ESKOM'S FINANCIAL CRISIS AND THE VIABILITY OF COAL-FIRED POWER IN SOUTH AFRICA

IMPLICATIONS FOR KUSILE AND THE OLDER COAL-FIRED POWER STATIONS

Grové Steyn, Jesse Burton, Marco Steenkamp
Contact: grove.steyn@meridianeconomics.co.za

15 November 2017

ACKNOWLEDGEMENTS

This study should be cited as:

Steyn, G, Burton, J, Steenkamp, M (2017) "Eskom's financial crisis and the viability of coal-fired power in South Africa: Implications for Kusile and the older coal-fired power stations" *Meridian Economics,* Cape Town: South Africa.

---

[1] *Given the sensitive nature of the issues under consideration, and the difficulties currently experienced at Eskom, it was necessary to agree upfront that the names of interviewees will not be disclosed.*

EXECUTIVE SUMMARY

The South African power system has reached a crossroads. Eskom, the national power utility, is experiencing an unprecedented period of demand stagnation and decline, while having simultaneously embarked on an enormous, coal-fired power station construction programme (Medupi 4 764 MW and Kusile 4 800 MW) that has been plagued with delays and cost over-runs. This has forced Eskom to implement the highest tariff increases in recorded history, and has led to a crisis in its financial viability and, at the time of writing, a liquidity crisis (Groenewald & Yelland, 2017).

Having recently suffered from capacity shortages, Eskom's inflexible construction programme has now resulted in a significant and growing surplus of expensive generation capacity. Recently, the Minister of Finance, Mr Gigaba indicated that Eskom has a surplus capacity of 5 GW (Creamer, 2017).[2] Eskom's Medium-term System Adequacy Outlook (MTSAO) (Eskom, 2017a), published in July, estimates excess capacity of between 4 and 5 GW in 2019/20, assuming a higher demand than is currently experienced (Eskom, 2017a). The latest MTSAO (Eskom, 2017b) indicates an expected excess capacity of just over 8 GW in 2022 based on their low demand scenario.

South Africa has also embarked on a highly successful renewable energy procurement programme. Although this programme initially resulted in expensive renewables prices, it has more recently produced highly competitive prices for wind and solar power in line with the paradigm-changing energy transition experienced globally. Despite these circumstances, Eskom nonetheless has not yet committed to decommission any of its older plants, even as they approach the end of their lives and the costs of running the older stations increase.

In this report we present the results of an independent study into several possible strategies to assist with ameliorating Eskom's critical financial challenges. Essentially, we have investigated two questions:

1. Should Eskom cancel part of its power station construction programme to reduce costs?
2. Should Eskom bring forward the decommissioning of some of its older coal power stations to reduce costs?

Our method allows us to assess whether the costs associated with running a particular station for its remaining life exceed the value of that station to the electricity system. The comparison hinges on the alternative cost of meeting demand if a station is decommissioned early (or other new plant construction is cancelled i.e. not completed). If the system can meet demand over the same time period through alternative resources (existing and new) at a cost lower than the levelised cost of electricity from a particular station, then it makes economic sense to decommission that station early (or to not complete it). Our analysis is thus premised on two parts:

- a system-wide analysis concerned with calculating the system alternative value of a station (the station's avoided cost);
- which is then compared against the incremental levelised costs of running that station.

The system analysis undertaken by the CSIR Energy Centre for the reference scenario produced results that are in themselves important: in a 34 year, least cost optimised, power system operation and expansion plan, no new coal-fired power capacity is built after Kusile, and no new nuclear plant is built either. New coal and nuclear plants are simply no longer competitive. When new capacity is required, demand is met at lowest cost primarily from new solar PV and wind. In the more plausible moderate demand scenario renewable energy is supplemented by flexible technologies, storage (pumped storage and batteries) and open-cycle gas turbines (OCGTs) for peaking, but no combined cycle gas turbines. In the less plausible high demand scenario, combined cycle gas turbines are only required after 2040 and produce little energy. In the moderate demand scenario this means that the gas demand for peaking OCGTs will remain low until at least 2030 or later. Overall the system level analysis thus shows that South Africa does not need a nuclear,

---

coal or gas power procurement or construction programme.

Figure A shows our results for the analysis of the individual stations for a moderate demand scenario (in which we assumed higher demand than currently seen in the economy).
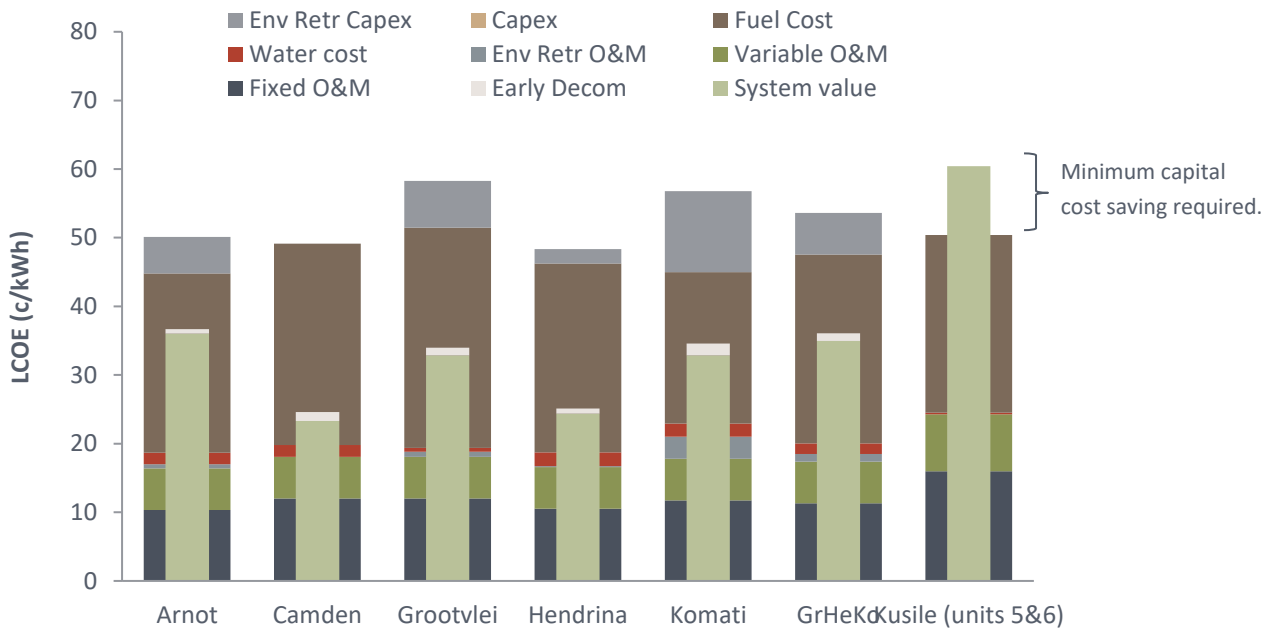

Figure A: Comparison of system alternative value and levelised costs per station (2017 c/kWh) in a moderate demand scenario

The results show that it makes economic sense to decommission the older stations early, since the system can meet demand at a lower cost than running each of the stations. This holds for the scenario even where we decommission three stations early (Grootvlei, Hendrina, and Komati – GrHeKo).

Table A shows the potential savings associated with the early decommissioning of each station.

Table A: Estimated system cost savings arising from earlier decommissioning (R'm)

Scenario	Arnot	Camden	Grootvlei	Hendrina	Komati	GrHeKo
Moderate Demand	5 177	5 139	5 714	7 829	3 371	12 568

Note: These savings are not additive; our methodology assesses each station individually, except in the case of GrHeKo.

By decommissioning GrHeKo early, Eskom can save as much as R12.5bn in present value terms.

The incremental cost of Kusile units 5 and 6 includes the avoidable capital cost of completing these units. However, we were not able to obtain reliable estimates of the avoidable capital costs for units 5 and 6. We have therefore reversed part of the analysis in this case by netting off the other components of its levelised incremental cost from its system alternative value. This determines the avoidable capital cost at which the option of cancelling Kusile units 5 and 6 costs the same (given the costs of the alternative resources that will then be used) as completing it. This is the threshold capital cost saving. Therefore, if the capital cost saving is more than this threshold it will be more economic to cancel the construction of Kusile units 5 and 6 than to complete it, even considering that other resources will have to

be employed in future to replace the supplies that would have come from units 5 & 6.

Table B below shows that this threshold capital cost saving level is approximately R4 747m for the moderate demand scenario and our stated assumptions. To put this into perspective, assuming that Eskom will still incur a 15% budget overrun on the remaining capital budget for the station, the cancelling cost savings threshold required is approximately 1.9% of the total capital cost of the station, or approximately 13% of the estimated cost to completion of Kusile. Table B shows what net savings that will result if the cancelling saving is larger than this threshold.

Table B: Kusile Cost Saving threshold (Moderate Demand Scenario)

Percentage of estimated cost to completion for Kusile	PV of CAPEX saving (R'm)	Nett CAPEX Saving (R'm)
13.18%	4 747	0
20%	7 202	2 455
25%	9 002	4 256

Our further estimates show that decommissioning GrHeKo and avoiding the completion of Kusile units 5 and 6 could giving rise to a financial saving in the region of R15 - 17bn without affecting security of supply. These estimates do not reflect the additional large savings in the impact on human health, local environment and climate change that will result.

These are large and difficult decisions to make and are fraught with vested interests that will be affected. We have already seen from Eskom's ongoing governance crisis, that Government and Eskom are partially paralysed, and could struggle to take the right decisions in the public interest. It is exactly for situations like this (i.e. where democratic governance fails), that countries create independent regulators (or independent public protectors, independent courts, etc.). It is therefore critical that the National Energy Regulator of South Africa (NERSA) ensures that these issues are investigated and addressed, and that Eskom is only allowed to recover efficient costs in its tariffs.

Ensuring a just transition for existing employees is of paramount importance and should be the subject of a multi-stakeholder political process and further analysis. Workers and communities should not bear the brunt of Eskom's financial crisis. Part of the savings realised could be used to cushion the impacts on workers and communities, and provide support for re-training, skills development, relocation, etc.

Lastly, we have to consider the possibility that Eskom's financial position is even worse than generally understood at the time of writing. The analysis presented above was focussed on the relative economics of the options considered, and did not consider the financing implications of each option. However, if Eskom's financial crisis continues to worsen, as we suspect it might, financial constraints will have to be brought into the picture. In this case, further possibilities must be considered in the light of the systemic risk to the state and the entire economy posed by Eskom's financial crisis. Assuming that the economy's ability to absorb further tariff increases and government's ability to provide further bailouts and sovereign guarantees are rapidly diminishing, Eskom will have to urgently find other ways of maintaining its solvency and avoiding a liquidity crisis. In this scenario, the only option will be to reduce the haemorrhaging of cash. The question will be: how can this be achieved without letting the lights go out?

Although not discussed in this report, it appears that Eskom has some scope for cutting back on human resources costs, and on reducing its primary energy costs. However, this is unlikely to be achievable over the short-term or to be sufficient. Two key insights

that emerged during this study are therefore critical for considering how best to address this question:

1. The level of surplus capacity that Eskom now anticipates for the foreseeable future is at least equal to an entire Medupi or Kusile power station, or more.

2. By the time this spare capacity would be required in future, it will be cheaper to provide it by a combination of alternative means (renewable energy, gas turbines, battery storage, etc.).

Essentially the unavoidable conclusion is that Eskom is still spending vast amounts of capital on a power station construction programme that South Africa does not need and cannot afford.[3] Drastically curtailing Eskom's power station capital programme (beyond Kusile 5 and 6) might be the only way to restore its solvency. This will of course come at a high cost in terms of the penalties to be paid by Eskom in future, and the impact on personnel working on the construction projects. But, the lights will stay on, Eskom's cash flow situation could rapidly improve, and confidence in Eskom and the economy would be restored.

In this scenario South Africa might well face a stark choice: Abandon a large part of the Kusile (and possibly part of the Medupi) project, or allow Eskom and possibly the state to default on its financial obligations and pay an enormous economic and social price.

In either case it now appears critical that Eskom puts in place a process to plan for the urgent decommissioning of its older power stations and prepares for the possibility that its capital programme will have to be curtailed. Furthermore, it will be unrealistic to expect Eskom to drive these decisions on their own accord. It will be necessary for key government departments, NERSA, consumers and other stakeholders to act in order to protect the integrity of the power system and enable the South African economy to participate in the global energy transition to lower cost, clean energy resources.

---

[3] To put this into context, we estimate that Medupi and Kusile will still require at least R80bn capital expenditure (excluding interest) as of March 2017.

CONTENTS

1 INTRODUCTION

The South African power system has reached a crossroads. Eskom, the national power utility, is experiencing an unprecedented period of demand stagnation and decline, while having simultaneously embarked on an enormous, coal-fired power station construction programme (Medupi 4 764 MW and Kusile 4 800 MW) that has been plagued with delays and cost over-runs. This has forced Eskom to implement the highest tariff increases in recorded history, and has led to a crisis in its financial viability.[4] Having recently suffered from capacity shortages, Eskom's inflexible construction programme has now resulted in a significant and growing surplus of generation plant. Recently, Minister Gigaba indicated that Eskom has a surplus capacity of 5 GW (Creamer, 2017)[2]. Eskom's Medium-term System Adequacy Outlook (MTSAO) (Eskom, 2017a), published in July, estimates excess capacity of between 4 and 5 GW in 2019/20, assuming a higher demand than is currently experienced (Eskom, 2017a). The latest MTSAO (Eskom, 2017b) indicates an excess capacity of just over 8 GW in 2022 based on their low demand scenario.

South Africa has also embarked on a highly successful renewable energy procurement programme. Although this programme initially resulted in expensive renewables prices, it has more recently produced highly competitive prices for wind and solar power. Despite now being the cheapest source of new electrical energy, the renewables programme has been caught up in Eskom's crises with the utility refusing to sign the power purchase agreements (PPAs) for the most recent procurement rounds.

In this report we present the results of an independent study into several possible strategies to assist with ameliorating Eskom's critical financial challenges. Essentially, we have investigated two questions:

1. Should Eskom cancel part of its power station construction programme to reduce costs?

2. Should Eskom bring forward the decommissioning of some of its older coal power stations to reduce costs?

We adopted a conservative approach throughout the study. Therefore, with respect to the first question, we focussed on the area where the least progress has been made and therefore where cost savings might be most likely - Kusile power station's last two units (units 5 and 6). Similarly, we focussed our investigation on the older stations that are likely to be the most uneconomic to continue operating, namely: Camden, Grootvlei, Hendrina, Komati and Arnot. We also investigated the option of simultaneously decommissioning three of the older stations earlier than planned, namely: Grootvlei, Hendrina, and Komati.

In addition to the financial costs coal-fired power stations impose on Eskom, coal power also places enormous economic, social and environmental costs on third parties. These costs take the form of negative impacts on human health and mortality, local pollution impacts on the environment and agriculture and its contribution to climate change. These externality impacts are substantial and should be included in the cost benefit assessment of power generation options. However, given the crises with Eskom's tariffs and finances, our study focussed on the direct financial impact on Eskom associated with the options under investigation.

---

[4] *Eskom has recently applied to the National Energy Regulator of South Africa (NERSA) for a further 19.9 % tariff increase and intends to implement yet further increases as a way out of its financial and funding crises (Eskom, 2017c).*

2 CONTEXT

The review of current global and local developments in the power sector, presented in this section, provides important context for understanding the motivation for our study and for interpreting the findings.

2.1 GLOBAL CONTEXT

Countries around the world are reducing their dependence on coal and moving instead to an increased reliance on renewable resources. While in the past subsidies played an important role, the energy transition is now driven by economic and financial considerations. Transition steps include cancellation of projects already under construction, retirement of older stations and deferral of proposed coal-fired capacity additions. At the same time, renewable energy costs have fallen dramatically across the world, delivering prices that are increasingly competitive with existing conventional generation prices.

Although global growth in coal power over the past decade has been highest in China and India, both countries cancelled more than 50% of their planned coal power plants in 2015 and 2016 (United Nations Environment Programme, 2017). China has taken major steps to reduce its coal use and produce power from renewable wind and solar resources. For example, in the autumn of 2016, China halted construction on 30 large coal-fired power plants. Another 30 projects, for which transmission lines were already under construction, were also stopped (Myllyvirta & Mills, 2016). A new list, issued in January 2017, identified the cancellation of 103 coal-fired projects, eliminating 120 GW of planned capacity. These cancellations included dozens of projects on which construction had already started, representing a combined output of 54 GW (Forsythe, 2017).

In India, lower-than-expected growth in electricity demand, combined with rapidly declining costs for renewable resources and falling utilisation rates at existing plants, led to the cancellation of 13.7 GW of planned coal-fired power plants. These factors have also led to the admission that an additional 8.6 GW of newly built coal-fired capacity is not financially viable. (Hill, 2017). Only two of the planned 16 Ultra Mega

Power Projects have actually been built. In addition, India's state-owned power generator, the National Thermal Power Corporation has also announced its decision to shut down 11 GW of its oldest coal-fired capacity. (The Times of India, 2017).

These shifts away from coal have been echoed across the world. The South Korean government announced plans to operate 10 of its oldest coal-fired power plants during the non-spring months only, with the permanent closure of these plants by 2022, three years earlier than previously planned (Chung, 2017). The Dutch government announced that all coal-fired power plants would be shut down by 2030, including three plants that were only completed in 2015 (Wynn, 2017). The Netherlands joins several G7 countries that have announced coal phaseouts.

The Indonesian Energy Minister recently announced that the government will not approve any new coal-fired plants on the country's Java grid (Jensen, 2017). Lower than expected electricity demand placed their plan to increase the nation's generating capacity by 35 GW, including coal-fired capacity, in doubt and the plan now appears to be scaled back. Some 9 000 MW of planning capacity has been put on hold until 2024, and thousands more megawatts (including coal-fired plants) will be cancelled (Jensen, 2017).

While the cancellation of these plants during pre-construction and construction phases, and early coal closures, are subject to market dynamics and policy interventions in these countries, they are also supported by rapidly falling renewable energy costs across the world. Renewable energy auctions have delivered record-breaking declines in price, driven both by falling technology costs and newly established competitive procurement frameworks.

Recent auctions (up to the end of 2016) have consistently delivered solar photovoltaic (PV) prices of less than USD 50/MWh, in countries such as the US, Peru, Mexico and Chile. Even lower prices have materialised in countries with good solar resources such as Abu Dhabi (2,42 USc/kWh), Dubai and Texas. From the beginning of 2017, it is increasingly the norm for solar auctions to deliver prices of around 3 USc/kWh, even unsubsidised. Even lower prices have been seen in countries offering subsidies such as concessional finance or special pricing arrangements

(e.g. Saudi Arabia's 1,79 USc/kWh). In Arizona solar PV without storage has come in at 3 USc/kWh, and with storage at 4,5 USc/kWh (Wright, Arndt, et al., 2017; Diaz Lopez, 2016; Whiteman et al., 2017).

Wind energy costs have fallen less rapidly, but auctions also frequently deliver prices of below 50 USD/MWh, currently converging at around 40 USD/MWh (Whiteman et al., 2017), with lower prices achieved in Mexico, Peru and Morocco. In the latter, onshore wind achieved a price of 3 USc/kWh (Wright, Arndt, et al., 2017). These prices are close to the costs assumed in our study for renewable energy in 2030, highlighting that cost reductions may happen substantially more quickly than anticipated in our modelling (see 0 below).

2.2 LOCAL CONTEXT

After several years of supply shortages, Eskom now faces a surplus of generation capacity as demand has stagnated and new plants have come online.

Figure 1 shows South Africa's electricity demand from 1985 to the present. As can be seen, demand has been flat for the last decade. This new trend was driven by rapidly increasing prices, low economic growth and changes in electricity intensity. The demand forecast of the original 2010 Integrated Resource Plan (IRP) Base Case scenario is shown for comparison. As can be seen, current demand is approximately 78 TWhs[5] below the 2010 IRP projection. This is similar to the energy output of two and a half Kusile power stations at full output. The substantial overestimate in demand in the 2010 IRP also highlights that committing to large, high complexity, inflexible, new build with long lead times is a very risky strategy (Steyn, 2001; Steyn & Eberhard, 2010).[6]
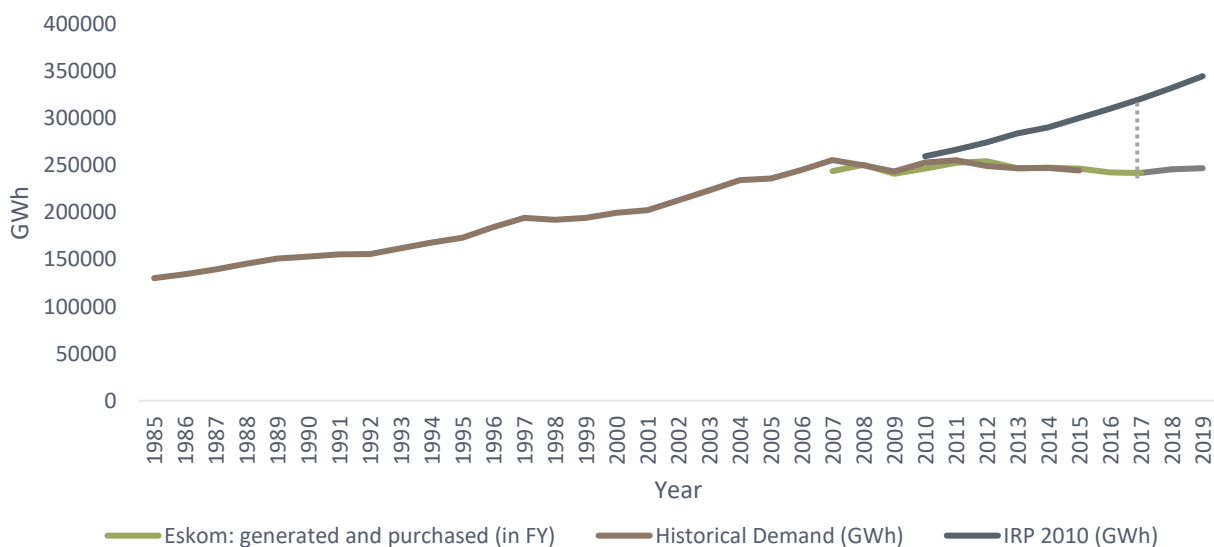
Figure 1: Historical Electrical Energy Demand (GWh) [7]

Source: Eskom, 2017d,e; Wright, Calitz, et al., 2017

---

[5] *The IRP 2010 forecast (320.751 TWh) is approximately 78 TWh more than the energy available by Eskom 2016/17 (Eskom financial year) (242.023 TWh).*

[6] *This exact contingency was foreseen and warned against in Steyn(2001, 2006)*

[7] *The Eskom: generated and purchased are in Eskom financial years whereas the other data is in calendar years. The grey part of the "Eskom: generated and purchased" line show Eskom's projections included in their 2017 NERSA Revenue Application (Eskom, 2017c) and is the Total Gross Production in GWh. Both the Eskom: generated and purchased and the Total Gross Production are inclusive of energy generated by Eskom, purchased from IPP's, wheeling and energy imports from SADC countries*

Indeed, Eskom's own system adequacy report highlighted that the surplus is forecast to grow to between 4 and 5 GW in the next five years, assuming their moderate growth in demand (Eskom, 2017b). This surplus is primarily a result of the commissioning of the large units at Medupi and Kusile, which effectively stranded the older, less efficient, coal-fired stations, given the low demand for electricity over the past decade. In Eskom's low demand forecast (Eskom, 2017b), surplus capacity grows to over 8 GW by 2022, when new Independent Power Producer (IPP) renewable energy capacity is included (and close to 6 GW even without new IPPs).

Stagnant demand is likely to be at least partly a result of Eskom's unprecedented tariff increases. Yet Eskom continues to request tariff increases. In addition to the 350% increase in real terms since 2007, Eskom requested a 19.9% average increase in tariffs in its 2017 National Energy Regulator of South Africa (NERSA) revenue application. A key aim of the application is to make up for declining sales volumes. This appears to be an early sign of the utility death spiral, where higher prices drive down demand and sales, which in turn leads to higher prices to recover a fixed cost base.

With repeated cost escalations and time overruns at the Medupi and Kusile construction projects, reduced sales are putting Eskom under enormous financial strain. Eskom's financial woes have reached the point where the Finance Minister and others have deemed the utility to be a systemic risk to the South African economy (Bonorchis & Burkhardt, 2017; Creamer, 2017; de Vos, 2017).

Eskom's cost base is exacerbated by the costs associated with an inefficient and ageing coal fleet that faces escalating coal costs, requires increased maintenance and refurbishment, is not environmentally compliant and therefore requires substantial capital expenditure to meet legislative standards.

Primary energy costs have risen substantially in real terms over the past 18 years (see section 4.4.5 below). More recently Eskom's average cost of coal has risen from less than R200/ton in Financial Year (FY)[8] 2010,

to R393/ton in FY 2017, and is expected to increase to R430/ton by FY 2019 (Burton & Winkler, 2014; Eskom, 2017e). However, these overall cost increases mask divergent station-specific costs that affect the merit order of the stations. Station-specific costs should be driving future choices around investment in refurbishment, life extensions, environmental compliance and the option of earlier decommissioning. Part of the cost increase is due to corruption, as has been widely reported in the South African press. However, poor planning (partly because of political interference) and mining sector market dynamics are also driving higher coal prices for Eskom.

Most independent analyses of the South African electricity sector have not used detailed, station-specific coal, water and other input costs. This limitation curtails insight into how Eskom manages the coal fleet and the understanding of which plants may be surplus to the system and/or uneconomic to run. This study aims to fill the gap. An independent economic analysis remains important because, despite the challenges facing Eskom as outlined above, the utility has not put plans in place for the imminent decommissioning of its power plants, nor for the socioeconomic impacts of these closures - even as these plants rapidly approach their planned decommissioning dates. In response to several Promotion of Access to Information Act (PAIA) requests, for example, Eskom continues to state that it has no plans to decommission its plants (Eskom, 2017f) and is side-stepping the issue of decommissioning (let alone early decommissioning) by keeping the option of life extension of the older plants on the table. We understand from our interviewees that the motivation is partly political. Politicians are concerned about potential electoral impacts of plant closures and want to minimise perceived job losses in the run up to the 2019 elections. There are also calls from unions and others outside Eskom (e.g. the Fossil Fuel Foundation) to extend the lives of the aged plants (iNet Bridge, 2017).

In practice, however, the surplus of capacity has resulted in Eskom already placing many units (at various stations) in extended cold reserve, with a call up time of up to five days. Eskom also recently

---

[8] The financial years referred to in the report are Eskom financial year i.e. from April to March, unless stated otherwise

announced that Grootvlei, Hendrina, and Komati would be placed in extended cold reserve in their entirety (though not decommissioned) (le Cordeur, 2017a; Eskom, 2017d). These stations will therefore continue to incur costs even though they might be surplus to the country's requirements[9]. Furthermore, Eskom continues to sign new coal contracts for power stations that are supposed to be decommissioned in the coming years, locking itself into expensive take-or-pay contracts for coal it does not and will not need.

Within this context of Eskom's financial crisis, falling demand, surplus capacity and rising coal costs, South Africa has successfully implemented renewable energy auctions that reflect international trends in technology cost reductions, delivering falling prices over successive bid windows.

It is now clear that renewable plants are the lowest cost new build options in South Africa. The latest round of renewable energy bids (Round 4.5), at an average of 62 c/kWh (2016 ZAR), are approximately 40% lower than the bids received for the new independent coal power plants at over R1,0/kWh. Furthermore, according to our calculations, the latest round of new renewable energy bids is substantially below the levelised costs of Eskom's new coal plants. We calculate Medupi's levelised cost of electricity (LCOE) as R1,70/kWh and the LCOE of Kusile as R1,91/kWh (2017 ZAR; see Annexure A on page 39 for details of the calculations). Energy from new renewable projects is therefore approximately one-third of the costs of new Eskom mega coal plants. South Africa has every reason to expect that the prices for new renewable energy projects will continue to fall (see section 0 below) to the point where coal-fired plants will be made redundant.

Any structural changes in the energy economy will of course have socioeconomic impacts that should not be underplayed. Table 1 shows the number of employees at Eskom's coal-fired power stations.[10]

Table 1: Employment at Eskom's Coal-fired Power Stations

Power Station	Employment
Arnot	677
Camden	324
Duvha	696
Grootvlei	427
Hendrina	644
Kendal	668
Komati	331
Kriel	701
Kusile	247
Lethabo	628
Majuba	508
Matimba	476
Matla	659
Medupi	293
Tutuka	649

Source: Centre for Environmental Rights, 2017

---

[9] *Eskom does not explain what it means by these various terms, but in general, cold reserve means a station is not running but can be called up if needed within 12-16 hours; extended cold reserve means the station can be called up within 5 days. Mothballing means an asset is closed but not permanently so, and can be used again in the future.*

[10] *In addition to the direct employees at stations, we note that there are significant numbers of people temporarily employed at Kusile during construction. Eskom's latest MYPD applications indicated 22 000 workers at Kusile. This is substantially higher than earlier numbers provided by Eskom, and has grown from 8000 peak construction jobs in 2008, to 12 000 direct and 1 700 indirect jobs in 2011, to 17 000 jobs in 2015. In 2015, Eskom also stated that: " the project had reached its peak in terms of employment numbers and had no additional employment opportunities." (Mafika, 2008; Parliamentary Monitoring Group, 2011; Steyn, 2015)*

3 RESEARCH DESIGN AND METHODOLOGY

This section outlines our research design and methodology, describes two key analytical approaches, explains important methodological concepts and highlights a fundamental principle on which the study relied.

In order to address this study's research questions, we had to adopt a research design that was both practical and achievable, but that also produced reliable results. Both research questions set up a counterfactual logic. Essentially, we are assuming that electricity demand will be met in all cases, but whether it will be met with or without the plant in question is the crux of the matter. Accordingly, this analysis has to compare the costs to Eskom of meeting electricity demand both with and without the plant, in each option under investigation (Kusile units 5 and 6, or the older coal stations).

We employed two analytical approaches in order to conduct this analysis. Firstly, we investigated the optimised resource allocation and cost of supply for the entire South African power system. This system-level analysis was performed by the Council for Scientific and Industrial Research (CSIR) Energy Group, using their PLEXOS power system modelling tool. In order to meet a particular demand forecast, the model schedules existing plants, based on their incremental costs (subject to certain constraints), and constructs new system resources as required, based on their total costs.

Secondly, we conducted a detailed investigation into the future incremental costs of each individual power station in question. This station level analysis was undertaken by the Meridian Economics project team.

The key concepts described below explain our methodology and how we utilised these two levels of analysis:

Incremental costs

When considering the costs of alternative strategies, economists would generally accept that sunk costs should be ignored (or deemed zero). All that matters are the costs that the decision maker still has discretion over, and which can, in principle, still be avoided. Incremental costs are thus similar to avoidable costs.

Levelised costs

The relative economics of different electricity generation options can be analysed by calculating their levelised costs. Generally, the levelised cost is calculated so as to express all the relevant costs over the lifetime of the project as a single cost per unit of production (e.g. per kilowatt-hour for electricity). This is similar to a simple average cost, but the calculation takes the timing of the costs and of the production volumes over the life of a project into account. Mathematically the levelised cost is calculated as the present value of the project costs, divided by the present value of its production volumes.

While levelised cost analysis is usually used to compare the total costs of a resource (power station), any aspect of its costs can be levelised over the volumes, in order to show the result as a cost/unit of volume. It is therefore also possible to express the incremental cost of running a power station in levelised cents/kWh terms.

System alternative value

When conducting the analysis of an entire power system, as we did for this study, we relied on a fundamental principle: The energy and capacity provided by any resource (a supply or demand side option) can alternatively be provided by an optimised combination of other system resources, should the initial resource be unavailable. This should be a like-for-like comparison with respect to the dispatchability and reliability provided by the plant under investigation. In economic terms, therefore, the value of a power station to the system is the alternative costs to the system that are avoided by having this station available and operational. We refer to this as the system alternative value (SAV) of the station.[11] The system alternative value can be expressed as a levelised cost per unit of output (e.g. kWh).

---

[11] This can also be referred to as a power station's levelised avoided cost of energy, i.e. the costs that are avoided by keeping the station on the system and dispatching it in accordance with its economic merit order.

It will only be economic to operate an existing power station, or build a new one, if the alternative (its system alternative value or SAV) will cost more. Conversely, if the station's levelised cost is more than its SAV, it means that the energy and capacity services to the system can be provided at a lower cost by available alternative resources, and therefore, all things being equal, should be closed down (if already operating) or not constructed at all. The system alternative value thus becomes a ceiling value that the costs of any power station (existing or to be constructed) should not exceed.

Our methodology consists of the following steps:

1. Use the system model to determine the optimal use of each station and the construction of new stations to produce a reference (or base) scenario. This provides an energy output profile (energy profile) for each station over the analysis period, for a high and a moderate demand scenario.

2. Use the system model to determine each station's system alternative value.

3. Investigate each station's incremental cost of operation and calculate the levelised incremental cost of producing the energy profile required from each.

4. Compare each station's incremental levelised cost to its system value to determine, in the case of an existing station, whether it should be decommissioned, or in the case of pending construction, whether it should be completed or cancelled.

In the case of the investigation into the economics of completing Kusile units 5 and 6, the incremental cost includes the avoidable capital cost of both these units. As discussed below, we were, however, unable to obtain any reasonable estimates of this cost. We therefore reversed the analysis in step four and calculated the avoidable capital cost (in cents per kWh) by netting off the units' other components of levelised incremental cost from its system value. At this level, cancelling both units would cost the same as completing them. This is the threshold capital cost

saving. If the saving is higher than this level, it would be more economic to cancel rather than complete construction of the Kusile units 5 and 6.

3.1 SYSTEM LEVEL ANALYSIS

The primary aim of the system modelling was to determine the system alternative value for each power station option under consideration. For these purposes we utilised the CSIR's energy system modelling capability. The model determines the lowest total electricity system cost over 34 years by optimising the utilisation of existing generators (which decommission over time) and new investments. In doing so it ensures that the energy balance is maintained for every period in a least-cost manner subject to system adequacy requirements (i.e. reserves and cost of unserved energy). The optimisation is also subject to a range of other user-defined constraints, e.g. supply technology technical characteristics (ramp rates, start/stop costs, minimum up/down times, etc.), supply technology reliability and operational limitations (pumped storage weekly cycling) (Wright, Calitz, et al., 2017)[12].

3.2 POWER STATION LEVEL ANALYSIS

The aim of the power station level analysis was to conduct a detailed investigation into the incremental levelised costs of operating each power station under consideration. To conduct this calculation, we had to investigate the circumstances of each station and gather best estimates of its present and future relevant cost drivers, including factors such as:

- Primary energy cost (coal supply arrangements and costs)
- Power station efficiency
- Water costs
- Fixed and variable operating and maintenance costs (FOM and VOM)
- Refurbishment costs
- Environmental compliance retrofits required and the costs thereof
- The increased operating cost associated with environmental retrofits

---

[12] For further details on the approach adopted by the CSIR see their technical report (Wright, Calitz, et al., 2017) also available on the Meridian Economics website (www.meridianeconomics.co.za).

- The environmental levy
- Kusile's outstanding capital expenditure (CAPEX)
- Energy production profile (from system modelling)
- Operating capacity
- The costs of station decommissioning and the net present value cost impact thereof

We have constructed a discounted cash flow model that calculates the levelised cost of electricity (LCOE) for each power station. For the purposes of this analysis, the cost data used to drive the calculation only reflects the avoidable incremental cost of running each station.

The power stations under investigation in this study are shown in Table 2.

Table 2: Nominal Capacity of Power Stations Investigated (MW)

Power Station	Number of Units	Nominal Capacity (MW)
Arnot	6	2220
Camden	8	1900
Grootvlei	6	1520
Hendina	10	900
Komati	6	1080
Kusile (all units)	6	4338
Kusile units 5 and 6	2	1446

4 DATA AND ASSUMPTIONS

This section outlines the main sources of data and the assumptions used in the analysis. We detail assumptions on the demand and technology costs used in the system model, after which the data and assumptions used for calculating the levelised costs for each station are described.

4.1 MAIN SOURCES OF INFORMATION

Publicly available information was used as far as possible. The main sources of information used for the

station level analysis were obtained from the following:

- Information authored by Eskom and available in the public domain, either on their website, published in articles or provided in response to requests made in terms of the Promotion of Access to Information Act (PAIA).
- Technical reports available in the public domain or provided in terms of the PAIA.
- Annual reports, reserves and resources reports, sustainable development reports, investor reports for Eskom's coal suppliers and possible future coal suppliers where known, as well as industry reports on coal mines and Eskom's coal supply.
- General news and industry news publications.
- Interviews with people who have intimate knowledge of Eskom's operations, related air quality compliance matters and the coal sector.[1]

4.2 COMMON ASSUMPTIONS[13]

To ensure consistency, a number of overarching assumptions were used in both the system level and station level analyses. The main overarching assumptions include:

- The analysis period is from 2016/17 to 2049/50, and although the PLEXOS model was run in calendar years, all output required for the station model was adjusted for financial years (i.e. Eskom financial year 1 April – 31 March).
- The commissioning and decommissioning schedules are as per the draft IRP 2016 (Department of Energy, 2016a).
- CAPEX and operating expenses (OPEX) for new build power generators, unless stated otherwise, are as reported in the Electric Power Resource Initiative (EPRI) (2015) study.
- All costs are in real terms and are presented in 2017-rand terms, unless stated otherwise.
- An after tax real discount rate of 8.2% which is equal to the economic opportunity cost of capital (EOCK) specified by National Treasury (National Treasury, 2016: 27).

---

[13] A detailed explanation of the system level modelling assumptions can be found in Wright et al (2017).

- The station level analysis used the energy and capacity profiles (for the various scenarios) produced by the system level analysis.

4.3   SYSTEM LEVEL ANALYSIS

In this section we briefly outline the key assumptions used for the system level analysis. The model aims to meet demand at the lowest cost, subject to the operational and other system constraints (e.g. ramp rates, lead times to build new capacity, reserve margins, etc.), and uses an hourly time resolution.

Many of the assumptions in the reference scenarios were aligned with the draft IRP 2016 (Department of Energy, 2016a). For example, the energy availability factor, discount rate, cost of unserved energy and the decommissioning schedule of the existing fleet (50-year life or as per draft IRP 2016). In the reference scenarios, all six units at Kusile are commissioned as planned, and the P80 commissioning dates for

committed plants (Medupi, Kusile and Ingula) were used. Unlike the draft IRP 2016 (Department of Energy, 2016a), this study assumes that all renewable capacity from the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) Bid Window 1, 2, 3, 3.5 and 4 is committed, but excludes Bid Window 4 Additional, Expedited and the new build coal IPPs. That is, the model optimally meets demand (either from existing stations or using least-cost new capacity) after the REIPPPP Bid Window 4 and Kusile. A full set of assumptions can be found in Wright, Arndt, et al., 2017. The demand forecasts used in the reference scenarios and the assumptions on technology costs and learning curves for renewable energy are shown below.

4.3.1   Demand forecasts

Figure 2 shows the high and moderate demand forecasts used in the system modelling.
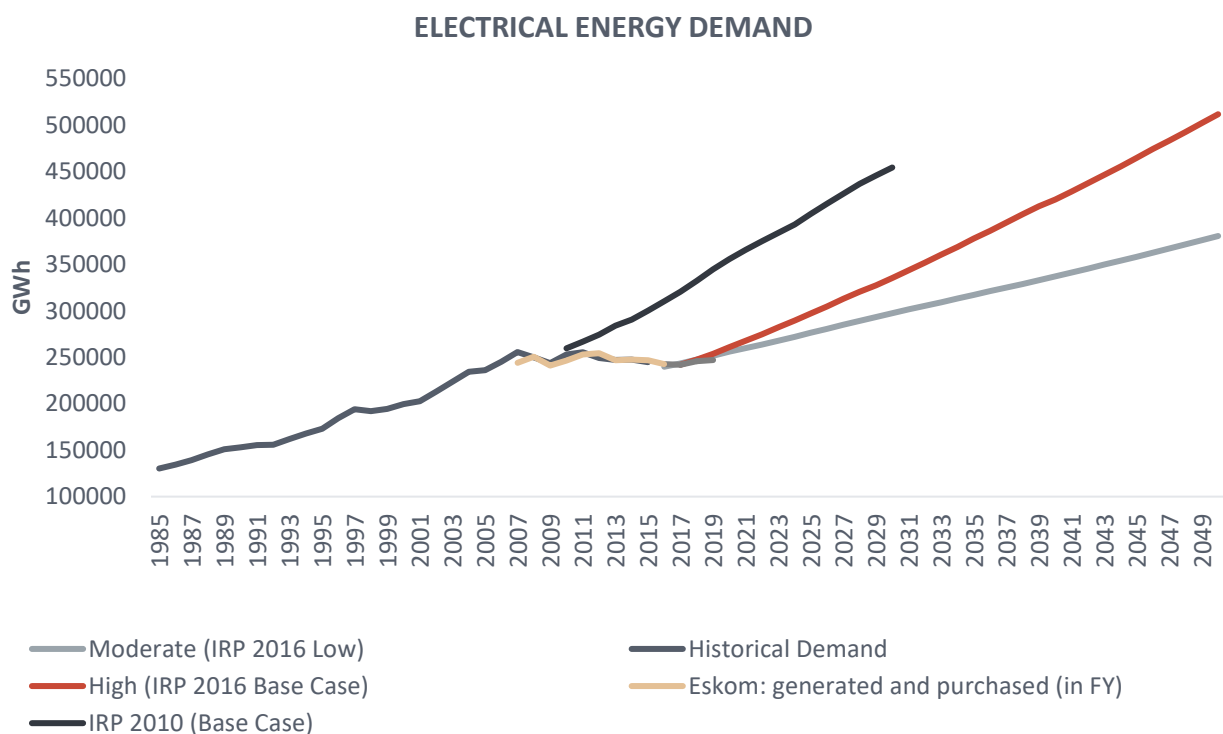

ELECTRICAL ENERGY DEMAND

Legend:
— Moderate (IRP 2016 Low)
— High (IRP 2016 Base Case)
— IRP 2010 (Base Case)
— Historical Demand
— Eskom: generated and purchased (in FY)

Figure 2: Electrical Energy Demand (GWh)[7]

The high demand projections were taken from the Base Case presented in the draft IRP 2016 while the moderate demand forecast is an update from the draft IRP 2016 low demand which was developed by the Energy Intensive User Group (Wright, Calitz, et al., 2017: 9).

As can be seen, Eskom's short-term projections are well below the forecasts used in this analysis. Furthermore, these electricity growth assumptions are premised on a GDP growth of 1.9%, 2.4% and 2.7% for the 2017, 2018 and 2019 years respectively (Eskom, 2017e: 39). However, more recent National Treasury (2017b: 12) estimates for South Africa's growth rate have been reduced to 0.7% and 1.1% for 2017 and 2018 respectively. If one compares the compound annual growth rate (CAGR) of the period 2007 to 2017, to the CAGR forecasted in the two scenarios for the period 2017 to 2027, the numbers reveal a discrepancy between historic and forecasted demand. The CAGR of the historic demand is negative 0.07%. This is essentially stagnant demand, although one needs to bear in mind the supply limitations due to load shedding. The CAGR for the high demand scenario is 2.37%, and for the moderate demand scenario, 1.44%. As mentioned in the introduction to this report, both these forecasts are relatively optimistic and unlikely to be realised under current economic conditions.

It is therefore apparent that it would have been appropriate to have also considered a lower demand forecast scenario similar to that of Eskom's latest 10-year forecast, which would be pitched somewhere

between zero growth and the moderate demand used in this study. The moderate demand scenario might well be on the upper end of the range of plausible future outcomes. Generally speaking, a lower demand forecast will lead to a lower system alternative value and a higher incremental LCOE. We therefore consider the moderate scenario to be a conservative assumption, particularly in the short to medium-term.

4.3.2   Technology learning curves

Conventional technology costs are based on the draft IRP 2016 (Department of Energy, 2016b) and EPRI 2015 (Electric Power Resource Institute [EPRI], 2015). Renewable energy starting costs were based on the Bid Window 4 (Expedited) tariffs, with learning curves based on Bloomberg (2017). Wind energy costs decline by approximately 25% by 2030 and approximately 50% by 2040, remaining constant thereafter. Solar PV costs decline by approximately 35% by 2030 and approximately 70% by 2040, remaining constant thereafter (see Wright, Calitz, et al., 2017 for a full breakdown of the cost structure of the technologies). The cost assumptions for 2030 used in our study were already globally realised in 2016 and 2017. The 2030 wind energy cost of 3,1 USc/kWh (2016 USD) is close to the price recently achieved in Morocco, while the 2030 solar PV cost of 2,5 USc/kWh has been achieved in several countries already, albeit with supportive policy (Diaz Lopez, 2016; Wright, Arndt, et al., 2017).

Based on the latest realised prices for these technologies, our learning curve assumptions are considered to be conservative (See Figure 3).
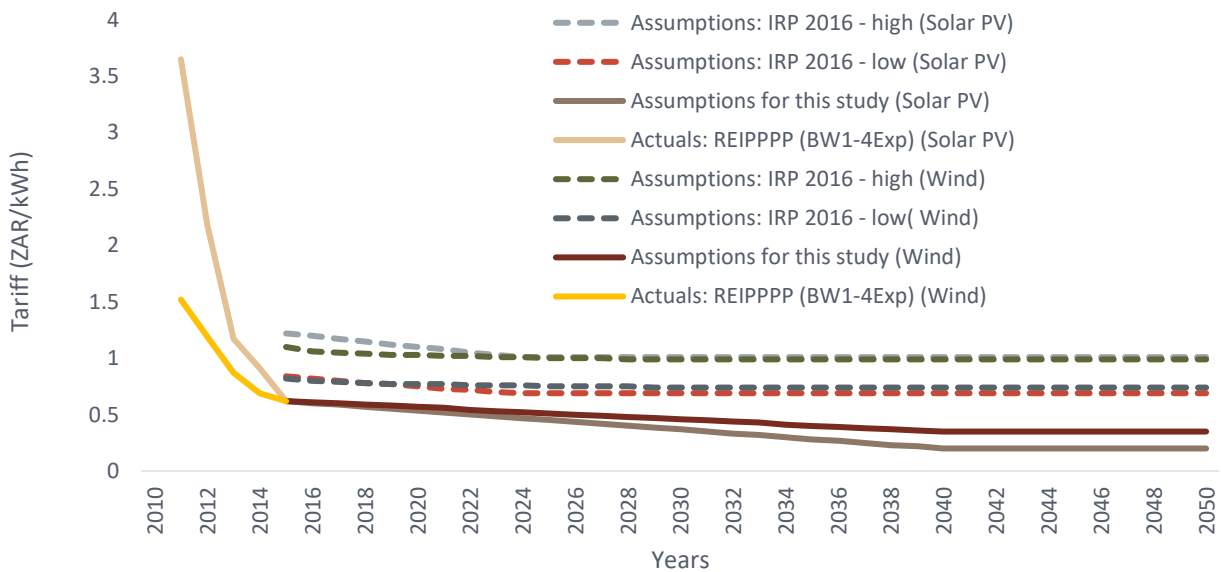
Figure 3: Equivalent Cost Assumptions for Wind and Solar PV

4.4 POWER STATION ANALYSIS

This section outlines the data and assumptions used in the study for each set of costs per power station. We also note where we excluded particular costs (usually for lack of data), as well as whether and why we think particular costs may be an overestimate or underestimate. We have relied on publicly available data wherever possible. This data was used to compare the costs per station in the analysis against the system alternative value for the stations, as calculated in the optimisation modelling.

4.4.1 Operating and maintenance costs

We were unable to obtain any public information on the fixed and variable operating and maintenance costs (FOM and VOM) for each Eskom power station investigated. We therefore relied on data provided by the Electric Power Research Institute for South African power stations (Electric Power Resource Institute [EPRI], 2015; Wright, Arndt, et al., 2017).

4.4.2 Refurbishment

Evidence from other countries, from PAIA requests to Eskom, and from our interviews, show that the operating and maintenance cost estimates do not include all refurbishment and maintenance costs. This

is because, in terms of the International Financial Reporting Standards, not all these costs are expensed, indeed some are capitalised. Furthermore, for older stations, and especially older stations that have been run very hard, these costs may underestimate the capital spend required.

It is difficult to find interchangeable capital cost estimates for power stations, as stations vary in age, design, capacity and operational conditions. In addition, it is not always clear which refurbishment costs are included in fixed and variable operating and maintenance cost estimates. Publicly available information on refurbishment cost estimates is rare and seldom discloses the extent of refurbishment associated with these costs (as some refurbishments may include life extensions). Additionally, the specific refurbishment requirements at Eskom's different power stations are unclear.[14] This makes estimating the refurbishment costs for Eskom's existing coal-fired power stations extremely challenging, even though it is clear that many stations require substantial investment in refurbishment (Dentons, 2015). Eskom's stations have been run exceptionally hard and Eskom has not made adequate capital investments into its fleet over the past 15 years. For example, all of the

---

[14] While we submitted a PAIA request for the data, we were denied the cost estimates as Eskom deemed the information commercially sensitive.

stations in our study have exceeded their boiler and turbine design lives (Dentons, 2015: 18)

The Hendrina Power Station Life-Ex Study (Siemens, 2015), commissioned by Eskom, also includes a capital expenditure scenario for the investments required to ensure Hendrina functions until 2025, the plant's original decommissioning date. These investments imply that there is a need for capital expenditure over and above normal maintenance.

Nonetheless, international estimates for the CAPEX associated with older plants gives a broad sense of the costs involved. Carbon Tracker (2017), found that in the US, refurbishment costs for stations older than 30 years are approximately R250/kW[15] (or approximately R560m to refurbish Arnot). Refurbishment costs need to be incurred in addition to the annual fixed and variable operating and maintenance costs.

We decided, however, not to include any further refurbishment costs in addition to those which might

be included in our FOM and VOM assumptions, given the plant specific data constraints we encountered. In effect this is a conservative assumption given that most stations could be expected to require substantial further refurbishment investments to complete their original life span.

4.4.3 Water

Water is a key input into the electricity production process. Each station pays specific tariffs related to the catchment it draws from, and the associated infrastructure requirements for the provision of water. This study makes use of the current tariffs for supplying water to Eskom for each station (the Department of Water Affairs third party tariff), obtained from the DWA. Water consumption data for each station was obtained from the World Bank's Water-Energy Nexus study (World Bank, 2017a). The water tariffs and consumption are presented in Table 3.

Table 3: Water Tariffs and Water Consumption

Power Station	Water (ZAR/kl)	Raw Water Use (l/MWh)
Arnot	7.6493	2220
Hendrina	7.6493	2610
Camden	7.4886	2310
Komati	7.6493	2490
Grootvlei	3.5077	1710*
Kusile	19.27	120**

*Notes: *Four units, wet closed cycle and two units direct dry system with spray condenser and dry cooling tower*

***this is estimated based on the Matimba Power Station*

Source: World Bank, 2017

The administered prices used in the study do not include the externality costs of water supply and use. That is, these prices do not capture society's welfare impact due to the externalities associated with water supply and use (Spalding-Fecher & Matibe, 2003). These may be substantial, for example, recent work has shown that water accounts for 65% of the

externality costs (Nkambule & Blignaut, 2017). The water tariff, therefore, does not have any signalling power for the actual social cost of water use.

4.4.4 Air quality compliance

Eskom has in recent years faced mounting pressure to comply with environmental regulations and legislation

---

[15] The refurbishment figures were originally in 2012 USD terms. The average exchange rate of ZAR:USD for 2012 was used, i.e. R8.20, to convert the cost into 2012 ZAR terms. This was then inflated to 2016 ZAR based on the historic SA inflation rate.

in respect of its polluting emissions. There are two primary tools at government's disposal for regulating the reduction of emissions in South Africa. These are the Minimum Emission Standards (MES) and the Atmospheric Emission Licences (AEL). The MES is 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, 2004. The AEL is an air pollution licence issued by the relevant atmospheric emission 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. 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 licence-holder. In the case of Eskom, the licences set out these limits in terms of particulate matter (PM), sulphur dioxide (SO_2) and oxides of nitrogen oxides (NOx), measured in terms of mg/Nm³. Each power station requires an AEL. All of Eskom's power stations (including Medupi and Kusile) qualify, in terms of the List of Activities, as existing plants, which should have met existing plant MES by 1 April 2015, and should meet new plant MES by 1 April 2020.

However, all but one of Eskom's power stations (Kusile) sought, and largely obtained, several postponements of compliance with the 2015 and 2020 MES (for which provision is made in the List of Activities and the National Framework for Air Quality Management). Although the List of Activities contemplates postponements for a maximum of five years each, there is no prohibition on applying for more than one postponement. However, exemptions from the MES are not legally permissible. Eskom appears to have indicated an intention to apply for

rolling postponements for various stations and pollutants (primarily SO_2) until the stations are eventually decommissioned. Interviewees indicated that this would have the same effect as an exemption, which is, as noted above, not legally permissible.

In order to meet the relevant emission standards, various capital equipment must be installed or retrofitted onto power stations. A fabric filter plant (FFP) can be used to reduce PM emissions, flue gas desulphurisation (FGD) can be used to reduce SO_2 emissions, and low NOx burners can be used to reduce NOx. Any upgrade or retrofit to the existing power generation infrastructure will result in cost implications for Eskom. This will include the initial capital cost and an associated operating cost, as well as the cost of emission monitoring equipment (such as particulate emission monitors, gaseous emission monitors and ambient air quality monitoring equipment). There will also be additional costs associated with increased water and energy consumption once operating with certain retrofitted components.

The status of current compliance is informed by an assessment of Eskom's coal-fired power stations for air quality compliance prepared by Cairncross (2017). Assessment results are assumed to remain constant in the absence of appropriate retrofits. Table 4 below shows the infrastructure investment needed to ensure that each station is compliant with the MES. The achievement of air quality compliance, or lack thereof, based on the current emissions given the station's AEL and MES, is represented by various colours.

In our model this is implemented to ensure compliance assuming a lead time of two years for the various technologies (Eskom, 2011)[16]. This also needs to be viewed in the context of the decommissioning schedule as outlined in the draft IRP 2016 (Department of Energy, 2016a) and in Table 7.

---

[16] *According to the Air Quality Strategy the outage time required to perform the retro fits is 150, 130, 120 days for Low NOx burners, FGD and FFP respectively, which can be planned to coincide with General Overall outages.*

Table 4: Air Quality Compliance

		Arnot[17]	Camden	Grootvlei[18]	Hendrina	Komati
PM	AEL (1 April '15 - 31 March '20)	Insufficient Data	Compliant	Range compliance/non-compliance	Compliant	Range compliance/non-compliance
	MES (Existing Station Stnds - 1 April '15)	Insufficient Data	Compliant	Range compliance/non-compliance	Compliant	Range compliance/non-compliance
	AEL (1 April '20 - 31 March '25)	Insufficient Data	Compliant	Non-compliant	Compliant	Non-compliant
	MES (New Station Stnds - 1 April '20)	Insufficient Data	Compliant	Non-compliant	Compliant	Non-compliant
SO$_2$	AEL (1 April '15 - 31 March '20)	Insufficient Data	Compliant	Compliant	Compliant	Compliant
	MES (Existing Station Stnds - 1 April '15)	Insufficient Data	Compliant	Compliant	Compliant	Compliant
	AEL (1 April '20 - 31 March '25)	Insufficient Data	Compliant	Compliant	Compliant	Compliant
	MES (New Station Stnds - 1 April '20)	Insufficient Data	Compliant	Non-compliant	Compliant	Compliant
NOx	AEL (1 April '15 - 31 March '20)	Insufficient Data	Compliant	Compliant	Compliant	Compliant
	MES (Existing Station Stnds - 1 April '15)	Insufficient Data	Compliant	Compliant	Compliant	Compliant
	AEL (1 April '20 - 31 March '25)	Insufficient Data	Non-compliant	Compliant	Compliant	Compliant
	MES (New Station Stnds - 1 April '20)	Insufficient Data	Non-compliant	Compliant	Compliant	Non-compliant
Assumed retrofits required for MES compliance (1 April 2025 onwards)		FGD, Low NOx burners	FFP, FGD, Low NOx burners (currently being fitted)	FFP (currently being fitted), FGD	FGD	FFP, FGD, Low NOX burners

Legend:
- Insufficient Data[19]
- Current emissions range between compliance and non-compliance[20]
- Compliant
- Non-compliant

---

[17] De Witt (2003) reported that units 1,2 and 3 were to receive FFP retrofits.

[18] This is for Grootvlei units 2-4.

In terms of the conditions of Grootvlei's AEL's, the PM value limits are changed 3 times over the 5-year period. That is, between 01 April 2015 to 31 December 2016 the limit is 350 mg/Nm³, between 01 January 2017 to 31 March 2018 it is 200 mg/Nm³, and from 01 April 2018 to 31 March 2020 it is 100 mg/Nm³.

[19] According to Cairncross (2017) there is "insufficient data" for Arnot's emissions, but we have assumed that FGD and Low NOx burners are required.

[20] In the case of Grootvlei and Komati, the PM emissions were recorded as 182 – 237 mg/Nm³ and 73 – 155 mg/Nm³ respectively. Given the AEL's for these two stations, these current emission figures range between being compliant and being non-compliant with air quality requirements as set out in their AEL's.

Given the current state of air quality compliance, the following has been input into the station level analysis[21] per station:

In the absence of sufficient current emission data, Arnot is assumed to be within the limit values set out in its AEL for PM, SO_2 and NOx emissions till 31 March 2020. It is also assumed that its SO_2 emissions are above the MES (as at 1 April 2020) as it has been exempted from SO_2 emissions until 31 March 2025. We also assume, therefore, that both PM and NOx are within the MES till 31 March 2025. Based on these assumptions, Arnot will only require FGD for the remaining units from 1 April 2025 until decommissioning of the last unit by 2029.

Camden's last unit will be decommissioned in 2024, and it is therefore assumed that no retrofitting (apart from the current retrofitting of low NOx burners) will be required.

We have assumed that FFP and FGD will retrofitted at Grootvlei in order to be compliant until the last unit is decommissioned in 2028.

We have assumed that Hendrina will be retrofitted with FGD from 1 April 2025 till decommissioning of its last units in 2026.

Komati will require FGD, FFP and low NOx burners to be compliant with the MES. We have assumed that these retrofits will be done in order to be compliant until the last unit is decommissioned in 2028.

As mentioned above, achieving air quality compliance requires a capital investment by Eskom and the equipment incurs an ongoing operating expense. Furthermore, additional costs, associated with the increased consumption of water and energy when operating these retrofits, are incurred, although these have been excluded from our study. Eskom has published numerous documents containing the costs associated with retrofits for air quality compliance, but has refrained from breaking down the costs per station, or per component[22].

The costs used in this study, presented in Table 5 below, are based on the work done by De Wit (2014) and are in 2014 ZAR[23]. Table 5 clearly shows that FGD is the costliest retrofit relative to the other technologies. As discussed above, it is also the technology required at all the power stations we investigated[24], with the exception of Kusile (which will be fitted with FGD from the outset). Eskom will have to be prepared to incur significant costs in ensuring air quality compliance if it insists on continuing to operate the older coal-fired power stations.

Table 5: Alternative Baseline Abatement Units Cost Estimates

Emissions	Technology (%removal efficiency)	CAPEX (R/kW)	OPEX (R/kW)
PM	FFP	2514	156*
NOx	LNB (30%)	775	8
SO_2	Semi-dry FGD (90%)	5508	141

Notes: * excluding OPEX for DHP

Source: de Wit, 2013

---

[21] A presentation by the DEA on 7 November showed the uncertainty by Eskom regarding the implementation of retrofits required to achieve air quality compliance at Arnot, Camden and Hendrina.

[22] The Air Quality Improvement Plan (Eskom, 2016a), the executive summary of a meeting with the board of sustainability (Eskom, 2014a), Air quality Strategy 2015 (Eskom, 2015a), Eskom's response at parliament regarding the MES (Eskom, 2017g) and a number of other documents.

[23] CAPEX for PM, NOx and SO_2 in 2017ZAR is approximately R3001/kW, R925/kW and R6575/kW respectively.

[24] According to Eskom (Eskom, 2017h), all existing coal-fired power stations will require FGD retrofits to be compliant with the MES from 1 April 2025.

4.4.5   Coal costs

Besides geological factors that contributed to the low costs of extracting coal, Eskom historically utilised low-grade coal and built plants at the mouth of tied mines, moving coal short distances from the mine, primarily by conveyor, thus incurring very low transport costs. Long-term coal supply agreements (CSA) were based on two contract models that furthermore reduced the explicit cost of coal to Eskom, cost-plus and fixed price contracts. This resulted in Eskom paying very low prices for its coal. In 2000, Eskom's average coal price was approximately R60/t (in nominal terms). By FY 2018 this had risen to R400/t.[25]

The cost increases in recent times have been driven by various factors, including expansions into more challenging geological areas, general mining cost inflation (which averaged 14% from 2004 - 2014)(Obholzer & Daly, 2014), a shift away from long-term mine mouth suppliers to medium and short-term contracts, and greater transport costs associated with the new contracts.

Eskom's reliance on short and medium-term contracts has grown from 1 million tons (Mt) in 2000 to 45 Mt in 2015) (Dentons, 2015). The increase is driven by the need for Eskom to supplement its long-term coal supply agreements. Reasons for this include Eskom's plant burning more coal per unit of electricity, inability of long-term contracts at cost-plus collieries to deliver their contracted volumes (Dentons, 2015), and because Eskom returned older plants, which did not have long-term coal supply agreements, to service. These return-to-service (RTS) stations include Camden, Komati and Grootvlei.

While the short and medium-term contracts are not necessarily more expensive than tied mines at the mine gate (though many are), they are typically significantly more expensive on a delivered basis. As Eskom has shifted increasingly to short and medium-term contracts (either because of underperformance of tied mines or because the RTS stations did not have

tied mine supply), the tonnages that are trucked or railed, rather than moved via conveyor, have increased. By 2015, Eskom was transporting 60% of its coal on conveyor, 30% on road and 10% on rail. This equates to around 40 million tons per annum (Mtpa) being moved via truck (Singh, 2015), up from only 14% of coal moved on truck in 2007 (Burton & Winkler, 2014).

Trucked coal is either costed as delivered (when mines transport the coal on behalf of Eskom) or on free carrier agreements (where Eskom contracts trucking services). Though both types of contract are based on Eskom's transport model and should be comparable, the reality is that trucking costs depend on the length of route (and thus turnaround times at stations), and on road conditions. Direct transport costs per ton of coal are therefore not directly comparable across contracts, though in 2015 they were around R1/t/km excluding handling at the mine (Dentons, 2015; interviews). We have used figures in Oberholzer & Daly (2014) as an average cost of trucking and handling of R117/100km/ton (2014 ZAR). This is purely the direct financial cost. Externality costs such as pollution, accidents and congestion are not accounted for.

Transport has particular relevance for this study, given that the RTS stations are typically purchasing their coal on short and medium-term contracts with potentially high mine gate prices and transport costs. This places them at the top of the fuel cost curve. While Grootvlei and Camden have rail infrastructure, at Camden this is a containerised solution (i.e. more expensive than usual rail). Costs of blended transport (truck to rail or vice-versa), as used at Grootvlei, can be higher than when trucking only (Singh, 2015). Blended transport does, however, minimise the externalities associated with trucking. While previously less relevant at Arnot, transport costs are also now important for coal supply at that station.

---

[25] *In the cost-plus tied collieries, capital expenditure was shared between Eskom and the mining houses; Eskom paid all the operational costs of mining while mining companies earned a return (around 9%, Merven & Durbach, 2015) on their capital input and a fee for mining. Eskom secured access to the resource but bears all CAPEX and OPEX risks (with planning oversight). At mines where the resource could support both exports and Eskom supply of coal, miners would export the higher-grade coal and supply the middlings fraction -an intermediate grade product - to Eskom at marginal cost. This typically resulted in very cheap coal, amongst the cheapest contracts on the system. Essentially, company returns were supported from higher value exports (Burton & Winkler, 2014).*

Costs associated with long-term contracts at the older stations are also set to increase over the next few years. For example, Hendrina's very cheap fixed price contract expires at the end of 2018, and will have to be renegotiated upwards from the R162/ton (2015 ZAR) to cover mining costs at Optimum Coal Mine.

At Arnot, historically supplied from a cost-plus contract, Eskom was liable for sustaining capital expenditure in the mine, which it did not provide. This had the effect of reducing the capacity at the mine without reducing its fixed costs, thereby driving up unit costs. This made alternative short-term contracts with high transport costs appear increasingly competitive, even though it would have been comparable in costs to recapitalise the mine. It is widely believed that the primary reason that Eskom has not made the necessary investments (in all the cost-plus mines) is because it is capital constrained. Indeed, Eskom acknowledged this in its integrated report (2015: 49), stating that its financial constraints are "restricting capital expenditure at cost-plus mines, which may impact future coal supply".

However, the refusal to recapitalise old mines (or timeously negotiate new cost-plus contracts) is also a result of political interference. According to interviewees, in 2014 the Department of Public Enterprises notified Eskom that the utility would not be allowed to provide further capital to mines. Eskom was thus prevented from making the necessary investments to sustain its long-term coal supply and secure future supplies. This has had the effect of artificially raising the cost of coal from cost-plus mines, making alternative supply options appear competitive, and inflating primary energy costs across the fleet.

The limit on capitalising mines also undermined negotiations between Eskom and Anglo American regarding the supply of coal from the New Largo resource to Kusile. As discussed in Section 4.4.5.6 below, this has delayed the development of the tied mine for which Kusile's boilers were designed. It has also led to the procurement of coal that will have to

be trucked or railed to the station, both until the mine is developed, and to supplement supply throughout the station's life. This will raise the costs of coal to Kusile, and impacts supply security at the station because of physical limits to imports such as transport options and stockyard design. It will also require trucking of coal or investment in new rail infrastructure to serve the plant[26].

Our coal cost projections for each of the stations in our study are based on a detailed bottom-up analysis. Our main source of information on current contracts and volumes is the Dentons report (2015). This is supplemented by reviews of coal industry reports to ascertain other possible supply options (e.g. Prevost, 2009), company reports (Environmental Impact Assessments, annual reports, reserves and resources reports), news articles and interviews. We have also compared our supply options against Du Plooy (2010), which optimised coal supply for Eskom to 2020.[27] Where contracts have ended, or end in the near future, we have assumed that future contracts will be renegotiated (provided the resource remains available) on similar terms, despite above-inflation increases in labour and other input costs. We have also assumed some economic rationality in coal supply, for example at Arnot. However, comparing current contracts with optimised scenarios, as in Du Plooy, highlights that Eskom's basket of contracts is suboptimal, and many resources that should have been developed in the past 10 years have not been developed.

The following section briefly describes the background and context of coal supply for each station in this study.

4.4.5.1   Arnot

Arnot's coal supply has been mired in controversy after the long-term coal supply agreement with Exxaro's Arnot colliery ended[28] on 31 December 2015, seven years earlier than Eskom Primary Energy's internal end date for the CSA of 31 December 2023

---

[26] By a rough estimate, if 50% of Kusile's coal demand is trucked-in, it will equate to approximately 750 trucks per day.

[27] Unfortunately, many of the resources supplying our stations in Du Plooy (2010) (which optimised coal supply to Eskom to 2020) have not been developed. In short, Eskom's current coal supply mix remains sub-optimal.

[28] Eskom typically describes this as "allowed to expire" and Exxaro as "terminated".

(Dentons, 2015). Eskom legitimised the cancellation of the CSA because of the very high price per ton, caused by lack of capital expenditure at the mine. By the end of the contract in 2015, the mine was delivering 1 Mtpa (according to Eskom's then Acting CEO Matshela Koko), versus contractual volumes of 4,1 Mtpa (Dentons, 2015; Creamer, 2016). Given that a significant portion of costs do not vary with production volume this substantially increased the cost per ton. Eskom's contract information reports a price of R686/ton in 2015 (or around R30/GJ), making it amongst the most expensive coal procured by Eskom. However the delivered cost of coal has been publicly disputed between Eskom and Exxaro (Dentons, 2015; McKay, 2016).

Eskom further claimed that Exxaro offered to extend the contract at an average price of R737/ton excluding capital and closure costs (Eskom, 2016b). This differs with public statements made by Exxaro where they claim the cost of coal from the recapitalisation and extension of Arnot Colliery would be around R500/ton (Exxaro, 2015). The Exxaro price was confirmed as approximately correct by interviewees, though it would be a function of detailed mine design and coal specifications.

However, even though Eskom cancelled the Arnot Colliery CSA, they failed to secure a medium-term supply of coal for the plant, releasing a RFP for supply of coal to Arnot only in August 2015 (RFP GEN

3264)(Eskom, 2016b). At the start of 2016, the station had to be supplied on a month to month basis from a variety of short-term contracts, before Eskom awarded the contract to Optimum Mine (amaBhungane, 2016).[29]

The deal meant Eskom was paying approximately R583/ton[30], including transport costs. But Eskom's contract with Optimum for suppling Hendrina with coal, costs only R162/ton (2015 ZAR), meaning that instead of maximising coal purchases on that contract and transporting the coal to Arnot, Eskom simply paid three times as much for the coal, as well as transport costs (Public Protector South Africa, 2016).[31] This is roughly comparable to the price Exxaro offered at Arnot, but the circumstances of the payment have been widely criticised as corrupt, especially since the release of the GuptaLeaks (amaBhungane & Scorpio, 2017). Eskom's early termination of the Arnot Colliery CSA thus appears to have been intended to create demand for coal at Arnot so that the Gupta-owned Tegeta mine could supply the station from a profitable CSA linked to the Optimum coal mine. [32]

By August 2016, however, National Treasury had blocked the extension of Tegeta's contract with Arnot, citing contraventions of procurement rules. Despite this, several interviewees suggested that the Guptas were continuing to supply Arnot. Currently the mine seems to be supplied from various short and medium-term contracts.

---

[29] *In April 2016, Eskom pre-paid Tegeta (at that point not yet the owners of Optimum Mine) R659 million for supply of coal to Arnot. The pre-payment was signed off by Matshela Koko and Eskom's Board Tender Committee at a late-night meeting, and the Public Protector's Report has shown that the prepayment contributed to the payment made by Tegeta to Glencore to acquire Optimum Coal Holdings. The business rescue practitioners later reported suspicious activity regarding the contract in that the prepayment was not used for investment at OCM for the supply of coal (PP Report) and also https://www.dailymaverick.co.za/article/2016-10-20-amabhungane-r587m-in-six-hours-how-eskom-paid-for-gupta-mine/#.Wd474iN953I*

[30] *According to Eskom (2016b), they prepaid R659m for 1,2Mt of coal: R550/ton. Arnot is approximately 24km from Hendrina.*

[31] *The economics of Optimum and the Hendrina contract are elaborated on in section 4.4.5.4, but we note that Hendrina's coal supply was subsidized from exports and the price Eskom pays (R162/ton) is below the current costs of extraction. Optimum therefore has to cross-subsidise that contract from exports (since cancelled) or the Arnot contract, or other mines in the Optimum Coal Holdings stable (e.g. Koornfontein). The prepayment and higher prices have been justified because it required further investment at Optimum; this has been disputed by the business rescue practitioners (Public Protector South Africa, 2016).*

[32] *The economics of Optimum and the Hendrina contract are elaborated on in Section 4.4.5.4, but we note that Hendrina's coal supply was subsidized from exports and the price Eskom pays (R162/ton) is below the current costs of extraction. Optimum therefore has to cross-subsidise that contract from exports (since cancelled) or the Arnot contract, or other mines in the Optimum Coal Holdings stable (e.g. Koornfontein). The prepayment and higher prices have been justified because it required further investment at Optimum; this has been disputed by the business rescue practitioners (Public Protector South Africa, 2016).*

Our analysis assumes the extension of existing contracts provided that there are sufficient resources at those mines and subject to planned mine closures. The suppliers are Hlagisa Wildfontein (1,6 Mtpa, R338/ton ex-mine), Umsimbithi Wonderfontein (2,1 Mtpa, R450/ton), North Block Complex (3,1 Mtpa, R255/ton ex-mine) (2015 ZAR) [33]. However, we have also assumed that Eskom agrees to recapitalise the now-closed Arnot Colliery (including the Mooifontein extension) since that would minimise transport costs and the concomitant impacts of trucking coal. Based on nearby mining options, Eskom's purchase of surface rights at Arnot (which pre-dated the termination of the CSA), and the goal of minimising coal trucking, the re-opening of Arnot colliery as a base supplier to Arnot, would likely be the optimal supply solution, with top-up contracts utilising middlings coal from the many multiproduct mines in the area (such as Mafube, or Exxaro's Belfast project). This has the effect of reducing the average cost of coal to Arnot compared to the high prices seen in 2015.

4.4.5.2   Camden

According to Dentons (2015), two supply contracts were running up until 2015, and parliamentary questions to the Department of Public Enterprises in September 2017 confirmed that the contracts have been extended. Suppliers are Vunene Mining Usutu Colliery (1,5 Mtpa, R370/ton delivered) and Sudor Halfgewonnen (1,9 Mtpa, R225 ex-mine) (2015 ZAR). These volumes are not sufficient to supply Camden in our scenarios, and we have therefore costed the incremental coal at a spot price of R650 delivered. This is based on the incremental cost information released by Matshela Koko (le Cordeur, 2017a) that shows the average cost of coal at Camden is over R500/ton. This puts Camden at the top of the coal cost merit order, a view supported by our interviews.

Even with this high marginal coal cost, the lower cost contracts reduce the average cost of coal going into Camden, which we have modelled at R457/ton (2017

ZAR). It is also possible that a higher price was negotiated when existing contracts from Halfgewonnen and Usutu were extended in 2015, but there is no public cost information about either mine. Halfgewonnen is privately owned and Vunene have not released contract information since they moved to underground mining at Usutu.[34]

This conservatively under-costs the supply of coal at Camden, lowering the station's levelised cost of electricity.

4.4.5.3   Grootvlei

Grootvlei has no tied mine and has only one medium-term contract, with HCI Khusela's Palesa Colliery (1,92 Mtpa, R180/ton ex-mine) (2015 ZAR) which runs until 31 March 2018. However, demand from Grootvlei exceeds this in the high and low demand scenario. Historically, the station has "never had a stable supply" (interview) and was topped up from multiple contracts. In 2013, the station had at least 10 suppliers (Eskom, 2013). In optimised scenarios for Grootvlei (du Plooy, 2010), supply comes from several resources that are currently not developed, and none of our interviewees could provide further insight about current supply. We assume that much of the coal is being provided to Grootvlei from contracts linked to other stations.

To simplify the modelling, we have extended the contract with Palesa to the end of the station's life (based on an assessment of the available resource at Palesa) (Hoskens Consolidated Investments, 2016). We have then supplied the station with coal that is costed to match the fuel cost at Grootvlei released by Matshela Koko in January 2016 (le Cordeur, 2017b).

4.4.5.4   Hendrina

Hendrina is primarily supplied from a long-term fixed price contract from Optimum Coal Mine (OCM) (5,5 Mtpa, R162/ton delivered) (2015 ZAR) which expires in December 2018. The station is also supplied from a

---

[33] While the CSA with North Block Complex is for 4 Mtpa, Exxaro's has stated that domestic saleable tons from the mine are only 3,1Mt (Exxaro reserves and resources report 2016). For all three contracts, we have calculated transport costs on top of these contract prices.

[34] A more recent contract with Silverlake Trading Uitgevalen was included in Parliamentary questions in September 2017, but is for less than 1 Mtpa, and is not included in our modelling.

medium-term contract with Liketh Investments (KK Pit 5) (2,4 Mtpa, R418/ton delivered, expires March 2018) (Dentons, 2015).

Optimum was formerly owned by Glencore and was sold to the Gupta-owned Tegeta in 2016. The Optimum contract (originally cost-plus) was converted to a fixed price contract signed in 1993, and, as with other fixed price contracts, middlings coal was supplied to Eskom at a very low price in return for the right to export coal. In recent years, as mining costs increased and export prices have decreased (in dollar terms), the mine has increasingly struggled to cover the costs of supplying the Eskom coal, claiming hardship and attempting to renegotiate the terms.[35] Optimum was running at a loss of about R130 million per month at the time of Tegeta's purchase (Public Protector South Africa, 2016), was no longer participating in the export market (McKay, 2015) and therefore needed to reduce the Hendrina contract.

We have assumed that the station will continue to purchase coal from its current suppliers until the end of its life. Interviewees indicated that if resources are not mined out, Eskom would typically renegotiate contracts with existing suppliers. Liketh reprocesses dumps and we therefore assume there is substantial product still available to supply Hendrina after 2018. Similarly, the resource at Optimum is sufficient to supply Hendrina until the original decommissioning date in 2026 (interview, industry expert).

We assume that Eskom will maximise the Liketh contract in terms of contracted volumes. While the current delivered tonnage from Liketh coal is not known (Eskom will not make this information available due to claims of commercial sensitivity), medium-term fixed price contracts have some volume flexibility on an annual basis, but not over the contract period. Eskom can reduce or increase off-take within specified bounds, about 10% depending on the contract, but must have purchased the total contracted volume by

the end of the contract. We have also assumed delivered prices remain the same, i.e. include transport costs. However, we do not know the distances covered and note that this assumption might underestimate future transport costs. [36]

Hendrina cannot be supplied at full load except from a mix that includes a tied mine (i.e. only partial imports are possible due to the existing infrastructure layout at the station) (industry interview). Therefore, we have assumed that if the station is run past end 2018, a new CSA with Optimum will have to be negotiated with a higher price to cover the costs of mining and capital. We have based this on Glencore's negotiations with Eskom, where Glencore noted that operating costs at the mine were approximately R300/ton, and that after the contract expires at the end of 2018, the price required by Glencore was approximately R570/ton (in 2019 ZAR). This would more than triple the cost of coal going into the station.

4.4.5.5 Komati

Komati is currently primarily supplied from the Koornfontein Mine, which was sold by Glencore in 2016 as part of the Optimum Coal Holdings transaction with the Gupta owned Tegeta. The mine was included in the transaction under pressure from Eskom. Matshela Koko insisted that Eskom could not approve the sale of the Optimum coal mine only, as to do so would impact the future security of coal supply. He argued that the mine was not viable as a stand-alone asset under the current terms of the Eskom contract. Koornfontein mine has supplied Komati since at least 2012, and is located proximate to the Komati station, although it is not connected by a conveyor. Media reports indicate that coal is still being trucked 10km from Koornfontein to the station (Comrie, 2017).

In August 2016, Eskom awarded Koornfontein a contract worth R6,9bn for the period August 2016-

---

[35] We should note that while export prices have fallen in dollar terms, rand prices of exports have been more stable because of the devaluation of the rand. However, mining costs have risen across the industry, which would account for some of the hardship felt by Optimum Mine. Furthermore, the contracts were designed so that mining companies earned very high returns in early years (covering costs of Eskom supply and high earnings on exports). This seems to have been forgotten by subsequent purchasers of the mine.

[36] Given that the plant output was reduced in recent years and the Liketh contract is delivering the contracted tonnages, this would reduce the quantity of coal required at Hendrina from Optimum Mine. This would have allowed the mine to maximise the higher value contract at Arnot instead of the loss-making contract at Hendrina (in 2016), which is partly how the Guptas could have succeeded in covering their costs.

2023 (2,4 Mtpa), or approximately R414/ton (Public Protector South Africa, 2016; Comrie, 2017).

Despite the suspicious circumstances under which the contract was awarded, we assume that the station is now locked into this coal supply agreement. We also assume that the existing Liketh Tavistock/Tweefontein contract is extended beyond March 2018 because it is relatively well priced, and there are substantial discard dumps available for processing. While the contract with Liketh is split between Duvha and Komati, we assume that the full supply is going to Komati. This is because Duvha currently has two units offline, and is supplied from the fixed price Middelburg mine. Fixed price contracts have limited volume flexibility. It is likely therefore that there is an oversupply at either Duvha or Komati, or indeed both. Since the Liketh contract is marginally better priced than the Koornfontein contract, rational planning would utilise the contract as much as possible within the technical parameters of the station and the contractual terms of each agreement. While the Dentons study includes North Block Complex as a supply option, we have assumed all production from North Block Complex is currently being used at Arnot (and the mine is close to the end of its life). There is also a minor contribution at Komati from Lurco VDD (0,48Mt), which became public in September 2017 via parliamentary questions. This is not included in our modelling. The contract is also for seven years. Compared to Eskom's coal consumption data at Komati over the past six years (Eskom, 2016c), it appears as though the station is (contractually, at least) oversupplied. This is exacerbated by the recent announcements that the station is to be placed in lean preservation and in practice already has several units offline.

4.4.5.6   Kusile

This section outlines our estimates of the incremental costs of coal supply associated with Kusile units 5 and 6, over and above the costs of supplying the first four units. Kusile's cost of coal depends on our assumptions about:

- the already signed coal supply contracts;
- the cost of coal from the as yet to be built New Largo coal mine; and
- long-term imports to the station (mine and transport costs) from yet to be contracted sources.

Kusile was originally designed to burn coal from the co-located Anglo American New Largo resource. Despite Anglo initiating environmental and regulatory permitting processes as far back as 2007, the mine remains undeveloped. Progress was hindered by Eskom and Anglo's inability to find mutually agreeable terms for the coal supply agreement. Key sticking points related to the capital sharing arrangements, returns to be earned by the shareholders, and Black Economic Empowerment ownership requirements.

In the interim, Eskom signed medium-term contracts for the station's initial years. Despite the substantial additional costs and externalities of importing such coal to Kusile from other mines, Eskom has only recently released a tender for long-term coal supply at the station, which is expected to include a response from New Largo. However, it is clear from interviews that due to financing challenges, a smaller version of the mine will be designed and will supply around half of Kusile's total demand (15 Mtpa at full load). This still leaves a substantial residual volume of coal to be imported to Kusile over its lifetime following the construction of New Largo.

Given that Kusile was designed to be supplied by a large tied mine, the coal yard infrastructure was not designed to facilitate large-scale coal imports and will face challenges in congestion, stockpiling and blending, if 50% of its supply is imported. Procurement of many smaller, cheaper contracts will exacerbate this problem due to the greater need for coal blending and handling. These constraints will therefore require further capital investment should large imports be required.

Our assumed supply scenario to the station is thus premised on the existing contracts Eskom has signed, an assumption about what portion of supply will come from New Largo (based on industry interviews and modelling), and assumptions about future supply options. We have assumed that New Largo will still be the base supplier to the station given the constraints of transporting coal from further afield. The portion of these residual imports that are considered to be incremental (or avoidable) are those tons that are not yet contracted and are not to be supplied from New Largo. We therefore assume that most of these incremental imports will only be required if units 5 and 6 are commissioned (planned for November 2021 and

September 2022 respectively) and they are therefore included in the cost of coal to these units. Conversely, we assume that the smaller New Largo will be built, even if units 5 and 6 are not completed, and therefore associate its coal cost mostly with units 1 to 4. The coal for the last two units will therefore be more expensive.

We developed a financial model of New Largo in order to estimate its cost of coal. The model was based on the size of the mine, type of mining and mine parameters (e.g. strip ratio, washing costs, etc.), and capital expenditure and phasing. We estimated the cost of coal from New Largo to be R335/ton (2017 ZAR).

Existing contracts for Kusile in Dentons (2015) are typically to multiple plants (Rirhandzu Mine 1,2 Mtpa, R256/ton ex-mine, ending March 2018; Universal Wolvenfontein, 2 Mtpa, R353/ton ex-mine, ending March 2023; Tshedza Manungu, 1,62 Mtpa, R245/ton ex-mine, ending March 2030).[37] However, based on other sources, we have assumed that Tshedza's Manungu mine will supply up to 3 Mtpa from 2018 (ICHORCOAL, 2015; Industrial Development Corporation, 2016). We did not extend Wolvenfontein

past 2023, although the resource may allow for it (the Middelbult resource).

We have allocated the residual demand for coal at Kusile to the Eloff Resource. This was identified by interviewees as one of the few large resources of the correct quality left in the Central Basin. We assumed similar ex-mine prices as at Wolvenfontein, as it is a contiguous resource.[38] Thus, if the Wolvenfontein contract was to be extended as an alternative to the Eloff resource, it would not change the economics of this coal supply to Kusile significantly.

Figure 4 shows how the coal supplies to Kusile have been allocated and therefore which coal supplies we count towards the incremental coal costs of units 5 and 6. The residual imported supply of coal is the difference between Kusile's full demand of 15 Mtpa and the existing contracts already signed (Wolvenfontein and Manungu) and our assumed contribution from New Largo. In earlier years, this is slightly less than 5 Mtpa because of the size of New Largo and existing contracts. The incremental coal supplied to units 5 and 6 is assumed to be the coal above the 10 Mtpa line.

---

[37] Information released after the completion of the modelling showed two new contracts that we did not include: AEMFCs Mzimkhulu and Chilwavhusiku mines (3,38 Mtpa over 10 years) (DPE, 2017). However, no pricing information was released by the DPE and AEMFC has not reported any details of the contracts, and we have thus excluded these mines in our modelling.

[38] There was limited data available on the resource, limiting more detailed modelling of costs.
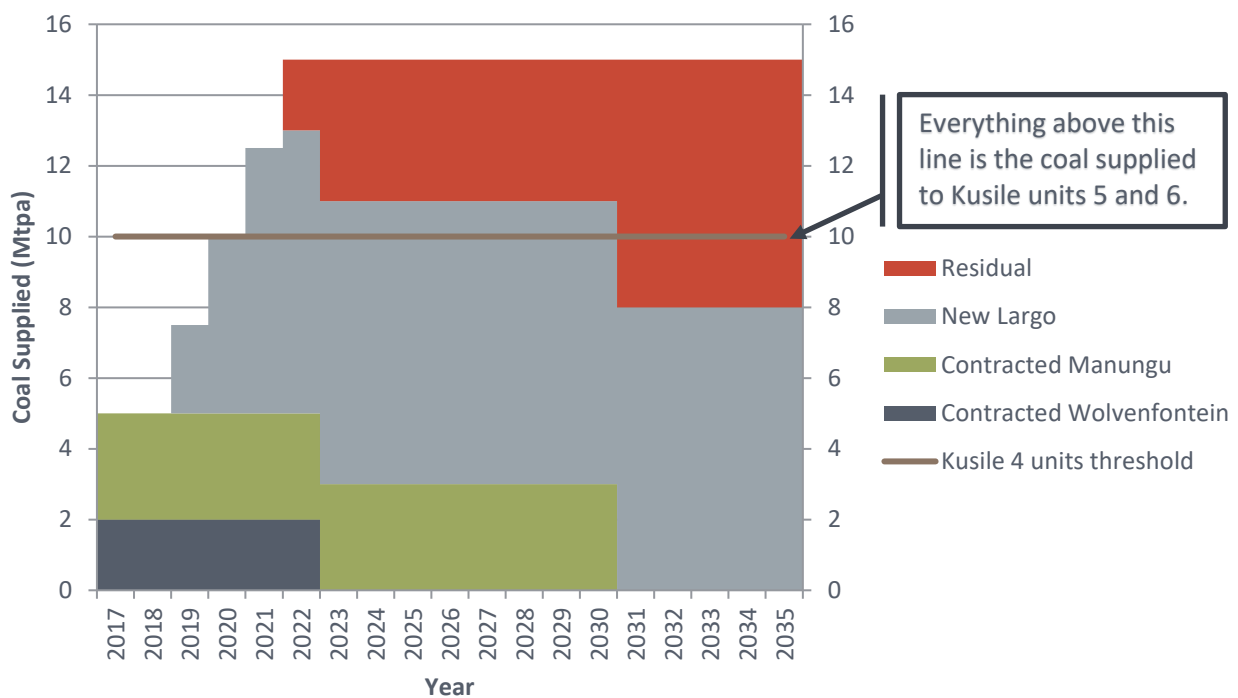
Figure 4: Coal Supplied to Kusile (Dentons, 2015; Ichor 2015; IDC, 2016; interviewees; authors own calculations

The cost of coal to Kusile overall is R377/ton (2017 ZAR) and the incremental cost of coal for units 5 and 6 is R446/ton. Since the required imports would be substantially lower without these two units negating the need for stockyard capital expenditure and transport costs, the supply of coal to these units can realistically be assumed to be higher.[39] Furthermore, there are few large mines where coal can be extracted more cheaply than our assumed ex-mine prices. Earlier estimates of coal costs to Kusile have ranged from R350/ton in current terms and substantially higher; Macquarie estimated costs of R374/ton (2014 ZAR) (Daly & Oberholzer, 2014), and interviewees' calculations ranged from R350 to over R500/ton (subject to size of New Largo, financing arrangements, and imports). These are comparable with official estimates of coal costs, for example in the draft IRP 2016 (R500/ton)(Department of Energy, 2016b).

While the final coal mix at Kusile may differ, we nonetheless consider these estimates to be

conservative. A sensitivity analysis of this result can be found in Section 5.3 below.

4.4.5.7   Conclusions

It is likely that our coal cost assumptions are an underestimate, given that demand at Arnot and the RTS stations has not been fully met from the medium-term contracts listed in the Dentons report. It is likely that each of these stations has short-term or even spot price coal purchases, or is being topped up from other existing contracts (where transport costs are not known and therefore not included in our estimates). Eskom's average price of coal this year is R398/ton (Eskom, 2017e), but this includes the low cost, high volume contracts at stations such as Medupi, Matimba, Kendal, Duvha and Lethabo. The average coal cost for the older stations will be significantly higher. The stations in our analysis are all higher coal cost stations, as is evidenced by the information

---

[39] The evaluation of prices in Eskom's RFP for coal at Kusile does not include logistics costs (i.e. does not differentiate bids based on delivered prices), although total costs including logistics will be considered prior to award of the contract. This means that cheaper ex-mine contracts located far from Kusile could be competitive with New Largo as logistics is not a part of the pricing adjudication (RFP GEN 3277) (Eskom, 2017).

Matshela Koko (le Cordeur, 2017b) made public, and confirmed by our interview findings.

Further analysis of the precise coal supply arrangements and costs would provide further insight into the levelised costs of the older stations and would certainly lead to an increase in our assumed coal costs.

Table 6 summarises the costs per station discussed in the preceding sections.

Table 6: Summary of Costs (2017 ZAR)

	Arnot	**Camden**	**Grootvlei**	**Hendrina**	**Komati**	**Kusile**	**Kusile (units 5&6)**
O&M - fixed (R/kW/a)	638	686	686	638	686	959	959
O&M - variable (c/kWh)	6	6	6	6	6	8	8
Water (R/kl)	8	7	4	8	8	19	19
Coal - delivered (R/ton)	380	457	519	407	407	377	446

4.4.6 Other power station analysis assumptions

Table 7 below shows the default IRP 2016 decommissioning dates that we used for the reference scenario. It also shows the earlier decommissioning dates tested in our analysis.

Table 7: Decommissioning Scenarios

Power station	IRP 2016 Decommissioning: Start	IRP 2016 Decommissioning: End
Arnot	2021	2029
Camden	2020	2023
Grootvlei	2025	2028
Hendrina	2020	2026
Komati	2024	2028
Grootvlei, Hendrina, Komati (GrHeKo)		2019, 2019, 2020

While in practice decommissioning cash flows can occur over a period of many years, even decades after the official closure date, we assumed a single decommissioning cash flow for each scenario to occur five years after the actual date. As can be seen in our results below, we are not concerned with the actual cost of decommissioning the older plant, because Eskom is already committed to incurring this cost. We must, however, reflect the net cost increase that is caused by the earlier decommissioning scenario tested for each station. This decommissioning cost increase can be avoided by not decommissioning a station earlier than planned. We therefore add this net decommissioning cost increase to the system alternative value or avoided cost of running each station.

We further have to account for the cost of corporate income tax, which was done by grossing up the National Treasury post-tax economic opportunity cost of capital by the corporate tax rate.

4.5   STUDY LIMITATIONS

Given the complexity of the South African power system, a study of this nature must inevitably accept many limitations, including the following:

- By its very nature numerical modelling of the power system and its economics entails a myriad of simplifying assumptions.
- Very little information is available in the public domain about all aspects of Eskom's operations, and that which is released is carefully controlled by Eskom. The lack of transparency severely hinders public scrutiny and investigations by independent analysts. As Eskom is a public utility, this is clearly not consistent with the values of an open democratic society.
- We have excluded some costs for which we lacked data; coal handling, refurbishment costs, and some coal contract data. These would add to the costs associated with running the stations in this analysis.
- As explained above we did not investigate a low demand scenario.

5 RESULTS

This section presents the results of our study. We describe the system level analysis outcomes, and then present the more detailed findings per power station option investigated.

5.1 SYSTEM MODEL RESULTS

The reference scenarios used in this analysis provide several interesting insights into the future of the South African electricity system. The installed capacity and energy output can be seen in Figure 5 and Figure 6 (for the moderate demand) and in Figure 7 and Figure 8 (for the high demand).

In both demand scenarios, coal-fired power stations provide most electrical energy until about 2025, after which coal's contribution starts to decline (as older coal-fired plants are decommissioned). No new coal-fired power is built after Kusile (which is taken as committed in the reference scenarios), as new coal is simply no longer competitive. Demand is met primarily from new solar PV and wind generation. Renewable energy is supplemented by flexible technologies; storage (pumped storage and batteries) and open-cycle gas turbines for peaking. In the high demand scenario, combined cycle gas turbines are deployed after 2040. No new nuclear plants are built in any scenario either. Coal and nuclear are no longer a part of South Africa's least cost electricity mix.
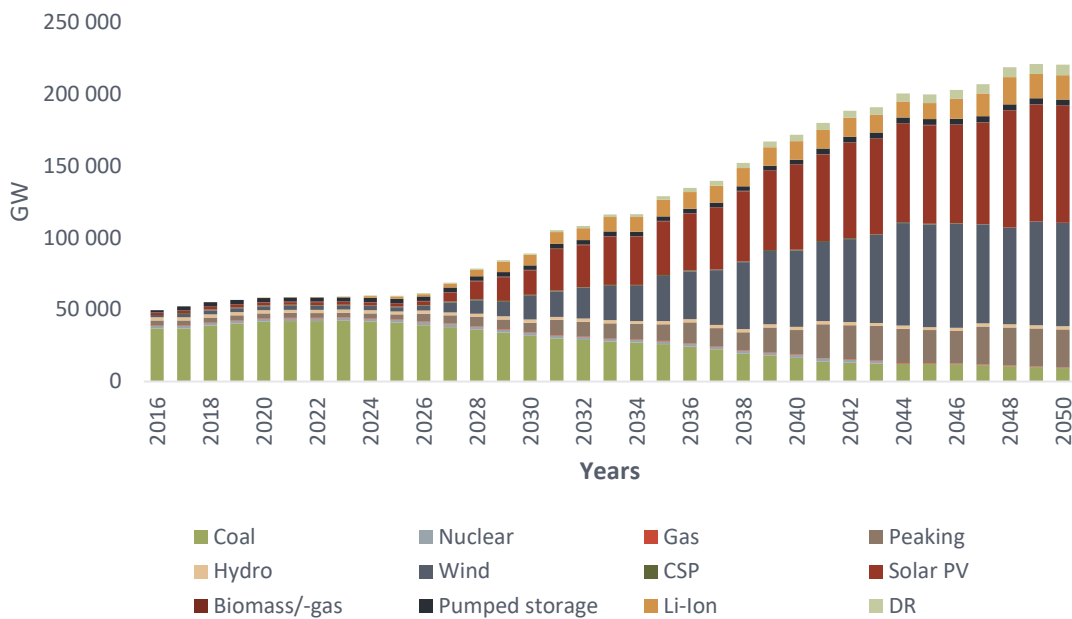

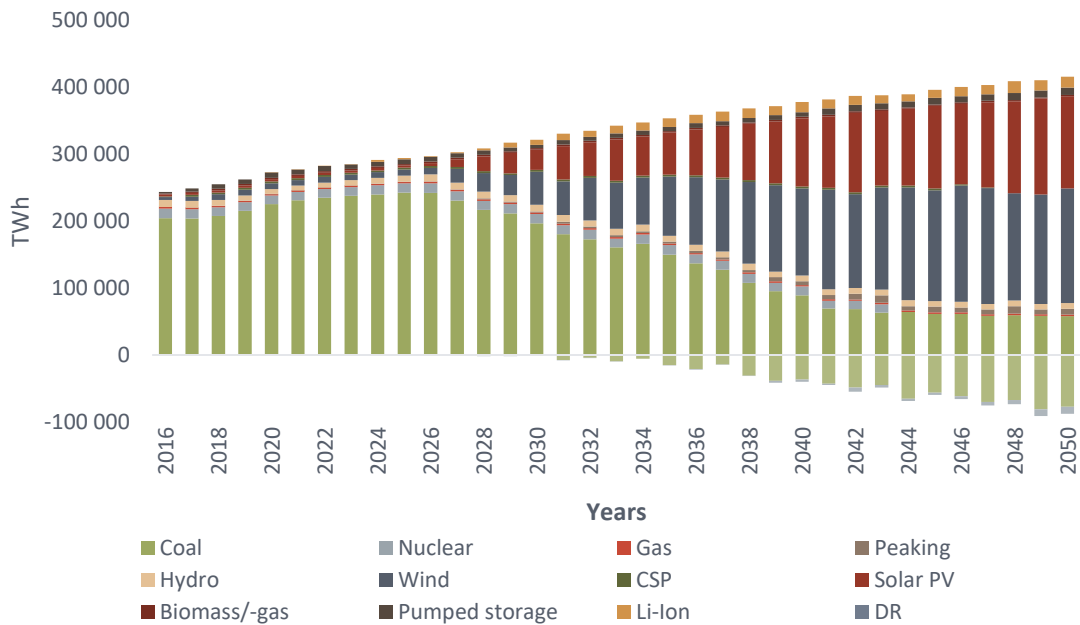**Figure 5: Moderate Demand Scenario Installed Capacity (GW)**

Figure 6: Moderate Demand Scenario Energy Mix (TWh/year)

In the moderate demand scenario, renewable energy accounts for 41% of installed capacity by 2050 (Figure 5). Renewable energy supplies 26% of electricity by 2030, and 74% by 2050 (Figure 6). By 2030, renewable energy provides 33% of electricity in the high demand scenario, increasing to 79% by 2050 (Figure 8).
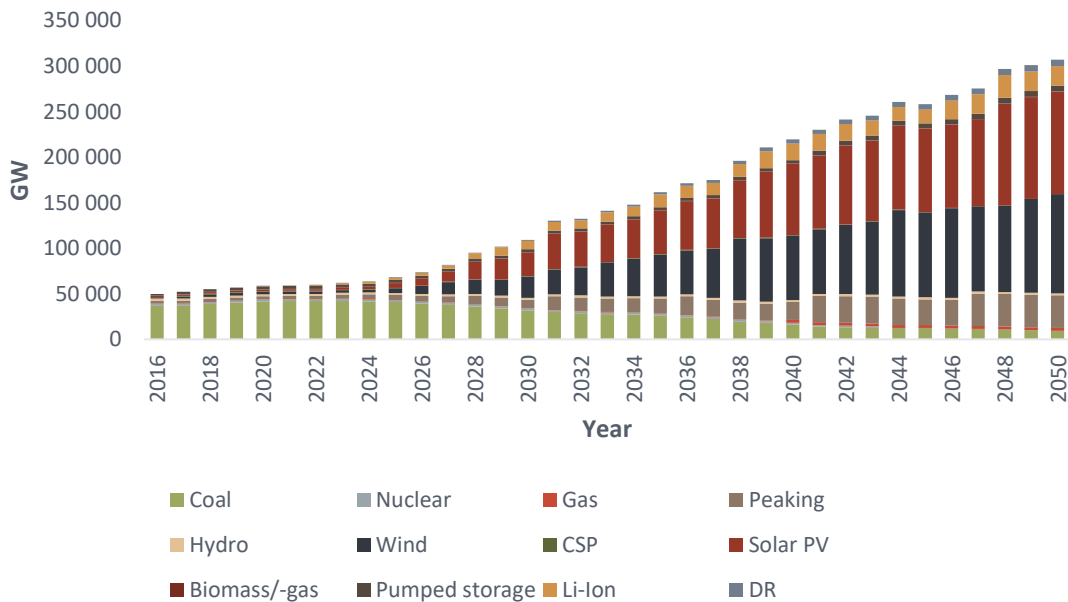

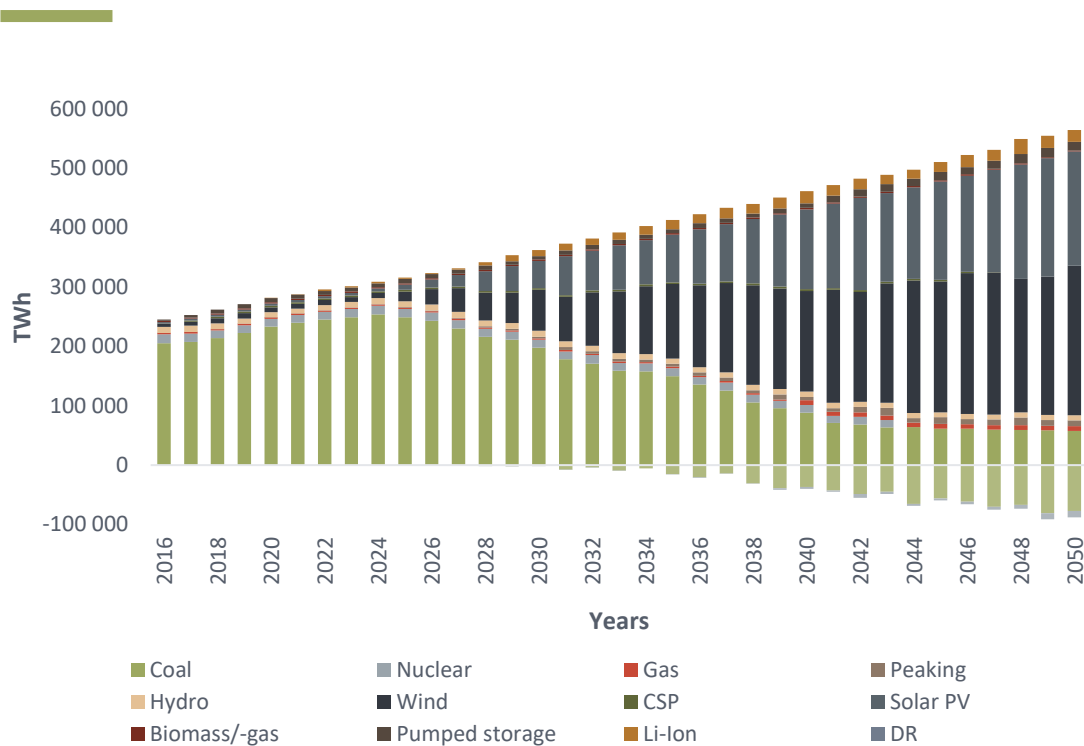**Figure 7: High Demand Scenario Installed Capacity (GW)**

Figure 8: High Demand Scenario Energy Mix (TWh/year)

The remainder of this section describes the difference between the reference system scenarios (moderate demand and high demand) and the scenarios where a particular option is removed (i.e. stations are not completed, in the case of Kusile units 5 and 6, or are decommissioned early, either as individual stations or simultaneously). The scenarios where a particular option is removed, are used to determine the cost of filling the gap, by means of other existing and new resources available to the system and the system alternative value (SAV) (or avoided cost) of the option.

After the removal of a station (like Arnot), the model optimises the use of existing stations and new investments, and in so doing, ensures that the energy balance is maintained at the least cost (given certain system requirements). The energy mix of the system is altered in this case. Although slightly different in each case, the energy mix remains fairly consistent between scenarios. That is, after early decommissioning of an existing coal-fired power station, demand is initially met mostly by existing coal generation capacity in the earlier years (for all scenarios), i.e. by running the existing fleet at higher load factors. This remains the case even when removing Grootvlei, Hendrina and Komati simultaneously. The energy from the existing

fleet is supplemented by a combination of new build wind, solar PV, and peaking and battery capacity. In Arnot's case, open-cycle gas turbines (OCGTs) are also built. This diversified energy mix is evident in both the high and moderate demand scenarios.

Similar to the other scenarios, the energy from Kusile units 5 and 6 is primarily replaced by additional energy from the existing coal fleet in the first four years, followed by new wind, solar PV, peaking, batteries and gas capacity in the high demand forecast scenario. In the low demand forecast scenario, the initial energy gap is supplied by the existing coal fleet (but for a longer period), followed by the deployment of new wind, solar PV, peaking and battery capacity.

The system alternative value (SAV) varies between scenarios, as depicted in Figure 9. The SAV for Kusile's last two units was found to be between 0.57 - 0.61 R/kWh for the moderate and high demand forecast scenarios respectively. For the older stations, the SAV is typically much lower, even in the high demand scenario. The system can meet demand when a station is decommissioned early, even with very high demand, at a cost of 50 c/kWh and at a moderate demand at 34 c/kWh, which are included in Figure 10 and Figure 11.
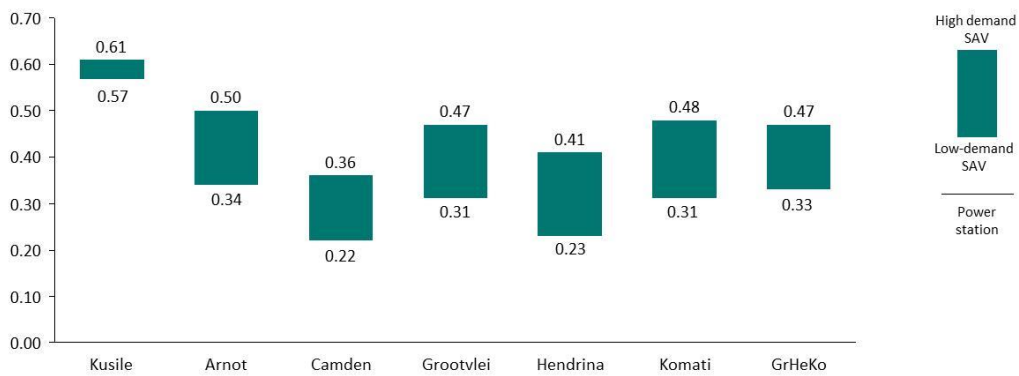
System Alternative Value [R/kWh]

Figure 9: System Alternative Value for Each Power Station for High and Moderate Demand Forecasts

The following section briefly describes the results of the station level analysis and compares the SAV against the levelised cost of electricity produced at a particular station.

5.2 STATION LEVEL ANALYSIS

Table 8 and Table 9 show a breakdown of the components of the incremental levelised cost per station for each demand scenario. As can be seen, the incremental LCOE is driven by primary energy costs, and fixed and variable operating costs. Capital expenditure to meet air quality standards is a relatively smaller portion of total costs, as are the associated operations and maintenance (O&M) and water costs. In both demand scenarios, the LCOEs of the stations range from approximately 48 c/kWh to 58 c/kWh.

Table 8: Components of Incremental Levelised Costs in the Moderate Demand Scenario (2017 c/kWh)

	Fixed O&M	Variable O&M	Env Retro O&M	Water cost	Fuel Cost	Env Retro Capex	Total LCOE
Arnot	10.3	6.1	0.6	1.7	26.1	5.3	50.1
Camden	12.0	6.1	0.0	1.7	29.3	0.0	49.1
Grootvlei	12.0	6.1	0.7	0.6	32.1	6.8	58.3
Hendrina	10.5	6.1	0.1	2.0	27.5	2.1	48.3
Komati	11.7	6.1	3.2	1.9	22.0	11.8	56.8
GrHeKo	11.3	6.1	1.1	1.5	27.5	6.0	53.6
Kusile (units 5&6)	16.0	8.3	0.0	0.2	25.9	0.0	50.4

Table 9 shows the same breakdown but in a high demand scenario. Here, the LCOEs range from 48,2 c/kWh to 58,1 c/kWh, which is only slightly different to the moderate demand scenario LCOEs.

Table 9: Components of Incremental Levelised Costs in the High Demand Scenario (2017 c/kWh)

	Fixed O&M	Variable O&M	Env Retro O&M	Water cost	Fuel Cost	Env Retro Capex	Total LCOE
Arnot	10.2	6.1	0.5	1.7	26.1	5.2	49.9
Camden	12.0	6.1	0.0	1.7	29.3	0.0	49.1
Grootvlei	11.9	6.1	0.7	0.6	32.1	6.7	58.1
Hendrina	10.4	6.1	0.1	2.0	27.6	2.0	48.2
Komati	11.6	6.1	3.2	1.9	22.0	11.7	56.4
GrHeKo	11.2	6.1	1.1	1.5	27.5	6.0	53.4
Kusile (units 5&6)	15.7	8.3	0.0	0.2	25.9	0.0	50.1

Figure 10 and Figure 11 compare the LCOE for each scenario against the system alternative value (SAV) plus the net costs incurred for early decommissioning.
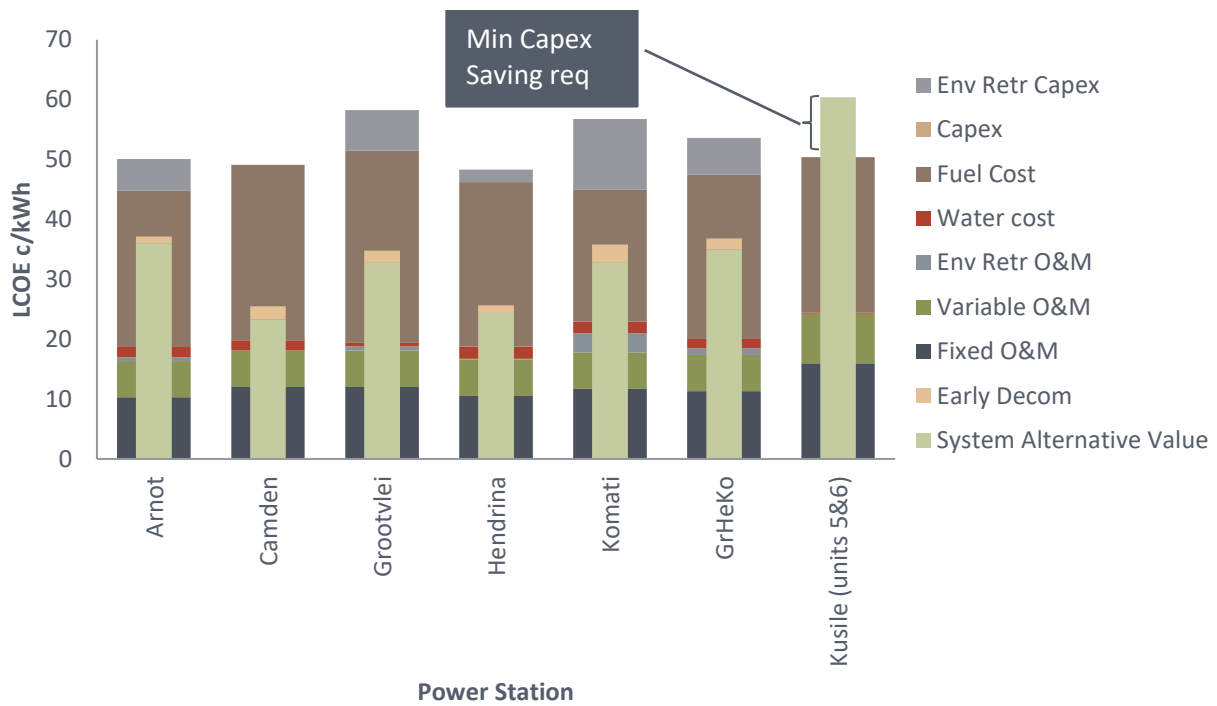

Figure 10: Comparison of System Alternative Value and Levelised Costs per Station (2017 c/kWh) in the Moderate Demand Scenario
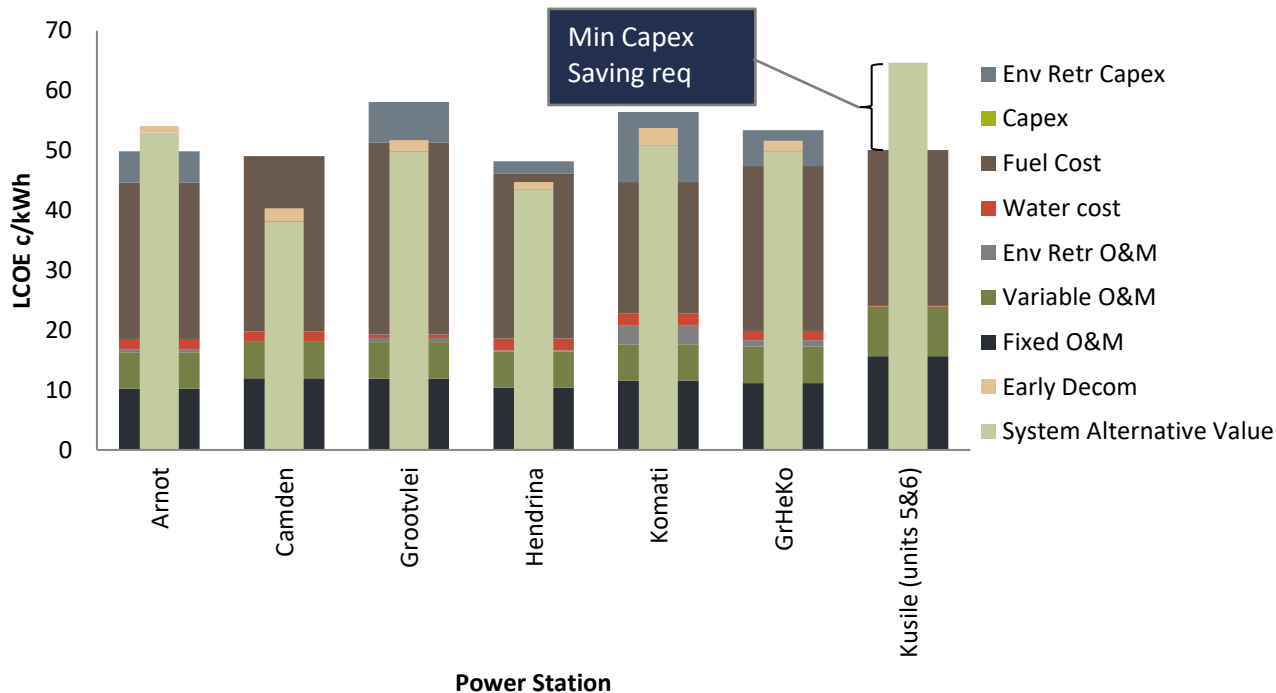
Figure 11: Comparison of System Alternative Value and Levelised Costs per Station (2017 c/kWh) in a High Demand Scenario

We discuss the results for each option below:

5.2.1   Individual stations

As can be seen in the tables and figures above, Arnot's levelised cost of electricity (LCOE) exceeds the system alternative value (SAV) of the station in a moderate demand situation, but not in a high demand scenario. Arnot's LCOE in the moderate demand scenario is 50,1 c/kWh, and the SAV of the station is 36 c/kWh (including early decommissioning). Arnot's LCOE in the high demand scenario is 49,9 c/kWh, and the SAV is 53 c/kWh (including early decommissioning).

Under the moderate demand scenario, therefore, it is possible to meet demand without running the station, and Eskom would save approximately R5,1bn if it decommissioned the station early (see Table 10 below). In a high demand scenario (which is now considered highly unlikely), the system alternative value of the station is higher, suggesting it may be prudent to keep the station running. Early closure would incur costs of R1,6bn. Arnot's role in maintaining grid stability on the Mozambique line

means that Eskom would need to invest in a new substation to replace the station before committing to decommissioning.[40]

Furthermore, compared to the moderate demand reference scenario, early decommissioning of Arnot would result in a saving of 40 Mt of CO_2.

The LCOE at Camden is 49,1 c/kWh, and exceeds the system alternative value in both a high and moderate demand scenario. The SAV in the moderate demand scenario is 23,3 c/kWh, and in the high demand scenario it is 38,2 c/kWh. Early decommissioning of Camden could save Eskom R5,1bn (moderate demand scenario) or R1,9bn (high demand scenario).

The LCOE of Grootvlei in the moderate demand scenario is 58,3 c/kWh, and the system alternative value is substantially lower at 32,9 c/kWh. In the high demand scenario, the LCOE is 58,1 c/kWh, and the SAV is 49,8 c/kWh. In both a high and moderate demand it is therefore a net saving to the system to decommission Grootvlei early. This could save Eskom

---

[40] *We have also been informed of Arnot's role in maintaining grid stability on a transmission line supplying Mozambique and that this means that Eskom would need to invest in a new substation to replace this role.*

R1,56bn (high demand) or R5,7bn (moderate demand).

In the moderate demand scenario, the LCOE of Komati is 56,8 c/kWh, and the system alternative value of the station is 32,9 c/kWh. In the high demand scenario, the station's LCOE is 56,4 c/kWh, and the SAV is 50,9 c/kWh. Early decommissioning of Komati could save Eskom R434m or R3.3bn, depending on the demand scenario.

In a moderate demand scenario, Hendrina's system alternative value is 24,4 c/kWh and its LCOE is 48,3 c/kWh. In the high demand scenario, the station's SAV is 43,5 c/kWh but is still below the cost of running the plant at 48,2 c/kWh. In either demand scenario it is therefore more cost effective to decommission the station earlier. This could save Eskom R1,2bn or R7,8bn, depending on the demand scenario.

Given the state of the station and the requisite CAPEX for refurbishment that is probably required (not modelled here), the plant is a prime candidate for early decommissioning. The substantial increase in coal costs from January 2019 support the early closure of the station.

5.2.2   GrHeKo

In the GrHeKo scenario, instead of decommissioning a single station early, we investigated a more realistic scenario of decommissioning three stations, totalling around 4 GW, over an earlier period of three years. In both the high and moderate demand scenario, the levelised costs of the three stations exceed the system alternative value. In the moderate demand scenario, the LCOE of GrHeKo is 53,6 c/kWh, and the SAV is 35 c/kWh. In the high demand scenario, GrHeKo's LCOE of is 53,4 c/kWh, and the SAV 49,8 c/kWh. Even the simultaneous, early decommissioning of three stations is a net saving to the electricity system, saving Eskom R1,3bn in the high demand scenario, and R12,5bn in the moderate demand scenario (which is much more probable).

Early decommissioning of GrHeKo also reduces CO_2 emissions by approximately 70Mt compared to the reference scenario (moderate demand). The savings are primarily made before 2030.

Table 10 summarises the cost savings for Eskom if it decommissions stations early.

Table 10: System Cost Savings Arising from Earlier Decommissioning (R'm)

Scenario	Arnot	Camden	Grootvlei	Hendrina	Komati	GrHeKo
Moderate Demand	5 177	5 139	5 714	7 829	3 371	12 568
High Demand	-1 696	1 914	1 567	1 228	435	1 336

Note: These savings are not additive; our methodology assesses each station individually, except in the case of GrHeKo.

5.2.3   Kusile units 5 and 6

The results of Kusile units 5 and 6 need to be interpreted slightly differently to those of the other scenarios. Although we have explained our methodology in section 3, it is worth revisiting again here, before explaining the results.

Bearing in mind that the station level analysis looks at the incremental or avoidable costs, in the case of the other scenarios we compared each station's incremental levelised cost to its system alternative value (SAV) to determine whether the station in question should be decommissioned early, or as in the

case of Kusile, whether Kusile units 5 and 6 should be completed or cancelled.

The incremental cost of Kusile includes the avoidable capital cost of Kusile units 5 and 6. However, we were not able to obtain reliable estimates of the avoidable capital costs for these units. We have therefore reversed part of the analysis in this case by netting off the other components of its levelised incremental cost from its system alternative value. This determines the avoidable capital cost at which the option of cancelling Kusile units 5 and 6 costs the same as completing it (given the costs of the alternative resources that will be used in this case). This is the threshold capital cost saving. Therefore, if the capital cost saving is more

than this threshold, it will be more economic to cancel rather than complete construction of Kusile units 5 and 6, even considering that other resources will have to be employed in future to replace the supplies that would have come from these units.

Table 11 below shows that this threshold capital cost saving level is approximately R4 747m for the moderate demand scenario and our stated assumptions. To put this into perspective, the capital cost savings threshold required is approximately 1.9% of the total capital cost of the station,[41] or approximately 13% of the estimated cost to completion of Kusile.[42] Table 11 shows that, compared to the system alternative value (the avoided cost of operating the two units), the net saving of not completing the two units is zero at this minimum threshold level. If the capital savings that can be realised by not completing these two units is larger, positive net savings will result.

Table 11: Kusile Cost Saving Threshold (Moderate Demand Scenario)

Percentage of estimated cost to completion for Kusile	Present Value of CAPEX saving (R'm)	Nett CAPEX Saving (R'm)
13.18%	4 747	0
20%	7 202	2 455
25%	9 002	4 256

Furthermore, if Eskom curtails capital expenditure at Kusile, and chooses not to complete the plant, the CO_2 savings would be 59Mt in 2030, compared to the moderate reference scenario. Over the period to 2050, the saving would total 256Mt CO_2.

5.3 SENSITIVITIES

In this section we report on the additional sensitivity analysis of a few key parameters. One of the most important sensitivities, changes in the demand forecast, is reported on throughout.

We also investigated the impact of increasing the cost of coal supply to Kusile units 5 and 6. As discussed in section 4.4.5.6, it is not unlikely that the coal prices for Kusile could increase to R500/ton (i.e. R530/ton in 2017 ZAR, approximately 19% above the current coal price assumed for units 5 and 6). If this was the case, then the capital savings threshold for discontinuing the construction of units 5 and 6, for the moderate demand scenario, would reduce from R4 747m to R2 784m. This is an even lower minimum capital cost saving threshold when, given the costs of the alternatives available, it becomes cheaper to discontinue units 5 and 6 than complete them.

While there is a smaller possibility of the cost of coal increasing as much for the other stations investigated, for comparative purposes our results show that with this same percentage coal cost increase, the savings from decommissioning GrHeKo go up from R12 567m to R15 903m. However, this savings increase is likely to be overstated because in the case of the older stations they are in effect replacements for each other in the early years (especially Majuba, which is run much harder) and the cost of coal to these alternative stations is also likely to increase in this higher coal cost scenario.

We also considered a case where the operating costs (which includes Fixed and Variable O&M and the additional operating costs associated with environmental retrofits) were reduced by 20% for all stations considered in this study. This would reduce the LCOE for all older stations marginally, but not enough to reduce it below the system alternative

---

[41] *The cost is calculated as a present value of the capital expenditure cash flows.*

[42] *Assuming, in line with a long history of cost over runs, that the cost to completion will be 15% more than Eskom's current budget to completion for the station as reported in their 2016/17 Integrated Report (Eskom, 2017d).*

value (SAV) and in the moderate demand scenario. Therefore, the result remains unchanged for this scenario. In the high demand scenario, the LCOE remains below Arnot's SAV, but the LCOE of Komati and GrHeKo is reduced to below their SAV. All other stations' LCOE remain above their respective system alternative values.

In the case of Kusile, reducing the operating costs by 20% results in an increase in the capital cost saving threshold to just over R7bn.

We also considered whether the only reason that there would be savings from decommissioning the older stations results from the environmental retrofit capital costs and associated higher operating costs. As can be seen from the figures in Section 5.2 above, if these costs are removed, the savings from earlier decommissioning are still positive in the moderate demand scenario. In the (less plausible) high demand scenario, the results are mixed with decommissioning GrHeKo incurring a net cost.

6 BROADER IMPLICATIONS AND CONCLUSIONS

In this section we review the implications of our findings and present our conclusions. At the outset we described two important aspects of the circumstances that Eskom currently finds itself in. Firstly, it is confronted with a global energy transition towards cheaper renewable power generation and associated technologies. Secondly, Eskom faces a crisis in its financial viability with a risk to its solvency and liquidity that could have a large, negative systemic impact on the economy if not urgently addressed. It is in this context that our study was initiated to investigate the economics of decommissioning Eskom's older coal-fired power stations and curtail part of its construction programme.

We were careful to adopt a conservative approach in the methodology and assumptions used. In many ways reality has already overtaken our assumptions: our high demand scenario is now clearly unrealistic, whereas it has become apparent that a demand scenario lower than our moderate scenario should be considered, and achieved renewable technology learning curves are clearly more aggressive than we assumed, etc. If these conservative assumptions are corrected, it will affect the system alternative value (SAV) of the options we investigated, and increase the savings associated with removing each plant option from the system. The analysis did not consider the large social, economic, and environmental costs associated with coal-fired power. South Africa cannot continue to effectively ignore these costs. They must be included when the costs and benefits of power sector options are considered in the IRP process and other planning discussions.

The system analysis undertaken by the CSIR for the reference scenario produced results that are in themselves important. For a least cost optimised system, no new coal-fired power is built after Kusile, and no new nuclear plant is built either. New coal and nuclear plant is simply no longer competitive. When new capacity is required, demand is met primarily from new solar PV and wind. In the more plausible moderate demand scenario, renewable energy is supplemented by flexible technologies, storage (pumped storage and batteries) and open-cycle gas

turbines (OCGTs) for peaking, but no combined cycle gas turbines. In the high demand scenario, combined cycle gas turbines are only deployed after 2040. In the moderate demand scenario this means that the gas demand for peaking OCGTs will remain low until at least 2030 or later. Overall the system level analysis thus shows that South Africa does not need a nuclear, coal or gas procurement programme.

These conclusions are substantially different from those included in the government's 2010 IRP, and even the updated draft 2016 version. This serves to emphasise the importance of regularly updating the IRP and using realistic, up-to-date input assumptions to maintain a credible plan that will ensure South Africa retains its competitive advantage in low cost reliable electricity supply.

South Africa is endowed with among the best renewable energy resources in the world. Renewable energy resources now provide the cheapest source of energy on a new build basis, and will soon be cheaper than running many existing coal stations. South Africa cannot afford to fall behind while our trading partners and competitors are rapidly adopting lower cost power.

Our results show that decommissioning the older coal plant or abandoning the construction of Kusile units 5 and 6 are likely to be the most economic way forward for Eskom. Our further estimates show that decommissioning GrHeKo and avoiding the completion of Kusile units 5 and 6 could give rise to a financial saving in the region of R15 - 17bn without affecting security of supply. Some further model runs are required to confirm this conclusion. These estimates do not reflect the large savings in the negative impact on human health, local environment and climate change that will result.

These are large and difficult decisions to make and are fraught with vested interests that will be affected. We have already seen from Eskom's ongoing governance crises that Government and Eskom are partially paralysed, and could struggle to take the right decisions in public interest. It is exactly for situations like this (i.e. where democratic governance fails), that countries create independent regulators (or independent public protectors, independent courts, etc.). It is therefore critical that the National Energy

Regulator of South Africa (NERSA) ensures that these issues are investigated and addressed, and that Eskom is only allowed to recover efficient costs in its tariffs.[43]

Despite the fact that the economics now dictates that at least 4 GW of older plant should be decommissioned, Eskom does not have proper plans in place to do so. It is therefore critical that NERSA and the relevant government departments require Eskom to put this process in motion.

Ensuring a just transition for existing employees is of paramount importance and should be the subject of a multi-stakeholder political process and further analysis. Workers and communities should not bear the brunt of Eskom's financial crisis. Part of the savings realised could be used to cushion the impacts on workers and communities and provide support for re-training, skills development, relocation, etc.

Lastly, we have to consider the possibility that Eskom's financial position is even worse than generally understood at the time of writing. Our analysis was focussed on the relative economics of the options considered, and did not consider the financing implications of each option. However, if Eskom's financial crisis continues to worsen, as we suspect it might, financial constraints will have to be brought into the picture. In this case, further possibilities must be considered in the light of the systemic risk to the state and the entire economy. Assuming that the economy's ability to absorb further tariff increases[44] and Government's ability to provide further bailouts and sovereign guarantees are rapidly diminishing, Eskom will have to urgently find other ways of maintaining its solvency and avoiding a liquidity crisis. In this scenario, the only option will be to reduce the haemorrhaging of cash. The question will be how this can be achieved without letting the lights go out?

Although not discussed in this report, it appears that Eskom has some scope for cutting back on human resources costs, and on reducing its primary energy costs. However, this is unlikely to be achievable over the short-term or to be sufficient. Two key insights that emerged during this study are therefore critical for considering how best to address this question:

- The level of surplus capacity that Eskom now anticipates for the foreseeable future is at least equal to an entire Medupi or Kusile power station, or more.
- By the time this spare capacity will be required in future, it will be cheaper to provide it by a combination of alternative means (renewable energy, gas turbines, battery storage, etc.).

Essentially the unavoidable conclusion is that Eskom is still spending vast amounts of capital on a power station construction programme that it does not need and cannot afford.[45] Drastically curtailing Eskom's power station capital programme (beyond Kusile units 5 and 6) might be the only way to restore its solvency. This will, of course, come at a high cost in terms of the penalties to be paid by Eskom in future, and the impact on personnel working on the construction projects. But, the lights will stay on, Eskom's cash flow situation could rapidly improve and confidence in Eskom and the economy would be restored.

In this scenario South Africa might well face a stark choice: abandon a large part of the Kusile (and possibly part of the Medupi) project, or allow Eskom, and possibly the state, to default on its financial obligations and pay an enormous economic and social price.

---

[43] See subsection 15(1)(a) of the Electricity Regulation Act (4 of 2006)

[44] Or, as a result of the utility death spiral dynamic, that tariff increases will only generate small revenue increases for Eskom while having an increasingly negative impact on the economy.

[45] To put this into context, we estimate that Medupi and Kusile will still require approximately R80bn capital expenditure (excluding interest) as of March 2017.

7 ANNEXURE A

Calculating the levelised cost of electricity for Medupi and Kusile

In this annexure, we will explain the capital expenditure profile assumed in this study for both Medupi and Kusile, as well as the other components of the LCOE calculation.

Eskom's new capital expenditure programme includes the construction of two mega projects, namely Kusile and Medupi, which are both coal-fired power stations with an installed capacity of nearly 5 GW each, and an approved budget totalling more than R300bn (Eskom, 2017d). In Eskom's latest revenue application (Eskom, 2017e), the utility stated that, "the new build capital expenditure for Medupi and Kusile contributes R20

billion to Generation CAPEX spend of R46 494 million in 2018/19". It is therefore clear that these two projects will have a significant impact on the financial situation at Eskom, both now and in the foreseeable future.

The availability of information pertaining to the capital expenditure for both Kusile and Medupi is limited. However, we were able to obtain useful information from the Eskom Integrated Reports (2010, 2011b, 2013b, 2015b, 2016d, 2017d)

The capital expenditure to date for Medupi and Kusile is tabulated in Table 12

The information sourced is for the period 2010 – 2017. As at 2016/17 the cumulative capital expenditure for Medupi and Kusile was R101.3bn and R112.4bn respectively.

Table 12: Capital Expenditure to Date in R'bn

	Financial year	Medupi Power Station	Kusile Power Station
Cumulative cost incurred on this project	March 2017	R 101.30	R 112.40
	March 2016	R 93.90	R 95.10
	March 2015	R 84.70	R 78.70
	March 2014	R 77.00	R 66.60
	March 2013	R 66.90	R 54.30
	2012[46]	R 54.80	R 39.50
Total: Inception to date expenditure 2005 – 2011		R 41. 910	R 24.896
Total: Inception to date expenditure 2005 - 2010		R 32. 076	R 14.697

---

[46] This cumulative cost was estimated by subtracting the estimated expenditure for the year 2012/13 obtained from National Treasury (2016:129), from the 2012/13 Eskom Integrated Report cost incurred to date (2013) (i.e. R54.3bn less 14.8bn in the case of Kusile, and R66.9bn less R12.1bn as in the case of Medupi).

The previous approved budgets for Kusile and Medupi, as presented in the Eskom Integrated Report (Eskom 2015), are R 118.5bn and R 105bn respectively. However, a revision of the budget resulted in increases to R 161.4bn and R 145bn respectively (Eskom 2016). The upward revision of the budgets was due to cost escalations resulting from time and cost overruns, some of which can be attributed to strike settlements (2016).

Given the information available, we attempted to reconstruct the typical S-curve capital expenditure profile of large infrastructure projects such as that of Kusile and Medupi (Electric Power Resource Institute [EPRI], 2015).

Two important points to bear in mind are: Firstly, we assume that the figures presented in the integrated and annual reports are accounting numbers and reflect the accounting cost in corresponding year terms, and that the total expenditure to date is therefore a simple summation (the budget figure is similarly an accounting number summing the cash outflows expected in future years).

Secondly, we did not attempt to independently estimate what the remaining cost to completion is, but rather distributed the remaining approved budget (i.e. R145bn − R101.3bn = R43.7bn for Medupi, and R161.4bn − R112.4bn = R49bn for Kusile) over the remaining years to completion, based on the planned commissioning dates of the remaining units as stated in the draft IRP 2016 (Department of Energy, 2016b)[47]. This is shown in Table 13 below.

---

[47] *This estimate does not allow for any possible future cost and time overruns.*

Table 13: Distribution of Capital Expenditure per FY (R'bn)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Medupi cumulative cost	1.0	2.0	4.0	8.0	16.0	32.1	41.9	54.8	66.9	77.0	84.7	93.9	101.3	117.4	127.6	137.6	145.0		
Kusile cumulative cost		0.9	1.8	3.7	7.3	14.7	24.9	39.5	54.3	66.6	78.7	95.1	112.4	126.1	135.9	143.8	150.6	156.5	161.4
Medupi CAPEX per annum	1.0	1.0	2.0	4.0	8.0	16.0	9.8	12.9	12.1	10.1	7.7	9.2	7.4	16.1	10.2	10.1	7.4		
Kusile CAPEX per annum		0.9	0.9	1.8	3.7	7.3	10.2	14.6	14.8	12.3	12.1	16.4	17.3	13.7	9.8	7.8	6.9	5.9	4.9

The figures in Table 13 show the cost in terms of expenditure per annum, which is simply calculated as the difference between the cumulative cost in the current year and the previous year. The cells shaded in orange are those for which we have data, and those shaded in grey indicate interpolated figures to achieve the S-curve expenditure profile. As mentioned above, this table represents accounting numbers in each year. According to EPRI(2015), the lead-time and project schedule should be approximately nine years. In both the case of Medupi and of Kusile, significant time overruns are evident.

The figures in Table 13 do not include the capital cost associated with the retrofitting of Flue Gas Desulphurisation (FGD) facilities at Medupi.

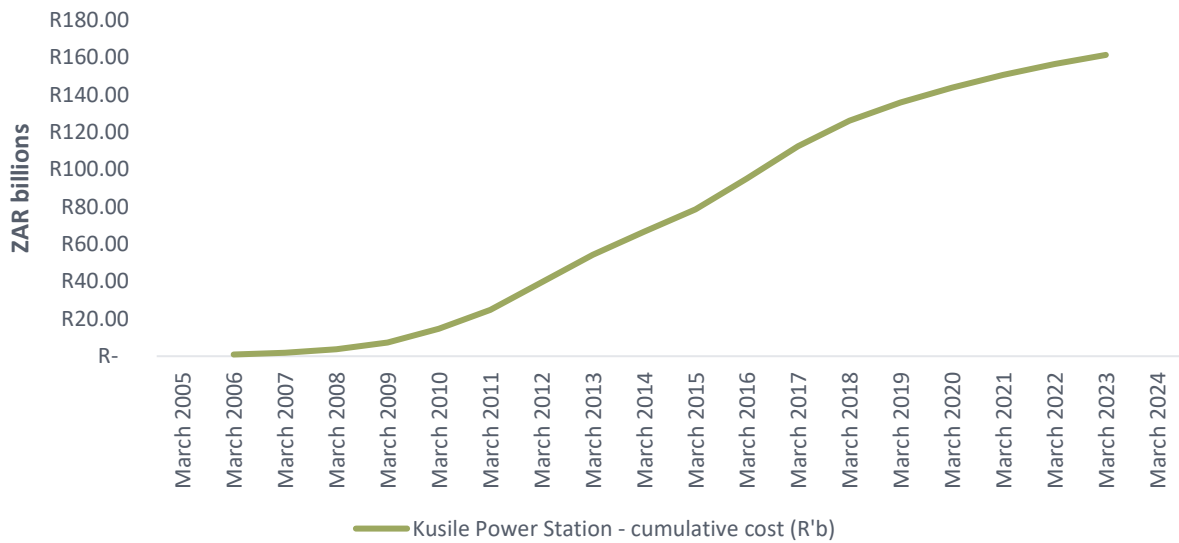Figure 12 and Figure 13 below illustrate the information in Table 13 graphically.
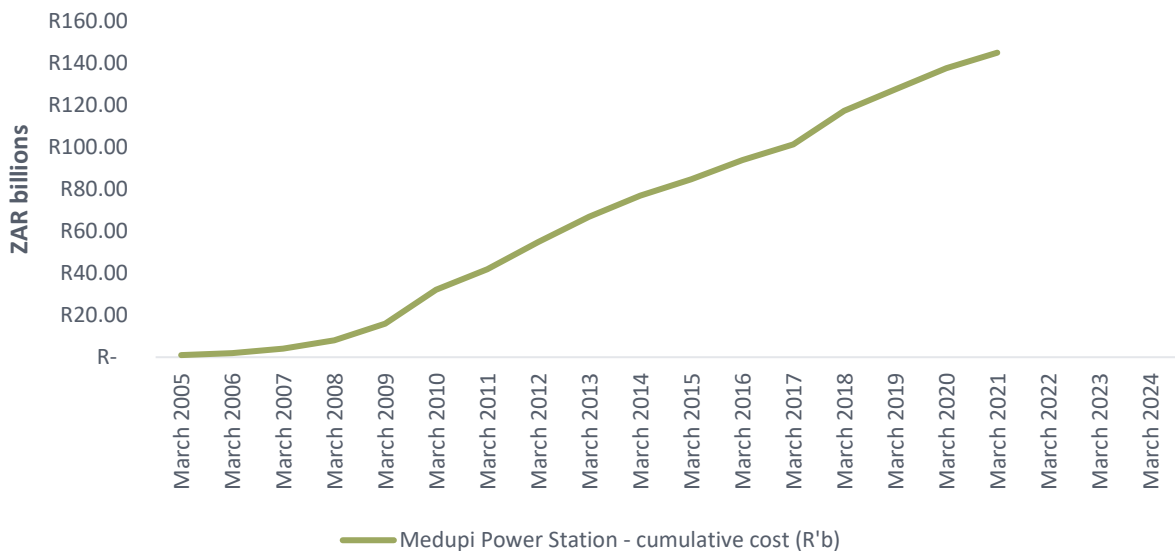

Figure 12: Kusile Cumulative Capital Expenditure

Figure 13: Medupi Cumulative Capital Expenditure

Medupi requires flue gas desulphurisation retrofits in order to comply with the MES SO_2 emissions standards, as explained in the main report.[48,49] Furthermore, compliance with the conditions of its World Bank loan agreement also require FGD equipment to be installed. At the time of signing the loan agreement, FGD installation was to take place at the first planned major outage of each unit, the first of which would take place six years after the commissioning of the first unit. All six units were to be retrofitted with FGD by 31 December 2021. However, given Eskom's current schedule for construction of Medupi's FGD, it is unlikely that final construction and commissioning will take place by the end of 2021 as required by Eskom's loan agreement with the World Bank (World Bank, 2017b).

The capital cost information for Medupi FGD was obtained from the Medupi FGD Retrofit Technology Selection Study Report (Eskom, 2014b). The total capital requirements, including direct costs, contingency and escalation, amount to R16.66bn in 2012 ZAR terms. We have also assumed that the FGD cost is in addition to the normal capital budget for Medupi and that these costs will be incurred six years after the commissioning of each unit. These costs are presented in Table 14

Table 14: Medupi FGD Cost Distribution (R'm)

Financial year	Cost estimate (R'm)
2023	2776.733
2024	2776.733
2025	5553.466
2026	5553.466

We used the EPRI (Electric Power Resource Institute [EPRI], 2015) operating and maintenance costs for both Medupi and Kusile. The estimates for Kusile were based on the pulverised coal with FGD costs. For Medupi the estimates without FGD were used, and after the retrofitting of FGD the same costs as for Kusile were used[50].

An after tax real discount rate of 8.2% was used, which is equal to the economic opportunity cost of capital (EOCK) specified by National Treasury. Tax was accounted for by grossing up the discount rate.

To determine the LCOE for Kusile and Medupi, the capital expenditure and operating expenditure, along with various other components, were used in the discounted cash flow model. Figure 14 illustrates the LCOE of Medupi and Kusile as R1,70/kWh R1,91/kWh respectively. Capital costs and the impact of time overruns dominate the cost of power from both these stations with the capital component of the LCOE equal and 76% and 75% for Medupi and Kusile respectively. Medupi also requires FGD, which further increases the capital cost contribution (by 2%) to the levelised cost.

---

[48] The construction of Kusile includes FGD.

[49] Section 4.4.4 in the main report explains the air quality compliance requirements in more detail.

[50] It should be noted that this approach is different to that taken for the older coal-fired power station with regards to OPEX after retrofitting components. In the case of the older coal-fired power station we used De Wit (de Wit, 2013) CAPEX and OPEX figures. In the case of Medupi we used the EPRI (Electric Power Resource Institute [EPRI], 2015) figures.
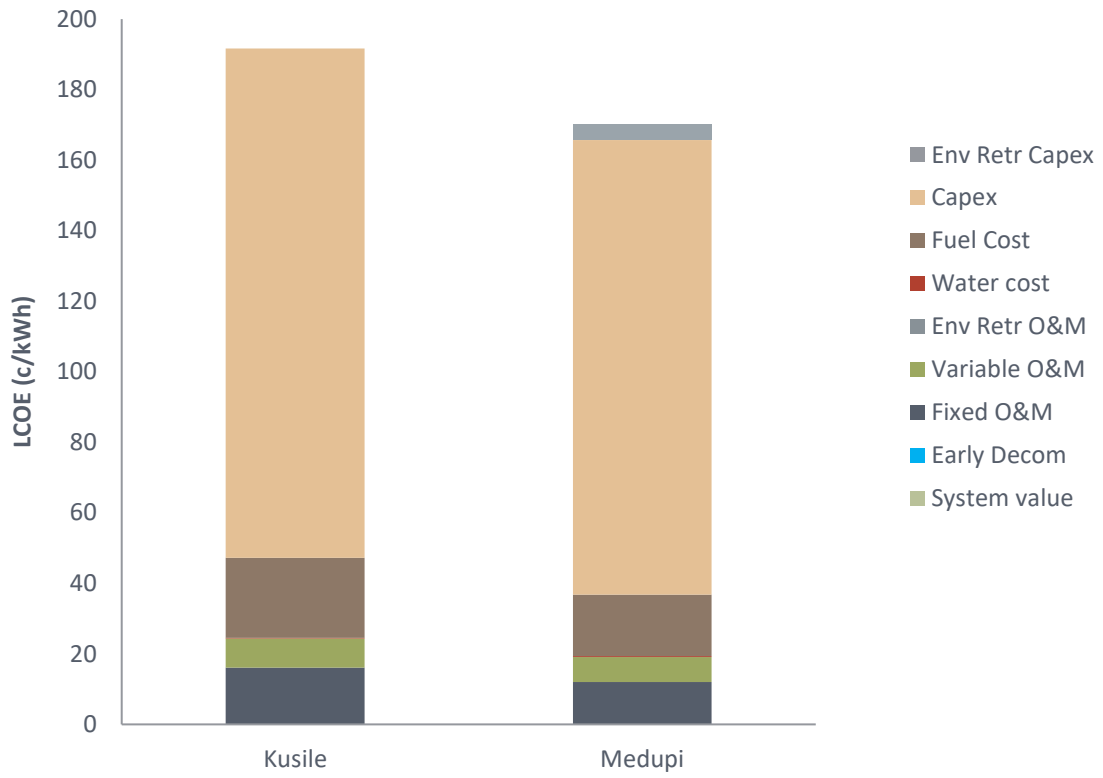
Figure 14: Kusile and Medupi LCOE

8 BIBLIOGRAPHY

amaBhungane. 2016. *R587m in six hours – how Eskom paid for Gupta mine*. Available: https://www.dailymaverick.co.za/article/2016-10-20-amabhungane-r587m-in-six-hours-how-eskom-paid-for-gupta-mine/ [2017, November 09].

amaBhungane & Scorpio. 2017. *#GuptaLeaks: Guptas pushed Eskom for R1.68bn prepayment*. Available: http://amabhungane.co.za/article/2017-06-01-guptaleaks-guptas-pushed-eskom-for-r168bn-prepayment [2017, November 02].

Bonorchis, R. & Burkhardt, P. 2017. Goldman Sees Eskom as Biggest Risk to South African Economy. *Bloomberg.com*. 22 September. Available: https://www.bloomberg.com/news/articles/2017-09-22/goldman-sachs-sees-eskom-as-biggest-risk-to-s-african-economy [2017, November 07].

Burton, J. & Winkler, H. 2014. South Africa's planned coal infrastructure expansion: drivers, dynamics and impacts on greenhouse gas emissions. *Energy Research Centre, University of Cape Town. Available: http://www. erc. uct. ac. za/Research/publications/14-Burton-Winkler-Coal_expansion. pdf*. (October).

Cairncross, E. 2017. *Assessment of Eskom Coal Fired Power Stations for compliance with their 1 April 2015 AELs over the period 1 April 2015 to 31 March 2016; and ranking of their pollutant and CO2 emission intensities*. Centre for Environmental Rights. Available: https://cer.org.za/wp-content/uploads/2016/07/AEL-Compliance-Assessment-of-Eskom-CFPSs-final-19-May-2017_final.pdf [2017, November 09].

Carbon Tracker Initiative. 2017. *No country for coal gen – Below 2°C and regulatory risk for US coal power owners*. Available: https://www.carbontracker.org/reports/no-country-for-coal-gen-below-2c-and-regulatory-risk-for-us-coal-power-owners/ [2017, November 08].

Centre for Environmental Rights. 2017. *Eskom station employment figures extract from SAP July 2017*.

Chung, J. 2017. *South Korea to suspend eight older coal-fired power plants to tackle pollution*. Available: https://www.reuters.com/article/us-southkorea-coal/south-korea-to-suspend-eight-older-coal-fired-power-plants-to-tackle-pollution-idUSKBN18Q041 [2017, November 07].

Comrie, S. 2017. *R10bn in 15 days another massive Eskom boost for the Guptas*. Available: http://amabhungane.co.za/article/2017-04-22-r10bn-in-15-days-another-massive-eskom-boost-for-the-guptas [2017, November 09].

le Cordeur, M. 2017a. *Eskom has cunning plan to avoid future load shedding*. Available: http://m.fin24.com/fin24/Economy/Eskom/eskom-has-cunning-plan-to-avoid-future-load-shedding-20170811 [2017, November 08].

le Cordeur, M. 2017b. *Koko unpacks Eskom's renewable costs, but experts disagree*. Available: http://m.fin24.com/fin24/Economy/Eskom/koko-unpacks-eskoms-renewable-costs-but-experts-disagree-20170117 [2017, November 02].

Creamer, T. 2016. *Cost-plus mines under scrutiny as Eskom rolls out new coal procurement strategy*. Available: http://www.miningweekly.com/article/cost-plus-mines-under-scrutiny-as-eskom-rolls-out-new-coal-procurement-strategy-2016-01-26/searchString:Arnot eskom 3 february 2016 [2017, November 02].

Creamer, T. 2017. Eskom a 'risk to entire economy', Gigaba says as he reaffirms unaffordability of nuclear. *Mining Weekly*. (October, 25). Available: http://www.miningweekly.com/article/budget2-2017-10-25 [2017, November 07].

Dentons. 2015. *REPORT: in respect of the investigation in to the status of the business and challenges experienced by Eskom, instituted by the board of Eskom Holdings (SOC) Ltd in terms of a resolution passed on 11 March 2015*.

Department of Energy. 2016a. *Integrated Resource Plan Update: Assumptions, Base Case Results and Observations*. (Revision 1). Available: http://www.energy.gov.za/IRP/2016/Draft-IRP-2016-Assumptions-Base-Case-and-Observations-Revision1.pdf [2017, November 13].

Department of Energy. 2016b. *Draft Integrated Resource Plan 2016*. DoE. Available: http://www.energy.gov.za/IRP/2016/Draft-IRP-2016-Assumptions-Base-Case-and-Observations-Revision1.pdf [2017, November 08].

Diaz Lopez, B. 2016. *Success for solar in electricity auctions in Latin America*. Available: https://www.pv-magazine.com/2016/10/20/success-for-solar-in-electricity-auctions-in-latin-america_100026590/ [2017, November 02].

du Plooy. 2010. Coal Contract Portfolio Management. University of Stellenbosch.

Electric Power Resource Institute [EPRI]. 2015. *Power Generation Technology Data for Integrated Resource Plan of South Africa*. EPRI. Available: http://www.energy.gov.za/IRP/2016/IRP-AnnexureA-EPRI-Report-Power-Generation-Technology-Data-for-IRP-of-SA.pdf [2017, November 08].

Eskom. 2010. *Integrated Report 2010.* (Integrated Report). Eskom.

Eskom. 2011. *Air Quality Strategy*. Eskom

Eskom. 2011b. *Integrated Report 2011*. (Integrated Report). Eskom.

Eskom. 2013. *General Information for Grootvlei Power Station*. (Annexure A). Eskom.

Eskom. 2013b. *Integrated Report 2011*. (Integrated Report). Eskom.

Eskom. 2014a. *Submission to board sustainability committee on 2 August 2013*. Eskom.

Eskom. 2014b. *Medupi FGD Retrofit Technology Selection Study Report*.

Eskom. 2015a. *Eskom Air Quality Strategy*. Eskom.

Eskom. 2015b. *Integrated Report 31 March 2015*. (Integrated Report). Eskom.

Eskom. 2016a. *Eskom Air Quality Improvement Plan*. Eskom.

Eskom. 2016b. *Eskom's response to the Public Protector report*. (Presentation). Available: http://www.eskom.co.za/news/Documents/EskomResponseV6.pdf [2017, November 02].

Eskom. 2016c. *Eskom Generation Fleet Consumption Data*.

Eskom. 2016d. *Integrated Report 31 March 2016*. (Integrated Report). Eskom. Available: http://www.eskom.co.za/IR2016/Documents/Eskom_integrated_report_2016.pdf [2017, February 24].

Eskom. 2017a. *Eskom Medium Term System Adequacy Outlook 2016-2021*. Eskom.

Eskom. 2017b. *Medium-term System Adequacy Outlook 2017-2022*. Eskom. Available: http://www.eskom.co.za/Whatweredoing/SupplyStatus/Documents/MTSAO_Oct2017Report.pdf [2017, November 09].

Eskom. 2017c. *Revenue application FY2018/19*. (Revenue Application). Eskom.

Eskom. 2017d. *Eskom Integrated Report 31 March 2017*. Eskom. Available: http://www.eskom.co.za/IR2017/Documents/Eskom_integrated_report_2017.pdf [2017, November 08].

Eskom. 2017e. *Eskom 2018/19 Revenue Application*. (Presentation). Eskom. Available: http://www.eskom.co.za/OurCompany/stakeholderNews/Documents/RevenueApplFY2018-19_20092017.pdf [2017, November 09].

Eskom. 2017f. *PAIA Query1-637 - Generation Atmospheric Emissions Licence Compliance and Decommissing*. (Formal Letter). Eskom.

Eskom. 2017g. *Eskom's response to MES*. (Presentation). Eskom.

Eskom. 2017h. *Eskom's compliance with the Minimum Emission Standards*. (Presentation). Eskom.

Exxaro. 2015. *Exxaro Resources Limited ("Exxaro") – Position statement in relation to termination of Arnot Coal Mine's Coal Supply Agreement by Eskom Holdings (Pty) Ltd ("Eskom") | Exxaro*. Available: http://www.exxaro.com/index.php/exxaro-resources-limited-exxaro-position-statement-in-relation-to-termination-of-arnot-coal-mines-coal-supply-agreement-by-eskom-holdings-pty-ltd-eskom/ [2017, November 02].

Forsythe, M. 2017. China Cancels 103 Coal Plants, Mindful of Smog and Wasted Capacity. *The New York Times*. 18 January. Available: https://www.nytimes.com/2017/01/18/world/asia/china-coal-power-plants-pollution.html [2017, November 07].

Groenewald, Y. & Yelland, C. 2017. *EXCLUSIVE: Eskom's cash dries up*. Available:

https://www.fin24.com/Economy/Eskom/exclusive-eskoms-cash-dries-up-20171113-2 [2017, November 13].

Hill, J. 2017. *India Cancels Nearly 14 Gigawatts Of Proposed Coal Plants*. Available: https://cleantechnica.com/2017/05/25/india-cancels-nearly-14-gw-proposed-coal-plants/ [2017, November 07].

Hoskens Consolidated Investments. 2016. *Integrated Annual Report*. (Annual). HCI. Available: http://www.hci.co.za/reports/integrated_report_2016.pdf [2017, November 09].

ICHORCOAL. Annual Report 2015. 2015.

Industrial Development Corporation. 2016.

iNet Bridge. 2017. *Numsa threatens 'mother of all strikes' if Eskom closes plants*. Available: http://www.enca.com/money/numsa-threatens-mother-of-all-strikes-if-eskom-closes-plants [2017, November 08].

Jensen, F. 2017. No new coal power stations in Java, Indonesia energy minister says. *Reuters*. 12 October. Available: https://www.reuters.com/article/indonesia-power-coal/no-new-coal-power-stations-in-java-indonesia-energy-minister-says-idUSL4N1MN4ZI [2017, November 07].

Mafika. 2008. Work begins on Kusile power station. Available: https://www.brandsouthafrica.com/investments-immigration/business/economy/infrastructure/kusile-110808 [2017, November 09].

McKay, D. 2015. Eskom may divert Medupi coal to Hendrina. Available: http://www.miningmx.com/news/energy/14378-eskom-may-divert-medupi-coal-to-hendrina/ [2017, November 09].

McKay, D. 2016. Anglo strikes back after Eskom labels coal deal "unacceptable". *Miningmx*. 5 July. Available: http://www.miningmx.com/news/energy/27549-eskom-labels-anglo-coal-deal-tutuka-unacceptable/ [2017, November 02].

Myllyvirta, L. & Mills, J. 2016. *China starts cancelling under-construction coal plants*. Available: https://unearthed.greenpeace.org/2016/10/21/china-coal-crackdown-cancel-new-power-plants/ [2017, November 07].

National Treasury. 2016. *Calculating the Social Discount Rate for the IEP and the IRP*. (Presentation). National Treasury.

National Treasury. 2017b. *Medium Term Budget Policy Statement 2017*.

Nkambule, N.P. & Blignaut, J.N. 2017. Externality costs of the coal-fuel cycle: The case of Kusile Power Station. *South African Journal of Science*. 113. DOI: http://dx.doi.org/10.17159/sajs.2017/20160314.

Obholzer, J. & Daly, K. 2014. *South African Thermal Coal*. MacQuarie Research.

Parliamentary Monitoring Group. 2011. *Labour issues at Kusile and Medupi Power stations: Eskom briefing | PMG*. Available: https://pmg.org.za/committee-meeting/13108/ [2017, November 09].

Public Protector South Africa. 2016. *State of Capture*. (No 6 of 2016/2017). Public Protector of South Africa.

Steyn, G. 2001. Governance, Finance and Investment Decision making and risk in the Electric Power Sector.

Steyn, G. 2006. Investment and Uncertainty: Historical Experience with power sector investment in South Africa and its implications for current challenges. (Working Paper).

Steyn, L. 2015. *Sinking into Eskom's black hole*. Available: https://mg.co.za/article/2015-02-05-sinking-into-eskoms-black-hole/ [2017, November 09].

Steyn, G. & Eberhard, A. 2010. Eberhard and Steyn: Public Enterprises. 30 April.

The Times of India. 2017. NTPC to shut down old plants with capacity of 11 giga watts. *The Times of India*. 6 February. Available: http://timesofindia.indiatimes.com/india/ntpc-to-shut-down-old-plants-with-capacity-of-11-giga-watts/articleshow/57001353.cms [2017, November 07].

United Nations Environment Programme (UNEP). 2017. *The Emissions Gap Report 2017*. Available: http://www.unepfi.org/wordpress/wp-content/uploads/2017/10/Emissions-Gap-Report-2017.pdf [2017, November 07].

de Vos, D. 2017. *South Africans must defend PIC till the bitter end – failure could cost us the country*. Available: https://www.dailymaverick.co.za/article/2017-09-22-analysis-south-africans-must-defend-pic-till-the-bitter-end-failure-could-cost-us-the-country/#.WgBtM4-CxEY). [2017, November 07].

Whiteman, A., Rinke, T., Esparrago, J., Arkhipova, I. & Elsayed, S. 2017. *Renewable capacity statistics 2017*. IRENA.

de Wit, M. 2013. *A Review Of Abatement Cost Estimates For Pm, Nox And So2 Control At Eskom Coalfired Power Stations*. Iliso Consulting Environmental.

de Witt, R. 2003. Arnot Refurbishment 1968 trendsetter in billion -rand face-lift. *Mining Weekly*. (December, 5):32,33.

World Bank. 2017a. *Modeling the Water-Energy Nexus: How Do Water Constraints Affect Energy Planning in South Africa?* Washington DC: World Bank.

World Bank. 2017b. *Eskomg Investment Support Project: Environmental and Social Aide memoire*. World Bank.

Wright, J., Arndt, C., Ireland, G., Hartley, F., Merven, B., Burton, J., Caetano, T., McCall, B., et al. 2017. *The developing energy landscape in South Africa: Technical Report*. EPRI.

Wright, J., Calitz, J., Bischof-Niemz, T. & Mushwana, C. 2017. *The long-term viability of coal for power generation in South Africa*. CSIR.

Wynn, G. 2017. *IEEFA Update: Netherlands, in New Program to Close All Coal-Fired Generation by 2030, Sends European Energy Markets a Sharp Signal*. Available: http://ieefa.org/ieefa-update-netherlands-new-program-close-coal-fired-generation-2030-sends-european-energy-markets-sharp-signal/ [2017, November 07].