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Least cost integrated resource planning and cost optimal climate change mitigation policy

Alternatives for the South African electricity system

Bryce McCall, Jesse Burton, Andrew Marquard, Faaiqa Hartley, Fadiel Ahjum, Gregory Ireland, and Bruno Merven

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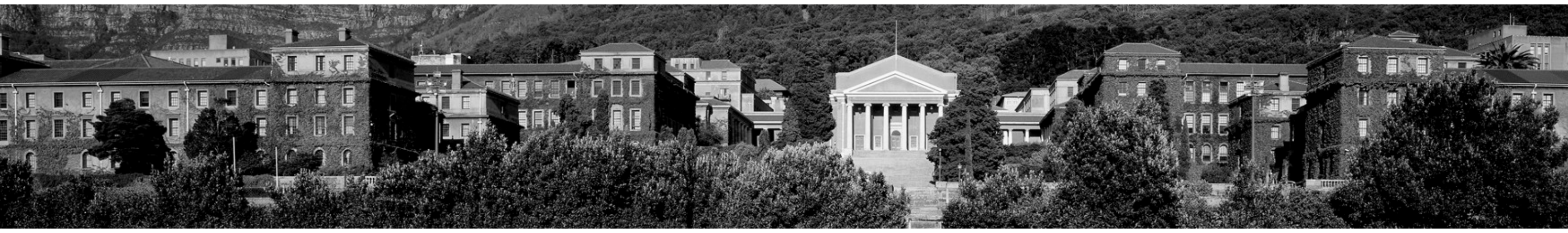

Least-cost integrated resource planning and cost-optimal climate change mitigation policy: Alternatives for the South African electricity system

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Contents

Executive summary

This study is an alternative technical assessment of South Africa's electricity future to inform debate on IRP 2018, South Africa's latest electricity plan due to be released shortly. We have used a similar modelling methodology, with the addition of an economic model to account for key indicators such as employment and economic growth, and assessed all the key assumptions used in the draft IRP 2018 against available evidence as the basis for our analysis. We have also assumed that existing coal power plants will be required to conform with current air pollution legislation, which will impose further costs on the existing system not taken into account by the draft IRP 2018. In addition, we have assessed the suitability of one of the most important drivers of the IRP – the greenhouse gas emissions constraint – in the light of South Africa's overall mitigation potential, with the aim of understanding better the contribution which the electricity sector should be making, especially in the light of future contributions to the global mitigation effort South Africa wil be required to make in the next decade. We have modelled two scenarios:

1) **Reference scenario:** A least-cost electricity investment plan using the best available evidence on key parameters. These include realistic technology costs and learning curves for renewable energy and batteries, more realistic plant availabilities for the Eskom fleet, and compliance of the existing coal fleet with the Air Quality Act (AQA) and Minimum Emission Standards (MES);

2) **Least cost mitigation scenario:** A least-cost, low-carbon scenario compatible with the Paris Agreement's long-term temperature goal of limiting warming to "well below 2^{o}C". Methodologically, we assessed the economic implications of various greenhouse gas (GHG) emissions budgets, and this scenario represents a more ambitious climate change mitigation approach than the current "Peak, Plateau, and Decline" trajectory in the NCCRWP. We model a 7.75Gt CO2-eq budget over the period 2020-2050. This equated to reducing emissions below the low-PPD budget by around 20%, without imposing large costs on the economy.

One of the key critiques of the draft IRP 2018 is that it does not adequately address the central problem of climate change mitigation, even though the electricity sector currently accounts for more than 40% of South Africa's emissions. There are two dimensions to this problem. The first dimension is the extent to which the proposed IRP can be said to be aligned with South Africa's current climate change policy. We argue here that the emissions constraints derived from the national emissions trajectory benchmark range contained in the National Climate Change Response Policy (either the "moderate decline", the "advanced decline" or the "carbon budget") do not reflect a least-cost mitigation pathway from the point of view of the national economy. Some low-carbon technology investment options in the electricity sector are now cheaper than high-emitting options – a dramatic change from a decade ago. Mitigation options in the rest of the economy are considerably more expensive, and so from a national point of view, emissions constraints for the electricity sector should be far more ambitious, to avoid imposing additional costs on the rest of the economy. We address this problem by using a full sector energy model rather than an electricity sector-only model.

The second dimension of this problem is that under the Paris Agreement, South Africa is obliged to submit a Nationally Determined Contribution (NDC) every five years which represents a progression on the previous NDC. Moreover, it is clear that all countries will have to increase their mitigation ambition to collectively meet the Paris temperature goal of well below 2 degrees. The recently released IPCC Special report on 1.5 degrees forcefully underlined the importance of urgent additional mitigation action. It is highly likely that as part of the global effort to address climate change, South Africa will therefore be required to increase its mitigation efforts in the 2020s and 2030s, and that our future NDCs will move towards the lower end of the PPD range, or even below.

For example, Climate Action Tracker[1] has deemed our current mitigation commitment under the Paris Agreement as "critically insufficient", based on the upper range of the PPD. This implies that if other countries had the same level of ambition as South Africa, we would be heading for a world with more than 4ºC of climate change. The lower range of the PPD is rated in 2025 and 2030 as "2 degrees compatible", meaning that this would be a fair contribution to the Paris temperature goal. In the long term (in 2050), the PPD range is rated as "insufficient" (meaning a 3 degree world) at the upper end, and "2 degrees compatible" at the lower end. Therefore meeting the global temperature goal of "well below 2ºC" will require moving below the low-PPD. It will be even more important under these circumstances to pursue rapid decarbonization of the electricity sector, to avoid additional mitigation costs to the rest of the economy.

Existing analyses of the national emissions budget corresponding to the low-PPD trajectory include a rapid phase-out of coal in the electricity sector, with all coal-fired stations retired by 2035-2040 (Burton et al, 2018). This is broadly consistent with international analyses that have examined the future of coal in the power sector globally (see UNEP, 2017 for a review of the extant literature), most of which includes a global phase out of unabated coal in the power sector by 2050 (depending on country-specific circumstances). The IEA's "well below 2ºC" scenario (WB2D) also includes decarbonising the South African electricity sector by 2040. Finally, the IPCC Special Report on 1.5ºC has shown that globally, coal in the power sector is phased out by 2050 in all scenarios consistent with 1.5ºC (IPCC, 2018).

The methodology applied in this study was to assess the effects of various GHG budgets on the electricity price and the economy. The emissions budget applied in the least cost mitigation scenario represents an ambitious reduction below low-PPD, but at relatively low economic cost.

Results: reference scenario

Peak demand in 2050 totals 65 GW and total installed capacity in 2050 is 229 GW including battery storage. The installed capacity is made up primarily of wind and solar PV (161 GW), and a small contribution from existing coal (9 GW) and pumped storage (3GW). Investment in new battery storage technology begins in 2026, growing to 53 GW by 2050 to complement variable renewable energy technologies. Wind, solar, and batteries provide the least cost option for South Africa's electricity future.

By 2030, renewables (wind, solar, micro-hydro, and biomass) produce 42% of electricity, and this increases to 90% by 2050 (wind and solar together contribute 38% and 88% in 2030 and 2050 respectively). The higher demand forecast illustrates the important role of full sector analysis: in the reference case, large scale electrification of transport takes place. By 2050, 66% of private passenger vehicle activity is from electric vehicles, and 63% of road freight (primarily through the use of electrified light commercial vehicles). Transport demand for electricity accounts for 10.8TWh and 40TWh in 2030 and 2050 respectively.

The reference scenario includes large scale retrofitting of Eskom power stations to meet the 2020 MES ("new plant standards") by 2025. For the remainder of the fleet, plants must either implement the technology options to meet the 2020 new plant MES or else retire over the period to 2025. The results show that the least cost option is to retrofit most of the fleet with a total of 18 GW of plant retrofits across the fleet over the period to 2025. A total of 31 units are retrofitted out of a possible 42 across the fleet. All stations available for retrofitting are partially or fully retrofitted except Majuba, which is fully decommissioned by 2025.

[1] Climate Action Tracker (climateactionrtacker.org) is one of the best independent sources for assessment of the adequacy of the mitigation component of countries' Nationally Determined Contributions in terms of the Paris temperature goals. CAT models a wide variety of published approaches to sharing the global mitigation burden, which represent a wide range of developed and developing country perspectives.

The remainder of the coal fleet is also sensitive to coal cost assumptions, even without any emissions constraints imposed on the scenario. While Medupi runs at maximum capacity factor (80%) to 2050, Kusile (with higher coal costs) starts to run at a much lower load factor from 2040 onwards, running at only a 41% load factor to 2050.

The high penetration of renewable energy in the electricity sector results in a reduction in emissions over the period. Energy and industrial emissions fall from 422 Mt CO_2-eq to 238Mt by 2050, again, without any emissions constraint applied to the scenario. In industry, there is little change in the mix of energy carriers – namely coal and electricity. Coal continues to be a primary source of process heat and emissions in industry, and grows over the period with increased industrial growth. As mentioned above, transport electrifies substantially, although some fossil fuel use remains. On the supply side, Sasol's Secunda CTL plant retires between 2040 and 2045. Although the electricity sector does not fully decarbonise over the period, the carbon-intensity of the electricity sector declines dramatically, from 891g CO_2-eq/kWh in 2020 to just 81 g CO_2-eq/kWh by 2050. Emissions for the electricity sector for the period 2021 to 2050 total 3.6Gt CO2-eq, which is considerably lower than any of the IRP cases (which all remain above 4.9 Gt over the same period). The most stringent emissions constraint in the IRP (the 'carbon budget' approach) constrains emissions to 5.5 Gt over the same period. Clearly, since the actual emissions budget achieved in an economy-wide model for an unconstrained least-cost scenario is so much lower than this, this constitutes a significant overallocation of emissions space to the electricity sector. This will become more apparent below in the mitigation scenario.

Results: least cost mitigation scenario

Energy system results

In this scenario the linked energy-economy model is run with the same labour and capital supply and productivity growth forecasts as the reference scenario but with the 7.75Gt emissions budget applied over the period to the energy system. In this scenario, the impact of the carbon budget on the energy system feeds back into the economy-wide model through the electricity price and the total investment requirements in the energy system. This affects economic growth which in turn impacts demand for electricity. The result is a total demand for electricity of 312TWh in 2030 and 542TWh in 2050. This is a slightly lower than the reference scenario owing to the impact on GDP growth (see section 5.2), but only marginally so at 7 TWh difference to the reference. Peak demand for electricity is similar to the reference scenario at 65GW in 2050.

As with the reference scenario, all new electricity generation capacity is a combination of wind, solar PV, and battery storage. Total installed capacity is 113GW by 2030 and 240GW by 2050. The installed capacity is 11GW higher than the reference case by 2050 despite the lower electricity demand, and renewable energy technologies (wind, solar, micro-hydro, and biomass) provides 62% of electricity generated by 2030 and 99% by 2050 (Wind and solar together make up 57.3% and 96.3% by 2030 and 2050 respectively).

Compared with the reference scenario, there is an accelerated investment in renewable energy in the medium-term – particularly as more coal capacity comes offline in the 2020s or is run at lower load factors. There is still coal capacity available in the long term from Kusile and Medupi (but not Majuba), however Kusile operates at a 55% load factor and Medupi at 75% load factor from 2026. Neither station generates electricity from 2040 onwards, though they remain available to the system.

Coal capacity is lower in this scenario owing to more stations retiring instead of being retrofitted for compliance with the MES. In total, 11GW of coal capacity is retrofitted, compared to 18GW in the reference scenario.

In this scenario Kendal station is not retrofitted at all and retires by 2025 along with Majuba. Lethabo, Matimba, Matla and Tutuka are partially retrofitted and partially retired. Due to the lower capital cost expenditure on retrofits and earlier retirement of coal plants, the electricity price is lower in the medium term compared to the reference scenario. The electricity price is higher in the long term compared to the reference case as higher investment in renewable energy and storage capacity is required to meet the emissions constraint. The higher investment in RE plus batteries is needed to replace retiring coal capacity, Medupi and Kusile post-2040, as well as the renewable capacity installed in the 2020s (when the capacity becomes due for replacement in the 2040s).

Figure A shows there is a general decline in emissions from 2015 onward, but this trend accelerates from 2020. The power sector contributes the largest mitigation effort, as discussed above – with fewer coal units operating overall and those that do run operating with lower load factors and result in an electricity carbon intensity of just 8g CO2eq/kWh by 2040 and zero by 2050.

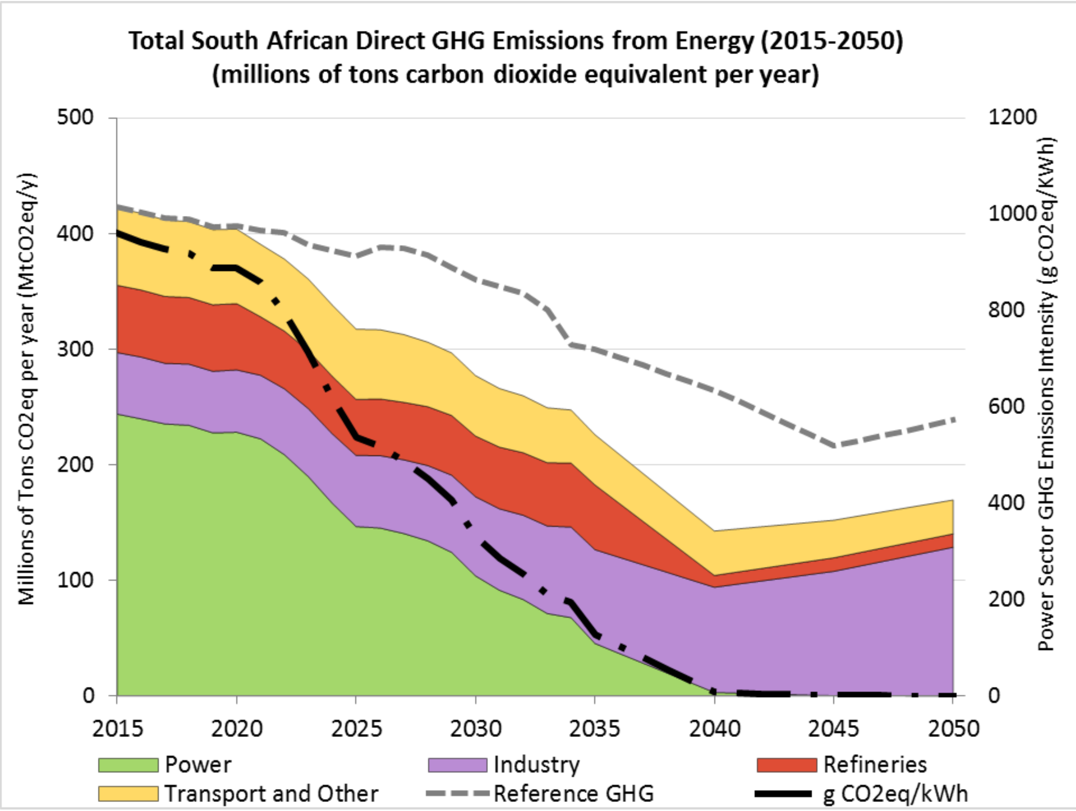

Figure A: GHG emissions in least cost mitigation scenario with carbon intensity of electricity

There is also a significant mitigation contribution from coal-based synthetic fuel production as these CTL facilities are offline between 2035 and 2040 compared to 2045 in the reference scenario. The CTL facility also reduce their production levels over their lifetime. Lower demand for liquid fossil fuels for transport (driven by lower GDP and higher electrification of transport) results in emissions savings relative to the reference scenario. As in the reference scenario, transport is largely electrified and thus most of the emissions savings would come from upstream power sector emissions savings.

Although the rate of growth is lower for the industrial sector relative to the reference scenario, and despite higher uptake of fuel switching to electricity, coal remains the lowest-cost supply option for heat in the industrial sector. In the long term the industrial sector becomes the largest source of emissions from energy in South Africa – the majority of these from process heat requirements, particularly from boilers.

Economy-wide results

Including an emissions constraint of 7.75 Gt CO_2-eq has a small negative impact on real GDP with the real GDP level being 4.2% lower by 2050 (Figure B (i). This translates into a 0.14 percentage point decline in the average growth rate and implies that the level of real GDP experienced under the unconstrained least cost scenario in 2050 would be delayed by between 1 and 2 years. The lower level of GDP is the result of the higher electricity investment requirement, which results in lower available funds for investment in other sectors; as well as a higher electricity price. Total electricity investment is 11.6% higher under the 7.75 Gt CO_2-eq scenario, while the electricity price is 3.4% higher by 2050 (Figure B (ii)). Employment is 4.1% lower (1.84 million job-years in 2050), in line with the lower real GDP level.

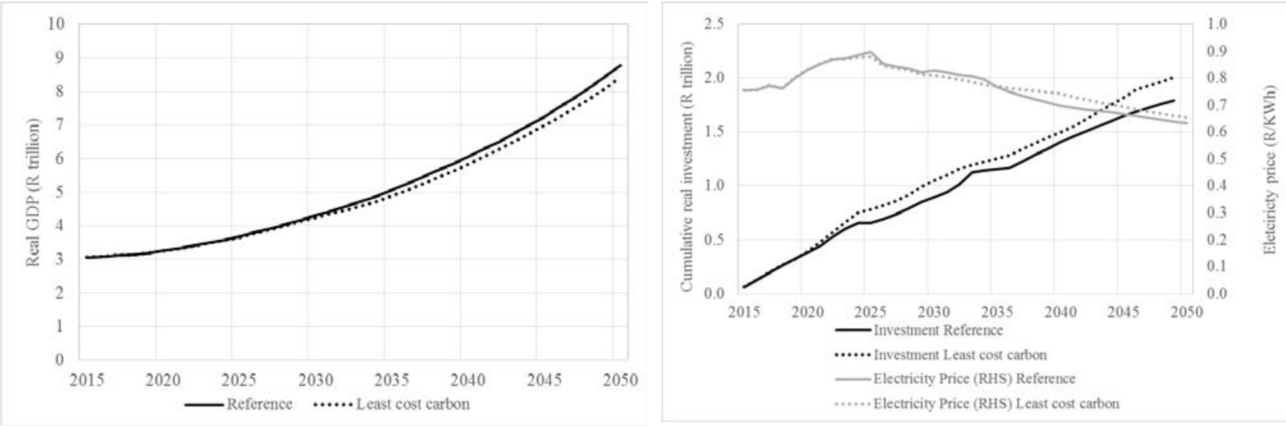

Figure B: i) Real GDP, ii) Electricity investment and price

Lower levels of activity are experienced across all sectors of the economy in the 7.75 Gt CO_2-eq scenario with the largest declines in activity taking place in the mining and manufacturing sectors. Mining and manufacturing GDP is 4.6% and 4.3% lower by 2050. The largest declines within the manufacturing sector occurs within the non-metallic minerals, metal products and motor vehicles sub-sectors who are typically energy intensive users. The differences in employment are the largest in the services sector which is the largest employer in the country. Employment in the services sector is 1.32 million job-years lower in the 7.75 Gt CO_2-eq scenario. The next largest differences are in the manufacturing and other industry sectors which employ 237,000 and 165,000 fewer workers than in the reference scenario. Employment losses are largest amongst higher educated workers (i.e. Grade 12 and higher levels of education).

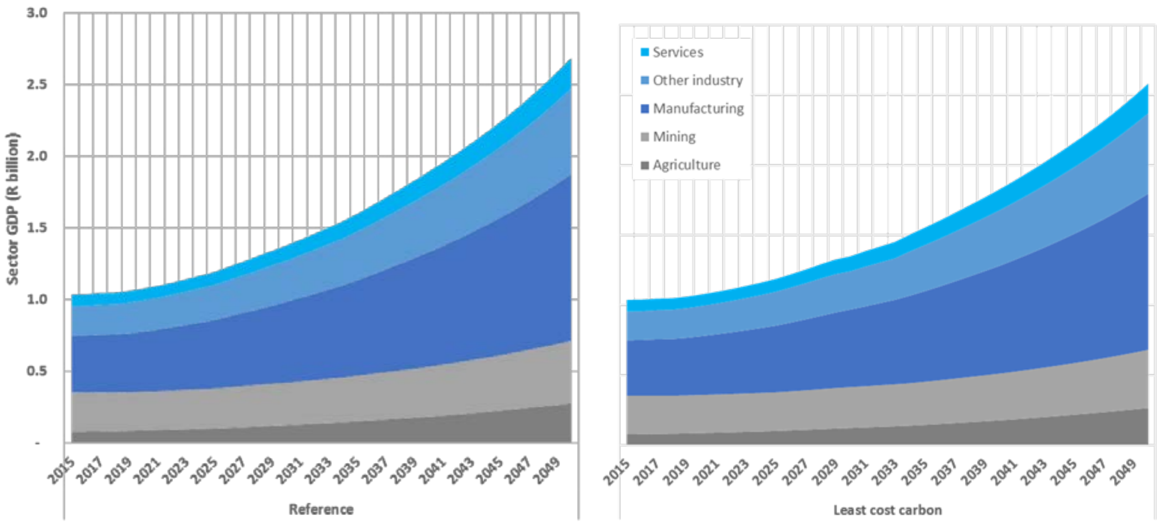

Figure C: Sector GDP in the reference, and in the least cost mitigation scenarios

Conclusion

This study has examined the implementation of a least-cost scenario for South Africa's electricity sector to 2050. The findings have implications for the IRP 2018 that is currently being updated by the DoE. Firstly, the study reiterates earlier findings that future supply will come primarily from wind and solar PV. Renewable energy plus flexibility provides the least cost pathway for the electricity sector. No new coal or nuclear power plants feature in South Africa's electricity future, and their inclusion would require subsidies from consumers (Burton et al, CSIR, 2017, Ireland & Burton 2018, Steyn et al, 2017). Secondly, this study has also shown that a large scale procurement programme for battery technology to provide storage capabilities for variable renewable energy should be pursued in South Africa.

Third, retrofitting stations for compliance with the Minimum Emission Standards (MES) is, for the most part, the least cost option for the electricity sector (due to the relatively higher costs of new technologies in the period 2020-2025). It is cost optimal to retrofit Eskom's coal-fired fleet to meet the new plant standards by 2025 rather than retire them, except in the case of Majuba. There are potential cost and greenhouse gas emissions savings if compliance with the new plant standards is suspended for some stations (e.g. Duvha and Matla) and they are instead retired early. We propose that the DEA considers suspending compliance requirements for the best performing (in terms of pollutants) stations and in exchange Eskom agrees to retire the stations by 2030 at the latest. For the remainder of the fleet, Eskom should commence retrofitting the stations for compliance with the MES, subject to ongoing cost assessments (e.g. coal costs per station, which may alter whether a station should be retrofitted or retired).

Finally, this study has examined the effects on the electricity system, the energy system and the economy of a more ambitious climate change mitigation policy. We have found that phasing out coal in the power sector by 2040 is cost optimal for South Africa to fulfil its commitment to the Paris Agreement goal of limiting warming to well below 2ºC without significant impact on the economy, and that therefore South Africa can afford to be more ambitious in its mitigation policy. Reducing emissions below the level of the low-PPD by 2050 can therefore be achieved through rapid decarbonisation of the electricity sector and fuel switching. A well below 2ºC compatible pathway is possible with only a 4% reduction in GDP in 2050 – translating to a delay of between 1 and 2 years in absolute terms in achieving the same economic growth level in 2050. The IRP 2018, which currently allocates more than 5Gt of greenhouse gases to the electricity sector, should therefore significantly reduce this allocation in line with an economy-wide, least cost allocation of emissions space to different sectors. Even with no emissions constraint, our reference case achieves lower emissions than the IRP budget.

1. Introduction

The 2010 Integrated Resource Plan (IRP) (DoE, 2011) was a breakthrough for electricity planning in South Africa for two reasons: firstly, it established a planning process with extensive stakeholder involvement, and secondly, it contained for the first time a greenhouse gas (GHG) emissions constraint. Although at the time South Africa had no official climate change policy – the National Climate Change Response White Paper was only finalised later in 2011 – the policy-adjusted IRP included an emissions constraint that, along with the falling costs of renewable energy, resulted in the large-scale uptake of renewable energy in the final scenario. The IRP 2010, however, while still providing the basis for new power sector procurement, is however out of date in many important respects. Since 2010, renewable energy (RE) costs have fallen dramatically both globally and in South Africa, national electricity demand has been stagnant for a decade, and South Africa has committed to doing its part in limiting global warming to ‘well below 2 degrees’ under the Paris Agreement. The electricity sector is key to meeting this goal at lowest cost, given relative mitigation costs in different sectors of the South African economy.

The draft IRP 2018 addresses in many respects the critiques levelled at the earlier IRP base case released for comment in 2016 and provides a necessary update to the IRP 2010, in particular by acknowledging that a least-cost electricity future for South Africa is now comprised primarily of renewable energy and does not feature new investment in nuclear- or coal-fired power. Nonetheless, the draft IRP 2018 reflects the fact that the Department of Energy is persisting in procuring new coal-fired power from the proposed Thabametsi and Khanyisa power plants, which have been ‘forced into’[2] 2018 IRP; Eskom is continuing with the construction of Medupi and Kusile, which is also uncritically reflected in the draft, and Eskom also has no explicit plans for decommissioning its oldest coal stations (only placing them in ‘cold storage’[3]); and the draft IRP 2018 continues to assume that existing coal-fired power plants will continue to be competitive until these reach 50 years of age and should therefore be kept running until that time, even though earlier retirement could be a more economical option. Artificial and arbitrary constraints on renewable energy investment in the draft also raise costs and limit the sector’s contribution to meeting South Africa’s future energy requirements and its climate change mitigation goals.

At the same time, Eskom is in crisis. Its runaway capital and operating costs point to a potential utility death spiral as many of its customers invest in energy efficiency and on-site, distributed energy generation, leading to stagnating demand for electricity from the central grid. The IRP 2018 does not consider either this context in its assessment of future technology roll out or the global energy technology shifts taking place that will fundamentally alter the viability of the current fleet, either because of economics or global climate change policy.

In this context, this study is an alternative technical assessment of South Africa’s electricity future, with a focus on a) a least-cost reference scenario and b) a least cost, policy-adjusted climate change mitigation scenario. The least-cost reference scenario can be compared against the modelling undertaken by the DoE for the IRP 2018, and highlights the most important parameters for assessing and providing a critical perspective on that modelling.

A key difference between the approach used in the modelling of the IRP and the approach used in this analysis is that the electricity sector is modelled here in an economy-wide model, not confined to the electricity sector, but including a comparable level of detail in the electricity sector to the approach used for IRP 2018. The policy-adjusted climate change mitigation scenario therefore highlights the critical role played by the electricity sector in meeting South Africa’s mitigation goals, compared to the roles of other sectors. The scenario shows the potential that

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2 The kind of model used for the IRP analysis would typically select a set of investments which could meet the demand required of a future electricity system at least cost. If a specific investment has been ‘forced into’ the model, it implies that the modellers have required the model to choose that investment regardless of its cost compared to other possible options, and that the investment in question has not been evaluated against other possible options.

3 ‘Cold storage’ is described as a state in which units taken out of service could be brought back into service within a year if required.

exists, given the dramatic fall in costs of low-carbon technologies, for an accelerated decarbonisation of the electricity sector. This analysis anticipates South Africa's next nationally determined contribution (NDC), due to be communicated to the UNFCCC by 2025, which will almost certainly require a more ambitious mitigation goal in the light of current and future assessments of the adequacy of global mitigation efforts, which will be further highlighted in the Paris Agreement's Global Stocktake in 2023.

2. Why do an alternative IRP analysis?

This study provides a technical analysis of the draft IRP 2018 by using a similar modelling methodology[4] to better understand the IRP's key drivers, to test claims concerning least-cost options for the South African electricity sector in the IRP, and to provide additional insight into what would be required for a more ambitious decarbonisation pathway for the sector in the light of the requirements of the Paris Agreement. Each scenario is evaluated in terms of key policy-relevant parameters. The aim is to develop, using the modelling framework outlined in Appendix A:

A least-cost electricity investment plan to contrast to the IRP's reference case, using the best available information on technology costs, future electricity demand and other key parameters. We have highlighted the areas in the report in which parameters used in this study deviate from those used in the IRP, to the extent possible (some of the parameters used in the IRP are not publicly available).

- A least-cost, low-carbon scenario compatible with the Paris Agreement's long-term temperature goals, to assess the policy adjustments required. This scenario also provides comparison against the least cost reference case above, as well as any low-carbon scenario which may be proposed in the IRP 2018.

The analysis includes an assessment of modelled electricity plans in the context of the overall economy, and an assessment of the key drivers of results both in the IRP 2018 and in this analysis. The IRP 2018 does not consider the economy-wide impacts of either the electricity build plan proposed (in terms of investment and job creation) or the effect of electricity price increases on the broader economy.

In particular, we argue that the IRP 2018 has excluded several important aspects that are a necessary part of assessing South Africa's future electricity system. Our analysis therefore implemented several model developments to allow for a more comprehensive assessment of South Africa's electricity future. This includes modelling the following:

- Compliance of the existing coal fleet with the Air Quality Act (AQA) and Minimum Emission Standards (MES) regulated in terms of the AQA. Up until now, the IRP has failed to assess what the legal requirement for Eskom's compliance with the MES would mean for the electricity sector, either in terms of costs of compliance through retrofitting power stations to comply with existing regulations, or the effect on the electricity system of retiring coal capacity that cannot be economically retrofitted. Given that compliance is a legal requirement under the AQA, and rolling (indefinite) postponements are not permitted, this is a key oversight.

- An exploration of the implications of higher uptake of distributed or centralised renewable energy based on more realistic cost assumptions.

[4] Both the IRP and this study will use similarly constructed linear optimisation models of the South African electricity sector, but a key additional feature of the modelling framework proposed in Appendix A is that it includes not only the electricity sector but also the rest of the energy system, and also includes a linked economic model. The analysis will thus also take into account the economic impact of changes in the electricity price (which the IRP does not), including changes in electricity demand, and also provides scope for the impact of the IRP on the rest of the economy. It will additionally provide insights into the role of the electricity sector in overall mitigation in the South African economy, which is not possible in a modelling framework which only considers the electricity sector.

- Assessing the effect of modelling lower plant availabilities for the current coal fleet (which would more closely reflect the state of the current fleet, based on Eskom's system adequacy reports, than those assumed in the IRP 2018).
- The inclusion of utility-scale batteries with more realistic technology cost reductions.
- An analysis of the role of the electricity sector in meeting South Africa's mitigation objectives.[5] The electricity sector is currently responsible for over 40% of South Africa's GHG emissions and, since low-carbon technologies are now cheaper than high-carbon ones (Ireland et al, 2017), the sector will play a key role in implementing South Africa's contribution to limiting warming to well below 2^{o}C. South Africa's current long-term goal is contained in the National Climate Change Response White Paper and represented by the 'peak, plateau and decline' (PPD) emissions trajectory range to 2050.

2.1 Climate change mitigation planning

One of the key critiques of the draft IRP 2018 is that it does not adequately address the central problem of climate change mitigation. There are two dimensions to this problem. The first is the extent to which the proposed IRP can be said to be aligned with South Africa's current climate change policy. We argue here that the emissions constraints derived from the national emissions trajectory benchmark range contained in the National Climate Change Response Policy (either the 'moderate decline', the 'advanced decline' or the 'carbon budget') do not reflect a least-cost mitigation pathway from the point of view of the national economy (this will be discussed in more detail below, in the results section). Some low-carbon technology investment options in the electricity sector are now cheaper than high-emitting options – a dramatic change from a decade ago. Mitigation options in the rest of the economy are considerably more expensive and so, from a national point of view, emissions constraints for the electricity sector should be far more ambitious, to avoid imposing additional costs on the rest of the economy. We address this problem by using a full sector energy model rather than an electricity sector-only model.

The second dimension of this problem is that under the Paris Agreement, South Africa is obliged to submit a Nationally Determined Contribution (NDC) every five years, which represents a progression on the previous NDC. Moreover, it is clear that all countries will have to increase their mitigation ambition to collectively meet the Paris temperature goal of well below 2°. The recently released IPCC Special report on 1.5° forcefully underlined the importance of urgent additional mitigation action. It is highly likely that, as part of the global effort to address climate change, South Africa will therefore be required to increase its mitigation efforts in the 2020s and 2030s, and that its future NDCs will move towards the lower end of the PPD range, or even below.

For example, Climate Action Tracker[6] has deemed South Africa's current mitigation commitment under the Paris Agreement as 'critically insufficient', based on the upper range of the PPD. This implies that if other countries had the same level of ambition as South Africa, we would be heading for a world with more than 4^{o}C of climate change. The lower range of the PPD is rated in 2025 and 2030 as '2° compatible', meaning that this would be a fair contribution to the Paris temperature goal. In the long term (in 2050), the PPD range is rated as 'insufficient' (meaning a 3° world) at the upper end, and '2° compatible' at the lower end. Therefore, meeting the global temperature goal of 'well below 2^{o}C' will require moving below the low-PPD. It will be even more important under these circumstances to pursue rapid decarbonisation of the electricity sector, to avoid additional mitigation costs to the rest of the economy.

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[5] It is clear that there are a number of policy contexts in which the question of the contribution of the electricity sector to South Africa's overall mitigation effort should be considered (in relation to the contribution of other sectors), but in addition to these the IRP process is uniquely placed to provide an updated assessment of what the potential and associated costs and benefits might be for mitigation in the sector.

[6] Climate Action Tracker (climateactionrtacker.org) is one of the best independent sources for assessing the adequacy of the mitigation component of countries' NDCs in terms of the Paris temperature goals. It models a wide variety of published approaches to sharing the global mitigation burden, which represent a wide range of developed and developing country perspectives.

Existing analyses of the national emissions budget corresponding to the low-PPD trajectory include a rapid phase-out of coal in the electricity sector, with all coal-fired stations retired by 2035–2040 (Burton et al, 2018). This is broadly consistent with international analyses that have examined the future of coal in the power sector globally (see UNEP (2017) for a review of the extant literature), most of which assumes a global phase out of unabated coal in the power sector by 2050 (depending on country-specific circumstances). The International Energy Agency's (IEA) 'well below 2ºC' scenario (WB2D) also includes decarbonising the South African electricity sector by 2040. However, it assumes large quantities of carbon capture and storage (CCS) – up to 50 TWh from coal generation capacity with CCS for South Africa – which is probably not feasible in the light of recent studies on potential for CCS in South Africa, or in terms of the falling costs of alternatives, in particular in the timeframe proposed in the IEA analysis which includes this uptake before 2040.[7] Finally, the IPCC Special Report on 1.5ºC has shown that globally, coal in the power sector is phased out by 2050 in all scenarios consistent with 1.5ºC (IPCC, 2018).

3. Scenarios and assumptions

3.1 Scenarios

3.1.1 Reference scenario

The reference scenario is a least-cost scenario without constraints on GHG emissions or any exogenously imposed technology preferences (for example, no new generation capacity technologies are 'forced in' to the scenario). The scenario *includes* legal compliance with the Air Quality Act for the existing coal fleet (with the timing of implementation of compliance set at 2025). Detailed assumptions are as described in section 3.2 (Assumptions).

3.1.2 Least-cost mitigation scenario

This scenario examines the role of the electricity sector in mitigating GHG emissions in South Africa. The scenario assumptions are the same as those of the reference case, except that a policy adjustment is made to cap GHG emissions in a manner that is consistent with South Africa's current and potential future commitments under the Paris Agreement. A key component of this analysis is the consideration of mitigation in the electricity sector in the context of the overall energy system and the economy – the GHG emissions cap is therefore applied to the *whole* economy rather than to a specific sector. The model chooses the most cost-effective measures across the whole economy, which indicates the most cost-effective mitigation pathway for the electricity sector *vis a vis* the rest of the economy. As described in section 3.2.9, we have explored various GHG constraints and the effects of imposing these on the economy. This helped us to identify what a more ambitious mitigation target for South Africa might be, assuming existing technologies and the current economic structure of the country.

In earlier studies, a cumulative GHG constraint of 9.5Gt was applied to energy and industrial process and product use (IPPU) emissions (i.e. excluding emissions from agriculture, forestry and land use, and waste) (for example, PAMS, 2018; Burton et al, 2018). The sectoral constraint was devolved from the low-PPD emissions budget over the period 2020-2050 (of 10,8 Gt CO_2-eq), with an allocation made to the waste and AFOLU (agriculture, forestry and other land use) sectors consistent with the analysis undertaken in the recent PAMS[8] study (see PAMS for a detailed methodological assessment of waste and AFOLU emission allocations).

[7] Imposing the IEA scenario, in which the electricity sector is effectively decarbonised completely by 2040 but still has 12.5% firm/dispatchable coal capacity that is also 'low-carbon' may result in an unrealistic build plan in terms of energy security, costs, and other economic impacts.

[8] The PAMs study is a recent study undertaken by the Department of Environmental Affairs to assess the overall impact of planned mitigation policies and measures in relation to South Africa's mitigation targets contained in its NDC, with the goal of assessing whether these policies and measures were adequate, or whether additional PAMs were required. The study has not been finalised, but the draft report, to which he references here are made, is available at https://www.environment.gov.za/sites/default/files/docs/policyandmeasures_draftreport.pdf.

The 9,5Gt constraint applied in earlier analyses therefore represents one possible allocation of national emissions space to the energy and IPPU sectors. Nonetheless, given that most of South Africa's emissions come from energy and industry, higher ambition will be required from those sectors for national emissions to be consistent with the Paris Agreement.

We found that meeting a cumulative GHG constraint of 7.75Gt CO_2-eq over the period 2020-2050 (for the energy and industrial sectors) is achievable at a relatively low cost to the economy. This constraint represents a reduction of 1.75Gt CO_2-eq over previous modelling assessments such as PAMS (2018) and Burton et al (2018). In short, South Africa can achieve an 18.5% reduction in its emission budget below the 2ºC-compatible low-PPD at relatively low cost to the economy. Meeting this more ambitious target requires accelerated investment in low-carbon technologies and accelerated decommissioning of high-carbon-emitting assets, but is accompanied by an increasingly resilient and dynamic electrical grid in a future carbon-constrained world.

3.2 Assumptions

3.2.1 Drivers of the demand forecast

In SATIM (the model used for this analysis), electricity demand is endogenous to the model,[9] and depends on future economic and population growth, economic structure and the resulting demand for useful energy (e.g. lighting, process heat and mobility). In the reference scenario we use a moderate growth rate for GDP of 2.6% pa to 2030, and a higher growth rate to the end of the horizon of 3.6% pa between 2030 and 2050. In the least-cost mitigation scenario we use the same GDP input assumption, but this will change endogenously within the model as the economy reacts to changes in the energy system resulting from the emissions constraint.

The GDP assumptions result in an electricity demand of 318 TWh by 2030, and 550 TWh by 2050. This demand forecast includes a large uptake of electric vehicles, which partly accounts for the higher demand.

[9] For the IRP, the demand forecast is an input to the model, and is projected based on economic growth and other assumptions. For this analysis, which considers the whole energy system, future electricity demand is determined in the model for the whole economy.

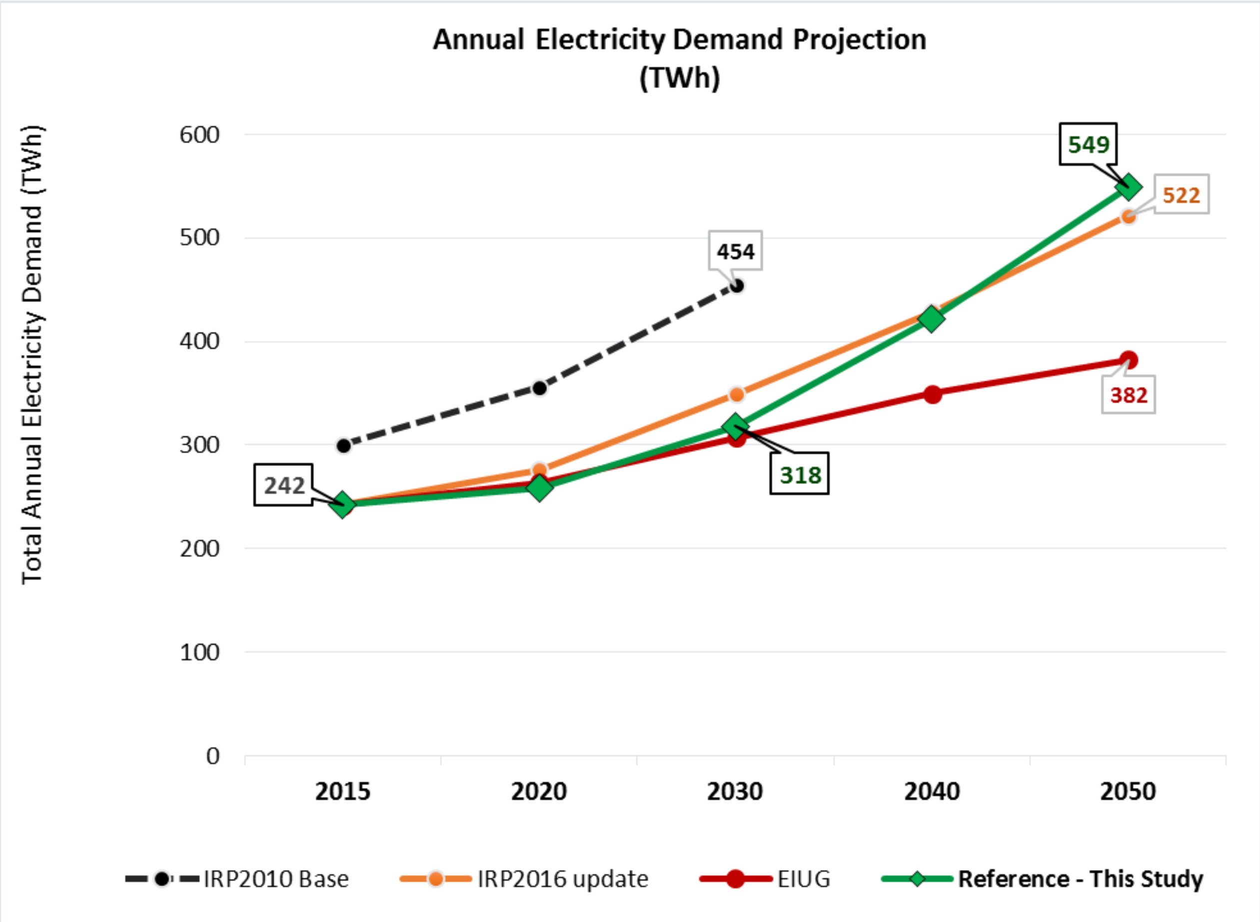


Figure 1: Electricity demand in this work compared with IRP 2010, IRP 2016 update, and the Energy Intensive Users Group projections

3.2.2 Renewable energy costs

The IRP 2018 states that it uses overnight capital costs based on the REIPPPP, however, the IRP 2018 states that these costs are in January 2017 ZAR, but the numbers in table 1 are the same as table 8 in the IRP 2016 . It is therefore not clear what currency the figures are in, nor what underlying data they are actually aligned with. The assumptions need to be clearly articulated in the next version of the IRP, for comparison with other modelling studies.

Renewable energy costs in this analysis are based on the learning curves developed in Ireland & Burton (2018). Figure 2 shows the projected levelised cost of solar PV and wind based on the improvements for the respective technology parameters.

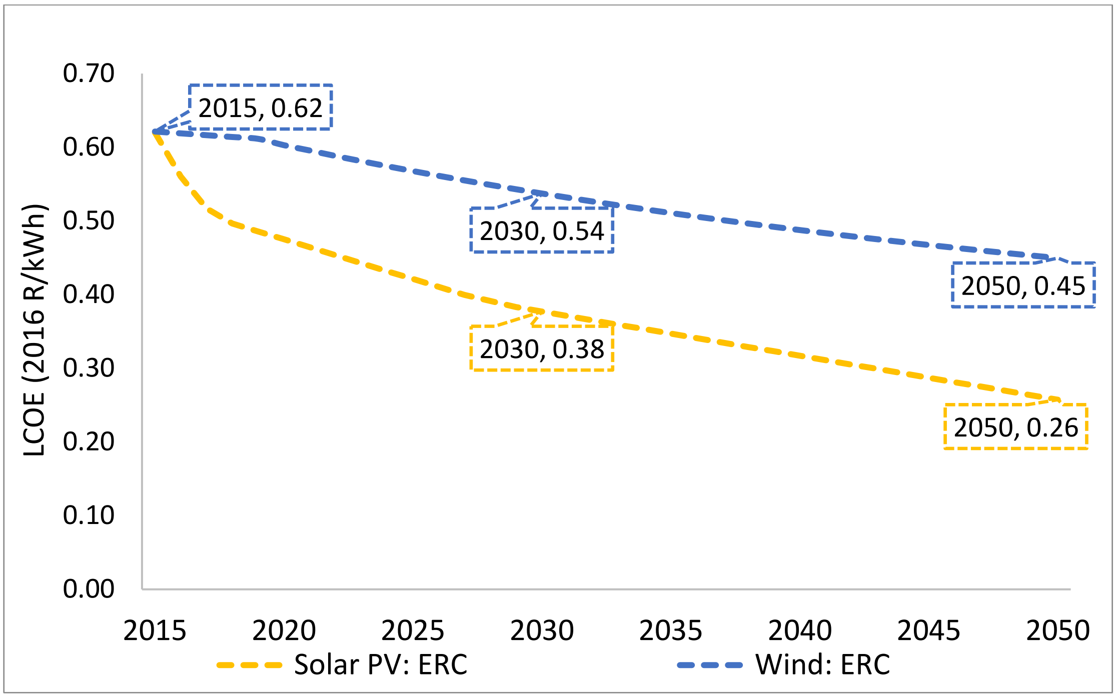


Figure 2: Solar PV and wind cost and learning assumptions 2015–2050 (April 2016 ZAR)

3.2.2.1 Solar PV learning assumptions

- Technology learning starts from 2015; both capital cost and operation and maintenance (O&M) cost reductions are applied.
- Plant cost and performance parameters are modelled to start at calculated 2015 Round 4-expedited REIPPPP values, and improve, using adapted projected rates of change in the latest National Renewable Energy Laboratory (NREL) Annual Technology Baseline (NREL ATB, 2017), UNEP (2015) and Fraunhofer (2015).
- Plant capacity factors remain the same for all projections.

3.2.2.2 Onshore wind learning assumptions

- Technology learning starts from 2015; capital and O&M cost reductions are applied and annual capacity factors of new plants improve (existing plants do not improve).
- Plant cost and performance parameters are modelled to start at calculated 2015 REIPPPP values and change using adjusted projected rates of improvement in the 2017 latest NREL Annual Technology Baseline (NREL ATB, 2017), IEA Wind (2018), and Agora Energiewende (2017).

3.2.3 Renewable energy build rates

The IRP 2018 has imposed annual upper build limits on new renewable energy of 1.6 GW for wind and 1 GW for solar PV throughout the modelled period (to 2050) in most of the scenarios analysed, for which no rationale is given. The ‘IRP 1’ scenario does not, however, impose such a constraint, and the DoE notes that this provides the least-cost option. It is clear that there could be limits to the extent to which annual rollout of renewable energy could be accelerated, which could include technical (grid or Engineering, Procurement and Construction (EPC) capacity), logistical (e.g. port capacity), institutional (start dates and length of procurement processes), legal or financial (prudential) limits. Thus, while there is no rational reason for the specific annual limits used by the DoE, we concur that some limit needs to be imposed on the model to approximate the real-world constraints facing the sector. It is therefore necessary to constrain the model to more accurately represent the real-world barriers to extremely large investments in a single year.

Developing realistic constraints is challenging and requires further work and assessment as the RE industry grows in South Africa and globally, but in the meantime we have developed an interim approach to setting limits based on a number of considerations in existing studies and in conversations with the RE industry. We considered:

- The analysis undertaken by Wright (2017) to assess the rate of renewable energy roll-out in other countries and penetration as a portion of peak demand. That analysis found that the proposed annual new build levels of solar PV and wind in South Africa by 2030 and 2050 as a percentage of peak demand was already surpassed in existing electricity systems around the world in 2017. Wright also found that total installed capacity levels (as a percentage of peak demand) for both wind and solar in South Africa were lower than existing systems globally.
- Research on the availability of grid capacity for, and economics of, additional solar PV investment (which has fewer infrastructure constraints than wind power) (Poeller, Obert & Moodley, 2015). In addition, research by Senatla (2018) highlights that there are already large quantities (in the order of GWs) of potential rooftop PV economically viable in South African metros. In other words, a large-scale roll out of currently economically-viable distributed solar PV generation in South Africa would not face logistical or grid constraints.
- The Transmission Development Plan 2018-2027 (Eskom, 2017), which assumes that after round 4 of the REIPPPP solar PV expansion will be 3500 MW and wind 4400 MW, for which transmission development is already planned over the period to 2027. Cost estimates in the Grid Connection Capacity Assessment for 2022 also highlight that grid costs for utility-scale RE (at R18 billion) are relatively low as a portion of total grid expenditure (R174 billion) and furthermore are very low as a portion of total system costs in SATIM (though they will grow as the contribution from RE increases).

We also interviewed several wind and solar PV project developers, EPC contractors, and industry representatives to test assumptions against their views on plausible timelines and rates of growth. All those we spoke with emphasized that initial constraints facing the sector can be overcome provided there is certainty in future roll-out. We suggest that the precise constraints require further analysis if very high levels of renewable build-out are required. This is a key oversight of the IRP 2018 and a detailed analysis is likely required.

As in Ireland and Burton (2018), the annual new capacity constraints used in this study by assessing recently contracted rounds (Round 4) of installed capacities: between 2016 and 2017, 620 MW of wind came online and between 2015 and 2016, 420 MW of solar PV. Annual installation limits for PV and wind are set to start in 2021 at the total capacity awarded in round 4 for each technology. Each year thereafter, the annual installation limit increases by the portion of capacity awarded in the final expedited round (590 MW for PV and 618 MW for wind) until 2030, when the limits are no longer imposed (Ireland and Burton, 2018), on the basis that national capability to build new capacity can in principle be increased at this historical rate annually, as required. For the period after 2030, we assume that the capability for long-term capacity expansion will be developed in response to whatever is required by the IRP. Annual new build limits are therefore applied as in Table 1.

Table 1: Annual new build upper limits on renewable energy 2020–2030 (GW)

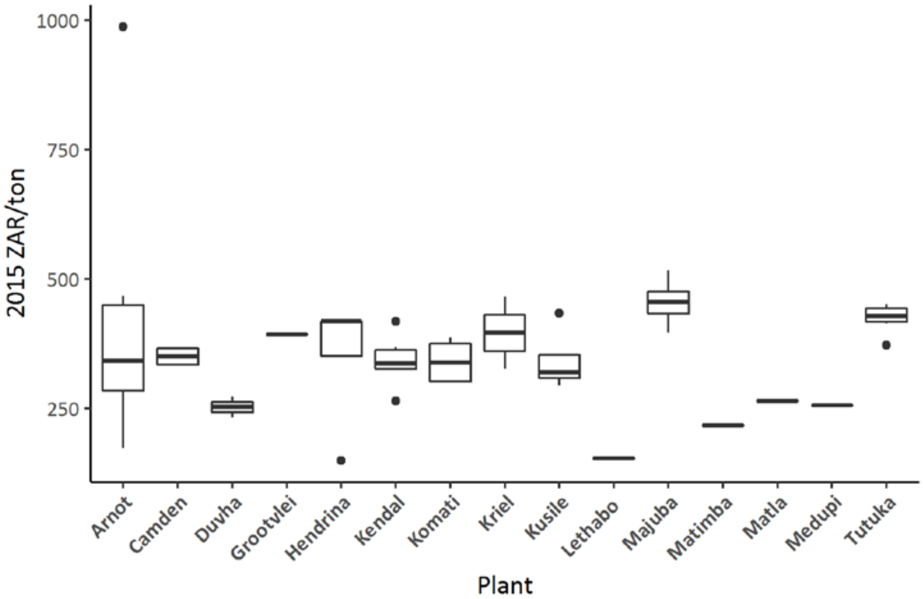
Technology	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Wind	1.36	2.04	2.73	3.41	4.09	4.77	5.45	6.13	6.81	7.49	8.17
Solar PV	1.40	2.00	2.59	3.18	3.77	4.36	4.95	5.54	6.13	6.72	7.31

3.2.4 Committed coal builds

The IRP 2018 assumes that the coal IPPs Thabametsi and Khanyisa (1000 MW is assumed in the plan, although these plants are only 863 MW) will be built and will come online in 2023–2024. The economic impact of building these plants is thus not analysed by the IRP. We do not force any technologies into SATIM except the REIPPPP round 4 projects which have already reached financial close. The coal IPPs remain unpermitted and have not yet reached financial close. The plants therefore are not chosen by the model unless they form part of the least-cost investment plan, and have to compete with other options, including renewable energy options. Previous studies have shown that these plants are not least-cost. For instance, Ireland and Burton (2018) showed that the coal IPPs would raise costs in the electricity sector by R20 billion in present value terms, a finding supported by the DoE's own analysis (R23 billion). Unsurprisingly, in this analysis the plants are not chosen by the model in either scenario.

3.2.5 Coal costs

We have used the Energy Research Centre's coal supply model which has station-specific coal supply options and costs, based on Dentons (2015), Steyn et al (2017) and Burton et al (2018). The costs per power station can be seen as box plots in Figure 3, in 2015 ZAR per ton and ZAR/GJ over the lifetime of the existing contracts.[10] The charts show the range of contract costs per station. The boxes show the 25-75th percentile range of costs across the contracts supplying the stations. The horizontal line shows the median costs of coal to the station and the vertical lines show the full range excluding outlier contracts (shown with dots). A single horizontal line means that the station in question is supplied from a single tied mine/contract (Lethabo, Matimba, Matla, Medupi) or with lower volumes of coal being brought in to the station (e.g. Duvha).



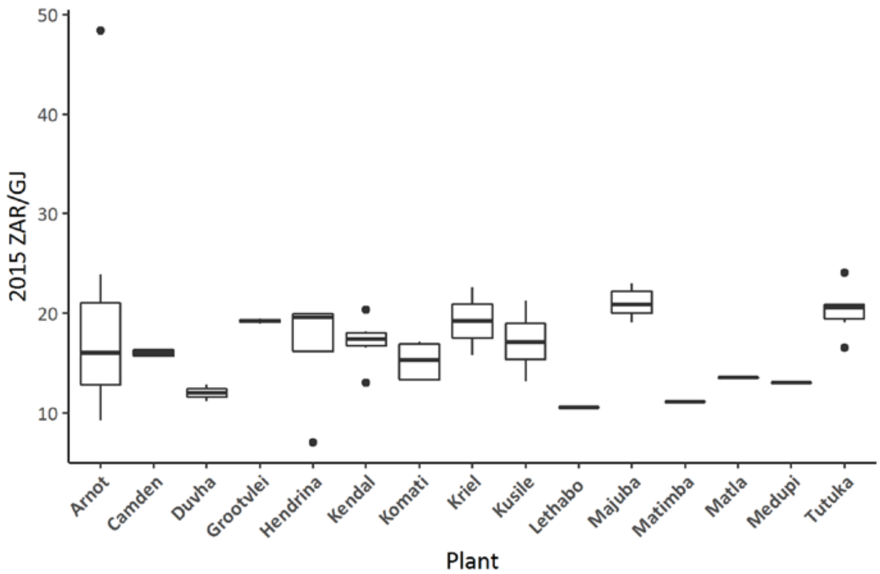


Figure 3: Existing coal costs (in ZAR per tonne above, and ZAR per GJ below) to coal power stations in SATIM

[10] The costs are weighted by volume in the model.

The cost of new coal supply to plants after the dedicated mines reach their end of life, or existing short and medium term contracts expire, is given in Table 2

Table 2: New coal supply costs 2015 R/GJ (Durbach et al, 2017)

	2020	*2030*	*2040*	*2050*
Central Basin	33	37	39	39
Waterberg	22	24	25	25

3.2.6 Battery storage

Battery storage technology cost and performance parameters are presented in Table 3 and are based on Lazard (2017), representing utility-scale grid connected lithium-ion batteries. Learning on capital costs are based on the average of the projections made by (BNEF, 2017; IRENA, 2017; CSIRO, 2015; EIA, 2017; Apricum, 2017) as shown in Figure 4 . An exchange rate of 13.59 USD:ZAR is used as per the IRP 2018. The proportional learning rates from the industry cost reduction projections are applied to the initial 2017 Lazard parameters to 2030, not the total USD/kWh cost shown in Figure 4. A total installed capital cost reduction of 70% is expected in 2035 from 2015 levels.

Table 3: Input assumptions of typical utility scale lithium-ion battery storage project in 2017

Power rating (MW)	*Storage duration (hours)*	*Usable energy (MWh)*	*100% depth of discharge cycles/day*	*Project life (years)*	*Installed system capital cost (USD/kWh)*	*Fixed maintenance cost (% of CAPEX/annum)*	*Efficiency: round trip (%)*
100	4	400	1	15	483	0.6 %	89 %

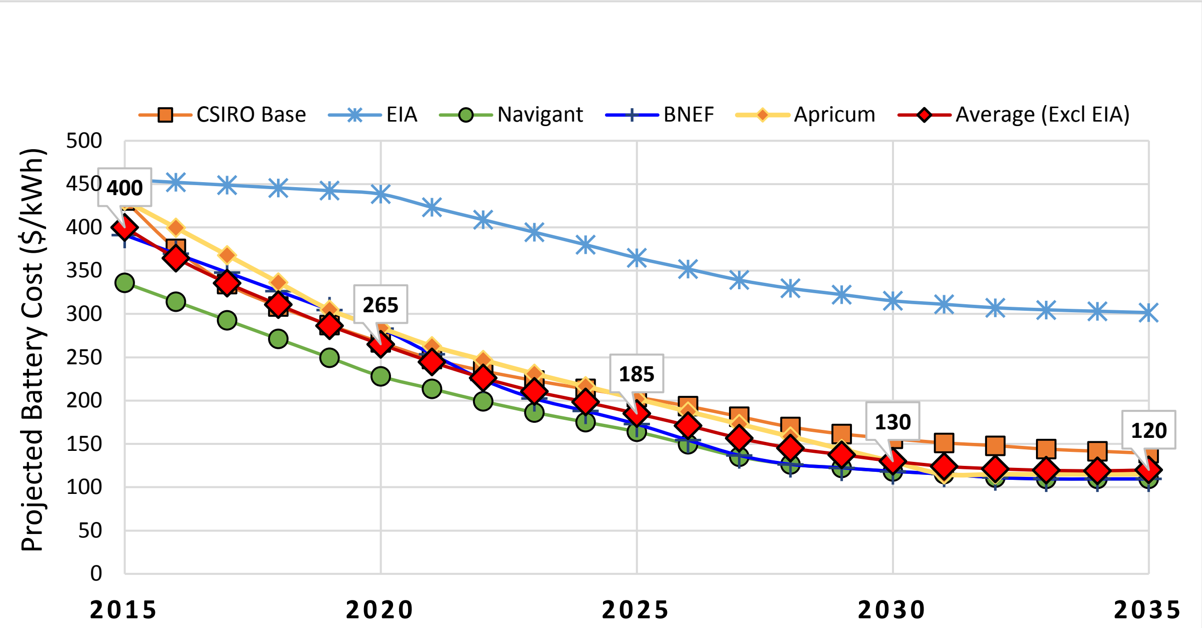


Figure 4: Utility-scale lithium-ion battery cost projections 2015–2035 (USD/kWh)

3.2.7 Compliance with the Air Quality Act and Minimum Emission Standards

The minimum emissions standards (MES) are the legislated maximum emission limit values for all existing and new (as defined) power stations, in terms of the List of Activities published under the National Environmental Management: Air Quality Act, no 39 of 2004. They are supplemented by an air emission licence (AEL) issued by the relevant licensing authority, usually a district or metropolitan municipality, to various facilities, which cannot operate without an AEL. Emissions from such facilities must at least meet the MES, unless, as described below, a postponement of compliance has been successfully obtained (which is reflected in the AEL). Stricter emission standards may also be included in AELs. The purpose of the AEL is to provide permission to emit particular pollutants within limits to a license-holder. In the case of Eskom, the licences set out these limits in terms of three pollutants: particulate matter (PM), sulphur dioxide (SO_2) and oxides of nitrogen oxides (NO_x), measured in mg/Nm^3.

The MES has both 'existing plant' and 'new plant' standards. The former had to be met by 1 April 2015, and the latter by 1 April 2020 (although termed 'new plant' limits, all plants must meet the 2020 limits, unless a postponement has been granted).

Table 4: Compliance timeframes and release rates by pollutant under the Minimum Emission Standards (Naledzi/Eskom, 2018)

MES compliance timeframe	*Max release rate (mg/Nm^3)*		
	PM	*SO_2*	*NO_x*
April 2015	100	3500	1100
April 2020	50	500	750

To meet the MES, Eskom can implement various technologies to limit pollutant emissions. For PM, this includes existing electrostatic precipitators (ESPs), or else fabric filter plants (FFPs), or a high frequency power supply (HFPS) and flue gas conditioning (FGC) (either with sulphur, ammonia or brine injection (Eskom BID, 2018). For NO_x, the implementation of low-NO_x burners is required. Finally for SO_2, flue gas desulphurisation (FGD) technology is required (either wet or dry FGD). Eskom has since applied for, and been granted, postponements for compliance with both the 2015 and 2020 MES. The AQA allows for a maximum of five years of postponement, and Eskom can apply for more than one postponement. However, exemptions from the MES are not legally permissible, and thus ongoing postponements to compliance would not be allowed (Steyn, Burton & Steenkamp, 2017).

In this context, modelling Eskom's compliance with the MES is necessary to understand what the costs of compliance are likely to be, and what the implications will be of these costs for the decommissioning schedule of the fleet, since given the cost of compliance, it is very likely that Eskom will choose to retire some plants rather than retrofit them. The IRP 2018 states that:

> the decommissioning schedule is linked to Eskom complying with the minimum emission standards in the Air Quality Act No. 39 of 2004 in line with the postponements granted to them by the Department of Environmental Affairs (DEA). A number of Eskom power plants (Majuba, Tutuka, Duvha, Matla, Kriel and Grootvlei) requires extensive emission abatement retrofits to ensure compliance with the law. Failure to comply is likely to result in these plants becoming unavailable for production, which could lead to the early retirement of some of the units at these plants. (DoE, 2018)

However, our assessment of the capacity that is being retired is that the IRP assumes a 50-year life for power stations and retires them accordingly (i.e. that the IRP does not link decommissioning to compliance), as per the discussion on decommissioning above, where 12.7GW of capacity is retired by 2030.

The reference and least cost mitigation scenarios includes modelling compliance for the stations found in

. The stations (or units thereof) must either retrofit to meet the new plant MES by 2025 or retire. We have excluded the stations that retire by 2025 (Hendrina, Komati, Grootvlei, Camden) or 2030 (Arnot and Kriel), though we note that they may not be compliant over the period 2015–2020 with either the MES or their respective AELs. The assessment of the specific technology interventions required at the stations that we do retrofit/retire is based on Eskom's own assessment of whether the station is compliant with the new plant standards (see

Appendix B: Implementation of compliance with the MES) or if it will require further capital expenditure. We have excluded borderline stations from capex (Duvha and Lethabo on NO_x), which may underestimate the costs of compliance for those stations (Kendal and Matimba meet the 2020 standards for NOx according to Eskom).

Table 5: Parameterisation of pollutant abatement options per station for compliance with new plant MES (2015 ZAR)[11]

Plant	*AQ technology already installed*	*Technology investment*			*Capex (ZAR/kW)*	*Opex (ZAR/kW)*	*Water tariff (R/m³)*
		PM10	*NO_x*	*So_x*			
Duvha	FFP to units (1-3)	FFP (3 units)	n/a - borderline	Wet FGD	8798	318	2.70
Kendal	ESP +FGC	FFP (3 units)	n/a - compliant	Semi-dry FGD	8325	308	21.66
Lethabo	ESP +FGC	FFP (3 units)	n/a- borderline	Wet FGD	8798	318	0.65
Majuba	FFP	n/a - compliant	LNB (30%)	Wet FGD	8798	318	0.65
Matimba	ESP +FGC	FFP	n/a - compliant	Wet FGD	8798	318	1.75
Matla	ESP+FGC	FFP	LNB (30%)	Wet FGD	8798	318	3.29
Tutuka	ESP	FFP	LNB (30%)	Wet FGD	8798	318	3.64

The modelled costs per abatement technology are based on de Wit (2013) and are shown in Table 6.

Table 6: Pollutant abatement technology options and costs (de Wit, 2013) (2015 ZAR)

Pollutant	*Abatement technology (% removal efficiency)*	*Capex (R/kW)*	*Opex (R/kW)*	*Comparison of efficiency - fossil power generation (Ecofys,2006)*	*Water use (l/kWh)*
PM	Fabric filter plant	2 609	162		
NO_x	Low NO_x burner (30%)	804	8		
SO_2	Wet FGD (90%)	6 189	156	0.015	0.21
SO_2	Semi-dry FGD (90%)	5 716	146	-0.0078	0.14

In total, the total capital costs for compliance per station across all pollutants are as shown in Table 7.

Table 7: Total capex costs per station for compliance across all pollutants (2017 ZAR)

Station	*Total overnight capex (billion 2017 ZAR)*
Duvha	29.5
Kendal	40.5
Lethabo	36.5
Majuba dry	16.1
Majuba wet	16.1
Matimba	39.3
Matla	38.7

[11] See

Appendix B for a full explanation of assumed compliance technology requirements based on Eskom pollutants per station.

Tutuka	39.4
Medupi	33.0
Total	**289.2**

3.2.8 Water costs

Station-specific water costs are used as given in Table 8.

Table 8: Water tariffs (ZAR/m^3) per power station for 2018/2019 (2015 ZAR) (DWS)[12]

Power plant	*Total tariff (ZAR cents/m^3)*	*Consumption tariff*	*Catchment management area charge*	*Water resource infrastructure charge*
Camden	780	195	2.32	583
Grootvlei	65	62	2.32	0
Komati	525	48	2.32	475
Arnot	50	48	2.32	0
Duvha	270	17	3.57	249
Hendrina	525	48	2.32	475
Kendal	2166	550	2.32	1 614
Kriel	833	165	2.32	666
Lethabo	65	62	2.32	0
Majuba	65	62	2.32	0
Matimba	175	171	3.82	0
Matla	329	137	2.32	190
Tutuka	364	116	2.32	246

3.2.9 Carbon constraint for the electricity sector

This study does not impose a carbon constraint on the electricity sector in the reference scenario. In the least-cost mitigation scenario, we impose a constraint of 7.75 Gt CO_2-eq on the entire energy system. This results in an allocation of 2.27 Gt $C0_2$-eq for the electricity sector for the 2021–2050 period. The IRP 2018 imposes two types of carbon constraint: i) in the form of a carbon budget of 5.47 Gt CO_2-eq over three ten-year intervals (DoE, 2018: 29), which is substantially higher than the 2.27 Gt CO_2-eq constraint of the least-cost mitigation scenario analysed here; and ii) an emissions limit defined by allocating a generous proportion of the overall PPD to the electricity sector. In reality, because of the revolution in the cost of renewable energy technology, no case in the IRP reaches the second constraint in any particular year, and all the IRP's cases remain close to the first constraint (<6 Gt over the period 2021–2050). Results reported below from the reference scenario suggest that there is a risk that not constraining emissions more stringently in the IRP, and in the context of an economy-wide analysis, could lead to a suboptimal national outcome in terms of mitigation.

Table 9: Emissions-reduction constraints used in the 'IRP 6' scenario from IRP 2018 (DoE, 2018: 29)

Decade	*Budget in Mt CO_2-eq*
2021–2030	2 750
2031–2040	1 800
2041–2050	920

12 Department of Water and Sanitation http://www.dwa.gov.za/Projects/WARMS/.

3.2.9.1 Method for assessing a higher ambition contribution to the Paris Agreement

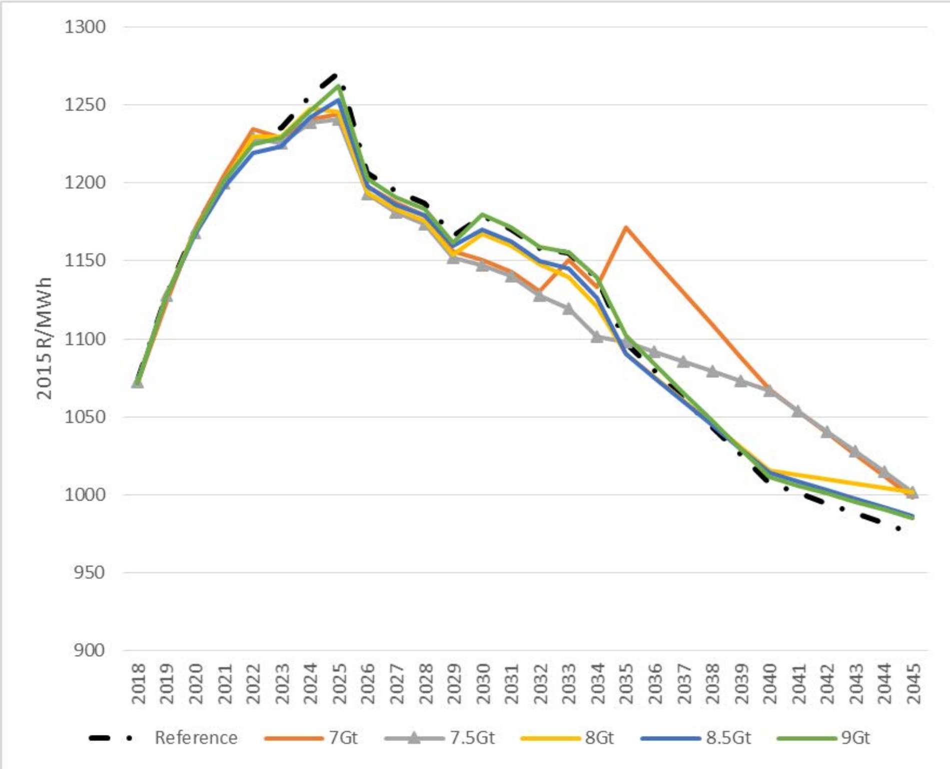
As described previously, the low-PPD budget is unlikely to be a sufficient contribution to limiting warming to the Paris Agreement target of ‘well below’ 2ºC; in particular, to limit warming to below the 1.5ºC target requires global net zero emissions by around 2050. However, the point at which more ambitious mitigation may start to have deleterious effects on the South African economy has never been explored. In addition to this, recent changes in key drivers (specifically the cost of renewable energy technologies, and changes in the coal price) have significantly changed the economics of mitigation in South Africa. The analysis in this work therefore explores the effect on the electricity price and on economic growth rates of various GHG emissions budgets.

We have taken the low-PPD budget of 9.5Gt CO_2-eq for the energy and industrial sectors between 2020 and 2050 as the starting point of our assessment. By lowering the budget in incremental steps of 500Mt, we were able to explore the mitigation response of different sectors – in particular the electricity sector but also other sectors, as well as any potential tipping points for the economy. We have taken the electricity price as a proxy for impacts on the economy (and also to assess the behaviour of the electricity sector under increasingly stringent emissions budgets), and then directly analysed economic impacts for a narrower range of emissions constraint.

Figure 5 below shows the evolution of the electricity price for different emission constraints. The overall price path is very different from the tariff analysis in IRP 2018, which rises steadily to 2050. By comparison, the price path here rises steeply to 2025 (on account of the cost of retrofitting existing coal plants to control air pollution, and the construction of Medupi and Kusile and other new capacity), and then declines towards 2050 as new plant becomes cheaper and more expensive older coal plants retire.

The different electricity price trajectories are driven by a combination of factors in each scenario. These include the quantum of new capacity investments, the savings from retiring instead of retrofitting the coal plants for MES compliance), and savings from reduced coal use at coal stations results in a dynamic price path variation between the scenarios.

As Figure 5 reflects, imposing a more stringent GHG budget on the entire energy system has a relatively limited impact on electricity prices between 9.5Gt and 8Gt, in particular to 2040, although the difference grows post-2040. However, at 7.5Gt and below, the electricity price follows a significantly higher trajectory in general over the entire modelling period (despite being lower in the 2029 to 2035 year range). This indicates a possible tipping point for the electricity sector in terms of its ability to absorb further mitigation action.



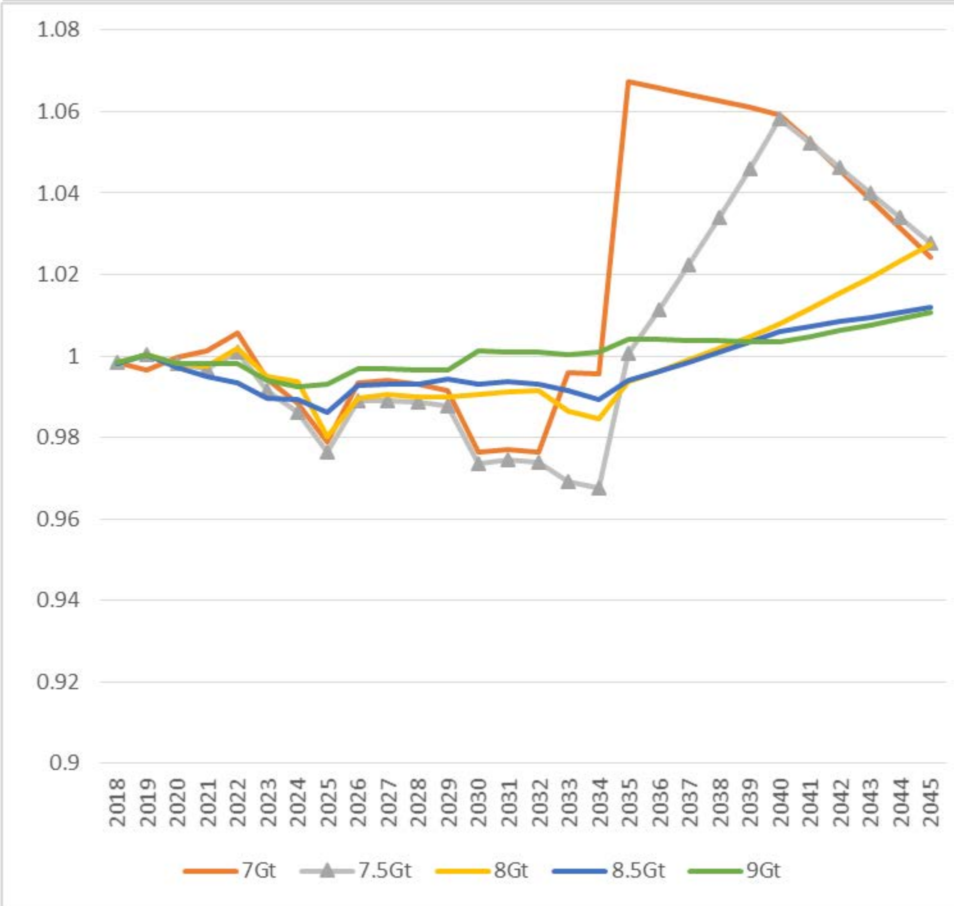


Figure 5: Effect on the electricity price of various GHG emissions budgets 2015 ZAR/MWh above and indexed to reference scenario below

Observing the relative contributions to mitigation from different sectors in Figure 6, it is striking that almost all mitigation occurs in the power sector, followed by a much smaller contribution from the refineries sector. In the refineries sector most of the mitigation results from lowered output from synthetic fuels plants, and a higher proportion of liquid fuels are imported.

Electrification of transport occurs in the reference case (due to falling costs of electric vehicles) and thus there is minimal additional mitigation from the transport sector under an emissions constraint.

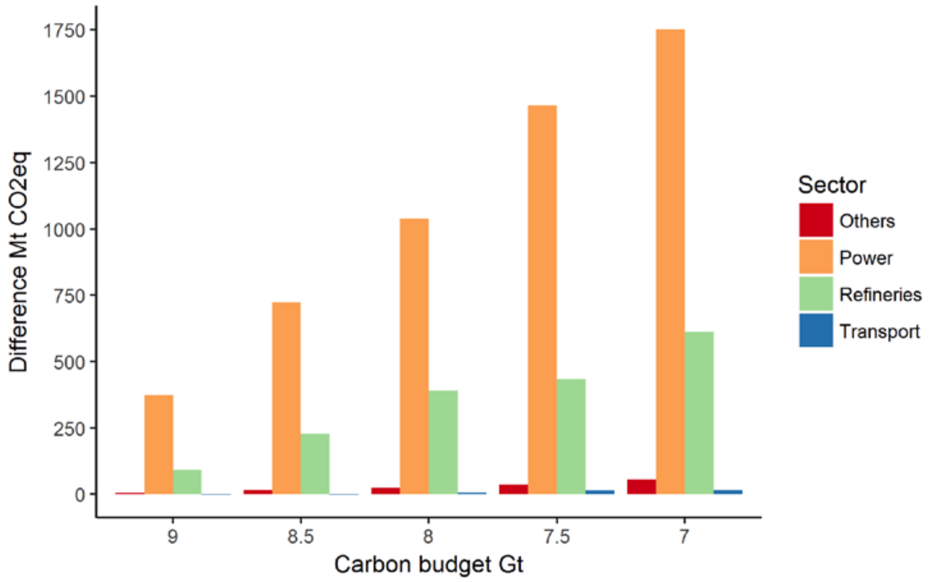


Figure 6: Sectoral mitigation (cumulative 2020 to 2050 CO_2-eq) burden under different GHG constraints compared to reference case

As a next step, we assessed a series of more narrow increments of 100Mt and explored the effects of different GHG budgets between 7.5 and 8 Gt on both the energy sector and the economy. In this assessment of these sensitivities, we use the linked energy and economy-wide model SATIMGE.

The results of the sensitivity analysis to GHG emissions budgets on the economy are presented in Figure 7. At 7.5Gt, the impact on the economy by 2045 is a 16% reduction in GDP compared to the reference scenario. We consider this to be beyond a reasonable growth impact scenario for South Africa to handle as a developing country. By exploring the region above 7.5 Gt mitigation effort, we found that a GHG budget of 7.75 Gt has a far lower negative effect on the economy in SATIMGE, with a reduction in GDP of 4% by 2045 compared to the reference scenario.

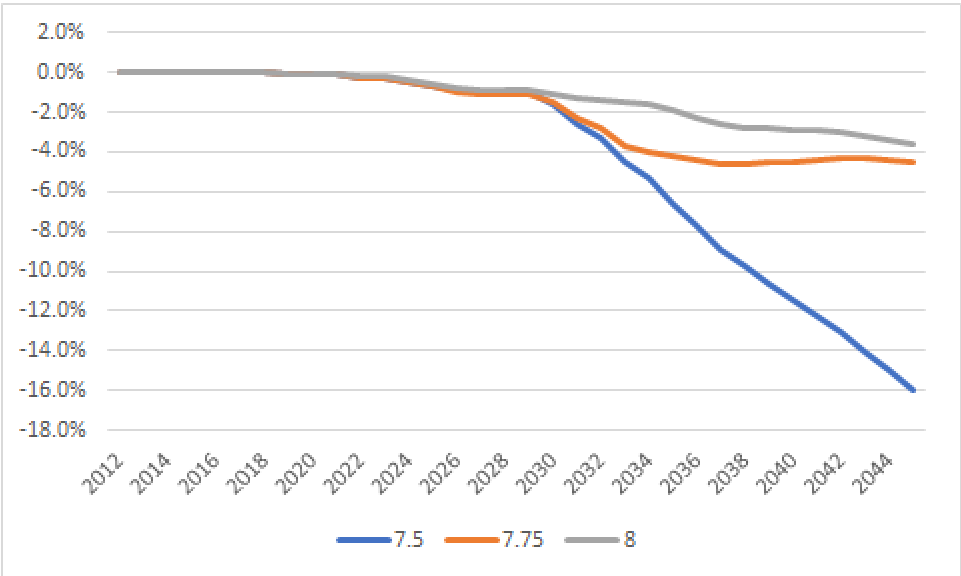


Figure 7: **GDP impact of varying greenhouse gas emission budgets – deviation relative to the reference scenario**

From this sensitivity analysis we proceed to use a GHG budget of 7.75Gt as a high ambition scenario for South Africa's contribution to limiting warming to 'well below 2ºC' as per its commitment to the Paris Agreement. The analysis shows that South Africa can increase its ambition at relatively low cost to the economy, at under two years of additional economic growth. It is possible that proactive supportive policies (including industrial policies) and further technology developments could erase this difference. Further research needs to be undertaken to assess the extent to which the modelling framework may over- or under-count costs to the economy under a high-ambition scenario. For example, the current modelling framework excludes the benefits of reforming fossil fuel subsidies and does not include the costs of environmental externalities such as water and air pollution and impacts on human health, nor therefore the benefits accruing to the economy of lower fossil fuel use. Many elements of a large-scale economic transformation away from fossil fuels and towards new technologies cannot easily be captured in the CGE framework (for example, the development of new sectors, or further flexibilities such as behaviour changes and consumer preferences, or the relationship between the utilisation of capital and labour into the future). These should be explored to assess more fully the cost differentials in high ambition scenarios.

3.2.10 Decommissioning of the existing fleet

The massive changes in the economics of the power sector in the last few years, coupled with the cost of retrofitting existing power plants to control air pollution, raise the possibility that early retirement of some or all of the coal fleet may be economically desirable. This possibility is confirmed in Steyn et al (2017). The IRP 2018 modelling does not evaluate this possibility, but assumes that the existing fleet will run for a pre-determined 50 years. In addition to the steeply declining cost of alternatives, the decline in maintenance spending over the last few years (Paton, 2018), declining performance of the fleet, and the rising costs of coal implies that this is an oversight that underestimates supply risks to the system (as stations will possibly retire sooner than expected) or raises costs (as the plants remain on the system sub-economically).

Unfortunately, it is not possible in the TIMES modelling framework to analyse the environmental retrofits along with endogenous retirement of the fleet, but based on Eskom's announced closures of some of its older stations, we have retired several power plants exogenously, i.e. we have retired them in a given year as an input to the model, since they are already closed or Eskom has announced their closure). These include units at Grootvlei, Hendrina, and Komati which are already either in cold storage or no longer running as of 2018.[13] Doing so avoids underbuilding replacement capacity in the scenarios analysed below. The IRP only includes decommissioning from 2021 onwards as portrayed in the IRP 2018's Figure 27 (DoE, 2018: 62), which could have the effect of underestimating the need for new capacity, and is not consistent with what is already happening in the electricity sector.

[13] This is consistent with earlier work that showed that retiring these stations would be a net saving to the electricity system (Steyn et al, 2017; CSIR, 2017).

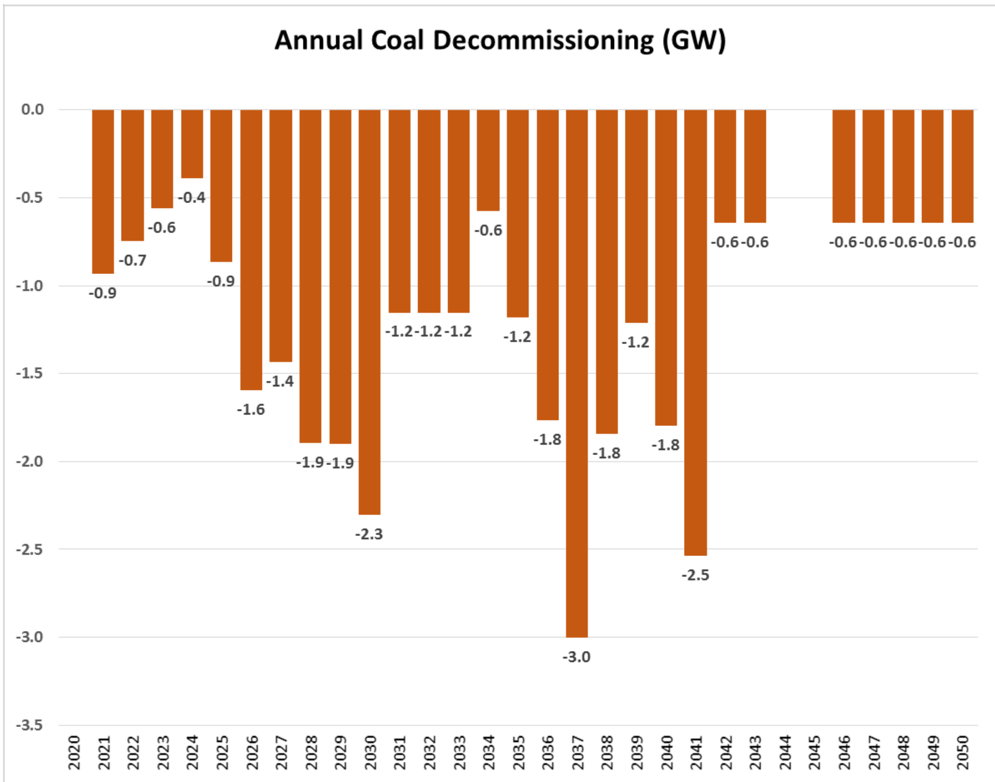


Figure 8: Assumed decommissioning schedule of coal stations in IRP 2018 (DoE, 2018)

We have staggered the closures in the pre-2022 period as in Table 10.

	2018	*2019*	*2020*	*2021*	*2022*
Arnot				1	
Komati	5	3	1		
Hendrina	3	2	2	2	1
Grootvlei	2	2	1		

Table 10 The number of assumed decommissioning of Eskom station units in pre-2022 period

We suggest that in the future, the IRP endogenously retires coal-fired power plants and makes available updates and consistent decommissioning plans from Eskom. Furthermore, the IRP states the largest driver of new capacity requirements in the period to 2030 is the decommissioning of the coal fleet, rather than load growth. Page 54 states that:

> Up to the end of the first decade (2030), the new capacity requirement is driven primarily by the decommissioning of existing coal-fired plants. The total installed capacity around 2020 will be about 50 GW. Assuming there will be no commissioning of new plants or decommissioning of existing plants, the earliest need for new capacity will be post 2030, based on high load growth. With decommissioning in line with the information in Appendix B**,** the earliest need for new capacity will be around 2025. This is a clear indication that the new capacity requirement driver in this decade will be decommissioning.

However, the IRP does not consider earlier decommissioning of coal plants that is already taking place, does not account for lower availability of Eskom plant as a risk to supply, nor examine economic retirement of coal plant. All of these create risks related to sufficient and secure supply of energy in the period to 2025 and could fundamentally alter the need for new build.

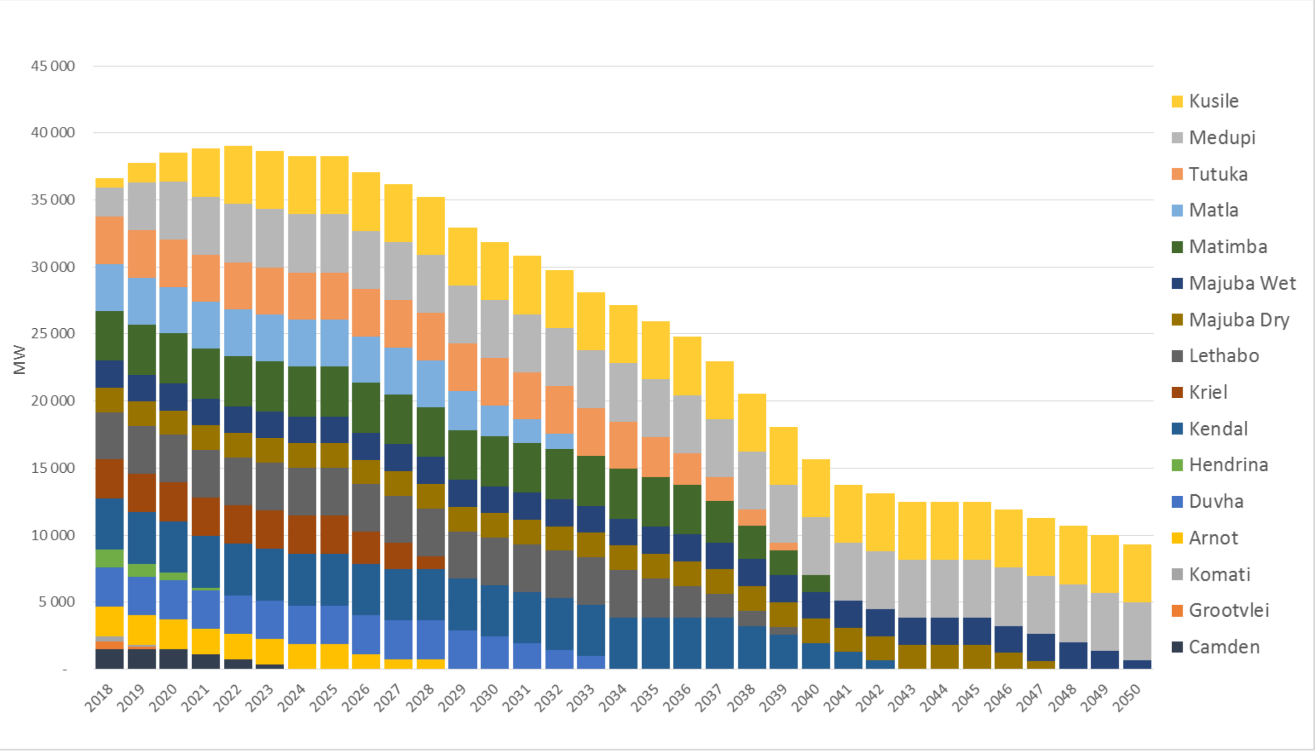


Figure 9: Existing coal capacity (with Medupi and Kusile expected unit commissioning) in SATIM

4. Reference case results

Peak demand in 2050 totals 65 GW and total installed capacity in 2050 is 229 GW including battery storage (Figure 10). The installed capacity is made up primarily of wind and solar PV (161 GW), and a small contribution from existing coal (9 GW) and pumped storage (3GW). Investment in new battery storage technology begins in 2026, growing to 53 GW by 2050 to complement variable renewable energy technologies. Wind, solar, and batteries provide the least-cost option for South Africa's electricity future.

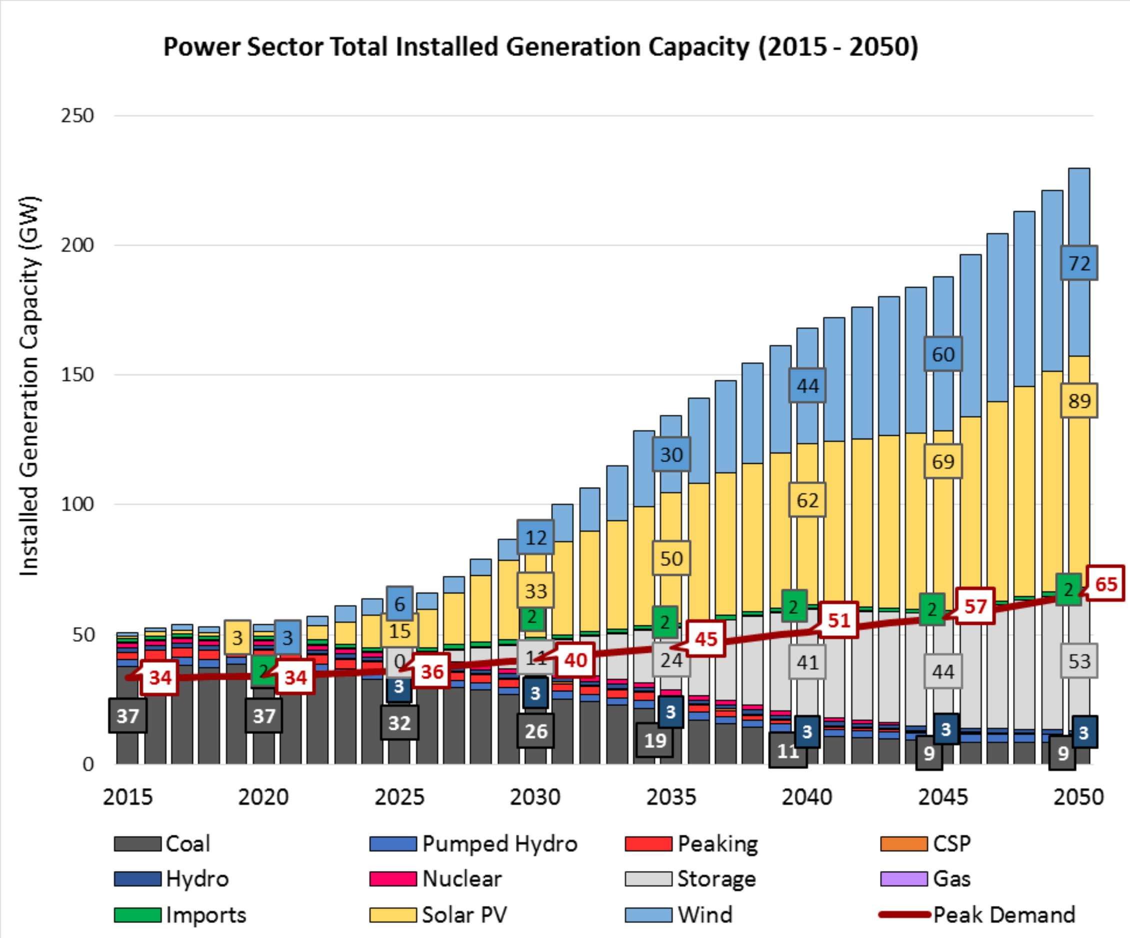


Figure 10: Installed generation capacity, reference case 2015–2050 (GW)

By 2030, renewables (wind, solar, micro-hydro, and biomass) produce 42% of electricity, and this increases to 90% by 2050 (wind and solar together contribute 38% and 88% in 2030 and 2050 respectively). The higher demand forecast illustrates the important role of full sector analysis: in the reference case, large scale electrification of transport takes place. By 2050, 66% of private passenger vehicle activity is from electric vehicles, and 63% of road freight (primarily through the use of electrified light commercial vehicles). Transport demand for electricity accounts for 10.8 TWh and 40 TWh in 2030 and 2050 respectively.

The supply of electricity from coal power stations declines over the scenario horizon. This is due to the scheduled retirement of coal stations over time and supply is also lower over the period due to earlier retirement of some stations or units which are not economic to retrofit to meet the MES and which retire early.

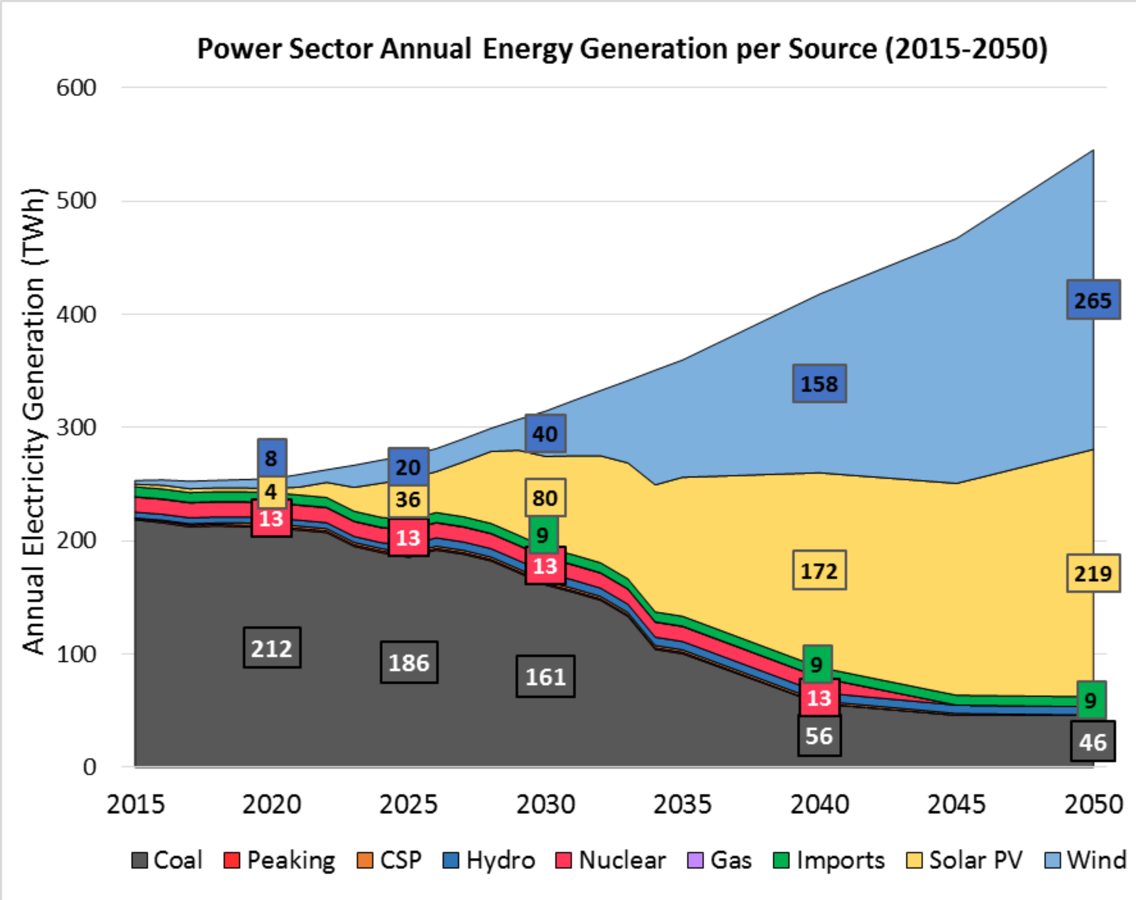


Figure 11: Electricity generation by source, reference case, 2015-2050 (TWh)

The reference scenario includes large-scale retrofitting of Eskom power stations to meet the 2020 MES ('new plant standards') by 2025. As discussed in Section 3.2.7 this study allows all stations that are scheduled to retire before 2030 to avoid meeting the 2020 plant standards (as per Eskom's stated intentions and the latest regulations). For the remainder of the fleet, plants must either implement the technology options to meet the 2020 new plant MES or else retire over the period to 2025. The results show that the least-cost option is to retrofit most of the fleet to comply with the 2020 plant standards. However, here we have implemented the retrofits over the period to 2025 (in line with postponements that Eskom has already received or is already requesting).

The scenario results show a total of 18 GW of plant retrofits across the fleet over the period to 2025. A total of 31 units are retrofitted out of a possible 42 across the fleet. All stations available for retrofitting are partially or fully retrofitted[14] except Majuba, which is fully decommissioned by 2025.[15] Table 11 shows the results of the SATIM model reference scenario and the number of units retrofitted for compliance with the MES.

The retirement of Majuba highlights an important consideration. The station is retired rather than retrofitted due to its higher coal costs; but the costs of coal at Majuba are likely similar to the costs of recent contracts as Eskom competes to procures coal during a period of very high export coal prices and declining volumes from its tied mines. Since coal costs will continue to increase, it is worth exploring the fuel cost tipping point for each station to be retrofitted or retired. With better oversight of future maintenance needs and coal costs, it is plausible that some stations should retire rather than be retrofitted.

14 We run SATIM using linear programming, and not mixed integer programming; therefore the scenario does not distinguish between stations at a unit level.

15 This is accounted for by Majuba's high costs of coal; the station does not have a tied mine and its coal supply costs are amongst the highest on the system. An important area of further assessment would be to analyse the point at which coal cost increases would make environmental retrofitting of each station uneconomic.

Table 11: Results of MES compliance per station

Station	*Number of units retrofitted*	*Retrofitted/ retired*
Duvha	6	Fully retrofitted
Kendal	6	Fully
Lethabo	6	Fully
Matimba	6	Fully
Majuba	0	Retired 2025
Matla	5	Partially
Tutuka	2	Partially

The remainder of the coal fleet is also sensitive to coal cost assumptions, even without any emissions constraints imposed on the scenario. While Medupi runs at maximum capacity factor (80%) to 2050, Kusile (with higher coal costs) starts to run at a much lower load factor from 2040 onwards, running at only a 41% load factor to 2050.

The high penetration of RE in the electricity sector results in a reduction in emissions over the period. Energy and industrial emissions fall from 422 Mt CO_2-eq to 238 Mt by 2050, again, without any emissions constraint applied to the scenario. In industry, there is little change in the mix of energy carriers, namely coal and electricity. Coal continues to be a primary source of process heat and emissions in industry, and grows over the period with increased industrial growth. As mentioned above, transport electrifies substantially, although some fossil fuel use remains. On the supply side, Sasol's Secunda CTL plant retires between 2040 and 2045. Although the electricity sector does not fully decarbonise over the period, the carbon-intensity of the electricity sector declines dramatically, from 891g CO_2-eq/kWh in 2020 to just 81 g CO_2-eq/kWh by 2050. Emissions for the electricity sector for the period 2021 to 2050 total 3.6Gt CO2-eq, which is considerably lower than any of the IRP cases (which all remain above 4.9 Gt over the same period). The most stringent emissions constraint in the IRP (the 'carbon budget' approach) constrains emissions to 5.5 Gt over the same period. Clearly, since the actual emissions budget achieved in an economy-wide model for an unconstrained least-cost scenario is so much lower than this, this constitutes a significant over-allocation of emissions space to the electricity sector. This will become more apparent below in the mitigation scenario.

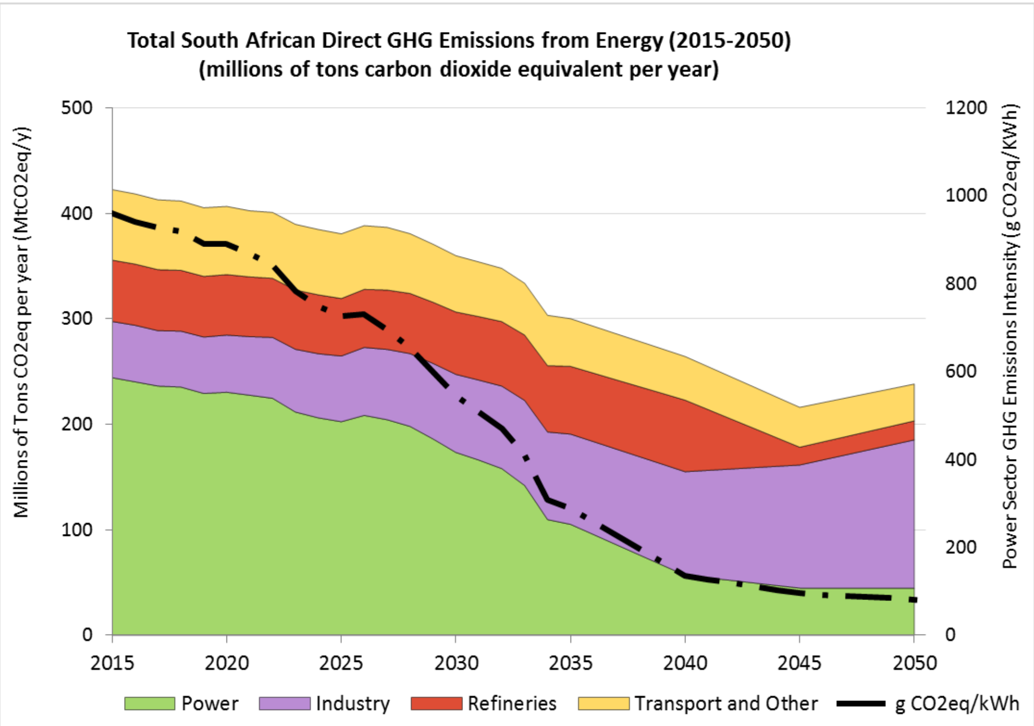


Figure 12: Total direct greenhouse gas emission from energy (2015-2050) in the reference scenario

4.1.1.1 Sensitivity on MES suspension of compliance

Recent regulations released by the Department of Environmental Affairs have suggested that stations that retire by 2030 will not have to be compliant with the new plant MES, and can instead apply for a once-off 'suspension of compliance'. Such a suspension depends on the provision of detailed decommissioning plans (amongst other things). Already, Eskom implicitly applies this rule to Camden, Hendrina, Komati, Grootvlei, Arnot, and Kriel. The sensitivity here explores this suspension of compliance for two further stations: Duvha and Matla. These stations are the next two stations due to retire post-2030 (with Duvha completely offline by 2035 and Matla by 2034 if a 50-year life is assumed), have relatively lower cost coal, and Duvha ranks better in terms of air pollution relative to the rest of the fleet.[16] We explore the option of suspending the compliance requirement on these two stations but require them to be offline by 1 Jan 2030. The results show that there is evidence to support the suspension of compliance for Duvha and Matla alongside earlier retirement of the stations by 2030. The sensitivity results show that suspending compliance reduces costs and GHG emissions (but increases emissions of other pollutants). As there is no expenditure on retrofit requirements for these two stations, the electricity price is lower in this scenario.

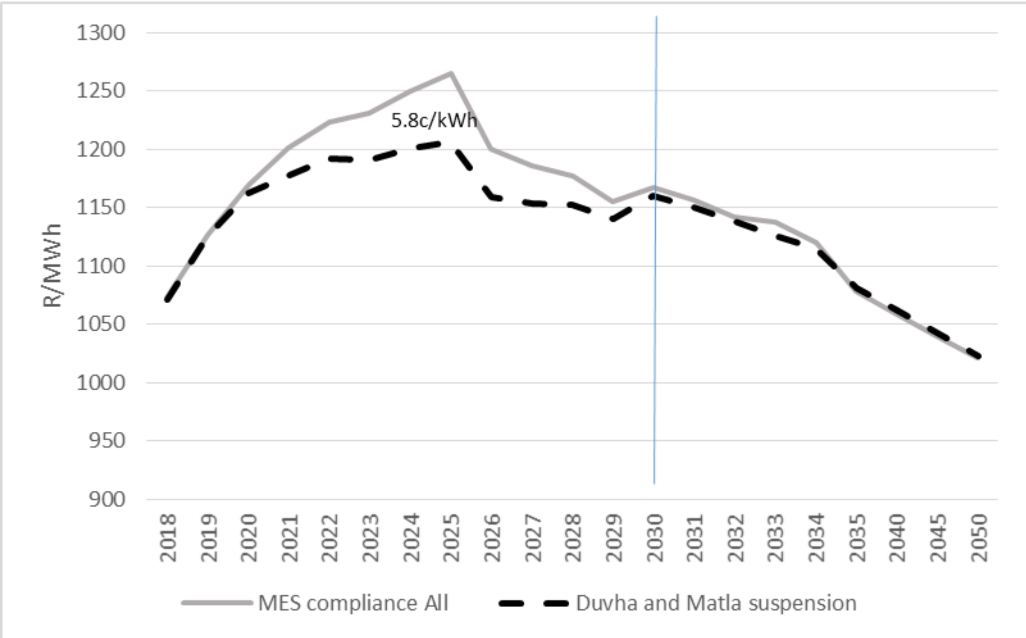


Figure 13: SATIM electricity price comparison with full MES compliance versus suspension of Duvha and Matla MES compliance

The suspension of compliance on Matla and Duvha requires the stations to come offline by 2030, which results in the need for more new capacity relative to the reference scenario by 2030 and through to 2035. However, this only brings forward the construction of new renewable energy capacity. This is highlighted in Figure 14, showing that the total RE and storage capacity is the same between the two scenarios by 2035.

[16] A comparison of the studies by Holland, Pretorius, and Sahu (Holland, 2017; Pretorius et. al. 2017; Sahu, 2018) was done by ranking the stations from those studies that we model with MES retrofit requirements. All studies agreed that of the stations requiring MES compliance, Duvha and Matla ranked well compared to the other stations.

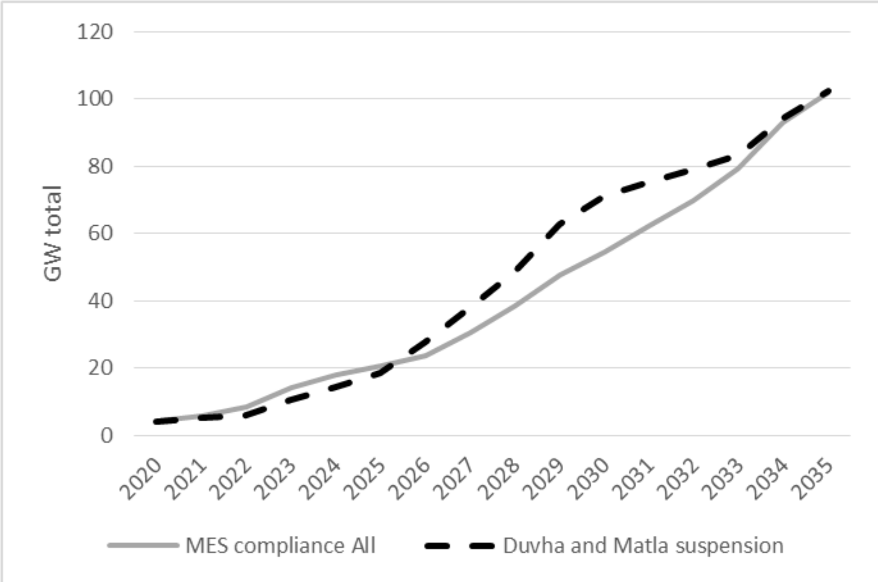


Figure 14: Total installed capacity of RE plus batteries in reference and Duvha and Matla suspension scenarios

Greenhouse gas emissions for the energy system in this sensitivity are shown in Figure 15 . There is an overall emissions savings of 136Mt CO_2-eq relative to the reference scenario due to the earlier retirement of Duvha and Matla.

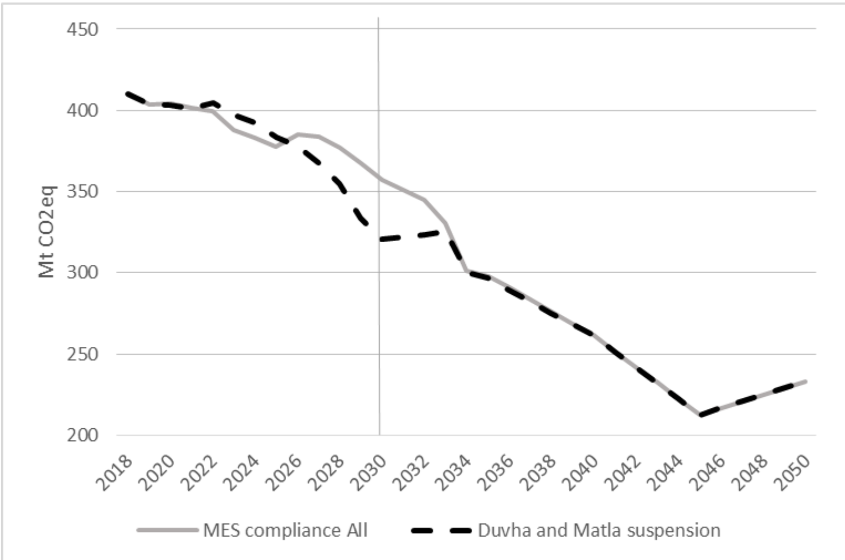


Figure 15: Emissions in reference scenario with full MES compliance compared to MES suspension for Duvha and Matla

5. Results: least-cost climate mitigation

5.1 Energy system results

In this scenario the linked energy-economy model is run with the same labour and capital supply and productivity growth forecasts as the reference scenario but with the 7.75 Gt emissions budget applied over the period to the energy system. In this scenario, the impact of the carbon budget on the energy system feeds back into the economy-wide model through the electricity price and the total investment requirements in the energy system. This affects economic growth which in turn impacts demand for electricity. The result is a total demand for electricity of 312 TWh in 2030 and 542 TWh in 2050. This is a slightly lower than the reference scenario owing to the impact on

GDP growth (see section 5.2), but only marginally so at 7 TWh difference to the reference. Peak demand for electricity is similar to the reference scenario at 65 GW in 2050.

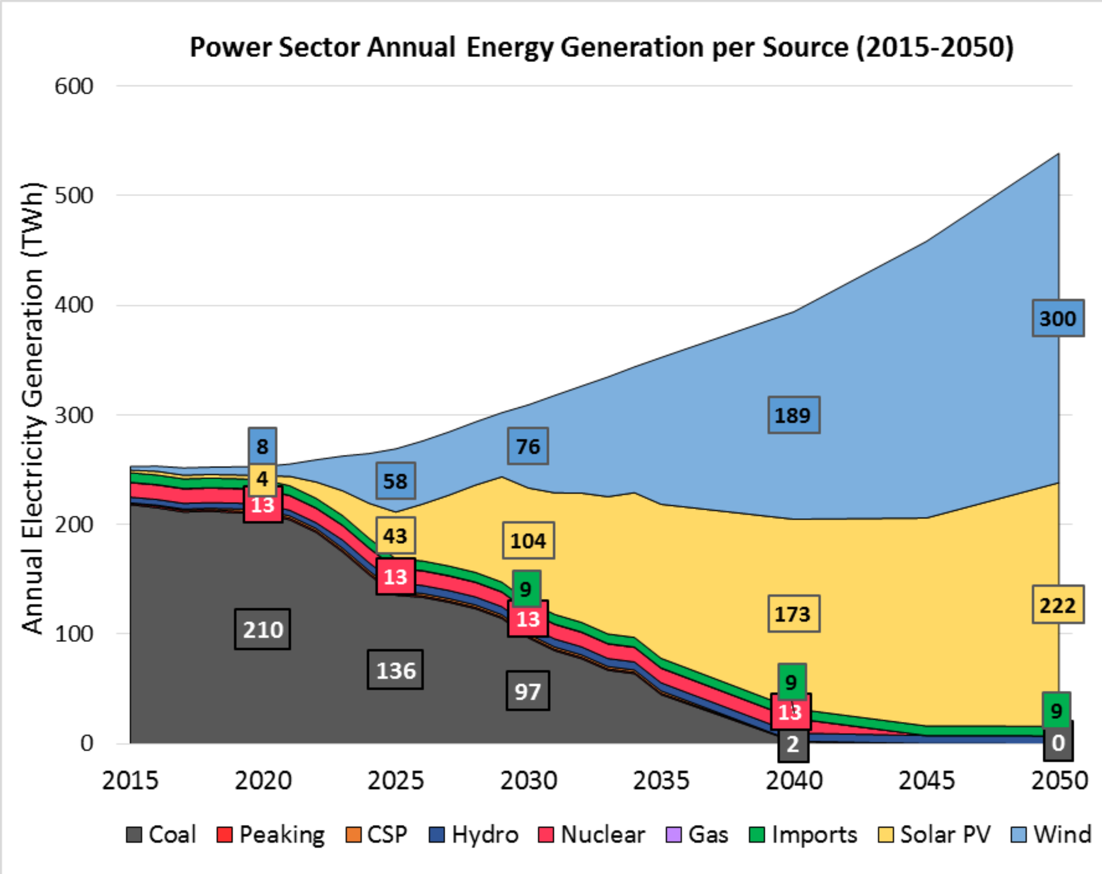


Figure 16: Annual generation of electricity by technology in the least cost mitigation scenario

As with the reference scenario, all new electricity generation capacity is a combination of wind, solar PV, and battery storage. Total installed capacity is 113 GW by 2030 and 240 GW by 2050. The installed capacity is 11 GW higher than the reference case by 2050 despite the lower electricity demand, and renewable energy technologies (wind, solar, micro-hydro, and biomass) provide 62% of electricity generated by 2030 and 99% by 2050 (wind and solar together make up 57.3% and 96.3% by 2030 and 2050 respectively).

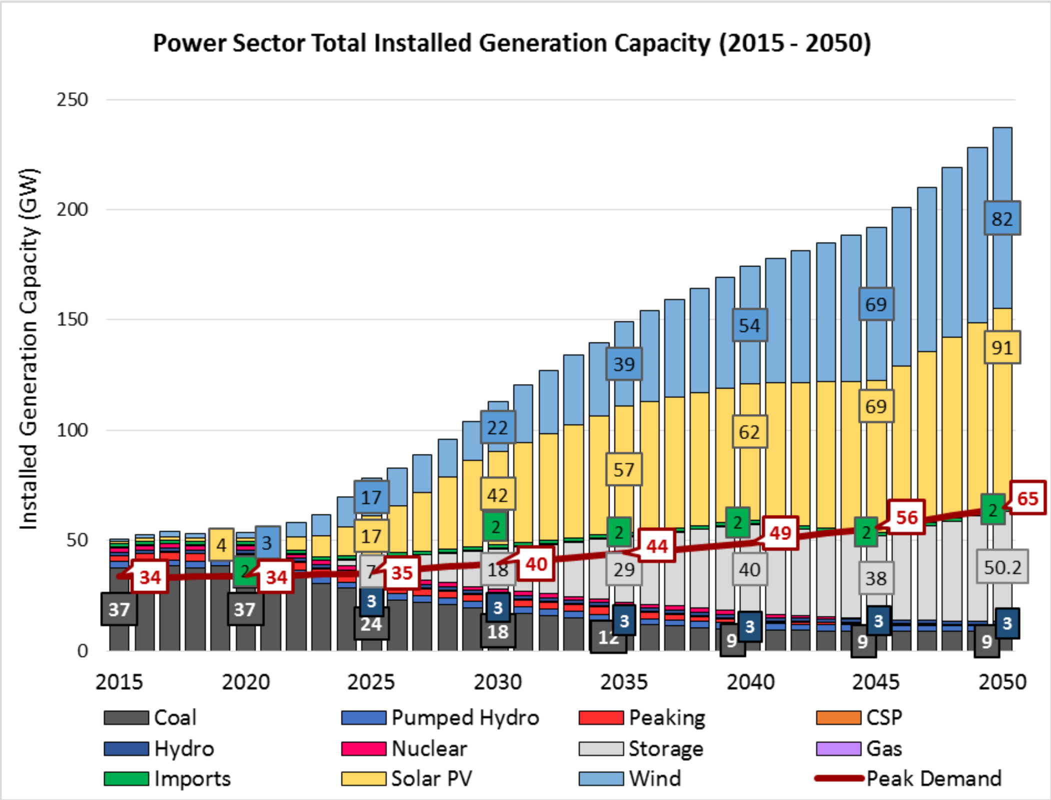


Figure 17: Total system generation capacity for the least-cost mitigation scenario

Compared with the reference scenario, there is an accelerated investment in renewable energy in the medium-term – particularly as more coal capacity comes offline in the 2020s or is run at lower load factors. There is still coal capacity available in the long term from Kusile and Medupi (but not Majuba), but Kusile operates at a 55% load factor and Medupi at 75% load factor from 2026. Neither station generates electricity from 2040 onwards, though they remain available to the system.

Coal capacity is lower in this scenario owing to more stations retiring instead of being retrofitted for compliance with the MES (see Table 12). In total, 11GW of coal capacity is retrofitted, compared to 18GW in the reference scenario.

Table 12: MES compliance in the least-cost mitigation scenario

Station	*Number of units retrofitted*	*Retrofitted/ retired*
Duvha	6	Fully
Kendal	0	Retired
Lethabo	2	Partially
Matimba	5	Partially
Majuba	0	Retired
Matla	5	Partially
Tutuka	2	Partially

In this scenario Kendal station is not retrofitted at all and retires by 2025 along with Majuba. Lethabo, Matimba, Matla and Tutuka are partially retrofitted and partially retired. Due to the lower capital cost expenditure on retrofits and earlier retirement of coal plants, the electricity price is lower in the medium term compared to the reference scenario. The electricity price is higher in the long term compared to the reference case as higher investment in renewable energy and storage capacity is required to meet the emissions constraint. The higher investment in RE plus batteries is needed to replace retiring coal capacity, Medupi and Kusile post-2040, as well as the renewable capacity installed in the 2020s (when the capacity becomes due for replacement in the 2040s).

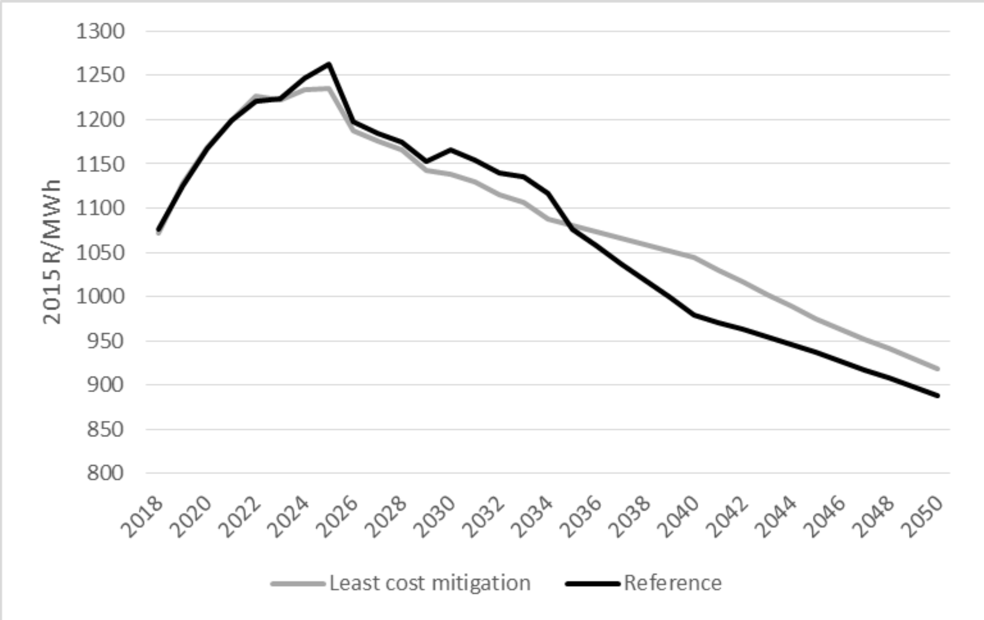


Figure 18: Electricity price comparison for reference and least-cost mitigation scenarios

Figure 19 shows there is a general decline in emissions from 2015 onward, but this trend accelerates from 2020. The power sector contributes the largest mitigation effort, as discussed above – with fewer coal units operating overall and those that do run operating with lower load factors and result in an electricity carbon intensity of just 8 g CO_2-eq/kWh by 2040 and zero by 2050.

There is also a significant mitigation contribution from coal-based synthetic fuel production as these CTL facilities are offline between 2035 and 2040, compared to 2045 in the reference scenario. The CTL facility also reduce their production levels over their lifetime. Lower demand for liquid fossil fuels for transport (driven by lower GDP and higher electrification of transport) results in emissions savings relative to the reference scenario. As in the reference scenario, transport is largely electrified and thus most of the emissions savings would come from upstream power sector emissions savings.

Although the rate of growth is lower for the industrial sector relative to the reference scenario, and despite higher uptake of fuel switching to electricity, coal remains the lowest-cost supply option for heat in the industrial sector. In the long term the industrial sector becomes the largest source of emissions from energy in South Africa – the majority of these from process heat requirements, particularly from boilers.

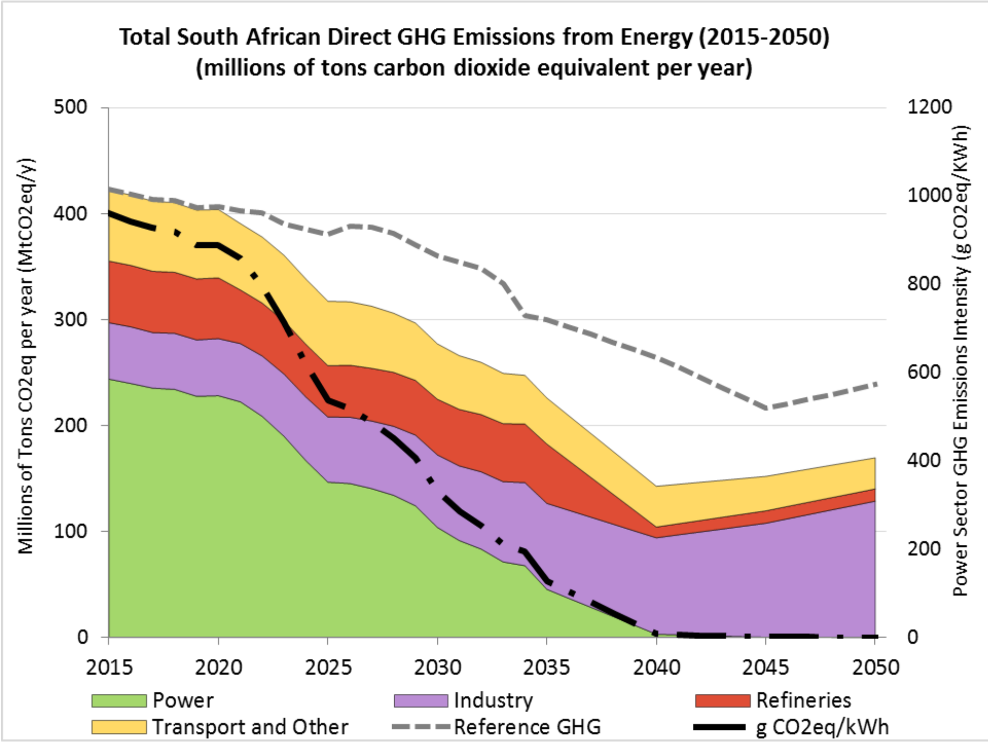


Figure 19: GHG emissions in least-cost mitigation scenario with carbon intensity of electricity

5.2 Economy-wide results

Including an emissions constraint of 7.75 Gt CO_2-eq has a small negative impact on real GDP with the real GDP level being 4.2% lower by 2050 (Figure 20 (a)). This translates into a 0.14 percentage point decline in the average growth rate and implies that the level of real GDP experienced under the unconstrained least cost scenario in 2050 would be delayed by between one and two years. The lower level of GDP is the result of the higher electricity investment requirement, which results in lower available funds for investment in other sectors; as well as a higher electricity price. Total electricity investment is 11.6% higher under the 7.75 Gt CO_2-eq scenario, while the electricity price is 3.4% higher by 2050 (Figure 20 (b)). Employment is 4.1% lower (1.84 million job-years in 2050), in line with the lower real GDP level.

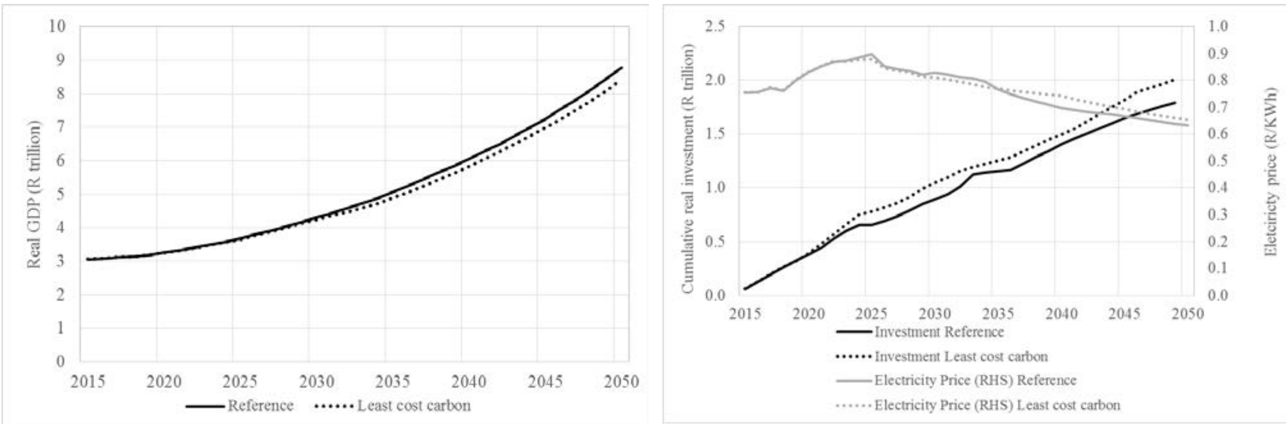


Figure 20: a) Real GDP; b) Electricity investment and price

Lower levels of activity are experienced across all sectors of the economy in the 7.75 Gt CO_2-eq scenario with the largest declines in activity taking place in the mining and manufacturing sectors. Mining and manufacturing GDP is 4.6% and 4.3% lower by 2050. The largest declines within the manufacturing sector occurs within the non-metallic minerals, metal products and motor vehicles sub-sectors, which are typically energy-intensive users. The differences in employment are the largest in the services sector, which is the largest employer in the country. Employment in the services sector is 1.32 million job-years lower in the 7.75 Gt CO_2-eq scenario. The next largest differences are in the manufacturing and other industry sectors which employ 237 000 and 165 000 fewer workers than in the reference scenario. Employment losses are largest amongst higher educated workers (i.e. Grade 12 and higher levels of education).

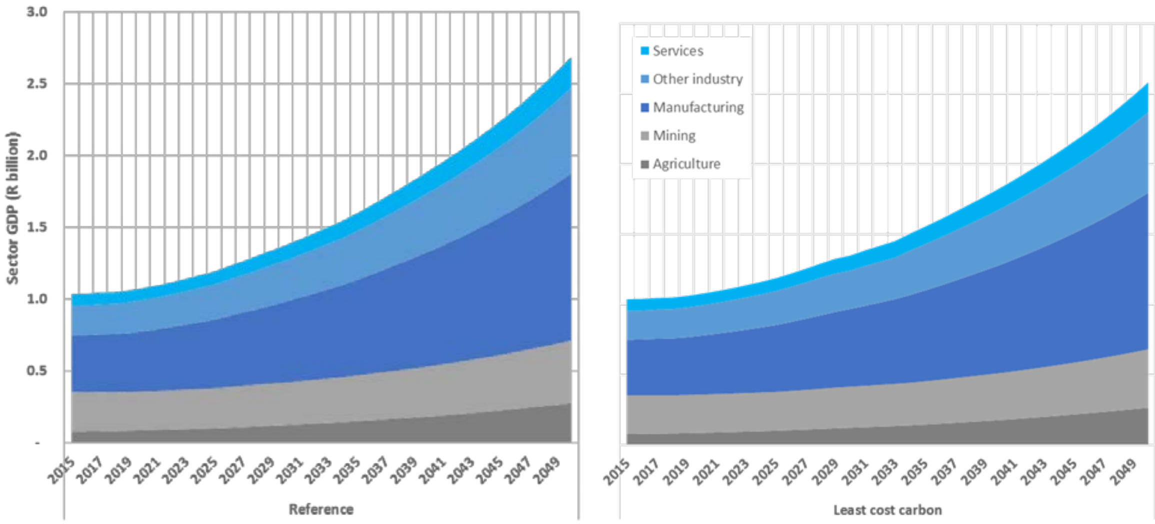


Figure 21: Sector GDP in the reference, and in the least-cost mitigation scenarios

6. Future work and study limitations

This section briefly outlines areas for future work and limitations of the study. Future research questions should examine the following:

- Further analysis on the potential efficiency measures and technology and fuel-switching options in the industrial end-use sectors. Given the large contribution to GHGs by the end of the modelling period, emission reductions technologies and policy packages are needed to support mitigation in the industrial sector.
- Endogenous retirement of coal power plants with environmental retrofits. At this time, TIMES is not able to endogenously retire the retrofitted plants in SATIM.
- A sensitivity analysis on suspension of MES compliance on further power plants, and an assessment of the costs and benefits of such a strategy in terms of externalities and health.
- Gas price versus battery prices sensitivity analysist to assess trade-offs between the uptake of gas versus batteries for flexible supply
- Given uncertainties around battery costs, South Africa should also continue to explore a suite of options to supply flexibility to the grid. Our results show that gas-to-power may no longer be a competitive supply option when battery cost reductions take place in line with industry expectations. The contribution to electricity from gas has been low (10–15% of electricity demand in 2050) in other modelling studies (Burton et al. 2018; Wright et al., 2018), though none have excluded gas entirely from the long-term future of the power sector. A response that reduces the risks for future power generation coming from uncertainties around future costs of large-scale batteries would include the prioritisation of continued exploration of new options for handling very high penetration levels of VRE generation. This could include flexible demand options (Ireland, 2018), regional import options, and demand-supply balancing technologies, or 'power-to-X' systems (Lund et al, 2015; JRC, 2015).
- Further model development related to non-fossil fuel sectors and their value chains (for example, better representation of the battery value chain in the economic model would alter the overall economic costs incurred by a rapid switch away from coal in the electricity sector).

7. Conclusion

This study has examined the implementation of a least-cost scenario for South Africa's electricity sector to 2050. The findings have implications for the Integrated Resource Plan (IRP) 2018 that is currently being updated by the Department of Energy. Firstly, the study reiterates earlier findings that future supply will come primarily from wind and solar PV. Renewable energy plus flexibility provides the least-cost pathway for the electricity sector. No new coal or nuclear power plants feature in South Africa's electricity future, and their inclusion would require subsidies from consumers (Burton et al 2018; CSIR, 2017; CSIR 2018; Ireland & Burton 2018; Steyn et al, 2017).

Secondly, this study has also shown that a large-scale procurement programme for battery technology to provide storage capabilities for variable renewable energy should be pursued in South Africa.

Third, retrofitting stations for compliance with the minimum emission standards (MES) is, for the most part, the least-cost option for the electricity sector (due to the relatively higher costs of new technologies in the period 2020–2025). It is cost-optimal to retrofit Eskom's coal-fired fleet to meet the new plant standards by 2025 rather than retire them, except in the case of Majuba. There are potential cost and greenhouse gas emissions savings if compliance with the new plant standards is suspended for some stations (e.g. Duvha and Matla) and they are instead retired early. We propose that the Department of Environmental Affairs considers suspending compliance requirements for the best performing (in terms of pollutants) stations and in exchange Eskom agrees to retire the stations by 2030 at the latest. For the remainder of the fleet, Eskom should commence retrofitting the stations for compliance with the MES, subject to ongoing cost assessments (e.g. coal costs per station, which may alter whether a station should be retrofitted or retired).

Finally, this study has examined the effects on the electricity system, the energy system and the economy of a more ambitious climate change mitigation policy. We have found that phasing out coal in the power sector by 2040 is cost optimal for South Africa to fulfil its commitment to the Paris Agreement goal of limiting warming to well below 2ºC without significant impact on the economy, and that therefore South Africa can afford to be more ambitious in its mitigation policy. Reducing emissions below the level of the low-PPD by 2050 can therefore be achieved through rapid decarbonisation of the electricity sector and fuel switching. A well below 2ºC compatible pathway is possible with only a 4% reduction in GDP in 2050 – translating to a delay of between 1 and 2 years in absolute terms in achieving the same economic growth level in 2050. The IRP 2018, which currently allocates more than 5Gt of greenhouse gases to the electricity sector, should therefore significantly reduce this allocation in line with an economy-wide, least cost allocation of emissions space to different sectors.

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Appendix A: Description of the ERC's TIMES and ESAGE models

The South African Times Model (SATIM)

Originally created for the Long Term Mitigation Scenarios, the South African Times Model (SATIM) is a full economic sector energy-systems model that undergoes continual development. SATIM is based on TIMES (a successor to MARKAL) which is a partial equilibrium linear optimisation model developed by the International Energy Agency.

The model includes economic costs, emissions, and a range of sector-specific constraints that can be applied at a point in time or cumulatively. A user interface provides a framework for both structuring the model and scenarios, and for interpreting results.

The SATIM model is fundamentally 'sectoral', in that it organises the demand for energy by economic sector and characterises the demand for energy in a sector by the energy services required by that sector. SATIM is therefore a full-sector TIMES model that includes both the supply and demand side of the South African energy system. SATIM can be run using linear or mixed integer programming to solve the least-cost planning problem of meeting projected future energy demand, given assumptions such as the retirement schedule of existing infrastructure, future fuel costs, future technology costs, learning rates, and efficiency improvements, as well as any constraints such as the availability of resources. The model has five demand sectors and two supply sectors, which can be analysed individually or together. The demand sectors are industry, agriculture, residential, commercial, and transport, and the supply sectors are electricity and liquid fuels. SATIM allows for trade-offs between the supply and demand sectors, and it explicitly captures the impact of structural changes in the economy (i.e. different sectors growing at different rates), process changes, fuel and mode switching, and technical improvements related to efficiency gains (Altieri et al. 2015).

SATIM, however, does not endogenously account for the feedback from the economy as sectors and consumers respond to changes in energy prices, and as the economy responds to energy investment requirements. By not accounting for this feedback, it is likely that SATIM will over- or under-estimate energy demand when used independent of an economic model.

The level of detail for a sector depends on the relative contribution of the sector to total consumption and on how much funding has been historically received for developing that sector in the model. Thus, the model for the Transport sector is quite detailed but that of the Agricultural sector is quite simplistically represented in SATIM, because in South Africa the Agriculture sector accounts for relatively small energy consumption and low emissions.

In SATIM, services supplied to each of the five sectors are driven by technologies that require energy, with the quantity of that energy supply depending on the efficiency of the technology.

Useful energy is an exogenous model input disaggregated by energy carrier, for each demand sector. Final energy demand is determined endogenously using the assumed efficiencies of the least cost demand-side technologies selected by the model. The two supply sectors and primary energy sources must meet the sum of these demands, with the model optimizing the mix of supply-side technologies to meet the demand for final energy at least cost.

The SATIM model includes a number of parameters and general assumptions broadly covering, for each sector: (a) the structure of the sector and its energy services as it impacts on the demand for energy; (b) the establishment of base year demand for energy in the sector; (c) technical and cost parameters of the technologies available to satisfy the demand for energy services currently and in the future; (d) the projection of future demand for energy services.

SATIM can be broadly summarised as follows:

- Bottom-up (end-use) energy systems optimisation, similar to the national Integrated Energy Plan (IEP)

- Full economic sector representation allowing resource and emissions trade-offs between demand and supply
- Captures full economy energy emissions (excluding land use, land-use change and forestry) allowing the modelling of carbon taxes and carbon budgets.

Limitations of the existing model is that at present:

- no demand response is implemented: if elastic demand is used a price elasticity is required for each end-use.

Figure A1 depicts the primary SATIM model components while Table A1 summarises the economic demand sector representation. Of note is the importance of the base year energy balance which provides the calibration reference for the model's supply and demand assumptions.

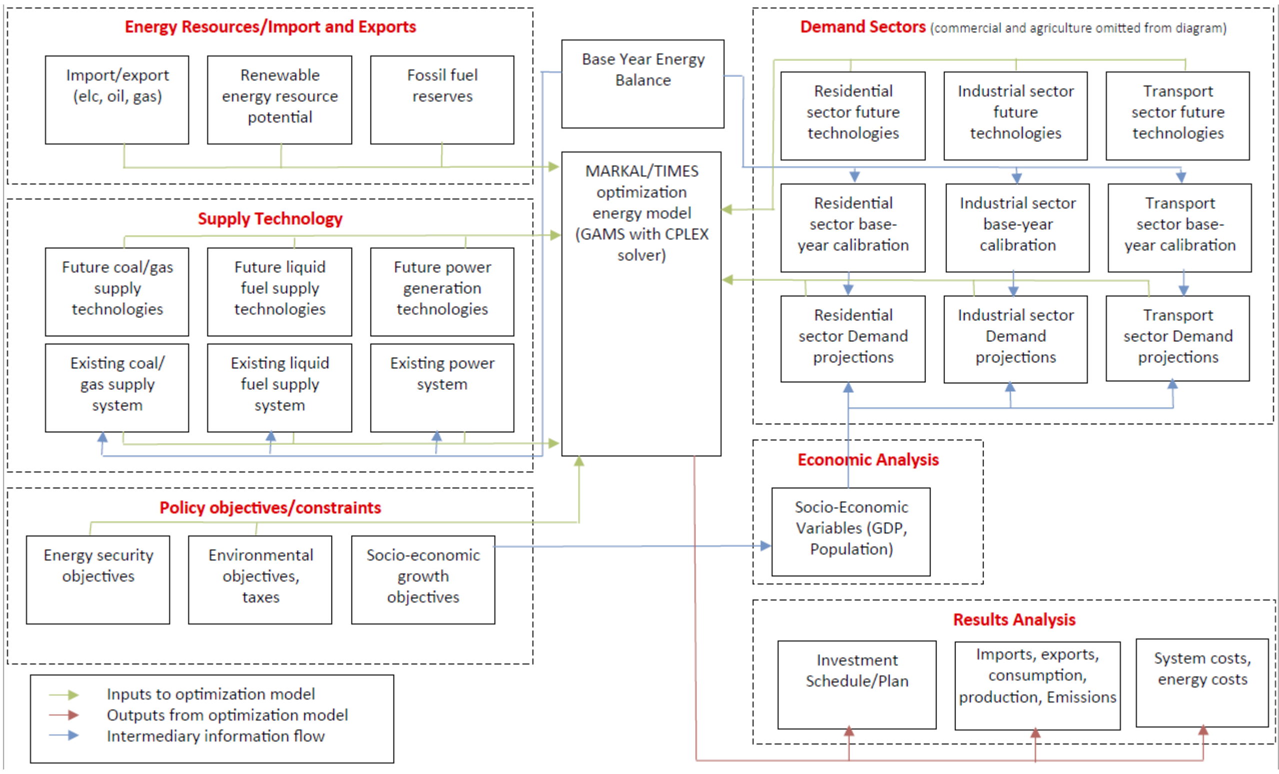

Figure A1: A schematic summary of the South African Times Model (SATIM)

Table A1: Summary of economic sector representation in SATIM and their main drivers

Sector	*Disaggregation*	*Driver*
Agriculture	By end use: e.g. irrigation and traction.	Agriculture GDP
Residential	High, medium and low-income households: electrified and non-electrified	Population, Household-income, electrification rate
	By end use: e.g. cooking, lighting.	
Commercial	By end use: e.g. lighting, HVAC.	Total GDP, building stock
Industrial	By sector: iron and steel, pulp and paper	Sectoral Value Added
	By end use: thermal fuel or electricity (e.g. compressed air, cooling, pumping)	
Transport	By sector: air, freight and pipeline	Transport GDP, Population and household category and income
	By end use: e.g. freight rail and road (light, medium, heavy)	
	By end use: e.g. Passenger: Cars, SUV, Bus.	

e-SAGE

ESAGE is a dynamic recursive computable general equilibrium (CGE) model for South Africa with a detailed electricity and petroleum sector which includes the different technologies used to produce electricity and petroleum. The CGE model is based on a social accounting matrix (SAM), which captures all transactions and transfers in the economy, and with the rest of the world, at a specific point in time thus providing useful insights on the direct and indirect linkages within the economy.

Behavioural equations in the model capture the decision-making process of agents and allow them to respond to changes in the system such as the implementation of a new government policy. This behaviour of industries and households is governed by rational expectations (Thurlow 2004). Structural equations or closure rules ensure macroeconomic consistency between incomes and expenditures within the model and are used to describe the functioning of the economy. These include the behaviour of exchange rates, investment, government savings, prices and quantities of factors of production.

The dynamic recursive nature of the model allows for an assessment over time as investment is turned into capital within the model in a putty-clay fashion, i.e. investment in period t is turned into capital and allocated to sectors in period t+1. The sector capital allocation is determined by the initial share of aggregate capital income; the capital depreciation rate; and period t sectoral profit-rate differentials. While not a forecasting tool, CGE models are useful for developing a consistent baseline accounting. A key feature of the e-SAGE model is that non-energy industries can react to energy price changes during the between period by shifting their investments to less energy-intensive capital and technologies, the ease of which is specified exogenously (Alton et al. 2014).[17]

The model, initially developed for the National Treasury by the United Nations World Institute for Development Economics Research, is based on the generic static and dynamic models described in Lofgren et al. (2002) and Diao and Thurlow (2012); and is a descendant of the class of CGE models introduced by Dervis et al. (1982). The ESAGE model used within the linked modelling framework is updated and maintained within the ERC and is currently based on a detailed energy version of the 2012 SAM. More information on the ESAGE model and 2012 SAM can be found in Arndt et al. (2016) and van Seventer et al. (2016).

The extended 2012 SAM consists of 67 activities and 55 commodities (see Annexure A for a detailed list of activities and commodities). It includes 4 categories of labour which distinguishes between skill level (determined by education). Skills levels are classified according to primary (<Grade 8), middle (Grade 8-10), secondary (Grade 11-12) and tertiary (> Grade 12). To further highlight the differences between the energy and non-energy sectors capital is disaggregated between energy and non-energy capital. Households are divided into 15 representative household groups and represent the quintile income distribution in rural farm, rural non-farm and urban households. Other institutions: government, enterprises and the rest of the world are also represented. Key taxes in South Africa (i.e. personal and corporate income taxes; sales taxes; activity taxes; import duties) are also represented in the SAM.

SATIM-eSAGE

SATIMGE combines the ERC's South African TIMES (SATIM) model, a bottom-up integrated energy systems model, with eSAGE model, a recursive dynamic computable general equilibrium (CGE) economy wide model for South Africa, based on the standard IFPRI CGE model. Both models are calibrated to the 2012 social accounting matrix and energy balances for South Africa. The reconciliation of the SAM with the energy balance in physical units requires some adjustments to the SAM in a 'hybridization' process.

17 Energy is considered an intermediate input and the interaction between intermediates and factors is governed by a Leontief production function. To decrease the rigidity of using a Leontief production function, there is 'response elasticity' that governs the amount sectors are able to change in their energy inputs per unit of output based on energy prices.

Given an initial growth projection for the demand sectors and household income, which are translated into projections for demand in energy services (e.g. process heat in cement, tonkm, etc.), SATIM is used to compute the least-cost energy technology mix that meets the demand for energy services over a planning horizon extending to 2050. In the electricity sector, the investment (capital growth and expenditure on power plant construction), share of electricity production by technology group (via the electricity sector production function), and changes in average electricity generation cost are passed on to the eSAGE. In other productive sectors, the production functions are adjusted to reflect technology change (efficiency gains and fuel switching) observed in SATIM. This results in a new growth trajectory for the economy. Activity-level and household income changes observed in eSAGE are then passed onto to SATIM, which is run again in the next iteration.

After around 5 iterations, the energy utilization (and associated CO_2 emissions) in both models are relatively closely aligned and internally consistent in terms of demand, price and technology/fuel mix. The Technology mix, the technology investment schedule, and CO_2 trajectory are obtained from SATIM, and the GDP, welfare and income indicators associated with each of the energy/climate policy scenarios are obtained from eSAGE. (Merven et al 2016).

Appendix B: Implementation of compliance with the MES

SATIM model implementation of the AQA MES for Eskom's coal fleet: abatement technology selection method.

The National Environmental Management: Air Quality Act 39 (2004) requires existing stations to comply with the more stringent 'New Plant' Minimum Emission Standards by 2020. Allowing for a 5 year postponement from the legislated year, stations which are reported to commence their retirement before or shortly after 2025 as detailed in the IRP (2018) were therefore excluded from further consideration.

Table B1: Stations which are excluded from further investment in air emissions abatement technology

Station	*Intended decom date#*
Arnot	2021/2022
Camden	2020/2021
Hendrina	2020/2021
Komati	2024/2025
Kriel	2026/2027
Grootvlei	2025/2026

Coal power stations which were deemed candidates for investment in abatement technology are listed below along with the technology investment required.

Table B2: Stations for which investment in air emissions abatement technology is required by 2025

Station	*Available Capacity (GW)*	*Units*	*AQ technology already installed*	*AQ technology investment*		
				PM10	*NO_x*	*SO_x*
Duvha	2.9	5	FFP to units (1-3)	FFP (3 units)	n/a	Wet FGD
Kendal	3.8	6	ESP+FGC	FFP (3 units)	n/a	Wet FGD
Lethabo	3.5	6	ESP+FGC	FFP (3 units)	n/a	Wet FGD
Majuba-DRY	1.8	3	FFP	n/a	LNB (30%)	Wet FGD
Majuba-WET	2.0	3	FFP	n/a	LNB (30%)	Wet FGD
Matimba	3.7	6	ESP+FGC	FFP	n/a	Wet FGD
Matla	3.5	6	ESP+FGC	FFP	LNB (30%)	Wet FGD
Tutuka	3.5	6	ESP	FFP	LNB (30%)	Wet FGD
Medupi	4.3	6	FFP, LNB	n/a	n/a	Wet FGD

FFP: Fabric Filter Plant; ESP: Electrostatic Precipitator; FGC: Flue Gas Conditioning; LNB: Low NOx Burner; FGD: Flue Gas Desulphurisation

The selected abatement technology investment is based on a consideration of:

1) technology already in place (Eskom,2018); and
2) exemption in lieu of pre-existing emissions compliance (Table and Table).

Thus, for example, Low NOx Burners with 30% removal efficacy was therefore selected as the lower cost technology which would meet the requirement for NOx emissions compliance.

Similarly, FFP technology, reported by Eskom (2018) as the technology of choice, was included where PM reduction was necessary.

Table B3: Average particulate matter emissions reported by Eskom (Patel, 2012)

Station	*Current limit*	*Average Emissions*	*Priority*	*Compliance*
Tutuka	250	150-220	High	Fabric filter plant retrofit needed. Aim to achieve compliance by 50mg/Nm3 limit by 2020, but not with 100 mg/Nm3 limit by 2015, if capacity allows outage time for retrofits.
Grootvlei	250/200 Apr2012: 175/150	70-300		
Kriel	225	80-250		
Matla	150/175	100-200	Medium-high	
Duvha 4-6	75	50	Lower	Fabric filter plant retrofit needed. Should achieve compliance with 50 mg/Nm3 by 2025, if capacity allows time for retrofits.
Lethabo	75	60-70		
Kendal	75	60		
Matimba	75	50		
Arnot	50	<50	No need for reduction	Already compliant with 2020 standard – no need for retrofit.
Camden	50	<50		
Majuba	50	<50		
Duvha 1-3	50	<50		
Hendrina	50	<50		
Komati	100	Unlikely		Station to be decommissioned in the 2020s – not feasible to retrofit

Minimum Emission Standards: 1 April 2015: 100 mg/Nm^3; 1 April 2020: 50 mg/Nm^3

Table B3: Average NO_x emissions reported by Eskom (Patel, 2012)

Station	*NO_x emissions (mg/Nm^3)*	*Priorities and Comments*
Kriel	1212	Technology required to achieve compliance is being assessed. Will not be compliant by 2015. Compliance by 2020 can only be achieved if capacity allows outage time.
Majuba	1127 – 1157	
Matla	942 – 1034	
Tutuka	538 – 924 (538 mg/Nm3 at 430 MW)	
Lethabo	777 – 835	Average emissions are close to 750 mg/Nm3 limit and no exceedances of ambient limits. Are retrofits needed?
Duvha	754 – 774	
Arnot	661 – 887	Will comply with Existing Plant Standard, but not with New Plant Standard. Already have Low NOx Burners, and stations are old.
Grootvlei	733 – 871	
Komati	1006 – 1039	Station decommissioning starts in 2020s –retrofits not feasible
Camden	839 – 1012	
Hendrina	879 – 984	
Kendal	449 – 576	Comply with New Plant Standard. No retrofits required.
Matimba	499 – 560	

Minimum Emission Standards: 1100 mg/Nm^3 by 2015; 750 mg/Nm^3 by 2020 60

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Appendix C: Further model documentation

Transmission and distribution representation and costing

In SATIM the centralised bulk electricity transmission system is modelled as a single node and sized to meet the projected peak electrical demand in each year. The cost of replacement and new transmission lines and transformers are costed as a single R/GWpeak value based on Eskom integrated annual reports – central transmission losses are also modelled according to Eskom integrated reports (Eskom, 2018). Distribution systems are sized and invested in within each economic sector according to their respective peak demands - their energy losses (technical and non-technical) are modelled on aggregate per sector and aligned with NERSA (2012). Separate transmission costs or typologies are not modelled individually per generation technology (such as individual RE collector stations as in the IRP2018) and are accounted for as a whole as above - the exception to this is for Inga hydro imports using an HDVC line which does not affect the rest of the model.