

Can renewable energy, with LNG for flexibility, replace nuclear energy as a base-load option in South Africa?

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ABSTRACT

As a result of the low prices realised in Bid Window 4 of the REIPPP programme, a growing number of South African energy experts have expressed the belief that the least-cost new build option for South Africa is variable renewable energy, in the form of solar PV and wind, with natural gas generation to provide a flexible back-up. They believe furthermore, that this signals the end of the road for traditional “base-load” technologies such as nuclear and coal. These ideas are vehemently opposed by the pro-nuclear lobby which views the combination of renewables and natural gas as a recipe for disaster.

This study investigates whether a combination of solar PV and wind with LNG for flexibility can indeed supply base-load and in so doing, replace nuclear technology as a base-load option for South Africa. It compares the cost of three combinations of solar PV and wind with an LNG back-up to nuclear, using LCOE as a metric for comparison. It then investigates the technical feasibility of supplying base-load with renewables and LNG, firstly by comparing gas turbine ramping rates to renewables variability rates and secondly, through a literature review, whether there are any other insurmountable technical challenges. The literature review includes an assessment of whether renewables can supply 100 % of an electricity system’s requirements.

It finds that renewables plus natural gas for flexibility is cheaper than nuclear for all three scenarios analysed, and that there are no insurmountable technical problems to renewables supplying a significant portion of a system’s base-load requirements. On the matter of renewables providing 100 % of a system’s needs however, there remains a lack of historical evidence that renewables can do this.

Although LCOE is a valuable comparative tool, it sometimes omits significant externalities. In this case the data used was found to exclude the cost of establishing LNG importing infrastructure in South Africa. Importing LNG will also introduce the risk of price shocks and negative exchange rate fluctuations. Furthermore, although LNG is cleaner than coal it is not as clean as nuclear.

The prudent approach to energy planning in South Africa therefore, is to spread the risk and adopt an “energy mix” approach in which no single technology dominates.

A small window of opportunity remains open for nuclear technology in South Africa, but to exploit this opportunity nuclear technology must urgently find ways to address commonly held public perceptions that it is an expensive and unsafe technology.

Key terms: Levelised cost of electricity, variability, flexibility, renewables, liquefied natural gas, nuclear technology.

LIST OF ABBREVIATIONS AND ACRONYMS

DEA	Department of Environmental Affairs
BWR	Boiling Water Reactor
CAPEX	Capital Expenditure
CCGE	Combined Cycle Gas Engines
CCGT	Combined Cycle Gas Turbines
CSIR	The Council for Scientific and Industrial Research
CSP	Concentrated Solar Power
DAM	Day-ahead Market
DoE	Department of Energy
DPE	Department of Public Enterprises
DSM	Demand Side Management
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EUR	European Utility Requirements
FGD	Flue-gas Desulphurisation
GHG	Greenhouse Gas
GT	Gas Turbine
HFO	Heavy Fuel Oil
HTR	High Temperature Reactors
ICE	Internal Combustion Engine
IDC	Interest During Construction
IPIECA	International Petroleum Industry Environmental Conservation Association
IPP	Independent Power Producer
IRP	Integrated Resources Plan

IRR	Internal Rate of Return
LCOE	Levelised Cost of Electricity/Energy
LNG	Liquefied Natural Gas
LWR	Light Water Reactor
MENA	Middle East and North Africa
MIT	Massachusetts Institute of Technology
NEA	Nuclear Energy Association
NNR	National Nuclear Regulator
NPP	Nuclear Power Plant
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
PBMR	Pebble Bed Modular Reactor
PV	Photovoltaic
PWR	Pressurised Water Reactor
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
SAPP	Southern African Power Pool
TWh	Terrawatt hour
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital
WNA	World Nuclear Association

DEFINITIONS

Base-load - The minimum level of load on an electrical system over a time period (day, month, year). Base-load plants are those which operate at very high load factors at all times except when they are offline for maintenance.

Discount rate - Is the rate used to calculate the present value of future cash flows. The weighted average cost of capital (WACC) or another required rate of return are normally used as the discount rate.

Dispatchable generation - Sources of electricity that can be used on demand and dispatched at the request of power grid operators, according to market needs; dispatchable generators can be turned on or off, or can adjust their power output according to an order.

Fission - Is the division of one heavy atom into two or more smaller atoms.

Flexibility - The capability of a power system to cope with the variability and uncertainty that renewable energy generation introduces into the system in different time scales, from the very short to the long term, avoiding curtailment of renewable energy and reliably supplying all the demanded energy to customers.

Fusion - The combination of two light atoms into a larger one.

Greenfields project - A project to be developed on a previously undeveloped site where there is no need to remodel or demolish an existing structure.

Levelised cost of electricity (LCOE) - A metric that provides an indication of the unit energy cost over the full life of a project, including capital, operating and financing costs. LCOE is the net present value (NPV) of the unit-cost of electricity over the lifetime of a generating asset.

Merit order dispatching - The sequence in which power plants are designated to deliver power. The system operator will bring those plants on-line that have the lowest marginal cost per kilowatt - hour, first.

Merit order effect - Renewable energy sources have low or near zero marginal cost and have caused conventional power plant to be pushed further towards the end of the merit order.

Mid-merit power - That part of the load duration curve which lies between base-load and peaking power; it is typically the increase in daily electricity demand that lasts from morning until the demand drops off in the evening. Mid-merit plant can adjust its power output as demand for electricity fluctuates throughout the day.

Net present value (NPV) - Is the difference between the present value of cash inflows and the present value of cash outflows over a period of time.

Operating reserves - Reserves that are available to the system operator and that consist of power plants that can adjust their generation at fast ramp rates, or of loads that can be increased or decreased at short notice.

Overnight cost - The cost of a project if no interest or other financing costs are incurred during construction, i.e. as if the project was completed "overnight."

Peaking power - Is power used to meet the peak load during the course of the day. Peaking plant is turned on rarely to meet the peak load and typically operate at load factors of 10 % or less.

Primary reserves - Are used to limit the change in the power system's frequency due to an imbalance between supply and demand. They are locally automated and react to deviations in the nominal system frequency.

Pumped storage schemes - Hydroelectric schemes that store energy in the form of the gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation reservoir. During periods of high electrical demand, the stored water is released through turbines to produce electric power.

Ramping rate - Is the rate at which a power plant can increase or decrease output and is typically measured in MW/min or %full-load/min.

Reliability of a system - Depends on adequacy and security. Adequacy is the existence of sufficient generation to meet consumer demand, security is the ability of the system to respond to disturbances in the quality of supply.

Renewable Energy (RE) - Energy produced from sources that do not deplete or can be replenished within a human's life time. For the purposes of this study RE refers to solar PV and wind unless stated otherwise.

Secondary reserves - Are used to restore the frequency to its design value. They are automated centrally and serve to release the primary reserves for future operations.

Variable renewable energy (VRE) - A renewable energy source that is non-dispatchable due to its fluctuating nature, such as wind and solar power. For the purposes of this study VRE refers to a combination of solar PV and wind unless stated otherwise.

Weighted average cost of capital - The WACC is the product of the cost of debt and the percentage of debt financing plus the product of the cost of equity and the percentage of equity financing. This sum can additionally be adjusted by a risk factor.

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CHAPTER 1 INTRODUCTION

1.1 Background

South Africa ranks amongst the top 20 highest carbon dioxide emitters in the world, and one of the largest contributors to this statistic is its coal electricity generation fleet. In its 2018 Integrated Report, Eskom, the national electricity utility, reported that of a total of 221 936TWh of electricity sent out that year, 202 106TWh was from coal fired power stations, or 91 % of its total output. As a result of this, Eskom's total carbon dioxide emissions for the year were 205.5 Mt (Eskom, 2018, p. 10). In addition, large quantities of other greenhouse gases such as sulphur dioxide, nitrous oxide and nitrogen oxide were also emitted.

South Africa is committed to reducing its carbon footprint and in 2016 ratified the Paris Agreement, an international, legally binding accord whose objective is to guide the process for universal action on climate change (DEA, 2016).

The South African public and most energy industry experts are supportive of the need to reduce greenhouse gas emissions. It is generally agreed that a larger share of new electricity capacity should be built from cleaner generation technologies. As happens elsewhere in the world, however, there is passionate disagreement on which technology will achieve this the most efficiently and cost effectively.

Both nuclear and renewable technologies are well established in South Africa and the debate about which technology delivers the most cost effective “clean” electricity has raged for more than a decade.

In the years leading up to the Integrated Resource Plan of 2010 (IRP 2010), the South African Government viewed nuclear technology favourably. Not only was the SA Government planning to greatly expand Eskom's nuclear fleet, but plans were also being made to establish a new state owned company, Pebble Bed Modular Reactor (PBMR), to build high temperature reactors (HTR). The Department of Public Enterprises (DPE) promoted the idea that nuclear technology presented an opportunity to provide the country with a fleet of emission-free power stations that would not only provide cheap electricity, but also the opportunity to build a nuclear power station construction industry similar to that established in South Korea.

Although the nuclear lobby was dealt setbacks in 2008 with the cancellation of the Eskom nuclear procurement program and in 2010 by the termination of the PBMR project, Government remained committed to nuclear. This is evident from the contents of the IRP 2010, which proposed the

construction of a nuclear fleet of 9 600MW to be commissioned from 2023 onwards (DoE, 2010, p. vii).

It is probably fair to say that in 2010 renewable technology had not yet gained general acceptance in South Africa as a technologically feasible or economically viable alternative to achieve emissions reduction objectives. The nuclear lobby's views that renewable technologies such as solar photovoltaic (PV) and wind were prohibitively expensive and could not deliver dispatchable, base-load electricity because they are variable, intermittent sources of electricity was the conventional wisdom of the day.

However, the cancellation of South Africa's conventional nuclear procurement programme provided the supporters of renewables with powerful ammunition. The renewable lobby had always contended that cheap nuclear electricity is a myth. Not only could they now point to the cancelled Eskom procurement process, but also to lengthy and very expensive delays to most nuclear projects being built in the western hemisphere, such as Olkiluoto 3 and Flamanville 3. In addition to concerns about the cost of nuclear energy, the renewables lobby has always been concerned about the by-products of nuclear electricity – namely radioactive waste.

Since 2010, as a result of various factors, including the Fukushima Daiichi accident in Japan in 2011, a highly lauded renewables program run by the Department of Energy (DoE), progressively lower construction costs for renewables technologies, progressively higher construction costs for nuclear in the West and a political scandal involving nuclear procurement, public opinion has swayed strongly in favour of renewables.

The IRP 2016 Update postponed the nuclear program, shifting the commissioning date of the first new unit from 2023 to 2037 (DoE, 2016, p. 16). At the same time significant amounts of additional renewable capacity was added to the plan.

The IRP 2016 Update was, however, never approved, leading to speculation in some quarters that the reason for this was that delaying the nuclear program had not met with the approval of certain members of the political elite.

A change of political leadership in late 2017, was followed by the release of the Draft IRP 2018 for public comment. One of the main features of this new plan was that the planning horizon was drastically reduced from 2050 in the IRP 2016 Update to 2030. Significantly, the technology emphasis in the IRP 2018 shifted very firmly towards renewables and natural gas, whilst the debate about nuclear seemed to have been neutralised through the omission of what is planned for the period beyond 2030. (DoE, 2018, p. 11). Since nuclear is seen as an alternative that can only be realised in the medium- to long-term, i.e. beyond 2030, this shorter term focus meant that

the plan did not need to pronounce on whether nuclear remained a future new build option. The IRP 2018 included 8 100MW of new gas projects, 5 670MW of new solar PV projects, 8 100MW of new wind projects and 2 500MW of new hydro projects.

The hypothesis that solar PV and wind can provide utility-scale base-load electricity reliably and cost-effectively, and is therefore a direct substitute for nuclear energy, has gathered momentum in recent years. The Draft IRP 2018 appeared to provide impetus to this hypothesis. The Council for Scientific and Industrial Research (CSIR) highlighted in its comments on the IRP 2018 that solar PV and wind combined with natural gas for flexibility is now the least-cost combination of new-build options (CSIR, 2018, p. 4).

The Draft IRP 2018 did not meet with universal approval, however. The polarised nature of the debate about which technology is the most suitable for South Africa is exemplified by an article that was published in the Business Day, 12 December 2018. In it, Andrew Kenny, a South African energy expert argues: “SA is stumbling towards energy disaster..... The IRP’s “least-cost option” is in fact the most expensive option possible, which has seen electricity costs soaring wherever it has been tried. This is a combination of wind, solar and imported gas. It was drawn up by the Council for Scientific and Industrial Research (CSIR) and supported by the IRP. It is a recipe for calamity” (Kenny, 2018). The article points to the fact that the combination of renewables and gas has led to more expensive electricity in countries such as Germany and Denmark, and highlights that renewables are difficult to integrate into a transmission grid, a problem that has led to blackouts in South Australia.

1.2 Problem Statement

The foregoing discussion serves to highlight that the debate between nuclear and renewable technologies as sources of cleaner energy, is as often ideological and political, as it is financial and scientific. There is room therefore for independent, empirical analysis of the contention that a combination of renewables and natural gas can replace nuclear as a supplier of base-load in South Africa.

This study was principally inspired by three reports:

- A working paper by Dr D. Serfontein of the North-West University, “Can new nuclear compete with new renewables in South Africa?” (Serfontein, 2018);
- The CSIRs “Formal comments on the Draft Integrated Resource Plan (IRP) 2018” (CSIR, 2018); and

- A presentation by Dr T. Bischof-Niemz, CSIR Energy Centre Manager, “Can renewables supply base-load?” (Bischof-Niemz, 2016).

Serfontein points out that market factors that affect the nuclear levelised cost of electricity (LCOE), such as interest rates, construction schedule overruns on Eskom projects, and overestimated capacity factors have all moved in the wrong direction for nuclear in recent times, making nuclear power expensive.

Serfontein argues further that wind and solar-PV “are probably unstoppable” due to their fast learning rates and continuously decreasing costs. Therefore; “in spite of all the problems that they create for Eskom, there is probably no point in trying to fight the increasing deployment of wind and solar PV” (Serfontein, 2018).

The CSIR are unambiguous in their support for variable renewable energy (VRE). In their formal comments on the IRP 2018, they highlight as a key finding that, “through the IRP1 scenario variable renewable energy (solar PV and wind) combined with flexibility in the form of natural gas fired generation capacity are the least-cost combination of new-build options as the existing coal fleet decommissions. This results in a power system that is 25% renewables based (dominated by solar PV and wind) / 30 % CO₂ free (incl. nuclear) by 2030 and 70 % renewables-based by 2050” (CSIR, 2018).

Lastly, and of greatest relevance to this study, in a “thought experiment” explained in a 2016 presentation, Bischof-Niemz, asserts that “a mix of solar PV, wind and flexible power can supply this base-load demand in the same reliable manner as a base-power generator.” His hypothesis seems to be based primarily on the cost reductions realised during the course of South Africa’s Renewable Energy Independent Power Producer Procurement programme (REIPPP) since 2011, which make “solar PV and wind the cheapest new-build options per kWh today” (Bischof-Niemz, 2016).

The problem statement for this study therefore is, “to establish whether or not a mix of solar PV and wind with liquefied natural gas as a source of flexibility can in fact supply base-load in a cost effective and reliable manner and therefore potentially replace nuclear as a source of base-load electricity”.

1.3 Research Aim

The general aim of this study is to augment a cost comparison using the levelised cost of electricity (LCOE) metric with an evaluation of the technical feasibility of integrating VRE in the form of solar

PV and wind into a power system, and present a balanced assessment of whether VRE with liquefied natural gas for flexibility can supply base-load more cheaply and reliably than nuclear energy and therefore replace nuclear technology as a base-load option for South Africa.

1.4 Research Objectives

There are two specific primary research objectives:

- i. To compare the cost of supplying base-load in South Africa between a nuclear system and a system consisting of solar PV and wind with LNG flexibility by calculating and comparing the LCOEs of both systems under local conditions.
- ii. To identify and discuss the technical problems that result from the integration of wind and solar energy into a power system such as that found in South Africa, and establish whether these problems can be successfully overcome.

Secondary objectives of this report include:

- i. To provide a description of each technology.
- ii. To investigate experiences of countries that have introduced high percentages of renewable energy into their electricity supply systems.
- iii. To discuss the main risks associated with nuclear and gas systems, i.e. cost and time overruns during construction in the case of nuclear, and the risk of relying on imported LNG in the case of the renewable system.
- iv. To identify a suitable mix of wind, solar and natural gas to provide a stipulated capacity quantum.
- v. To discuss the suitability of LCOE as a method for comparing generating technologies

1.5 Research Methodology

1.5.1 Empirical cost analysis

Three main sources of data were used for the empirical study:

- i. Costing data for all conventional technologies was obtained from the Electric Power Research Institute (EPRI) 2017 report upon which the IRP 2018 report was based, “Power generation technology data for Integrated Resources Plan of South Africa, Technical Update, April 2017”.

- ii. Costing data for solar PV and wind was obtained from the actual tariffs realised in Bid Window 4 of the REIPPP programme.
- iii. Load profile time series for wind, concentrated solar power (CSP), and solar PV, as well as for the overall Eskom system power demand were obtained from an excel spreadsheet provided by the CSIR that provides hourly data for the period January 2016 to December 2018 (CSIR, 2018). This spreadsheet is openly available to all members of the public requesting it.

A number of LCOE methodologies of differing characteristics were evaluated, after which it was decided to base the LCOE calculations on a simplified LCOE methodology using an excel model developed in conjunction with the Eskom Test and Research unit. Validation of results obtained was conducted through comparison with price studies obtained from CSIR reports and presentations, and the EPRI report.

LCOEs were calculated for three nuclear technologies (AP1000, EPR and VVER1200), solar PV, wind, open-cycle gas turbines (OCGT) and closed-cycle gas turbines (CCGT) technologies. Additional LCOEs were also calculated for coal technologies for the purposes of benchmarking.

The load profile time series obtained from the CSIR was used to determine both the individual and combined average capacity factors for wind and solar PV.

A hypothetical scenario was then developed to evaluate the relative cost of supply of our technology options. After evaluation of many potential combinations of renewables and LNG, three scenarios were selected for discussion in this study as they either highlight important characteristics of renewables electricity generation, such as surpluses, or provide important results, such as a good fit to the base-load requirement.

A theoretical 10 000MW base-load system was initially assumed, purely because this quantum is similar to the 9600MW that the South African Government planned to build in the IRP 2010. As a first iteration, it was assumed that wind, and solar PV would be deployed in this system in the current national ratios, i.e. approximately equal quantities or 10 000MW installed capacity each. It was determined that a 100 % capacity backup from LNG would be required, i.e. 10000MW because our time-series indicated that at times there is almost zero production from the renewable sources. The capacity factor for the LNG flexibility supply was calculated as the difference between the combined load factor for wind, and solar PV and the 100 % theoretical base-load factor required. A combined LCOE was then calculated for the combined generating system, i.e. solar PV, wind and LNG.

In the second scenario selected, the installed capacity of wind was doubled, and the resulting LCOE similarly calculated. This scenario served to illustrate the challenges that result from the production of surpluses by renewables. As a third approximation, a wind only scenario was developed because it provided a very good fit to the base-load requirement and the same comparison methodology applied.

Lastly, the combined LCOEs were compared to the nuclear LCOE obtained from the LCOE excel model and the results evaluated, discussed, and conclusions drawn.

1.5.2 Technical feasibility analysis

The technical feasibility analysis firstly analyses the ramping rates of gas technologies to assess whether these are suitable to meet the variability of renewable energy and secondly, through a literature review of academic journals and industry reports, assesses the challenges and experiences with the integration of renewables both in South Africa and internationally.

Thirdly, the literature review investigates the feasibility of renewable energy supplying 100 % of a system's technical requirements, and in so doing its ability not just to compliment but to completely replace nuclear technology.

1.6 Limitations of the Study

This study was conducted using simplified levelised costing, which is a methodology employed by many researchers doing comparative studies. The results obtained are first-order calculations useful in comparing technologies, but not suitable for making investment decisions, which requires a financial modelling approach. The results obtained were nevertheless successfully validated against results obtained by other researchers doing similar comparisons.

LCOEs were not calculated for other potential sources of flexibility such as battery storage pumped storage or Demand Side Management (DSM). The LCOEs calculated generally include the cost of connection to the interconnection substation, but not to the switchyard and associated transmission system.

1.7 Outline of the Dissertation

This dissertation consists of five chapters, the content of which are as follows:

- Chapter 1 – Introduction. Background, Problem Statement, Research Aim, Research Objectives, Research Methodology, Limitations of the Study, and Outline of Dissertation.
- Chapter 2 – Literature Survey. Definitions are provided of what base-load and LCOE are. Also covered are both South African and international perspectives of nuclear, natural gas and renewable technologies, including technology, economics and developments of relevance. The main risks associated with nuclear construction and natural gas operation are discussed. A synopsis of South Africa's REIPPP programme is presented.
- Chapter 3 – Methodology. Describes how both the literature survey and empirical studies were conducted, how load profiles were obtained, how the LCOEs were calculated, and presents data used as input to the LCOE. Lastly, it describes the 10 000MW base-load calculation for the combination of VRE and LNG and how it will be compared to nuclear LCOE calculated.
- Chapter 4 – Results. Presents the outcomes of the empirical cost analysis and of the technical feasibility analysis.
- Chapter 5 – Conclusions and Recommendations. Based on the results reported in chapter 4, conclusions are drawn about whether renewables are economically and technically suited to replace nuclear as a base-load option. This chapter also makes recommendations based on the conclusions drawn, including which areas of the study require deeper analysis.

These chapters are followed by:

- Bibliography.
- Appendices.

CHAPTER 2 LITERATURE REVIEW

This chapter defines concepts such as base-load and levelised cost of electricity which are necessary to understand the methodology employed in our analyses. It also provides high level descriptions of the technologies compared including technical and economic information about nuclear, natural gas, solar PV and wind technologies in the South African context and of relevance to the objectives of this report.

2.1 Definition of Base-load

Arranging daily demand from highest to lowest provides a visually effective manner that can be used to illustrate the difference between base-load, mid-merit and peaking power. Figure 2-1 (CSIR, 2018) presents the South African daily average load duration curve in this manner. It depicts the country's load in MWh for the period January 2016 to December 2018.

Base-load can be described as the minimum demand on an electrical system for a given period of time (Troy, et al., 2008). Base-load units are those which operate at very high load factors, typically as high as 90%, except when they are offline for maintenance. From Figure 2-1 it can be seen that in South Africa there is minimum demand of between 21GW and 23GW, 24 hours/day.

Peaking power, on the other hand, is power used to meet the peak load during the course of the day (Troy, et al., 2008). From Figure 2-2 (CSIR, 2018), which provides the same information as Figure 2-1 in chronological order, it can be seen that in South Africa peak demand happens in the evening between 18h00 and 20h00. From Figure 2-1, it can be seen that this peak demand is greater than 29GW. Peaking plant is plant that is normally only turned on to meet the peak load and typically operates at load factors of 10% or lower.

Mid-merit load is that part of the load duration curve which lies between base-load and peaking power. It is typically the increase in daily electricity demand that lasts from morning until the demand drops off in the evening (Troy, et al., 2008). A load-following generating plant, typically also known as mid-merit plant, is a plant that can adjust its power output as demand for electricity fluctuates throughout the day.

Figure 2-3 (EPRI, 2017) illustrates typical screening curves, or annualised costs in R/kW-yr for a selected number of technologies at different capacity factors. Screening curves illustrate prices for various technologies at different load factors, and serve to show the point at which a system operator could switch between technologies. The exact load factor for which two technologies have identical costs, and hence the point at which the system operator could switch between

them, depends on details such as the station's initial capital cost and the operating cost, of which the fuel cost can be a large component. In some countries, the cost of emissions is included and will tend to raise the cost of “dirty” or polluting technologies (Green & Vsilakos, 2010, p. 4).

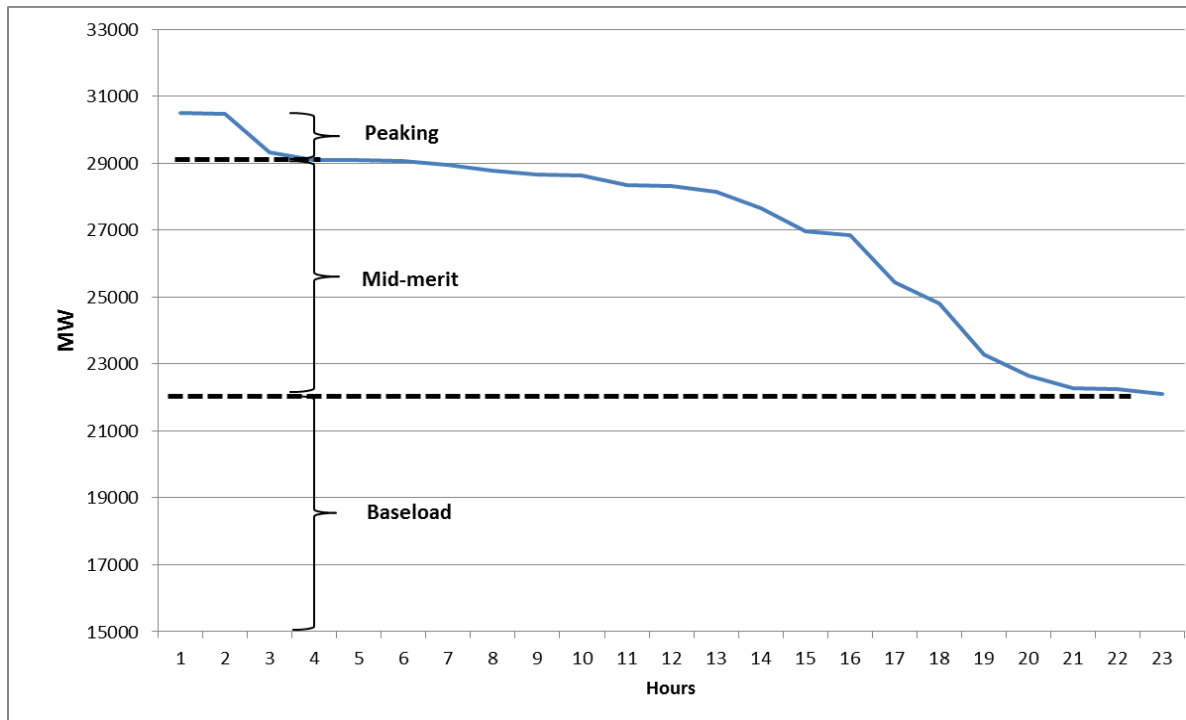


Figure 2-1: South African load duration curve from highest to lowest (2016 to 2018)

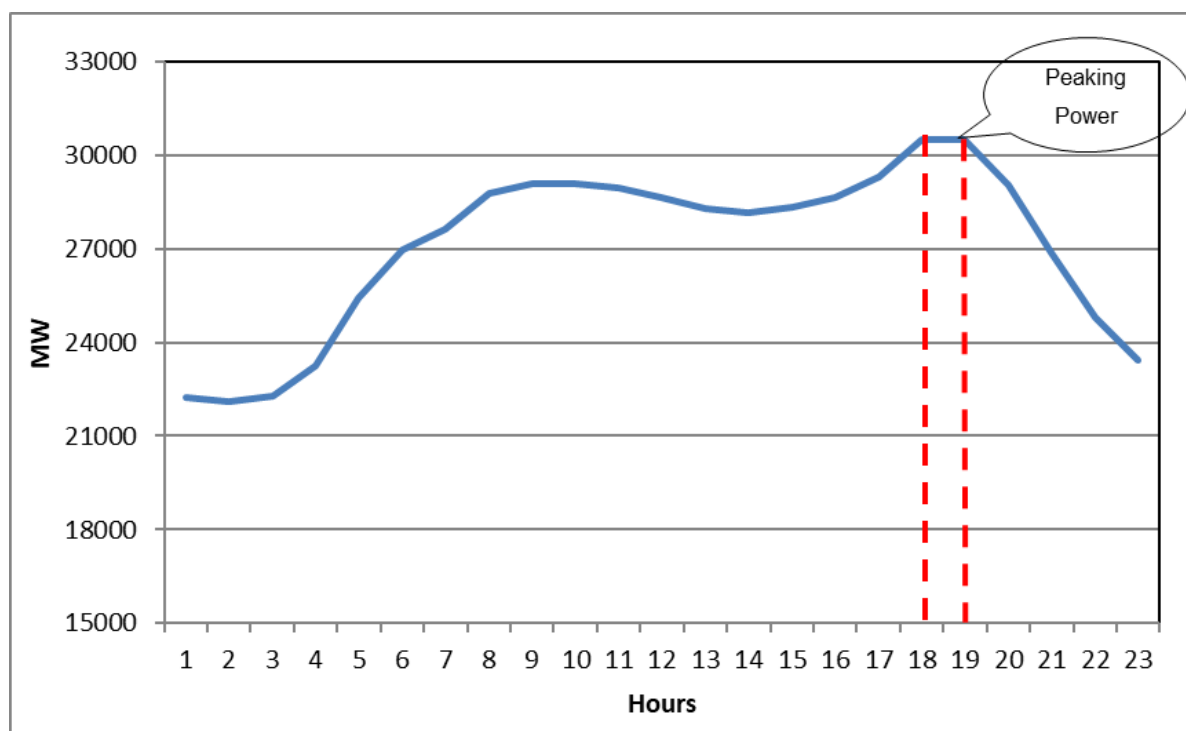


Figure 2-2: South African load duration curve in chronological order (2016 to 2018)

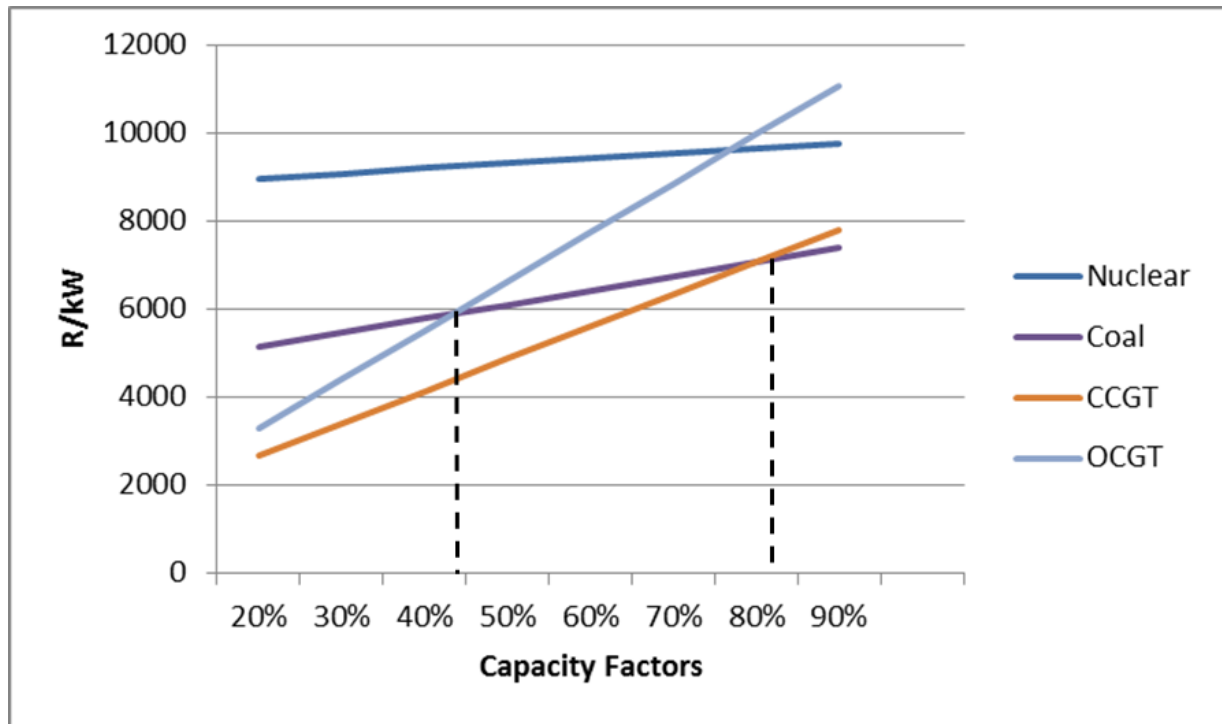


Figure 2-3: Annualised costs of select technologies as a function of capacity factor

When dispatching power plant, the system operator will bring on-line those plants that have the lowest marginal cost per kilowatt-hour, first. This is known as merit-order dispatching. According to the merit order, power plant that continuously produce electricity at very low prices are the first to be called upon to supply power. As demand increases, power plant with higher marginal costs are subsequently added until demand is met. Demand varies between night and day, time of day and the time of year.

Where electricity markets exist, the feed-in of renewable energy sources with low or near zero marginal cost has resulted in a shift of the merit order. Conventional power plant are being pushed further towards the end of the merit order and electricity prices on the spot market are being reduced. This is known as the merit order effect (Deane, et al., 2017, p. 105).

Figure 2-3 serves to illustrate that, for a given set of costs, different technologies, because of their unique operating characteristics, can deliver power more cheaply at different capacity factors.

Open cycle gas turbine stations are ideal peaking plants because they can be started up and reach peak operating power in a relatively short space of time. They can therefore be switched on and off when peaking power is needed. They have relatively low capital costs and therefore have low fixed costs, and although their variable costs, mainly fuel, are high, it is still efficient to build them to meet demands that will only last for a small proportion of the year. Other forms of

peaking plants include pumped-storage hydroelectric plants and battery storage. Pumped-storage and batteries are net consumers, however, as they have no inherent energy source, and the conversion between electricity and storage and back incurs losses.

Nuclear and coal burning plants are not ideal to meet peak demand because they take relatively long to reach operating temperature and pressure. Older nuclear (and coal) power plants may take many hours to achieve a steady state power output, and they cannot be switched off between peak demand periods. However, at high capacity factors, when they operate continuously, stopping only for maintenance or unexpected outages, they deliver relatively cheap base-load power.

Before the capital costs of wind and solar PV plants plummeted, the aforementioned base-load plants supplied the cheapest power and were therefore normally used to supply base-load. However, today a combination of wind, solar and gas power might be cheaper than nuclear or coal base-load power, depending on the capital and fuel costs of the base-load nuclear or coal plants.

Load following power plants can be hydroelectric power plants, diesel and gas engine power plants, combined cycle gas turbine power plants and steam turbine power plants that run on natural gas or heavy fuel oil, although heavy fuel oil plants make up a very small portion of the energy mix. In South Africa mid-merit capacity is supplied primarily by coal plants. Load-following plants are typically in-between base load and peaking power plants in efficiency, speed of start-up and shutdown, construction cost, cost of electricity and capacity factor.

As more and more renewable energy is connected to the electricity system, so the requirements for and the demands on load-following plant also grows. This is because the natural variability of the renewable technologies increases the variability of the electricity supply, and there is more of a need to call on load-following plant.

2.2 Levelised Cost of Electricity (LCOE)

The economic evaluation of the various generating technologies analysed in this report was conducted using the levelised cost of electricity metric. The LCOE is a robust metric that helps with technology selection and decision support for electricity projects and the expansion of electricity portfolios. However, the LCOE metric's limitations must be understood, and taken into account when using it, so that accurate analysis and due diligence are performed when making decisions that have widespread economic, social, and environmental impacts in the long run (Sklar-Chick, et al., 2016, p. 132).

Too often, LCOE figures for different power plants or electricity generation technologies are discussed, presented or compared without a clear statement of the parameters and assumptions upon which the calculations are based, in which case the figures have little meaning (Aldersey-Williams & Rubert, 2019).

2.2.1 Definitions

The LCOE metric provides an indication of the unit energy cost over the full life of a project, including capital, operating and financing costs. The LCOE is the net present value (NPV) of the unit-cost of electricity over the lifetime of a generating asset. It is often taken as a proxy for the average price that the generating asset must receive in a market to break even over its lifetime.

In general terms, the metric sums the lifetime costs of the energy system under consideration (such as a wind farm, or OCGT plant), and divides by the lifetime energy production to deliver an output in cost per unit energy.

Conventionally, LCOE includes only “plant level costs” and does not take account of “effects at the system” in the sense that specific technologies demand additional investments in transmission and distribution grids or demand specific additional reconfigurations of the electricity systems (Aldersey-Williams & Rubert, 2019, p. 170).

2.2.2 Mathematical definition

$$LCOE = \frac{\text{sum of costs over lifetime}}{\text{sum of electrical energy produced over lifetime}}$$

Mathematically,

$$LCOE = \frac{\sum_{t=0}^n \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^n \frac{E_t}{(1+r)^t}}$$

Where,

I_t = Capital expenditure in the year t

M_t = operation and maintenance expenditures in the year t

F_t = fuel expenditures in the year t

E_t = electrical energy generated in the year t

r = discount rate = weighted average cost of capital (WACC)

$n = \text{expected economic lifetime of the power plant (years)}$

Considering the LCOE formula above, the numerator is the total discounted expense, and includes CAPEX, O&M and fuel costs (for fossil- and nuclear-fuelled technologies), and decommissioning costs. In many cases, the decommissioning costs are neglected because it is assumed that the present value of these costs for long-term projects is negligible. At the end of a 50-year coal-fired plant's life, the equipment could also be sold off for scrap to counter the other costs. However, for nuclear plants the decommissioning costs is substantial and should be included.

For consistency in the formulation of the LCOE, total power must likewise be discounted. The denominator concerns the power generated over time, which needs to be computed in present value terms, since the numerator is in present value monetary format too (Sklar-Chick, et al., 2016, p. 128).

Except where otherwise indicated, the data used for the LCOE calculations in this study was taken from the "Power generation technology data for Integrated Resource Plan of South Africa" report, prepared by EPRI in 2017 for the purposes of updating the IRP 2018. In the case of the variable renewable technologies however, the LCOEs used for comparison purposes are the actual tariffs realised in Bid Window 4 of the Renewable Energy Independent Power Producer Programme.

2.2.2.1 Constant vs. Current Rands

The LCOE calculations in this study use constant (or real) Rand costing rather than current (nominal) Rands. In a constant Rand analysis, the effects of inflation are not taken into account, while in current Rands analysis, inflation is accounted for. While both methods are completely valid, current Rands analysis leads to higher costs because they account for year-by-year inflation in the cost of fuel, O&M, and the cost of money (EPRI, 2017, pp. 5-10).

2.2.2.2 Capital contribution to LCOE

CAPEX costs used in this study are presented as overnight costs, escalated using the discount rate to the commercial operating date to arrive at the same present value year as the operating and fuel costs. The overnight cost is the cost of a project if no interest is incurred during construction, i.e. as if the project was completed "overnight." No adjustments were made to overnight costs for interest during construction (IDC), risk, internal rate of return (IRR) or any other form of owner's costs. Capital costs in this report are presented in R/kW or R/MW.

2.2.2.3 O&M contribution to LCOE

Fixed O&M costs used in this report are also presented as overnight costs in a Rand per kilowatt-year basis, and in constant Rands, i.e. inflation was not taken into account. Therefore the fixed O&M cost remains the same throughout the life of the plant. The rand-per-year fixed O&M costs are then divided by the annual output of the plant (kWh) to calculate the fixed O&M cost of electricity (R/kWh).

Variable O&M are often already presented as R/kWh costs and, therefore, do not need to be converted to find the cost of electricity contribution.

2.2.2.4 Fuel contribution to LCOE

The annual cost of fuel is calculated by multiplying the fuel cost in rand per gigajoule by the heat rate of the plant. (EPRI, 2017, pp. 5-11)

2.2.2.5 Annual Megawatt-hours produced

To calculate annual electricity production, the net capacity of the plant is multiplied by the number of hours that it operated in the year. The number of hours operated in a year is equal to the capacity factor of the plant multiplied by 8760 hours/year.

The capacity factor is the ratio of the actual amount of electricity produced by the plant over the maximum amount that could be produced if it operated at full load for 24 hours per day. A plant that operates for more hours in a year ultimately has more hours of electricity generation over which to spread its annual revenue cost requirements.

2.2.2.6 Discount rate

The discount rate is the rate used to convert annual costs to the NPV. Often the weighted average cost of capital (WACC) is used as a discount rate. The WACC is the product of the cost of debt (or interest rate) and the percentage of debt financing plus the product of the cost of equity and the percentage of equity financing. This sum can additionally be adjusted by a risk factor (EPRI, 2017, pp. 5-7).

Discount rates used in LCOE calculations can vary from entity to entity depending on their returns expectations. Discount rates can also be real or nominal. For the purposes of our study a real discount rate of 8.2 % was used, as it was also used in the EPRI report. The nominal discount rate is equal to the real discount rate plus the inflation rate.

2.2.3 Different methods to calculate LCOE

There are several ways in which LCOE can be calculated. This makes it essential that data for the various generation options under consideration must be calculated in the same way to make the comparison meaningful. Two main approaches are explained in this section; the simplified and financial modelling approaches (Black & Veatch, 2011).

2.2.3.1 Simplified LCOE Approach

The formula introduced in section 2.2.2 above and reproduced here is representative of the simplified LCOE methodology.

$$LCOE = \frac{\sum_{t=0}^n \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^n \frac{E_t}{(1+r)^t}}$$

The simplified method uses a discount rate, r , (or a WACC), to calculate the minimum price at which energy must be sold for an energy project to break even (or have a present value of zero). It provides a good first order approximation and is used primarily in the early stages of project development (Black & Veatch, 2011).

2.2.3.2 Financial modelling approach

The financial modelling approach solves for the required revenue to achieve a certain rate of return. It captures the impacts of tax incentives and depreciation as well as other more complex financing assumptions and revenue requirements for the investor. The financial modelling approach is more project and site specific and is used at the more advanced stages of the project development life-cycle (Black & Veatch, 2011).

2.2.4 Limitations of LCOE

The topic of levelised costing and its limitations is well covered in academic journals. Sklar-Chick, et al (2016), found that the LCOE metric has some significant shortcomings. These are discussed below.

- i. The LCOE does not account for the daily variation in demand and supply, which are the real value of energy. It uses an average of the costs and energy profiles over time.
- ii. LCOE often fails to capture important externalities. The term externalities is broad, and can encompass many different costs and impacts. They include: “damage from air pollution, energy security, transmission and distribution costs, and other environmental

impacts” (Roth & Lambs, 2004). Essentially, externalities are costs and benefits that do not accrue to the parties involved in the activity. Other important externalities include health costs as a result of pollution, which are difficult yet necessary to quantify.

- iii. LCOE does not account for system costs. From a system perspective, a technology portfolio (all power stations in the grid) is the level of analysis, not merely one type of technology (single power station).
- iv. LCOE does not account for technology types. A difficulty is encountered when comparing dispatchable and non-dispatchable technologies, as the LCOE merely accounts for average electricity produced, and does not take into account the production profiles and the market value of energy produced by the different technologies (Milligan & Kirby, 2009).
- v. The LCOE is only as accurate as the input data that is used in the electricity project evaluation model.

Of relevance to this study are findings by Joskow P.L. (2011) of the Massachusetts Institute of Technology (MIT). Joskow writes: “...this metric is inappropriate for comparing intermittent generating technologies like wind and solar with dispatchable generating technologies like nuclear, gas combined cycle, and coal. Levelized cost comparisons are a misleading metric for comparing intermittent and dispatchable generating technologies because they fail to take into account differences in the production profiles of intermittent and dispatchable generating technologies and the associated large variations in the market value of the electricity they supply. Levelized cost comparisons overvalue intermittent generating technologies compared to dispatchable base load generating technologies”. (Joskow, 2011).

The LCOE for renewable energy (solar PV and wind) were calculated for this study using the EPRI data but resulted in LCOEs that were unrealistically high compared to the actual tariffs that have been realised in South Africa through the REIPPP programme. Therefore a decision was taken to use the actual tariffs rather than the calculated LCOEs for comparative purposes. In this way the disadvantages of the LCOE methodology when applied to renewables as described by Joskow above were avoided. The actual tariffs were also used in the compilation of the IRP2018 (DoE, 2018, p. 23).

2.3 Nuclear Technology

The costs provided for nuclear technology in the IRP 2018, were not based on the EPRI Report of 2017, but on the “Study of the cost of Nuclear Power” report prepared by INGEROP South Africa for the DoE (DoE, 2018, p. 23). The INGEROP study expanded the analysis by EPRI to include a technology cost analysis from projects in Asia (Ingerop South Africa, 2013).

Nevertheless, for the purposes of this study, the EPRI Report was used to source data for the AP1000 and the EPR reactor. The EPRI Report does not explain why these two reactors were selected for analysis ahead of other designs available from suppliers from around the world, but availability of strongly relevant information was probably a consideration. The manufacturers of these reactors, Westinghouse (AP1000) and Areva (EPR) both submitted detailed proposals to Eskom during the course of a formal procurement process launched by Eskom for new nuclear capacity in 2006-2008 (WNA, 2019). The procurement process was terminated at an advanced stage, but a great deal of information was collected from the bids submitted by both organisations before the process was terminated.

For the purposes of this study, an evaluation of the Rosatom VVER 1200 technology has also been included. Prior to the release of the IRP 2018 Update in August 2018, speculation had been rife in South Africa that an illegal deal had already been signed with Rosatom, so the inclusion of the VVER 1200 was seen as relevant. The data for the VVER was obtained from a report sourced from EE Publishers, “The cost of electricity from a new-nuclear build in SA under various assumptions” (Yelland, 2016). The information provided by EE Publishers was structured in a similar way to the information provided by EPRI and is therefore readily comparable.

This section provides a technical description (characteristics) of our selected reactors, followed by an assessment of nuclear economics, and lastly a description of developments in the nuclear industry globally and in South Africa of relevance to this report. Included in the description of global developments is a section on construction risk, an important risk associated with new nuclear projects, especially in the western hemisphere.

2.3.1 Reactor characteristics

There are two basic ways to produce nuclear energy: nuclear fission and nuclear fusion. Both are processes by which atoms are altered to release energy. Fission is the division of one heavy atom into two or more smaller atoms, while fusion is the combination of two light atoms into a larger one.

Fusion is a developmental technology which holds the promise of producing reliable, clean energy, but which has not yet been developed to a point where more energy is produced than is needed to create the fusion reaction.

Nuclear fission therefore is the basis of nuclear energy production worldwide. Nuclear power utilizes the resulting energy to boil water, which in turn turns a turbine-generator set and, ultimately, produce electricity (Kadak, 2017, p. 13).

The main focus of nuclear reactor design since the 1940s has been on how to efficiently and effectively produce energy in a safe, reliable, and sustainable way. Over the intervening seventy years, reactor designs have adjusted to include more safety features, particularly in response to highly public accidents, such as Three Mile Island, Chernobyl, and Fukushima.

Uranium is the most common choice of fuel for nuclear reactors currently in operation, although plutonium or thorium can be used instead or complementary to the use of uranium. Uranium occurs naturally in the earth's crust and is predominantly a mixture of two isotopes: fissile uranium-235 (U-235) and fertile uranium-238 (U-238). U-238 makes up about 99.3 wt% of uranium in the earth's crust, while U-235 accounts for the remaining 0.7 wt%. However, U-235 is the fissionable isotope, and reactor designers have therefore, had to either develop specific designs that can utilize this low fissile fraction of natural uranium or find ways to increase the overall fraction of U-235 in the fuel. The latter process is known as fuel enrichment (Kadak, 2017, p. 13).

All three of the reactors discussed in this section are examples of Pressurised Water Reactors (PWR), a subset of Light Water Reactors (LWR), and produce heat through fission, using uranium as a fuel source. Boiling Water reactors (BWR) are also LWRs.

2.3.1.1 AP1000

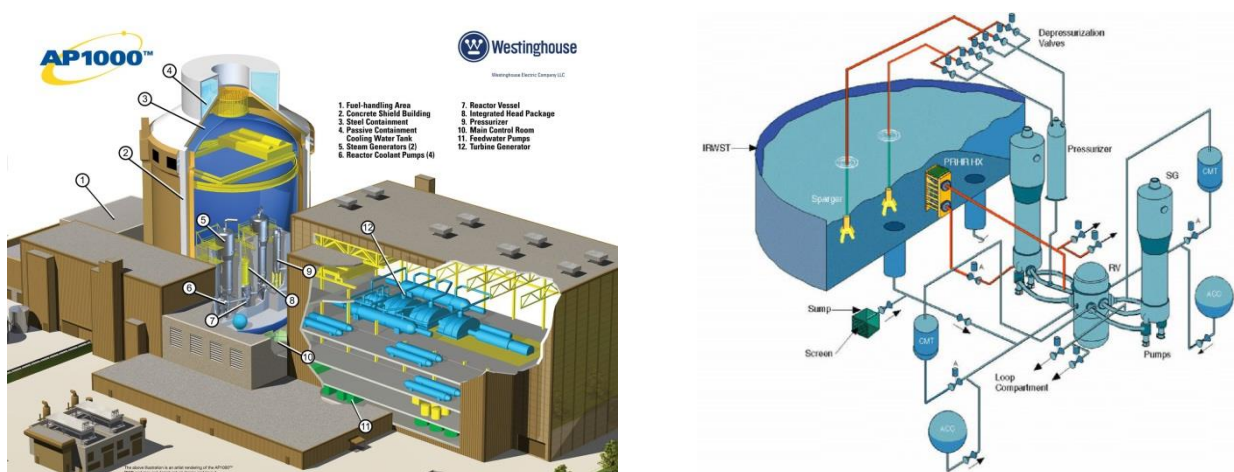


Figure 2-4: AP1000 Plant Layout and Passive Safety Systems

Designed by Westinghouse Electric, an American company, owned by Toshiba of Japan, the AP1000 is a PWR and is currently under construction in China and in the United States. Figure 2-4 provides illustrations of the AP1000 layout and passive safety system, whilst Table 2-1 provides plant design features (Kadak, 2017). The maximum thermal power capacity is

3 415MWth, with a net electrical generation of 1 115MWe. It was designed with the primary goal of reducing the number of costly components, piping, and cabling and increasing the inherent safety features of the plant. This goal is achieved by relying more on passive safety features and avoiding active cooling pumps for safety functions. A mainly passive safety feature is a large water tank in the roof that releases enough water during a nuclear accident so that the reactor core is submerged in water. This prevents the melting of the reactor pressure vessel and thus prevents the release of huge quantities of radioactivity into the environment.

The AP1000 has 50 % fewer safety-related valves, 35 % fewer pumps, 80 % less safety-related piping, 85 % less control cable, and 45% less seismic building volume. This rationalisation is intended to improve the economics of the plant. Significant modularity was also introduced to enable pre-construction of some large structures at a central factory before being shipped to site for erection. This shortens the time to construct of the plants (Kadak, 2017).

2.3.1.1.1 AP1000s under construction in China

As of 9 January 2019, there were four AP1000s in operation in China. In September 2007, Westinghouse and its partner, the Shaw Group, received authorisation to construct four AP1000 units in China: two at Sanmen in Zhejiang province and two more at Haiyang (WNN, 2019). The 2 Haiyang plants are shown in Figure 2-5 (WNN, 2019). Construction of both Sanmen and Haiyang started in 2009.

Sanmen 1 was the world's first AP1000 to start up, entering commercial operation on 21 September 2019. Haiyang Unit 1 and Sanmen unit 2 followed, entering commercial operation on 22 October and 5 November 2019, respectively.

As of January 2019, four AP1000 reactors were also being built in the USA - two each at Vogtle and Summer. However, construction of the two Summer units were suspended in August 2017, resulting in Westinghouse' temporary bankruptcy. This was caused by major cost overruns, significant delays, and other issues. Vogtle 3 and 4 are scheduled to start operating in November 2021 and November 2022, respectively (WNN, 2019).



Figure 2-5: Haiyang 1 and 2

Table 2-1 Key Plant Design Features of AP 1000

Reactor Thermal Power	3 415MWh
Reactor Electrical Power	1115MWe
Containment	Single
Core Inlet/Outlet Temperature	280.7°C/321.1°C
Number of Fuel Assemblies	157
Fuel Assembly Length	14 ft.
Core Damage Frequency	2.4×10^{-7}
Emergency Safeguards	Passive In-Vessel Retention System
Number of Steam Generators	2
Main Coolant Pumps	4 Canned Rotor
Refuelling Intervals	18 months
Construction Period	3 years

2.3.1.2 European Pressurised Reactor (EPR)



Figure 2-6: EPR plant layout and plant under construction in Okiluoto

Source: (Kadak, 2017)

The EPR is a third generation PWR design, and was designed and developed mainly by Framatome (part of Areva between 2001 and 2017) and Électricité de France (EDF) in France, and Siemens in Germany. The main design objectives of the EPR were to increase safety and to provide increased economic competitiveness. The size of the plant was increased over previous French and German designs to capture economies of scale and to make the plants more cost competitive.

The EPR is a 4 500MWth PWR that generates 1 660MWe. The design includes more independent and redundant safety systems and a core catcher, should the plant's safety systems fail to deal with potential fuel melt accidents. By adding more active and passive safety systems, this design increased cost and complexity.

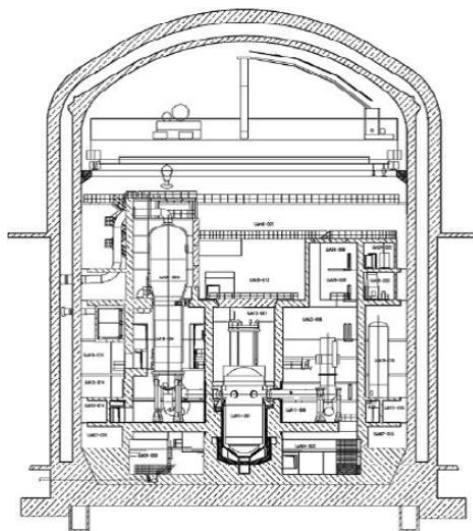


Figure 2-7: EPR double containment structure

A unique feature of the EPR design is the double containment structure, and the addition of a core-melt retention system to prevent the release of radioactivity into the environment during severe accidents. Shown in Figure 2-7 (Kadak, 2017) above is a cutaway drawing of the plant's reactor containment system. Overall the EPR is a standard evolutionary PWR design that has been scaled up from previous French versions and to which superior safety systems have been added (Kadak, 2017, p. 32). Key plant characteristics are provided in Table 2-2 (Kadak, 2017).

2.3.1.2.1 EPRs under construction

Four EPRs are currently under construction: one in Finland, one in France, and two in China. Shown in Figure 2-6 (Kadak, 2017) above is the first EPR. It started construction in Olkiluoto, Finland, in 2005.

World Nuclear News reported on 14 December 2018, that the first EPR, Taishan unit 1, in Guangdong province, China, had completed all commissioning work and was qualified for commercial operation. It became the first EPR reactor to reach that milestone. Taishan 1 and 2 are the first two reactors based on the EPR design to be built in China. Construction of unit 1 started in 2009. (WNN, 2018).

These two units are the third and fourth EPR units under construction globally, after the Olkiluoto 3 project in Finland and the Flamanville 3 project in France. At present, both projects are seriously over budget and behind schedule, mainly due to some first-of-a-kind construction problems. On March, 7, 2019, the Finnish government announced that it had finally granted an operating permit to allow Olkiluoto 3 to start production in 2020.

Flamanville 3 has been under construction since December 2007. Project cost has ballooned to €10.5 billion, triple the original budget. It is currently projected that first fuel loading could happen in 2019, and start-up in 2020.

It is interesting to note is that the cost of these plants varies tremendously by country. Overall cost depends on cost of construction in the country, regulatory systems, and delays incurred. The expectation is that lessons will be learned from past construction experiences that will reduce these capital costs in the future (Kadak, 2017, p. 32).

Table 2-2: Key Plant Design Features - EPR

Reactor Thermal Power	4 500MWh
Reactor Electrical Power	1 660MWe
System Pressure	2 250 PSIA

Core Inlet/Outlet Temperature	295.6°C/329.8°C
Number of Fuel Assemblies	241
Fuel Assembly Length	480cm
Core Damage Frequency	5×10^{-7}
Emergency Safeguards	Active (4 Independent Trains)
Steam Generators	4
Main Coolant Pumps	4
Containment	Double
Main Coolant Pumps	4 Canned Rotor
Refueling Intervals	18 months
Construction Period	5 years

2.3.1.3 VVER 1200

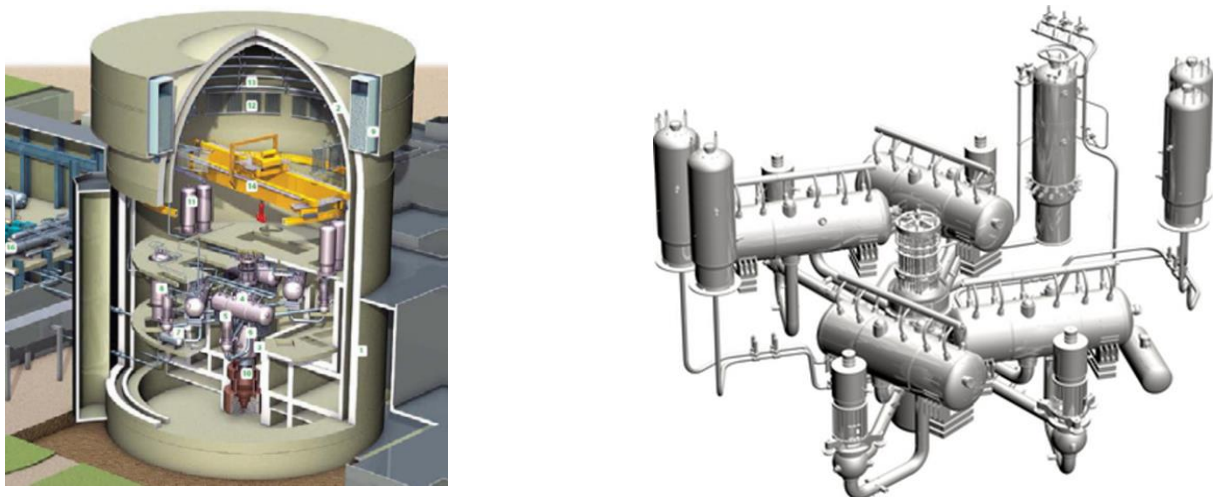


Figure 2-8: Containment; and primary cooling circuits and pressuriser layout

The Water-Water Energetic Reactor (VVER) as depicted in Figure 2-8 (Kadak, 2017), is an evolutionary PWR developed by OKB Gidopress of Russia, and is based on the VVER 1000 reactor. The VVER 1000 has a combined total of five hundred years of operating experience.

The design implements a number of advanced safety measures including double containment, a core-catcher for retaining molten core materials, a passive steam generator heat removal system, and a passive core flooding system (Asmolov, et al., 2017). Key plant design features are provided in Table 2-3 (Kadak, 2017).

2.3.1.3.1 VVER 1200s under construction

In August 2016 the first VVER 1200, Novovoronezh II-1, was connected to the Russian grid and started commercial operation on 27 February 2017. There are four other VVER 1200s under construction in Russia, Kaliningrad, and Belarus (Kadak, 2017, p. 32).

Russia is aggressively marketing the VVER 1200 with financial proposals to Turkey, Egypt, Finland, Hungary, and Bangladesh. It proposes to finance the cost to build, operate, and sell power to local power companies and countries.

Table 2-3 Key Plant Design Features VVER 1200

Reactor Thermal Power	3 212MWh
Reactor Electrical Power	1 660MWe
Core Inlet/Outlet Temperature	298.2°C/328.9°C
Number of Fuel Assemblies	163
Fuel Assembly Length	457 cm
Core Damage Frequency	7.37×10^{-7}
Emergency Safeguards	Active (4 Independent Trains)
Steam Generators	4 Horizontal
Main Coolant Pumps	4
Containment	Double
Main Coolant Pumps	4 Canned Rotor
Refueling Intervals	18 -20 months
Construction Period	54 months

2.3.2 Nuclear Economics

The economics of new nuclear plants are heavily influenced by their capital cost, which accounts for at least 60 % of their levelised cost of electricity (LCOE). Nuclear power plants are expensive to build but relatively cheap to run. In many places, nuclear energy is competitive with fossil fuels as a means of electricity generation (World Nuclear Association, 2018).

Due to the large capital component of its cost, the levelised cost of nuclear plant is heavily influenced by the discount rate. The higher the discount rate the less competitive nuclear plants become. In terms of operational costs, however, nuclear plants are very competitive. Nuclear power combines the advantages of reliable base-load generation, with very low greenhouse gas

emissions, and lifespans of 60 year, and even longer for newer plant (Nuclear Energy Association, 2015).

The effect of different WACC's (discount rates) is also emphasised by Serfontein, D., in his article "Nuclear power more profitable than coal if funded with low cost capital: A South-African case study". Serfontein concludes, "..... although the nuclear LCOE is very sensitive to the value of the Overnight Cost for high WACC%, for low WACC% nuclear will produce much lower LCOEs, irrespective of the higher overnight cost. Therefore, if the nuclear project can be funded with low interest rate loans, high overnight costs will not lead to excessive LCOEs." (Serfontein, 2014)

The World Nuclear Association (WNA) argues that nuclear fares better in regulated rather than unregulated markets because in regulated markets government utilities make investment decisions focused on ensuring reliable operation while minimising total costs over the long-term. In a deregulated market a merchant generator depends on the inherently short-term and often volatile market for its revenue, which places the operator at risk; and the developer of a new plant faces considerable uncertainty due to greater completion risk. The WNA argues therefore that Government support is needed to mitigate these risks and make new nuclear projects bankable (World Nuclear Association, 2018).

In an article titled, "Nuclear power – unaffordable, or lowest cost energy available?", Cilliers, A., describes the deal concluded between Russia and Egypt and marvels at the very low levelised costs obtained for nuclear energy: "The reason in this scenario is rather simple: the combined effect of the extremely low interest rate offered by the vendor state as well as the long economic life of the plant. This often-overlooked combination makes it virtually impossible for other energy sources to compete at the same level. This is the reason why we see nuclear plants becoming the cheapest operating plants on the grids of many countries after around 20 years. It also emphasises the importance of the financing model." (Cilliers, 2017). Although Cilliers' analogy here is flawed in that a LCOE of a plant is spread over the whole lifetime, his analysis serves to emphasise that, once a nuclear plant has been constructed, the production cost of electricity is low, predictably stable, and provides emission-free electricity.

The cost of nuclear power has been seriously impacted by new designs and higher safety specifications that were made necessary by accidents such as Three Mile Island, Chernobyl and Fukushima. According to the US Energy Information Administration (EIA) statistics, in constant 2002 values, the realized overnight cost of a nuclear power plant built in the USA grew from \$1 500/kWe in the early 1960s to \$4 000/kWe in the mid-1970s, and to \$5 945/kW by 2016. The EIA ascribes this increase to more stringent regulatory requirements (including design changes

that required plants to be back-fitted with modified equipment), licensing problems, project management problems and poor estimation of costs and demand.

Assessing the relative costs of new generating plants utilising different technologies is a complex matter and the results depend crucially on location. There are significant variations in nuclear capital costs by country, particularly between the emerging industrial economies of East Asia and the mature markets of Europe and North America. Variations have a variety of explanations, including: differential labour costs; more experience in the recent building of reactors; economies of scale from building multiple units; and streamlined licensing and project management within large civil engineering projects. In countries where continuous development programs have been maintained, capital costs have been contained and, in the case of South Korea, even reduced. Over the last 15 years global median construction periods have fallen (WNA, 2017).

2.3.3 Nuclear power around the globe

2.3.3.1 Nuclear Electricity Production

Around 11 % of the world's electricity is generated by about 450 nuclear power reactors. About 60 more reactors are under construction, equivalent to about 15% of existing capacity.

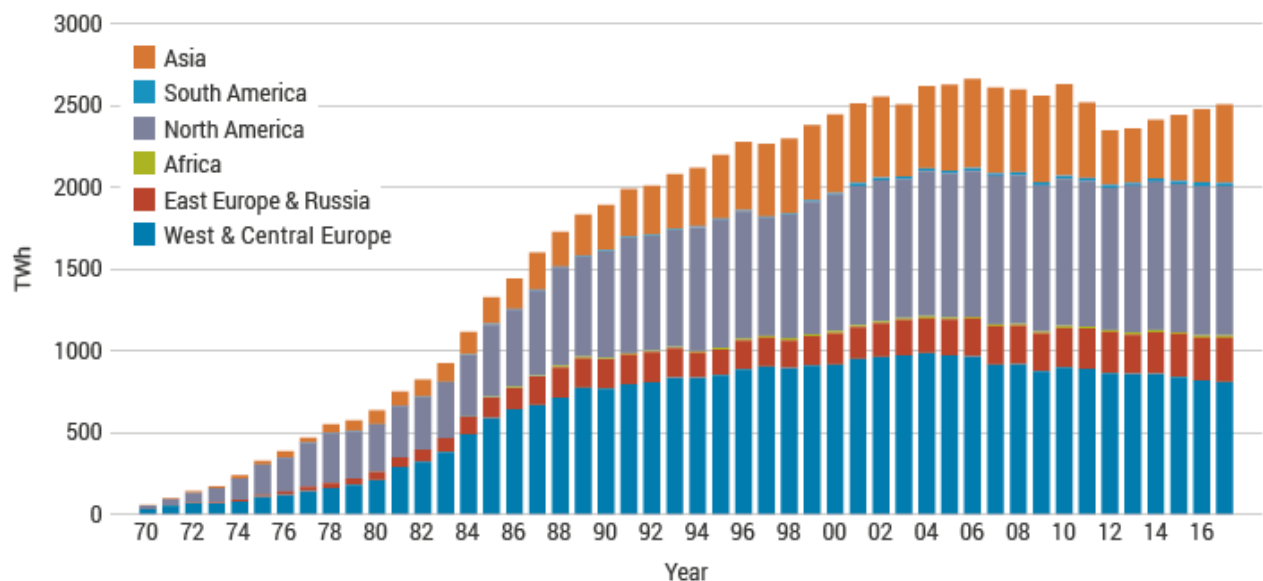


Figure 2-9: Global electricity production from nuclear

As Figure 2-9 (WNA, 2019) indicates, in 2017 nuclear plants supplied 2 487TWh of electricity, up from 2 477TWh in 2016. This was the fifth consecutive year that global nuclear generation had risen, with output 142TWh higher than in 2012 (WNA, 2019). The nuclear share of global

electricity generation has remained roughly stable between 2013 and 2017 (–0.5 percentage points), with a long-term declining trend, from 17.5 % in 1996 to 10.3 in 2017.

2.3.3.2 Global synopsis

In order to provide a balanced view of the global nuclear industry the following statistics are taken from The World Nuclear Industry Status Report of 2018, compiled by Mycle Schneider Consulting, a notoriously pro-renewables and anti-nuclear think tank.

2.3.3.2.1 The dominance of China

World nuclear power generation increased by 1 % in 2017, due primarily to an 18 % increase in China. Excluding China, global nuclear power generation declined for the third year in a row.

There were four reactor starts in 2017 of which three were in China and one in Pakistan (built by a Chinese company). Five units started up in the first half of 2018, of which three were in China—including the world’s first EPR and AP1000—and two in Russia.

There were five construction starts in the world in 2017, of which one was a demonstration fast reactor project in China. The number of units under construction globally declined for the fifth year in a row, from 68 reactors at the end of 2013 to 50 by mid-2018, of which 16 are in China

There have been no new starts of construction of any commercial reactors in China since December 2016. China spent a record US\$126 billion on renewables in 2017 (Schneider & Forggatt, 2018, p. 15).

2.3.3.2.2 Operational Status and Construction Delays

Seven years after the Fukushima events, Japan had restarted five units by the end of 2017- still generating only 3.6 % of the country’s power in 2017- and 9 % by mid-2018. As of mid-2018, 32 reactors - including 26 in Japan - are in Long-Term Outage (LTO).

At least 33 of the 50 units under construction are behind schedule, mostly by several years. China is no exception; at least half of 16 units under construction in China are delayed. Of the 33 delayed construction projects, 15 have reported increased delays over the past year. Only a quarter of the 16 units scheduled for start-up in 2017 were actually connected to the grid.

New-build plans have either been cancelled including in Jordan, Malaysia and the U.S.; or postponed such as in Argentina, Indonesia, and Kazakhstan. (Schneider & Forggatt, 2018, p. 15)

2.3.3.2.3 Decommissioning Status Report

As of mid-2018, 115 units are undergoing decommissioning - 70 % of the 173 permanently shut-down reactors in the world.

Only 19 units have been fully decommissioned: 13 in the U.S., five in Germany, and one in Japan. Of these, only 10 have been returned to Greenfield sites. (Schneider & Forggatt, 2018, p. 15)

2.3.3.2.4 Renewables accelerate take-over

Globally, wind power output grew by 17 % in 2017, solar by 35%, nuclear by 1 %. Non-hydro renewables generate over 3 000TWh more power than a decade ago, while nuclear produces less. Nine of the 31 nuclear countries - Brazil, China, Germany, India, Japan, Mexico, Netherlands, Spain and United Kingdom (U.K.) - generated more electricity in 2017 from non-hydro renewables than from nuclear power. (Schneider & Forggatt, 2018, p. 15)

2.3.3.3 Construction risk

The greatest risk associated with the construction of new nuclear plants is the risk of long project delays during construction. As we have seen the capital cost of nuclear projects has the highest impact on its levelised cost, and project delays can greatly exacerbate this problem. The economics of nuclear projects are dependent on successful project implementation. Building to budgeted cost and schedule is essential to maintain the economic competitiveness of the plant, which was the basis for securing project approval in the first place (Caplan, 2018). Examples of NPPs running over budget and behind schedule include:

- EPR Olkiluoto 3, with a timeline of about 19 years. The application to the Finnish cabinet for a decision-in-principle was in 2000. Operation is expected in 2019 (WNN 2017). The final cost is unknown but is probably close to €8.5 billion (Milne 2016);
- EPR Flamanville 3, with a timeline of about 14 years. The beginning of the national public debate was in October 2005. Operation is expected in 2019 (WNN 2017). The final cost is expected to be above €10 billion (EDF 2015);
- AP1000. The costs to build the two Vogtle units could range between \$18.3 billion and \$19.8 billion (Patel 2017). The AP1000 units in Virgil C. Summer have a comparable budget, and the projects are currently (September 2017) suspended (Locatelli, 2018, p. 11).

Nuclear technology is not necessarily to blame, however: in South Korea, nuclear power plants (NPPs) are delivered on time & within budget and have very good operational performance. The reasons for this success can be found in the project delivery chain.

NPPs, or any other type of megaprojects, are likely to be delivered over-budget and late when the project is a complex “one-of-its-kind white elephant” combining a novel complex technology with a complex network of stakeholders. This combination of novelty and complexity makes the megaproject fragile, i.e. it is likely that something will go wrong and the project will be very difficult to recover (Locatelli, 2018, p. 21).

The proven way to address this issue is standardisation, which played a key role in the South Korean success. Standardization needs to be twofold: technical standardisation, i.e. the construction of the infrastructure with the same (or very similar) designs over and over, and the “project delivery chain” standardisation, i.e. the same stakeholders involved in the delivery of a project that is replicable multiple times (Locatelli, 2018, p. 21).

2.3.4 Nuclear in South Africa

In August 2018 the South African government announced that it had abandoned plans to build 9 600MW of new nuclear capacity by 2030. The draft IRP 2018 was an update of the IRP 2010, and despite endorsing the role of nuclear power, it did not include any new nuclear capacity by 2030. The IRP 2010 outlined a required 52GW of new capacity by 2030, with nuclear to provide at least 9.6GW of that. An update to the IRP issued in November 2016 called for 1.4GW of new nuclear capacity by 2037, and a total of 20GW long-term (WNA, 2019).

Table 2-4 Operating South African power reactors

Reactor	Type	Net Capacity	First Power	Planned closure
Koeberg 1	PWR	930MWe	April 1984	2024
Koeberg 2	PWR	900MWe	July 1985	2025
TOTAL		1 830MWe		

2.3.4.1 Nuclear industry development in South Africa

South Africa's main coal reserves are concentrated in Mpumalanga in the northeast, while much of the load is on the coast near Cape Town and Durban. Moving either coal or electricity long

distances is inefficient, so it was decided in the mid-1970s to build some 1 800MW of nuclear capacity at Koeberg near Cape Town.

The Koeberg plant was built by Framatome (now Areva) and commissioned in 1984-85. It is owned and operated by Eskom and has twin 900MW class (970 & 940 MWe gross) PWRs (WNA, 2019).

2.3.4.1.1 Siting

Although the procurement of conventional new nuclear capacity in South Africa was halted in 2008, work has continued with an environmental impact assessment (EIA) process initiated in 2006, for the licensing of three potential sites for the next nuclear power units: Thyspunt, Bantamsklip and Duynefontein, the last of which is very close to the Koeberg nuclear plant.

In March 2016 Eskom submitted site licence applications to the National Nuclear Regulator (NNR) for both Thyspunt and Duynefontein to construct and operate "multiple nuclear installations (power reactors) and associated auxiliary nuclear installations". In December 2016 the SA Council for Geoscience confirmed the geological and geotechnical suitability of Thyspunt. In October 2017 the Department of Environmental Affairs authorised 4 000MWe nuclear capacity to be built at either site (WNA, 2019).

2.4 Gas Technology

The technical discussion in this section is limited to a generic description of the characteristics of two types of natural gas technologies used to generate electricity, namely Open Cycle Gas Turbines (OCGT) and Combined Cycle Gas Turbines (CCGT). From the point of view of this report, it is important to understand how each technology can be utilised to provide the flexibility needed to enable a system consisting of a high percentage of renewables to supply base-load. This section also provides a brief overview of the global gas markets, including a discussion of global liquefied natural gas (LNG) developments. An overview of South African plans to establish a gas market is provided next, including a summary of the main risks associated with importing natural gas into South Africa. Lastly, an assessment of just how clean natural gas is, is presented by comparing gas emissions to those of oil and coal.

2.4.1 Natural gas technology

When used for power production, gas turbines can either be operated in an open cycle mode (exhaust to atmosphere) often referred to as an Open Cycle Gas Turbine as illustrated in Figure

2-10 (IPIECA, 2014), or in a combined-cycle mode (Combined Cycle Gas Turbine) as shown in Figure 2-11 (IPIECA, 2013).

2.4.1.1 Open cycle gas turbines

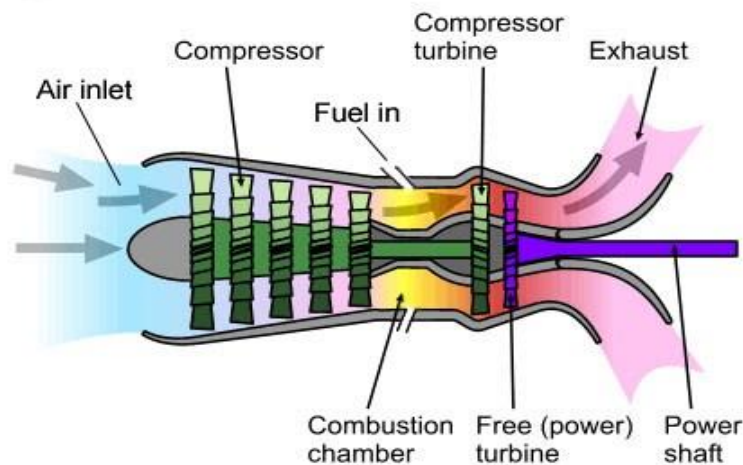


Figure 2-10: Open-cycle gas turbine schematic

A gas turbine extracts energy from a flow of combustion gas. In a CCGT plant, it is the first stage in the process of producing electricity. It has an upstream compressor coupled to a downstream turbine, and a combustion chamber in-between. The term gas turbine (GT) may also refer to just the turbine element.

Figure 2-10 is a schematic of a gas turbine used for electrical power production. A typical gas turbine unit consists of three major components:

- Compressor - Compresses the incoming air to high pressure;
- Combustion area - Burns the fuel and produces high-pressure, high-velocity gas; and
- Turbine - Extracts the energy from the high-pressure, high-velocity gas flowing from the combustion chamber.

The gas turbine compressor draws in air from the environment via a filter. This air is compressed to a higher pressure in the compressor and then directed into the combustion chamber. This combustible gas is then mixed in air and combustion takes place generating hot gases under high pressure. The energy released is converted into a mechanical rotation which powers the generator (Eskom, 2008, p. 14)

In an OCGT the working fluid remains gaseous throughout the thermodynamic cycle (Brayton cycle). This thermodynamic cycle consists of adiabatic compression, isobaric heating, adiabatic expansion, and isobaric cooling. In the expansion turbine section of the GT, the energy of the hot gases is converted into work. This conversion actually takes place in two steps. In the nozzle section of the turbine, the hot gases expand and a portion of the thermal energy is converted into kinetic energy. In the subsequent bucket section of the turbine, a portion of the kinetic energy is transferred to the rotating buckets and converted to work (EPRI, 2017, p. 139).

Typically, more than 50 % of the work developed by the turbine sections is used to power the axial flow compressor, while the remainder is available as useful work to drive the generator.

The main advantages of OCGTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost, and short construction times. These advantages make them attractive for peaking duty applications. Their main disadvantage is high fuel cost.

Peaking duty open cycle site arrangements can be designed to allow for later conversion to combined-cycle through staged development.

2.4.1.2 Combined cycle gas turbines

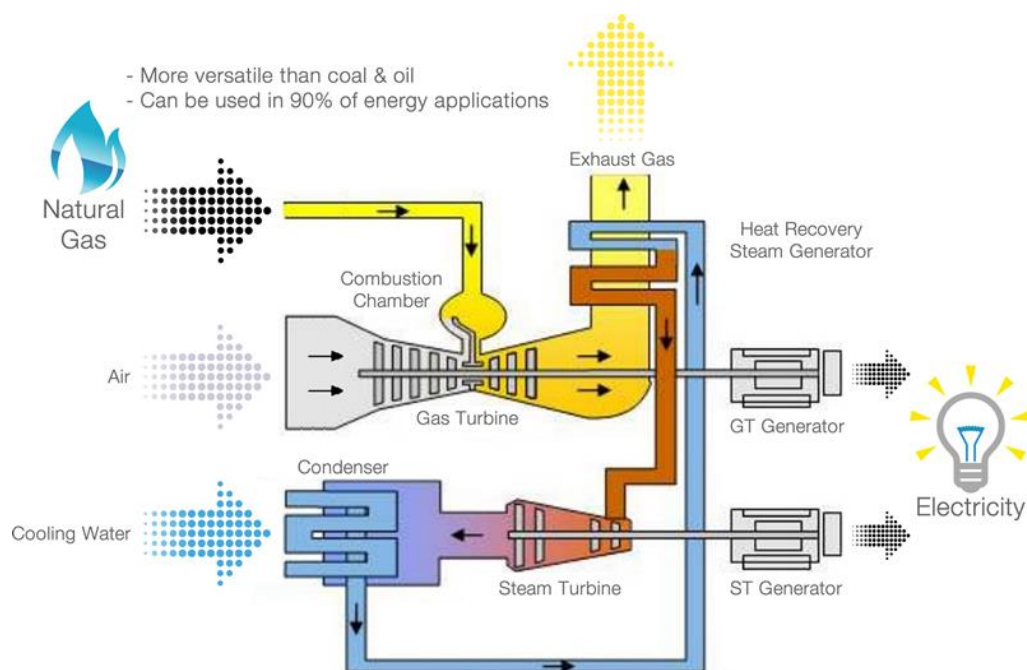


Figure 2-11: Combined cycle gas turbine flow chart

As illustrated in Figure 2-11, a CCGT power plant uses a cycle configuration of an OCGT that generates electricity, followed by a heat recovery steam generator (HRSG), which is heated by the exhaust gasses of the OCGT. The steam from the steam generator then drives a steam turbine to generate additional electricity (Eskom, 2008, p. 13). This last step enhances the efficiency of overall electricity generation since it generates extra electricity without consuming extra gas.

A combined cycle is characteristic of a power-producing engine or plant that employs more than one thermodynamic cycle. Simple cycle heat engines are only able to use a portion of the energy their fuel generates. The remaining heat from combustion is generally wasted. This combination of two power generation cycles enhances the efficiency of the plant. While the electrical efficiency of a simple cycle power plant without waste heat utilization typically ranges between 25% and 40 %, a CCGT can achieve electrical efficiencies of 60 % and more.

In a thermal power plant, high-temperature heat as input to the power plant, usually from burning of fuel, is converted to electricity as one of the outputs and low-temperature heat as another output. As a rule, in order to achieve high efficiency, the temperature difference between the input and output heat levels should be as high as possible (Carnot efficiency). This is achieved by combining the Rankine (steam) and Brayton (gas) thermodynamic cycles (EPRI, 2017, p. 137).

The hot exhaust gas exits the GT at temperatures between 538°C and 593°C and passes through the steam generator (boiler) where it exchanges heat with water producing steam and which may incorporate a reheat loop. The exhaust gas is cooled down to between 80°C and 135°C before exiting through the steam generator stack.

The steam produced in the steam generator is used to drive a steam turbine generator. In larger plants, it is common to have two or three gas-turbine/steam-generator trains providing steam for a single large steam turbine. Usually, about two-thirds of the total power is produced from the gas turbines and one-third from the steam turbine. The steam from the steam turbine is condensed using an air-cooled condenser or a closed-loop cooling tower, and the condensate is returned to the steam generator by condensate pumps (EPRI, 2017, p. 138).

2.4.1.3 Load-following gas turbines and system variability

The introduction of large amounts of renewable energy in electrical systems has increased the need for flexibility. Flexibility is the capability of a power system to cope with the variability and uncertainty that renewable energy generation introduces into the system in different time scales, from the very short to the long term, avoiding curtailment of renewable energy and reliably supplying all the demanded energy to customers (IRENA, 2018).

OCGTs are generally used for peaking because their very quick response time from being stopped to being at full load gives them excellent peaking abilities, while its high fuel consumption makes it too expensive for mid-merit load following. CCGTs are very well suited for mid-merit load-following because their open cycle gas turbines give them the ability to follow the load relatively quickly, while their steam turbines reduce their fuel cost by increasing their efficiency.

Gas turbines are not the only form of peaking plant. Hydroelectric dams are intentionally variable and can generate less during off-peak and quickly respond to peak demands. Consequently, hydroelectric plants may function as load followers or as peaking plants. When sufficient water is available, they may even serve as base-load plant.

According to the 2016 BP Statistical Review of World Energy, global consumption of wind and solar power increased by a factor of 10 between 2005 and 2015. As these sources are highly variable - with output changing from minute to minute - a new class of peakers has emerged. To adjust to the increased variability of the grid as renewable penetration grows, the load following power plant has grown in importance (Rapier, 2017).

In contrast to the traditional peaker, a load following peaker operates at a lower load for longer hours to balance out the variability of renewables. It has different performance requirements than a traditional peaker plant. Load following plant has to have faster response times to handle transient loads, and may even need a zero-minute start time. With the emergence of utility-scale battery storage, energy storage can be combined with gas turbines to provide an immediate response while the gas turbine is coming online.

Load following plants also have to deal with more variables than traditional peakers. The load may need to be changed during the ramp-up, for instance, or the ramp-up speed may need to be quickened or slowed.

As with traditional peakers, the electricity produced by load following plant is more expensive than that from plants producing base-load power. Gas turbines are at their greatest efficiency when operating at maximum load. That means that load following plants running at minimum or partial loads are less efficient than similar plants acting as traditional peakers (Rapier, 2017).

2.4.2 The global gas market

In addition to transporting gas via pipelines for use in power generation, other end uses for natural gas include export as liquefied natural gas (LNG) or conversion into other liquid products via gas-to-liquids (GTL) technologies. GTL technologies can convert natural gas into liquids products

such as gasoline, diesel or jet fuel. Natural gas can be "associated" (found in oil fields), or "non-associated" (isolated in natural gas fields), and is also found in coal beds (as coalbed methane).

2.4.2.1 Natural gas outlook

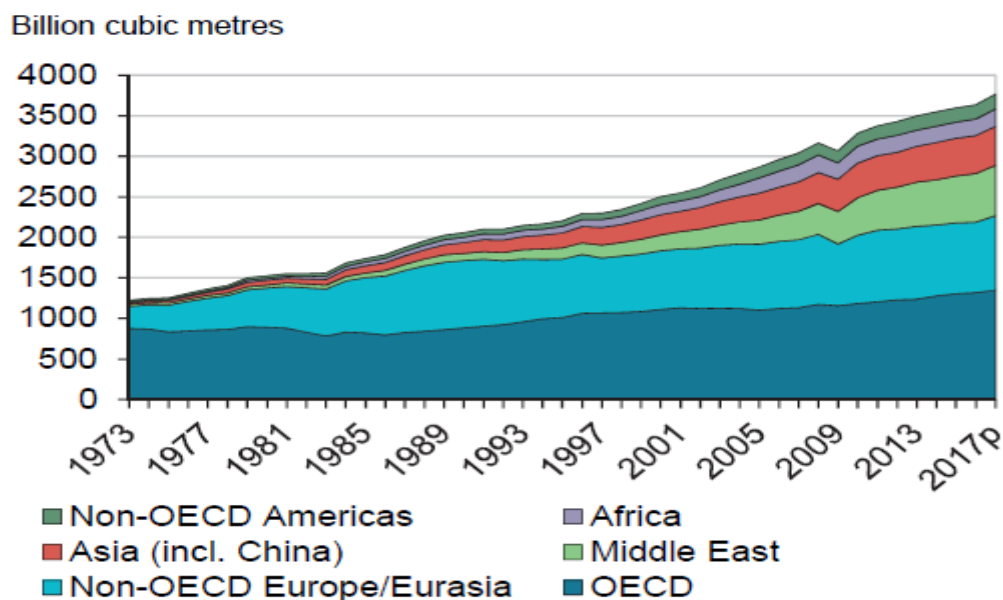


Figure 2-12: World Natural gas production by region

Global natural gas output has grown almost three-fold since the 1970s, as Figure 2-12 (IEA, 2018) shows. Natural gas is the only fossil fuel with a growing share of global energy and is poised to replace oil as the leading fuel in U.S. energy consumption by 2023. BP forecasts that by 2035, oil will account for 30 % of U.S. energy consumption, and natural gas for 39 %. (U.S. Commodity Futures Trading Commission, 2018)

China and emerging Asian markets drive growth in global natural gas consumption. Global demand for natural gas is forecast to increase at an average of 1.6 % over the period 2018 – 2023 with emerging Asian markets as the main engine for demand. 2017 was a year of strong growth for natural gas. Global natural gas demand grew by 3 %, the highest increase since 2010. China, where demand grew 15%, accounted for nearly a third of the global increase, driven by a determined policy effort to improve air quality through coal to gas boiler conversions in the residential and industrial sectors. This led to an unprecedented surge in LNG imports, placing China as the world's second-largest LNG importer after Japan (IEA, 2018, p. 3).

Three major drivers are set to shape the evolution of global natural gas markets in the short-term:

- The People's Republic of China is set to become the world's leading importer of natural gas. Driven by continuous economic growth and strong policy support to curb air pollution,

it is anticipated that China could account for as much as 37 % of the global increase in natural gas consumption between 2017 and 2023, more than any other country. As domestic production cannot keep pace, China will become the world's largest natural gas importer by 2019, mostly supplied by LNG.

- The industrial sector is set to take the lead from power generation as the main driver of global growth in demand for natural gas. Emerging markets, primarily in Asia, will account for the bulk of this increase with uses as fuel for industrial processes as well as for feedstock for chemicals and fertilisers. It is expected that industrial gas demand will also grow in major producing regions, such as North America and the Middle East, to support expansion of their petrochemicals sectors.
- The United States will be the source of much of the growth in natural gas production and most of the additional LNG exports. The United States, already the world's top producer, accounts for almost 45% of the growth in global production and nearly three-quarters of LNG export growth. The development of destination-free and gas-indexed US LNG exports provides additional flexibility to the expanding global LNG market (IEA, 2018).

2.4.2.2 Liquefied natural gas

Without conversion to LNG, natural gas can only be transported via pipelines, which leads to regional pricing differences based upon the pipeline grid. LNG transportation via ships has changed the dynamic that natural gas at the production source of the pipeline can only serve the downstream delivery location of the pipeline by opening up new international markets with the consequent global pricing influence.

LNG uses natural gas as feedstock, taking the gaseous form and chilling it to -160°C until it becomes a liquid. In liquid form, it occupies just 1/600th the space and can be transported over sea using specialized tankers. The process increases the cost of the commodity significantly, so the LNG industry depends on substantial natural gas price spreads around the globe to support trade. At the point of receipt, regasification plants convert the LNG back to a gaseous state for use as a source of energy or as industrial feedstock. (U.S. Commodity Futures Trading Commission, 2018, p. 3)

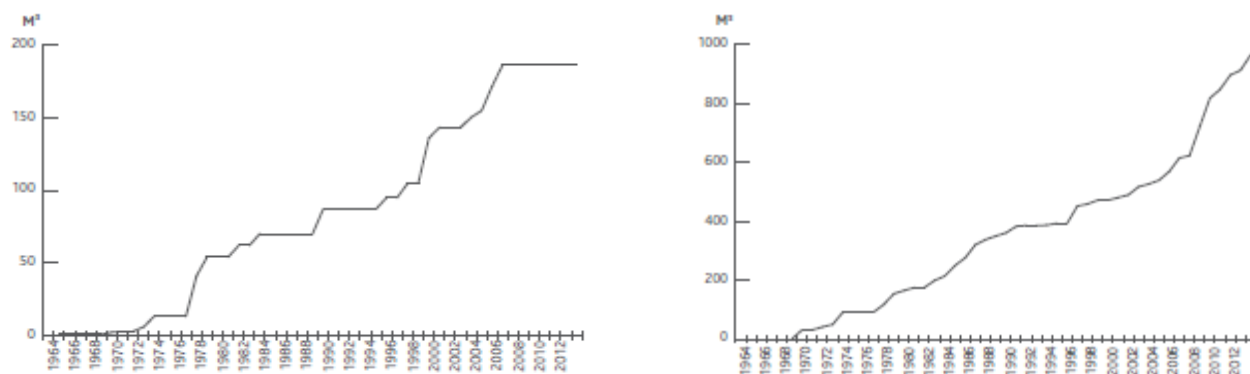


Figure 2-13: Liquefaction capacity, and gasification capacity (1964-2013)

The growth in supply and demand between 1964 and 2012 is illustrated in Figure 2-13 (Pirrong, 2014), which depicts the aggregate cumulative liquefaction and gasification capacity by year from 1964 to 2012. In the early years, growth was extremely rapid. The annual growth rate in capacity from 1964 to 1978 was 380 %. There was something of a hiatus in the growth of capacity in the 1980s and 1990s. No major projects came on line between 1983 and 1989, and there was another gap from 1989 to 1995. Capacity growth from 1980 to 1996 averaged only 4.7 % per annum. The rate increased in the late-1990s with the entry of Trinidad and especially Qatar as major producers. From 1996 to 2006, the growth rate in capacity doubled to 9.6 % per annum.

The initial growth in LNG capacity occurred in the Middle-East and North Africa (MENA), Algeria and Abu Dhabi, and in South Asia (Brunei and Indonesia). In the 1980s, Malaysia and Australia developed as major producers. In the late 1990s, a major change occurred with Qatar's emergence as a dominant force in the marketplace. The 1990s also saw the first major supplier in the Western Hemisphere: Trinidad and Tobago.

On the demand side, although Europe was the initial destination for large-scale LNG shipments, Asia, and especially Japan, emerged as the predominant demand region very rapidly. This is illustrated in Figure 2-13, which depicts regasification capacity shares across major importing countries. In the early-1990s, Japan, South Korea, and Taiwan accounted for approximately 75 % of LNG imports, but their share had fallen to slightly above 50 % in 2009. The entry of China and India as buyers kept the overall Asian share at approximately 70 %: the Chinese and Indian shares are expected to increase appreciably in the coming years. In Europe, Belgium, Italy, Spain, and France have maintained a relatively constant share hovering around 20 %. (Pirrong, 2014, p. 4)

2.4.3 Natural gas in South Africa

2.4.3.1 Gas Utilisation Master Plan

The South African Government is in the process of developing the Gas Utilisation Master Plan (GUMP). The GUMP is a roadmap for the development of a gas economy. It analyses the potential and opportunity for the development of South Africa's gas economy and sets out a plan of how this could be achieved. One of the key objectives of the GUMP is to enable the development of indigenous gas resources and to create the opportunity to stimulate the introduction of a portfolio of gas supply options.

The initial period of the development of South Africa's gas industry could be anchored on the demand provided by a Gas to Power Programme. The intention of the Gas to Power Programme is not only to supply power but also to supply a limited amount of gas, marketed in the form of a Gas Supply Agreement (GSA), for use by industrial and other users. In alignment with the GUMP, the Gas to Power Programme will, therefore, help enable the development of South Africa's gas sector (DoE IPP Office , 2019).

2.4.3.2 The Gas to Power Programme

In 2012, the DoE issued Ministerial Determinations that new generation capacity should be procured from hydro, coal and gas sources to support South Africa's base-load energy mix. The Determinations require that 3 126MW of base-load and/or mid-merit energy generation capacity be built from gas-fired power generation to contribute towards energy security. The gas required for such power generation will be from both imported and domestic gas resources (DoE IPP Office , 2019).

It was originally anticipated that a request for proposals (RFQ) for the LNG-to-Power IPP procurement programme would be released to the market in November 2016, but due to delays in developing an integrated resources plan, and the need to align the LNG-to-power programme with the IRP, the RFQ has not been issued yet. It is expected that new timelines for this programme will be developed soon now that the IRP 2019 has been released.

2.4.3.3 Risks posed to South Africa from importing natural gas

In his report "Can new nuclear compete with new renewables in SA?", Serfontein in a discussion about risks that also include the risks of terrorism and of military attacks, discusses two of the risks associated with importing LNG, namely security of supply and LNG price shocks (Serfontein, 2018).

Serfontein concludes that:

- i. When gas power is mixed in appropriate ratios with much less expensive wind, solar PV, the cost risk from imported LNG is substantially diluted.
- ii. Since 2009, natural gas and LNG prices decreased by about 50 %. Just as importantly, their prices also became much more stable.
- iii. The LNG import market also improved in that it has expanded and there are now many suppliers and many buyers. This resulted in a reasonably stable spot market. It is thus no longer necessary to sign long-term fixed take-or-pay contracts. It is now viable to pay per shipload from the spot-market.

Serfontein's observations on the price of LNG are corroborated by Figure 2-14 (EIA, 2019) and Figure 2-15 (EIA, 2019). Although prone to the occasional price shock, the price of LNG has dropped from US\$12.49 on June 5, 2008, to US\$3.25 in January 2019. Figure 2-14 also shows that prices in January 2019 are quite similar to those of January 1997.

A contributor to this could be, as also pointed out by Serfontein, that there are now a variety of LNG exporters and security of supply risk has reduced accordingly.

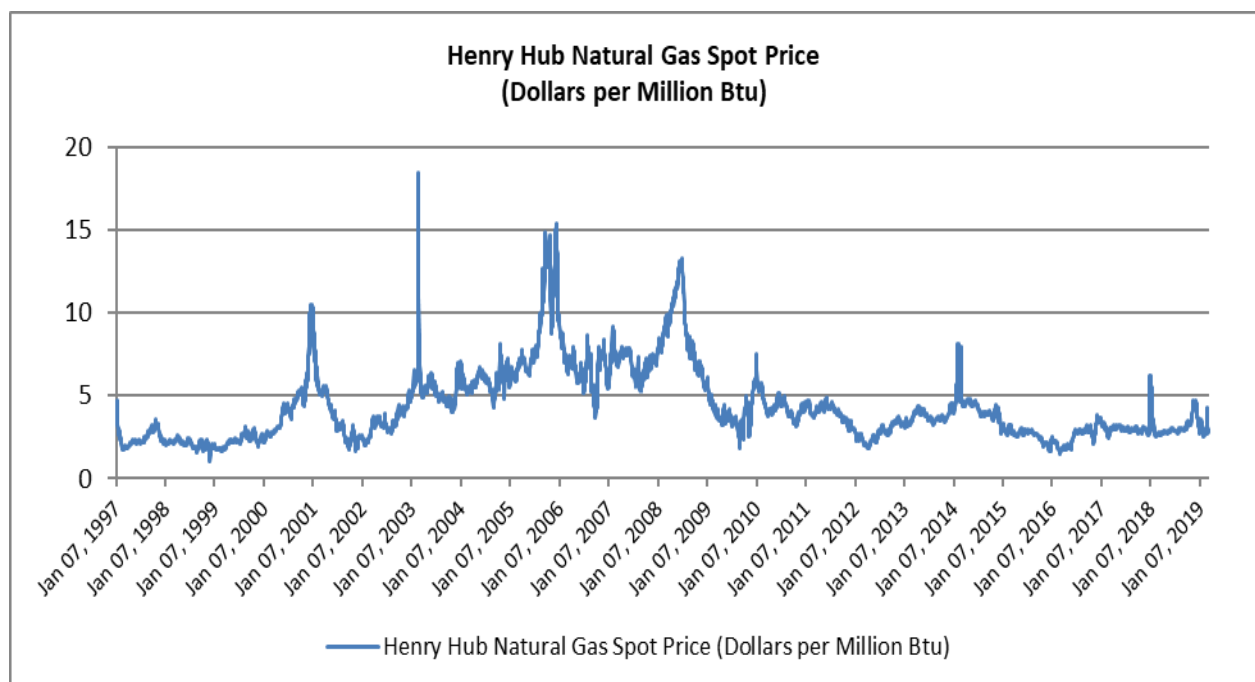


Figure 2-14: LNG prices 1997 – 2019

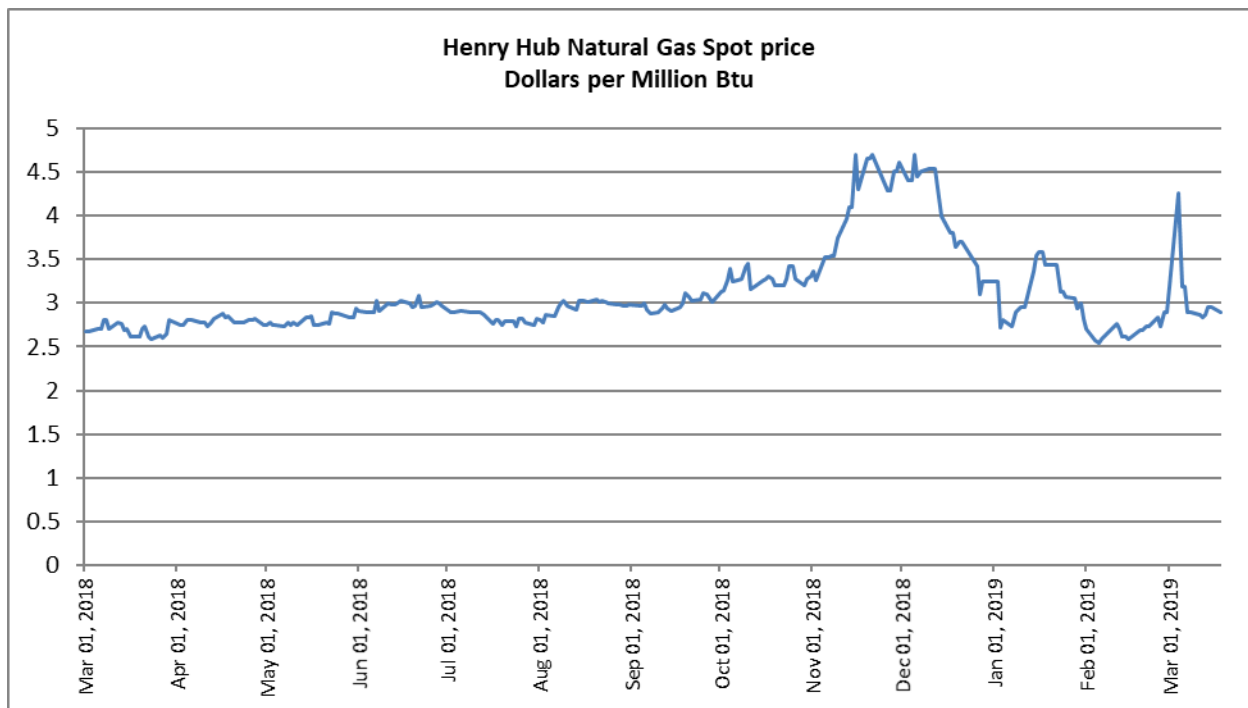


Figure 2-15: LNG prices Mar 2018 to Mar 2019

However, another aspect of pricing that must also be considered, is the risk of exchange rate fluctuations. Importing LNG will place a strain on South Africa's balance of payments. As can be seen from Figure 2-16 (FRED, 2019), the Rand devalues consistently against the dollar. Although the average compounded currency depreciation at approximately 3.5% over the past 20 years, is not great, sudden changes to the exchange rate could place the country under pressure.

South Africa's debt/GDP ratio is currently already very high, and as a result South Africa currently has a "junk status" investment grade. Further exposure to imports in foreign currency and the vagaries of foreign exchange movements could make the debt situation even worse.

South Africa has abundant resources of coal and uranium, the utilisation of which do not place the country at risk of increased debt from imports or fluctuating exchange rates. The South African Government has traditionally taken a conservative view of energy imports and it remains to be seen whether it will be willing to commit to importing a large proportion of its energy requirements.

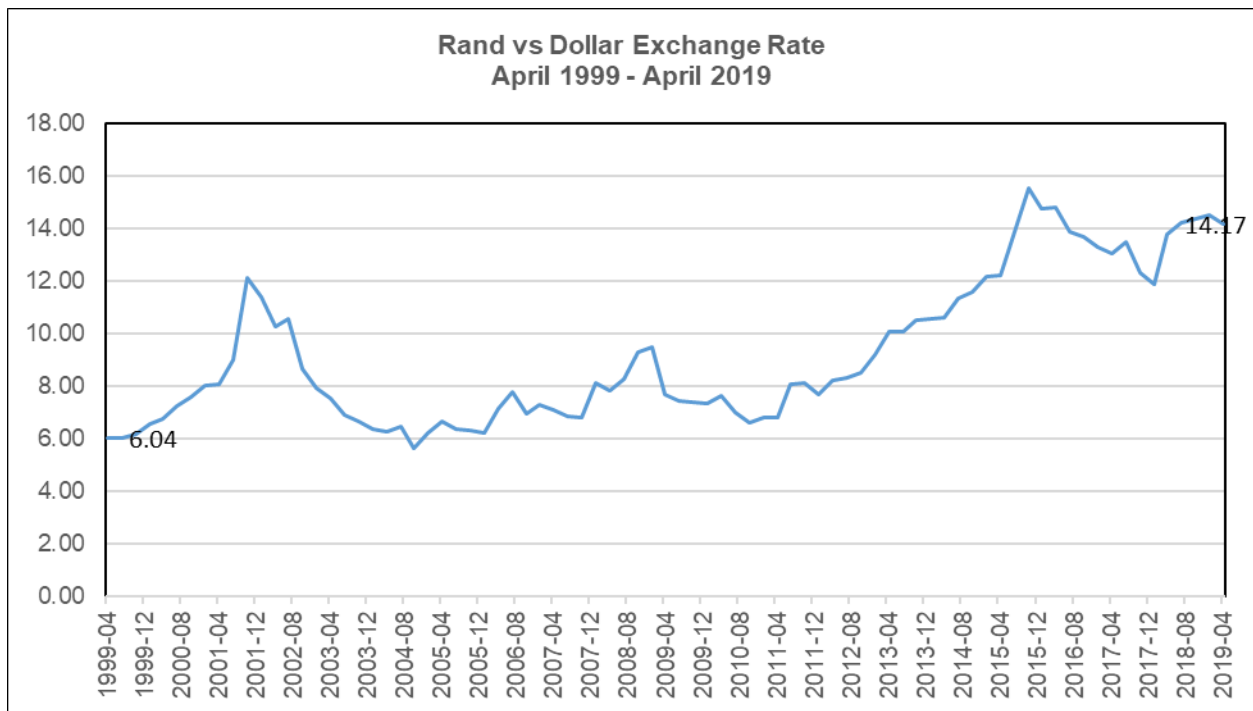


Figure 2-16: Rand/Dollar exchange rates 1990 – 2019

2.4.4 Effect of natural gas release

Natural gas is mainly composed of methane. After release to the atmosphere, it is removed by gradual oxidation to carbon dioxide and water by hydroxyl radicals (OH^-) formed in the troposphere or stratosphere, giving the overall chemical reaction $\text{CH}_4 + 2\text{O}_2 \rightarrow \text{CO}_2 + 2\text{H}_2\text{O}$.

While the lifetime of atmospheric methane is relatively short when compared to carbon dioxide with a half-life of about 7 years, it is more efficient at trapping heat in the atmosphere, so that a given quantity of methane has 84 times the global warming potential of carbon dioxide over a 20-year period and 28 times over a 100-year period. Natural gas is thus a more potent greenhouse gas than carbon dioxide due to the greater global-warming potential of methane. 2009 estimates by the US Environmental Protection Agency (EPA) place global emissions of methane at 85 cubic kilometres annually, or 3 % of global production. Direct emissions of methane represented 14.3 % by volume of all global anthropogenic greenhouse gas emissions in 2004.

During extraction, storage, transportation, and distribution, natural gas is known to leak into the atmosphere, particularly during the extraction process. A Cornell University study in 2011 demonstrated that the leak rate of methane may be high enough to jeopardize its global warming

advantage over coal. This study was criticized later for its over-estimation of methane leakage values.

2.4.4.1 Carbon dioxide emissions

Natural gas is often described as the cleanest fossil fuel. It produces 25–30 % and 40–45 % less carbon dioxide per joule delivered than oil and coal respectively, and potentially fewer other pollutants than other hydrocarbon fuels. However, in absolute terms, it comprises a substantial percentage of human carbon emissions, and this contribution is projected to grow. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, in 2004, natural gas produced about 5.3 billion tons a year of CO₂ emissions, while coal and oil produced 10.6 and 10.2 billion tons respectively.

According to an updated version of the IPCC Special Report on Emissions Scenario by 2030, natural gas would be the source of 11 billion tons a year, with coal and oil reduced to 8.4 and 17.2 billion respectively because demand for natural gas is increasing 1.9 % a year.

To reduce its greenhouse emissions, the government of the Netherlands is subsidizing a transition away from natural gas for all homes in the country by 2050. In Amsterdam, no new residential gas accounts are allowed as of July 1, 2018, and all homes in the city are expected to be converted by 2040.

Table 2-5: Comparison of emissions - natural gas, oil and coal (EIA, 1998)

Pollutant (lb/MMBtu)	Natural gas	Oil	Coal
Carbon Dioxide	117	164	208
Carbon Monoxide	0.04	0.033	0.208
Sulphur dioxide	0.001	1.122	2.591
Nitrogen oxide	0.092	0.448	0.457
Particulates	0.007	0.084	2.744
Mercury	0	0.000007	0.000016

2.5 Renewable Technology

There is a fundamental attractiveness about harnessing renewable sources of energy in an age which is very conscious of the environmental effects of burning fossil fuels, and where sustainability is an ethical norm. Today the focus is not only on adequacy of energy supply long-term but also on the environmental implications of particular sources. If the fundamental opportunity of these renewables is their abundance and relatively widespread occurrence, the fundamental challenge, especially for electricity supply, is applying them to meet demand given their variable nature (WNA, 2018).

The renewable energy electricity generating sources of relevance to this study are wind and solar PV. In this section a generic technical description is provided of both, as are discussions of the economics of renewables; the growth and challenges experienced by renewables globally; as well as recent developments in the renewables industry in South Africa, including the DoE REIPPP programme, and a report produced by the CSIR of relevance to this study.

2.5.1 Renewable technologies

2.5.1.1 Wind technology

In recent years, wind has been the fastest growing form of electricity generation in the world. The World Wind Energy Association reports that by the end of 2014 worldwide installed wind capacity had reached 370 000MW. Almost all wind power capacity installed to date is on-shore wind. However, the superior wind resources available off-shore along coastlines has led to considerable research and development of larger offshore wind turbines and the construction of a few off-shore wind farms (EPRI, 2017, pp. 6- 35).

2.5.1.1.1 On-Shore Wind

During the past 20 years of development, numerous wind turbine design configurations have been proposed and tested, including vertical- and horizontal-axes, upwind and downwind rotors, two or three blades, direct and gearbox-drive train, and fixed-speed, two-speed, and variable-speed generators. Today, the most common wind turbine configuration is the three-blade, upwind, horizontal-axis design with a three-stage gearbox, variable-speed generator and power electronics to generate 50 or 60 Hz power.

The primary components of an on-shore wind turbine include the tower and foundation, the rotor, the nacelle and drive train, rotor pitch and yaw systems, power electronics, and electrical controls,

all of which are described in more detail below. Figure 2-17 shows a typical wind turbine (EPRI, 2017, pp. 6-36).

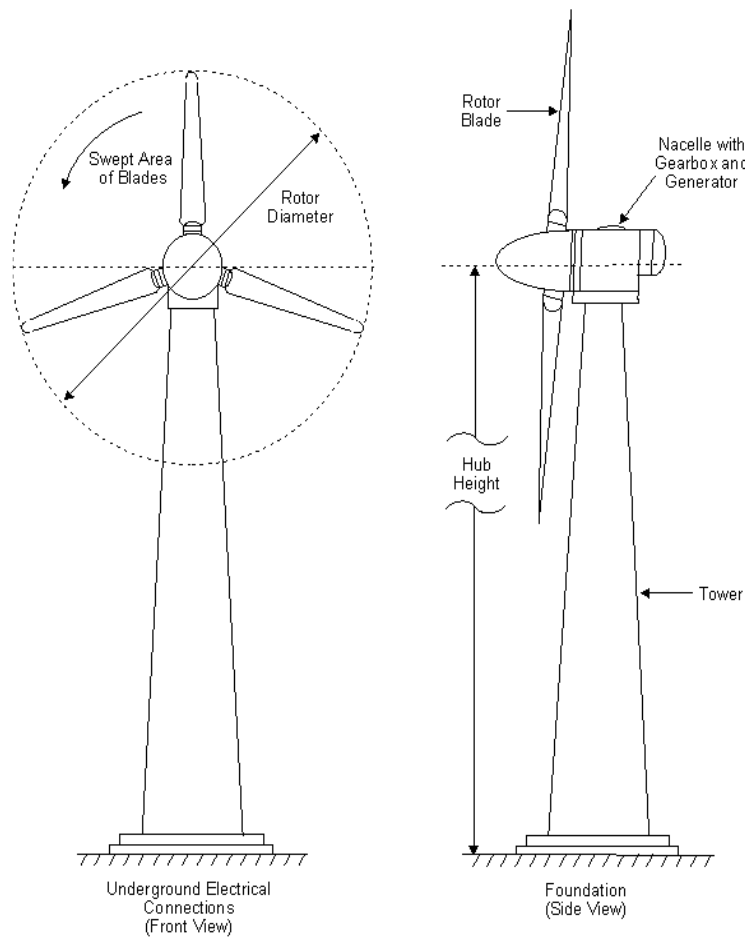


Figure 2-17: Typical wind turbine

The tower is the base that holds the nacelle and the rotor. Typically, turbine towers are constructed from steel. To support the tower, the rotor, and the nacelle, as well as the dynamic structural loads created by the rotating turbine, a large steel-reinforced concrete foundation designed for the site and soil conditions is typically required.

For large-scale electricity production, multiple wind turbines are typically arranged in single or multiple rows, which are oriented to maximize generation when the wind is from the prevailing direction. The wind turbines must be arranged to minimize the impact of wake turbulence on other downwind turbines. To do this, they are often separated by five to 15 rotor diameters downwind and three to five rotor diameters in the direction perpendicular to the wind. Because individual wind turbines require a minimal area for the foundation, only 5-10 % of the total land covered by

the wind farm is used for the turbines and the remaining land area is available for crop production, grazing land for livestock, or other uses.

At the top of the tower, the rotor blades capture the wind and transfer its power to the rotor hub, which is attached to the low-speed drive shaft. As the rotor blades capture the wind, they rotate the hub and the low-speed shaft of the turbine. Some turbine designs use direct-drive multiple-pole generators, and most use a three-stage gearbox to increase the rotation speed and drive the generator to produce electricity. The rotor, gearbox, and generator are designed to capture wind energy efficiently at both low and high wind speeds.

Wind turbines are designed to operate within a wind speed window, which is bound by a “cut-in” speed and a “cut-out” speed. When the wind is below the cut-in speed, the energy in the wind is too low to utilize. When the wind reaches the turbine’s cut-in speed, the turbine begins to operate and produce electricity. As the wind speed increases, the power output of the turbine increases until it reaches its rated power. After this, the blade pitch is controlled to maintain the rated power output, even as the wind speed increases, until the wind reaches its cut-out speed. At the cut-out speed, the turbine is shut down to prevent mechanical damage.

Wind plants typically are operated unattended and are monitored and controlled by a supervisory control and data acquisition (SCADA) system. Using on-board computers, wind turbines start up when the wind reaches its cut-in speed and shut down when the wind exceeds its cut-out speed or drops back below the cut-in speed. The system is also designed to shut down the turbine if there are any mechanical or electrical failures detected, and maintenance crews will be notified (EPRI, 2017, p. 144).

2.5.1.1.2 Off-Shore Wind

Some countries have begun to investigate placing wind farms off-shore. The primary difference between off-shore and on-shore wind turbines is the size and foundation requirements. Due to the high cost of offshore wind turbine foundations and undersea electric cables, off-shore wind turbines are typically larger than their on-shore counterparts in order to take advantage of economies of scale. In addition to the difference in size, off-shore wind turbines have been modified in a number of ways to withstand the corrosive marine environment, such as implementation of a fully-sealed or positive-pressure nacelle to prevent corrosive saline air from coming in contact with critical electrical components, structural upgrades to the tower to withstand wave loading, and enhanced condition monitoring and controls to minimize service trips (EPRI, 2017, p. 145).

2.5.1.2 Solar PV

Solar PVs are rapidly becoming a viable utility-scale renewable technology option. This technology converts sunlight into electrical power and has been through various levels of commercialization since its development in the 1950s. One of the first applications of solar PV technology was to power remote equipment such as satellites, buoys, and telecommunication equipment in combination with batteries to maintain a backup of energy. As costs have decreased and government incentives and mandates have proliferated, applications now span grid-connected homes, buildings, and large ground-mounted systems (EPRI, 2017, pp. 6-47).

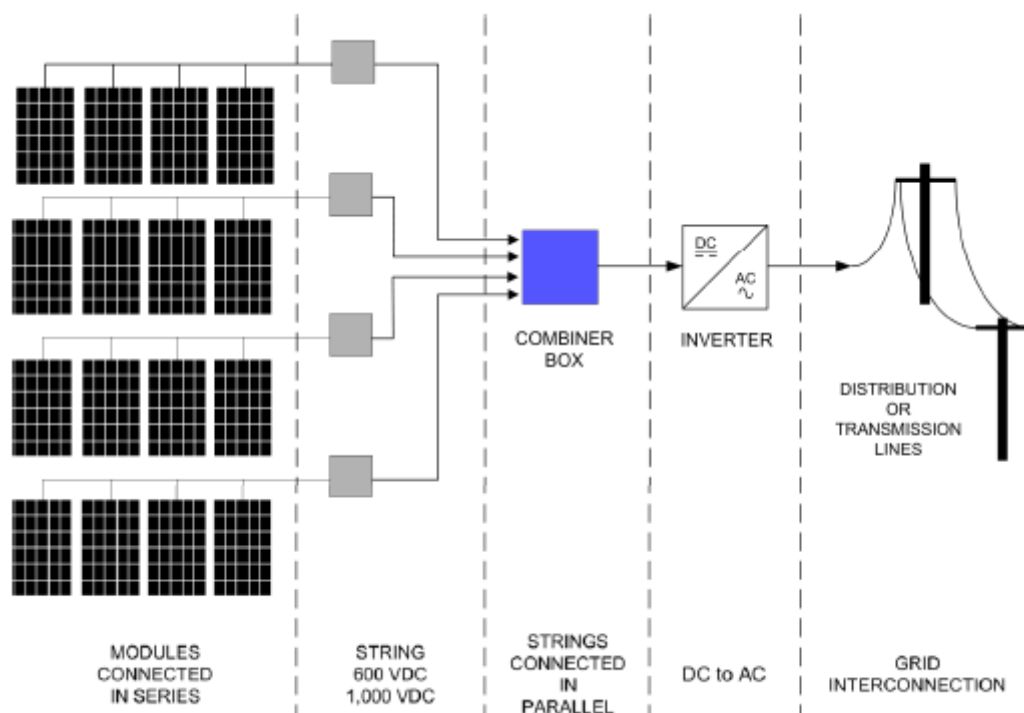


Figure 2-18: Conceptual overview of solar

The market for solar PVs is growing rapidly. South Africa became the first African country to install close to 1GW in 2014, while many more countries across the continent have a number of projects in various stages of planning and construction.

PV technologies convert sunlight directly into electricity using semiconductor materials that produce electric currents when exposed to light. Semiconductor materials used for PV cells are typically silicon doped with other elements that have either one more or one less valence electron to alter the conductivity of the silicon. For example, if the silicon is doped with an element having one more valence electron, such as phosphorus, then the resulting material will have an extra

electron available for conduction. This material is called an n-type semiconductor. Conversely, when the silicon is doped with an element having one less valence electron, such as boron, then the p-type semiconductor that is produced has an electron vacancy or hole. When adjacent layers of n-type and p-type materials are illuminated, a voltage develops between them, which can cause a DC electric current to flow in an external circuit (EPRI, 2017, pp. 6-47).

One characteristic of solar PV that sets it apart from other renewable technologies is its modular nature, which makes it applicable to small distributed systems as well as large utility-scale power plants. The building block of a solar PV system is the PV module, illustrated in Figure 2-18. The solar module consists of multiple solar cells connected in series, and it generates the electrical energy in the form of direct current power. Modules are connected in series to form a string in order to increase the voltage of the system. Higher system voltage results in reduced resistance losses across DC collection system wiring distances.

The multiple strings of a PV system are connected in parallel at a combiner box and fed to an inverter, a power electronics device that converts the DC power into AC power. Utility-scale systems make use of multiple inverters; for example, a 10MW plant could have twenty 500kW inverters. Depending on the technology, the land area required for a 10MW power plant varies between 40 and 80 acres or more. Therefore, the distance between the inverters and the point of interconnection to the grid can be significant. To increase the distribution efficiency of the electrical AC energy generated by the inverters in a utility-scale system, it is typical to step up the voltage after the inverter to the maximum distribution voltage possible before connecting to a substation for transmission over power lines.

Three array configurations are used for PV systems: fixed-tilt arrays that are stationary and are either mounted flat or oriented to tilt towards the equator for maximum sun exposure, single-axis tracking that tracks the sun's movement from east to west, and two-axis tracking that tracks the sun to remain perpendicularly oriented to the sun's rays. There are also three main types of PV technology: flat plate c-Si, thin-film, and concentrated PV (CPV).

The addition of tracking can increase energy production by over 30 % relative to a horizontal, fixed PV system. System performance improvements with trackers are most pronounced at sites with high-quality solar resources (e.g., desert locations) and can, in turn, have a greater impact in reducing a PV plant's LCOE (EPRI, 2017, p. 157).

2.5.2 Growth of renewables worldwide

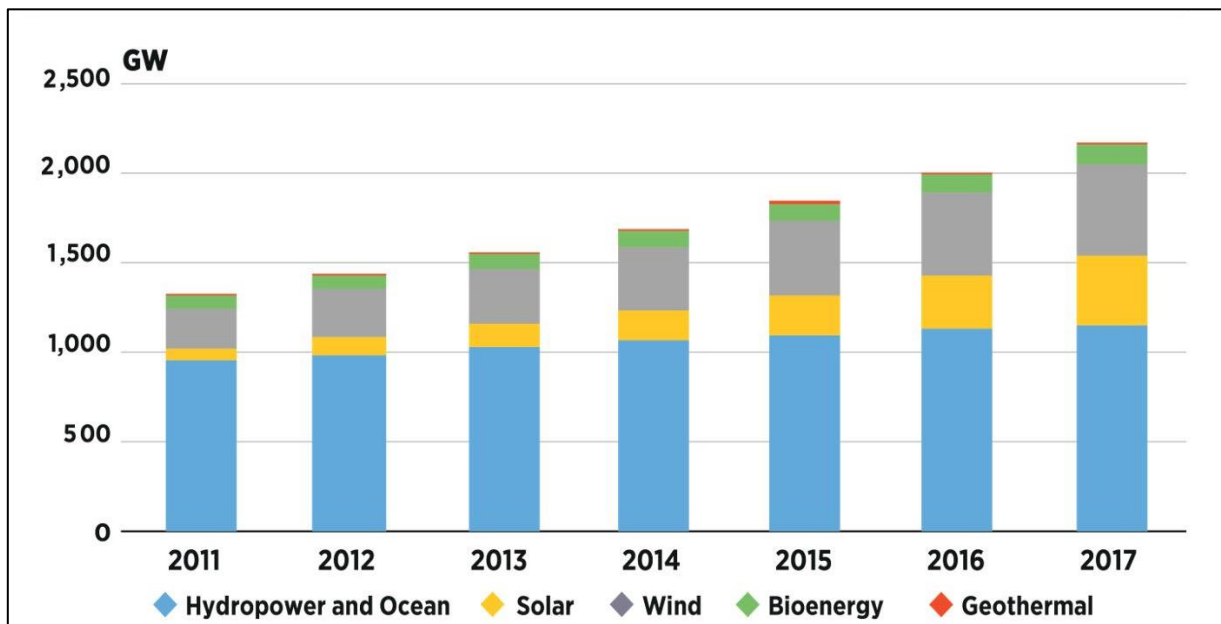


Figure 2-19: Total renewable power generation capacity, 2011- 2017

During the course of 2017, as illustrated in Figure 2-19 (IRENA, 2018) global renewable generation capacity increased by 167GW and reached 2 179GW worldwide. This represents a yearly growth rate has been around 8.3 % for seven years in a row (IRENA, 2018).

Solar photovoltaics (PV) grew by 32 % in 2017, followed by wind energy, which grew by 10 %. Underlying this growth are substantial cost reductions, with the levelised cost of electricity from solar PV decreasing by 73 %, and onshore wind by nearly one-quarter between 2010 and 2017. Both technologies are now well within the cost range of power generated by fossil fuels.

China led global capacity additions, installing nearly half of all new capacity in 2017. 10 % of all new capacity additions came from India, mostly in solar and wind. Asia accounted for 64 % of new capacity additions in 2017, up from 58 % in 2016. Europe added 24GW of new capacity in 2017, followed by North America with 16GW. Brazil installed 1GW of solar generation, a ten-fold increase from the previous year (IRENA, 2018).

Off-grid renewables capacity saw unprecedented growth in 2017, with an estimated 6.6GW serving off-grid customers. This represents a 10 % growth from 2016, with around 146 million people now using off-grid renewables.

- Hydropower: The amount of new hydro capacity commissioned in 2017 was the lowest seen in the last decade. Brazil and China continued to account for most of this expansion (12.4GW or 60 % of all new capacity). Hydro capacity also increased by more than 1GW in Angola and India.
- Wind energy: Three-quarters of new wind energy capacity was installed in five countries: China (15GW); USA (6GW); Germany (6GW); UK (4GW); and India (4GW). Brazil and France also installed more than 1GW.
- Bioenergy: Asia continued to account for most of the increase in bioenergy capacity, with increases of 2.1GW in China, 510MW in India and 430MW in Thailand. Bioenergy capacity also increased in Europe (1.0GW) and South America (0.5GW), but the increase in South America was relatively low compared to previous years.
- Solar energy: Asia continued to dominate the global solar capacity expansion, with a 72 GW increase. Three countries accounted for most of this growth, with increases of 53GW (+68 %) in China, 9.6GW (+100 %) in India and 7GW (+17 %) in Japan. China alone accounted for more than half of all new solar capacity installed in 2017. Other countries that installed more than 1GW of solar in 2017 included: USA (8.2 GW); Turkey (2.6 GW); Germany (1.7GW); Australia (1.2GW); South Korea (1.1GW); and Brazil (1GW).
- Geothermal energy: Geothermal power capacity increased by 64 MW in 2017, with major expansions in Indonesia (306MW) and Turkey (243MW). Turkey passed the level of 1 GW geothermal capacity at the year-end and Indonesia is fast approaching 2GW (IRENA, 2018).

2.5.3 Challenges experienced with the growth of renewables

Today we are well advanced in meeting the challenge of harnessing renewable energy sources to meet demand. Wind turbines have developed greatly in recent decades, solar photovoltaic technology is much more efficient, and there are improved prospects of harnessing the energy in tides and waves. Solar thermal technologies in particular (with some heat storage) have great potential in sunny climates. With government encouragement to utilise wind and solar technologies, their costs have come down and are now in the same league per kilowatt-hour as the increased costs of fossil fuel technologies, especially with likely carbon emission charges on electricity generation from them (WNA, 2018, p. 1).

The World Nuclear Association, has the following to say about the growth of renewables: "...the variability of wind and solar power does not correspond with most demand, and as substantial capacity has been built in several countries in response to government incentives, occasional massive output from these sources creates major problems in maintaining the reliability and economic viability of the whole system" (WNA, 2018).

In the sections below we take a look at four countries often quoted as examples of what can go wrong when transforming electrical systems to renewable energy to see whether their experiences correspond with the WNA views.

2.5.3.1 Denmark

Denmark has excellent wind resources, thanks to its flat terrain and proximity to the sea. West Denmark (the main peninsula part) has the densest concentration of wind-turbines in the world, with 1.74 per 1000 people – 4 700 turbines totalling 2 315MWe. 1 800MWe of this capacity has priority dispatch and power must be taken by the grid when it is producing (WNA, 2018).

Climate and hydrology allow high yields of biomass from agriculture even though land itself is a scarce resource due to the country's small size and relatively high population density. The long Danish coastline could allow wave energy to become important in the future. Photovoltaics and solar heating could also contribute in the future, though their cost-effectiveness is not as attractive as in sunnier countries to the south.

Denmark's power system is characterized by combined heat and power (CHP) plants that deliver heat to district heating systems, and a high proportion of wind power. The CHP plants are a combination of a few large plants fuelled mainly by coal and natural gas, and a large number of distributed CHP plants using natural gas, biomass and municipal waste. Fuel for road transport is dominated by gasoline and diesel.

Denmark has major transmission interconnections with Norway, Sweden and Germany, of some 1 000MWe, 600MWe and 1 300MWe respectively. Furthermore, especially in Norway, hydro resources can normally be called upon, which are ideal for meeting demand at short notice. (WNA, 2018).

Denmark is often cited as an example of how introducing renewable energy leads to soaring electricity prices. Figure 2-20 (Keane Greunding, 2016) provides a break-down of the makeup of the Danish price of electricity. From it, it becomes clear that although the Danes are undergoing a rapid energy system transformation, and it appears that electricity consumers are bearing the brunt of its government's energy policies, the lion's share of Denmark's high electricity prices can actually be attributed to taxes not specific to energy policy (Keane Greunding, 2016).

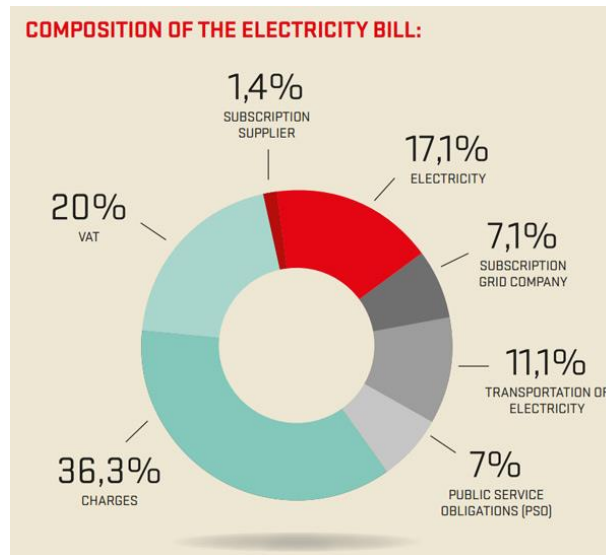


Figure 2-20: Composition of the electricity bill in Denmark

The country pays for its high level of social services with very high taxes on both the wealthy and the middle class. As can be seen from Figure 2-20, Denmark also has a number of taxes on energy. It is true that Danes pay the world's highest per-kilowatt electricity rates, but this is mainly because Denmark crams a lot of taxes into electricity bills, a higher share than any other EU country.

Denmark's energy mix is relatively clean and only getting cleaner. Danish government proposals call for sourcing just over half of its electricity from wind turbines by 2020 and all of its energy from renewable sources in 2050 (Behind Energy, 2018).

In early 2012 the Danish government presented its Energy Strategy 2050, which outlines how Denmark should become independent of coal, oil, and gas by 2050 and significantly reduce emissions of greenhouse gases. The strategy includes a strong expansion of renewable energy from wind, biomass, and biogas. It will lift the share of renewables to one third of the total energy consumption over the next ten years. The long-term vision is a total phase-out of fossil fuels in Denmark.

2.5.3.2 Germany

In 2010 Germany launched its energy strategy known as *Energiewende*. It was launched in hope of dramatically increasing the share of the country's electricity that comes from renewable energy and slashing the country's overall carbon emissions to 40 % below 1990 levels by 2020.

The Energiewende began as a bottom-up movement that took off in 2000 when grassroots campaigns persuaded legislators to support renewable energy expansion through feed-in tariffs. In the aftermath of the Fukushima nuclear disaster in Japan in 2011, Chancellor Angela Merkel and her government got behind the energy transition and drafted blueprints to guide it.

But in recent years, the government, in the face of auto industry opposition, backed off decarbonizing the transportation sector; has not supported a significant price on carbon; has dragged its feet on grid expansion; has declined to set a date for phasing out coal; and has not implemented significant parts of its own 2050 climate program. Some analysts say that Merkel's decision to step down in 2021 could be a boon for the Energiewende, as the Green Party is rising in the polls and will likely play an important role in the next government.

Some aspects of the Energiewende have been successful: renewable sources accounted for nearly one-third of the electricity consumed in Germany in 2015. The country is now the world's largest solar market. Germany's carbon emissions in 2014 were 27 % lower than 1990 levels. Renewable sources of energy overtook coal as Germany's main power source for the first time in 2018. Solar, wind, biomass and hydroelectric generation rose 4.3 per cent in 2018 to account for 40 per cent of German electricity production, up from 38.2 per cent in 2017 and 19.1 per cent in 2010 (The Independent , 2019).

Despite this, Germany's carbon emissions have stagnated at roughly their 2009 level. The country remains Europe's largest producer and burner of coal, which generates more than one-third of Germany's power supply. Moreover, emissions in the transportation sector have shot up by 20 % since 1995 and are rising with no end in sight, experts say. If Germany continues on its present course, its carbon emissions will fall by only 62 % by 2050 – against a target of 95% reduction by 2050.

German consumers have seen their electricity bills soar since 2000, in part because of the renewable energy surcharge (Hockenos, 2018). Additional costs have arisen from insufficiently flexible plants in the electrical system. As fossil-fuel-powered plants cannot easily ramp down generation in response to excess supply on the grid, on sunny, windy days there is sometimes so much power in the system that the price goes negative—in other words, operators of large plants, most of which run on coal or natural gas, must pay commercial customers to consume electricity. That situation has also arisen recently in Texas and California when the generation of solar power has maxed out (Martin, 2016).

Until quite recently, most of Germany's industrial sectors, particularly the more energy-intensive among them, had treated Energiewende with acute scepticism, worried that high energy costs and supply bottlenecks would hurt their competitive edge in international export markets.

Germany's failings have come as a vexing shock to its environmentally conscious citizenry. Germans still overwhelmingly back the energy transition - for year's polls showed support in excess of 90 % - and about three-quarters say the government is not doing enough to slow global warming (Hockenos, 2018)

Lately, German industry is becoming more deeply involved in the Energiewende too, given the demand for the likes of renewable energy infrastructure (for instance wind turbines manufactured by Siemens), electric vehicles, and other green energy technologies. Industry now believes it's better to jump on the bandwagon and engage in policy discussions rather than complain from the side-lines.

Earlier this year, for example, a call for government action signed by 50 prominent businesses — including Siemens and the electronics and construction industries — insisted that “Germany needs a robust strategy for implementing its comparatively stringent emission reduction targets if it does not want to fall behind in the global race to develop carbon-neutral economies” (Hockenos, 2018).

Germany is an example of a country that has experienced a sometimes problematic transition to a renewable system. Its citizens pay higher prices for electricity and has experienced integration problems due to its renewable energy policy. However, the social pressure to continue on the path to an emissions-free future is only increasing and the economic benefits of the renewables revolution are becoming ever more apparent.

2.5.3.3 South Australia

South Australia has introduced a high percentage of renewables into its supply mix and is often cited as an example of the technical problems that such a policy can result in. SA experienced several major supply outages in 2016 and 2017. As this section explains, however, solutions are being found to the problems caused by renewables.

On 28th September 2016, a severe storm smashed South Australia and damaged several remote transmission towers. The SA grid subsequently lost 52 % of wind generation within a few minutes. This deficit had to be replaced by power imports from the neighbouring state, Victoria, through an interconnecting transmission line. Such an increased power flow was beyond the capability of the interconnection, however. Ultimately, the Southern Australian network was separated from the

rest of the Southeast Australian network and collapsed soon afterwards. This state-wide major blackout sent around 1.7 million people into darkness and resulted in a financial loss of approximately 367 million Australian Dollars.

With around 2 900MW peak load, SA has developed approximately 1 600MW wind and 730MW photovoltaic (PV) generation. Right before the blackout event, wind and PV power provided almost 50 % of the total demand in SA, while conventional synchronous generation only accounted for 17.6 %. The rest came from the interconnection. Therefore, the proliferation of renewable energy in SA was accused by some sectors for this catastrophic blackout (Yan, et al., 2018)

Upon completion of an investigation by the Australian Energy Market Operator (AEMO) however, the final report identified the action of a control setting responding to multiple disturbances as the cause of the 'black system'. The report said the unexpected operation of the control settings resulted in the sudden loss of generation from the wind farms. AEMO identified software settings in the wind farms that prevented repeated restarts once voltage or frequency events occurred too often. The group of wind turbines that could accept 9 “ride-throughs” in 120 seconds stayed online through much of the event before the system went black. The rather larger group of turbines that could not accept this many repeated “ride-throughs” dropped out, instigating the overload and shutdown of the interconnector, and hence the electricity supply. AEMO has suggested better fault ride-through capability for the wind farms. The high wind speed caused 20MW of wind power to disconnect to prevent over-speed (AEMO, 2017)

"Had the generation deficit not occurred, AEMO's modelling indicates SA would have remained connected to Victoria and the black system would have been avoided," the report said.

The AEMO report also highlighted the need for frequency control services, which can be provided at relatively low cost: “The generation mix now includes increased amounts of the non-synchronous and inverter-connected plant. This generation has different characteristics to conventional plant, and uses active control systems, or complex software, to ride through disturbances. With less synchronous generation online, the system is experiencing more periods with low inertia and low available fault levels, so AEMO is working with industry on ways to use the capability of these new types of power generation to build resilience to extreme events” (AEMO, 2017, p. 5).

Further widespread blackouts occurred on Tuesday 27 December 2016, with areas losing power for upwards of twelve hours following severe storms causing damage to over 300 power-lines in

the electricity distribution network. The storms also caused flooding and wind damage, including property destruction due to fallen trees.

Lastly, on 8 February 2017, over 90 000 households in Adelaide lost power for 45 minutes in the middle of a major heatwave. AEMO ordered 100MW of load shedding, but 300MW was cut, causing controversy with the state government.

The state Energy Minister, Tom Koutsantonis said that the state had spare generation capacity but the market didn't turn that generation on. A 165MW spare generator at a gas-fired power station had gas and was ready to go. The owner of the station later clarified that it was not allowed to bid into the market if supply cannot be guaranteed, and it did not have a current gas supply contract for the second unit. It was able to respond promptly once directed to do so on 9 February during continuing high-temperature weather.

2.5.3.3.1 Tesla big battery

In response to these technical and operating problems, a push for battery storage was made by the South Australian government. The Tesla big battery – the world's biggest lithium-ion battery storage installation to date – was officially switched on in South Australia on 1 Dec 2017 at the Hornsdale windfarm (Figure 2-21), owned by Neoen, a French renewable energy company (Parkinson, 2017).



Figure 2-21: Hornsdale wind is South Australia,

Source: Renew economy

It is expected to be just the first of a number of battery storage installations in South Australia, and across the country, and will be followed by a number of pumped hydro projects too.

South Australia, which leads the world with the amount of wind and solar in its grid (more than 50 %), is now leading the world in dispatchable renewable energy (Parkinson, 2017).

2.5.3.4 South Africa

South Africa has experienced its share of problems as a result of the introduction of renewable energy into its electrical system. Eskom has an installed capacity of over 45 000MW much of which is made up of base-load capacity - nearly 38 000MW coal and 1 800MW nuclear. Eskom also has 2 700MW of pumped storage, 600 MW of hydro and 2 400MW of gas-fired stations, for a total of 5 700MW of mid-merit capacity (Eskom, 2018, p. 9). The introduction of over 6 000MW of renewable energy by Independent Power Producers (IPPs) into a system which has declining reliability of its base-load stations and little flexibility at its disposal, has resulted in both integration and financial problems.

In 2016, Eskom announced that it would not sign several power purchasing agreements (PPAs) citing costs and electricity overcapacity in the country as reasons for its decision. This temporarily halted the REIPPPP and South Africa was subsequently overtaken by many countries where auctions continued. (Arndt, et al., 2018, p. 9)

In its Integrated Report of March 2018, Eskom reported purchases of 9 584GWh from renewable energy IPPs at a cost of R21.3 billion during the 2017/18 financial year (Eskom, 2018, p. 140). These purchases were made at an average of 222c/kWh compared to an average 85.06c/kWh selling price (Eskom, 2018, p. 12).

However, purchases from the Bid Window 4 renewable IPP plant are being made at just 65c/kWh. It is the cost of the earlier rounds that has inflated Eskom's average cost so much, not the latest purchases.

After a lengthy delay the DoE Minister, Jeff Radebe, finally signed the PPAs in April 2018. Explaining their rationale for not wanting to sign the PPAs, Eskom communicated that the PPAs introduce greater non-dispatchable capacity into the electricity grid, thereby affecting grid stability and exacerbating operational challenges (Moyo, 2018).

Eskom also expressed concern that the decision to sign the PPAs had a negative impact on its financial sustainability. With the IPP power being dispatched ahead of Eskom's own capacity, a surplus was created on the Eskom side.

In an opinion piece posted on the DoE website dated 27 July 2018, Minister Jeff Radebe seems to contradict Eskom by indicating that Eskom is allowed to recover the cost of its renewables purchases through the cost recovery mechanism (CRM) (Radebe, 2018).

Eskom's reluctance to sign the PPAs however, is not because of the cost of the energy purchases from IPPs but because of externalities linked to these purchases: insufficient flexibility in its system to compliment the variability of the renewable supply and reduced sales from Eskom's own production which it must keep operational to back-up the renewable supply.

2.5.3.5 Conclusions

As technology matures and costs fall, wind and solar power are becoming increasingly viable options in utility-scale power systems. The greatest barriers to adopting renewable energy are no longer modular costs but the technical, institutional, policy, and market adjustments required to incorporate renewable energy cost-effectively into an electric system.

These challenges are collectively referred to as system integration. Among the most prominent of these challenges is the variable and not fully predictable nature of renewable energy coupled with the need to balance electricity supply and consumption at all times. However, system integration and its associated costs are increasingly well understood as countries like Denmark approach 50 % of total generating capacity from renewable energy (Arndt, et al., 2018, p. 8).

2.5.4 Growth of renewables in South Africa

2.5.4.1 The Renewable Energy Independent Power Producer Procurement Programme

The South African REIPPPP is a competitive tender process that has been designed to facilitate private sector investment into grid-connected renewable energy generation in South Africa. IPPs are invited to submit bids for onshore wind, solar PV, CSP, small hydro, biomass, and biogas or landfill gas projects. Between 2011 and 2015 four such bidding rounds have been completed, referred to as Bid Windows, with an additional round for CSP only (Eberhard & Naude, 2016, p. 1).

In total 390 submissions have been made, with just under a quarter being successful. To date, 6 328MW has been procured amounting to R193bn (USD 13.6bn) in investment. Table 2-6 (GreenCape, 2017) is a summary of the actual procured generation capacities per REIPPPP programme bid window. Prices have fallen sharply over the course the four bid windows. Prices were originally quite expensive, and as a result, the average price paid by Eskom to all IPPs is still quite high (222c/kWh in 2018). The actual tariff for Bid Window 4 however, is now amongst

the lowest priced grid-connected RE projects in the world. The prices of winning bids in the latest tender indicate that solar PV and wind energy are now cheaper than the national utility, Eskom's, average cost of supply and far below the cost of its new coal power stations (Figure 2-22 (Calitz & Jarrad, 2019) and Figure 2-23 (Eskom, 2018)).

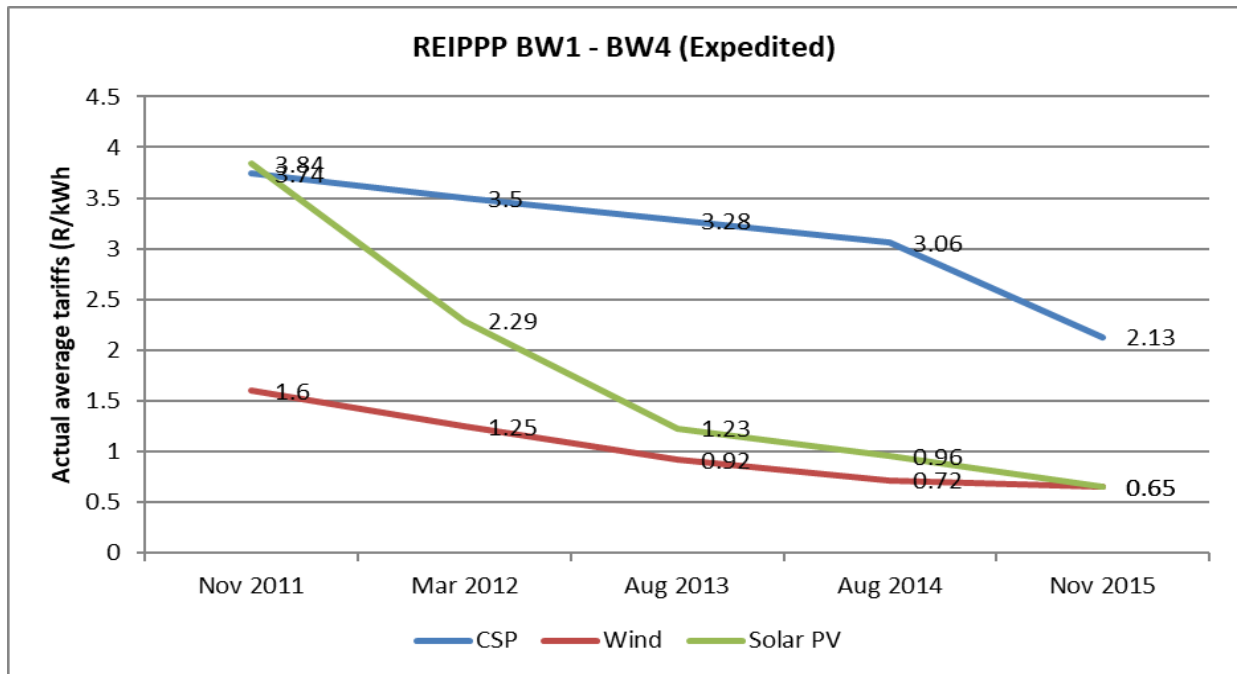


Figure 2-22: REIPPPP Actual average tariffs 2011 – 2015

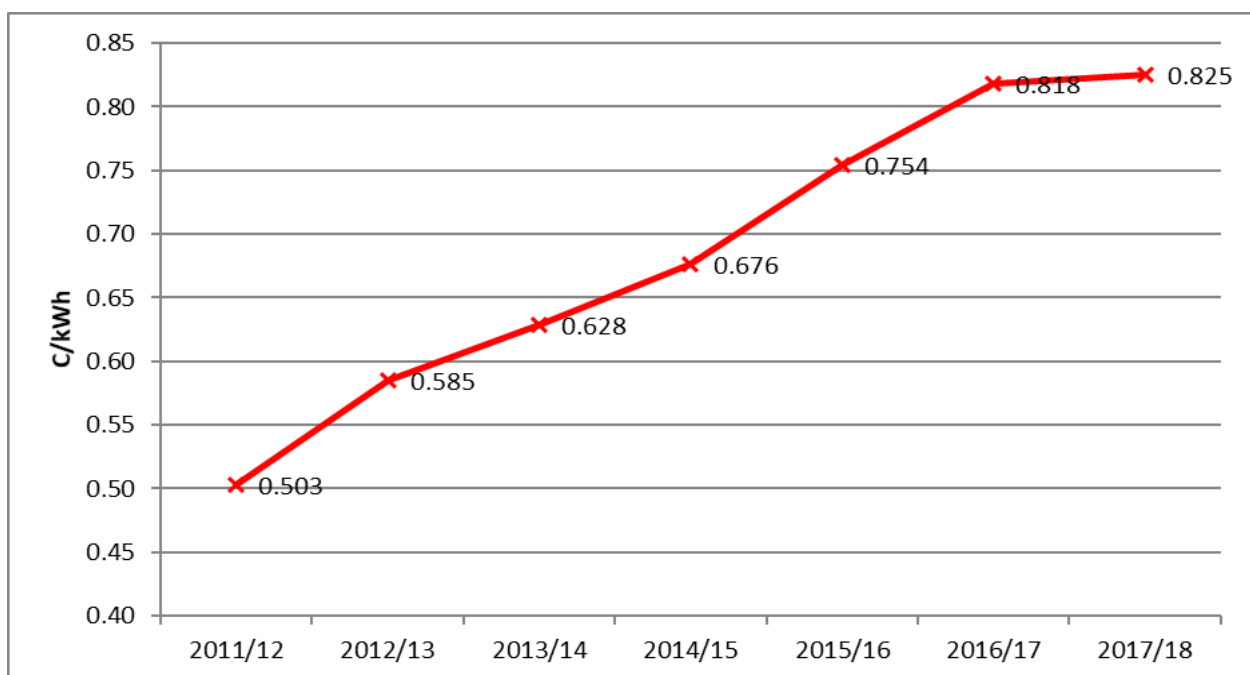


Figure 2-23: Eskom average sales prices March 2012 – March 2018

An Expedited Bid Window (BW) was also run in 2015. This was designed primarily to provide bid projects that had been unsuccessful during prior rounds with a second opportunity to bid. 1 800MW was made available for tender under this Expedited BW, with bid submissions in November 2015.

The Department of Energy (DOE) also introduced the Small Projects IPP Procurement Programme (SP-IPPPP) in 2013, which aims to procure 200MW from projects of only 1 – 5 MW each. This programme aims to encourage participation from small and medium enterprises (SMEs). In October 2013 the SP-IPPPP offered 50MW for tender. After a prequalification phase in March 2014, 29 bids totalling 139 MW were received in November 2014. Of these, 10 projects totalling 49MW were awarded in October 2015. A further 10 projects have been awarded in January 2017.

Table 2-6: Actual procured generation capacities per REIPPPP bid window

Technology	Actual capacity procured per round (MW)					
	Round 1	Round 2	Round 3	Round 4	Round 4B	Small IPP
Wind	648	558	787	676	687	10
Solar PV	626	417	435	415	398	30
CSP	150	50	400	0	0	0
Landfill gas	0	0	18	0	0	0
Small hydro	0	14	0	5	0	0
Biomass	0	0	16	25	0	10
Biogas	0	0	0	0	0	0
TOTAL (MW)	1424	1040	1656	1121	1085	50
Total generation capacity procured (MWp)					6378	

Once IPPs are appointed as Preferred Bidders they are required to sign standardised, non-negotiable, Rand denominated 20-year PPAs with Eskom. The PPA is supported by an

Implementation Agreement (IA) between the IPP and government (DOE), which, along with a Government Framework Support Agreement, effectively guarantees Eskom's payments. This is an agreement between the Department of Energy, National Treasury, Eskom and NERSA. The effect of the agreement is that the IPP payments are ring-fenced and passed through to the consumers. This also applies in the case of Eskom defaulting on the payments, which in effect prevents the sovereign guarantee contained in the IA from being called by protecting the revenue flow to the IPPs (Eberhard & Naude, 2016, p. 2).

Bidders generally regard the REIPPPP as being well designed and managed, and the process as being transparent and fair. The REIPPPP is run by a separate DOE IPP unit, which is led by a management team seconded from the Public-Private Partnership Unit of the National Treasury. (Eberhard & Naude, 2016, p. 2)

The REIPPPP is steadily progressing towards achieving the National Development Plan's (NDP) interim target of adding 7 000MW of operational RE generation capacity by 2020 and the Integrated Resource Plan's (IRP) target of 17 800MW from RE generation by 2030 (DOE, 2015).

2.5.4.2 Wind and Solar PV Resource Aggregation Study for South Africa - CSIR

The "Wind and Solar PV Resource Aggregation Study for South Africa" (Knorr, et al., 2016), a joint research study conducted by the CSIR in collaboration with the South African Energy Development Institute (SANEDI), Eskom and the Fraunhofer Institute for Wind Energy and Energy Systems (IWES) in Kassel, Germany, reveals that South Africa has an abundance of both wind and solar resources. The study, conducted over 11 months (May 2015 to March 2016), provides a quantified fact base that can be a useful tool for future planning purposes.

The overarching objective of this study was to increase the fact base and the understanding of aggregated wind and solar photovoltaic (PV) profiles in South Africa, and to serve as input into South African energy-planning processes such as the Integrated Energy Plan (IEP), the Integrated Resource Plan (IRP) for electricity, strategic grid planning, the Transmission Development Plan (TDP), wind and solar PV Strategic Environmental Assessments (SEAs) (Knorr, et al., 2016).

The magnitude and cost competitiveness of wind power in South Africa is on par with that of solar PV. In addition, wind and solar PV are complimentary, with wind supply peaking in the evening and solar PV peaking at midday (see Figure 2-24, (CSIR, 2018)).

The total technical wind power potential in South Africa if wind farms were to be installed all across the country except in exclusion areas (National Parks, settlement areas, etc.) is 6 700GW, which

is a wind fleet large enough to supply the entire world's electricity demand. In order to generate 250TWh/yr, which is approximately today's South African electricity demand, 0.6 % of the available South African landmass would have to be dedicated for wind farms with an installed capacity of approximately 75GW.

The total solar PV potential in South Africa from distributed and utility-scale installations in already applied EIAs is 300GW.

The study also revealed that although individual solar PV and wind farms exhibit strong short-term (intra-hour) variability, the portfolio effect of aggregating the power output of several farms spread over a wide area leads to disappearance of intermittency and short-term fluctuations. The aggregated wind portfolio power output exhibits intra-day variability with changes over several hours. This level of variability is more manageable from a system operator's point of view.

In summary, the study revealed that South Africa has “immense” wind and solar energy potential, and puts forward that this knowledge can be used to strategically drive the energy industry and the economy by significantly increasing the share of renewables in the power generation mix (Knorr, et al., 2016).

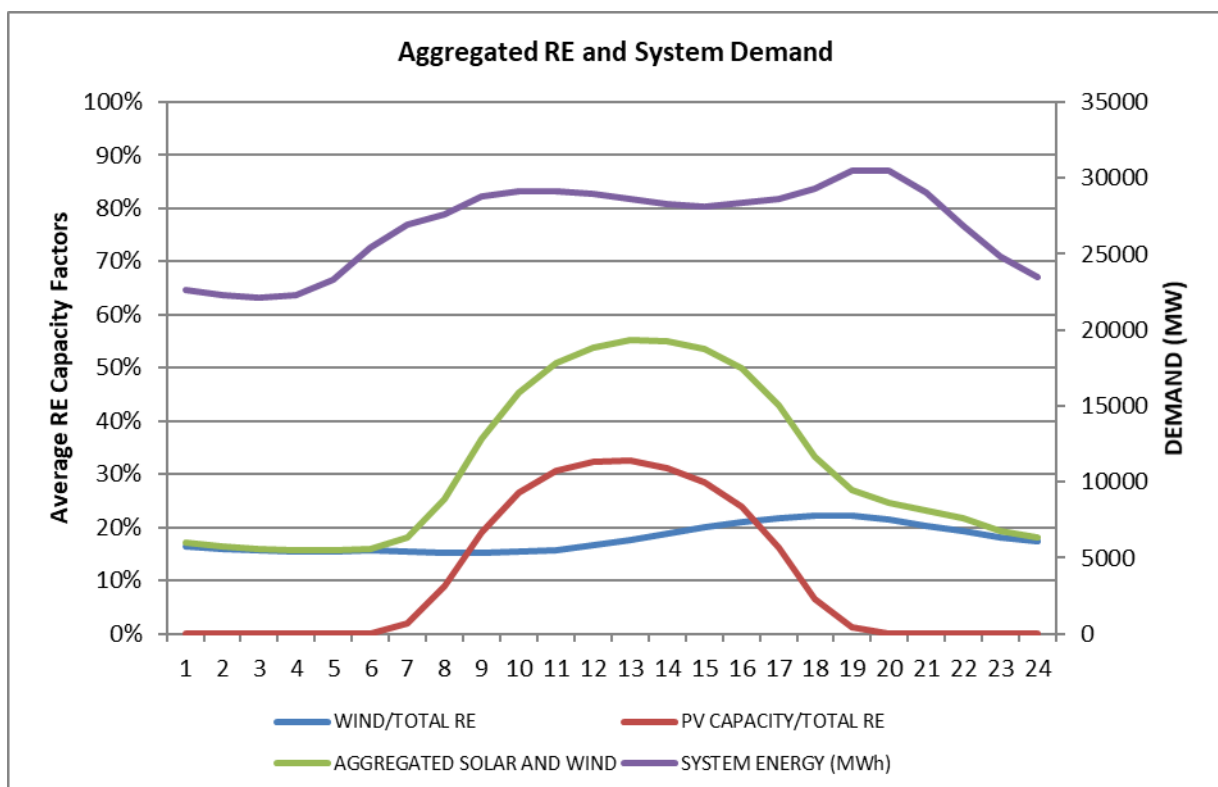


Figure 2-24: Average daily profiles of wind and PV feed-in and demand

CHAPTER 3 METHODOLOGY

3.1 Introduction

The aim of this study is to assess whether a combination of solar-PV and wind, in combination with LNG to provide flexibility, can displace nuclear energy as a source of base-load in South Africa. To do this it is not sufficient to compare the economics of the two systems alone. Industry media is replete with stories of the problems experienced when integrating variable renewable energy into an electrical grid. It is necessary, therefore, to conduct an assessment of the integration and system challenges and costs when comparing renewables-based systems with nuclear or other base-load systems.

This study analyses both the economic and the technical feasibility of producing base-load with a combination of solar-PV and wind with LNG to provide flexibility and compares it to the cost of providing base-load with nuclear energy. Economic feasibility was assessed through the comparison of the levelised costs of electricity for the various technologies using excel as a tool for comparison, while technical feasibility was assessed through a review of available literature on this topic.

3.2 Empirical cost analysis

3.2.1 Calculation of LCOE

The LCOEs were calculated for nuclear, gas, and coal technologies using data contained in the EPRI April 2017 update report prepared for the IRP 2018 report, as the main input. As LCOEs can be calculated in various ways, a number of potential models were considered, including models sourced from within Eskom and from the CSIR. For the purposes of this study, it was decided to develop a simplified LCOE model instead of taking a financial modelling approach. The principal reason for this is that simplified LCOE provides a suitable methodology to conduct a first-order comparison. It also makes comparisons and benchmarking easier as it is widely used in the industry media.

The relevant formula as introduced in section 2.2.2 is set out below.

$$LCOE = \frac{\text{sum of costs over lifetime}}{\text{sum of electrical energy produced over lifetime}}$$

Mathematically,

$$LCOE = \frac{\sum_{t=0}^n \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^n \frac{E_t}{(1+r)^t}}$$

Where,

I_t = CAPEX (investment expenditures) in the year t

M_t = O&M (operation and maintenance expenditure) in the year t

F_t = fuel expenditures in the year t

E_t = electrical energy generated in the year t

r = discount rate

n = expected economic lifetime of the power plant (years)

LCOE is the net present value (NPV) of the unit-cost of electricity over the lifetime of a generating asset. It is often taken as a proxy for the average price that the generating asset must receive in a market to break even over its lifetime.

LCOE calculations combine the capital and O&M costs of a plant with the expected performance and operating characteristics of the plant into a cost per megawatt-hour/kilowatt-hour basis. This procedure allows for comparison of technologies across a variety of sizes and operating conditions and allows for the comparison of the cost of electricity of a new plant with that of an existing plant. (EPRI, 2017, pp. 5-9)

Investment, O&M and fuel costs were all sourced from the EPRI report. Overnight costs were used for investment (total plant costs) but brought to the same present value date as the life-time plant costs, i.e. escalated using the discount rate to the commercial operating date. The overnight cost is the cost of a project if no interest is incurred during construction, i.e. as if the project was completed "overnight." No adjustments were made to overnight costs for interest during construction (IDC), risk, internal rate of return (IRR) or any other form of owner's costs, as would've been the case if a financial modelling cost approach had been taken. O&M costs provided are for the economic life of the plant only and do not include decommissioning.

The analysis was conducted in constant-Rands, i.e. inflation was not taken into account and therefore, the fixed O&M, variable O&M and fuel costs remain the same throughout the life of the plant.

The rand-per-year fixed O&M costs were divided by the annual electrical output (MW) of the plant to calculate the fixed O&M cost of electricity (R/kW-yr). Variable O&M was already presented as R/MWh costs and was multiplied by the hours available in a year (8760) to obtain the cost per kW-yr. The annual cost of fuel was calculated by multiplying the fuel cost in rand per gigajoule by the heat-rate of the plant to obtain a cost in R/kW-yr.

In order to achieve consistency, electricity produced was also discounted. The denominator of the LCOE formula concerns the power generated over time and must be computed in present value terms since the numerator is in present value monetary format too. Electricity produced is the product of the capacity factor (ratio of rated power output to the actual power generated in a year), the nameplate power of the plant, the degradation factor (which accounts for wear and tear of the plant), and the efficiency of the power plant. (Sklar-Chick, et al., 2016, p. 128)

The cost data provided in the EPRI report was converted to Rands from USD at 1 January 2017 prices using an exchange rate of R13.57/USD. The discount rate used was 8.2 %.

LCOE calculations were performed for solar PV and wind technologies too, but the results obtained using the EPRI data resulted in values which were significantly higher than those realised in South Africa through the REIPPPP. They were therefore discarded in favour of the actual tariffs realised during bid window 4 (BW4) of the REIPPPP.

As already alluded to, results obtained using simplified LCOE methodology provide a good first-order economic assessment of the cost competitiveness of an electricity-generating system. They can be of assistance to policymakers, researchers and other interested parties in guiding discussions and decision making, and are therefore sufficient for the purposes of this study. Much deeper analysis of the financial modelling kind is required when an investment decision is made, however.

3.2.2 Calculation of aggregated renewable energy load profiles

The time series used to calculate renewable energy load profiles was an excel workbook sourced from the CSIR, “Renewables January 2016 – December 2018 inc Sere (Public Release)”.

This workbook provides hourly production data over a three year period from January 2016 to December 2018 for CSP, solar PV, and wind, as well as for the entire Eskom system. From it,

average load profiles for the renewable technologies were calculated and the highest and lowest hours and days of renewable energy production over the course of that period identified. These load profiles were then aggregated to provide a single renewables load profile, i.e. a combination of the solar PV and wind load profiles.

From the aggregated profile a renewables capacity factor was calculated. By deducting the renewables load factor from the required base-load load factor of 100 % the LNG capacity factor was deduced i.e. the LNG “flexibility” capacity factor is the capacity factor needed to increase the total supply profile to 100 % of a stipulated or assumed supply quantum which in this case was set at 10 000MW.

The use of hourly data for analysing renewables data is controversial. In a critique of reports that claim that 100 % renewables systems are possible, Heard et al, find that lack of simulation below hourly levels as a fault in many of the reports. They emphasise the importance of using resolutions as low as 5 minutes in order to capture the full variability of demand and the renewables supply (Heard & Brook, 2017, p. 1125).

In response, Brown et al argue that while it is important that models have enough time resolution to capture variations in energy demand and variations in wind and solar generation, the time resolution should depend on the area under consideration, since short-term weather fluctuations are not correlated over large distances and therefore tend to balance out. The time resolution should, therefore, depend on the size of the area being studied, the weather conditions found there and the research question. Models for whole countries typically use hourly simulations and are sufficient for long-term energy system planning (Brown, et al., 2018, p. 837).

On this basis, it was decided to use the hourly data obtained from the CSIR as it is of sufficient resolution for the purposes of this study which is to conduct a first-order study.

3.2.3 Sources of data

Two primary sources of information were used for our evaluation:

i. Power generation technology data for Integrated Resources Plan of South Africa, Technical Update; April 2017.

This is a report prepared by EPRI for the IRP 2018 update and was the principal source of data used in this study for the LCOE calculations of the AP1000 and EPR nuclear technologies as well as for the gas and coal technologies.

ii. Renewables January 2016 – December 2018 inc Sere (Public Release).

This is an excel workbook obtainable from the CSIR which provides time-series data for CSP, wind and solar PV.

The following data was not sourced from the EPRI report:

- iii. The LCOEs used for solar-PV and wind for comparison with nuclear were the actual tariffs realised during bid window 4 (BW4) of the REIPPP programme.
- iv. The data used for the calculation of the VVER 1200 LCOE was obtained from an article published in Energize magazine, “The cost of electricity from a new-nuclear build in SA under various assumptions” (Yelland, 2016). A decision was taken to include modelling the VVER even though it is not contained in the IRP 2018 because for long periods it was rumoured that South Africa had already concluded a nuclear procurement deal with Rosatom. The data also proved very useful for validation and benchmarking purposes as results for modelling this technology were available. This data was modelled using the same parameters as for the other nuclear technologies for relevance and ease of comparison. The modelling parameters used are provided in the following section.

3.2.4 Technology costs, performance and other input data

3.2.4.1 Nuclear

The input data used for calculating the LCOE of the AP1000 and the EPR technologies was sourced from the EPRI 2017 report. The core data used for the VVER 1200 technology was sourced from an Energize magazine article (Yelland, 2016) and adapted to make it directly comparable to the other two technologies, i.e. the same exchange rates and discount rates were used. The following is a summary of the basis for the data provided in the EPRI report for nuclear.

3.2.4.1.1 Location

Costs for the nuclear plants were adapted to assume construction at the coast of South Africa. Coastal location enables the use of once-through cooling with seawater and therefore impacts capital and O&M costs. It was assumed that new nuclear units would be located either at the existing nuclear station at Koeberg or on the southern coast about 50 to 100 km west of Port Elizabeth.

3.2.4.1.2 Duty Cycle

The nuclear plants in this study are base-load units. Base-load units are characterized by high availability and high efficiency, but generally, have less flexibility in their output and are less

efficient under part-load conditions, thus minimizing their use as load-following units. A capacity factor of 90 % was assumed for all of the nuclear units.

It should be noted that modern European reactors are now designed to be more flexible. In countries such as France and Germany that have large shares of nuclear capacity, operational flexibility is now a key ingredient to successful grid operations that now includes larger amounts of intermittent generation. In 1991, European utilities developed the European Utilities' Requirements, which explicitly defines load cycling in the operating handbook of nuclear power plants along with the appropriate safety margins. The French PWR makes use of "grey" control rods that allow for load cycling of 30 – 100 % of the plant capacity (EPRI, 2017, p. 59).

3.2.4.1.3 Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For a nuclear plant, this includes the nuclear reactor and the power block, and all support facilities needed to operate the plant, such as wastewater treatment facilities, shops, offices, and cafeteria. The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines.

The fuel costs included in Table 3-1 assumes direct disposal of waste fuel. The costs include on-site, temporary storage costs while a permanent storage solution is being developed and a tax to support development of a permanent storage plan (EPRI, 2017, p. 62).

Table 3-1: Nuclear Technology and Performance data

	AP1000	EPR	VVER1200
Plant net output (MW)	1 x 1 117	1 x 1 600	1 x 1 082
Overnight cost (R/kW)	75 271	98 079	78 380
Average construction period (years)	6	6	6
Capital spend schedule during construction	15%,15%,25%, 25%, 10 %, 10 %	15%,15%,15%, 25%, 10 %, 10 %	15%, 15%, 25%, 25%,10 %, 10 %
Discount rate (%)	8.2	8.2	8.2
Exchange rate (R/USD)	13.57	13.57	13.57

Economic life (yrs)	60	60	60
Average annual capacity factor (%)	90	90	90
Fuel cost (R/GJ)	9.1	9.1	9.1
Fixed O&M (R/kW-yr)	1254	933	657
Variable O&M (R/MWh)	31.2	52.3	36.45

3.2.4.2 Natural gas

The input data used for calculating the LCOE of the gas technologies was sourced directly from the EPRI 2017 report. Some of the assumptions informing the EPRI costing are listed below.

3.2.4.2.1 Location

Cost assumptions for natural gas include site location at a generic coastal Greenfield site in South Africa, near liquefied natural gas (LNG) terminals for easy access to a fuel supply. For all technologies, the primary assumption is that dry cooling systems are necessary and, therefore, no assumptions were made about the site's proximity to a raw water supply.

3.2.4.2.2 Duty Cycle

The EPRI report assumed the CCGT evaluated to be an intermediate unit and the OCGT to be a peaking unit. Intermediate units have costs and operating flexibility that are a cross between a base-load and peaking units. They generally have increased output flexibility compared to base-load units, but have longer construction time and higher capital costs than peaking units. Peaking units, like the open cycle GT, typically have lower capital costs, shorter construction time, quicker start-up times and higher flexibility in their plant output compared to base-load units. However, they generally have higher fuel costs and can be less efficient and, therefore, run less frequently than base load units. (EPRI, 2017, p. 62).

The EPRI report provides LCOEs for CCGTs and OCGTs based on capacity factors of 50 % and 10 % respectively. For the purposes of this report however, the capacity factors for these technologies are based on the system requirement that is not supplied by the variable renewable technologies. For example, if the capacity factor supplied by VRE is 60 %, it is assumed that the capacity factor for the gas plant will be 40 %.

3.2.4.2.3 Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For example, the cost boundary for a combined cycle plant includes all major parts of the unit, such as gas and steam turbines, heat recovery steam generators, turbine generators, and all support facilities needed to operate the plant. The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. The switchyard and transmission lines are generally influenced by transmission system-specific conditions and are therefore not included in the cost estimate (EPRI, 2017, pp. 3-21).

Table 3-2: Natural Gas Technology and Performance data

	OCGT	CCGT excl. CCS	CCGT inc. CCS
Plant net output (MW)	1 x 132	1 x 732	1 x 635
Overnight cost (R/kW)	9 226	10 131	22 262
Average construction period (yrs)	2	3	3
Capital spend schedule during construction	90 %, 10 %	40 %, 50 %, 10 %	40 %, 50 %, 10 %
Discount rate (%)	8.2	8.2	8.2
Exchange rate (R/USD)	13.57	13.57	13.57
Economic life (yrs)	30	30	30
Average annual capacity factor (%)	To be calculated	To be calculated	To be calculated
Fuel cost (R/GJ)	63.9	63.9	63.9
Fixed O&M (R/kW-yr)	181	187	444
Variable O&M (R/MWh)	2.7	24.7	38.4

The EPRI Report provides cost data for three natural gas technologies, OCGT, and CCGT including and excluding carbon capture and storage (CCS). All three have been modelled in this study as the addition of CCGT plus CCS provides an interesting insight into how the combination

of natural gas with renewable energy changes in cost when natural gas is penalised by having to build a cleaner, more expensive option, and how this affects its competitive position against the price of nuclear generation. It would've been ideal to model CCGT plus flue-gas desulphurisation, as has been done for coal below, but unfortunately the EPRI report did not include costs for CCGT plus FGD.

3.2.4.3 Coal

Two coal technologies were modelled for the purposes of this report, pulverised fuel (PF) with and without flue gas desulphurisation (FGD). The input data was sourced from the EPRI 2017 report. These two technologies were included so as to compare the cost-competitiveness of both nuclear and renewable energy against what has traditionally been South Africa's main source of primary energy. Although now highly unpopular with financiers and environmentalists alike, coal could remain a major source of fuel for power stations if the economics continue to warrant it. As it is unlikely that any new coal power stations will be built in South Africa without having to meet more stringent environmental requirements, PF with FGD was modelled too. Of the coal stations currently being built in South Africa, Medupi will be retrofitted with FGD whilst Kusile is the first South African station being built with FGD. This is being done to meet both World Bank funding requirements and the standards set in the National Environmental Management: Air Quality Act, 2004 (AQA).

3.2.4.3.1 Location

EPRI chose the site location for coal to be a generic Greenfield site in northern South Africa near Matimba, 50 km southeast of the Botswana border. The site is assumed to be the mine mouth, removing the need for a nearby railroad for fuel delivery purposes. For all technologies, the primary assumption is that dry cooling systems are necessary and, therefore, no assumption was made about the site's proximity to a raw water supply.

3.2.4.3.2 Duty Cycle

The coal plants in this study are base-load units. Base-load units are characterized by high availability and high efficiency, but generally, have less flexibility in their output and are less efficient under part-load conditions, thus minimizing their use as load-following units. A capacity factor of 85% is assumed for all of the base-load coal units. (EPRI, 2017, p. 52)

3.2.4.3.3 Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For example, the cost boundary for a steam plant includes all major parts of the unit, such as boiler and turbine generator, and all support facilities needed to operate the plant.

The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines, which are generally influenced by transmission system-specific conditions and are therefore not included in the cost estimate.

Table 3-3: Coal Technology and Performance data

	PF excl. FGD	PF incl. FGD
Plant net output (MW)	1 x 750	1 x 750
Overnight cost (R/kW)	36 983	46 092
Average construction period (yrs)	4	4
Capital spend schedule during construction	10 %, 25%, 45%, 20 %	10 %, 25%, 45%, 20 %
Discount rate (%)	8.2	8.2
Exchange rate (R/USD)	13.57	13.57
Economic life (yrs)	30	30
Average annual capacity factor (%)	85	85
Fuel cost (R/GJ)	31.1	31.1
Fixed O&M (R/kW-yr)	789	1 229
Variable O&M (R/MWh)	65.9	90.3

3.2.4.4 Renewables

It was decided to follow the example set by both the IRP 2018 and other researchers by using the actual tariffs realised in the REIPPP programme Bid Window 4 rather than to calculate LCOEs

based on the EPRI Report. This is because using the EPRI data results in unrealistically high levelised costs when compared with the actual tariffs. In summary, the following were used:

- Wind R0.65/kWh
- Solar PV R0.65/kWh

By doing this we eliminate the criticism of the LCOE methodology which is considered by many as being especially unsuited for variable renewables (Joskow, 2011). It is argued that LCOE, when applied to variable technologies, overlooks variability and integration costs in particular. The use of actual South African tariffs provides very credible estimates for future renewables projects also located in South Africa.

3.2.4.5 Costing basis for this report

As the costs for the conventional technologies (nuclear, natural gas, coal) discussed above were obtained from the EPRI 2017 Report published in April 2017. The first version of this report was originally produced in 2015 and subsequently updated in April 2017 to reflect costs as at January 2017. The exchange rates used to convert import costs to Rands is provided in Table 3-1 to Table 3-3 as R13.57/USD.

The costs used for solar PV and wind as discussed above are the actual prices realised for the Renewable Energy Independent Power Producers Bid Window 4, escalated to April 2017 Rands.

The results reported on in the further sections of this report for LCOEs are therefore in 2017 Rands.

3.2.5 Benchmarking

In order to establish the veracity of the LCOE results produced by the model built for this study, a benchmarking exercise was conducted. A CSIR presentation dated 14 October 2016, “Cost of new power generators in South Africa”, by Bischof-Niemz and Fourie was sourced which provided an excellent source for benchmarking the technologies depicted in Figure 4-8 (Bischof-Niemz & Fourie, 2016). As the EPRI Report from which most of our model’s data was sourced is dated April 2017, both sets of data are for approximately the same period. Additional benchmarking was conducted against the EPRI report itself.

3.2.6 Comparison of base-load LCOE - VRE plus LNG vs. Nuclear

The objective of this study is to determine whether renewable energy with LNG for flexibility can replace nuclear energy as a base-load option for South Africa. Put in another way, the objective

of our study is to compare the cost of supplying base-load with the VRE plus LNG for flexibility combination against the cost of supplying base-load with nuclear.

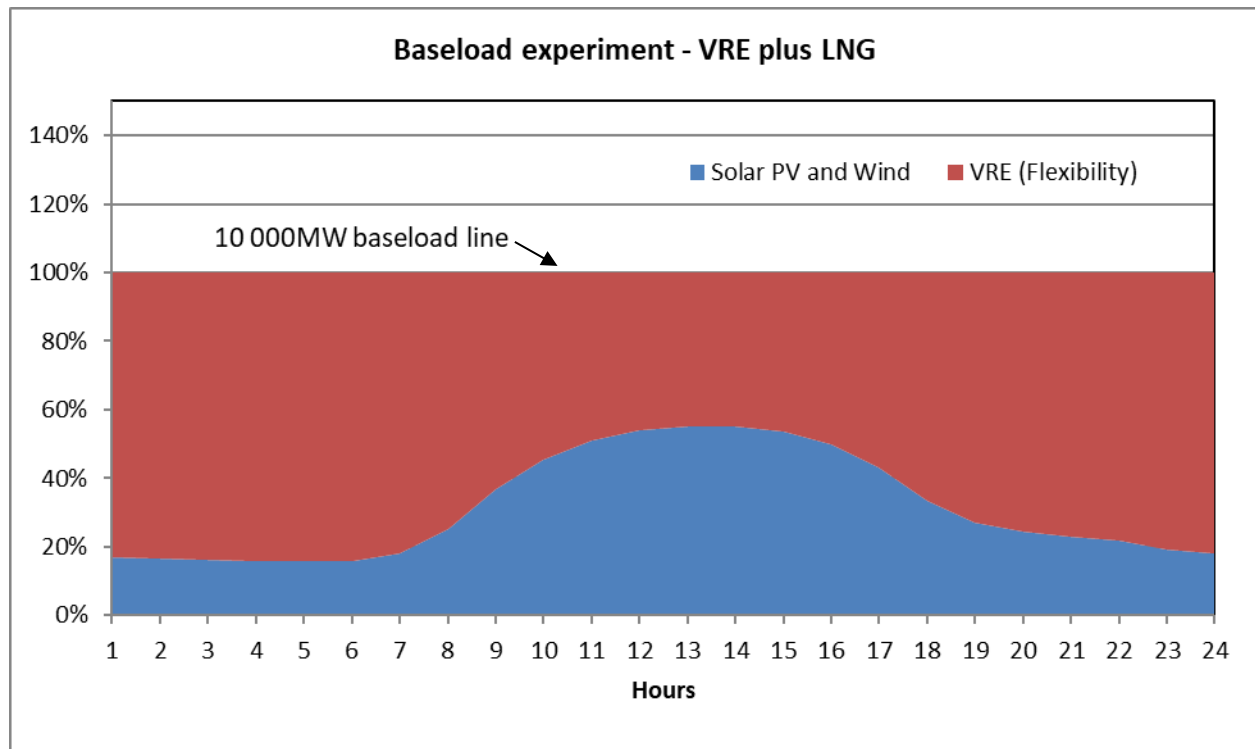


Figure 3-1: Typical base-load profile for a combination of VRE with LNG for flexibility

For the purposes of comparing the respective costs, numerous hypothetical scenarios were developed, of which three were eventually selected for presentation in this report. It was decided that the cost to meet a demand of 10 000MW of electricity would be calculated for the competing technologies/combination of technologies. This quantum is based on the capacity of nuclear contained in the IRP 2010 (9 600MW) rounded up for ease of calculation.

It was further assumed that the cost of supplying this demand with nuclear technology would be the levelised cost calculated by our LCOE model for the VVER 1200 technology. The VVER technology was selected because it is the cheapest of the three modelled and also to humour the rumour that the South African Government has already struck a deal with the Russians.

To calculate the cost of the renewables plus LNG combination three different scenarios were selected for comparison with nuclear. These are discussed in the following section.

3.2.6.1 Scenario 1

As a starting point, it was decided that scenario 1 would consist of equal amounts of solar PV and wind capacity simply because that approximates their current ratios in the South African system. It was decided that 10 000MW would be built of both solar PV and wind. In order to provide sufficient cover for the renewables in the system, it was determined that 10 000MW of LNG flexibility would also be required, because the lowest hourly capacity factor obtained from our renewables load profiles was almost zero, and base-load requires a constant supply.

Using the average load profiles calculated from the CSIR load profile data, it was calculated how much energy would be produced by the wind and solar PV combination on the average South African day. The result is a profile similar to the blue area depicted in Figure 3-1.

By subtracting the energy produced by the renewables from the base-load energy requirement, the energy and capacity factor of the flexibility source was determined (the red area in Figure 3-1). This capacity factor was then entered into the LCOE model to obtain the levelised cost of the LNG supply. LCOEs were determined for OCGT, CCGT, and CCGT with carbon capture and storage (CCS).

The reason why three LNG technologies were modelled was to assess whether it might not be more economical to use CCGT technology rather than OCGT technology, if it was found that the faster ramping rates of OCGT are not necessary. The cost of CCGT with CCS was also modelled because, although LNG is “cleaner” than coal, it is still a fossil fuel technology and in future could be subjected to environmental pressures to provide cleaner energy.

Lastly, the costs of the renewable energy and the LCOE calculated for the LNG technologies were added together for comparison with the nuclear LCOE. The results are provided in Chapter 4.

3.2.6.2 Scenarios 2 and 3

In order to test the sensitivity of the combined price of VRE plus LNG, two additional scenarios are presented in this report:

- Scenario 2 – 20 000MW wind, 10 000MW of solar PV and 10 000MW of LNG generation as cover. This scenario was selected because it provides an insight into surpluses, a problem that can result from the presence of renewables in an electrical system.
- Scenario 3 – 25 000MW of wind with 10 000MW of LNG generation as cover. This scenario was selected because it provided a very close fit with the base-load requirement and provides an introduction for the debate on a wind-only renewables system.

In both instances the objective remained the same as for Scenario 1, i.e. to produce 10 000MW of base-load for comparison with nuclear base-load. The methodology to calculate the combined LCOEs also remained the same.

The results for all three scenarios and analysis of their implications are provided in Chapter 4.

3.3 Technical feasibility analysis

The second objective of this report is to provide an assessment of whether it is technically feasible to have an electrical power generating system consisting of renewables plus LNG generation for flexibility, i.e. can such a system actually work? LCOE studies have failings in that they often do not consider important externalities, such as system costs, while the intermittency of renewables presents technical challenges that must be overcome.

To assess the technical feasibility of our hypothetical system, an analysis was firstly conducted of the ramping rates of gas technologies so as to assess whether they are suited to meet the variability rates of our renewable system, and secondly a literature review of academic journal articles was conducted to determine what both the pro-renewables and anti-renewables camps have to say about the technical feasibility of renewables supplying an electrical system's requirements.

The meanings of variability and flexibility were explored and an assessment was made of whether variability is an insurmountable problem or merely a technical challenge that can be overcome. An attempt was made to identify the various technical challenges that must be overcome when integrating renewables into a power system and to discuss them from both the pro- and contra-points of view.

As the objective of this report is to assess whether renewable energy can, not just complement but replace nuclear technology, our review includes a look whether 100 % renewables systems are feasible.

CHAPTER 4 RESULTS

4.1 Empirical cost analysis

4.1.1 Levelised Cost of Electricity

4.1.1.1 Nuclear technologies

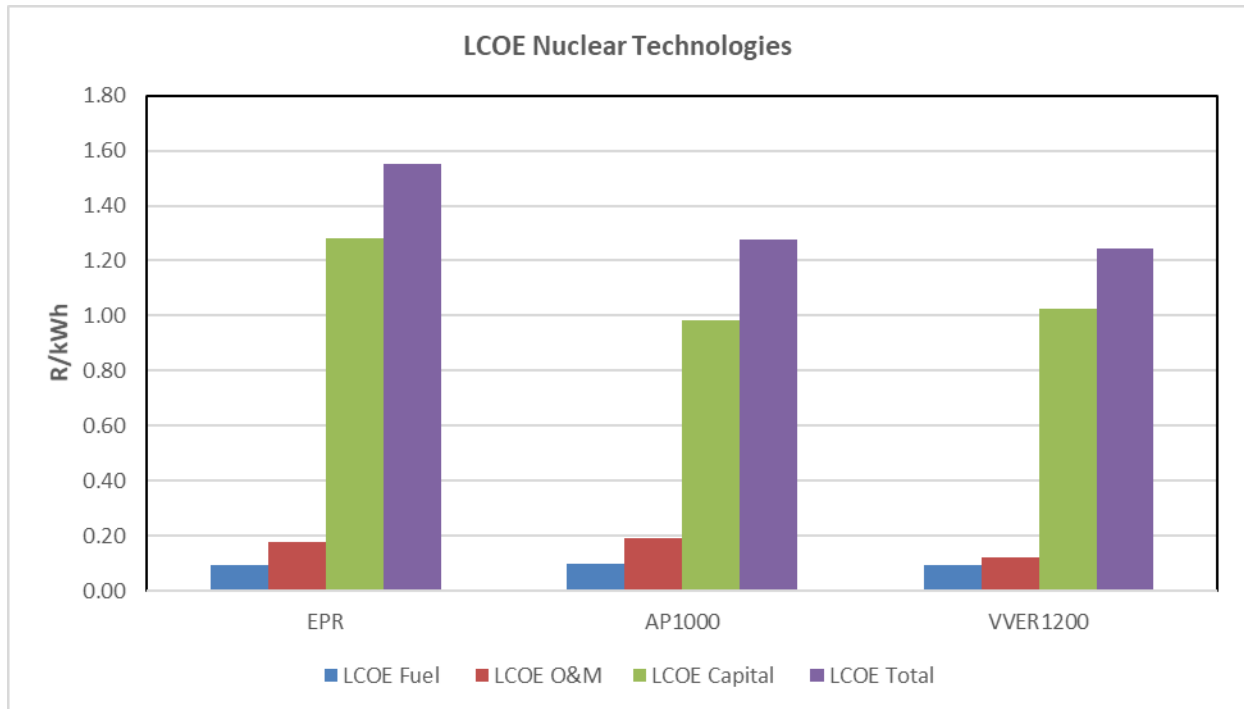


Figure 4-1: LCOEs of selected nuclear technologies

Figure 4-1 above and Table 4-1 below present the results for the LCOE calculations for the three nuclear technologies modelled, in 2017 Rands. They should be read together with Table 3-1 which provides the input data upon which these results are based.

As can be seen from them, the LCOE for the EPR is significantly higher than for the other two technologies. The main contributors to this are the EPR's higher CAPEX and variable O&M costs. Although the VVER 1200 had a slightly higher capital cost than the AP1000 its LCOE is lower due to it being more economical to operate and maintain.

For the purposes of our comparison, it was decided to benchmark the renewables plus LNG results against the LCOE of the VVER 1200 as it proved to be the most competitive nuclear option, based on the model's results.

Table 4-1: LCOEs of selected nuclear technologies – 2017 Rands

	AP1000	EPR	VVER1200
LCOE Fuel (R/kWh)	0.10	0.09	0.09
LCOE O&M (R/kWh)	0.19	0.18	0.12
LCOE Capital (R/kWh)	0.98	1.28	1.02
LCOE Total (R/kWh)	1.28	1.55	1.24

4.1.1.2 Conventional technologies

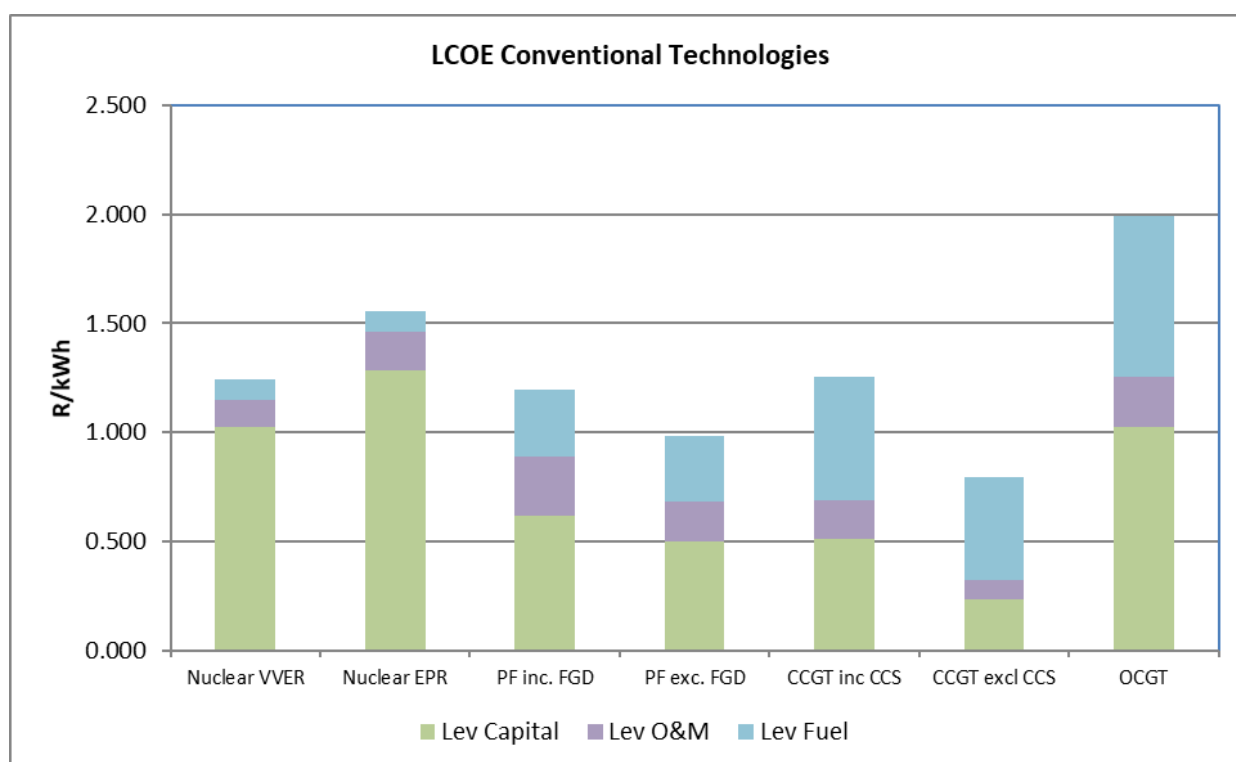


Figure 4-2: LCOE of selected conventional technologies

Table 4-2 and Figure 4-2 should be read together with the input data in Chapter 3 and Appendix 1. They provide a comparison of the LCOEs of the conventional generating technologies relevant to this study when they are operated at “expected” capacity factors. By this, it is meant that the natural gas technology results depicted are for operation at much lower capacity factors than for nuclear or coal. CCGT, in this case, is modelled at 50 % capacity factor and OCGT at 10 % as per the capacity factors provided in the EPRI 2017 report.

Table 4-2: LCOES of selected conventional technologies – 2017 Rands

	PF inc. FGD	PF exc. FGD	CCGT inc CCS	CCGT excl CCS	OCGT
Lev Capital (R/kWh)	0.62	0.50	0.51	0.23	1.02
Lev O&M (R/kWh)	0.27	0.18	0.18	0.09	0.23
Lev Fuel (R/kWh)	0.31	0.30	0.57	0.47	0.73
Lev Total (R/kWh)	1.20	0.98	1.26	0.80	1.99

Figure 4-3 provides a different perspective of technology prices. From it, it can clearly be seen that all technologies are cheaper per kWh when operated at high capacity factors. OCGT when operated at “base-load” capacity factors (80 % - 90 %) is cheaper than when operated at 10 %. Natural gas LCOEs are sensitive to the price of fuel, so a spike in the price of LNG can significantly change its relative LCOE competitiveness position.

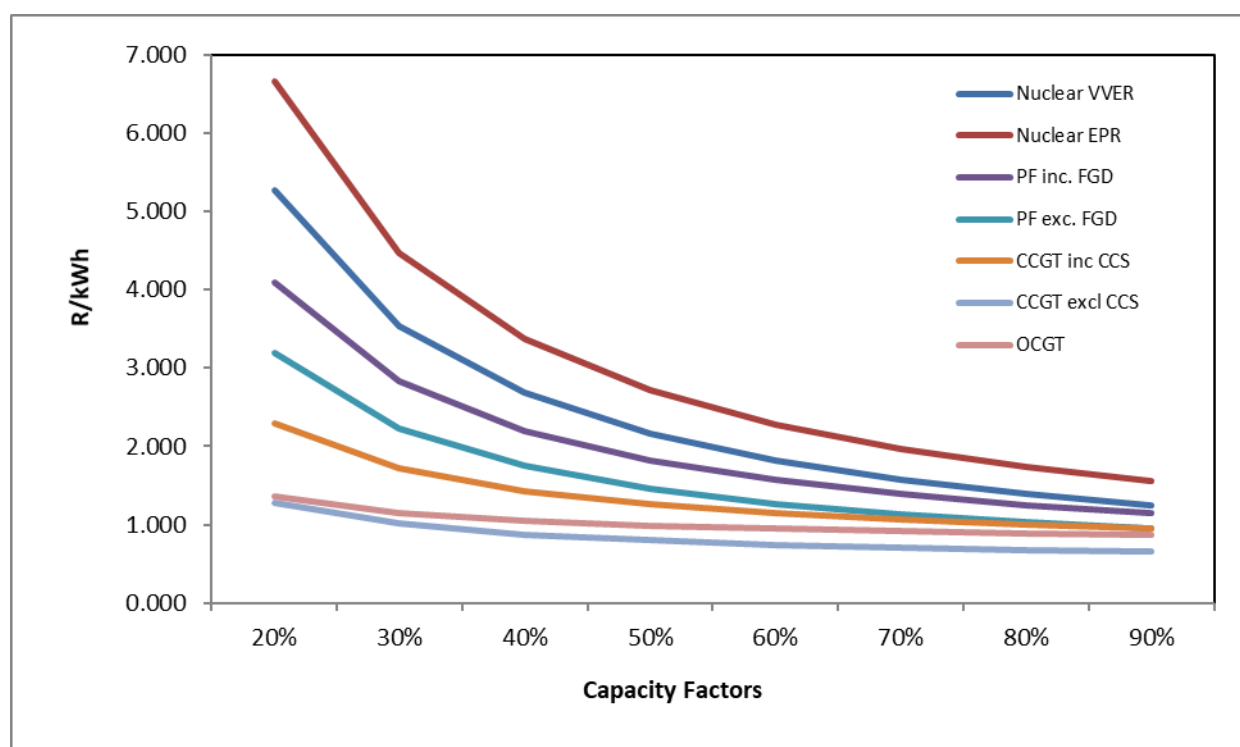


Figure 4-3: Conventional technologies at various capacity factors

The natural gas prices in Figure 4-3 are based on a gas price of R63.9/GJ as provided in the EPRI Report, which is significantly lower than the R110/GJ on which much previous research published in industry media had been based.

Table 4-3 and Figure 4-4 are a sensitivity analysis of the effect of the price of LNG on the LCOE of natural gas technologies. For the purposes of this analysis, the capacity factor was fixed at 88 % and the price of LNG varied. As can be seen from the table and the figure, natural gas technology LCOE's are very sensitive to the price of natural gas as it is a major component of its life-cycle costs.

For the purposes of our comparison between nuclear and VRE plus LNG, it was therefore decided to provide the costs for renewables plus LNG based on two prices, R63.9/GJ and R110/GJ.

Table 4-3: LCOE of natural gas technologies at various LNG costs – 2017 Rands

LNG Prices R/GJ	CCGT excl CCS	OCGT
63.9	0.66	0.88
70	0.70	0.95
80	0.78	1.06
90	0.85	1.18
100	0.92	1.29
110	0.99	1.41
120	1.07	1.52

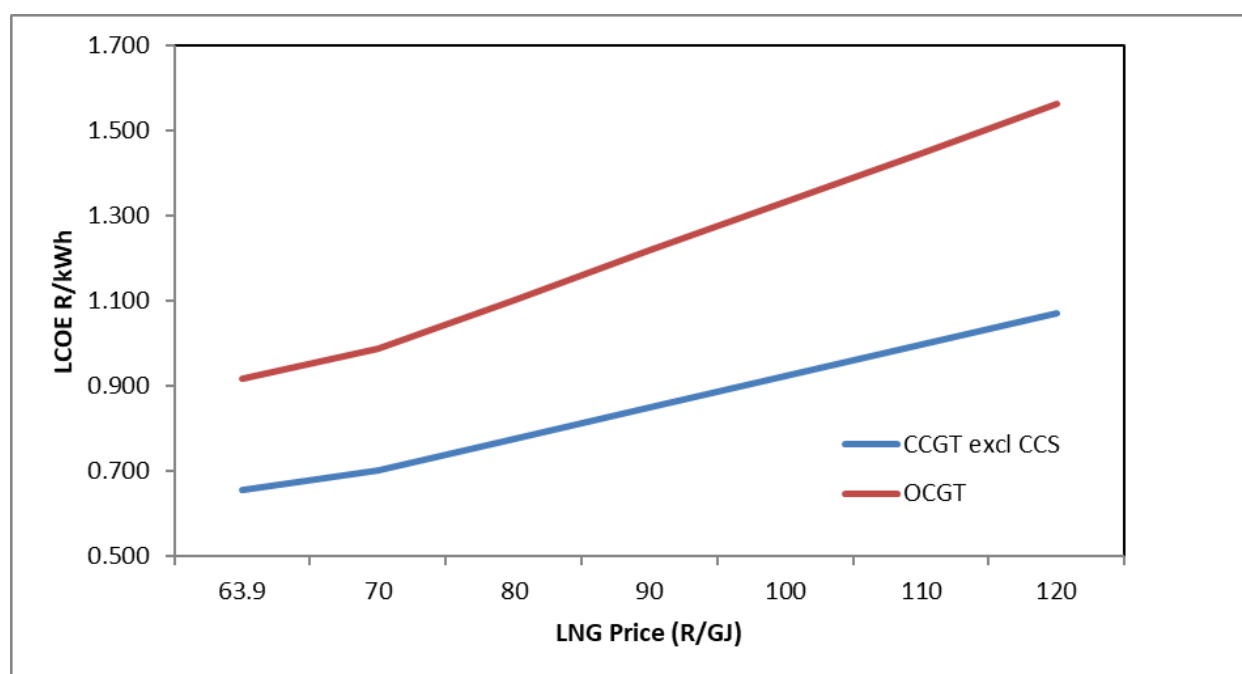


Figure 4-4: Effect of the price of LNG on natural gas technologies

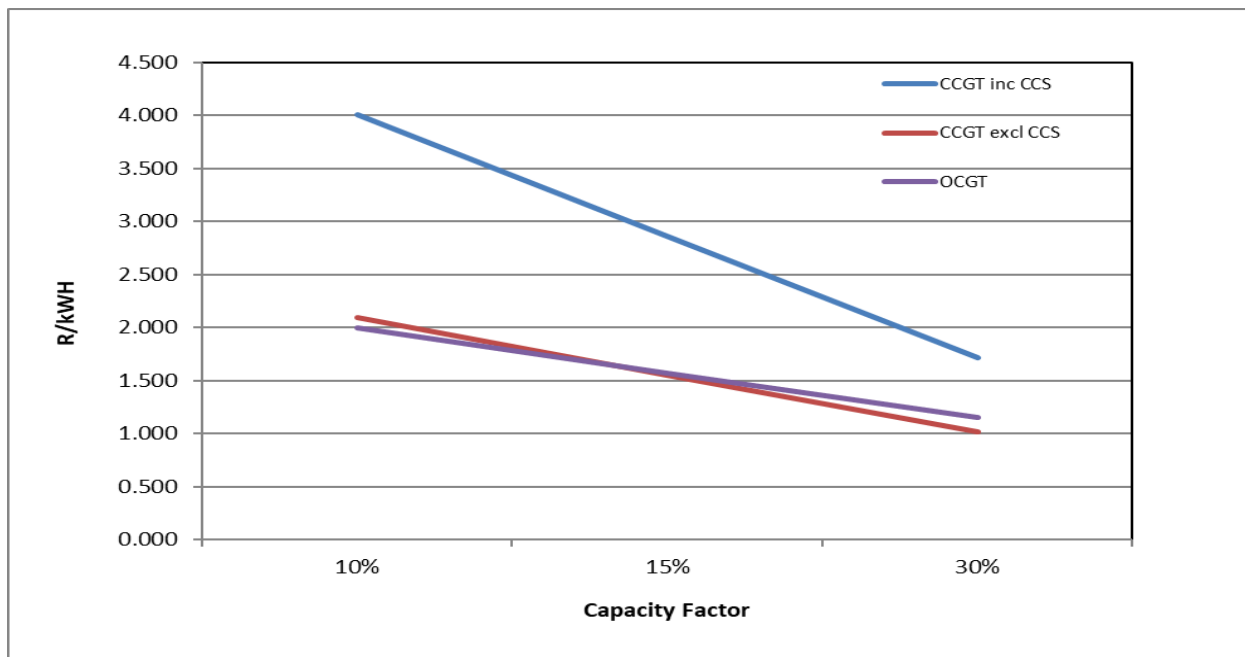


Figure 4-5: Natural gas technologies at various capacity factors

Figure 4-5 provides another interesting perspective on the LCOE results obtained. It shows that, except at very low capacity factors, typically below 10 %, CCGT without CCS is cheaper to run than OCGT. OCGT seems to be preferred as a form of flexibility in most of the literature reviewed because of its faster start-up times, and an ability to be run as a load-following machine (see section 2.4.1.3). Typical ramping rates provided for OCGTs are in the order of 20 %/min and hot start-up times about 10 mins compared to ramping rates and hot start-up times of 8% and 2 hrs respectively for CCGTs (Gonzalez-Salazar, et al., 2018, p. 1499).

Nevertheless, our calculated renewables load factors indicate that the type of flexibility needed falls within the mid-merit range of load factors and that the use of CCGTs for flexibility could be a feasible alternative. Further analysis of which technology would best suit our suite of scenarios is provided in section 4.2.3.

Figure 4-6 serves to illustrate one of the strengths of nuclear technology. When, for illustrative purposes, the capital costs are excluded, nuclear power has the lowest LCOE of all conventional technologies. Stated in a different manner, because of its very long life cycle (60 years), once the CAPEX has been paid off, a nuclear power station provides many years of efficient, emission-free electricity at very low cost.

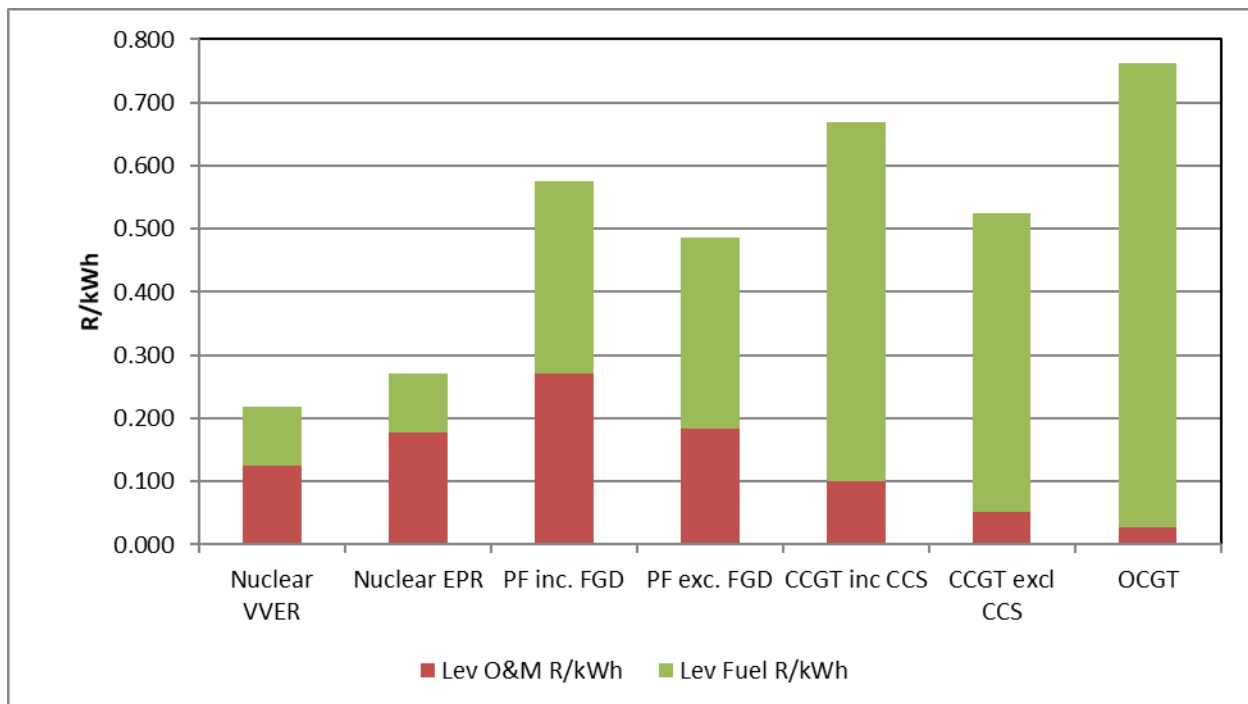


Figure 4-6: LCOE of O&M and Fuel for various conventional technologies

Figure 4-7, on the other hand, illustrates the effect on the nuclear LCOE of what is probably the biggest risk associated with investing in nuclear technology, namely delays in construction. The changes in CAPEX phasing for this exercise were arbitrarily calculated in order to emphasise that a delay during construction can have an effect on the levelised cost over the entire lifetime of a nuclear project.

This is a point that is important to emphasise because Eskom is currently in the process of building two coal-fired mega-projects, the Kusile and Medupi power stations. Both projects are significantly behind schedule and over-budget. Kusile and Medupi, the third and fourth-largest coal power plants in the world, were originally due to come online in 2014 and 2012 respectively. According to a September 2019 report, it was estimated that they would only be completed in 2023 and 2020 respectively. Kusile's capital cost has grown from R81bn to R161bn, while Medupi's costs have risen from R79bn to R146bn (Steyn, 2019). These increases in cost have had a negative effect not only on Eskom's debt levels but also on South Africa's debt/GDP ratio. As can be seen from Chapter 3, nuclear CAPEX costs are significantly higher than for coal projects, so a repeat of the delays experienced with Medupi and Kusile, with a nuclear project, could have a catastrophic effect on the whole country.

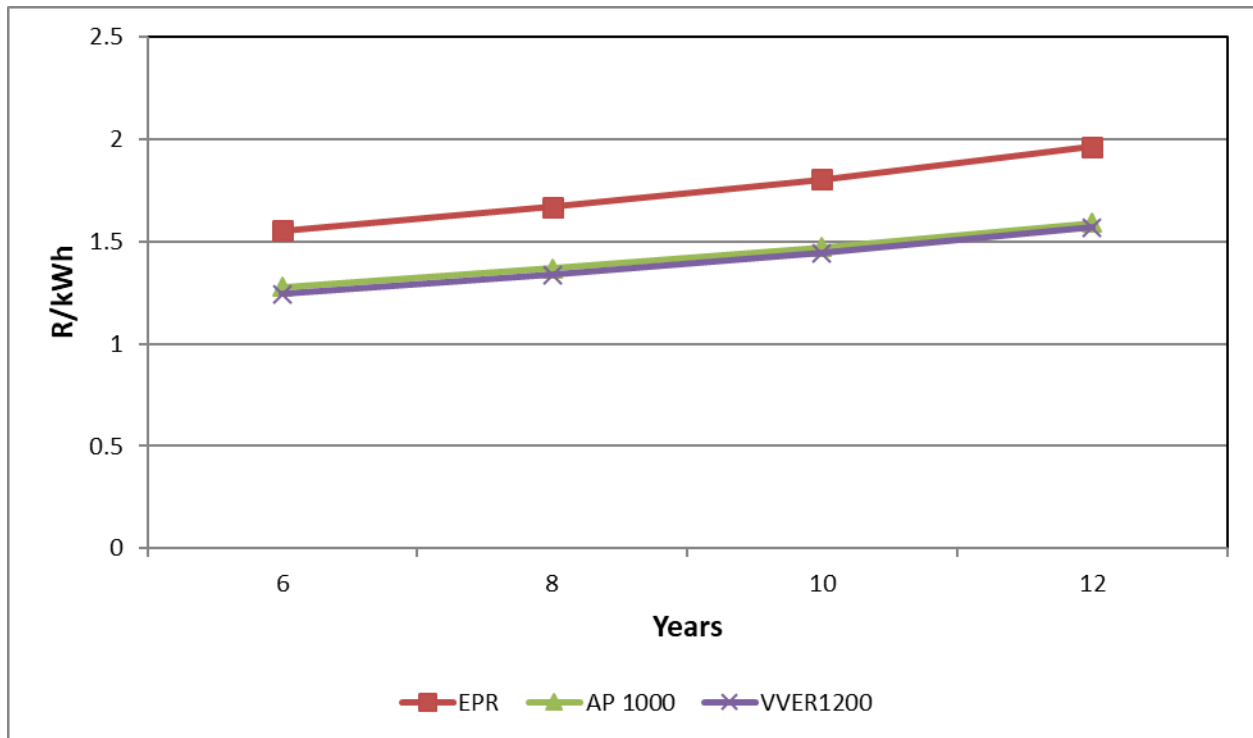


Figure 4-7: Effect of construction delays on nuclear LCOE

In summary of the discussion on levelised costing, the nuclear technology selected to take forward for comparison with our hypothetical renewables plus LNG combination was the VVER 1200 because it resulted in the most competitive price. It needs to be borne in mind that the other technologies are less competitive.

As will be seen in the ensuing sections, the capacity factors required for the flexible supply (LNG) fall in the mid-merit range. Since the LCOEs obtained for CCGT were generally lower in this range than for OCGT, our comparison was extended to include flexible supply not just from OCGT, but also from CCGT with and without carbon capture and storage. An analysis of which technology is considered most suitable from the viewpoint of this study is provided in section 4.2.3.

4.1.1.3 Renewable technologies

Although LCOEs were developed for solar PV and wind using the EPRI report as input data, the results obtained were significantly higher than those of the actual tariffs realised for Bid Window 4 of the REIPPPP, i.e. the tariffs for Nov 2015 in Table 4-4 below. A decision was taken therefore, to use the actual tariffs of BW4. In so doing we also avoid the disadvantages associated with LCOE comparisons between conventional and renewables LCOEs, as explained in section 2.2.4.

The price for both solar PV and wind for all load factors is assumed to be a constant R0.65/kWh for the purposes of our comparison between nuclear and VRE plus LNG

Table 4-4: REIPPPP BW1 to BW4 (Expedited) - Actual Tariffs, April 2017 Rands

R/kWh	CSP	Wind	Solar PV
Nov 2011	3.74	1.6	3.84
Mar 2012	3.5	1.25	2.29
Aug 2013	3.28	0.92	1.23
Aug 2014	3.06	0.72	0.96
Nov 2015	2.13	0.65	0.65

4.1.1.4 Benchmarking

In order to establish the veracity of the LCOE calculations results produced by the LCOE model built for this study, a benchmarking exercise was conducted. A CSIR presentation dated 14 October, “Cost of new power generators in South Africa”, (Bischof-Niemz & Fourie, 2016) was sourced which provided an excellent source for benchmarking the technologies depicted in Figure 4-8. As the EPRI 2017 Report from which most of our model’s data was sourced provides costs in January 2017 Rands, both sets of data are for approximately the same period. Although the CSIR presentation did not provide an LCOE for OCGT, an earlier CSIR presentations dated March 2016 put the OCGT price at R2/kWh which is the same as obtained by our model at a load factor of 10 %, the load factor at which OCGT is normally modelled (Bischof-Niemz, 2016).

This CSIR data was also used as the basis for a number of articles that appeared in industry media in late 2017, and served to reinforce the costing of the VVER 1200 LCOE. These articles also expressed a growing realisation in the industry that the old paradigm and approach of dispatching base-load, mid-merit and peaking generation capacity, in that order, is being turned on its head (Yelland, 2017).

As can be seen from Figure 4-8, where this study’s results are presented in yellow, there is a very strong correlation between the LCOE’s being used by the CSIR and other industry researchers and those calculated for the purposes of this report. This would seem to verify that the LCOE calculation methodology used in our study is similar to those used by other researchers doing first first-order analysis. It also strengthens the level of confidence in the analytical work that follows in this report.

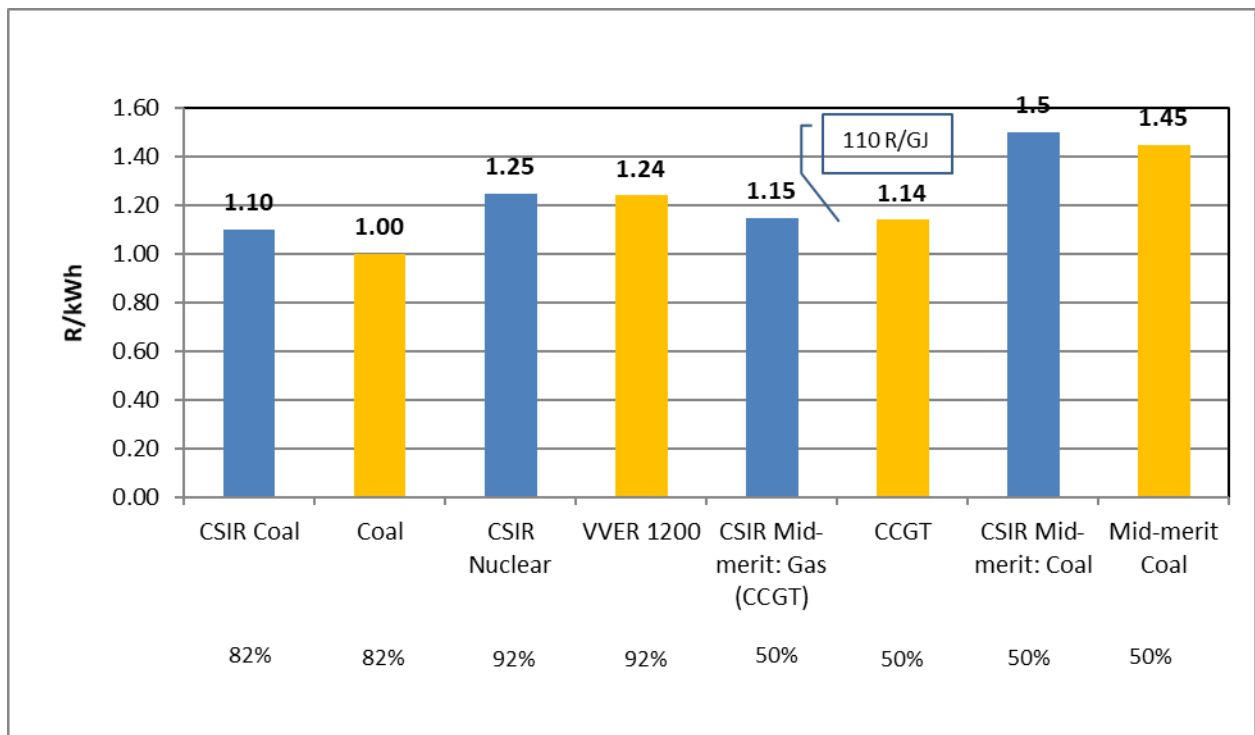


Figure 4-8: Benchmarking against CSIR results of October 2016

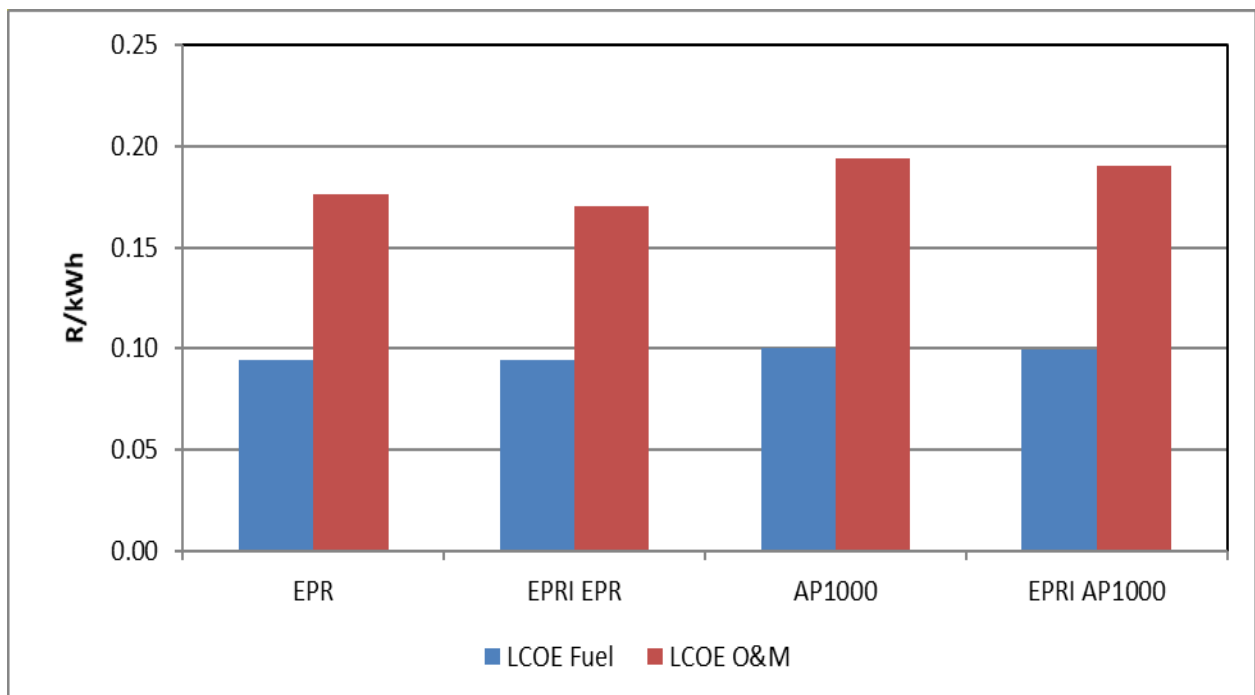


Figure 4-9: Benchmarking against EPRI - January 2017 Rands

The LCOE results were also benchmarked against those presented in the EPRI report itself (see Figure 4-9). In this case, the capital LCOEs did not correlate strongly but there is a strong correlation of the fuel and O&M LCOEs as the figure demonstrates.

The difference in capital LCOEs is due to contingencies added by EPRI to account for risk and which are not explained in their report. EPRI includes contingencies for all technologies evaluated in their report. The amount of contingency varies, based on the assessment of cost risk of the various technologies, with the selected values being considered appropriate for the state of experience for each technology (EPRI, 2017, pp. 3-16).

4.1.2 Renewable energy profiles

The solar PV and wind load profiles presented in this study were derived from data obtained from the CSIR in the form of an excel time series, “Renewables January 2016 – December 2018 inc. Sere (Public Release)”.

This workbook contains hourly production data for CSP, solar PV, wind, and the overall Eskom system. From this data average hourly load profiles were produced for solar PV and wind for use in our comparison between nuclear and renewables plus LNG. As explained in chapter 3 the suitability of hourly resolution was investigated through the literature review, before being accepted for use in this study.

The results presented here for solar PV and wind should be read in conjunction with the tables in Appendices 10 to 12 of this report. The appendices provide data about average load factors as well as typical highest and lowest load factors for solar PV and wind in the three years of data that were analysed.

4.1.2.1 Introduction

Knorr et al in a renewable resource study commissioned by the CSIR, the South African National Energy Development Institute (SANEDI) and Eskom in 2016, found that South Africa has very good aggregated solar and wind resources. The potential electrical capacity obtainable from them far exceeds the current and expected future demand by far (Knorr, et al., 2016).

The report explains that, compared to the rest of the world, South African wind conditions and solar irradiation display low seasonality and will enable a steady electricity supply from renewable resources, while the existing widespread interconnected electricity system enables spatial aggregation.

Solar resources in South Africa display very little seasonality. The total solar PV potential in South Africa from distributed and utility-scale installations exceeds 300GW, with about 220 GW of this being utility-scale potential.

Wind resources are more seasonal than solar, with wind speeds and generation from wind closely following the demand over the year. On a daily scale, South African wind resources produce less output during the day and more during the evening, which complements both the electricity demand and solar diurnal production pattern.

Wind turbines can be built and operated with high load factors - above 30 % - in locations all over the country, with large areas offering potential load factors of over 40 %. More than 80 % of South Africa's landmass has enough wind resources for low-cost wind energy production (Knorr, et al., 2016, p. 60).

4.1.2.2 Results of Solar PV time series

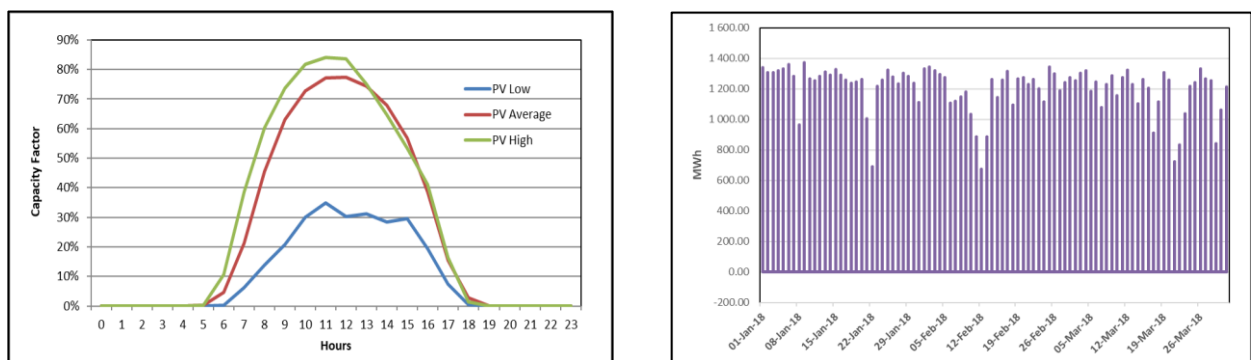


Figure 4-10: Diurnal and quarterly load profiles - solar PV

The load profiles obtained from the CSIR time series support the findings of the CSIR aggregation report. As can be seen from Figure 4-10, the diurnal maximum and average load profiles for solar PV production are very close together, indicating remarkable consistency, while the quarterly load profile serves to reinforce this point over a three month period. However, for any given day this profile can obviously fluctuate greatly.

The average capacity factor for solar PV was found to be 26 % with the highest and lowest capacity factors being 29 % and 11 % respectively.

4.1.2.3 Wind

Our results for onshore wind indicate that wind is less consistent than our solar resources, as can be seen from both the daily and quarterly data presented in Figure 4-11. The maximum and

average load profiles are less close together in the daily profile and the quarterly graphic also displays greater variability than is shown for solar.

Having said this, wind load factors are far higher than for solar. The average, high and low capacity factors obtained, as indicated in appendices 10 to 12, are 35 %, 72 % and 11 % respectively, which supports the findings of the CSIR aggregation report.

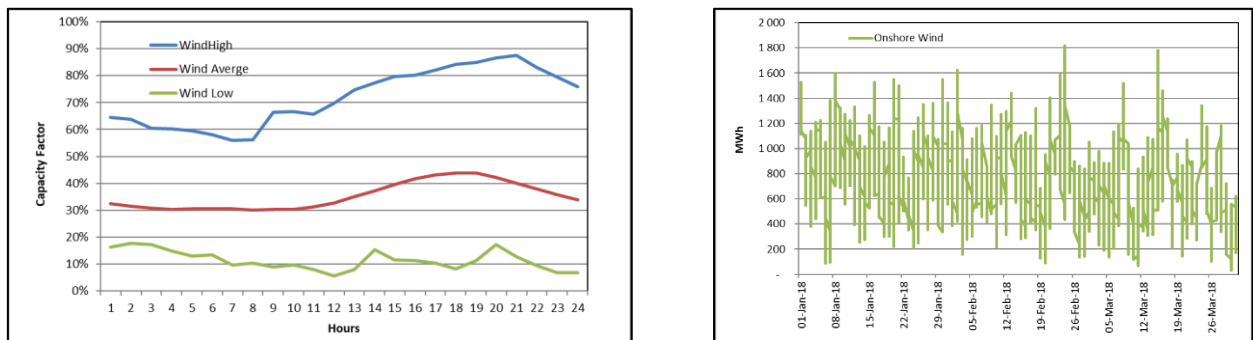


Figure 4-11: Daily and quarterly load profiles – onshore wind

Our results for onshore wind indicate that wind is less consistent than our solar resources, as can be seen from both the daily and quarterly data presented in Figure 4-11. The maximum and average load profiles are less close together in the daily profile and quarterly graphic also displays greater variability than is shown for solar.

Having said this, wind load factors are far higher than for solar. The average, high and low capacity factors obtained, as indicated in appendices 10 to 12, are 35 %, 72 % and 11 % respectively, which supports the findings of the CSIR aggregation report.

4.1.2.4 Summary of findings and benchmarking

The analysis of the CSIR time series for wind and solar can be aggregated to derive combined renewables capacity factors and load profiles as depicted in Figure 4-12 (CSIR, 2018). The overall Eskom system profile has been included in the figure on a secondary axis to illustrate certain characteristics of South African renewables load profiles which will become increasingly important as the share of renewables in the system grows.

As can be seen from Figure 4-12, there is a mismatch between the overall system peak and the renewables peak. Due to the solar profile, the renewables peak is at midday, whilst the overall system peak is in the evening. The wind profile on its own correlates more closely with the overall system profile. These individual characteristics should be used as inputs to inform how much of each technology is built in future.

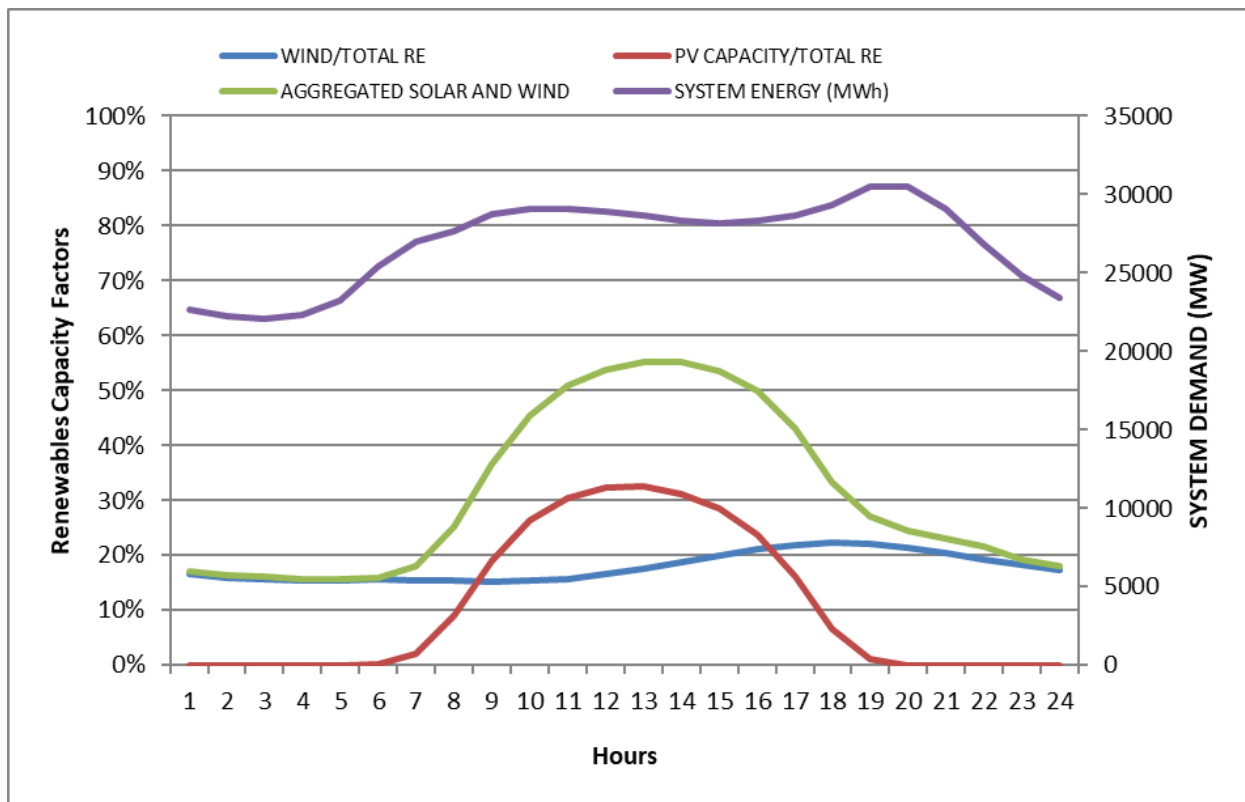


Figure 4-12: Aggregated average wind and solar resources

A significant amount of distributed rooftop solar capacity is being deployed by individual consumers at present to reduce the dual impacts of load shedding and steadily increasing Eskom tariffs. This could lead to surplus production at certain times of the day which will eventually necessitate that measures be taken such as curtailment of production or the introduction of technologies to store this surplus production. This suggests that utility-scale solar farms will be more beneficial to the country than rooftop solar, because the orderly roll out and control of such solar farms can be much better controlled than individual solar panels on the roofs of consumers. Due to economies of scale, solar farms also produce solar power much cheaper than rooftop solar panels.

From the point of view of this study's objectives, the most important information obtained from the analysis of the CSIR time series are the renewables average hourly capacity factors and the maximum and minimum aggregate renewables supply.

As can be seen from Table 4-5, at times the minimum hourly capacity factors for wind and solar are almost negligible. These extremely low capacity factors are typically found just before sunrise when there are relatively low wind and solar conditions. The implication of this is that in order to

supply base-load using only wind and solar power a 100 % back-up by a flexible generating source is required.

The maximum capacity factor is also important because it is an indication of how much production must be either curtailed or stored at times when these load factors are realised. The output of coal-fired power plants, when operated in load-following mode, can be curtailed relatively easily in order to counter oversupply by wind and solar. However, for economic reasons, nuclear plants are normally operated in base-load mode and thus their output cannot be curtailed in this manner. Therefore it is more difficult to balance wind and solar power with nuclear power than with coal power. The daily capacity factors in Table 4-5 have been included in the table for purposes of comparison only.

Table 4-5: Hourly and daily maximum and minimum capacity factors for renewables

Hourly	Maximum Capacity Factor	85%
	Minimum Capacity Factor	1 %
Daily	Maximum Capacity Factor	53 %
	Minimum Capacity Factor	10 %

Table 4-6 provides the average hourly capacity factors necessary to calculate how much our hypothetical renewables system will produce every hour.

For the purposes of benchmarking our results, the average daily capacity factors for wind and solar are also included. Kemper et al analysed the production data for the period January 2014 to 31 August 2016 and obtained annual capacity factors of 32 % and 25 % for wind and solar PV respectively. Their report also provided the averages for the Draft IRP Update Base Case 2016 which were 34% for wind and 26 % for solar PV (Kemper, et al., 2017). These results correlate very closely with the results obtained for this study and provide a high level of confidence for their use in our calculations.

Table 4-6: Average hourly and daily capacity factors

PERIOD	Wind Average Capacity Factors	PV Capacity Factors	AGGREGATED CAPACITY FACTORS
0	32 %	0 %	18 %
1	31 %	0 %	17 %
2	31 %	0 %	17 %
3	30 %	0 %	17 %
4	30 %	0 %	17 %
5	31 %	0 %	17 %
6	30 %	5%	19 %
7	30 %	21 %	26 %

8	30 %	45%	37 %
9	30 %	63 %	45%
10	31 %	73 %	50 %
11	33 %	77 %	53 %
12	35%	77 %	54%
13	37 %	74%	54%
14	40 %	68 %	53 %
15	42 %	57 %	49 %
16	43 %	38 %	41 %
17	44%	16 %	31 %
18	44%	3 %	25%
19	42 %	0 %	23 %
20	40 %	0 %	22 %
21	38 %	0 %	21 %
22	36 %	0 %	20 %
23	34%	0 %	19 %
Average Capacity Factors	35%	26 %	31 %

4.1.3 Results of LCOE comparison

One of the principal objectives of this study is to ascertain whether renewables with LNG as a source of flexibility can replace nuclear energy as a source of base-load power for South Africa.

To do this a simple experiment was designed. A hypothetical power system is assumed that must deliver 10 000MW of base-load. The costs of supplying this quantum of base-load were calculated in 2017 Rands for both nuclear and renewables plus LNG and then compared.

The results obtained are of a first-order nature due to the metric used for comparison, simplified LCOE, as well as other assumptions introduced to simplify this exercise. All assumptions made are explained as they are applied in this section. In spite of the imperfect nature of this methodology, the results reported here nevertheless provide an indication of whether there is value in carrying out further, more detailed investigations.

4.1.3.1 Hypothetical base-load scenario - Scenario 1

4.1.3.1.1 Objective of scenario 1

To supply 10 000MW over an average 24 hours period under South African conditions, i.e. to supply 240 000MWh over the period of an average South African day with average South African

weather conditions. 10 000MW was selected because in 2010 South Africa produced an electricity plan that included 9 600MW of nuclear capacity – the IRP2010 (DoE, 2010). For ease of calculation the quantum in the IRP has been rounded up to 10 000MW.

4.1.3.1.2 Cost of supply with nuclear technology

As nuclear is a “base-load” technology, it is assumed that nuclear technology will be able to supply 240 000MWh at the LCOE calculated by our modelling. The technology selected for modelling was the VVER 1200 technology because it was the cheapest of the nuclear technologies modelled and also to humour the rumour that South Africa had already entered into a deal with Rosatom.

It is assumed that the VVER technology can supply exactly 10 000MW without any over- or under-supply, i.e. nuclear power stations can be built to supply exactly 10 000MW. All locational and integration challenges and costs are ignored as they also are for the renewable technologies.

Therefore the cost to supply 10 000MW of base-load in South Africa using nuclear technology is assumed to be R124/MWh and is represented by the solid horizontal line in Figure 4-13.

4.1.3.1.3 Cost of supply with renewable energy plus an LNG flexibility source

For a first iteration of this cost, it was decided to use the approximate ratio of solar PV and wind capacity that currently exists in South Africa, i.e. 50 % each. It is assumed further that 10 000MW of each technology is installed. In summary, our hypothetical system contains:

- 10 000MW solar PV, and
- 10 000MW wind

As it was found when analysing the CSIR time-series that for certain hours almost no supply was provided by either technology, it was decided that a 100 % LNG flexibility back-up was needed, i.e. 10 000MW of LNG. It was furthermore decided to model the cost of that flexibility for three technologies, namely OCGT, CCGT without CCS, and CCGT with CCS.

The capacities built of solar PV, wind and LNG flexibility are summarised in the table below.

Technology	Capacity installed (MW)
Wind	10 000
Solar PV	10 000
LNG Flexibility	10 000
TOTAL	30000

The next step was to apply the capacity factors for solar PV and wind calculated from the CSIR time-series, and represented in Table 4-6, to the installed capacities of wind and solar PV assumed for this scenario. The results are presented in Table 4-7 below and represented graphically in Figure 4-13.

Table 4-7: Renewable energy supplied and flexibility required - Scenario 1

	Wind	Solar PV	Total Production	Flexibility	
	MWh	MWh	MWh	Shortage (MWh)	Surplus (MW)
0	3246	0	3246	6754	
1	3145	7.875E-4	3145	6855	
2	3077	0	3077	6923	
3	3037	1.19E-05	3037	6963	
4	3046	0.01	3046	6954	
5	3064	21	3086	6914	
6	3046	474	3520	6480	
7	3018	2122	5140	4860	
8	3023	4545	7568	2432	
9	3033	6304	9339	661	
10	3119	7280	10399		399
11	3274	7714	10988		988
12	3495	7734	11229		1229
13	3729	7435	11164		1164
14	3964	6785	10749		749
15	4168	5673	9840	160	
16	4314	3847	8161	1839	
17	4396	1555	5951	4049	
18	4379	284	4663	5337	
19	4228	8	4236	5764	
20	4003	0.01	4003	5997	
21	3793	0.02	3793	6207	
22	3569	0	3569	6431	
23	338	0	3388	6612	
TOTALS	84555	61781	146337	98192	4528
Average Capacity Factors	35 %	26 %	61 %	41 %	2 %

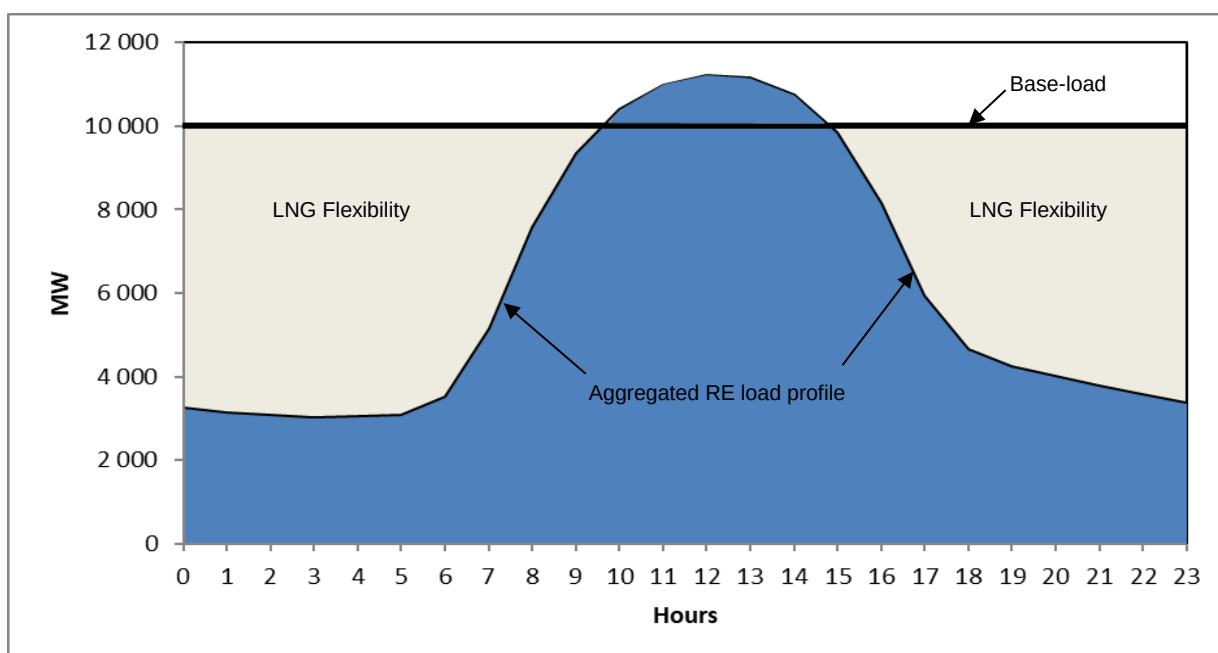


Figure 4-13: Hypothetical base-load scenario - Scenario 1

Important outcomes from the point of view of our analysis are the quantity of renewable energy produced, the quantity and capacity factor of the flexibility required, and lastly, the surplus produced by this combination of renewable energy sources. These are summarised below:

- Total renewable energy produced – 146 337MWh
- Flexibility required to meet base-load demand - 98 192MWh
- Capacity factor of flexibility requirement – 41 %
- Surplus produced by renewable energy – 4 528MWh

The levelised cost for the supply of flexibility was calculated by applying the capacity factor calculated for flexibility above (i.e. 41%) in our LCOE model. Table 4-8 provides the LCOEs for three forms of flexibility – OCGT, CCGT with CCS and CCGT without CCS – and also the total cost of the flexible supply, for two prices of LNG – R63.9/GJ and R110/GJ.

Table 4-8: Levelised costs for various forms of flexibility - Scenario 1

Flexibility required (MWh)		LEVELISED COSTS (2017 Rands)					
		OCGT (40.91 %CF)		CCGT CCS (40.91 % CF)		CCGT (40.91 %)	
	LNG (R/GJ)	R63.9 /GJ	R110/GJ	R63.9 /GJ	R110/GJ	R63.9/GJ	R110/GJ
	LCOE	1040	1570	1410	1820	870	1210
98192	Total Cost of Flexible Supply (Rands)	102 119 481	154 161 139	138450 450	178 709 091	85 426 873	118 812 088

The total cost of the renewable energy combination is provided in Table 4-9. The levelised cost used is taken from the actual tariff realised for Bid Window 4 of the REIPPP programme process.

Table 4-9: Total cost of renewables supply

	MWh	LNG Levelised Cost (R/MWh)	Total Cost (Rands)
WIND	84 555	650	54 960 868
SOLAR PV	61 781	650	40 157 874
TOTAL VRE	146 336		95 118 742

Table 4-10 combines the costs of the renewables supply and the costs of the various forms of flexibility supply to provide the overall levelised costs for the combinations of renewables plus LNG flexibility for our two prices of LNG. A levelised cost has been calculated for the provision of base-load that assumes that the surplus was curtailed (total system cost excluding surplus), as well as a levelised cost of base-load that assumes that the surplus can also be usefully utilised in the system to supply mid-merit or to be stored, for instance, (total system cost including surplus).

Table 4-10: Levelised costs for combinations of renewables and flexibility

	Shortage (MWh)	Levelised Cost (R/MWh)	Cost (Rands)	Total levelised cost exc. Surplus (VRE + LNG Option - R/MWh)	Total Levelised cost inc. Surplus (VRE + LNG Option - R/MWh)	SURPLUS (MWh)
TOTAL VRE	146 337	650	95 118 742			
LNG Options						
OCGT R63.9/GJ	98 192	1040	102 119 481	822	807	
OCGT R110/GJ	98 192	1570	154 161 139	1039	1019	
CCGT CCS R63.9/GJ	98 192	1410	138 450 450	973	955	
CCGT CCS R110/GJ	98 192	1820	178 709 091	1141	1120	
CCGT R63.9/GJ	98 192	870	85 426 873	752	738	
CCGT R110/GJ	98 192	1210	11 8812 088	891	875	4528

Note: The total levelised costs in 2017 Rands including and excluding the surplus generation, are a combination of the VRE levelised cost shown above in line 2 and the LNG Option listed in column 1. For instance, the total levelised cost of VRE and LNG @ R63.6/GJ excluding the surplus is R822/MWh.

4.1.3.1.4 Analysis

Lastly, the levelised costs for the supply of base-load, the objective of this exercise, are compared in Table 4-11 and depicted in Figure 4-14.

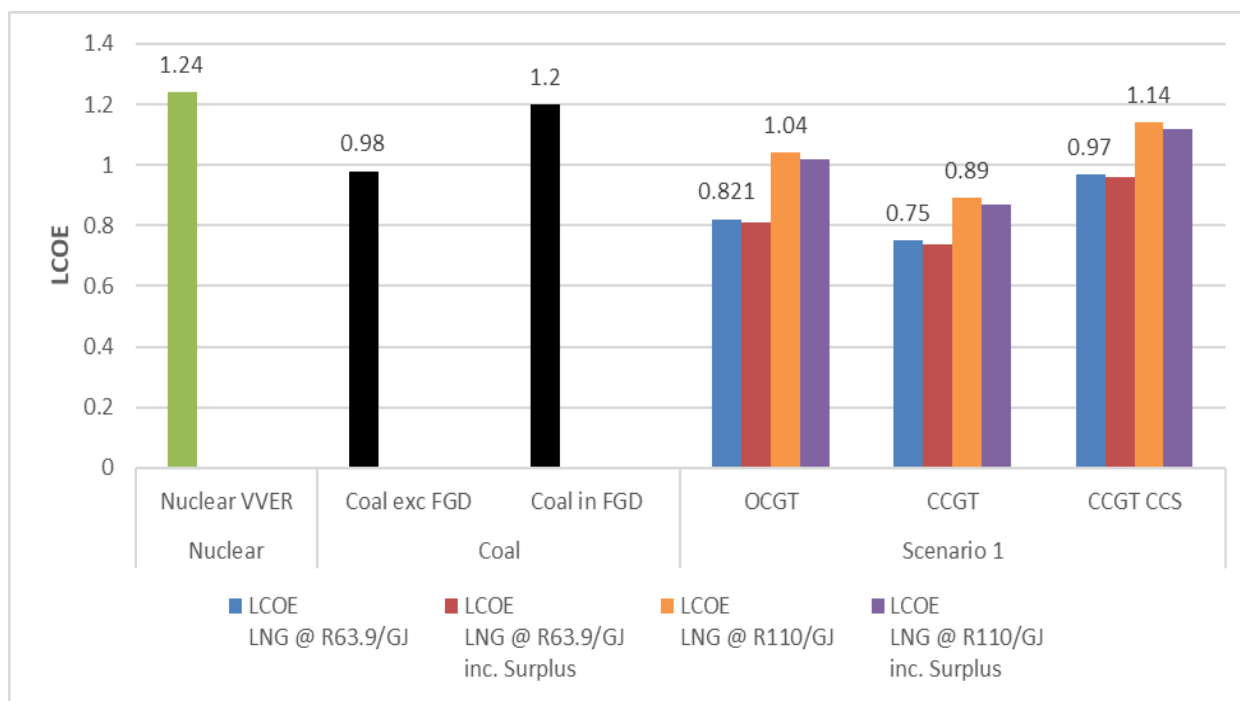
As can be seen from Figure 4-14 nuclear is significantly more expensive than all combinations of renewables plus LNG flexibility modelled in this scenario for both prices of LNG. However, it is

important to note that the LCOE of renewables plus LNG is sensitive to the price of LNG - the higher the price of LNG, the more expensive renewables plus LNG combination becomes.

Table 4-11: LCOE comparison - base-load for nuclear, coal and VRE plus LNG

	Nuclear	Coal		Scenario 1 VRE Plus		
	Nuclear VVER	Coal exc FGD	Coal in FGD	OCGT	CCGT	CCGT CCS
LCOE (R/kWh) LNG @ R63.9/GJ	1.24	0.98	1.2	0.82	0.75	0.97
Comparison to nuclear		79 %	97 %	68 %	60 %	78 %
LCOE (R/kWh) LNG @ R63.9/GJ inc. Surplus				0.81	0.74	0.96
Comparison to nuclear				65%	62 %	77 %
LCOE (R/kWh) LNG @ R110/GJ				1.04	0.89	1.14
Comparison to nuclear				84%	72 %	95%
LCOE (R/kWh) LNG @ R110/GJ inc. Surplus				1.02	0.87	1.12
Comparison to nuclear				82 %	70 %	90 %

Figure 4-14: LCOE comparison - base-load for nuclear, coal and VRE plus LNG



It must also be considered that although LNG is cleaner than coal, it is not as clean as nuclear and could be subject to carbon penalties or taxes. This additional cost can only be mitigated to a

certain extent by investing in cleaner forms of technology, such as carbon capture and storage. When this is done, as our results show, the LCOE of renewables plus LNG combination increases, although it is still cheaper than nuclear. It must be noted that, although CCGT with CCS may be cleaner than CCGT without CCS, it is still not clean and will still emit more carbon dioxide than nuclear - and in so doing, potentially attract carbon taxes.

An interesting outcome of our analysis is that the renewables plus LNG combination is also cheaper than coal including and excluding FGD at low prices of LNG. However, as the price of LNG goes up this difference is diminished. When compared to coal with FGD, the technology that it is assumed new coal stations in South Africa will have to invest in, renewables plus LNG is cheaper even when LNG technology is similarly penalised. However, as always, the price of LNG once again is an important determinant of competitiveness.

A final observation of importance is that at this capacity factor, CCGT excluding CCS is a cheaper source of flexibility than OCGT for both prices of LNG. Although the literature reviewed generally favours OCGT as a form of flexibility, at a 41 % capacity factor it could prove to be cost-effective to use CCGT instead, and this is therefore worthy of further investigation. The suitability of CCGT to supply flexibility for the scenarios analysed in this report is discussed further in section 4.2.3.

4.1.3.2 Hypothetical base-load scenario - Scenario 2

From numerous combinations of renewables and LNG modelled, two other combinations of solar PV and wind were selected for discussion in this study.

4.1.3.2.1 Objective of scenario 2

The objective of scenario 2 remains the same as for scenario 1 - to supply 10 000MW over an average 24 hours period under South African conditions, i.e. to supply 240 000MWh over the period of an average South African day with average South African weather conditions. Scenario 2 was selected because it serves to demonstrate that renewables can lead to the production of significant surpluses, and to evaluate the effect of this characteristic on flexibility requirements and costs.

4.1.3.2.2 Cost of supply with nuclear technology

The same assumptions for the cost of nuclear supply are made, i.e. the cost to supply 10 000MW of base-load in South Africa using nuclear technology, is assumed to be R124/MWh, the solid horizontal line in Figure 4-15.

4.1.3.2.3 Cost of supply with renewable energy plus an LNG flexibility source

For scenario 2 the wind capacity was doubled from 10 000MW to 20 000MW. The capacities for solar PV and the LNG flexibility supply was held the same as for scenario 1. The same three forms of flexibility were modelled.

The capacities installed for solar PV, wind and LNG flexibility for scenario 2 are summarised in the table below.

Technology	Capacity installed MW
Wind	20 000
Solar PV	10 000
LNG Flexibility	10 000
TOTAL	40000

The same methodology used in scenario 1 was used to calculate the renewables production, the flexibility capacity factor and the resultant surplus. Table 4-12 provides the results of our production modelling, whilst Figure 4-15 is an illustration of this scenario's results.

Table 4-12: Renewable energy supplied and flexibility required - Scenario 2

	Wind	Solar PV	Total Production	Flexibility	
	MWh	MWh	MWh	Shortage (MWh)	Surplus (MWh)
0	6492	0	6493	3508	
1	6290	7.9E-4	6290	3710	
2	6154	0	6154	3846	
3	6075	1.2E-05	6075	3925	
4	6092	7.6E-3	6092	3908	
5	6129	21	6150	3850	
6	6093	474	6566	3434	
7	6037	2121	8158	1842	
8	6046	4545	10591		591
9	6070	6304	12374		2374
10	6237	7280	13517		3517
11	6548	7714	14262		4262
12	6989	7734	14723		4723
13	7458	7435	14892		4892
14	7928	6785	14713		4713
15	8335	5672	14008		4008
16	8628	3847	12475		2475
17	8792	1555	10347		347
18	8758	284	9042	958	
19	8456	8	8464	1536	

20	8006	9.27E-3	8006	1994	
21	7586	1.5E-2	7586	2414	
22	7137	0	7137	2863	
23	6776	0	6776	3223	
TOTALS	169110	61781	230892	41011	31903
Average Capacity Factors	70 %	26 %	96 %	17 %	13 %

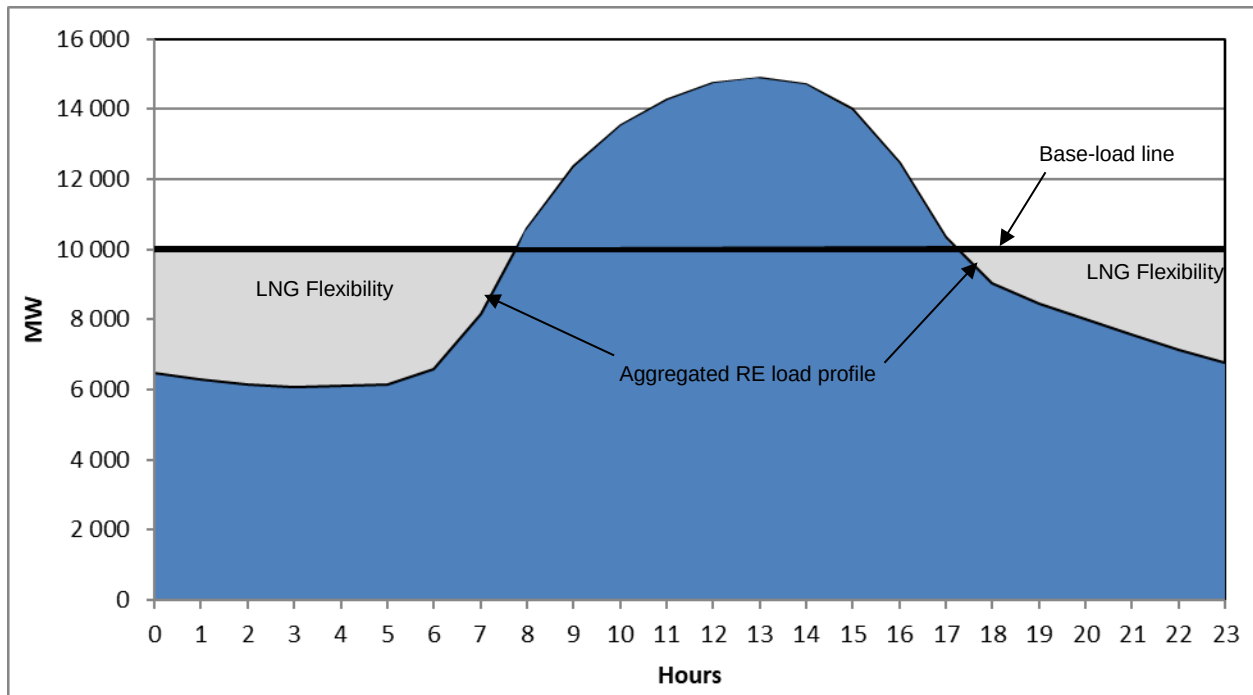


Figure 4-15: Hypothetical base-load scenario - Scenario 2

The most important results from Table 4-12 are summarised below:

- Total renewable energy produced – 230 892MWh
- Flexibility required to meet base-load demand - 41 011MWh
- Capacity factor of flexibility requirement – 17 %
- Surplus produced by renewable energy – 31 903MWh.

It is noticeable that the renewables production is greater, the flexibility capacity factor is smaller and the amount of surplus produced is significantly greater when compared to scenario 1.

Table 4-13 combines the costs of the renewables supply and the costs of the various forms of flexibility supply to provide the overall levelised costs for the combinations of renewables plus LNG flexibility for our two prices of LNG. As for scenario 1, a levelised cost has been calculated

for the total system cost excluding the renewables surplus, and for the total system cost including the surplus.

Table 4-13: Levelised costs for combinations of renewables and flexibility

	Shortage (MWh)	Levelised Cost (R/MWh)	Cost (Rands)	Total levelised cost exc. Surplus (VRE + LNG Option R/MWh)	Total levelised cost inc. Surplus (VRE + LNG Option R/MWh)	SURPLUS (MWh)
TOTAL VRE	230 892	650	150 079 610			31903
LNG Option						
OCGT R63.9/GJ	41 011	1470	60 286 211	877	774	
OCGT R110/GJ	41 011	2000	82 022 055	967	854	
CCGT CCS R63.9/GJ	41 011	2580	105 808 451	1066	941	
CCGT CCS R110/GJ	41 011	3000	123 033 083	1138	1004	
CCGT R63.9/GJ	41 011	1420	58 235 659	868	766	
CCGT R110/GJ	41 011	1760	721 79 409	926	817	

Note: The total levelised costs in 2017 Rands including and excluding the surplus generation, are a combination of the VRE levelised cost shown above in line 2 and the LNG Option listed in column 1. For instance, the total levelised cost of VRE and LNG @ R63.6/GJ excluding the surplus is R877/MWh.

4.1.3.2.4 Analysis

Table 4-14: LCOE comparison - base-load for nuclear, coal and VRE plus LNG

	Nuclear	Coal		Scenario 2 VRE Plus		
	Nuclear VVER	Coal exc FGD	Coal inc FGD	OCGT	CCGT	CCGT CCS
LCOE (R/kWh) LNG @ R63.9/GJ	1.24	0.98	1.2	0.88	0.87	1.07
Comparison to nuclear		79 %	97 %	71 %	70 %	86 %
LCOE (R/kWh) LNG @ R63.9/GJ inc. Surplus				0.77	0.77	0.94
Comparison to nuclear				62 %	62 %	76 %
LCOE (R/kWh) LNG @ R110/GJ				0.97	0.93	1.14
Comparison to nuclear				78 %	75 %	92 %
LCOE (R/kWh) LNG @ R110/GJ inc. Surplus				0.85	0.82	1
Comparison to nuclear				69 %	66 %	81 %

Table 4-14 and Figure 4-16 summarise the results for scenario 2. Due to the flexibility capacity factor being smaller, the levelised costs of the flexibility sources are higher but the overall cost of flexibility decreased. On the other hand, the total spend on renewable energy went up due to there being more of it. The amount of surplus produced for this scenario went up by more than 700 %.

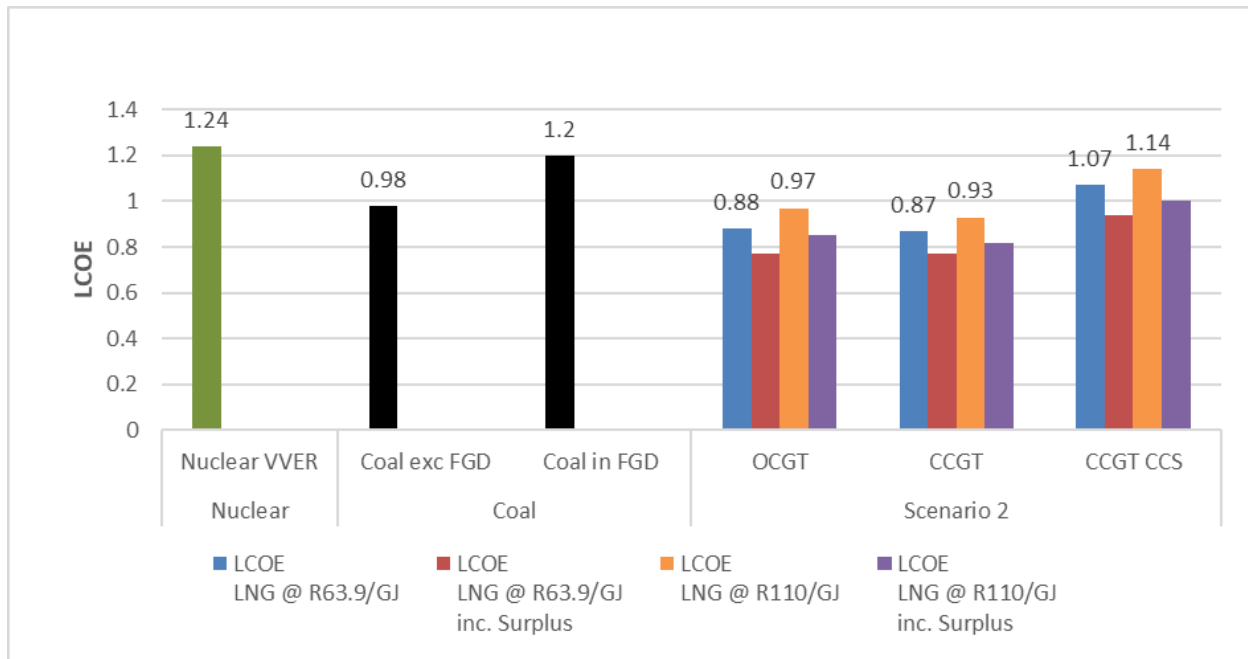


Figure 4-16: LCOE comparison - base-load for nuclear, coal and VRE plus LNG

An interesting result of the lower flexibility capacity factor is that for OCGT the levelised cost of supplying just the base-load quantum was higher at R63.6/GJ than for scenario 1 but lower when the price of the fuel goes up to R110/GJ. For CCGT including and excluding CCS the levelised cost of supplying base-load was more expensive for both prices of LNG when compared with scenario 1 because of the lower capacity factor. As for scenario 1, the cost of supplying base-load at this capacity factor was cheaper with CCGT technology without CCS than with OCGT.

Due to there being a lot more energy produced from renewables in this scenario than for the other two scenarios, and the low price of renewables, for all combinations of renewables and LNG flexibility the levelised cost of all production, i.e. including the surplus, was lower for this scenario, except in the case of CCGT without CCS at low LNG prices.

The utility of this scenario's combination of technologies over the combination of scenario 1 is therefore dependant on the price of LNG and whether the surplus can be stored, or utilised as mid-merit energy by the system operator. If the system operator procures the surplus then this scenario is more cost effective than scenario 1 overall except when CCGT without CCS is used and the price of LNG is low.

As far as comparison to nuclear power goes, although the levelised cost of supplying base-load is generally higher for this scenario than for Scenario 1, it is not sufficiently higher to impact on the analysis of scenario 1, as can be seen from Figure 4-16. The levelised cost of supplying base-

load from renewables plus LNG flexibility is significantly lower than the levelised cost of nuclear base-load, although the difference is less in the case of CCGT plus CCS.

Except for the case of CCGT with CCS, renewables plus flexibility is competitive with coal excluding FGD at low prices of LNG but less so as the price of LNG escalates. All forms of renewables plus flexibility are cheaper than coal plus FGD for both prices of LNG analysed here, but with diminishing competitiveness as the price of LNG escalates.

Lastly, for this scenario when the levelised cost of all renewables plus LNG production is compared to nuclear and coal the relative competitive positions are better than for scenario 1, but with the same reservation – as the price of LNG escalates so the competitive position diminishes.

4.1.3.3 Hypothetical base-load scenario - Scenario 3

4.1.3.3.1 Objective of scenario 3

The objective for scenario 3 is the same as for scenarios 1 and 2 - to supply 10 000MW over an average 24 hours period under South African conditions, i.e. to supply 240 000MWh over the period of an average South African day with average South African weather conditions. This scenario was selected for incorporation in this report because of its excellent fit to the base-load line and to evaluate its effect on the flexibility requirement and the resultant renewables production surplus.

4.1.3.3.2 Cost of supply with nuclear technology

The same assumptions for the cost of nuclear supply are made, i.e. the cost to supply 10 000MW of base-load in South Africa using nuclear technology, is assumed to be R124/MWh, the solid horizontal line in Figure 4-17.

4.1.3.3.3 Cost of supply with renewable energy plus an LNG flexibility source

For scenario 3 the wind capacity was increased to 25 000MW and solar PV was eliminated. The LNG flexibility supply capacity was held the same as for scenarios 1 and 2, i.e. 10 000MW. The same three forms of flexibility were modelled, i.e. OCGT and CCGT with and without CCS.

The capacities installed for wind and LNG flexibility for scenario 3 are summarised in the table below.

Technology	Capacity installed MW
Wind	25 000
LNG Flexibility	10 000
	<u>35000</u>

The same methodology used in scenarios 1 and 2 was used to calculate the renewables production, the flexibility capacity factor and the resultant surplus. Table 4-15 provides the results of our renewables production modelling, whilst Figure 4-17 depicts this scenario's results.

Table 4-15: Renewable energy supplied and flexibility required - Scenario 3

	Wind	Total Production	Flexibility	
	MWh	MWh	Shortage (MWh)	Surplus (MWh)
0	8114	8114	1886	
1	7862	7862	2138	
2	7693	7693	2307	
3	7594	7594	2406	
4	7615	7615	2385	
5	7661	7661	2339	
6	7616	7616	2384	
7	7546	7546	2454	
8	7557	7557	2442	
9	7587	7587	2413	
10	7796	7796	2204	
11	8185	8185	1815	
12	8737	8737	1263	
13	9322	9322	678	
14	9910	9910	90	
15	10419	10419		419
16	10785	10784		784.6219
17	10990	10990		990
18	10947	10947		947
19	10570	10570		570
20	10007	10007		7
21	9483	9483	517	
22	8922	8922	1078	
23	8470	8470	1530	
TOTAL	211388	211388	32330	3718
Average Capacity Factors	88 %	88 %	13 %	2 %

The most important results from Table 4-15 are summarise below:

- Total renewable energy produced – 211 388MWh
- Flexibility required to meet base-load demand - 32 339MWh
- Capacity factor of flexibility requirement – 13 %
- Surplus produced by renewable energy – 3 718MWh.

It is noticeable that in this scenario the renewables production, the flexibility capacity factor and the amount of surplus produced are all smaller than in scenario 2. Compared to scenario 1 renewables production is greater but the flexibility capacity factor and the surplus produced are smaller.

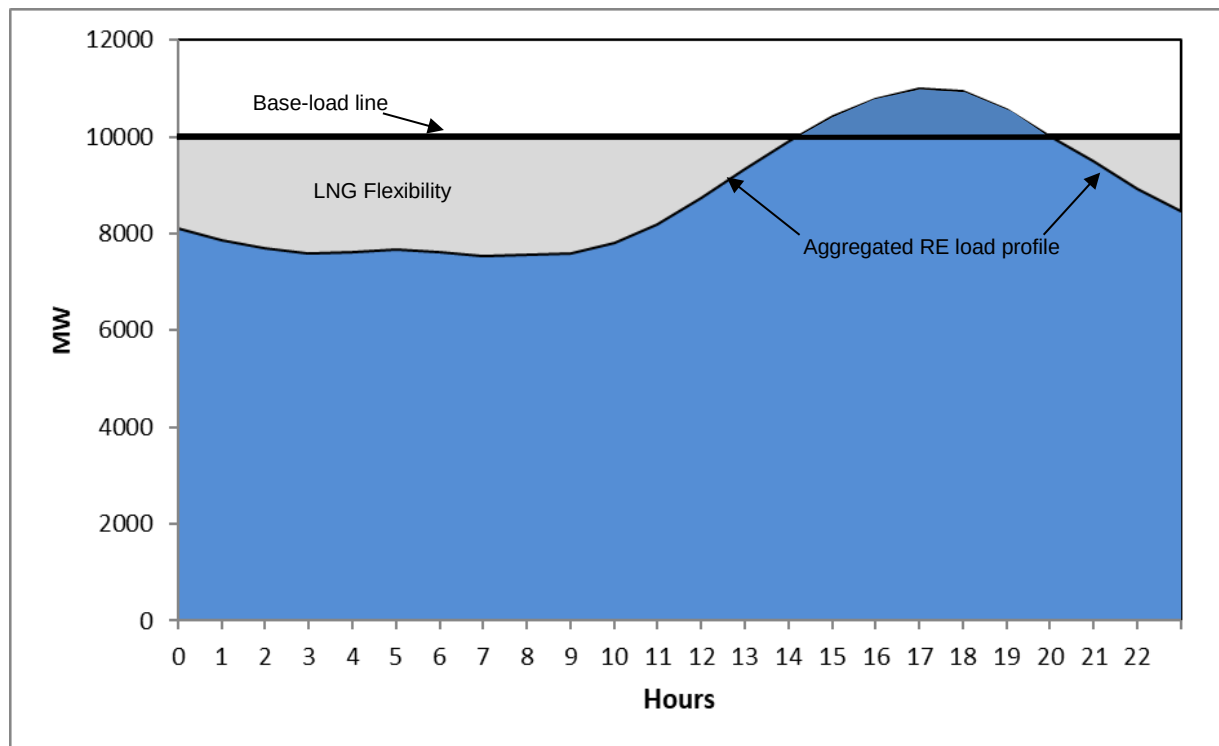


Figure 4-17: Hypothetical base-load - Scenario 3

Table 4-16 combines the costs of the renewables supply and the costs of the various forms of flexibility supply to provide the overall levelised costs for the combinations of renewables plus LNG flexibility for our two prices of LNG. As for the previous two scenarios, a levelised cost has been calculated for the total system cost excluding the renewables surplus, and for the total system cost including the surplus.

Table 4-16: Levelised costs for combinations of renewables and flexibility

	Shortage (MWh)	Levelised Cost (R/MWh)	Total Cost (Rands)	Total levelised cost exc. Surplus (VRE + LNG Option - R/MWh)	Total levelised cost inc. Surplus (VRE + LNG Options - R/MWh)	SURPLUS (MWh)
TOTAL VRE	211 388	6.50	137402169			
LNG Options						
OCGT R63.9/GJ	32 330	1670	53991297	797	785	
OCGT R110/GJ	32 330	2200	71126260	869	856	
CCGT CCS R63.9/GJ	32 330	3120	100869968	993	978	
CCGT CCS R110/GJ	32 330	3533	114222307	1048	1032	
CCGT R63.9/GJ	32 330	1680	54314598	799	787	
CCGT R110/GJ	32 330	2020	65306839	845	832	3718

Note: The total levelised costs in 2017 Rands including and excluding the surplus generation, are a combination of the VRE levelised cost shown above in line 2 and the LNG Options listed in column 1. For instance, the total levelised cost of VRE and LNG @ R63.6/GJ excluding the surplus is R797/MWh.

4.1.3.3.4 Analysis

Scenario 3 is noteworthy for having the lowest flexibility requirement and for producing the smallest surplus. It produced the least-cost base-load OCGT plus renewables LCOE. When CCGT is used as flexibility both with and without CCS, at low LNG prices the base-load LCOE is more expensive than Scenario 1, but at high LNG prices it is once again the least-cost base-load producer. Overall therefore, this wind only scenario can be considered to be the best of the three scenario analysed for the production of base-load.

At this very low flexibility capacity factor the properties of OCGT came the fore and its LCOE was very close to that of CCGT at the lower LNG price. Continued drops in capacity factor would result in the OCGT LCOE dropping below that of CCGT. In terms of the base-load LCOE, OCGT and CCGT flexibility resulted in similar LCOEs at low LNG price. At the higher LNG price CCGT flexibility resulted in a slightly cheaper base-load LCOE.

Due to a much smaller surplus, the LCOE for the full renewables production plus LNG flexibility was higher than for scenario 2, but generally lower than for scenario 1, although at low LNG prices scenario 1 was cheaper for the cost of full production when CCGT was used as flexibility.

As for the previous two scenarios, nuclear is significantly more expensive than renewables plus flexibility although, as for the other two scenarios, renewables plus flexibility's competitive edge decreases as the price of LNG goes up. It is noticeable that the LCOE of renewables plus CCGT with CCS is not as high for this scenario at high LNG prices as for the other two scenarios, resulting in nuclear being less competitive against renewables even when LNG is penalised by having to invest in more expensive technology.

The same analysis applies here as for the other two scenarios for the comparison with coal. Renewables plus LNG is competitive with coal without FGD, and significantly cheaper than coal with FGD. As for the nuclear comparison, in this scenario, renewables plus CCGT with CCS is cheaper when compared to coal than for the other two scenarios.

Table 4-17: LCOE comparison - base-load for nuclear, coal and VRE plus LNG

	Nuclear	Coal		Scenario 3 VRE Plus		
	Nuclear VVER	Coal exc FGD	Coal in FGD	OCGT	CCGT	CCGT CCS
LCOE R/kWh LNG @ R63.9/GJ	1.24	0.98	1.2	0.8	0.8	0.99
Comparison to nuclear		79 %	97 %	65%	65%	80 %
LCOE R/kWh LNG @ R63.9/GJ inc. Surplus				0.79	0.79	0.98
Comparison to nuclear				64%	64%	79 %
LCOE R/kWh LNG @ R110/GJ				0.87	0.84	1.05
Comparison to nuclear				70 %	68 %	85%
LCOE R/kWh LNG @ R110/GJ inc. Surplus				0.86	0.83	1.03
Comparison to nuclear				69 %	67 %	83 %

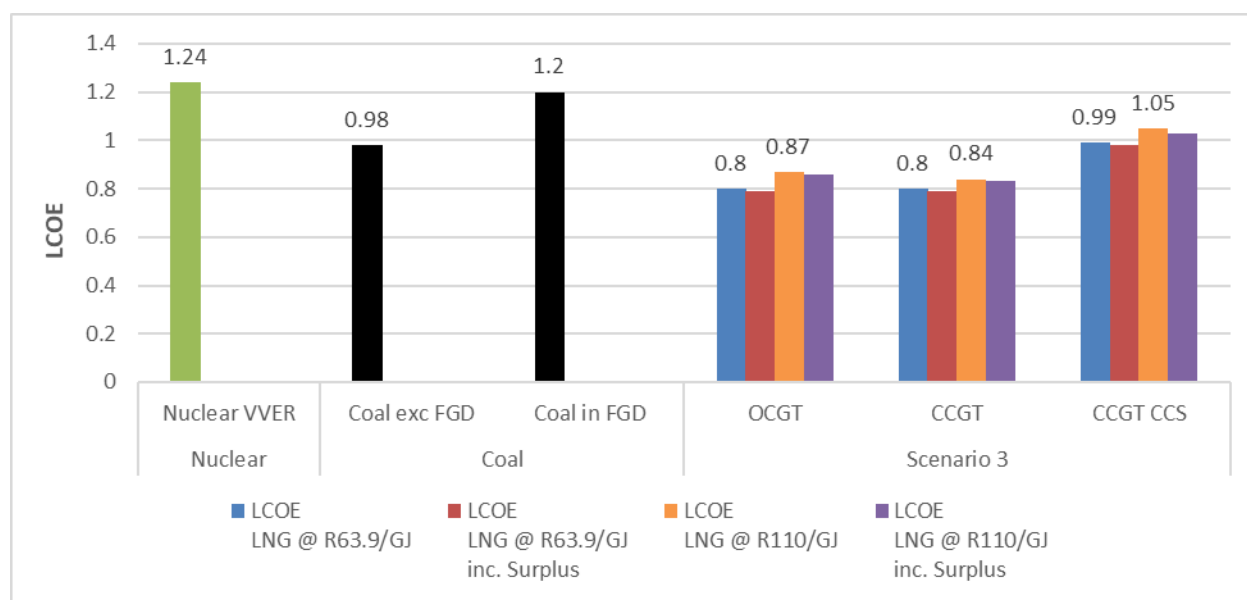


Figure 4-18: LCOE comparison - base-load for nuclear, coal and VRE plus LNG

4.1.3.4 Summary of results – cost to supply base-load with VRE plus LNG for flexibility

Scenario 3 provided the best fit to the base-load requirement. It required the least flexibility and produced the smallest surplus. When OCGT is used as flexibility it produced the least-cost base-load LCOE of the three scenarios. When CCGT is used as flexibility both with and without CCS, at low LNG prices the base-load LCOE is more expensive than Scenario 1 because of the lower flexibility capacity factors, but at high LNG prices it is once again the least-cost base-load producer. Overall therefore, the wind only scenario can be considered to be the best of the three scenarios analysed for the production of base-load as it becomes increasingly competitive when compared to the other two scenarios as the price of LNG increases.

However, it must be noted that when all production including surpluses are considered, then Scenario 2 provided the lowest LCOEs for renewables plus LNG, because the greater quantity of renewable energy produced in scenario 2 and the low price of renewables when compared to the LCOEs of other technologies.

Table 4-18: Summary of comparison of nuclear to coal and VRE plus LNG flexibility

	Nuclear	Coal		Scenario 1 VRE Plus			Scenario 2 VRE Plus			Scenario 3 VRE Plus		
	Nuclear VVER	Coal exc FGD	Coal inc. FGD	OCGT	CCGT	CCGT CCS	OCGT	CCGT	CCGT CCS	OCGT	CCGT	CCGT CCS
LCOE (R/kWh) LNG @ R63.9/GJ	1.24	0.98	1.2	0.821	0.75	0.97	0.88	0.87	1.07	0.8	0.8	0.99
Comparison to nuclear		79 %	97 %	66 %	60 %	78 %	71 %	70 %	86 %	65%	65%	80 %
LCOE (R/kWh) LNG @ R110/GJ				1.04	0.89	1.14	0.967	0.926	1.14	0.87	0.84	1.05
Comparison to nuclear				84%	72 %	92 %	78 %	75%	92 %	70 %	69 %	85%

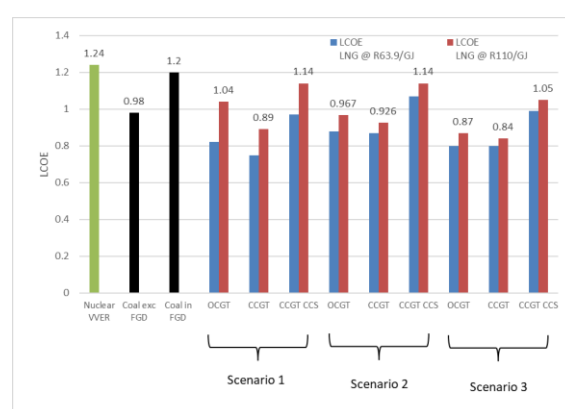
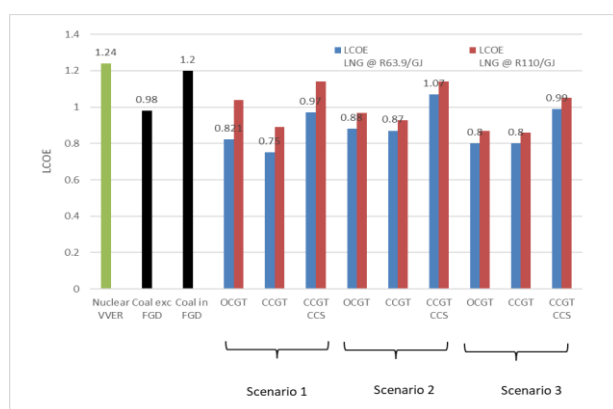


Figure 4-19: Summary of comparison of nuclear to coal and VRE plus LNG

All three scenarios analysed resulted in cheaper base-load with renewables plus LNG flexibility supply than the cheapest nuclear technology we analysed – VVER 1200. However, it was noticeable that this advantage diminishes as the price of LNG increases.

Furthermore, nuclear's competitive position is improved when compared to cleaner LNG technologies such as CCGT plus CCS. This applies to nuclear's competitive position relative to coal too. Although the nuclear LCOE is significantly more expensive than coal without FGD, when FGD is factored in, nuclear is more competitive. On this point, it must be noted that even "clean" coal or "clean" natural gas is not as emission-free as nuclear, so although renewables plus LNG flexibility may be a cleaner alternative than coal, it remains less clean than nuclear.

Our analysis also showed that not only is renewables plus LNG cheaper than nuclear on a levelised cost basis but that it is competitive with the dirtier forms of coal generation and significantly cheaper than the more expensive cleaner coal technologies. This would seem to confirm the assertions made by researchers that claim that renewables plus natural gas is now the cheapest alternative for new build in South Africa.

However, it must be noted, as pointed out elsewhere in this report that LCOE has its limitations when used to compare technologies. Although it provides a useful first-order metric of comparison, far deeper analysis and investigation are required when making an actual investment. This will be discussed further in the next chapter.

4.1.3.5 Management of surplus electricity from variable renewable energy

A unique aspect of renewables generation is that it can produce surpluses due to the distributed production of solar electricity by individuals or as a result of being coupled to inflexible base-load sources of generation. These surpluses will normally be realised during certain times of day when there is a combination of high renewables production due to favourable weather conditions, and low demand from the consumer base. An increasing number of studies are being conducted about this aspect of renewables electricity production.

In Denmark, electricity production exceeds demand during certain times of the day. Consequently, in 2001, at the request of the Danish Parliament, the Danish Energy Agency formed an expert group to investigate this phenomenon and to provide strategies to manage it.

To date, investigations have been focused on the construction of additional transmission lines. Denmark usually manages to export surplus production to neighbouring countries but at times finds that the transmission system is constrained.

Another area of investigation has been increasing the flexibility of the Danish system. In this context, flexibility means investing in heat pumps and storage facilities such as pumped storage hydro.

To date, it has been determined that investing in additional transmission lines might not be economically viable and that investment in flexibility could prove to be a more viable alternative, especially if environmental benefits for exports are not be received from a future European electricity market (Lund & Munster, 2003, p. 73).

A German study of this problem found that possible solutions could include curtailment of production, adaptation of electricity consumption through demand-side management, and storage facilities including pumped storage and batteries (Wagner, 2016).

4.2 Technical feasibility analysis

4.2.1 Introduction: the role of power system flexibility

Variability in power systems is not limited to those power systems with high penetrations of VRE. Variability is also a characteristic of power systems that consist of little or no renewable generation technologies and can be caused by factors such as forecast errors that lead to mismatches in supply and demand, and unplanned power plant and transmission outages. (Welsch & Mentis, 2014, p. 216).

Several factors have led to an increase in variability in global power systems in recent years, including widespread deployment of variable renewable energy sources, growing power market activity that sometimes results in transient power imbalances and more volatile power flows, and the emergence of smart-grids as a driver for change in power system operation (Ulbig & Anderson, 2014, p. 227). South Africa is not an exception to this phenomenon. In South Africa steadily increasing variability is the result of a growing share of renewable energy, varying country demand, and especially declining availability of its ageing coal fleet. In its Integrated Report of 2019, Eskom reported an Energy Availability Factor (EAF) of 71 %, including rotational load shedding of 30 days. This compares to EAFs of 90 % and higher in the early 1990s. The current very low EAF is partly due to an increasing number of unplanned outages.

System operators compensate for variability by procuring flexibility from providers of ancillary services. They balance variations in supply and demand by drawing on short-term balancing services provided by so-called operating reserves. Operating reserves usually consist of power plants that can adjust their generation at fast ramp rates or of loads that can be increased or

decreased at short notice. Most commonly, operating reserves are distinguished by the time scales within which they can be activated (Welsch & Mentis, 2014, p. 216).

- Primary reserves - are used to limit the change in the power system's frequency due to an imbalance between supply and demand. They are locally automated and react to deviations in the nominal system frequency.
- Secondary reserves – are used to restore the frequency to its design value. They are automated centrally and serve to release the primary reserves for future operations.
- Tertiary reserves are used to restore the secondary reserve.

The time frames associated with these reserves vary. Commonly, primary reserves can be activated within 30 seconds, while secondary and tertiary reserves have to be fully available within 5 -15 minutes. If any of these reserves is drawn on to increase the system's frequency (e.g. by increasing generation), this is referred to as upward reserve. If the system's frequency needs to be reduced, downward reserves are activated.

Conventionally, operating reserves are activated by adjusting generation, but demand-side response measures are also possible and can be available at faster rates than supply-side options. The ability to realize this potential draws to a large extent on the increased communications, automation, and control made possible by smart grids. Apart from adjusting generation and demand-response measures, storage technologies provide another option to balance the variability in demand and generation (Welsch & Mentis, 2014, p. 216).

Ancillary service markets enable system operators to procure cost-effective control reserve products. Flexibility in power operations and dispatch has significant value (Ulbig & Anderson, 2014, p. 227).

The value of all flexibility options has increased with increasing shares of renewable power generation, from supply-side to demand-side and storage options. Too little flexibility in a power system can result in the need to curtail generation from renewables, or in the worst-case scenario, it will increasingly cause outages due to an unreliable power system that is unable to curb deviations from the system's design frequency (Welsch & Mentis, 2014, p. 216).

In South Africa, the system operator had normal operating reserves of about 2 800MW in 2008, classified as either operating (immediate to 10 minutes) or supplemental (30 minutes to 6 hours). Operating reserves consisted of demand-side products, coal, and pumped storage and hydro power stations. Supplemental reserves consisted of demand-side products and coal power stations. In addition to normal operating reserves, the system operator also had emergency reserves at its disposal of about 3 000MW to 4 000MW. Emergency reserves are classified into

immediate reserves consisting of contracted interruptible loads and increased output from generators above their maximum capability rating, and reserves that require up to 2 hours warning, consisting of demand-side products and open-cycle turbines (van Heerden, 2008).

The need for this additional flexibility can be limited by employing advanced forecasting systems. Modern wind turbines can be throttled and, if operated below maximum capacity can provide additional reserve themselves.

4.2.2 Sources of power system flexibility

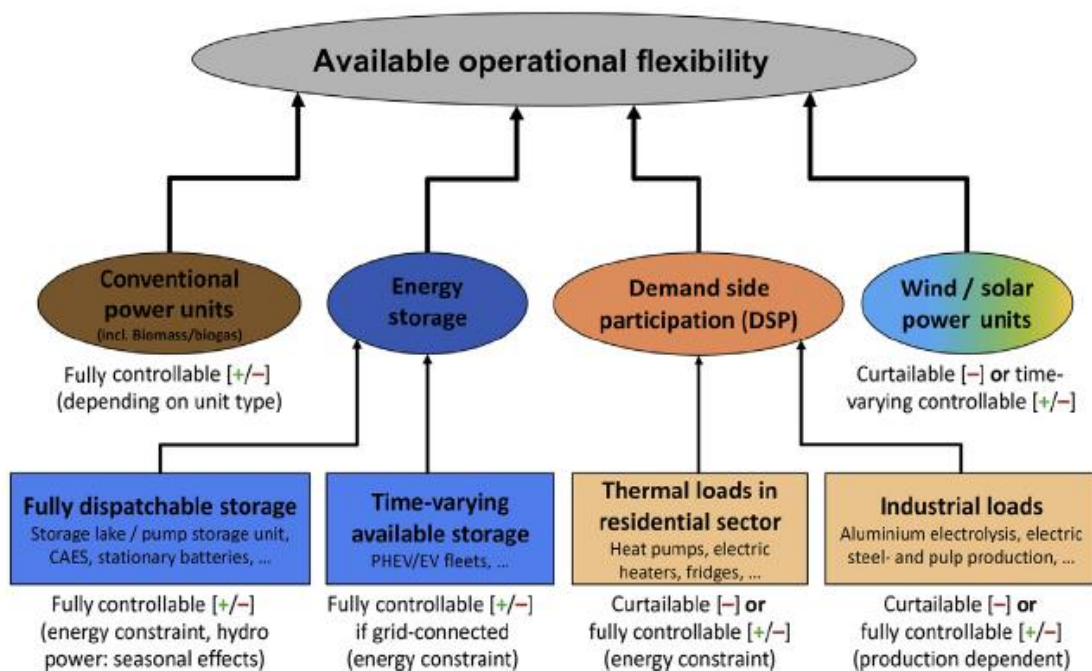


Figure 4-20: Sources of power system flexibility

Several sources of power system flexibility exist, as illustrated in Figure 4-20 (Ulbig & Anderson, 2014). On the generation side, operational flexibility can be obtained in the form of dynamically fast-responding conventional power plants, such as gas- or oil- fuelled turbines, or even modern coal-fired power which is designed to be flexible. On the demand side, flexibility can be provided through the adaptation of the load demand curve to partially absorb variable renewable energy sources power feed-in. In addition to this, renewable production can also be curtailed or, in more general terms, throttled below its maximum output level. Lastly, stationary storage capacities, e.g. hydro storage, Compressed Air Storage (CAES), stationary battery, or fly-wheel systems, and time-variant storage capacities, e.g. Plug-in Hybrid Electric Vehicles (PHEV) and Electric Vehicles (EV) fleets, are well suited for providing operational flexibility.

Where interconnected grids zones exist, additional flexibility can be obtained from other grid zones through interconnecting transmission lines, should available operational flexibility in one zone be insufficient or more expensive than in another zone. For power system operation, importing needed power in certain situations and exporting undesirable (surplus) power in-feed in other situations to neighbouring grid zones is, for the time being, probably the most convenient and cheapest measure for increasing operational flexibility (Ulbig & Anderson, 2014, p. 229).

4.2.3 Technical feasibility of our hypothetical system – ramping rates

The first step in our technical feasibility study is to investigate whether the gas technologies that we have discussed in this document are flexible enough to match the variability of wind and solar PV. In other words, can OCGT and/or CCGT “ramp” up and down fast enough to match the changing output of our variable, intermittent renewable technologies.

The ramping rate of a power plant can be described as the rate at which it can increase or decrease output and is typically measured in MW/min or %full load/min. OCGTs (20%/min) ramp at far higher rates than CCGTs (8%/min). OCGTs also start-up from a hot start (10mins) faster than CCGTs (2 hrs) (Gonzalez-Salazar, et al., 2018, p. 1499).

To conduct this investigation a simple methodology was devised. Firstly, the same renewables time-series used for our LCOE comparisons in section 4.1.3 (CSIR, 2018) was used to identify the most and least variable days between January 2016 and December 2018. For the purposes of this investigation, the most variable day is defined as that day when the difference between most and least renewables output was greatest, while the least variable day is defined as that day when the difference between greatest and least renewables output was least.

The hourly load profiles for these two days were calculated and then used to calculate the load profiles and ramp rates for a scenario similar to that in Scenario 1 in section 4.1.3 in the previous section, namely:

- Base-load requirement – 10 000MW
- Installed solar PV capacity – 10 000MW
- Installed wind capacity – 10 000MW
- LNG flexibility required – 10 000MW (OCGT or CCGT)

The load profile and ramping rates for the most variable day are depicted in Figure 4-21 and Figure 4-22 respectively whilst the load profile and ramping rates for the least variable day are presented in Figure 4-23 and Figure 4-24 respectively.

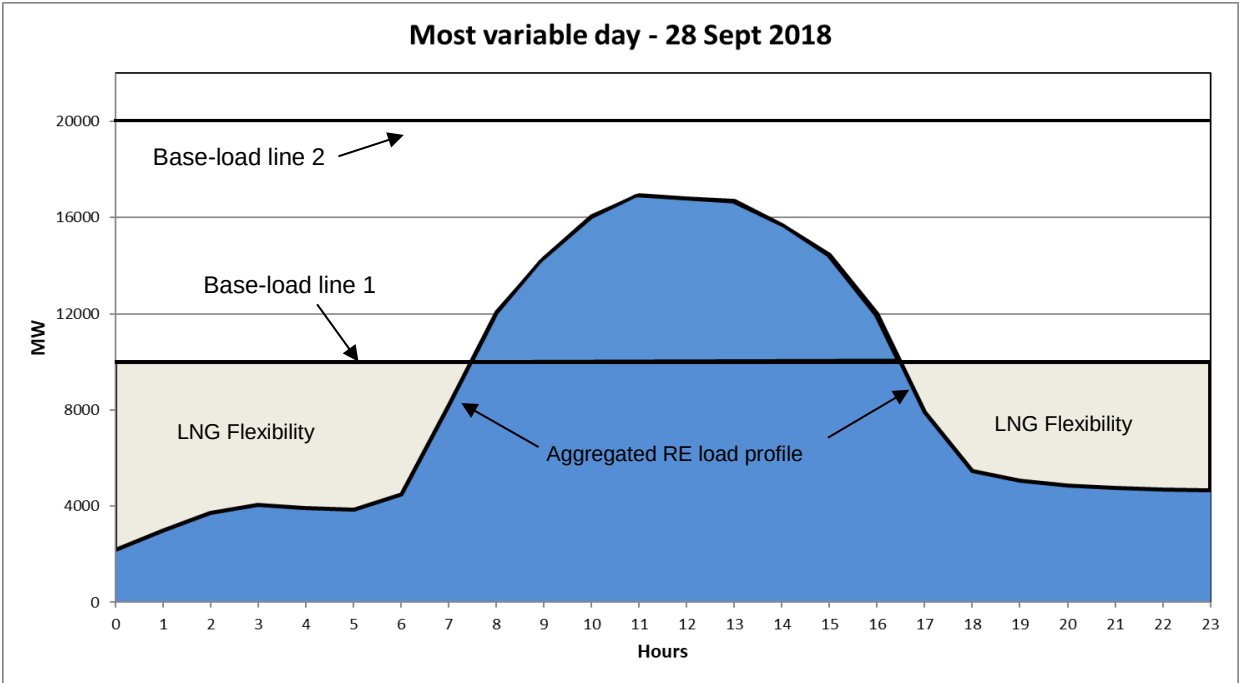


Figure 4-21: Load profile of most variable day

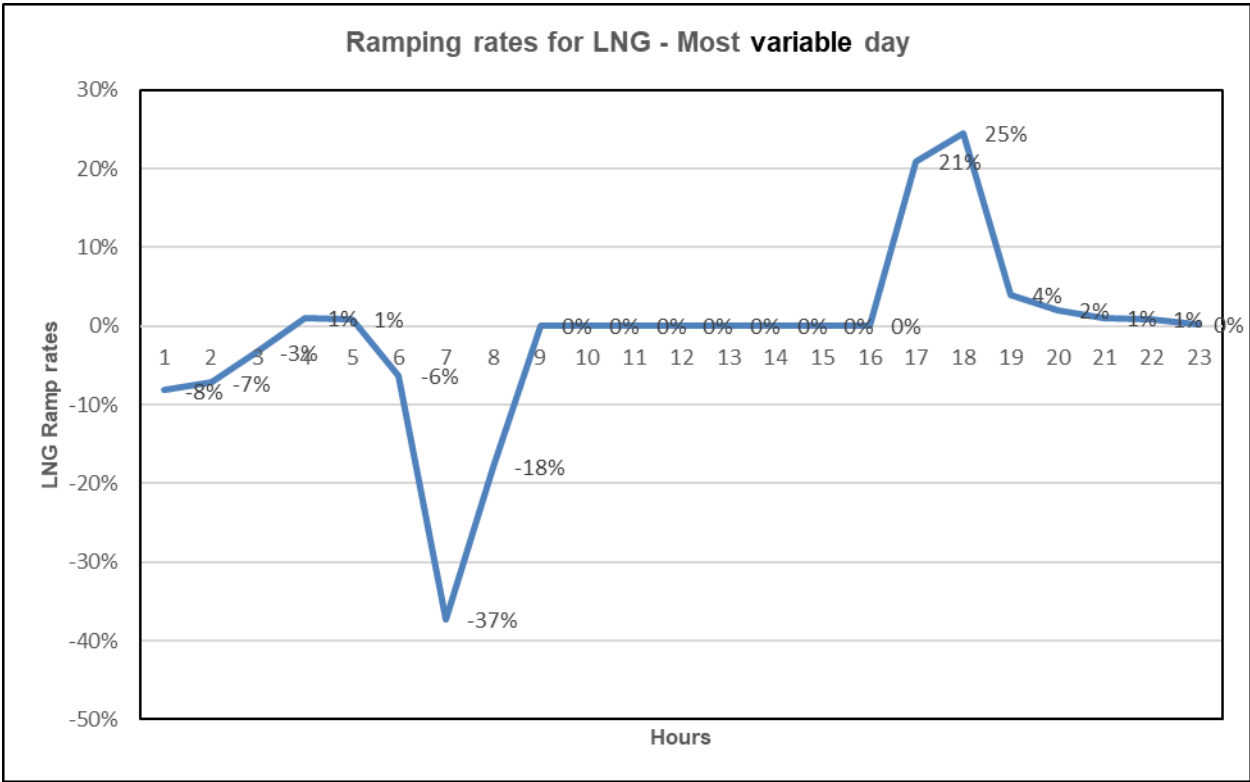


Figure 4-22: Required ramp rates of the most variable day

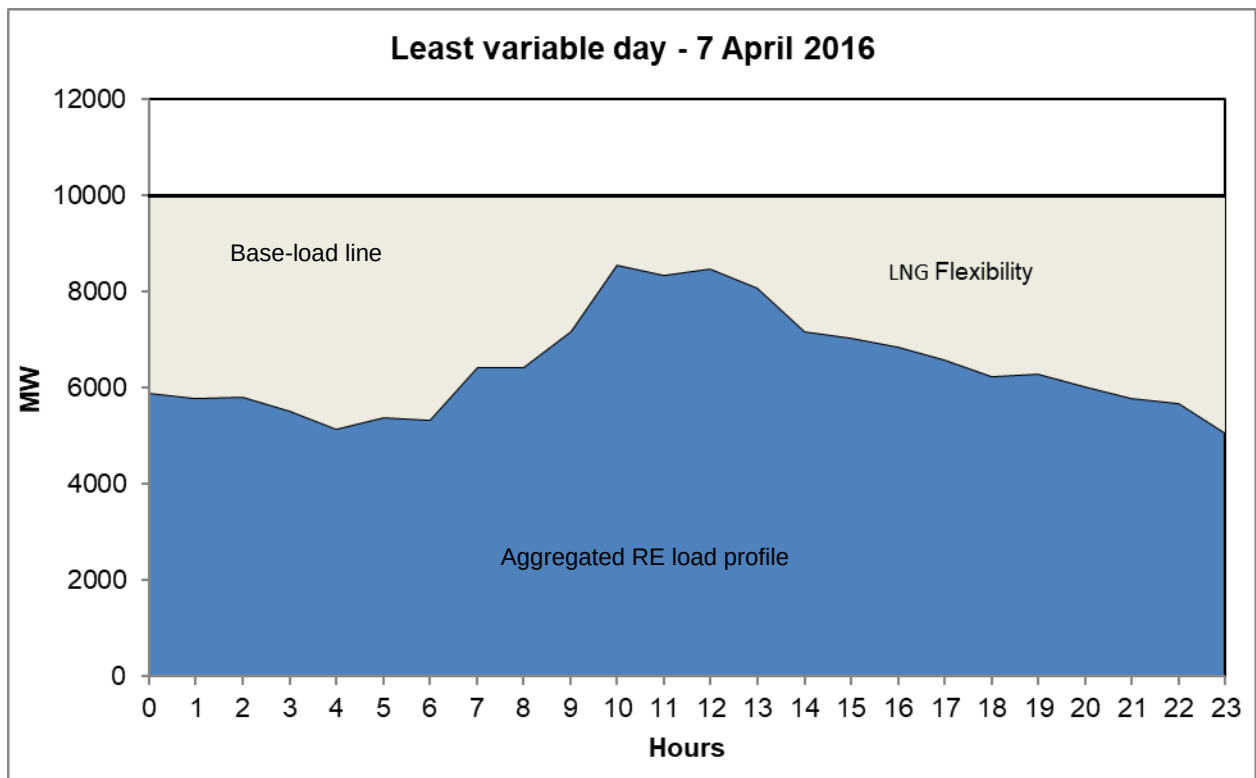


Figure 4-23: Load profile of least variable

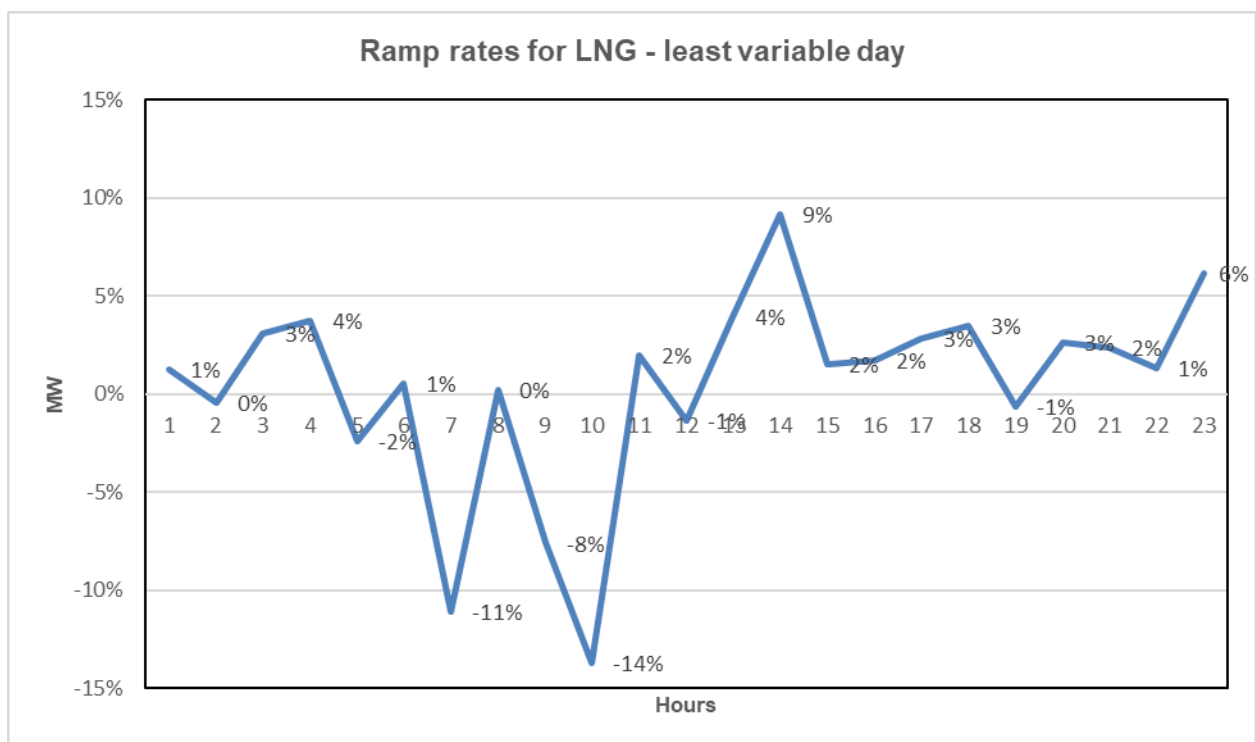


Figure 4-24: Required ramp rate of least variable day

This scenario was selected because it provides results that are useful in illustrating the conditions that must be met by our two gas technologies, namely a day when surpluses are produced and a day when they are not. The actual quantum of the surpluses produced is not as important in this analysis as the ramp rates and number of start-ups required. It must be noted that the number of potential combinations of wind and solar PV load factors is large and also that this is a hypothetical scenario used to illustrate in a simple way the characteristics of the combination of renewables and LNG generation. The actual overall system profile for South Africa is quite different to what is being described here, and this must be borne in mind when discussing the outcomes produced by this methodology.

When comparing the hourly load changes for both days to the ramp rates possible for both OCGT and CCGT, it is clear that either technology can easily match the required ramp rates. On the most variable day the largest downward ramp is -37% ($\pm 3\,700\text{MW}$), whilst the largest upward ramp is 25% ($\pm 2\,500\text{MW}$). Even at the slower CCGT ramp rates (8%/min) these ramp rates are not excessive for either of our gas technologies. On the least variable day the required ramp rates are far gentler and can be easily managed by both technologies.

For CCGT the greatest challenge is what to do about the surplus produced on the most variable day. CCGT has a very long start-up time even from a hot start of about 2 hours (Gonzalez-Salazar, et al., 2018) and it would therefore require very accurate short-term forecasting to enable it to shut-down and be available again to produce when required. Any failure in this forecasting would require the procurement of balancing reserves from the system operator to meet demand whilst the CCGT is starting-up.

However, curtailment is not the only alternative for CCGT (and for the surplus solar PV production). For instance, as we are discussing the supply of base-load energy, a possibility exists that the surplus production from CCGT and renewables can be used to meet the mid-merit load and thereby reduce the requirements of the mid-merit plant. Other alternatives are to store production, or sell it. South Africa trades electricity with neighbouring countries through a day-ahead market (DAM) in the Southern African Power Pool (SAPP), so the possibility of selling this surplus production is a real one, providing that these surpluses can be sufficiently accurately forecast. A more feasible alternative could be to use the excess production to replenish the pumped-storage dams. In future, pumped storage schemes can be supplemented with battery storage, further improving the possibility of this alternative. The options in deploying CCGT are complex and too numerous to explore in this report, and therefore are best left as the topic of further investigations.

Lastly, it must be noted that the scenario sketched here is not representative of the current South African electricity system. In a scenario where the base-load line is as shown by Base-load line 2 in Figure 4-21, which is more representative of South African reality, there would be no need to curtail renewables or CCGT production as there would be no surplus.

Renewable energy is currently less than 10 % of the country's installed capacity. The most likely outcome of having CCGTs in the energy mix is that whatever is not needed to provide flexibility for renewables, can be used to supply mid-merit load or even to supplement the system operator's operating reserves. It is therefore not surprising that the IRP 2019, which was promulgated in October 2019, states quite explicitly that natural gas is required to provide the flexibility required to complement renewable energy, and that this flexibility will be supplied by CCGT, combined cycle gas engines (CCGE) and internal combustion engines (ICE) (DMRE, 2019, p. 12) .

For OCGT the analysis of meeting demand on the most and least variable days is far simpler. With its higher ramping rates, OCGT can comfortably meet the required ramping, and with its fast start-up times it can be switched off and on during periods of surplus supply. Any shortfalls during start-ups can be supplied through balancing reserves procured from the system operator, but these would be for very short periods of time and can be further reduced through forecasting.

Estimating the cost of balancing reserves that would be required by OCGT is a complex task, and it is not possible to say without detailed investigation whether the cost of balancing reserves would be greater for OCGT than for nuclear power stations. Nuclear power stations are subject to planned and unplanned outages and are therefore also clients of the system operator for balancing reserves. Balancing power can be provided by traditional providers, battery systems, fast-acting demand-side management, or even by wind and solar generators being run below their maximum available output. In the case of a renewables study for Germany in 2030 in which renewables are increased to 65GW of solar PV and 81GW of wind (52% renewable energy share), it was found that the additional renewable capacity could be added with no additional primary reserves being necessary (Brown, et al., 2018, p. 839). It is highly unlikely therefore, that the need for a small amount of balancing reserves would significantly alter the analysis regarding the LCOEs of renewables plus OCGT conducted in section 4.1.3.

The purpose of this study is to investigate whether base-load can be supplied by a combination of renewables and natural LNG. In the case of OCGT, the result is far more explicit than for CCGT. OCGT in combination with renewables has been shown to be cost effective when LCOEs are compared, and easily analysable for technical feasibility. For this reason it is often selected as the preferred source of flexibility for renewables studies to ensure stable supply and reliability

(Brown, et al., 2018, p. 837). OCGT was also the flexibility technology of choice in the CSIR study that inspired this report (Bischof-Niemz, 2016).

For the remainder of this report therefore, it must be taken that OCGT is the preferred natural gas technology of choice of this study, although CCGT was shown to be a very competitive option in our LCOE analysis, can meet the required ramp rates, and is explicitly mentioned in the IRP 2019.

4.2.4 The feasibility of 100 % renewable electrical systems

The logical conclusion from the preceding sections would seem to be that there are no insurmountable technical problems to a combination of renewables plus LNG for flexibility providing at least some base-load. After all, renewable generators are a fast-growing characteristic of global powers systems, and they are clearly functional.

However the objective of this study is to investigate whether this combination of technologies can replace nuclear as a base-load option, and not merely supplement it as another base-load option. To do this, it is important to investigate whether there is a limit to how much renewable energy a system can incorporate. Is it possible to have a system that consists only of VRE with the necessary flexibility, or is there a limit to how much renewables a system can incorporate? The implication of this question is that if it is only possible for renewables to supply a portion of a system's requirements, then perhaps a place remains for nuclear as part of an energy portfolio.

Some countries have experienced problems when integrating VRE technologies due to system integration problems or high curtailment. Ireland put a moratorium on new wind developments following major concerns about the "security and stability of the power system" in 2003, when wind technology contributed 2 % of annual generation. However challenges were subsequently analysed in a systematic manner, and a strategy for resolving them was designed and implemented. As of 2017, Ireland had 25% wind power in its generation mix and is moving towards 39 % by 2023 while maintaining reliability and without significant additional costs. (IEA, 2019)

Similarly, curtailment levels of the Electricity Reliability Council of Texas (ERCOT) peaked around 20 % in 2009 due to wind power capacity increasing more quickly than required grid infrastructure. Since then, the grid has been built out and curtailment has fallen to a healthy level (below 2 %). (IEA, 2019).

The advancement of VRE seems to be unstoppable but it is argued by some experts that there is a limit to how much renewables can be integrated into a power system. One of the arguments put forward is that increasing amounts of operating reserves are required as variable generation

capacity increases. It is also argued that the range of capacity credits attributed to variable generation reduces significantly as penetration levels increase. The capacity credit is a measure of the contribution of a technology to the overall system adequacy (i.e. the system's ability to meet demand throughout the year under steady-state conditions). Therefore, larger shares of variable renewables with a lower capacity credit require increased total generation capacities to maintain system reliability. (Welsch & Mentis, 2014, p. 216)

How much renewables a system can take, and its cost is a topic of hot debate with polar opposite opinions held by "experts" depending on whether they favour conventional or renewable generation technologies. The following is a discussion of the arguments for and against systems which consist only of renewable technologies.

4.2.4.1 Arguments against 100 % renewables

Proponents of conventional technologies argue that there is no existing proof that demonstrates that 100 % renewable electricity systems are feasible. They argue that there is a burden of proof upon planners that put forward plans for 100 % renewables systems, as there is a total lack of historical evidence for the technical feasibility of 100 % renewable-electricity systems operating at large scale (Heard & Brook, 2017, p. 1124).

Heard et al contend that technologies such as nuclear and carbon capture and storage are often being excluded from new build plans being devised by academic, governmental and non-governmental organisations because they are focusing increasingly on developing energy scenarios that are devoted exclusively to renewable technologies.

Arguments against renewable energy include that it cannot provide electricity reliably. Reliability has two components: adequacy and security. Adequacy refers to the existence of sufficient generation for the electricity power system to satisfy consumer demand at any time, and security describes the ability of the system to respond to multiple types of disturbances in the quality of supply (Heard & Brook, 2017, p. 1124).

Heard et al critically reviewed 24 studies that indicated that 100 % renewables systems are possible, but found that all systems that claimed near 100 % renewables components actually relied on high proportions of dispatchable generation sources for the provision of a reliable electricity system. These systems generally exploited two intrinsically 'stored' resources: hydroelectricity and biomass.

They go on to claim that the integration of variable renewable energy sources into existing grids can be cost-effective up to penetrations of around 20 %, after which integration costs escalate

rapidly. They conclude from evidence sourced in the UK that there is an upper threshold to which wind can penetrate a system economically. Beyond this threshold additional wind makes little difference in meeting demand in times of low wind supply.

A second argument against renewables is that generally studies for the development of renewable generation largely ignore the requirement for expanded transmission and enhanced distribution systems, needed both to transport electricity from more sources over greater distances and to maintain stable system operations. Heard et al reference various studies that indicate that a cost-optimised transmission system to meet a target of 80 % renewables in Europe by 2050 would require transmission grid extension of between 76 % and 500 % of the base network. Nevertheless Heard et al concede that providing the addition networks is more a matter of economic viability rather than technical feasibility.

A third argument against projected 100 % renewable electricity systems is that they are unable to provide ancillary services. Two examples of ancillary services are frequency control and network voltage control.

Changes in frequency arise from the small, instantaneous and ongoing variations in load that occur due to consumer behaviour, and also as a result of larger changes in demand that occur during the normal course of the day. Instantaneous frequency control is typically provided by the inertia of 'synchronous' generators, where electricity is generated through turbines spinning in unison at close to the regulated standard. It is argued that wind and solar are asynchronous generators and displace traditional synchronous generators from the market (Heard & Brook, 2017, p. 1125).

Voltage must be managed to within specified tolerances for insulation and safety equipment. Voltage management is affected by the expansion of generation that is connected to an electrical-distribution network, known as 'embedded' generation. Voltage control at distribution level has become a concern in markets with high penetrations of solar photovoltaics.

Heard et al's assessment is that the state of research into how variable renewable energy sources such as wind can provide frequency control is nascent. They argue that in spite of much research having gone into the role of batteries in providing frequency control and general reliability, this technology is expensive and not yet sufficiently proven. A renewable scenario for California suggested that moving to 100 % generation from renewables would require a lower bound storage capacity of 65 % of the peak demand. This compares to just 2 – 10 % storage requirement for electrical systems consisting of generic, dispatchable zero-carbon generation as well as VRE generation (Heard & Brook, 2017, p. 1130).

As far as voltage control goes, evidence from Germany is that voltage overloading is leading to very expensive grid-reinforcements. Potential partial solutions include intelligent operation of distributed energy storage (i.e. batteries), grid reinforcement, active power curtailment (i.e. preventing export from the photovoltaic to the feeder), and active and reactive power control from the photovoltaic unit itself, demanding more advanced inverters.

Heard et al's, concluding remarks, are that a 100 % renewable electricity supply system would demand a reinvention of the entire electricity supply-and-demand system to enable renewable supplies to approach the reliability of current systems.

4.2.4.2 Arguments in favour of 100 % renewables

Several researchers that favour renewables have published articles rebutting the arguments put forward by Heard et al.

On the matter of 100 % renewables systems, countries put forward as having close to 100 % renewables systems include Paraguay (99 %), Norway (97 %), Uruguay (95 %), Costa Rica (93 %), Brazil (76 %) and Canada (62 %). However, it is conceded that in these cases there is sufficient synchronous generation to stabilise the grid, either from hydroelectricity, geothermal, or biomass, or an alternating current connection to a neighbour (Brown, et al., 2018, p. 842)

The response provided to the concern about renewable systems being unreliable include advocating the use of OCGTs for flexibility. Brown et al put forward, as an illustrative example, a cost analysis to maintain an OCGT fleet for cover of Germany's 80GW peak demand. They conclude that the cost of maintaining such a fleet would be approximately 0.01 €/kWh which represents just 7.3 % of total spending on electricity in Germany in 2015 - €69.4 billion. (Brown, et al., 2018, p. 837).

They also point out that solutions based on battery storage are already in the system and are likely to be at even lower cost. Lastly, they point out that OCGTs can provide a flexible source of upward reserve power and ancillary services such as inertia provision, fault current, voltage regulation and black-starting the system. A clutch can be provided to decouple the generator from the turbine to allow the generator to operate in synchronous compensator mode, which means that it can provide many ancillary services without burning gas (Brown, et al., 2018, p. 838). The decoupling of the generator from the turbine through a clutch is suitable where it is required to supply reactive power to the grid but no active power, i.e. turbine not in operation. When active power is required the turbine can be reconnected ensuring the maximum level of operating flexibility. In this way the OCGT can operate in two modes: power mode (turbine engaged), and synchronous condenser mode (turbine disengaged).

On transmission and distribution costs, Brown et al argue that these costs are not decisive as they are generally a small fraction of total electricity system costs, typically 10 – 15 % of total system costs in Europe. They concede that transmission and distribution costs can represent a potential problem where public acceptance problems prevent the expansion of overhead transmission lines, requiring the power lines to be put underground. Underground lines are typically 3 – 8 times more expensive than overhead lines. They argue further that distribution expansion costs depend on how much the scenario depends on decentralised, rooftop PV generation. If all wind and utility-scale PV is connected to the transmission grid, then there is no need to consider distribution grids at all. Brown et al reference a case study for the increase of renewable electricity in Europe to 68 % by 2030 which would result in additional transmission costs of approximately 10 – 15 % of the total system costs and therefore verify their estimates (Brown, et al., 2018, p. 838).

On the topic of ancillary services, Brown et al contend that these can be provided with established technologies, including wind and solar plants in some instances, and that the cost to provide them is second-order compared to the costs of energy generation (Brown, et al., 2018, p. 839).

For the provision of fault current, voltage support and inertia, synchronous compensators are recommended, while wind, solar PV and storage units now coupled to the grid can be or are already fitted with inverters which can control voltage with both active and reactive power. They contend that from a feasibility point of view synchronous compensators could be placed throughout the network, and add that there could be cheaper solutions. Synchronous compensators, also called synchronous condensers, which are essentially synchronous generators, without a prime mover to provide active power, can provide all the ancillary services of conventional generators except those requiring active power, i.e. they can provide fault current, inertia and voltage support just like synchronous generators. Active power is then provided by renewable generators and storage devices. They provide a cost estimate for the provision of synchronous compensators for Great Britain of 0.0003 €/kWh for Great Britain (9 GVar at €129 million per year) (Brown, et al., 2018, p. 839) .

Brown et al point out that synchronous condensers are an established, mature technology, which provides a feasible upper bound on the costs of providing non-active-power-related ancillary services. The inverters of wind, solar and batteries already provide reactive power for voltage control and can provide the other ancillary services, including virtual or synthetic inertia, by programming the functionality into the inverter software. Inverters are much more flexible than mechanics-bound synchronous generators and can change their output with high accuracy within milliseconds. The reason that wind and solar plants have only recently been providing these

services is that there was no need before, and no system operators required it (Brown, et al., 2018, p. 839).

As far as balancing reserves go, Brown et al posit that this can be provided by traditional providers, such as battery systems, fast-acting demand-side management or by wind and solar generators. Upward reserves can also be provided by variable renewable plants by operating them below their available power. In a study for Germany in 2030 with 65MW PV and 81GW wind (52 % renewable energy share), no need is seen for additional primary reserve, with at most a doubling of the need for other types of reserves. For 100 % renewables, it is a similar story (Brown, et al., 2018, p. 839).

Brown et al also address the matter of black-starts. This is the ability to restart the electricity system in the case of a total blackout. Most thermal power stations consume electricity when starting up, so special provisions are needed when black-starting the system, by making sure that there are generators which can start without an electricity supply. Typically system operators use hydroelectric plants, diesel generators or battery systems which can then start a gas turbine, which can then start other plants. Brown et al contend that maintaining conventional capacity for black-start is inexpensive compared to system costs. This was demonstrated in the study for 52 % renewables in Germany by 2030 – no additional measures for black-starting are required. Finally, decentralised renewable generators and storage may also be able to provide black-starting facilities in future. The use of battery storage to black-start gas turbines has been demonstrated in Germany.

Diesendorf & Elliston in a response to Heard et al and other critics of renewable energy, make some interesting points. They focussed on regions that have no conventional hydro potential and therefore require large contributions from wind and solar PV. They conclude that well-designed 100 % RE systems can meet the basic requirements of reliability, affordability, security, and low environmental impact. In their opinion, the main barrier to a faster transition to renewable energy is the political power of the incumbent fossil fuel, nuclear and electricity industries, bolstered by misinformation disseminated by RE critics, and existing institutions such as market rules that are inappropriate for climate mitigation and discourage RE and flexible dispatchable power stations. They view the IEA estimate of 78 % renewable generation by 2060 as being conservative and flawed. They advocate the use of turbines, including OCGTs for the maintenance of frequency and the provision of peaking-power. They contend that although in the immediate future OCGTs and reciprocating engines will operate on fossil fuels, in future they can be converted to renewable fuels such as biofuels, hydrogen and ammonia. Lastly, they also point out that South Australia's two coal-fired power stations were closed down due to being unable to compete with wind on

price and that the state's remaining base-load station (gas-fired) is expected to close too for the same reasons (Diesendorf & Elliston, 2018, p. 323).

An increasing number of academic articles are being published about the feasibility of achieving 100 % renewable electricity in South Africa.

The CSIR has established that South Africa has more than enough solar PV and wind potential to build a 100 % renewables system. The CSIR estimated that 220GW of utility-scale solar PV can be installed in South Africa and that wind projects can be built all over South Africa with capacity factors of over 30 %. They estimate that the potential installed capacity for wind power to be as high as 6700GW – a fleet large enough to supply the entire world's electricity demand (Knorr, et al., 2016).

Oyewo et al conclude that a 100% RE-based system is achievable by 2050 in South Africa and that it would be the least-cost, least-water intensive, least-greenhouse-gas-emitting and most job-rich option for the South African energy system. The total system costs range from 47.1 €/MWh (771.5 R/MWh) and 50.8 €/MWh (832.1 R/MWh). They attribute most of the cost savings to a continuing cost decrease in RE technologies. Storage technologies, transmission grids and gas power plants (87% OCGT and 13% CCGT) provide the required flexibility in a fully RE-based power system. No new coal and nuclear power plants are installed in the least-cost pathway, and existing fossil fuel capacities are phased out based on their technical lifetimes. They warn that new investments in coal and nuclear could become stranded assets. Lastly, they advise that energy policy in South Africa should place solar PV and wind energy at its core, as they are the least cost options for electricity supply (Oyewo, et al., 2019).

McCall et al produced an alternative IRP for South Africa in response to the release of the IRP 2018. A key critique of the IRP 2018 is that it does not address the problem of climate change mitigation, so McCall et al developed an alternative IRP in which the methodology applied was to assess the effects of various GHG budgets on the electricity price and the economy, and arrive at a least-cost scenario. Their key finding is that future supply will come primarily from wind and solar PV with small contributions from coal and pumped storage. Renewable energy plus flexibility provides the least-cost pathway for the electricity sector. No new coal or nuclear power plants feature in South Africa's electricity future, and their inclusion would require subsidies from consumers. The study also shows that a large scale procurement programme for battery technology to provide storage capabilities for variable renewable energy should be pursued in South Africa (McCall, et al., 2019).

4.2.4.3 Conclusions

When comparing the positions of Heard et al to those of the researchers that are opposed to their findings it is apparent that neither side questions that renewables can make a contribution to the supply of electricity worldwide. The differences are only about what percentage of global supply can be met with renewables. Heard et al argue that renewables cannot achieve 100 % penetration and that technologies such as nuclear and carbon capture and storage have a contribution to make. Brown et al, on the other hand, posit that electricity can be supplied without the need for the traditional “base-load” technologies, although they still find a need for flexible technologies like OCGT, and concede that most of the high-renewables systems currently in existence are either connected to a neighbour or have sufficient synchronous generation available to stabilise the grid. Brown et al concede that high penetrations of renewables can be at greater cost, especially when there are objections to overhead transmission lines, for instance.

Zappa et al investigated if a 100 % renewable European system is feasible by 2050. They found that a 100 % renewable European power system could operate with the same level of system adequacy as today when relying on European sources alone “even in the most challenging weather year observed in the period from 1979 to 2015”. However, they also point out that even when wind and solar photovoltaic capacity is installed in optimum locations, the total cost of 100 % renewable power system would be approximately 30 % higher than a power system which includes other low-carbon technologies such as nuclear or carbon capture and storage. (Zappa, et al., 2019, p. 1027)

From a cost point of view, Brown et al identified three additional cost groups that could increase the LCOEs for renewables plus LNG: additional costs for an OCGT backup, additional transmission costs, and additional costs for the provision of ancillary services.

In our analysis in section 4.1.3, we have provided the cost of a natural gas primary reserve, which in addition can also provide ancillary services such as inertia provision, fault current, voltage regulation and black starting capability. The cost for the additional ancillary services provided by synchronous compensators, was estimated for Great Britain as €0.0003/kWh, which is less than a South African cent per kWh. The only significant additional cost identified by Brown et al, therefore, would appear to be transmission costs, which they put at 10 – 15 % unless there is public dissatisfaction with overhead lines necessitating the construction of underground lines. Underground lines can cost 3 – 8 times as much as underground lines.

An increase of 10 – 15 % on our calculated LCOEs for VRE plus LNG flexibility would make the most expensive VRE plus LNG (CCGT plus CCS) only marginally less expensive than nuclear. A

30 – 80 % increase certainly would result in renewables being significantly more expensive. It must be pointed out though that the construction of nuclear power stations in South Africa, at any location other than Koeberg, would also incur significant transmission costs.

In conclusion of this chapter, it can be said that there is sufficient evidence to support that a portion of base-load can be built cost effectively in South Africa from renewables with LNG for flexibility. There would also appear to be no insurmountable technical challenges to doing so. However, there is not yet conclusive evidence that 100 % renewables systems are economically viable.

It must be added further, that in practical reality, the need is not to supply base-load but rather to supply the total demand curve of South Africa, which would be even easier and cheaper than base-load, since wind power naturally complements the need for power during the evening demand peak. Therefore, the current study can be viewed as conservative.

CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

All three combinations of solar PV, wind and natural gas flexibility analysed in this study resulted in a cheaper base-load LCOE than can be achieved with the cheapest nuclear technology analysed – VVER 1200, under South African conditions.

A wind- only scenario, Scenario 3, provided the best fit for the base-load requirement. It resulted in the lowest LNG flexibility requirement and produced the smallest energy surplus. It produced the least-cost base-load LCOE when OCGT is used as flexibility. When CCGT is used as flexibility both with and without carbon capture and storage, the wind-only base-load LCOE at high LNG prices is also the least-cost base-load producer. Overall therefore, the wind-only scenario can be considered to be the best of the three scenarios analysed for the production of base-load as it provides the best fit, produces the smallest surplus, and mitigates the risk of higher LNG prices best.

It must be noted however, that when all production including surpluses are considered, Scenario 2, a combination of wind and solar PV provided the lowest LCOEs for the simple reason that it consisted of more renewable energy than the other two scenarios. The cost of solar PV and wind is significantly lower than for other technologies in South Africa, and the more renewables a system has the cheaper it is. This would seem to back up the contention made by supporters of renewable energy that, at the current prices of renewables, the more renewables in the electricity system the cheaper electricity becomes. The trend in lower renewables prices is forecast to continue by some experts, resulting in ever-lower LCOEs going into the future (Oyewo, et al., 2019, p. 563).

Our analysis of the technical feasibility of producing base-load with a combination of wind, solar PV and gas technologies showed that both OCGT and CCGT can comfortably ramp at the rates required to meet renewables variability even on the most variable and least variable days. Although the gas load factors produced by our analysis result in cheaper LCOEs with CCGT than with OCGT, OCGT is preferred over CCGT as a provider of flexibility because its much faster start-up times make it more suitable in scenarios where surpluses of energy are produced frequently, necessitating frequent start-ups. OCGT can easily handle the ramp rates required by renewables with minimal support from primary reserve capacity from the system operator. As nuclear is susceptible to both planned and unplanned outages and is therefore also a client for primary reserves, it is unlikely that the minimal primary reserves required by OCGT will affect the

comparison between the two technologies. OCGT is a common choice by many researchers conducting first-order studies as the preferred technology to supply flexibility for renewables (Brown, et al., 2018).

Devising a strategy to implement CCGT in a scenario where surpluses exist is not impossible to imagine. For instance, the surplus capacity can be stored in pumped storage schemes or batteries, used to supply mid-merit in addition to base-load, or used to provide ancillary services and reserve capacity. However, the analysis of these and other options is complex and best handled in a separate study for this purpose.

In realistic scenarios where surpluses are not produced, such as the South African electricity system, there appears to be no reason why CCGT cannot be cost-effectively deployed to provide flexibility for renewables. It is not surprising therefore that the IRP 2019, promulgated in October 2019, includes natural gas as a source of flexibility to compliment renewables in the form of CCGT and gas engine technology (DMRE, 2019, p. 12).

Our assessment of the reliability of renewables is corroborated by the experiences of countries that have deployed large quantities of renewables in their electricity systems including Denmark, Germany and South Australia. Although the anti-renewables lobby frequently reference the technical problems experienced by countries that have introduced large amounts of renewables as a disadvantage of renewables systems, our research shows that generally these countries find solutions to the problems that have materialised, and remain in favour of ever-increasing quantities of renewables. Ireland, for instance, put a moratorium on new wind developments following major concerns about the “security and stability of the power system” in 2003, when wind technology contributed 2 % of annual generation. As of 2017, Ireland had 25 % wind power in its generation mix and is moving towards 39 % by 2023 while maintaining reliability and without significant additional costs (IEA, 2019).

In a survey of European Union citizens for the European Commission in 2017, 89 % thought it was important for their national government to set targets to increase renewable energy use by 2030 (Brown, et al., 2018, p. 841).

In spite of the foregoing discussion, a choice between nuclear and renewables for South Africa is not as clear-cut as it might appear at first glance. Firstly, although our analysis resulted in lower base-load LCOEs for renewables than for nuclear technology, this advantage diminishes as the price of LNG increases. The widespread deployment of gas technology in South Africa, which currently has no significant domestic sources of natural gas, will place the country at risk of gas price shocks. Although our analysis indicates that current prices of LNG are not much changed

from those of two decades ago, there have been occasional price shocks along the way. As investments in electricity infrastructure are long-term investments, security and cost of supply are important considerations when making investment decisions, and there can be no certainty about what will happen to the price of LNG in the long-term. South Africa has abundant uranium resources which reduces the risk of similar fuel price shocks for nuclear technology.

Secondly, even if the price of LNG remains relatively stable into the future in dollar terms, large-scale imports of LNG could place the country at risk of higher electricity prices caused by negative exchange rate movements. South Africa already has an unhealthy debt-to-GDP ratio, a major contributor to the country's "junk status" ranking by some global ratings agencies. An increased debt burden caused by the need to pay for LNG imports could lead to accelerating currency depreciation which could, in turn, lead to higher electricity prices, and further acceleration of the debt burden - a classic debt trap scenario. This risk is reduced by relying on domestic sources of fuel such as uranium.

Thirdly, although "cleaner" than coal, LNG is not a "clean" technology. This is probably nuclear technology's greatest advantage over its competitors. Our analysis shows that when the cost of cleaning-up LNG is included, such as with carbon capture and storage for instance, nuclear's competitive position is greatly improved. This analysis applies to nuclear's competitive position relative to coal too. Although the nuclear LCOE is significantly more expensive than coal without FGD, when FGD is factored in, the difference is greatly reduced.

Fourthly, the LCOE metric has its limitations as a method for comparison as it fails to capture important externalities. Externalities are costs and benefits that do not accrue to the parties involved in the activity. A very important externality not captured by EPRI, the source of the data for calculating the LCOEs in this report, is the cost of building LNG import and processing infrastructure. The EPRI report assumes that LNG terminals exist and that Greenfields power stations would be placed close to them (EPRI, 2017, pp. 3-19). The cost of building this gas infrastructure could significantly affect the price of establishing a gas industry in South Africa. This cost should be factored into the LCOE of the gas technologies and could significantly alter the competitiveness of renewables plus gas.

Lastly, the objective of this report is to assess whether a combination of renewables and LNG can, not just compliment but replace nuclear as a source of base-load. To leave no opportunity at all for nuclear, renewables would have to be able to supply 100 % of a system's needs. Although our literature review on this topic found that there is a growing body of academic articles claiming that it can do precisely that, not all experts agree. Heard at al council that there is a lack of historical evidence for the technical feasibility of 100 % renewable electricity. The cost of

transmission and distribution systems and doubts about the ability of renewables systems to provide ancillary services are highlighted as areas of concern (Heard & Brook, 2017, p. 1123).

When all of the risks and unknowns associated with the deployment of renewables are considered, the prudent approach to the deployment of renewables in South Africa, is to do what other countries have done, and that is to increase the amount of renewables in the energy mix at a pace that makes sense economically, technologically and politically.

The risks associated with an overly high percentage of any technology in the South African electricity system seem to have influenced the South African Government in developing the IRP 2019. The IRP 2019 favours a diversified energy mix, which reduces reliance on a single or few primary energy sources. The IRP 2019 increases renewable's share of total installed capacity to 33% by 2030, but does not close the door on nuclear technology. It includes the life-extension of Koeberg Power station and provides a statement in a section devoted to nuclear that additional capacity from any technology (presumably including nuclear), will be added at a scale and pace that avoids tariff shocks to the user (DMRE, 2019, p. 11).

An opportunity, however tenuous, remains for nuclear technology. To make use of this opportunity, however, nuclear technology needs to overcome a poor image which has resulted from much bad publicity over the years. This bad publicity has firstly, led to a perception amongst many that nuclear is unsafe. It produces radioactive waste which can become a serious danger to the public when accidents such as Three Mile Island, Chernobyl and Fukushima occur. Secondly, nuclear's image has been further tarnished by projects in the western hemisphere that have generally resulted in huge cost and schedule overruns.

To survive, nuclear technology must acknowledge and embrace the rapid changes that have happened in the electricity generation industry in the past decade. There is a growing body of literature on the economics and business cases for nuclear-renewable hybrid systems. Nuclear-renewable hybrid systems are defined as integrated facilities comprised of nuclear reactors, renewable energy generation, and industrial processes that can simultaneously address the need for grid flexibility, greenhouse gas emission reductions, and optimal use of investment capital. Some of the applications that have been explored include a nuclear-renewable hybrid system that produces methanol from natural gas; and a hybrid system that uses a nuclear facility and storage to balance the variability of wind-generated electricity, with excess heat used in a chemical complex (Ruth, et al., 2014).

The Massachusetts Institute of Technology (MIT) in 2018 produced a report on the future of nuclear energy in a carbon constrained world. It concludes that the prospects for the expansion

of nuclear energy remain “decidedly dim” in many parts of the world, the fundamental cause being cost. Other generation technologies have become cheaper while nuclear plants have become costlier. The report’s recommendations to improve costs include using proven project/construction management practices; and making a shift away from primarily field construction of cumbersome, highly site-dependent plants to more serial manufacturing of standardised plants. To improve public perceptions that nuclear technology is unsafe the report recommends a shift towards reactor designs that incorporate inherent and passive safety features. Lastly, the report recommends some key actions that are required from policy makers to capture the benefits of nuclear energy. These include decarbonisation policies that create a level, competitive playing field and do not disadvantage nuclear technology; the establishment by governments of reactor sites where companies can deploy prototype reactors for testing and operation oriented to regulatory licensing; and the establishment by governments of funding programs to finance prototype testing and commercial deployment of advanced reactor designs (MIT, 2018).

In conclusion we reference the IRP 2019 which concludes that in South Africa post 2030, the expected decommissioning of 24 100MW of coal fired power plants supports the need for additional capacity from clean energy technologies including nuclear. The nuclear industry needs to address its short-comings urgently if it wants to become a part of the country’s future energy mix. If renewables technology continues to advance at the current rapid rate, there is a real danger that any new investments in nuclear or fossil fuels could become stranded investments in the not too distant future.

5.2 Recommendations

The results obtained in this study can be enhanced by conducting a number of further studies:

- Investigation of the cost of developing a gas economy in South Africa. Of special interest here is the cost to develop the infrastructure to import the large volumes of LNG that will be necessary to support renewable technologies.
- Development of a strategy for the deployment of combined cycle gas turbines in a case where surplus electricity is produced. The LCOE of CCGTs at capacity factors above 15 % is lower than for OCGT, but the need for frequent stops and starts disadvantages CCGTs. Finding ways to use the power produced by CCGTS at times of day when there is no demand, could serve to reduce electricity prices.
- Comparison of the cost of procuring reserve energy and ancillary services for gas and nuclear technologies. There could be a need to procure reserve energy for short periods

when starting up OCGTs (and CCGTs). Nuclear technology is susceptible to relatively long outages, such as for refuelling, when reserve energy must also be procured. This comparison will further refine the comparison of costs between renewables and nuclear.

- Investigation of the use of batteries as a source of flexibility. A number of studies indicate that the sun could be setting on the gas industry because it is not sufficiently clean. However, batteries do not produce electricity, they only store it. A study for South Africa identifying which batteries would be best suited to the prevalent conditions, which technologies would be used to charge the batteries, and the resultant costs, would serve to validate whether battery technology is a viable source of flexibility.
- Investigation of the feasibility of using biofuels, hydrogen and ammonia as a fuel source for gas turbines/engines. These fuels are seen as the source to developing a sustainable future for gas generation technology, and could also serve to extend a gas economy, should one be rolled out in South Africa.

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APPENDIX 1: LCOE – Inputs and results for conventional technologies

		Nuclear VVER	Nuclear EPR	PF inc. FGD	PF exc. FGD	CCGT inc. CCS	CCGT excl. CCS	OCGT
PV Capital Cost	R/kW	97630	122167	50989	40 913	24 695	11 238	9 907
Fixed O&M	R/kW	657	933	1229	789	444	187	181
Variable O&M	R/kWh	0.04	0.05	0.09	0.07	0.04	0.02	0.002
Efficiency	%	35 %	35 %	36.7 %	37.1 %	41 %	49 %	31.30 %
Fuel Cost	R/GJ	9.1	9.1	31.1	31.1	63.9	63.9	63.9
Availability	%	90 %	90 %	85 %	85 %	50 %	50 %	10.00 %
Life Time	years	60	60	30	30	30	30	30
Lev Capital	R/kWh	1.02	1.28	0.62	0.50	0.51	0.23	1.02
Lev O&M	R/kWh	0.12	0.18	0.27	0.18	0.18	0.09	0.23
Lev Fuel	R/kWh	0.09	0.09	0.31	0.30	0.57	0.47	0.74
Lev Total	R/kWh	1.24	1.55	1.20	0.98	1.26	0.80	1.99

APPENDIX 2: LCOE – Conventional technologies at varying capacity factors

Levelized Costs - 2017		Nuclear VVER	Nuclear EPR	PF inc. FGD	PF exc. FGD	CCGT inc CCS	CCGT excl CCS	OCGT
CF	20%	5.26	6.66	4.09	3.20	2.29	1.28	1.36
CF	30 %	3.54	4.47	2.83	2.23	1.72	1.01	1.15
CF	40 %	2.68	3.38	2.20	1.75	1.43	0.88	1.05
CF	50 %	2.16	2.72	1.82	1.46	1.26	0.80	0.99
CF	60 %	1.82	2.28	1.57	1.27	1.14	0.74	0.94
CF	70 %	1.57	1.97	1.39	1.13	1.06	0.70	0.91
CF	80 %	1.39	1.73	1.25	1.03	1.00	0.68	0.89
CF	90 %	1.24	1.55	1.15	0.94	0.95	0.65	0.87

APPENDIX 3: LCOE – AP1000

INPUTS

PLANT

Overnight investment	R/kW	75271
Capacity factor	%	90%
Fuel	R/GJ	9.1
Efficiency	%	33%
Fixed O&M	R/kW-yr	1254
Var O&M	R/kWh	0.0312
Operating Period	Yrs	60

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX	1.08346149	0.789860456	0.19372298	0.09987805
LCOE Discounted CAPEX	1.27745008	0.983849048	0.19372298	0.09987805
LCOE No CAPEX	0.29360103	0	0.19372298	0.09987805

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	6	5	4	3	2	1	0	0	0	0	0	0
Construction Phasing	%	100%	15%	15%	25%	25%	10%	10%					
Overnight CAPEX	R/kW	75271	11290.65	11290.65	18817.75	18817.75	7527.1	7527.1	0	0	0	0	0
Present Value		16743.8471	15474.90487	23836.88366	22030.39155	8144.3222	7527.1	0	0	0	0	0	0
Total Present Value		93757.449											

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	75271					103250.1742			94377.5726	95296.57983	18461.1377	9518.03645
0	75271			75271	1	75271						
1		1527.312	787.4385366	2314.750537	0.924214418	2139.325819	7884	8542.01	7894.64914	7286.50647	1411.56377	727.762049
2		1527.312	787.4385366	2314.750537	0.85417229	1977.195767	7884	8542.01	7296.34856	6734.294334	1304.58759	672.608178
3		1527.312	787.4385366	2314.750537	0.789438346	1827.352834	7884	8542.01	6743.39054	6223.931917	1205.71866	621.634176
4		1527.312	787.4385366	2314.750537	0.729610301	1688.865836	7884	8542.01	6232.33876	5752.247613	1114.34257	574.523268
5		1527.312	787.4385366	2314.750537	0.674316359	1560.874155	7884	8542.01	5760.01734	5316.310178	1029.89147	530.982687
6		1527.312	787.4385366	2314.750537	0.623212902	1442.582398	7884	8542.01	5323.49107	4913.410516	951.840543	490.741855
7		1527.312	787.4385366	2314.750537	0.575982349	1333.255451	7884	8542.01	4920.0472	4541.044839	879.704753	453.550698
8		1527.312	787.4385366	2314.750537	0.532331191	1232.213911	7884	8542.01	4547.17856	4196.899112	813.035816	419.178094
9		1527.312	787.4385366	2314.750537	0.491988162	1138.829862	7884	8542.01	4202.56798	3878.834669	751.419424	387.410438
10		1527.312	787.4385366	2314.750537	0.454702553	1052.522978	7884	8542.01	3884.07392	3584.874925	694.472665	358.050313
11		1527.312	787.4385366	2314.750537	0.420242655	972.756911	7884	8542.01	3589.71712	3313.193092	641.84165	330.915261
12		1527.312	787.4385366	2314.750537	0.388394321	899.0359621	7884	8542.01	3317.66832	3062.100824	593.199307	305.836655
13		1527.312	787.4385366	2314.750537	0.358959631	830.9019983	7884	8542.01	3066.23689	2830.03773	548.243352	282.658646
14		1527.312	787.4385366	2314.750537	0.331755666	767.9316065	7884	8542.01	2833.86034	2615.561673	506.69441	261.237196
15		1527.312	787.4385366	2314.750537	0.30661337	709.7334626	7884	8542.01	2619.09459	2417.339809	468.294279	241.439183
16		1527.312	787.4385366	2314.750537	0.283376497	655.9458989	7884	8542.01	2420.60498	2234.140304	432.804325	223.141574
17		1527.312	787.4385366	2314.750537	0.261900644	606.234667	7884	8542.01	2237.15802	2064.82468	400.003997	206.23066
18		1527.312	787.4385366	2314.750537	0.242052352	560.2908106	7884	8542.01	2067.6137	1908.340739	369.689461	190.601349
19		1527.312	787.4385366	2314.750537	0.223708273	517.8288452	7884	8542.01	1910.91839	1763.716025	341.67233	176.156515
20		1527.312	787.4385366	2314.750537	0.206754411	478.5848847	7884	8542.01	1766.09833	1630.051779	315.778494	162.806391
21		1527.312	787.4385366	2314.750537	0.191085408	442.3150506	7884	8542.01	1632.25354	1506.517356	291.847037	150.468014
22		1527.312	787.4385366	2314.750537	0.176603889	408.7939469	7884	8542.01	1508.55225	1392.345061	269.729239	139.064708
23		1527.312	787.4385366	2314.750537	0.16321986	377.8132596	7884	8542.01	1394.22574	1286.82538	249.287652	128.525608
24		1527.312	787.4385366	2314.750537	0.150850148	349.1804618	7884	8542.01	1288.56353	1189.302569	230.395242	118.78522
25		1527.312	787.4385366	2314.750537	0.139417882	322.7176171	7884	8542.01	1190.90899	1099.170582	212.934604	109.783013
26		1527.312	787.4385366	2314.750537	0.128852017	298.2602746	7884	8542.01	1100.65526	1015.869299	196.797231	101.463043
27		1527.312	787.4385366	2314.750537	0.119086892	275.6564461	7884	8542.01	1017.24146	938.8810528	181.882838	93.7736076
28		1527.312	787.4385366	2314.750537	0.110061822	254.7656618	7884	8542.01	940.149226	867.7274055	168.098742	86.6669201
29		1527.312	787.4385366	2314.750537	0.101720723	235.4580978	7884	8542.01	868.899469	801.9661789	155.359281	80.0988171
30		1527.312	787.4385366	2314.750537	0.094011759	217.6137687	7884	8542.01	803.049417	741.188705	143.585287	74.0284816
31		1527.312	787.4385366	2314.750537	0.086887023	201.1217826	7884	8542.01	742.18985	685.0172875	132.703593	68.4181901
32		1527.312	787.4385366	2314.750537	0.080302239	185.8796512	7884	8542.01	685.94256	633.1028535	122.646573	63.2330777
33		1527.312	787.4385366	2314.750537	0.074216487	171.7926536	7884	8542.01	633.958003	585.1227851	113.351732	58.4409221
34		1527.312	787.4385366	2314.750537	0.068591948	158.7732473	7884	8542.01	585.913127	540.7789141	104.761305	54.0119428
35		1527.312	787.4385366	2314.750537	0.063393667	146.7405243	7884	8542.01	541.50936	499.7956693	96.8219081	49.9186162
36		1527.312	787.4385366	2314.750537	0.058589341	135.6197082	7884	8542.01	500.470757	461.9183635	89.4842034	46.1355048
37		1527.312	787.4385366	2314.750537	0.054149114	125.3416897	7884	8542.01	462.54229	426.9116113	82.7025909	42.6390987
38		1527.312	787.4385366	2314.750537	0.050045391	115.8425967	7884	8542.01	427.488253	394.5578663	76.4349269	39.4076698
39		1527.312	787.4385366	2314.750537	0.046252672	107.0633981	7884	8542.01	395.090807	364.6560687	70.6422615	36.4211366
40		1527.312	787.4385366	2314.750537	0.042747387	98.94953614	7884	8542.01	365.14862	337.0203962	65.2885966	33.6609396
41		1527.312	787.4385366	2314.750537	0.039507751	91.45058793	7884	8542.01	337.475619	311.4791092	60.3406623	31.1099257
42		1527.312	787.4385366	2314.750537	0.036513633	84.51995187	7884	8542.01	311.899833	287.8734836	55.76771	28.7522418
43		1527.312	787.4385366	2314.750537	0.033746426	78.11455811	7884	8542.01	288.262322	266.056824	51.5413217	26.5732364
44		1527.312	787.4385366	2314.750537	0.031188934	72.19460084	7884	8542.01	266.416194	245.8935527	47.6352326	24.5593682
45		1527.312	787.4385366	2314.750537	0.028825262	66.72329098	7884	8542.01	246.225688	227.2583666	44.0251688	22.6981222
46		1527.312	787.4385366	2314.750537	0.026640723	61.66662752	7884	8542.01	227.565331	210.035459	40.6886957	20.9779318
47		1527.312	787.4385366	2314.750537	0.02462174	56.99318625	7884	8542.01	210.31916	194.1177994	37.6050792	19.388107
48		1527.312	787.4385366	2314.750537	0.022755767	52.67392444	7884	8542.01	194.38	179.406469	34.7551564	17.9187681
49		1527.312	787.4385366	2314.750537	0.021031208	48.68200041	7884	8542.01	179.648798	165.8100453	32.1212166	16.5607838
50		1527.312	787.4385366	2314.750537	0.019437346	44.99260666	7884	8542.01	166.03401	153.2440344	29.6868915	15.3057151
51		1527.312	787.4385366	2314.750537	0.017964275	41.58281577	7884	8542.01	153.451025	141.6303461	27.4370532	14.1457626
52		1527.312	787.4385366	2314.750537	0.016602842	38.43143787	7884	8542.01	141.82165	130.8968078	25.3577201	13.0737178
53		1527.312	787.4385366	2314.750537	0.015344586	35.51888897	7884	8542.01	131.073614	120.976717	23.4359705	12.0829184
54		1527.312	787.4385366	2314.750537	0.014181688	32.82706929	7884	8542.01	121.140124	111.8084261	21.6598619	11.1672074
55		1527.312	787.4385366	2314.750537	0.01310692	30.33925073	7884	8542.01	111.959449	103.3349594	20.0183566	10.3208941
56		1527.312	787.4385366	2314.750537	0.012113605	28.03997295	7884	8542.01	103.474537	95.50365935	18.5012538	9.53871915
57		1527.312	787.4385366	2314.750537	0.011195568	25.91494727	7884	8542.01	95.6326588	88.26585892	17.0991255	8.81582176
58		1527.312	787.4385366	2314.750537	0.010347105	23.9509679	7884	8542.01	88.3850821	81.5765794	15.8032583	8.14770958
59		1527.312	787.4385366	2314.750537	0.009562944	22.13582985	7884	8542.01	81.6867672	75.39425084	14.6055992	7.5302306

APPENDIX 4: LCOE - EPR

INPUTS

PLANT

Overnight investment	R/kW	98079
Capacity factor	%	90%
Fuel	R/GJ	9.1
Efficiency	%	35%
Fixed O&M	R/kW-yr	933
Var O&M	R/kWh	0.0523
Operating Period	Yrs	60

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX		79%	14%	7%
	1.29978747	1.029197482	0.17645205	0.09413793
LCOE Discounted CAPEX		83%	11%	6%
	1.55255689	1.281966903	0.17645205	0.09413793
LCOE No CAPEX		0%	65%	35%
	0.27058999	0	0.17645205	0.09413793

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	6	5	4	3	2	1	0	0	0	0	0	0
Construction Phasing	%	100%	15%	15%	25%	25%	10%	10%					
Overnight CAPEX	R/kW	98079	14711.85	14711.85	24519.75	24519.75	9807.9	9807.9	0	0	0	0	0
Present Value			21817.43	20163.9834	31059.7403	28705.8598	10612.1478	9807.9	0	0	0	0	0
Total Present Value			122167.06										

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/KW-yr		R/kW-yr	kWh			kWh		
TOTAL	98079					123865.3002			113221.178	95296.57983	16815.2773	8971.02286
0	98079			98079	1	98079						
1		1391.148	742.1834483	2133.331448	0.924214418	1971.655682	7884	10247.5244	9470.90979	7286.50647	1285.71904	685.936644
2		1391.148	742.1834483	2133.331448	0.85417229	1822.232608	7884	10247.5244	8753.15138	6734.294334	1188.28007	635.952536
3		1391.148	742.1834483	2133.331448	0.789438346	1684.133649	7884	10247.5244	8089.78871	6223.931917	1098.22558	585.908074
4		1391.148	742.1834483	2133.331448	0.729610301	1556.5006	7884	10247.5244	7476.69936	5752.247613	1014.99591	541.504689
5		1391.148	742.1834483	2133.331448	0.674316359	1438.540296	7884	10247.5244	6910.07334	5316.310178	938.073855	500.466441
6		1391.148	742.1834483	2133.331448	0.623212902	1329.519682	7884	10247.5244	6386.38941	4913.410516	866.981382	462.5383
7		1391.148	742.1834483	2133.331448	0.575982349	1228.761259	7884	10247.5244	5902.39317	4541.040839	801.276693	427.484566
8		1391.148	742.1834483	2133.331448	0.532331191	1135.638871	7884	10247.5244	5455.07687	4196.899112	740.551472	395.087399
9		1391.148	742.1834483	2133.331448	0.491988162	1049.573818	7884	10247.5244	5041.66069	3878.834669	684.428348	365.145471
10		1391.148	742.1834483	2133.331448	0.454702553	970.0312552	7884	10247.5244	4659.5755	3584.874925	632.558547	337.472708
11		1391.148	742.1834483	2133.331448	0.420242655	896.5168717	7884	10247.5244	4306.44686	3313.19092	584.619729	311.897143
12		1391.148	742.1834483	2133.331448	0.388394321	828.5738186	7884	10247.5244	3980.08028	3062.100824	540.313982	288.259836
13		1391.148	742.1834483	2133.331448	0.358959631	765.7798693	7884	10247.5244	3678.44757	2830.03773	499.365973	266.413897
14		1391.148	742.1834483	2133.331448	0.331755666	707.744796	7884	10247.5244	3399.67428	2615.561673	461.521232	246.223564
15		1391.148	742.1834483	2133.331448	0.30661337	654.1079446	7884	10247.5244	3142.02799	2417.339809	426.544576	227.563368
16		1391.148	742.1834483	2133.331448	0.283376497	604.5359931	7884	10247.5244	2903.90757	2234.140304	394.218647	210.317346
17		1391.148	742.1834483	2133.331448	0.261900644	558.7208809	7884	10247.5244	2683.83324	2064.82468	364.342558	194.378323
18		1391.148	742.1834483	2133.331448	0.242052352	516.3778936	7884	10247.5244	2480.43738	1908.340739	336.730645	179.647249
19		1391.148	742.1834483	2133.331448	0.223708273	477.2438943	7884	10247.5244	2292.45599	1763.716025	311.211317	166.032578
20		1391.148	742.1834483	2133.331448	0.206754411	441.0756879	7884	10247.5244	2118.72087	1630.051779	287.625986	153.449702
21		1391.148	742.1834483	2133.331448	0.191085408	407.6485101	7884	10247.5244	1958.15238	1506.517356	265.828083	141.820427
22		1391.148	742.1834483	2133.331448	0.176603889	376.7546304	7884	10247.5244	1809.75266	1392.345061	245.682147	131.072483
23		1391.148	742.1834483	2133.331448	0.16321986	348.202613	7884	10247.5244	1672.5995	1286.82538	227.062982	121.139079
24		1391.148	742.1834483	2133.331448	0.1508050148	321.8133654	7884	10247.5244	1545.84057	1189.302569	209.854882	111.958483
25		1391.148	742.1834483	2133.331448	0.139417882	297.4245521	7884	10247.5244	1428.68815	1099.170582	193.950908	103.473644
26		1391.148	742.1834483	2133.331448	0.128852017	274.8840592	7884	10247.5244	1320.41418	1015.869299	179.252225	95.631834
27		1391.148	742.1834483	2133.331448	0.119086892	254.0518108	7884	10247.5244	1220.34583	938.8810528	165.667491	88.3843198
28		1391.148	742.1834483	2133.331448	0.110061822	234.7983464	7884	10247.5244	1127.86121	867.7274055	153.112284	81.6860267
29		1391.148	742.1834483	2133.331448	0.101720723	217.004017	7884	10247.5244	1042.38559	801.9661789	141.50858	75.4954368
30		1391.148	742.1834483	2133.331448	0.094011759	200.5582412	7884	10247.5244	963.38779	741.188705	130.78427	69.7739712
31		1391.148	742.1834483	2133.331448	0.086887023	185.3588181	7884	10247.5244	890.376885	685.0172875	120.872708	64.4861102
32		1391.148	742.1834483	2133.331448	0.080302239	171.3112922	7884	10247.5244	822.899155	633.1028535	111.712299	59.589928
33		1391.148	742.1834483	2133.331448	0.074216487	158.3283661	7884	10247.5244	760.535263	585.1227851	103.246118	55.0822484
34		1391.148	742.1834483	2133.331448	0.068591948	146.3293587	7884	10247.5244	702.897655	540.7789141	95.4215506	50.9078081
35		1391.148	742.1834483	2133.331448	0.063393667	135.2397031	7884	10247.5244	649.628147	499.7956693	88.1899728	47.0497302
36		1391.148	742.1834483	2133.331448	0.058589341	124.9904834	7884	10247.5244	600.3957	461.9183635	81.5064444	43.484039
37		1391.148	742.1834483	2133.331448	0.054149114	115.5180069	7884	10247.5244	554.894362	426.9116113	75.329431	40.1885758
38		1391.148	742.1834483	2133.331448	0.050045391	106.7634074	7884	10247.5244	512.84137	394.5578663	69.6205462	37.1428612
39		1391.148	742.1834483	2133.331448	0.046252672	98.67228045	7884	10247.5244	473.975388	364.6560687	64.3443126	34.3279678
40		1391.148	742.1834483	2133.331448	0.042747387	91.19434423	7884	10247.5244	438.054887	337.0203962	59.4679414	31.7264028
41		1391.148	742.1834483	2133.331448	0.039507751	84.28312775	7884	10247.5244	404.856643	311.4791092	54.9611288	29.3219989
42		1391.148	742.1834483	2133.331448	0.036513633	77.89568184	7884	10247.5244	374.174346	287.8734836	50.7958677	27.0998141
43		1391.148	742.1834483	2133.331448	0.033746426	71.99231224	7884	10247.5244	345.817326	266.056824	46.9462733	25.0460389
44		1391.148	742.1834483	2133.331448	0.031188934	66.53633294	7884	10247.5244	319.609358	245.8935527	43.3884226	23.1479103
45		1391.148	742.1834483	2133.331448	0.028825262	61.4938382	7884	10247.5244	295.387577	227.2583666	40.1002058	21.3936324
46		1391.148	742.1834483	2133.331448	0.026640723	56.83349187	7884	10247.5244	273.001457	210.035459	37.0611883	19.7723036
47		1391.148	742.1834483	2133.331448	0.02462174	52.5263326	7884	10247.5244	252.311883	194.1177994	34.2524846	18.273848
48		1391.148	742.1834483	2133.331448	0.022755767	48.5455939	7884	10247.5244	233.19028	179.406469	31.6566401	16.8889538
49		1391.148	742.1834483	2133.331448	0.021031208	44.8665378	7884	10247.5244	215.517819	165.8100453	29.2575232	15.6090146
50		1391.148	742.1834483	2133.331448	0.019437346	41.46630111	7884	10247.5244	199.184675	153.2440344	27.0402248	14.4260763
51		1391.148	742.1834483	2133.331448	0.017964275	38.32375333	7884	10247.5244	184.089349	141.6303461	24.9909656	13.3327877
52		1391.148	742.1834483	2133.331448	0.016602842	35.41936537	7884	10247.5244	170.13803	130.8968078	23.0970107	12.3223547
53		1391.148	742.1834483	2133.331448	0.015344586	32.73508814	7884	10247.5244	157.244021	120.976717	21.3465903	11.3884978
54		1391.148	742.1834483	2133.331448	0.014181688	30.25424043	7884	10247.5244	145.327191	111.8084261	19.7288265	10.5254139
55		1391.148	742.1834483	2133.331448	0.01310692	27.9614052	7884	10247.5244	134.313485	103.3349594	18.2336659	9.72773928
56		1391.148	742.1834483	2133.331448	0.012113605	25.84233383	7884	10247.5244	124.13446	95.50365935	16.8518169	8.9905169
57		1391.148	742.1834483	2133.331448	0.01195568	23.88385751	7884	10247.5244	114.726857	88.26585892	15.5746922	8.30916534
58		1391.148	742.1834483	2133.331448	0.010347105	22.07380546	7884	10247.5244	106.032216	81.5765794	14.3943551	7.67945041
59		1391.148	742.1834483	2133.331448	0.009562944	20.40092927	7884	10247.5244	97.9965024	75.3940284	13.3034705	7.09748579
60		1391.148	742.1834483	2133.331448	0.008838211	18.85483296	7884	10247.5244	90.5697804	69.68405364	12.2952592	6.59597374

APPENDIX 5: LCOE – VVER 1200

INPUTS

PLANT

Overnight investment	R/kW	78380
Capacity factor	%	90%
Fuel	R/GJ	9.1
Efficiency	%	35%
Fixed O&M	R/kW-yr	657.2
Var O&M	R/kWh	0.04
Operating Period	Yrs	60

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX		79%	12%	9%
	1.04047295	0.822484922	0.1238501	0.09413793
LCOE Discounted CAPEX		82%	10%	8%
	1.24247407	1.024486036	0.1238501	0.09413793
LCOE No CAPEX		0%	57%	43%
	0.21798803	0	0.1238501	0.09413793

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	6	5	4	3	2	1	0	0	0	0	0	0
Construction Phasing	%	100%	15%	15%	25%	25%	10%	10%					
Overnight CAPEX	R/kW	78380	11757	11757	19595	19595	7838	7838	0	0	0	0	0
Present Value		17435.4364	16114.0817	24821.4444	22940.33678	8480.716	7838	0	0	0	0	0	0
Total Present Value		97630.015											

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	78380					99153.51394			90632.9508	95296.57983	11802.4911	8971.02286
0	78380			78380	1	78380						
1		976.4342	742.1834483	1718.617648	0.924214418	1588.371209	7884	8203.089	7581.41291	7286.506437	902.434566	685.936644
2		976.4342	742.1834483	1718.617648	0.854172729	1467.995572	7884	8203.089	7006.85112	6734.294334	834.043037	633.952536
3		976.4342	742.1834483	1718.617648	0.789438346	1356.742673	7884	8203.089	6475.83283	6223.931917	770.834599	585.908074
4		976.4342	742.1834483	1718.617648	0.729610301	1253.92114	7884	8203.089	5985.05807	5752.247613	712.416451	541.504689
5		976.4342	742.1834483	1718.617648	0.674316359	1158.891996	7884	8203.089	5531.47696	5316.310178	658.425555	500.466441
6		976.4342	742.1834483	1718.617648	0.623212902	1071.064691	7884	8203.089	5112.27075	4913.410516	608.526391	462.5383
7		976.4342	742.1834483	1718.617648	0.575982349	989.89343	7884	8203.089	4724.83434	4541.044839	562.408864	427.484566
8		976.4342	742.1834483	1718.617648	0.532331191	914.87378	7884	8203.089	4366.76002	4196.899112	519.786381	395.087399
9		976.4342	742.1834483	1718.617648	0.491988162	845.5395379	7884	8203.089	4035.82257	3878.834669	480.394067	365.145471
10		976.4342	742.1834483	1718.617648	0.454702553	781.4598317	7884	8203.089	3729.9654	3584.874925	443.987123	337.472708
11		976.4342	742.1834483	1718.617648	0.420242655	722.2364433	7884	8203.089	3447.2875	3313.193092	410.339301	311.897143
12		976.4342	742.1834483	1718.617648	0.388394321	667.501334	7884	8203.089	3186.03309	3062.100824	379.241498	288.259836
13		976.4342	742.1834483	1718.617648	0.358959631	616.9143567	7884	8203.089	2944.57772	2830.03773	350.50046	266.413897
14		976.4342	742.1834483	1718.617648	0.331755666	570.161143	7884	8203.089	2721.42118	2615.561673	323.937579	246.223564
15		976.4342	742.1834483	1718.617648	0.30661337	526.9511488	7884	8203.089	2515.17669	2417.339809	299.387781	227.563368
16		976.4342	742.1834483	1718.617648	0.283376497	487.0158492	7884	8203.089	2324.56256	2234.140304	276.698503	210.317346
17		976.4342	742.1834483	1718.617648	0.261900644	450.1070695	7884	8203.089	2148.39423	2064.82468	255.728746	194.378323
18		976.4342	742.1834483	1718.617648	0.242052352	415.9954431	7884	8203.089	1985.57693	1908.340739	236.348194	179.647249
19		976.4342	742.1834483	1718.617648	0.223708273	384.4689863	7884	8203.089	1835.09882	1763.716025	218.436409	166.032578
20		976.4342	742.1834483	1718.617648	0.206754411	355.3317803	7884	8203.089	1696.02479	1630.051779	201.882078	153.449702
21		976.4342	742.1834483	1718.617648	0.191085408	328.4027544	7884	8203.089	1567.49056	1506.517356	186.582327	141.820427
22		976.4342	742.1834483	1718.617648	0.176603889	303.5145605	7884	8203.089	1448.69738	1392.345061	172.442077	131.072483
23		976.4342	742.1834483	1718.617648	0.16321986	280.5125328	7884	8203.089	1338.907	1286.82538	159.373454	121.139079
24		976.4342	742.1834483	1718.617648	0.150850148	259.2537271	7884	8203.089	1237.43716	1189.302569	147.295244	111.958483
25		976.4342	742.1834483	1718.617648	0.139417882	239.6060325	7884	8203.089	1143.65726	1099.107582	136.132388	103.473644
26		976.4342	742.1834483	1718.617648	0.128852017	221.4473498	7884	8203.089	1056.98453	1015.869299	125.815516	95.631834
27		976.4342	742.1834483	1718.617648	0.119086892	204.6648335	7884	8203.089	976.880343	938.8810528	116.280514	88.3843198
28		976.4342	742.1834483	1718.617648	0.110061822	189.1541899	7884	8203.089	902.846897	867.7274055	107.468127	81.6860627
29		976.4342	742.1834483	1718.617648	0.101720723	174.8190295	7884	8203.089	834.424119	801.9661789	99.3235926	75.4954368
30		976.4342	742.1834483	1718.617648	0.094011759	161.5702675	7884	8203.089	771.186802	741.188705	91.7962963	69.7739712
31		976.4342	742.1834483	1718.617648	0.086887023	149.3255707	7884	8203.089	712.741961	685.0172875	84.8394606	64.4861102
32		976.4342	742.1834483	1718.617648	0.080302239	138.0088454	7884	8203.089	658.726396	633.1028535	78.4098526	59.5989928
33		976.4342	742.1834483	1718.617648	0.074216487	127.5497647	7884	8203.089	608.804433	585.1227851	72.4675163	55.0822484
34		976.4342	742.1834483	1718.617648	0.068591948	117.8833315	7884	8203.089	562.665834	540.7789141	66.9755234	50.9078081
35		976.4342	742.1834483	1718.617648	0.063393667	108.9494746	7884	8203.089	520.023876	499.7956693	61.8997444	47.0497302
36		976.4342	742.1834483	1718.617648	0.058589341	100.6926752	7884	8203.089	480.613564	461.9183635	57.2086362	43.484039
37		976.4342	742.1834483	1718.617648	0.054149114	93.06162221	7884	8203.089	444.189985	426.9116113	52.8730464	40.1885758
38		976.4342	742.1834483	1718.617648	0.050045391	86.00889298	7884	8203.089	410.526789	394.5578663	48.8660318	37.1428612
39		976.4342	742.1834483	1718.617648	0.046252672	79.49065895	7884	8203.089	379.414777	364.6560687	45.1626911	34.3279678
40		976.4342	742.1834483	1718.617648	0.042747387	73.46641308	7884	8203.089	350.660607	337.0203962	41.7400103	31.7264028
41		976.4342	742.1834483	1718.617648	0.039507751	67.89871819	7884	8203.089	324.085589	311.4791092	38.5767193	29.3219989
42		976.4342	742.1834483	1718.617648	0.036513633	62.75297429	7884	8203.089	299.524574	287.8734836	35.6531602	27.0998141
43		976.4342	742.1834483	1718.617648	0.033746426	57.9972036	7884	8203.089	276.82493	266.056822	32.9511646	25.0460389
44		976.4342	742.1834483	1718.617648	0.031188934	53.60185175	7884	8203.089	255.845591	245.8935527	30.4539415	23.1479103
45		976.4342	742.1834483	1718.617648	0.028825262	49.53960421	7884	8203.089	236.456184	227.2583666	28.1459718	21.3936324
46		976.4342	742.1834483	1718.617648	0.026640723	45.78521646	7884	8203.089	218.536214	210.035459	26.0129129	19.7723036
47		976.4342	742.1834483	1718.617648	0.02462174	42.31535717	7884	8203.089	201.97432	194.1177994	24.0415092	18.273848
48		976.4342	742.1834483	1718.617648	0.022755767	39.10846319	7884	8203.089	186.667579	179.406469	22.2195094	16.8889538
49		976.4342	742.1834483	1718.617648	0.021031208	36.14460554	7884	8203.089	172.520868	165.8100453	20.5355909	15.6090146
50		976.4342	742.1834483	1718.617648	0.019437346	33.40536556	7884	8203.089	159.446273	153.2440344	18.9792892	14.4260763
51		976.4342	742.1834483	1718.617648	0.017964275	30.87372048	7884	8203.089	147.362545	141.6303461	17.5409327	13.3327877
52		976.4342	742.1834483	1718.617648	0.016602842	28.5339376	7884	8203.089	136.194588	130.8968078	16.2115829	12.3223547
53		976.4342	742.1834483	1718.617648	0.015344586	26.37147652	7884	8203.089	125.873002	120.976717	14.9829787	11.3884978
54		976.4342	742.1834483	1718.617648	0.014181688	24.37289882	7884	8203.089	116.333643	111.8084261	13.8474849	10.5254139
55		976.4342	742.1834483	1718.617648	0.01310692	22.52578449	7884	8203.089	107.51723	103.3349594	12.7980452	9.72773928
56		976.4342	742.1834483	1718.617648	0.012113605	20.8186548	7884	8203.089	99.3689746	95.50365935	11.8281379	8.9905169
57		976.4342	742.1834483	1718.617648	0.011195568	19.24090092	7884	8203.089	91.838239	88.26585892	10.9317356	8.30916534
58		976.4342	742.1834483	1718.617648	0.010347105	17.78271804	7884	8203.089	84.8782246	81.5765794	10.1032676	7.67945041
59		976.4342	742.1834483	1718.617648	0.009562944	16.4350444	7884	8203.089	78.4456789	75.39425084	9.33758562	7.09745879
60		976.4342	742.1834483	1718.617648	0.00883211	15.18950499	7884	8203.089	72.5006274	69.40045364	8.62993125	6.55953774

APPENDIX 6: LCOE – Coal including flue gas desulphurisation

INPUTS

PLANT

Overnight investment	R/kW	46092
Capacity factor	%	85%
Fuel	R/GJ	31.1
Efficiency	%	37%
Fixed O&M	R/kW-yr	1229.0
Var O&M	R/MWh	0.09
Operating Period	Yrs	30

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX	1.14	49%	0.27	27%
LCOE Discounted CAPEX	1.20	0.52	0.23	0.26
LCOE No CAPEX	0.58	0.00	0.47	0.53

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	4	3	2	1	0	0	0	0	0	0	0	0
Construction Phasing	%	100%	10%	25%	45%	20%							
Overnight CAPEX	R/kW	46092	4609.2	11523	20741.4	9218.4	0	0	0	0	0	0	0
Present Value		5838.58135	13490.25265	22442.1948	9218.4	0	0	0	0	0	0	0	0
Total Present Value		50989.429											

	Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
		R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL		46092					93507.94667			93507.9467	82268.15177	22318.5563	25097.3904
	0	46092			46092	1	46092						
1			2020.028	2271.537221	4291.565221	0.924214418	3966.326452	7446	8463.301	7821.90525	6881.700555	1866.939	2099.38745
2			2020.028	2271.537221	4291.565221	0.85417229	3665.736092	7446	8463.301	7229.11761	6360.166871	1725.45194	1940.28415
3			2020.028	2271.537221	4291.565221	0.789438346	3387.926148	7446	8463.301	6681.25472	5878.157922	1594.68756	1793.23859
4			2020.028	2271.537221	4291.565221	0.729610301	3131.170192	7446	8463.301	6174.91194	5432.678301	1473.83324	1657.33696
5			2020.028	2271.537221	4291.565221	0.674316359	2893.872636	7446	8463.301	5706.94265	5020.959613	1362.13793	1531.73471
6			2020.028	2271.537221	4291.565221	0.623212902	2674.558813	7446	8463.301	5274.43867	4640.443265	1258.90751	1415.6513
7			2020.028	2271.537221	4291.565221	0.575982349	2471.865816	7446	8463.301	4874.71227	4288.76457	1163.50047	1308.36534
8			2020.028	2271.537221	4291.565221	0.532331191	2284.534026	7446	8463.301	4505.27936	3963.73805	1075.32391	1209.21011
9			2020.028	2271.537221	4291.565221	0.491988162	2111.399285	7446	8463.301	4163.84414	3663.343854	993.829863	1117.56942
10			2020.028	2271.537221	4291.565221	0.454702553	1951.385661	7446	8463.301	3848.28479	3385.715207	918.511888	1032.87377
11			2020.028	2271.537221	4291.565221	0.420242655	1803.498762	7446	8463.301	3556.64028	3129.126809	848.90193	954.596832
12			2020.028	2271.537221	4291.565221	0.388394321	1666.819558	7446	8463.301	3287.09823	2891.984112	784.567403	882.252156
13			2020.028	2271.537221	4291.565221	0.358959631	1540.498668	7446	8463.301	3037.98358	2672.813412	725.108505	815.390162
14			2020.028	2271.537221	4291.565221	0.331755666	1423.751079	7446	8463.301	2807.74822	2470.252691	670.155735	753.595344
15			2020.028	2271.537221	4291.565221	0.30661337	1315.851275	7446	8463.301	2594.96139	2283.043153	619.367592	696.483682
16			2020.028	2271.537221	4291.565221	0.283376497	1216.12872	7446	8463.301	2398.30073	2110.021398	572.428459	643.700261
17			2020.028	2271.537221	4291.565221	0.261900644	1123.963697	7446	8463.301	2216.54411	1950.112198	529.046635	594.917062
18			2020.028	2271.537221	4291.565221	0.242052352	1038.783453	7446	8463.301	2048.56203	1802.321809	488.952528	549.830926
19			2020.028	2271.537221	4291.565221	0.223708273	960.0586445	7446	8463.301	1893.31056	1665.731802	451.896976	508.161669
20			2020.028	2271.537221	4291.565221	0.206754411	887.3000411	7446	8463.301	1749.82492	1539.493347	417.6497	469.650341
21			2020.028	2271.537221	4291.565221	0.191085408	820.0554909	7446	8463.301	1617.21342	1422.821947	385.997874	434.057616
22			2020.028	2271.537221	4291.565221	0.176603889	757.907108	7446	8463.301	1494.65196	1314.992558	356.744801	401.162307
23			2020.028	2271.537221	4291.565221	0.16321986	700.4686766	7446	8463.301	1381.37889	1215.335081	329.708688	370.759988
24			2020.028	2271.537221	4291.565221	0.150850148	647.38325	7446	8463.301	1276.69028	1123.230204	304.721523	342.661727
25			2020.028	2271.537221	4291.565221	0.139417882	598.3209335	7446	8463.301	1179.93557	1038.105549	281.628025	316.692908
26			2020.028	2271.537221	4291.565221	0.128852017	552.9768332	7446	8463.301	1090.51346	959.4321158	260.284681	292.692152
27			2020.028	2271.537221	4291.565221	0.119086892	511.0691619	7446	8463.301	1007.86827	886.7209943	240.558855	270.510307
28			2020.028	2271.537221	4291.565221	0.110061822	472.3374879	7446	8463.301	931.486382	819.5203274	222.327962	250.009526
29			2020.028	2271.537221	4291.565221	0.101720723	436.5411164	7446	8463.301	860.893144	757.4125022	205.478708	231.062408
30			2020.028	2271.537221	4291.565221	0.094011759	403.4575937	7446	8463.301	795.649856	700.0115548	189.906385	213.551209

APPENDIX 7: LCOE – Coal excluding flue gas desulphurisation

INPUTS

PLANT

Overnight investment	R/kW	36983
Capacity factor	%	85%
Fuel	R/GJ	31.1
Efficiency	%	37%
Fixed O&M	R/kW-yr	789.0
Var O&M	R/MWh	0.07
Operating Period	Yrs	30

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX		48%	20%	32%
	0.93	0.45	0.18	0.30
LCOE Discounted CAPEX		51%	19%	31%
	0.98	0.50	0.18	0.30
LCOE No CAPEX		0%	38%	62%
	0.49	0.00	0.18	0.30

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	4	3	2	1	0	0	0	0	0	0	0	0
Construction Phasing	%	100%	10%	25%	45%	20%							
Overnight CAPEX	R/kW	36983	3698.3	9245.75	16642.35	7396.6	0	0	0	0	0	0	0
Present Value			4684.72303	10824.22142	18007.0227	7396.6	0	0	0	0	0	0	0
Total Present Value		40912.567											

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	36983					76905.37466			76905.3747	82268.15177	15095.5761	24826.7986
0	36983			36983	1	36983						
1		1366.284	2247.046253	3613.330253	0.924214418	3339.491916	7446	6960.621	6433.10623	6881.700555	1262.73937	2076.75254
2		1366.284	2247.046253	3613.330253	0.854172229	3086.406577	7446	6960.621	5945.56953	6360.166871	1167.04193	1919.36464
3		1366.284	2247.046253	3613.330253	0.789438346	2852.501457	7446	6960.621	5494.98108	5878.157922	1078.59698	1773.90448
4		1366.284	2247.046253	3613.330253	0.729610301	2636.322974	7446	6960.621	5078.54074	5432.678301	996.85488	1639.46809
5		1366.284	2247.046253	3613.330253	0.674316359	2436.527702	7446	6960.621	4693.66057	5020.959613	921.307653	1515.22005
6		1366.284	2247.046253	3613.330253	0.623212902	2251.874031	7446	6960.621	4337.94877	4640.443265	851.485816	1400.38822
7		1366.284	2247.046253	3613.330253	0.575982349	2081.214447	7446	6960.621	4009.1948	4288.76457	786.955468	1294.25898
8		1366.284	2247.046253	3613.330253	0.532331191	1923.488398	7446	6960.621	3705.35564	3963.73805	727.315589	1196.17281
9		1366.284	2247.046253	3613.330253	0.491988162	1777.71571	7446	6960.621	3424.5431	3663.343854	672.195554	1105.52016
10		1366.284	2247.046253	3613.330253	0.454702553	1642.99049	7446	6960.621	3165.01211	3385.715207	621.252822	1021.73767
11		1366.284	2247.046253	3613.330253	0.420242655	1518.475499	7446	6960.621	2925.14982	3129.126809	574.170816	944.304683
12		1366.284	2247.046253	3613.330253	0.388394321	1403.396949	7446	6960.621	2703.46564	2891.984112	530.656946	872.740003
13		1366.284	2247.046253	3613.330253	0.358959631	1297.039694	7446	6960.621	2498.58192	2672.813412	490.4408	806.598894
14		1366.284	2247.046253	3613.330253	0.331755666	1198.742786	7446	6960.621	2309.22544	2470.252691	453.272459	745.470327
15		1366.284	2247.046253	3613.330253	0.30661337	1107.895366	7446	6960.621	2134.21944	2283.043153	418.920942	688.974424
16		1366.284	2247.046253	3613.330253	0.283376497	1023.93287	7446	6960.621	1972.47638	2110.021398	387.172774	636.760096
17		1366.284	2247.046253	3613.330253	0.261900644	946.3335216	7446	6960.621	1822.99111	1950.112198	357.83066	588.502862
18		1366.284	2247.046253	3613.330253	0.242052352	874.6150846	7446	6960.621	1684.83467	1802.321809	330.712255	543.90283
19		1366.284	2247.046253	3613.330253	0.223708273	808.3318712	7446	6960.621	1557.14849	1665.731802	305.649034	502.682837
20		1366.284	2247.046253	3613.330253	0.206754411	747.0719697	7446	6960.621	1439.13908	1539.493347	282.485244	464.586725
21		1366.284	2247.046253	3613.330253	0.191085408	690.4546855	7446	6960.621	1330.07309	1422.821947	261.076935	429.37775
22		1366.284	2247.046253	3613.330253	0.176603889	638.1281751	7446	6960.621	1229.27273	1314.992558	241.291068	396.837107
23		1366.284	2247.046253	3613.330253	0.16321986	589.7672598	7446	6960.621	1136.11158	1215.335081	223.004684	366.762576
24		1366.284	2247.046253	3613.330253	0.150850148	545.0714046	7446	6960.621	1050.0107	1123.230204	206.104144	338.967261
25		1366.284	2247.046253	3613.330253	0.139417882	503.7628509	7446	6960.621	970.435028	1038.105549	190.484421	313.278429
26		1366.284	2247.046253	3613.330253	0.128852017	465.5848899	7446	6960.621	896.890045	959.4321158	176.048449	289.536441
27		1366.284	2247.046253	3613.330253	0.119086892	430.3002679	7446	6960.621	828.91871	886.7209943	162.706514	267.593753
28		1366.284	2247.046253	3613.330253	0.110061822	397.6897116	7446	6960.621	766.098623	819.5203274	150.375707	247.314005
29		1366.284	2247.046253	3613.330253	0.101720723	367.5505652	7446	6960.621	708.039393	757.4125022	138.979396	228.571169
30		1366.284	2247.046253	3613.330253	0.094011759	339.6955316	7446	6960.621	654.380215	700.0115548	128.446762	211.24877

APPENDIX 8: LCOE – CCGT excluding carbon capture and storage

INPUTS

PLANT

Overnight investment	R/kW	10131
Capacity factor	%	50%
Fuel	R/GJ	63.9
Efficiency	%	49%
Fixed O&M	R/kW-yr	187.0
Var O&M	R/kWh	0.02
Operating Period	Yrs	30

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX	0.77	0.21	0.09	0.47
LCOE Discounted CAPEX	0.80	0.23	0.09	0.47
LCOE No CAPEX	0.56	0.00	0.09	0.47

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	3	2	1	0	0	0	0	0	0	0	0	0
Construction Phasing	%	100%	40%	50%	10%								
Overnight CAPEX	R/kW	10131	4052.4	5065.5	1013.1	0	0	0	0	0	0	0	0
Present Value			4744.24194	5480.871	1013.1	0	0	0	0	0	0	0	0
Total Present Value		11238.213											

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	10131					37446.71028			37446.7103	48393.03045	4456.71084	22858.9994
0	10131			10131	1	10131						
1		403.372	2068.942916	2472.314916	0.924214418	2284.94909	4380	3389.261	3132.4035	4048.05915	372.802218	1912.14687
2		403.372	2068.942916	2472.314916	0.85417229	2111.782893	4380	3389.261	2895.01248	3741.27463	344.549185	1767.23371
3		403.372	2068.942916	2472.314916	0.789438346	1951.740197	4380	3389.261	2675.61227	3457.739954	318.437324	1633.30287
4		403.372	2068.942916	2472.314916	0.729610301	1803.82643	4380	3389.261	2472.83944	3195.693118	294.304366	1509.52206
5		403.372	2068.942916	2472.314916	0.674316359	1667.122393	4380	3389.261	2285.43386	2953.505654	272.000339	1395.12205
6		403.372	2068.942916	2472.314916	0.623212902	1540.778552	4380	3389.261	2112.23093	2729.672509	251.386635	1289.39192
7		403.372	2068.942916	2472.314916	0.575982349	1424.009753	4380	3389.261	1952.15428	2522.802688	232.335152	1191.6746
8		403.372	2068.942916	2472.314916	0.532331191	1316.090344	4380	3389.261	1804.20913	2331.610618	214.727497	1101.36285
9		403.372	2068.942916	2472.314916	0.491988162	1216.349671	4380	3389.261	1667.47609	2154.908149	198.454249	1017.89542
10		403.372	2068.942916	2472.314916	0.454702553	1124.167903	4380	3389.261	1541.10544	1991.597181	183.414278	940.753625
11		403.372	2068.942916	2472.314916	0.420242655	1038.972184	4380	3389.261	1424.31187	1840.662829	169.51412	869.458064
12		403.372	2068.942916	2472.314916	0.388394321	960.2330722	4380	3389.261	1316.36956	1701.167124	156.667394	803.565678
13		403.372	2068.942916	2472.314916	0.358959631	887.4612497	4380	3389.261	1216.60773	1572.243183	144.794264	742.666985
14		403.372	2068.942916	2472.314916	0.331755666	820.2044822	4380	3389.261	1124.40641	1453.089818	133.820947	686.383536
15		403.372	2068.942916	2472.314916	0.30661337	758.0448079	4380	3389.261	1039.19261	1342.96656	123.679248	634.36556
16		403.372	2068.942916	2472.314916	0.283376497	700.5959408	4380	3389.261	960.436794	1241.189058	114.306144	586.289796
17		403.372	2068.942916	2472.314916	0.261900644	647.5008695	4380	3389.261	887.649533	1147.124822	105.643387	541.857483
18		403.372	2068.942916	2472.314916	0.242052352	598.4296391	4380	3389.261	820.378496	1060.1893	97.6371411	500.792498
19		403.372	2068.942916	2472.314916	0.223708273	553.0773004	4380	3389.261	758.205634	979.8422363	90.2376535	462.839647
20		403.372	2068.942916	2472.314916	0.206754411	511.1620152	4380	3389.261	700.744579	905.5843219	83.3989404	427.763075
21		403.372	2068.942916	2472.314916	0.191085408	472.4233042	4380	3389.261	647.638243	836.9540868	77.0785032	395.344801
22		403.372	2068.942916	2472.314916	0.176603889	436.6204291	4380	3389.261	598.556601	773.525034	71.2370639	365.383365
23		403.372	2068.942916	2472.314916	0.16321986	403.5308956	4380	3389.261	553.194641	714.9029889	65.8383216	337.692574
24		403.372	2068.942916	2472.314916	0.150850148	372.9490717	4380	3389.261	511.270463	660.7236496	60.848726	312.100346
25		403.372	2068.942916	2472.314916	0.139417882	344.6849092	4380	3389.261	472.523533	610.6503231	56.2372699	288.447639
26		403.372	2068.942916	2472.314916	0.128852017	318.5627626	4380	3389.261	436.713062	564.3718328	51.9752957	266.587467
27		403.372	2068.942916	2472.314916	0.119086892	294.4202982	4380	3389.261	403.616508	521.6005849	48.0363176	246.383981
28		403.372	2068.942916	2472.314916	0.110061822	272.1074845	4380	3389.261	373.028196	482.0707808	44.3958573	227.711627
29		403.372	2068.942916	2472.314916	0.101720723	251.4856603	4380	3389.261	344.758037	445.536766	41.0312914	210.454369
30		403.372	2068.942916	2472.314916	0.094011759	232.4266731	4380	3389.261	318.630349	411.7715028	37.9217111	194.504962

APPENDIX 9: LCOE – CCGT including carbon capture and storage

INPUTS

PLANT

Overnight investment	R/kW	22262
Capacity factor	%	50%
Fuel	R/GJ	63.9
Efficiency	%	41%
Fixed O&M	R/kW-yr	444.0
Var O&M	R/kWh	0.04
Operating Period	Yrs	30

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX	1.21	0.46	0.18	0.57
LCOE Discounted CAPEX	1.26	0.51	0.18	0.57
LCOE No CAPEX	0.75	0.00	0.18	0.57

Construction Period	Yrs	3	1	2	3	4	5	6	7	8	9	10	11	12
Construction Phasing	%	100%	40%	50%	10%	0	0	0	0	0	0	0	0	0
Overnight CAPEX	R/kW	22262		11131	2226.2	0	0	0	0	0	0	0	0	0
Present Value			10425.0631	12043.742	2226.2	0	0	0	0	0	0	0	0	0
Total Present Value		24695.005												

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	22262					58371.4209			58371.4209	48393.03045	8622.17961	27487.2413
0	22262			22262	1	22262						
1		780.384	2487.84	3268.224	0.924214418	3020.539741	4380	5283.133	4882.74783	4048.05915	721.242144	2299.2976
2		780.384	2487.84	3268.224	0.85417229	2791.626378	4380	5283.133	4512.70594	3741.27463	666.582388	2125.04399
3		780.384	2487.84	3268.224	0.789438346	2580.061348	4380	5283.133	4170.7079	3457.739954	616.065054	1963.99629
4		780.384	2487.84	3268.224	0.729610301	2384.529896	4380	5283.133	3854.62837	3195.693118	569.376205	1815.15369
5		780.384	2487.84	3268.224	0.674316359	2203.81691	4380	5283.133	3562.50311	2953.505654	526.225698	1677.59121
6		780.384	2487.84	3268.224	0.623212902	2036.799362	4380	5283.133	3292.51674	2729.672509	486.345377	1550.45398
7		780.384	2487.84	3268.224	0.575982349	1882.439336	4380	5283.133	3042.99144	2522.802688	449.487409	1432.95193
8		780.384	2487.84	3268.224	0.532331191	1739.777575	4380	5283.133	2812.37656	2331.610618	415.422744	1324.35483
9		780.384	2487.84	3268.224	0.491988162	1607.927519	4380	5283.133	2599.23897	2154.908149	383.93969	1223.98783
10		780.384	2487.84	3268.224	0.454702553	1486.069795	4380	5283.133	2402.25413	1991.597181	354.842597	1131.2272
11		780.384	2487.84	3268.224	0.420242655	1373.447131	4380	5283.133	2220.1979	1840.662829	327.950644	1045.49649
12		780.384	2487.84	3268.224	0.388394321	1269.35964	4380	5283.133	2051.93891	1701.167124	303.096714	966.262927
13		780.384	2487.84	3268.224	0.358959631	1173.160481	4380	5283.133	1896.43153	1572.243183	280.126353	893.034128
14		780.384	2487.84	3268.224	0.331755666	1084.251831	4380	5283.133	1752.70936	1453.089818	258.896814	825.355017
15		780.384	2487.84	3268.224	0.30661337	1002.081174	4380	5283.133	1619.87926	1342.96656	239.276168	762.805006
16		780.384	2487.84	3268.224	0.283376497	926.1378691	4380	5283.133	1497.11577	1241.189058	221.142484	704.995385
17		780.384	2487.84	3268.224	0.261900644	855.9499715	4380	5283.133	1383.65598	1147.124822	204.383072	651.566899
18		780.384	2487.84	3268.224	0.242052352	791.0813045	4380	5283.133	1278.7948	1060.1893	188.893782	602.187522
19		780.384	2487.84	3268.224	0.223708273	731.1287472	4380	5283.133	1181.88059	979.8422363	174.578357	556.55039
20		780.384	2487.84	3268.224	0.206754411	675.7197294	4380	5283.133	1092.31109	905.5843219	161.347835	514.371895
21		780.384	2487.84	3268.224	0.191085408	624.5099163	4380	5283.133	1009.52965	836.9540868	149.119995	475.389921
22		780.384	2487.84	3268.224	0.176603889	577.1810686	4380	5283.133	933.021861	773.525034	137.818849	439.362219
23		780.384	2487.84	3268.224	0.16321986	533.4390653	4380	5283.133	862.312256	714.9029889	127.374168	406.064898
24		780.384	2487.84	3268.224	0.150805148	493.0120751	4380	5283.133	796.96142	660.7236496	117.721042	375.291033
25		780.384	2487.84	3268.224	0.139417882	455.648868	4380	5283.133	736.563234	610.6503231	108.799484	346.849384
26		780.384	2487.84	3268.224	0.128852017	421.1172532	4380	5283.133	680.742361	564.3718328	100.554052	320.563201
27		780.384	2487.84	3268.224	0.119086892	389.202637	4380	5283.133	629.151905	521.6005849	92.9335048	296.269132
28		780.384	2487.84	3268.224	0.110061822	359.7066885	4380	5283.133	581.471261	482.0707808	85.890485	273.816204
29		780.384	2487.84	3268.224	0.101720723	332.4461077	4380	5283.133	537.404123	445.536766	79.3812246	253.064883
30		780.384	2487.84	3268.224	0.094011759	307.2514858	4380	5283.133	496.676639	411.7715028	73.3652722	233.886214

APPENDIX 9: LCOE – OCGT

INPUTS

PLANT

Overnight investment	R/kW	9226
Capacity factor	%	10%
Fuel	R/GJ	63.9
Efficiency	%	31%
Fixed O&M	R/kW-yr	181.0
Var O&M	R/kWh	0.0027
Operating Period	Yrs	30

FINANCIAL

Discount rate		8%
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CONVERSION FACTORS

Hrs per year		8760
Fuel Conversion Factor	kW/GJ	0.0036

OUTPUTS

	TOTAL	CAPEX	O&M	Fuel
LCOE Overnight CAPEX	1.92	0.95	0.23	0.73
LCOE Discounted CAPEX	1.99	1.02	0.23	0.73
LCOE No CAPEX	0.97	0.00	0.23	0.73

		1	2	3	4	5	6	7	8	9	10	11	12
Construction Period	Yrs	2	1	0	0	0	0	0	0	0	0	0	0
Construction Phasing	%	100%	90%	10%									
Overnight CAPEX	R/kW	9226	8303.4	922.6	0	0	0	0	0	0	0	0	0
Present Value			8984.2788	922.6	0	0	0	0	0	0	0	0	0
Total Present Value		9906.8788											

Year	Investment	O&M	Fuel	Total	Discount factor	Discounted cost	Electricity	Revenue	Disc. Rev	Discounted Electricity	Discounted O&M	Discounted Fuel
	R/kW-yr	R/kW-yr	R/kW-yr	R/kW-yr		R/kW-yr	MWh			MWh		
TOTAL	9226					18600.43732			18600.4373	9678.606091	2261.12568	7113.31165
0	9226			9226	1	9226						
1		204.652	643.8180192	848.4700192	0.924214418	784.1682247	876	1683.505	1555.91972	809.6118299	189.142329	595.025896
2		204.652	643.8180192	848.4700192	0.85417229	724.7395792	876	1683.505	1438.00344	748.254926	174.808067	549.931512
3		204.652	643.8180192	848.4700192	0.789438346	669.8147682	876	1683.505	1329.02351	691.5479908	161.560136	508.254632
4		204.652	643.8180192	848.4700192	0.729610301	619.052466	876	1683.505	1228.30269	639.1386236	149.316207	469.736259
5		204.652	643.8180192	848.4700192	0.674316359	572.1372144	876	1683.505	1135.21506	590.7011309	138.000192	434.137023
6		204.652	643.8180192	848.4700192	0.623212902	528.7774625	876	1683.505	1049.18212	545.9345018	127.541767	401.235696
7		204.652	643.8180192	848.4700192	0.575982349	488.7037546	876	1683.505	969.669245	504.5605377	117.87594	370.827815
8		204.652	643.8180192	848.4700192	0.532331191	451.667056	876	1683.505	896.182296	466.3221235	108.942643	342.724413
9		204.652	643.8180192	848.4700192	0.491988162	417.4372052	876	1683.505	828.264599	430.9816299	100.686361	316.750844
10		204.652	643.8180192	848.4700192	0.454702553	385.8014836	876	1683.505	765.494084	398.3194361	93.0557868	292.745697
11		204.652	643.8180192	848.4700192	0.420242655	356.5632935	876	1683.505	707.480669	368.1325657	86.0034998	270.559794
12		204.652	643.8180192	848.4700192	0.388394321	329.5409367	876	1683.505	653.863835	340.2334249	79.4856745	250.055262
13		204.652	643.8180192	848.4700192	0.358959631	304.5664849	876	1683.505	604.310383	314.4486367	73.4618064	231.104679
14		204.652	643.8180192	848.4700192	0.331755666	281.4847365	876	1683.505	558.512369	290.6179637	67.8944606	213.590276
15		204.652	643.8180192	848.4700192	0.30661337	260.1522519	876	1683.505	516.185184	268.5933121	62.7490394	197.403212
16		204.652	643.8180192	848.4700192	0.283376497	240.436462	876	1683.505	477.065789	248.2378115	57.9935669	182.442895
17		204.652	643.8180192	848.4700192	0.261900644	222.2148447	876	1683.505	440.911081	229.4249644	53.5984907	168.616354
18		204.652	643.8180192	848.4700192	0.242052352	205.3741633	876	1683.505	407.496378	212.0378599	49.5364978	155.837665
19		204.652	643.8180192	848.4700192	0.223708273	189.8097628	876	1683.505	376.614028	195.9684473	45.7823455	144.027417
20		204.652	643.8180192	848.4700192	0.206754411	175.4249194	876	1683.505	348.072114	181.1168644	42.3127038	133.112216
21		204.652	643.8180192	848.4700192	0.191085408	162.1302397	876	1683.505	321.693266	167.3908174	39.1060109	123.024229
22		204.652	643.8180192	848.4700192	0.176603889	149.8431051	876	1683.505	297.313555	154.7050068	36.1423391	113.700766
23		204.652	643.8180192	848.4700192	0.16321986	138.4871581	876	1683.505	274.781474	142.9805978	33.4032709	105.083887
24		204.652	643.8180192	848.4700192	0.150850148	127.9918282	876	1683.505	253.957	132.1447299	30.8717846	97.1200437
25		204.652	643.8180192	848.4700192	0.139417882	118.291893	876	1683.505	234.710721	122.1300646	28.5321484	89.7597446
26		204.652	643.8180192	848.4700192	0.128852017	109.327073	876	1683.505	216.923032	112.8743666	26.3698229	82.9572501
27		204.652	643.8180192	848.4700192	0.119086892	101.0416571	876	1683.505	200.483394	104.320117	24.3713705	76.6702866
28		204.652	643.8180192	848.4700192	0.110061822	93.38415632	876	1683.505	185.289643	96.41415617	22.524372	70.8597843
29		204.652	643.8180192	848.4700192	0.101720723	86.30698366	876	1683.505	171.24736	89.10735321	20.8173494	65.4896343
30		204.652	643.8180192	848.4700192	0.094011759	79.76615865	876	1683.505	158.269279	82.35430056	19.2396944	60.5264642

APPENDIX 10: Average renewables availability

	PRODUCTION (kWh)			CAPACITIES (kWh)			CAPACITY FACTORS		
PERIOD	Onshore Wind	Solar PV	Total	Wind Capacity	PV Capacity	Total	Wind Capacity	PV Capacity	TOTAL CAPACITY
0	537156.28	0	537156.28	1640883.61	1361309.20	3002192.81	32 %	0 %	18 %
1	519928.15	0.12	519928.27	1640883.61	1361309.20	3002192.81	31 %	0 %	17 %
2	508524.81	0	508524.81	1640883.61	1361309.20	3002192.81	31 %	0 %	17 %
3	502301.46	0.002	502301.46	1640883.61	1361309.20	3002192.81	30 %	0 %	17 %
4	503710.89	1.13	503712.02	1640883.61	1361309.20	3002192.81	30 %	0 %	17 %
5	506728.46	3022.05	509750.51	1640883.61	1361309.20	3002192.81	31 %	0 %	17 %
6	503550.33	66326.97	569877.313	1640883.61	1361309.20	3002192.81	30 %	5 %	19 %
7	497656.78	291645.05	789301.83	1640883.61	1361309.20	3002192.81	30 %	21 %	26 %
8	497189.08	619775.69	1116964.77	1640883.61	1361309.20	3002192.81	30 %	45 %	37 %
9	498742.96	858809.07	1357552.04	1640883.61	1361309.20	3002192.81	30 %	63 %	45 %
10	512594.68	992256.11	1504850.81	1640883.61	1361309.20	3002192.81	31 %	73 %	50 %
11	538171.47	1051659.65	1589831.12	1640883.61	1361309.20	3002192.81	33 %	77 %	53 %
12	574532.85	1054651.38	1629184.23	1640883.61	1361309.20	3002192.81	35 %	77 %	54 %
13	612678.75	1013757.66	1626436.41	1640883.61	1361309.20	3002192.81	37 %	74 %	54 %
14	651239.53	925028.31	1576267.84	1640883.61	1361309.20	3002192.81	40 %	68 %	53 %
15	684986.49	773320.95	1458307.44	1640883.61	1361309.20	3002192.81	42 %	57 %	49 %
16	709061.06	524730.91	1233791.97	1640883.61	1361309.20	3002192.81	43 %	38 %	41 %
17	723078.98	212915.68	935994.66	1640883.61	1361309.20	3002192.81	44 %	16 %	31 %
18	721089.76	39119.89	760209.65	1640883.61	1361309.20	3002192.81	44 %	3 %	25 %
19	698103.95	1157.36	699261.31	1640883.61	1361309.20	3002192.81	42 %	0 %	23 %
20	661444.75	1.35407	661446.10	1640883.61	1361309.20	3002192.81	40 %	0 %	22 %
21	626969.03	2.25048	626971.28	1640883.61	1361309.20	3002192.81	38 %	0 %	21 %
22	590219.43	0	590219.43	1640883.61	1361309.20	3002192.81	36 %	0 %	20 %
23	561049.25	0	561049.25	1640883.61	1361309.20	3002192.81	34 %	0 %	19 %
						TOTAL	35 %	26 %	31 %

APPENDIX 11: Highest renewables availability

	PRODUCTION (kWh)			CAPACITIES (kWh)			CAPACITY FACTORS		
PERIOD	Onshore Wind	Solar PV	Total	Wind Capacity	PV Capacity	Total	Wind Capacity	PV Capacity	TOTAL CAPACITY
0	1343530.73	0	1343530.73	2079760	1474190	3553950	64.60 %	0.00 %	37.80 %
1	1327893.55	0	1327893.55	2079760	1474190	3553950	63.85 %	0.00 %	37.36 %
2	1257130.39	0	1257130.39	2079760	1474190	3553950	60.45 %	0.00 %	35.37 %
3	1250281.03	0	1250281.03	2079760	1474190	3553950	60.12 %	0.00 %	35.18 %
4	1238136.04	0	1238136.04	2079760	1474190	3553950	59.53 %	0.00 %	34.84 %
5	1210092.33	3828.79	1213921.12	2079760	1474190	3553950	58.18 %	0.26 %	34.16 %
6	1165202.21	157689.24	1322891.45	2079760	1474190	3553950	56.03 %	10.70 %	37.22 %
7	1167917.31	568315.60	1736232.91	2079760	1474190	3553950	56.16 %	38.55 %	48.85 %
8	1380825.69	887677.78	2268503.48	2079760	1474190	3553950	66.39 %	60.21 %	63.83 %
9	1386709.28	1086659.36	2473368.63	2079760	1474190	3553950	66.68 %	73.71 %	69.59 %
10	1365340.49	1205283.23	2570623.72	2079760	1474190	3553950	65.65 %	81.76 %	72.33 %
11	1450298.10	1238553.20	2688851.30	2079760	1474190	3553950	69.73 %	84.02 %	75.66 %
12	1556023.81	1233479.16	2789502.97	2079760	1474190	3553950	74.82 %	83.67 %	78.49 %
13	1609944.87	1105140.04	2715084.91	2079760	1474190	3553950	77.41 %	74.97 %	76.40 %
14	1656458.18	953702.50	2610160.69	2079760	1474190	3553950	79.65 %	64.69 %	73.44 %
15	1667367.02	786179.49	2453546.51	2079760	1474190	3553950	80.17 %	53.33 %	69.04 %
16	1704439.18	605829.28	2310268.46	2079760	1474190	3553950	81.95 %	41.10 %	65.01 %
17	1749951.40	241873.99	1991825.386	2079760	1474190	3553950	84.14 %	16.41 %	56.05 %
18	1768487.29	19906.16	1788393.45	2079760	1474190	3553950	85.03 %	1.35 %	50.32 %
19	1798883.99	0	1798883.99	2079760	1474190	3553950	86.49 %	0.00 %	50.62 %
20	1819255.73	0	1819255.74	2079760	1474190	3553950	87.47 %	0.00 %	51.19 %
21	1726029.38	0	1726029.38	2079760	1474190	3553950	82.99 %	0.00 %	48.57 %
22	1651423.11	0	1651423.11	2079760	1474190	3553950	79.40 %	0.00 %	46.47 %
23	1577031.86	0	1577031.86	2079760	1474190	3553950	75.83 %	0.00 %	44.37 %
						TOTAL	71.78 %	28.53 %	53.84 %

APPENDIX 12: Lowest renewables availability

	PRODUCTION (kWh)			CAPACITIES (kWh)			CAPACITY FACTORS		
PERIOD	Onshore Wind	Solar PV	Total	Wind Capacity	PV Capacity	Total	Wind Capacity	PV Capacity	TOTAL CAPACITY
0	339015.66	0	339015.66	2077720	1474190	3551910	16.32 %	0.00 %	9.54 %
1	367734.085	0	367734.08	2077720	1474190	3551910	17.70 %	0.00 %	10.35 %
2	359601.94	0	359601.94	2077720	1474190	3551910	17.31 %	0.00 %	10.12 %
3	307997.26	0	307997.26	2077720	1474190	3551910	14.82 %	0.00 %	8.67 %
4	268540.118	0	268540.11	2077720	1474190	3551910	12.92 %	0.00 %	7.56 %
5	277530.39	0	277530.39	2077720	1474190	3551910	13.36 %	0.00 %	7.81 %
6	199025.20	4652.03	203677.23	2077720	1474190	3551910	9.58 %	0.32 %	5.73 %
7	215322.57	92971.22	308293.80	2077720	1474190	3551910	10.36 %	6.31 %	8.68 %
8	183797.83	203357.19	387155.02	2077720	1474190	3551910	8.85 %	13.79 %	10.90 %
9	200206.09	306657.68	506863.77	2077720	1474190	3551910	9.64 %	20.80 %	14.27 %
10	165176.14	442411.86	607588.00	2077720	1474190	3551910	7.95 %	30.01 %	17.11 %
11	114651.91	513603.44	628255.34	2077720	1474190	3551910	5.52 %	34.84 %	17.69 %
12	165165.71	446792.85	611958.558	2077720	1474190	3551910	7.95 %	30.31 %	17.23 %
13	321375.62	460277.55	781653.17	2077720	1474190	3551910	15.47 %	31.22 %	22.01 %
14	238577.58	418538.03	657115.61	2077720	1474190	3551910	11.48 %	28.39 %	18.50 %
15	233550.73	435410.81	668961.55	2077720	1474190	3551910	11.24 %	29.54 %	18.83 %
16	216411.26	284939.87	501351.14	2077720	1474190	3551910	10.42 %	19.33 %	14.11 %
17	169611.79	109074.30	278686.10	2077720	1474190	3551910	8.16 %	7.40 %	7.85 %
18	233362.90	7344.47	240707.37	2077720	1474190	3551910	11.23 %	0.50 %	6.78 %
19	360515.43	0	360515.43	2077720	1474190	3551910	17.35 %	0.00 %	10.15 %
20	267104.67	0	267104.67	2077720	1474190	3551910	12.86 %	0.00 %	7.52 %
21	197750.72	0	197750.72	2077720	1474190	3551910	9.52 %	0.00 %	5.57 %
22	144049.48	0	144049.48	2077720	1474190	3551910	6.93 %	0.00 %	4.06 %
23	139755.23	0	139755.23	2077720	1474190	3551910	6.73 %	0.00 %	3.93 %
						TOTAL	11.40 %	10.53 %	11.04 %