

Costing a 2020 Target of 15% Renewable Electricity for South Africa

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With an appendix by Kilian Hagemann on South African wind resources

FINAL DRAFT

EXECUTIVE SUMMARY

This study explores the implications of a renewable energy target, with South Africa setting and achieving 15% of electricity generated from renewables by 2020. We report the effects of 15% renewable electricity on the total cost of electricity production, investment in electricity infrastructure, and national greenhouse gas emissions. Achieving such a target will pose institutional, financing and policy challenges and we consider several options. The two most promising technologies for South African conditions are wind and solar thermal electricity.

The modelling framework used for the recently-completed Long-Term Mitigation Scenarios is used for this study. During the course of the study, new research on wind resources in South Africa was encountered which indicates that the potential for wind power is far greater than previously thought. Since these findings are relatively new, both the LTMS assumptions and the new assumptions were used to get a range of costs for a large-scale wind energy programme.

A number of scenarios were modelled to explore various ways in which the target could be met, what impact high or low wind resource assumptions had on the target, and what impact an energy efficiency programme would have on the costs of such a target. The most promising scenario is a mix of solar thermal and wind, which benefits both from the lower cost of wind and the ability of solar thermal plants to contribute to peak demand.

Key findings of the modelling were:

- Reaching a 15% renewable target by 2020 will not cost the earth: by 2020 average electricity costs will only be slightly higher than the baseline (around 15%).
- Combined with an energy efficiency programme, average electricity costs will be lower than the baseline for most of the 2015-2020 period.
- With the addition of carbon finance for both the efficiency programme and the renewable programme, average electricity costs will drop to 18% **below** the baseline by 2020.

Emissions reductions for all scenarios were similar: around 165 Mt of CO₂-eq over the period (2006-2020), with higher reductions (up to 400Mt) with an energy efficiency programme as well. By 2020, without energy efficiency, GHG emissions from the electricity sector are reduced by 14%, or 6.5 % of total emissions.

These are grounds to take renewable energy seriously. The modelling indicates that by itself, such a programme would have less of an impact on the electricity price than this year's price increase. The alternatives to electricity supply from coal in South Africa are renewable energy and nuclear. This study suggests that the renewables option is not more expensive than nuclear. Indeed, if what we have referred to as 'partner programmes' are also implemented, the overall cost of renewables will be lower than business-as-usual.

There are four areas where supportive programmes would help reduce costs:

- 1) research and development;
- 2) infrastructure development;
- 3) industrial strategy; and
- 4) energy efficiency.

Energy efficiency has numerous benefits: it would create employment, save the country money and avoid the risk of blackouts up to 2012. An industrial strategy based on a) increasing the local content of renewables plants, and b) aimed at developing a competitive edge in solar thermal technology internationally, would funnel as much of this investment as possible back into the local economy, and ultimately earn significant export revenue as the rest of the world attaches more and more value to low-carbon energy sources. If carbon finance is added to this the picture becomes even more positive. Tradable 'white' certificates for are another promising option for financing energy efficiency.

The main challenge, financing the renewable electricity programme, could be accomplished through a feed-in tariff, through tradable renewable energy certificates, through international climate-related finance, and through subsidies for technology development. Support for

technology, finance and capacity for developing countries is very likely to form part of the future of the international climate agreement, due to be negotiated by end of 2009. Eskom, as the national utility, could play a key development role in piloting solar thermal technology, as well as investing in solar thermal and wind, and with the right incentives, IPPs could play a major role in both technologies. In order to meet the target, however, planning should start immediately and conclude by 2010, and the optimal implementation of such a target would require sophisticated policymaking and a high degree of co-ordination between key stakeholders. South Africa has the necessary institutional, technical and physical infrastructure to achieve this, and committing the nation to a target such as this would put South Africa in a leading position internationally amongst developing countries, making renewables part of a measurable, reportable and verifiable mitigation action.

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1. Introduction

The aim of this study is to investigate, using the modelling framework developed for the recently-completed Long Term Mitigation Scenarios process (LTMS), the costs and benefits of setting a target of generating 15% of South Africa's electricity from renewable sources by 2020. The study has proceeded in two parts. In the first part, we have used the modelling framework to develop a set of alternatives, and in the second part we have attempted to clothe these modelling outcomes more substantially by exploring key policy issues and problems which the implementation of such a target would pose.

Given the magnitude of the challenge of meeting such a target, we have focused on a few technologies with the potential to meet such a target. We have thus excluded renewable technologies with small resource bases in South Africa, such as biomass and small hydro, and also unproven technologies such as wave energy. We have included solar photovoltaics in the model, but the current high cost excluded this from consideration. The analysis thus concentrated on two technologies only – wind power and solar thermal power. We assume that there is no limit on solar resources in South Africa. In the case of wind, this is different. Previous assessments have always regarded the potential for wind energy as distinctly limited in South Africa – this was questioned recently by Banks and Schaffler, who reworked a study done by the DME to conclude that total potential was significantly higher; up to 50GW of wind capacity could be installed with availabilities of between 24 and 37 percent, with the potential to produce 106 TWh annually (Banks and Schaffler 2006). This was taken a significant step further in research undertaken by Kilian Hagemann towards his PhD in UCT's Climate Systems Analysis Group, who demonstrated, using a downscaled climate model calibrated with actual wind data coupled with a GIS system which identified potential wind sites close to existing electricity and road infrastructure, that the wind potential in South Africa is considerably larger than previously estimated, and would easily support such a renewable target at lower cost than previously thought. Further analysis done by Hagemann for the purposes of this study provided new availability factors for peak periods which are much higher than those previously used for modelling the inclusion of wind energy into the South African electricity system. Although his work has not yet been peer-reviewed (his thesis is currently being examined), we feel that it is important enough to include in our modelling. In order to guard against the eventuality that his findings are too optimistic, we have also used the more conservative resource estimations in the LTMS. This has the added advantage of providing a range of possible costs. While the costs of wind technology are well-established, those of solar thermal technology are not (although the technology itself is well-established). There is thus a far higher degree of uncertainty regarding these findings.

We have made the assumption that implementation of the target will begin in 2015, when the first new renewable plants will come online and produce 2.5% of South Africa's electricity, which will increase linearly until reaching 15% in 2020. Earlier implementation at scale would require shutting down existing plant or postponing planned investment, although the extremely low reserve margin between now and 2014 suggests that there is scope for a significant pilot programme, and also scope for deployment of smaller-scale renewable technologies such as biomass plants. In addition, given the lead time of new plants and the requirement to undertake planning and EIAs, if the first plants came online in 2015, the planning process for wind would have to begin around 2010, and possibly before this for solar thermal plants. Another important factor is technology learning: we have used the same model for technology learning developed for the LTMS, but have used more conservative assumptions for wind energy from the IEA's 2008 Energy Technology Perspectives. By 2015, renewable technology is considerably cheaper than it is today.

Since it would be perverse for any government to set such a target (which imposes an additional cost on the electricity system) without also implementing an energy efficiency programme (which lowers demand and defers investment, thus lowering costs), we have also modelled some combined efficiency and renewable options to investigate the impact on the costs of the target of such a programme. The impact of the energy efficiency programme is significant (we have used the same programme for industrial efficiency modelled for the LTMS, but only the parts of the programme which apply to electricity use), and result in the postponement of the second planned new coal plant. We have also modelled a nuclear alternative, to investigate the comparative costs of a nuclear and a renewable

programme up to 2020. Although it might be desirable to have both technologies in the South African system, it is unlikely that both a renewable and a nuclear programme can be accommodated up to 2020 without underutilising generation plant.

The investment requirements for the power sector in South Africa are massive, and will be even more massive if such a target is set; fortunately, it is likely that a significant proportion of these costs can be offset through financial arrangements currently in place (the CDM) in terms of international climate change agreements, and potentially enhanced agreements in the wake of the Copenhagen Conference of the Parties at the end of 2009, which will most likely conclude arrangements for a post-2012 climate regime.

Translating modelling outcomes into policy proposals is challenging: a renewable electricity target could inhabit three separate policy domains: 1) climate mitigation policy, with implications for South Africa's domestic climate policy as well as for South Africa's negotiating position in the current international process leading up to Copenhagen; 2) energy policy, with implications for energy security and diversification, as well as for the development of new technology capacities; and 3) sustainable development – the attempt to shift South Africa away from the minerals-energy complex and onto a more sustainable development path, including the development of new industrial complexes based on technologies such as solar thermal. We have tried to explore the implications of such a target in all these domains, as well as consider the institutional implications in the context of bridging the cost gap between a reference scenario in which coal predominates and the incorporation of an increasing share of non-coal electricity generating technology into the national electricity system.

Modelling inputs and outcomes have been described in brief in the body of the report. For those who require more detail, a more comprehensive set of input data and model outcomes has been included in the Appendices, as well as a summary of Hagemann's wind resource findings, and a sensitivity analysis to various critical assumptions in the modelling process.

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2. Methodology

The approach that we have used in assessing the costs and benefits of the 15% renewable target by 2020 has three aspects:

1. An assessment of the levelled costs of individual electricity generation technologies.
2. The use of a partial-equilibrium optimisation model of the South African energy system to assess the impact of the policy on the electricity system as a whole.
3. The development of policy options for implementation, based on (1) and (2) above, which addresses financing and regulatory options for implementation.

Methods (1) and (2) are complementary: while the cost implications of individual plants can be assessed through method (1), this is not sufficient to assess the cost impacts of introducing specific generating technologies to the electricity grid¹. Whereas stand-alone assessments of generating plant provide a useful way of comparing costs for producing electricity, these depend on the characteristics of the power plants alone (capital cost, availability, reliability, fixed and variable operating and maintenance costs, efficiency, fuel cost). There will likely be significant additional costs and/or benefits in introducing specific plant into an electricity system, which depend on the characteristics of the system itself, including when the peak load occurs, the reliability of other plants on the grid, reserve margin requirements, and projected growth in demand and changes in the load curve. Both these analyses are done from a national perspective; in other words, from the perspective of a decision-maker able to choose the most appropriate development path for the national electricity system. Actual investment decisions are driven by a range of other factors, including institutional, regulatory and financial circumstances, and we have tried to elaborate on these in (3) below. We will briefly outline methodologies (1) and (2) below, which both in turn depend critically on an assessment of power plant characteristics. These are outlined below, with a more detailed discussion in Appendix 1 of which plant costs were used and why.

2.1 Levelled Cost Methodology

The Levelled Cost of Electricity (LEC) methodology is the most widely-used methodology internationally for comparing the costs of electricity generation from different technologies (International Energy Agency, 2005), but is not necessarily an adequate method for determining the actual cost of implementation of a specific project. While finance charges are imputed through using present value capital costs (see Appendix 1), and through the use of a discount rate, the total costs of financing a project are not necessarily reflected. The basic principle of LEC methodology is to calculate the average cost of a unit of electricity over the lifetime of the plant using a particular discount rate. There are two approaches to doing this, which produce identical results (Gross et al, 2007), if one assumes a constant output per year. The first is the so-called 'IEA method', which sums the costs incurred by the plant in each year, discounts these, and divides these by the discounted electricity output for each year, given by the following equation (International Energy Agency, 2005):

$$LEC = \Sigma[(I_t + M_t + F_t) (1+r)^{-t}] / \Sigma[E_t (1+r)^{-t}]$$

With: LEC = Average lifetime levelled electricity generation cost

I_t = Investment expenditures in the year t

M_t = Operations and maintenance expenditures in the year t

F_t = Fuel expenditures in the year t

E_t = Electricity generation in the year t

r = Discount rate

The second method, which we have used in this study, the so-called 'annuity' method, involves annualising the cost stream (discounting the annual costs, and then levelling these into equal annual payments), and then dividing this by the annual electricity output. The cost stream comprises the capital cost (expressed in Rands per kW), the fixed operating cost (Rands per kW), the variable operating cost (Rands per MWh), and the fuel cost (Rands per MWh – zero for renewable

¹ International Energy Agency, 2005, Appendix 5

technologies). We assume for the purposes of this study that the fuel cost varies with time, but that the fixed and variable costs are constant in real terms. Thus, using the annualising function AC (-PMT in Excel), the capital and the fixed cost are divided by the annual output of the plant, which is the number of hours in one year (365 x 24) multiplied by the availability of the plant (the fraction of a time period during which the plant generates electricity), which gives a value in Rands per kWh, which is then converted to Rands per MWh by multiplying by 1000. To these are added the variable costs, and the fuel costs, which have been discounted and levelled to get an annualised fuel cost. Thus the LEC is specified by the following equation:

$$\text{LEC} = (\text{AC}(\text{capital cost}) + \text{fixed cost}) \times 1000 / (365 \times 24) \times \text{CF} + \text{variable cost} + \text{AC}(\text{NPV}(\text{fuel cost}))$$

where NPV is the net present value (discounted value) of the fuel costs over the lifetime of the plant. Both discounting and annualising are significantly influenced by the discount rate; the choice of discount rate is thus very significant when comparing LECs of different power plants. This is illustrated in the sensitivity analysis below. It should also be borne in mind that LECs do not reflect any of the more complex aspects of plant interaction in electricity systems, such as dispatchability; technologies with low LECs might impose higher system costs compared to other plants with higher LECs; hence the value of system modelling.

2.2 Systems Model Methodology

The model of the South African energy system which we used for this study is a partial equilibrium linear optimisation model developed by the ERC for the Long-Term Mitigation Scenarios Scenario Building Team (Hughes et al 2007; Winkler 2007). The modelling platform used is MARKAL, 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 maintained; 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. 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. These demands, which are met by an optimal combination of supply and demand technologies, are specified exogenously, and do not respond to changes in price.

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. useful energy demand, the calculation of which (outside the model) is usually determined by factors such as GDP growth and population.
3. the structure of the energy system
4. historical data on the existing energy system

2.2.1 Modelling alternative futures

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. These constraints can then be lifted or altered to represent alternative scenarios. It is then possible to compare the scenario in question to the reference scenario in terms of total system cost, and in terms of other factors such as GHG emissions. This makes it possible to draw conclusions about the broader costs and benefits of introducing new energy technologies, or other measures such as energy efficiency policies.

2.2.2 Application of MARKAL for modeling the electricity system

Markal has one limitation as regards electricity. One of the most critical properties of electricity systems is that a) demand fluctuates at different times of the day and year, and b) that, generally, electricity has to be produced as it is used. Peak demand is typically significantly higher than average demand on an electricity system. Thus, within the period of a year, a specific electricity system would need to produce a certain amount of electrical energy, but the demand for this energy is not evenly distributed; thus, in addition to having the capacity to produce a certain output of electrical energy within a year, an electricity system must also have enough capacity to meet demand during peak times. Thus in order to model the electricity system realistically, a model must represent the demand curve in enough detail to ensure that the system has enough capacity to meet peak demand. MARKAL represents the demand curve at a very aggregate level, in 6 blocks: 3 seasons - day/night. Expansion plans based purely on this more aggregated demand curve will have insufficient capacity (in MW) relative to what is required to meet peak demand with some capacity in reserve. The standard approach to compensate for this limitation is to impose a constraint on the minimum capacity set to a higher value than the desired reserve margin level. There are 2 parameters here that have to be specified as they are not the result of the optimization done in the model: a) the desired level of true reserve (relative to the true demand in MW), b) the reserve as seen by the model, taking into account the true reserve and the more aggregated demand seen by the model.

i. The “True” Reserve Margin

The reserve margin is a measure of the generating capacity available over and above the amount required to meet the system demand (power in MW) requirements to allow for such factors as generator breakdown, severe weather, demand forecast uncertainty and transmission problems that could result in a loss of generation.

$$\text{Reserve Margin} = (\text{installed capacity} - \text{maximum demand}) / \text{maximum demand}.$$

The lower the reserve, the higher are the risks of blackouts. The higher the reserve, the lower are the risks of blackouts but the higher the investment expenditure. There is currently no explicitly defined generation security standard in South Africa for electricity generation. NIRP2 used a 10% reserve level in its base case, NIRP3 19%, and Eskom has recently stated that a reserve of 15% to 25% is the desirable range, however, this is higher than what has been considered in the past.

ii. The “model” Reserve Margin

The reserve margin as seen by the model is set via a calibration process in the base year by looking at what peak the model “sees” in relation to what it actually is and what the desired true margin is.

$$\text{Model Reserve} = ((\text{True Reserve} + 1) * \text{True Peak} - \text{Model Peak}) / \text{Model Peak}.$$

iii. Other reliability indicators: LOLP

The reserve margin is a known and accepted deterministic indicator of the reliability of a system. However, it does not take into account some system characteristics which are also affect the reliability of a system, such as the size of the individual units that make up a system in relation to the size of the system and their individual outage rates; random weather fluctuations that may affect both demand and supply (in the case of wind). Reliability assessments are then done by using probabilistic approaches/indicators such as LOLP (Loss of load probability). The MARKAL model doesn’t have built-in feature to calculate such indicators, however they can be calculated off-line, once the results are obtained. Parameters are then adjusted, the model re-run and iterated until the desired level of reliability according to these indicators, are achieved. LOLP is reliability index

that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. LOLP is normally expressed as a ratio of times: for example, 0.1 days per year, equals a probability of 0.000274 (i.e. 0.1/365). Target LOLP levels are typically set in the USA, and Europe for long-range planning.

2.2.3 Model data and structure

The structure of the model which we are using is essentially unaltered from the LTMS, except for the updating of the costs of electricity-generating technologies, and costs of energy carriers. Other costs remain the same. Details on the LTMS model structure and assumptions can be found in the LTMS Technical Report and Technical Report Appendix (Winkler 2007, ERC 2007). Unlike the LTMS, the current study only considers the period from 2006 to 2020. Data for emissions factors and the underlying assumptions for the growth of the economy, the evolving structure of the economy, and for population growth remain the same as for the LTMS model.

3. Characteristics of Key Technologies

As mentioned above, the two key renewable energy technologies which form the core of this study are wind and solar thermal technologies, the characteristics of which are briefly reviewed below. Wind power in South Africa is anticipated to come in the form of onshore wind installations – there are no current prospects for offshore wind, although this may change in the next few decades. Solar thermal technologies with storage come in two predominant forms currently being invested in on a large scale: central-receiver or ‘power tower’ technology, whereby a bank of mirrors directs sunlight onto a central receiver to heat a working fluid, or parabolic trough plants, comprised of arrays of parabolic troughs with a working fluid running through a pipe at the focus of the parabola. Eskom currently favours the power tower technology for its planned pilot plant in the Northern Cape, but it is not yet clear which technology is better adapted for South African conditions.

3.1.1 Large scale on-shore wind

Wind power is one of the most mature new renewable technologies, is currently in widespread use throughout the world, and is still growing very rapidly, particularly in developing countries such as China and India: Within a very short time, the Chinese wind programme has accelerated to a point where almost 3500MW of new wind power is being installed each year (with estimates of 50 000MW installed by 2015), and 40 local companies are involved in manufacturing 56% of the equipment (Global Wind Energy Council 2007). An additional 20 000MW was installed globally in 2007, almost one fifth of totally global installed capacity of close to 100 000MW. There is also a trend towards larger-scale installations – currently, wind farms of over 1000MW are being planned in a number of locations.

International wind farm operators are typically either large utilities who have moved into the wind space (Iberdrola, Florida Power and Light, Endesa, DONG, Vattenfal, E.ON and RWE), and large Independent Power Producers (IPPs), often financed by investment banks (Global Wind Energy Council 2007). On the manufacturing side, the industry has seen a number of mergers and acquisitions recently, with the large industrial conglomerates moving into the market. Major manufacturers now include Alstom, Arriva, Suzlon and General Electric, as well as emerging manufacturers in developing countries. The wind market is therefore dominated by large and well established manufacturing and operating companies, utilities and well backed IPPs, with a trend towards consolidation of the smaller developers. From a country perspective, both wind farm operators and equipment manufacturers are still dominated by European players, although the global market is expanding rapidly, with increasing manufacturing happening in China and Asia, and as government subsidies and incentives are firmed up in other countries, many globalised and well financed companies are waiting to enter the market. It is however believed that China is likely to dominate the wind market in the future given its capacity and competitive advantage in large scale production and manufacture (Global Wind Energy Council 2007). The boom in wind has resulted from clear government support for the technology. In Europe this has largely been in the form of feed-in tariffs, whilst in the US portfolio standards have played a major role.

Large scale wind farms have a relatively short lead time of around two years, plus an additional margin for EIAs, which is a key advantage of the technology. However, lead times on plant manufacture for a substantial wind programme can be substantial, as there is currently a significant under-supply of wind turbines internationally, with large orders needing to be placed years in advance, and requiring sizeable financial backing to secure the delivery date from the manufacturers (Global Wind Energy Council 2007). With the expansion of the market globally, equipment shortages are likely to ease in the near future. Given the maturity of the technology, the costs of wind generation are known with a high degree of certainty.

A wind programme in South Africa thus has the advantages of comprising a well understood, low risk and mature technology, subject to developing appropriate local skills and infrastructure. The opportunities for competing on a cost basis in manufacturing are minimal at present, and an extensive programme would initially be implemented with imported equipment and using international expertise. However, the introduction of a large-scale programme could provide local economic opportunities for component manufacture, and with an appropriate industrial policy it would be

possible to leverage South Africa's relatively cheap steel resources. The distance from other international manufacturers will also confer a competitive advantage, especially for less-specialised large-scale components such as steel towers. A large scale wind programme will require significant infrastructure and planning support. Sites will need to be identified and taken through EIA processes, with planning required to absorb the heavy-load transport throughout the country. Proactive state involvement could significantly lower transaction costs in this regard.

3.1.2 Solar thermal plants

By contrast, solar thermal technology has extremely limited deployment internationally; after a series of successful experimental plants were built in the 1980s in the USA, no further investment was forthcoming until 2004, at which point global installed capacity was less than 300MW. Since then, about 100MW of new capacity has been completed, and favourable policy regimes in Spain and the USA have led to an explosion of new orders, and around 3000MW of new capacity is currently planned for the next few years (Ren 21 2007). The IEA's Energy Technology Perspectives identifies solar thermal technology as a very promising option for areas of the world with extremely good solar resources, which includes about half the land area of South Africa (IEA 2008). Moreover, there are a number of proposals to create 'supergrids' linking these areas to other regions; the most developed proposals outline plans to link north Africa and the middle east to central and northern Europe using high-voltage DC transmission lines². Thus, while the technology is relatively new commercially, which entails significant risks and uncertainties; it is technically proven, ideally matched to South African conditions, and has the potential to develop on a massive scale globally. The lack of market maturity also implies that there would be opportunities for South Africa to develop a competitive advantage in design and manufacture of the technology, particularly if able to prove the technology at scale. South Africa has an excellent solar regime, with ample resource to provide significant future electricity generation, and potentially has the right mix of skills and manufacturing capabilities to create a competitive advantage in this market (Goedgedacht 2008). In addition, because Solar thermal plants are most suitably located in areas with a very high incidence of solar radiation, there is little competition for alternative land use.

Thus in commercial terms solar thermal plants represent a technology in its early stages, yet with good potential to operate efficiently at scale. Additionally, almost all plants have onsite heat storage, which makes them dispatchable; solar thermal plants can thus generate peak electricity when required, and recent plants have very high availability factors – The Solar Tres plant in Spain currently under construction has an availability factor of 74%³. Thus, unlike wind, which has availabilities of 15-35%, in the long term solar thermal technology has the potential to compete with other baseload technologies.

All solar thermal pilot plants have been funded by consortia, comprising either all public (Solar One) or public and private parties. Utilities have played a role in funding and implementing the pilots, as has grant funding. Solar thermal plants have lead times of around three to four years, although there is significant uncertainty attached to this figure, given the scale and limited number of existing plants.

² See for instance <http://www.desertec.org/>

³ See http://www.solarpaces.org/Tasks/Task1/Solar_Tres.htm

4. Key Assumptions

4.1 Discount rate, inflation, deflators and exchange rate

We have used a real discount rate of 7.5%, which is close to the discount rate that has been used by Eskom, but lower than the 10% discount rate used routinely for comparing power plant costs by international organisations such as the IEA; the discount rate used in the LTMS was also 10%. See below for sensitivity analyses. The discount rate is used both in the LEC analysis, and in the MARKAL model, as well as for discounting model results.

All costs are constant costs, expressed in 2003 Rands, unless specifically stated. We used the South African Producer Price Index to compare costs from different years. Almost all our costs are from either 2006 or 2007 sources. Where 2008 equivalents are provided, the PPI value for mid-year has been used to convert 2003 Rands to 2008 Rands.

We have used a constant exchange rate of 7.5 rands to the US dollar, and 15 Rands to the UK Pound, to eliminate the influence of short-term currency fluctuations. The impact of this on costs is discussed as part of the sensitivity analysis in Appendix 4. There are several ways in which to convert currencies to constant Rands in a specific base year. The one we have used throughout is to convert other currencies to US dollars, to convert US dollars to a nominal amount in Rands, and then deflate the amount in Rands to 2003 Rands using the PPI.

4.2 Power Plant costs

The challenge in developing a model which simulates decision-making into the future is in attempting to determine the key economic parameters in the future. The objective function of an energy systems model such as MARKAL is cost minimisation, and so the basis for the projected costs for power plants is largely determinant of the model outcome, as it is in many instances for real-world decision-making on medium-term power sector investments. Thus, given that the modelling period in this case is from 2006 to 2020, and that decision-making about building new plant will only take place after 2012 (new build before this has already been committed), the critical factor is what plant costs will be in the period 2012 to 2020. Since technology learning, the reduction of the cost of technology in relation to its installed capacity, is a well-established phenomenon, current costs for new plant have been as accurately assessed from existing literature as possible, and then a learning curve has been calculated to project the capital costs of plants in the modelling period. Thus, in all cases where learning curves apply, the capital costs of plants fall throughout the modelling period. The learning curve data and methodology which has been applied was developed for the LTMS⁴; more detail on the learning curves which were used can be found in Appendix 1 below. No technology learning is modelled for non-capital costs; there may thus be potential for further cost reduction in certain renewable technologies such as wind, which have relatively high O and M costs.

Current cost estimates for power plants vary widely, and have also risen significantly in the last two years⁵. We have thus updated the costs for key plant types in the model. Sources vary widely in comprehensiveness and credibility, and we have drawn on three main sources, with others to provide context, in updating costs. These are the IEA's 2008 Energy Technology Perspectives, the US Energy Information Administration's Annual Energy Outlook, and NERSA's NIRP3 process, the assumptions for which are available on the NERSA website (IEA 2008, EIA 2008a, EIA 2008b, NERSA 2007). Updates plant costs have been sourced for the following technologies:

- supercritical, fluidised bed combustion and integrated gasification combined cycle coal plants

⁴ A detailed technical description can be found in the LTMS Technical Report (Winkler 2007) and Technical Appendix (ERC 2007).

⁵ There is currently a debate in the energy policy community about the source of this sharp rise in prices. The rise has been widely attributed to commodity price rises, but apparently there have not been similar rises in prices in China and India. An alternative explanation, which has significant support, is that the current price rises are being caused by a component bottleneck, which is expected to abate in the medium term (personal communication: Dr Dolf Gielen, International Energy Agency)

- combined cycle gas plants
- pressurised water reactor nuclear plants
- solar thermal parabolic trough and central receiver tower plants
- solar PV
- wind

The most recently-published source drawn on by the NIRP3 process has been the US EIA's Annual Energy Outlook 2007 (NERSA 2007), which are in turn derived from assumptions in the US DOE's NEMS modelling system. We have drawn on the same data from the 2008 Annual Energy Outlook (EIA 2008a, 2008b), although there are certain costs (for instance the PBMR) which are specific to South Africa. Generally, where possible, costs have been drawn from one source for consistency (the IEA's 2008 Energy technology Perspectives), and the other sources have been used for comparison.

The costs, lifetimes, efficiencies and availabilities of the key plants are contained in the table below, including projected capital costs for 2006, 2014 and 2020. More detail on determining these costs is contained in Appendix 1 below.

Table 1 – Power plant characteristics

	Capital Cost 2006	Capital Cost 2014	Capital Cost 2020	Fixed O&M	Variable O&M	Efficiency	Availability	Lifetime
	R/kW	R/kW	R/kW	R/kW	R/MWh			
Combined-Cycle Gas Turbine	5023	4814	4745	135	7	50%	85%	40
Supercritical Coal	11306	10865	10662	227	17	38%	88%	35
Fluidised Bed Combustion Coal	11511	11511	11511	205	20	37%	86%	35
Integrated Gasification Combined Cycle Coal	13068	13068	13068	246	19	46%	88%	35
Nuclear Pressurised Water Reactor	19809	19809	19809	546	21	31%	83%	40
Nuclear Pebble-Bed Modular Reactor	26623	26623	26623	118	20	41%	95%	40
Onshore Wind	10523	8097	7057	195	-	1	20-35%	20
Solar Photovoltaic	38377	20485	13320	69	-	1	23%	30
Solar Power Tower / CSP	38000	28711	24320	178	-	1	55%	30
Solar Parabolic	35000	28544	25288	280	-	1	55%	30

4.3 Energy carrier costs

Energy carrier costs have risen considerably in the last two years, and long-term forecasts have changed dramatically. Given current trends in the oil price, we have assumed a price of oil of \$100 per barrel in 2008, rising to \$150 in 2020⁶. The price of imported liquid fuels and of natural gas are

⁶ Even given the current drop in the oil price, this view is supported for the long term by the US EIA (EIA 2008c); see also IEA 2007 for an analysis of medium-term constraints on crude supply.

indexed to the oil price, based on historical trends in the relationship between the international crude price and the South African Basic Fuel Price for imported liquid fuels products in the case of liquid fuels. The relevance of the oil price for electricity generation lies mainly in the price of diesel and other liquid fuels used in open-cycle gas turbines, as well as the price for natural gas, since natural gas-fired CCGT plants could make a potential contribution to future electricity generation in South Africa. Whereas in MARKAL the effective price for these fuels used in the optimisation process is a combination of a shadow price calculated from the costs of production of liquid fuels from either coal or oil, and the exogenously-derived price for imported liquid fuels, for the purposes of the levelled cost calculations we have used only the import price.

The coal price has also risen, indicating a structural shift in the economics of the coal industry in South Africa. The South African Coal Report (August 2008) quoted an average price of R110/ton (2008 Rands) for coal currently being consumed by the electricity sector. NIRP3 proposed a price of R120/ton in 2006 Rands (about R157/ton in 2008 Rands) for new electricity generation projects (NERSA 2007). We have thus assumed a price of coal in 2008 of R110/ton (2008 Rands), rising by 40% over a 20-year period, for current coal-fired power plants, and a price in 2008 of R150/ton (2008 Rands), rising by the same percentage over a 20-year period.

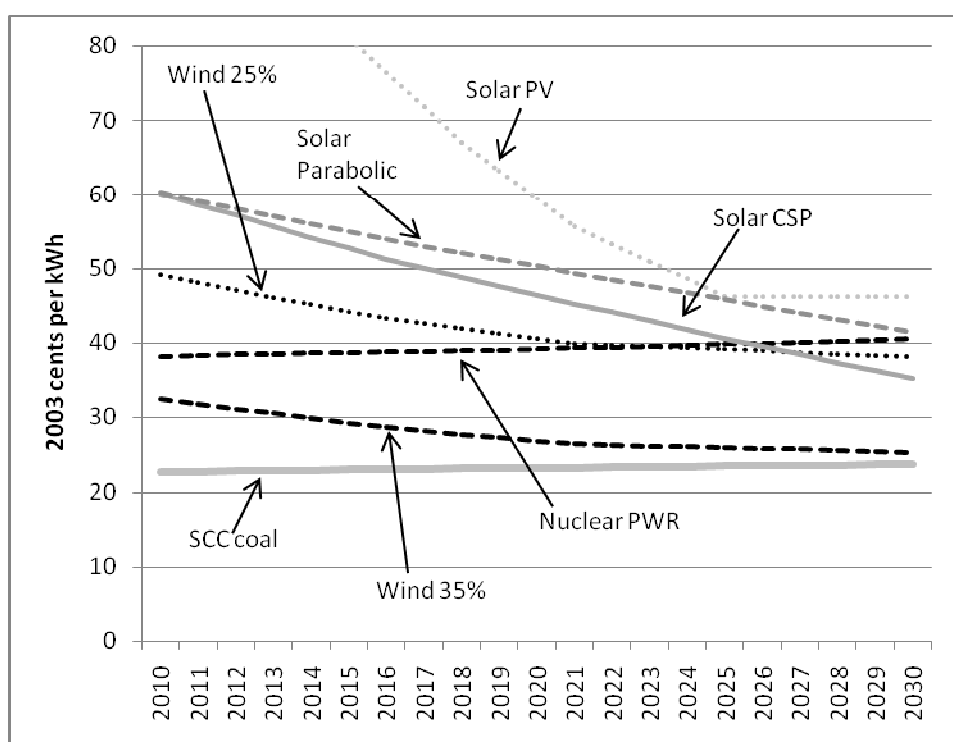
Nuclear fuel was priced at 28 Rands/MWh for the LTMS study. We have used an updated price of R57/MWh, sourced via the IEA's 2008 Energy Technology Perspectives from a comprehensive 2007 study by the UK government's DTI into the cost of nuclear power (UK DTI 2007). We assume that this price will escalate by 20% by 2020 as the cost of enrichment rises with rising global electricity prices as climate change mitigation policies are implemented, and new enrichment capacity comes onstream.

5. Levelled costs

Levelled plant costs are portrayed in Figure 1. Note that these are in 2003 Rands. The significant benchmarks for the costs of renewable are the costs of the two conventional baseload technologies, nuclear PWRs and coal. The cost of nuclear power is considerably higher than coal, and while no renewable technology is competitive with coal in the period to 2030, both solar thermal and wind become competitive with nuclear technology. This is important, as coal will probably be ruled out of contention in the medium term unless combined with CCS technology, which will increase the cost significantly. Costs for renewables decline significantly towards 2030 due to the impact of technology learning. Technology learning for supercritical coal is offset by rising fuel prices, and nuclear PWR⁷ technology costs are constant and affected only by rising fuel costs. PV is uncompetitive compared to other renewable technologies even in 2030.

⁷ We have neglected PBMRs entirely, as the point at which these become a viable commercial technology constantly recedes. These are not currently forecast to make any significant contribution to the South African electricity system before 2025 and are thus irrelevant to this analysis. Given the fact that there is not a single commercially operational PBMR in existence, we have consigned the technology to the same category as wave energy, i.e. a developmental technology.

Figure 1 – Levellised plant costs in 2003 Rands



The IEA and others (IEA 2008, Greenpeace 2007) have a more optimistic prognosis for PV up to 2050, but it does not feature in this analysis as up to 2020 it is not competitive. The costs of wind depend heavily on the relevant wind resource - turbines erected at a 35% availability site are 2/5ths cheaper than those erected at a 25% availability site. The levellised costs of high-availability wind come close to competing with supercritical coal plants by 2030, and are consistently cheaper than nuclear PWRs. Both types of solar thermal plants become competitive with nuclear power by 2030; the costs of these plants, as well as the technology learning rates, are subject to a high degree of uncertainty, and so the cost differences between these two technologies should not be taken as an indication that CSP/solar power towers are necessarily more competitive. With low wind availability assumptions, solar thermal and wind are similar in cost, especially with limits on higher availabilities.

The impact of fuel costs on LECs are significant only for gas turbines (OCGT plants fuelled by diesel and CCGT plants fuelled by natural gas). For nuclear plants and coal plants, fuel cost rises make very little difference to their respective LECs. Figure 2, Figure 3, Figure 4 and Figure 5 show the breakdown of the levellised costs for nuclear PWRs, supercritical coal plants, a CCGT plant and a high-availability wind farm. While the coal cost makes up a bigger fraction of total coal-fired power costs, the fuel price increase is not a major factor in the total cost. For CCGT plants, on the other hand, fuel cost is the biggest component. For wind, capital cost is the main determinant, which also means that the costs for electricity production from renewable sources are fixed at inception.

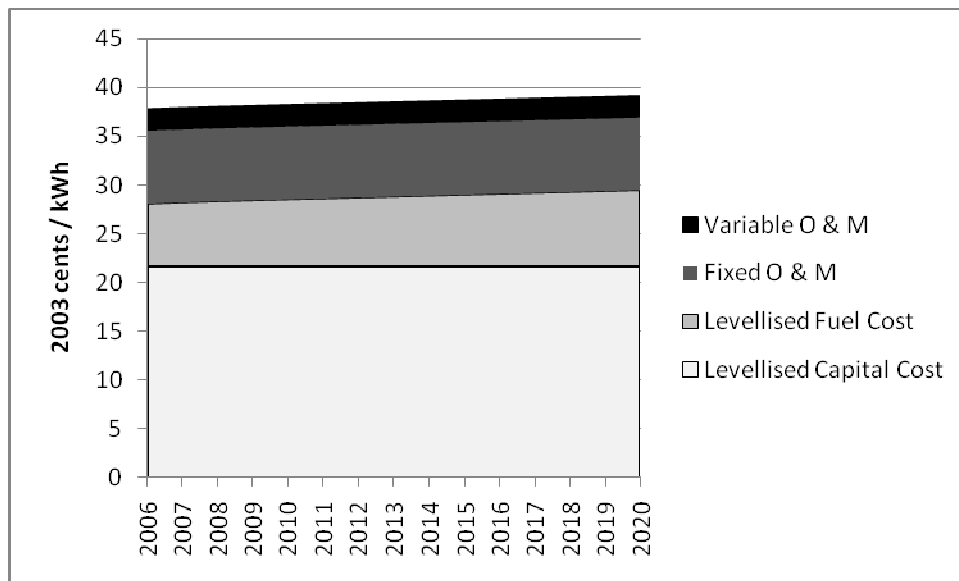
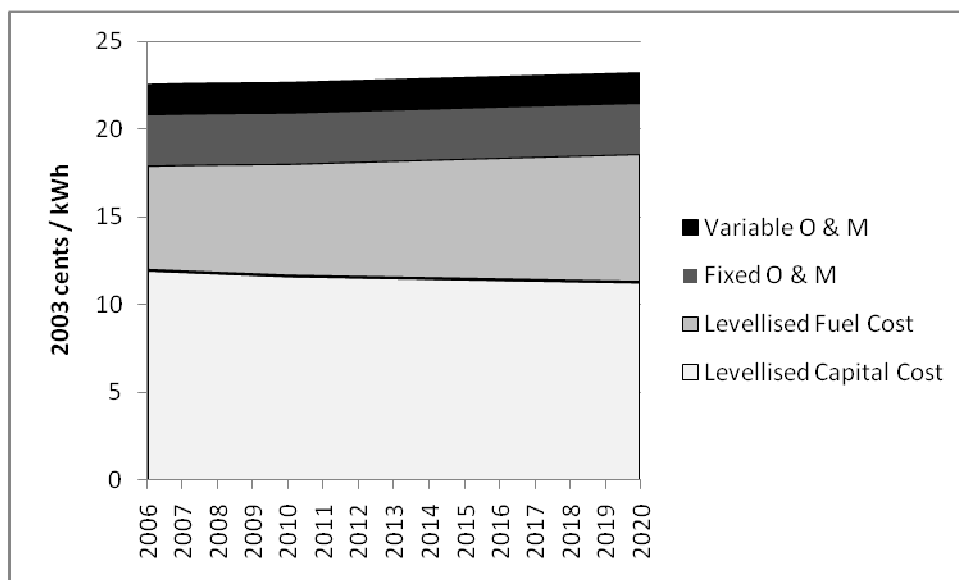
Figure 2 – breakdown of levelled costs for nuclear PWR**Figure 3 - breakdown of levelled costs for supercritical coal**

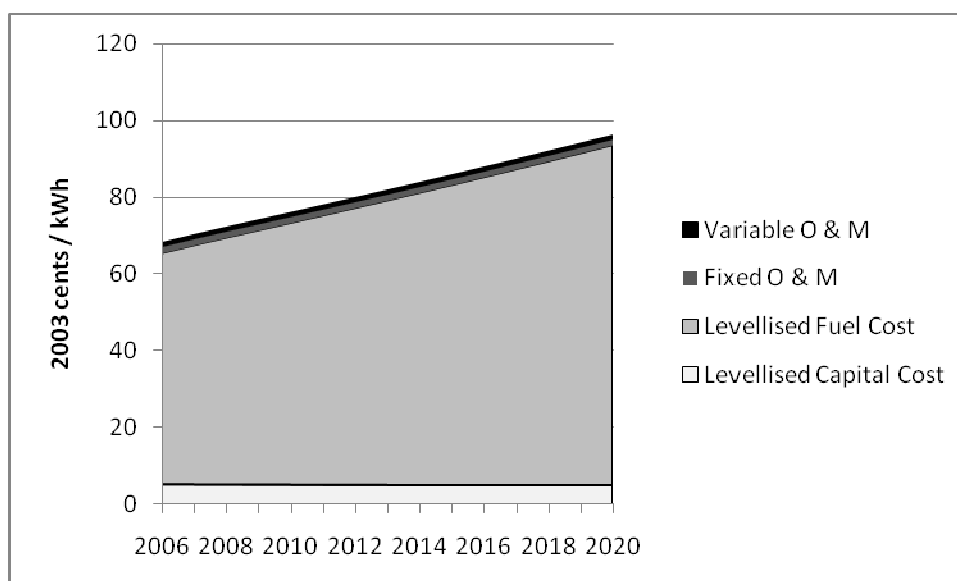
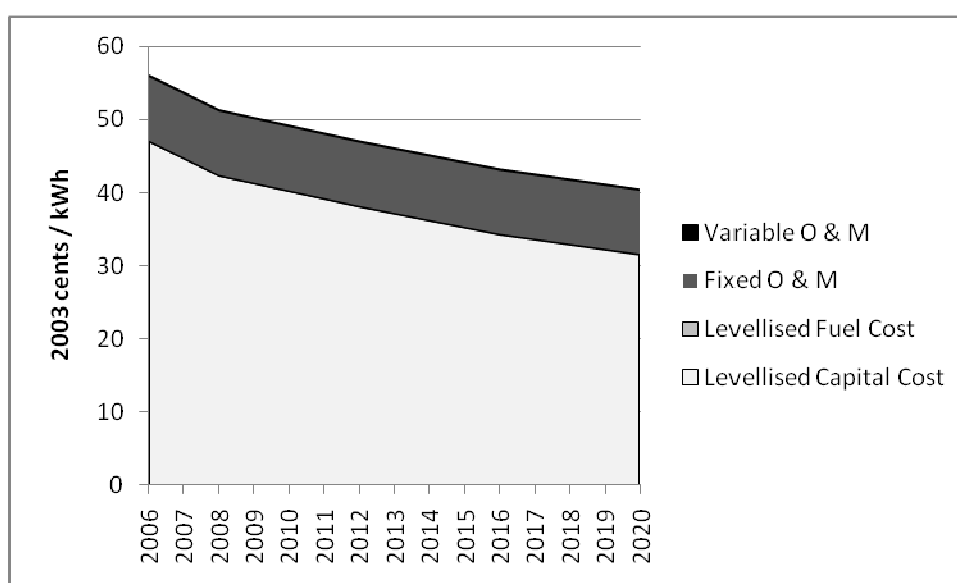
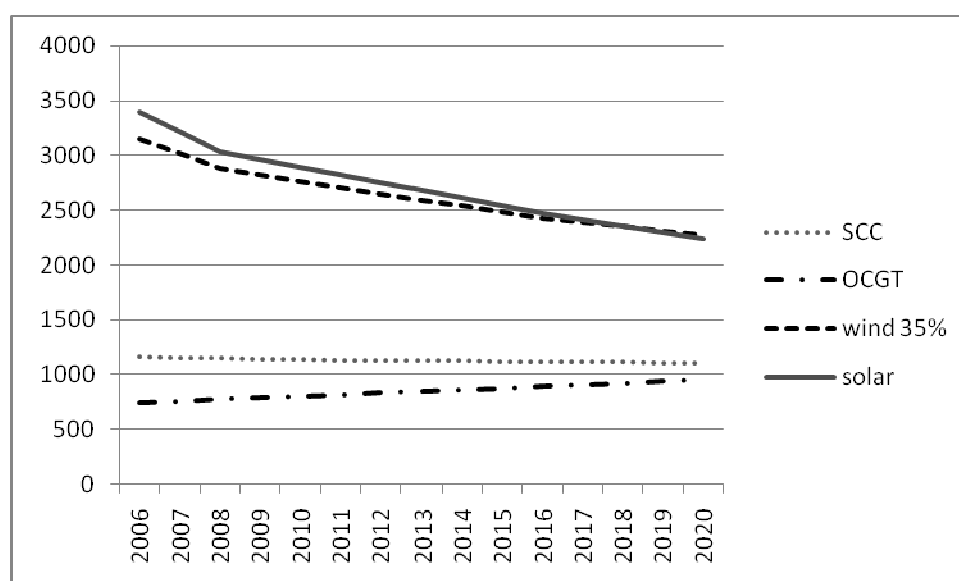
Figure 4 - breakdown of levelled costs for a combined-cycle gas turbine**Figure 5 - breakdown of levelled costs for a 25% availability wind installation**

Figure 6 portrays the levelled cost of 1kW of capacity run at 2% capacity⁸, which is a good indicator of the cost of peaking plant. 2% represents about half an hour per day. In this case, solar thermal and wind plants are comparable (although this is a hypothetical comparison, since wind is not dispatchable), and OCGT plants are still competitive even given high fuel costs. While no investor would build a solar thermal plant solely for generating peak power (since the marginal cost of running the plant a other times is close to zero), this does give an indication of the relative ability of the technologies to contribute to peak demand. It also suggests, contrary to some proponents of solar thermal plants, that for the purposes of considering the cost gap, solar thermal technology should be compared to coal baseload plant. While OCGT plants are expensive to run, their total levelled cost at low capacity factors is far lower than any other technology even given high fuel prices.

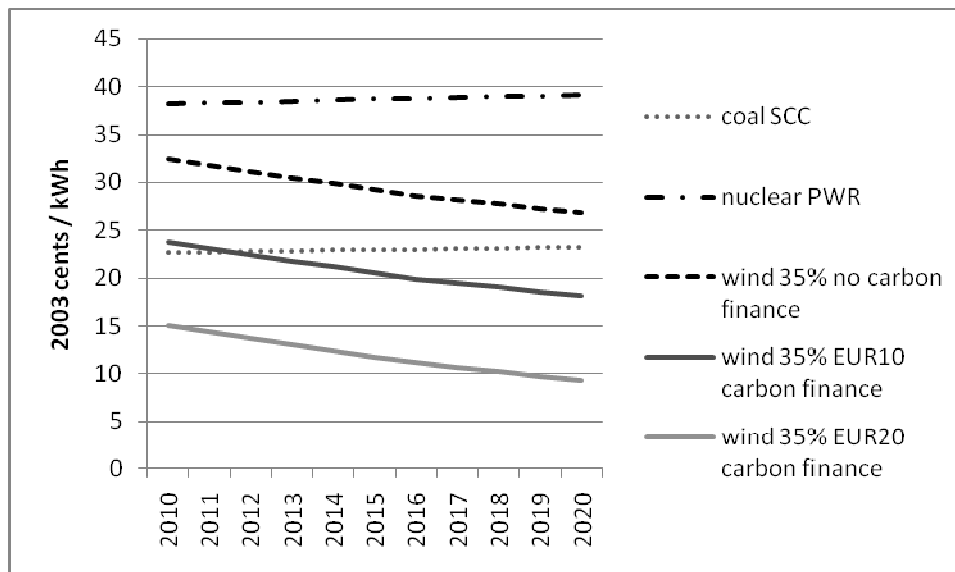
⁸ For the MARKAL model runs, we used 3%.

Figure 6 – levellised cost of 1kW of capacity run at 2% capacity in 2003 R/kW

As alluded to above, although levellised costs are a useful indicator of the cost gap between renewable technologies and their alternatives, they importantly are NOT an indicator of the true absolute cost of new renewables, which a feed-in tariff would have to address; this would require a more detailed assessment of financing costs and other costs, especially for deployment of technologies new to a particular environment, which is outside the scope of this study. Nevertheless, the relative costs are important in understanding the cost gap.

The impact of carbon finance on the levellised costs of specific renewable technologies can be easily determined; payments per ton of GHG displaced amount to a direct subsidy, assuming payments for CERs go to the plant owner. Since the systems model provides a precise indication of avoided GHG emissions and electricity generated by new renewable per year, a factor for avoided emissions per kWh can easily be calculated (in this case, 1.057kg of CO₂-eq per kWh, which is higher than the current grid average of 0.958 kg CO₂/kWh (Eskom 2007)), and used to calculate carbon revenue given a price per ton. Figure 7 gives an indication of the impact of two different levels of carbon price on the levellised cost of 35% availability wind. The impact on solar thermal plants would be similar, i.e. the levellised costs would be reduced by the same amount.

Figure 7 – impact of carbon finance on levelised costs of wind



6. Modelling a 15% renewable target for 2020

In order to explore the ramifications of such a policy for the South African electricity system, ten scenarios were modelled: one reference scenario in which the dominance of coal remains, six renewable scenarios, and one efficiency scenario and two nuclear scenarios for comparison. There are two main variations: 1) the use of two scenarios for wind resources (high and low); and 2) the inclusion of a fairly modest energy efficiency scenario, which has the impact of lowering total electricity consumption and peak demand by around 10% by 2020. The scenarios will be outlined below, followed by a comparison between scenarios of a) electricity capacity and production; b) GHG and non-GHG emissions, and c) costs. In addition, for those who require more detail, comprehensive data on the model outputs for each scenario is contained in Appendix 2 below.

6.1 Scenarios modelled

The **reference case** follows capacity expansion currently planned up to the commissioning of the last unit of Kusile (assumed to take place in 2016), after which the model chooses the least-cost option for meeting additional demand. New capacity currently planned which is included in the reference case is the completion of the return to service of the mothballed stations, the expansion of existing OCGT plants, a 100MW wind farm in 2010 and a small landfill gas project in 2008 (70MW). Additional pumped storage is also added from 2012. Other proposed but not committed plants such as the IPP peaking plant or Eskom's solar thermal plant in the Northern Cape are not included in the reference case.

The **energy efficiency case** was set up to investigate the impact of an energy efficiency programme on the 15% target. The programme which is modelled is an industrial energy efficiency programme identical to that modelled in the LTMS, but excluding all non-electricity efficiency measures. Therefore unlike in the LTMS, there are no cost, energy or emissions savings from increases in coal boiler efficiency. The main impact of the energy efficiency measures is to reduce total demand for electricity by 9%, and reduce peak demand by 8%. This is achieved through average electricity savings in industrial subsectors of around 7% in 2010, and around 18% in 2020. A more detailed breakdown per sector is included in Appendix 2 below. In addition to these measures, the planned coal plants (Medupi and Kusile) are modelled differently. Only Medupi is built, and the model chooses the least-cost option after this. Without other constraints and with the same level of demand, this is usually the equivalent of Kusile (a new supercritical coal plant), but in some scenarios the model has been constrained to explore other alternatives.

Three basic renewable energy scenarios are modelled, with three variations. In the first one, referred to hereafter as **Case 1**, LTMS assumptions regarding wind resources are used. While the cost of wind generating capacity is assumed to be the same per installed MW for all sites, the availability of wind resources is subject to differing assumptions – in Case 1, it is assumed that there are two different average wind availabilities at sites of wind farms – 25% and 20%. In **Case 2**, higher availabilities are assumed, extracted from Hagemann's recent work described in more detail in Appendix ? below. Availabilities of 35% and 30% are assumed, with output limits of around 33 000 GWh for the 35% class, and around 45 000 GWh for the 30% class, which approximate a conservative limit on wind sites with these average availabilities (see Appendix ? for a more detailed explanation). In both Case 1 and Case 2, the model chooses a least-cost way of meeting the 15% target. In **Case 3**, by contrast, the model is constrained in its technology choice, and produces an equal share of the target from wind and solar thermal technologies. For this scenario, the higher wind assumptions are used. For all three cases, the renewable target is ramped up linearly from 2.5% in 2015 to 15% in 2020. Given the exponential growth in electricity demand, this obviously implies an exponential growth in renewable generating capacity.

The efficiency case as specified above is run with these three renewable scenarios to give **Case 1A**, **Case 2A** and **Case 3A**. The reason for doing this is to explore the cost and other implications of implementing a renewable target and an energy efficiency programme at the same time, which the modelling results indicate are significant, as described below.

For purposes of comparison, two nuclear cases were also modelled. The first, titled **Eskom's Nuclear Option**, simulates a large nuclear programme of the kind which Eskom is currently considering, which is implemented after the completion of Kusile. All new capacity built after Kusile consists of new-generation nuclear pressurised water reactors (PWRs) similar to Koeberg. A **Nuclear with Efficiency** case has also been modelled – in this case it is assumed that in addition to an industrial electricity efficiency programme, all capacity after Medupi consists of new-generation PWRs. The reason for modelling the nuclear cases is to compare the costs and mitigation potential of a nuclear programme with the renewable target; however, while this is useful for comparison of policies, when comparing costs and mitigation potential, the fact that there is no target comparable to the renewable scenarios imposed in the modelling must be taken into account.

6.2 Electricity Capacity and Production

Peak demand and the amount of electricity required per annum depend on the final demand, which changes only with the addition of efficiency measures. Thus, cases 1A to 3A, Nuclear with Efficiency, and the energy efficiency case have a lower peak demand, and a lower electricity production requirement. Thus, whereas in cases 1 to 3, total required electricity in 2020 is 375 192 GWh, in the efficiency cases this is 342 875 GWh, and thus the 15% target is correspondingly lower (51 400 GWh instead of 56 200 GWh), leading to a considerable savings in investment. However, in order to attain the same reliability as the reference case, higher reserve margins were used in some cases (and lower in others). These are described in more detail below.

The analysis below concentrates on the capacity brought online from 2015 to 2020, since no new renewable capacity apart from the planned 100MW wind farm in the reference case is brought online before this. New capacity in wind, solar thermal and coal is detailed for the reference and renewable cases below:

Table 2 – new generation capacity in GW for each scenario commissioned from 2015-2020

	coal	wind	solar thermal	% new coal capacity displaced
reference	12.17	0.00	0.00	-
case 1	2.94	8.76	6.90	76%
case 2	6.92	18.27	0.00	43%
case 3	4.03	9.08	5.09	67%
case 1A	0.74	5.76	7.26	94%
case 2A	5.19	16.43	0.00	57%
case 3A	2.51	8.29	4.59	79%

In the reference case 12 GW of coal is added to the grid in the period. In Cases 1 and 1A, a balance of solar thermal and wind is the lowest cost option, given the similarity of the levelled costs of the two technologies by 2015 (assuming a lower availability of wind). In case 1A, given the lower proportion of coal in the system, the balance is tipped in favour of solar thermal. In Cases 2 and 2A, using the higher-availability wind assumptions, wind is significantly cheaper, and no solar thermal capacity is built. In Case 3 and 3A, using the higher availability assumptions for wind, half the target is dedicated to wind and half to solar thermal. There are two notable aspects of these scenarios: 1) the significantly lower availability of wind (even with higher availability assumptions) implies that significantly more installed capacity is required to produce the same annual output, and 2) a higher proportion of coal is displaced in scenarios containing a higher proportion of solar thermal plants. This latter outcome is due to the non-dispatchability of wind, which requires more dispatchable plant to be built to achieve the same reliability than solar thermal, which is dispatchable. Thus the scenarios which displace the most investment in coal are those which contain the highest proportion of solar thermal. The total installed capacity for each scenario, the peak demand and the effective reserve margin, are contained in the table below:

Table 3 – installed capacity, peak demand and reserve margin

	AF reserve margin	peak demand (GW)	total installed capacity (GW)
reference	15%	57.48	66.18
case 1	14%	57.48	72.61
case 2	18%	57.48	79.2
case 3	16%	57.48	72.21
case 1A	15%	53.04	65.6
case 2A	19%	53.04	73.46
case 3A	17%	53.04	67.23
nuclear	15%	57.48	66.46
nuclear efficiency	17%	53.04	62.39

In calculating the reserve margin, an Availability Factor (AF) at peak times has been used to add built capacity, which is 1 for all plant except wind, where it is 0.23 for the lower resource estimate, and 0.39 for the higher availability factor; thus the reserve margin reported here does not reflect the significantly higher installed capacity for wind required on account of its lower availability (for instance, the physical reserve margin for Case 1 is around 26%), but it does reflect additional non-wind capacity necessary to achieve the same reliability as the reference case. As above, the highest reserve margins are necessary for Cases 2 and 2A, which have the highest proportion of wind. This has an obvious implication for cost, which will be further explored below.

The renewables target, as well as the efficiency measures, displace a significant fraction of coal output – in the efficiency cases, electricity production itself is displaced. In the period 2015 to 2020, 95% of electricity is produced from coal. This declines to 87% in the renewables cases, and lower in the nuclear case. In the efficiency cases, just over half the coal-fired electricity displaced is avoided production, and the impact of renewable is smaller (around 147900 as opposed to 163300 GWh) due to the lower electricity requirement.

Table 4 – Amount of coal-fired electricity displaced, 2015-2020

	% electricity from coal	Coal electricity displaced - GWh	Electricity generated by renewables - GWh	Electricity generated by nuclear - GWh	% coal electricity displaced by wind	% coal electricity displaced by solar	% coal electricity displaced by nuclear	% coal electricity avoided by efficiency
reference	95%	0	0	0	0%	0%	0%	0%
case 1	87%	163642	163122	0	51%	48%	0%	0%
case 2	87%	163244	163267	0	100%	0%	0%	0%
case 3	87%	163397	163228	0	56%	44%	0%	0%
case 1A	87%	314067	147908	0	19%	28%	0%	53%
case 2A	87%	313864	147944	0	47%	0%	0%	53%
case 3A	87%	313864	147944	0	27%	20%	0%	53%
nuclear	86%	181947	0	181978	0%	0%	100%	0%
nuclear efficiency	83%	370247	0	204331	0%	0%	55%	45%

6.3 Emissions

The impact on GHG and non-GHG emissions in the electricity sector follows similar patterns. The table below describes GHG emissions reductions (more detailed data is available in Appendix 2 below):

Table 5– GHG emissions mitigation for all scenarios, 2006 to 2020

	GHG emissions saved (Mt CO ₂ -eq)	GHG emissions saved as a result of renewables /nuclear	% reduction from reference case	% reduction as a result of renewables /nuclear	% reduction in electricity sector emissions	% reduction in electricity sector emissions as a result of renewable /nuclear	% of savings occurring from 2015 to 2020	% reduction in electricity emissions in 2020	% reduction in electricity emissions in 2020 as a result of renewables /nuclear
Case 1	161	161	1.7%	1.7%	3.9%	3.9%	100%	14%	14.1%
Case 2	169	169	1.8%	1.8%	4.1%	4.1%	100%	15%	14.9%
Case 3	162	162	1.8%	1.8%	3.9%	3.9%	100%	14%	14.3%
Case 1A	400	151	4.3%	1.6%	9.6%	3.6%	79%	22%	13.9%
Case 2A	407	159	4.4%	1.7%	9.8%	3.8%	79%	23%	14.4%
Case 3A	403	154	4.4%	1.7%	9.7%	3.7%	79%	23%	14.1%
nuclear	182	182	2.0%	2.0%	4.4%	4.4%	100%	19%	18.9%
nuclear with efficiency	460	211	5.0%	2.3%	11.1%	5.1%	82%	29%	20.4%
efficiency alone	248	-	2.7%	-	6.0%	-	66%	9%	-

All the savings from renewable or nuclear electricity substitution take place in the last 5 years, whereas in the industrial efficiency case itself, emissions are avoided over a longer period. All renewable cases result in similar reductions (around 1.8% of total emissions in the 2006-2020 period), with slightly lower reductions from the efficiency scenarios as a result of the lower total electricity demand. By 2020, the renewable target is mitigating around 14% of electricity sector emissions, and around 6% of total emissions.

Reduction of non-GHG emissions follow similar patterns, with slight variations due to the different emissions profiles of old and new coal technologies.

Table 6 – non-GHG emissions mitigation

	CO	% reduction without efficiency	NMVOcs	% reduction without efficiency	NOx	% reduction without efficiency	SOx	% reduction without efficiency
Case 1	2.1%	2.1%	1.2%	1.2%	4.5%	4.5%	1.3%	1.3%
Case 2	2.6%	2.6%	2.2%	2.2%	4.5%	4.5%	2.3%	2.3%
Case 3	2.2%	2.2%	1.4%	1.4%	4.5%	4.5%	1.5%	1.5%
Case 1A	6.3%	2.4%	5.4%	2.0%	10.6%	4.0%	5.7%	2.1%
Case 2A	6.9%	3.0%	6.6%	3.2%	10.5%	3.9%	6.9%	3.3%
Case 3A	6.6%	2.6%	5.9%	2.4%	10.5%	4.0%	6.1%	2.5%
nuclear	2.5%	2.5%	1.8%	1.8%	5.0%	5.0%	1.8%	1.8%
nuclear with efficiency	7.6%	3.6%	6.9%	3.5%	12.0%	5.4%	7.2%	3.6%
efficiency alone	4.0%	-	3.4%	-	6.5%	-	3.6%	-

New coal plants are assumed to be built with FGD, and so reduction in SO₂ emissions is much smaller than that of other pollutants.

6.4 Costs and Investment Requirements

Costs have been calculated in several different ways, in an attempt to make as detailed a comparison as possible between the different scenarios. Two basic approaches have been used. The first is the method used in the LTMS to estimate the cost of mitigation (measured in R/ton of CO₂-eq mitigated). This approach uses the total incremental system costs, which are annualised (discounted and then levelled), and then divided by the total annual CO₂-eq mitigated, which is an internationally-accepted approach for comparing mitigation costs of alternative measures (see ERC 2007 for a more detailed explanation of the methodology). The second approach uses the model output (capacity expansion and electricity production) to calculate direct costs in the electricity sector from the input costs. Three cost measures are described below:

1. Investment costs, which represent the present value of investment in the year before new plant is commissioned. These form a good basis for comparing investment requirements, but are only an approximate reflection of the timing of investment. Due to the lower lead time for renewables, these are more accurately reflected, whereas the timing of coal investments, for example, is inaccurately close to the point at which the capacity comes online. This has the effect of underestimating investment needed to meet the renewable target in the period leading up to 2015, and overestimating the concentration of investment in the period from 2015-2020. Results should be interpreted in this light.
2. Total undiscounted annual electricity production costs. These consist of annual fuel costs, annual O and M costs, and annualised capital costs for new capacity (over the period of the lifetime of new plant). Existing capacity at the start of the modelling period is assumed to have no capital cost. This is approximately accurate, as most plants were built in the 1970s and 1980s, but the impact of this assumption will be to underestimate the total cost of production, particularly in the period before 2015, and to overestimate the rise in production costs as new capacity is introduced. However, it does provide a useful indicator of the difference between costs in the reference case and the other cases.
3. Average annual electricity production costs per kWh. Costs in (2) are used to calculate average annual cost of production per kWh, which is a proxy for understanding the impact of the target on the electricity price. It is not possible to predict the electricity price from the model output, since this depends on regulatory policy and accounting policy, but this cost is a useful indicator of a price trend for the energy component of the electricity price, which in 2004 was around 60% of the average electricity price.
4. The impact of carbon finance on the average cost of electricity is calculated for Cases 1 to 3, using two carbon prices: 10 Euros per ton, and 20 Euros per ton (in current terms).

All costs are expressed in 2003 Rands. Costs can be converted to 2008 rands by multiplying by the relevant PPI ratio (in this case, about 180/124, where 180 is an estimate of the PPI for 2008).

6.4.1 Mitigation costs

The energy system costs which are used in this section include the costs of investing in energy-efficient equipment for the efficiency scenarios. The mitigation costs, contained in the table below, for Cases 1 to 3 are relatively low, with costs for Cases 2 and 3 comparable to the mitigation cost of a nuclear programme. The additional fraction of GDP required would also be very small, with average values of less than 0.1%. The efficiency case is, as was found in the LTMS, a negative cost option; in other words, implementing energy efficiency would save money and reduce GHG emissions. As a result, implementing the efficiency programme and Cases 1 to 3 (or the nuclear option), would also be negative cost options. The savings in these cases come not only from avoided electricity investment and production (lower fuel and O and M costs), but also because less renewable capacity would be required to meet the 15% target due to the lower baseline. However, this would not preclude the need for additional investment in both power plants and also in energy-efficient equipment.

Table 7 – Mitigation costs using annualised total incremental system costs

	Rands per ton	Incremental costs as a % of GDP

case 1	R141	0.10%
case 2	R101	0.08%
case 3	R104	0.08%
case 1A	-R32	-0.05%
case 2A	-R37	-0.07%
case 3A	-R39	-0.07%
nuclear	R105	0.09%
nuclear efficiency	-R17	-0.03%
Efficiency alone	-123	-0.14%

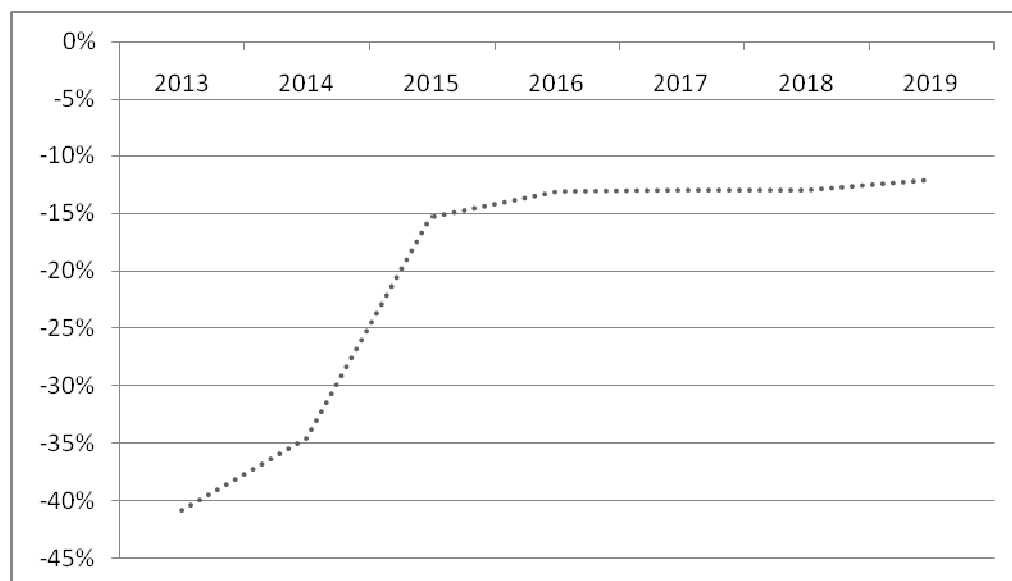
6.4.2 Investment required

Here, unlike in the cost calculations in the previous section, only investments required in the electricity sector have been considered; thus, incremental demand-side investments (for instance, in the efficiency cases) are excluded. Investment requirements are identical until 2012, when the scenarios begin to diverge. In the industrial efficiency scenario, due to the delay of new plant from 2013 because of lower demand, investment levels are considerably lower than in the reference case.

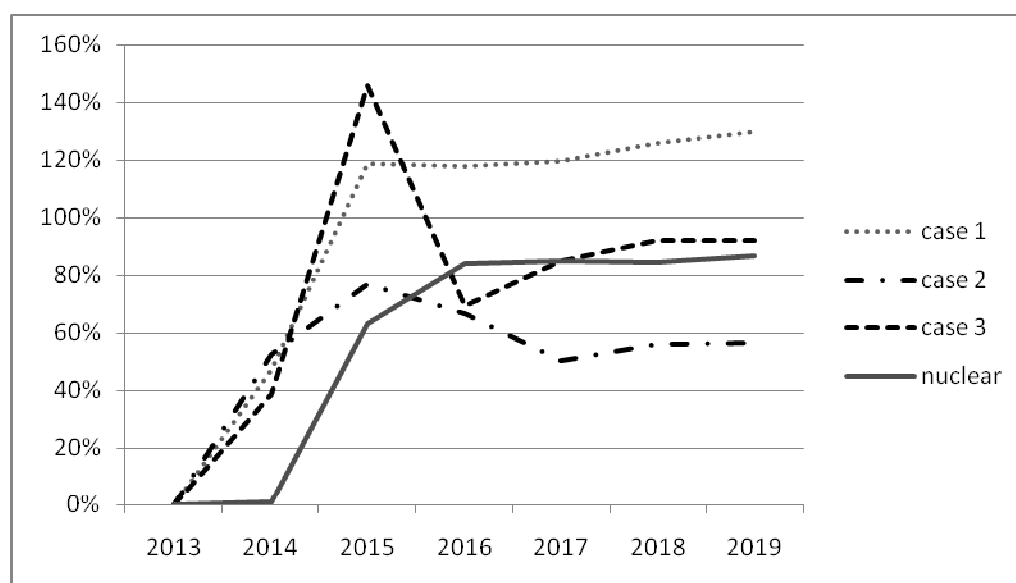
Table 8 – Power sector investment requirement , 2012-2019 (Millions of 2003 Rands)

	2012	2013	2014	2015	2016	2017	2018	2019
reference	27283	38480	28701	18332	21487	22388	23284	23959
case 1	27283	38480	42283	40124	46747	49156	52599	55048
case 2	27283	38480	43766	32426	35834	33669	36305	37449
case 3	27283	38480	39768	45094	36407	41397	44776	46001
case 1A	19302	22785	24531	34378	44621	46299	48417	50929
case 2A	19302	22785	29842	29500	33129	29541	31697	33140
case 3A	19302	22785	26925	34448	37158	38601	39743	40850
nuclear	27283	38480	28894	29896	39617	41400	42985	44768
nuclear efficiency	19302	22785	13248	33478	47541	38033	37835	39221
efficiency alone	19302	22785	18789	15540	18680	19482	20279	21071

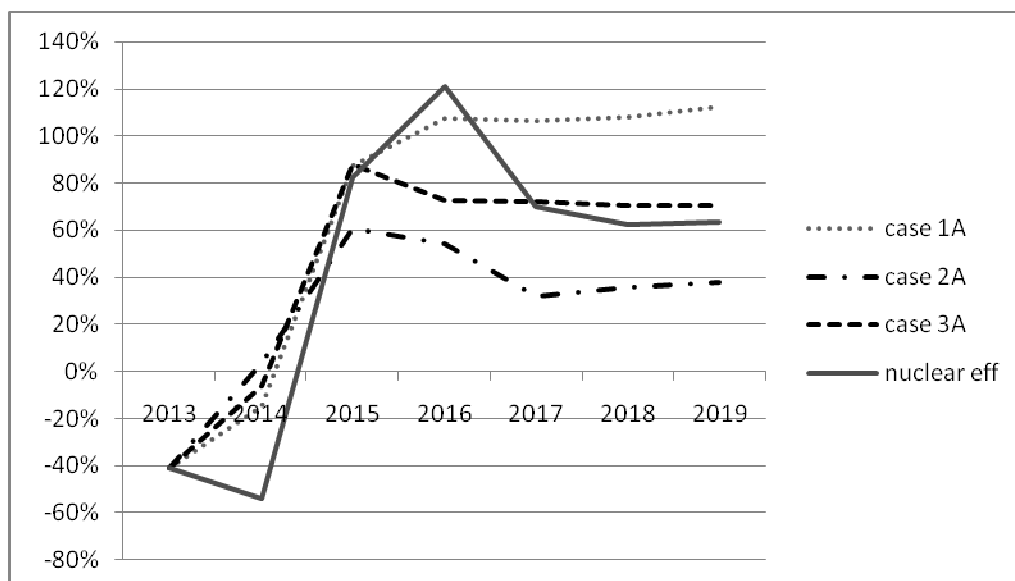
The percentage difference is portrayed below. The initial delay in building power plants results in a requirement in 2013 of 40% less investment, which shrinks to around 12% from 2015 onwards. The obvious implication of this is that a renewable target implemented with an efficiency programme would impose far lower investment costs on the power sector.

Figure 8 - % difference in investment requirement between reference case and energy efficiency case

Investment costs for Cases 1 to 3 are considerably higher than the reference case, as portrayed in the figure below, which portrays the % increase in investment requirements:

Figure 9 - % increase in investment costs for Cases 1 to 3 and nuclear

Investment costs increase by 140% of the reference case in 2015 (in other words, are 240% of reference case costs). The nuclear case requires an investment comparative with the better wind resources scenario, but sustained investment is required at a higher level. By comparison, in Cases 1A to 3A, required investment is lower, and is also offset against lower overall investment requirements, as portrayed below:

Figure 10 - % increase in investment costs for Cases 1A to 3A and nuclear efficiency

In this case, the investment requirement in the nuclear scenario is relatively higher because of additional reserve requirements.

6.4.3 Annual electricity production costs

Figure 11 and Figure 12 portray annual electricity production costs relative to the reference case. In both cases, nuclear costs are the highest by 2020, which is a result of the combined impact of escalating nuclear fuel prices and the assumption that no technological learning takes place. Cases 2 and 3, and 2A and 3A are fairly close in total cost terms. With the efficiency programme, the total costs only exceed the reference case in 2018, whereas without the efficiency case, costs are 15-20% higher by 2020.

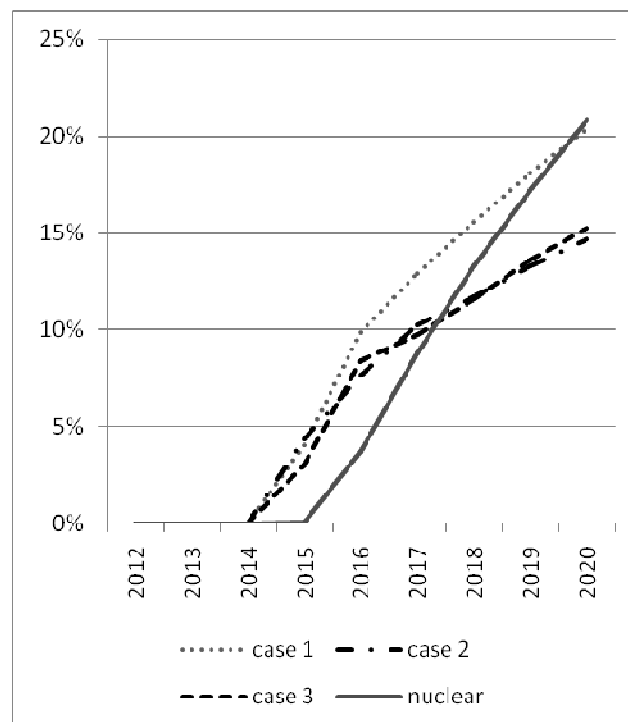
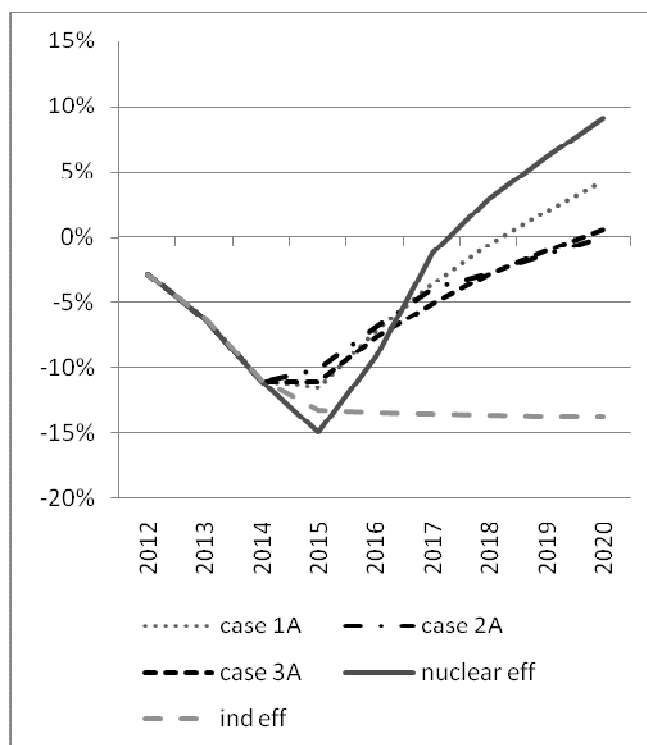
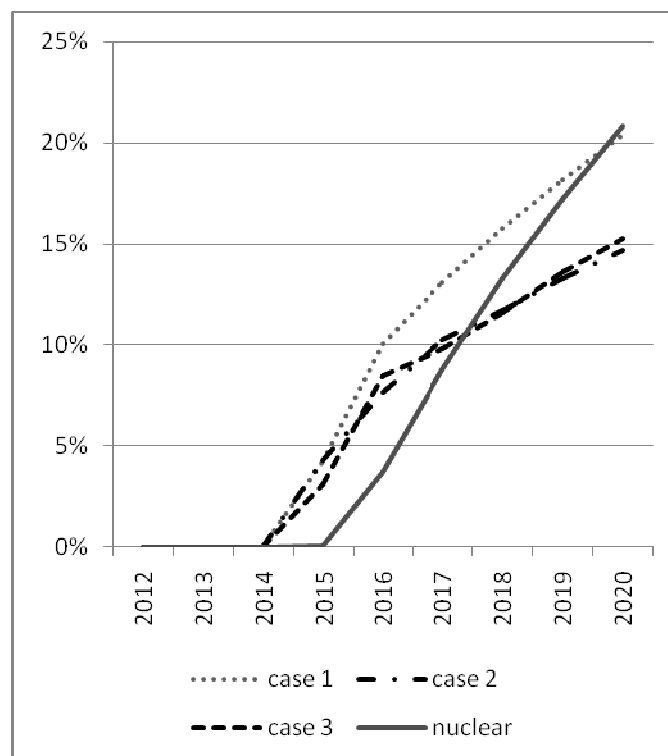
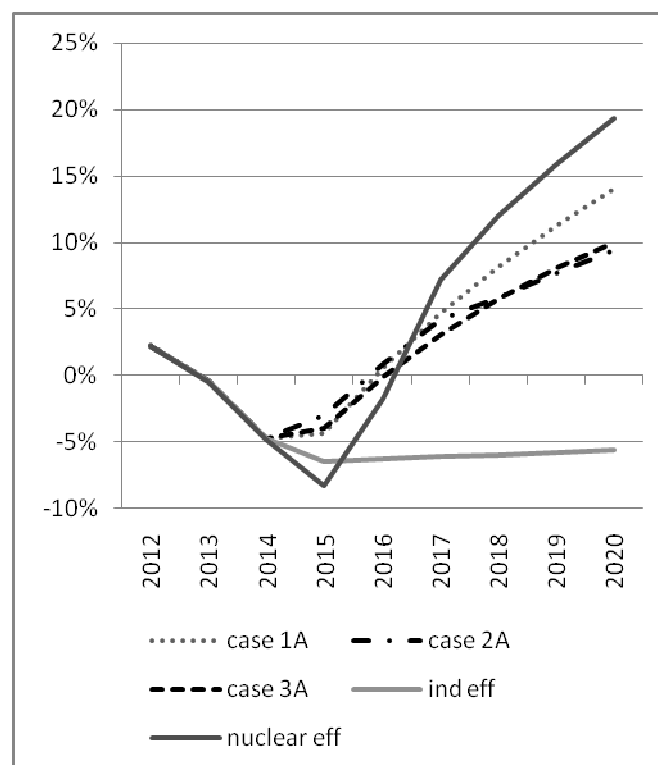
Figure 11 - % increase in total annual production costs, cases 1-3 and nuclear

Figure 12 - % increase in total annual production costs, cases 1A-3A, nuclear efficiency and efficiency alone



6.4.4 Average cost per kWh

This indicator is a proxy for price increases. The actual average price increase would be significantly lower, as this analysis is concerned only with the cost of producing electricity and not with the transmission or distribution costs. In the reference scenario, the cost of producing electricity increases by 2.13 times from 2006 to 2020 in real terms. In other cases, the increase is greater – between 2.45 and 2.56 for the renewable scenarios, and 2.57 for the nuclear scenario. The increase is lower for the efficiency scenarios, but not below the reference scenario – between 2.34 and 2.42 for the renewables scenarios, and 2.54 for the nuclear scenario. For the pure efficiency scenario, the increase is lower than the reference scenario – 2.01. The relative increase (in % terms) of the cost per kWh is portrayed in the figures below:

Figure 13 – % change from reference in average cost of electricity for Cases 1 to 3 and nuclear**Figure 14 – % change from reference in average cost of electricity for Cases 1A to 3A and nuclear efficiency**

The pattern is similar to the total costs, except that in the efficiency cases, the rise is more marked. In addition, due to a higher reserve margin, average costs are higher in the earlier years than in the reference scenario.

6.4.5 Impact of Carbon Finance

In order to calculate the impact of carbon finance on the average price of electricity, using the same costing methodology, the following assumptions have been made: 1) a price of 10 Euros per ton of CO₂ and 20 Euros per ton of CO₂ have been used, in current terms (these values are quite conservative in terms of current market prices, and probably very conservative for 2020 market prices) – to derive a price for the modelling, these values were converted into 2008 Rands and then deflated using the PPI to 2003 Rands; 2) all avoided coal emissions were paid at the average rate of avoided emissions per kWh for all three scenarios, which was 1.058 kg/kWh of renewable electricity generated. The grid average has been variously estimated for South African CDM projects (see Edkins 2008), but Eskom's average figure is 0.958 for 2007 (Eskom 2007); this uncertainty should be taken in account when interpreting these results. 3) the payment is assumed to be net of transaction costs. The impact of these two levels of carbon finance is portrayed in the figures below. While a 10 Euro carbon price lowers the impact on the average cost of electricity from between 15-20% to between 6-14%, a 20 Euro price has a much more significant impact, lowering the cost of electricity production below the reference case in the latter years. More dramatic effects result if one adds the efficiency programme. If one assumes that carbon finance is also received for the efficiency programme, a 10 Euro price offsets the programme entirely except for Case 1, and a 20 Euro price does the same, but to a greater extent. It must be emphasised again that these are system costs, and assess the cost change for the whole electricity system. These costs and benefits would still be shared amongst different actors in the system, and there would still be the investment requirements outlined above.

6.4.6 Conclusion – a note on the limitation of system cost analyses

The impact of the target on total electricity system costs implied by these results is modest, especially with the impact of carbon finance; nevertheless, a massive investment programme would be required. These requirements could be mitigated considerably by the simultaneous implementation of an energy efficiency programme as outlined above, which would delay the requirement for investment in planned capacity and avoid the need to invest in as much renewable capacity to achieve the same objective. However, it is important to note that these costs are assessed using a systems model, which does not account for several important sources of extra costs:

- Finance costs may be quite significantly higher, especially for IPPs – these results are based on a 7.5% real discount rate, whereas the real cost of capital may be significantly higher
- Short-run inflation of components, and other short-run costs resulting from factors such as scarcity of key skills, which might affect the power sector unevenly
- Additional infrastructure costs incurred, such as road access, and the impact of abnormal loads on the road network
- The macro-economic impact of a massive power sector investment programme, which was significant in the 1980s.

Thus, a more precise analysis of the costs of such a programme would be required to ascertain the actual costs of implementation at a project level. What the modelling exercise does is to establish the case for developing a policy package featuring such a target. We now turn to a more detailed discussion of what such a policy package would look like, what some of the institutional issues would be, and what some of the mechanisms for financing such a package might be.

Figure 15 – Impact of a EUR10 carbon price on the % change from reference in average cost of electricity for Cases 1 to 3

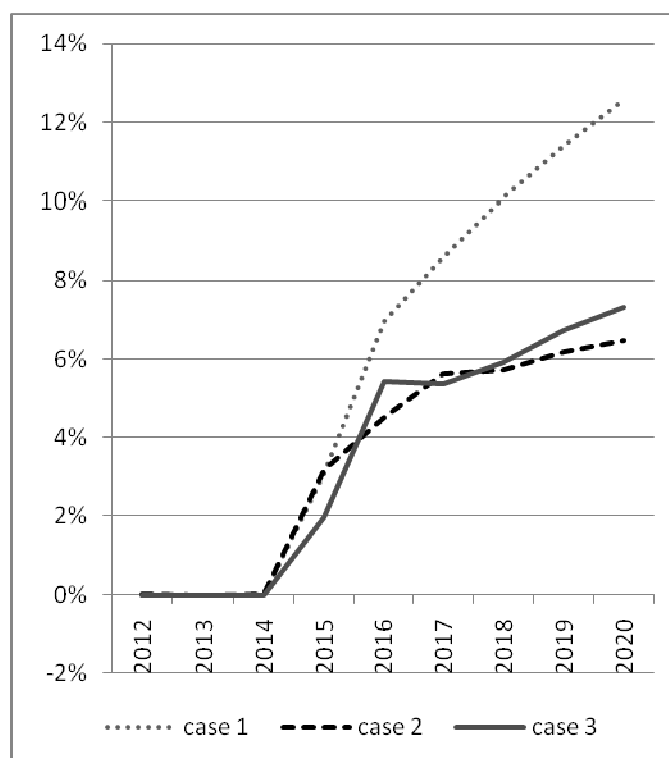


Figure 16 – Impact of a EUR20 carbon price on the % change from reference in average cost of electricity for Cases 1 to 3

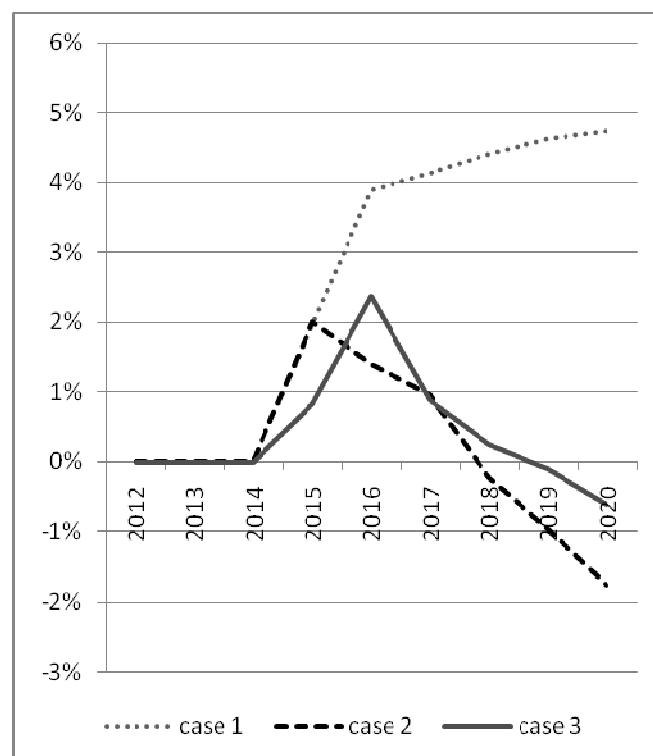


Figure 17 – Impact of a EUR10 carbon price on the % change from reference in average cost of electricity for Cases 1A to 3A (with carbon finance for energy efficiency as well)

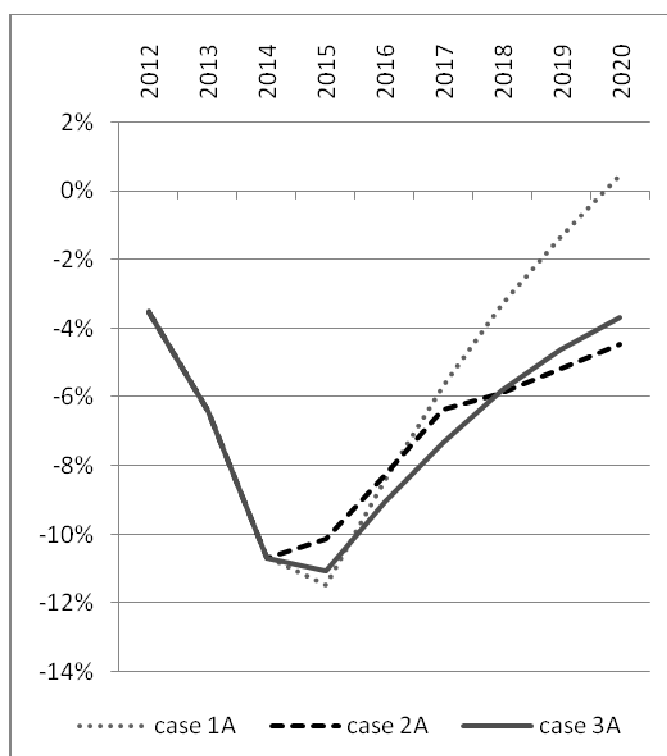
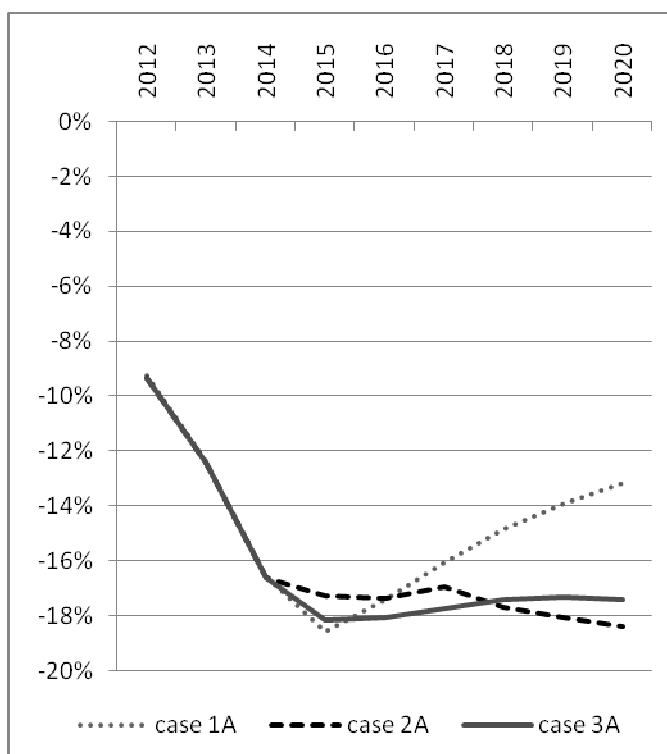


Figure 18 – Impact of a EUR20 carbon price on the % change from reference in average cost of electricity for Cases 1A to 3A (with carbon finance for energy efficiency as well)



7. Developing a 15% renewable target policy package

The modelling outlined above provides a detailed account of how the energy system, and the electricity system as a whole, reacts to the setting of a 15% renewable target for 2020. The model provides detail on three aspects of this reaction: 1) the technical properties of the system, i.e. infrastructure and electricity production; 2) emissions and emissions reductions; and 3) relative costs of different scenarios. Models are developed from a national systems perspective and result reflect changes in overall costs and benefits; in other words, a one-actor world; the closest reality to this would be a national monopoly utility which acted without any sectoral interests. In reality, the electricity system, and the society at large which depends on it, is not populated by one actor but by many. In order to reflect on the policy implications of these modelling results, it is necessary to think about their implications for the many actors and interests, and the institutional setting in which these exist, which inhabit the electricity and energy policy domains.

The modelling considers three scenarios, plus an energy efficiency policy variation for each, for achieving the 15% renewable electricity (RE) target by 2020. These scenarios, modelling outputs, describe the technologies, capacity and costs required to meet the 15% RE target from a systems perspective. Case 1 and 3 are similar in technology composition, with different assumptions about the available wind resources; therefore, the strategic choice is really between Cases 2 and 3, with attention to Case 1 as reflecting the costs of lower wind availability.

We have focused attention on a programme which has the profile of Case 3 (and its variant with energy efficiency, Case 3A) as the most promising scenario for a number of reasons. Apart from the wind assumption-driven cost differences, the key difference between the scenarios is that of diversity. Case 2 represents a large investment in a mature technology, with inferior dispatch qualities, and in a highly globalised sector with many large industrial conglomerates and utilities having many years' head start in terms of production capacity and expertise. Whilst this certainly represents a cost advantage which is reflected in the modelling outputs, it leaves little scope for South Africa to establish its own manufacturing capacity, or competitive skills base. It is also likely to negatively impact the country's balance of payments situation, with a high reliance on imported components, if a significant level of local content is not achieved. Another important factor is that the ongoing development of each scenario post 2020 is not considered in this report, but an ongoing trend towards the use of renewables as a share of electricity generation is anticipated as the future becomes increasingly carbon-constrained. Reliance on one technology, wind, which has a limited contribution in the long term because of dispatch issues may be a sub-optimal strategy, and gives limited opportunity for South Africa to benefit from the anticipated international renewables industry boom which is likely to emerge in the next few decades. Thus, a programme involving both wind and solar thermal plants is proposed. The downside risk of the approach is that progressive wind efficiencies are not realised. The advantages of the approach are believed to be substantial. Solar thermal plants are considered to offer the most potential of all renewable technologies for South Africa to establish and maintain a competitive advantage (Goedgedacht 2008): the country has an excellent solar regime and the international sector has low barriers to entry currently. The technology is dispatchable, and represents base load capacity, offering a viable ramp-up renewables option at scale post 2020. The issues around land availability are anticipated to be less problematic for solar thermal plants than for wind farms, given the lower competition for land use in areas with high solar radiation.

The modelling results make the case unequivocally for the implementation of an energy efficiency programme with the renewable target, which also has many other co-benefits, including additional GHG mitigation and job creation. However, there are compelling reasons not to consider the two measures as one policy package. The two most compelling reasons are 1) that in terms of the international climate change negotiations process (and the UNFCCC in particular), Annex 1 countries have pledged to fund the agreed incremental costs of mitigation; these costs should be fully reflected against a baseline, which they are in Case 1; there is an additional risk that planned energy efficiency programmes might not be implemented, as South Africa does not have a good record up to now on energy efficiency implementation; and 2) that, institutionally, these programmes involve separate sets of actors. This does not preclude a significant degree of co-ordination between the programmes. There are other potential programmes which support the implementation of a renewable target as well, and

would also lower its cost, which have not been modelled here, such as an industrial development strategy designed around manufacturing solar thermal or wind components or whole plants if appropriate, which would also enhance the impact of the target on the economy as a whole by increasing local content, thus channelling a much higher share of investment made to reach the target back into the South African economy. These supportive and co-ordinated programmes have been referred to here as *partner programmes*, separate programmes which have strong synergies with reaching a 15% renewable target. We outline what some of these partnership programmes might be, and provide very limited sketches about how these might be implemented alongside the target.

This section therefore explores what would be required from a financial and regulatory perspective to incentivise and enforce the 15% RE target, together with recommendations of what the RE programme may most effectively look like, guided by the modelling outputs. In doing so, a number of assumptions are made around the details of the build programmes, and notes are made where flexibility in the interpretation of the model's outputs may assist in implementation and financing. The section focuses on interpreting the relative differences indicated by the model outputs and their application to financing and regulatory support requirements, as opposed to identifying detailed costs and pricing associated with a proposed RE programme.

7.1 Timing and design of a 15% target programme and partner programmes

The build programme for a 15% target is very ambitious, but not unprecedented (see, for instance, China's wind programme). Current estimates for wind farms are that an 18-month to 2-year lead time are required, with some time before this for EIAs and other forms of planning permission and contractual processes. For solar thermal plants, lead time is estimated to be three years, with an additional planning period. If we assume a 2-year planning period in each case, a programme as outlined in Case 3 or Case 3A will require investors to begin planning at the beginning of 2010 in the case of solar thermal, and in 2011 in the case of wind, which leaves just over a year from the date of the completion of this report. Thereafter the programme accelerates significantly; in Case 3, an average of one GW of new solar thermal capacity is added every year between 2014 and 2019, and an average of around two GW of new wind capacity. Thus, while 2015 is still seven years away, implementation of the target will require decision-makers to make commitments within the next two years.

As mentioned above, the optimal implementation of a target programme would require the simultaneous implementation of partner programmes in four areas: 1) research and development; 2) infrastructure development; 3) industrial strategy; and 4) energy efficiency. Research and development programmes would concentrate on developing and optimising solar thermal technologies for South African conditions; an industrial strategy would maximise local content and develop local content industries where economically advantageous; and an infrastructure development strategy would support the programme by addressing bottlenecks and co-ordinating the development of state infrastructure resources with the programme. Infrastructure co-ordination programmes will have to be implemented by 2012, and the other two programmes will have to be implemented sooner to provide effective support and take advantage of synergies.

A mandatory energy efficiency target, supported by regulatory and other measures, will contribute both to climate change mitigation and to alleviating the electricity supply side crisis, relieving the pressure on the grid's reserve margin. Energy efficiency is a negative cost option, with the model characterising it as having a cost saving of R123 per tonne of CO₂ mitigated, compared to positive costs in the same vicinity for an RE programme. It therefore represents a rational 'first policy option' for both greenhouse gas mitigation and energy supply constraints. The energy efficiency scenario also delays new coal build, with co-benefits from reduced water consumption and non-GHG emissions. Further, cabinet has indicated that mandatory energy efficiency targets will be one of the first aspects of a climate change mitigation strategy implemented⁹. The efficiency scenario which was modelled was restricted to industry, but it would certainly be advantageous to implement energy efficiency programmes in the residential and commercial sectors as well, which would provide greater flexibility

⁹ Marthinus van Schalkwyk's media release on Cabinet's approach to mitigation strategy, July 2008

in meeting targets, and would have a greater impact on peak demand. In order to have the most impact on the cost of a renewable energy target, an energy efficiency partner programme would have to be implemented as soon as possible to slow demand growth. As pointed out above, this also has critical benefits in the short term by significantly raising the reserve margin in the period up to 2012.

Another impact of such a target which has not been analysed here is the impact on employment; although no specific analysis has been done for this study, earlier work done in South Africa indicates that the impact on employment would be positive, as renewable energy technologies have a higher employment intensity than fossil fuel technologies (Morris et al 2003); moreover, new employment would be far more widely geographically distributed¹⁰, which would have additional regional development benefits.

7.2 Institutional and Policy Background

South Africa's electricity sector is monopolistic in structure, dominated by the wholly state-owned national utility, Eskom. Eskom owns and operates the national grid and the overwhelming majority of generating plant. Ownership of the distribution sector is divided between Eskom and local authorities.

The approach to electricity supply over the past three decades has focused on utilising South Africa's abundant coal resource to produce some of the cheapest electricity in the world using one technological model adapted to South African conditions (coal characteristics and lack of water). This approach emerged from a mineral-energy complex which has its roots in the colonial and apartheid eras, where the primary objective of the electricity supply sector was to fuel the developing minerals sector which has played a central role in the country's economic development. With the end of apartheid in 1994, this objective broadened to include electrification of the largely ignored rural and lower income urban residential sectors, and Eskom and local authorities embarked on an ambitious and successful electrification programme. There are thus two groups of consumers to whom cheap electricity is particularly important: energy-intensive users (primarily the mining, minerals-processing and some parts of the chemicals sectors), and poor households.

The 1998 Energy White Paper indicated government's intention to restructure the electricity sector, with the aim of introducing a market in electricity generation. To facilitate this process, Eskom would be broken up into distribution (which would be included in consolidated regional distributors), transmission/system operation, and several generation units which would compete against each other and new entrants in a wholesale electricity market. This intention was reversed by government in 2004, and Eskom was again given a central role in building new generation capacity. The current power crisis has made it unlikely that these plans will be revived in the near future, and thus Eskom is set to play a dominant role in the electricity system for the foreseeable future.

While the national energy planning function resides in the government Department of Minerals and Energy, and has been most recently set out in the Energy Bill¹¹ (draft awaiting Presidential approval, October 2008), NERSA has also been tasked with the development of periodic National Integrated Resource Plans for the electricity sector. In reality, however, Eskom's own planning process is the most influential, and is probably the most relevant in terms of human capacity and accurate data. The National Energy Regulator of South Africa (NERSA) provides regulatory oversight to the sector, and sets tariffs and aspects such as grid access regulations. While government is still in principle committed to encouraging private investment in the electricity supply sector, there is currently uncertainty as to what the role of IPPs will be in the electricity sector, and who will conclude agreements with them. Previously this role was filled (unsuccessfully) by the DME, but there are now indications that Eskom will fill this role in future. There is also uncertainty about the process of setting parameters for IPP participation, which is linked to the uncertainty surrounding the planning process.

Renewable energy (apart from traditional biomass use) has never featured highly in South Africa's electricity mix, despite the country having abundant renewable energy resources (Banks and Schaffler 2006). Aside from the very low price of coal in South Africa, the electricity supply approach favouring large centralised plant is one cause for this; another is poorly developed regulation for independent

¹⁰ We are indebted to Glynn Morris for this insight.

¹¹ Enshrined in this bill are the principles of reducing the environmental and health impacts of energy carriers, universal access to energy, and cost efficiency of generation.

grid access. The dominant culture in the sector does not as yet have a serious appetite for renewable electricity generation (Goedgedacht 2008), with the current Integrated Energy Plan only considering renewables in one of its four scenarios, and then only as 5% of total electricity generation by 2020. The 2008 Energy Bill does not substantially address renewables, although it does give the Minister powers to set mandatory targets for both renewable energy and energy efficiency. The 2003 Renewable Energy White Paper sets a 10 000GWh target for renewable energy by 2013, with limited and poorly functioning capital subsidies managed by the DME. A renewable energy strategy, identified in the 2003 White Paper, has not yet been developed to support the target. The reference scenario modelled above achieves under 4000 GWh, mainly from existing sources such as hydro.

International experience shows that significant deployment of renewable energy technologies requires both financing and regulatory support to compete with the dominant and mature fossil technologies, themselves often supported by a well-established historical subsidy base¹². The South African government has acknowledged the need for renewable electricity support, and a feed-in tariff has been identified as the favoured policy option. Tradable renewable energy certificates have also been cited as likely to contribute to the policy mix, with work ongoing to consider these by DME. NERSA is developing a feed-in tariff structure to provide support to the current renewable energy target. This tariff is currently in a draft phase.

From a regulatory and implementation perspective, the centralised approach to electricity supply has resulted in poorly developed and discriminatory regulation and processes surrounding the private supply of power to the grid (DME 2003). This is changing slowly with government's mandate that Eskom secure 30% of generation capacity from the private sector. In response, Eskom has released a three part tender programme, covering cogeneration and base load capacity. It is widely anticipated that this supply will largely come from coal. Eskom's power procurement programmes do not currently stipulate any generation from renewable energy

7.3 Financing and Regulatory Options

A 15% RE target by 2020 is therefore substantially beyond what is currently being considered and planned for within the electricity sector. The financing and regulatory support instruments which are under slow development within DME, Eskom and NERSA would need to be prioritised, clarified and significantly strengthened; the programme outlined here would require a step change in government's thinking about developing these mechanisms. Critical to the success of the programme would be full commitment by the key stakeholders in the electricity sector: DME, Eskom and its shareholder, the Department of Public Enterprises, NERSA, and both the proposed South African National Energy Development Institute (SANEDI) and the Department of Science and Technology in technology research and development support roles, as well as the Departments of Trade and Industry, to integrate the implementation of the programme into national industrial strategies. The target must be legally enforced and mandatory for those responsible for its delivery, largely the DME, Eskom and NERSA. Clear, long term and legal signals must be communicated to the private sector as early on as possible.

7.3.1 An Institutional and Regulatory Framework

There are broadly three institutional arrangements which might transpire by 2015:

- Continued monopoly, where Eskom dominates the electricity sector in the same way it does today, and there is little if any private sector involvement
- Open access system, in which Eskom still plays a dominant role, but there are well-defined rules for private sector involvement and a significant number of IPPs. Eskom maintains control of the system operator, and plays a central role both in planning and in promoting socio-economic and technology development in the electricity system.
- Market system, in Eskom has a residual role and IPPs sell power in a competitive market, as envisaged by the 1998 White Paper.

¹² Direct subsidies in the South African power sector or fossil fuel industry are rare (with the exception of Sasol); however, there have been various indirect subsidies (for instance, forward cover for exchange rate risk for Eskom borrowing in the 1980s by the Reserve Bank), and recently the government has loaned Eskom R60 Billion on very soft terms.

Different support mechanisms are suited to different institutional contexts; scenario 3 is considered to be extremely unlikely, and since scenario 1 represents the current inadequate situation, it seems sensible to consider regulatory instruments which are well-suited to scenario 2, as well as the conditions which would need to be established for success. RE generally requires the cost gap to be bridged in some form; in other words, subsidisation, for power generation projects to be viable. The questions addressed in this section are how this subsidisation is managed (a regulatory framework), and who manages it (the institutional framework).

A number of regulatory options are in use internationally to promote the uptake of renewable electricity. Much has been written on the appropriateness of these different options for South Africa (for example Winkler, 2003 and DME, 2003), and some progress has been made in deciding on a suite of regulatory options, and even towards implementation of these. This section will not return to the debate of regulatory mechanisms. With new RE build commissioning occurring in 2015 under the model, the timeframe for the programme is extremely tight, especially for substantial institutional change, and for building the regulatory framework to support the programme. This is particularly relevant since the electricity crisis has created a resistance to change within the sector, in order to protect security of supply. Therefore, current thinking and progress within the sector will be considered as a base with regard to appropriate mechanisms. The use of additional mechanisms, where required, is discussed.

The DME (2003) identified three mechanisms as being most successful in incentivising renewable energy: Incentives, such as subsidies or tax credits; feed-in tariffs and set-asides. Feed-in tariffs represent a guaranteed price paid to renewable electricity generators which is usually set at a significantly higher level than the average cost of electricity generation. These can be specified per technology in order to ensure diversification of RE technologies in meeting a target. A set aside marks off a block of electricity provision for RE technologies, which project developers then tender for. A subsidy in the form of a feed-in tariff or equivalent is then used to provide the winning projects with financial support. The feed-in tariff and set-aside models differ only in that in the first instance the regulator sets the incentive, relying on its own information on generation costs, whilst in the second the generators provide cost information through the tender process, thereby reducing the risk of significant producer surplus, or underperformance of the sector if the tariffs are set too low. Incentives can be in the form of capital subsidies, assistance with R&D, or the establishment of a renewable tradable certificate scheme.

Given the significant differences in technology maturity, the two dominant technology types modelled for the RE target, more than one mechanism may be appropriate. A central question which needs to be addressed is what the role of Eskom would be in such a programme, both in planning and co-ordinating the programme, in building power plants and in managing the grid. It is assumed that the current situation of a dominant Eskom will persist, but that the electricity supply sector will gradually become more competitive, particularly given the 30% private generator supply target. This implies that Eskom will play a key role in planning, and also in developing the system management techniques necessary for the incorporation of bulk renewable at scale into the grid. In order to guarantee the stability of the grid, additional investment decisions will have to be made, which will have to be included in Eskom's rate base.

Traditionally, Eskom has been seen as a proponent of coal and an opponent of large-scale renewable technologies; however, Eskom has also traditionally played (since the 1922 Electricity Act) a facilitative role in the development of the national electricity system. Eskom also comprises the largest concentration of technical expertise in electricity generation in the country, and probably on the continent; thus, the utility is well-suited to pioneer the development of new technologies in the country. Given the developed state of wind technology, this role need only be brief, but for solar thermal technology, development requirements and the typical pilot project structure to date suggest that there is a significant role for a national utility in partnering with a combination of government, DFIs and private investors whilst the technology is maturing.

7.3.1.1 Feed-in tariffs

A feed-in tariff usually entails cross-subsidisation from the rest of the electricity system, which means that the additional cost would be borne by electricity consumers, having an incremental impact on the electricity price. The impact of this would be the same as the incremental system cost, although this

systems analysis covers the costs of additional reserve capacity as well, and does not cover the cost of additional finance costs which would probably occurred by private investors.

Subsequent to the 2003 white paper, government has moved forward with the concept of a feed-in tariff, currently under development by NERSA (a consultation document was released this year). Feed-in tariffs have the advantage of being relatively simple to implement, and provide certainty and incentive to the RE project developer. The establishment of a feed-in tariff mechanism for one technology may also be expanded to additional RE technologies over time.

Key to the success of feed-in tariffs is the arrival at the right level for the tariff structure. NERSA is considering what this tariff level should be, with a draft proposal released. Tariffs can be adjusted for the inclusion of new plant into the system, but are very difficult to adjust retrospectively for existing plant, as these require the certainty of the subsidy to make their investment work. Feed-in tariffs are perhaps more appropriate for technologies which may be implemented in smaller units, and about which better cost information exists. Thus, feed-in tariffs would be well-suited to a large-scale wind programme. The wind component of Case 3 is likely to involve at least 50 wind farm projects, with relatively good information about costs. The feed-in tariff can be extended to solar thermal plants in the later stages of the period, should it prove successful and as cost information on solar thermal is revealed through a pilot programme.

Institutionally, it is anticipated that a feed-in tariff would be administered by Eskom (since Eskom would be contracting to buy the electricity from the provider), with oversight from the Regulator. A key question is whether Eskom could also benefit from the tariff, and particularly how Eskom would participate in determining the appropriate tariff structure. NERSA would be required to play a strong role, perhaps assisted by SANEDI, with clear ring-fencing of RE investments by Eskom in order for them to be eligible for the feed-in tariff, assuming that if the tariff was set appropriately, returns would be higher than Eskom's cost of building renewable plants. This would also incentivise Eskom to participate in the programme.

7.3.1.2 Incentives: subsidies or tax credits

Incentives in the form of subsidies or tax credits are not typically a preferred economic regulatory instrument. They are a burden to the fiscus, and involve government 'picking winning technologies', something it is not renowned for being particularly good at. Subsidies and tax credits are also not particularly economically efficient.

However, these can be appropriate for strategic investments, and the creation of future competitive advantages for a country. Incentives are likely to therefore play an important role in supporting the concentrated solar thermal component of the programme. An investment in research, development and pilot plants will be required to enable the commissioning of a large scale thermal power tower after 2015. An investment on behalf of the South African government will be required to incentivise this work to occur within the country, and to position local players as industry front-runners. It is imperative that this initiative is embedded in industrial policy.

It is suggested that Eskom play a key role in the solar thermal component of the programme, together with national government (DST) and SANEDI. International players may be attracted to the solar thermal initiatives through co-operation on climate change issues (see the financing section below), or through a partnering approach to establishing a viable international solar thermal industry.

7.3.1.3 Trading mechanisms

Renewable energy trading mechanisms are being promoted amongst many actors in the electricity sector, with DME currently exploring the role of the mechanism within South Africa. Trading credits to achieve an environmental good is a highly efficient and sophisticated economic instrument. Trading however relies on liquidity to achieve this efficiency, and a mandatory scheme would be required to achieve a mandatory RE target. Mandatory trading schemes for renewable energy certificates are operating in the more liberalised electricity markets internationally (Europe, Australia, the US), with electricity distributors and retailers, together with large electricity consumers, the ones to receive a mandatory RE cap under which they can trade. One of the key disadvantages to renewable energy certificate trading is that it does not present power producers with certainty of long term demand. This risk is particularly difficult for IPPs, which are anticipated to play an important role in the RE programme.

In South Africa, there are a number of challenges to the successful deployment of this instrument. The continued dominance of Eskom in all aspects of the electricity sector is one. The sophistication and complexity of the instrument is another, together with the lack of familiarity of the electricity sector with trading mechanisms. South Africa's electricity sector is unlikely to be able to successfully manage a mandatory renewable energy trading scheme given its current levels of administrative and institutional capacity.

Where an energy credit trading scheme may well prove to be a particularly effective regulatory instrument is to support the energy efficiency programme. 'White certificate trading' involves the trading of energy efficiency quotas. This system, administered by Eskom, is already partially conceptualised under the Power Conservation Programme, and provides a response to both greenhouse gas mitigation and the electricity crisis. This would engage the large energy users in something they are best able to direct and control.

7.3.2 Conclusion

The RE programme would therefore be supported by a suite of regulatory mechanisms including a feed-in tariff for wind power, and subsidies (in the form of developmental finance/grants) for the development of a pilot solar thermal programme. After a period of learning, solar thermal technology could also graduate to a feed-in tariff; mechanisms should also be developed for private participation in the pilot phase. A white energy certificate trading scheme is recommended to support the industrial energy efficiency programme, an important partner programme of the RE target.

7.4 Financing the 15% renewable energy target

The incremental costs of the programme have been modelled above from a systems perspective, but as noted above, specific project-level evaluations would have to be carried out to evaluate the actual cost of the programme. The usefulness of the model results is mainly in indicating the incremental costs in relation to a baseline. The need for additional financing (subsidisation) of a RE programme to attract project developers is universally acknowledged. Financing for the programme can come from three primary sources: consumers in the form of increased tariffs or taxes levied on electricity, the fiscus in the form of subsidisation, and international finance. Development finance institutions (DFIs), both local and international, can assist in reducing the financing cost through bridging finance and soft loans, and are anticipated to be important players.

7.4.1 Funding from the tariff

Funding from the tariff, such as a feed-in tariff, would involve higher average electricity prices; the increments would then have to be distributed amongst different consumer groups. From an energy policy point of view it makes sense to distribute the costs unevenly. There are two groups who are vulnerable to real electricity price rises: poor households and energy-intensive users. Affordable and universal energy access to all is one of the priorities of South African energy policy, and the poor should be safeguarded from additional electricity price rises, particularly when real price increases are inevitable in the reference scenario. There are two compelling reasons for this: 1) there are general societal benefits to poor households consuming electricity, since the external costs which result from using inferior fuels (paraffin, coal, wood) are very high; and 2) poor households make up a small proportion of electricity use. This does strengthen the rationale for an enhanced residential energy efficiency programme for households.

Energy intensive industries form a powerful lobby in the electricity sector. These consumers tend to have long term electricity contracts, and are therefore largely locked in to lower price tariffs, sometimes for decades. The legal implication of policy changes such as the introduction of carbon taxes for these contracts has not been explored. Significant electricity tariff rises over a short period of time is unlikely to be economically efficient for this important economic sector, and will affect their international competitiveness. For existing energy-intensive users, a lower share of the costs of meeting the renewable energy target could be imposed in exchange for participation in a stringent energy efficiency programme, or participation in a 'white certificate'¹³ trading scheme, which would

¹³ White certificate schemes are used by Italy and France (with similar schemes in the UK and some US states) to enforce least-cost energy efficiency. Mandatory targets for energy efficiency are set, and white certificates are issued

enforce energy efficiency in a more flexible manner, enabling those that can to reduce their electricity use, whilst those for whom it is prohibitively expensive can purchase credits on the market. New energy-intensive firms/plants or extensions to existing plants should face the full average cost of electricity generation, to avoid further subsidisation of energy intensive industry. This might pose competition or WTO difficulties; a more detailed analysis would be necessary to determine this.

Other consumer groups (non-poor households, commerce, agriculture and non-energy intensive industry) would pay above the average additional cost, which would encourage energy efficiency.

7.4.2 Funding from the Fiscus

The fiscus will undoubtedly have a role to play in subsidising the programme, and to the extent that the programme is anticipated to create a new source of competitive advantage in the form of a leading position in the solar thermal industry, this is appropriate. The RE programme has significant benefits in the form of SO_x, NO_x and particulate emission reductions, together with water savings in the magnitude of over one litre per kWh. RE is also anticipated to provide greater employment creation potential than the equivalent capacity in fossil fuels. These co-benefits present additional reasons for public sector subsidisation of the programme, and are anticipated to realise financial benefits in health and eco-system services. One source of budget financing for government investment in the RE programme is through the carbon tax currently under consideration by Treasury¹⁴, and implemented in embryonic form as the current 2c/kWh levy imposed on fossil fuel-derived electricity. However, given the many pressures on the budget of a developing country it is necessary that international finance is utilised to its greatest potential.

7.4.3 International Finance

The value of the RE programme to the international community lies largely in its climate change mitigation impacts. Under the current international policy framework, the Kyoto Protocol, this is recognised through the Clean Development Mechanism (CDM). Carbon trading and project based credit generation as operationalised through the CDM are likely to remain in place post the current framework which expires in 2012, although it is widely anticipated that the mechanism will be scaled up to focus on programme, sector or policy-led emission reduction activities. It is therefore likely that South Africa's RE target will be eligible under the CDM, or 'new CDM'. Whilst it is not yet certain how this 'new CDM' would work, an estimate of funding opportunities can be made based on emissions reduced according to the current CDM rulings.

The RE programme is modelled to reduce in the region of 164 million tonnes of CO₂ equivalent over the period from the reference scenario. When the energy efficiency programme savings are included, this rises to just over 400 million tonnes. Assuming that all these reductions are eligible under 'new CDM', this would result in R20 billion, or R48 billion¹⁵ for the 'A' scenarios. The implications for carbon finance on levelled plant costs and on the average cost of generating electricity are explored above in the relevant modelling sections.

Carbon revenue under the CDM is currently only available to the programme developer once the emission reductions have occurred. Whilst there are ways to securing some funding upfront, this is generally an expensive way of financing a programme. What may be more attractive is the use of the future carbon revenue stream as collateral for DFI loans, or as a form of guarantee by an investment grade party to the programme financing, which will improve the overall cost of the financing structure. It is important to note that CDM payments are likely to continue, under current CDM rules, up to 2041¹⁶, presenting a significant additional return to electricity sales.

for certified increases in efficiency, which are then tradable; thus companies which exceed their quota can sell additional reductions to companies which have not succeeded in meeting quotas, thus ensuring least-cost reductions.

¹⁴ Trevor Manuel, mid term budget speech, October 2008

¹⁵ These figures are derived from a simple 'back of the envelope' calculation, appropriate for the high levels of policy and numerical uncertainty surrounding carbon finance way into the future. (400*€10*12 (R:€ exchange)=R48b)

¹⁶ A three times 21 year crediting period is currently the maximum allowed under the CDM. The generating plant built before 2020 will therefore deliver carbon credits for 21 years after they are commissioned, taking into account the lifetime of plants, which is estimated as 20 years for wind, and 30 years for solar thermal. However, in the case of wind farm, the individual life of the turbines is 20 years, and since these come in small modules they could be replaced indefinitely.

Predicting any circumstances long into the future increases the level of uncertainty. There are a number of key uncertainties surrounding CDM, most significant being the international post-2012 climate change policy framework. However, some clarity should be achieved on this by the end of 2009, in time for incorporation into the key decisions on the large plant builds.

Programmatic, sectoral or policy CDM would require a co-ordinating entity and / or clear owner of the carbon credits. Because the actual performance of the RE plant, and the monitoring of these emission reductions is where the carbon credit is actually generated, it is important to link this performance and monitoring to the carbon finance as closely as possible. For the wind programme, this may be through a CDM programme managed by Eskom, and used to finance the feed-in tariff. This is particularly well-aligned as both the CDM and the feed-in tariff only disburse funding as the renewable electricity is generated. The same model may be followed for the solar thermal plants once the technology is proven commercially.

A second form of international climate change mitigation assistance may be forthcoming through the proposed Sustainable Development Policy and Measures (SD-PAMS) stream under the international climate change negotiations. SD-PAMS are developing country policy packages which reduce greenhouse gas emissions and position developing countries on sustainable and low-emissions development paths. The 15% RE target fits the characteristics of an SD-PAM, and could therefore potentially attract international climate change financing and assistance through this emerging mechanism¹⁷.

The details of the mechanism are in the early stages of development, and on what basis the funding size and form is calculated remains unclear. At this stage an SD-PAM may attract assistance in the form of:

- Technical assistance
- Financial assistance
- Collaboration with other developing or developed countries to enable access to test facilities and markets

South Africa has recently made a formal proposal to the COP's Ad-hoc Working Group on Long-term Co-operate Action that in terms of the Bali Action Plan a register of nationally-appropriate mitigation actions be established, which would include SD-PAMS. If such a register is established, South Africa could register the 15% renewable energy target as an SD-PAM (Winkler 2008 ; RSA 2006; Winkler 2002).. Given the different technological characteristics of wind and solar, and their opportunity sets, it's possible that the country could enter two pledges, one in collaboration with other developing countries wishing to exploit their wind resources, which would request both technical and financial assistance. The second could be in the form of a single country pledge, for financing to assist South Africa invest in technology pilots for solar thermal towers, and to enable access to land and favourable feed-in tariff and tax regimes to attract international technology developers to invest in pilots in the country, in partnership with local players primed to evolve into international market leaders in the technology space. Alternatively, South Africa may wish to collaborate specifically with a country like Spain to jointly develop a competitive advantage around solar thermal technologies (Dubash 2005).

¹⁷ Note that SD PAMS are still very much under development as mechanisms under the international climate change framework. However, progress on this is anticipated to be made at the 15th Conference of the Parties to the Kyoto Protocol to be held in Copenhagen in 2009.

8. Conclusions

A renewable energy target of 15% for 2020 comprising wind and solar thermal, particularly if combined with partner programmes such as an energy efficiency programme, will provide significant greenhouse gas mitigation, together with air quality, health and eco-system service co-benefits to South Africa. There are also opportunities for the country to develop a competitive advantage in solar thermal technologies, and establish South African industry and technicians as front-runners in this area of the rapidly expanding international renewable energy sector.

The additional costs are likely to be financed predominantly through the CDM, or 'new CDM', or supported as an SD-PAM, and could also be offset against savings from energy efficiency. Remaining additional costs can be allocated to electricity consumers. There is also scope for direct grant funding from government for technology development programmes.

A clear, certain and mandatory target is crucial to the success of the RE programme. This target must be supported by a well developed regulatory framework. It is proposed that this framework is comprised of a feed-in tariff for wind in the first instance, extended to solar thermal once the tariff mechanism is proven, combined with subsidies and tax incentives for the development of the solar thermal technology, and investment in expertise, capacity and capability as leaders in this international sector. An energy efficiency trading scheme is proposed as the foundation for achieving the industrial energy efficiency target.

While this study makes the general case for considering such a target, further studies would be required to explore a potential programme in more detail, especially in terms of investment requirements and mechanisms. Other areas which could be explored include technical options such as storage systems, more in-depth analysis of risks associated with power sector investments (including using other approaches such as portfolio approaches, and assessing the risks arising from current investment patterns), as well as the implications of different planning approaches emphasising distributed generation.

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10. Appendices

10.1 Appendix 1 – More detail on model assumptions and inputs

10.1.1 Initial plant costs

Most plant costs were sourced from the IEA's 2008 Energy Technology Perspectives, which provides range of plant capital costs (minimum and maximum values). In most cases, the average value was used. For **CCGT** plants, the ETP average was used, which compared well with the EIA's 2008 value. For new **supercritical coal plants**, the EIA's cost was adopted, which was towards the higher end of the IEA's values, but closer to Eskom's recent pronouncements on the price of Medupi (which was higher than the EIA cost). The capital cost of **nuclear PWRs** are subject to a much greater degree of uncertainty due to the complexity of the engineering and in most cases lack of standardisation involved – historically, there have been massive cost overruns, and not many new plants have recently been built. The IEA's estimate is based on a UK study carried out by the UK DTI, and takes into account estimates for the Finnish plant currently under construction (a new-generation PWR, and one of the two plant types under consideration by Eskom). A recently-published set of estimates for plants proposed by US utilities from Nuclear Energy Institute were also consulted. The ETP value was used, which is conservative compared to the NEI's costs. Updated costs for the **PBMR** were sourced from NIRP3, but this technology did not feature. The costs for **wind** were also the average ETP cost for onshore wind, which were slightly higher than the EIA's costs. Costs for **solar PV** were also taken from the ETP. PV is a well-established technology, and costs are well known. The same is not true for solar thermal technology. For **solar parabolic** technology, the more widely-used technology of the two, a lower value than the ETP value was adopted, which was within the ETP range and higher than the EIA value. This was also compared to the reported cost of a recently-completed plant (Nevada 1), which was considerably lower than the value chosen for this study, which is thus a conservatively high value for this technology. For **solar CSP** (power tower), the challenge is greater as there are almost no operating plants, and none on the scale planned (100MW or more). Almost no comparative information was available; for the LTMS, Eskom's estimates were used, but recent media releases indicate that these have risen considerably. The ETP contains only a very high value for a small pilot plant. The recently-completed Spanish plant (also on a very small scale) cost just less than R30 000 per kW (2003 Rands), whereas Eskom's latest press release claimed that the planned plant for the northern Cape would cost around R40 000 per kW in 2003 Rands. A value of R38 000 was therefore chosen; also a conservative value.

The solar power tower poses more of a problem, since there have only been three plants built so far – Solar 1 and 2 (Solar 2 was an upgrade of Solar 1) in the USA, which operated from 1982-1986 and 1995 to 1999 respectively with an output of 10MW, Themis in France, which operated from 1983-6 and had an output of 2MW, and PS10, a new plant in Spain and the first commercial plant, with a capacity of 11MW in 2007. A new plant, Solar Tres, with an output of 15MW, is under construction in Spain. Eskom announced plans a few years ago to build a 100MW plant in the northern Cape, but a final decision on the project is still awaited. Cost information varies significantly. The Eskom project was initially reported at a relatively low cost, and these figures were used in the LTMS. The recently-completed 11MW PS10 in Spain cost a reported EUR35 million, equivalent to around R28 000/kW in 2003 Rands. Solar Tres, with advanced thermal storage and an effective availability of 74%, is estimated to cost the equivalent of around R95 000/kW (source: <http://www.solarpaces.org> – retrieved 9 October 2008). Recent media statements by Eskom estimate the cost at around R60 000/kW. The ETP provides a lower estimate only for a small plant. Given the lack of experience with the technology, and the scale of the proposed Eskom plant, we have assumed an optimistic cost estimate for the technology just below the most recently-reported Eskom cost. An availability factor of 55% has been assumed. A conservative availability factor of 55% for both technologies was assumed – by comparison, the Spanish plant Solar Tres currently under construction will have an availability of over 70% (but a much higher capital cost).

10.1.2 Converting overnight costs to present value costs

Capital cost, which is in most cases the most significant cost of power plants, is usually given as an ‘overnight cost’, the total cost of building the plant without interest which would normally be accrued during the lead time; financially, this is equivalent to the assumption that the plant is built ‘overnight’, during the night before it begins operation. On the other hand the present cost assumes that the overnight cost has been incurred over a number of years prior to commissioning, and sometimes afterwards – thus the plant owner would incur interest during construction. We have used present value costs for both the levelised cost calculations and for the energy model, which have been calculated by allocating the overnight costs according to assumptions used in NIRP3 (NERSA 2007), and then discounting at the relevant discount rate to present value. For plants with short lead times such as wind installations, this makes little difference (2% higher costs at a 7.5% discount rate), but for plants with long lead times such as nuclear, the difference is significant (20% higher at the same discount rate). The yearly allocation of capital is contained in the table below:

Table 9 – Allocation of capital to plant building programme – Source: NIRP 3

	year -6	year -5	year -4	year -3	year -2	year -1	year 0	year 1
CCGT	0%	0%	0%	10%	9%	41%	41%	0%
coal SCC	0%	0%	10%	2%	35%	48%	5%	0%
coal FBC	0%	0%	10%	2%	35%	48%	5%	0%
coal IGCC	0%	0%	10%	2%	35%	48%	5%	0%
nuclear PWR	20%	8%	4%	6%	20%	20%	14%	8%
nuclear PBMR	20%	8%	4%	6%	20%	20%	14%	8%
wind medium (onshore)	0%	0%	0%	0%	5%	20%	75%	0%
wind high (offshore)	0%	0%	0%	0%	5%	20%	75%	0%
solar PV	0%	0%	0%	0%	0%	0%	100%	0%
solar CSP	0%	0%	0%	10%	9%	9%	72%	0%
solar parabolic	0%	0%	0%	10%	9%	9%	72%	0%

Plants become operational at the beginning of year 1, and are constructed in the period denoted by the red-shaded cells. Fractions of the cost before this are costs incurred before construction.

10.1.3 Learning rates

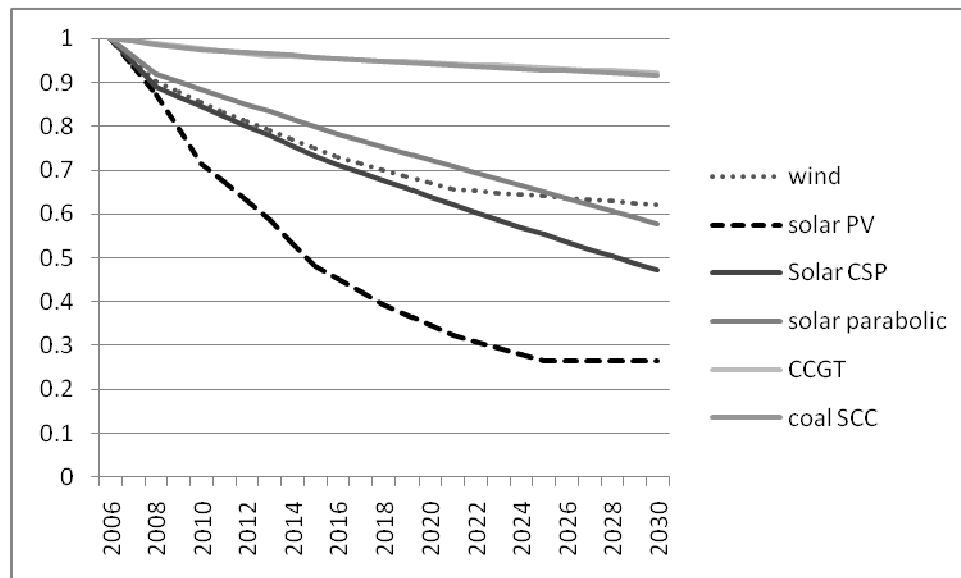
We assumed for this study that technology learning occurs; while the analytical basis for this was developed in the LTMS, technology learning was not applied in the modelling. We have assumed that the only cost which is affected by technology learning is the capital cost, which reduces as learning takes place. The same learning rates have been applied as for the LTMS, with the exception of photovoltaics and wind. For PV, we used a lower learning rate of 18% instead of 22%, consistent with the IEA’s 2008 ETP (IEA 2008). For wind, we have assumed a learning rate of 10%, also in line with the IEA’s 2008 ETP; the European Wind Energy Association proposes a learning rate of between 9-17%.

Thus, we have assumed the following learning rates: wind – 19%, solar PV – 18%, solar thermal parabolic trough – 15%, solar thermal concentrated receiver – 20%, supercritical coal – 4%, and CCGT 5%. The important exception for this was nuclear technology. The LTMS framework, which we draw on for this study, did not include a learning rate for nuclear power. Some studies include negative learning rates for nuclear, based on the historical interaction between constantly rising regulatory standards and rapidly-evolving reactor design (Jamash and Kohler 2007). If it is assumed that regulatory standards have reached a stable point, and that future reactor designs will reach higher levels of standardisation, then there is no reason to assume that technology learning will not take place, particularly within specific nuclear technologies. The IEA’s ETP estimates that 3rd-generation nuclear technologies will decline in capital cost by 20% by 2025, given an assumed deployment rate. They assume a 3% learning rate. The current concerns with proliferation might however result in the imposition of further regulatory costs, as might whatever long-term solution is arrived at for waste

disposal. These uncertainties are not however necessarily greater than those associated with projections for solar thermal technology.

Capital cost reduction indices which result from the application of learning rates (given assumptions about deployment rates and limits of global installed capacity) are given in the figure below. The CCGT index is very similar to that of coal.

Figure 19 – Learning indices for power plant technologies



10.2 Appendix 2 – Detailed Description of modelling results

The policy which was modelled was a target of 15% of domestic electricity generated by renewable sources by 2020. While the modelling was underway, more detailed work was encountered on the availability of wind resources in South Africa by Kilian Hagemann in the Climate Systems Analysis Group at UCT, the subject of his PhD research (see Appendix 3 for a more detailed overview). The work is much more detailed and comprehensive than previous assessments of South Africa's wind resources, and indicates a much higher potential. Since the work has not yet been peer-reviewed (his PhD is still under evaluation), two different sets of wind availability assumptions have been used – a lower availability (used in the LTMS), and a higher availability, using Hagemann's data. In addition to the reference case, three scenarios were modelled: 1) a scenario using the lower wind assumptions in which the model chooses the least-cost approach to meeting the target (referred to as **Case 1**); 2) a scenario using the higher wind assumptions in which the model chooses the least-cost approach to meeting the target (referred to as **Case 2**); and 3) a scenario using the higher wind assumptions in which a certain proportion of solar thermal is specified (50% electricity from each technology – referred to as **Case 3**). In addition to this, an energy efficiency programme was modelled with the reference case and with the above scenarios (**Cases 1A, 2A and 3A**), as well as a nuclear scenario, in which nuclear plants are built instead of coal plants after 2015. More detailed data on capacity, output, peak demand and AF reserve margin are provided for each modelled scenario below.

10.2.1 The reference case

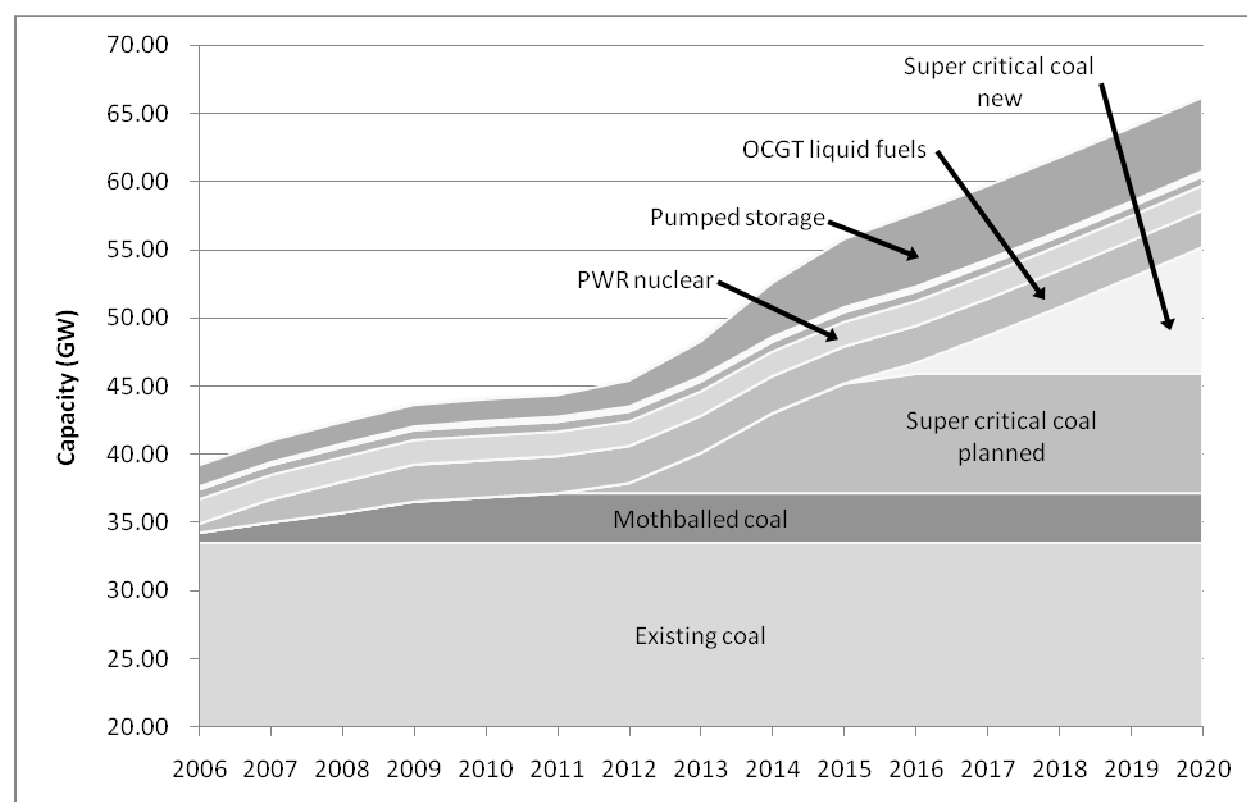
10.2.1.1 Outline

The reference case follows the current development plans in the electricity sector closely; the mothballed plants are returned to service according to current timetables, Medupi and Kusile¹⁸ come onstream as scheduled, planned expansion in Eskom's OCGTs is carried out, and one 100MW wind farm is built. The IPP OCGT project forming part of the DME's current tendering process is omitted.

10.2.1.2 Capacity

The expansion plan is shown below:

¹⁸ Kusile is the name of the new SCC power plant which has up to now been referred to as Bravo.

Figure 20 – expansion plan for reference scenario

The main source of electricity remains coal-fired power; there is no investment in new nuclear energy, and apart from the wind farm, no new investment in renewable energy. New capacity is brought online as specified in the table below:

Table 10 – Installed Capacity in GW for reference scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Super critical coal planned	-	-	0.74	2.94	5.86	8.04	8.77	8.77	8.77	8.77	8.77
Super critical coal new	-	-	-	-	-	-	0.78	2.77	4.85	7.02	9.26
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.00	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	48.26	52.56	55.78	57.70	59.69	61.77	63.94	66.18

The two new planned coal-fired stations are built, and are completed by 2016. A further two coal-fires plants are added to the grid by 2020.

10.2.1.3 Electricity Output

Figure 21 – electricity output for reference scenario

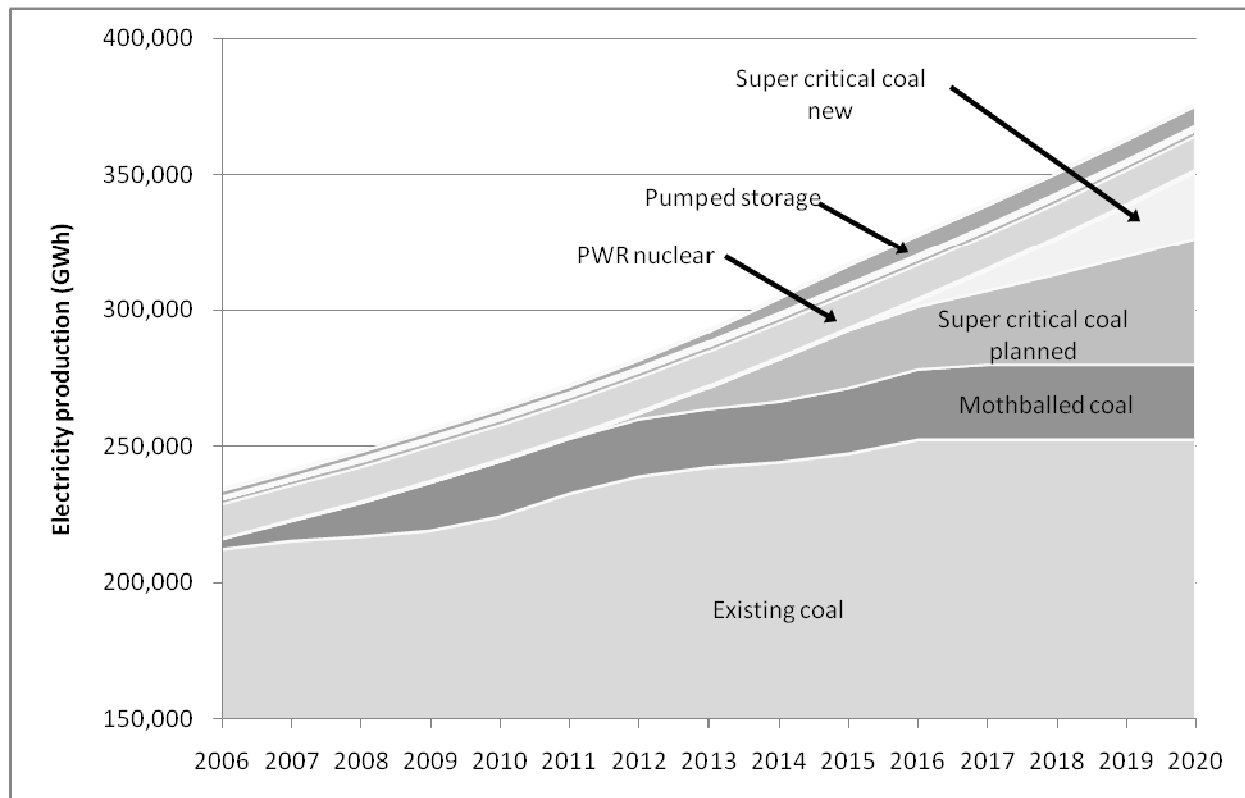


Table 11 – Electricity Output in GWh for reference scenario

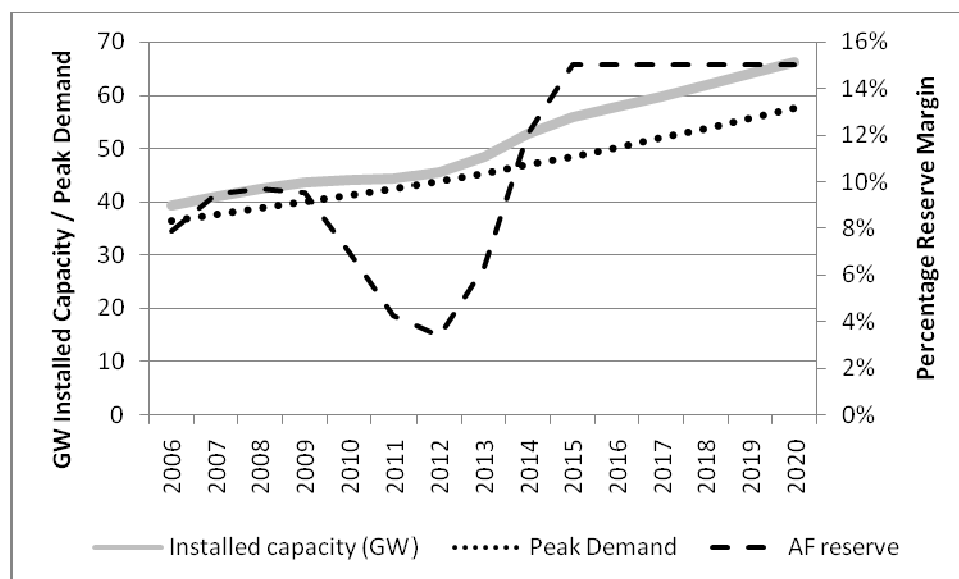
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	224214	232647	238914	242336	244175	247342	252428	252428	252428	252428	252428
Mothballed coal	20039	20039	20900	21322	22161	23939	25733	27483	27483	27483	27483
Super critical coal planned	0	0	1939	7719	15397	21136	23036	27192	33267	39892	46656
Super critical coal new	0	0	0	0	0	0	2044	7278	12886	18439	24347
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	219	219	219	219	219	219
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6569	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	261419	269853	278919	288544	298900	309583	320408	331547	343231	355408	368081
% renewable	1.5%	1.4%	1.4%	1.3%	1.3%	1.2%	1.2%	1.2%	1.1%	1.1%	1.0%
% coal	93.4%	93.6%	93.8%	94.1%	94.3%	94.5%	94.6%	94.8%	95.0%	95.2%	95.3%
% liquid fuels	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	3.8%	3.7%	3.5%	3.4%

The share of coal-fired electricity actually increases as new coal-fired plants are built towards the end of the period. The contribution from other primary energy sources remains static in absolute terms.

10.2.1.4 Reserve margin and peak demand

Due to the current delay in the new build programme, the reserve margin declines to very low levels towards 2012, before recovering towards 2020, as demonstrated in the figure below:

Figure 22 – reserve margin, peak demand and installed capacity for reference scenario



Peak demand reaches just under 60GW by 2020, and installed capacity reaches just over 66GW. The reserve margin reported above is an availability factor reserve margin, which is based on the sum of plant availability during the winter peak. For all dispatchable technologies, the availability is 1; for wind, the availability factor is less than 1, which means that only a fraction of the installed capacity is counted towards the reserve margin. We have used two figures: for the low wind potential estimates we have used 23% (NIRP3), and for the higher wind potential a figure of 39% was used, derived from Hagemann's work (details in Appendix 4).

10.2.2 The reference case with residential efficiency

10.2.2.1 Outline

If the reference case is modelled with an industrial energy efficiency programme, both peak demand and total electricity required per year grow more slowly, which has a very significant impact on the requirement for new capacity. It becomes necessary to defer the development of the second planned SC coal plant, Kusile. While this effect is not so evident in the efficiency case alone, it is an important element in Cases 1A to 3A, since with higher end-use efficiencies, the renewables plants built to meet the 15% target displace, delay or avoid building Kusile in part or entirely, which comprises a large percentage of the savings in these scenarios over the reference case. The table below indicates the savings in relation to the baseline for specific sectors. It is interesting to note that in the last few months some of the 2010 savings rates were achieved in a very short time under the impetus of the power crisis. Savings targets here are not much more ambitious than the existing Energy Efficiency Accord targets for 2015. Moreover, a programme spread over all sectors could achieve the same effect with more gradual targets.

Table 12 – % electricity savings by industrial sector in efficiency scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Gold mining	7%	9%	11%	13%	15%	18%	18%	18%	18%	18%	18%
Other mining	8%	10%	12%	14%	16%	18%	18%	18%	18%	18%	18%
Iron and Steel	5%	6%	7%	8%	10%	11%	11%	12%	12%	13%	13%
Chemical	5%	6%	8%	9%	10%	12%	12%	13%	13%	14%	14%
Precious and NFM	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%
Non-Metallic Minerals	6%	8%	10%	11%	13%	14%	15%	16%	17%	18%	18%

Pulp and paper	6%	8%	10%	12%	13%	15%	15%	16%	16%	17%	17%
Food and Beverages	6%	8%	10%	11%	13%	14%	15%	15%	16%	17%	17%
Other industry	7%	9%	11%	12%	14%	15%	16%	17%	18%	18%	19%

10.2.2.2 Capacity

The impact on capacity is that 5GW less coal-fired power are required. Installed capacity in 2020 is 62GW instead of 67GW, which represents a considerable savings in investment.

Figure 23 – expansion plan for efficiency scenario

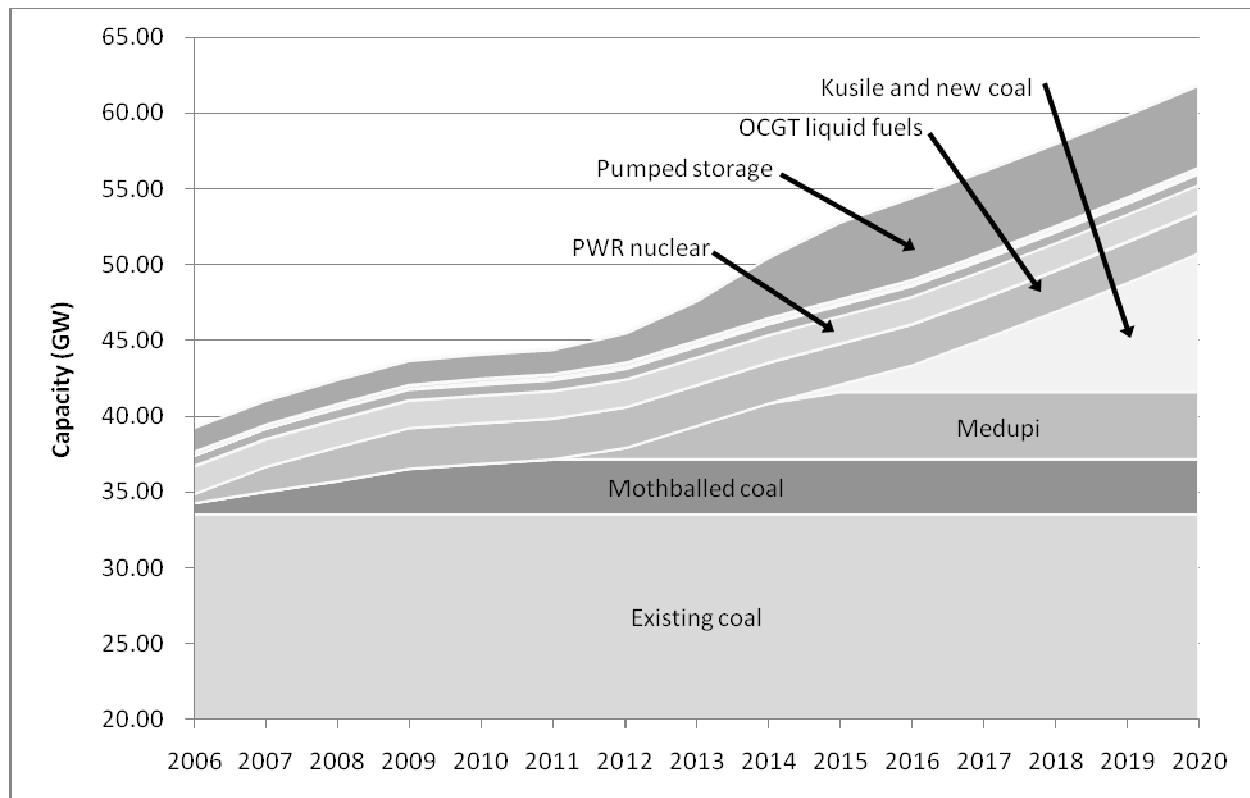


Table 13 – expansion plan for efficiency scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Medupi	-	-	0.74	2.21	3.69	4.43	4.43	4.43	4.43	4.43	4.43
Kusile and new SCC	-	-	-	-	-	0.51	1.78	3.51	5.32	7.21	9.18
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10

Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	47.53	50.39	52.72	54.36	56.09	57.90	59.79	61.76

10.2.2.3 Electricity output

Output has the same composition as the reference scenario, but at a lower level.

Figure 24 – electricity output for efficiency scenario

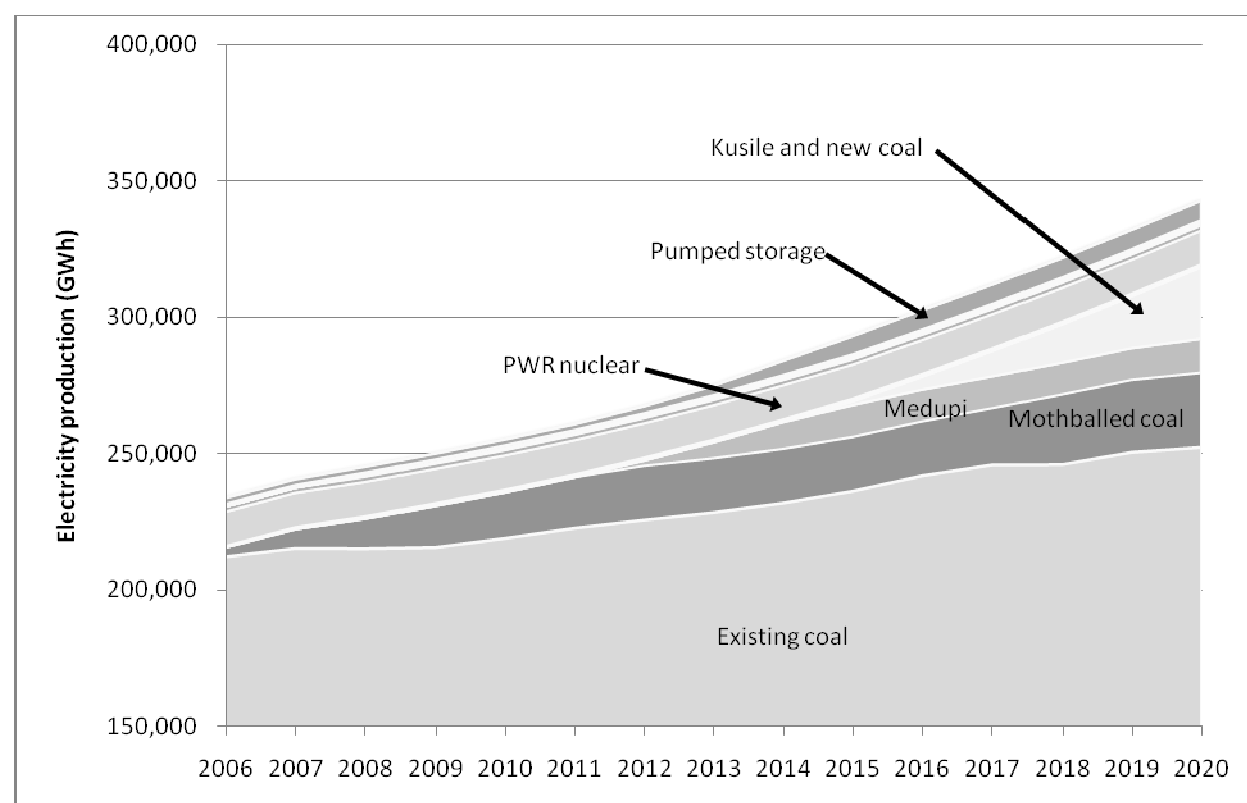


Table 14 – electricity output for efficiency scenario

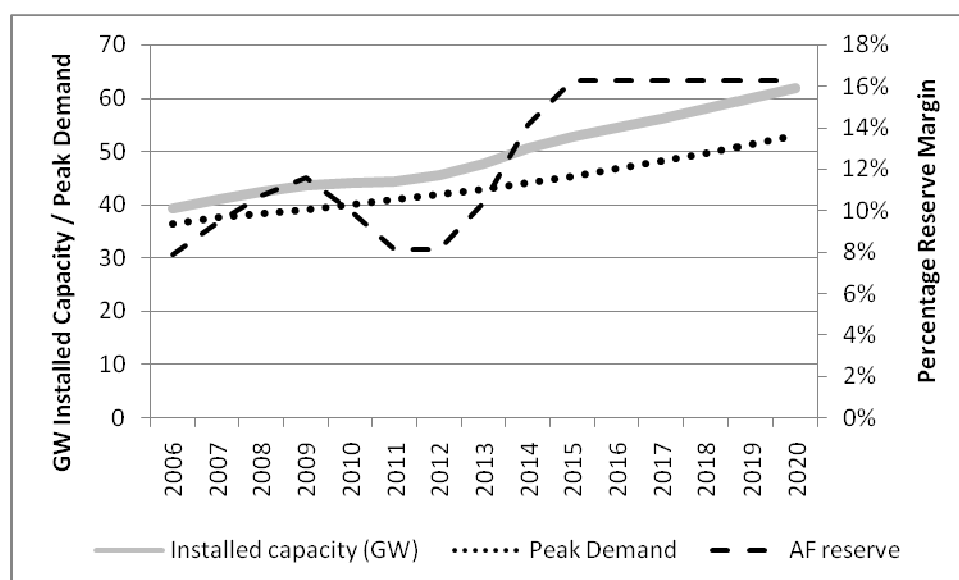
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	218997	222753	225731	228508	231967	236303	241983	245986	246139	250628	252428
Mothballed coal	16983	18803	20039	20039	20039	20039	20039	20853	25789	26636	27483
Medupi	0	0	1939	5819	9697	11636	11636	11636	11636	11636	12414
Kusile and new SCC	0	0	0	0	0	1333	4672	9219	13986	18950	26267
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	219	219	219	219	219	219
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111

TOTAL (excl pumped storage)	253147	258722	264875	271533	278869	286478	295497	304861	314717	325017	335758
% renewable	1.5%	1.5%	1.5%	1.4%	1.4%	1.3%	1.3%	1.3%	1.2%	1.2%	1.1%
% coal	93.2%	93.4%	93.5%	93.7%	93.8%	94.0%	94.2%	94.4%	94.5%	94.7%	94.9%
% liquid fuels	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	4.3%	4.1%	4.0%	3.9%	3.8%

10.2.2.4 Reserve margin and peak demand

There is a significant difference in the reserve margin, which declines only to 8% in 2012, thereby significantly decreasing the probability of blackouts in the short term.

Figure 25 – reserve margin, peak demand and installed capacity for efficiency scenario



10.2.3 Case 1

10.2.3.1 Outline

Case 1 uses the lower availability wind resource assumptions from the LTMS, and the model chooses the least-cost path to meet the target. Since with lower availability and technology learning, wind approaches the cost of solar thermal, this scenario contains quite a proportion of solar thermal technology. Because of the higher availability of solar thermal and its dispatchability, almost no new coal capacity is built after Kusile.

10.2.3.2 Capacity

New solar thermal and wind plants avoid the need for more coal after Kusile:

Figure 26 – expansion plan for Case 1

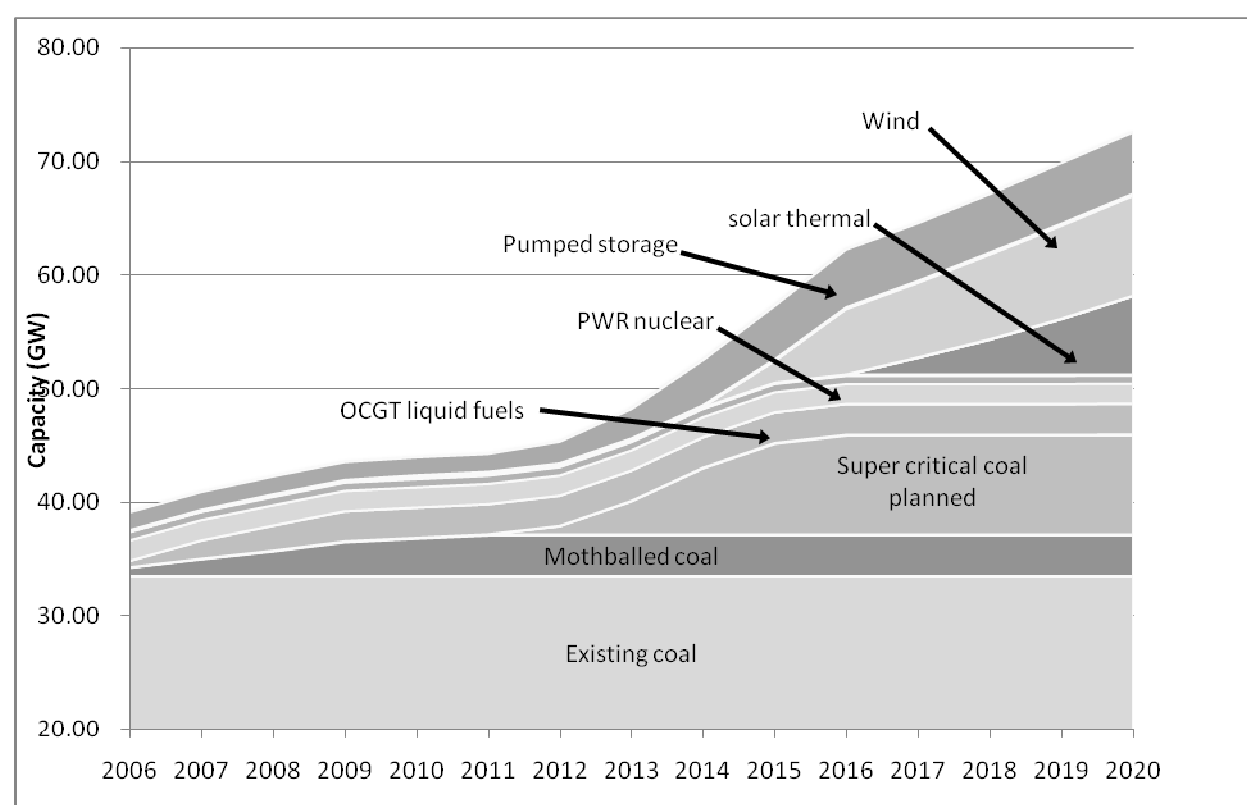


Table 15 – expansion plan for Case 1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Super critical coal planned	-	-	0.74	2.94	5.86	8.04	8.77	8.77	8.77	8.77	8.77
Super critical coal new	-	-	-	-	-	-	-	-	-	-	0.03
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	1.50	3.10	4.90	6.90
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	1.95	5.81	6.62	7.50	8.25	8.86
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	4.71	5.08	5.08	5.16	5.34	5.41
TOTAL	44.02	44.32	45.39	48.26	52.56	57.34	62.30	64.61	67.17	69.90	72.61

10.2.3.3 Electricity output

The new coal plants are used at a lower level, to absorb the output from the new renewable plants.

Figure 27 – electricity output for Case 1

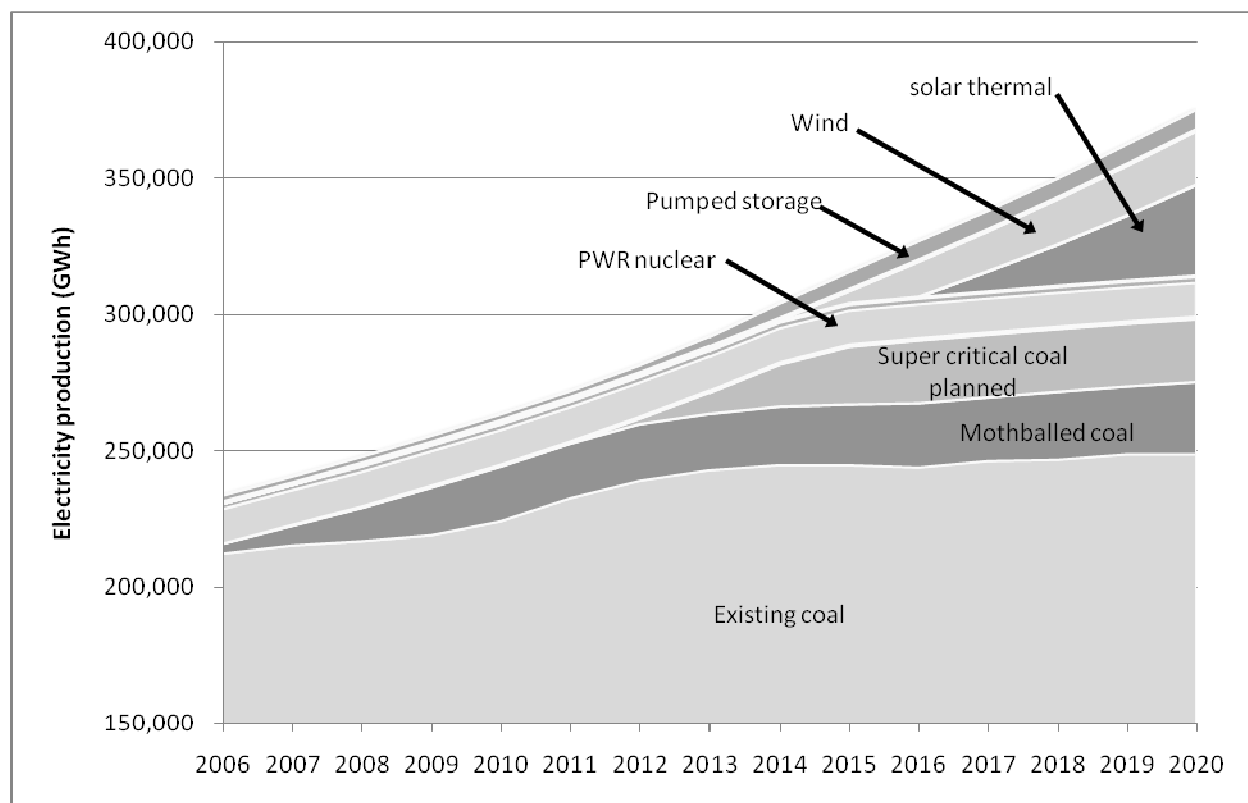


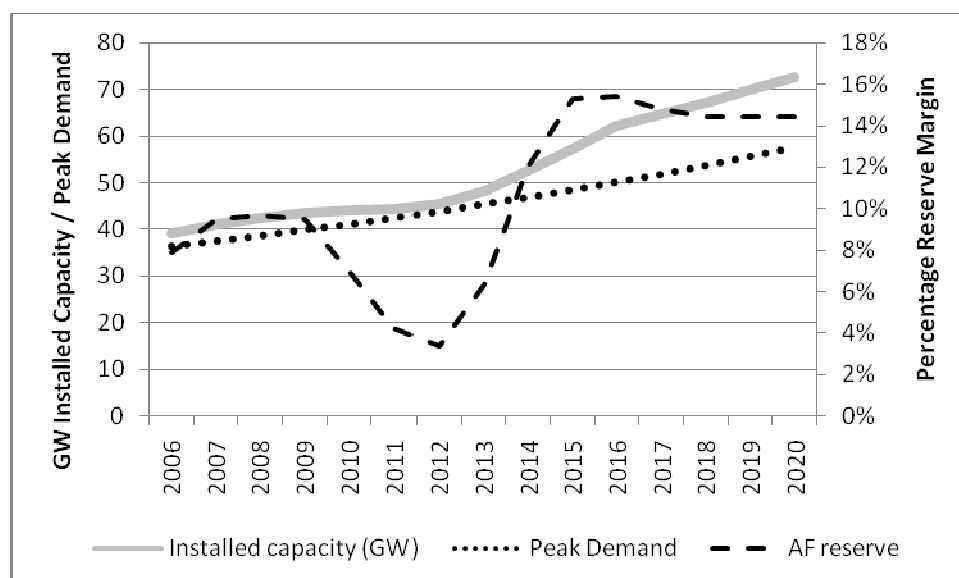
Table 16 – electricity output for Case 1

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	224214	232647	239072	242978	244889	244836	243981	246353	246822	248828	248772
Mothballed coal	20039	20039	20742	20681	21447	22272	23581	23342	24953	24892	26597
Super critical coal planned	0	0	1939	7719	15397	21136	23036	23036	23036	23036	23036
Super critical coal new	0	0	0	0	0	0	0	0	0	0	72
CCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	7228	14936	23608	33244
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	4269	12725	14508	16433	18072	19414
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6178	6672	6672	6781	7019	7111
TOTAL (excl pumped storage)	261419	269853	278919	288544	298900	309461	320269	331414	343128	355383	368083
% renewable	1.5%	1.4%	1.4%	1.3%	1.3%	2.6%	5.1%	7.7%	10.2%	12.7%	15.3%
% coal	93.4%	93.6%	93.8%	94.1%	94.3%	93.1%	90.7%	88.3%	85.9%	83.5%	81.1%
% liquid fuels	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	3.8%	3.7%	3.5%	3.4%

10.2.3.4 Reserve margin and peak demand

Graph

Figure 28– reserve margin, peak demand and installed capacity for Case 1



10.2.4 Case 2

10.2.4.1 Outline

Case 2 uses the higher-availability wind assumptions outlined in Appendix 3, and the model chooses the least-cost route to the target. As a result, solar thermal is not competitive as high-resource wind is much cheaper, and does not feature in this scenario.

10.2.4.2 Capacity

Almost 19GW of new wind capacity are built by 2020. Because of the lower reliability of wind, some new coal plant is built as well to meet peak demand. The highest-availability sites (35%) are used up within a few years, and the slightly more expensive 30% begin to be used.

Figure 29 – expansion plan for Case 2

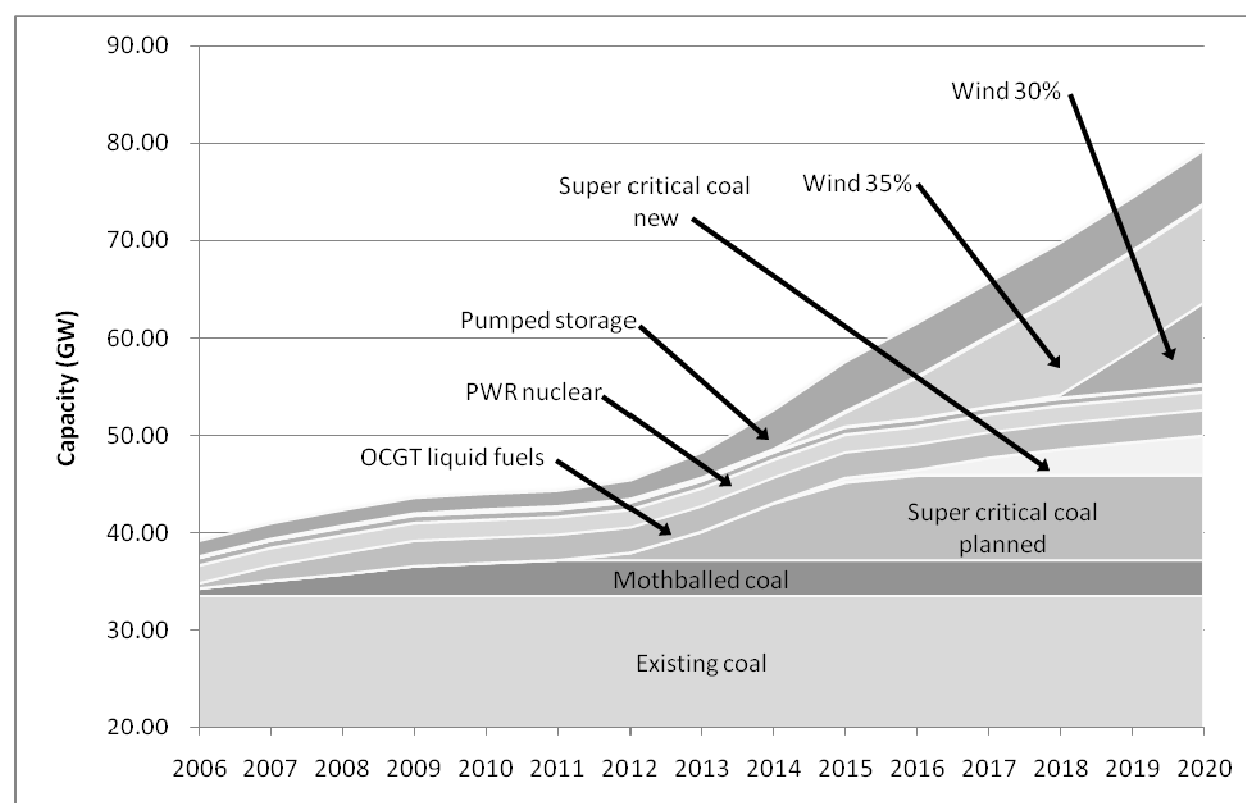


Table 17 – expansion plan for Case 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Super critical coal planned	-	-	0.74	2.94	5.86	8.04	8.77	8.77	8.77	8.77	8.77
Super critical coal new	-	-	-	-	-	0.40	0.49	1.72	2.62	3.32	4.01
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 30	-	-	-	-	-	-	-	-	0.29	4.20	8.37
Wind 35	0.10	0.10	0.10	0.10	0.10	1.40	4.16	7.10	10.00	10.00	10.00
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	48.26	52.56	57.52	61.47	65.64	69.73	74.34	79.20

10.2.4.3 Electricity output

Figure 30 – electricity output for Case 2

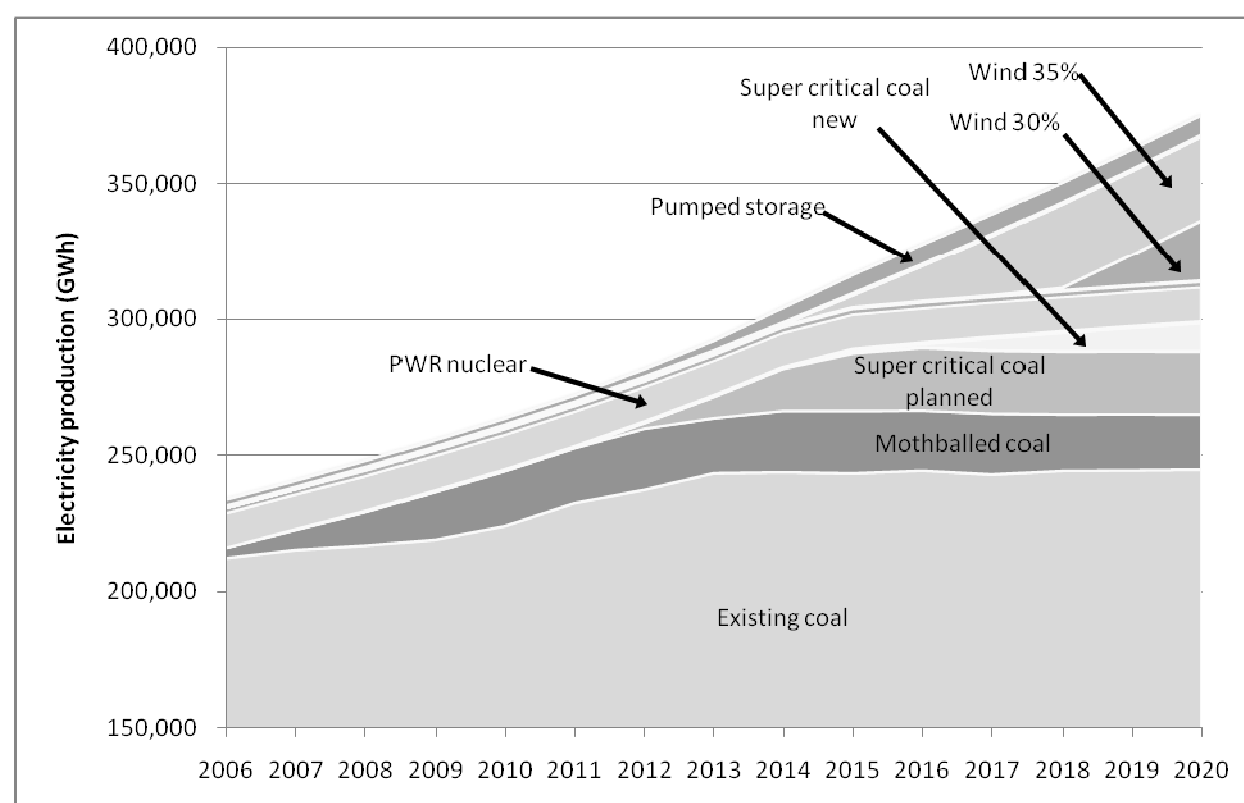


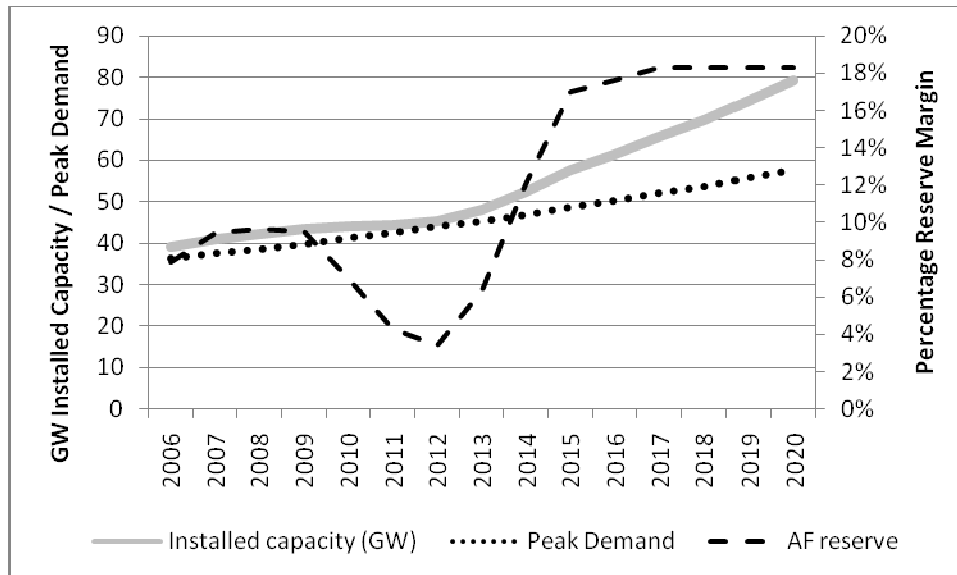
Table 18 – electricity output for Case 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	224128	232561	237456	243531	243911	243467	244506	243033	244425	244606	244872
Mothballed coal	20039	20039	22272	20039	22339	22722	21872	22231	20525	20400	20039
Super critical coal planned	0	0	1939	7719	15397	21136	23036	23036	23036	23036	23036
Super critical coal new	0	0	0	0	0	1042	1292	4522	6886	8728	10531
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 30	0	0	0	0	0	0	0	0	753	11033	21997
Wind 35	306	306	306	306	306	4283	12756	21778	30661	30661	30661
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	261419	269853	278919	288542	298900	309597	320408	331547	343233	355411	368083
% renewable	1.5%	1.5%	1.4%	1.4%	1.3%	2.6%	5.1%	7.7%	10.2%	12.8%	15.3%
% coal	93.4%	93.6%	93.8%	94.0%	94.2%	93.1%	90.7%	88.3%	85.9%	83.5%	81.1%
% liquid fuels	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	3.8%	3.7%	3.5%	3.4%

10.2.4.4 Reserve margin and peak demand

To attain the same level of reliability as the reference case, a higher reserve margin was required, which partially offsets the lower investment costs of the higher availability wind.

Figure 31 – reserve margin, peak demand and installed capacity for Case 2



10.2.5 Case 3

10.2.5.1 Outline

Case 3 has the same assumptions as Case 2, but the model is constrained to produce half the 15% target from solar thermal plants, which are otherwise not competitive with high-availability wind. This can be termed a ‘technology development’ scenario, as it would promote learning in solar thermal technology, but would require extra support.

10.2.5.2 Capacity

The expansion plan has similarities with Case 1, but with a lower share of solar thermal, and slightly more wind. The higher proportion of wind leads to investment in more new coal as a reserve.

Figure 32 – expansion plan for Case 3

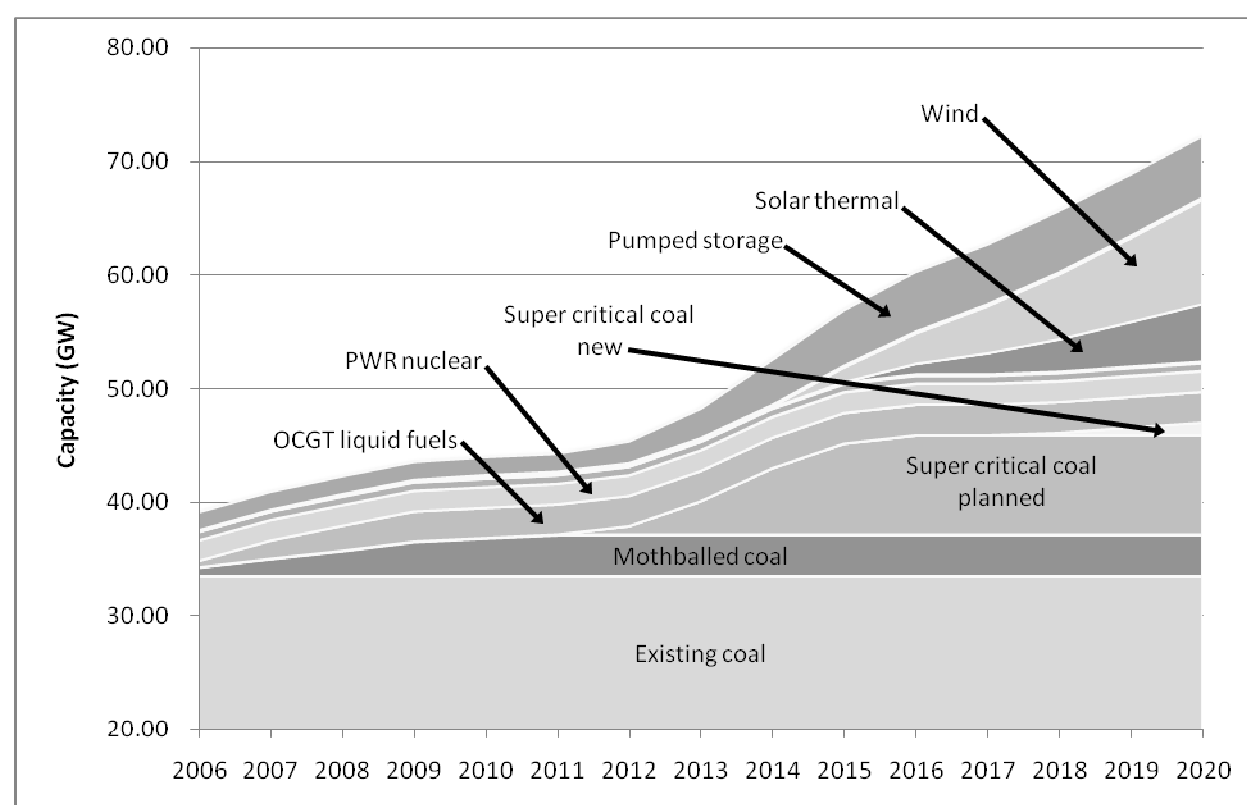


Table 19 – expansion plan for Case 3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Super critical coal planned	-	-	0.74	2.94	5.86	8.04	8.77	8.77	8.77	8.77	8.77
Super critical coal new	-	-	-	-	-	-	-	-	0.23	0.69	1.12
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	0.07	0.95	1.88	2.88	3.95	5.09
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 30	-	-	-	-	-	-	-	-	-	-	-
Wind 35	0.10	0.10	0.10	0.10	0.10	1.29	2.67	4.14	5.71	7.39	9.18
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	4.88	5.25	5.25	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	48.26	52.56	56.92	60.28	62.68	65.64	68.85	72.21

10.2.5.3 Electricity output

Figure 33 – electricity output for Case3

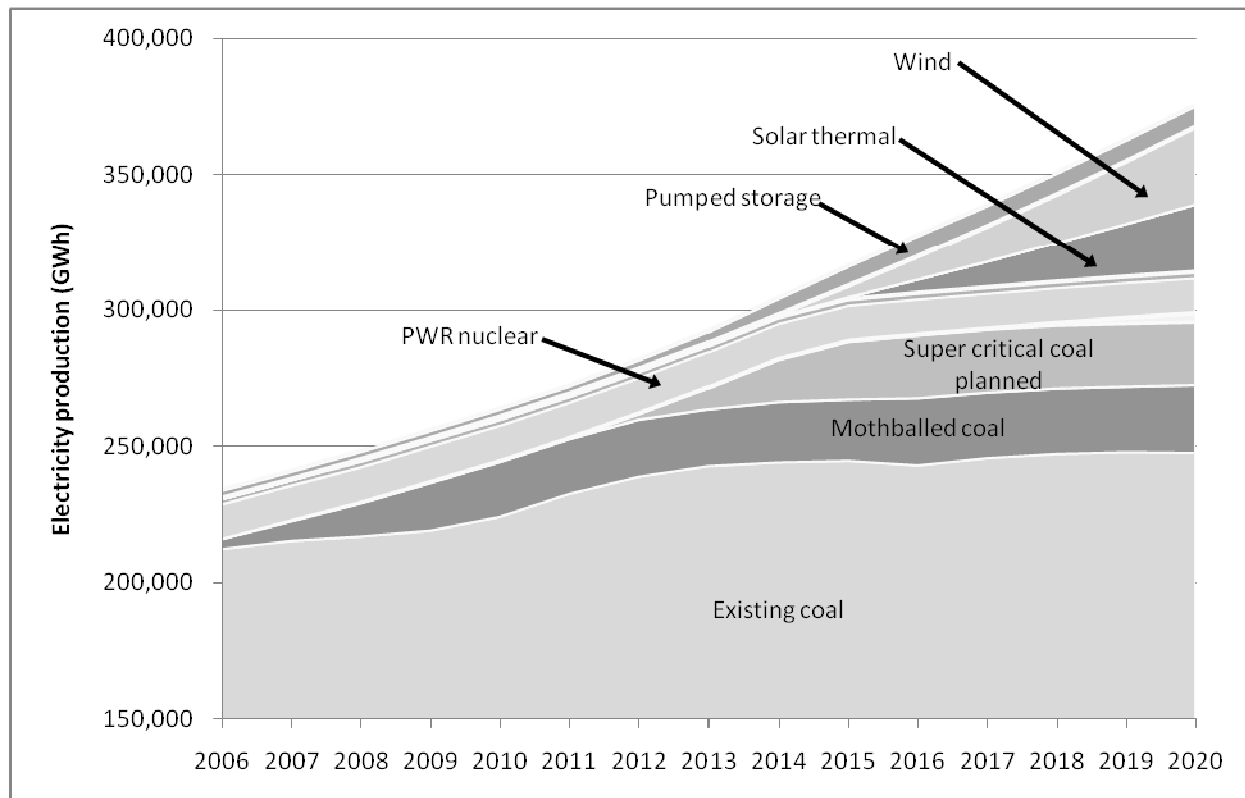


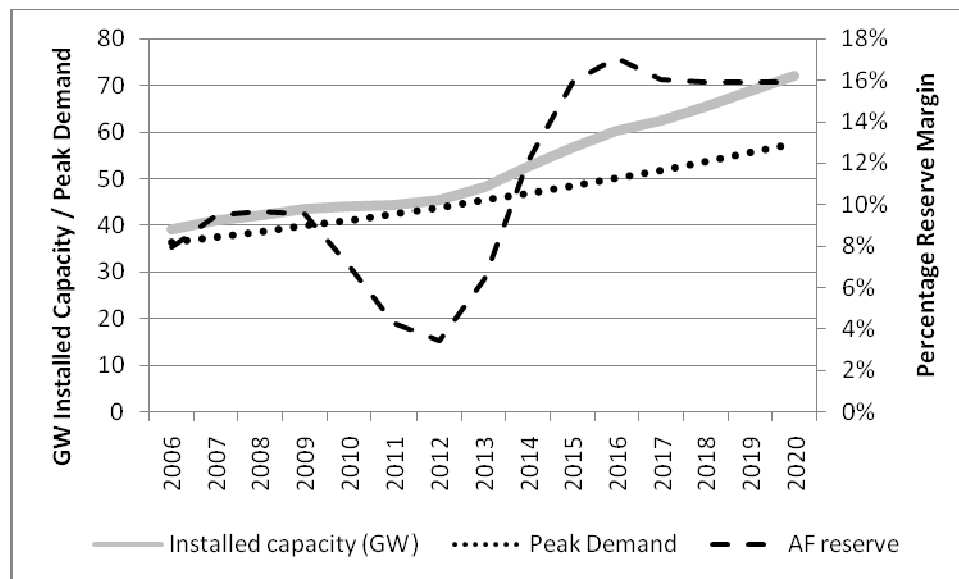
Table 20 – electricity output for Case3

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	224128	232561	238842	242753	244122	244672	242978	245672	247231	247894	247586
Mothballed coal	20039	20039	20886	20817	22131	22497	24642	24072	23994	24014	24897
Super critical coal planned	0	0	1939	7719	15397	21136	23036	23036	23036	23036	23036
Super critical coal new	0	0	0	0	0	0	0	0	614	1825	2956
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	328	4561	9069	13897	19036	24519
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 30	0	0	0	0	0	0	0	0	0	0	0
Wind 35	306	306	306	306	306	3950	8181	12689	17517	22658	28139
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6411	6906	6906	7111	7111	7111
TOTAL (excl pumped storage)	261419	269853	278919	288542	298903	309531	320344	331486	343236	355411	368081
% renewable	1.5%	1.5%	1.4%	1.4%	1.3%	2.6%	5.1%	7.7%	10.2%	12.8%	15.3%
% coal	93.4%	93.6%	93.8%	94.0%	94.2%	93.1%	90.7%	88.3%	85.9%	83.5%	81.1%
% liquid fuels	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	3.9%	3.8%	3.7%	3.5%	3.4%

10.2.5.4 Reserve margin and peak demand

A lower reserve margin is required than for Case 2 due to the higher proportion of solar thermal plants.

Figure 34 – reserve margin, peak demand and installed capacity for Case 3



10.2.6 Case 1A

10.2.6.1 Outline

Case 1A is identical in inputs to Case 1 but is run with the efficiency programme.

10.2.6.2 Capacity

Less renewable capacity is required to meet the 15% target because of lowered demand. Kusile is postponed until after 2020.

Figure 35 – expansion plan for Case 1A scenario

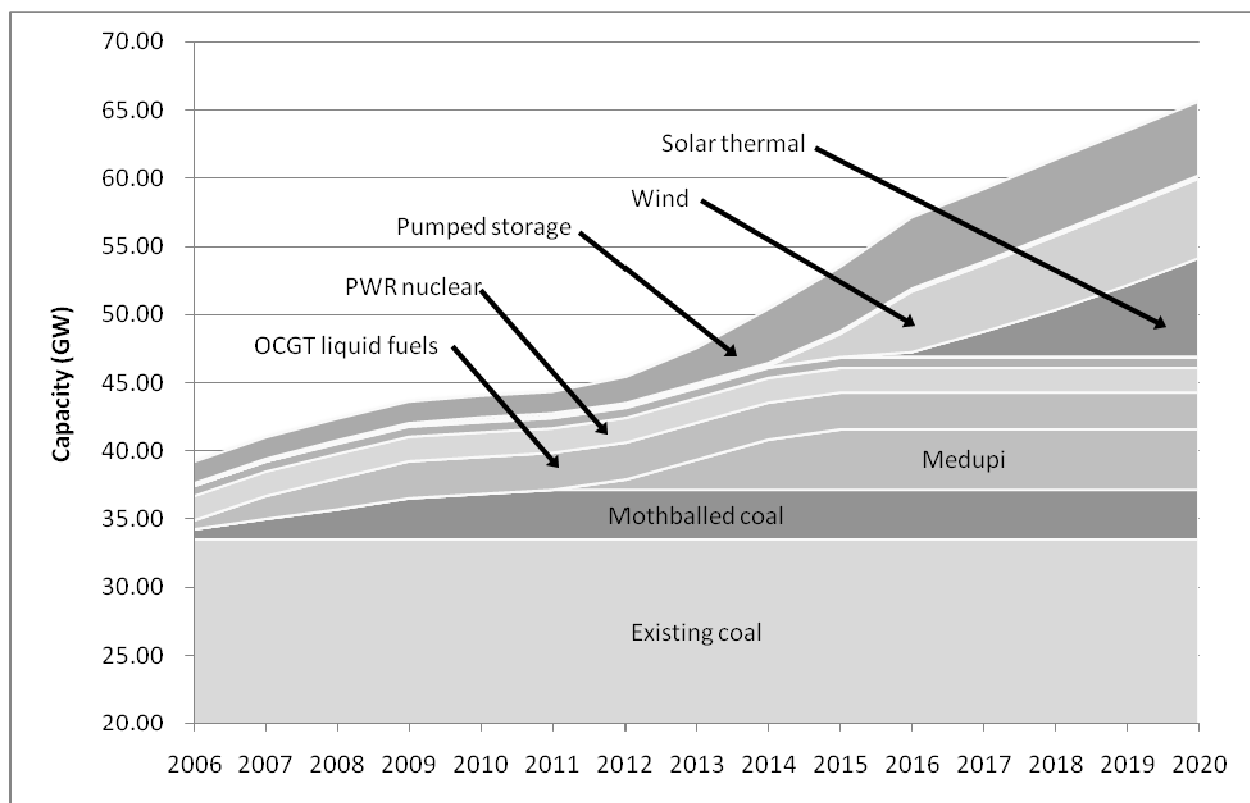


Table 21 – expansion plan for Case 1A scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Medupi	-	-	0.74	2.21	3.69	4.43	4.43	4.43	4.43	4.43	4.43
Kusile and new SCC	-	-	-	-	-	-	-	-	-	-	-
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	0.36	1.86	3.46	5.26	7.26
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	1.69	4.46	4.93	5.43	5.73	5.86
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	4.71	5.23	5.33	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	47.53	50.39	53.47	57.12	59.19	61.37	63.47	65.60

10.2.6.3 Electricity output

A higher level of coal-fired electricity is displaced than in Case 1; about half of this is through lowered demand, and the rest is displaced by renewable.

Figure 36 – electricity output for Case 1A

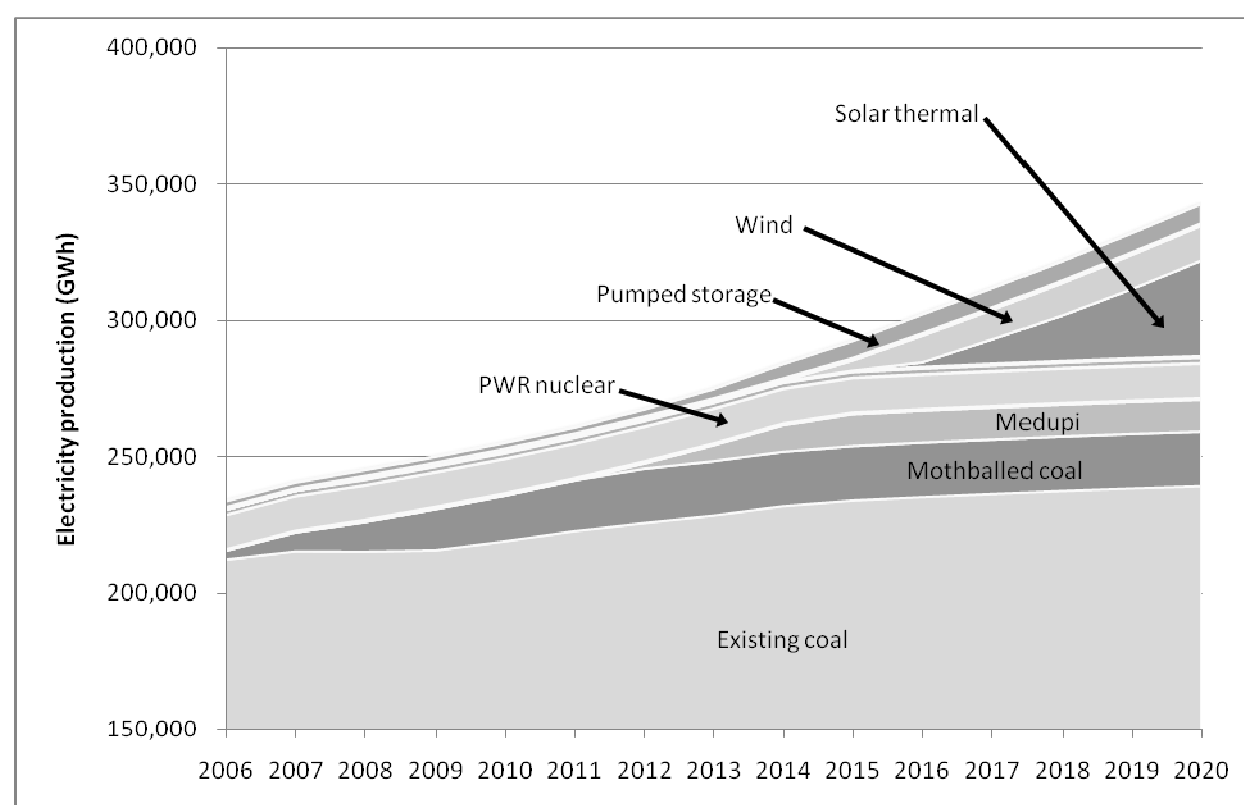
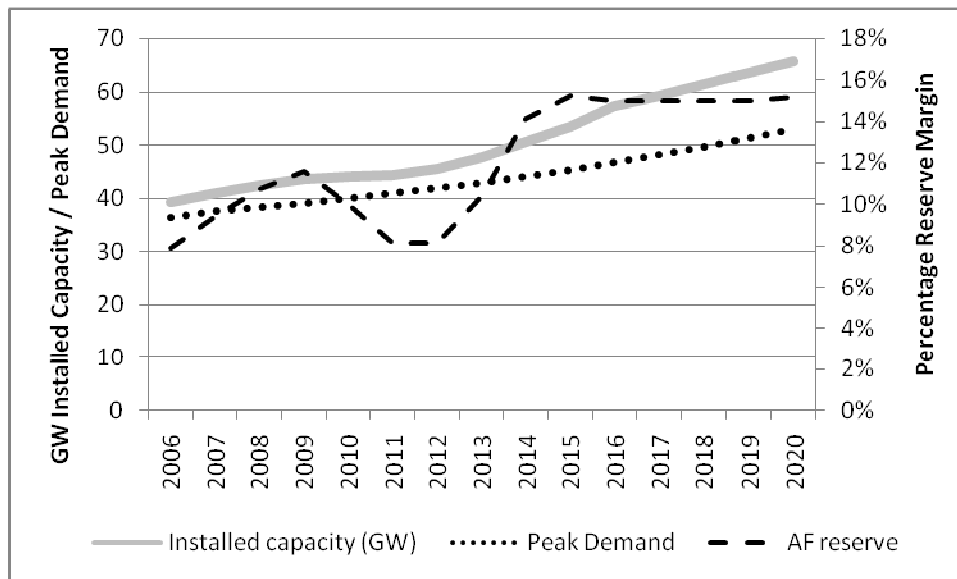


Table 22 – electricity output for Case 1A

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	218997	222753	225731	228508	231967	234025	235308	236439	237536	238503	239331
Mothballed coal	16981	18803	20039	20039	20039	20039	20039	20039	20039	20039	20039
Medupi	0	0	1939	5819	9697	11636	11636	11636	11636	11636	11636
Kusile and new SCC	0	0	0	0	0	0	0	0	0	0	0
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	1736	8964	16672	25344	34981
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	3692	9758	10803	11892	12553	12831
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6178	6872	7006	7111	7111	7111
TOTAL (excl pumped storage)	253144	258722	264875	271533	278869	286339	295425	304828	314722	325022	335764
% renewable	1.5%	1.5%	1.5%	1.4%	1.4%	2.6%	5.1%	7.7%	10.2%	12.8%	15.3%
% coal	93.2%	93.4%	93.5%	93.7%	93.8%	92.8%	90.4%	88.0%	85.5%	83.1%	80.7%
% liquid fuels	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	4.3%	4.1%	4.0%	3.9%	3.8%

10.2.6.4 Reserve margin and peak demand

Figure 37 – reserve margin, peak demand and installed capacity for Case 1A



10.2.7 Case 2A

10.2.7.1 Outline

Case 2A is the same as to Case 2 but run with the efficiency programme.

10.2.7.2 Capacity

All of Kusile is built to provide the necessary system reliability, with a slightly lower wind capacity than in Case 2.

Figure 38 – expansion plan for Case 2A

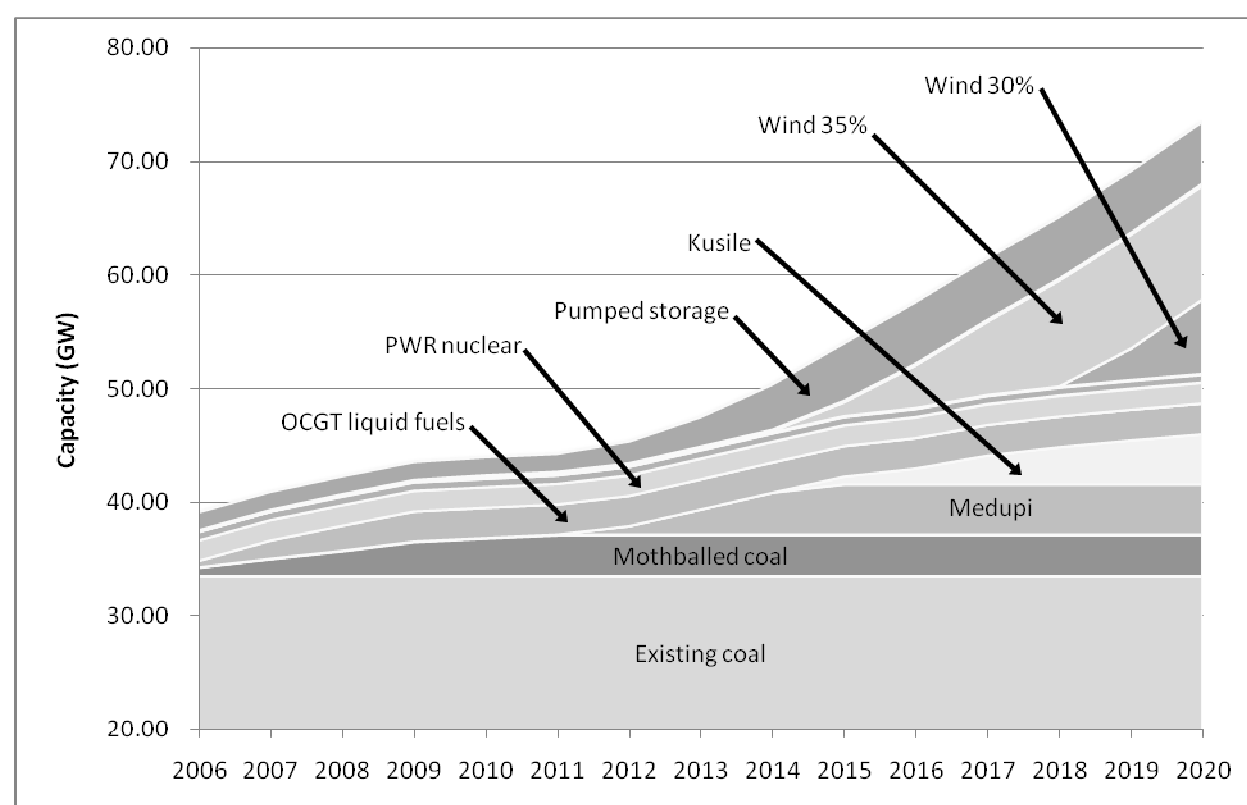


Table 23 – expansion plan for Case 2A

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Medupi	-	-	0.74	2.21	3.69	4.43	4.43	4.43	4.43	4.43	4.43
Kusile and new SCC	-	-	-	-	-	0.70	1.41	2.56	3.30	3.90	4.45
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 30	-	-	-	-	-	-	-	-	-	2.75	6.53
Wind 35	0.10	0.10	0.10	0.10	0.10	1.21	3.75	6.45	9.32	10.00	10.00
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	47.53	50.39	54.02	57.64	61.49	65.10	69.13	73.46

10.2.7.3 Electricity output

Medupi and Kusile are run at a much lower rate than in Case 2

Figure 39 – electricity output for Case2A

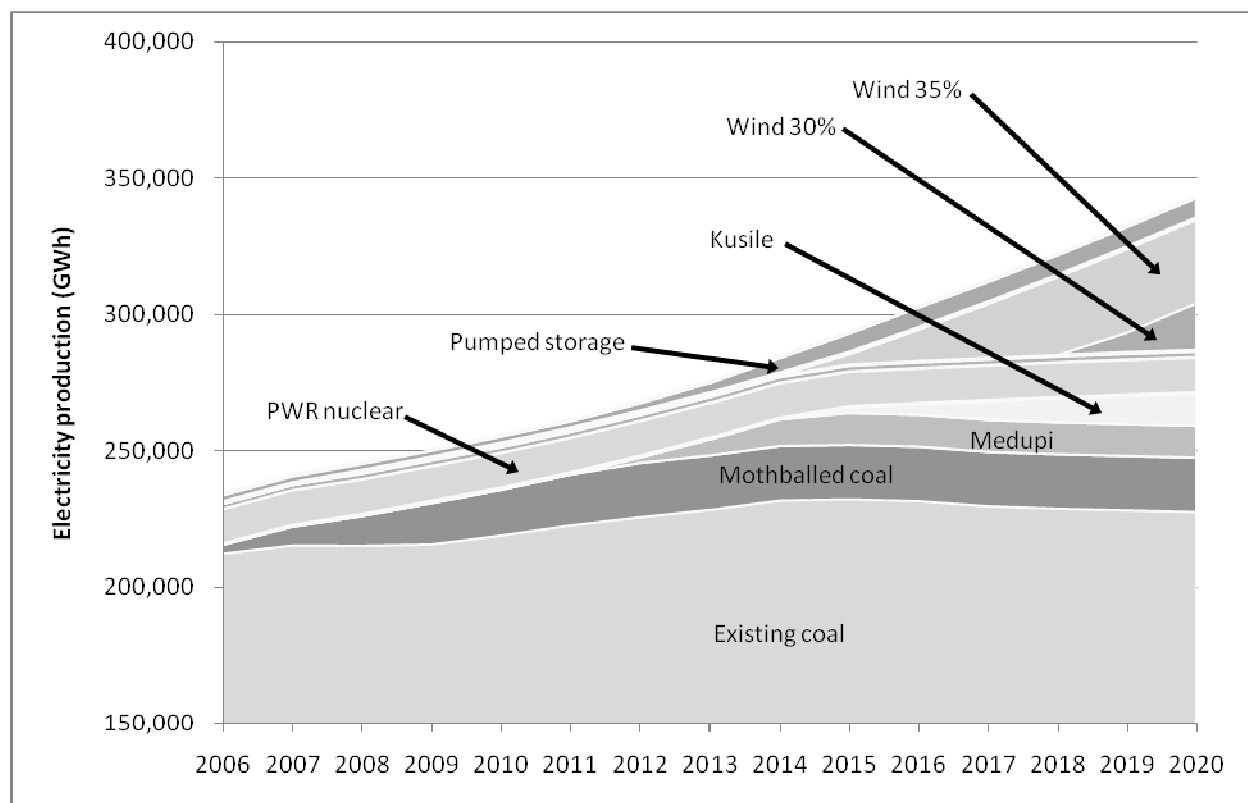


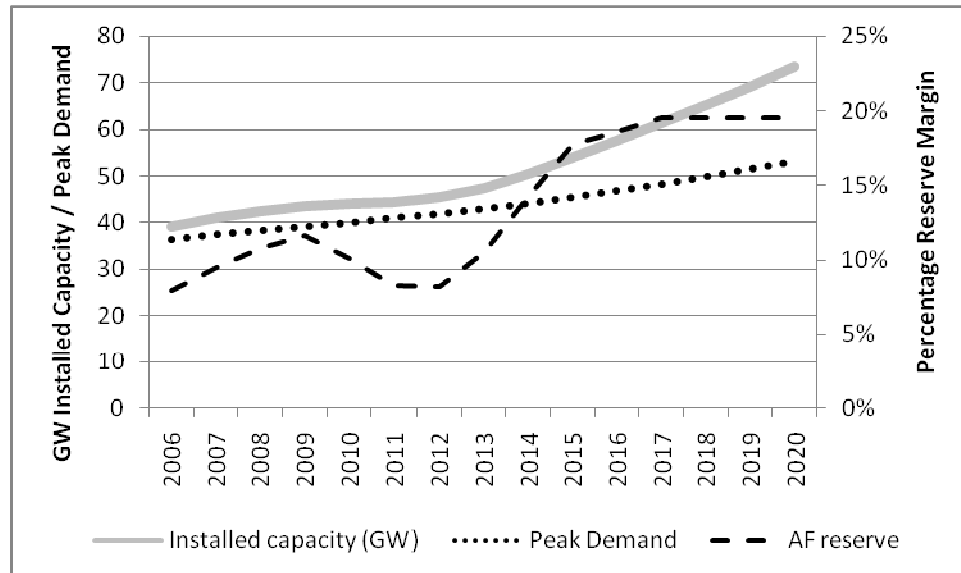
Table 24 – electricity output for Case2A

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	218944	222697	225647	228425	231878	232319	231658	229747	228858	228247	227636
Mothballed coal	16950	18772	20039	20039	20039	20039	20039	20039	20039	20039	20039
Medupi	0	0	1939	5819	9697	11636	11636	11636	11636	11636	11636
Kusile and new SCC	0	0	0	0	0	1828	3711	6714	8675	10256	11694
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 30	0	0	0	0	0	0	0	0	0	7236	17150
Wind 35	306	306	306	306	306	3706	11508	19778	28561	30661	30661
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	253147	258722	264878	271536	278867	286475	295500	304861	314717	325022	335764
% renewable	1.6%	1.5%	1.5%	1.4%	1.4%	2.6%	5.1%	7.7%	10.2%	12.8%	15.3%
% coal	93.2%	93.3%	93.5%	93.6%	93.8%	92.8%	90.4%	88.0%	85.5%	83.1%	80.7%
% liquid fuels	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	4.3%	4.1%	4.0%	3.9%	3.8%

10.2.7.4 Reserve margin and peak demand

The reserve margin is even higher than in Case 2 because of the difference in unit sizes in relation to peak demand. To achieve the same reliability as the reference scenario, a reserve margin of almost 20% is required.

Figure 40 – reserve margin, peak demand and installed capacity for Case 2A



10.2.8 Case 3A

10.2.8.1 Outline

Case 3A is the same as Case 3 but run with the efficiency programme.

10.2.8.2 Capacity

A much smaller share of Kusile is built due to the higher share of solar thermal than in Case 2A.

Figure 41 – expansion plan for Case 3A

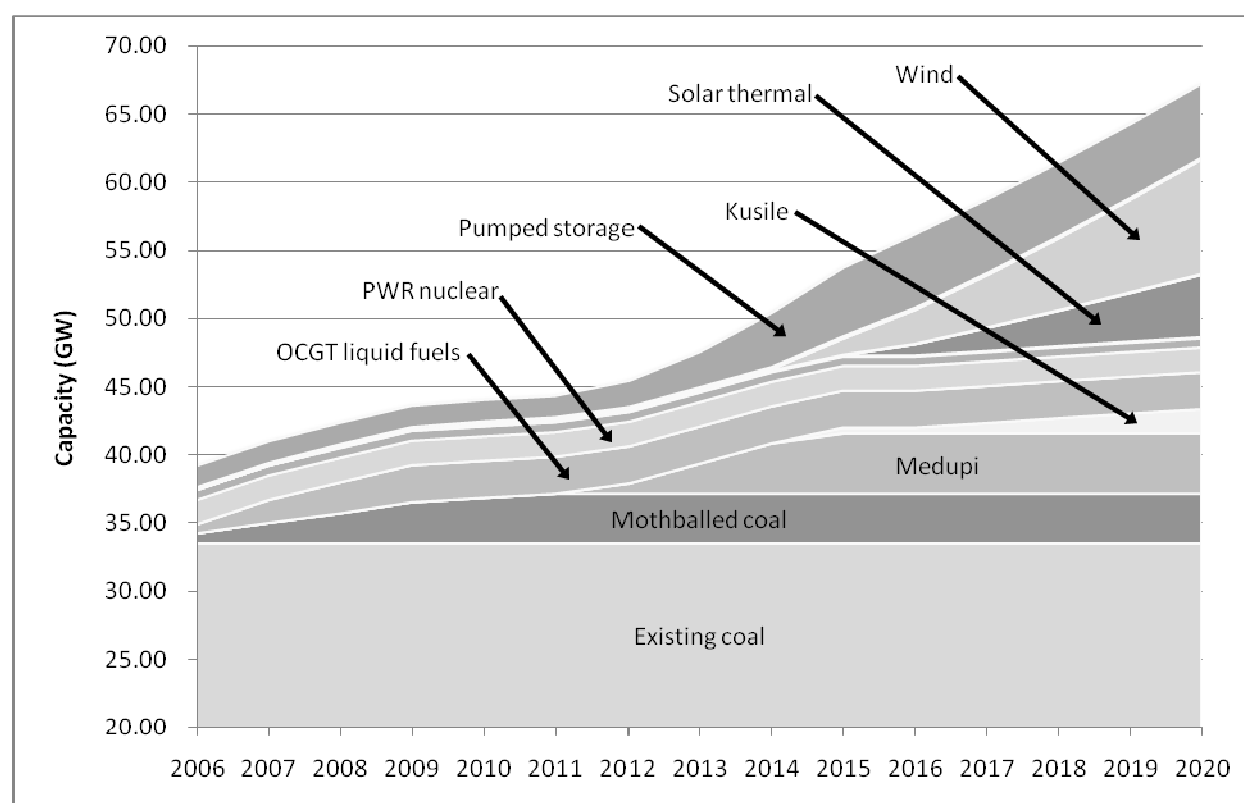


Table 25 – expansion plan for Case 3A

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Medupi	-	-	0.74	2.21	3.69	4.43	4.43	4.43	4.43	4.43	4.43
Kusile and new SCC	-	-	-	-	-	0.42	0.42	0.75	1.11	1.45	1.77
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	0.01	0.82	1.68	2.59	3.56	4.59
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 30	-	-	-	-	-	-	-	-	-	-	-
Wind 35	0.10	0.10	0.10	0.10	0.10	1.19	2.47	3.82	5.25	6.77	8.39
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	47.53	50.39	53.73	56.19	58.73	61.43	64.26	67.23

10.2.8.3 Electricity output

Figure 42 – electricity output for Case 3A

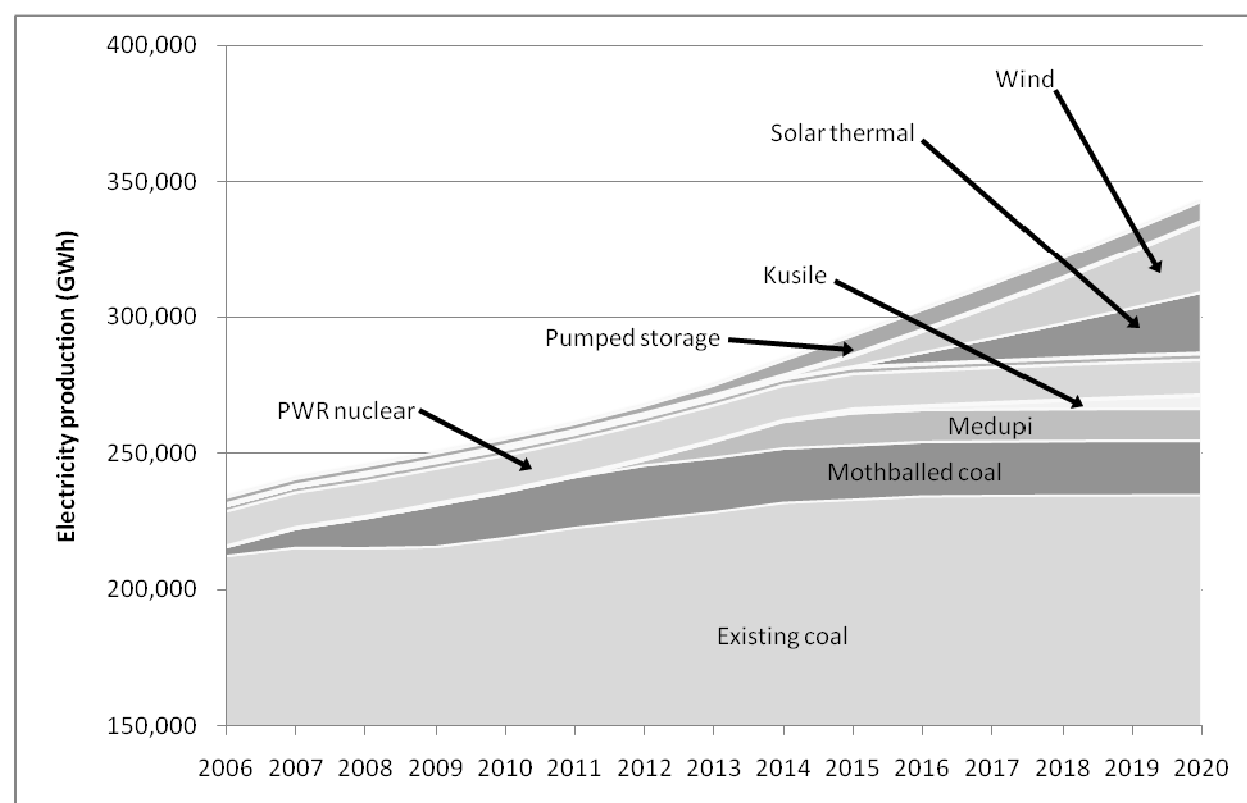


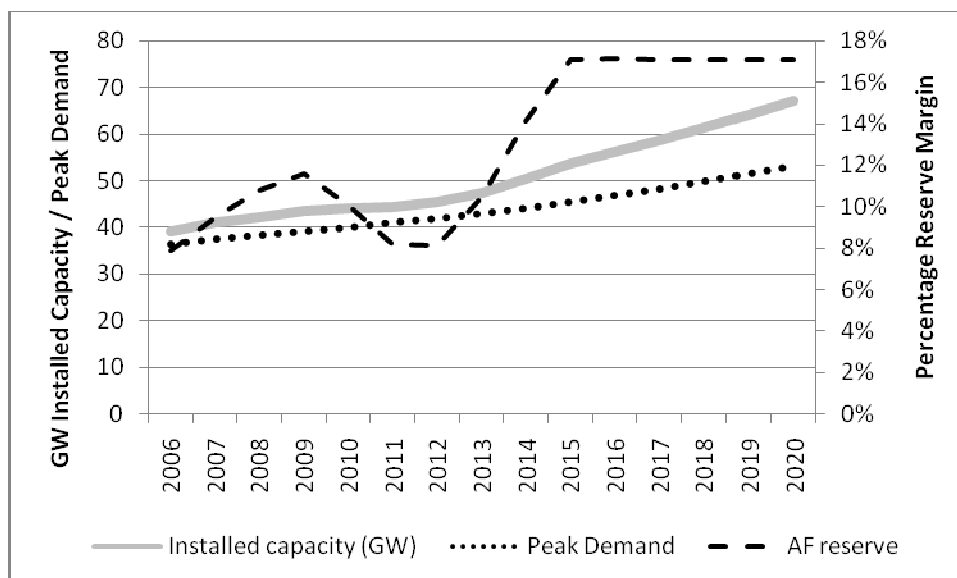
Table 26 – electricity output for Case 3A

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	218944	222697	225647	228425	231878	233050	234269	234489	234625	234700	234689
Mothballed coal	16950	18769	20039	20039	20039	20039	20039	20039	20039	20039	20039
Medupi	0	0	1939	5819	9697	11636	11636	11636	11636	11636	11636
Kusile and new SCC	0	0	0	0	0	1097	1097	1975	2908	3803	4642
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614	12614
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	42	3944	8078	12469	17136	22094
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 30	0	0	0	0	0	0	0	0	0	0	0
Wind 35	306	306	306	306	306	3664	7567	11700	16092	20758	25717
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	253147	258719	264878	271536	278867	286475	295500	304864	314717	325019	335764
% renewable	1.6%	1.5%	1.5%	1.4%	1.4%	2.6%	5.1%	7.7%	10.2%	12.8%	15.3%
% coal	93.2%	93.3%	93.5%	93.6%	93.8%	92.8%	90.4%	88.0%	85.5%	83.1%	80.7%
% liquid fuels	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	4.3%	4.1%	4.0%	3.9%	3.8%

10.2.8.4 Reserve margin and peak demand

A higher reserve margin is required, but not as high as Case 2A.

Figure 43 – reserve margin, peak demand and installed capacity for Case 3A



10.2.9 Nuclear

10.2.9.1 Outline

The nuclear scenario was run for comparison, but the constraints are not identical. This represents a 'business as usual nuclear scenario' in which Eskom would switch to building nuclear plants after Kusile. There is no target requirement, so the GHG savings and costs are not directly comparable, but this does form a good basis on which to compare alternative policies.

10.2.9.2 Capacity

After Kusile, no new coal capacity is built.

Figure 44 – expansion plan for nuclear scenario

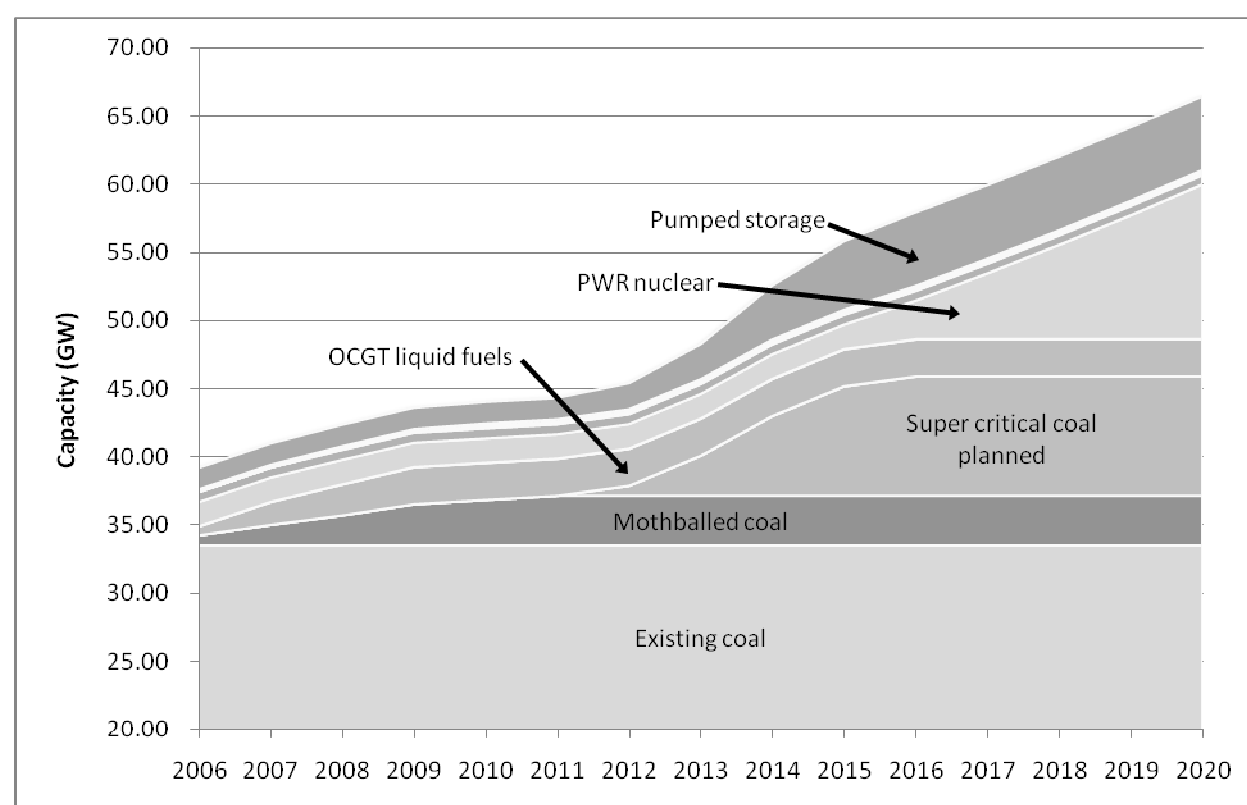


Table 27 – expansion plan for nuclear scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Super critical coal planned	-	-	0.74	2.94	5.86	8.04	8.77	8.77	8.77	8.77	8.77
Super critical coal new	-	-	-	-	-	-	-	-	-	-	-
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	2.82	4.82	6.91	9.08	11.34
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	48.26	52.56	55.82	57.94	59.94	62.03	64.20	66.46

10.2.9.3 Electricity output

Because the marginal cost (variable O and M, fuel) of running the nuclear plants is still lower than that of coal by 2020, the nuclear plants are dispatched first, and displace a significant amount of coal-fired electricity.

Figure 45 – electricity output for nuclear scenario

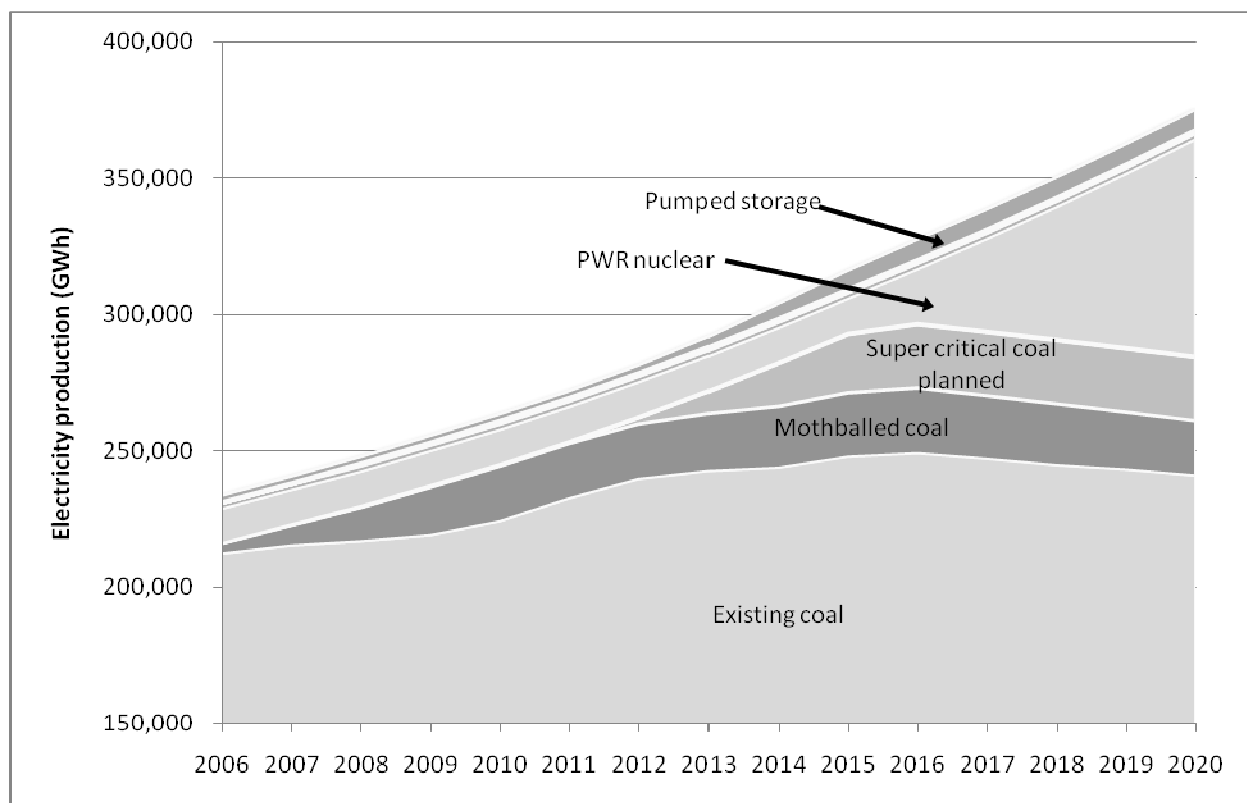


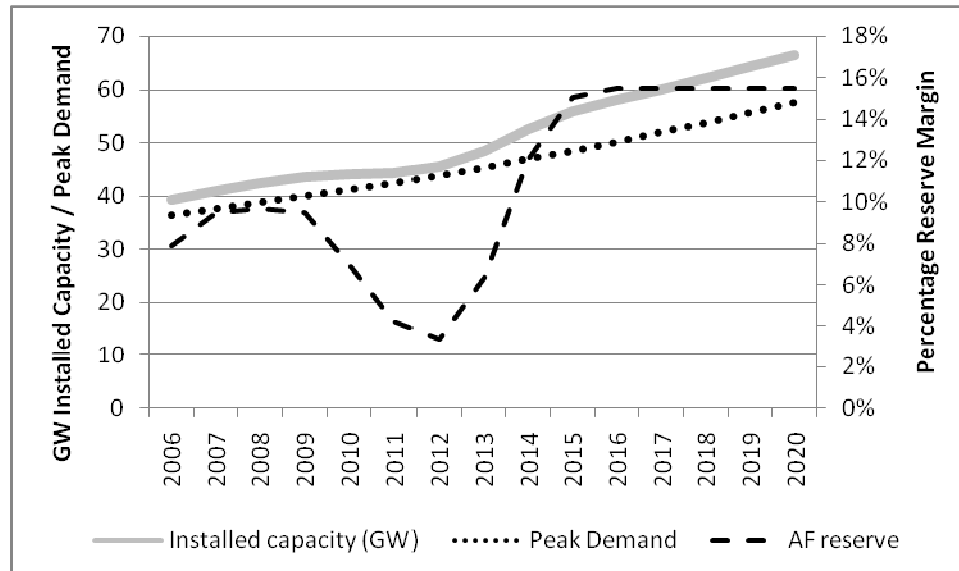
Table 28 – electricity output for nuclear scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	224214	232647	239775	242669	243919	248053	249286	247247	244847	243244	240986
Mothballed coal	20039	20039	20039	20989	22417	23244	23786	22950	22383	20928	20039
Super critical coal planned	0	0	1939	7719	15397	21136	23036	23036	23036	23036	23036
Super critical coal new	0	0	0	0	0	0	0	0	0	0	0
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	19747	33764	48417	63650	79469
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	219	219	219	219	219	219
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	261419	269853	278919	288544	298900	309600	320408	331550	343236	355411	368083
% renewable	1.5%	1.4%	1.4%	1.3%	1.3%	1.2%	1.2%	1.2%	1.1%	1.1%	1.0%
% coal	93.4%	93.6%	93.8%	94.1%	94.3%	94.5%	92.4%	88.4%	84.6%	80.8%	77.2%
% liquid fuels	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	4.8%	4.7%	4.5%	4.4%	4.2%	4.1%	6.2%	10.2%	14.1%	17.9%	21.6%

10.2.9.4 Reserve margin and peak demand

A higher reserve margin is required for the nuclear scenario on account of the larger unit sizes of nuclear plants. We have used smaller unit sizes than those actually proposed for the new PWRs, so the reserve margin is conservatively low.

Figure 46 -- reserve margin, peak demand and installed capacity for nuclear scenario



10.2.10 Nuclear with efficiency

10.2.10.1 Outline

This scenario is the same as the nuclear scenario, but Kusile is cancelled in favour of a nuclear plant. No more coal is built.

10.2.10.2 Capacity

Figure 47 – expansion plan for nuclear with efficiency scenario

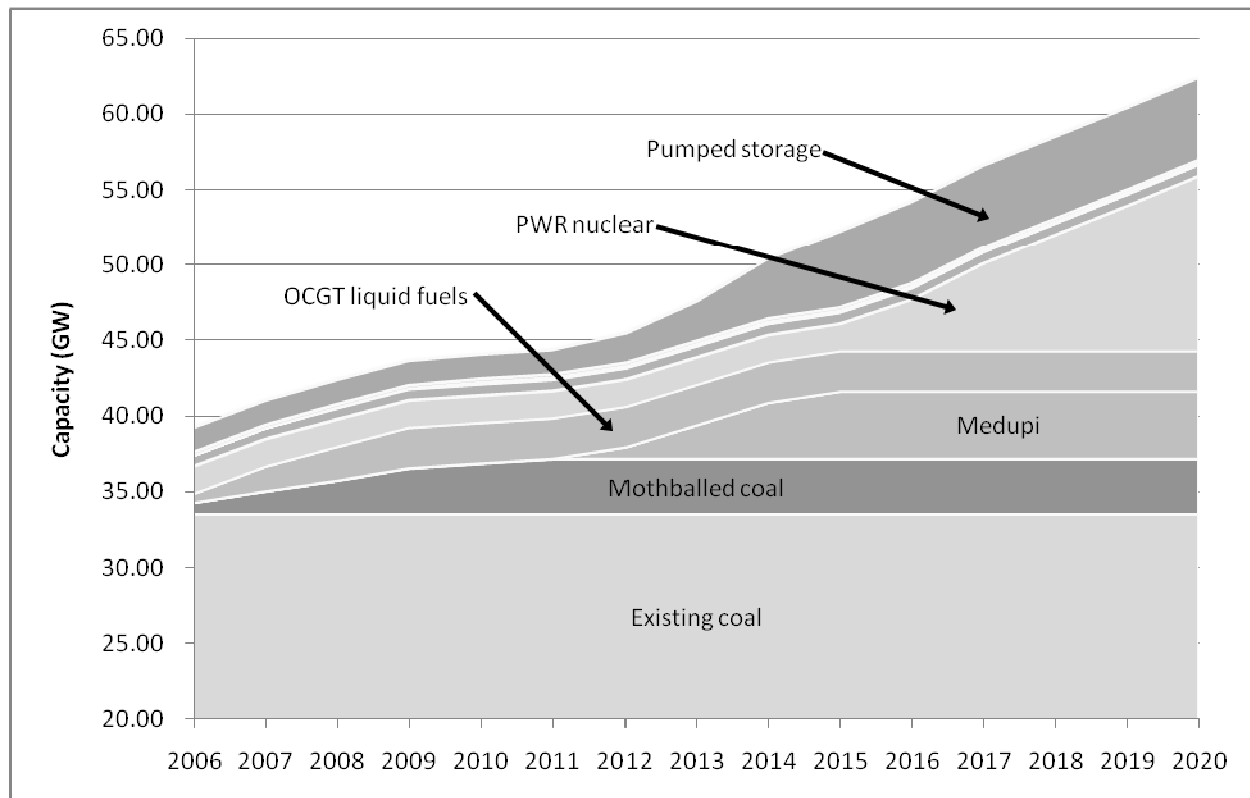


Table 29 – expansion plan for nuclear with efficiency scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48	33.48
Mothballed coal	3.36	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66
Medupi	-	-	0.74	2.21	3.69	4.43	4.43	4.43	4.43	4.43	4.43
Kusile and new SCC	-	-	-	-	-	-	-	-	-	-	-
OCGT liquid fuels	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
CCGT	-	-	-	-	-	-	-	-	-	-	-
PWR nuclear	1.80	1.80	1.80	1.80	1.80	1.80	3.40	5.80	7.72	9.63	11.61
Hydro	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Landfill gas	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Solar trough	-	-	-	-	-	-	-	-	-	-	-
Solar tower	-	-	-	-	-	-	-	-	-	-	-
Solar PV	-	-	-	-	-	-	-	-	-	-	-
Wind 20	-	-	-	-	-	-	-	-	-	-	-
Wind 25	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Biomass	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
Pumped storage	1.58	1.58	1.91	2.58	3.96	5.04	5.41	5.41	5.41	5.41	5.41
TOTAL	44.02	44.32	45.39	47.53	50.39	52.21	54.18	56.58	58.50	60.41	62.39

10.2.10.3 Electricity output

This scenario features the highest displacement of coal-fired electricity relative to the lower electricity demand. Older capacity is used at a significantly lower rate in the last five years.

Figure 48 – electricity output for nuclear with efficiency scenario

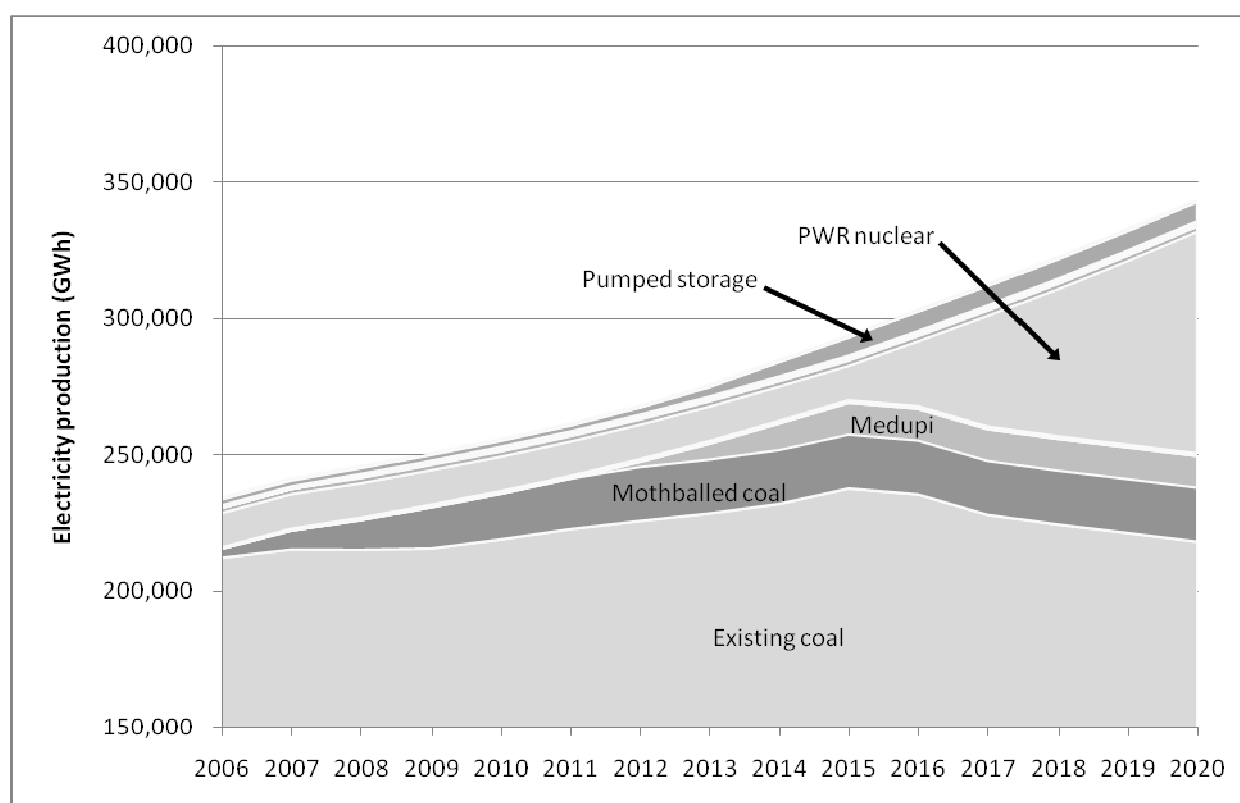


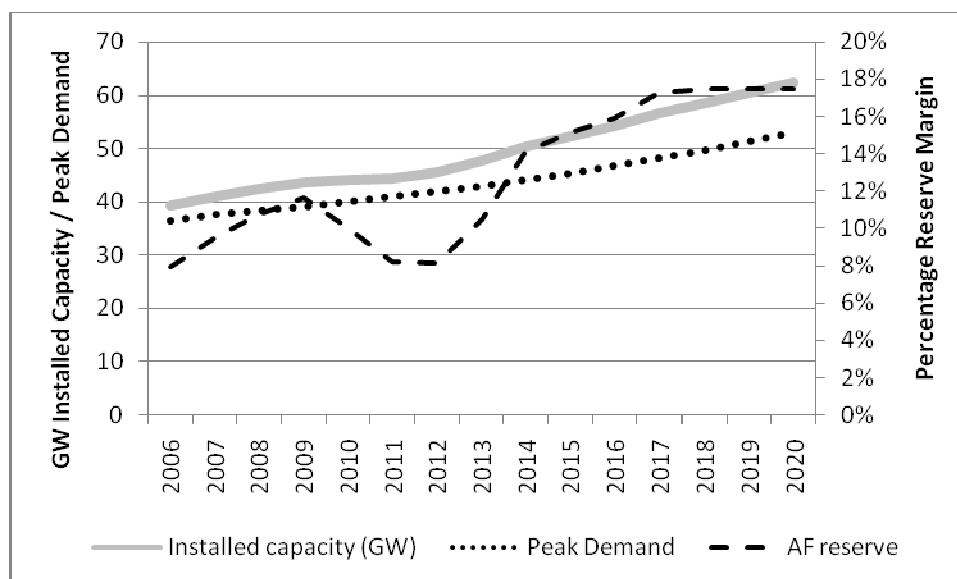
Table 30 – electricity output for nuclear with efficiency scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Existing coal	218997	222753	225731	228508	231967	237636	235444	227989	224406	221328	218158
Mothballed coal	16981	18803	20039	20039	20039	20039	20039	20039	20039	20039	20039
Medupi	0	0	1939	5819	9697	11636	11636	11636	11636	11636	11636
Kusile and new SCC	0	0	0	0	0	0	0	0	0	0	0
OCGT liquid fuels	711	711	711	711	711	711	711	711	711	711	711
CCGT	0	0	0	0	0	0	0	0	0	0	0
PWR nuclear	12614	12614	12614	12614	12614	12614	23828	40647	54086	67464	81375
Hydro	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081	2081
Landfill gas	578	578	578	578	578	578	578	578	578	578	578
Solar trough	0	0	0	0	0	0	0	0	0	0	0
Solar tower	0	0	0	0	0	0	0	0	0	0	0
Solar PV	0	0	0	0	0	0	0	0	0	0	0
Wind 20	0	0	0	0	0	0	0	0	0	0	0
Wind 25	219	219	219	219	219	219	219	219	219	219	219
Biomass	964	964	964	964	964	964	964	964	964	964	964
Pumped storage	2075	2075	2514	3389	5192	6617	7111	7111	7111	7111	7111
TOTAL (excl pumped storage)	253144	258722	264875	271533	278869	286478	295500	304864	314719	325019	335761
% renewable	1.5%	1.5%	1.5%	1.4%	1.4%	1.3%	1.3%	1.3%	1.2%	1.2%	1.1%
% coal	93.2%	93.4%	93.5%	93.7%	93.8%	94.0%	90.4%	85.2%	81.4%	77.8%	74.4%
% liquid fuels	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
% nuclear	5.0%	4.9%	4.8%	4.6%	4.5%	4.4%	8.1%	13.3%	17.2%	20.8%	24.2%

10.2.10.4 Reserve margin and peak demand

A higher reserve margin is necessary than in the nuclear scenario because of the relationship between the lowered demand, the higher proportion of nuclear capacity, and the larger nuclear unit sizes.

Figure 49 – reserve margin, peak demand and installed capacity for nuclear with efficiency scenario



10.3 Appendix 3 – New assessment of wind resources for South Africa, by Kilian Hagemann

10.3.1 Introduction

For the planning and modelling of South Africa's future electricity generation it is important to know which technologies are at planners' disposal to satisfy the national demand. The criteria to evaluate how the future energy mix should ideally be structured depends on factors such as total potential capacity (as limited by the primary resources and other constraints), cost and average availability factors of each technology.

For traditional fossil energy carriers such as coal and nuclear these parameters are fairly well known. For renewables such as wind, however, all three factors are very difficult to determine, particularly due to the lack of operational wind farms in the country as well as a lack of reliable and usable data regarding the national wind resources.

This work's primary reference, the “Mesoscale Wind Atlas of South Africa”, the PhD dissertation by the same author, significantly eased this shortfall by producing a nationwide wind dataset at 18km resolution based on the meteorological mesoscale model MM5. It provides wind speed and direction for various heights above ground, including 60m, 80m and 100m, at hourly temporal resolution for a representative yet contiguous 365 day time period. Based on comparison with 17 South African Weather Service wind monitoring stations the accuracy lies, on average, within 0.7m/s.

Section 5.4 of the thesis already addresses the question of how much total wind power potential there is in South Africa. It integrates the expected power production of a standard Vestas V80 2MW wind turbine at each 18x18km grid cell with the availability of road and transmission infrastructure. Other criteria are the expected turbine capacity factor and hub height. All assumptions are then varied according to a pessimistic, realistic and optimistic scenario which increasingly favour the wide spread adoption of wind energy as a significant energy carrier in South Africa. It was found that based on the realistic scenario (within 4km of infrastructure, 80m hub height and minimum feasible capacity factor of 30%) it is possible to generate 80TWh or 35% of Eskom's total 2007 electricity sales.

The purpose of this report is to augment these results with probabilistic availability factors of a “wind power plant” that covers all of the areas of feasible high wind resources. This information is crucial in order to model how wind as a technology would fit into a national electricity generation strategy in terms of minimised cost and satisfaction of demand profiles, particularly during peak times. The results are sought in terms of the probability density function(pdf) of instantaneous generation as a percentage of rated capacity of the “plant”. This calculation is limited to the winter season which always coincides with peak demand patterns in South Africa.

10.3.2 Method

The methodology is loosely based on the approach taken in section 5.4 of the wind atlas. The details thereof shall not be reproduced here for the sake of brevity. Instead, this section focuses on the deviations from that methodology, as required by the nature of the desired results.

Previously summary statistics such as total yearly energy production or capacity factor per 18km grid cell, i.e. two dimensional datasets, were sufficient for the analysis. In this context though the pdf must necessarily be generated from the full time series. Due to the sheer size of the underlying data volumes (several GB's of data, the full model output is 182GB) it is thus no longer possible to interpolate and regrid the power production data to 1km resolution. To seek an optimal trade off between high resolution required for accurate infrastructure distance calculations and minimising storage footprint, the original 365 day power series (i.e. the power production of a single Vestas 2MW as a function of time and space) is reduced to hourly values between 1 July and 31 August. The resulting 62day by 24h subset is then interpolated to a grid of approximately 4x4km.

Parallel to that the original 18km yearly energy production and capacity factors are interpolated to the identical 4km grid to allow for the same feasibility calculation to be carried out as in the wind atlas, with roads, transmission and border GIS data converted into the same raster. Throughout the entire process the hub height is standardised to 80m above ground in order to simplify many of the algorithms.

The country is then divided into three categories corresponding to three separate wind “technologies” for use in an energy model. Unlike before they are designed to be non-overlapping:

- Wind35 – locations with capacity factor of $\geq 35\%$ (similar to pessimistic scenario)
- Wind30 – locations with $30\% \leq \text{capacity factor} < 35\%$ (similar to realistic scenario)
- Wind25 – locations with $25\% \leq \text{capacity factor} < 30\%$ (similar to optimistic scenario)

Instead of varying it in all three cases the maximum distance to roads and suitable transmission lines is kept constant at 4km (one grid length), again in the interests of standardising and simplifying the calculation. The results are compared with the previous ones to ensure that no regressions are introduced by moving from 1km to a much coarser 4km.

This GIS analysis yields a true/false grid of eligibility for each category which is now used to extract the relevant time series from the 3 dimensional, time dependent regridded wind power data. Since the grid dimensions are identical this process is simple and the individual series are simply summed up and multiplied by the turbine density to yield a single nationwide time series of instantaneous power production for Wind35, Wind30 and Wind25. It is trivial to calculate the pdf from this result.

10.3.3 Results and Discussion

Assuming the same turbine density of $1/\text{km}^2$ (16 per 4km grid cell) the 4km GIS feasibility calculation yields for the union of Wind35 and Wind30 a total annual wind power potential of 156TWh. Compared to the original 1km analysis this is almost twice as large, a discrepancy which can be traced back to the fact that a 4km raster is spread much wider than a 1km one, especially when it comes to the distance maps for infrastructure, yielding in a much higher qualifying area. As the original figures are almost certainly more accurate, this is countered by assuming a turbine density of $0.5/\text{km}^2$ (8 per 4km grid cell) which yields a slightly lower potential than before in the realistic scenario to stay on the conservative side (78TWh vs 80TWh).

The total rated power and annual energy production figures for all qualifying areas in each category are given in Table 1. It must be stressed again that they may differ from those published in the wind atlas because of slightly different assumptions taken such as a now constant 80m hub height and maximum 4km distance to infrastructure. They do, however, impress equally well in terms of just how much of South Africa's electricity demand may be satisfied through wind. Accuracy considerations regarding these values may be found in the wind atlas.

Table 2 provides the probability density function which is sampled for the 8pm time slot which is most important for energy planning since it coincides with the evening demand peak. It shows that the probability of zero wind power fed into the grid at any given time is exceedingly low which disproves the commonly held opinion that wind is inherently unreliable and should not be invested in because of the requirement of backup capacity of equal rated power at times when the “wind does not blow”.

	Wind25	Wind30	Wind35
Number of qualifying 4km^2 grid cells	1997	1665	622
Total Rated Power (MW)	31952	26640	9952
Total Annual Energy Production (TWh)	67.8	44.6	33.3
Total Annual Energy Production (percentage of Eskom 2007 sales)	29.5%	19.4%	14.5%

Table 31: Summary Statistics for the three wind categories based on the 4km GIS analysis

	Wind power plant utilisation (% of rated power)									
	0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	80-90	90-100
Wind25 probability (%)	4.84	17.74	25.81	19.35	17.74	9.68	4.84	0	0	0
Wind30 probability (%)	0	14.52	14.52	16.13	24.19	17.74	11.29	1.61	0	0
Wind35 probability (%)	0	11.29	17.74	12.9	12.9	19.35	16.13	8.06	1.61	0

Table 32: Probability Density Function at 8pm in winter for the three wind categories

While for Wind25 it is most likely that it will generate 20-30% of its rated power during a winter evening for Wind30 and Wind35 this is much more favourable at 40-50% and 50-60% respectively which comes much closer to the availability factors of fossil fuel power plants. Of course wind is still at a disadvantage relative to traditional energy carriers because for all three categories the probability of generating at maximum output is zero.

At this point the uncertainty in these deliberations must be put into perspective. The original selection of the 365 day time period for the MM5 model integration was based on a year which was closest to climatological means – 20 March 1996 until 19 March 1997 – according to a specially developed algorithm (see chapter 3 of wind atlas). While this ensures that the time span is representative of the long term wind regime it does *not* necessarily imply that the individual seasons, let alone all the months, contained therein were average. Thus the risk that the above figures come from a particularly windy or calm 1 July – 31 August cannot be completely ignored.

Furthermore when extracting pdf's for a particular time of the day one must carefully consider the skill of the model in reproducing the daily cycle of the wind. While significant efforts were dedicated in the wind atlas towards making this feature of the variability as accurate as possible with very good results for coastal regions, it turned out that the average inland 24h evolution was much less in line with observations. Coupled with the fact that most of the qualified wind resource in this context is inland this may cause for significant errors.

Finally it should be noted that statistically an effective sample size of 62 per hour of the day is still fairly small for the determination of an accurate pdf, so even if the underlying data were 100% correct the limited sample would still yield somewhat skewed probabilities.

For these reasons the figures of Table 2 should be accepted with some caution. However, in the absence of more reliable data (e.g. winter time series for several years) this is the best that current research is able to provide.

10.3.4 Conclusion

Based on the foundation laid down by the “Mesoscale Wind Atlas of South Africa” by the same author the reliability of wind power as a significant technology in the country's electricity generation mix has been quantified. For the first time this was possible without relying purely on estimates and/or international experience, instead basing a calculation on carefully validated nationwide wind model data and sound resource feasibility criteria.

The probability density function energy production of wind power, if all available resources were reasonably exploited, has been determined for all times of the day and three different economic categories based on minimum capacity factors. The pdf has been presented for the winter evening peak (8pm); this data may now be easily employed in energy modelling in order to determine where wind energy will fit into a future electricity generation strategy for South Africa.

10.4 Sensitivity Analysis

The sensitivity analysis has been conducted on the levlised costs alone, since MARKAL uses a similar approach in optimisation. Changes in the levlised costs would thus affect the outcome of the optimisation process in the same way.

10.4.1 Discount rate

The impact of different discount rates is most significant in terms of the relative changes in costs of different technologies, which in turn is dependent on the capital intensiveness of the technology. Thus, if the discount rate is increased from 0% to 15%, costs of solar thermal, which is the most capital-intensive technology, increase by approximately 4 times, followed by nuclear (2.9), wind (2.5) and coal (2.2). Thus the choice of discount rate has a significant effect on the relative costs of technologies, and hence on conclusions which might be drawn on their competitiveness. A high discount rate disadvantages capital-intensive technologies.

10.4.2 Fuel price assumptions

Fuel price changes have a lower impact on coal and nuclear power, which are both relatively capital-intensive technologies, than on OCGT and CCGT plants, which are extremely sensitive to fuel price variations. At a 7.5% discount rate and assuming no technology learning and a constant fuel price, the levelled cost of coal doubles if the coal price increases by more than 4 times. For nuclear power, for the levelled cost to double, the fuel price must increase by 13 times. Thus, the fuel price increases modelled do not impact on the levelled costs of these technologies significantly.

10.4.3 Exchange rate assumptions and conversion techniques

Surprisingly, there is no definitive way to convert values from one currency in one year to another currency in another year. In a world with a perfectly-functioning market, exchange rates would reflect differences in inflation rates between countries, and this would not be a problem; however, since this is not the case, different conversion factors can be arrived at using different methods. This is only a problem if it changes the relative costs of different technologies, which is the case if the costs are sourced from different years. In addition, short-term fluctuations in nominal currency rates can have a significantly distorting effect, especially if costs are assumed to be constant. An assumed variable exchange rate during the modelling period also gives rise to significant uncertainty. We have used a constant rate; since we have only drawn costs from two years (2006 and 2007), the difference between using a constant and a variable exchange rate for converting initial values is quite small (3-4%).