An assessment of the costs and GHG emissions implications of new coal powerplant procurement in South Africa

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Abstract

South Africa's coal baseload independent power producer (CIPP) procurement programme was launched in 2014, in line with the new coal capacity envisaged in the 2010 Integrated Resource Plan for Electricity (IRP 2010) (DoE, 2011). Since the IRP 2010, however, there have been fundamental changes in the costs of competing supply technologies, coupled with a decline in demand for electricity in South Africa. These combined have rendered the 2010 IRP increasingly out of date which until the gazetting of a new IRP, remains the official generating capacity expansion plan policy in South Africa. This results in the provision of new generation capacity that as shown in this study is not necessary to meet demand, provides more costly electricity, and increases greenhouse gas emissions. These plants will also place additional pressure on the national power utility, Eskom, whom would be forced to purchase all electricity from the CIPPs regardless of existing available capacity.

This study quantifies the impacts of the CIPP program in South Africa's electricity system for the period from 2022 to 2052 – specifically for the 557MW Thabametsi and 306MW Khanyisa coal-fired sub-critical fluidised-bed combustion (FBC) plants with 30-year power purchase agreements (PPAs). We quantify the cost implications that the inclusion of the CIPPs imposes on the system relative to cheaper alternatives, the additional GHG emission 'lock-in' from the plants, and the effects this has on South Africa meeting its long-term climate change commitments.

Several optimised baseline scenarios are modelled without the CIPPs using the South African Times Model (SATIM): a reference scenario including best- and worst-case sensitivities, and an NDC compatible climate change mitigation policy (CCP) scenario with an economy-wide emissions budget. Compared to the baselines, we run comparative scenarios where the CIPPs are committed and "forced into" the model and the deviations from the optimised scenarios are then measured and reported. In all scenarios, no new coal, new hydropower imports, nor new nuclear are necessary nor economic, and the least-cost future new-build is a combination of wind, solar PV, and flexible natural gas generation.

In the reference scenario, the additional discounted cost of building the CIPPs is R19.68 billion, and power sector emissions are increased by 205.7Mt CO_2eq over the period. With best- and worst-case sensitivities on costs and emissions using pessimistic renewable energy cost projections, higher gas costs, and best-in-class supercritical FBC technology the CIPPs still increase system costs and emissions. Additionally, building the CIPPs in the context of a climate change mitigation policy scenario (CCP) places additional mitigation pressure on the power and liquid fuel sectors. The additional costs range from a low-end of R16.4 billion in the best-case scenario to a high-end of R27.99 billion in the CCP scenario.

Keywords: Coal Independent Power Producers, integrated energy system modelling, impact assessment, costs, greenhouse gas emissions, climate change NDCs, Thabametsi, Khanyisa, power purchase agreements, Eskom, South Africa, Integrated Resource Plan, fluidised-bed combustion coal power

1. Introduction

South Africa's coal baseload independent power producers (CIPP) procurement programme was launched in 2014, in line with the new coal capacity envisaged in the 2010 Integrated Resource Plan for Electricity (IRP 2010) (DoE, 2011). Since the release of the IRP 2010, however, there have been fundamental changes to the South African electricity sector. In particular, rapid changes in the costs of competing supply technologies and fuels globally and in South Africa, coupled with an unprecedented decline in demand for electricity. These changes have rendered the assumptions of the 2010 IRP increasingly out of date. Later iterations of the IRP (2013 and 2016) were not or have not yet been gazetted, and the 2010 IRP thus remains the official policy for the construction of new power plants. This has the result of provisioning the addition of new generation capacity that is not necessary to meet demand and ensure security of supply of electricity, provides more costly electricity, and increases greenhouse gas emissions.

Under the first round of the coal IPP programme, preferred bidder status has been awarded to two projects: the Thabametsi and Khanyisa coal-fired power plants, with net capacity of 557MW and 306 MW respectively, and both planning to use sub-critical fluidised bed combustion (FBC) technology. Both plants have faced considerable opposition from environmental groups and have not yet reached financial close. In the case of Thabametsi, a court ruled that the Department of Environmental Affairs (DEA) had not adequately considered the climate change impacts of the plant before making the decisions to authorise the power station, and a climate change impact assessment was undertaken. The Minister of Environmental Affairs subsequently upheld the environmental authorisation claiming the impacts identified in the climate change impact assessment report and supported by the independent review are justified. The Minister has argued that the justification is based on the capacity allocated to coal in the IRP 2010 because the IRP decisions makers "concluded that the harms that would result from the establishment of new coal-fired facilities... were outweighed by the benefit to the country of having the additional energy generation capacity".

Furthermore, in the "policy-adjusted" IRP 2010 (DoE, 2011), the DoE brought the construction of new coal capacity forward to 2014/15; new coal was initially only required from 2026 onwards in the "revised balanced scenario" (RBS). The IRP states the following in this regard: "*The RBS allowed for coal-fired generation after 2026. The policy requirement for continuing a coal programme could result in this coal-fired generation being brought forward to 2019-2025… Existing coal-fired generation is run at lower load factors to accommodate the new coal options*" (DoE, 2011: 11, section 4.7). Thus, even with more favourable assumptions used in the IRP 2010, with a much higher demand forecast and more expensive competing alternatives, the IRP acknowledges that the CIPPs were surplus to new generation needs, would result in excess capacity, and would mean running the rest of the coal fleet at lower load factors. Their inclusion in the build plan was moved forward due to a policy commitment to coal and was not a least-cost modelling result nor was it necessary for supply security concerns. The cost and emissions implications of this were not presented.

Given this context, this study aims to quantify the effects of the CIPPs in South Africa's electricity system for the period from 2022 to 2052. The modelling highlights several key changes in the electricity sector that have not been considered by the Minister of Environmental Affairs in her decision to uphold the environmental authorisation. This includes the reduced demand forecast since the IRP 2010, and availability of cheaper and lower emission alternatives, rendering the CIPPs unnecessary.

We investigate the cost implications that the inclusion of the CIPPs imposes on the system relative to cheaper alternatives, the GHG emission 'lock-in' from the plants, and the effects this has on South Africa meeting its long-term climate change commitments. The modelling framework also indirectly allows for an assessment of supply security by ensuring a 15% firm reserve margin of fully dispatchable plants. The relative costs of a system with or without the CIPPs thus reflects the costs of ensuring an approximated equivalent level of reliability and system adequacy.

To do this, we model several scenarios using the South African Times Model (SATIM) (see section 2 and appendix) that allows an assessment of the effects of building the stations compared to an optimised plan that excludes the CIPPs. To assess the implications of the inclusion of CIPPs in the South African electricity system, we model the following scenarios:

- Reference scenario
- Best-case sensitivity for CIPPs
- Worst-case sensitivity for CIPPs
- Climate change mitigation policy (CCP) scenario

A key finding of the study is that in each scenario, neither new coal, new hydropower imports, nor new nuclear power is required to meet demand at lowest cost.[1] Thus, since a least-cost electricity build plan for South Africa does not include new coal plants, after running each scenario we run a comparative scenario with all assumptions held equal, except that the CIPPs are "committed" and forced into the model. We then report the deviations in the system between an optimised case and the case where the CIPPs are forced in to the scenario.

In all scenarios, we find that the inclusion of the CIPPs in South Africa's electricity build plan raises the total system costs compared to a scenario without the CIPPs, and similarly in all scenarios, the CIPPs increase the GHG emissions of the energy system.

[1]The finding that a least-cost optimised energy system excludes new coal in general and the CIPPs is consistent with other modelling analysis undertaken in South Africa (CSIR, 2017; Meridian Economics, 2018).

Additionally, not only are the CIPPs not required to meet demand, raise costs, and increase emissions, but they also result in increasing pressure on Eskom and the country. Building new coal plants when sufficient capacity exists means reducing the output of Eskom's fleet, potentially accelerating the 'utility death spiral' in which Eskom already finds itself and putting the electricity supply industry – and thus the South African economy at increased risk.

The paper is structured as follows: section 2 briefly describes the SATIM modelling framework used in the analysis (South African TIMES Model). Section 3 presents the system impact evaluation methodology using SATIM, the key assumptions used, and the modelled scenarios in detail. Section 4 outlines the baseline results for each scenario, and the impacts of committing the CIPPs. Section 5 concludes.

2. South African TIMES Model (SATIM)

The South African TIMES Model (SATIM) model forms the basis of the system impact analysis of the research presented in this paper. SATIM covers all economic and energy sectors of South Africa and is developed within the Energy Systems, Economics, and Policy Group (ESEP) of the Energy Research Centre within the University of Cape Town (UCT) in South Africa. It undergoes continual development, updates, and maintenance, with multiple internal and external stakeholders. For the SATIM model and documentation see: energydata.uct.ac.za/organization/erc-satim). SATIM is based on TIMES which is a partial equilibrium linear optimisation framework developed by the International Energy Agency used by numerous energy research groups (IEA-ETSAP, 2018).

The outputs of SATIM provide projections for the future least-cost system evolution and energy system investment projection scenarios comparable to those of the DoE IRP and IEP processes (DoE, 2011; 2016; 2018). The model endogenously choses the most appropriate end-use supply technologies, investments in energy efficiency measures, and fuel switching capabilities. SATIM considers not only the demand for electricity but also the energy demands and their non-electric energy carriers (e.g. for transportation and industrial processes), and how these impact other sectors and vice-versa. It also allows holistic evaluation of scenarios where the full South African economy is subjected to greenhouse gas emission constraints.

3. Study methodology and scenario descriptions

This study uses the SATIM modelling framework to assess the implications of the coal IPP programme on system costs and GHG emissions for each scenario. Each scenario assesses the difference to the system with or without the plants over the 30-year time horizon of the power purchase agreements (PPA) (2022-2052). The energy system investment is modelled and presented annually from 2015 to 2035 and at 5-year milestone years from 2035 to 2050 (though we run the model to 2052 to capture the effects of the full life times of the stations).

Since an optimised least-cost build plan includes no new coal-fired power plants in the investment horizon to 2050, testing the system implications of the CIPPs requires the plant or plants to be "forced-in" to the electricity system build plan. Thereafter, when the plants are committed, the deviation from the baseline least-cost system can be quantified and analysed. The study models both CIPPs as a combined investment, as well as each project committed in isolation, however only the combined impacts are reported here. The following metrics are reported on and compared for each scenario; in each case comparing that scenario with and without the CIPPs.

Primary system metrics measured:

- Annual and total discounted differences in national electricity system cost
- Difference in the capacity expansion plan and electricity production profile
- Change in annual and cumulative GHG emissions

Metrics not included in direct analysis[2]:

- Water use and infrastructure requirements
- Environmental impacts such as PM, SO_2, NO_2, pollutants or acid mine drainage
- Employment and GDP impacts

3.1 Representation of the CIPPs in the model

Both Thabametsi and Khanyisa are modelled as Fluidised Bed Combustion (FBC) coal-fired power plants of 557 MW and 306 MW respectively (DoE, 2015). The total tariffs Eskom pays to Thabametsi and Khanyisa are R1,03/kWh, and R1,04/kWh, respectively (May 2016 Rand). This is calculated by inflating the evaluation price using the CPI index from April 2014 Rand to May 2016 Rand (which includes the shallow grid connection costs) and excluding the carbon tax (included in the evaluation price). This tariff is used as the total cost of the plants in the model (validated by pers. communication, CSIR).

- PPA = Evaluation price (–) Carbon Tax (120 R/t CO_2)

[2] These impact metrics fall outside of this study's scope; however, they can be directly measured using the extended SATIM framework when including the linked CGE energy-economic model, e-SAGE (SATIMGE), and SATIM-W

The PPA also includes the requirement for a fixed minimum off-take of electricity by the system operator, totalling 85% of the energy generation capacity of the plant. This offtake is required regardless of the availability of cheaper plants in the system. This would lock the country in to the plants' future emissions and additional costs, while also reducing economic dispatch and system flexibility.

The GHG emissions intensity of Thabametsi is reported to be 1.23 tCO_2eq/MWh (ERM, 2017). We assume the same GHG-intensity for Khanyisa[3], since it also uses FBC technology. Importantly, this GHG-intensity includes both the direct carbon dioxide (CO_2) and the CO_2 equivalent of expected nitrous oxide (N_2O) emissions from the plants (not to be confused with the pollutant nitrogen dioxide (NO_2)). Fluidised bed plants typically emit significantly more N_2O than conventional pulverised fuel coal plants, such as the existing Eskom coal plants, and most of the world's existing plants (Zhu, 2013; Koorneef, 2017). N_2O has a 100-year global warming potential (GWP) 310 times greater per ton than CO_2 (UNFCCC, 2018), therefore even relatively small volumes of N_2O can make a large contribution to overall GHG emissions. As shown in Figure 1, including the N_2O emissions of the CIPPs increases their GHG-intensity by 20.5%, from 1.02 to 1.23 tCO2-eq/MWh. This makes the GHG-intensity of the CIPPs much higher than the world average. For comparison, N_2O emissions from Eskom plants only make up 0.4% of total CO2-eq emissions (Eskom, 2017b). This GHG-intensity is approximately 24% higher than the current Eskom fleet average and 58% higher than Medupi & Kusile.

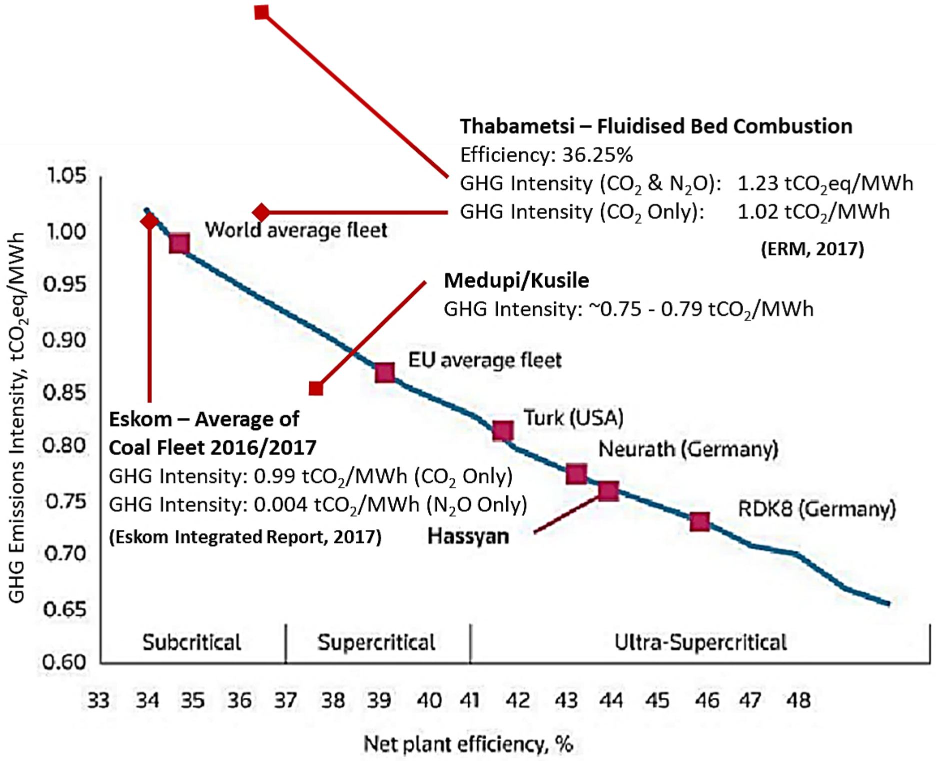


Figure 1: Comparison of various coal power plant efficiencies and emissions intensities. Adapted from PFI Yearbook & ACWA (2017). Sources: Eskom (2017), ERM (2017).

Table 1: Summary of key input assumptions for CIPPs (DoE, 2015; ERM, 2017; Aurecon, 2012)

Parameter	*Thabametsi*	*Khanyisa*
Plant Capacity (net sent out)	557 MW	306 MW
Efficiency (net)	36.25%	35.5%
PPA Tariff (2016 Rands)	1.03 R/kWh	1.04 R/kWh
GHG Emissions Intensity	1.23 tons CO_2-eq /MWh	
Assumed Final Commissioning Date	2022	
Project and PPA Lifetime	30 years	

[3] The same emissions intensity of 1.23 tons CO2eq/MWh (ERM, 2017) is used for Khanyisa and Thabametsi, although Aurecon (2012) states an expected GHG emissions intensity of 1.1 tCO2eq/MWh. The ERM report is the most comprehensively investigated figure accounting for GHG emissions of FBC in South Africa which explicitly includes N_2O in a total CO2eq emissions intensity value – N_2O emissions are usually negligible in pulverised fuel coal plants (such as Eskom plants) and have not been explicitly included in the IRP modelling to date. A best-case sensitivity covers the Aurecon value by using a much lower CO_2-eq intensity of 700g/kWh by assuming ultra-super-critical boilers and negligible N_2O emissions – this best-case scenario still increases overall emissions beyond the optimal system.

3.2 Reference baseline scenario description

The reference scenario is the modelled least-cost energy system pathway without carbon constraints or caps on centralised renewable energy construction. The power sector is modelled in SATIM and provides a future electricity system build plan determining the optimal timing and quantities of new power sector investments, taking into account the existing power system and its integration with the larger South African energy system. An outline of key assumptions can be found in the following sections.

3.2.1 Electricity demand projections

Electricity demand forecasts in South Africa for the past 8-10 years have been consistently over-estimated (StatsSA, 2018; DoE 2016; DoE 2011). A combination of factors have impacted electricity demand growth, including: low economic growth rates, structural changes in economic structure, and changes in energy use patterns driven by higher electricity costs and energy efficiency improvements. Distributed and smart energy technologies such as solar photovoltaic (PV), battery storage, and "smart-grids" have not played a highly significant role in reducing total centralised electricity demand yet in the overall South African system, but their wider uptake is expected to have an increasing impact on centralised grid demand.

Energy demand profiles are included per end-use, per sector, to determine the temporal daily and seasonal electricity demand profiles and are not based on a fixed scaling of the current electricity demand profile. This includes choice of energy carriers and assumed energy efficiency of demand technologies

The UCT-ESEP demand projection can be seen below, compared to the IRP 2010, IRP 2016, CSIR, and EIUG forecasts. The demand forecast for this study includes the full South African energy system. For the electricity sector, this projection falls between the IRP 2016 (CSIR High-Low Intensity) and the Energy Intensive Users Group 'EIUG' demand forecast – which is similar to the CSIR "low demand" forecast developed for the IRP 2016 (DoE, 2016, CSIR, 2017, EIUG, 2017). Importantly, the SATIM demand projection includes the electrification of transportation which makes up most of the difference from the EIUG projection. Also, of interest is the flattened demand since 2010 and the subsequent large differences from the existing demand forecast of the IRP 2010 from which the determination for the procurement of the CIPPs was made.

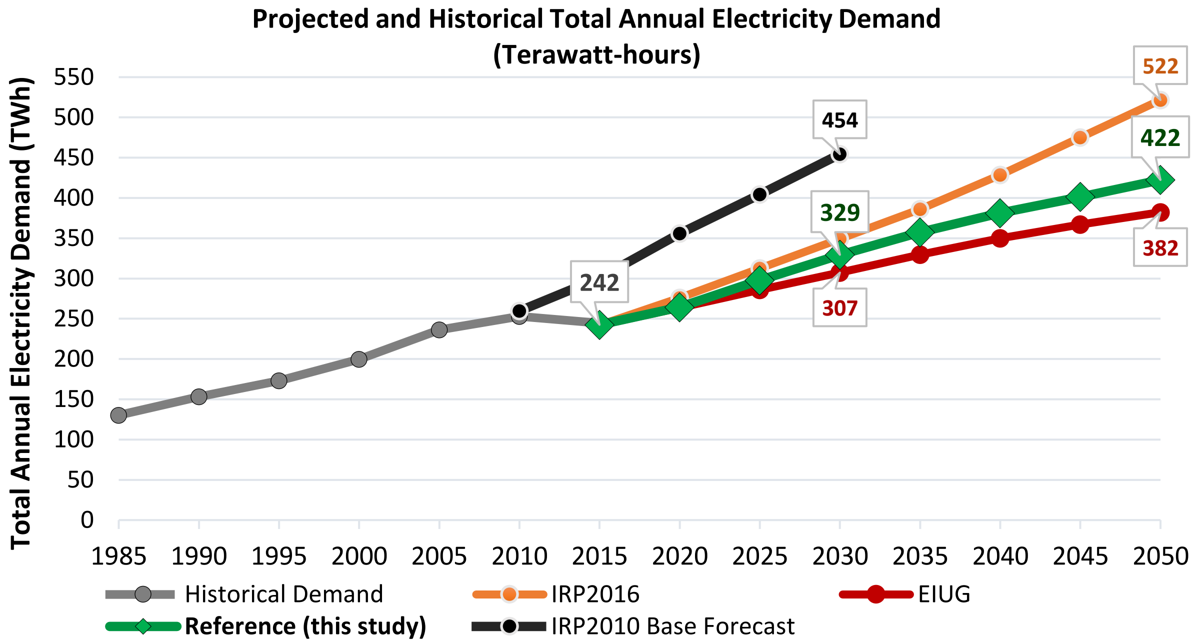


Figure 2: Comparison of historical (StatsSA, 2018) and forecasted annual electricity demands between SATIM, CSIR, EIUG, and the IRP 2010 and draft IRP 2016 update.

3.2.1 New Electricity Generation Technologies

All new-build conventional technology costs and performance parameters are aligned with the draft IRP 2016 update (based on the independent EPRI report commissioned for the IRP), other than the parameters on nuclear, which were provided by the Department of Energy (DoE, 2016). Conventional generating technology investment options available for the model to use include: new coal, nuclear, gas turbines and engines, and regional hydro. The cost and performance parameters of conventional technologies all remain fixed throughout the model optimisation horizon to 2050.

Starting technology costs for utility-scale solar PV and onshore wind are aligned with the draft IRP 2016 update and are calculated to align with the recent Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) tariffs, i.e. Bid Window 4.5 (expedited). Between Bid Window 3 and Bid Window 4 (expedited), solar PV and wind prices decreased by 47% and 29% respectively, with both reaching an average of R0.62/kWh (2015 Rand). The evolution of the REIPPPP price and capacity auctions is included below for reference (Figure 3). Only projects with signed PPAs as of May 2018 are included as committed in the baseline.

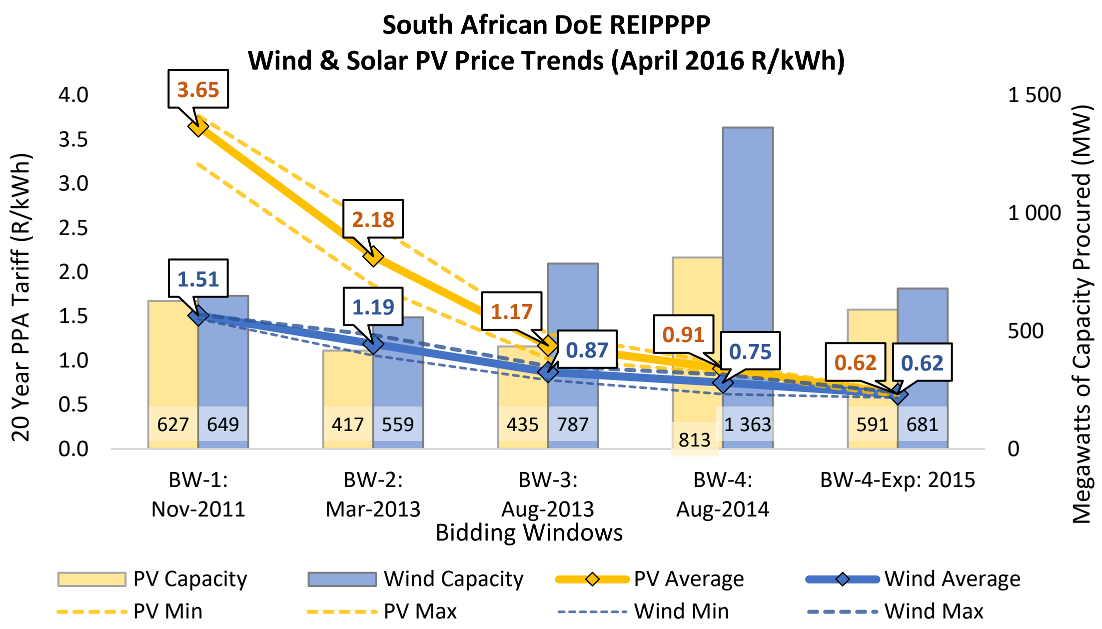


Figure 3: Historical solar PV and onshore wind Renewable Energy Independent Power Producer Procurement Program PPA prices and procured capacity for each round.[4]

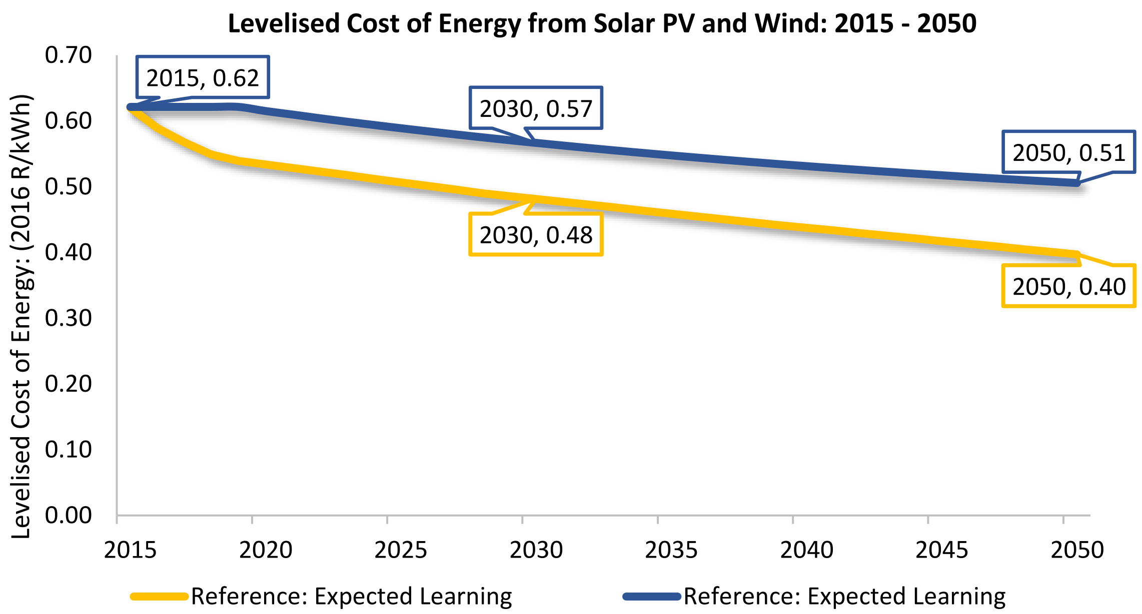


Figure 4: Starting and projected levelised costs of electricity from centralised single-axis tracking solar PV and onshore wind from 2015 to 2050 (April 2016 R/kWh).[4]

Solar PV and wind technology cost projections for the reference scenario ("expected") learning can be seen in Figure 4[4]. We also include optimistic and pessimistic sensitivities on the technology learning in Section 3.3. No total future resource constraints are imposed for PV or wind, and new capacity can be constructed from 2021 onwards. Annual installation limits for PV and wind increase according to the observed market expansion rates of the REI4P and are set in 2020 to start 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 (590MW for PV and 618MW for wind), until 2030 where the limits are no longer imposed. Wind and PV temporal energy production profiles and removal of total resource constraints are based on Fraunhofer (2015) and CSIR (2017).

Solar PV reference scenario technology assumptions:

- Annual capacity factors are assumed to be 28% using single-axis tracking solar PV technology, and 25% for fixed-tilt centralised plants of 75MW+. This is based on existing South African plant performance history, using averaged hourly production data from 2015-2017 (DoE REDIS, 2018). Capacity factors remain fixed to 2050.
- Costs in 2015[4] (reference): Investment costs of 12,500 R/kW and fixed O&M costs 200 R/kW/year

[4] Figure costs are quoted in April 2016 Rand, while SATIM base year costs are in January 2015 Rands using a 0.9416 ratio (SatsSA CPI).

- Costs in 2050 (reference): Investment costs of 7,247 R/kW and fixed O&M costs 154 R/kW/year
- Plant life is 25 years, and construction time is 1 year.

Onshore wind reference scenario technology assumptions:

- Annual capacity factors for new onshore wind farms are assumed to start at 36.4% for plants of size 100MW+ (DoE REDIS, 2018). Capacity factors increase from 36.4% in 2018 to 43% in 2050 in the reference learning projection.
- Costs in 2015[4] (reference): Investment costs of 12,500 R/kW and fixed O&M costs 500 R/kW/year
- Costs in 2050 (reference): Investment costs of 11,860 R/kW and fixed O&M costs 500 R/kW/year
- Plant life is 20 years, and construction time is 2 years.

The modelling in this study includes the assumption that wind and solar generators are never able to contribute reliably to the peak demand reserve margin requirement and must be fully backed up by dispatchable firm synchronous generators regardless of if their profiles do contribute during these times (i.e. 0% capacity credit). Battery storage or other flexibility options are currently not included as economic, but both have a growing future potential to contribute to peak demand reductions and system services if deployed in future.

3.2.2 Existing South African Electricity System

Existing power plant performance parameters are included in SATIM as per the modelling undertaken for the DEA's Policies and Measures analysis (ERC, 2018) and the draft IRP 2016 update where data is given (DoE, 2016). These quantify the individual plant capacities, efficiencies, fixed and variable operations and maintenance costs, water use, and GHG and pollutant emissions. The retirement dates of existing plants are aligned to the draft IRP 2016 update (50-year life of plant for all Eskom coal plants). Medupi and Kusile are modelled to come online incrementally, according to the October 2017 Eskom Medium Term System Adequacy Outlook; with 3 units online already and the remainder coming online by end 2022 (Eskom, 2017). The investment and O&M costs related to Eskom's compliance with air quality legislation and station-specific licenses is not included in the modelling. The existing South African power system (excluding variable renewables) and planned retirement schedule is depicted in Figure 5.

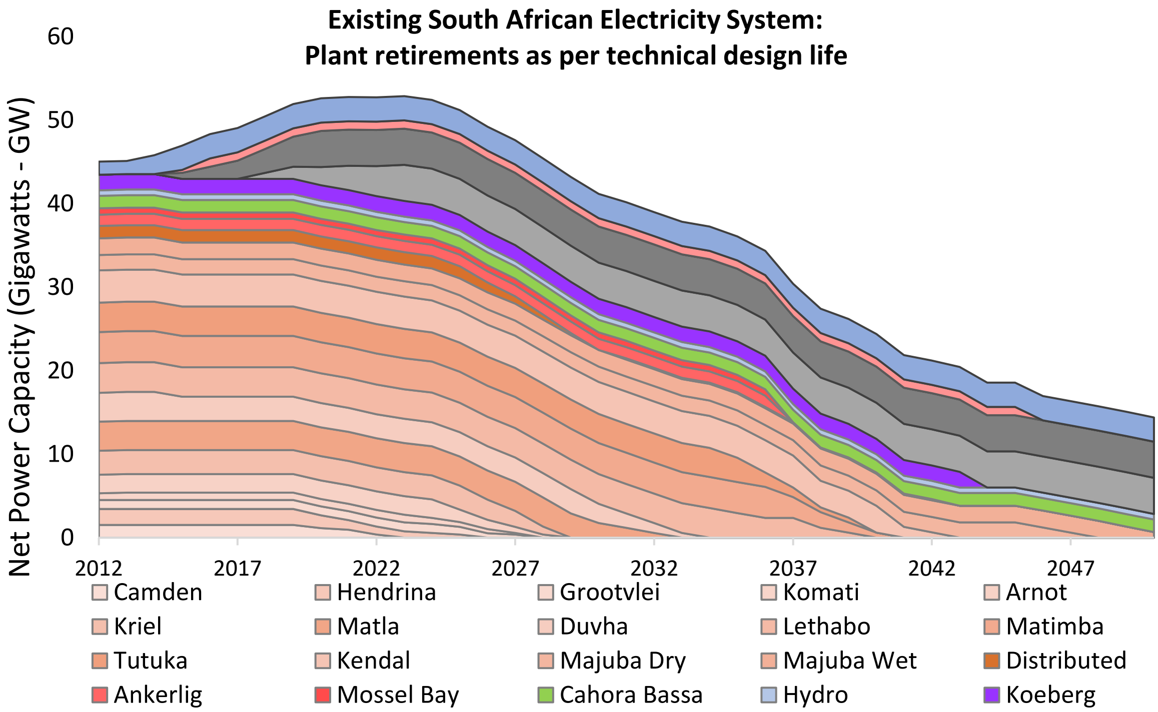


Figure 5: Existing South African power generation capacity with decommissioning schedules as per 50-year life and draft IRP 2016 update retirement dates.

3.3 Combined scenarios: best and worst cases for coal IPPs

The "best-case for CIPPss" and "worst-case for coal IPPs" are scenarios that combine sensitivities on key modelling assumptions, specifically the costs of competing technologies or the GHG emissions intensity of the CIPPs. This allows us to test and analyse various uncertainties that may materialise regarding future generation costs and the mitigation of GHGs by the stations (which could lower the overall GHG impact of the CIPPs). We have constructed the scenarios to be weighted towards a future world that, in one scenario, is the "best" case for CIPPs (for example, expensive renewable energy and gas, and low GHG-intensity from the CIPPs), and in the other, is the "worst" for the CIPPs (for example, cheaper renewables and gas and high GHG-intensity). In this way, a broader range of uncertainty can be explored, along with a broader sense of the magnitude of the potential risks and opportunities of committing to the CIPPs.

3.3.1 Determinants of best and worst cases

3.3.1.1 Renewable energy and natural generation costs

A key power system planning uncertainty is around the future costs of renewable energy technologies. While the overall trend for renewable energy technologies is towards substantially lower costs, the difference in total system costs with and without the CIPPs could be substantially larger depending on the relative costs of alternative supply options. This represents the cost of a 'missed-opportunity' through the lock-in to the purchase of power from the CIPPs at a higher cost than other new-build alternatives. We test our cost assumptions through imposing pessimistic and optimistic learning rates for new solar PV and wind as in Figure 6.

Solar PV learning assumptions:

- Learning starts from 2015 for the reference and optimistic scenarios, and 2021 for the pessimistic scenario.
- 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).
- Capital cost reductions are applied for all scenarios, and operations and maintenance (O&M) improvements are also applied for the optimistic case. Plant capacity factors remain the same for all projections.

Onshore wind learning assumptions:

- Learning starts from 2021 for the reference scenario, and 2015 for the optimistic scenario.
- No technology learning or cost reductions are applied in the pessimistic case.
- Learning is applied to capital costs and annual capacity factors of new plants for the reference and optimistic scenarios (existing plants do not improve), reductions in O&M costs are also applied for the optimistic case.
- 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).

The figures below show the projected levelised cost of solar PV (centralised single-axis tracking) and onshore wind for the optimistic and pessimistic learning, based on the improvements for the respective technology parameters from 2015 to 2050.

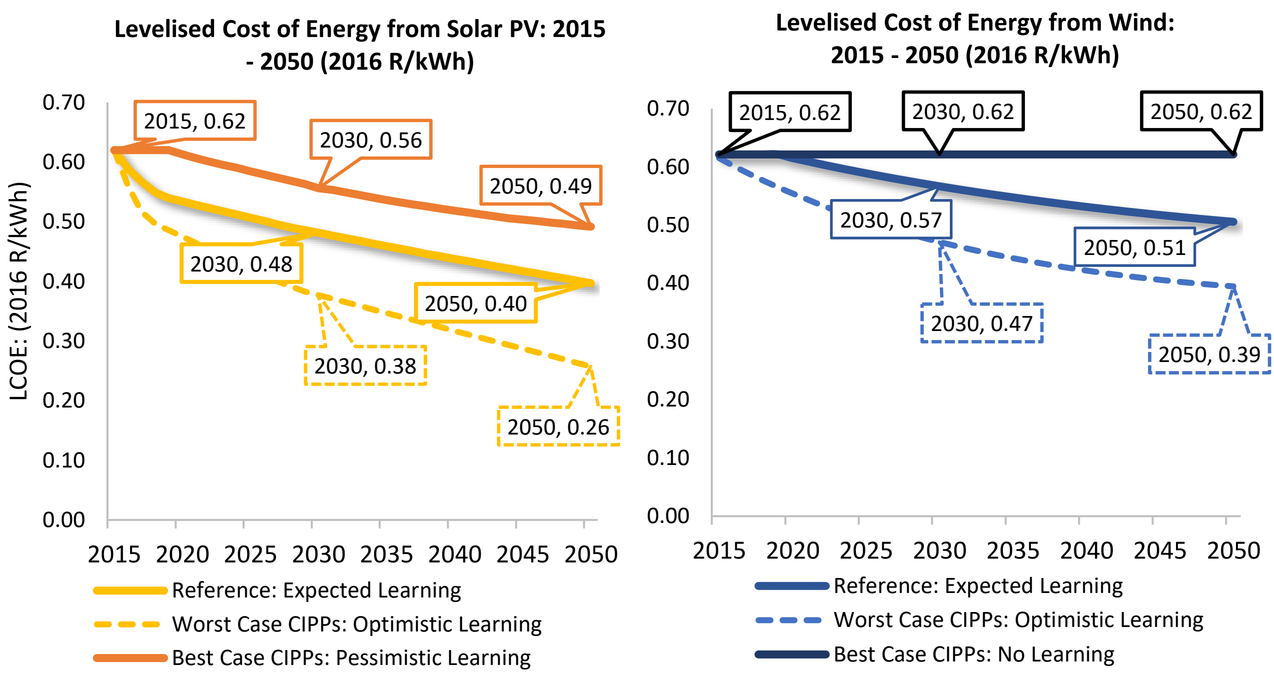


Figure 6: Centralised Solar PV (single-axis tracking) and onshore wind cost assumptions (April 2016 Rand)

3.3.1.2 Greenhouse gas emissions-intensity of proposed plants

We include this sensitivity because there are options that could potentially lower N_2O emissions for the type of plant planned, depending on fuel inputs, possible blending with biomass, or alternative operating conditions such as changing combustion temperature (Koorneef, 2007; Zhu, 2013; Armesto, 2003; Valentim, 2006). These do not seem to have been fully explored or quantified in the measures suggested in ERM (2017). Combined measures, if achievable in these particular plants, could result in reductions in GHGs of up to 25% below many other Eskom plants.

However, even without the high N_2O emissions, the inclusion of the CIPPs in the build plan results in overall higher emissions over the full period of operation (because the least-cost optimised alternatives – gas plus renewable energy - all have lower GHG emissions). By modelling a reduction in GHG-intensity, this conservatively highlights the additional emissions caused by the plants even under 'best case' outcomes for GHG mitigation by the CIPPs.

Although carbon capture and storage could be an option for mitigating emissions further (by approximately 90%), the technology remains unproven in South Africa, and results in substantially higher costs and efficiency losses - currently around US$100/tonne of CO_2 (UNEP, 2017). The South African coal roadmap has also highlighted the challenges of CCS in South Africa (SACRM, 2011).

3.3.2 "Best-case scenario" for CIPPs:

- Pessimistic renewable energy costs: no learning for wind (62c/kWh), solar PV learning from 2020 reaches 56c/kWh by 2030, and 49c/kWh by 2050 (all in 2016 Rand).
- Global liquefied natural gas (LNG) price is 25% higher than the reference scenario at US$15/MBTU (R182/GJ in January 2015 Rand[5])
- Low GHG-intensity (assumed low cost abatement of N_2O) and ultra-super-critical coal, as per the proposed KiPower plant (2018)[6]. Greenhouse gas intensity of 0,7 t/MWh CO_2-eq (vs reference case of 1,23t/MWh).

3.3.3 "Worst-case scenario" for CIPPs:

- Optimistic renewable energy costs: wind learning from 2015, 47c/kWh by 2030, and 39c/kWh by 2050. Solar PV learning from 2015, 38c/kWh by 2030, and 26c/kWh by 2050 (2016 Rand).
- Global LNG price is 25% lower than reference at US$10/MBTU (R122/GJ in January 2015 Rand)
- GHG-intensity remains unchanged from the reference scenario, as reported in Thabametsi's climate change impact assessment (ERM, 2017). Given the high GHG-intensity of the CIPPs, as discussed in section Figure 1 and section 3.1.1, we assume that the GHG-intensity of the proposed plants is already 'worst case' without mitigation (approximately 24% higher than the current Eskom fleet average, and 58% higher than Medupi).

3.4 Climate change mitigation policy (CCP) scenario description

With current technology and cost assumptions, the reference scenario described above for the South African energy system is not consistent with meeting the lower range of South Africa's peak, plateau, and decline (PPD) trajectory, as committed to in the National Climate Change Response White Paper (DEA, 2011). The PPD aims to peak emissions in 2025 between 398-614 Mt CO_2-eq, plateau emission for a decade, and then decline to a 2050 range between 212 and 428 Mt CO_2-eq.

While South Africa's nationally determined contribution (NDC) to the Paris Agreement is based on the PPD trajectory range, it currently only includes a quantified emission range of 398-614 Mt CO_2-eq for the years 2025 and 2030. Based on the negotiations, South Africa will likely update its NDC in 2025, for the post-2030 period.

At the same time, globally, NDCs do not yet meet the target of the Paris Agreement to limit warming to 'well below' 2°C. The Paris Agreement 'ratchet mechanism' is designed to encourage increasing ambition from countries over time. In the long-run, keeping temperature well below 2°C and aiming for 1.5°C will require all countries to increase their ambition. If all countries collectively agree to do so, South Africa should reduce emissions further than envisaged in the current NDC for the period after 2030 (or even for the period 2025-2030), or at least commit to meeting the lower range of the PPD.

Currently, Climate Action Tracker (CAT) deems South Africa's NDC to be an insufficient contribution to meeting 2°C; in particular, the upper range of the trajectory outlined in the PPD and included in the NDC (CAT, 2018). South Africa can meet the upper range of the PPD to 2050 if it implements a least-cost energy system to 2050; that is, one that excludes new coal-fired power plants, achieves high levels of energy efficiency and continues to invest in renewables. However only achieving the upper PPD range would not be an adequate contribution to limiting warming to below 2°C (PRIMAP, 2018). According to both CAT and PRIMAP, the low-PPD range may be considered an adequate contribution to 2°C, but this depends on assumptions about the global carbon budget and the equity approach applied in a given analysis. CAT (2018) considers the low-PPD emission in 2050 as consistent with meeting 2°C, but is not clear on the long-term trajectory implied by this. Given this uncertainty, we model South Africa's low-PPD to 2050 since this already South Africa's own policy commitment, even if in the future meeting 2°C requires reducing emission below the low-PPD trajectory.

More generally, there is considerable literature on energy pathways consistent with 2°C and the future of coal within that. UNEP (2017) summarises these studies, which show that unabated coal (without CCS) will have to be phased out globally by mid-century.

We thus include a scenario that assesses the impact of building the CIPPs in a case where South Africa also meets the low-PPD emissions constraint to 2050 at the lowest system cost. The key assumptions remain the same as in the reference scenario, but also include a CO_2-eq constraint consistent with low-PPD (9.5 Gt CO_2-eq over the period 2020-2050) (ERC, 2018).

The rationale for analysing the implications of such a scenario is as follows. Meeting the PPD range requires reducing emission in the electricity sector. Meeting low-PPD requires even more rapid decarbonisation of the electricity sector, as well as increased mitigation in other sectors. When the CIPPs are forced into the electricity build plan, this results in decreased use of existing coal plants (which are also cheaper than the CIPPs), which raises costs overall and puts Eskom at risk. As more of the emissions 'budget' is used in the

[5] Using the draft IRP 2016 update 11.55 R/USD exchange rate from January 2015. The cost of LNG in the IRP 2016 is 115.5 R/GJ (January 2015 Rand)

[6] Though this is not proposed for the CIPPs under the current tariff structure

electricity sector, this requires either increased mitigation in the power sector through stranding existing coal assets in the later years of the modelling horizon, or increased mitigation in non-electricity sectors (where mitigation is typically costlier than in the power sector). Understanding this trade-off between the CIPPs and other coal plants and sectors allows an assessment of the costs of increasing the mitigation burden to other sectors. Essentially, we analyse the effects of "committing" carbon space to the CIPPs.

3.5 Key assumptions summary for each scenario

Table 2 below shows a summary table of the assumptions used for each parameter. Their details are described further in the sections below.

Table 2: Summary of key parameters per scenario and sensitivity

	Reference Scenario: Base	Reference Scenario: Best case for CIPPs	Reference Scenario: Worst case for CIPPs	Climate change mitigation Scenario
GDP Growth	3,2% average annual	3,2% average annual	3,2% average annual	3,2% average annual
Wind and Solar PV costs	Expected Reductions	Pessimistic (PV) No Reduction (Wind)	More Optimistic Reductions	Expected Reductions
Import LNG price[7]	12.5 $/MBTU (R152 /GJ)	15.0 $/MBTU (R183/GJ)	10.0 $/MBTU (R122/GJ)	12.5 $/MBTU (R152/GJ)
CIPPs GHG intensity	1,23 t CO_2-eq/MWh	0,7 t CO_2-eq/MWh	1,23 t CO_2-eq/MWh	1,23 t CO_2-eq/MWh
GHG emissions constraint	No constraint	No constraint	No constraint	9.5 Gt CO_2-eq total energy emissions budget between 2020 - 2050
Discount rate[7]	8.2%	8.2%	8.2%	8.2%

[7] January 2015 Rand and USD. Using 11.55 R/USD exchange rate, and discount rate as in (DoE, 2016)

4. Results

4.1 Reference scenario: baseline energy system optimisation results

The reference scenario is the modelled least-cost energy system pathway without carbon constraints or caps on centralised renewable energy construction. The power sector is modelled in SATIM and provides a future electricity system build plan determining the optimal timing and quantities of new power sector investments, considering the existing power system with its operational and system adequacy requirements, and integration with the larger South African energy system.

The figures below show the reference case least-cost optimised build plan to 2050 for the electricity sector, depicting the total installed system capacity of each technology in the system, including existing and new-build power plants each year. A least-cost optimised future build plans include no new coal or nuclear power plants as they are uneconomic against alternatives using the technology assumptions described above. Concentrating Solar Power (CSP) and modern storage technologies (lithium-ion or flow batteries, hydrogen, power-to-X etc.) are also not currently considered least-cost options using present day cost assumptions. However, if potential cost declines and technology performance improvements are realised these technologies could play an important role in the future South African energy system with the potential to complement or compete with current options.

South African electricity demand has flattened over the last decade, while large units at Medupi and Kusile are still being added to the grid, resulting in surplus capacity expected for the medium-term outlook. Thereafter, as demand grows, and existing coal plants are decommissioned, the least-cost mix of new centralised generation is a combination of wind, solar PV, and gas.

Figure 8 presents a comparison of the SATIM baseline results against other recent comparable future South African optimal electricity system projections available in the public domain. Left of the figure shows projected electricity demand forecast comparisons, with the SATIM forecast similar to the Energy Intensive Users Group (EIUG, 2017). Right of the figure compares the total expected average annual electricity generation shares from non-hydro renewable energy (solar and wind). In a least-cost investment pathway all of these models project a steep increase in wind and solar PV electricity penetration, which is complemented by new flexible LNG generation and the existing coal, hydro, and peaking resources remaining in the system.

In the reference scenario, installed capacity reaches 168 GW in 2050, comprising 32% wind, 27% solar, and 31.5% gas (Figure 8). Renewable energy makes up 28.5% of electricity generation by 2030 and 74% by 2050, with gas contributing 11%, and coal 15% in 2050. Medupi and Kusile are the only coal plants still running in 2050 (Figure 9).

Greenhouse gas emissions from the energy and industrial sectors can be seen in Figure 11. GHG emissions peak around 2025 and decline to just over 256Mt CO_2-eq by 2050. A substantial part of these savings come from the electricity sector, where mitigation is achieved at low cost, even as emissions from industry increase substantially. However, as mentioned previously, this emissions trajectory is not consistent with meeting 2°C (CAT, 2018; PRIMAP, 2018). Further mitigation is required to move South Africa towards the low-PPD trajectory. This is explored in more detail in the Climate Change Policy (CCP) scenario.

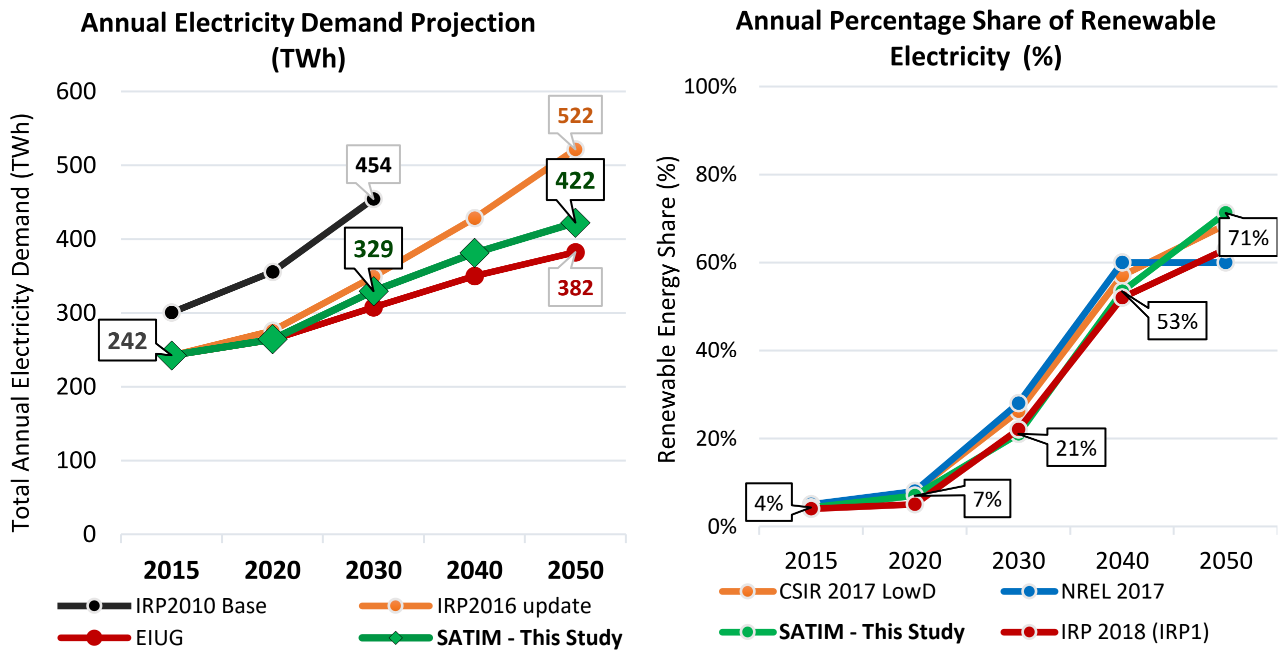


Figure 7: Comparison annual electricity demand projections and expected non-hydro renewable energy percentage share contributions per year. SATIM values are compared to (DoE, 2011, 2016, 2018; NREL, 2017; CSIR, 2017; EIUG 2017).

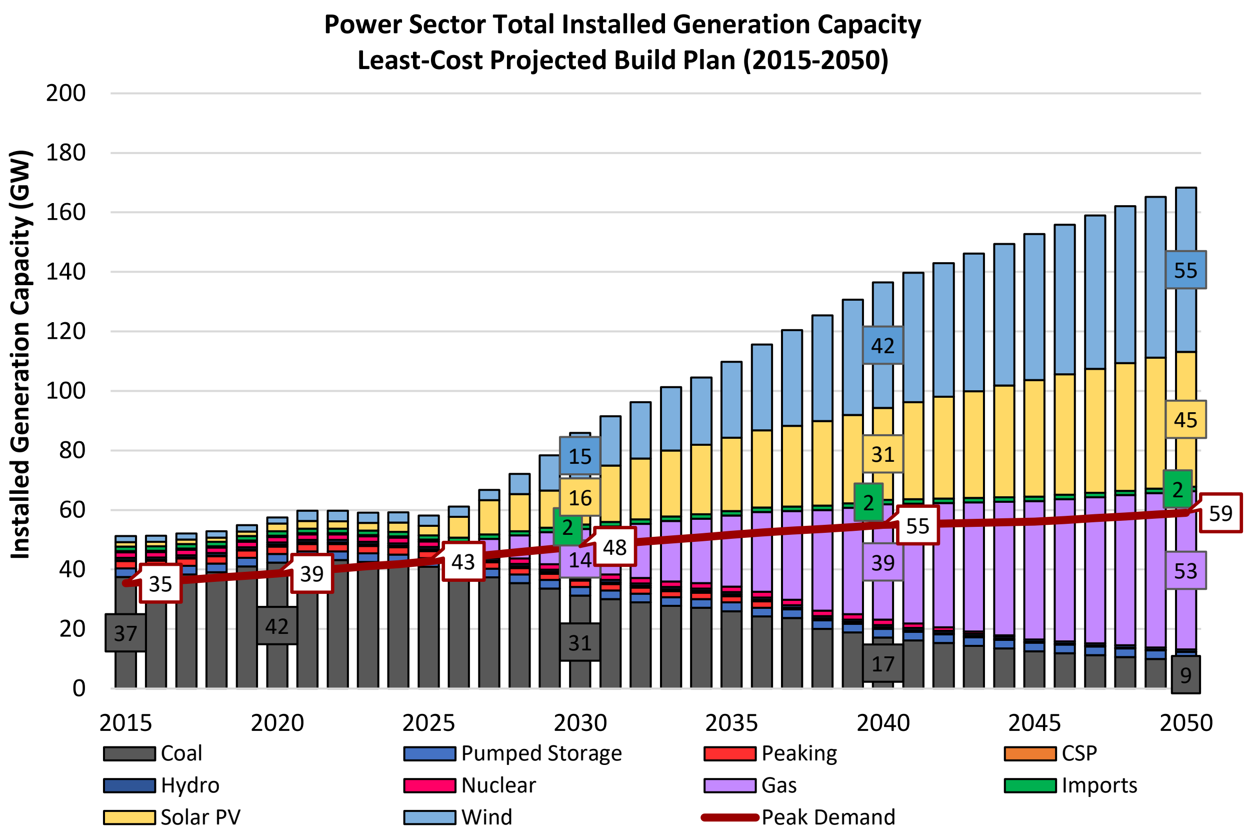


Figure 8: Reference Scenario: installed generation capacity shown and projected peak electricity demand (2015 – 2050)

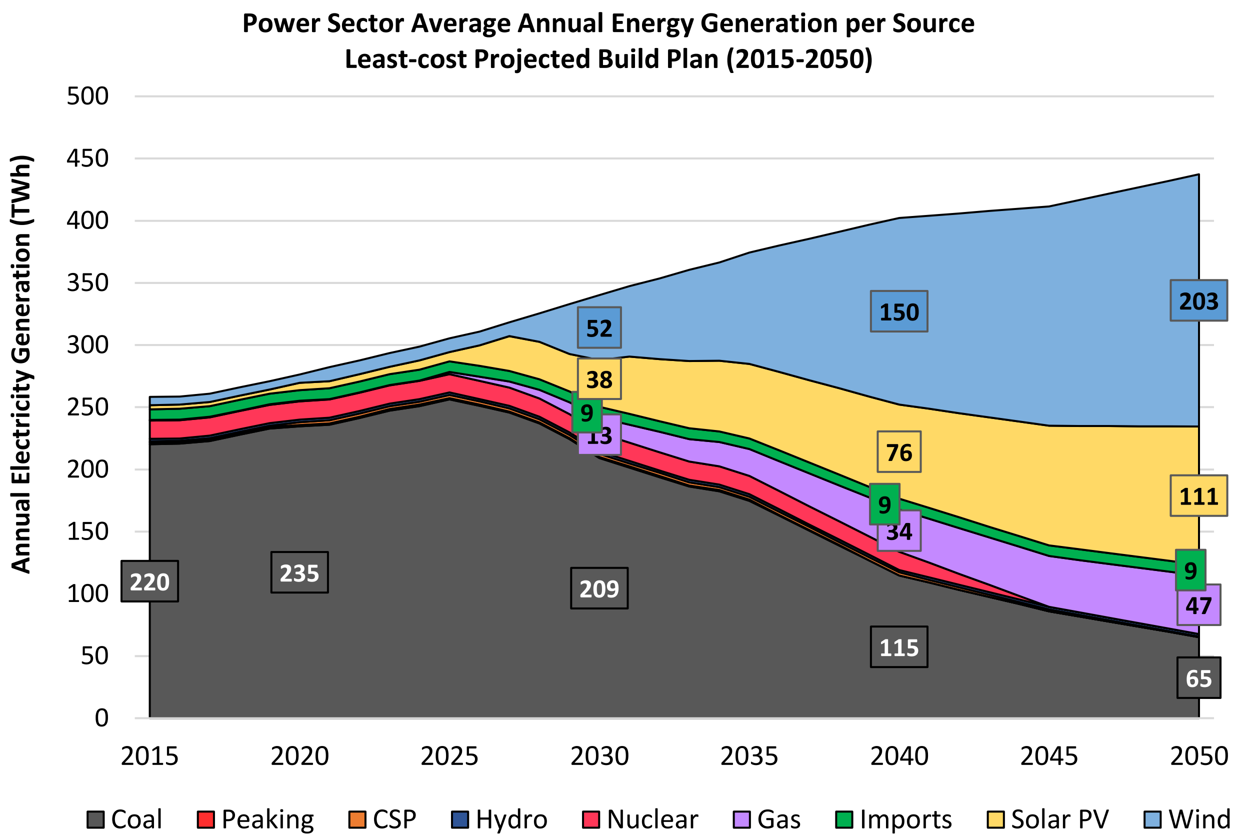


Figure 9: Reference Scenario: annual electricity generation by source (2015-2050)

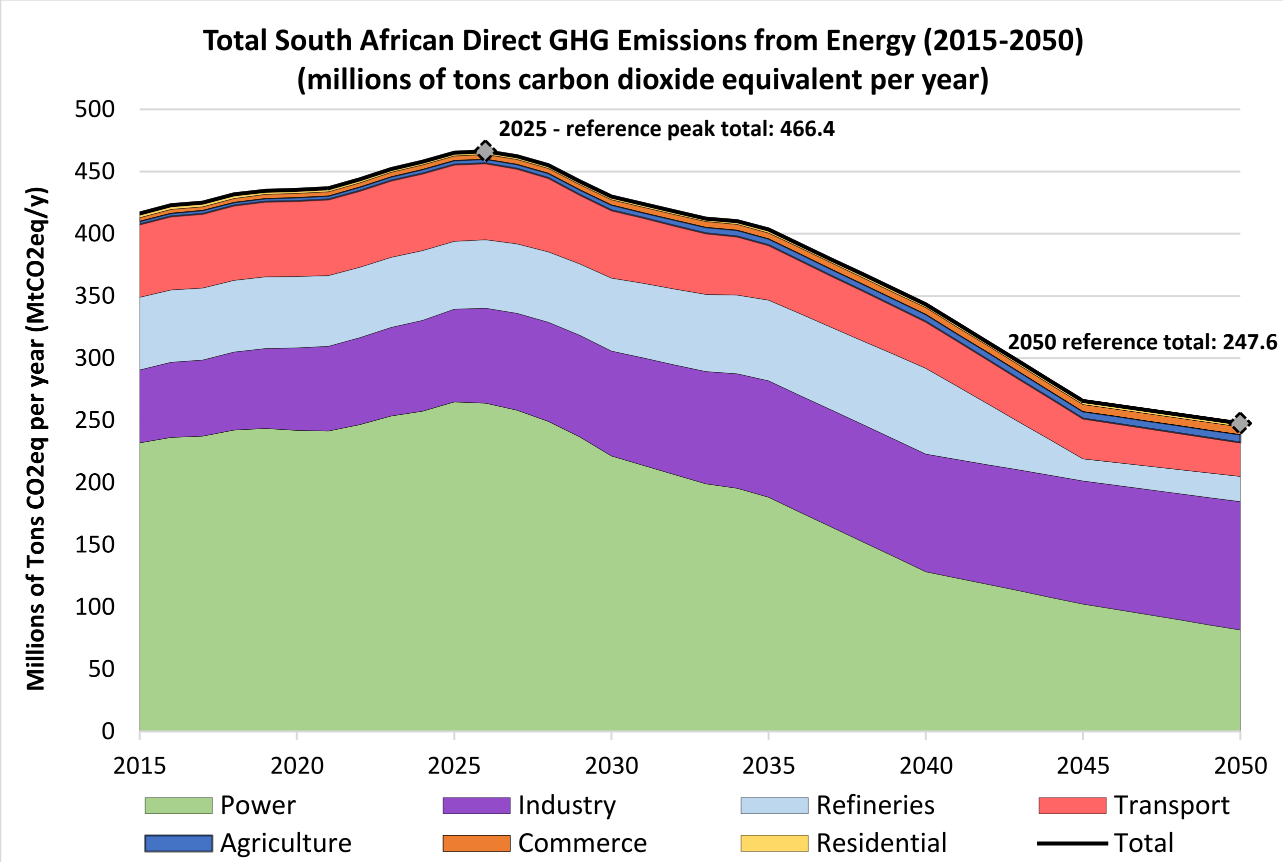


Figure 10: Reference Scenario greenhouse gas emissions by sector 2015 to 2050[8]

4.2 Climate Change mitigation Policy (CCP) scenario: baseline optimisation results

As discussed in section 3.4, the upper range of South Africa's NDC and PPD trajectory is not considered consistent with limiting warming to below 2°C above industrial levels. While the lower-PPD to 2050 may be considered compatible with 2°C (depending on which equity considerations are applied), South Africa is not currently on track to meet this lower GHG emissions trajectory. Given that all countries are required to raise their ambition over time under the Paris Agreement, we have assessed the implications of meeting the low-PPD trajectory to 2050 considering the planned increases in coal-fired generation capacity. We have modelled a 9.5 Gt CO_2-eq constraint (i.e. a budget) over the period 2020-2050.

Figure 18 shows the electricity build plan consistent with the 9.5 Gt budget. The higher peak demand than in the reference case is due to increased electrification and fuel switching towards electricity in various sectors. By 2050, the installed capacity is 180 GW, with renewable energy comprising 59.3%, gas 31.4%, and coal 6.1% (Figure 18).

In energy terms, by 2050, renewable energy provides 79% of electricity, gas 11.8%, and coal 6.7% (Figure 19). Medupi is still running in 2050, though Kusile is stranded and no longer runs, highlighting the risks of stranded assets facing the existing fleet, even without the inclusions of the CIPPs. Figure 20 shows the energy emissions trajectory consistent with the low-PPD emissions budget. As can be seen, substantial savings come from the electricity sector, which has relatively cheaper mitigation options compared to other sectors (such as industry). It is important to note that, to meet the low-PPD budget with current technology options already requires that the existing coal plants are run at lower load factors to 2050, i.e. there is stranded capacity in the sector.

[8] Shown are only direct energy emissions for each sector (eg. commerce or industry's indirect electricity sector emissions are accounted for in power sector emissions). Non-energy emissions from agriculture, forestry, land-use change, or waste are not included in this total

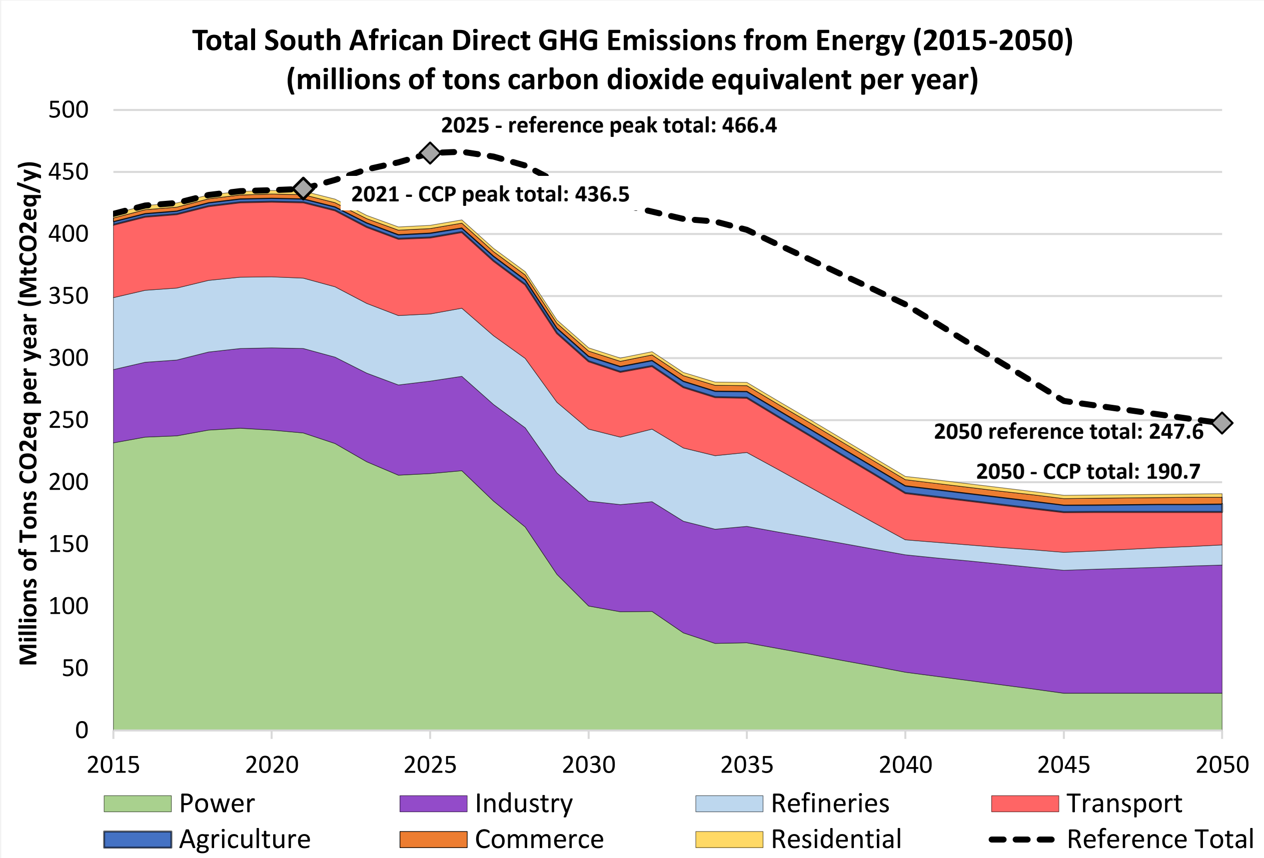


Figure 11: GHG Emissions Budget Scenario Least-cost Baseline System – Total projected energy system CO2 equivalent

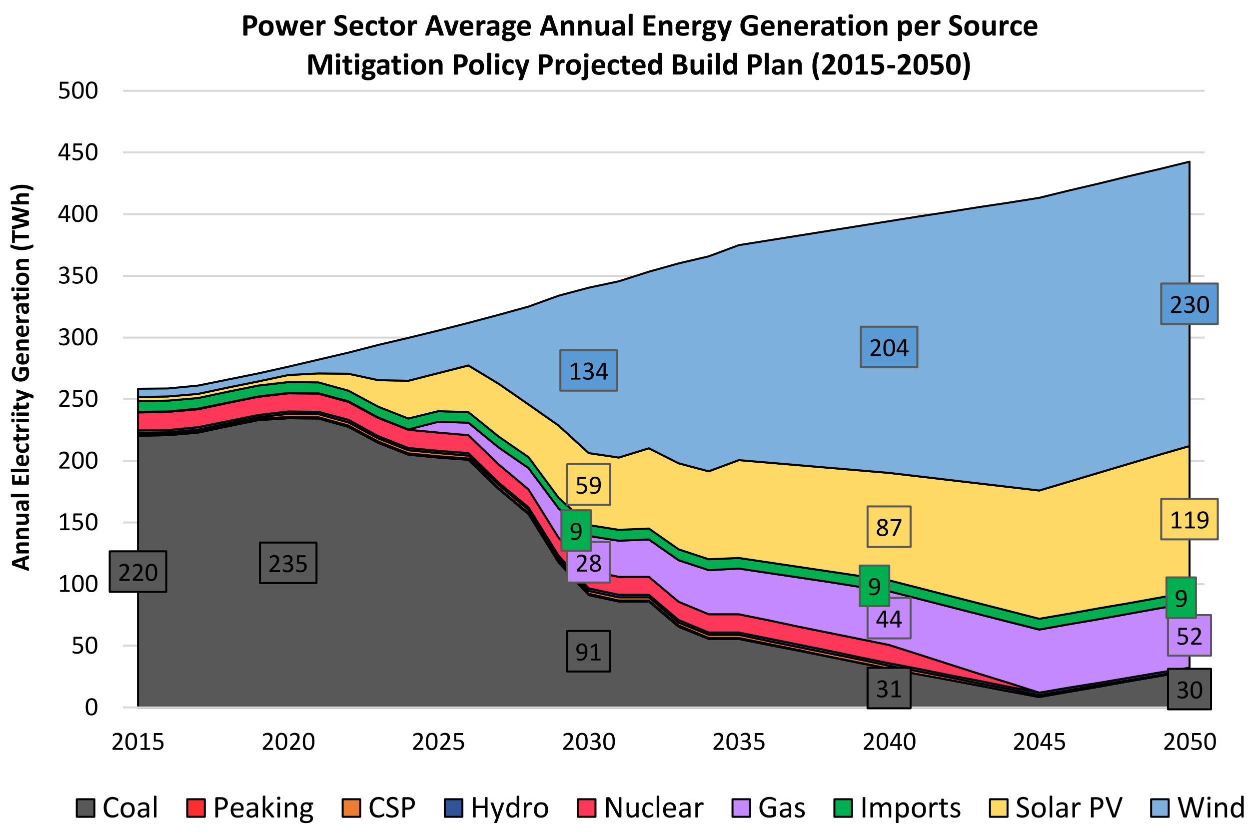


Figure 12: GHG Emissions Budget Scenario Baseline: Average annual energy provided per source in the least-cost baseline system (2015-2050)

4.3 Reference scenario with CIPPs committed

This section outlines the difference between the least-cost reference scenario and the reference scenario with the CIPPs committed (Reference plus CIPPs).

The optimised least-cost build plan includes no new coal-fired power plants in the investment horizon to 2050. Therefore, testing the system implications of signing the 30-year PPAs of the CIPPs requires the plants to be "forced-in" to the build plan, after which the deviation from the baseline cost optimal system can be directly quantified and analysed.

Committing to building the CIPPs changes the power plant investment schedule and energy generation profile compared to the reference scenario described in section 4.1.

Figure 12 shows the deviation in electricity generation from the reference scenario electricity system. From 2022 to 2025, the least-cost system would have used the cheaper existing Eskom coal-fired power plants to meet the demand for electricity. Thereafter the optimised system would have provided this energy with a combination of wind, solar PV, and gas (Figure 12). Most of the energy in the optimised power system comes from wind, with a lesser contribution from solar PV, and existing coal. Gas provides a smaller contribution to energy, but is an important contributor to firm capacity, providing full flexible back-up to the variable renewable energy technologies.

The energy from the CIPPs that replaces existing coal totals around 20 TWhs from 2022-2027. For comparison, a unit at Medupi or Kusile produces around 5 TWhs per year. It thus replaces comparable supply capacity in the system (part of the existing fleet), but at a higher cost (discussed below).

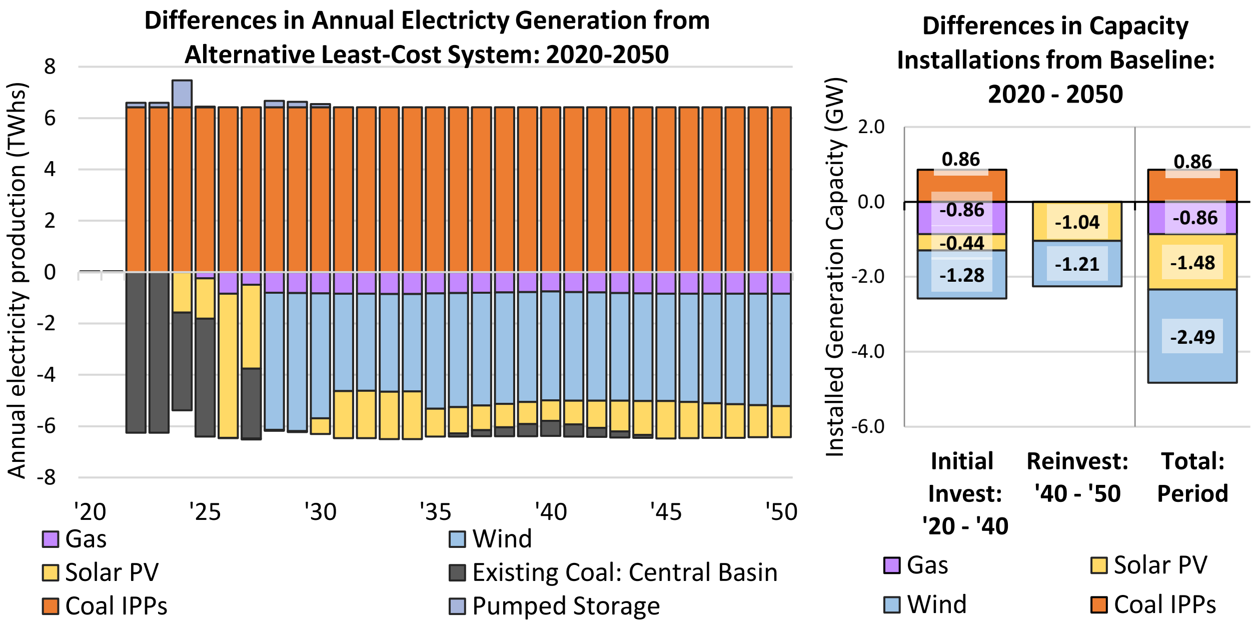


Figure 13: Reference Scenario: Difference in annual energy generation profile between the reference scenario baseline and the reference scenario plus CIPPs committed (left) and the differences in constructed generation capacity mix per period (right)

The total differences of installed capacity are shown in Figure 14 for the combined coal IPP programme (including both Thabametsi and Khanyisa and totalling 863 MW).[9] Deviations shown as positive values in each year are the amount of additional capacity built or energy generated in that period. As can be seen in Figure 13, the technology mix in the reference scenario to provide the equivalent level of firm capacity and energy is a combination of 863 MW of gas, 440 MW of solar PV, and 1280 MW of wind.

Since wind technologies are modelled to have a 20-year life, and solar PV 25 years, the system reinvests in new capacity for these technologies at the end of their lives between 2040 and 2050. The plants are replaced with newer and cheaper capacity later in the period after projected cost reductions are achieved, allowing further reductions in system costs later in the modelling period (Figure 14). The CIPPs therefore not only replace investments in gas, solar, and wind in the 2020s, but because of their long-lived PPAs, also replace new, much cheaper, generation capacity in the 2040s.

[9] The same deviations for each set of results are modelled and measured for each of the individual and combined CIPPs, but for simplicity only the combination of both plants is shown below. This is necessary to determine the specific individual impacts of each plant on the future South African energy system. In a complex and interconnected system, the impacts of different investment decisions are often non-linear.

4.4 Climate Change mitigation Policy (CCP) scenario with CIPPs committed

A climate change mitigation policy scenario (described in 3.3) is included that assesses the impact of building the CIPPs when South Africa also meets the low-PPD emissions constraint to 2050 at the lowest system cost. The key assumptions remain the same as in the reference scenario, but also include a CO_2-eq constraint consistent with low-PPD (9.5 Gt CO_2-eq over the period 2020-2050) (ERC, 2018).

The CCP scenario requires the existing coal fleet to be run at lower load factors to meet the emission constraints and requires additional investment into renewable energy to replace this energy. When the IPPs are committed into the system, this investment into renewable energy increases dramatically to make more 'space' for the emissions from the CIPPs

Error! Reference source not found. shows the differences in electricity generated between the CCP and CCP plus coal scenario. As can be seen, the CCP scenario primarily uses the existing fleet, plus a combination of wind and solar to meet demand. When the CIPPs are committed to the system, electricity demand is met by the CIPPs and by large investments in solar (in the 2020s) and wind (in the 2040s). If South Africa commits to the CIPPs and then aims to meet its climate change mitigation targets, this will result in increased stranding of Eskom's assets in the short and long-term. Given Eskom's dire financial position, procuring new coal-fired power that forces out the Eskom plants raises risks for the entire economy.

Figure 22 shows this large increase in investment into low carbon generation technology in the CCP plus coal scenario. Additional low carbon energy is needed in the case with the CIPPs committed compared to a 9.5Gt CO_2-eq budget without the CIPPs; the new investment is required to displace energy from existing coal-fired power plants which are no longer run due to the emissions from the CIPPs.

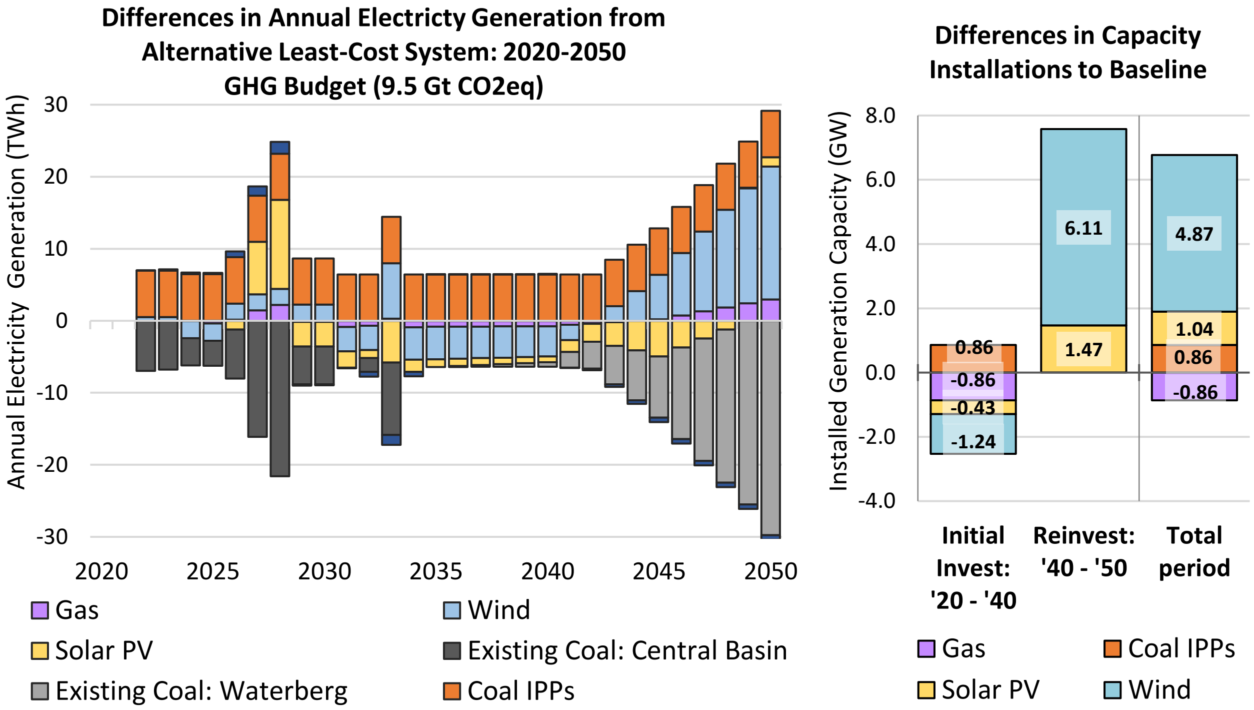


Figure 14: CCP Scenario: Difference in annual energy generation profile between the CCP scenario baseline and the CCP scenario plus CIPPs committed (left) and the differences in constructed generation capacity mix per period (right)

4.5 Power Sector Greenhouse Gas Emissions Impacts

As can be seen in Figure 15, the inclusion of the CIPPs in the build programme results in a net increase in GHG emissions over the modelling period. The additional GHGs for Thabametsi and Khanyisa are 136.1Mt CO_2-eq and 75.9Mt CO_2-eq respectively. If both plants are built, the CIPPs add 205.7Mt additional GHG emissions over the 30-year period between 2022 and 2052.

In comparison, the Department of Environmental Affairs has recently commissioned modelling that analysed the emissions savings of various mitigation policies and measures (ERC, 2018). Those results show that the emissions savings of the post-2015 National Energy Efficiency Strategy to 2050 will be 222 Mt CO2-eq.

The energy generation profile in Figure 12 shows that the energy generated by the CIPPs would replace Eskom's existing coal fleet over the period 2022-2027 (and marginally in the late 2030s). Several commentators have argued that replacing this energy with the newer, more efficient IPPs would be better for GHG emissions. However, while the CIPPs could decrease GHG emissions marginally in the short-term (assuming Eskom runs its most inefficient coal plants to replace the IPPs), in the medium to long-term, the CIPPs replace cheaper lower-carbon generation. The combination of wind, solar PV, gas, and existing coal is substantially lower in emissions over the lifetime of the stations, and the IPPs thus always increase GHG emissions when compared to a least-cost electricity system.

4.5.1 GHG Emissions: Best- and worst-case combined sensitivity

In the best-case scenario, GHG emissions are significantly reduced due to the assumption of much higher efficiency plant (ultra-super critical) and the mitigation of N_2O emissions. Even so, the difference in total GHG emissions between the best-case scenario with and without the CIPPs is 97 Mt Co_2-eq. While there are emissions savings in the early 2020s, due to the lower GHG intensity of the CIPPs compared to the least efficient of Eskom's existing plants, net additional emissions are positive before 2030. For comparison, the carbon tax is expected to reduce CO_2 emissions by around 115 Mt over the period 2020-2050 (ERC, 2018).

In the worst case, even though the GHG-intensity is the same as the reference scenario, cumulative emissions are higher due to higher cost renewable energy and gas being pushed out by 1-2 years. The result is worst case cumulative emissions of 217,9 Mt CO_2-eq by 2050.

4.5.2 GHG Emissions: Climate Change Policy scenario

There are no differences in total emissions in the CCP scenario since we impose a total GHG constraint which must be met with or without the CIPPs. However, the effect on the energy sector of meeting the constraint is important. With the CIPPs committed, there is an additional need to reduce emissions further in the power sector (through running other coal plants at lower load factors). In other sectors, additional emissions reductions come most economically from refineries reducing production of coal-to-liquids.

Ratcheting mechanisms - Further decarbonisation required, in total, and in other sectors. Further GHG reductions economy-wide have higher marginal costs – CIPP commitment takes up carbon space and shifts decarbonisation costs further on this cost curve.

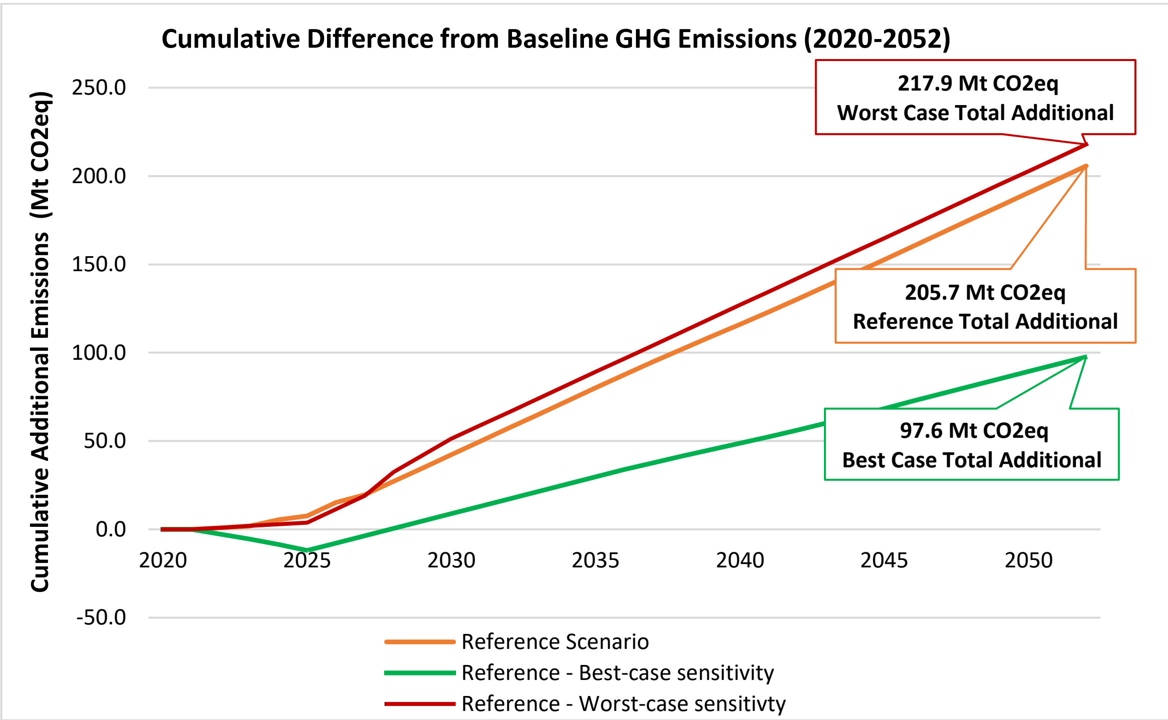


Figure 15: Cumulative additional power sector greenhouse gas emissions compared to baselines for the CIPPs. There is no total difference in GHG emissions in the CCP scenario as the system is forced to mitigate these from other power plants and other sectors.

4.6 Electricity System Cost Impacts

Since the cost-optimal reference scenario does not include new CIPPs, we can expect that their inclusion in the build plan will raise the total system costs for the energy sector. The tariffs that will be paid to the IPPs are currently substantially higher than Eskom's marginal cost of generation and thus the difference in the earlier years between running the existing fleet and building the CIPPs is large. Over time, as new capacity is built, and the cost rises to fund new capacity (compared to plants where capital costs have been paid off), this differential between the cost optimal blend of electricity from renewable energy, gas, and the existing fleet compared to the CIPPs, starts to fall. Nonetheless, over the modelling period, the CIPPs result in additional costs in the electricity sector. Figure 16 shows the deviation in billions of Rand between the reference scenario with and without the CIPPs. The differential peaks between 2022 and 2025 at just less than R3.5bn before falling to between R1.5 and R2bn per year by 2050.

The higher difference in the earlier years is due to the medium-term generation surplus currently facing South Africa if Medupi and Kusile come online as expected. The plan to procure the CIPPs was brought forward by the policy-adjusted IRP 2010, which as noted previously overestimated demand considerably. Thus, the plants are neither necessary to meet demand, nor are they competitive with alternative supply technologies. In a situation where increased new build is required earlier in the period, the differential would be smaller in the earlier years. In the long-term, the CIPPs are consistently more expensive than alternatives.

4.6.1 Electricity costs: Best- and worst-case combined sensitivity

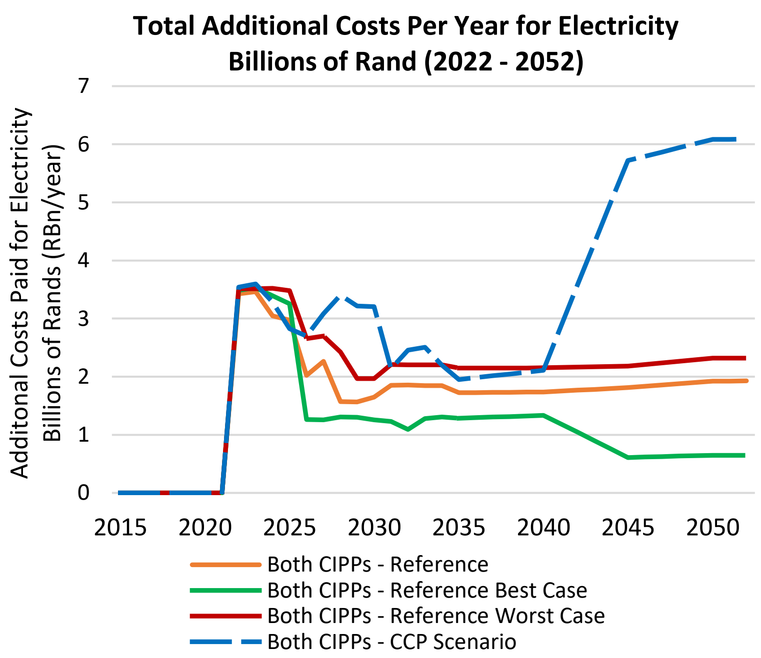
Figure 25 shows the additional system costs incurred in the best-case and worst-case sensitivity analyses. Even in the best-case the inclusion of the CIPPs increases the annual costs in the electricity system by up to R3.5bn initially, reducing to between R1-1.5bn per year over the period 2025-2040, and then to between R0.5 and R1bn to 2050. The best-case scenario includes very high costs for renewables and gas, increasing the system cost overall (and thus reducing the differential to the CIPPs). Even in the best-case world, however, the CIPPs increase the additional system cost by R16.14bn compared to the best-case scenario without the CIPPs.

On the other hand, in the worst case, the CIPPs would add costs of up to R3.5bn annually in the early years and would maintain an increase of over R2bn per year to 2050. In total, the additional discounted system costs could increase by R23.11bn compared to a worst case without the CIPPs.

The total discounted system cost difference between the least cost reference and the committed coal can be seen in Figure 16. The combined CIPPs add an additional system cost of R19,68 billion in present value terms (2018 Rand using a discount rate of 8.2%).

4.6.2 Electricity costs: Climate Change Policy Scenario

Error! Reference source not found. shows the increases in costs for each station individually and combined. Committing to both of the CIPPs results in annual increases in the electricity system costs of R2-R3.5bn per year from 2022 to 2040. The expansion of investment in new renewable energy in the 2040s to replace the existing fleet that cannot be run due to the commitment to the CIPPs and a commitment to meeting the carbon constraint results in very large increase in annual costs in the 2040s. Between 2040 and 2050, the annual difference in system costs when the CIPPs are committed compared to the CCP scenario without the CIPPs ranges from R2bn to R6bn. The total discounted system cost difference between the CCP scenario and the CCP plus coal scenario is R27.9 billion rand in present value terms.



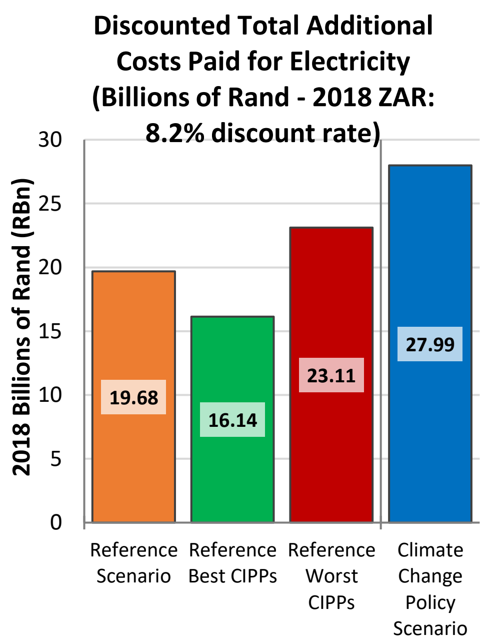


Figure 16: Reference, best-case, worst-case, and CCP scenarios additional annual electricity costs for the CIPPs (left) and totals discounted to 2018 (right)

5. Conclusions

The result of the assessment of new CIPPs has shown that these plants are not necessary to meet demand, and, further, that their inclusion in South Africa's electricity system will substantially raise costs in the electricity sector, and substantially increase GHG emissions over their lifetimes.

In the reference scenario, the additional present value cost of building the CIPPs is R19.68 billion. The stations also increase emissions by 205,7Mt CO_2eq over the period. This amounts to a negative carbon price of R96/t CO_2-eq; that is, this is the price per ton that South Africans will pay for the extra emissions if the CIPPs are built.

The analysis also includes sensitivities on costs and emissions to test whether more pessimistic renewable energy and gas costs could impact the overall findings. We find that even with pessimistic renewable energy cost projections and high gas costs, the CIPPs still increase the system costs in the electricity sector compared to an optimised electricity build plan. Even in the best case for the CIPPs, when competing alternatives are expensive and the IPPs are able to mitigate their emissions significantly, the overall increase in system costs is R16bn, and the increase in emissions is 97Mt. In the worst case for the CIPPs, the increase in system costs is R23bn and emissions increase by 218Mt.

In comparison, the Department of Environmental Affairs has recently modelled the emissions savings of various mitigation policies (ERC, 2018). Those results show that the emissions savings of the post-2015 National Energy Efficiency Strategy to 2050 will be 222 Mt CO2-eq. The carbon tax is expected to result in reductions of 115 Mt over the period 2020-2050. Thus, the GHG emissions of the CIPPs in the reference scenario and worst-case will almost offset the National Energy Efficiency Strategy. Even under the best- case for GHG emissions, the CIPPs will almost offset the emission savings of the carbon tax for the South African economy. The coal IPP programme essentially negates key mitigation actions at the disposal of the government

Finally, we tested the effects of building the CIPPs in the context of climate change mitigation policy. Should South Africa take its own climate change commitments seriously, building the CIPPs will dramatically raise the costs of meeting the low-PPD carbon budget as outlined in the National Climate Change Response White Paper and committed to under the Paris Agreement. Further mitigation will be required in the power sector, with the existing fleet run at lower load factors to make room for the CIPPs, and substantial higher investment required for new generation capacity. Notably, other sectors will also face higher mitigation burdens. In total, the additional discounted system costs to meet the low-PPD trajectory with the CIPPs is R27.9bn.

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