner coal**

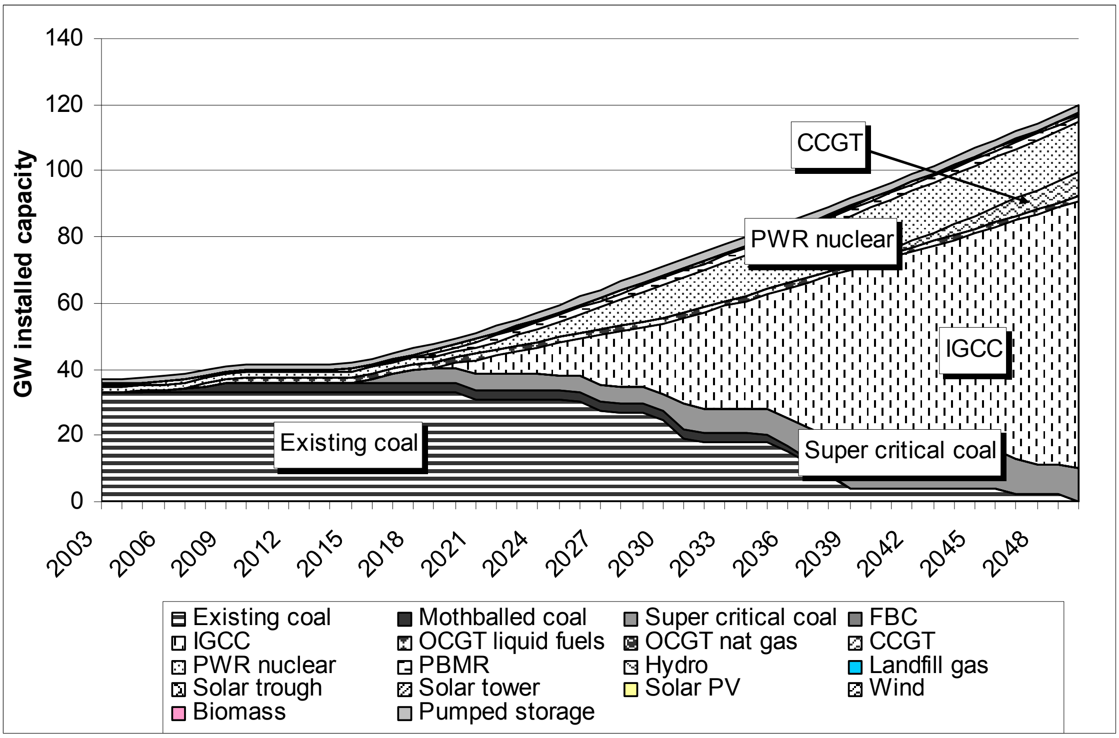


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**Table 23: Electricity generating capacity by generation type in the cleaner coal case**

| | *2003* | *2005* | *2015* | *2025* | *2035* | *2045* | *2050* |
|---|---|---|---|---|---|---|---|
| Existing coal | 32.8 | 32.8 | 32.8 | 30.6 | 17.8 | 4.0 | 0.0 |
| Mothballed coal | 0 | 0.38 | 2.79 | 2.79 | 2.41 | 0 | 0 |
| Super critical coal | 0 | 0 | 0.31 | 4.82 | 7.57 | 12.66 | 10.1 |
| FBC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IGCC | 0.0 | 0.0 | 0.0 | 9.7 | 35.1 | 64.4 | 80.7 |
| OCGT liquid fuels | 0.17 | 0.17 | 1.69 | 1.69 | 1.52 | 1.52 | 1.52 |
| OCGT nat gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCGT | 0 | 0 | 0 | 0 | 0 | 3.96 | 7.21 |
| PWR nuclear | 1.8 | 1.8 | 1.8 | 4.75 | 12.49 | 15 | 15 |
| PBMR | 0 | 0 | 0 | 1.98 | 1.98 | 1.98 | 1.98 |
| Hydro | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 | 0.73 |
| Landfill gas | 0 | 0 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Solar trough | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar tower | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomass | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Pumped storage | 1.58 | 1.58 | 1.77 | 2.38 | 2.73 | 2.33 | 2.33 |
| Total | 37 | 38 | 42 | 60 | 82 | 107 | 120 |

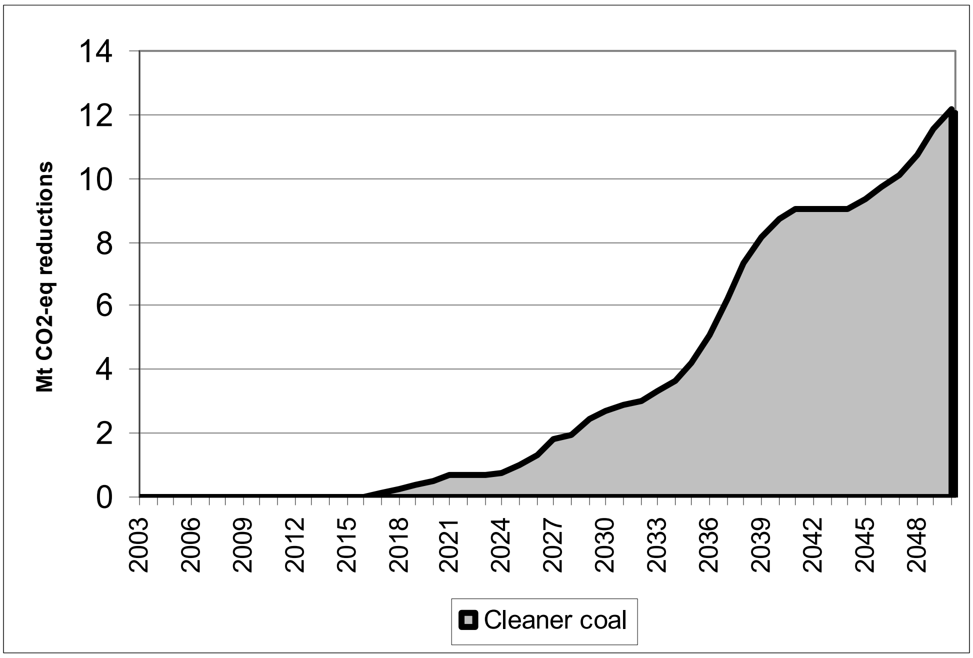
As with renewable energy technologies, learning for cleaner coal technologies is a function of global installed capacity (see Appendices). For cleaner coal technologies, data was available for super-critical coal (4%), which is included in GWC and therefore no different in the mitigation case.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -74 | -17 | -6 |
| Annual $CO_2$eq saving (Mt/yr) | 3 | | |
| Cost effectiveness (R/t $CO_2$eq) | -21 | -5 | -2 |
| Total CO2eq saving (Mt, 2003-2050) | 167 | | |
| % increase on GWC costs | -0.01% | | |
| % of GDP | 0.00% | | |

The cleaner coal wedge in Figure 43 is relatively small, with annual average reductions of 3 Mt $CO_2$-eq. Over the period, the reductions add up to 167 Mt $CO_2$-eq, at a cost of -R5 / t $CO_2$-eq, due to the increased efficiency of IGCC technology.

**Figure 43: Emission reductions from cleaner coal**



Emission reductions over time are shown in Figure 43with small reductions in this case compared to total emissions in GWC.

### 6.2.10 Mitigation actions: cleaner coal - limited CCS from electricity generation

Carbon capture and storage (CCS) is different to other mitigation options in that it actively captures the emissions and stores $CO_2$. Using CCS will in general necessitate the addressing of a range of concerns about its impacts on local sustainable development and an appropriate regulatory framework would need to be developed. Power plants with CCS use more fuel than those without and do not capture all of the $CO_2$ emitted (roughly 86%) (IPCC 2005a).

Carbon capture and storage (CCS) on electricity generation is limited to 2 Mt per year, adjusted downward from the previous 20 Mt modeled for SBT4. The SBT suggested a lower limit, given the scale of existing and planned CCS facilities. Costs for the higher figure are also reported.

It is important to understand that the amount of $CO_2$ avoided by a power plant with CCS is *not* the same as the amount of $CO_2$ capture. The efficiency of a power station with CCS will be lower than that of a reference plant. As Figure 44 shows, some of the $CO_2$ captured and stored off-sets the increase in total emissions. Secondly, there are some emission from the plant with CCS (estimated at around 15%). Thus, while the CCS action stores say 2 Mt $CO_2$ per year of, the net impact on emissions reduction is less. In addition, in this case the slightly higher capacity of coal-fired power displaces some renewables, hence the spike in emissions in 2048.

**Figure 44: $CO_2$ capture and storage from power plants**

*Source: (IPCC 2005a)*

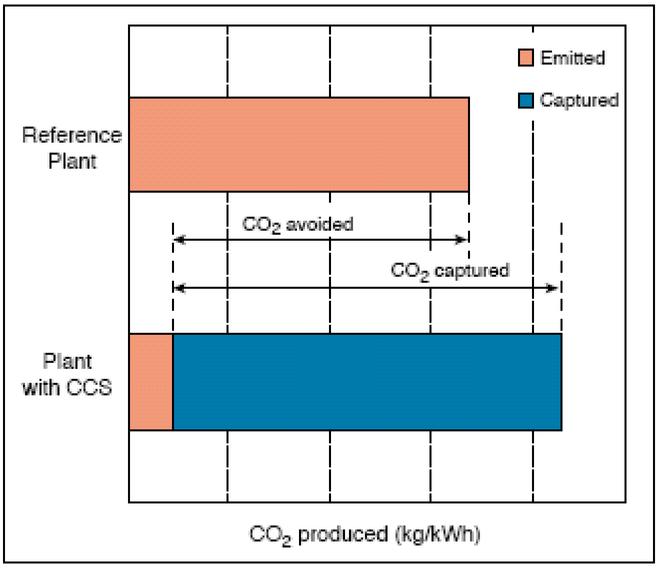


**Figure TS.11.** $CO_2$ capture and storage from power plants. The increased $CO_2$ production resulting from loss in overall efficiency of power plants due to the additional energy required for capture, transport and storage, and any leakage from transport result in a larger amount of "$CO_2$ produced per unit of product" (lower bar) relative to the reference plant (upper bar) without capture.

It should be noted that the nominal cost of CCS reported by IPCC has wide ranges, but would be over \$50 / t $CO_2$-eq[11]. In addition, South African geological conditions are not favourable for CCS, and thus a limit of 20 Mt $CO_2$-eq per year was imposed on the model; in addition, in South African conditions, this is unproven technology. Storing higher amounts of $CO_2$ per year would require a technological breakthrough. The streams of $CO_2$ available for capture are large, although for power stations the costs of separating fairly dilute streams of $CO_2$ from other gases make it more expensive that CCS from synfuels. CCS limited to 2 Mt saves an average of 6 Mt of $CO_2$-eq per year. The difference between this figure and the storage limit is due to slight shifts away from coal in the model due to the increased price of CSS-generated power.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 1,289 | 425 | 211 |
| Annual $CO_2$eq saving (Mt/yr) | 6 | | |
| Cost effectiveness (R/t $CO_2$eq) | 202 | 67 | 33 |
| Total CO2eq saving (Mt, 2003-2050) | 306 | | |
| % increase on GWC costs | 0.17% | | |
| % of GDP | 0.04% | | |

CCS limited to 20 Mt only saves an average of 9 Mt a year, due to the same kinds of systemic effects.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 1,815 | 677 | 360 |

---

[11] Most of this (\$45 / t $CO_2$-eq) would be for capture, with the rest for transport (\$4), geological storage (\$4) and monitoring and verification (\$0.2).

| | | | |
|---|---|---|---|
| Annual CO$_2$eq saving (Mt/yr) | 9 | | |
| Cost effectiveness (R/t CO$_2$eq) | 194 | 72 | 38 |
| Total CO2eq saving (Mt, 2003-2050) | 449 | | |
| % increase on GWC costs | 0.25% | | |
| % of GDP | 0.05% | | |

## 6.3 Mitigation actions: Economic instruments

The SBT at its fourth meeting decided to analyse a broader set of economic instruments, as a separate basket of mitigation actions. The research teams analysed $CO_2$ tax (applied to the whole energy sector) and various incentives.

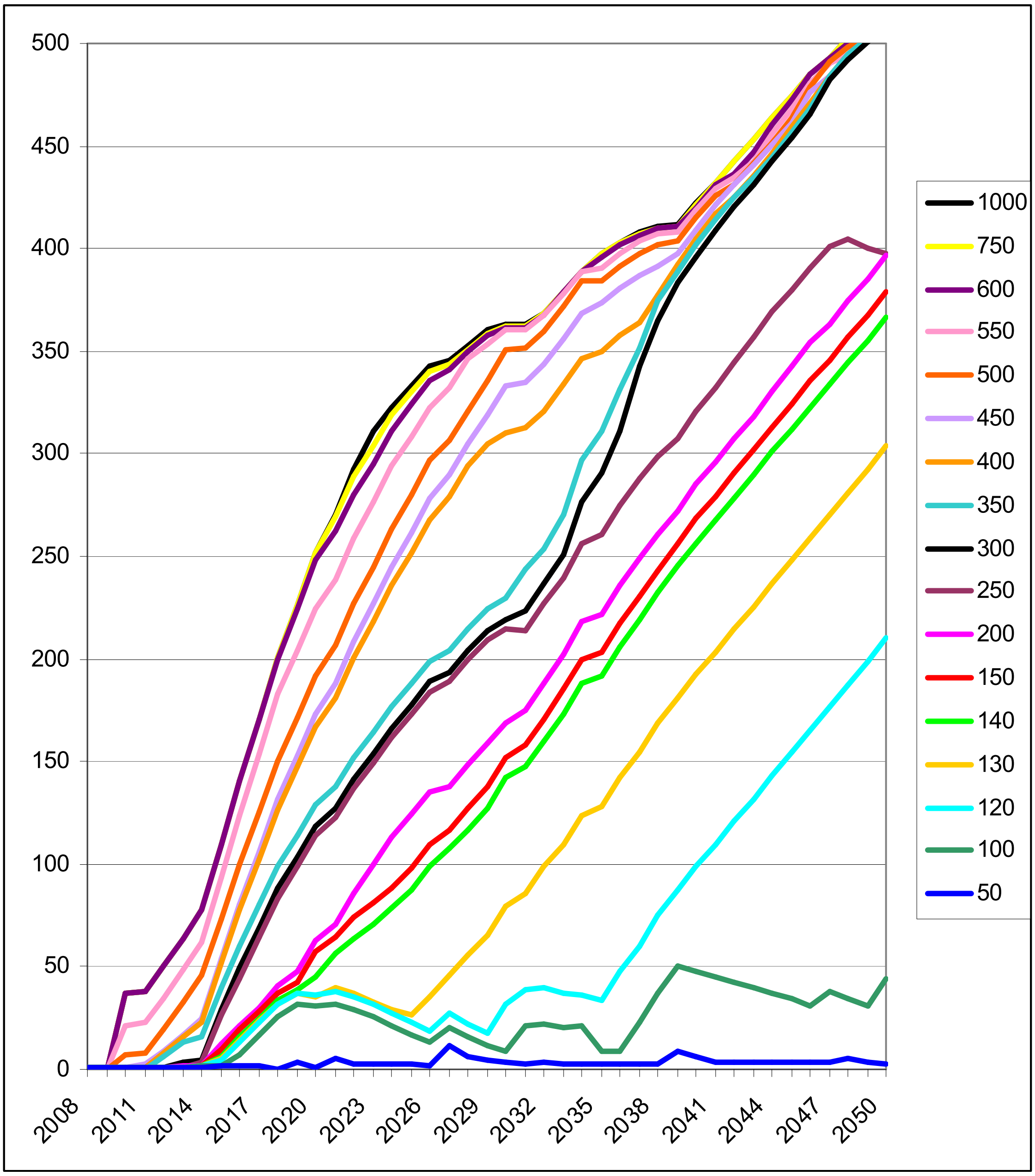
The full effect of the $CO_2$ tax will not be evident if the model cannot choose different options. In running the tax cases, bounds need to be freed up compared to GWC. All the tax cases therefore allow more building of nuclear and renewables, as well as switching to more efficiency on the demand side. The model is not told explicitly to reach a certain level of these technologies, as in other wedges, but responds to the price incentive resulting from the tax.

### 6.3.1 Mitigation actions: $CO_2$ tax

#### *6.3.1.1 The mitigation impact of different tax levels*

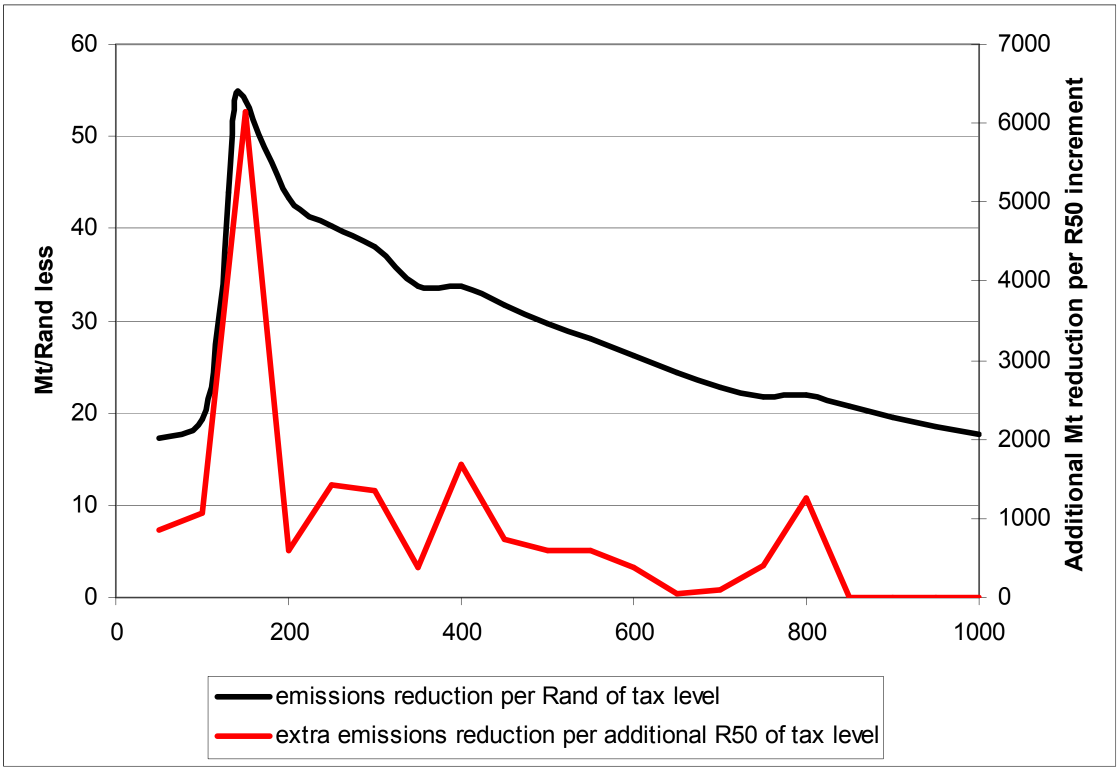
Given the limited technologies and energy carriers currently available, there are limits to the impact that a carbon tax would have on the energy system as a whole – after a certain threshold, imposing a higher tax makes no difference to the level of $CO_2$ emissions, since all possibilities for switching to lower-carbon energy options have been taken up at lower levels of the tax. The development of new options, however, would increase the level at which the tax could usefully be applied. The figure below illustrates the modelled response of the energy system to different tax levels. Whereas a R50 tax has a negligible impact, from R100 the impact becomes significant, and increases rapidly until it slows down in the range between R 100 and R200, around R140. From R200 to R300, and from R300 to R400, there are significant increases in emissions savings, although from R400 to 1000 additional gains are insignificant. This is illustrated in Figure 46, in which it can be seen that the average impact of higher tax levels peaks sharply at around R140, and declines steadily after that.

**Figure 45: Mitigation impact of different tax levels**



The marginal benefit of increasing the tax level provides some more detail: a large initial peak in the R100-200 region is followed by a small number of peaks, culminating in a small R750-800 peak, after which raising the tax level has minimal impact on emissions.

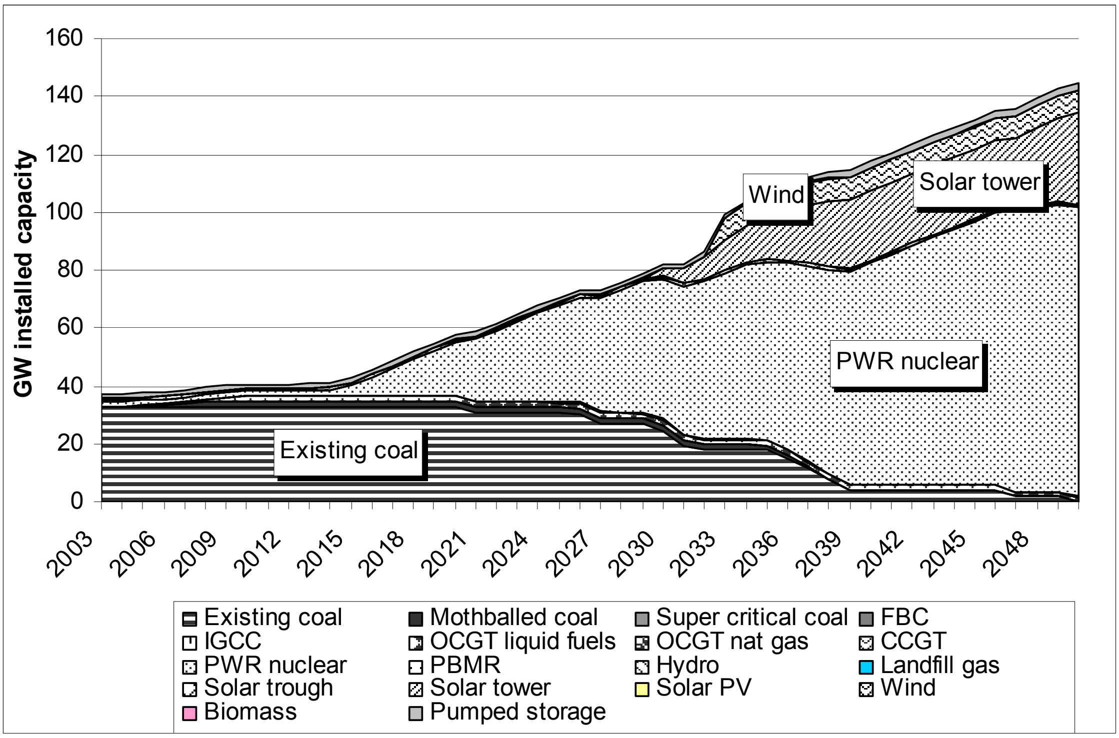
Figure 46: Average and marginal impact of various tax levels



#### 6.3.1.2 *Escalating tax*

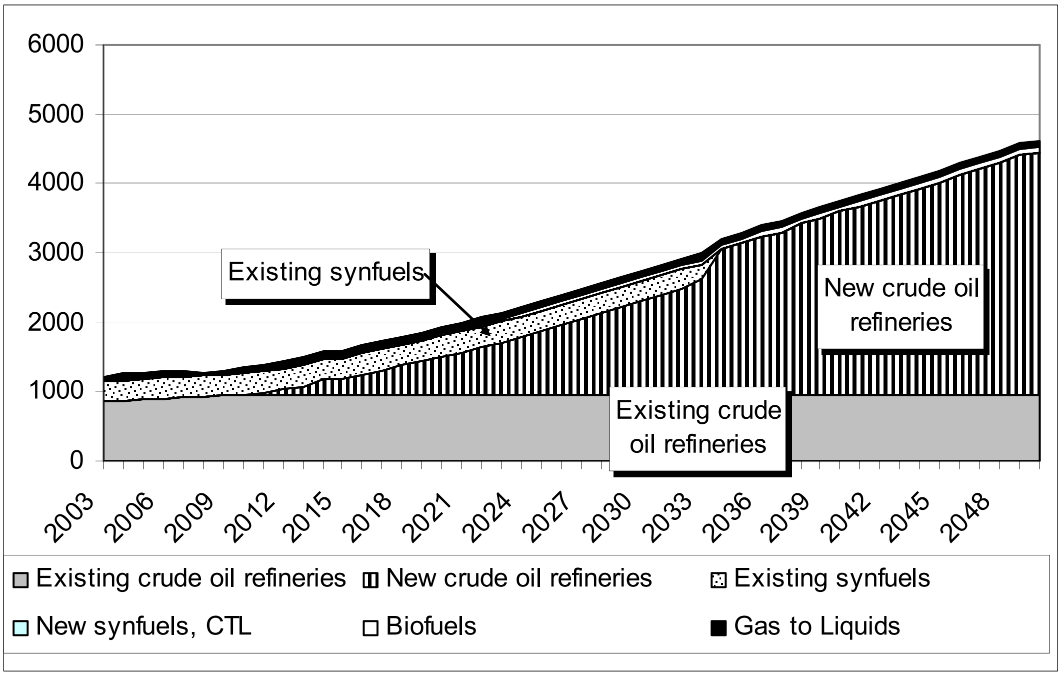
In the tax case which was modelled, an escalating tax rate is applied. The tax level starts at R 100 / t $CO_2$-eq in 2008, rises to R250 by 2020, i.e. in a period when the *rate of growth* of emissions might need to be slowed, even if absolute emissions still rise. It is then kept at that level for a decade, approximating a case where emissions stabilise (since the tax still induces changes in the system). After 2030, it rises more sharply in a phase of absolute emission reductions. It is capped at R 750, a level which is maintained for the last decade. The main impact of the tax is to reduce coal use; as a result, the projected electricity grid is dominated by nuclear and renewables, as represented in the figure below:

Figure 47: Electricity generating capacity by plant type: escalating $CO_2$ tax



In addition, as can be seen in Figure 48 there is very little use of synfuels. No new plants are commissioned, and existing plants produce no fuel from 2035, as the tax escalates through the R500 level.

**Figure 48: Ouput from refineries and synfuel plants: escalating $CO_2$ tax**

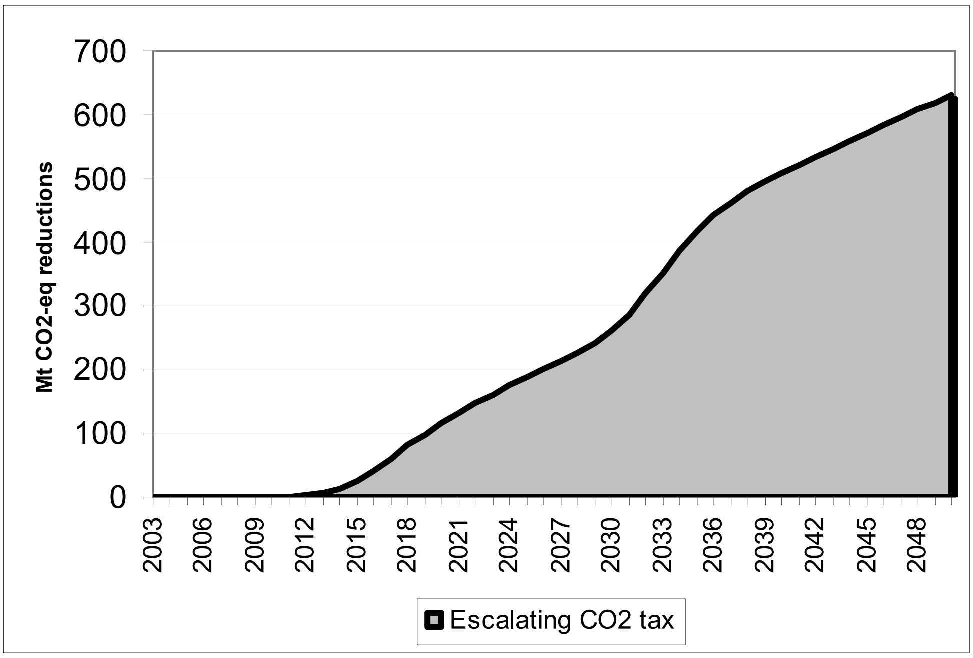


The application of the tax mitigates 12 287 Mt of $CO_2$-eq over the period, at a cost of R42 per ton.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 32,769 | 10,714 | 4,848 |
| Annual $CO_2$eq saving (Mt/yr) | 256 | | |
| Cost effectiveness (R/t $CO_2$eq) | 128 | 42 | 19 |

| | |
|---|---|
| Total CO2eq saving (Mt, 2003-2050) | 12,287 |
| % increase on GWC costs | 4.28% |
| % of GDP | 0.92% |

Figure 49: Emission reductions from an escalating $CO_2$ tax



### 6.3.1.3 *Previous tax levels analysed*

In previous analysis, $CO_2$ taxes of R 100 and R 1000 / t $CO_2$-eq were examined. A tax of R100/ton of $CO_2$ is placed on all $CO_2$ emissions. The emissions reductions are concentrated in the last two decades, when a slightly higher proportion of low-$CO_2$ emitting technologies are built – higher proportions of nuclear and renewables plants. Towards the end of the period, as more renewable technologies emerge in the GWC case, the effect of the $CO_2$ tax declines and disappears.

The R100 tax reduced emissions by 1 804 Mt $CO_2$-eq from 2003 to 2050, while at R 1000, cumulative emission reductions are substantially higher at 16 361 Mt. The total mitigation costs as a share of GDP are on average 0.05% of GDP, while the R 1000 tax is close to 2% total mitigation cost, relative to the size of the economy.

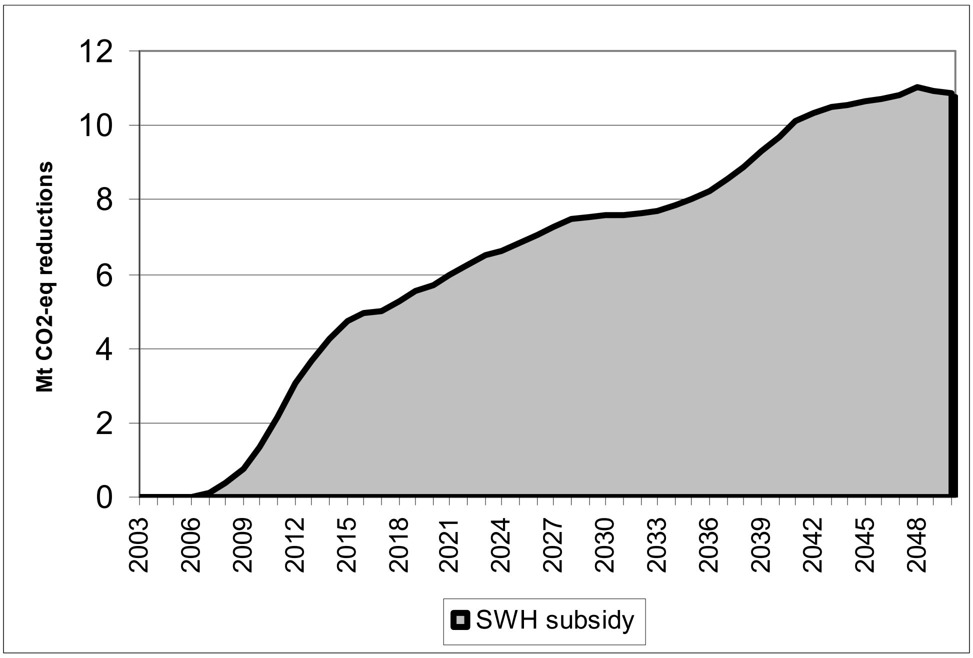
### 6.3.2 Subsidy for Solar Water Heaters

A subsidy of on residential solar water heaters has significant socio-economic benefits. In many poorer households, it could provide a service – hot water – that is not yet available. In richer households, it can reduce electricity bills substantially. For each individual household, the emissions reductions are small.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -2,932 | -1,328 | -773 |
| Annual $CO_2$eq saving (Mt/yr) | 6 | | |
| Cost effectiveness (R/t $CO_2$eq) | -459 | -208 | -121 |
| Total CO2eq saving (Mt, 2003-2050) | 307 | | |
| % increase on GWC costs | -0.43% | | |
| % of GDP | -0.09% | | |

Figure 50 shows that, if implemented widely across the country, SWH can contribute a sizeable wedge, with annual reductions of 6 Mt, adding up to 307 Mt $CO_2$-eq over the period. The mitigation can be achieved at -R 208 / t $CO_2$-eq.

**Figure 50: Emission reductions from subsidising residential SWH**

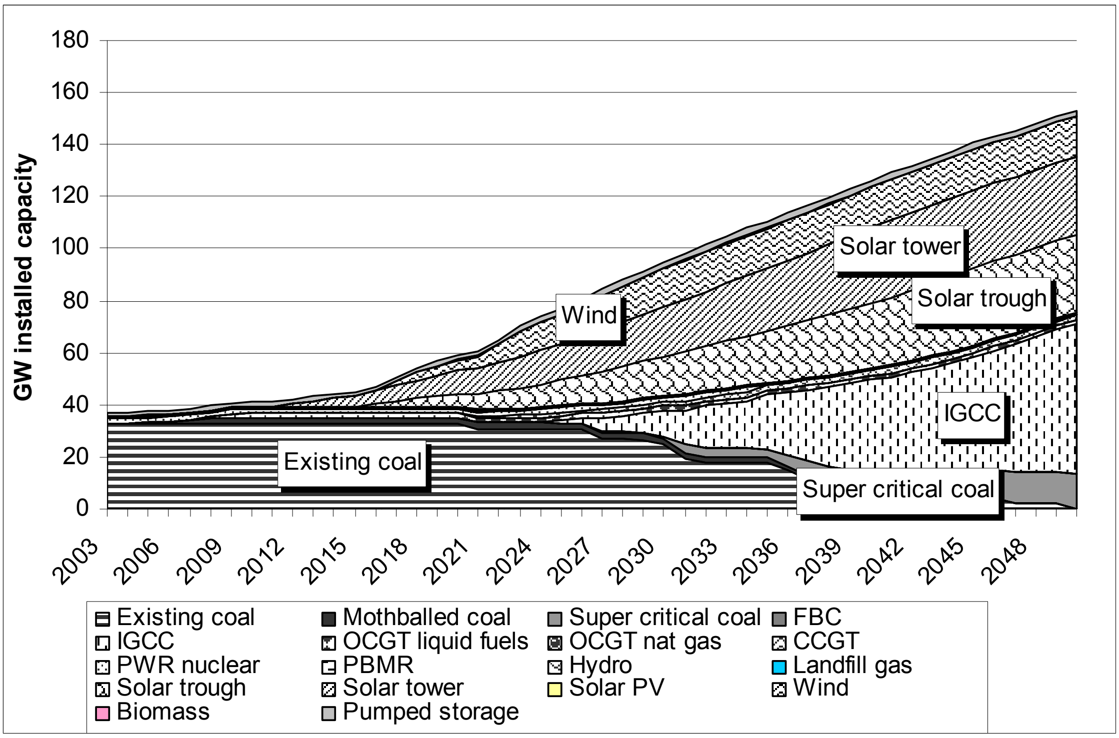


## 6.3.3 Subsidy for renewable electricity

A subsidy on renewable electricity, equivalent to 38 c / kWh, induces a significant change in which renewable electricity plants are built, resulting in the plan shown in

Figure 51. The two solar thermal electric technologies appear as in other renewables wedges, but noticeably more wind is built. The overall size of the grid is over 150 GW by 2050.

**Figure 51: Electricity generation capacity with renewables subsidy (GW)**

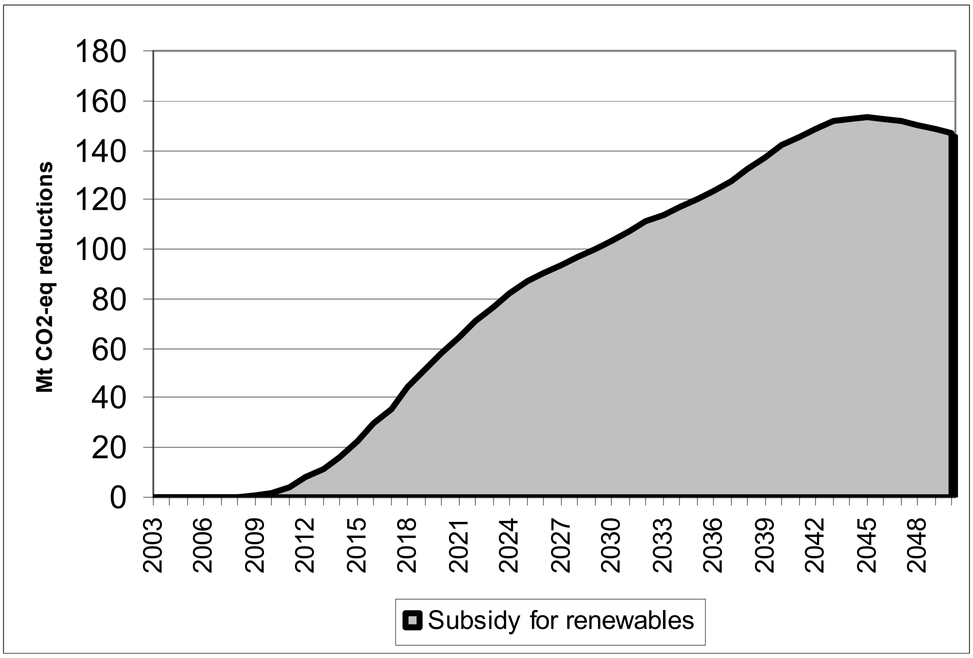


These changes in response to the subsidy result in emission reductions of 81 Mt per year, adding up to 3 887 Mt $CO_2$-eq over the period. The average mitigation cost at 10% discount rate is R 125 / t $CO_2$-eq. Overall, the cost of abatement through this measure would be 0.77% of GDP.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 26,811 | 10,130 | 5,080 |
| Annual $CO_2$eq saving (Mt/yr) | 81 | | |
| Cost effectiveness (R/t $CO_2$eq) | 331 | 125 | 63 |
| Total CO2eq saving (Mt, 2003-2050) | 3,887 | | |
| % increase on GWC costs | 3.65% | | |
| % of GDP | 0.77% | | |

**It is worth noting that the absolute reductions flowing from the subsidy for renewable electricity are greater than in any of the other renewables cases, be they initial, with learning or extended, with the exception of the extended renewables with learning case.**

**Figure 52: Emission reductions from subsidising renewables for electricity generation**



## 6.4 Required by science (RBS)

The IPCC's Second Assessment report had indicated the need for a 60-80% reduction in order to achieve stabilization of concentrations for GHGs in the atmosphere, which is the objective of the UNFCCC. The scenario assumes that South Africa implements mitigation to the extent required by science *for global emission reductions*, not adjusted for differentiation between Annex I and non-Annex I.

Subsequent to the SBT agreement, the IPCC's Fourth Assessment Report framed the challenge in different terms:

> 'For any given stabilisation pathway, a higher climate sensitivity raises the probability of exceeding temperature thresholds for key vulnerabilities *(high agreement, much evidence)*. For example, policymakers may want to use the highest values of climate sensitivity (i.e. 4.5oC) within the 'likely' range of 2-4.5oC set out by Working Group I (Ch 10) to guide decisions, which would mean that achieving a target of 2°C (above the pre-industrial level), at equilibrium, is already outside the range of scenarios considered in this chapter, whilst a target of 3°C (above the pre-industrial level) would imply stringent mitigation scenarios with emissions peaking within 10 years. Using the 'best estimate' assumption of climate sensitivity, the most stringent scenarios (stabilising at 435- 490 ppmv $CO_2$-eq) could limit global mean temperature increases to 2-2.4°C above the pre-industrial level, at equilibrium, requiring emissions to peak within 15 years and to be around 50% of current levels by 2050. Scenarios stabilising at 535-590 ppmv $CO_2$-eq could limit the increase to 2.8-3.2°C above the pre-industrial level and those at 590- 710 $CO_2$-eq to 3.2- 4°C, requiring emissions to peak within the next 25 and 55 years respectively' (IPCC 2007: chapter 3)

The AR4 spells out the trade-off between mitigation and climate impacts more clearly. Emission reductions relate to atmospheric concentrations and ultimately temperature increase considered tolerable and to climate sensitivity. If climate change impacts over 2°C were considered not tolerable, then the global target needs to be -50% by 2050.

Based on this information, SBT2 agreed to consider reductions of - 30 – 40% of the base year levels by 2050. This is the scenario of actions 'required by science' (RBS).[12] This is the only scenario that sets a climate targets, and works backwards to specific actions. The question is how this might impact on SA's economy – might it even result in negative growth?

In the energy modeling, an attempt was made to implement the RBS scenario. Emissions in 2050 were constrained to 30% compared to base year (2003) levels, with limited results:

- Initial analysis in Markal showed that RBS cannot be achieved with in a least-cost minimisation framework and the 'ambitious but realistic' limits on resources, technologies, and policies implied in that framework. The RBS climate target cannot be met within this framework. [13]
- Even applied to the reference case, the resulting Markal scenario provide 'infeasible' – in other words, the linear programme found no solution that could meet the level of energy demand and meet all the constraints (including the new climate-constraint).
- This in itself is a result – the energy modelling provides an assessment of technologies that are 'ambitious but realistic', i.e. penetration rates of new technologies are bounded to levels found in other countries; there are limits on resource availability (e.g. sites for hydro-electricity in SA). The RBS climate target cannot be met within this framework. This suggest that either one need to redefine what is realistic (e.g., re-considering the extent to which mitigation options can be achieved 'realistically'); or the analysis needs to be conducted outside of the confines of a constrained modeling approach.

With the analysis to date, no results are available for the costs of an RBS scenario. The emission reductions required, however, are implicit in the target itself. To indicate the level of emission reductions that would be required by science, we assume that emissions continue to increase only for a short while, peaking by 2015 at 550 Mt $CO_2$-eq (already slightly lower than GWC), before declining according to a polynomial interpolation to the target of -30% of base year levels by 2050. This allows at least an emissions path to be sketched, but as yet without information on the cost implications.

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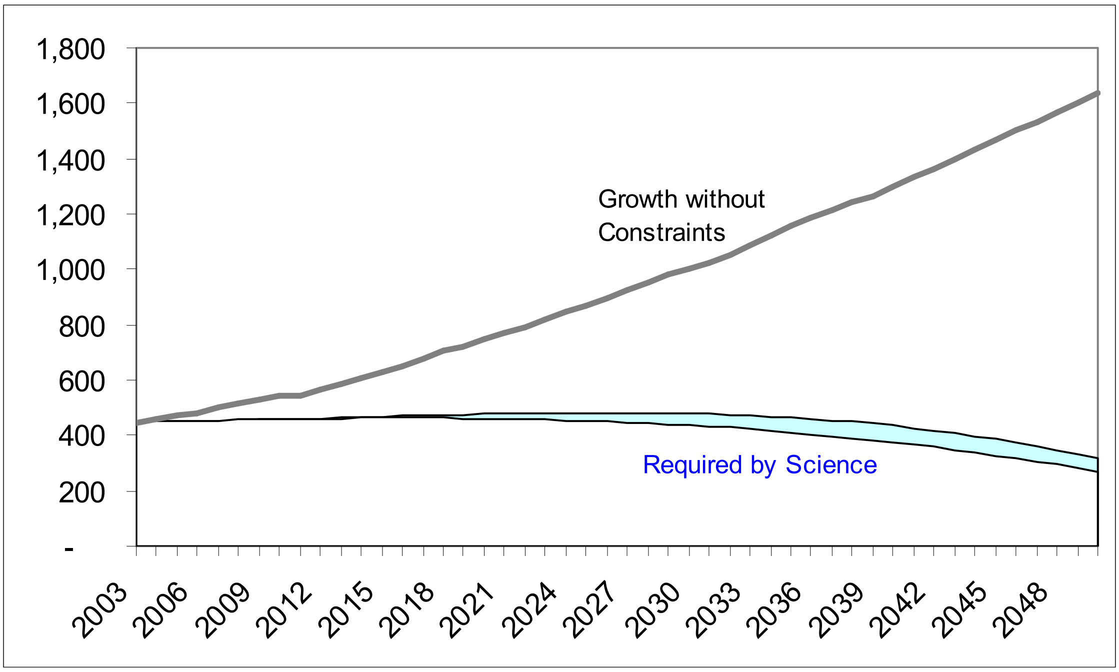
[12] In other words, it assumes that SA would act in a way that it wants everyone else to act, following the Kant's categorical imperative: 'Act only according to that maxim whereby you can at the same time will that it should become a universal law' (Immanuel Kant, *Metaphysics of Morals*)

[13] In the language of MARKAL, RBS run with the same bounds as CDP but a climate constraint turns out to be 'infeasible'. The linear programme cannot find a solution which meets all the constraints (climate target and all the energy system equations built in). This does not mean that RBS cannot be achieved in other frameworks. This should not come as a surprise – Albert Einstein already observed that '[p]roblems cannot be solved by the same level of thinking that created them.'

**Figure 53: Emission reductions required by science compared to GWC**



As suggested by SBT5, the RBS scenario has been adjusted downward and shows a range. The lower lline, reducing to -40% by 2050, shows a a global or collective bottom line, while the cloud related to South Africa's contribution to this, and not every country has the same responsibility. Compared to the gap between GWC and the whole RBS cloud, however, the differences within the RBS cloud are within a relatively narrow range.

**Table 24: Parameters used to define the RBS cloud**

| | *Beginning* | *Peak value* | *Peak year* | *End value* | *% of start* |
|---|---|---|---|---|---|
| Low cloud | 446 | 463 | 2016 | 268 | 60% |
| Median | 446 | 473 | 2020 | 290 | 65% |
| High cloud | 448 | 483 | 2026 | 314 | 70% |

The RBS 'cloud' in Figure 53 is constructed on a storyline that represents emissions peaking soon and then declining to specified level. In the first few years, emissions continue to grow, but the rate of growth is already lower than in GWC. For the bottom line of the RBS cloud, the peak is earliest (2016), for the top line it is later, by 2026. The lines do not converge by 2050. The earlier peak (bottom line) reduces emissions by -40% below 2003 levels by 2050, while the top line gets to -30%. The later the peak, the higher the emissions level at which it peaks (463, 473 and 483 Mt $CO_2$-eq respectively). This would to some extent reflect an adjustment to national circumstances, where countries more reliant on fossil fuels are required to do less than those with large renewable resources. Another example would be that some countries need a lot of energy to heat or cool space, while others have a moderate climate. The same level of comfort has different emissions implications. The middle line peaks by 2020 and reduces emissions by -35% by 2050.

# 7. Combined cases

GWC sees total emissions – energy, non-energy and industrial process combined – multiply by just under four times. Even with the effort put into current development plans, reductions are relatively small compare to growth. A target requiring an absolute reduction is significantly more ambitious. Combining cases progressively move emissions down from GWC to RBS, providing an analytical basis for the Strategic Options in the LTMS Scenario document.

## 7.1 Combined cases – initial wedges (Start Now)

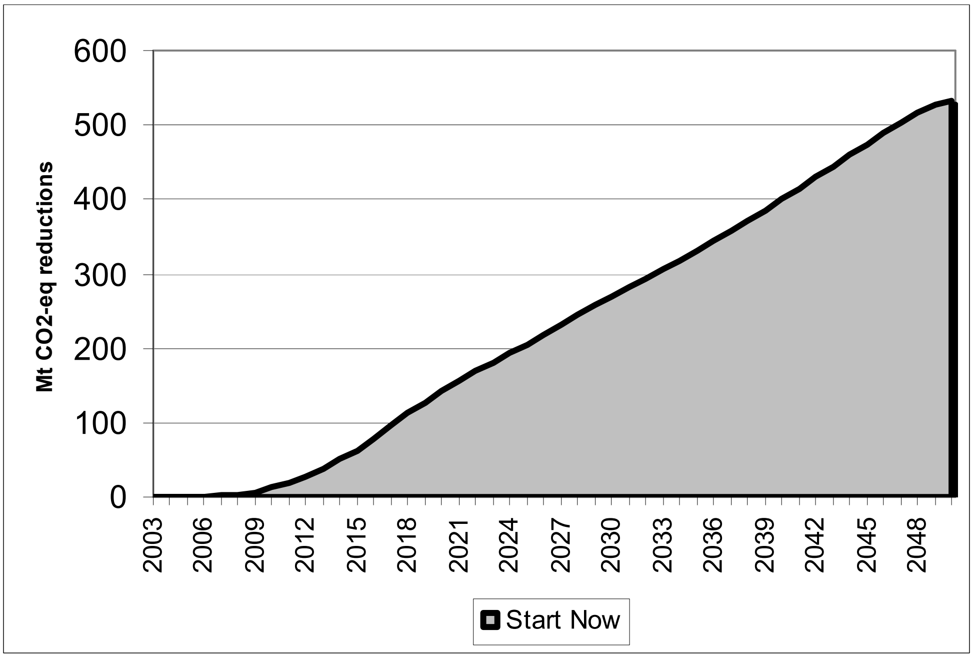
This case combines the wedges as initially modelled for SBT4, but excluding the $CO_2$ tax, which is reported as part of economic instruments. This combined case includes efficiency in various sectors (industry, commerce, residential, vehicles), options in transport including SUVs, hybrids and passenger modal shifts; cleaner coal, renewables and nuclear for electricity generations and CCS with the agreed limit.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | -18,965 | -2,971 | -467 |
| Annual $CO_2$eq saving (Mt/yr) | 231 | | |
| Cost effectiveness (R/t $CO_2$eq) | -82 | -13 | -2 |
| Total CO2eq saving (Mt, 2003-2050) | 11,079 | | |
| % increase on GWC costs | -2.18% | | |
| % of GDP | -0.48% | | |

The combined wedges reduce a cumulative amount of 11 079 Mt $CO_2$-eq from 2003 to 2050. The large wedge is shown in Figure 54 has average annual emission reductions of 231 Mt $CO_2$-eq. With substantial energy efficiency options and relatively (to the extended case) modest positive cost wedges, this can be done at –R13 t $CO_2$-eq. The share of GDP is also a negative number, reflecting a net saving of 0.48% of GDP, or a saving of the total cost of the energy system of 2.18%.

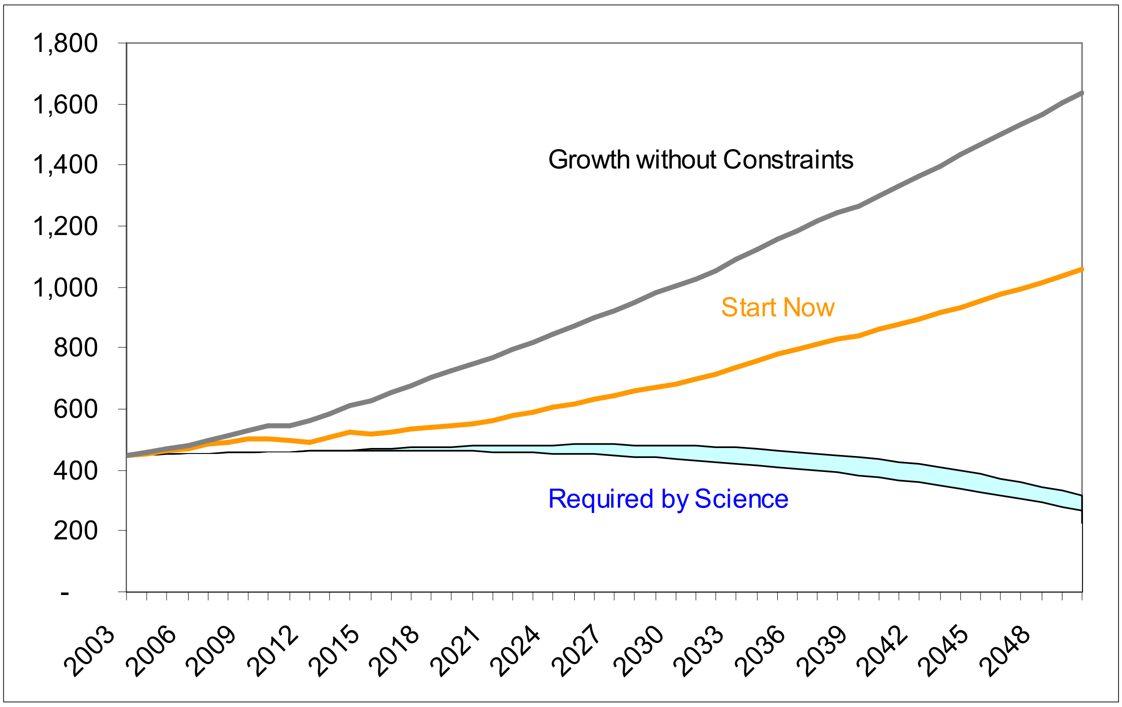
The emission reductions and costs shown above are only for the energy system. As this report has made clear, there are further emission reductions from non-energy emissions. These *are* taken into account when calculating the difference between the strategic options and *total* GWC emissions. In other words, the lines for the combined cases in Figure 55, Figure 57 and Figure 59 all include the emission reductions in other sectors.

**Figure 54: Emission reductions from combined initial wedges**



In plain language, the combined initial wedges reduce emissions very substantially, at a net saving to the country. The main qualifier is that the emissions are reduced relative to the high baseline in GWC. In absolute terms, emissions continue to rise in the initial combined case, as shown in Figure 55.

**Figure 55: Emissions with combined initial wedges compared to GWC**



## 7.2 Combined cases – extended wedges (Scale Up)

This combined case draws on the extended wedges modeled since SBT4. The extended nuclear and renewables wedges are included here (without learning). For cleaner coal technologies, the limit of storing $CO_2$ is relaxed to 20 Mt $CO_2$ per year.[14] It is extended further by including biofuels and electric vehicles, in addition to all previous transport wedges. Finally, the lower limit on SUVs is also assumed in this combination. The efficiency cases are the same as in the combination of initial wedges.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 25,772 | 11,209 | 5,842 |
| Annual $CO_2$eq saving (Mt/yr) | 287 | | |
| Cost effectiveness (R/t $CO_2$eq) | 90 | 39 | 20 |
| Total CO2eq saving (Mt, 2003-2050) | 13,761 | | |
| % increase on GWC costs | 3.63% | | |
| % of GDP | 0.77% | | |

The results for the combined extended case show that significantly higher emission reductions (13 761 Mt $CO_2$-eq) can be achieved over the period, or an average of 287 per year. However, this gain is now at a net positive cost or R 39 / t $CO_2$-eq. The mitigation costs represent a share of 0.77% of GDP.

**Figure 56: Emission reductions from combined extended wedges**

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[14] This was the limit on which the SBT4 results were based. It was proposed that he limit was then reduced to 2 Mt $CO_2$ per year, the scale of largest planned project. This has been implemented for the CCS wedge, but in the extended case, we have relaxed this again, since other technologies are also extended.

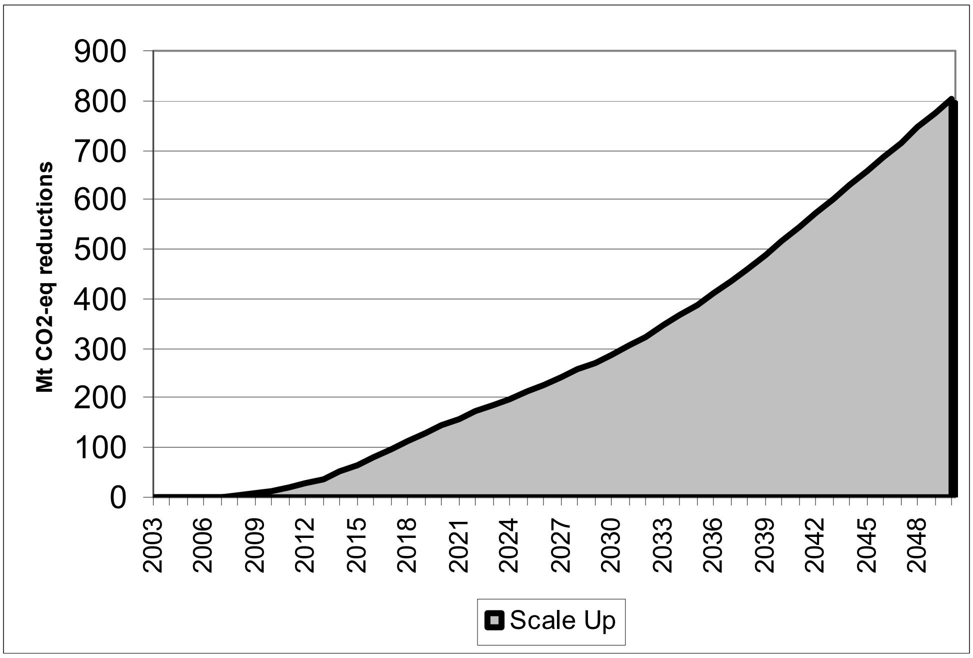
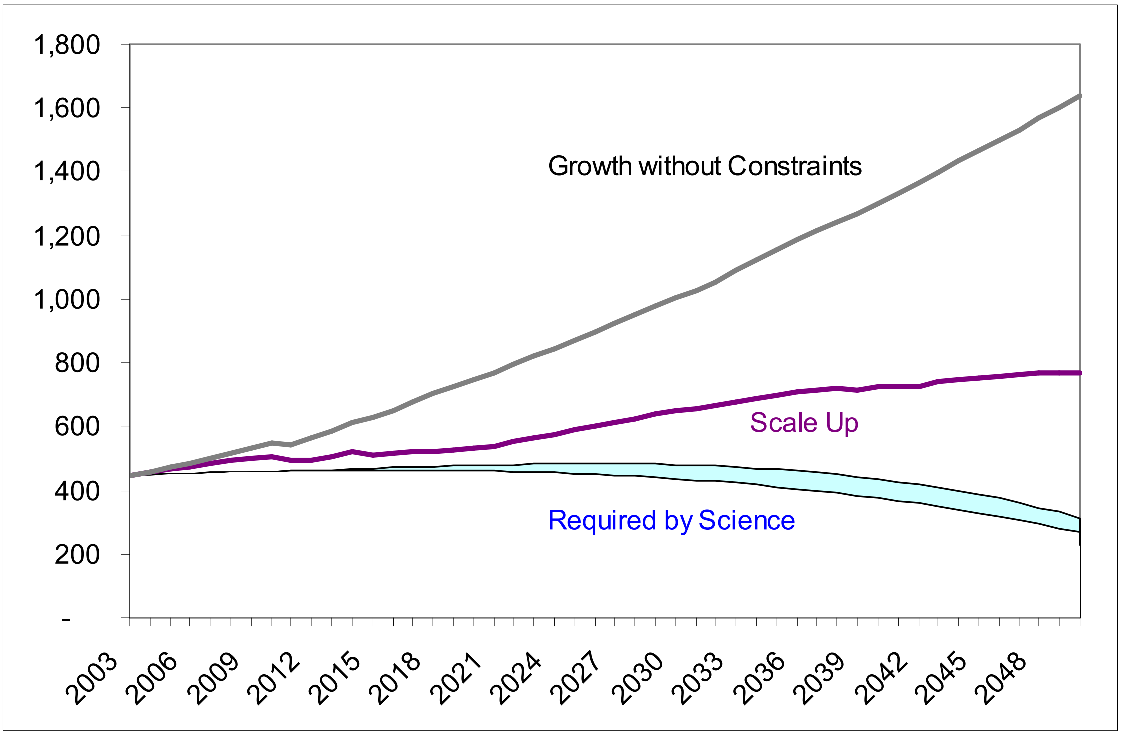


Figure 57: Emissions with combined extended wedges compared to GWC



Relative to GWC, emissions are even more substantially reduced than in the initial case, although this varies over time (for a comparison, see section **Error! Reference source not found.**). Figure 57 shows that absolute emissions increase for most of the period, but then flatten out in the last decade.

The extended combined case adds more positive cost mitigation wedges. Again, there are substantial relative emission reductions. A key difference to the initial combined case is that emission stabilise, albeit only right at the end of the period. Expressed in terms of the gap between GWC and RBS, the combined extended case has closed more than half (64%) of this gap in the year 2050. The scale of emission reductions in the wedge shown in Figure 56 is larger than all except the wedge combining the economic instruments.

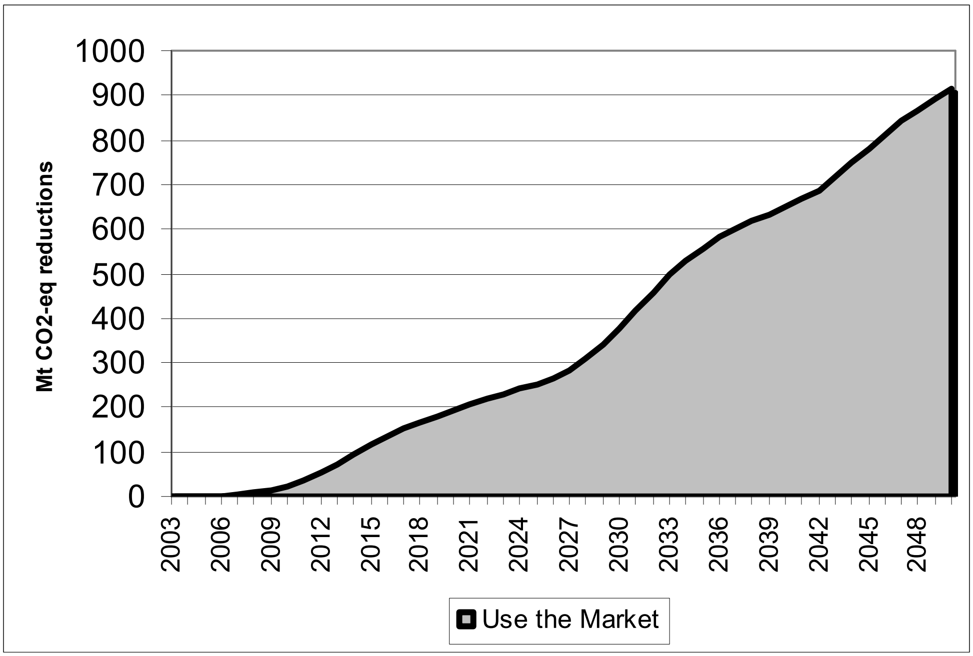
## 7.3 Combined economic instruments (Use the Market)

This combined case includes the three subsidies – SWH, renewables and biofuels – together with a higher $CO_2$ tax. To see the full effect of the measures, the model is allowed to shift to more efficient or lower-carbon fuels options. For example, greater uptake of energy efficiency as in industry and commercial is allowed, compared to GWC; and the bounds on solar water heaters are higher, as in the subsidy case.

| *Discount rate* | *3%* | *10%* | *15%* |
|---|---|---|---|
| Incremental Annual Cost (R millions) | 2,358 | 3,522 | 2,507 |
| Annual $CO_2$eq saving (Mt/yr) | 363 | | |
| Cost effectiveness (R/t $CO_2$eq) | 6 | 10 | 7 |
| Total CO2eq saving (Mt, 2003-2050) | 17,434 | | |
| % increase on GWC costs | 0.60% | | |
| % of GDP | 0.11% | | |

This combined case results in the largest wedge analysed for LTMS, as shown in Figure 58. Total emission reductions over the period are 17 434 Mt, at an average of 363 Mt $CO_2$-eq per year. Clearly the actions that would be taken in response to a combination of taxes and subsidies would constitute significant effort. To put them in one context, the annual reductions are slightly larger than national emissions in GWC in the base year for the energy sector, 2003 (at 352 Mt).

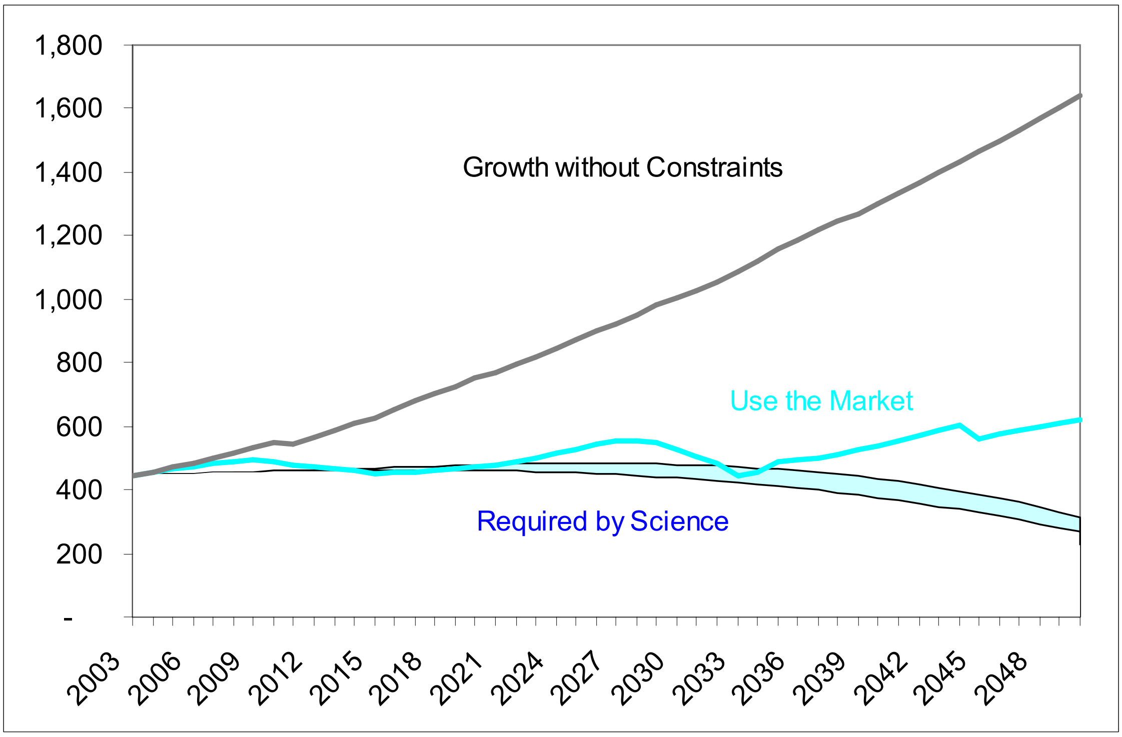
**Figure 58: Emission reductions from combined economic instruments**



**The emission reductions in response to a combination of economic instruments are large in the South African context, with reductions averaging more than 2003 energy sector emissions. Compared to GWC (see Figure 59), emissions fluctuate around base year levels up to 2036. However, in the second half of the period, emissions grow again.**

Since this is the largest wedge considered in this analysis, the extent to which it bridges the gap between GWC and RBS is worth examining. **Over time, combined economic instruments go most of the way to closing the gap, 85% in total. However, with the rising trend from 2025 to 2050, in the end year, the gap is only closed by 76%.**

Figure 59: Emissions with combined economic instruments compared to GWC



Since the combined economic case includes both taxes and subsidies, it generates tax revenues on the one hand, but requires financing of subsidies within this case. The revenues, discounted over the period at 10%, amount to R 553 billion. **Policy options that might be investigated are using tax revenue from a $CO_2$ tax to fund subsidies, making the overall basket of interventions closer to revenue-neutral.**

# 8. Sensitivity analysis

Three types of sensitivity analysis were conducted. The first sensitivity was to discount rate – three different discount rates were calculated offline for mitigation costs, three of which were reported for each wedge in this Technical Report. The results of sensitivity analysis for two other paramters – GDP and energy prices – are reported below.

## 8.1 Sensitivity to GDP

The most influential driver of emission in the modeling is GDP. Politically, this is assumed to lie between 3 and 6%. Any percentage growth sustained over a long period of time becomes exponential. Projections of 4.5 - 6% GDP growth over long periods of time are probably not realistic – actually growth is never smoothly exponential.

The energy modeling team conducted initial sensitivity analysis with with GDP at 3.9% (instead of peaking at 6% and then declining to 3% towards 2050). GDP growth and demand in the commercial, transport and industrial sector are linked with elasticities, therefore lowering the GDP growth, lowers demand in these sectors. Demand in the residential sector is driven by population growth and therefore remains unchanged.

This sensitivity analysis shows large emission reductions (174 Mt $CO_2$-eq per year, or 8 332 Mt over the period), in other words larger than any of the other options examined here. At a 10% discount rate, this case showed a ‘saving’ of R227 / t $CO_2$-eq. This saving is due to reduced economic activity, which lessens energy demand and therefore requires less investment in the energy system overall. Over 2003-2050, the saving in the energy system from reduced economic activity would be lower by almost R40 billion.

If one keeps the structure of the energy economy fixed, energy demand remains closely linked to GDP growth. Any constant percentage growth over a long time is exponential, unless the emissions-intensity of the economy changes.

The key change implemented after SBT4 in this regard is that the composition of GDP is no longer assumed to remain as it is currently. Based in particular on input received from macro-economists[15]

## 8.2 Sensitivity to energy prices

Energy prices are key parameters on which to conduct sensitivity analysis. In accordance with an SBT5 decision, the following price changes were modelled:

1. Oil / gas / petroleum product sensitivity
    a. On the oil prices
        i. First, starting from $ 55 / bbl rising in 2003 to $ 100 / bbl in 2030 and extrapolated at the same rate beyond
        ii. Secondly, from $ 55 / bbl rising in 2003 to $ 150 / bbl in 2030 and extrapolated at the same rate beyond
    b. The ratios of increase in energy prices would then be used to make equivalent adjustment to import prices for liquid fuels, as well as local and import prices for natural gas. This will be run together with the oil prices, i.e. one sensitivity on crude oil, all imported petroleum products and natural gas.
2. Coal price sensitivity
    a. A separate sensitivity analysis will be done on the coal price, increased at the ratio of the *first* oil price sensitivity
3. Nuclear fuel price sensitivity
    a. A separate sensitivity analysis will be done on the price of imported nuclear fuel, increased at the ratio of the *first* oil price sensitivity

Price changes were modelled in each instance for four cases: Growth Without Restraints (GWC), and the three main strategic options, Start Now, Scale Up and Use the Market below). The four price changes above were modelled .Significant impacts resulted from oil and coal prices changes, but no significant impacts from the change in price of nuclear fuel. The impact on GWC was minimal in terms of emissions, with the exception of coal – an increased coal price resulted in a total emissions reduction of around 1400Mt, mainly resulting from the non-construction of synfuels plants – very little new capacity is built. The major impact however is on total system costs, as reflected in the table below:

| | ***% increase in total system costs*** | ***Increase as a % of GDP*** |
|---|---|---|
| Coal price increase | 6% | 1.2% |
| Crude price increase 1 | 15% | 3% |
| Crude price increase 2 | 31% | 6% |
| Nuclear fuel price increase | 0.1% | 0.0% |

The most notable impact results from a significant oil price increase, which reflects probable prices in an oil-scarce world such as a post-peak oil world. These increases in system costs dwarf the costs

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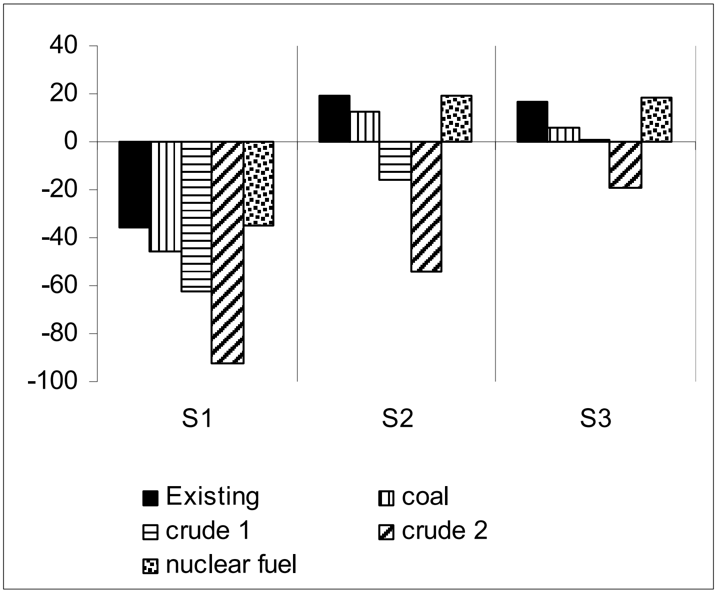
[15] See notes of meeting of (meeting of 12 July 2007)

of even very costly mitigation options. As a result, with increased prices for primary energy commodities, mitigation costs *decrease*, since both energy efficiency and alternative energy options avoid the consumption of fossil fuels. An exception to this is nuclear fuel - an increase in nuclear fuel prices as outlined above makes little difference to emissions or costs. These figures, in the three tables below, are derived by comparing each of the three strategies to new baselines with the higher energy prices. The first table compares the cost effectiveness of strategies 1 to 3 with their cost effectiveness in each of the price increase cases (coal, crude 1 and 2, and nuclear fuel):

| | ***Existing*** | ***coal*** | ***crude 1*** | ***crude 2*** | ***nuclear fuel*** |
|---|---|---|---|---|---|
| Start Now | -36 | -46 | -63 | -93 | -35 |
| Scale Up | 19 | 12 | -15 | -54 | 19 |
| Use the Market | 17 | 6 | 0.6 | -19 | 19 |

The impact of price changes on cost-effectiveness is shown in Figure 60.

**Figure 60: Impact of price on cost-effectiveness**

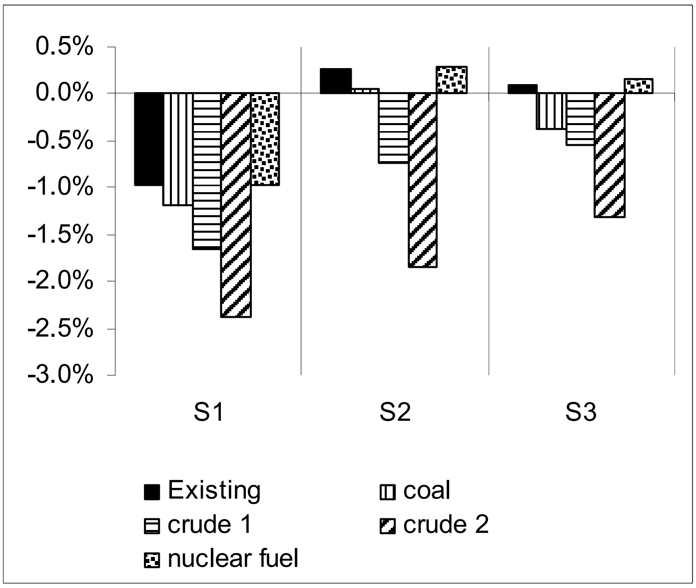


Aside from the slight differences in the nuclear case (due to a slight shift from nuclear power), increased fuel prices reduce the cost of mitigation. The same trend is reflected in the change in percentage of GDP required by the energy system, whereby increased hydrocarbon prices result in a lower additional fraction of the GDP required by the energy system for mitigation. Again, the nuclear fuel case is an exception to this, involving a slight increase in Scale Up and Use the Market.

| | ***Existing*** | ***coal*** | ***crude 1*** | ***crude 2*** | ***nuclear fuel*** |
|---|---|---|---|---|---|
| Start Now | -1.0% | -1.2% | -1.6% | -2.4% | -1.0% |
| Scale Up | 0.3% | 0.0% | -0.7% | -1.8% | 0.3% |
| Use the Market | 0.1% | -0.4% | -0.5% | -1.3% | 0.2% |

The impact of price changes on mitigation costs as share of GDP is shown in Figure 60.

**Figure 61: Impact of price on cost-effectiveness**

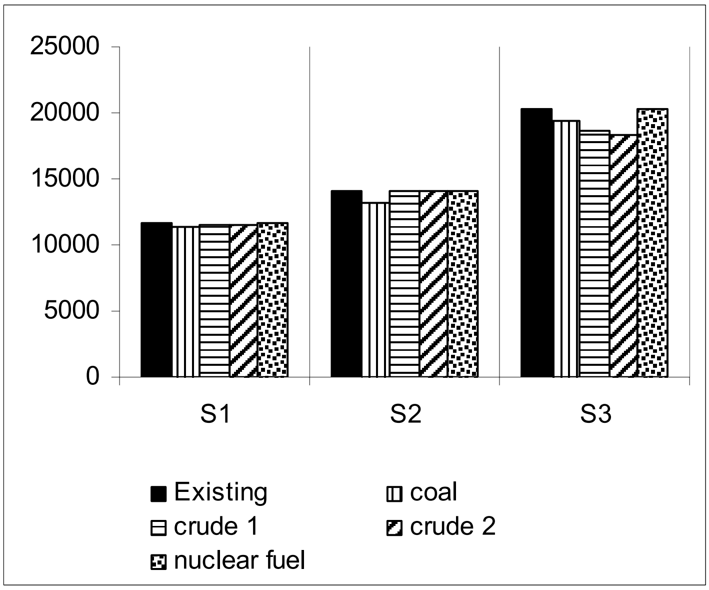


Resulting mitigation is slightly lower in the increased price cases, although these differences are slight, except for the increased coal price case, due to the lower use of synfuels in the new baseline, excluding this as a mitigation option.

| | *Existing* | *coal* | *crude 1* | *crude 2* | *nuclear fuel* |
|---|---|---|---|---|---|
| Start Now | 11611 | 11309 | 11565 | 11560 | 11621 |
| Scale Up | 14126 | 13175 | 14048 | 14039 | 14139 |
| Use the Market | 20200 | 19340 | 18630 | 18407 | 20281 |

The reasons for these shifts are more evident by comparing emissions from the strategies directly with emissions from the high-price strategies, as detailed in the table below:

**Figure 62: Impact of energy price changes on emission reductions**



| ***Scenario*** | *Coal* | *Crude 1* | *Crude 2* | *Nuclear fuel* |
|---|---|---|---|---|
| Start Now | Significantly less emissions from synfuels use (1400Mt), another 400Mt saved due to shift away from coal for electricity generation | Insignificant – slight sift away from natural gas and liquid fuels for electricity generation | Insignificant – slight sift away from natural gas and liquid fuels for electricity generation | Insignificant |
| Scale Up | More modest decline in coal use, some from electricity, and some from less synfuels – $CO_2$ reduction totalling 356Mt | Insignificant – slight sift away from natural gas and liquid fuels for electricity generation | Insignificant – slight sift away from natural gas and liquid fuels for electricity generation | Insignficant |
| Use the Market | Slight decline in synfuels emissions, big decline in industry coal use emissions as industry switches to gas (net 500 Mt less $CO_2$) | Significantly **more** $CO_2$ emissions (2730 Mt), from increased use of synfuels and coal in industry (no switch to gas) | Even more $CO_2$ emissions (3840 Mt) due to higher use of synfuels, increased coal use in industry | Insignificant |

The most significant factor is the impact of price shifts on synfuel use: increased coal prices exclude synfuels the high coal price cases, but in cases where synfuel use is minimised (carbon tax), a high crude oil price *increases* the use of synfuels, thus raising emissions. The second significant impact of price changes was on industrial use of gas – high coal prices cause an earlier shift to gas, causing a drop in emissions, whereas higher gas prices mean that gas is displaced by coal, leading to higher emissions. Again, higher nuclear fuel prices do not have a significant impact on emissions.

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