The Use of Natural Gas to Facilitate the Transition to Renewable Electric Power Generation in South Africa

by
Stephen Richard Clark

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Supervisor: Johannes L. van Niekerk
Co-supervisor: Jim Petrie

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Declaration

By submitting this dissertation electronically, I declare that the entirety of the work contained therein is my own, original work, that I am the sole author thereof (save to the extent explicitly otherwise stated), that reproduction and publication thereof by Stellenbosch University will not infringe any third party rights and that I have not previously in its entirety or in part submitted it for obtaining any qualification.

Date: 11 August 2020

Abstract

Title: The Use of Natural Gas to Facilitate the Transition to Renewable Electric Power Generation in South Africa

Name of student: Stephen Richard Clark
Supervisor: Johannes L. van Niekerk
Co-supervisor: Jim Petrie

Research Question: The proposed study aims to address the appropriate role for natural gas in meeting the requirement for dispatchable energy in the South African electricity grid to support the transition to a renewable energy based generation system.

As a path for achieving its international commitments on climate change, South Africa intends to develop a renewable energy based electricity generation system to meet its greenhouse gas emission reduction targets. One of the necessary conditions for large scale renewable energy implementation is the corresponding use of dispatchable power to mitigate the variable nature of the renewable sources. This study intends to answer the question of whether natural gas dispatchable power is the best way to meet this need. This involves the determination of timing and amount of dispatchable gas power that will be required, as well as the sourcing of the gas and the economics of this particular use. The analysis covers the time period between 2020 and 2050, but as per the Integrated Resource Plan (IRP) process concentrates on the period up to 2030.

This research establishes the economic case for natural gas based dispatchable power. The analysis has been based on system modelling on referenced renewable energy plans using performance data from installed wind and solar generation sources. While there has been much discussion within the South Africa Integrated Resource Plan (IRP) process about the benefit of the transition to renewable generation backed up with dispatchable gas generation, there have always been questions about the source for this gas in the IRPs. This research compares the potential use of shale gas, imported LNG and pipeline gas to meet this need.

Review of the IRP scenarios shows there is a large range in the potential requirement for dispatchable power depending on growth in the amount of power required as well as the performance and decommissioning of the existing base load generation system. While there has been general realisation within the IRP process of the benefit of natural gas fuelled dispatchable power, the sourcing for that gas has been left undefined. This analysis shows that small total volumes of gas on an annualised basis are needed for dispatchable generation for any likely scenario. There are several reasonable sources that can be utilised. Previously not discussed in any forum, storing the gas to provide for dispatchable use – large rates for short periods - presents the major challenge for whatever source is utilised. Solutions to store the gas have been reviewed and a conceptual option for storage utilising abandoned mine shafts is proposed.

The analysis indicated that the dispatchable energy requirement from the system in 2030 could vary from 5 to 15 GW, with an expected capacity factor between 2 % and 5 %. This corresponds to an fuel requirement of 9 to 78 PJ per year, with an expected value of 27 PJ/a, compared to the current importation of gas into the country of 200 PJ/a. Storage of 140 million cubic meters of gas would likely be required to meet the forecasted demand profile.

This work fills in this missing piece that currently exists in the IRP planning for the transition to renewable power generation, The results of this study, explaining the requirement for gas storage to make gas generation viably dispatchable, can assist policy makers and planners in setting up long term plans for development programmes for renewable generation backed up with dispatchable gas generation.

Opsomming

Titel: Die rol van natuurlike gas in die oorgang na hernubare elektrisiteit in Suid-Afrika.

Naam van Student: Stephen Richard Clark
Promotor: Johannes L. van Niekerk
Mede-Promotor: Jim Petrie

Met die oog daarop om sy internasionale verpligtinge met betrekking tot klimaatsverandering na te kom, beplan Suid-Afrika om ’n hernubare energiegebaseerde elektrisiteitsopwekkingstelsel te ontwikkel om sodoende sy teikens vir die vermindering van kweekhuisgasse te behaal. Navorsingsvraag: Die doel van hierdie studie was om te bepaal hoe toepaslik natuurlike gas is om te voldoen aan die vereiste vir versendbare (Eng: dispatchable) elektrisiteit in die Suid-Afrikaanse elektrisiteitsnetwerk om die oorgang na ’n grootliks hernubare-gebaseerde opwekkingstelsel te ondersteun.

Een van die noodsaaklike voorwaardes vir die grootskaalse implementering van hernubare energie is die vereiste van versendbare krag om die variërende aard van die hernubare energie bronne aan te vul. Hierdie studie poog om die vraag te beantwoord of elektrisiteit van gas-kragstasies die beste manier is om hierdie behoefte aan te spreek. Dit behels, onder andere, die bepaling van wanneer en hoeveel versendbare krag benodig sal word, sowel as die bron van die gas en hoe om dit ekonomies te gebruik. Die analise dek die tydperk tussen 2020 en 2050, maar volgens die beplanning van die “Integrated Resource Plan (IRP)” proses word daar gefokus op die periode tot en met 2030.

Hierdie navorsing bevestig die ekonomiese meriete vir natuurlike gas gebaseerde versendbare krag. Die ontleding is gebaseer op stelsel modellering van bestaande hernubare energie opwekking deur gebruik te maak van data oor die prestasie van bestaande wind- en sonkragstasies. Hoewel daar deeglike onderhandelinge tydens die Suid-Afrikaanse IRP-proses plaasgevind het oor die voordeel van die omskakeling na hernubare opwekking gerugsteun deur versendbare gas opwekking, was daar altyd vrae oor die bron van hierdie gas in die IRP’s. Hierdie navorsing vergelyk die potensiële gebruik van skalie-gas, ingevoerde vloeibare natuurlike gas en pyplyn-gas om aan hierdie behoefte te voldoen.

Ontleding van die IRP scenario’s dui daarop dat daar heelwat speling is in die potensiële vereiste vir versendbare krag, afhangend van die toename in die krag-aanvraag sowel as die prestasie en die aftakeling van bestaande steenkool-kragstasies. Terwyl daar binne die IRP-proses die voordele van natuurlike gas kragstasies uitgelig is, is die verkryging van die gas ongedefinieerd gelaat. Die analise van die studie dui daarop dat die totale volume gas benodig in ‘n jaar klein is vir al die scenario’s wat ondersoek is. Daar is verskeie beskikbare bronne wat gebruik sou kon word. Ongeag van watter bron gebruik word, is ’n wesenlike uitdaging wat nog nie op enige forum bespreek is nie, die stoor van die gas – groot volumes gas word vir kort periodes benodig - om die kragstelsel te ondersteun. Oplossings om die gas te stoor is verder

ondersoek en ’n konsep, wat ook gepatenteer is, om verlate mynskagte te gebruik word voorgestel.

Die analise dui daarop dat die versendbare energievereiste vanuit die stelsel in 2030 kan wissel van 5 tot 15 GW, met ’n verwagte kapasiteitsfaktor tussen 2 % en 5 %. Dit korrespondeer met ’n verwagte brandstofvereiste van 27 PJ/a, in vergelyking met die huidige invoer van gas van 200 PJ/a. Die stoor van 140 miljoen kubieke meter gas sal waarskynlik benodig word om aan die voorspelde vereistes te voldoen.

Hierdie ondersoek verskaf die ontbrekende legkaartstuk in die IRP-beplanning vir die omskakeling na grootskaalse hernubare kragopwekking. Die verwagting is dat die uitkoms van hierdie studie, wat die behoefte aan die stoor van natuurlike gas om dit lewensvatbaar te maak as ‘n bron van versendbare krag te maak verduidelik, beleidvormers en beplanners kan help met die opstel van langtermyn planne vir ontwikkeling van hernubare kragopwekking gerugsteun deur versendbare gasopwekking

Addendum – Changes After Close of Analysis - 2020

This thesis is intended to review the long-term forecasting of the electricity power system in South Africa. To this end, costs for the elements of power generation were based, as much as possible, on long-term trends. However, on a short-term, the values can be affected by specific events. The analysis was closed using prices up to 2019. In 2020, there were three events that have brought questions to all of the trends related to this analysis.

- The Coronavirus Pandemic. In the first quarter of 2020, a pandemic from the coronavirus swept the world. This pandemic has caused widespread disruption to all activities, with populations locked into their houses and disruption to all forms of economic activity. In South Africa, this has resulted in the electricity demand dropping by over 9 GW, or approximately 30 % from the beginning of March 2020 to April 2020. Recovery (if, when and how) from this disruption of economic activity is actively debated throughout the world. The focus of most of these discussions are on relatively short-term considerations, the long-term effects are still unknown.

- The collapse of oil prices. In March 2020, a dispute between Saudi Arabia and Russia on control of the oil market led to a massive oversupply situation in the oil market and an associated collapse in the price of oil. The price of a barrel (160 litres) of oil dropped from approximately USD 60 to, at least for a few days, below zero. Much of the overproduction has been put into storage and this storage must be reduced, in addition to reduced production, before markets come into balance. The collapse of economic activity from the Coronavirus internationally has also had a major effect on the volume of oil used. The collapse of oil prices has led to significant price drops in other fuels, with coal on the export market dropping from USD 70 to 52 per tonne and natural gas delivered to Japan as LNG dropping to a price of USD 3 per GJ in March 2020, from over USD 6 per GJ in January.

- Exchange rate change. For South Africa, in March 2020, the exchange rate for the Rand dropped in the month by 30 %. In US dollar terms, the rate went from 15 R per USD to 19 R per USD. The long-term trend for the Rand compared to the dollar and related currencies has been downward for the last twenty years averaging a decline of approximately 4 % per year but this recent drop has been much quicker and more significant than the trend.

How these major disruptions will affect the long-term trends related to the cost of electricity generation is a matter that will debated for some time. Clearly, the specific numbers derived from the analysis in this thesis were based on premises that have changed. However, it is unlikely that the trends will change enough to affect the relative comparisons to the point where the conclusions would change. Capital costs for all new developments in South Africa will be affected by the exchange rate changes. All of the likely developments involve significant portions of imported technology, whether from Japan as per Kusile and Medupi, Russia or

France in the proposed nuclear plants or China and Europe for solar PV and wind components. The revised exchange rates will likely raise the cost of any development by a proportional amount. This will increase the advantage of low capital cost projects related to wind, solar PV and dispatchable gas.

The effect on fuel costs for the various dispatchable power options is more complicated as the drop in oil, gas and coal costs are offset to some extent by the drop in the value of the Rand. The most significant factor that these changes have brought to the conversation of fuel costs is the amount of volatility that exists for all fuels. This volatility has been demonstrated in the cost of all fuels therefore the current prices do not appear to change the comparison between fuels. As the CSIR noted in their 2018 IRP review, this volatility in fuel costs will not have a material effect on the cost of power due to the low amount of dispatchable power that is needed.

One trend that likely has more impact that those noted above and has continued throughout this very complex period is the continued decline in the cost of solar PV and wind. The utility providing electricity to New Mexico in the USA announced this last month two solar PV projects with a price of USD 0.015 per kWh for 100 MW of solar PV generation and USD 0.02 for a 100 MW project with 50 MW of four hours storage. As the price for these developments continues to drop below the cost of fuelling fossil fuel plants, the transition to renewable sources becomes more clearly the most economical choice.

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Dedications

I would like to dedicate this body of work to the memory of my parents, Roy and Helen Clark, who unfortunately did not live long enough to see their son accomplish this task. I can only hope that they would look favourably on the effort that went into achieving this work and the resulting report.

Table of Contents

Declaration ii
Abstract iii
Opsomming v
Addendum – Changes After Close of Analysis - 2020 vii
Acknowledgements ix
Dedications x
Table of Contents xi
List of Figures xv
List of Tables xviii
Nomenclature xix
1. Introduction 1
2. Motivation and Scope of Study 4
2.1. Motivation 5
2.2. Methodology 7
3. Literature Review 9
3.1. South African greenhouse gas (GHG) emission plans 9
3.2. Global efforts towards renewable generation 9
3.3. International experience 12
3.4. Large "island" systems 14
3.4.1. Relevance for South Africa 18
3.5. The integrated resource plan process – definition and usage 18
3.6. South Africa progress and plans 19
3.6.1. South Africa energy transition planning 2010-2019 19
3.6.2. WWF 2030 scenario 21
3.6.3. CSIR 2016 review 21
3.6.4. CSIR 2018 review 22
3.6.5. Renewable energy progress 22
3.6.6. South Africa renewable energy development 23
3.6.7. South Africa gas 25
3.7. Worst case planning – maximum power and energy requirement 30
3.8. Potential to replace gas as a dispatchable source 31
3.8.1. Renewable dispatchable energy 31
3.8.2. Renewable generation plus storage 32
3.9. Chapter summary 39
4. Dispatchable Power in the South African Grid 41

4.1. Assume a renewable energy scenario ... 41
4.2. Determine the best model tool to utilise ... 42
4.3. Using the system model to develop a dispatchable energy profile ... 46
4.4. Results from the Dispatchable Energy Model ... 47
4.5. Worst case analysis – maximum power and energy required ... 48
4.6. Review of energy storage options ... 50
4.7. Chapter summary ... 54
5. Gas Supply Options Specific to South Africa ... 55
5.1. Potential gas sources ... 56
5.1.1. Local shale gas ... 56
5.1.2. Local offshore gas ... 58
5.1.3. Imported liquified natural gas (LNG) ... 58
5.1.4. Pipeline from Mozambique ... 62
5.1.5. Rompco pipeline ... 64
5.1.6. Liquid petroleum gas (LPG) ... 65
5.1.7. Gas supply option - storage ... 65
5.2. Compare gas fuelled electricity generation costs to alternatives ... 66
5.2.1. Levelized cost of electricity (LCOE) ... 66
5.2.2. Scenario costing ... 70
5.2.3. Capacity Payments ... 71
5.3. Gas storage ... 71
5.3.1. Gas storage history ... 72
5.3.2. Underground gas storage ... 73
5.3.3. Above-ground storage ... 77
5.3.4. Storage as LNG ... 78
5.3.5. Relevance for South Africa ... 80
5.3.6. The storage requirement in South Africa ... 82
5.3.7. LNG storage ... 83
5.4. Mine shaft storage for South Africa ... 83
5.4.1. Mine shafts ... 84
5.4.2. The concept ... 85
5.4.3. Capital cost ... 86
5.4.4. Environmental issues ... 86
5.5. Chapter summary ... 89
6. Dispatchable Power Supply Scenarios ... 90
6.1. South Africa gas dispatchable power scenario ... 90
6.1.1. Diesel fuel replacement using LPG ... 90
6.1.2. Gas from Rompco to meet first dispatchable power ... 91
6.1.3. West Coast solution from Brulpadda ... 94

6.1.4. FSRU in Richards Bay 95
6.1.5. Reverse flow in Lilly and add more dispatchable generation in Gauteng 96
6.1.6. Other advantages 97
6.2. Sensitivity and robustness review 98
6.2.1. Varying Demand Growth 98
6.2.2. Creation of a gas business 98
6.2.3. Base Load Plant Retirement Scheduling 98
6.2.4. System Inertia 99
6.2.5. Greenhouse gas 99
6.2.6. System Breakdown Backup 100
6.3. Potential to replace gas with renewable sourced dispatchable energy 100
6.4. Chapter summary 102
7. Conclusions and Recommendations 103
7.1. Main conclusions 103
7.2. Other conclusions 106
7.3. Recommendations 107
7.4. Further study 109
Appendix A – Forecast Inputs (2017) Review 110
A.1. Renewable energy model creation 110
A.2. Choosing a modelling tool 110
A.3. Demand 112
A.4. Renewable generation 113
A.4. Comparison to IRP models 117
A.5. Conclusion 119
Appendix B – Range of Forecasts 120
B.1. Background 120
B.2. IRP 120
B.3. Forecast model 122
B.4. Sensitivities 123
B.5. Growth in demand 126
B.6. Energy availability factor (EAF) 131
B.7. Decommissioning 132
B.8. Effects of volume of wind and solar PV 134
B.9. Resulting uncertainty 135
B.10. Recommendation 136
Appendix C – Shale Gas Economics 137
C.1. Introduction 137
C.2. Background 138

C.3. Economic analysis 141
C.4. Risk factors 146
C.5. Conclusion 150
Appendix D – Comparative Cost for Dispatchable Power 152
D.1 Background 152
D.2 LCOE 152
D.3. Comparison of scenarios 163
D.4. Capacity Market 165
Appendix E – Using LPG fuel to reduce the operating cost of the Ankerlig Peaking Power Plant 168
E.1. Introduction 168
E.2. The LPG Option 169
E.3. Recommendation 172
Appendix F – Publications and Presentations 173
Appendix G – Storage Patent 174
References 189

List of Figures

Figure 1 - Research Flow Diagram 7
Figure 2 - Growth of Global Wind and Solar Generation - data (BP, 2019) 10
Figure 3 - Levelised Cost of Electricity by Technology (Lazard Assoc., 2018) 11
Figure 4 - G20 Wind and Solar Generation – data (BP, 2019) 12
Figure 5 - Spanish Installed Capacity and Generation – data (REE, 2017) 15
Figure 6 - Spanish Renewable Generation - 4 January 2018 – data (REE, 2018) 16
Figure 7 - Spanish Renewable Generation - 8 January 2018 – data (REE, 2018) 17
Figure 8 - Spanish Generation by Source - 4 January 2018 – data (REE, 2018) 17
Figure 9 - Spanish Generation by Source - 8 January 2018 – data (REE, 2018) 17
Figure 10 - South Africa Installed Capacity and Generation for 2016 – data (ESKOM, 2017) 18
Figure 11 - Rompco Pipeline Route (mjm energy, 2012) 28
Figure 12 - Map of Shale Gas Concessions (Scholes, *et al.*, 2016) 30
Figure 13 - NREL Battery Cost Forecast – data (Cole & Frazier, 2019) 34
Figure 14 - IEA Energy Storage Breakdown (OECD & IEA, 2015) 38
Figure 15 - Wind Performance Curves 2016 - 2018 44
Figure 16 – Solar PV Performance Curves 2016 – 2018 45
Figure 17 - Demand Growth Projections 46
Figure 18 - Dispatchable Energy Sensitivities 2030 47
Figure 19 - Range of Expected Dispatchable Generation 2030 47
Figure 20 - High Dispatchable Demand Period - IRP 2030 50
Figure 21 - Iowa 20 Year Renewables Review (Ziegler, *et al.*, 2019) 50
Figure 22 - Effect of Storage on Dispatchable Generation 53
Figure 23 - Dispatchable Demand with Storage 53
Figure 24 - World Bank LNG Price Forecast - data (World Bank, 2018a) 60
Figure 25 - Richards Bay LNG Terminal Proposals (Transnet, 2016) 61
Figure 26 - Potential Mozambique Gas Pipeline Route (Gasnuso, n.d.) 63
Figure 27 - IRP 2019 Capital Cost Estimates by Technology – data (SA DoE, 2019a) 67
Figure 28 - Estimated LCOEs for Generation by Technology 68
Figure 29 - Estimated LCOE by Technology for Dispatchable Generation 69
Figure 30 - Oberhausen Gasholder (Gasometer Oberhausen History, 2019) 72

Figure 31 - Egoli Gasholder (PricewaterhouseCoopers Inc., 2015) 73
Figure 32 - Map of Underground Natural Gas Storage (International Gas Union, 2014) 74
Figure 33 - Underground Storage Types (Giouse, 2012) 74
Figure 34 - Skallen Storage Schematic (Johansson, 2014) 76
Figure 35 - Example of Surface Piped Storage (Kruck, *et al.*, 2013) 77
Figure 36 - CNG Storage Concepts (Ward, 2016) 78
Figure 37 - USA LNG Storage Map (Tractebel Engineering, 2015) 79
Figure 38 - Typical Small-Scale LNG Storage (McDermott, no date) 80
Figure 39 - Typical LNG Storage Tank (Wartsila, 2015) 80
Figure 40 - Annual Dispatchable Energy Usage – from model simulation 81
Figure 41 - Annual Gas Storage Requirement - from model simulation 82
Figure 42 - Photo of a Typical Mine Shaft (Murray and Roberts, 2019) 84
Figure 43 - Mine Shaft Storage Schematic 88
Figure 44 - South Africa Gas Pipeline Routing (Louw, 2015) 92
Figure 45 - Sasol Sasolburg Gas Fuelled Power Plant (Sasol, 2013) 92
Figure 46 - Eskom Load Centres (Eskom, 2019c) 93
Figure 47 - Potential Gas Plants – pipeline routing from (Transnet, 2016) 97
Figure 48 - IEA Energy Storage Breakdown (OECD & IEA, 2015) 101
Figure 49 - Renewable Generation Sites in South Africa 115
Figure 50 - CSIR Wind Aggregation Curves (Knorr *et al.*, 2015) 115
Figure 51 - Actual Wind Generation Curves 2016-2018 116
Figure 52 - Actual Solar PV Performance vs GHI Model 2016 - 2018 117
Figure 53 - Sensitivity Factors 2030 123
Figure 54 - Sensitivity Factors 2040 124
Figure 55 - Sensitivity Factors 2050 124
Figure 56 - IRP Base Case 2030 125
Figure 57 - Predictions of Rate of Demand Growth 126
Figure 58 - History of Demand Growth and GPD Growth 127
Figure 59 - Demand Growth Compared to Tariff Growth 129
Figure 60 - South Africa Demand Growth Compared to OECD 129
Figure 61 - Per Capita Demand Growth in Representative Countries 130
Figure 62 - Effect of Demand Growth 130

Figure 63 - Historical Coal Plant Availability Factors (Nichols, 2016) 131
Figure 64 - Effect of EAF 132
Figure 65 - Eskom Decommissioning Plan 2018 vs 2019 133
Figure 66 - Effect of Decommissioning 133
Figure 67 - Effect of Wind 134
Figure 68 - Effect of Solar PV 134
Figure 69 - Monte Carlo Simulation Output 135
Figure 70 - South Africa Shale Development Process (SAOGA, 2017) 143
Figure 71 - Shale Well Economics 144
Figure 72 - Shale Gas Steady State Production Profile 145
Figure 73 - Shale Gas Price with NPV@ 8.2 % 145
Figure 74 - Shale Gs Price with NPV @ 15 % 145
Figure 75 - Shale Gas Price Sensitivities 146
Figure 76 - Well Cost versus Depth - adapted from (Lukawski, *et al.*, 2014) 148
Figure 77 - IRP 2018 Capital Cost Comparisons – data (SA DOE, 2018) 155
Figure 78 - LCOE by Generation Technology 162
Figure 79 - LCOE for Dispatchable Usage by Technology 162

List of Tables

Table 1 - REIPPPP Awarded Renewable Energy 19
Table 2 - South Africa Renewable Energy Scenarios from the IRP Process 24
Table 3 - Energy Storage Costs (Mongird, *et al.*, 2019) 34
Table 4 - Utility Scale Battery Storage (Spector, 2019) 37
Table 5 - Eskom Generation 2015-2019 42
Table 6 - Renewable Generation Statistics 2015-2019 43
Table 7 - IRP 2019 Generation Comparisons 45
Table 8 - IRP 2019 Renewable Generation Plan 45
Table 9 - IRP 2019 Generation Costs 68
Table 10 - IRP Premise LCOEs 69
Table 11- Generation Scenario Cost Comparison 2020-2050 71
Table 12 - Mine Shaft Storage System Cost Estimate 86
Table 13 - Dispatchable Energy Storage Scenario 97
Table 14 - Eskom Generation 2015-2018 112
Table 15 - Renewable Generation Factors - 2015-2018 data ((Eskom, 2019b) 113
Table 16 - IRP to Model Comparison 2030 118
Table 17 - IRP to Model Comparison 2040 118
Table 18 - IRP to Model Comparison 2050 118
Table 19 - IRP 2019 Renewable Plan 121
Table 20 - Monte Carlo Simulation Parameters 135
Table 21 - International Shale Potential 139
Table 22 - Royalty Rates - adapted from (Daniel, *et al.*, 2017) 149
Table 23 - Comparative LCOE for various technologies 154
Table 24 - Generation Cost by Technology 155
Table 25 - Eskom Reported Diesel Costs 160
Table 26 - Generation Scenario Output 164

Nomenclature

bar – Atmospheric pressure

BAU – business as usual

BCM / bcm – billion cubic metres

BESS – Battery energy storage system

CO_2 – carbon dioxide

CCGT – combined cycle gas turbine

CF – capacity factor

CNG – compressed natural gas

CSIR – Council for Scientific and Industrial Research (South Africa)

CSP – concentrating solar power

CTL – coal to liquid

DEE – Department of Environment and Energy (Australia)

DMRE – Department of Mineral Resources and Energy (South Africa)

DOE – Department of Energy (South Africa) now incorporated into DMRE

EAF – Energy Availability Factor

EG – embedded generation

EPRI – Electric Power Research Institute

ERCOT – Electric Reliability Council of Texas

EUR – expected ultimate recovery

FSRU – Floating Storage and Regasification Unit

GHG – greenhouse gas

GJ – Giga Joule (10^9)

GTL – gas to liquid

GUMP – gas utilisation master plan (South Africa)

GW – giga Watt (10^9)

GWh – giga Watt hour

IEA – International Energy Agency

INDC – intended nationally determined contribution

IRP – Integrated Resource Plan

kW – kilo Watt (10^3)

kWh – kilo Watt hour

LCOE – levelised cost of electricity

LNG – liquified natural gas

LTPF – long term planning framework

MCM – million cubic metre

MJ – mega Joule (10^6)
MW – mega Watt (10^6)
Mt – million tonnes
NREL – national renewable energy laboratory (United States)
OCGT – open cycle gas turbine
OECD – Organisation for Economic Co-operation and Development
PASA – Petroleum Agency South Africa
PJ – peta Joule (10^{15})
PSS – Power System Simulator
PV – photovoltaic
R – South African Rand
REE – RED Eléctrica de España
REIPPP – Renewable Energy Independent Power Producer Programme
SAPP – Southern Africa Power Pool
SCM – standard cubic metre
STERG – Solar Thermal Energy Research Group @ Stellenbosch University
TCF – trillion cubic feet
TCM – trillion cubic metre
TWh – tera Watt hour (10^{12})
UK – United Kingdom
USA – United States of America
USD – US dollar
US EIA (EIA) – United States Energy Information Agency
WACC – weighted average cost of capital
WWF – Worldwide Fund for Nature

1. Introduction

With their signing of the Paris Accord in 2015, many countries of the world have recognised the need for action against climate change. In this Accord, the countries committed to individual activities that would limit the increase in the average world temperature to less than 2 degrees Celsius. The main activity to achieve this would be limiting the release of CO_2 into the atmosphere. The benefit of building a renewable energy-based electricity generation system to help in achieving this objective is generally accepted. In the Paris Accord of 2015, South Africa committed to an emissions peak between 2020 and 2025 and declining from 2030 onwards. To achieve these goals, South Africa has introduced plans to update its electric power grid to include renewable power including both wind and solar energies as well as other renewable sources, of which it has significant resources.

Globally, with the large-scale implementation of wind and solar energy projects, technology and manufacturing technique improvements have resulted in significantly decreasing costs over the last decade. With these reductions of costs of solar and wind power generation systems, renewable energy sources are currently the least expensive sources for new generation and are approaching levels where they are less expensive than continuing to use existing coal and nuclear base generation. In the last year, around the world several wind and solar projects have been initiated with prices of power below USD 0.017 per kilo Watt hour for projects in Dubai and Portugal (Ieefa, 2019; Argus, 2019). This is below the cost of fuel for most conventional generation plants.

The South African electric grid system, as much of the world's electric grids, is a centralised system based on base load power from large coal generation plants. Besides being designed for base load usage, with challenges to provide dispatchable power, these large plants, (such as the Kusile and Medupi plants in South Africa (Steyn, 2019)) take many years to be built, creating the need for inflexible long-term planning cycles. The plants are built in large sizes to take advantages of economies of scale. On the other hand, wind and solar projects do not have the same economies of scale and can be built on a more modular basis. The time to install a wind or solar plant is also much shorter than a large base load generating plant, with solar PV plants such as the 85 MW Scatec plant in Upington constructed in less than one year (Scatec, 2020). This leads to more flexibility in the planning process.

Along with the environmental advantages that these renewable sources provide, low costs, scalability and short project development time are making the implementation of wind and solar based energy systems the lowest cost alternative to continuing with the business-as-usual generation systems. However, wind and solar generation is not just a direct replacement for existing systems. The distributed nature of the resource, the need to locate plants at the location of the resource and the variability of the supply create

new challenges. Grid stability concerns are also a developing issue that is requiring analysis as renewable generation replaces large base generation.

One of the major concerns with both solar and wind energy generation is their variability. Solar energy can only be generated when the sun is shining, and wind generation varies based on local wind speed at the point of generation. Due to the variable output of these resources, it is necessary for the grid to also include enough dispatchable power to balance their variability. Dispatchable power must be able to ramp up and ramp down rapidly to fill the gap between the demand and the supply from renewable source (Nichols, 2016). This must be achieved by either using base load systems in a dispatchable mode or replacing the base load systems with generation plants designed for dispatchable use. Large thermal plants do not ramp up or down quickly and are difficult to use in this service (Kumar, *et al.*, 2012).

For much of the world, this dispatchable power comes from the use of natural gas fired facilities. Natural gas generation has the lowest capital cost of any utility scale generation systems and, generally, has a much lower cycling cost than either coal or nuclear fuelled power plants. Gas plants are also more modular than coal or nuclear and can be constructed in a shorter period. For most countries, these advantages make gas fuelled generation the logical choice for dispatchable power to back up a renewable based grid. While utilisation of these peaking facilities is low leading to relative high costs per unit of generated energy, it is lower cost than alternatives and lower than the costs associated with failure to deliver electricity, which is estimated to be over 49 R per kWh (SA DoE, 2019a). This will be further developed in Chapter 5.

Currently, South Africa does not have any significant gas industry, with gas providing less than 1 % of a total energy usage in the country, and no significant indigenous production (SA DoE, 2019b). The electricity power generation system is almost completely coal based - over 85 % of the overall generation comes from coal fuelled generation (Eskom, 2019a). Low cost coal-based electricity has traditionally been a disincentive to industrial gas utilisation. What little local natural gas production that has occurred has been utilised for conversion to liquid fuels such as diesel through gas to liquid (GTL) processes. Therefore, the potential for a natural gas based dispatchable backup system in South Africa is not obvious. While there has been much talk about the potential for shale gas in the Karoo as well as some extensive regional gas discoveries in recent years, there has been minimal progress in developing the South Africa gas market (SAOGA, 2017). In the meantime, peaking power for the South African electric grid (such as the Ankerlig and Gourikwa power plants) is fuelled with diesel.

There is research being conducted on how to provide the grid stability that is currently supplied into the grid through the large generation plants (IEA -ETSAP, 2015). The inertia that these plants provide to the system due to the large rotating mass of their turbine drive shafts does not exist in solar PV or wind systems. Research is

heading towards methods to introduce this grid stability into the system through electronic means, but it is also possible to provide some of this need through the use of open cycle gas turbine (OCGT) peaking plants such as Ankerlig and Gourikwa.

This current research establishes the technical and economic case (techno-economic) for natural gas based dispatchable power to facilitate the transition to renewable electric power generation in South Africa, based on system modelling on referenced renewable energy scenarios.

This thesis is divided into seven chapters. Following this introduction, Chapter 2 will review the motivation and the methodology that is used in the analysis. Chapter 3 reviews the literature to summarise international experience and the processes that South Africa has in place for the energy transition. Chapter 4 will cover the calculations to determine the amount of dispatchable energy that will be needed to balance the system. Chapter 5 describes the options for gas to supply the required dispatchable energy, describing sources, costs, and challenges. Chapter 6 presents a potential scenario to meet the dispatchable energy need and Chapter 7 shows the conclusions and recommendations that have resulted from this analysis.

2. Motivation and Scope of Study

Research Question: The proposed study aims to address the appropriate role for natural gas in meeting the requirement for dispatchable energy in the South African electricity grid to support the transition to a renewable based generation system.

As stated in their commitment to the Paris Climate Accord, South Africa intends to develop renewable energy power supply to achieve its greenhouse gas emission reduction targets (SA DoE, 2015a). One of the necessary conditions for large scale renewable energy supply is the corresponding use of dispatchable power to mitigate the variable nature of the renewable sources. The proposed study intends to answer the question of whether natural gas dispatchable power is the best way to meet this need. This will involve the determination of timing and amount of dispatchable gas power that will be required, as well as the sourcing of the gas and the economics of this particular use. The analysis will cover the time period between 2020 and 2050.

The study will be based on system modelling of renewable energy scenarios, incorporating the required level of dispatchable power from gas generation to meet economical renewable implementation within the study period.

The specific objectives leading to results used to answer the research question are:

- Review relevant international case studies of large independent grid systems (Australia, Spain, UK, Taiwan, and Texas), it should be possible to draw from that experience to optimise plans for South Africa. This will involve assessing the relevance of aforementioned examples, as well as asking the question of how natural gas fits into these situations and what is relevant for South Africa.
- Compare the potential sources of natural gas to demonstrate the feasibility of utilising gas as a dispatchable power source in South Africa, determining the timing and costs to develop the necessary gas fired power plants and the required infrastructure to supply the necessary gas from the various potential sources.
- Review the sensitivity of the use of gas to the parameters that could alter the economic preference for this scenario.
- Develop and propose a gas scenario that will best meet the dispatchable needs for the IRP proposed renewable generation system.
- Once the gas scenario is established, review the technologies within the renewable energy sphere that could be utilised to replace gas as the backup dispatchable power for the grid to determine if a renewable based system will become a more economical choice compared to maintaining natural gas based dispatchable power.

It is expected that this research will provide an analysis and information for planning for policy makers and investors in the South African electrical power system.

A listing of papers and presentations of portions of this work are included in Appendix F.

2.1. Motivation

For many years, South Africa has participated in the international discussions on the climate change of the world and the need for action to minimise the effects of man-made actions on it. These discussions commenced in 1992 in Rio de Janeiro with the signing of the United Nations Framework Convention on Climate Change (UNFCCC, 1994). In 2009, in Copenhagen, South Africa made a commitment to reduce CO_2 emissions by 34 %, by 2020, below what they would be in a "business-as-usual" (BAU) scenario. The Copenhagen conference did not result in a formal international agreement, but the discussions continued and culminated in an international agreement in 2015 known as the Paris Accord (UNFCCC, 2015).

Almost every country in the world has committed, through the Paris Accord, to reduce their production of greenhouse gases (GHG) to minimise the impact on climate change. In this Accord, each country has made its own commitments to develop renewable energy production sources to minimise the amount of greenhouse gases that are produced by burning fossil fuels. For South Africa, this commitment includes a peak in GHG emissions and decrease going forward by reducing the production of electricity from "inefficient" coal generation, as stated in the South Africa "Intended Nationally Determined Contribution" (INDC) (Climate Analytics.Org, 2015). In the INDC, South Africa committed to having the country's emissions peak between 2020 and 2025 at 550Mt CO_2-eq, remain flat for a decade, and decline from 2030 onwards (SA DoE, 2015a). The New Climate Institute analysis on planned actions indicates that the country is on a path to "over-achieve" its targeted reductions (Climate Action Tracker, 2019).

The government of South Africa has noted in their INDC that, as part of the Paris Accord, there is a need to utilise renewable energy sources to achieve the GHG reductions that its commitments envisage. The Integrated Resource Plan (IRP) detailed the electricity supply options that the government intends to implement to meet these objectives. The INDC indicates that the Renewable Energy Independent Power Producer Purchase Programme (REIPPPP) would be one of the first steps in developing these resources. Implementation of this programme commenced in 2011 and renewable generation sources are already incorporated into the grid. Wind and solar sources provided 11.5 TWh of generation or 5.0 % of the South African total in 2019 (Eskom, 2019b).

In an analysis of the renewable programme in 2014, the CSIR demonstrated that South Africa has already reduced generation costs significantly (CSIR, 2015). In a review of the IRP 2016 update, the CSIR provided evidence that a renewable based generation system would be the most economical scenario for power generation in South Africa (Wright, *et al.*, 2017). In the fourth bid window of the REIPPPP, wind projects were submitted with an average PPA price of 0.67 R per kWh and solar PV projects with an average PPA price of 0.82 R per kWh (Eberhard & Naude, 2016). In their report, "*Least Cost Electricity Mix for South Africa*" the CSIR also indicated that recent cost reductions, beyond the costs from the fourth bid window of the REIPPPP, would increase the advantages of this scenario (Wright, *et al.*, 2017). Since that report, a number of recent international solar and wind projects have shown a continual decline in costs that is even faster than anticipated by the CSIR. Some of the current international examples have indicated costs to install new renewable generation that are lower than maintaining current coal fuelled generation (Lazard Assoc., 2017; US EIA, 2017a).

One of the major concerns with the implementation of a renewable energy-based power network is the stability of the grid. With large fossil fuel power plants, grid frequency and voltage control are provided by the inertia that these facilities provide to the grid. With wind and solar PV generation, inertia is not inherent in their systems and due to this lack, grid stability becomes an issue. However, system inertia can be maintained with the use of gas plants that provide peaking power. Eskom indicated in their Ankerlig / Gourikwa Technical Brochure that this ability to provide grid inertia was one of the factors in the development of the Ankerlig and Gourikwa gas power stations (Eskom, 2014).

Due to the variability of the supply of power from wind and solar generation, it is challenging to meet system demand from these resources. Grids must contain a given amount of storage or dispatchable power to balance the supply with demand on the system. These needs can be short term (matters of minutes and seconds), diurnal (with day/night storage requirements) and longer term, considered in days, weeks or seasonal. This last type of storage is the most challenging as the amount of energy that must be stored would be quite large. This leads to the need for dispatchable power from sources with access to large fuel supplies. For most countries, the development of increased dispatchable power is most economically met by increasing the amount of gas fired generation in the installed capacity and to utilise this capacity, as needed, to balance the variability of renewable generation.

In South Africa, the use of natural gas is not as obvious because there is no existing extensive gas infrastructure. The IRP includes provision for developing the required dispatchable generation and indicated that this would be specified in a Gas Utilisation Master Plan (GUMP) that would define how gas is to be developed in South Africa to meet this dispatchable power need. The GUMP was prepared in draft but has never been issued. This has left a significant missing piece in the energy planning process in

South Africa. To close this gap, it is necessary to address the questions of gas sourcing for the South Africa network, including the potential for shale gas development and the potential utilisation of recent regional gas discoveries. To consider gas for the provision of dispatchable power for South Africa, the source of gas must be defined, the cost established and the infrastructure to provide this gas must be defined. Analysis of these elements is an important portion of the scope of this study.

2.2. Methodology

Following a review of international examples of isolated grid systems of similar size to South Africa that are proceeding through the transition to renewables, the focus of this research has been the development of gas sourcing and deployment scenarios. The related development of a model is intended to test how gas supply could fit into the renewable energy development plans in South Africa. The basis was the scenario developed for the Integrated Resource Plan with the IRP 2018 and 2019 update. Data for input into the model was taken from results provided by Eskom for 2015 to 2019. The process is laid out in Figure 1 and summarised below. In all steps throughout the process, the results from the modelling were compared to that developed in the IRP process and other modelling efforts. The focus of the analysis was not on developing counter bases to those proposed by the IRP, but on finding the best use of dispatchable power within the framework defined by that process. However, the validity of the IRP premises was reviewed to understand how this affects the dispatchable requirement.

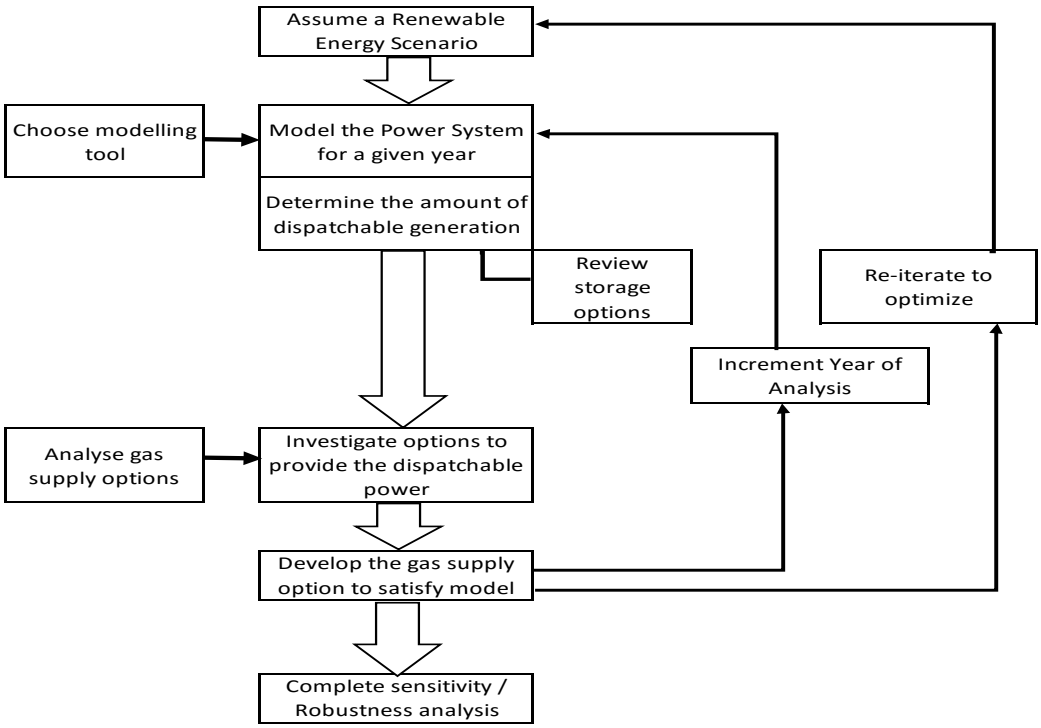

Figure 1 - Research Flow Diagram

The steps outlined in Figure 1 can be summarised as follows:

- Assume a Renewable Energy Scenario – Several transition scenarios have been developed during the IRP process. The first step in the analysis is to choose a representative scenario.
- Choose a modelling tool – With the scenario selected, it is necessary to choose a methodology to model the scenario.
- Model the Power System for a given year – With the scenario selected and the model chosen, the next step is to model the system for a given year within the time frame of the study.
- Determine the amount of dispatchable generation – The amount (installed capacity and amount of energy generation) of dispatchable power required to balance the system is the desired output for the model based on the selected scenario.
- Review storage options – Energy Storage is a potential alternative to reduce the dispatchable power requirement. The next step in the modelling is to determine how this impacts the dispatchable requirement.
- Investigate options to provide the dispatchable power – There are several technologies that can be utilised for providing the dispatchable energy required to balance the renewable supply, the potential options must be compared.
- Analyse gas supply options – As the potential use of natural gas is the focus of the modelling, it is essential to compare supply options for natural gas specific to South Africa.
- Develop the gas supply option to satisfy model – With gas dispatchable selected and sourced, the next step is to develop supply options to meet the dispatchable requirement.
- Increment year – The modelling is done on a specific year within the time frame. It is necessary to change the year to cover the time frame to ensure that changes in the parameters, such as demand and decommissioning are understood and considered.
- Re-iterate to optimise – The assumptions used in selecting a gas supply option needs to be tested through re-iteration.
- Complete sensitivity / robustness analysis – With a final gas supply option developed, it is important to understand how the scenario fits with likely changes to the premises of the scenario through a sensitivity and robustness check.

To understand where we are going with the transition to a renewable based electricity grid system, it is essential to review where the system is, where it came from and its progress toward the goal of establishing a renewable based generation system. In the next chapter, the literature will be reviewed to address these issues from a local South African perspective and from the international perspective. Progress and challenges for the transition will be discussed.

3. Literature Review

In this literature review, the South Africa transition plans will be reviewed, with a comparison to international experience and review of the progress that has been made up until now. The requirement for dispatchable energy to facilitate the transition will be reviewed from studies and international experience. As natural gas is the focus of the study, international use of gas fuelled dispatchable power and the potential for South Africa will be investigated. And finally, the potential to displace natural gas dispatchable generation with energy storage and non-fossil fuel generation will be introduced.

3.1. South African greenhouse gas (GHG) emission plans

South Africa has been an active participant in the international discussions on climate change. Prior to the Paris Accord, South Africa had made commitments to a reduction from the emissions coming from "business-as-usual" (BAU), which the government describes as growth without constraints in their INDC document. In the government BAU scenario, GHG emissions from South Africa would increase linearly up to approximately 1600 Mt CO2-eq, per year by 2050. For the Paris Accord, in its INDC, South Africa committed to "the curve of South Africa's GHG emissions towards a peak, plateau and decline trajectory range". As indicated in the government 2015 status report on Renewable Energy, the country's emissions would peak between 2020 and 2025 at 550 Mt CO_2-eq, remain flat for a decade, and decline from 2030 onwards. The South African government stated that this would reduce emissions by 34 % below the "business-as-usual" trajectory by 2020 (SA DoE, 2015a). In its 2019 review of the South Africa performance, the government indicated that between 2013 and 2017 South Africa's GHG emissions have been in the range of 550 to 560 Mt CO_2 per year (SA Department of Environmental Affairs, 2019). As noted above, the New Climate Institute indicates that the country is on a path to "over-achieve" its targeted reductions (Climate Action Tracker, 2019). However, they concluded that this is not enough to achieve the global target of less than 2° C world temperature increase.

The basis of the South African government GHG reduction planning was incorporated into the 2010 IRP (SA DoE, 2011). The South Africa INDC states that the "At the heart of this part of the transition to a low-carbon energy sector is a complete transformation of the future energy mix, which is designed to replace an inefficient fleet of ageing coal-fired power plants with clean and high efficiency technology going forward" (UNFCCC, no date, pg. 2).

3.2. Global efforts towards renewable generation

With a world total electricity production of 26 615 TWh (BP, 2019) in 2018, wind energy contributed 1 270 TWh and solar energy 585 TWh (BP 2019). This indicates

wind provided 4.8 % and solar 2.2 % of the world's electricity. These numbers have increased from only 133 TWh of wind and 5.7 TWh of solar in 2006 out of a total of 19 000 TWh, which combines to a renewable energy (excluding hydro) percentage in 2006 of less than one percent. As shown in Figure 2, the global wind and solar generation has grown at an average rate of 22 % per year for the last decade. The growth of the installation of wind and solar generation projects worldwide is increasing significantly, with the IEA predicting installation of over 900 GW of wind and solar generation in the five years from 2017 to 2022, of which 305 GW was installed in 2017 and 2018 (OECD & IEA, 2017)(BP, 2019). New wind capacity is expected to be stable at about 65 GW per year and solar PV additions are expected to grow from 100 GW per year to 180 GW per year in that period (Forecast International, 2019). This additional capacity should generate about 2 000 TWh per year, or approximately 10 % of overall global generation.

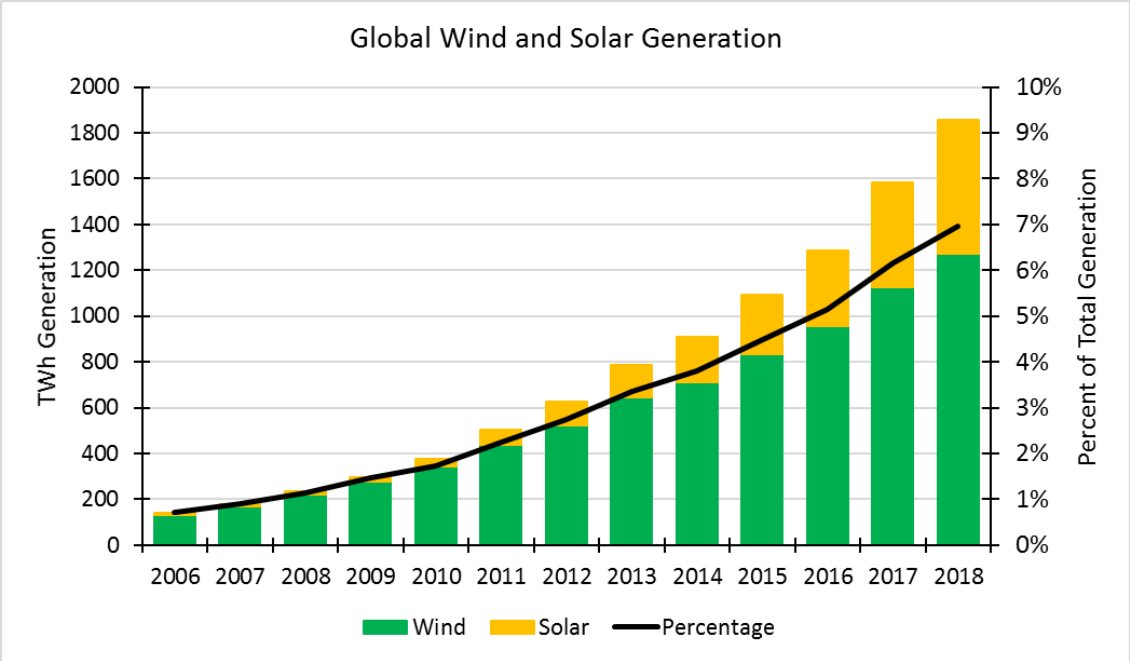

Figure 2 - Growth of Global Wind and Solar Generation - data (BP, 2019)

With this large and growing installation of wind and solar generation, costs are being reduced significantly. As shown in Figure 3, these costs have dropped below the cost of generation from fossil fuel and nuclear (Lazard Assoc., 2017; US EIA, 2017a). These costs continue to decrease each year and it is unknown how low they could eventually go. As of September 2019, new bids have been received for solar PV facilities in Dubai and Portugal at less than USD 0.017 per kilo Watt hour, implying that the trend downwards continues (Ieefa, 2019).

With the capital cost of solar PV projects decreasing rapidly, the interest rate that the project developer must pay for his capital has a larger impact on the price at which he can profitably produce energy. In reviewing recent solar projects in Europe, Vartiainen, *et al*. concluded that "Sensitivity analysis shows that apart from location,

weighted average cost of capital (WACC) is the most important input parameter in the calculation of solar PV LCOE. Increasing nominal WACC from 2 to 10 % will double the LCOE. Changes in solar PV CAPEX and OPEX, learning rates, or market volume growth scenarios have a relatively smaller impact on future solar PV LCOE" (Vartiainen, *et al.*, 2019, pg. 1). In their review of the low cost of projects in the middle east, IRENA concluded that "Very attractive conditions for financing – such as low interest rates, long loan duration and high debt to equity ratios – have supported the record solar PV and CSP prices of large renewable energy projects in the region" (IRENA, 2019, pg. 92).

With relatively high cost of capital, South Africa will not likely be able to achieve the prices recently seen, unless borrowing cost can be reduced.

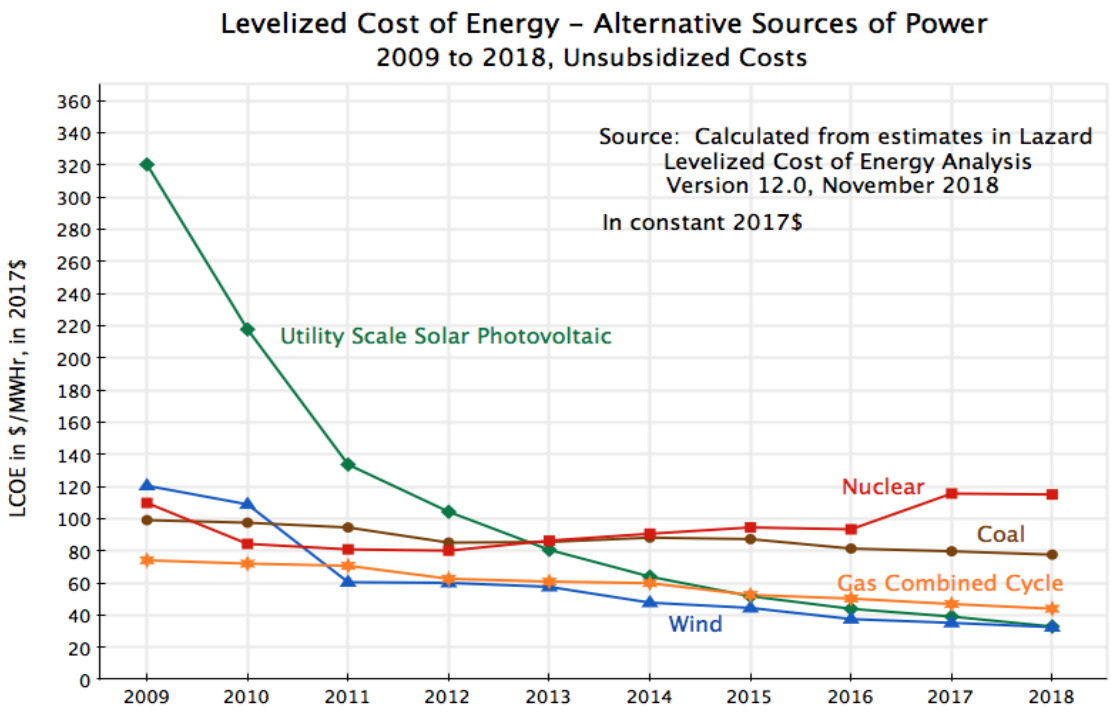

Figure 3 - Levelised Cost of Electricity by Technology (Lazard Assoc., 2018)

Some countries and regions have significantly higher percentages of wind and solar generation than the world numbers show. Many of the G20 countries (the nineteen countries in the world with the largest economies – twenty including the EU) currently have a notable portion of their generation coming from wind and solar sources, as shown in Figure 4.

For South Africa, wind and solar produced 5 % of its electricity in 2019, below the world average from 2016 of 7.0 % and the average 7.5 % of the G20 nations (Calitz and Wright, 2018;BP, 2019). Wind and solar generation in South Africa at the beginning of 2019 was 7.6 % of the total overall installed capacity.

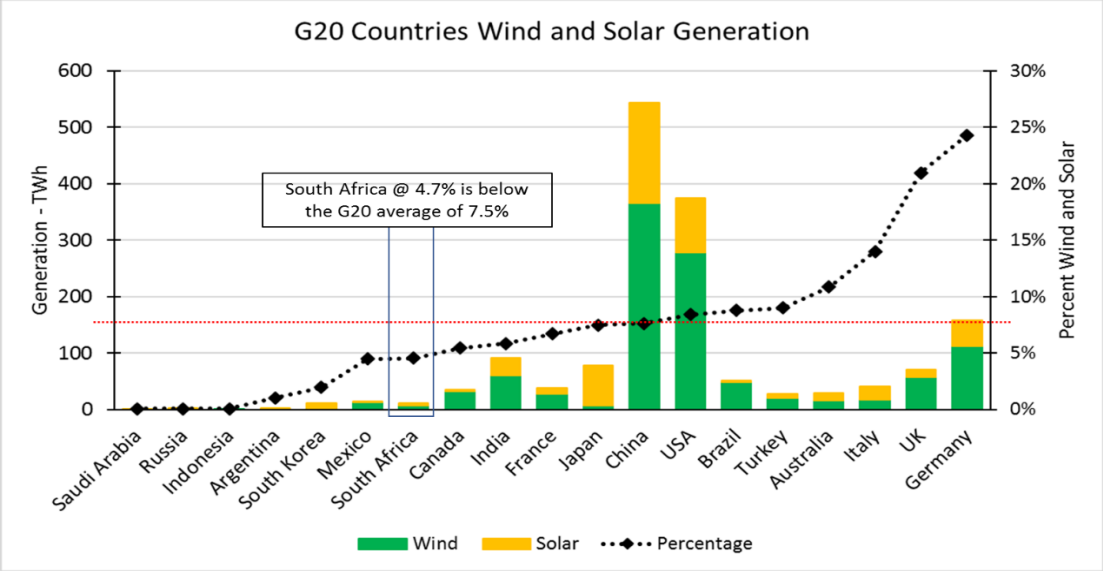

Figure 4 - G20 Wind and Solar Generation – data (BP, 2019)

3.3. International experience

There has been a debate around the world for many years about what percentage of renewable power generation can be utilised before the grid becomes unable to meet its requirements. As time has passed, the numbers have continually increased, to the point where now the debate is on whether 100 % renewables is realistic or not (Jacobsen, *et al.*, 2015; Clack, *et al.*, 2017). However, as all the expected numbers are quite high, what is more relevant than the absolute value of what a grid can handle are the conditions that must exist for the maximum percentage to be achieved. From this viewpoint, there seems to be consensus that dispatchable power is a necessary requirement for large scale renewable implementation (Clack, *et al.*, 2017; Brown, *et al.*, 2018).

To be successful, any proposed energy system must meet a few characteristics that balance the system demand and supply. As reviewed in the survey performed by Asha Zaman, with respect to implementation of 100 % renewable energy systems (Zaman, 2018), the system requirements can be summarised as follows; resource adequacy, transmission adequacy, power systems dynamics (frequency and voltage control) and ramping ability. Natural gas generation provides grid support in all these areas and appears to be an effective alternative for system dynamic support and ramping ability.

The major argument in the feasibility of 100 % renewable generation is how dispatchable power can be supplied by renewable sources such as hydropower (Heard, *et al.*, 2017). In the argument, those arguing for 100 % renewables conceded that maintaining a backup system with gas fired generation was a cost-effective method of ensuring availability of power and, as it would only be used as a contingent source of power, would not materially deviate from the supply of power free of carbon dioxide

emissions (Brown, *et al.*, 2018). They indicated that, eventually, it should be possible to replace this backup generation with renewably produced gas, (hydrogen or synthetic gas produced from excess wind and solar generation.

Currently in much of the world, the most economical dispatchable power comes from natural gas fired generation (Lee, *et al.*, 2012). Bloomberg New Energy Finance stated in their 2017 forecast on renewable energy that "Gas is a transition fuel, but not in the way most people think. [….] [G]as plants will mainly act as one of the flexible technologies needed to help meet peaks and provide system stability" (Henbest, *et al.*, 2017, pg. 4). While there has been progress in meeting the time-shift needs of a renewable based generation system with concentrating solar power (CSP) and battery storage systems (where energy can be stored until the time of day when it may be needed), there has been less progress on meeting the longer term dispatchable needs (Ziegler, *et al.*, 2019). For any type of stored energy system (whether it is batteries, compressed air, pumped hydro, or other technologies), the energy that could be provided by the backup system is limited to the volume of storage. For most systems, this is measured in hours. Studies in the United States and Europe have indicated that stored energy to supply the grid for up to 12 % to 15 % of the annual energy supply in Europe and 15 % to 18 % in the United States of America would be required to ensure grid stability to cover the worst case (Heide, *et al.*, 2011; Becker, *et al.*, 2014). This implies that stored energy could be required to meet the entire system load for over seven weeks in the worst case scenario.

Natural gas dispatchable power systems provide the capability to meet renewable energy shortages (whether it is for days, weeks or longer), depending on seasonal or unusual weather conditions. As it is unclear of how much backup power might be needed in the worst-case scenarios, most utility systems take the conservative view of having enough dispatchable power capacity available to completely replace the renewable supply as needed (Noha, *et al.*, 2017).

In a presentation to the Electric Reliability Council of Texas (ERCOT – the network operator) in Texas on 7 September 2017, Dr. Eugene Preston discussed the possibility of 100 % renewable sourced energy and concluded that, "If you miss a day of production in renewables you have to fire up the gas generators to fill in the demand. In fact, you have to keep most of your fossil fuel capacity in standby to fill in when renewables fail to produce enough energy" (Adams, 2017).

In a blog written in January 2017, the German economist, Heiner Flassbeck, indicated that a period of extremely low solar and wind power generation in December 2016 showed that Germany could never completely rely on variable renewable energy, regardless of how much new capacity will be built. He concluded that Germany must maintain at least 50 GW of fossil fuelled dispatchable generation capability to ensure power supply (Flassbeck, 2017).

The CSIR conducted an aggregation study for South Africa modelling how a fleet of solar and wind generation facilities could meet the majority of the needed generation in South Africa. However, their study noted that there were periods of the year where the total generation of the wind and solar fleet effectively has no output. For these periods, the backup dispatchable power must be able to pick up the entire load (Knorr, *et al.*, 2015).

In a 2016 review of the renewable energy implementation in 26 OECD countries between 1990 and 2013, Verdolini *et al*., 2016 concluded that, "A 1 % percent increase in the share of fast-reacting fossil generation capacity is associated with a 0.88 % percent increase in renewable in the long run" (Verdolini, *et al* , 2016, pg. 1). Gas fuelled dispatchable generation is a common condition in countries with high variable renewable energy production.

As mentioned above, even studies advocating the potential for 100 % renewable generation indicate the need for dispatchable backup power and the benefit that gas generation provides (Brown, *et al.*, 2018). The aforementioned review also indicates that gas dispatchable power systems assist with grid stability, providing inertia, voltage regulation and increased black start capabilities. Eskom has recognised the need for dispatchable power that also provides grid stability. The Ankerlig and Gourikwa peaking power plants provide inertia into the grid to assist in regulating grid voltage (Eskom, 2014).

3.4. Large "island" systems

It may be helpful to research countries such as Denmark with large percentages of renewable generation, exceeding 100 % of need at times, to understand what it takes to move to a completely renewable based generation system. However, many of these examples show that one of the major elements of the large-scale renewables' usage for a region or country is access to a large network where their shortfalls and excesses can be balanced. As concluded in a review of the Denmark example, "power exchange with neighbouring countries is the most important tool for dealing with high shares of wind power in Denmark" (Kofoed-Wiuff, *et al.*, 2015, pg. 1). To this end, most of Europe is interconnected, as well as North America being interconnected into two major systems (Mearns, 2015) (US DoE, 2015). China has a large network with a capacity rivalling that of Europe (GENI, 2017). Each of these interconnected systems allows high regional variable energy sources to be balanced with other supplies. There is a question, therefore, of the relevance of these examples to the situation of South Africa where there is no large external network to back up the system.

South Africa (while connected into the Southern Africa Power Pool; SAPP) is not connected into a large network of electric grid systems that would allow for balancing of its variable production from renewable sources. South Africa has approximately

80 % of the installed capacity in the SAPP and uses approximately 80 % of the power generated in the network (SAPP, 2018). Relevant examples for South Africa should be those regions and countries that have grids of similar sizes that are not connected into large networks. These systems could be considered to be 'large island' systems as they work in isolation from larger networks. The South African electric grid produces about 250 TWh per year. There are a few regions and countries with isolated grids of similar size. Those considered for this study are (a) Australia – specifically, the east coast states (b) Taiwan, (c) Spain, (d) the UK system, and (e) Texas. Each of these grid systems has experiences with integrating renewables into the network and dispatchable power in order to provide the backup to the variable renewable sources.

A review of the large island systems was presented at the SASEC 2018 conference in Durban in June 2018 (Clark, *et al*., 2018). An example from this review is the performance of renewable generation in Spain in early January 2018.

Spain, with its network effectively isolated from the rest of Europe, was one of the early adopter countries for both solar energy and wind power. In this early growth, from 2003 through 2012, Spain installed 23 GW of wind capacity and 6.9 GW of solar PV and CSP production (Cigre, 2015). At the same time, the country built 25 GW of gas-powered peaking plants (Río and Janeiro, 2016). As seen in Figure 5, co-generation, nuclear and coal-fired generation provide the base load in Spain with 23 % of the installed capacity and 49 % of the generation. Gas and hydro, both pumped hydro and straight hydro power, provide the flexible generation for the grid to handle the variable generation from the wind and solar systems (REE, 2017).

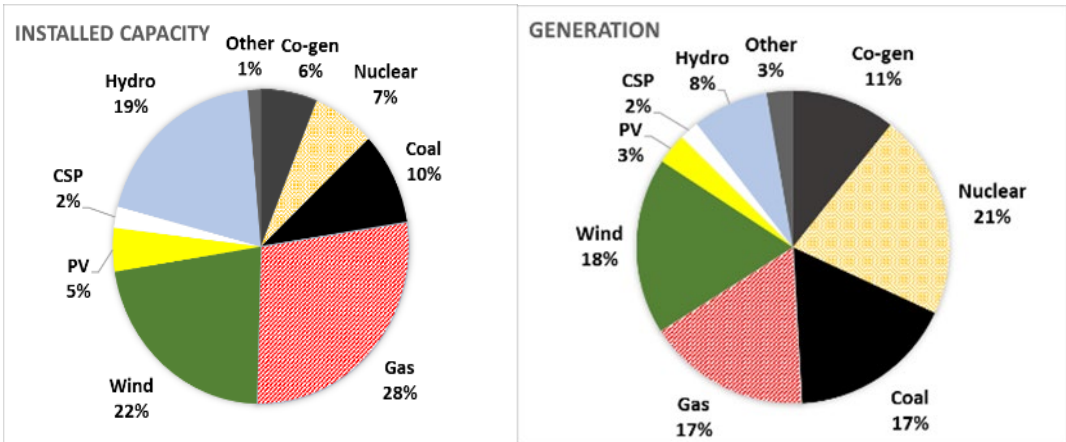

Figure 5 - Spanish Installed Capacity and Generation – data (REE, 2017)

With nearly 30 GW of installed wind and solar generation capacity and an annual average overall generation equivalent to 28 GW, Spain has the ability to generate a large percentage of its required power from renewable resources. As the energy from wind and solar resources is considered the priority supply, the remaining generation capacity must be utilised as mid-merit or peaking. Power provided by private co-generation (combined heat and power) facilities is utilised as a required input when

available. The only portion of the generation system used as base load is the nuclear power sector (8 GW installed capacity), which is used at about 80 % capacity factor. Coal-fuelled generation is only utilised at about 52 % capacity factor. Gas and hydro, (with 28 % and 19 % of the installed capacity), are utilised to provide the dispatchable power requirement, with capacity factors of 17 % for gas and 12 % for hydro. (REE, 2017).

During the period of 1 to 10 January 2018 (as seen in Figures 6 and 7), the percentage of power generated from wind and solar resources varied from providing 7 % to 44 % of the load (REE, 2018). As can be seen from Figures 8 and 9, this variability of generation showed the need for the use of dispatchable generation, with effectively all dispatchable power shut down on 4 January 2018 to accommodate the large renewable generation (REE, 2018). On the other hand, on 8 January, with minimal wind generation, all the alternate generation systems were fully utilised.

In the same analysis period of 1 to 10 January 2018, the percentage of renewable generation in the UK varied from 6 % to 24 % and in Texas, which is isolated from the other North America grids, from 5 % to 39 %. Texas had six continuous days of renewable generation below 10 % during this period. In each country, these variations were handled with the use of dispatchable backup power consisting of a large part of gas fuelled generation.

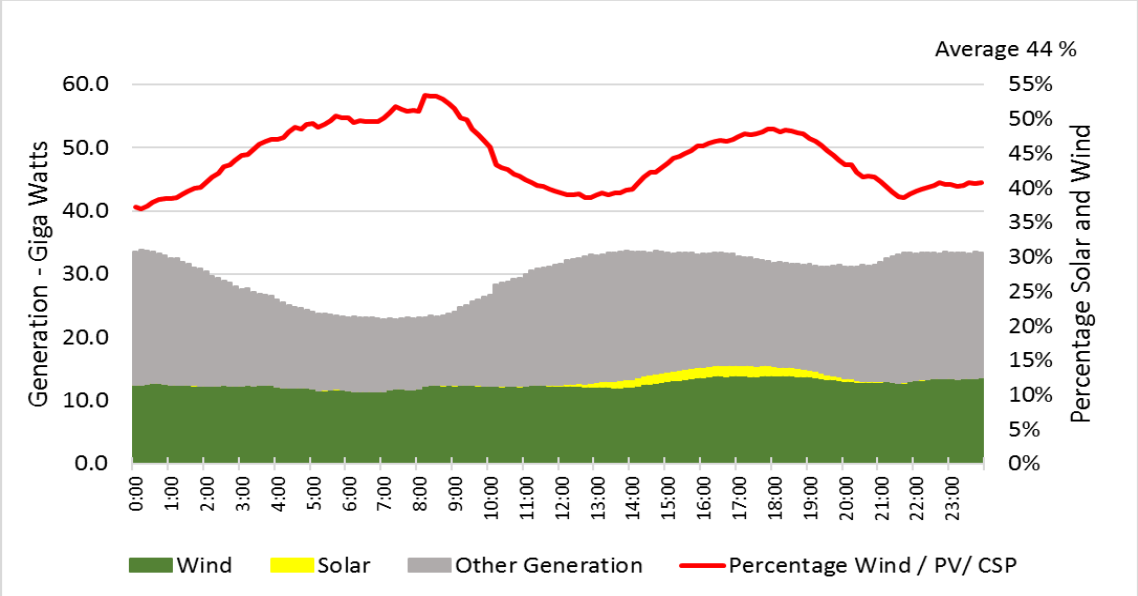

Figure 6 - Spanish Renewable Generation - 4 January 2018 – data (REE, 2018)

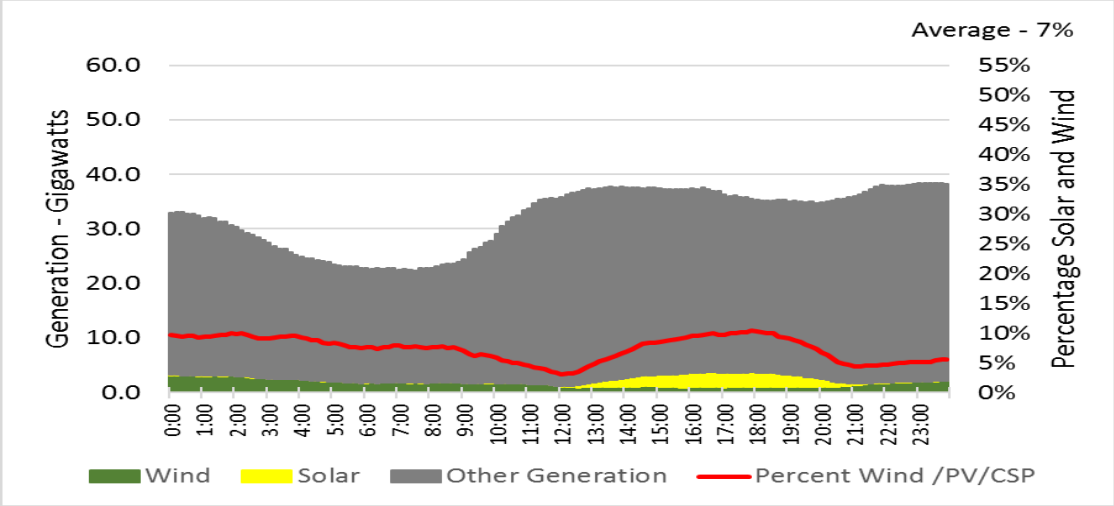

Figure 7 - Spanish Renewable Generation - 8 January 2018 – data (REE, 2018)

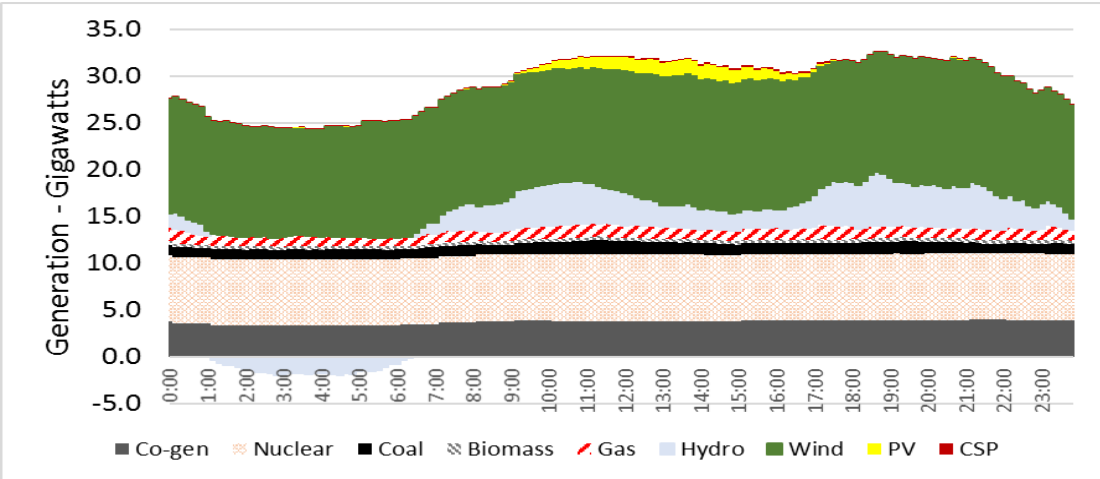

Figure 8 - Spanish Generation by Source - 4 January 2018 – data (REE, 2018)

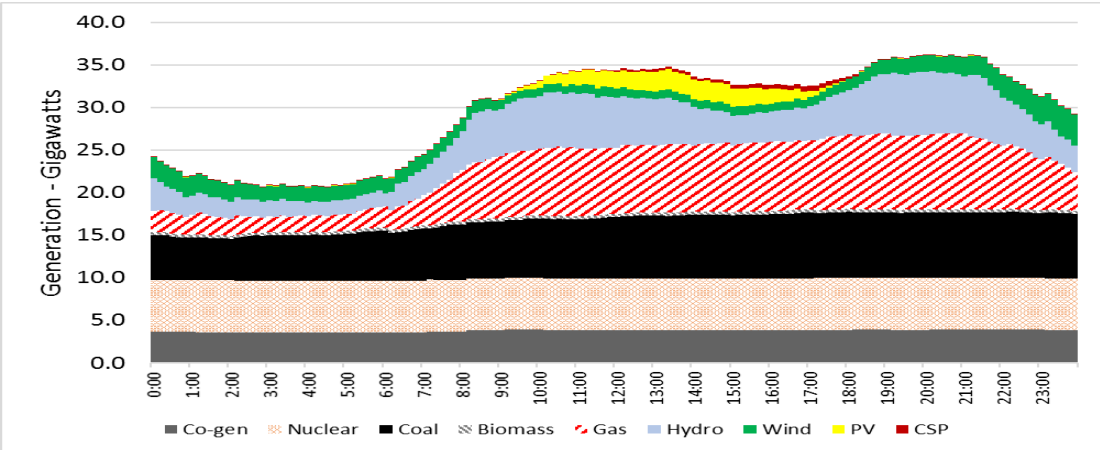

Figure 9 - Spanish Generation by Source - 8 January 2018 – data (REE, 2018)

3.4.1. Relevance for South Africa

Currently, the South African electric grid is a "stiff" system with most of the generation from coal fuelled baseload sources, with dispatchable power of 15 % of the installed capacity, as seen in Figure 10 (ESKOM, 2017). This rigidity makes it quite challenging to increase the percentage of renewable generation in the system. The review of the international large island systems shows the need to have sufficient dispatchable power to allow the operation of the grid with significant variable generation, thus, the development of dispatchable backup generation must be considered as an integral part of the development of the renewable based power system for South Africa

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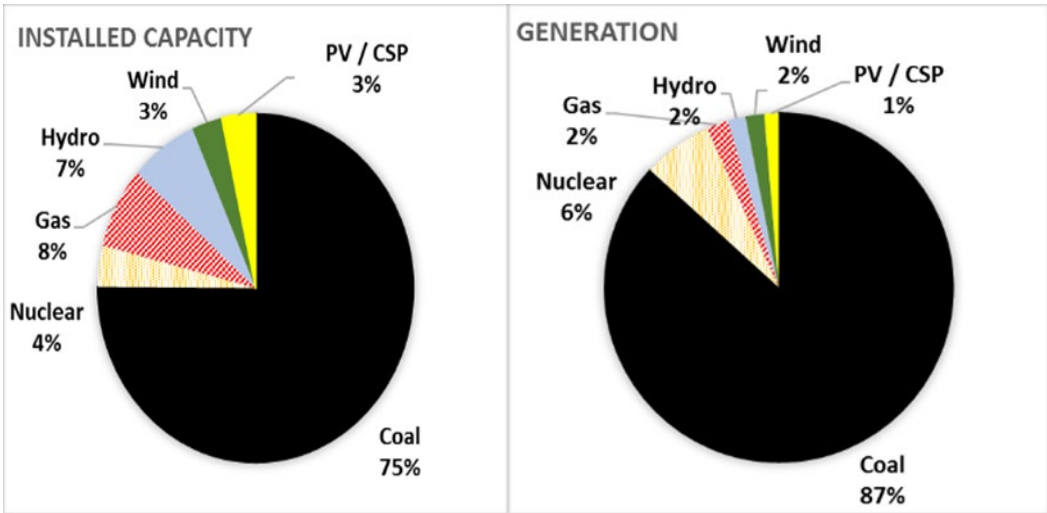


Figure 10 - South Africa Installed Capacity and Generation for 2016 – data (ESKOM, 2017)

3.5. The integrated resource plan process – definition and usage

The process of developing an integrated resource plan (IRP) to determine the required demand growth for the electricity grid is an action that is taken in most countries, states, and regions. According to a review of the IRP concept; "IRP was borne out of financial crises in the 1970s and 1980s in the US that arose from utilities investing in expensive power plants that were not needed, and from cost overruns from nuclear power plants" (Greacen, *et al*., 2013, pg. 6). The methodology of developing these plans varies from country and utility, however, all attempt to forecast and satisfy the required demand of twenty to thirty years into the future (D'sa, 2011).

One aspect that appears to be consistent in these plans is that they are developed as action plans by the utility or system operator and submitted to the relevant government agency for review and approval. The utility company in New Brunswick (NB), Canada stated "Collaboration is an integral part of the IRP process. NB Power communicated and consulted with key stakeholders, including the Government of New Brunswick and

customers, to ensure an optimum long-term supply of electricity for New Brunswick" (Energie NB Power, 2014, pg. 4). According to one study on the IRP processes used around the world, "South Africa appears to be the only country to legally require integrated resource plans for the electricity sector at the national level" (D'sa, 2011, pg. 9). These approval processes often involve changing the utilities plans to accomplish government mandated actions, such as maintaining coal and nuclear generation for either job concerns or security (Díaz, *et al*., 2013). Also, many plans are required to incorporate mandated renewable generation that might not have been in the utilities' planning. Subsequent to the approval process, the utility generally has the authority and responsibility to implement the approved action plan.

The process in South Africa is different from other countries and regions in that the IRP is developed by the government outside of the utility. According to a recent article in the South African press, "The plan maps out how government intends to manage electricity demand in industry, households and business up until 2030" (Omarjee, 2018, pg. 1). Eskom, the utility operator in South Africa, has indicated that they do not agree with some of the assumptions within the IRP but state in their planning documents that they will implement the government plan indicated in the IRP (Gosling, 2018; ESKOM, 2017). The IRPs that have resulted from this process are not action plans, but more aspirational plans expressing intent. Effectively, the only action plan that has resulted from the preparation of the IRPs is the renewable energy implementation plan, the REIPPPP. In this plan, through four bidding rounds, as shown in Table 1, the wind and solar generation currently supplying power to the grid were developed (SA DoE, 2015b). However, this was done externally to the grid operator and with resistance on their part, such as refusal to sign PPAs for awarded supply contracts (Yelland, 2017).

Table 1 - REIPPPP Awarded Renewable Energy

REIPPPP Awarded Capacity - MW					
Bid Round	**1**	**2**	**3**	**3.5**	**4**
Hydro	0	14	0	0	5
Biomass	0	0	17	0	25
Landfill	0	0	13	0	0
CSP	150	50	200	200	0
Solar PV	627	417	435	0	813
Wind	649	559	787	0	1 363

3.6. South Africa progress and plans

3.6.1. South Africa energy transition planning 2010-2019

The plan for implementation of a revised generation system in South Africa to meet the greenhouse gas reduction target was laid out in the Integrated Resource Plan of 2010 (IRP) (SA DoE, 2011). In this plan, the government indicated the intent to develop

18.8 GW of renewable energy generation capacity by 2030 (SA DoE, 2011). Associated with this renewable capacity, the plan indicated the installation of 9.7 GW of dispatchable gas generation capacity. The IRP mentioned the use of gas for dispatchable generation but did not identify sources or development concepts, saying that this was all to be laid out in the planned Gas Utilisation Master Plan (GUMP) that the government was to prepare.

In the 2013 update to the IRP, the plan time horizon was extended to 2050 and the base case target for renewables for 2050 was indicated as 55 GW, 17.6 GW of solar PV and 37.4 GW of wind (SA DoE, 2016). Along with this renewable generation, the plan called for 35.3 GW of dispatchable gas. The Department of Energy stated that "renewables and gas should form the biggest chunk of installed capacity in 2050" (Peyper, 2017, pg. 1). However, the only gas source considered was utilisation of local shale gas. The one sensitivity case of "no shale gas" did not consider the use of any other gas source (SA DoE, 2016).

During the course of this study, the 2018 update for the IRP was published for comments (SA DoE, 2018). In addition, a review of the 2018 IRP was updated in 2019 due to the inability for Eskom to meet the demand due to underperformance of the Eskom generation fleet at the end of 2018 (SA DoE, 2019c). The 2018 IRP had a slightly lower total demand expectation than the 2016 version, but no significant change in the premises for base load decline, renewable growth or dispatchable power need. The base load forecast for 2030 was slightly reduced from 42 GW to 40 GW, wind slightly raised from 9 to 11 GW, solar PV raised from 6 to 8 GW and dispatchable power lowered from 17 to 12 GW.

In the updated version from 2019, the major change was the reduction of 5 GW of the dispatchable power replaced with an addition of 3 GW of battery storage. The forecast for wind generation was increased from 11 to 18 GW, while solar PV was unchanged. The 2019 update did not make any changes to the longer-term forecasts (SA DoE, 2019c).

Work on developing the gas master plan (the GUMP that was referenced in the IRP), commenced in 2015 and a report was completed in 2016. However, this development plan has never been finalised and published. The unpublished report deals generally with the development of shale gas, with some discussion of the potential for LNG importation and, effectively, a complete disregard for gas imported by pipeline, indicating that it would be politically challenging and would take too long. The GUMP, as currently drafted, does not contain any implementation plan for providing gas for electric power generation (SA DoE, 2015c).

On the other hand, the renewables targets from the IRP were followed up with an implementation plan, the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) in 2011 that began being implemented in 2013 (Mojanaga,

2014). This programme was composed of multiple bidding opportunities – bid windows – with private investors bidding to supply renewable energy to the grid and the government awarding power purchase agreements to the winning bidders for supply of power. It was envisaged, and realised, that prices for the bids would improve over the series of bids as technology improved while bidder experience and comfort increased. This programme has resulted in the awarding of 6.3 GW of capacity from renewable sources through four bid windows (Calitz & Wright, 2018).

3.6.2. WWF 2030 scenario

In 2015, WWF commissioned an analysis of scenarios to achieve the highest potential share of renewable energy production in South Africa by 2030 if the limitations from the IRP were removed (Gauché, *et al*., 2015). This analysis produced a high and a low case, depending on demand growth. In this analysis, the low growth indicated that 2030 demand could be over 20 %, lower than that was estimated in the IRP 2010. Both WWF scenarios showed that a combination of renewable and flexible gas-turbine generation provided the most economical power capability for South Africa. The low case indicated coal and nuclear generation providing 72 % of the total generation with an availability factor (EAF) of about 78 %. Gas fired generation provided 4 % of the generation with a utilisation factor of about 21 %. Renewable sources provided 17 % of the total generation in this scenario. The report noted that one of the major concerns was the high degree of uncertainty about the availability of gas for the large additional capacity of OCGTs and CCGTs. The report did not address the supply of the required gas.

The update of the IRP in 2016 noted the lower demand growth and was based on a demand profile similar to that of the WWF low case. By the time the IRP 2018 was developed, the growth in demand expected from the 2016 update had not materialised. For the 2018 IRP and the 2019 update, the non-growth since the 2016 update was incorporated into the forecasts, but no material changes were made to the methodology in order to forecast growth going forward.

3.6.3. CSIR 2016 review

As part of the review of the IRP for the update in 2016, the CSIR conducted a research effort to determine a techno-economical optimisation of the costs of the generation system without policy constraints. This study concluded that, "Solar PV, wind and flexible power generators (e.g. gas, CSP, hydro, biogas) are the cheapest new-build mix " (Wright, *et al*., 2017, pg. 1) . Their least cost scenario had a residual installed coal capacity of about 10 GW by 2050 that had a 68 % utilisation factor. Natural gas (with combined and open cycle systems) had 56 GW of installed capacity, with a utilisation factor of 14 %. Most of the generation came from wind (49 %) and

solar (24 %). The CSIR calculated that this mix would be 10 % less expensive than the IRP base case.

This analysis was made with the prices of wind and solar from the fourth bid round of the REIPPPP programme. In their concluding remarks, the CSIR indicated that there should be further improvements in the renewables level and the reduced costs with expected price decreases of renewable sources.

3.6.4. CSIR 2018 review

As they had during the 2016 IRP update, the CSIR provided a techno-economic review of the proposed 2018 IRP update (Wright, *et al*, 2018). They concluded that the new IRP update explicitly confirmed that the lowest cost scenario (entitled IRP1) was the case maximising renewable generation with dispatchable gas fired generation. They concluded that the lowest cost case included is 25 % renewables based (dominated by solar PV and wind) by 2030 and 70 % renewables-based by 2050. They noted that "South Africa has the unique opportunity to decarbonise its electricity sector without pain. Clean and cheap power systems are no longer trade-offs anymore in South Africa" (Wright, *et al*, 2018, pg. iii). They also identified as risks and opportunities the Energy Availability Factor (EAF) of the existing Eskom coal fleet and the decommissioning schedule of existing coal plants. When these risks and opportunities are incorporated, increased levels of solar PV and wind are required along with dispatchable power and stationary storage. One of the concerns that had been expressed about gas generation in the IRP plan was the exposure to international gas pricing. CSIR concluded that the cost risk of imported natural gas is relatively small as it only contributes 2 % to 5 % of the energy mix by 2030.

One new consideration that CSIR added to their analysis of the 2018 IRP was the potential effect of embedded generation (EG) is becoming a significant factor that will change the demand curve to a more peaked profile. This would decrease the benefit of base load generation and increase the need for dispatchable power and storage.

3.6.5. Renewable energy progress

The CSIR conducted a review of the implementation of renewable projects through 2017 and reported that at the beginning of 2017, slightly over 3 GW of solar and wind resources were installed in South Africa through the REIPPPP programme (Calitz & Wright, 2018). An additional 600 MW of wind resources and 100 MW of CSP were added to this renewable capacity in 2017. The renewable generation sources provided approximately 9 TWh of energy or 3.4 % of the overall supply. In their analysis of the supply picture for 2017, the CSIR calculated that the share of capacity providing peaking production (defined as being utilised less than 1 000 hours per year) increased

from 5.4 GW to 6.6 GW. Base load capacity decreased from 24.9 to 24.1 GW. Mid-merit generation also decreased from 5.2 to 4.9 GW.

These headline statistics fail to describe the effect that these changes have had on the use of existing generation plants or the need for dispatchable power sources. Some of the mid-merit units (while continuing in this category) have needed more frequent cycling to meet morning and evening demand peaks. Thus, more of the mid-merit use is in slots of a few hours which is more challenging for a base load plant than the use of one cycle per day for a plateau shaped demand.

Slightly over 6 GW of REIPPPP projects have been assigned, compared to the 3.7 GW of projects that are operational. Once the back log of project PPAs is resolved and the projects implemented, the share of renewable energy will increase to around 7 % of the overall energy generation. This increase could be expected to have about the same shift of generation from base to peaking as the current renewable generation has had. This would bring the peaking generation to something in the range of 7.5 GW and lower the base load to about 23.5 GW. The effect on the cycling of mid-merit plants would likely be profound as well as the hours of generation for these plants would be reduced and they would be cycled more often.

3.6.6. South Africa renewable energy development

Time scale and amount of renewables

The IRP of 2010 was intended to cover the coming 20-year period – namely, 2010 to 2030. Thus, the final scenario was the plan for the year 2030. This was the year that was used as reference in comparing this plan with later iterations of the IRP. In the 2013 update of the IRP, the planning period was extended through 2050 so later models compared both 2030 and 2050 scenarios.

In the 2010 as well as the updated 2013, 2016 and 2018 IRPs, the expectation was to increase the capacity of renewable energy sources in 2030 by a factor of at least five from the current situation of 2017. By 2050, the renewable capacity is expected to grow to approximately ten times the current values. With renewables currently providing about 4 % of the generation, it could be concluded that renewable generation should grow to approximately 20 % of the total by 2030 and 40 % by 2050 according to the IRP.

During their analysis in 2016, the CSIR concluded that due to the drastically decreasing costs of solar and wind production, the lowest cost scenario for power generation was on maximising solar and wind. Their scenario indicates a growth in renewable capacity by 2030 of nine times and over forty times by 2050. With this growth, renewables would be expected to provide 70 % of the overall generation by 2050 (Bischof-Niemz, 2017).

In their review of the 2018 IRP, the CSIR confirmed the values that they estimated for percentage of renewables plus dispatchable power growth. With renewables expected to provide 70 % of the power generation by 2050 (Wright, *et al*., 2018).

2030 and 2050 comparisons

The estimated installed capacities for wind, solar and gas for the reference years of 2030 and 2050 from the various iterations of the IRP is shown in Table 2. It is apparent from the table that in all scenarios, growth in system capacity is expected to come almost exclusively from the growth of renewables and dispatchable gas.

From this information, it could be concluded that in all renewable energy scenarios, the growth of dispatchable gas generation is considered to be an essential element. The major parameters have been reasonably consistent throughout the IRP process, that is:

- decreasing base production captured in each update
- a significant growth in renewable generation that has also been increasing with each update
- an expectation of dispatchable generation to balance the variability of the renewable sources with needs

While gas generation is a common element in all the modelled scenarios, the modelled scenarios are silent on how gas can be provided to meet the required generation. The focus of all the models is how renewable generation could and should be provided. For the gas dispatchable generation, there is an assumption that it will be available when and as needed. However, none of the IRPs have included any specific plans to supply the gas. The comments from the various IRPs on gas are as follows.

Table 2 - South Africa Renewable Energy Scenarios from the IRP Process

Forecasted Installed Capacity - GW										
	2030					2050				
IRP >	2010	2013	2016	2018	2019	2010	2013	2016	2018	2019
Generation–TWh	437	416	350	320	320	X	622	540	399	399
Base (1)	57	55	42	40	38	X	74	43	27	27
Wind	9	5	9	11	18	X	10	39	32	32
Solar PV	8	11	6	8	8	X	25	19	25	25
CSP	1.2	0.7	0.6	0.6	0.6	X	11.5	0.6	0.6	0.6
Gas	10	12	17	12	7	X	24	37	39	39
Storage	3	3	3	3	5	X	3	3	5	5

Note1 - Base = Coal + Nuclear + Hydro + Other

Note 2 – the 2019 IRP update only changed the 2030 forecast from the 2018 update. The 2050 forecast remained as per the 2018 update.

2010 – In this IRP, it was recognised that gas would be the method of providing the most economical dispatchable power up to 2030 and that LNG importation could provide this. However, the IRP noted that dispatchable power would not be enough to anchor an LNG import terminal. Shale gas and Mozambique gas were still in the future and therefore not mentioned in this IRP (DOE, 2011).

2013 – By the time the 2013 update was produced, there was discussion of shale gas potential as well as discovery of gas in northern Mozambique. It was assumed that all peaking plants would be fuelled by natural gas rather than diesel. In this update, the concept of a "big gas" case was raised, where domestic gas would become inexpensive enough to displace coal base generation (DOE, 2013).

2016 – The gas focus in this IRP update was completely orientated to local shale gas. Four out of the five scenarios considered were based on shale gas and the fifth (with no shale gas) effectively assumed no gas generation – replaced with coal and nuclear (DOE, 2016).

2018 – This IRP acknowledged the economic advantage of a renewable generation system backed up with gas dispatchable power. However, the report indicated that sourcing of the gas was an unknown that needed study (SA DoE, 2018).

2019 – Due to concerns about gas sourcing, this IRP update is still based on renewables with gas fuelled dispatchable power but assumes that battery storage and coal will become more likely up to 2030 (SA DoE, 2019).

With the updated IRP of 2019 as a beginning point for analysis, a dispatchable energy forecast model for the system has been developed to confirm the volume of dispatchable power required to allow the appropriate generation scenario to be developed.

3.6.7. South Africa gas

Current situation

There is currently only a minimal gas business in South Africa. Natural gas provides about 2.2 % of total energy in the country, 150 PJ of energy usage out of a total of 6 500 PJ usage in 2017 and 56 % of that natural gas was converted to liquid fuel prior to usage (SA DoE, 2019b). Until quite recently, the only gas production in the country was gas sourced from offshore production to be used for liquid fuel (GTL) (Van der Spuy, 2013). This gas was produced from several small gas fields offshore of Mossel Bay. In 2004, Sasol completed a pipeline from Mozambique to their coal-to-liquid facility in Secunda and to Sasolburg, using gas for GTL and chemicals production (Sasol, 2015). They also market some of their gas to industries in the area.

Sasol and others (Gigajoule and Aggreko) utilise some of the gas through their pipeline from Mozambique to produce electricity at the border with Mozambique, where it is put into the grid connection between South Africa, Swaziland and Maputo in southern Mozambique. These generation facilities are within a facility that Mozambique has designated as "Gigapark". Current gas sourced generation at this facility is approximately 450 MW (Hill, 2013).

As described in the GUMP, there is also a small gas network between the Sasol Secunda plant, Richards Bay and Durban as well as connections to the Johannesburg area. From this network, a small number of industrial customers receive gas (SA DoE, 2015c).

Potential gas sources

Three new sources of gas have been identified for South Africa: LNG importation, pipeline gas from northern Mozambique and shale gas from the Karoo. None of these is currently in place and would require development (SA DoE, 2015c). The potential usage of each of these gas sources will be reviewed in section 5 below.

LNG

Globally, LNG has become a major business bringing gas to places with insufficient local production. Eighteen countries around the world export gas as LNG (International Gas Union, 2017). The major sources are Qatar, Australia, Malaysia and Nigeria (Oil Industry Insights, 2018). In Southern Africa, Angola has also joined the list of LNG export countries and Mozambique has at least one LNG export project currently in construction with an expected start-up by 2024 (eni, 2017). Two other larger LNG export projects are being considered for project sanction, with the large shale gas production in the United States, it has changed from being an LNG importer to being an LNG exporter. Exports, which commenced in 2016, up to a level of 20 MTPA by 2019, moving the United States of America to fourth place in the list of exporting countries. (International Gas Union, 2019a). The global market is estimated to be about 29 % oversupplied (Bloomberg New Energy Finance, 2018).

The largest LNG importer is Japan by a significant margin (Gas Strategies, 2017). The other major importing countries are South Korea, China, India, Taiwan, Spain, and the UK. Traditionally, the price of LNG imports has been set in comparison to oil prices as the gas is mostly utilised to replace oil fired electric generation (Statista, 2017).

In their 2018 forecast, Bloomberg New Energy Finance said that, "as the global LNG market enters a long phase of sufficient supply, buyers are enjoying low prices". There is a move in the LNG market of increased spot market pricing versus long term fixed price contracts. This has been accelerated with the entry of US exporters into the market, where their supply is related to USA gas prices that are not connected to oil prices (Bloomberg New Energy Finance, 2018).

LNG would be purchased in the market at a delivered price. The local investment would consist of storage, re-gasification, and distribution systems. The unpublished GUMP and the 2016 Transnet LTPF (Chapter 6 – Natural Gas Infrastructure Planning) both outlined the technical feasibility of putting the required LNG import facilities in several ports in South Africa (Transnet, 2016;SA DoE, 2015c).

Pipeline gas

Until the discovery of the major gas fields offshore Mozambique in 2011, the only known regional gas resources of any significant volume were those offshore Angola associated with oil reserves. Some of these gas reserves have been developed with an LNG project (Angola LNG, n.d.). Thus, it is possible to purchase Angolan gas in the form of LNG. In the last decade, however, significant gas resources have been found offshore southern Tanzania and northern Mozambique. The field discovered offshore northern Mozambique is one of five largest gas fields ever discovered in the world (SPTEC, 2013). The volume of the resources found in this basin, at over 2.8 trillion cubic metres would be enough to generate 235 TWh/yr. of electricity (meeting the entire current South Africa power generation requirement) for 50 years (INP, 2016).

In addition to the gas volumes already found offshore Mozambique, it is estimated that there is the potential to double the offshore resource base as further exploration is conducted in the areas adjacent to the current discoveries (Republic of Mozambique, 2014). With the expected ultimate reserve base, Tanzania and Mozambique could become one of the major gas supply sources in the world market (Crook, 2012).

The gas fields in Mozambique are offshore and in deep water, adjacent to the border with Tanzania. Therefore, getting the gas to South Africa by pipeline would require a pipeline in the range of 2500 kilometres.

With pipeline gas, the source and outlet for the gas are fixed, requiring both the supply and the market to be large enough and stable enough to justify the upfront investment. Transferring the gas from source to market by LNG offers both the producer and user greater flexibility. However, LNG requires a large upfront investment in the facilities to liquify the gas and uses a significant portion of the gas to supply the energy for the liquefaction process. Thus, it is critical that an objective analysis of the costs and benefits of pipeline gas is executed before committing to the investment or rejecting it (Wood, *et al*., 2008).

While not nearly as large as the gas fields discovered offshore northern Mozambique, several smaller gas fields were discovered onshore Mozambique, south of the city of Beira in the 1960s. These two fields, the Panda and Temane fields, were eventually developed by Sasol in 2004, with commercialisation of the gas via pipeline to their facilities in Secunda, as shown in Figure 11. In Secunda and Sasolburg Sasol uses this gas for liquid fuel and chemicals production (Sasol, 2020). It is expected that

the useful production life of these fields is in the range of 20 to 25 years. With a start of production in 2004, production decline is expected in the next decade. To meet any long-term supply commitments, additional gas sources must be developed. Sasol has been conducting extensive exploration in the vicinity and offshore in the same basin. It is not known at this time if these efforts will be successful and Sasol has been warning their customers and the government about the potential decline in the throughput from this line commencing by 2025 (ee publishing, 2019).

Should the exploration efforts and associated commercial negotiations be successful, Sasol will continue to supply gas into this system. Even if these efforts are not successful, there is discussion commencing on alternate sources of gas supply through this pipeline to meet customer needs in Mozambique and South Africa. The first possibility is to connect this pipeline to the supply from the extensive fields in northern Mozambique by pipeline. The second possibility is the use of LNG importation through the port of Maputo, where there is a connection into the Rompco pipeline. This appears to be a more likely medium-term alternative to supply gas into the Rompco system. Importation of gas into the South African market utilising this option should be more economical than any of the suggested LNG importation alternatives (ee publishing, 2019).

Figure 11 - Rompco Pipeline Route (mjm energy, 2012)

South African shale gas

During the 1960s in the search for local oil resources, the government company, SOEKOR, drilled 23 wells in the Karoo to test the regional potential. Except for one small gas test, these wells did not find any significant quantities of oil or gas. Subsequent to this effort, there has been no further exploration in the Karoo (Von Tonder, 2014).

As demonstrated by the gas test from the SOEKOR well, there is clearly some shale gas resource in South Africa (Van der Spuy, 2013). There are certainly questions as to how large the resource is and if it is economical to produce. In the initial study conducted by the US EIA agency in 2011, it put the shale gas resource base in South Africa as 14 trillion cubic metres (TCM), as compared to the 23 TCM that it estimated for the United States of America (Kuuskraa, *et al.*, 2011). This resource in South Africa was the fifth largest in the world. This is too large to ignore. In the 2013 update of this EIA report, the South Africa resource was lowered to 11 TCM (US EIA, 2013). This resource would provide South Africa's annual generation of about 235 TWh of electricity for over 175 years.

With the huge resource estimate of shale gas in South Africa from US EIA, there have been several local studies to verify this resource size. The studies have concluded that this may be an overly optimistic estimate, due to local geological conditions of the shales and the likely resource size is more on the order of 1 to 1.4 TCM, with some estimates being much smaller (Scholes, *et al.*, 2016). Even with these decreased sizes, it is still a sizable resource and one that must be considered in the overall energy capacity of South Africa – but possibly not the "game changing" size that the US EIA estimate would imply. Many questions remain about the size and commerciality of this resource.

The South African government has made concerted efforts in attempts to collate all the information that is available for the shale gas potential in the Karoo into a better definition of the resource base and the best areas for further development (Academy of Science of South Africa, 2016). PASA has made various studies that were incorporated and expanded into the extensive study developed at government request by the CSIR in 2016 (Scholes, *et al.*, 2016). The study showed a large potentially attractive area from west of Beaufort West to east of Graaff-Reinet, with the expected "sweet spot", i.e. the area with the best potential, to be in the area between these two cities as shown in Figure 12. If shale gas development moves to the exploration phase, it is expected that the first efforts will focus in this area. The first steps in the exploration process would only be in producing a seismic picture of the area of interest, followed by some wells (vertically drilled and not fractured) to collect core samples to analyse the properties of the target shales and their potential shale content. It was forecasted in the 2016 CSIR report that the exploration period would be at least 10 years prior to any development.

Additionally, should the "big gas" development case be pursued, this would likely not happen prior to approximately 2050 (Scholes, *et al.*, 2016).

While the potential shale gas resource in South Africa is quite large, it seems to be quite challenging to imagine the business case that would trigger the development of this resource. Many of the parameters for development which were found in the United States and in other countries that have developed their shale gas reserves do not exist in South Africa. To have a long-term business model for shale gas in South Africa, it would likely be necessary to develop the business to a size that could pay for the creation of a gas network and retail/commercial distribution of the produced gas. It would also be essential to build up a customer base currently not considering gas utilisation (Scholes, *et al.*, 2016).

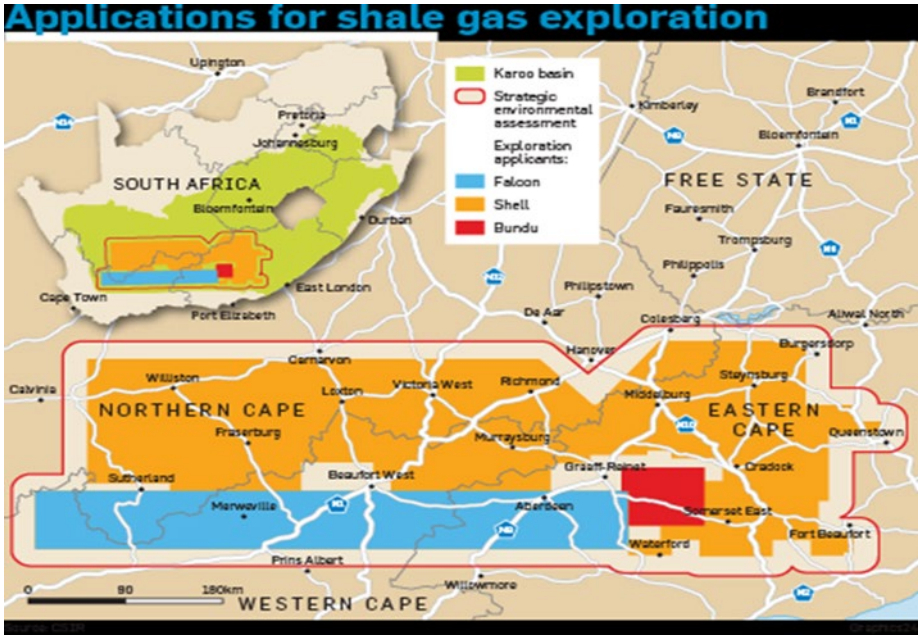


Figure 12 - Map of Shale Gas Concessions (Scholes, *et al.*, 2016)

These challenges can be overcome if the size and value of the resource is large enough but, as has been seen in other countries, the interest of investing companies in this business may not be up to the long-term focus needed to develop this new resource.

3.7. Worst case planning – maximum power and energy requirement

Utilities must plan for the electric grid system to deliver the requested load even in the most severe conditions. For this reason, they must determine the amount of dispatchable power that would be needed in the worst-case conditions for variable generation. Most studies have concluded that this implies having enough dispatchable power available to meet the system need with the assumption of no renewable

generation (Noha, *et al.*, 2017). If stored energy is to be used to totally support a generation system from renewable sources of wind and solar, the amount of stored energy which is required has been estimated for the United States of America to be in the range of eight to ten weeks of the energy of the entire network or about 15 % to 18 % of the annual demand (Becker, *et al.*, 2014). A German study in 2012 estimated that storage would be required to provide 12 % to 15 % of the annual demand to allow for a 100 % wind and solar generation system in Europe (Heide, *et al.*, 2011). These analyses indicate the need for extremely large energy storage systems if dispatchable power is to be eliminated.

3.8. Potential to replace gas as a dispatchable source

With variable availability from renewable energy sources such as wind or solar, as well as variable demand, a grid cannot be operated without a significant amount of dispatchable power. If this is to be met with renewable sources, peak production must be provided either in the generation process, as is done with gas peaking plants, or with large utility scale storage.

Gas fuelled power generation allows the system to meet three types of dispatchability; 1) short term, intra-day needs, 2) time of day loads, such as the hours when the sun is down and, 3) seasonal or annual variability loads. All three of these situations must be handled for proper grid management. Some peaking and storage options are most suitable for one or the other of these requirements and the ultimate optimal overall system will most likely require some assortment of solutions to meet each of these situations.

3.8.1. Renewable dispatchable energy

CSP

The only current solar energy technology with dispatchability built into the system is concentrated solar power (CSP) (Brand, *et al*., 2012). In these systems, there are one or more energy transfers within the system that allows the flow of energy in and energy out to be adjusted to match the input availability and output requirement and storage to be used to balance supply and demand. These systems have been proven to provide power generated from the sun on a 24-hour basis, as needed, with the ability to rapidly adjust the output. In California, there are examples of hybrid CSP systems, where the dispatchability that CSP storage provides is backed up by gas fired generation (Alqahtani & Patino-Echeverri, 2016). These systems become truly dispatchable generation sources with this configuration. Continued research is being conducted on the cost elements of CSP with the intent to bring the cost to a level where these systems can be competitive with renewable energy plus storage systems (Gauché , 2019).

At the South Africa Solar Energy Conference (SASEC) 2019, Paul Gauche´ from Sandia Labs reviewed a research program currently being conducted in the USA – SunShot 2030 – that has the aim of achieving a dispatchable cost from CSP of USD 0.1 per kWh (Gauche´, 2019). If CSP can achieve this figure, it should be competitive with solar PV plus battery systems for evening hour energy supply.

Biofuel

If fuel could be produced from crops grown for this purpose (commercially and in sufficient volume), much of the current infrastructures for fossil fuels still might be used for supplying energy needs. This includes refining through distribution to the vehicles and power plants that currently use most of the fossil fuels. The major oil and gas companies have a vested interest in this solution that would maximise the use of the existing infrastructures and there is much research into sources of fuels that could meet these needs, such as crops grown in non-agricultural areas and algae grown for energy. These could become the source of the power needed for replacing fossil fuel sourced peaking power (Rawat, *et al.*, 2013).

Presently, biomass is an expensive alternative to other types of generation. In the REIPPPP, biomass was one of the alternatives available. One biomass project was selected in bid round 4, for 25 MW of generation at a price of 1.5 R per kWh(SA DoE, 2015b) as can be seen from Table 1 above. This is the price for power from a base load facility. For dispatchable power, biomass is generally non-competitive due to high capital cost. The upside potential for biomass is limited as it must compete with food production for land and water usage.

In 2007, the South African government published a strategy to utilise biomass to provide up to 2 % of the energy needs in the country using biofuel (Department of Minerals and Energy, 2007). However, high costs have limited the uptake of biofuel and the current electricity production from biomass in South Africa is reported to be 1 000 GWh., mostly for internal consumption by the generating company (SA DoE, 2019b).

3.8.2. Renewable generation plus storage

While dispatchable renewable energy systems are limited, there are many options for energy generation with renewable sources combined with storage. The combination of these systems can be made to achieve dispatchable renewable systems. Energy storage is not a generation source. Instead, it is way to use excess generation to balance supply with demand. To make storage a valid consideration, there must be excess generation and a temporal imbalance between supply and demand. Since the demand curve has peaks and troughs during each day, there are opportunities to improve the efficiency of the grid using storage.

In the current South African grid, most of the generation is from base load facilities and there are economic benefits to using these facilities consistently rather than cycling them (Grol, *et al.*, 2015; Keatley, 2014). Base load thermal plants have slow ramp up and ramp down timing, making it challenging to use them to meet variable demand (Kumar, *et al.*, 2012). In addition, it has been demonstrated that cycling of these plants increases their operating costs due to fatigue stresses added to the creep stress that was considered in the design of the equipment (Shibli & Ford, 2014). Thus, there is a significant opportunity to utilise energy storage to allow these facilities to be used optimally by avoiding cycling.

However, as base load generation facilities are decommissioned and replaced with wind, solar and dispatchable generation, the concern for base load optimisation diminishes and storage either becomes redundant or other generation must be installed to provide the energy to charge the storage. In a grid based on renewable but variable generation from wind and solar, it is often preferable to overbuild these generation sources and provide the excess that these sources would generate at times for storage. In analysing the benefit of storage in the system, the use of storage to maximise the benefit of base load and the charging of storage from renewable sources are sufficiently different that they require separate consideration.

Flexibility considerations support the use of utility scale battery storage systems. From a long-term perspective, these may not be the optimal solutions as they do not have the life of some of the storage concepts, such as pumped hydro or compressed air energy storage systems (CAES), but batteries currently have a lower capital cost compared to alternative storage (IRENA, 2017). A recent report from the US DoE compared costs for various storage technologies and showed Li-Ion batteries to have capital cost of about 54 % on a per installed kW basis compared to pumped hydro. The Li-ion batteries have lower capital costs to alternatives, as shown in Table 3 (Mongird, *et al.*, 2019). NREL prepared a review of forecasts of Li-Ion battery system storage costs and predicts that costs of these systems are expected to drop to 50 % of the current 2018 cost by 2030, as shown in Figure 13 (Cole & Frazier, 2019). While the lifespan of these battery systems is less than half of the pumped hydro systems and the energy content is lower, their low capital costs, short development time and scalability fits with the current thinking for flexible power systems. They can also be sited at the user end of the grid, maximising their value.

In comparing storage systems, such as battery storage systems, it is essential to discuss not only the power of the system, but also the energy storage of the system. In most generation, the cost is mostly related to the cost of power of the generation and cost of energy is less of a consideration. In storage, it is the opposite. The amount of energy that can be stored in storage systems is more important than the cost of power. Generally, battery storage and most other storage systems are designed to provide a given number of hours of energy. To provide more energy, the size of the storage must be increased linearly with the time of use (Ziegler, *et al.*, 2019). It is critical to note that

due to this consideration, storage is competitive for the short-term energy imbalances in the system but may not significantly reduce the amount of dispatchable power that must be available to meet longer term needs (US EIA, 2018f).

Table 3 - Energy Storage Costs (Mongird, *et al.*, 2019)

Energy Storage Costs by Technology			
Technology	Capital Cost ($/kW)	Energy (Hours)	Life (Yrs.)
Pumped Hydro	2 638	16	>25
CAES	1 669	16	25
Flywheel	2 880	0.25	>20
Ultra-capacitor	930	0.0125	16
Li-Ion Battery	1 446	4	10
Led Acid Battery	1 854	4	3
Redox Flow Battery	2 598	4	15

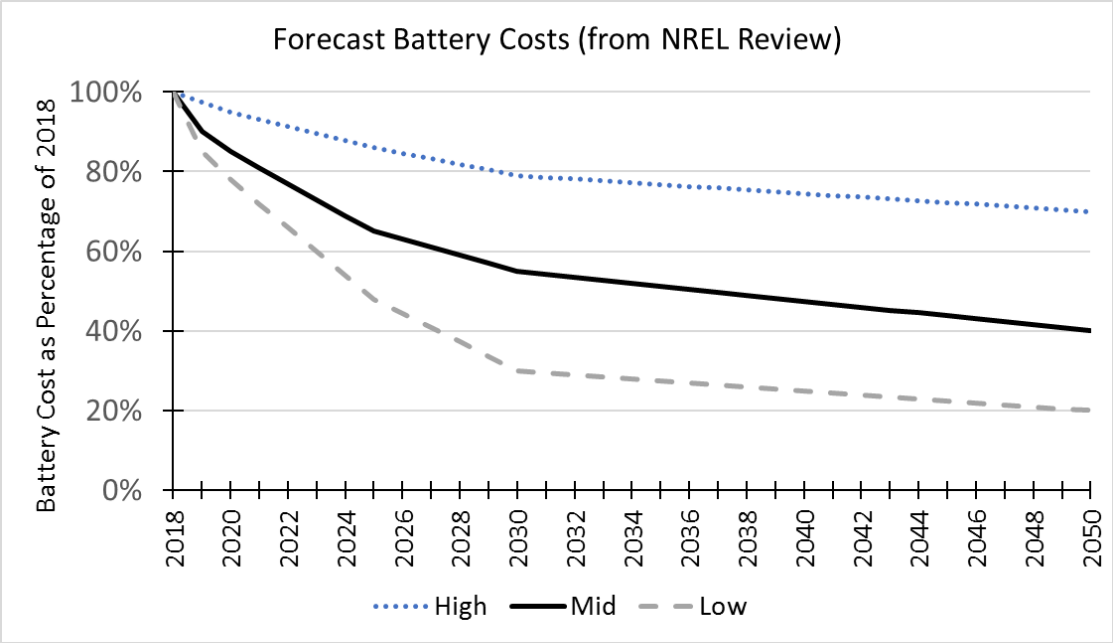


Figure 13 - NREL Battery Cost Forecast – data (Cole & Frazier, 2019)

As the addition of storage systems does not necessarily reduce the amount of dispatchable power that must be installed, the economics of storage are simply related to the savings in fuel and variable operating costs associated with dispatchable generation. In the United States of America, in places with excess renewable generation, the current market view is that these systems can replace power demand of up to about four hours which could double if battery costs decline as expected. For storage times longer than this, the battery systems become less economically competitive (US EIA, 2018a).

Storage options

According to a IEA study, there are currently about 141 GW of installed energy storage projects worldwide (IEA, 2020a). Of the 141 GW of current storage, roughly 140 GW or 99 % is pumped hydro. This overall storage capacity compares to a worldwide electric power generation capacity of 6400 GWs or around 2 % of the installed capacity. In the next five years, IEA predicts that energy storage volumes will grow by about 30 % but half of that growth will be in battery systems. Pumped hydro storage will drop to around 87 % of the total (IEA, 2020a).

With increasing use of variable power generation technologies (such as solar and wind), the need for extensive volumes of storage for peaking purposes and long-term storage will increase significantly. The amount of storage that would be required to meet grid stability with majority use of renewable resources is one of the major questions being asked in grid system management worldwide.

Pumped Hydro

Pumped hydro energy storage provides the vast majority of energy storage systems around the world. These systems can store large amounts of energy for long periods with minimal loss. The energy stored is limited by the volume of water that can be held in the reservoirs. Pumped hydro storage has a high upfront capital cost, but a long life. On a long-term basis, these systems provide the lowest cost energy storage. However, their use is geographically limited to locations with significant water reservoirs with elevation changes. South Africa has four pumped hydro systems in place, as listed below (Barta, 2018).

- Ingula – 4 x330 MW from 2016
- Drakensburg – 4 x 250 MW from 1982
- Palmiet - 2x 200 MW from 1987
- Steenbras – 180 MW from 1979

However, growth in this storage is quite slow. Besides the geographical limits to this storage option, the upfront cost for these systems is much higher than battery storage systems, as can be seen from Table 3. While battery storage may not have the lifespan that pumped hydro projects have, the advantage of low upfront cost means that battery storage systems offer greater flexibility for changing conditions compared to high capital cost alternatives such as pumped hydro. These advantages are the prime reasons that battery storage options are expected to be one half of newly installed storage in the next five years and pumped hydro would make up the other half. (IEA, 2020a)

Compressed Air Energy Storage

Another system that can be utilised to provide large volumes of stored energy is compressed air storage system (Budt, *et al.*, 2016). These systems utilise the energy that is stored in the release of pressure from compressed air. The two major challenges with these systems are the overall low energy efficiency as well as the large volume of air storage that is required (Meng, *et al.*, 2018). The energy generation phase from these systems requires the addition of heat to offset the cooling effect from flow across the pressure reduction system (Kim, *et al*., 2011). As in pumped hydro, the upfront cost of these systems is quite high as shown in Table 3.

Batteries

As noted above, in the IEA forecast for the growth of energy storage, batteries are expected to provide almost half of the growth in energy storage around the world in the next five years (IEA, 2020a). These systems have low initial costs, which are also declining as more systems are being built. The systems can be built at any size and in almost any location. The limitation with these systems up until now has been their limited life span. Battery systems have not been able to last longer than 10 years in the past, however new systems have the potential to last up to 20 years or more (US EIA, 2018a). With the declining costs, these systems are currently the technology of choice for most energy storage systems and are being installed in greater power and energy capacity systems around the world (Cole & Frazier, 2019).

Utility size battery systems have been selected in a number of places for renewable energy storage in recent years. Large international utility scale battery storage facilities are listed in Table 4 (Spector, 2019). Most of these projects are in the 100 MW power range with approximately four hours of output. A recent report published by Bloomberg New Energy Finance on the levelised cost of energy (LCOE) suggests that wind and solar generation combined with lithium-ion batteries are increasingly becoming a cost-competitive alternative to natural-gas-fired power plants providing the need is up to four hours capacity (Ieefa, 2018). These battery systems can be distributed or centralised to meet this need. Distributed battery storage can be matched to specific customer needs and is installed at the lower voltage portion of network, minimising the transformer costs. It is expected that this will generally be the preferred use of battery storage (Lounsbury, 2015).

Table 4 - Utility Scale Battery Storage (Spector, 2019)

Recent Utility Scale Battery Storage Installations				
Project Title	Location	Power (MW)	Energy (MWh)	Start-up
Manatee Energy Storage	Florida	409	900	2021
Moss Landing	California	300	1 200	2020
Skeleton Creek	Oklahoma	200	800	2023
Tesla Moss Landing	California	183	730	2020
Jiangbei	China	131	269	n/a
AES Arizona	Arizona	100	400	2021
Alamitos	California	100	400	2021
Oxnard	California	100	400	2020
Hornsdale	Australia	100	129	2017

Solar Fuel – fuels produced from renewable energy sources

With the use of solar and wind energy, it is possible to produce fuels – either hydrogen or manufactured methane – for dispatchable power. Both concepts are currently being extensively studied and might provide the best source of long use dispatchable power generation capacity. Manufactured methane allows the infrastructure associated with natural gas usage to continue to be used. Straight hydrogen use would require new infrastructure. Most of the proposals for hydrogen consider the use of fuel cells rather than hydrogen combustion.

While the short term dispatchable generation can be replaced with a number of energy storage systems, storage (from international examples) for longer terms up to a few weeks use would be needed to completely replace the use of dispatchable power. The IEA analysed storage for different volumes and duration and has concluded that hydrogen is the most probable storage medium for longer term storage, which they show in the Figure 14 (OECD & IEA, 2015).

As noted by IRENA, there is a growing consideration that hydrogen will be a major factor in the storage of renewable energy to meet longer term storage needs as well as the ability to transport this renewably generated energy over long distances to where it can be used. IRENA stated on the website for their hydrogen report that “In the long run, hydrogen could become a key element in 100 % renewable energy systems” (IRENA, 2018). When hydrogen is used to produce electricity either through combustion or in a fuel cell, the by-product is water.

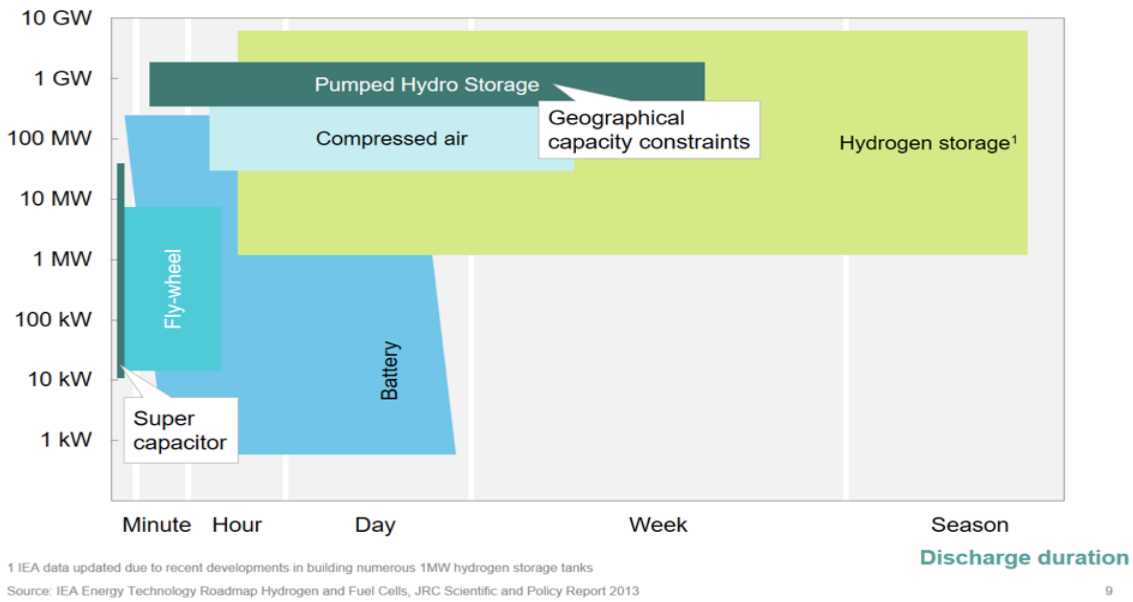


Figure 14 - IEA Energy Storage Breakdown (OECD & IEA, 2015)

While it is the most common element in the world, hydrogen does not exist in isolation to any extent and must be produced from other substances. Most hydrogen is currently refined from hydrocarbons, particularly coal and natural gas by steam reforming. However, producing hydrogen from these sources releases significant volumes of carbon dioxide. It is possible to produce hydrogen without any GHG emissions using the electrolysis of water with solar generated electricity.

Chemically, it is a simple process to produce hydrogen through this method. Water put through a fuel cell with electricity input will split into hydrogen and oxygen. The concern is the amount and related cost of the electricity that must be used in this process. Approximately 50 kWh of electricity is needed to produce one kilogram of hydrogen in a standard electrolysis process (Saur & Ainscough, 2011). The lower heating value of hydrogen is 120 MJ/kg (as compared to natural gas of 40 MJ/kg). Thus, the 50 kWh of electricity input produces about 120 MJ in the form of hydrogen.

According to a study on the economics of producing hydrogen using electrolysis, the cost of electricity is in the range of 75 % of the cost, assuming electricity at USD 0.06 per kWh (Schmidt, *et al.*, 2017). With the cost of solar PV generation dropping as quickly as it has been, the cost of hydrogen produced with solar generation is dropping along with this decrease. With the current cost of solar produced electricity, the likelihood of producing hydrogen at prices lower than natural gas is becoming more probable.

Producing peak electricity with hydrogen offers most of the benefits that natural gas fuelled power has. With the current improvements in costs, the capital cost for fuel cell generation systems are expected to become lower than combustion generation plants

by 2025 to 2030 (according to the US Department of Energy) (Papageorgopoulos, 2019). At this value, the low capital cost associated with gas fuelled generation will also be an advantage of hydrogen fuel cell generation. The flexibility and modularity of gas generation is also a feature of hydrogen-based electricity generation. However, the challenge of energy storage that natural gas has is also a challenge for hydrogen-based fuel (Herzog, 2018).

Much like natural gas, hydrogen can be transported as a compressed gas or liquefied at low temperature (-252° C for hydrogen as compared to -162° C for natural gas). However, hydrogen is a much smaller molecule than natural gas and leakage from pipelines and storage is more probable. In addition, hydrogen causes embrittlement in some materials and storage vessels utilised for natural gas may not be suitable for hydrogen. It is likely that much of the infrastructure used for natural gas cannot be used for hydrogen. In South Africa, with minimum existing natural gas infrastructure, this is less of a concern. One other concern for the use of hydrogen as a fuel is the larger range of the explosive limit for hydrogen compared to natural gas. Each of these limitations can be met but must be considered in design of a hydrogen based system.

With the use of hydrogen, there is also the possibility to transport and store the hydrogen in liquid carrier – known as a liquid organic hydrogen carrier (LOHC) (Preuster, *et al*., 2016). With this, the hydrogen is bonded into the liquid carrier through the process of hydrogenation. To be used for power generation, the hydrogen is removed from the carrier through dehydrogenation. The carrier fluid is not destroyed in this process and can be reused. The LOHC has much of the properties of liquid hydrocarbon fuels such as diesel and can be transported and stored in existing liquid fuel systems. LOHC fluids are in development and it has been confirmed that these fluids can hold about 7 % hydrogen by volume. The ability to hold on to the hydrogen in the fluid does not decrease over time, so this could be used for long term storage.

Current costs do not seem to support these hydrogen fuel technologies at this time, but they might be made competitive. There is a large amount of research being conducted in this area (Papageorgopoulos, 2019).

3.9. Chapter summary

In this chapter, the international transition to renewable energy-based generation systems has been reviewed. In the last decade, there has been significant progress around the world in developing wind and solar resources and it is now the lowest cost source for electricity generation. There are several countries with networks of similar size to South Africa that have made good progress in integrating significant renewable energy into their networks. Gas fuelled dispatchable back up power is a common element in these networks.

South Africa has made international commitments to lower its GHG emissions with the majority of this improvement coming from replacing its inefficient coal fuelled generation. In the last decade, South Africa has commenced the transition of its network to the point where 5 % of its generation is coming from wind and solar resources.

In the next chapter, the amount of dispatchable backup energy required to meet the desired transition in South Africa will be calculated.

4. Dispatchable Power in the South African Grid

The IRP process has been based on an overall plan for the national power generation system to commence the move to one based on wind and solar generation. As seen in other countries, due to the variability of wind and solar generation, dispatchable power will be required. However, the forecast amount of dispatchable power required has been one of the major questions from the IRP process.

Dispatchable generation is an output of the design of the generation system. The amount of dispatchable generation that will be required to balance the declining base load generation and the variability of a given amount of renewable energy is not a pre-determined amount. It is a calculated value required to meet the system generation needs when the designed base plus renewables does not met the demand. The intent of this generation source is a contingency plan, only to be utilised when required, which in a well-designed system is a minimal use.

Following the process laid out in the research proposal, the question of how much dispatchable generation is required will be addressed in the following chapters. The steps in this process can be summarised as follows.

- Assume a renewable energy scenario
- Choose a modelling tool
- Model the power system for a given year
- Determine the amount of dispatchable generation
- Review storage options
- Investigate options to provide the dispatchable power
- Analyse gas supply options
- Develop the gas supply option to satisfy model
- Increment year to cover study period
- Re-iterate to optimise
- Complete sensitivity and robustness review

4.1. Assume a renewable energy scenario

When the research proposal for this work was submitted, it was expected that updates to the IRP would be prepared during the research period that could affect the conclusions of the work. As expected, an update of the IRP was issued for comment in 2018 (SA DoE, 2018). In addition, an unexpected IRP update was developed a few months after the 2018 version and was issued for comments in early 2019 (SA DoE, 2019). This 2019 IRP was gazetted in September 2019 and has become the official IRP. The 2019 update became the basis for this analysis. As per previous iterations of the IRP, the basis for most new generation in the plan is from wind and solar sources.

4.2. Determine the best model tool to utilise

There are several forecasting models to predict performance of a given solar or wind power generation plant. In addition, there have been some studies to forecast how these plants can be aggregated into a South Africa system (Knorr, *et al.*, 2015). A discussion of modelling is included in Appendix A. For this analysis, it was decided to use a simple model developed for this exercise – the Dispatchable Energy Model – specifically to address the question of the amount of dispatchable energy will be required to balance the generation as outlined in the IRP process.

As South Africa is over three years into implementing solar and wind generation, it would be more appropriate to utilise actual performance data rather than theoretical predictions if possible. Performance data for Eskom demand and renewable generation was received for the years 2015 through 2019 and analysed for consistency and adequate spatial coverage to represent an aggregated system (Eskom, 2019b). This analysis is included in Appendix A. The analysis indicated excellent consistency through the years of study, even considering localised events such as load shedding and drought conditions. The comparison of demand for the period of 2015 to 2019 is shown in Table 5. As can be seen from the information in this table, the average, peak and minimum demand values for power generation were consistent throughout the data gathering period. This data appears to be sufficiently representative to be valid for forecasting future system performance. For this analysis, demand was forecast by scaling up the 2017 Eskom generation by the growth factor considered.

Table 5 - Eskom Generation 2015-2019

Eskom Generation 2015 – 2019					
	2015	**2016**	**2017**	**2018**	**2019**
Maximum – MW	34 068	34 742	35 553	35 179	34 122
Minimum – MW	19 683	19 400	18 963	19 008	16 351
Average – MW	27 073	27 067	26 788	26 763	26 376
Total - GWh	237 128	237 075	234 640	234 640	231 052
Percent of 2015	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	100 %	102 %	104 %	103 %	100 %
Minimum	100 %	99 %	96 %	97 %	83 %
Average	100 %	100 %	99 %	99 %	97 %
Total	100 %	100 %	99 %	99 %	97 %

The generation of energy from renewable sources was also reviewed with data from 2015 to 2019. It was found that the performance of both wind and solar generation during these years was consistent (as seen in Table 6) and performed as predicted by the aggregation models. For both wind and solar PV there was enough areal spread for the existing generation to represent what could be expected in the future from these resources. For renewable generation from wind and solar PV the 2017 hourly capacity

factors were utilised with the planned installed capacity for the year of analysis. This consistency can be shown in the two graphs of nominal generation hourly distribution shown in Figures 15 and 16 (this is covered in further detail in Appendix A).

Table 6 - Renewable Generation Statistics 2015-2019

South Africa Wind and Solar Generation 2015 - 2019					
Wind	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	560	1 070	1 474	2 078	2 078
Maximum	898	1 230	1 780	1 902	1 872
Minimum	1	3	11	20	16
Average	284	425	580	738	756
Total - GWh	2 489	3 719	5 081	6 467	6 624
Solar PV	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	960	965	1 474	1 474	1 474
Maximum	931	1 351	1 432	1 392	1 376
Average	249	299	380	375	380
Total - GWh	2 184	2 619	3 324	3 282	3 325
CSP	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	0	0	200	400	400
Maximum	0	201	400	400	502
Average	0	62	118	118	178
Total - GWh	0	492	687	1 031	1 557
Wind Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	93.2 %	92.2 %	91.4 %	91.5 %	90.0 %
Minimum	0.1 %	0.2 %	0.7 %	0.9 %	0.8 %
Average	32.2 %	34.4 %	35.8 %	35.5 %	36.4 %
Solar PV Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	96.5 %	94.1 %	97.2 %	94.4 %	93.3 %
Average	25.9 %	26.0 %	25.7 %	25.4 %	25.7 %
CSP Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	-	100.4 %	100.7 %	100.5 %	100.4 %
Average	-	28.1 %	30.0 %	37.9 %	36.5 %

As the IRP 2019 does not account for any growth in CSP or pumped hydro storage, these two systems were left as per their performance in 2017 and any growth was accounted for in generic dispatchable generation and storage.

An Excel hourly Dispatchable Energy Model was constructed to forecast the requirement for dispatchable energy within the framework of the assumed scenarios for electicty generation in South Africa as outlined in the IRP. A review of how thsi analysis tool compares to other modelling tools is reviewed in Appendix A. The model projects the data to the year in question, in particular 2030 as the basis of comparison with the information in the IRP plans. This Dispatchable Energy Model was able to reasonably replicate the installed capacity of the dispatchable power requirement

(approximately 10 GW) and use of these facilities for about 10 TWh as noted in the IRP for 2030 with the parameters assumed in the IRP of 2019.

It was found that the performance estimates used in the IRP process were more optimistic for both wind and solar PV performance compared prediction from both the Dispatchable Energy Model and the model developed by the CSIR. This analysis indicates that about 10 % more wind capacity will be needed to generate the energy estimated from the IRP and 16 % more solar PV. This is shown in Table 7 (figures in black are given and those in red are calculated). The implied IRP model capacity factors are 40 % for wind and 29 % for solar PV. This analysis gives a capacity factor for wind of 36 % and for solar PV 26 % based on actual performance in 2017. The CSIR aggregation study predicted an aggregate capacity factor for wind of 36 % and for solar PV of 22 % (Knorr, *et al*., 2015). From this, it can be concluded that there is better consistency between the predictions from the CSIR analysis and this Disptachable Energy Model than with the IRP analysis. However, as will be discussed in the next section, the range of likely forecasts for 2030 is much larger than predicted in the IRP process and the implementation program will need to be adjusted as time progresses.

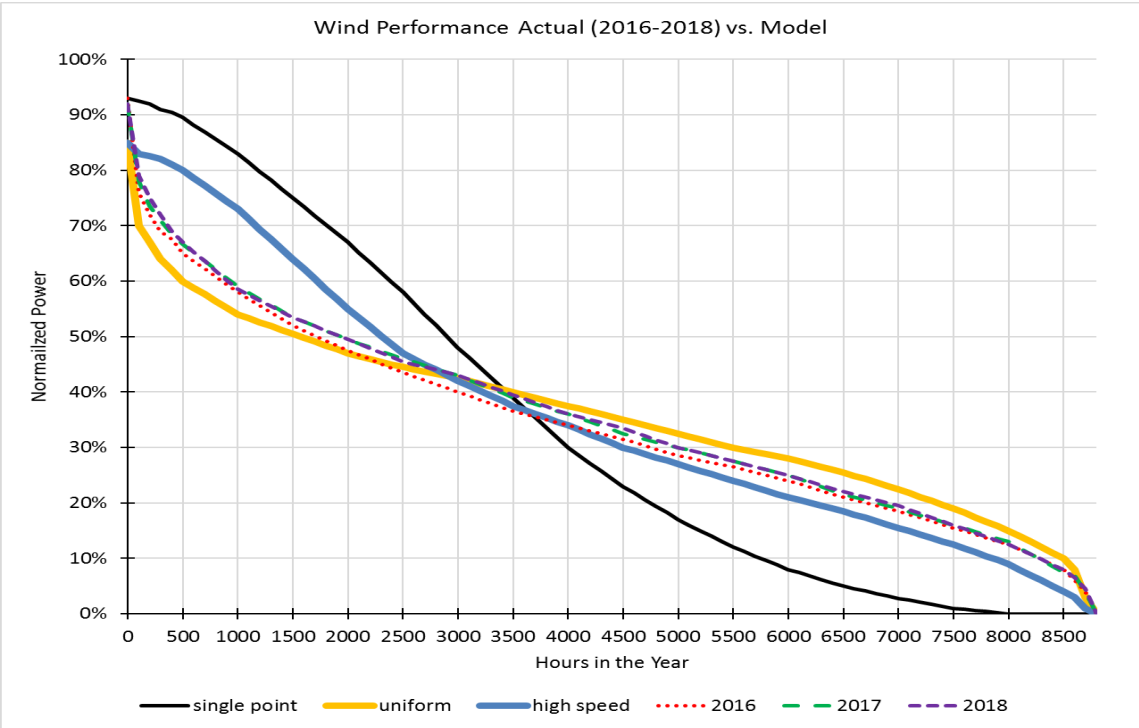


Figure 15 - Wind Performance Curves 2016 - 2018

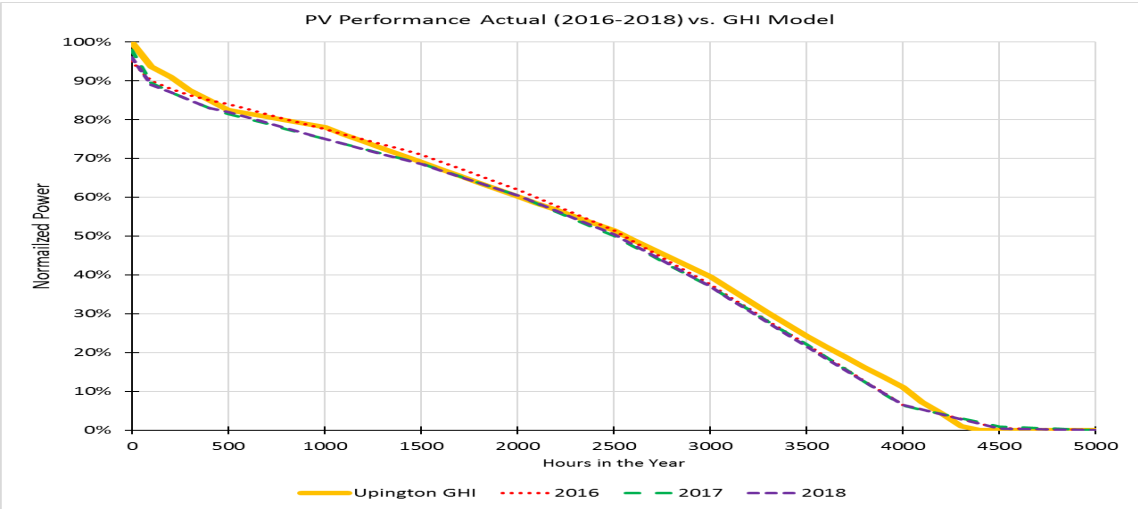


Figure 16 – Solar PV Performance Curves 2016 – 2018

Table 7 - IRP 2019 Generation Comparisons

2030 Generation Comparison – IRP and Dispatchable Energy Model						
IRP 2019 – IRP3 (Median Growth)			Dispatchable Energy Model		Adjusted Model for Renewable Generation	
	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)
Base (1)	42	245	42	250	42	245
Wind	13	45	13	41	15	45
Solar PV	9	23	9	21	11	23
Dispatch	13	9	15	10	15	9
Total	78	322	80	322	83	322

Note 1 – Base = Coal + Nuclear + Hydro + Other

The 2019 IRP plan for renewable generation and dispatchable requirements is shown in Table 8. The minimum and maximum renewable generation values are estimated based on the Dispatchable Energy Model using 2017 data. The dispatchable generation is calculated from the model as is required to meet the highest demand value.

Table 8 - IRP 2019 Renewable Generation Plan

IRP 2019 Renewable Generation Plan				
	2018	2030	2040	2050
Wind – GW	2	13	27	50
Solar PV – GW	1.5	7	18	35
Dispatchable - GW	5	10	25	40
Minimum - 1	0.1 %	0.7 %	1.2 %	1.9 %
Maximum - 2	11 %	51 %	101 %	161 %

Note 1 – Minimum percentage of total system generation from wind plus solar PV
Note 2 – Maximum percentage of total system generation from wind plus solar PV

4.3. Using the system model to develop a dispatchable energy profile

As discussed above, the Dispatchable Energy Model adequately replicates the required dispatchable power forecast by the 2019 IRP for 2030. However, as can be seen in Figure 17, there has been a distinct difference in the actual growth in power demand since 2010 from what was forecast in the 2010 IRP. Also shown in this figure is the forecast from the 2018 IRP as compared to growth since 2016, which was the base year for the 2018 IRP (SA DoE, 2018). The 2019 IRP did not update the growth forecast from 2018 but shifted it by two years. These differences in growth will make a significant difference in the required dispatchable power that will be required by 2030. To accurately forecast the dispatchable power requirement for 2030, these differences must be considered, which is done in this analysis.

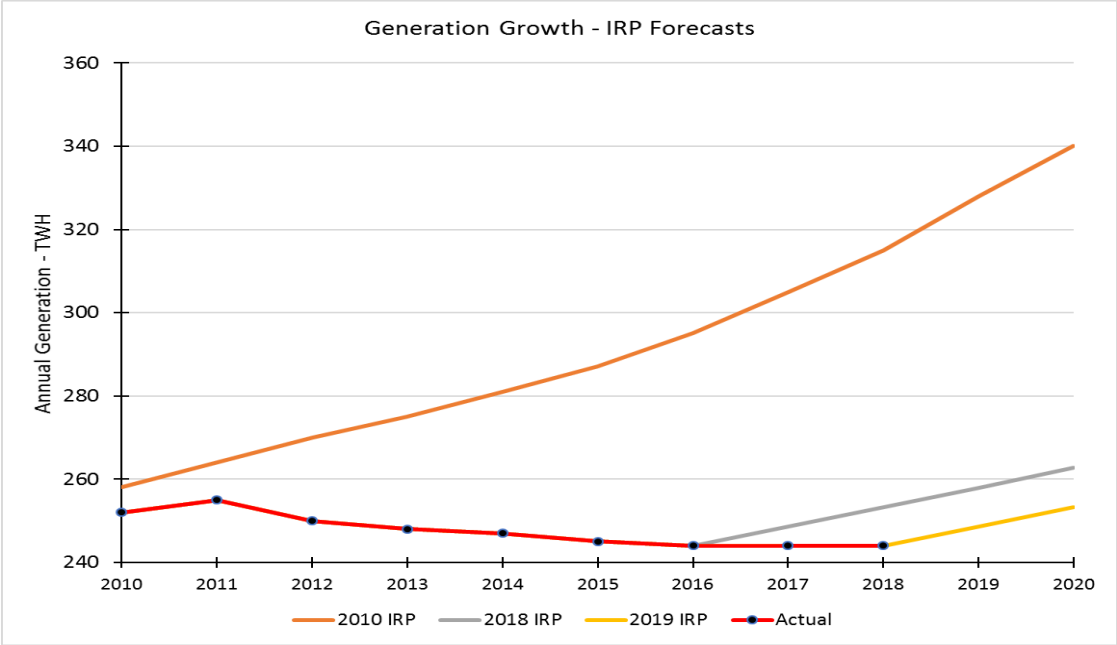


Figure 17 - Demand Growth Projections

The 2019 update to the 2018 IRP was brought about due to two other factors that changed significantly from what was used in the 2018 IRP forecast. From 2018 into 2019, Eskom reviewed their decommissioning plans and significantly changed the short-term expectations. In addition, the fleet performance of the Eskom coal generation plants – the Energy Availability Factor (EAF) – was much lower than the expectations of improving performance included in the previous IRPs (SA DoE, 2019c).

Each of these parameters has a range of probabilities that can affect the actual requirements of the system by 2030. The effect of each of these parameters is shown in Figure 18. Appendix B provides an analysis of the potential range of probabilities for each of these parameters and their effect. As determined in this analysis and shown in Figure 18, the dominant factors determining the required dispatchable power requirement, both for installed capacity and for the energy that would be generated from

this resource, are demand growth, decommissioning and base generation availability factor.

As shown in the analysis in Appendix B, demand growth remains the major factor in determining the dispatchable need up to 2050, with decommissioning and EAF decreasing in importance as more of the base load is eliminated over time.

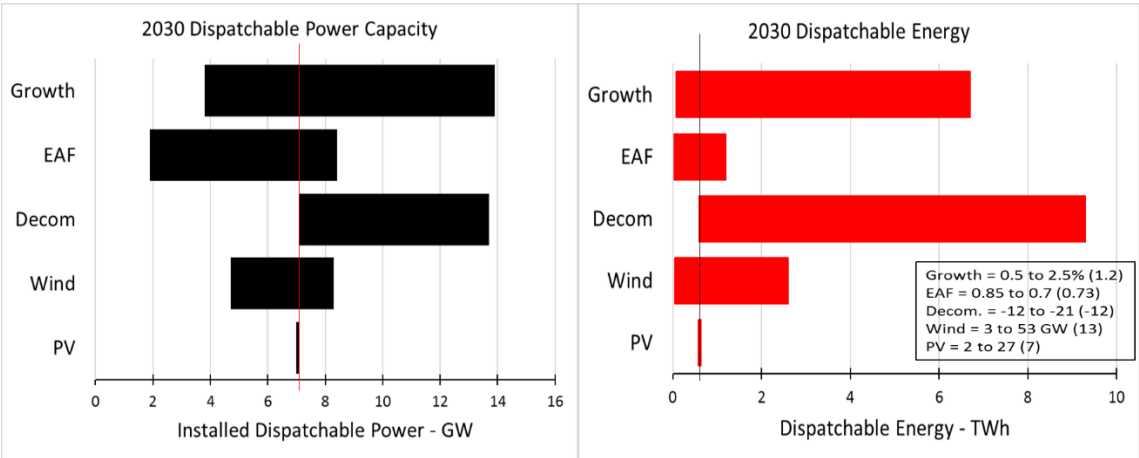


Figure 18 - Dispatchable Energy Sensitivities 2030

4.4. Results from the Dispatchable Energy Model

A Monte Carlo simulation utilising these parameters provides a range of expectations for required installed dispatchable power and the energy required from this dispatchable power for 2030 is shown in Figure 19. As can be seen from this curve, there is a large range of potential values to the required installed dispatchable power requirement. In addition, this analysis indicates that the required use of this dispatchable power should be minimal.

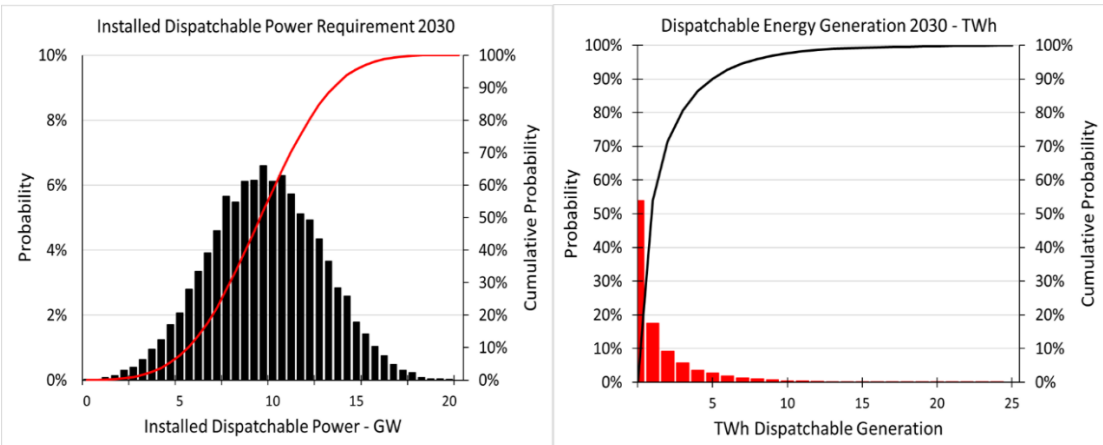


Figure 19 - Range of Expected Dispatchable Generation 2030

The probable required dispatchable power ranges from approximately 5 GW to 15 GW, with 875 GWh to 8 000 GWh of generation. This would indicate a 2 % to 6 % capacity factor for these generators. The median or expected requirement should be approximately 10 GW and 2700 GWh. The fuel requirement would be 9 to 78 PJ per year, with an expected value of 27 PJ, assuming a requirement of 10 000 GJ per GWh of generation.

From this sensitivity analysis, it appears that the scenario-based IRP fails to adequately cover the range of likely forecasts for what dispatchable power will be required. This analysis shows that the range of likely outcomes is quite large.

As can be seen in South Africa in the time it has taken from decision to implementation of the Medupi and Kusile coal plants, as well as international experience in the time required to implement coal and nuclear generation plants, a long lead time must be considered when making the decision on whether a base load plant is to be built. Because of the uncertainty of likely generation requirement, the probability of overbuilding is high. This causes added costs for the entire system that must be borne by the consumer. Wind, Solar PV, and gas plants can be built with a much shorter lead time. Therefore, it is not necessary to make long term forecasts on the need for these plants. The plan can also be adjusted as time goes on.

The planning process must move from being a prescriptive plan to being one that is reactive to the developing situation – particularly for demand growth. The plan must be able to adapt with shorter notice than the IRP planning process suggests. This leads towards a shorter development period system than the longer-term planning for base load generation, which implies a plan dependent on easy-to-install renewable generation with appropriate dispatchable power backup. As noted by the CSIR (Wright, *et al*., 2018) and discussed below, this generation mix is also the most cost effective so there is no trade-off to be made between meeting the need efficiently, system flexibility and providing the cleanest generation.

4.5. Worst case analysis – maximum power and energy required

As shown above in Table 8, the minimum generation expected from renewable sources in 2030 is less than 1 % of the demand. For sake of worst-case planning, (i.e. the, period with the largest load and the maximum time that the dispatchable generation might be required), the conservative answer is to call the wind and solar generation to be zero and indicate that dispatchable power must completely meet the need between base generation and total demand, as was discussed in the planning for dispatchable power in Germany and in Texas (Flassbeck, 2017; Noha, *et al.*, 2017).

To consider replacing dispatchable power with storage, it is not enough to look only at the volume of dispatchable power that must be provided, but it is also necessary to

consider the maximum time span over which this need might be required – the energy requirement. In turn, the three-year data period is not enough to establish a 100-year time or even a 10-year time worst case. However, some minimum estimates and expectations can be determined. Reviewing the wind supply curves, there is at least one period within the data years where wind power was below 5 % of the installed capacity for over 16 hours and periods up to 100 hours where generation is below 15 % for the period.

The longest time that dispatchable power was forecasted to be required in the 2030 simulation was 20 hours. As shown in Figure 20, from 16 to 20 May, dispatchable power was required for close to 19 hours each day with only a few hours between dispatchable need. This corresponds to the period of minimum wind generation. With small changes to the demand or supply numbers, this could have been 60 plus hours of continual dispatchable power requirement. With this dispatchable need, 600 GWh of energy would be required to be delivered from storage to meet this predicted shortage, equivalent to over 4500 of the "Tesla Big Batteries", not including allowance for round trip losses. It would be challenging for any storage system to cover this, particularly as there would be no recharge time between needs. It is not known how long this dispatchable need would be in the worst case. From the data from this model, this dispatchable need would be too long to build a storage-based system to reduce the dispatchable need.

Experience from Europe and the United States of America indicates that several weeks equivalent generation might be needed in the worst case (Becker, *et al.*, 2014; Heide, *et al.*, 2011). The western part of the USA, as well as Germany and the UK have suffered through "wind drought" periods (Brower, 2016; Baraniuk, 2018; Runyon, 2018). Twenty-year data sets are becoming available in the USA as well as Europe and correlations of these longer-term forecasts are being tested over this period. A recent study using data from the windy area of Iowa (USA) is presented in Figure 21 (Ziegler, *et al.*, 2019). From the graphs from this study, it is apparent that periods of zero generation from wind and solar must be planned for and storage will only take away a portion of the need. Dispatchable power must remain available. We can conclude the same for South Africa.

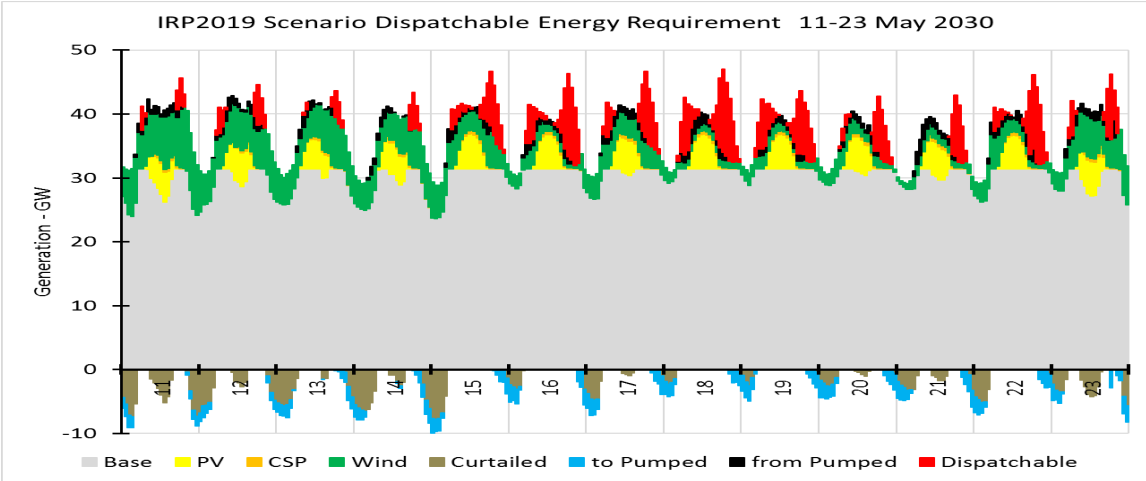


Figure 20 - High Dispatchable Demand Period - IRP 2030

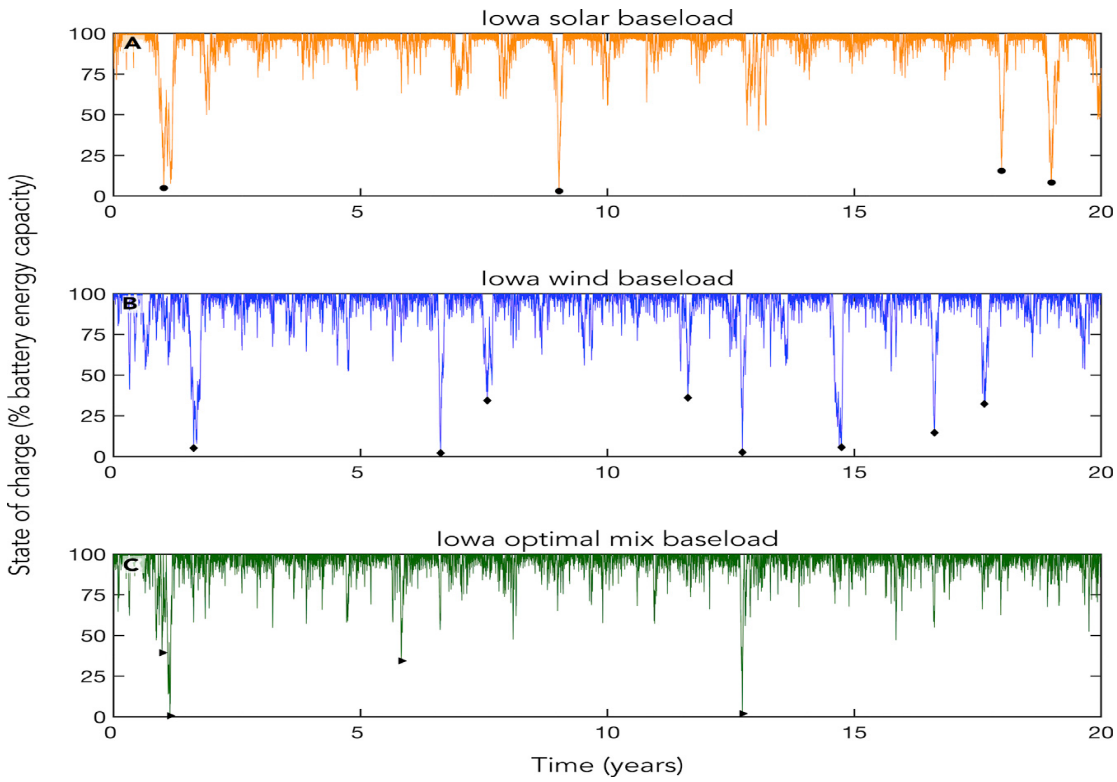


Figure 21 - Iowa 20 Year Renewables Review (Ziegler, *et al.*, 2019)

4.6. Review of energy storage options

Energy storage is not a generation source. Instead, it is way to use excess generation to balance supply with demand. To make storage a valid consideration, there must be excess generation and a temporal imbalance between supply and demand. Since the demand curve has peaks and troughs during each day, there are opportunities to improve the efficiency of the grid using storage.

In the current South African grid, over 85 % of the generation is from base load facilities and there are economic benefits to avoid cycling these facilities (Grol, *et al.*, 2015; Keatley, 2014). Base load thermal plants have slow ramp up and ramp down rates making it difficult to use them to meet variable demand (Kumar, *et al.*, 2012).There is a significant opportunity to utilise energy storage to allow these facilities to be used optimally, avoiding cycling by sending excess generation to storage when not needed.

As base load generation facilities are decommissioned and replaced with wind, solar and dispatchable generation, the concern for base load optimisation diminishes and storage either becomes redundant or other generation must be installed to provide the energy to charge the storage. In a grid based on renewable but variable generation from wind and solar, it is often preferable to overbuild these generation sources and provide the excess that these sources will generate at times for storage. In analysing the benefit of storage in the system, the use of storage to maximise the benefit of base load and the charging of storage from renewable sources are sufficiently different that they require separate consideration. As currently envisaged in the IRP process, there will not be any overbuilding of the wind and solar PV generation to provide for energy storage.

As was seen in the previous section, there is a large range in the potential forecasted electricity demand for the years 2030 and beyond. The decommissioning of the existing base load generation is more defined, but still variable and subject to shift in time. With all of this level of uncertainty, the long-term use of storage is probable but not well defined in timing or volume required. This supports solutions that are scalable, with both low upfront cost and short implementation timing. These considerations support the use of utility scale battery storage systems. As discussed in section 3.8.2, Li-Ion batteries have capital cost of about 54 % on a per installed kW basis compared to pumped hydro and lower capital costs to alternatives. The costs of these battery systems are expected to drop to 50 % of the 2018 cost by 2030, as was shown in Figure 13. This low capital cost, short development time and scalability fits with the current thinking for flexible power systems. They can also be sited at the user end of the grid, maximising their value.

Recently, Eskom recently announced a battery storage system (BESS) project that involves deployment of battery storage at multiple sites in various operating locations. Systems range in size from 1 to 60 MW. In September 2019, Eskom announced requests for bids for two phases of battery storage (Moyo, 2019). The first phase, to be completed by December 2020, is for 200 MW / 800 MWh in eight locations. The second phase will be for 160 MW / 640 MWh in 10 locations to be completed by December 2021. This program is being supported by the World Bank.

Generally, battery storage (and most other storage systems) is designed to provide a given number of hours of energy. To provide more energy, the size of the storage must be increased linearly for the time of use (Ziegler, *et al*., 2019). It is critical to note that

due to this consideration, storage is competitive for the short-term energy imbalances in the system but may not significantly reduce the amount of dispatchable power that must be available to meet longer term needs. As the addition of storage systems does not necessarily reduce the amount of dispatchable power that must be installed, the economics of storage are simply related to the savings in fuel associated with dispatchable generation.

In the IRP 2019 update, there was an indication that the amount of installed dispatchable capacity could be reduced from 11 GW to 6 GW for the base case with the installation of 5 GW of storage (SA DoE, 2019c). The analysis from this Dispatchable Energy Model disputes that conclusion, showing the required installed capacity reduction is quite small. There could be a reduction of the required dispatchable power installed capacity of approximately 5 %, but the required energy from the dispatchable generation drops significantly with additional storage.

The Dispatchable Energy Model was utilised to predict the reduced dispatchable energy required for 2030. The curve of storage compared to hours of dispatchable generation is shown in Figure 22. From the battery costs forecast by NREL of approximately 700 USD per kW for 4 hours with an assumed 10-year battery life, the fuel savings for diesel at 16 USD/GJ would support the installation of up to 5 GW of batteries. For gas fuel, there would be a breakeven for up to 3 GW power with 4 hours energy storage with the projected battery costs. There is a financial balance between installed battery storage and reduced fuel cost. Along with the dispatchable generation reductions due to installed storage in Figure 22 the equivalent battery breakeven cost for a 4-hour storage system is shown. The dramatic cost decreases make battery storage systems more attractive for replacing a significant amount of dispatchable energy, even if it does not reduce the need for installed capacity. In the NREL review, several sources that they cited indicate the potential for battery storage life spans to be up to 20 years or more. Should these battery storage system life spans be achieved, the benefits that they provide to the system would be increased proportionally (Cole & Frazier, 2019).

In Figure 23, the generation profile for dispatchable power for the period 15 and 16 May 2030, as forecast from the model using IRP premises is shown with the implementation of 5 GW power with 4 hours energy storage as compared to what was required without storage as seen above in Figure 20. On most days, storage will reduce the amount of energy that must be provided from dispatchable generation, it does not reduce the amount of dispatchable power (installed capacity) that must be available.

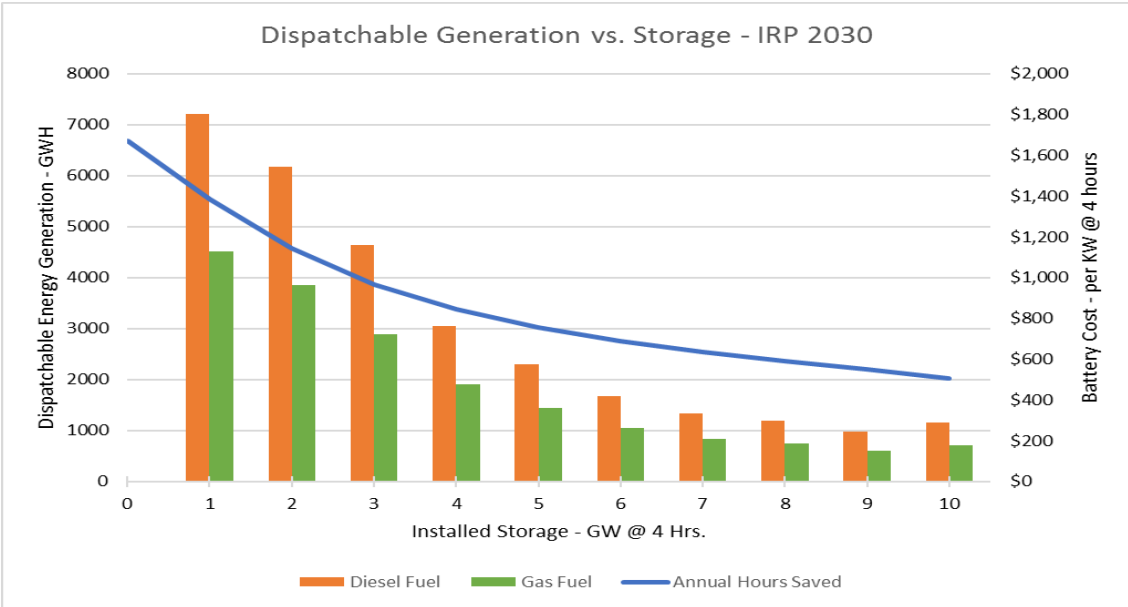


Figure 22 - Effect of Storage on Dispatchable Generation

As more of the base load generation facilities are decommissioned after 2030, there will be less "excess" base generation to supply the energy needed to provide for storage. Solar PV combined with battery storage is often suggested as an alternative, but this becomes a dispatchable generation concept rather than a storage option. To this end, the total cost of solar PV (or wind) plus battery or alternative storage systems must be considered in comparison to the saving in fuel and variable operating costs of the displaced dispatchable generation. To date, the economics of renewables generation plus battery storage does not match the economics of gas peaking. However, with dropping capital costs, it can be assumed that these costs will reach a level where they will displace some of the dispatchable generation in reduced hours of use rather than decreased installed capacity.

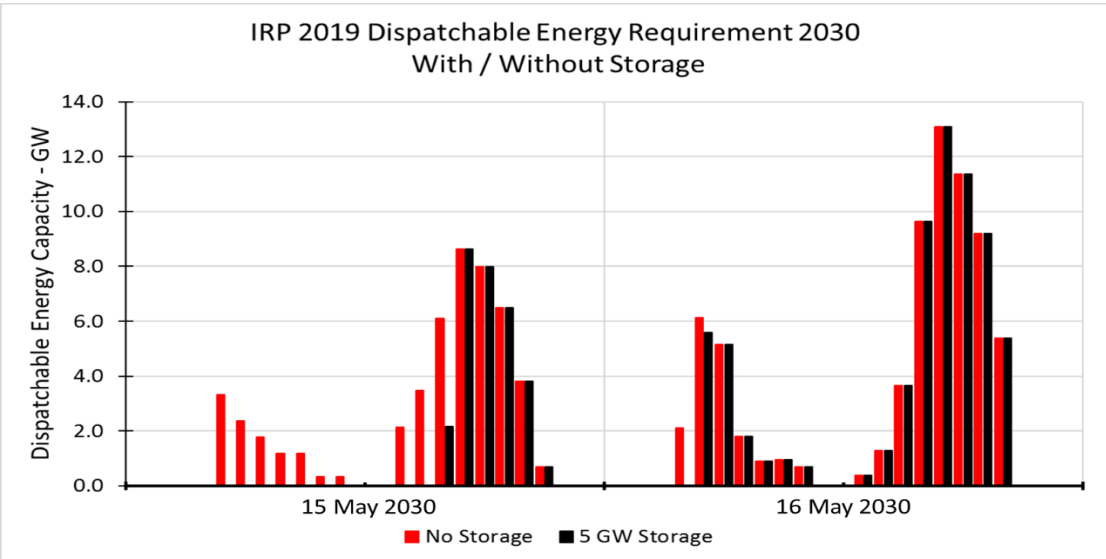


Figure 23 - Dispatchable Demand with Storage

These systems should already be competitive with diesel fuel cost and are becoming more competitive with natural gas with the following assumptions;

- Battery storage system costs USD 700 / kW for a four-hour system
- Operating cost at 2 % of capital costs
- Used 80 % of the time for four hours in the evening
- The cost of solar PV of USD 0.03 / kWh
- 10-year life

With these assumptions, the cost of storage would be USD 0.07 / kWh and the effective dispatchable energy cost would be USD 0.1/ kWh or 1.4 R / kWh.

As noted in Chapter 3, research is being conducted with the aim for dispatchable cost from CSP of USD 0.1 per kWh (Gauché, 2019). If CSP can achieve this figure, it should be competitive with solar PV plus battery systems to meet evening hour energy supply.

As noted above, the increased use of energy storage systems will reduce the energy that must be produced from dispatchable sources but has little impact on the installed capacity. From a gas fuel perspective, this minimises that amount of gas that needs to be used but makes the need for appropriate storage and delivery a clearer issue.

4.7. Chapter summary

In this chapter, the amount of dispatchable power required to balance the South Africa grid with the transition to renewable generation was calculated. It was found that the forecast for dispatchable power, both installed capacity and amount of generation required varies considerably depending on demand growth, decommissioning of base generation and the EAF of those facilities. For 2030, the expected requirement should be approximately 10 GW installed capacity and 2700 GWh of energy generation from dispatchable sources. The fuel requirement would be 27 PJ per year.

Energy storage will reduce the need for dispatchable energy to balance the system. As was shown in this chapter, this will likely only reduce the energy that must be generated by the dispatchable generation facilities, without reducing the required installed capacity.

The following chapter will analyse how natural gas can be utilised to meet this dispatchable power requirement in South Africa.

5. Gas Supply Options Specific to South Africa

Internationally, gas fuelled dispatchable generation is one of the major tools many countries are using to facilitate the transition to renewable based grids. In South Africa, the IRP process has assumed that gas fuelled generation would be an element in any transition implementation. However, the source for this gas and the steps to utilise this resource have not been detailed in any version of the IRP and is still an open question. With no effective existing gas fuelled dispatchable generation currently being used in South Africa, it is necessary to identify the potential sources of gas for the South African market, estimate the costs of acquiring this gas to the point of generation based on the dispatchable profiles required as per the scenario models, and compare the various gas sources.

At the commencement of the analysis, the three potential gas sources were expected to be local shale gas, LNG, and pipeline gas from Mozambique. However, as the analysis proceeded, several alternatives were also considered. These sources are local offshore gas and current gas imports (Rompco gas) as well as the alternative of liquid petroleum gas (LPG).

For this analysis, it was assumed that power generation from gas is the entire business for the various scenarios reviewed or potentially the anchor customer that allows further development. This would imply that the proposed concepts must be economically viable based on the power to be provided but could be considered to have some upside for development if further markets develop. The need for high supply rates but minimal annual volumes for the fuel needs of dispatchable power makes this supply challenging to match with any gas market supply. This can only be resolved with the implementation of suitable buffer storage of the gas being used for dispatchable generation.

From the time that the first IRP was drafted in 2010, there has been discussion of LNG importation in Saldanha Bay to meet potential west coast gas markets, including some peaking power use at the Ankerlig plant (Western Cape Government, 2019). There is no current industrial gas market on the west coast and the probability for this market developing and the project proceeding is unknown. Should the project be developed, it would be possible to convert the Ankerlig peaking plant to gas. However, as was stated in the first IRP, this usage would not be enough to justify the project (SA DoE, 2011).

In addition to the Saldanha Bay LNG proposal, most of the discussion for LNG importation has been centred on a terminal in Richards Bay(Transnet, 2016). There are some gas users in the Richards Bay and Durban area that are currently supplied gas from the Rompco and Lilly line system. This LNG facility could supply these customers as well as whatever growth there might be in this market. In addition, with a reversal

of flow in the Lilly line and a potential larger replacement, gas could flow from Richards Bay up into Gauteng Province. With this pipeline, the Richards Bay LNG terminal would be able to supply customers in the Richards Bay, Durban and Gauteng areas, including the needed peaking power. As with all alternatives, proper gas buffer storage would be required to meet the dispatchable requirement. This project has proceeded to a feasibility analysis stage led by Transnet (Creamer, 2019a).

Most of the customers considered for the Richards Bay LNG project are currently being served by gas coming into South Africa through the Rompco pipeline. Sasol has informed the government that their supply fields will begin depletion in the middle of the coming decade and other input gas will be needed to supply these customers. There is a proposal to bring LNG into Maputo to meet local needs there as well as supply into the Rompco system (Creamer, 2019b). With the existing infrastructure, the established customer base, and the potential to handle growth in demand from industrial users, as well as dispatchable generation, would imply that this project has the best chance for financial viability.

5.1. Potential gas sources

5.1.1. Local shale gas

It appears that the existence of local shale gas is a given, as shown from the SOEKER test wells (Rosewarne, 2014). However, the volume of commercially developable gas is an unknown as is the development cost. Some of the recent estimates of the resource paint a conservative estimate of the likely resource base, with an estimate of about 371 BCM of gas resource being currently discussed (Academy of Science of South Africa, 2016). In the 2016 version of the IRP, it was assumed that South Africa shale gas was the only potential gas source to be considered (SA DoE, 2016). Subsequent versions of the IRP have not been as focused on this option.

All the elements of a South Africa shale gas development scenario can be estimated, and a range of expected costs can be defined, but this will remain a 'guess' until the resource has been proven (volume, location, production rates, rate of depletion, etc.). The success of shale gas development in the United States of America has often been suggested as a model to be used in other locations to base the development of this resource. An economic analysis of shale gas development in South Africa was developed by the author for a journal submission and is included in Appendix C. The following paragraphs summarise the results from this analysis.

There are many of the elements of the USA development model that are not relevant to other potential shale gas developments. The existing oil and gas production base in the United States of America allows the shale gas business to have the resources for development, such as drilling rigs, fracturing equipment and trained personnel on call

as needed, specifically tailored to meet the needs in the particular development area. There is a large market that allows any discovered gas immediately to be produced at maximum rates, with a large pipeline network connecting the shale basins to market (US EIA, 2016). The three locations that have been able to develop shale gas outside of North America are Australia, Argentina and China (Saussay, 2018). In each of these countries the development occurred in regions that were already gas producing areas. The drilling and production equipment markets were also present in these development areas. Even in these areas there has been some struggle to develop a shale gas business. These conditions do not exist in South Africa.

While the major hurdle to shale gas development in South Africa, and much of the world, has been discussed to be local opposition to the environmental effects of fracturing required for shale gas development, negative economic value has also been a significant hurdle to replicating the US success (Fakir, 2015). The universal availability of LNG, with the growth of US shale gas, has set a base line price for gas around the world that is hard to compete with from local shale gas. An economic analysis of shale gas production in Europe indicates prices that are not competitive with LNG (Le, 2018). Considering the unique parameters of the local development of shale gas in South Africa, the cost for shale gas would likely be higher than what was estimated for European shale gas and too high to allow this to be considered a gas source for dispatchable power. With a wellhead breakeven price for shale gas above USD 14 per GJ, the price for this gas would be more than 50 % higher than the cost of imported LNG. By the time the infrastructure to utilise this gas for dispatchable power is included, it becomes much more expensive and not likely competitive with diesel.

None of the parameters that make shale gas attractive in the US exist in South Africa. There is no established oil and gas business and any needed equipment will have to be imported, which does not facilitate the optimised call out arrangements making US shale production viable. As there is no market for gas, there would need to be an exploration phase before any shale gas is developed, which does not suit the economic model of shale gas development of rapid production and decline (SAOGA, 2017).

With thousands of shale gas wells drilled each year in the United States of America and brought on to production immediately in the large gas market, there has been the ability to optimise shale gas development in each of the basins, including the abandonment of developments in some basins (US EIA, 2018b). As each shale gas well in South Africa would cost in the range of 20 million USD to drill, it would be impossible for South Africa to support an extensive shale development program to optimise the operations to local conditions.

While it is possible that there might be some exploration efforts continuing in the shale gas development in South Africa, the probable timing and cost of this gas minimises its usefulness for consideration in planning for gas dispatchable power. This is not a gas supply option that should be considered any further.

5.1.2. Local offshore gas

In February 2019, the oil and gas exploration consortium led by TOTAL announced that they had discovered a significant gas condensate field in deep water south of Mossel Bay in exploration block 11B / 12B. The discovery was called Brulpadda and is one of five potential fields in the Paddavissie prospective area. The operator has not indicated the composition of the gas, the level of condensates (liquid hydrocarbons) in the gas nor the volume of the field. However, from public information it is possible to estimate the size and likely development prospects of the field. Brulpadda field has a likely reserve base in the range of 1600 PJ (Clark *et al*., 2019b). This could provide a twenty-year production of 2.2 BCM (80 PJ) per year. With further exploration of the other fields in the area, this estimated resource is likely to triple. The calculations for these reserves were given in a presentation by the author to SANEA (Clark, *et al*., 2019b).

This gas should provide the possibility of use of the Gourikwa OCGT power plant to provide dispatchable power into the grid from the Mossel Bay area. The current capacity of this power plant is 740 MW but could be expanded. The plant currently uses diesel fuel. One of the requirements to convert this plant to use Brulpadda gas would be the development of gas storage at the power plant.

5.1.3. Imported liquified natural gas (LNG)

LNG has an extensive international marketing presence and is the solution most "gas short" countries use to meet the supply to their gas markets. Japan, with no indigenous gas and oil, has long been the dominant market for LNG. Other major countries, such as China and India also see this as a solution to their growing gas needs. Before the shale gas boom in the United States of America, the country itself was actively pursuing this avenue for gas supply. For South Africa, this has been the default assumption in all IRPs since the first IRP was developed in 2010. However, it was stated in that first IRP that dispatchable power alone would not be able to economically support an LNG importation infrastructure unless there are other significant markets (SA DoE, 2011). These markets have not developed over the period since the first IRP and while several LNG terminals are under discussion, no projects have proceeded past feasibility analysis (Creamer, 2019a) (Western Cape Government, 2019).

The international LNG business is quite large with approximately 400 BCM LNG or the equivalent of 10 million PJ of gas being transported around the world and sold as LNG per year (International Gas Union, 2017). This value is expected to grow considerably in the coming decade. The major LNG exporting countries are Qatar, Australia, and the USA. In sub-Saharan Africa, Nigeria and Angola are currently exporting LNG with Mozambique planning to become a major exporter in the coming decade, with projects that could build to 60 MTPA LNG export in various stages of

implementation (Crook, 2012) (eni, 2017)(Zawadzki, 2019). Tanzania also has gas reserves that might be developed for LNG export. A typical LNG tankship transports about 145 000 to 165 000 cubic metres of LNG which corresponds to 3.7 to 4.0 PJ of natural gas (Rogers, 2018).

Pricing for LNG has traditionally been related to the cost of alternate fuels that the LNG replaces, primarily oil and coal. To make LNG attractive, this price has been set at approximately 60 % of the price of oil on an energy basis. In Japan, the comparison is to the Japan Crude Oil basket price – the aggregate price of oil imported into Japan. In Europe, prices for LNG sales have been negotiated to individual buyers on a basket of prices for generation at the specific location. Most LNG has been sold on the basis of long-term contracts with pricing based on these comparative fuel prices. However, there is a growing market for spot pricing of LNG and for prices related to gas marker prices, such as the 'Henry Hub' price, which is the US gas marker price. In Europe TTF and BNP are the main pricing points (Heather, 2014). Prices at these reference points is not related to other fuels but to the price of gas in the US and the European gas markets (US EIA, 2018b;Heather, 2020). US LNG exporters are proposing Henry Hub related prices, where the LNG is delivered to the customer at a price related to Henry Hub gas, plus the cost of liquefaction and transport to the customer location (Charles River Associates, 2018). For South Africa, this implies a larger LNG supply market and one not tied to long-term contracts, but open for spot purchases. In general, this has resulted in pricing below the alternate fuel pricing.

Qatar and some of the other LNG exporting countries make most of their income related to LNG production from the related liquid products in the gas and condensate mix. Therefore, they are not sensitive to pricing of LNG. As US exports grow, there will be a more extensive shift in LNG pricing to this structure. Bloomberg and others predict that international LNG prices will decrease in the medium term and eventually stabilise at a Henry Hub related price (Bloomberg New Energy Finance, 2018). The World Bank forecasts that LNG prices will become pegged to Henry Hub and increase with inflation over the period that they have considered as shown in Figure 24 (World Bank, 2018a).

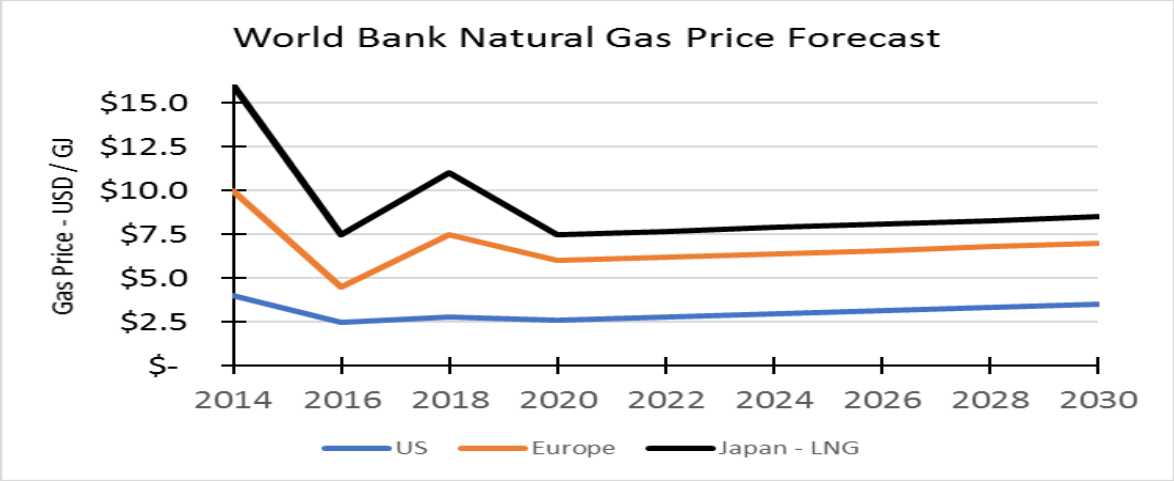


Figure 24 - World Bank LNG Price Forecast - data (World Bank, 2018a)

At the receiving end of the process, LNG must be stored and then converted back into the gaseous state for use. This is done through the process termed regasification. This process raises the temperature of the LNG from -162° C to ambient temperature through some form of heat exchanger. An LNG receiving terminal includes the facilities to receive LNG, store it and then regasify it to supply it into a gas pipeline. The current trend, with about 70 % of new construction in receiving terminals, is the use of integrated ship-based facilities – a floating storage and regasification unit (FSRU) to quickly and economically provide the facility to meet this importation need (International Gas Union, 2019a). However, an FSRU has minimal flexibility to adjust to changed needs for storage or regasification capacity. As part of the IRP and the GUMP processes, Transnet has reviewed the options for onshore and FSRU importation facilities in Richards Bay, Coega and Saldanha Bay. However, none of these facilities have been advanced to development. From the perspective of dispatchable power for the South African grid, the Richards Bay importation facility would have the most impact due to the existing gas pipeline infrastructure. The Transnet proposals for importation at Richards Bay are shown in Figure 25. Transnet reported that they are considering both onshore and FSRU proposals (Transnet, 2016) . Transnet is reported to be working with the IFC to develop a feasibility analysis for this LNG importation terminal proposal (Creamer, 2019a). The connection into the existing gas pipeline infrastructure can also be achieved with LNG importation into Maputo and connection through the Rompco system.

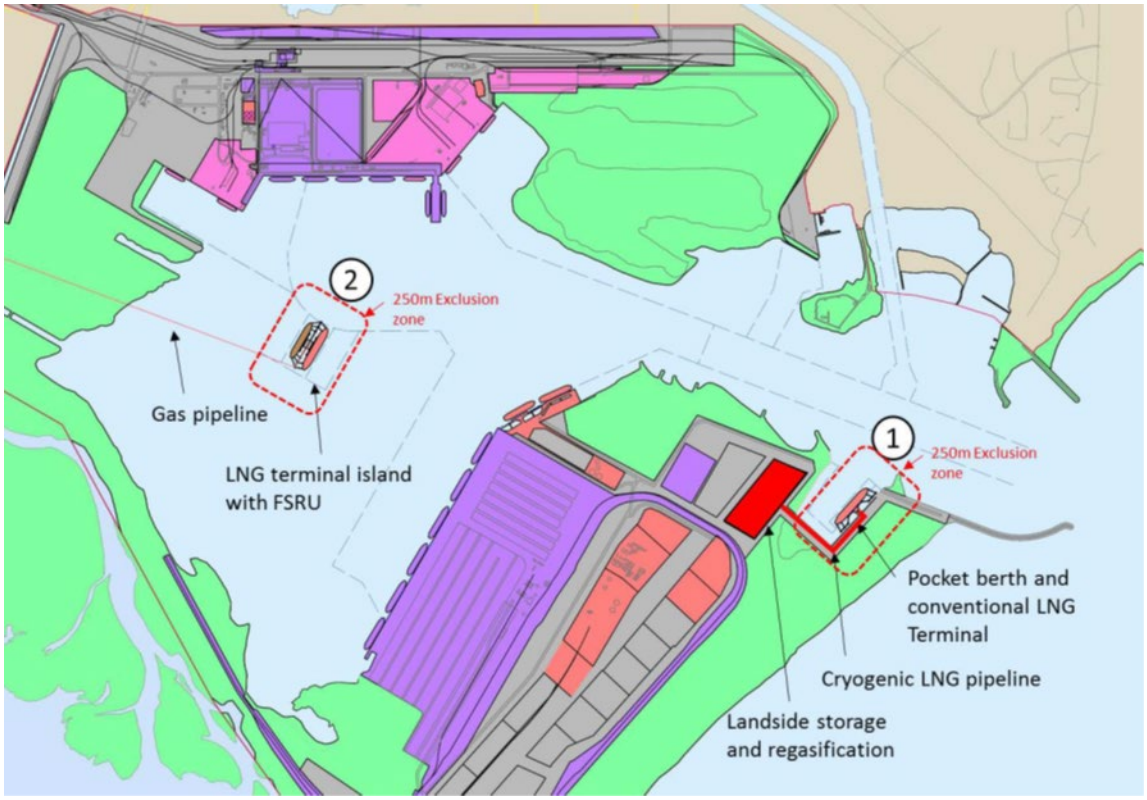


Figure 25 - Richards Bay LNG Terminal Proposals (Transnet, 2016)

For an onshore plant, LNG storage and related importation capacity can be increased by adding tankage. Normally, each onshore LNG tank holds about 160 000 cubic metres of LNG, allowing a ship load of LNG to be added when the tank capacity is at 10 % (ARUP, 2017). The speed of removing LNG from the tank is related to the installed size of the regasification facilities. By increasing the number of storage tanks and increasing the regasification capacity, the onshore terminal can be adjusted for almost any desired output level.

On the other hand, an FSRU is limited to the tankage in the vessel and to the installed regasification unit. A typical FSRU has 170 000 cubic metres of storage and a regasification capacity of 22 000 to 30 000 GJ per hour (Songhurst, 2017). With electricity generation requiring approximately 10 000 GJ / GWh in a typical open cycle gas turbine (US EIA, n.d.), this would correspond to 2 to 3 GW of continuous generation from one FSRU.

However, there is a challenge with LNG supply for dispatchable power that has not been discussed. The challenge with LNG as the source of dispatchable gas is that the facilities must be sized to meet the maximum instantaneous peak rates and would be unused or vastly underused for the majority of the time. This is the case with or without other markets for the LNG. Some proponents of LNG importation have indicated that this cost is marginal considering the price related benefit of using gas for dispatchable power (Bischof-Niemz, 2019). However, the large upfront investment cost, likely to be

over USD 1 billion for the importation and regasification facilities to meet the total dispatchable generation needs, have stopped progress on this option. To make this option work for dispatchable power, the regasification system must be sized to meet the maximum load for the dispatchable need in addition to any other market need. As dispatchable power requirements dictate that full gas be available from the time that the generation facility is brought online (Wartsila, 2019), gas storage at the power plants will also be required to meet the ramp up of power until the full regasification can be put online.

This gas storage can be built into the system. For example, a pipeline from Saldanha Bay to the Ankerlig power plant is about 80 km. Assuming a one-metre diameter pipeline was built to transport the gas to the power plant from an LNG plant in Saldanha, it would likely be operated at approximately 70 bar nominal pressure (Pipeline Safety Trust, 2015). If, in storage mode, the pipeline was "packed" with gas up to 100 bar, this should provide the gas needed (approximately 80 000 GJ) to power Ankerlig for 6 hours. With this gas storage, the LNG regasification facility can be ramped up to meet the demand.

5.1.4. Pipeline from Mozambique

After the first versions of the IRP were developed, the oil and gas industry discovered one of the world's largest natural gas fields offshore northern Mozambique. This field is estimated to contain over 3 TCM of gas or 105 000 PJ. It is listed as the fifth largest gas field in the world. With no gas market in Mozambique or surrounding countries, the best local market for this gas has been perceived to be South Africa with the only potentially large economy in the region. Several proposals for gas pipelines from these fields to markets in South Africa have been considered, but none have been pursued yet.

From the time that the gas fields offshore northern Mozambique were discovered there has been discussion of building a pipeline from these fields to markets in South Africa. The first significant proposal made in 2013; entitled 'Gasnuso', signifying a gas pipeline from the north to the south, was proposed by the sponsors of the Gigapark development in Ressano Garcia (Herbst, 2013). This project was designed to go down the length of Mozambique, terminating in Richards Bay, South Africa. While gas would be supplied to users all along the route of the proposed line, the anchor customer was expected to be base load gas fuelled electricity generation around Richard Bay of 7 to 10 GW (Smith, 2014).

Eventually, the sponsors of the Gasnuso pipeline proposal dropped their proposal due to lack of support from the government of Mozambique. However, their concept was revived by a group led by SACoil in 2015 (Bowker, 2016). This proposal had the support of both the governments of South Africa and Mozambique (Fraser, 2017). The

estimated cost was approximately USD 6 billion, and the endpoint was to be Gauteng rather than Richards Bay. The project started with a feasibility study commencing in 2016. The routing of this proposal is shown in Figure 26.

However, this proposal, even with government support from both countries, has not proceeded and the latest news is that it has been dropped due to lack of market (Frey, 2019).

This gas pipeline could bring in over 500 PJ per year of gas into the markets in Gauteng or Richards Bay. This would be enough to generate about 50 TWh of electricity. As of now there is no market for this gas. Dispatchable power generation would typically only be used about 3 to 5 percent of the time, so most of the time the installed pipeline capacity would not be used but the capacity must be available when needed. Thus, using this gas source to supply the dispatchable need is unlikely unless significant gas storage is built to complement the pipeline. Use of the gas for other customers would facilitate the justification for the pipeline but would not change the need for gas storage for dispatchable energy usage.

Figure 26 - Potential Mozambique Gas Pipeline Route (Gasnuso, n.d.)

5.1.5. Rompco pipeline

There is a gas source available in South Africa that is not mentioned in any of the IRP discussions. Sasol has in place a gas pipeline bringing gas from its gas production fields in Mozambique to its CTL plant at Secunda, It is reported by Rompco that the capacity of this line is 200 PJ/a (Rompco, 2020). Most of this capacity is in use, with the majority being used internally by Sasol at Secunda and Sasolburg. Some of the gas is delivered to gas fuelled power plants in Mozambique at Ressano-Garcia near the point where the pipeline crosses into South Africa. Current generation capacity at that location is approximately 450 MW (Creamer, 2015). There are some industrial customers in the Gauteng area that utilise Rompco gas.

At Secunda, the Rompco line interconnects with Transnet's Lilly pipeline. However from Secunda, there are different specifications for the gas being supplied through the two networks. The Gauteng network is based on natural gas and the Lilly line is based on "methane rich" gas. The difference between the two gas specifications is in the amount of higher heating value gases (ethane, propane, and butane) that are in the gas. This same difference is found in the international LNG business, where the US market is based around pipeline gas (which is almost exclusively methane) and Asian based gas (which has a higher heating value due to the inclusion of richer gases). This difference is challenging for the user as it requires different settings for heating and generation equipment between the two specifications of gas.

Using 10 % of the Rompco capacity would be enough to generate 5 GW of power with a 5 % capacity factor. This could meet much of the dispatchable energy needs in the South African grid in 2030. To utilise this gas, it must be collected and stored to be dispatched as needed.

Sasol has indicated recently that the production from the fields supplying the gas into this system will only be able to maintain the design throughput rate until approximately 2024. From that point forward, the fields will not be able to produce at the pipeline throughput rate, with an expected 10 % per year production decline from 2024. While Sasol have been exploring for additional gas fields in the area of their current production, they have been unsuccessful up to the current time. To continue supply through this system, there has been discussion of importing LNG into Maputo harbour and putting it into the Rompco system from that location (Creamer, 2019b). This would eventually require a larger pipeline from Maputo to Ressano-Garcia to maintain the full throughput in the line, but this would only be needed when the current fields decline below the capacity to keep the system full.

The estimated cost for the FSRU importation facility in Maputo is in line with estimates for terminals in Richards Bay and Saldanha at USD 350 million (Creamer, 2019b). A portion of the gas is intended for local use in Mozambique for power generation and local consumption. Thus, a portion of the importation capital and

operating costs will be taken up for this use. For supply to South Africa, there is in place a pipeline spur from the Rompco line in Ressano Garcia to Maputo with an estimated capacity of 8 PJ per year. As the Panda and Temane fields decline, reducing their supply into the Rompco line, this line should provide the capacity needed for some time (Matola Gas Company, 2020). Once the current system was unable to meet the throughput demand, a new loop line would be required for the 100 km back to Ressano Garcia. From that point, gas would go through the existing Rompco system, allowing up to 200 PJ of gas to be brought into the Gauteng area, with the Lilly line taking some of the gas to Richards Bay and Durban as needed.

5.1.6. Liquid petroleum gas (LPG)

While LPG is not natural gas as such, it can be used in most applications where natural gas is utilised. LPG has many of the advantages of natural gas, with some additional advantages compared to natural gas. The major advantage, which it shares with diesel, is the convenience of storage as a liquid. LPG can be stored as a liquid in surface tanks at nominal temperatures at a pressure of 1.5 bar. Like diesel, LPG can be delivered to the location by truck. By weight, LPG has a higher heating value than diesel, but due to it lower density, it has a lower volumetric heating value of 26 MJ per litre compared to diesel at 37 MJ per litre for diesel.

There is a current market for LPG in South Africa and the price is set by the regulator agency, currently at 4.9 R / L (SA DMRE, 2020). This gives a fuel cost for LPG of 1.9 R per kWh in comparison to diesel's cost of 3.8 R and natural gas with an estimated cost of 1.4 R per kWh. Thus, LPG would not be competitive with natural gas when both are available, but it is a realistic current option for diesel fuel replacement.

Bidvest is currently completing the installation of an LPG importation and storage facility in Richards Bay. This facility has the capacity to store 40 000 cubic metres of LPG, enough to generate slightly over 100 GWh of electricity in a OCGT plant (Bidvest, 2020). MOGS also has importation facilities for LPG in Saldanha Bay (Delphos International Ltd., 2019)

LPG fuel can be utilised for a quick diesel replacement solution and for some of the isolated peaking plants might present an option to be utilised instead of gas development or until a gas infrastructure is developed.

5.1.7. Gas supply option - storage

Reviewing the gas supply options shows that any option can supply the needed volumes of gas to provide the dispatchable power needs for the South African grid. However, the dispatchable nature of the demand will be a challenge for any of the supply options. The common challenge that must be overcome is the requirement to

store gas and deliver it at large rates when needed. This challenge does not change if there is a large industrial market that develops. The challenge of storage must be resolved to make gas supplied dispatchable power a reality in South Africa.

5.2. Compare gas fuelled electricity generation costs to alternatives

With no gas currently available to provide dispatchable power in South Africa, most of the dispatchable energy is currently provided using diesel fuel. This fuel, while more expensive than natural gas on an energy basis, is readily available, easy to transport and store. The economics of dispatchable power generated from the various choices of fuel will determine how this dispatchable power need is met. While summarised below, a more detailed discussion of the economics of generation is included in Appendix D.

5.2.1. Levelised cost of electricity (LCOE)

The first parameter that is considered in choosing a generation source is the upfront capital cost. This is the fixed cost that must be made before generation commences and is a major factor in the overall cost of generation. Overall cost of generation includes capital cost, as well as financing costs plus operating and maintenance costs plus fuel cost. Fuel is often considered to be included as an operating cost, but its significance to the comparison of technologies indicate the importance of treating it as a separate item. Normally, these costs are compared based on levelised cost of electricity (LCOE), which incorporates all these elements.

Upfront capital cost estimates are readily available and generally consistent in their comparisons, if not in exact numbers. The IRP process uses estimates provided by EPRI from the USA (SA DoE, 2018). The US EIA also publishes updates each year on projects being developed in the country for the various power sources (US EIA, 2017a). The comparison of capital costs for various technologies provided by EPRI and shown in the IRP 2018 are reproduced in Figure 27. The only significant difference from these numbers indicated in the US EIA data set are in the cost of coal plants, which the EIA shows as being approximately equal to the price of nuclear plants. This is noted in their statistics as related to the cost of carbon capture into these facilities as, in the United States of America, new coal fuelled plants cannot be built without this provision.

Figure 27 - IRP 2019 Capital Cost Estimates by Technology – data (SA DoE, 2019a)

As can be seen from Figure 27, the capital cost of open cycle gas facilities is less than 25 % of the capital cost of generation plants using coal or nuclear fuel. Some of this difference is recovered over time from the lower cost of fuel for coal and nuclear plants. Gas turbine and combustion engine power plants will have the same capital cost whichever fuel is used. For the sake of this analysis, it is assumed that providing the needed storage for natural gas will require approximately a 10 % increase on the capital cost for a plant fuelled by natural gas compared to one fuelled by diesel. Fuel cost is more of a factor for base load plants and becomes a much lower consideration as the capacity factor is reduced for dispatchable power use. Operating costs and fuel costs are significant factors in comparing generation choices and the estimates for each of these is shown in Table 9. Fixed operating costs were developed by the US EIA (US EIA, 2017a). Fuel costs are South Africa related prices for each of the fuel type (Mundi, 2018), with the exception of nuclear fuel, which comes from the World Nuclear Association (World Nuclear Association, 2019). Details of the calculation of estimated fuel costs are included in Appendix D.

LCOE compares the cost of each unit of energy produced over the life of the project. This compares upfront costs plus operating and fuel costs. Over the complete range of usage factors, it can be seen, as per Figure 28, that the higher fuel costs from diesel and gas fired facilities brings them closer to the cost of the capital-intensive coal and nuclear plants with high usage factors. At high usage rates, diesel fired power becomes the most expensive, while gas fuelled plants remain competitive at all usage rates.

Table 9 - IRP 2019 Generation Costs

IPR 2019 Generation Cost by Technology			
	Capital Cost	Fixed Operating Cost	Fuel
	Rand per kW	Rand per kW	Rand per kWh
Gas	10 449	148	1.40
LPG	9 499	148	1.92
Diesel	9 499	148	3.37
Coal	48 852	944	0.51
Nuclear	70 564	1 352	0.09
Wind	16 963	634	0
Solar PV	16 013	294	0
CSP	53 032	953	0

For dispatchable generation, usage factors are expected to be lower than 10 % and preferably to minimise the related fuel costs, lower than 5 %. As shown in Figure 29, the differences between gas or diesel compared to other generation sources is significant in these low usage rates. The IRP 2019 indicates that the cost of unserved power is estimated to be 49 R per kWh (SA DoE, 2019a). At the low usage factors expected from dispatchable power, gas or diesel generation are the only choices that can provide this power at cost below this value. While gas and diesel fuelled generation appear to be similar on the low capacity factor ranges, there is a consistent difference over the entire capacity factor in the fuel cost. These differences greatly understate the total cost differences between technologies at low usage rates as they do not account for the cost and technical challenges of ramping up and down thermal plants nor the cost of lower efficiency generation from maintaining minimum throughput rates to avoid warm or cold starts.

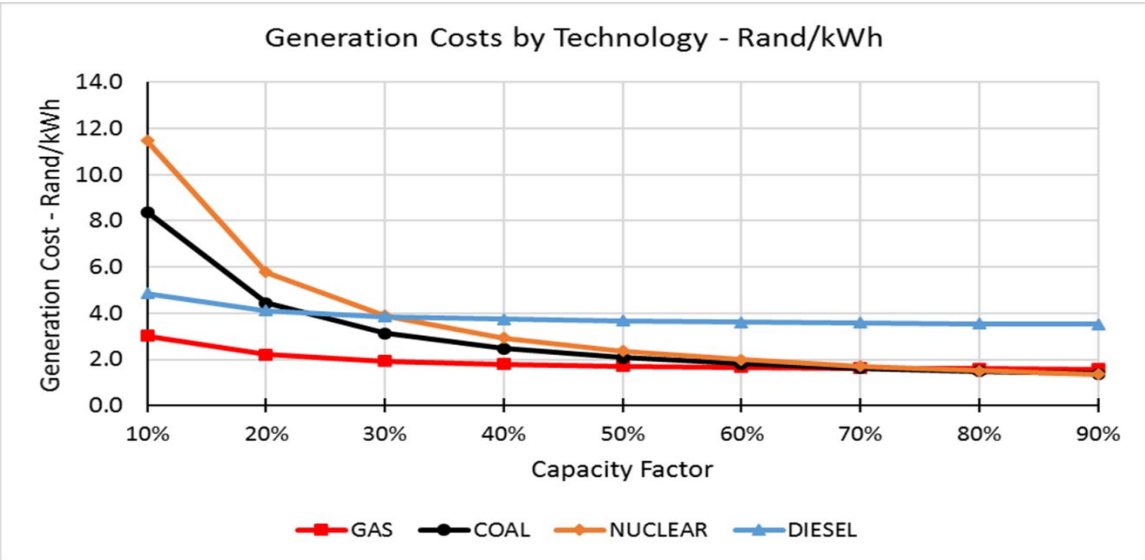


Figure 28 - Estimated LCOEs for Generation by Technology

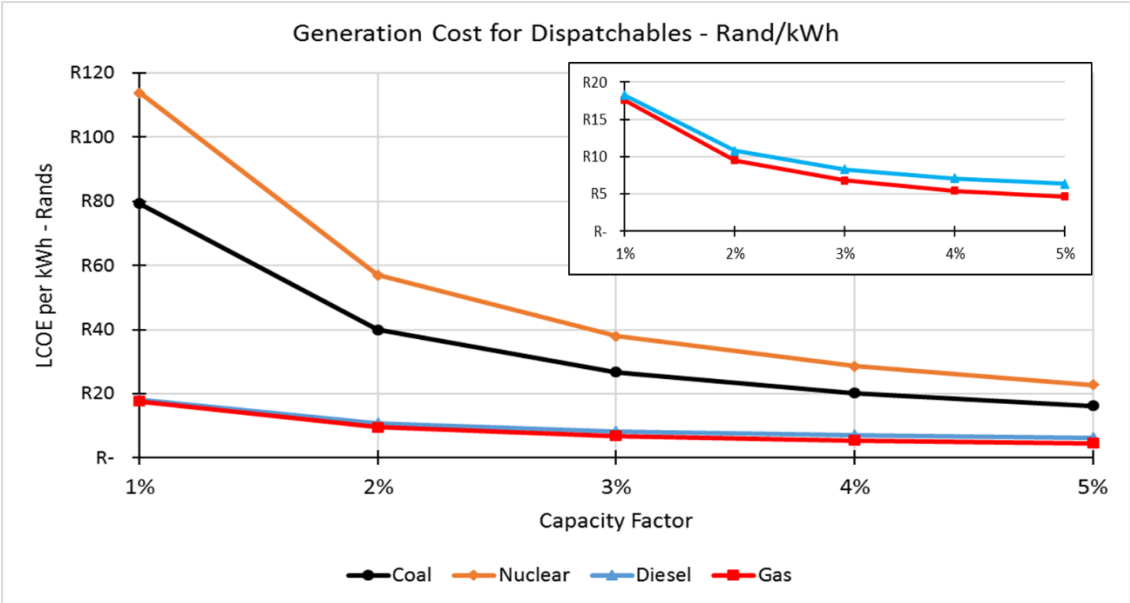


Figure 29 - Estimated LCOE by Technology for Dispatchable Generation

Besides showing the distinct capital cost difference between nuclear, coal and gas plants, the IRP capital cost comparison in Table 9 above also shows lower capital costs for solar and wind generation than for coal and nuclear plants. With no fuel costs for wind and solar generation, the LCOE of these renewable sources are much less than for nuclear, coal or gas fuelled generation, as can be seen in Table 10. Wind and solar capital costs have been dropping while the costs of other technologies have been reasonably constant in recent years, so the cost advantages of wind and solar continue to grow. The recent international awards of contracts for wind and solar PV generation below USD 0.02 per kWh, would imply a LCOE of wind and solar below 0.3 R per kWh. With financing rates in South Africa, these low values might not be currently achievable. However, it can be expected that the cost for new wind and solar PV projects will be significantly lower than what was seen in the latest round of the REIPPPP.

Table 10 - IRP Premise LCOEs

LCOE for Different Technologies		
	Capacity Factor	LCOE
	Percent	Rand per kWh
Nuclear	80 %	1.515
Coal	80 %	1.494
Gas	80 %	1.446
LPG	80 %	1.983
Diesel	80 %	3.555
Wind	36 %	0.811
Solar PV	25 %	0.892

5.2.2. Scenario costing

Advocates of nuclear and coal generation argue that a LCOE comparison does not account for all the factors that impact the actual cost of a grid system built on various technology sources and that instead total system cost must be considered.

A simplified system comparison of the new South Africa generation, (that which must be built to replace the current system as it is decommissioned, plus nominal growth) is compared in Table 11. In each scenario, the period from 2020 to 2050 was considered. For base case generation scenarios, an estimated additional 54 GW of generation would be required over this period, based on the IPR assumption that the base generation fleet would decrease to 20 GW over the period to 2050. The US EIA estimates construction time for nuclear generation of six years, four for coal and three for gas and diesel generation, not including the time for permitting, environmental reviews and other outside considerations (US EIA, 2019a). To put all options on a consistent basis, it was assumed that the first new generation would commence after six years, with twelve GW installed. From that point on, two GWs per year was added to achieve the 54 GW by 2050.

Detailed scenario comparison is included in Appendix D. From the Dispatchable Energy Model, it was determined that for a renewable scenario, with an equivalent wind and solar PV based system with dispatchable backup, the 54 GW base generation system needed to be replaced with 70 GW of wind generation plus 40 GW of solar PV backed up with 42 GW of dispatchable generation, or 2.3 GW wind, 1.3 GW solar PV and 1.4 GW dispatchable for each equivalent 2 GW of base generation. In the renewable scenario, these resources were installed at this ratio as per the base load scenarios. A construction time for wind, solar PV and gas generation of three years was used. Time for permitting and project approval are not included in this comparison but have been demonstrated to add significant time for all projects. Studies have not found that there are any significant differences in plant lifespans by technology and a consistent thirty-year lifespan was assumed for all scenarios (NREL, 2019). As the period of analysis was thirty years, decommissioning did not happen for any facilities within the period of analysis.

Not included in these costs are grid upgrades to incorporate these new generation sources. However, it is likely that none of the generation facilities for any of the concepts would be constructed in the locations of current generation and all would incur integration costs. Nuclear plants would likely be built along the coast, coal plants would be built where the new coal is sourced, and renewables are distributed throughout the country at suitable climatic, geographic and grid infrastructure sites. All the scenarios will imply system modifications to accommodate the generation sources. For a renewable scenario, wind and solar generation would most likely be positioned to optimise their generation and there would be required infrastructure changes to incorporate these generation sources. The gas peaking plants could be built within the

area where much of the current generation is being done where there currently is a gas network, so this would not have any significant related infrastructure costs.

This comparison also does not account for external costs and subsidies. These costs could be significant and would make nuclear and coal fired generation higher than those shown. This simple analysis reproduces the conclusion reached in the IRP process that a renewable based system with gas dispatchable backup is the most economical system. Details of the analysis are included in Appendix D.

Table 11- Generation Scenario Cost Comparison 2020-2050

Generation Scenario Cost Comparison					
	Billion Rands from 2020 to 2050				
	Capital	O&M	Fuel	Total	NPV@ 8.2 %
Nuclear	4 368	1 050	490	5 908	2162
Coal	3 024	735	2 464	6223	1822
Gas	647	116	6 776	7 538	1605
Diesel	588	116	16 310	17 014	3591
Renew + 10 % Gas	2 339	816	678	3 832	1155

The results shown above in Table 11 demonstrate that the cost of the grid supplied by renewable energy backed up with dispatchable power generated by natural gas is the lowest cost system that could be built, even with the need to provide extra capacity to handle the intermittency of the renewable sources of energy.

5.2.3. Capacity Payments

As indicated above, and detailed in Appendix D, a renewable based generation system with gas backup is the lowest cost system for electricity generation. However, this does not describe how to pay for the cost of the dispatchable energy when the facilities are only expected to be used less than 2 % of the time. As developed in Appendix D, the latest international thinking in this regard is for a system of capacity payments, which NREL says "Capacity markets can be defined as a means of providing revenue to owners of power plants who in return agree to stand ready to supply power when needed"(Jenkin, *et al.*, 2016, pg. 1). Natural gas fuelled dispatchable generation fits well into this concept, with low upfront cost and responsiveness both in the development phase and in usage. This is consistent with the move from Eskom to a system of demand charge plus energy usage charges (Mashiri & Bekker, 2018).

5.3. Gas storage

Gas is a convenient and economical fuel to use for dispatchable power with lower greenhouse gas emissions in addition to lower pollutants than other hydrocarbon fuels. However, it has always been known that there is a challenge to store enough gas to provide the volumes of gas needed when the dispatchable power is required. For liquid

fuels, such as diesel, this storage is reasonably easy to provide in above ground atmospheric pressure tanks. For natural gas, storing sufficient volumes of gas implies that the storage be done under pressure or that the gas be liquified and stored as a liquid (Stevens, 2012).

5.3.1. Gas storage history

Natural gas and town gas – generated from coal – have been used for centuries to provide heat and light throughout Europe and North America (Thomas, 2014). It was known since the first gas supplies were made that storage must be provided to make these deliveries dispatchable. The first tanks designed to provide this storage were above ground, atmospheric tanks, generally with floating roof structures to maintain the pressure on the gas. These tanks were known as gas holders or gasometers and at one time were a notable item in most towns that had gas systems (Thomas, 2014). These storage systems even appeared in South Africa, with gas holders being built in Cape Town and Johannesburg as early as 1820 (Whittingdale, 1973).

While most of the gas holders around the world have been replaced by sub-surface storage systems and liquified natural gas, there are still some gas holders in service including three owned by Egoli Gas in Johannesburg (PricewaterhouseCoopers Inc., 2015).

Since these tanks were at atmospheric pressure, they did not hold large quantities of gas. The largest gas holder ever built was in Oberhausen, Germany in 1929 as shown in Figure 30. The tank was 117 metres tall and 68 metres in diameter. Even with this large size, it held only 370 000 cubic metres of gas – enough to provide about 1 GW of power for one hour. This storage tank was taken out of service in 1988 and the building became an art installation (Gasometer Oberhausen History, 2019).

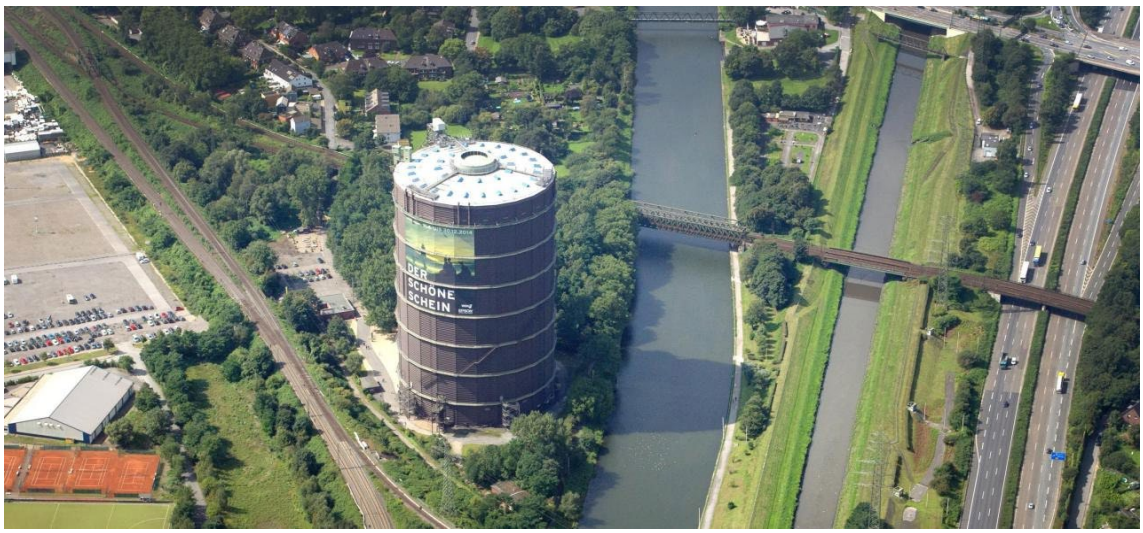


Figure 30 - Oberhausen Gasholder (Gasometer Oberhausen History, 2019)

Most gasometers systems held in the range of 50 000 cubic metres of gas, enough for 150 MWh of generation. It is reported that the tanks owned by Egoli gas in Johannesburg hold a total of 300 000 cubic metres, Figure 31 (PricewaterhouseCoopers Inc., 2015).

Figure 31 - Egoli Gasholder (PricewaterhouseCoopers Inc., 2015)

5.3.2. Underground gas storage

The first underground storage was built in Canada in 1915 and the US and Canada moved extensively into these storage systems. Underground storage systems can be quite large, holding 250 million cubic metres or more (US EIA, 2018d). The major use for these storage systems is for seasonal storage as the major gas demand in North America and Europe is for heat and increases significantly in cold winter weather (International Gas Union, 2014). As gas dispatchable power generation has grown, more storage is being built and used for smaller volumes that can be accessed quickly (Stopa & Kosowski, n.d.). The preferred subsurface storage for dispatchable power is in salt domes as quicker discharge can be achieved from these systems than for depleted oil and gas reservoirs or aquifers as salt domes do not have the issues of structural integrity that oil and gas formations have with rapid pressure reduction (Eberspaecher, 2017).

Underground natural gas storage is used throughout the world. Figure 32 maps the underground natural gas storage facilities around the world (International Gas Union, 2014). The types of underground storage systems in use are as follows, shown in Figure 33 (International Gas Union, 2014).

In Europe and North America, it is estimated that approximately 30 % of the annual gas usage is available in underground storage (International Gas Union, 2014).

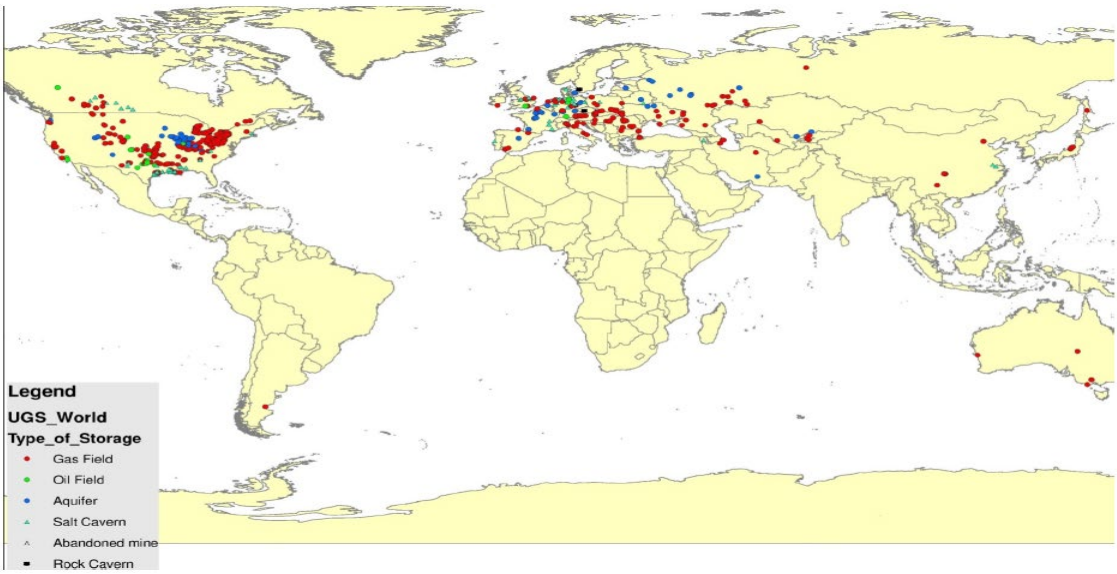


Figure 32 - Map of Underground Natural Gas Storage (International Gas Union, 2014)

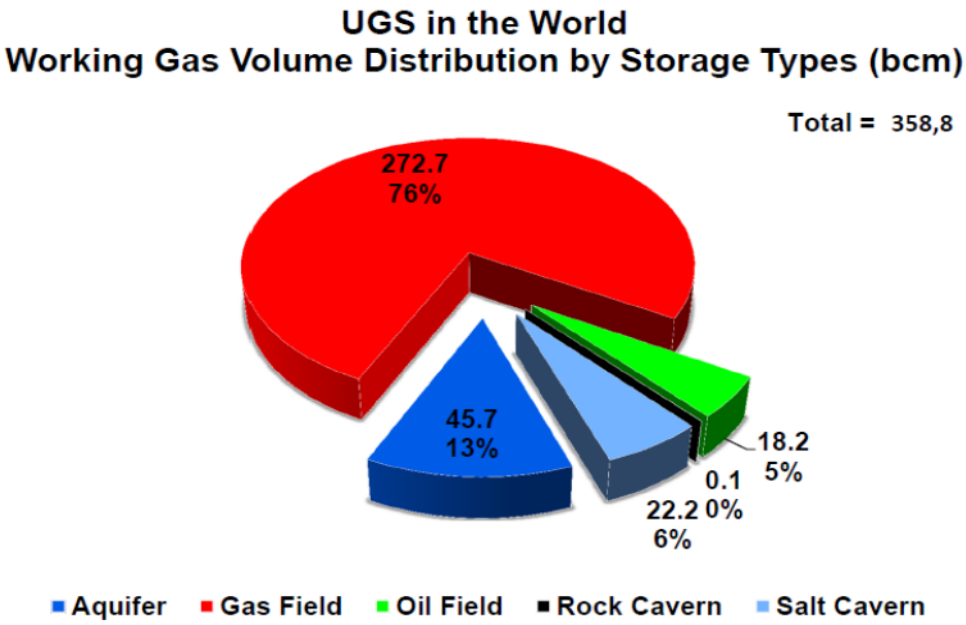


Figure 33 - Underground Storage Types (Giouse, 2012)

Besides the limitations that geology places on locating suitable underground storage facilities, logistics is also a significant consideration. It is desirable to have the stored gas as close to the market as reasonable to limit the pipeline infrastructure needed to handle the peak rates from storage to user, but it is also important to have the storage facility isolated from major population areas to avoid concerns about incidents. Growth in urban areas after the creation of a storage facility has been one of the major factors in the abandonment of these facilities.

Depleted gas or oil fields - Depleted gas fields have long been the preferred underground storage and the majority of gas is being stored in these systems (US EIA, 2018d). The experience that was gained from the production operations of the field provides a very good starting point for using these fields for storage. As gas was contained within the rock when the field was being produced, it is known that the rock is compatible with the gas and that it has pressure integrity (Stopa & Kosowski, n.d.). In many cases the infrastructure that was used for producing the original gas is available for the use of these fields for storage, minimising the cost for new infrastructure. These fields can be cycled from original pressure to abandonment pressure and back each year. The speed of removal of the storage gas is limited by the number of wells and the structural integrity of the formation rock. If gas is removed at too high a rate, there is the potential for formation collapse.

Depleted oil fields offer much of the same advantages as depleted gas fields. There are some issues with gas being absorbed into residual oil as well as some of the residual oil being absorbed into the gas. This implies that there can be losses of the injected gas as well as the need for gas processing to remove the absorbed oil from the produced gas. These two factors make oil fields less attractive than abandoned gas fields.

Aquifers - In areas where there are no suitable depleted oil or gas fields, storage in aquifers is an option but not one that is preferred (Kruck, *et al.*, 2013). The cost of creating these systems is quite large due to the requirement to explore the suitability of the chosen aquifer prior to its use. Pressure integrity for gas use must be confirmed. In addition, aquifer storage is noted for the requirement of large cushion gas. Cushion gas is injected into the storage area to create the storage volume but will never be recovered. In aquifers, much of the cushion gas is absorbed into the water surrounding the gas storage area. Aquifer storage is only suitable where large storage volumes are required to justify the high upfront costs and the cost of a large percentage of cushion gas. These costs have limited the use of this storage system to a bare minimum. The gas removal rate from aquifer storage is also limited to avoid formation failure and gas / water mixing. One of the more common failure modes in aquifer storage is from water "fingering" where water channels to the producing wells stopping the wells from gas production and trapping significant volumes of injected gas.

These types of underground storage systems are challenging and expensive to develop but can hold very large volumes of gas, enough to supply the seasonal changes in gas demand in large markets such as the United States of America or Europe. As the need in South Africa is for more dispatchable storage, these systems are not of much interest.

Salt domes - The preferred solution for dispatchable gas storage around the world is in salt domes or salt zones. The first requirement is the proper geological conditions to create salt domes (Kruck, *et al.*, 2013). Without the proper geology, salt domes cannot be created, and these storage systems are not available. Where suitable salt domes or

zones are available, the storage volumes are made by liquefying and removing a given volume of salt from the dome, creating a cavern that can be used for storage. The structural integrity of the salt dome creates the pressure integrity needed. In general, this structural integrity allows reasonably large discharge rates, making these systems suitable for dispatchable use. Unfortunately, there are no salt domes in southern Africa so this is not an available alternative (Naidoo, 2007).

Rock caverns - In some parts of the world where depleted oil and gas fields do not exist, aquifer storage is not considered to be a reasonable alternative and salt domes are not available, manmade caverns in hard rock have been created to store gas. The most well-known example of this is the Skallen storage field in Sweden as seen in Figure 34 (Johansson, 2014). In this facility, a cavern was created with 35-metre diameter and 52-metre height. Gas can be stored in this cavern at 200 bar; therefore, it can hold 10 MCM total volume, of which 8.5 MCM are considered to be working gas. Inside of this cavern a steel tank was built and cemented into the rock walls (Johansson, *et al.*, no date). The steel tank was constructed with 12 mm thick carbon steel sheets welded together. Two advantages of this system are the minimal cushion gas requirement and ability to remove gas at the speed needed for dispatchable use. However, this system has a high relative cost to create the cavern. Not many systems like this are in use.

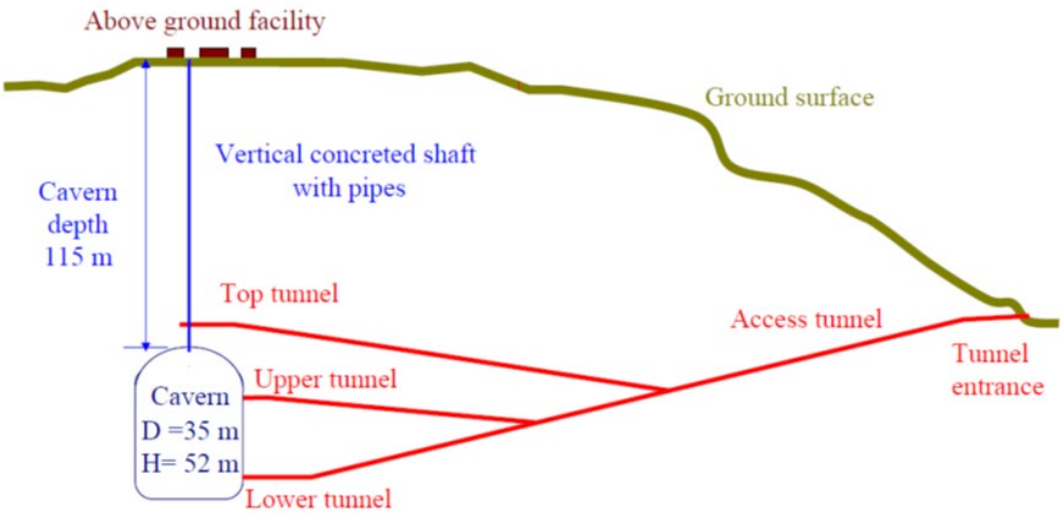


Figure 34 - Skallen Storage Schematic (Johansson, 2014)

Mine storage - There have been a number of proposals regarding the use of the space created in mines, particularly coal mines for storing gas (Alternative Energy Development Inc., 1998). While there is the potential for some absorption of the gas into the residual coal, there is also the potential for the coal to release some of the trapped methane (coal bed methane) into the stored gas. Studies indicated that this gas transfer with the coal would generally be positive for the stored volumes. As in depleted

gas zone storage, removal rates must be controlled to avoid stressing the rock structure and causing formation collapse.

The major challenge with utilising abandoned mines is trying to ensure that there are no leak paths. Most mines are built with multiple paths to the surface and in order to use these zones all of these leak paths must be sealed (Raven Ridge Resources, 1998). To overcome the leakage issue, a number of proposed systems for mine storage have recommended developing a water blanket around the zone in question (Li, *et al.*, 2016). The intent is to create a barrier using the water to prevent gas leakage. There is no evidence in the literature that this concept has ever been used in a commercial underground storage system.

5.3.3. Above-ground storage

For peaking use, several projects in Germany, Austria and Switzerland have been implemented to store compressed natural gas in pipeline arrays, or pipeline fields, at ground level as can be seen in Figure 35 (Kruck, *et al*., 2013). These storage systems use an array of conventional gas pipelines, laid out in a field pattern to store the gas (Kuhn, 2008). A 42-inch diameter (1.1 metres) pipeline has a volume of slightly over 1 000 cubic metres per kilometre. The storage in this system can be up to 100 bars, thus each 1 000-metre section holds about 100 000 SCM gas. A 1 000-metre by 500-metre array with 200 loops would hold 20 million SCM. The cost for pipelines of this size is in the range of USD 1 million per kilometre, so this 200 loop system would have a cost in the range of USD 200 million (US AID, n.d.).

Figure 35 - Example of Surface Piped Storage (Kruck, *et al.*, 2013)

Compressed natural gas (CNG) storage tanks are designed for operating gauge pressures up to 250 bars. A number of different concepts of CNG storage tankage for CNG ships have been designed (Stenning, *et al*., 2012). These systems use many smaller tanks to achieve this high pressure and the volumes needed as seen in Figure 36. The shipping company Knutsen estimates that the cost of the storage system for one CNG tanker - which holds about 10 million SCM of gas - would be USD 70 million for the tankage without the cost of the ship (Reepmeyer, 2006). Therefore, the cost of storing 20 million SCM as per the pipeline array would be about USD 200 million as well.

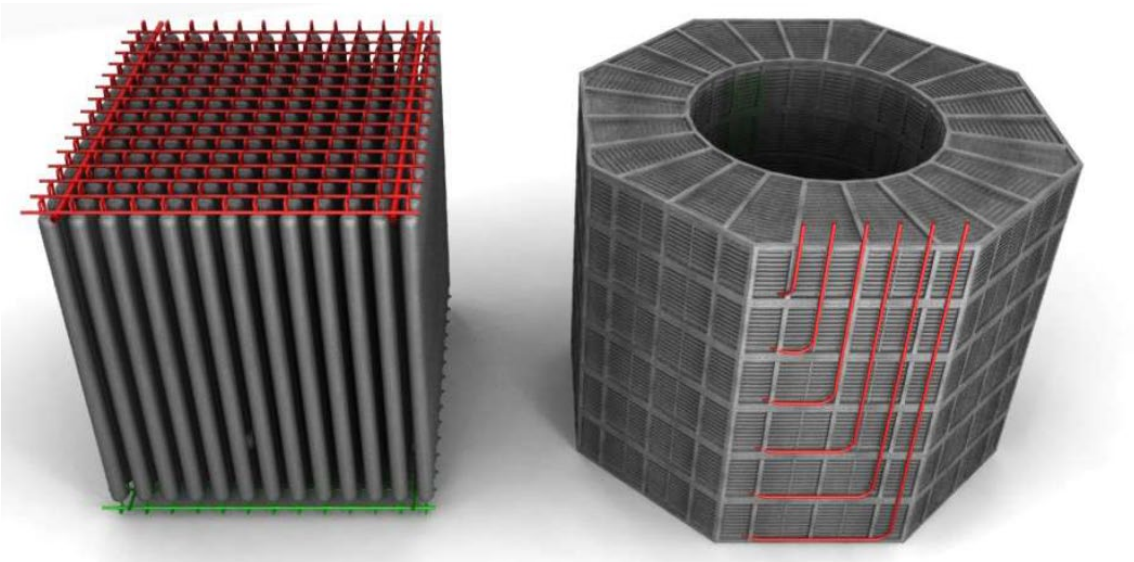
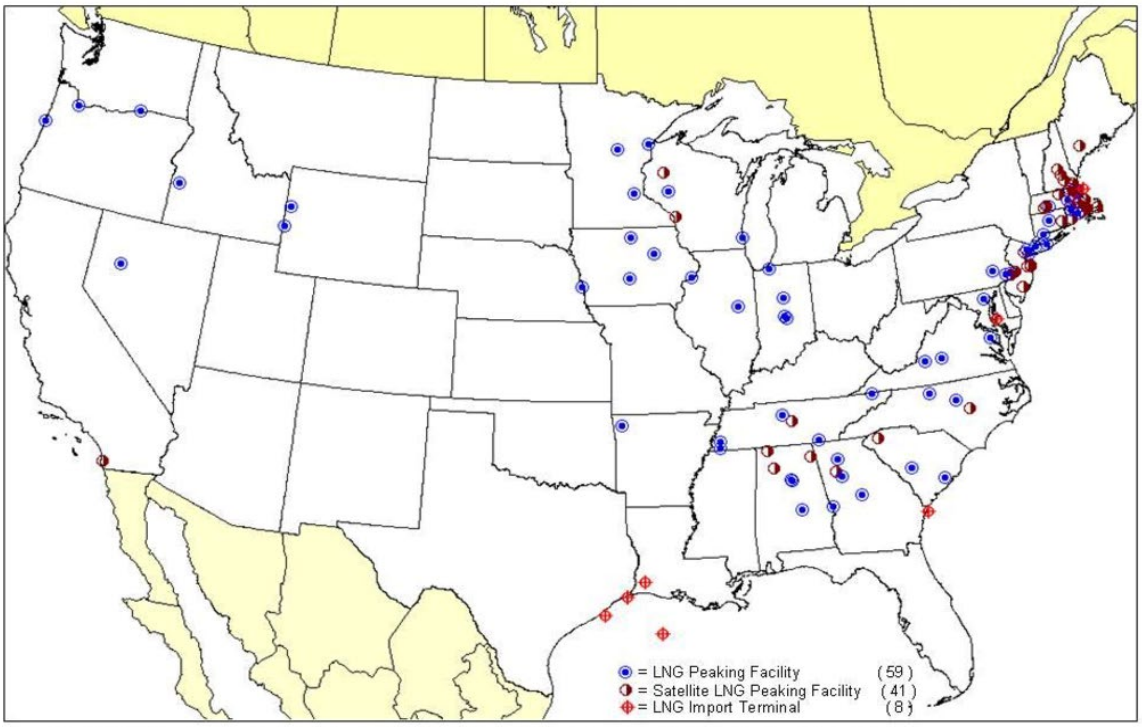


Figure 36 - CNG Storage Concepts (Ward, 2016)

5.3.4. Storage as LNG

For dispatchable use, there is a growing use of LNG in small volumes to meet the peak needs on a daily or weekly basis. In the United States of America, it is reported that there are nearly 100 power plants with LNG peaking storage. Of these storage facilities, 59 are reported to also include liquefaction, as shown in Figure 37 (US EIA, 2018d). It has also been reported that seven projects using small scale LNG regasification facilities for remote locations have been constructed in Australia with capacities ranging from 50 to 200 t per day (Heng, 2016). This would be enough to fuel a 100 to 200 MW generation plant. The usage for these small-scale regasification systems is in remote locations. In reviewing the applications, R. Bhullar stated "Most developing regions need less than 50 MW of power generation, with occasional required capacities of between 100 MW and 150 MW. Small-scale LNG is perfectly suited for such an application" (Bhullar, 2020, pg. 3). For South Africa, the challenge is different with several GW of power needed for short times as shown in section 5.3.5.

Tankage sizes can be reasonably small as the liquefaction process reduces the volume by 600 times from gas at standard conditions, thus making surface storage practical. An example of a small-scale LNG peaking system is shown in Figure 38. While the volume of an LNG storage tank is much smaller than that for CNG storage, the requirement to maintain a temperature of -162 degrees centigrade makes it more expensive. The design elements of an LNG storage tank are shown in Figure 39. A normal full containment LNG tank holding 170 000 CM LNG or about 100 million SCM gas would cost about USD 200 million to build (Michael Baker Inc., 2013). The International Gas Union (IGU) reports that the liquefaction process returns about 85 % of the volume of gas input into the system through the liquefaction and regasification process (International Gas Union, 2019b) with the other 15 % being used as energy consumed in producing the LNG.



Note: Satellite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Figure 37 - USA LNG Storage Map (Tractebel Engineering, 2015)

Figure 38 - Typical Small-Scale LNG Storage (McDermott, no date)

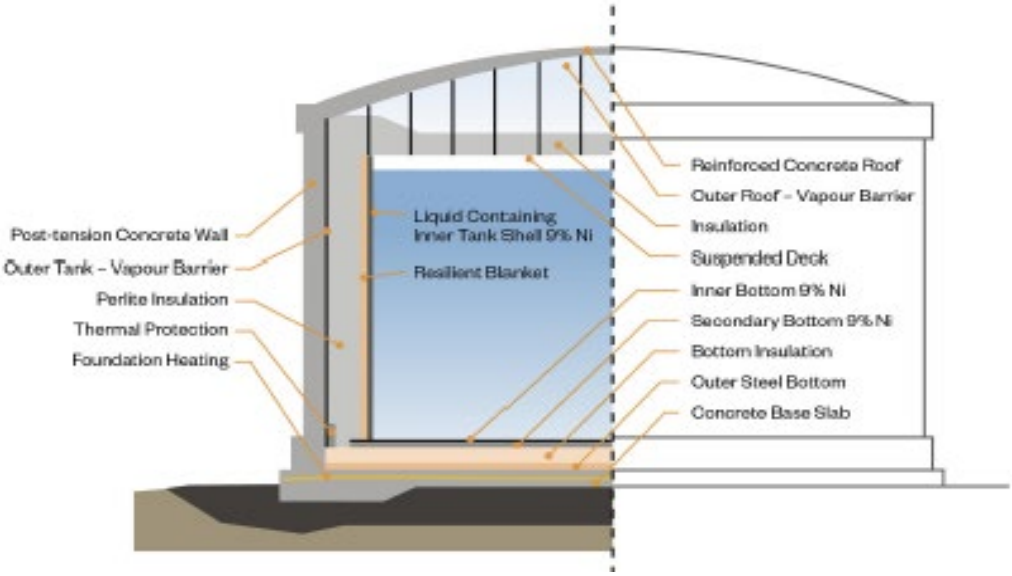


Figure 39 - Typical LNG Storage Tank (Wartsila, 2015)

5.3.5. Relevance for South Africa

Dispatchable Energy is only used occasionally and when it is used, it must be available in significant volumes. In their 2019 Integrated Report, Eskom reports that the target for use of peaking plants is a 2 % capacity factor (Eskom, 2019a). This makes the fuel supply a challenge unless there is a system to provide a buffer storage to provide the large volumes required when needed. As for the South African grid, by 2030 it is expected that dispatchable energy must be available to supply up to 10 GW for short

durations with a 2 % annual capacity factor. The forecasted distribution of this requirement over a year is shown in Figure 40.

While South Africa must solve the problem of gas storage to move to a system with dispatchable power based on natural gas fuel, it is not apparent that any of the solutions in general use in other places is the best solution in South Africa. Surface storage in gasometers does not seem like a reasonable alternative. With the world's largest gasometer only storing 370 000 cubic metres of gas, it would take hundreds of equivalent tanks to meet the need the for the more than one hundred million cubic metres needed. Most underground systems used around the world are not feasible because of local geology and those that are possible are not particularly attractive due to the high upfront cost as well as the need for large volumes of cushion gas. The only apparent candidate for underground gas storage that seems possible is that based on storage in abandoned coal mines, but international experience has not been positive and it would seem to be an expensive option to consider when the experience is so negative.

As mentioned above, abandoned mine storage is a concept that has had significant study in Europe and North America (Alternative Energy Development Inc., 1998). The limitations of these systems due to leakage has been investigated and options reviewed for handling these leakages (Li, *et al.*, 2016). The single example of storage systems using abandoned mines in the United States of America and the one in Belgium both have been abandoned due to leakage concerns and no new systems have been completed (Oil and Gas Commission of the State of Colorado, 2003) (Kruck, *et al.*, 2013). Abandoned mine storage would also be more suitable for seasonal storage rather than for dispatchable needs as the rate of gas removal is limited by the rock properties of the storage areas.

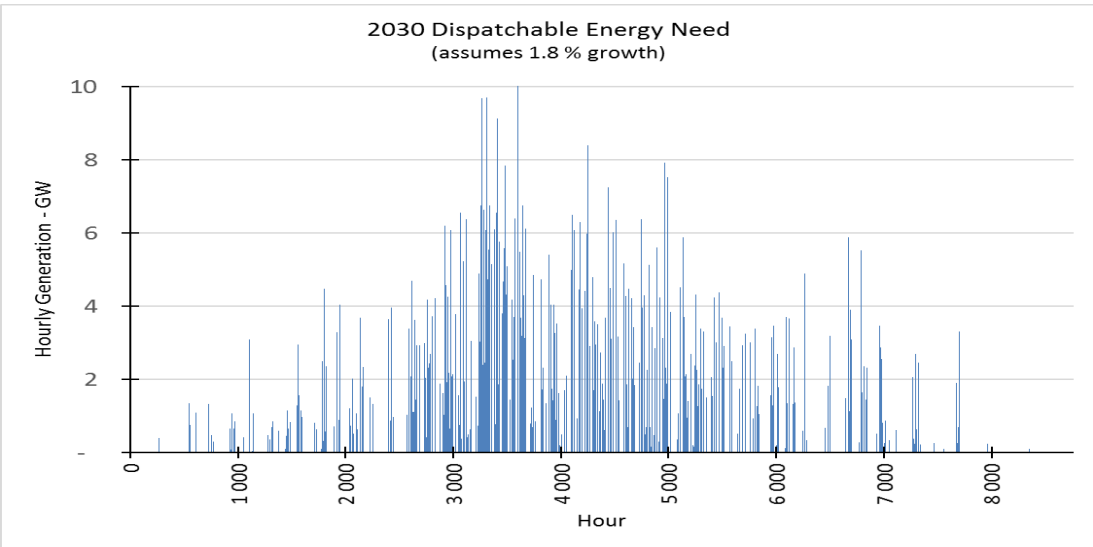


Figure 40 - Annual Dispatchable Energy Usage – from model simulation

5.3.6. The storage requirement in South Africa

The amount of storage needed is a function of the total needed at any time as well as the flexibility of the supply. If more supply can be called upon as needed, less needs to be available from storage. For this analysis, we will assume that the supply is constrained to a fixed amount with minimal flexibility and the dispatchability must be met from storage. This analysis has been based on natural gas storage needed to meet the IRP 2019 forecast 2030 dispatchable energy requirement.

The Rompco pipeline with a 200 PJ annual throughput rate has an hourly throughput rate of 23 000 GJ per hour. For 10 GW of generation, the hourly fuel usage would be 100 000 GJ per hour, or over 400 % of the hourly capacity of the Rompco system. However, this generation is only expected to be in use less than 5 % of the time. With the assumption of a call on 14 % of the Rompco throughput (77 000 GJ per day or up to 28 PJ per year), the storage volume calculated from the Dispatchable Energy Model described in Appendix A to meet the demand profile would be 4.5 PJ or 120 million standard cubic metres of gas corresponding to 150 days of supply from the pipeline at 8.5 % of pipeline capacity. The annual profile of the storage use is shown in Figure 41. As natural gas effectively performs as an ideal gas in storage terms, the volume of storage that is required will be reduced linearly with the increase in pressure of the storage system.

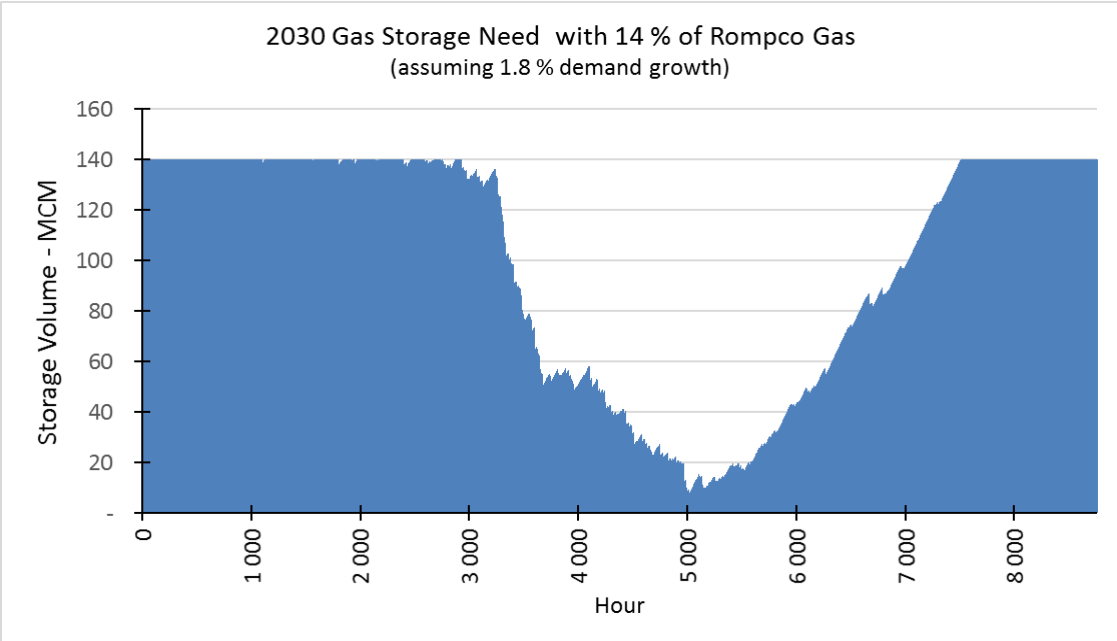


Figure 41 - Annual Gas Storage Requirement - from model simulation

5.3.7. LNG storage

LNG storage for peaking is an alternative that is utilised elsewhere and could be considered as a realistic alternative. If LNG importation is the source of the gas, which has been the major focus in IRP planning, keeping the imported LNG in storage until required for the dispatchable power is one reasonable storage option for long term storage. However, there are challenges between balancing LNG storage and the high rate short term usage required for dispatchable generation. To use LNG storage for dispatchable power, the regasification system must be sized to meet the maximum load for the dispatchable need. As dispatchable power requirements dictate that full gas be available from the time that the generation facility is brought online (Wartsila, 2019), gas storage will also be required to meet the ramp up of power until the full regasification can be put online.

This gas storage can be built into the system. As was discussed previously, an example of this built-in compressed gas storage could be a dedicated pipeline from Saldanha to Ankerlig. With this gas storage, the LNG regasification facility can be ramped up and down to meet the demand. This dictates that the system be built with facilities that can be utilised for this storage or that storage be specifically provided at the power plant. For other locations, it would need to analyse whether building the system to use "line packing" or dedicated buffer storage is more economical.

For gas that is not LNG, such as gas from the Rompco pipeline, it would not be cost effective to liquify the gas in order to store it. It would be more economical to build buffer storage for compressed gas at the power plants as needed.

It is therefore likely that several technologies would be used in different situations around the country. For dispatchable generation in the High Veld, mine shaft storage is an option that should be considered.

5.4. Mine shaft storage for South Africa

As described above, while mine storage seems to have some attraction in South Africa, due to the number of abandoned mines, the international experience does not paint an optimistic picture for this alternative. However, it should be possible to utilise the high-pressure space created underground by abandoned mines. A potentially economically attractive solution appears to be using the mine shaft volume and installing an open bottom steel tank into the shaft. These tanks can be quite large as the mine shafts in some of the deep mines go down to 3 000 metres below ground (Hillhouse and Lange, 1973). The size of the mine shafts is in the range of 5 to 7 metres in radius. Abandoned mines generally flood with formation water up to the surface; thus, the mine shaft is likely full of water (Cousens and Garrettt, 1969). As discussed in a paper on water management of flooded mines "Following the cessation of underground mining in the three original mining complexes in South Africa's

Witwatersrand Gold Field, mines started to flood with no control measures in place. In 2002, acidic water began to discharge from the West Rand Gold Field's underground workings…" and "In the years following this, underground operations ceased in the Central Rand and East Rand Gold Fields and the underground workings were allowed to flood" (Coetzee, 2016, pg. 1). In Johannesburg, there is a problem as the level of the water in some of the abandoned gold mines is above the elevation of parts of the city and must be pumped out to maintain a safe level (Winde, 2011). These properties can be utilised to create a large high-pressure storage tank without requiring extremely thick steel for pressure control.

By cementing a tank into the mine shaft, the pressure integrity of the tank is maintained without the requirement for the steel shell of the tank being designed for the full pressure differential. Most of the internal pressure is transferred into the rock around the mine shaft. As long as the fracture gradient of the rock is larger than the internal pressure in the tank, this system should not put undue stress into the rock.

This concept was developed into a system that has had a patent application submitted by Stellenbosch University, patent application #2019/03690.

5.4.1. Mine shafts

Mine shafts can be described as a concreted lined vertical cylinder up to 3 000 metres deep and with a diameter of up to 20 metres. At abandonment, most mine shafts flood due to water influx from the mined zones. A photo of a typical mine shaft is shown in Figure 42. The design of a typical mine shaft in South Africa is shown in Figure 43.

Figure 42 - Photo of a Typical Mine Shaft (Murray and Roberts, 2019)

5.4.2. The concept

The concept of mine shaft storage is to cement an open bottom steel storage tank inside the mine shaft. There will be a floating bottom seal in the tank separating the stored gas from the surrounding water. The water around the tank will provide a pressure buffer within the gas storage cylinder. Gas inlet and outlet piping will be installed at the top of the tank. A schematic of the storage tank is shown in Figure 43.

The dimensions of the storage tank will be limited by the dimensions of the chosen mine shafts. It is expected that the tank will have a radius of 5 to 7 metres and a vertical length of up to 1 000 metres. The pressure rating of the storage will also be affected by the depth that the tank is set at in the mine. This analysis assumes that the tank top will be set 1 000 metres into the mine shaft. To meet the 10 GW of dispatchable energy needs of South Africa in 2030 (as described in Figure 40). It is expected that 3 to 10 of these tanks must be installed depending in tank volumes. To minimise the number of installations that must be constructed, each tank will be built as large as possible, both in diameter and in length.

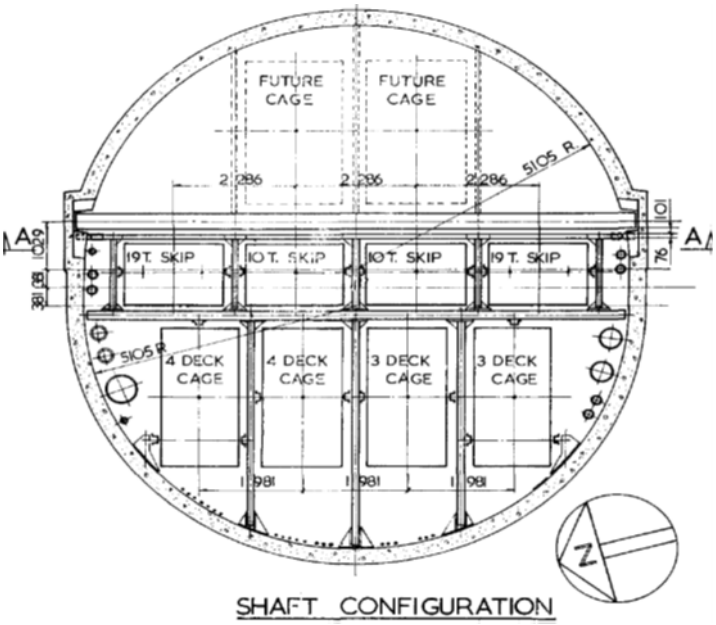


Figure 42 - Typical Mine Shaft Dimensions (Hillhouse and Lange, 1973)

The pressure on the outside of the tank is provided by the water gradient in the mine shaft and surrounding rock. The pressure on the bottom of the floating floor is provided by the water column in the mine shaft. When the storage tank is full, the pressure at the bottom of the tank is balanced, but there is a pressure differential inside the top of the tank equal to the gas pressure minus the pressure of the outside water. This pressure will be transferred into the surrounding rock. When empty, pressure differences are

eliminated. The water pressure on the floating floor ensures maximum delivery of gas as the tank is supplying the stored gas.

A tank of 1 000 metres long, with a radius of 7 metres, set at a depth of 500 metres would have an internal volume of 300 000 cubic metres. With an internal pressure of up to 150 bar, this would allow for storage of 31 million standard cubic metres (SCM) of gas, nearly100 times the volume of the largest gasholder. This is approximately the storage volume that could be achieved with 310 kilometres of surface pipeline storage.

5.4.3. Capital cost

The conceptual cost for a 32 MCM storage unit (1 000 metres) should be in the range of USD 50 million as detailed below in Table 12. This is a conceptual level estimate that must be refined during further engineering analysis. As a 500 metre tank will take approximately one half of the material and installation work, it can be expected that the cost will be nearly proportional to the tank size.

Assuming a cost of USD 25 million for the smaller tanks and USD 50 million for the 1 000 metre tank, the cost of this storage would be approximately 20 % of the cost of surface pipeline storage or CNG storage.

Table 12 - Mine Shaft Storage System Cost Estimate

Conceptual Cost Estimate for Mine Shaft Storage Tank		
Cost Element	Sub-element	Millions USD
1. Material, prepped and ready for installation into mine shaft		**10**
	Tank rings – 200 # - 5m, x 21 m. x 0.02m.	7
	Hemispherical pressure top cap – 14 m. diameter	1
	Floating floor	1
	Support structure and pipework	1
2. Tank assembly in mine shaft		**20**
	Assembly mobilisation	1
	Shaft prep. work	2
	Material positioning	5
	Welding and finishing	10
	Testing and demobilisation	2
3. Tank cementing		**5**
4. Surface equipment and installation		**15**
Total cost for one 1000-metre tank		**50**

5.4.4. Environmental issues

Pressurised gas storage systems always have some concern about leakage and explosion. In this system these problems are minimised as the system is deep

underground and has water cushions above and below the tank. The water barriers provide not only pressure maintenance but also a secondary control area for gas leakage. While no leakage should be expected in this system, monitoring for the presence of gas in the surrounding water is part of the leak detection system and an early warning to facilitate repairs as needed.

As this system is built into existing abandoned mines, there are no new areas affected by this development. This use will provide a new use for a problematic abandonment area. At the end of the life of the system, nothing needs to be removed and the system can simply be sealed with concrete. With the stored gas removed and utilised, there are no environmentally harmful items left behind.

STELLENBOSCH UNIVERSITY
PROVISIONAL SPECIFICATION

1 Sheets / Sheet 1

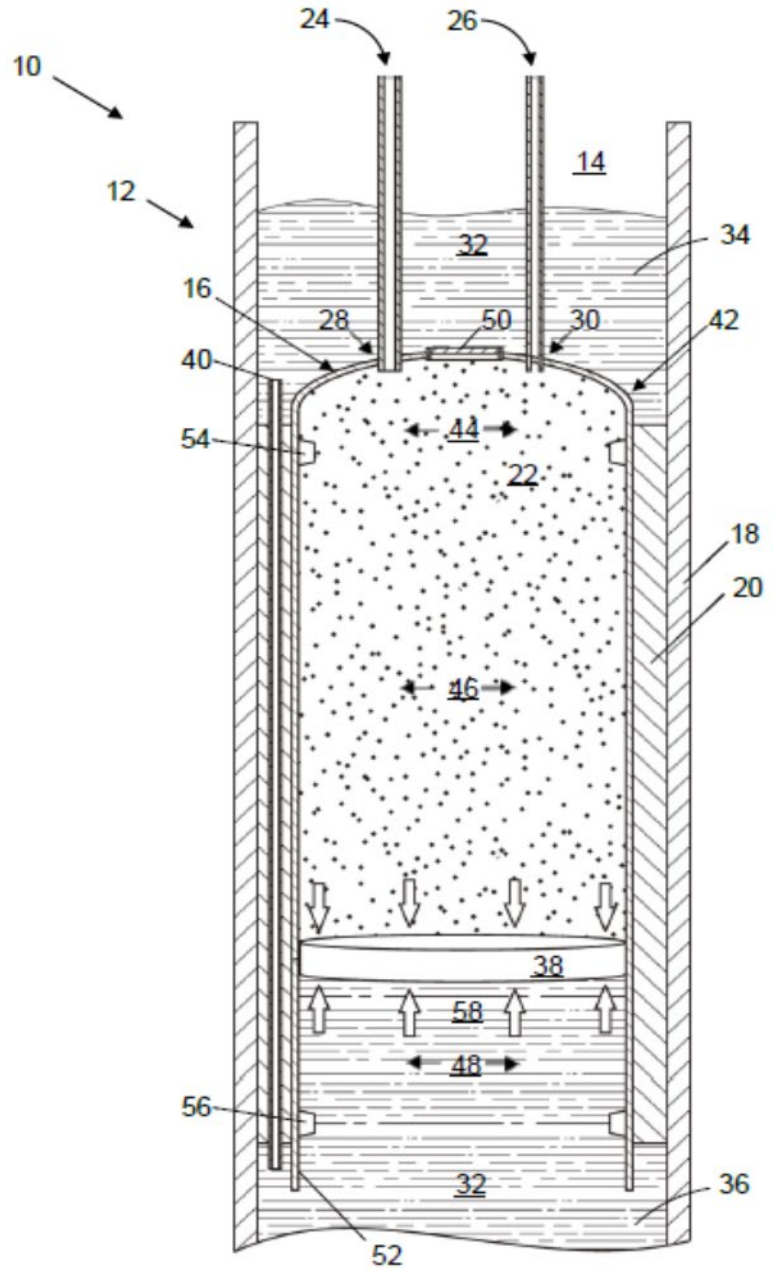


FIGURE 1

VON SEIDELS
FOR THE APPLICANT

Figure 43 - Mine Shaft Storage Schematic

5.5. Chapter summary

Chapter 5 has reviewed the supply options for providing dispatchable energy into the South African grid using natural gas. Gas supply options were reviewed, including the three potential sources originally premises: local shale gas, LNG importation and pipeline gas from northern Mozambique. Three alternatives were also added during the progress of the study, namely, Rompco gas, Brulpadda gas and LPG.

The cost of gas fuelled generation was compared to alternatives and determined to be economically attractive. Each of these sources could be utilised to provide the needed gas. However, due to the small volumes needed and the requirement for dispatchability, each of these sources had limitations. The major concern for any gas supply option was found to be the need for buffer storage.

Storage options for gas were reviewed and the recommendation for mine shaft storage was presented. This storage option can provide an economically attractive method for meeting this need. This concept has been recognised as a potentially attractive option and Stellenbosch University has submitted a patent application for the concept. The concept of mine shaft storage provides a unique contribution to the discussion on gas dispatchable generation.

In the next chapter, a potential scenario for supplying the needed dispatchable energy using gas generation will be laid out for consideration.

6. Dispatchable Power Supply Scenarios

In Chapter 4 the amount of dispatchable energy required to balance the South Africa grid was analysed. In Chapter 5, the relative cost of gas fuelled generation was reviewed and it was demonstrated that it is an economically competitive option, even in South Africa. In this chapter, a proposed development scenario for providing this gas fuelled dispatchable power will be described. This scenario is designed to meet the peaking power needs of the system with minimum cost and maximum flexibility. The intent is to develop an economically attractive method of providing natural gas for dispatchable power that can be developed in steps that can be implemented in reasonable short time frames. This would allow the scenario to meet variable forecasted demand levels and to be able to do so without long lead time, nor large upfront investment.

In reviewing the range of possible forecasted dispatchable generation demand for 2030, it was determined in this study that the range is quite large due to significant uncertainty in the forecast for demand growth, the performance of the base load generation fleet and the decommissioning of the aging base load plants. With these unknown factors, the range in required dispatchable power ranges from approximately 5 GW to 15 GW, with 2 % to 6 % capacity factor. This corresponds to 875 GWh to 8 000 GWh. The expected requirement should be approximately 10 GW and 2700 GWh. This translates into a fuel requirement of 9 to 78 PJ per year, with an expected value of 27 PJ. This compares to the 200 PJ of gas currently imported into South Africa through the Rompco system and approximately 4.7 PJ that would be imported per LNG tanker.

While it appears unlikely that the demand for dispatchable power will develop to the level indicated by the IRP 2019 for 2030 and beyond, the base case most discussed is the IRP 2109 base 2030 scenario for 14 GW of power with a capacity factor of 5 %. Thus for discussion, this scenario must be able to build to that level. These development scenarios only consider the supply of gas to dispatchable power plants, not the cost or use of the plants themselves.

6.1. South Africa gas dispatchable power scenario

6.1.1. Diesel fuel replacement using LPG

In 2020, Eskom estimates that they will be expending over 12 billion Rand for diesel fuel in their two main peaking plants, Ankerlig and Gourikwa. In future years and assuming they resolve the short-term capacity issues with the base plants, Eskom estimate that they would use these plants at a 5 % load factor and expend over 3.4 billion Rand per year for diesel fuel. Replacing this diesel fuel with LPG would reduce this fuel bill to 1.7 billion Rand, saving half of the peaking fuel cost.

Bidvest has recently completed an LPG importation and storage facility in Richards Bay. The cost of this facility was stated to be 1 billion Rand with a storage of 40 000 cubic metres of LPG (Bidvest, 2020). This volume of LPG would provide enough energy to generate 104 GWh of electricity or to run the two peaking plants for up to four days. This is twice the energy storage that these plants have in their diesel fuel systems. The Bidvest plant was built in three years. Building a duplicate facility near Ankerlig should cost less than the current plant and be completed in less time, with a pay-out from fuel cost savings in less than one year. Sunrise Energy currently imports LPG into Saldanha Bay and these facilities could be adapted for this supply.

With the use of LPG fuel for these plants, 75 % of the savings from using gas fuel compared to diesel would be achieved. Switching from LPG to gas would then only make financial sense if an LNG importation facility was installed at Saldanha to meet industrial demand with most of the costs absorbed by those customers. A technical paper reviewing this option for fuelling Ankerlig with LPG is included as Appendix E.

6.1.2. Gas from Rompco to meet first dispatchable power

The one current available source of gas in South Africa is gas being brought into South Africa from Mozambique by Sasol through the Rompco pipeline, as shown in Figure 11 above. The Rompco pipeline has a capacity of 200 PJ/a (Rompco, 2020). Most of the gas is used by Sasol in Secunda and Sasolburg. Some of the gas is sold to customers in the area around Johannesburg. The area of distribution for this gas covers the area between Secunda and Sasolburg, including Springs and Johannesburg as shown in the map in Figure 44.

In addition to the 450 MW generation at Ressano Garcia, Sasol is currently using some of this gas near their Sasolburg facility to produce power in a 175 MW gas engine power plant supplying some of their power needs and power to the grid as shown in Figure 45 (Sasol, 2013).

This area is also the home of much of the mining for gold and coal in South Africa (Mineral Accounts for South Africa, 2013). This is also the industrial centre of the country, and most of the current generation is centred in this area of the country (Eskom, 2013) and a good portion of the demand as indicated in Figure 46 (Eskom, 2019c). With all this infrastructure in place in the area, the new infrastructure to supply the required dispatchable power would be minimised by adding generation capacity into this area.

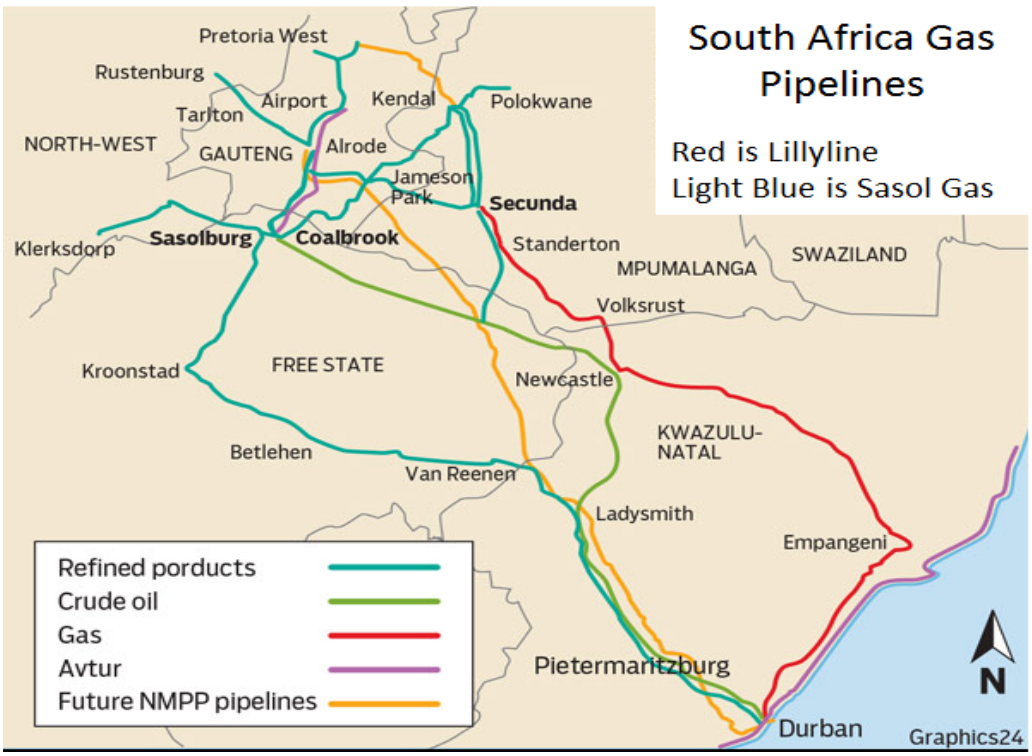


Figure 44 - South Africa Gas Pipeline Routing (Louw, 2015)

Figure 45 - Sasol Sasolburg Gas Fuelled Power Plant (Sasol, 2013)

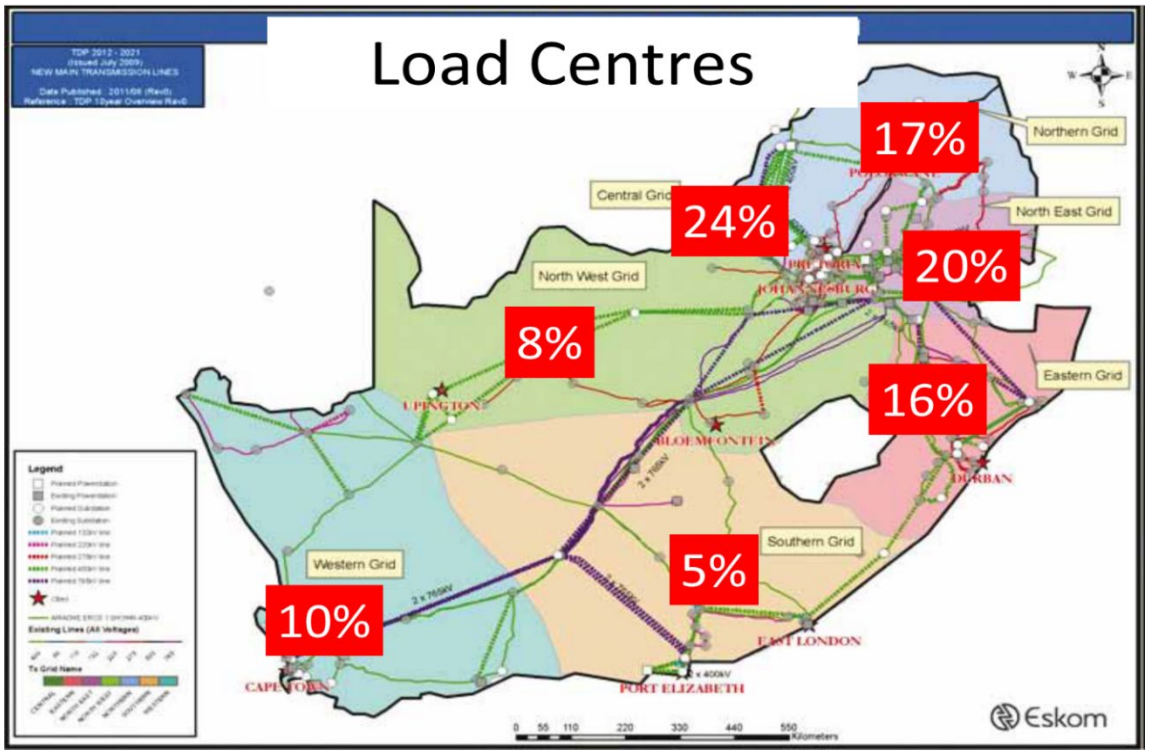


Figure 46 - Eskom Load Centres (Eskom, 2019c)

For this development, the premise is that a portion of the Rompco float gas is purchased and put into storage for use as dispatchable power in gas fuelled power plants in the Secunda to Sasolburg area. If 10 % of Rompco capacity is available, this would supply 20 PJ of gas per year. Using a generation factor of 10 000 GJ of gas for 1 GWh of electricity, this gas could generate up to 2000 GWh per year. This would provide up to 4.3 GW power at 5 % annual capacity factor.

The storage requirement for this dispatchable power demand would be approximately 30 million cubic metres of gas per GW of installed capacity to meet the dispatchable generation profile developed from the model. This storage volume is equal to the volume in two 500-metre mine shaft storage tanks or one 1 000-metre tank with a 100 bar design pressure. The storage volume of the small tanks is 15 million standard cubic metres (SCM) for 500-metre tank and the volume of the large tank is 31 million SCM for 1 000 metres.

The conceptual cost estimate for the 500 and 1 000 metre tanks are detailed in section 5.4.3. As shown in that analysis the cost for the smaller tanks is USD 25 million and USD 50 million for the 1 000-metre tanks. With capital cost recovery plus operating costs, this storage adds USD 1.6 / GJ to the gas purchase price. With four large storage tanks and the 10 % of Rompco float gas, the investment would be in the range of USD 200 million with a delivered gas price of USD 9.6 per GJ to the power plant, assuming a price of USD 8 per GJ into storage. This investment can be made in four or more instalments as needed. To bring the capacity up to 5 GW at 5 % capacity factor,

11.6 % of the Rompco capacity must be procured and five storage systems installed, the system cost would be USD 250 million invested in at least five increments.

It should also be feasible to make a commercial arrangement to purchase gas in an emergency basis to utilise this installed capacity for longer time periods if there is a major power demand lasting longer than the storage provides. As this gas is currently available, there would be no reason not to make provision for this supply at this time.

- For 5 GW at 5 % CF, the system cost would be USD 250 million invested in five increments. This would supply Rompco float gas to the power generation system in the range of USD 9.6 / GJ.

6.1.3. West Coast solution from Brulpadda

Diesel fuel replacement with LPG has such a short pay-out that it should be pursued as a short-term solution to the diesel fuel cost. If local gas production becomes available at the Gourikwa peaking plant at a competitive price, replacement of LPG with natural gas must be considered.

With the recent announcement of the discovery of the Brulpadda field offshore Mossel Bay in the Southern Ocean off the Western Cape, there is interest in the possibility of this gas providing a portion of the needed gas for dispatchable power in South Africa. TOTAL and partners have not proposed a development plan for this gas and are doing further exploration surrounding the discovery. Thus, timing and volumes of gas potentially being made available for dispatchable power are speculative at this time.

Should this gas be developed, with the announcement that the gas is condensate rich and comparative cost estimates for developing the gas offshore Mozambique, it should be available onshore at prices lower than any other alternate supply. With the size of the discovery and the location, it would appear likely that the most probable development for this gas would be some version of a rebirth of the PetroSA GTL plant producing liquid fuel for the domestic market. Assuming this development, some gas being available for dispatchable power is likely. With the Gourikwa plant in place near the PetroSA plant, it can also be assumed that a power plant at this location is probable.

From the estimate of the Brulpadda resource, it can be expected that the field will produce at least 80 PJ of gas per year for a period of 20 years. With the additional prospects around the Brulpadda field, this will probably be increased significantly. It can be assumed that a float production of at least 9 PJ per year can be taken from this stream, which should be enough power for 2 GW at 5 % capacity factor. There should be some flexibility in the supply rate from Brulpadda so it would not likely be necessary to assume that a fixed stream would be required.

In the area around the Gourikwa plant, there is no previous deep mining activity, so a mine shaft storage facility is unlikely. For this exercise, the costing of the gas storage was assumed to be the surface pipeline system as utilised in Germany, Switzerland and Austria as shown in Figure 35 in the discussion on gas storage. Other concepts based on CNG systems should also be investigated to determine the least cost system. For this exercise, the costing for the pipeline system has been assumed, with a unit cost of USD 1 million per kilometre of pipeline holding 125 000 SCM of gas.

Being in near vicinity of the Brulpadda development, it can be assumed that there should be some flexibility on the gas delivery that can be taken from the field. However, gas storage would be essential to avoid the extremely large fluctuations that dispatchable power required. Assuming a total storage requirement of 25 MSCM for 2 GW, a storage system of 200 km of pipelines would be required. This should have a cost in the range of USD 200 million.

TOTAL has not made any announcements about the potential to develop the Brulpadda field nor the cost of gas from the field. However, based on the estimated pricing for gas produced offshore Mozambique (Crook, 2012), it is estimated that the price of Brulpadda gas delivered onshore to the PetroSA GTL plant should be in the range of USD 6 to USD 7 per GJ. The USD 200 million storage cost (including capex, interest at 8 % plus opex) would add approximately USD 2 per GJ to the 9 PJ of gas utilised per year.

- For 2 GW at 5 % CF, the system cost would be USD 200 million invested in one increment. This would supply Brulpadda gas to the power generation system in the range of USD 9 / GJ.

6.1.4. FSRU in Richards Bay

If there is a development of an industrial gas market significantly larger than the current industrial market in South Africa, the gas source would most likely be LNG importation into Richards Bay. Transnet is currently developing a feasibility study for a Richards Bay LNG import facility proposals in conjunction with the International Finance Corporation – part of the World Bank (Creamer, 2019a). Assuming a FSRU import facility is chosen, the capacity would be up to 198 PJ/a (re-gas capacity) using up to one LNG ship per week. At this time there are no customers for that volume of gas, but it might develop, particularly if a FSRU is installed and there is gas available.

From a dispatchable power consideration, the most probable first use of imported LNG would be to replace the gas that is brought into Richards Bay through the Lilly line. Transnet indicated that the capacity of this line is 23 PJ per year. It would be possible for the Richards Bay LNG importation facility to take on these customers and leave the 23 PJ in Gauteng to supply dispatchable power needs. The cost of the FSRU

import facility is assumed to be met by the supply to these customers. The cost of the LNG importation supply would depend on the volume of the market that it would serve. Should the market only be the 23 PJ/a that it would supply compared to the Lilly line, the cost of the facilities would add USD 2.10 to the cost of the LNG delivered price. If the full market develops the cost should drop to something in the range of USD 0.25 per GJ on top of the LNG price.

By meeting this gas need in Durban and Richards Bay, this LNG importation frees up 23 PJ per year of gas in the High Veld to meet other needs. If this is redirected into a storage system for dispatchable power, this could add at least an additional 5 GW at 5 % CF to the natural gas fuelled power generation. For the dispatchable power system, this then becomes a repeat of the Rompco supply concept. It is assumed that the cost of this gas delivered into storage would be the same or lower than the float gas from the Rompco system, or less than USD 8 per GJ.

- For 5 GW at 5 % CF, the system cost would be USD 250 million invested in five increments.

6.1.5. Reverse flow in Lilly and add more dispatchable generation in Gauteng

With LNG importation meeting the gas needs in the Richards Bay and Durban markets, the Lilly line which had been used to supply gas to the area would no longer be in use. Reversing the flow through this line would add 23 PJ /a to the amount of gas available in the High Veld that could be used for dispatchable power. This in addition to the 23 PJ of local market being met by LNG would still only add up to 46 PJ /a, much less than the available annual capacity from the LNG import terminal.

- For 5 GW at 5 % CF, the system cost would be USD 250 million invested in five increments.

In culmination, it comes to an installed capacity of 17 GW with a cost of USD 950 million as summarised in Table 13 with the locations shown in the map in Figure 47. This compares to the IRP 2018 case of 14 GW and 10 TWh, with gas delivered below the USD 10 / GJ assuming USD 8 LNG price. Since this concept is incremental and each investment decision is independent, it can be stopped whenever the needs are met. With the exception of the replacement and reversal of the Lilly line gas, which are sequential, these developments can be conducted in whatever order and at whatever speed is found to be warranted.

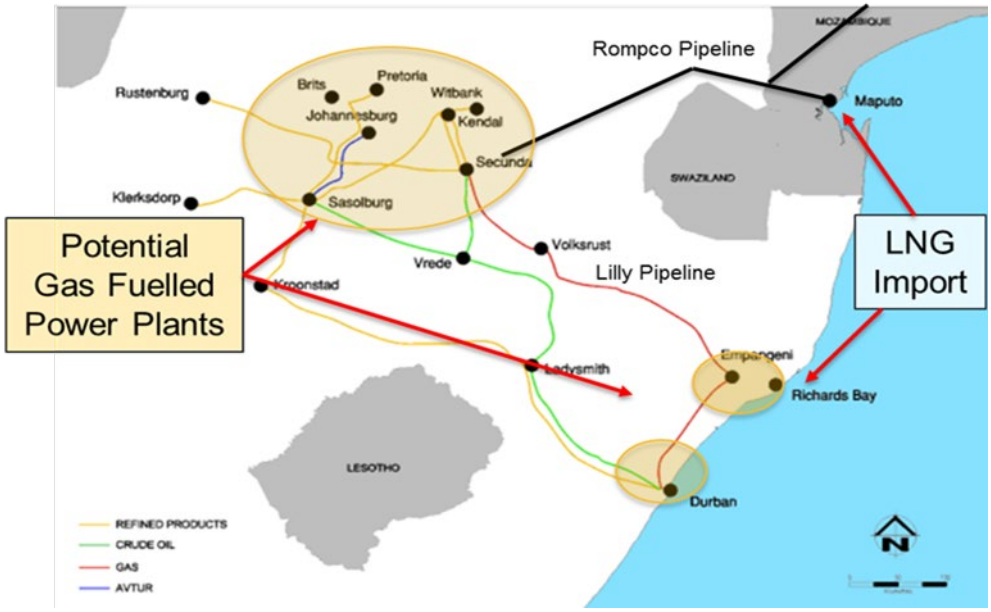


Figure 47 - Potential Gas Plants – pipeline routing from (Transnet, 2016)

Table 13 - Dispatchable Energy Storage Scenario

Dispatchable Energy Scenario Storage Costs		
Development Concept Element	Capacity (GW)	Capex (millions USD)
1. Rompco Float	5	250
2. West Coast with Brulpadda, LPG or LNG	2	200
3. FSRU with Lillyline Capacity	5	250
4. Lillyline Reversal	5	250
Total	17	950

6.1.6. Other advantages

Besides being independent from each other, these developments also present several advantages to the South African gas market and the provision of dispatchable power into the South African grid.

Each of these steps maximises the use of locally available gas without major infrastructure development which might not happen and has, to date, been a major hindrance towards gas dispatchable power development. If other markets develop during implementation, the system can be adjusted with minimal impact on the overall concept. Shale gas and coal bed methane can be reasonably accommodated if they were to be developed. However, dispatchable power usage cannot be considered as an anchor customer for any gas sourcing plan.

This is not to indicate that this development would not aid in gas market development. The use of an FSRU LNG importation into Richards Bay could facilitate

the growth of a market in those areas. The use of Brulpadda gas in the west coast would provide additional justification for Brulpadda development along with GTL usage as an anchor customer. Should a west coast market develop using Brulpadda or LNG importation, dispatchable power usage would fit into that development as an added benefit if suitable gas storage is developed.

6.2. Sensitivity and robustness review

With the gas scenarios developed, the next step in the model analysis is a sensitivity and robustness review. This step is essential in determining what the major concerns are within a given plan that could change the shape of the gas dispatchable scenario. Some of the sensitivities that were identified at the commencement of the analysis and will be reviewed as follows.

6.2.1. Varying Demand Growth

Varying demand growth was found in the review of the IRP forecasting process to be the major factor to increased ranges in the potential requirement for total power and to a larger extent, the need for dispatchable power. This large range in outputs is one of the major factors favouring the renewable generation concept with gas fuelled dispatchable backup. The proposed gas dispatchable system can be implemented and adjusted quicker than other alternatives to meet the changing load as needed.

6.2.2. Creation of a gas business

While the creation of a gas business in South Africa has been and remains a major conversation topic, it was found in this study that the creation of an industrial market for gas would likely not materially impact the plans for gas dispatchable power. Whether the industrial market develops or not, gas storage will be required in the volumes to meet the dispatchable load. While some flexibility can probably be made available from a gas infrastructure system providing gas to industrial and residential customers, it would likely not change the storage requirement to any great extent.

6.2.3. Base Load Plant Retirement Scheduling

Retirement scheduling is one of the major factors in the timing of the need for dispatchable power. As was shown in the changes from the 2018 IRP plant to that of the IRP 2019, there is reason to believe that there will be acceleration to the abandonment of some of the older coal plants as the economics of continued use of these plants is analysed. If Eskom is divided and individual plants must prove their economics, some will likely be found to be uneconomical, which would accelerate as additional significant maintenance is needed to keep them operational. The proposed

system meets the requirement to be flexible enough to meet the potential of accelerated retirement for the current base load.

6.2.4. System Inertia

Grid inertia is currently supplied due to the large mass of base load spinning generator drive shafts. As disruptions occur, this spinning mass takes time to change, minimising system disturbances. Wind and solar PV generation do not provide this inertia. Dispatchable power supply from natural gas fuelled turbine generators can provide inertia into the system. Eskom has indicated that this is a consideration for the Ankerlig and Gourikwa plants. As the model indicates that enough dispatchable power is required to completely replace renewable generation in the worst cases, the system should have as much inertia as exists in the current system.

On a related matter, system response time to changes in demand or generation will improve with increased storage from batteries and dispatchable gas fuelled generation.

6.2.5. Greenhouse gas

Most of the greenhouse gas emissions reductions for the IRP proposed system come from the use of wind and solar generation rather than base load coal generation. The only remaining emissions come for the dispatchable generation. As the dispatchable power is used for a small portion of the time, its addition to greenhouse gas emissions is minimised. Natural gas generation emits approximately half of the carbon dioxide compared to coal generation (US EIA, 2017b). Assuming that natural gas fuelled dispatchable power provides 3 % of the energy generation with assumed IRP renewable generation, the overall emissions of CO_2 would be reduced by approximately 98.5 % compared to coal fuelled generation.

Methane emissions, which is the primary component of natural gas, is also a greenhouse gas and emissions of methane must be minimised to achieve the desired greenhouse gas emission reductions. These emissions, according to the IEA, come mostly from leaks in the processing and transport of the gas. To keep these emissions to a minimum, leaks must be rapidly detected and eliminated (IEA, 2020b).

According to the United Nations International Panel on Climate Change (IPCC), LPG is not classified as a greenhouse (Solomon, *et al.*, 2007). When burned LPG has CO_2 emissions of approximately 84 % of that of diesel, compared to natural gas at 70 % of diesel (US EIA, 2017b). Therefore, LPG is a reasonable alternative to natural gas for greenhouse gas emission reduction.

As concerns grow about reducing greenhouse gas emission to the lowest level possible, this can be addressed with additional renewable generation plus storage and

less use of installed dispatchable generation. This may not impact the amount of dispatchable facilities that must be installed, but by reducing the energy generated from these plants, the amount of greenhouse gas emissions is minimised.

6.2.6. System Breakdown Backup

While somewhat outside of the scope of this analysis, the update to the IRP for 2019 showed significant challenges for the South African grid in the short to medium term due to problems with the base load plants. Beyond meeting dispatchable power needs, it is likely that the peaking generation facilities will be called into mid-merit service to provide some of the generation that should have come from the base load. Conversion of Ankerlig and Gourikwa to use LPG fuel would provide a way to reduce their fuel cost and move to cleaner generation for peaking and mid-merit usage. Once gas fuelled dispatchable generation is installed to meet the variability of wind and solar generation, it would also be available to meet shortages from base generation as well.

6.3. Potential to replace gas with renewable sourced dispatchable energy

With the growing international concern on climate change, it is certain that there will be growing desire to completely eliminate fossil fuel generation from the system. This must be balanced with the benefits that are brought to the electricity generation system and to society. The amount of greenhouse gas emissions from generation are from the amount of energy produced, not from the installed power capacity. If 10 % of the installed generation capacity is from natural gas generation, but only used to provide about 3 % of the electricity, as discussed above the CO_2 emissions as compared to coal generation would be reduced by approximately 98.5 % for the portion of the system supplied by renewables with dispatchable gas fuelled backup.

Short term energy storage systems using fly wheels, batteries, compressed air, pumped hydro or other solutions that might be developed over time would remove a significant portion of the energy that the natural gas dispatchable power would provide. This could reduce the majority of the negative impact from the gas generation. Wherever these storage systems make economic sense in comparison to the saving of fuel costs, they should be utilised.

While the short term dispatchable generation can be replaced with a number of energy storage systems, it was seen from the data as well as from international examples that storage for longer terms of up to a few weeks use would be needed to completely replace the use of dispatchable power. The IEA analysed storage for different volumes and duration and has concluded that hydrogen, produced from renewable sources, is the most probable storage medium for longer term storage, as shown in Figure 48 (OECD

& IEA, 2015). As seen from this figure, hydrogen is the fuel that they believe can provide the long-term storage needs.

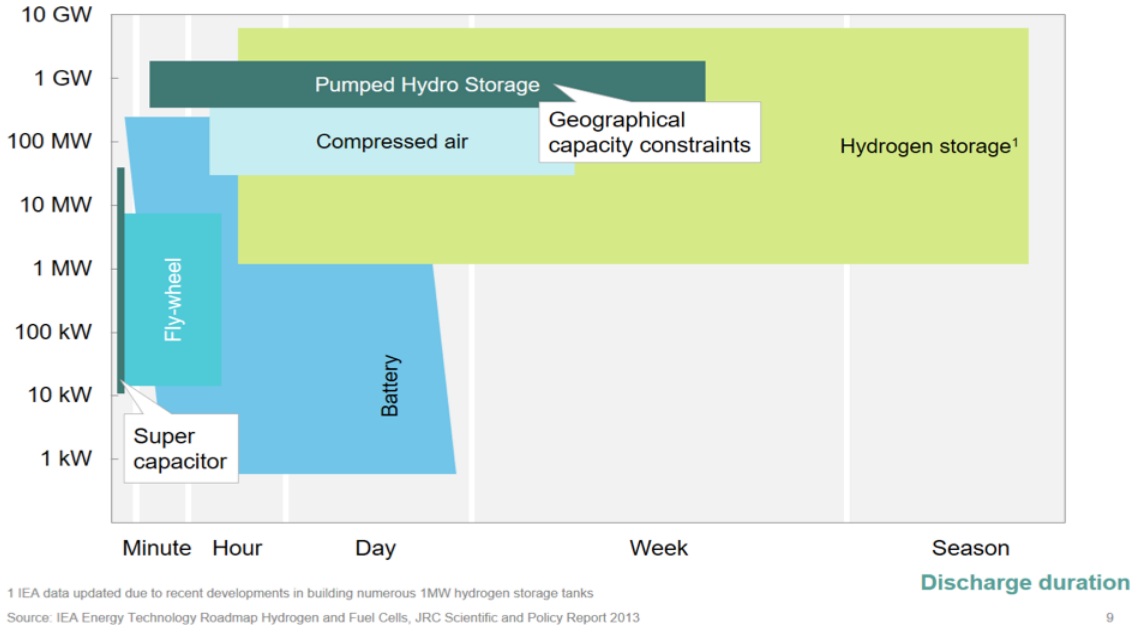


Figure 48 - IEA Energy Storage Breakdown (OECD & IEA, 2015)

Producing peak electricity with hydrogen offers most of the benefits that natural gas fuelled power has. With the current improvements in costs, the capital cost for fuel cell generation systems are expected to become lower than combustion generation plants by 2025 to 2030, according to the US Department of Energy, (Papageorgopoulos, 2019) so the low capital cost associated with gas fired generation would also be an advantage of hydrogen fuel cell based generation. The flexibility and modularity of gas generation is also a feature of hydrogen-based electricity generation.

As mentioned in section 5.3.8 above, the technology for hydrogen generation using electrolysis is well understood. There is research being conducted worldwide regarding the technologies involved and there is reason to expect that the technology will improve, and costs will be reduced with these innovations. As mentioned in that discussion, the major costs are the electrical energy required, the capital cost of electrolysis equipment and the life of this equipment.

For one kilogram of hydrogen approximately 50 kWh of electricity must be used. At USD 0.06 per kWh, this would indicate an expense of over USD 22 per GJ of hydrogen energy produced. Reducing this electricity cost to USD 0.015 per kWh, as seen from the latest solar PV projects, reduces this cost to USD 5.5 per GJ. This will make a significant impact in the overall cost of hydrogen production.

The capital cost of electrolysis has two elements to be considered, the specific technology utilised and the cost of this equipment at the scale required. Both of these

areas are currently being researched, with the expectation of the capital cost of drop from USD 1600 to 700 USD per kW by 2023 (Buttler & Splietho, 2018). Much of the cost reduction will be similar to solar PV price reductions where the change is due to the volume of manufacturing, but there is expected to be significant technology improvement as well. The life span of some of the elements of electrolysis systems is also one area that is being considered. As has been seen in the battery storage developments, the likelihood is that lifespan extension will also come with larger implementation and technology improvement (Staffell, *et al.*, 2018).

The challenge of energy storage that natural gas has is also a challenge for hydrogen-based fuel (Herzog, 2018). Hydrogen can be transported and stored much like natural gas. However, hydrogen is a much smaller molecule than natural gas and leakage from pipelines and storage is more probable. It is likely that much of the infrastructure used for natural gas cannot be used for hydrogen. In South Africa, with minimum existing natural gas infrastructure, this is less of a concern.

It is possible to produce, transport and store hydrogen in volumes to provide the long-term backup needed to ensure that the power can meet all needs when renewable sources might not meet the need for long periods of time. For South Africa, the important work in the analysis of the use of hydrogen for longer term dispatchable generation is to understand how all of the latest international developments and cost reductions can be applied to utilise the excellent wind and solar resources to produce hydrogen for this use.

6.4. Chapter summary

In this chapter, a gas based dispatchable energy scenario was laid out to meet the needs of the transition to a renewable based generation system in South Africa. With the large range of potential values of the need for dispatchable energy that could be required, it is unlikely that the system which finally emerges would look much like the scenario outlined. However, this scenario lays out the elements that can be put together to develop the actual scenario that will meet the needs as they develop. Gas fuelled dispatchable power will provide a flexible, economical backup system for the renewable based system.

This gas based dispatchable energy system meets the desired sensitivities and robustness which would provide a bridge to eventual replacement of a generation system without any fossil fuel usage. No massive scale investment program would be required to implement this gas fuelled generation system, requiring rather a number of smaller incremental investments over time will be required with the ability to move immediately into some steps to improve the national grid.

7. Conclusions and Recommendations

As discussed in this report, South Africa has committed to reduce its greenhouse gas emissions. To this end, South Africa has commenced a transition to an electricity generation system based mainly on renewable sources with the intent to meet these commitments. The aim of this study was to address the appropriate role for natural gas in meeting the requirement for dispatchable energy to support this transition in the South African power system. The conclusions that have been reached in this study are summarised below.

7.1. Main conclusions

- **The study concluded that a renewable energy-based generation system using wind and solar resources <u>backed up by natural gas fuelled dispatchable</u> power is the most economical and adaptable means of meeting the electricity generation requirement in South Africa.**

The costs (LCOE) of wind and solar generation in South Africa are significantly lower than any conventional generation sources (section 5.2). What is also shown in section 5.2 is that even with the required additional installed capacity necessary plus the required dispatchable backup gas fuelled generation, this generation mix would be more economical for South Africa than any other generation scenario. The CSIR has conducted several, similar studies that have supported this conclusion for the costs seen in South Africa (section 3.6). According to their analysis, these cost advantages have been improving over time, as demonstrated in the updates to the IRP.

As indicated in the literature review from international experiences in sections 3.2 and 3.3, the cost of wind and solar generation continues to decrease, and the economic advantages seen for these generation sources utilising REIPPPP prices is conservative. With time and decreasing costs, the cost advantage of these energy sources is increasing.

International experience and South African studies have indicated that there will be times in a nominal year that generation from wind plus solar PV sources will be effectively zero (section 3.3). Dispatchable generation must be installed at sufficient quantities to completely replace the installed wind and solar PV generation. As discussed in section 4.5, the experience for worst case analysis indicates that this backup requirement can be for some days if not weeks.

The Dispatchable Energy Model tested this assumption on actual data received from Eskom and as indicated in section 4.5, the conclusion was confirmed that the amount of installed dispatchable power must be able to effectively replace all the renewable sources. The range of potential need, both installed capacity and energy generation

varies significantly depending on demand growth, decommissioning, and energy availability factor of the existing base generation fleet (section 4.4). The amount of energy that must be generated from these newly installed dispatchable sources is small with capacity factors likely to be below 5 %.

As discussed in sections 3.5 and 3.6, South African planning in the IRP process has always assumed that dispatchable generation required to balance the variability of renewable sources would be fuelled with natural gas. However, the source for this gas and the way that gas would meet this need has not been defined in any version of the IRP.

Section 5.2 reviewed the comparative cost for gas fuelled dispatchable generation and demonstrated that it was a lower cost alternative compared to other technologies, such as coal, nuclear or diesel for dispatchable generation. Due to low capital cost, short development times and modular sizing, natural gas generation also facilitates a flexible system that can respond to changes in the requirements on the system (section 4.4). Base load generation, particularly in coal and nuclear plants, provide less flexibility due to required economy of scale, long development schedules and high upfront capital costs (section 5.2).

With the decreasing cost of battery storage and other alternatives such as CSP, the use of energy storage will have an increasing role in a lowest cost scenario. As shown in section 4.6, the Dispatchable Energy Model indicated that, for South Africa, battery storage would be able to replace a significant amount of fuel usage for dispatchable generation. Due to the requirement for longer term generation needs, the model shows that the use of storage will not reduce the total amount of installed dispatchable generation but can significantly reduce the energy that will be required from these sources.

- **The annual volume of gas needed to balance a renewable based South African electrical power system is not large BUT it needs to be supplied at high rates over short periods <u>making storage of gas a critical factor</u>.**

The range of required dispatchable power is significant due to the potential ranges for demand, decommissioning and system energy availability factor. As shown in section 4.4, it is forecast from the Dispatchable Energy Model that, for 2030, dispatchable power required to balance the maximum demand would be in the range of 5 to 15 GW. However, the energy to be generated from this dispatchable power would likely have a capacity factor to balance the system of between 2 % and 6 %.

The expected power requirement for dispatchable generation should be approximately 10 GW and 2700 GWh, a capacity factor of 3 % (section 4.4). This translates into an expected annual fuel requirement of 27 PJ. This compares to the 200 PJ of gas currently imported into South Africa annually through the Rompco system

and approximately 4.7 PJ that would be imported in each LNG tanker. These relatively small volumes will make the large investments in gas infrastructure, such as LNG terminals, challenging.

While most of the new dispatchable power would likely be centred around the Highveld region, the majority of the current dispatchable generation is in the Western Cape (section 6.1). Using these dispatchable generation sources would reduce the demand for new generation in the Highveld but will require specific gas sources. This can be done on a short-term basis at low cost using LPG fuel. In the longer-term, LNG might provide this supply as well as gas from Brulpadda.

As noted in section 5.1, the profile of the demand will be a challenge for any of the gas supply options. The common challenge that must be overcome is the dispatchability requirement – the requirement to store gas and make it available at large rates when needed for short intervals. This challenge does not change if there is a large industrial market that develops. While new gas sources might be developed if there is development of a gas market in the country and associated importation, the challenge of storage must be resolved to make reliable gas supplied dispatchable power a reality in South Africa.

The use of natural gas fuelled generation internationally has been predicated on gas storage technologies. As reviewed in section 5.3, there are several gas storage technologies being used around the world. Most have high cost and specific geological constraints that make them less than ideal for South Africa.

As noted above, the expected annual requirement of gas for 2030 will be in the range of 27 PJ, or 13 % of the annual capacity of the gas currently brought into South Africa through the Rompco system. For 10 GW of generation, the hourly rate would be 100 000 GJ per hour, or over 400 % of the hourly capacity of this system. As demonstrated in section 5.3, with the expected demand profile developed from the Dispatchable Energy Model for 2030, approximately 140 MSM of gas storage must be available to balance supply and demand.

- **In South Africa, gas storage can be provided economically using abandoned deep mine shaft storage.**

As discussed in section 5.4, mine shafts present an opportunity specific to the High Veld area in South Africa to utilise an extensively available, unused resource. The Highveld area has numerous abandoned mines with deep mine shafts that could provide economical storage space. These mines are in the area where the generation infrastructure exists, much of the demand is centred and gas infrastructure is currently in place. As described in section 5.4, one mine shaft storage tank should be able to store up to 30 MSM of gas. For dispatchable power in coastal areas, other storage concepts, such as surface pipeline storage will be required.

A proposed concept for mine shaft storage has been developed by the authors as part of this study and Stellenbosch University has submitted South Africa patent application # 2019/03690 for this gas storage concept as per Appendix G.

7.2. Other conclusions

While the above points are the most significant conclusions that were developed in the study and had the most impact on the results, there were some other conclusions reached in the study that could have an impact in the implementation of the gas fuelled dispatchable energy backup systems.

- **The dispatchable gas fuelled energy requirement will not require large scale upfront development projects for gas importation infrastructure.**

As discussed in sections 5.1 and 6.1, several large-scale investment proposals have been made for importation of gas into South Africa. None of these importation concepts (i.e. pipelines and LNG terminals), have advanced past feasibility stages as the likely throughput volumes are not enough to make them economically attractive. It will be possible to develop gas dispatchable generation without large upfront investments (section 6.1). Gas importation facilities can be built on an incremental basis as needs develop.

- **There are short-term solutions that are available immediately to move towards gas fuelled dispatchable power that will also be appropriate for the long-term need.**

Both the conversion of Ankerlig to LPG fuel and the development of new dispatchable generation in the Highveld can commence implementation based on existing infrastructure and gas supplies (section 6.1). Incremental decisions can be made to develop these solutions and neither of these short-term actions are inconsistent with longer term solutions. While LPG fuel might eventually be replaced by natural gas fuel if LNG importation proceeds, the upfront costs are low enough to be justified on the short-term benefit.

- **The development of a gas market is not a critical factor for dispatchable gas power.**

As discussed in section 3.6, from the first IRP in 2010, it was noted that the gas needed for dispatchable generation would not be enough volume to support LNG importation on its own. As the potential industrial market for gas has not developed since this first observation, none of the discussed LNG terminals have progressed to development. Even considering the extremely large supply of gas available from

northern Mozambique, the lack of a gas market in South Africa has stopped the proposed gas pipeline developments (section 5.1). Due to the small volumes needed, there are solutions to meet the gas needs for dispatchable power even without the gas market development. Should the gas market develop, the use of gas for dispatchable generation will likely not change.

- **Due to the high level of uncertainty in the required volume for dispatchable power, adaptability and modularity are important to avoid overbuilding or underbuilding the required generation.**

As noted in section 4.4, the Dispatchable Energy Model shows that the range of potential dispatchable energy requirement is quite large and the plan to meet this need must remain flexible and responsive to allow it to meet the needs without overbuilding. As discussed in section 5.2, large scale base load generation plants have long development times leading to rigid plans. Fortunately and as shown in the review in section 5.2, along with being the lowest cost technology, the implementation time for wind and solar PV projects is the shortest of the major technologies. Gas fuelled dispatchable power offers a flexible, short development time for backing up the low cost renewable based generation scenario and can also be built as smaller projects in the range of 50 MW to 500 MW.

7.3. Recommendations

- **Improve the IRP update process to recognise the range of potential forecasts and prepare for the actual range of system requirements. The focus should shift from large (mega) projects towards smaller, modular projects that could be adapted over a shorter planning horizon without compromising the overall long-term plan.**

As discussed in this study, the likely range of need for dispatchable power ranges from 5 GW to 15 GW by 2030. This range is not reflected in the scenarios shown in the IRP. Not looking at the likely range of potential outcomes causes the expectations to be more limited than they should be. This also leads to development plans that may not reflect the actual need. The IRP process should be revised to reflect the actual ranges in the parameters of the forecast. The planning must be based on scenarios that could be adjusted over time to meet changes in the development of the system requirements, whether this is speeding up implementation or slowing down.

With the range of outcomes defined, the future generation system should be analysed to understand the "chokepoints" to meet any level of demand and these must be resolved and the flexible parts of the system, such as installation of dispatchable generation, should be in the plan to be implemented when and as needed. Wind, solar PV, and gas fuelled generation are ideal for this flexible development.

Since the first IRP was developed, the focus has been on major changes and massive projects, such as shale gas development, LNG importation and a gas pipeline from northern Mozambique that could have a significant impact on the economy of the country. Unfortunately, these projects do not have the required economic viability to move into development. This discussion of the major projects should change to a discussion of a number of smaller changes that could be made to solve problems as they arise, such as the change to LPG fuel at Ankerlig and the development of dispatchable gas generation in the Highveld using existing supplies.

One of the revelations from the IRP 2019 compared to the IRP 2018 was the short-term problems in the current electricity grid in South Africa. The current system is a stiff system without sufficient redundancy to cater for the problems that come with aging large generation plants. The solutions for these short-term problems should focus on advancing the timing of the recognised needed changes to the system. Solutions that will create other problems in the longer term, such as the commitment to mid-merit gas generation to develop enough volume to support importation projects should be avoided. These solutions do not fit the long-term plan.

- **South Africa needs to commence a discussion on the role of gas storage to meet the dispatchable generation needed to support the transition to a renewable energy-based generation system.**

The IRP process in South Africa is a top-down process that attempts to develop prescriptive solutions to forecast the elements needed for power generation in the future. Gas-fuelled dispatchable generation is considered to be a major element of these forecasts. As has been demonstrated in this report, the planning to provide this gas for the IRP scenarios has not been established. One of the major requirements to meet this need is the ability to dispatch the gas as needed, implying that it must be stored up and ready to be delivered in large quantities over a short period.

The process of meeting this requirement for gas storage must become part of the national conversation of gas-fuelled generation.

- **To be able to utilise mine shaft storage, a full feasibility level engineering analysis should be conducted.**

Mine shaft storage is currently only at a conceptual level of analysis. The next level in the progress towards implementation of the concept is to conduct a detailed feasibility level engineering analysis. In particular, the geophysical limits of the surrounding rock structure should be addressed.

7.4. Further study

- **For an economy changing project to be developed in the long-term, research should focus on the development of the Hydrogen Economy.**

Hydrogen has been recognised to have the potential for longer term energy storage to meet the worst case dispatchable power backup requirements. While it may not be an economic alternative to natural gas fuelled dispatchable power at this time, there is much interest around the world in the development of a hydrogen economy based on renewable generation sources. Research is being conducted that reduces the capital costs and operating costs associated with this energy storage concept. This is an alternative that could exploit the fabulous solar resources of the country and massively change the direction of the economy. A long-term plan to develop these resources should receive research attention.

Appendix A – Model Development

A.1. Renewable energy model creation

To have a representative model for forecasting energy demand and generation into the future, it is essential to have good data and an appropriate methodology of using that data. For solar energy, it is possible to utilise solar irradiation maps to predict the performance of an individual facility at a given location. For wind generation, the same can be done using wind maps. However, what is desired for system forecasting is not the performance of an individual facility, but rather the performance of the entire fleet of facilities on an aggregate basis.

Several studies have been performed on aggregating performance to forecast the fleet covering the entire country. However, the best prediction should be made from the performance of the actual fleet assuming it can be demonstrated to be representative. This applies for demand as well as generation.

For South Africa, we have performance data of the fleet of solar PV and wind generation from 2015 through 2019 (Eskom, 2019b). With this data, it should be possible to build a reasonable aggregate data set representing electricity demand as well as generation from wind and solar sources. The data is available on an hourly basis, which may not be accurate enough to analyse some issues such as grid stability but should be usable in defining dispatchable power needs.

A.2. Choosing a modelling tool

Around the world, there are a large number of electricity generation system models in use. One study showed over 75 energy system models that are used in various locations and for various purposes (Ringkjøb, *et al,* 2018). A review from Stellenbosch University showed 22 models freely available in South Africa (Mabaso, *et al.*, 2016). In South Africa most of the analysis related to the IRP has been done utilising the Plexos model. This is the model used by the IRP team for preparing their scenarios and by CSIR in their reviews (Wright, *et al.*, 2018). The challenge with Plexos is that it is a 'black box' model that attempts to analyse everything related to the generation system. This type of model is divided into three sections, an input section, a calculation "black box", and an output section. The user can specify a large list of parameters in the input section and then the model will make a number of complex calculations to arrive at an optimised scenario based on this input data. This makes it difficult to separate the effect of one parameter to isolate its effects. In an analysis of 13 utility companies forecasting models in the USA, Lawrence Berkeley National Laboratory showed that all of them overestimated the growth in their systems and found that the models used emphasised accuracy of results compared to uncertainty in the premises (Carvallo, *et al.*, 2018).

As this analysis is only intended to study the need for dispatchable energy within the premises of the IRP, a simple transparent calculation tool is preferred over an all-encompassing model. The effect of uncertainties in this calculation is covered in Appendix B.

At Stellenbosch University in previous work, an unpublished model defined as the Power System Simulator model (PSS) was developed as a predictive tool for individual solar projects and how they fit into the grid system. This model was not designed for aggregated supplies and to use it for the analysis in this study, aggregated supply for wind and solar PV need to be input into the model. This was not the purpose that the PSS model was designed for.

For this analysis, a simple spreadsheet model was developed projecting actual South Africa wind and solar generation plus actual demand as supplied by Eskom. As will be discussed in the following sections, this data was tested to ensure that it represented a realistic estimate of what could be expected from a fleet of wind and solar generation sources. Minimal manipulation of the data was used to keep its validity. The actual demand profile and renewable generation profiles from 2017 were used by proportionally increasing them to the year in question. The demand profile was increased upward by the growth factor, which is one of the variable input parameters. The wind and solar PV curves were increased to the indicated installed capacities, which are also variable input parameters, with capacity factors from current generation.

The results from this Dispatchable Energy Model were compared to those that were forecast in the IRP and from that which would be produced from the PSS model. The results for calculated required dispatchable power were consistent with the results that were presented in the IRP as well as what was predicted from the PSS model with the same premises. The model results were also compared for consistency with the aggregation study results from CSIR for wind and solar resources, which will be covered in detail in the next sections.

This is a simple analysis tool for determining the requirement for dispatchable energy, that is the profile and volume (power and energy) requirements for dispatchable generation for the system to be in balance. There are a number of considerations that cannot be addressed by this analysis tool, as listed below:

- Technology selection - this model does nothing to compare technologies to meet the dispatchable energy requirement. The results of the simulation can be used as input into a technology selection analysis.
- Costing - this model does not have any cost information included. Again, the results of this model can be used as input for this calculation.

- Treatment of excess generation – while the model shows the profile and volumes (power and energy) of excess generation from the combination of renewable sources and the base load system, it does not address how this excess should be handled (merit order, curtailment, partial loading, *etc.*).
- Treatment of dispatchable renewable generation – the model does not address how dispatchable generation, such as CSP, can be utilised. Generation and storage are treated separately within the analysis.
- Major changes to demand profile – while the demand profiles for the data period (2015 through 2019) showed quite consistent profiles as discussed in the following section, the model does not make provision for potential long term changes to the demand profile.

There are other areas this model does not address; however, the purpose of model is to show the requirement for dispatchable energy and it meets this need.

A.3. Demand

For demand, the test needed is to demonstrate that the information chosen is representative of a "nominal" year. There is some concern raised that some unique events, such as load shedding which has been seen in recent times, could have enough effect on the data set to render the data unusable for long term analysis. If the data set is consistent from year to year, it is evidence that these unique events do not have a significant impact on the overall annual demand.

Table 14 shows the recorded data as received from Eskom. This covers the period from the beginning of 2105 through 2019. Table 14 also shows the relationship of the annual demand values compared to 2015. It can be seen from these tables that there is statistically very good correlation between the annual data. There has not been growth in the demand profile over the last four years.

Table 14 - Eskom Generation 2015-2018

Eskom Generation 2015 – 2019					
	2015	**2016**	**2017**	**2018**	**2019**
Maximum – MW	34 068	34 742	35 553	35 179	34 122
Minimum – MW	19 683	19 400	18 963	19 008	16 351
Average – MW	27 073	27 067	26 788	26 763	26 376
Total - GWh	237 128	237 075	234 640	234 640	231 052
Percent of 2015	2015	2016	2017	2018	2019
Maximum	100 %	102 %	104 %	103 %	100 %
Minimum	100 %	99 %	96 %	97 %	83 %
Average	100 %	100 %	99 %	99 %	97 %
Total	100 %	100 %	99 %	99 %	97 %

A.4. Renewable generation

As was considered above for demand review, the first step in determining the validity of the data is to show consistency from year to year over the period where data is available. For wind and solar generation, the period of 2015 through 2018 was a period of significant growth in installed capacity. Most of that addition occurred in 2015 and 2016. By the beginning of 2016, 1070 MW of wind power was installed. By 2017, this had grown to 1460 MW. By the beginning of 2018, this increased to 2078 MW. There was no growth in 2018. Solar PV had 965 MW of installed capacity by the beginning of 2016 and this increased to 1474 MW by the beginning of 2017, with no increase in 2017. As for wind, there was no increase in installed capacity in 2018. The performance of these generation sources is shown in Table 15.

Table 15 - Renewable Generation Factors - 2015-2018 data ((Eskom, 2019b)

South Africa Wind and Solar Generation 2015 - 2019					
Wind	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	560	1 070	1 474	2 078	2 078
Maximum	898	1 230	1 780	1 902	1 872
Minimum	1	3	11	20	16
Average	284	425	580	738	756
Total - GWh	2 489	3 719	5 081	6 467	6 624
Solar PV	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	960	965	1 474	1 474	1 474
Maximum	931	1 351	1 432	1 392	1 376
Average	249	299	380	375	380
Total - GWh	2 184	2 619	3 324	3 282	3 325
CSP	**2015**	**2016**	**2017**	**2018**	**2019**
Jan 1 Capacity – MW>	0	0	200	400	400
Maximum	0	201	400	400	502
Average	0	62	118	118	178
Total - GWh	0	492	687	1 031	1 557
Wind Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	93.2 %	92.2 %	91.4 %	91.5 %	90.0 %
Minimum	0.1 %	0.2 %	0.7 %	0.9 %	0.8 %
Average	32.2 %	34.4 %	35.8 %	35.5 %	36.4 %
Solar PV Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	96.5 %	94.1 %	97.2 %	94.4 %	93.3 %
Average	25.9 %	26.0 %	25.7 %	25.4 %	25.7 %
CSP Capacity Factor	**2015**	**2016**	**2017**	**2018**	**2019**
Maximum	-	100.4 %	100.7 %	100.5 %	100.4 %
Average	-	28.1 %	30.0 %	37.9 %	36.5 %

CSP was also recorded through the period. The installed capacity of CSP went from zero at the end of 2015 up to 300 MW by the end of 2017, with no addition in 2018. Growth in CSP is not considered in the IRP 2019 so this data was not used in the model.

With the growth in generation from all sources over the review period, it is essential to compare the generation on a normalised basis, which should eliminate the effect of growth. It can be seen from Table 15 that there is good correlation in the performance of each of the generation sources year to year.

Aggregate value

For renewable generation, in addition to showing that data is consistent, it is also essential to show that the data represents a valid picture of the aggregate performance of the hypothetical fleet. As a valid representation of the hypothetical fleet, this data set can be factored upwards directly upwards to model the performance of a larger fleet.

The first evidence of the aggregate value is showing the distribution of the generation sources on the map. This is visual indication of the spread of the generation sources. A map of the REIPPPP generation sources is shown in Figure 49. Most solar installations are in the Northern Cape province and it can be expected that most of the growth in this generation will occur within this area as it currently is the focus area. In terms of wind, most of the current generation is along the south western coast, with some extension into the Karoo. From an analysis by the CSIR, it can be expected that the growth in wind generation will rather shift to the Karoo. However, the coastal wind areas will still be a major growth area. From this visual information, it appears that there is reasonable areal extent to the current facilities to indicate that the generation is reasonably representative.

During the 2015 to 2016 period, the CSIR prepared a report analysing the expectation of an aggregate fleet of generation sources of wind and solar PV (Knorr, et al., 2015)., In the report, for wind generation, they studied various distributions of generation sources from single source to uniform distribution. The generation curves developed are based on wind speed models and wind turbine performance curves. They plotted the annual hours of generation from each of these sources versus installed capacity. The curves developed in this report are shown in Figure 50. It can be seen from these curves that there is a significant difference between a single source generation to the aggregate, with some variation of the aggregate based on different assumed distributions of the generation sources.

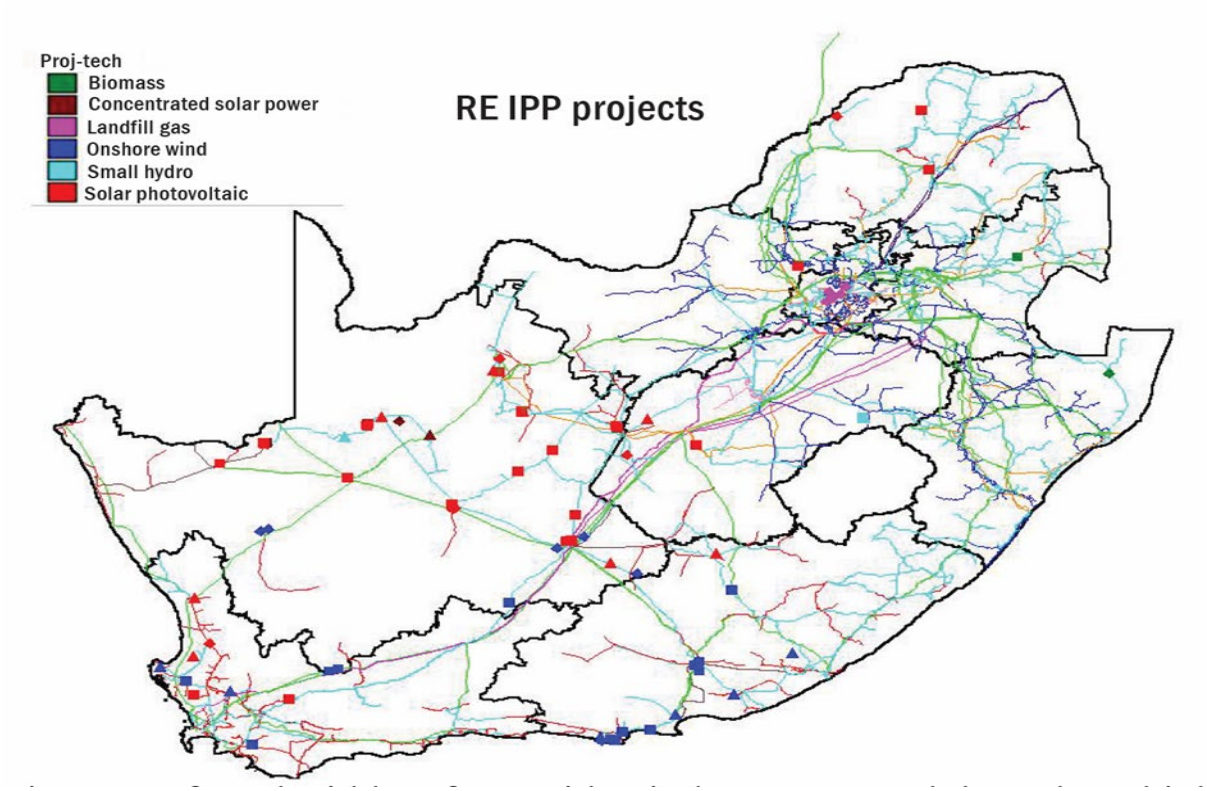


Figure 49 - Renewable Generation Sites in South Africa

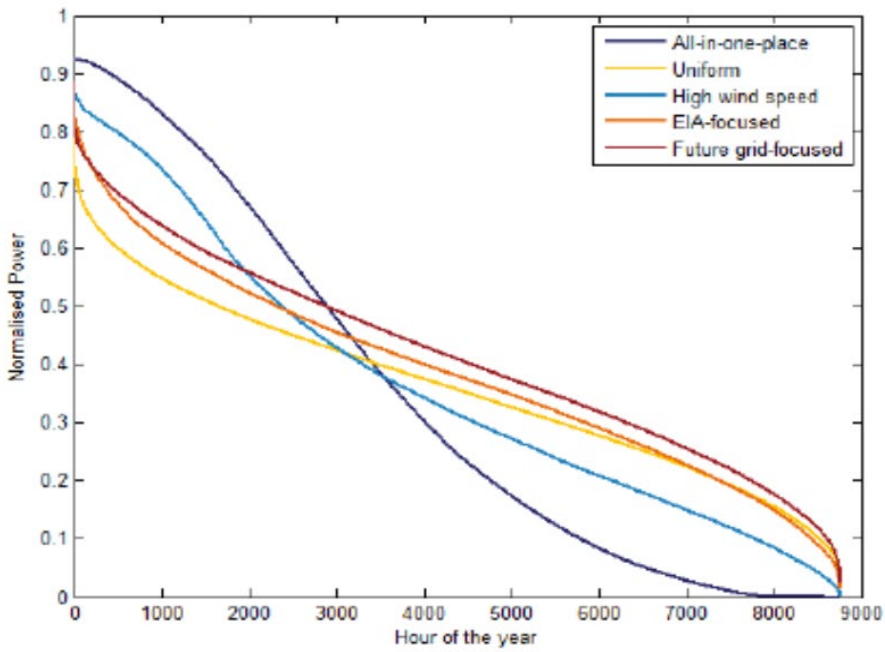


Figure 42: Aggregated wind power duration lines of different scenarios with 250 TWh of electricity generated from wind power, years: 2010-2012

Figure 50 - CSIR Wind Aggregation Curves (Knorr *et al.*, 2015)

The actual performance data from the South African wind fleet can be displayed on the same basis to compare the model to actual data. This is shown in Figure 51, which shows 2016 through 2018 data compared to the single source, the uniform distribution, and the high-speed generation sources. The actual data is internally quite consistent and reasonably close to the uniform generation curve from the model. The consistency of these curves validates the model forecasting as well as strongly indicates that the actual data realistically represents an aggregate value.

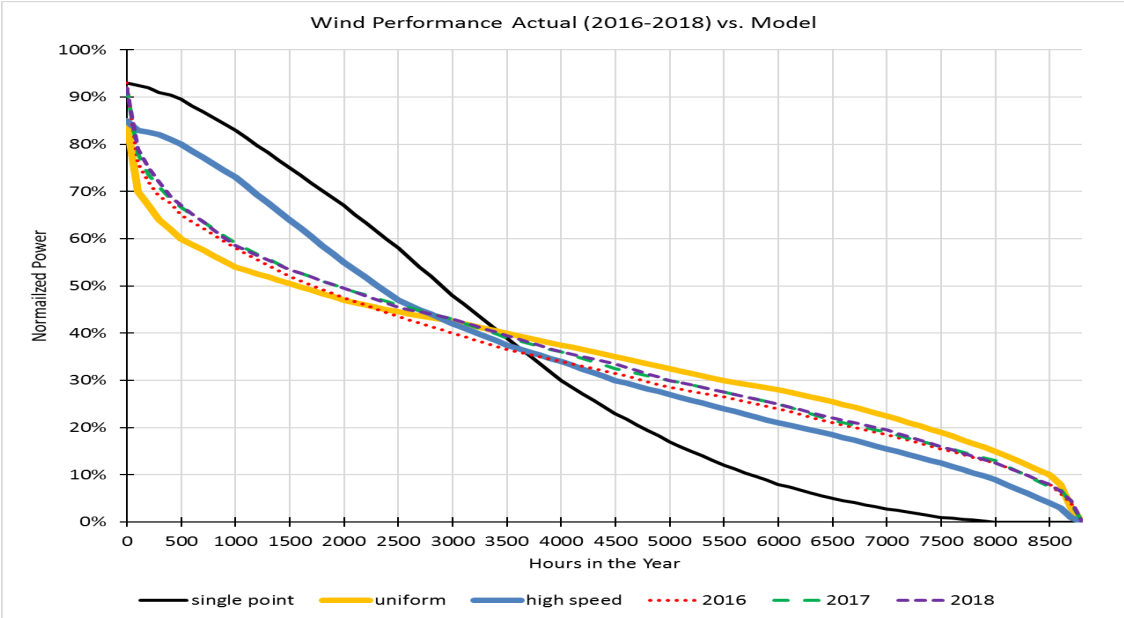


Figure 51 - Actual Wind Generation Curves 2016-2018

For solar PV, studies have been conducted to demonstrate the spread of solar generation sources needed to develop an aggregate generation. The major concern in aggregation of solar generation is enough spread to avoid weather effects from cloud coverage. This is a major concern in many countries, such as Germany. However, a study of South Africa indicated that this was not nearly the same concern that it is in other areas (Suri, *et al.*, 2014). While there is preference for generation in the Northern Cape province area due to high insolation and lack of cloud cover, there has been a reasonable distribution of solar generation to date to represent good spatial coverage.

From the study on solar PV aggregation, it was found that solar PV generation facilities distributed over a 500 km square area have a reasonable aggregation compared to a single source. In Figure 52, the performance of the solar fleet for 2016 to 2018 is compared to the theoretical performance of a solar generation facility in the Upington area. There is good correlation between these two curves. From this correlation, there is evidence that the actual performance curves are a reasonable representative value for the expected aggregate fleet and can be scaled up accordingly to represent growth in the fleet.

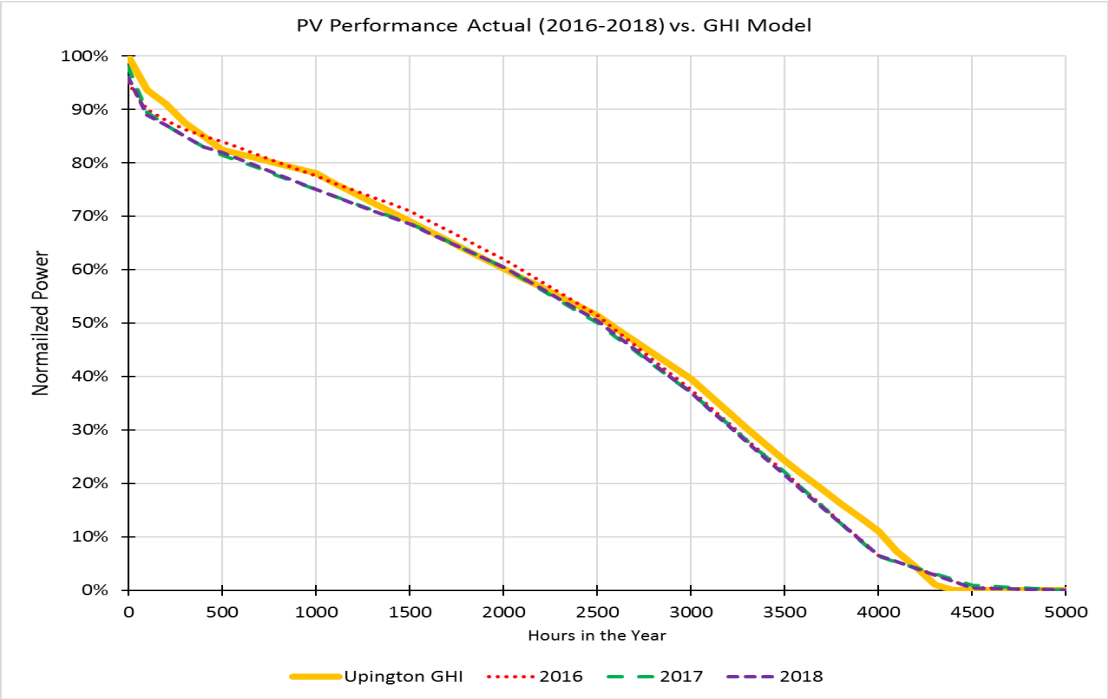


Figure 52 - Actual Solar PV Performance vs GHI Model 2016 - 2018

A.4. Comparison to IRP models

While the details behind the forecasts generated in the IRP are not published, the results are shown in the IRP, giving a defined generation for the installed capacity of each of the major technologies (SA DoE, 2018). In Table 16, the 2018 IRP median forecast values for 2030 are shown for installed capacity and the related generation. These are compared to the generation that would be predicted using the data set described in this analysis. There is a reasonable match, but the IRP predicts a 10 % better performance for installed wind than this data set gives and 16 % better output for solar PV. The capacity factors from the Dispatchable Energy Model are consistent with the results from the CSIR aggregation study, implying that the IRP figures are less likely to be correct than those from this model. Adjusting the amount of installed wind and solar PV into the Dispatchable Energy Model, as shown in the last columns, results in a very close match to the IRP forecasts. In this table, the figures in black are defined numbers and the red figures are those derived from modelling.

Repeating this same comparison for 2040 and 2050 shows the same results, as shown in Tables 17 and 18. From this comparison, it would appear that the IRP process for estimating performance of installed wind and solar PV is overstated by 10 % and 16 % respectively compared to the actual extrapolation of performance from the current installed capacity.

Table 16 - IRP to Model Comparison 2030

2030 Generation Comparison – IRP and Dispatchable Energy Model						
IRP 2019 – IRP3 (Median Growth)			Dispatchable Energy Model		Adjusted Model for Renewable Generation	
	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)
Base (1)	42	245	42	250	42	245
Wind	13	45	13	41	15	45
Solar PV	9	23	9	21	11	23
Dispatch	13	9	15	10	15	9
Total	78	322	80	322	83	322

Note 1 – Base = Coal + Nuclear +Hydro + Other

The implied IRP model capacity factors are 40 % for wind and 29 % for solar PV. This analysis gives a capacity factor for wind of 36 % and for solar PV 27 % based on actual performance in 2017. The CSIR aggregation study predicted an aggregate capacity factor for wind of 36 % and for solar PV of 22 %.

Table 17 - IRP to Model Comparison 2040

2040 Generation Comparison– IRP and Dispatchable Energy Model						
IRP 2019 – IRP3 (Median Growth)			Dispatchable Energy Model		Adjusted Model for Renewable Generation	
	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)
Base (1)	35	194	35	207	35	192
Wind	26	90	26	84	29	90
Solar PV	18	47	18	40	21	47
Dispatch	26	29	25	29	27	31
Total	105	360	104	360	112	360

Note 1 – Base = Coal + Nuclear +Hydro + Other

Table 18 - IRP to Model Comparison 2050

2050 Generation Comparison – IRP and Dispatchable Energy Model						
IRP 2019 – IRP3 (Median Growth)			Dispatchable Energy Model		Adjusted Model for Renewable Generation	
	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)	Capacity (GW)	Generation (TWh)
Base (1)	30	183	30	183	30	174
Wind	32	111	32	100	36	111
Solar PV	25	63	25	56	29	63
Dispatch	39	40	34	58	34	49
Total	126	397	121	397	83	397

Note 1 – Base = Coal + Nuclear +Hydro + Other

A.5. Conclusion

The Dispatchable Energy Model is a simple tool to determine the amount of dispatchable power that must be installed to balance the system and the expected energy to be derived from this installed power. It is transparent and allows a review of the parameters that can affect the calculations. It utilises actual performance data from the years 2015 through 2019 to forecast into future years. By making minimal manipulation to this data, forecasts can be based on observed performance. As will be reviewed in Appendix B, this model also allows the analysis of the uncertainty in the data and its effects on the requirement for dispatchable energy.

Appendix B – Range of Forecasts

B.1. Background

The dispatchable power that will be required needs to be forecasted from modelling. There are several factors that will have a major impact on the dispatchable power requirement, affecting the amount that must be installed as well as on the number of hours that this capacity is utilised each year. The effect of each of these parameters must be understood to make a reasonable forecast of the requirement for dispatchable power.

This analysis reviews each of these parameters to measure their impact and forecasts the range and expected value of dispatchable power that is likely to be needed in the reference years of 2030, 2040 and 2050, with emphasis on 2030. These forecasts are compared to those indicated in the 2018 IRP update to show how the IRP scenarios fit in the range of potential forecasts.

The range of dispatchable power requirements that the model forecasts supports the use of a reactive, adaptive plan to meet this need rather than a fixed long-term plan. This concept favours a plan based on renewable generation backed up with easy to implement dispatchable power.

B.2. IRP

The South African government has commissioned the development of an integrated resource plan (IRP) to forecast the electricity generation that will be required in the future. The first IRP was developed in 2010 and covered the period up to 2030 (SA DoE, 2011). Since that original IRP, there have been several updates developed. The latest update was prepared in 2018, with some revisions made in 2019 after the recent problems that Eskom had with their facilities (SA DoE, 2019c). In September 2019, the updated IRP 2019 was formally adapted.

The updated plans covered the period up to 2050, however, they have indicated that there is enough uncertainty in the later periods to refer to the forecast for these years as indicative. The process used for this forecasting is the creation of scenarios given development cases. Sensitivity is only considered by comparison of the various scenarios.

IRP renewable plan

One of the main objectives stated in the IRPs is to promote growth in electricity supply from renewable sources, particularly from wind and solar PV. In the plan, this

growth is supported by the development of dispatchable generation to handle the intermittency and to replace the aging base generation facilities.

Some wind, solar PV and CSP has already been developed and is supplying power to the grid. From Eskom statistics, this varied from meeting 0.1 % of the required power to up to 11 % in 2018 (Eskom, 2019b). The IRP anticipates growth in both wind and PV generation. Using the 2017 base information, this would imply up to 51 % of supply from these sources by 2030, building up to over 160 % of supply by 2050 as shown in Table 19. Based on the performance of the renewable resources in 2017 and the planned installed wind and PV capacities, the minimum supply stays below 2 % of the demand throughout the period.

Table 19 - IRP 2019 Renewable Plan

IRP 2019 Renewable Generation Plan				
	2018	2030	2040	2050
Wind – GW	2	13	27	50
Solar PV – GW	1.5	7	18	35
Dispatchable - GW	5	10	25	40
Minimum - 1	0.1 %	0.7 %	1.2 %	1.9 %
Maximum - 2	11 %	51 %	101 %	161 %

Note 1 – wind and solar percentage of overall generation for the minimum hour
Note 2 – wind and solar percentage of overall generation for the maximum hour

The IRP makes it clear that dispatchable power will be needed, however, there is an outstanding question of how much will be required. This analysis reviews the premises within the IRP to determine if the predictions for the dispatchable needs are reasonable and what is the likely range around the scenario-based numbers presented in the various IRP cases. This analysis was conducted by considering the major factors that went into the forecast and analysing how they impact the outcomes. In addition to the factors related to demand and supply of electricity generation, this analysis considers the percentage of power coming from wind and solar PV to understand how the amount of power that comes from these resources affects the dispatchable power requirement.

As was stated in Appendix A, this is only a technical feasibility analysis, implying that it is an analysis of what dispatchable power will be needed, not a technology selection or economic analysis.

B.3. Forecast model

As discussed in the previous appendices, the sensitivity analysis was conducted on a Dispatchable Energy Model for the hourly generation of electricity over a one-year period. The base information that went into the model was from Eskom 2017 performance data, with hourly demand information as well as supply from renewable sources. This information was compared to 2016 and 2019 data to ensure consistency (Eskom, 2019b). Both the demand and the renewable supply data showed consistency between the years reviewed.

For the year of analysis, the 2017 hourly demand values were increased by the growth factor. That is to say for the year 2030, the hourly data from 2017 was multiplied by a factor of the growth rate applied to the number of years between 2017 and 2030. For example, a 1.5 % annual demand growth would imply that each hourly reading from the Eskom 2017 data needs to be multiplied by 1.2 (=1.015^12). Wind and solar PV were, as per 2017 hourly capacity factors, multiplied by the stated installed capacity in the year of study. For 2030, the IRP shows installed capacity for wind at 13 GW and solar PV at 7 GW.

Base generation capacity, (provided by coal, nuclear and hydro generation plus imbedded generation and other minor supply sources), was taken from the Eskom plan presented in the IRP. In this analysis, the base generation was treated as a block and no attempt was model the cycling these facilities. As the analysis aims to determine the dispatchable power requirement, the difference between curtailed base generation and lower efficiency base generation is not relevant. The IRP showed 43 GW of installed base capacity in 2030. This results in a significant amount of curtailed or underutilised generation. Up to 10 GW of the installed base generation would need to be cycled twice per day with several hours use each day.

For CSP and pumped hydro storage, the IRP does not assume any growth. For this analysis, growth in these areas was treated as part of the required dispatchable generation.

The factors affecting dispatchable requirement that were considered for this analysis are:

- Demand growth - how much will the demand increase to the year in question.
- Energy availability factor (EAF) – what is the availability of the base load, that is the percentage of time that the equipment of the existing base fleet is usable to meet generation needs.
- Decommissioning – what would the effect be for changing the schedule for decommissioning of the base fleet.
- Wind – how does increased or decreased wind affect the need for dispatchable power.

- Solar PV – how does increased or decreased solar PV affect the need for dispatchable power.

B.4. Sensitivities

2030

In Figure 53, the two graphs show the effect of each of the parameters on the required capacity of dispatchable generation and the energy generation that will be used from these sources. The two graphs show that the major effect on capacity is from the sensitivity to growth. For 2030, EAF and decommissioning also have significant impacts. Changes in Wind and solar PV have minimal impact on the need for dispatchable generation.

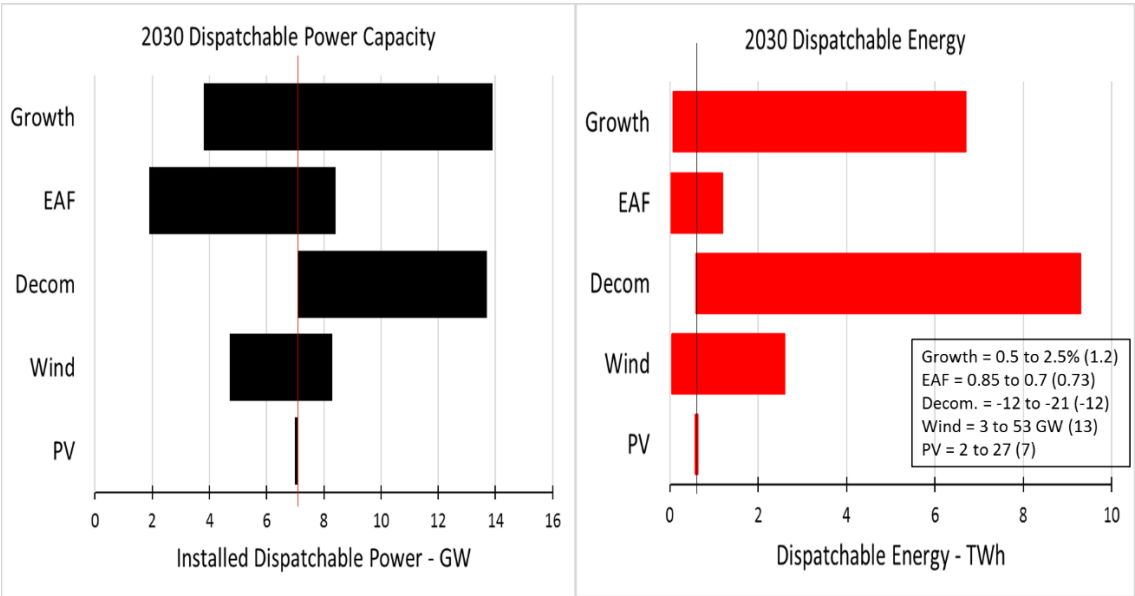


Figure 53 - Sensitivity Factors 2030

2040

As seen in Figure 54, growth is clearly the dominate effect by 2040. EAF still has some impact, while decommissioning is decreasing in impact as the base generation is decreasing. Wind and solar PV still have minor impact on the dispatchable requirement.

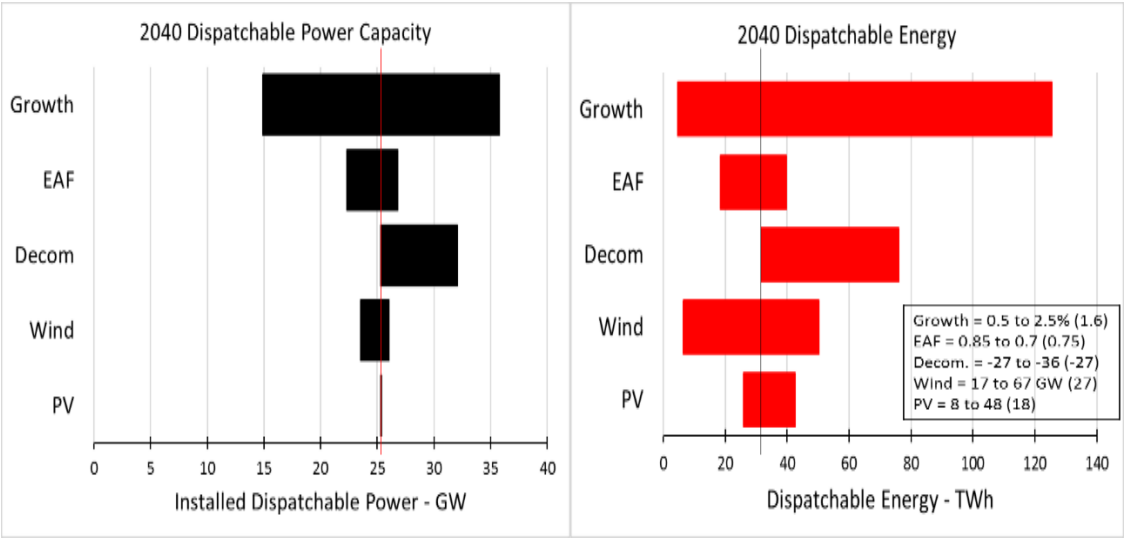


Figure 54 - Sensitivity Factors 2040

2050

As seen in Figure 55, by 2050, the sensitivity is totally dominated by growth. EAF and decommissioning have become insignificant as the base capacity has been greatly reduced. Wind and solar PV still have minimal effect.

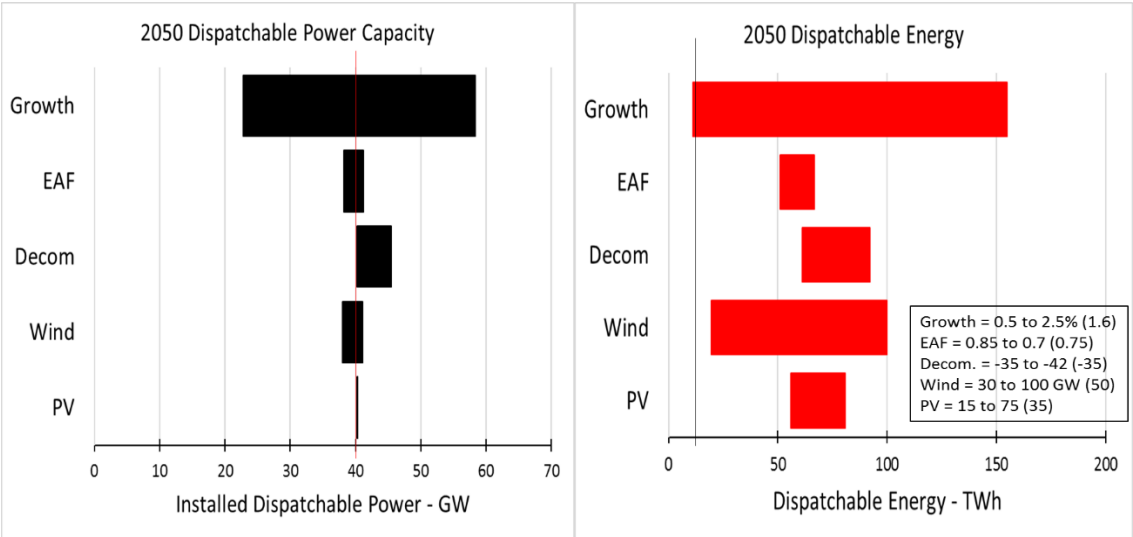


Figure 55 - Sensitivity Factors 2050

2030 Base forecast from IRP

In looking at each of the sensitivity parameters, the range of the potential dispatchable generation is quite large and grows significantly over the study period. Due to these large and growing uncertainty ranges the analysis will concentrate on the effects in 2030 as indicated from the IRP. As stated in the IRP, the forecasts up to 2030 should be the most 'firm' and those for later years are more 'indicative'.

May 2030

As discussed previously, the analysis is based on an hourly Dispatchable Energy Model to develop a base forecast for 2030. Based on the 2017 Eskom data, the peak month for dispatchable energy requirement is in May, and specifically the peak demand is defined by the requirement for May 16. This is not to say that this is a prediction of what will happen on 16 May 2030, but this is the nominal date that defines the peak need in the model. Therefore, this date is chosen as representative of the peak requirement that could be any date in the year.

As can be seen from Figure 56, the graph for the month of May 2030, the base generation has a twice daily exceedance, even in the peak month. This is represented by the black curves below the base line of the graph. On many days, the exceedance is over 10 GW out of the base of about 40 GW. This generation is either operated at non-optimal efficiency or a significant portion of the base fleet must be cycled twice per day which is a major challenge for coal or nuclear plants and adds significantly to their cost of operation.

On the peak date, almost 10 GW of dispatchable power is needed, but only for a few hours. Thus, this peak power must be available though it is rarely used.

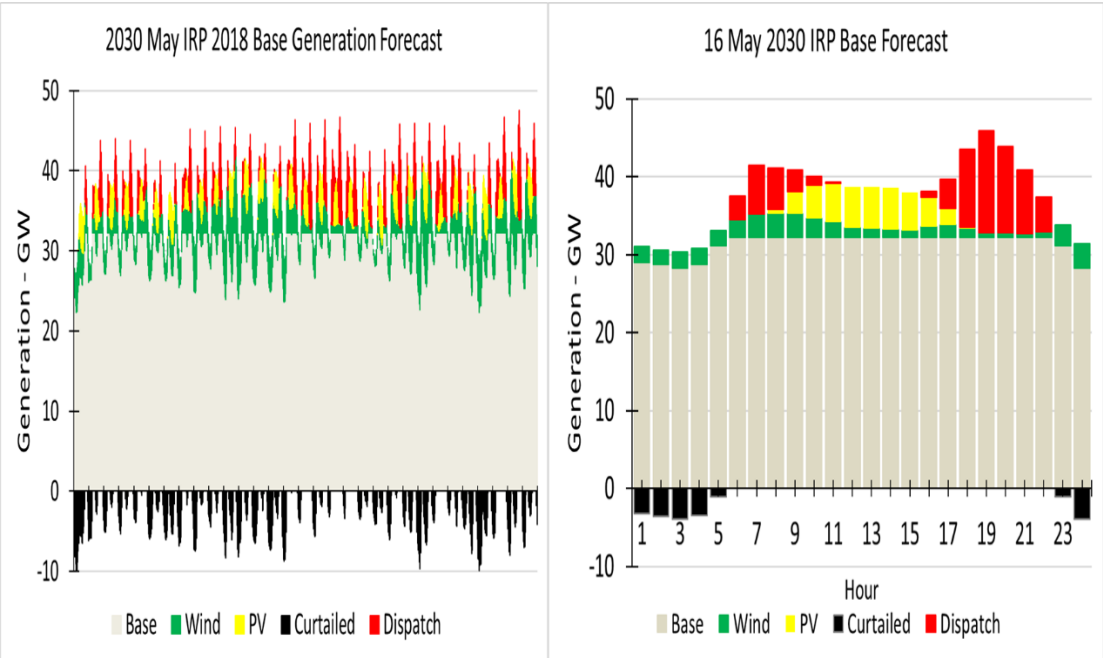


Figure 56 - IRP Base Case 2030

B.5. Growth in demand

IRP demand growth

Since the first iteration of the IRP in 2010, the developers have struggled to determine the proper growth forecast (SA DoE, 2019c). These growth forecasts are shown in Figure 57. The brown curve shows the prediction used in the 2010 IRP. The red curve shows the actual generation history from Eskom. The grey curve shows what was used for the 2018 update. For the 2019 update, the same curves as 2018 were used, just shifted by two years – with the starting year being 2018 rather than 2016. Due to the significance of this factor and the obvious challenges that it presents to forecasting (as shown from the IRPs), it is important to review the parameters that are used to develop this factor in the generation forecasts.

The growth of the demand from 1991 to 2018 was analysed based on an annual lagging 10-year period. I.e., the number for 2018 covers the period from 2008 to 2018 annualised, *et cetera*. This ten-year averaging eliminates short-term effects. On the ten-year average basis, there has still been growth in the recent years, but at a lower rate than previously.

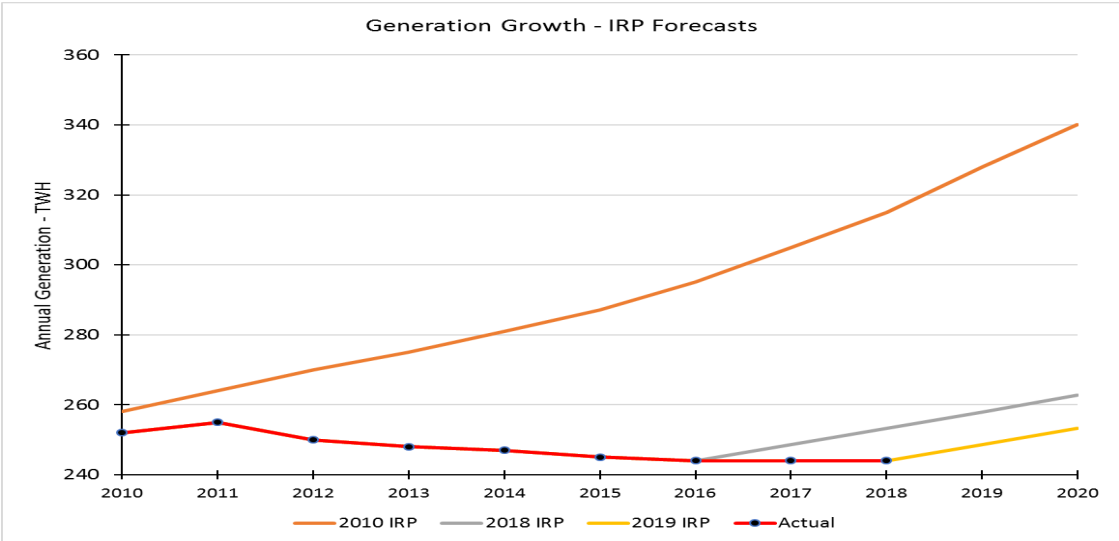


Figure 57 - Predictions of Rate of Demand Growth

GDP growth

There have been many theories discussed about the declining growth in the demand curve. The most common topic is the relation between demand growth and GDP growth. Two graphs are shown in Figure 58, The change in demand and the change in GDP over time are shown in the first graph (World Bank / data, 2019). The second graph displays the ratio of these two parameters. As can be seen from the ratio shown in this second graph, there is a reasonable correlation between GDP growth and

electricity demand growth, but this ratio has been decreasing over time. It can be assumed going forward that there will be a relationship between GDP growth and electricity demand growth, although it may not be as strong a ratio as in the past. This same observation was made by the US EIA in forecasting growth for power demand in the United States of America. They stated in their 2017 forecast "While growth in the economy and electricity demand remain linked, historically the linkage has continued to shift toward much slower electricity demand growth relative to economic growth" (US EIA, 2017a, pg. 76).

Growth forecast

From this analysis, it is not possible to determine a specific forecast for demand growth, however, it is reasonable to predict a range based on likely GDP growth. Since 1991, GDP growth has been between 1 and just above 4 %. Assuming a 0.5 ratio of power growth to GDP growth, this would imply an expected growth range from 0.5 to 2.2 %, with an expected growth in the range of 1.2 %.

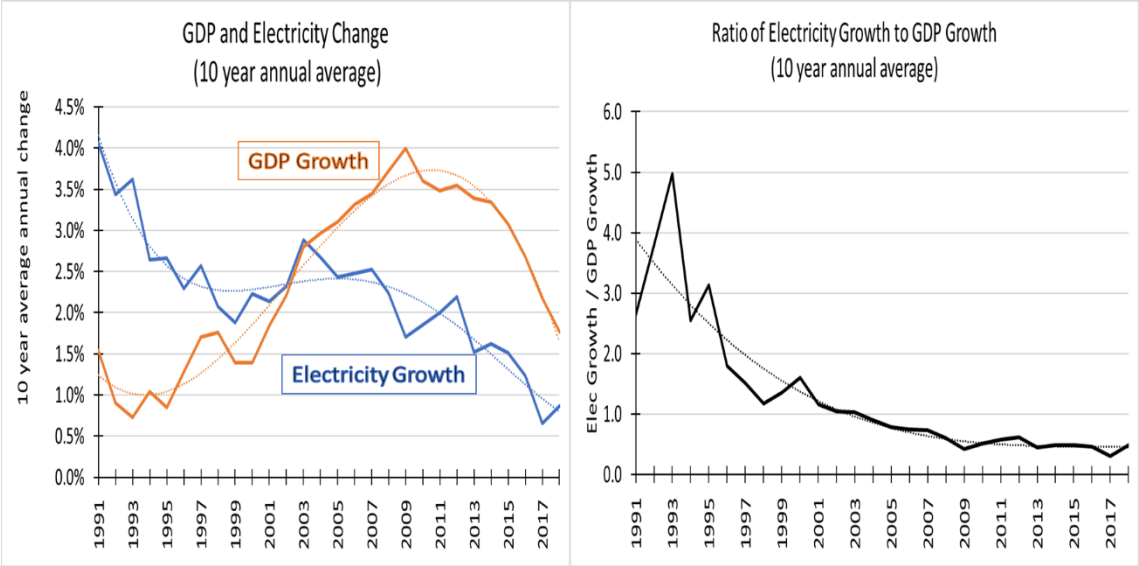


Figure 58 - History of Demand Growth and GPD Growth

International comparisons

Much of the talk in South Africa about the cause of the decrease in demand seen over the last decade has related to local economic problems. However, the evidence is contrary to local effects, indicating that this is an international experience and likely due to international effects. Eskom noted in their 2017 Integrated Report "Demand in global developed economies has declined by 1.4 % a year since 2010. Because of regulatory pressure and investment in efficiency programmes and increase in self-generation, demand for electricity in the European Union (EU) has declined by 1.5 % a year since 2010. Similarly, in the United States of America, demand has been stagnant

since 2010. In South Africa, power consumption has declined by 0.5 % a year on average since 2006. The decline was highest in large power users, declining by approximately 1.7 % a year over the last five to 10 years" (ESKOM, 2017, pg. 12).

One of the local issues that has been suggested as a major factor in determining the growth in demand has been the large increases in tariffs charged for power by Eskom. Figure 59 shows the relation between demand growth and tariff increases, As can be seen in this graph, in 2009, when tariffs increased by over 30 %, there was a significant drop in the growth curve. Nonetheless, the growth returned to its previous level in the following years, even with additional major increases in tariffs. 2009 was also the year of an international recession, and thus, it is not clear that the decrease in GDP growth was not due to international events and the tariff increase occurred at an unfortunate time. Figure 60 shows the change in demand per capita in the OECD countries as compared to South Africa (World Bank, 2014). A close coherence between these curves can be seen for the period.

The reduction in demand growth has been noticed by planning agency around the world and studies are being conducted to understand the factors behind the reduced demand growth. The US EIA noted in their 2019 forecast "Energy market projections are subject to much uncertainty because many of the events that shape energy markets as well as future developments in technologies, demographics, and resources cannot be foreseen with certainty" (US EIA, 2019a, pg. 4).

It has also been argued that the comparison for South Africa should not be OECD countries, but some other grouping, such as the BRICS countries. Figure 61 shows the change between per capita electric usage in a representative grouping of OECD counties, South Africa and the other BRIC countries (World Bank, 2014). As can be seen in the graph, China, India, and Brazil had quite low per capita electricity consumption in the year 2000 and grew from that low base. The increased power usage in Russia during this period had more to do with internal problems than growth. South Africa had a per capita consumption similar to OECD countries rather than BRIC countries. The decreased per capita demand in South Africa was repeated in most of the OECD countries shown.

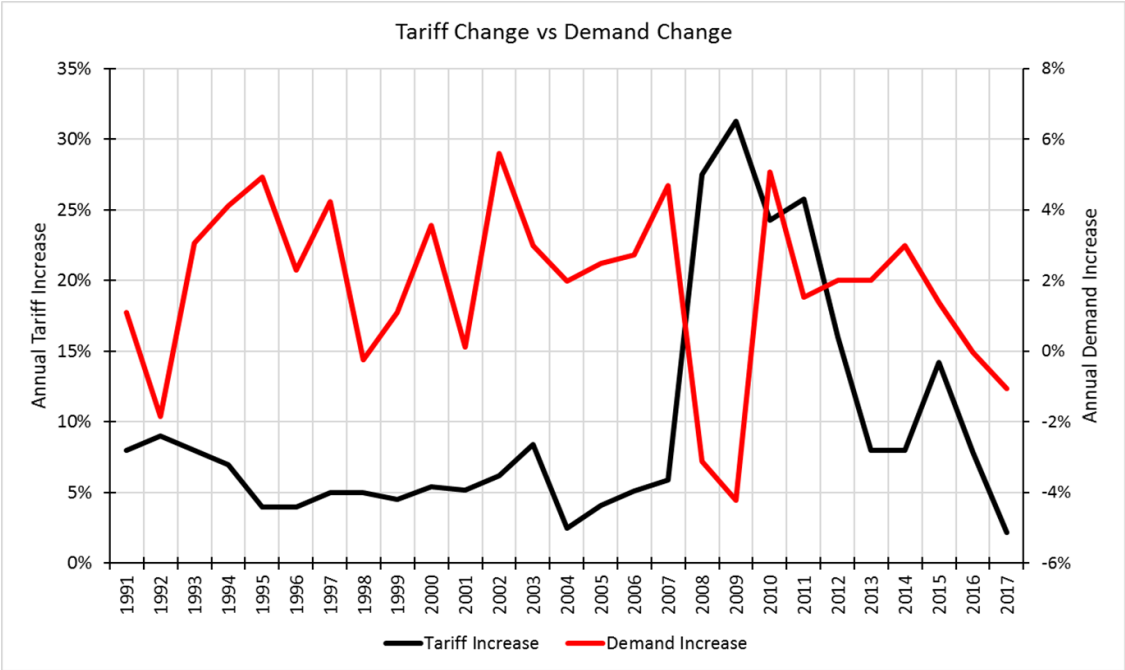


Figure 59 - Demand Growth Compared to Tariff Growth

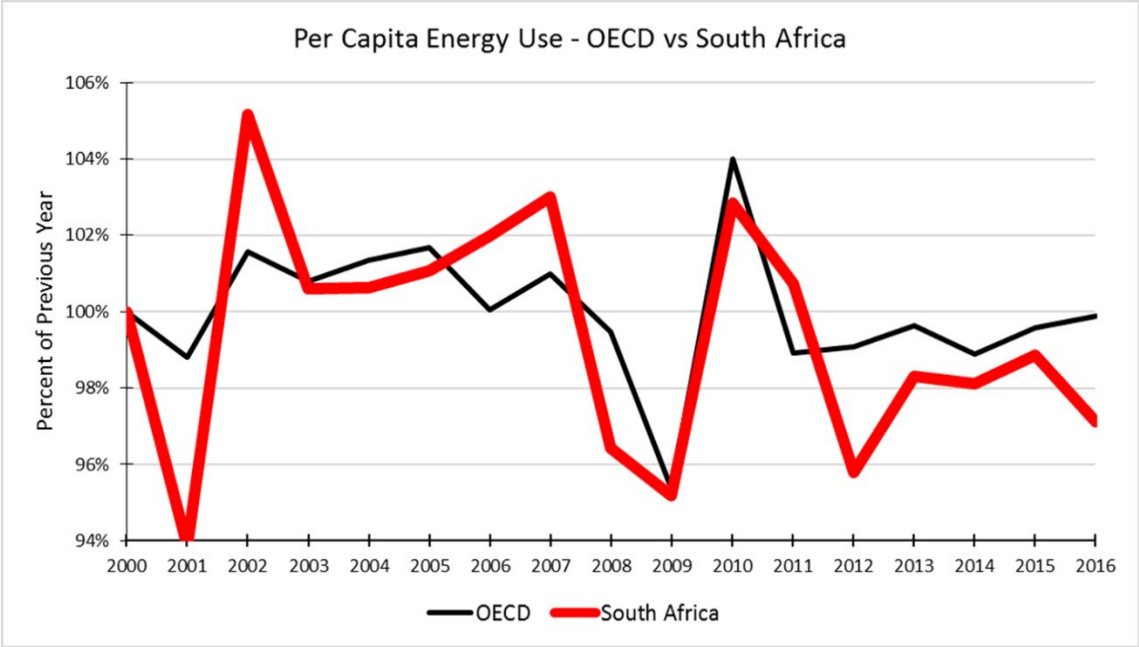


Figure 60 - South Africa Demand Growth Compared to OECD

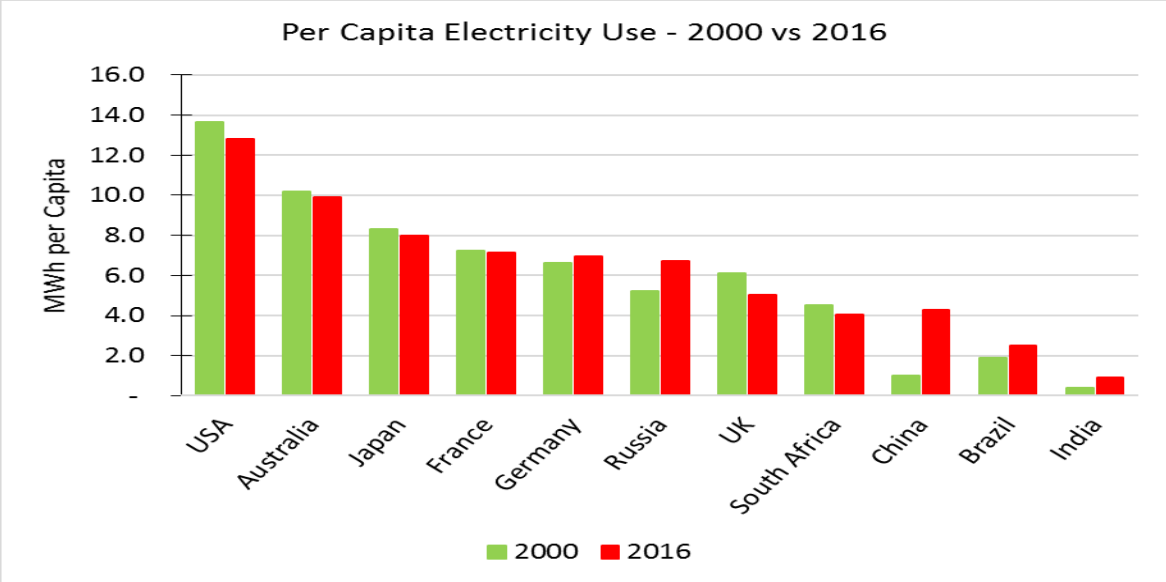


Figure 61 - Per Capita Demand Growth in Representative Countries

Effect on forecast for growth

The difference in dispatchable energy forecasted to be needed in the low growth case as compared to the high growth case is shown in Figure 62. As can be seen when comparing these two graphs, the effect of growth on required dispatchable power is quite significant.

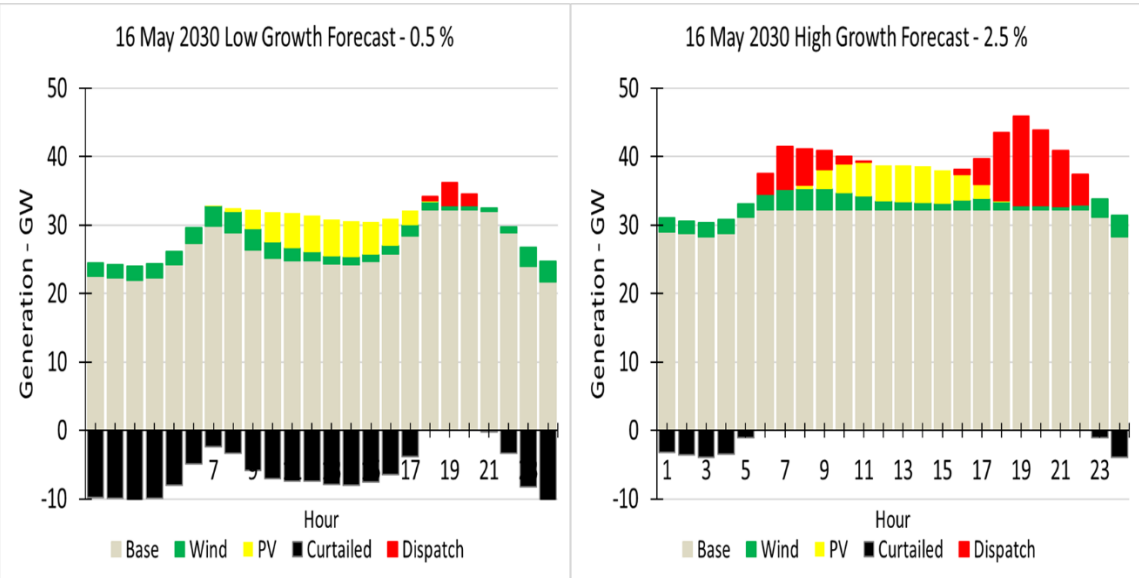


Figure 62 - Effect of Demand Growth

B.6. Energy availability factor (EAF)

The availability factor for the base plants should be one of the factors that is most well understood and controllable by the utility. However, this is not the case and this uncertainty in EAF causes a major uncertainty in the forecast.

EAF plan

Large base load coal generation plants should have an EAF of over 80 % when new. This will likely decrease over time as the facilities age. A statistical analysis of availability factors for coal plants in the United States of America is shown in Figure 63 (Nichols, 2016). The Eskom coal fleet has an average age of 30 years. From the NETL data, it could be expected that the EAF of the Eskom fleet would be around 70 %. At the time that the IRP was first developed, Eskom had an EAF of about 70 % and stated that they expected to improve this to 80 % within the first study period (SA DoE, 2011). However, there has not been an improvement, with the current EAF being below 70 % (Van der Merwe, 2019). Even in the latest IRP 2019, the expectation is that the EAF will improve to 75 % in the coming years. Eskom provided two scenarios to the IRP process, one with EAF averaging 80 % and one averaging 75 % by 2030. As stated in the approved IRP 2019, "Plant performance projections in the final plan contained in this report are based on the scenario with EAF of 75 % by 2030. In this scenario, EAF starts at 71 % in year 2020, and increases to 75.5 % by year 2025 and beyond." (SA DoE, 2019a, pg. 32).

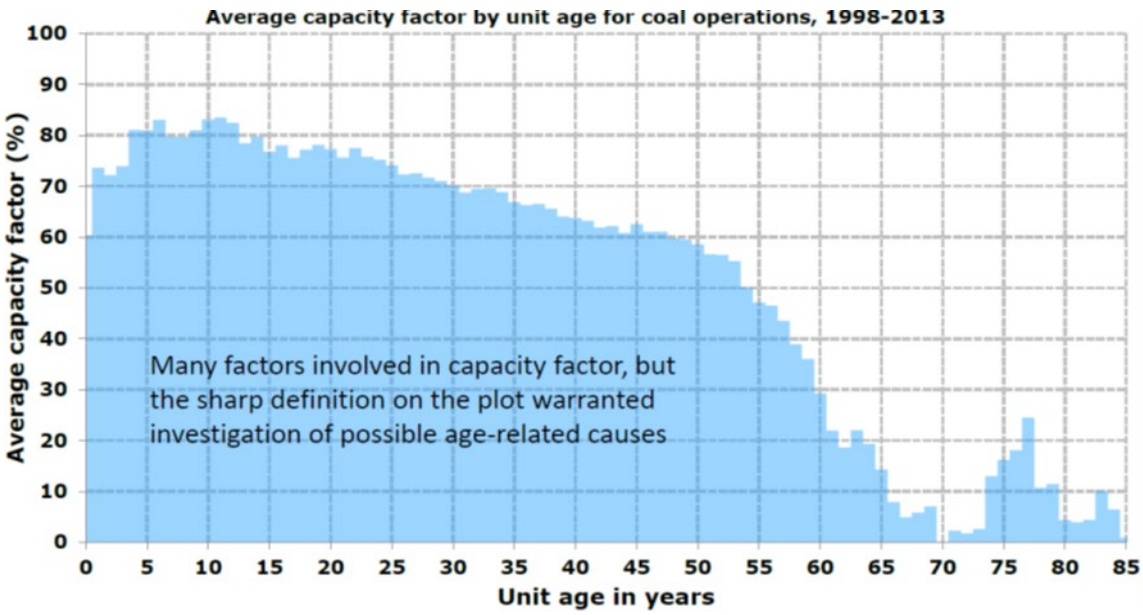


Figure 63 - Historical Coal Plant Availability Factors (Nichols, 2016)

Effect of EAF

The two graphs in Figure 64 show the effect of the range of EAF on the dispatchable power need for 2030, the EAF range shown is 70 % to 85 %. With a low EAF, the required dispatchable power increases significantly.

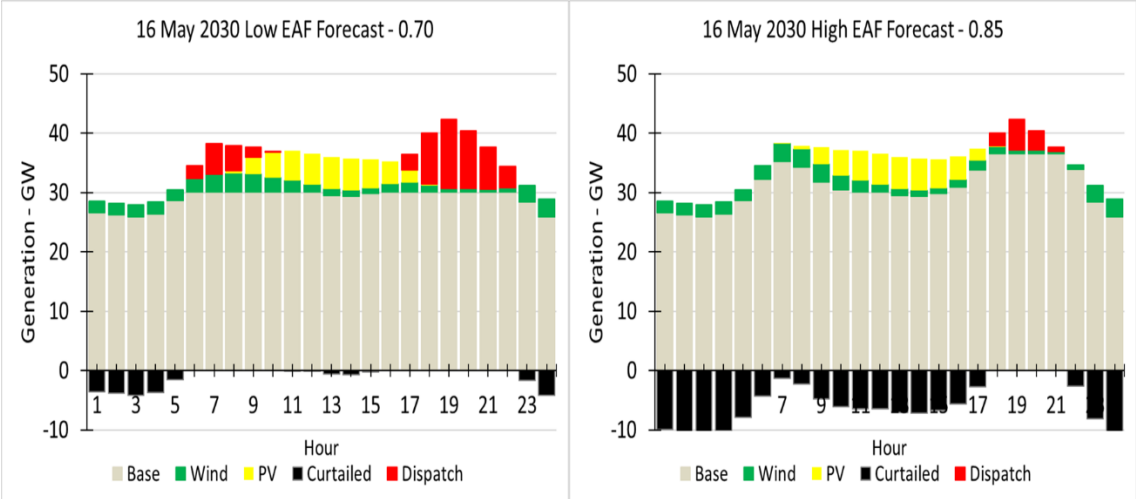


Figure 64 - Effect of EAF

B.7. Decommissioning

Decommissioning of the large base coal and nuclear plants is also a parameter that the operator should be able to control and to forecast with a given level of certainty. It is also a factor that can have a major impact on the need for dispatchable power.

Decommissioning plan

The average age of the Eskom coal generation fleet is over 30 years and Eskom predicts a plant life of 50 years for these facilities (SA DoE, 2018). Therefore within the planning period, almost all the base generation fleet will likely be retired. The timing of this retirement is the major question. Plant cycling adds significantly to the operating cost of base load plants and decreases their effective life considerably (Bergh & Delarue, 2015).

One of the major changes made between the 2018 IRP and the 2019 update was in the retirement schedule for the Eskom fleet and this major change was in the near term as shown in Figure 65. (SA DoE, 2019c). These changes bring the entire schedule into question as these near-term predictions should be the most within the operators' understanding and control.

The IRP assumes that about 12 GW of the base fleet will be decommissioned by 2030, with an additional 22 GW to be decommissioned between 2030 and 2050. If the decommissioning happens earlier than planned it will have a major impact on the need for dispatchable power. This difference in required dispatchable power is shown in the two graphs in Figure 66, comparing the base 12 GW planned decommissioning until 2030 to a forecast with an additional 9 GW of retirement.

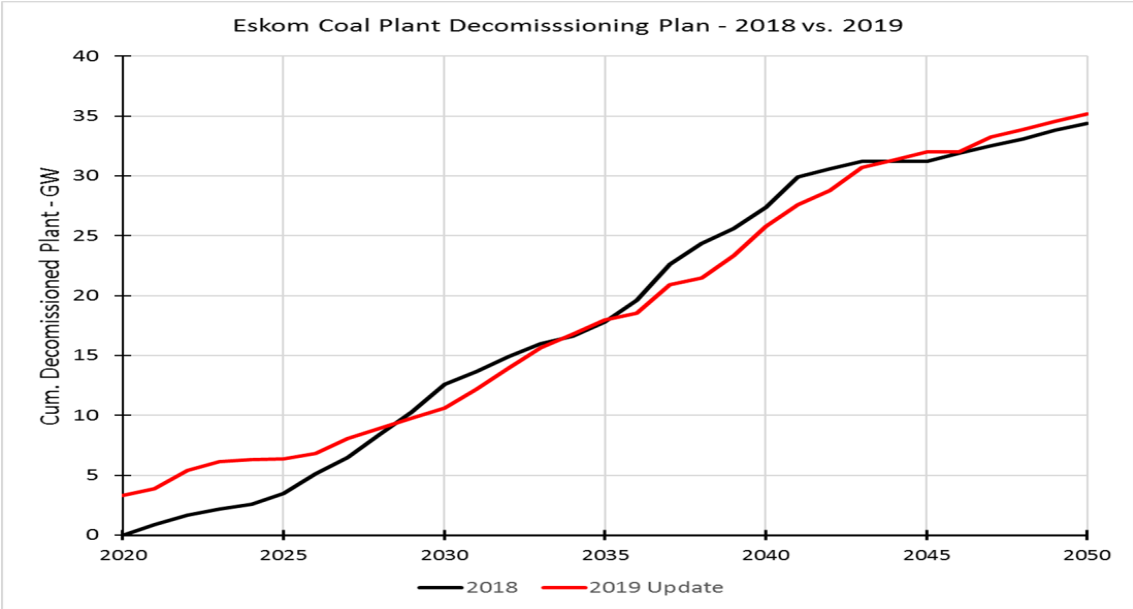


Figure 65 - Eskom Decommissioning Plan 2018 vs 2019

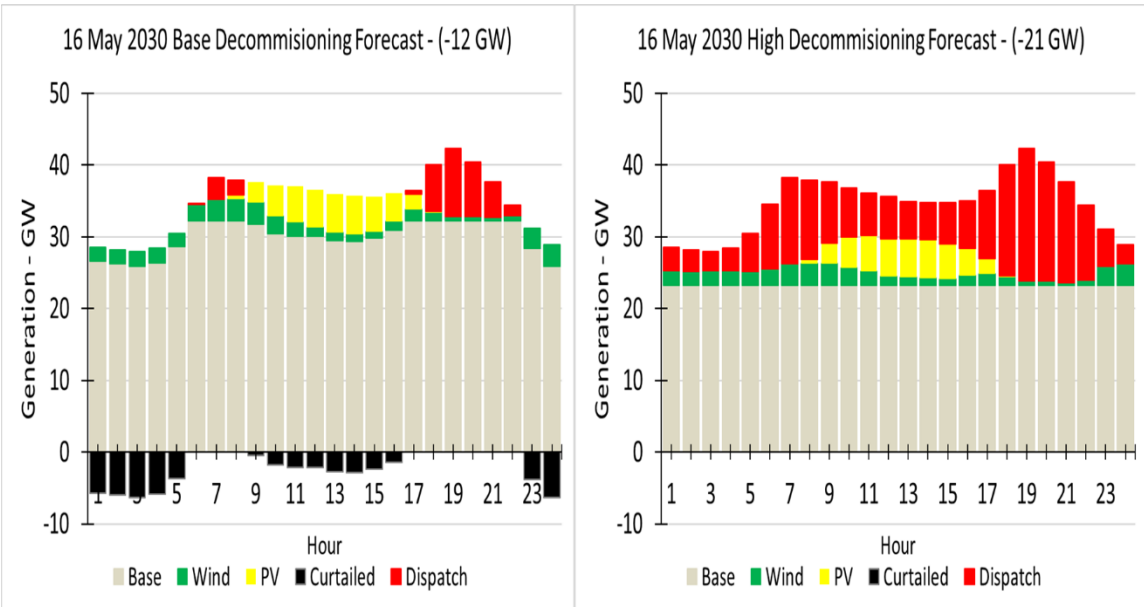


Figure 66 - Effect of Decommissioning

B.8. Effects of volume of wind and solar PV

Effect of wind generation

The peak day for dispatchable power in the forecast is defined by the day that the wind has the least impact. On 16 May, the 13 GW of expected wind capacity would average only 1.8 GW for the day and almost nothing in the evening. An additional 20 GW of wind would only make a small impact on the dispatchable requirement as can be seen in the graphs in Figure 67.

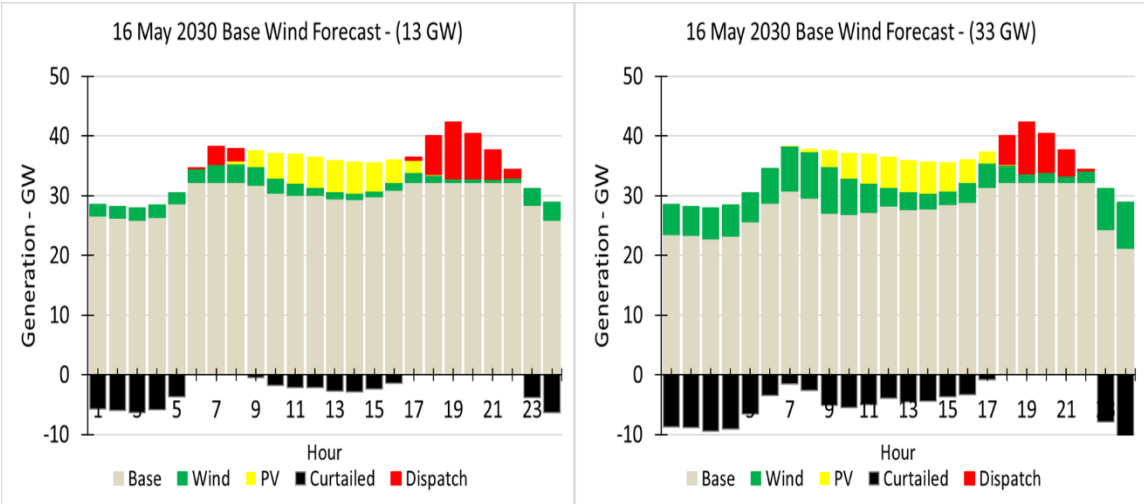


Figure 67 - Effect of Wind

Effect of solar PV generation

Additional solar PV will reduce the amount of base load generation required in the middle of the day but has effectively no impact on the evening peak of dispatchable power as can be seen in the graphs in Figure 68.

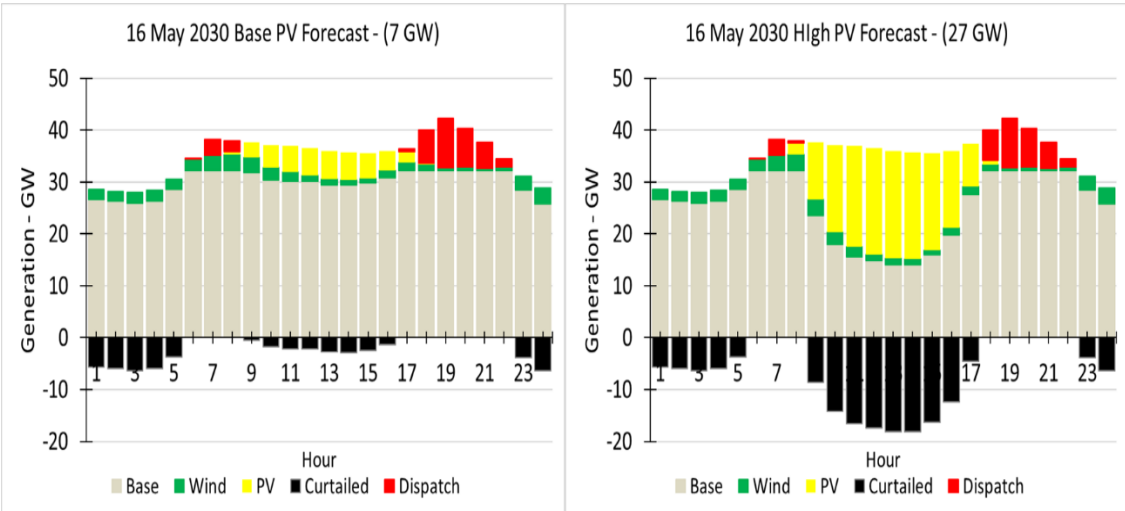


Figure 68 - Effect of Solar PV

B.9. Resulting uncertainty

The ranges for each of these parameters were built into a Monte Carlo simulation to determine the range and shape of the curve of likely dispatchable generation using the Dispatchable Energy Model of hourly generation for 2030 with the distribution indicated in Table 20. The Monte Carlo simulation uses the ranges for each of the factors that affect the growth and runs 50 000 scenarios to determine the range and distribution of potential outcomes. The parameters used as inputs were as described above. The outputs from the simulation were the amount of installed dispatchable power required and the energy that would be generated by that dispatchable power.

From the two resulting curves shown in Figure 69, the expected capacity for dispatchable power ranges from 5 to 15 GW on a P 10 to P 90 basis (10 % probability to 90 % probability) and the energy generation is most likely minimal but could be up to about 8 TWh or 2.5 % of the overall demand in the worst case.

Table 20 - Monte Carlo Simulation Parameters

2030 Forecast Monte Carlo Analysis			
Factor	Range	Base	Distribution
Demand Growth	0.5 % to 2.5 %	1.8 %	triangular
EAF	0.7 to 0.85	0.75	triangular
Decommissioning	12 to 21 GW	12 GW	triangular
Wind	3 to 53 GW	13 GW	triangular
Solar PV	2 to 27 GW	7 GW	triangular

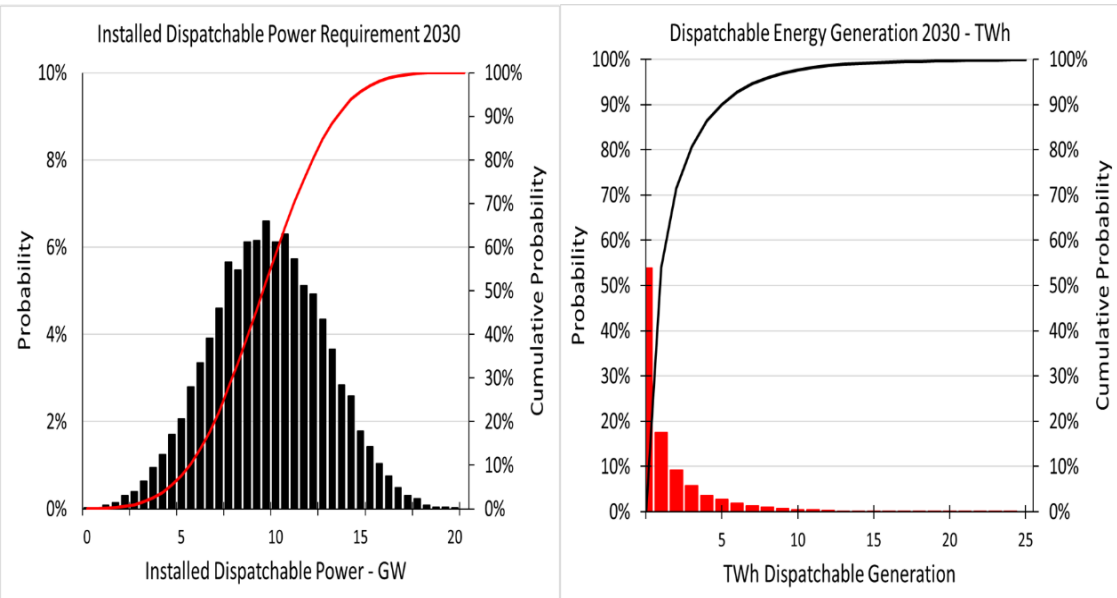


Figure 69 - Monte Carlo Simulation Output

B.10. Recommendation

From this sensitivity analysis, it appears that the scenario-based IRP fails to adequately cover the range of likely forecasts for what dispatchable power will be required. The analysis shows that the likely range of outcomes is quite large and not easily forecast.

As can be seen in South Africa in the time it has taken from decision to implementation of the Medupi and Kusile coal plants, as well as international experience in the time required to implement coal and nuclear generation plants, a long lead time must be considered when making the decision of whether a base load plant is to be built. Because of the uncertainty of likely generation requirement, in addition to the high cost of unserved demand, the probability of overbuilding is high. This causes added costs for the entire system that must be borne by the consumer. Wind, solar PV, and gas plants can be built with a much shorter lead time. Therefore, it is not necessary to make long term forecasts on the need for these plants. The plan can be adjusted as time goes on.

This modelling indicates that the planning process should move from being a prescriptive plan to being one that is reactive to the developing situation, particularly for demand growth. The plan must be able to adapt with shorter notice than the IRP planning process suggests. This leads rather to a shorter development period system than the longer-term planning for base load generation. This favours a system dependent on easy to install renewable generation with appropriate dispatchable power backup.

Appendix C – Shale Gas Economics

C.1. Introduction

As indicated in the South African Integrated Resource Plan (IRP), the need for dispatchable power in the South Africa electric grid has been recognised (SA DoE, 2018). In most countries, this dispatchable power is being supplied by natural gas fired generation (World Bank, 2018b). This is not the situation in South Africa.

South Africa has effectively no local gas production. The offshore gas production from fields in Mossel Bay supplying the PetroSA gas-to-liquids plant have been nearly depleted (PetroSA, 2016). There is some gas being brought into the country by pipeline from Mozambique with a capacity of 200 PJ/a (Rompco, 2020). Some of the gas is used to generate electricity at the border with Mozambique, currently with a generation capacity of 450 MW (Creamer, 2015).

The majority of the dispatchable power that is being generated in South Africa is fuelled with diesel. The cost of this fuel for electricity generation in South Africa is approximately USD 16 per GJ.[1] The cost of natural gas in the United States in May 2018 was USD 2.7 per GJ (US EIA, 2018c), in Europe USD 6.9 per GJ (YCharts, 2018) and LNG delivered to Japan was USD 7.8 per GJ (Japan Office of Director for Commodity Market, 2018).

In South Africa, there is a potential for natural gas production from shales in the Karoo, which could possibly supply all the dispatchable power needs in the country. However, this potential resource has yet to be confirmed and its commercial viability is unknown. In 2014, an analysis from WWF reported that an unpublished analysis from Wood Mackenzie quoted a break-even cost of USD 11.4 per GJ (Fakir, 2015). The assumptions that were used by Wood Mackenzie are not known. This compares quite closely to the forecast from a recent study on the price required for shale gas development in Europe of over USD 10 / GJ, not including tax and royalties (Saussay, 2018).

This analysis will use publicly available information to assess the likely break-even cost for shale gas in South Africa and the factors affecting that price.

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[1] The price for diesel for power generation in South Africa is the basic fuel price (BFP) plus approximately 4 Rand cents per litre to cover customs & excise plus a pipeline duty (OECD, 2018). BFP is based on international oil price plus refining and delivery costs (Motiang & Nembahe, 2017). Using 13 % above Brent oil price of USD 80 per barrel, this gives a BFP price of approximately 9 ZAR/L (as compared to the road use price of 15 ZAR/L). With an energy content for diesel of 0.38 GJ/L the cost of diesel is +/- 230 ZAR/GJ or USD 16 / GJ.

C.2. Background

From exploration wells drilled by SOEKOR in the Karoo during the 1960s, it is known that shale gas exists in that area (Rosewarne, 2014). However, it is not known if the gas exists in commercial quantities or if it can be produced at prices competitive to other fuels (SAOGA, 2017). Shale gas could potentially provide South Africa with all the gas fired dispatchable generation requirement that was identified in the IRP. For this analysis, we will review the current situation with shale gas around the world and discuss how these factors relate to South Africa.

United States of America (USA)

The United States of America is one of the world's major natural gas markets, consuming about 2.2 BCM of gas per day (US EIA, 2018e). The electric generation capacity in the USA is about 1 000 GW, of which about 450 GW is natural gas fuelled facilities (US EIA, 2018) with total annual generation of about 4100 TWh of which 1300 TWh is derived from gas fuel (US EIA, 2018g).

Up until the 1990s, the USA gas market was mostly met with local gas production (US EIA, 2018e). In the 1990s, gas from conventional reservoirs failed to meet the market needs. With this shortfall in domestic production, there was economic pressure to develop additional production sources. With the application of hydraulic fracturing (commonly known as 'fracking') and horizontal drilling, gas production from shales grew and created a large increase in domestic USA gas production (US EIA, 2018h).

Gas production grew enough to saturate the USA market. This has moved the United States of America from being an importer of gas to potentially becoming the world's largest gas exporter if all proposed projects were to be developed (International Gas Union, 2017). The first LNG export, with 18.6 BCM per annum capacity, was brought online in 2016 (Charles River Associates, 2018). As of 2018, 15 projects are in various stages of development, with the potential of up to 150 BCM per year capacity (International Gas Union, 2017). This compares to the largest LNG exporting country – Qatar – with 106 BCM (International Gas Union, 2017) per year capacity.

Global potential

From a geological perspective, there is no reason for shale gas production to be solely an activity for North America. Shale beds are spread throughout the world, with some larger than those found in the United States of America. In 2011, the US Energy Information Agency (US EIA) issued a report on the potential for shale development around the world (Kuuskraa, *et al.*, 2011). They updated this analysis in 2013 (Advanced Resouces International, 2013).

The study indicated that the potential resource of shale gas in the United States was about 25 Trillion Cubic Meters. The potential recoverable resources in the countries with the ten largest volumes identified from the 2011 report are shown in Table 21. China has the largest potential resource. To put these numbers into perspective, the amount of electric energy that could be developed from these resources is also included in the table. For this calculation, generation efficiency of 0.01 GJ of natural gas per kWh (US EIA, n.d.) and an energy content of 37 MJ/m3 for natural gas (Tran, 2002) were assumed.

Table 21 - International Shale Potential

US EIA International Shale Basin Potential				
Country	**2011 Study**	**2013 Study**		**Generation Potential**
	TCF	TCF	TCM	TWh
China	1 275	1 115	32	116 800
USA	820	1 161	33	121 618
Argentina	774	802	23	84 012
Mexico	681	545	15	57 091
South Africa	485	390	11	40 854
Australia	396	437	12	45 777
Canada	388	573	16	60 024
Libya	290	122	3	12 780
Algeria	230	707	20	74 061
Brazil	226	245	7	25 665

South Africa comes in at number five on this table from the 2011 study, dropping to number seven in the 2013 update. This study indicated a potential resource that could generate the 235 TWh of electricity currently used annually in South Africa for 175 years.

International experience

Since the first report of the US EIA was published, most of these countries made attempts to develop their shale resources.

Australia

Australia is one of the major LNG exporting countries, ranked second by volume (International Gas Union, 2017). Most of the gas for LNG production is either conventional gas or coal seam methane (Austrilan DEE, 2017). Australia has nearly 11 TCM of shale resources in six basins. Exploration and development of some of these resources has commenced (Zuhairi, 2013) in basins with established infrastructure – specifically, existing offtake pipelines. A review of the production of the three gas sources indicated that shale gas was about twice the cost of conventional gas. (Core Energy Group, 2015).

Argentina

Argentina has a long history of oil and gas development with a well-established natural gas production in the country. In recent years, that market has shifted to the point where imports, in the form of pipeline gas from Bolivia and LNG imports, have been necessary to supply the market (Brandt & Gomes, 2016). Development of a shale business was slow, due to political considerations, but commenced with the change in government in 2015 (Brandt & Gomes, 2016). One of the provisions that the new government used to encourage gas development is a floor on price of 7.4 USD/GJ (Deloitte, 2018). Shale gas production is now increasing. This production is coming from the Vaca Muerta region where the infrastructure for oil and gas development is in place (Deloitte, 2018).

China

China was identified in the US EIA 2011 study as potentially having the largest shale gas resource at over 34 TCM. China has a significant gas market, with local production which is supplemented with imports. The Chinese government has committed to developing the shale gas resources and government companies have made a major push to do so (Oil Peak, 2013). It is expected that Chinese shale gas will be a major contributor to the Chinese gas market (Qun, *et al.*, 2017) but gas imports continue and plans are in place to expand LNG importation, including a 22 year deal with Qatar for 3.4 MTPA (4.6 BCM/ year of gas) signed in September 2018 (Reuters, 2018).

South Africa

With the large potential resource for shale gas in South Africa, there was initial excitement about developing this resource (Petroleum Agency SA, 2013). The government received bids for most of the acreage in the Karoo basin (Van der Spuy, 2013). The bids were for technical cooperation permits, where desk top studies and surveys could be conducted but not exploration drilling (Van der Spuy, 2013). It was expected that these technical cooperation permits would last one year before license holders could apply to move into an exploration license. Due to concerns raised about the effects that drilling and fracking operations would have on the fragile Karoo environment, the move to the exploration phase has been put on hold (DMR, no date). Only three license holders remain (SAOGA, n.d.).

Environmental concerns

The concerns raised about the environmental risks of fracking mirror those of most of the countries considering shale developments (Netshishivhe, 2014). However, the specific conditions in the Karoo offer additional concerns (De Wit, 2011). The greatest concern is the impact on the water resources in a desert area. Drilling and fracking operations involve the use of large volumes of water and the sourcing of this water is an issue (ASSA, 2016). In addition, there is concern about contamination of the water that is used for drinking and agriculture from the chemicals used in fracking fluids and

from water produced with the shale gas (von Tonder, De Lange, Steyl, *et al.*, 2012). These concerns have slowed the move towards exploration and have led to development of stringent regulatory requirements for these operations (DMR, 2015).

In-activity

The net effect of the concerns about these operations is a standstill on permitting of any exploration activities (Roelf, 2017). In addition, the government has decided that baseline surveys of water resources and other environmental aspects must be conducted prior to the movement to exploration (Odendaal, 2016). As of 2018, the potential South African shale gas business is inactive.

C.3. Economic analysis

The CSIR prepared an extensive analysis in 2016 of the impacts and risks of shale gas development in the Karoo (Burns, *et al.*, 2016). Chapter one of the report laid out the steps in getting to the steady state development of the resource (Burns, *et al.*, 2016). The first phase that the CSIR identified was a period of studies in order to establish the base lines for air, water and environmental conditions prior to any drilling to ensure that effects related to shale gas drilling and production can be isolated. From the work program laid out in the study, the cost of these base line studies should be less than USD 10 million.

Exploration phase

In the United States of America (as well as in other places with an established gas business) shale gas development did not go through any extensive exploration phase. Exploration was incremental to the development, where wells could be brought on production almost immediately. The Karoo area in South Africa would be a completely new development area and the exploration efforts, prior to any development, will be much more extensive.

As discussed in the CSIR report, the process would consist of a two-dimensional (2D) seismic programme, reported to be about 2 000 km, followed by three-dimensional (3D) seismic over the areas of interest for development. In the USA and Canada, a 2D seismic programme would cost about USD 10 000 per km (Hunt, 2015). For a one-off seismic programme in South Africa (along with all imported equipment), the cost would be more in the range of USD 15 000 per km (NETL, 2013). Thus, the cost of the 2 000 km programme would be approximately USD 60 million.

As indicated in the study, this 2D programme would be followed by 3D analysis covering the areas of interest in each leasehold area. The CSIR assumes that about 5 % of the surveyed area would be considered for the additional survey work. The 3D program would be expected to cost in the range of USD 75 000 per square kilometre

(NETL, 2013). If the area covered is 500 square kilometres in each license area of interest, this would imply a cost of USD 37.5 million for this second seismic program for each lease holder.

Between data collection, data processing and analysis, these programs would each take approximately one year. Therefore, it can be assumed that the seismic phase of the exploration program would take two years.

The next step would be drilling exploration and appraisal wells. These would first be vertical wells, followed by wells with horizontal sections and finally wells with hydraulic fracturing. The estimate is that twenty four wells would be required for an operator to delineate the shale resources in his leasehold and identify the best areas, or the 'sweet spots' for initial development (Burns, *et al.*, 2016).

The last phase of the exploration effort would be three to six production tests for a limited number of wells. Wells would be drilled, completed, and then attached to temporary production facilities to burn off the produced gas. Production tests would normally last thirty to sixty days (SAOGA, 2017).

The total time for this effort would be a minimum of four years. Assuming that the operator will lease and import a rig specifically for this program, it is estimated that the drilling cost would be USD 120 million per year (Rose & Associates, 2016). Hence, the exploration drilling and production phase would cost an operator +/- USD 450 million.

After this expenditure, the operator would know significantly more about his potential resource including; relevant resource extent, drilling costs and expected well initial production rates (Burns, *et al.*, 2016). Nevertheless, it must be questioned if this would be enough to allow the companies to proceed with a full-scale development. In a presentation to the South African government, the South African Oil and Gas Alliance (SAOGA) indicated that a pilot program would be required before moving to a full scale development (SAOGA, 2017), as laid out in Figure 70.

Proof of concept and development phases

A likely option is to move from the exploration phase to a 'proof of concept' or pilot type development. In this scenario, a group of wells – e.g. nominally six to ten (about one year to eighteen months of drilling) would be developed, fracked and brought into production with a local power plant generating +/- 30 MW of base load power for consumption by the local region. This development would establish the flow capabilities of the shale gas wells and their long-term production viability. The power plant would operate long enough for the operator to become comfortable with the expected life of the shale gas wells.

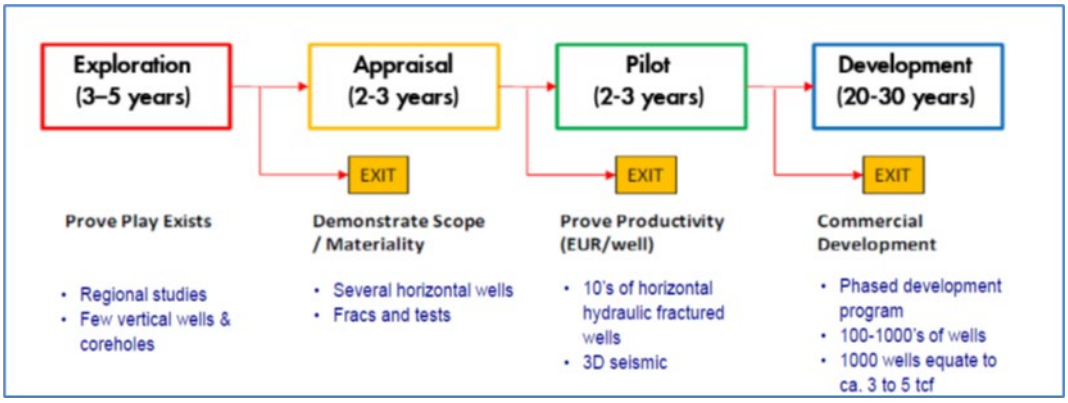

Figure 70 - South Africa Shale Development Process (SAOGA, 2017)

Assuming the proof of concept phase indicates the wells to be economically viable and gives the go ahead for full-scale development; the next phase would be to implement a continual steady state development. This would likely start out somewhat smaller than the small gas 550 well development scenario indicated in the CSIR analysis (Burns, *et al.,* 2016), but would still need to be large enough to keep a drilling rig occupied continuously. This is necessary to avoid the time and cost of rig mobilisation and importation for each drilling program. If we assume six wells per year for one drilling rig at USD 20 million per well, the annual cost would be USD 120 million for drilling and completion (Rose & Associates, 2018). Assuming a first-year average daily production rate of 5 000 GJ per well based on the expected ultimate recovery (EUR) per well of 114 MCM (Burns, *et al*., 2016), this would imply production of 24 PJ per year of gas, i.e. enough to produce 2.4 TWh of electricity in an OCGT plant. If this power is to be used in a dispatchable mode, buffer storage for ten or more days of use or at least 600 TJ must be included in the cost structure. Full development of the shale gas would indicate that some multiple of this steady state development be implemented. The CSIR small gas case assumes that three of these modules would be implemented (Burns, *et al*., 2016).

Individual well economics

The production profile of a typical shale gas well shows a high rate of production for some months after completion, followed by a rapid decline in the range of seventy to eighty percent in the first two years (Guo, *et al.*, 2016). The production then moves into a tail period that continues a less significant decline that lasts for ten to twenty years (Murphy, 2016). From an economical perspective, this is an attractive profile as it leads to quick recovery of costs and a maximisation of the time value of money. However, the production profile is not one conducive to use as a source of power generation. If the profile for a well is regulated to steady state over a ten-year productive life, the economics of a well would become unacceptable. This effect is indicated in Figure 71.

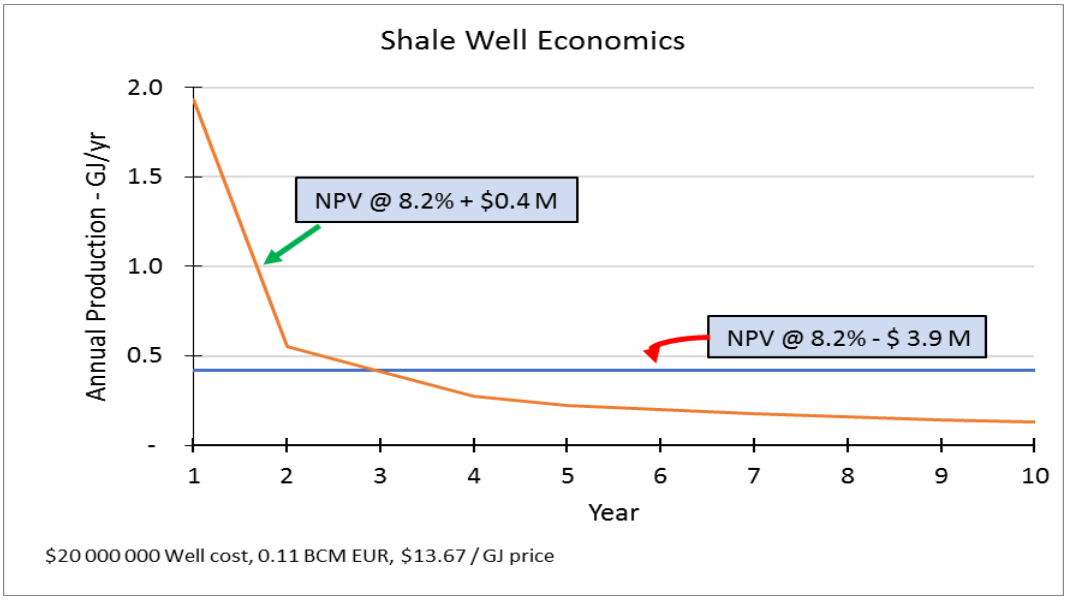

Figure 71 - Shale Well Economics

Economics of steady state development

The economics of shale gas production would not be optimal until it gets to a scale where a drilling rig is being utilised full time (avoiding significant mobilisation costs) and wells are immediately put on production as soon as they are completed. The development must also be large enough to allow the wells to be produced to their full extent and have their production replaced by new wells as they decline. Assuming a two month per well drilling and completion timing, one rig would drill about six wells per year (US EIA, 2016). This should bring steady state production to 24 PJ per year by the eighth year of the development and the plateau would be maintained as long as the drilling rig is kept working. Figure 72 shows a twenty-year development program after which the production drops off quickly. Assuming a recovery per well of 114 MCM, with a first-year production rate of 5 000 GJ per well, the break-even income required for this steady state development program would be in the range of 13.7 USD / GJ assuming a cost of capital of 8.2 % (Figure 73). If the ultimate recovery per well was 100 MCM and the initial rate lowered proportionally, this would raise the break-even price from 13.7 USD to 15.5 USD / GJ. However, due to the risks associated with oil and gas developments, no investor is likely to invest in a cost of capital project. For oil and gas developments, a break-even assuming a 15 % discount factor is normal. This would raise the required break-even price from 13.7 USD to 14.7 USD per GJ as shown in Figure 74. The operator must also make provisions to recover the sunk costs that have occurred through the exploration and pilot development phases.

In 2014, a report on the economics of the Karoo shale gas from WWF reported that an unpublished analysis from Wood Mackenzie quoted a break-even cost of 11.87 USD per GJ (Fakir, 2015). Unfortunately, Wood Mackenzie did not publish their assumptions or indicate if a sensitivity analysis had been performed.

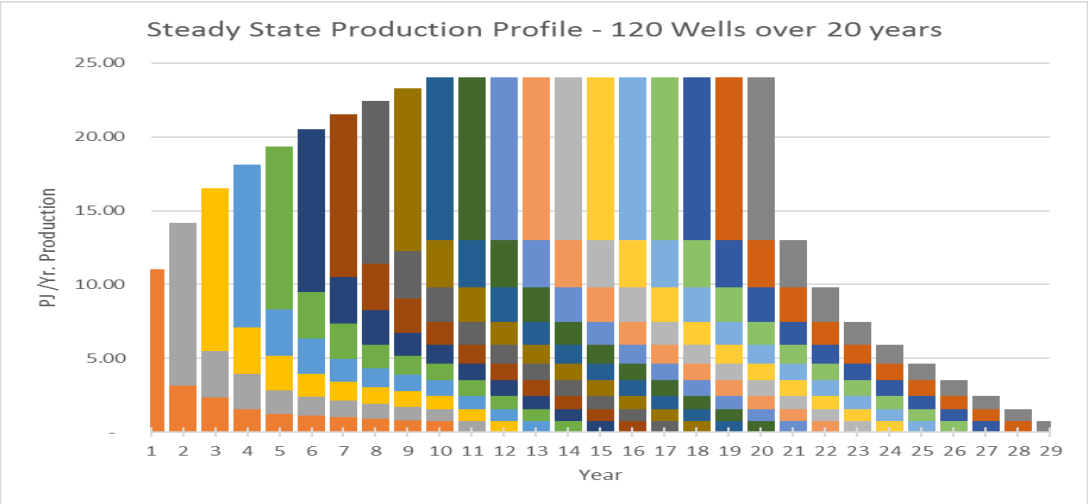

Figure 72 - Shale Gas Steady State Production Profile

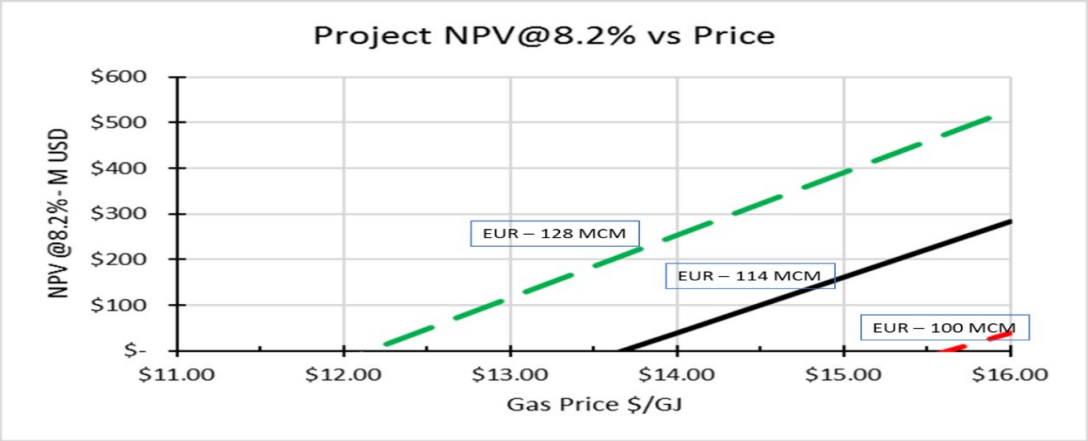

Figure 73 - Shale Gas Price with NPV@ 8.2 %

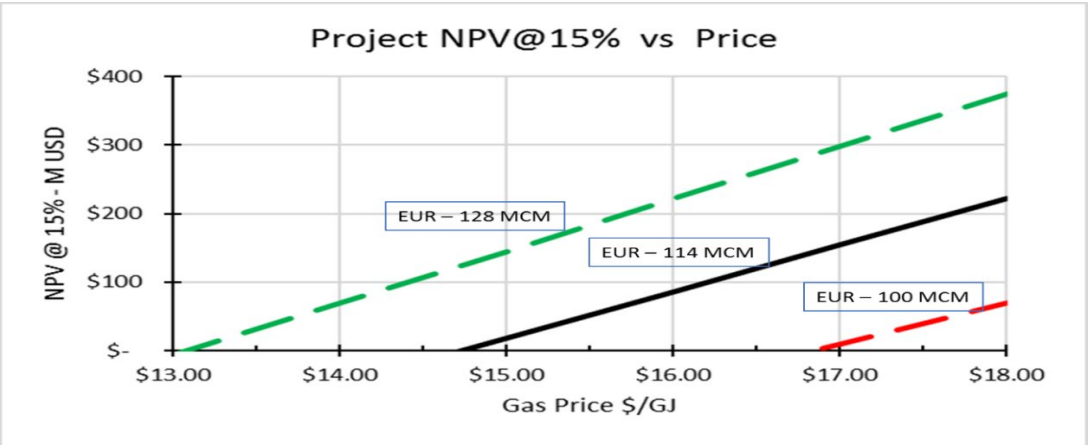

Figure 74 - Shale Gs Price with NPV @ 15 %

Timing of steady state development

With a one-year pre-exploration program as well as four years of exploration work and at least three years of a proof of concept test development, the earliest that one could expect the steady state development to begin would be at least ten years from the program commencement. However, with the likely review and approval processes, each phase of the exploration and development would take much longer (SAOGA, 2017).

C.4. Risk factors

There is significant variability in some of the factors that could have a major impact in the economics of the development of this resource. As there is no actual information from the Karoo about this resource, what can be assumed is based on experiences from other shale developments – particularly those in the United States of America. There is potential for major differences that could impact the local analysis.

For this sensitivity, the following parameters were reviewed:

- Well cost – USD 15 million to USD 25 million
- EUR – 100 to 128 MCM
- Opex – 5 % to 15 % of well cost per year
- Royalty – 0 % to 20 %

As can be seen in the tornado diagram in Figure 75, each of these parameters has a major impact.

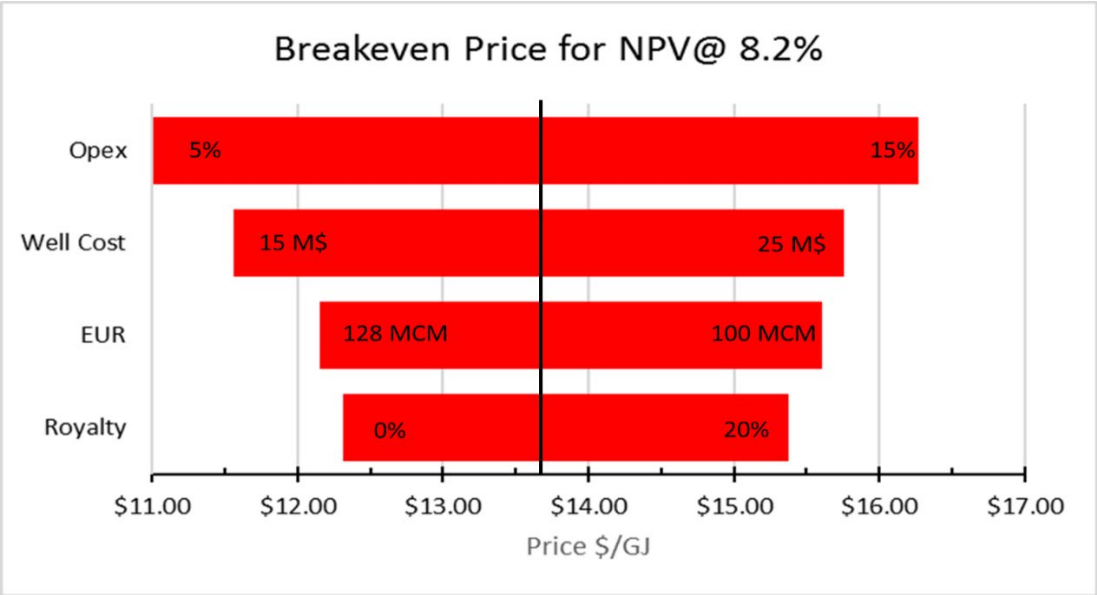

Figure 75 - Shale Gas Price Sensitivities

Recovery per well – expected ultimate recovery (EUR)

The amount of production that can be derived from each well would be one of the major factors in the economic performance of shale gas development. Nevertheless, it remains a question until the production period from each well. The CSIR assumed 114 MCM per well production as an average between the Barnett and the Marcellus shales in the United States of America (Burns, *et al.*, 2016). If the EUR per well is reduced to 100 MCM, the breakeven price is raised over USD 1 per GJ.

The USA shale gas production history offers significant inferences into what might be expected. While per well production has increased over time, this has come after many wells. In the Marcellus shale fields, over 14 000 wells have been drilled. Expected EURs per well have increased to above 114 MCM (Murphy, 2016). In an analysis in 2013, the US EIA showed an average range in shale basins from 30 to 90 MCM (Smythe, 2014).

Cost per well

Due to the large numbers of wells that must be drilled to maintain shale gas production, the cost of each well is a critical factor in the economics of shale gas production. The estimate used for this analysis was USD 20 million per well for drilling and completion (including fracking costs) (Rose & Associates, 2016).

Within the United States, these costs have been reduced to less than USD 10 million per well in most shale basins. This is mostly due to reductions of drilling and completions times from the experience of the large number of wells being drilled and completed. It is estimated that over 130 000 oil and gas wells have been drilled in the United States of America since 2010 (Meko & Karklis, 2017) with about 95 % of them being fracked and over half of these into shale formations (US EIA, 2018b). In the USA, the costs are also minimised because the drilling rigs and the fracking setups are optimised for the given location (US EIA, 2016). This is possible due to the large number of drilling rigs and fracking equipment available on call for any operation. In smaller markets, it is necessary to use a rig and have equipment to meet whatever might arise or to limit the output of the well to what can be achieved with the equipment used.

Costs to drill and complete wells is also a function of depth and length of horizontal section, with related size for the completion. The cost/depth relationship is not linear but increases with depth (Lukawski, *et al.*, 2014) as shown in Figure 76. As the target for the South African shales is in the 3500-metre range and the intent is to maximise per well productivity (implying longer horizontal sections), higher well costs can be expected. Drilling costs are a function of the measured depth of the well, which includes the vertical as well as horizontal components (Lukawski, *et al*., 2014).

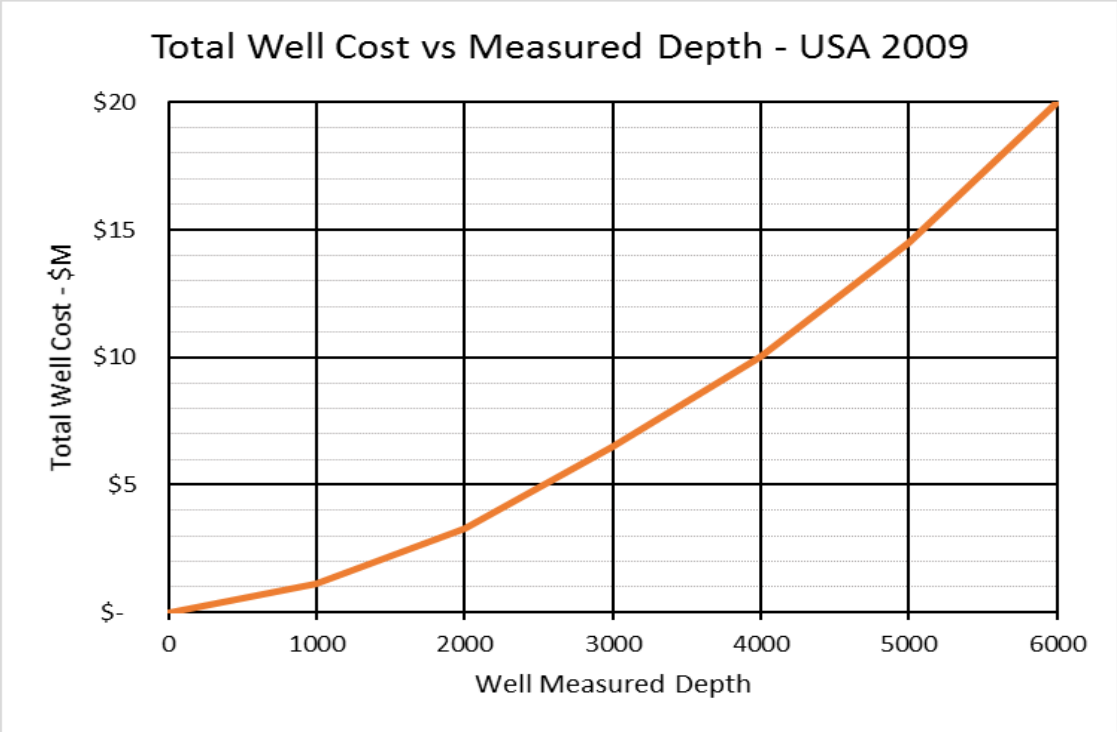

Figure 76 - Well Cost versus Depth - adapted from (Lukawski, *et al.*, 2014)

In Argentina, drilling and completion costs are about twice those of the costs in the United States of America (Deloitte, 2018). In Australia, similar costs were seen (Zuhairi, 2013). These are both areas with an established oil and gas business.

One factor that has not been addressed in any of these cases is the cost of water for drilling and completion operations. In an analysis of the replication of the USA experience to Europe and China, Minh-Thong Le found that the cost of water was one of the most significant cost issues, with water being ten times more expensive in shale drilling in Europe than per the USA experience (Le, 2018).

Operating cost – water disposal

Direct operating costs for gas wells in the United States of America are in general between USD 1 and USD 2 per GJ (US EIA, 2016) or USD 4 million to USD 8 million over the life of a well. However, the cost of disposal of produced water can be quite significant. In a study for the US EIA, IHS estimated that the cost of water disposal averaged about forty-two percent of the overall operating costs of wells in the USA (US EIA, 2016).

Water produced along with shale gas is of significant concern (Dunne, 2017)(Veil, 2015). A study by Duke University of oil and gas production in the United States of America indicated that the production of water from gas wells averages ninety-seven barrels of water per million cubic feet of gas produced (0.6 litres water per cubic metre of gas) (Kondash, Albright & Vengosh, 2016). Assuming the EUR of 114 MCM from a well, this would imply a production of 400 000 barrels (62 000 m^3) of formation water

from an average well. For the development analysed here from one hundred and twenty wells this would require the disposal of about 7.4 x 10^6 cubic metres of water, equivalent to the volume of almost 3 000 Olympic size swimming pools. The few exploration wells drilled into the shales in the Karoo have found significant levels of deep saline water reservoirs in the areas where shale gas could be produced. Thus, there is every expectation that this shale gas production would also bring about formation water as the experience from the United States of America indicates (Rosewarne, 2014).

Royalty or government share

The government of South Africa is the owner of the shale gas resources and has a desire to share in the economic value of the production of the gas. This sharing of the value can be in the form of a government carry or a royalty on production. The government has proposed that this government carry should be thirty percent of overall income from the production. The industry has stated that this is too onerous and that the royalty/government carry should be no more than ten percent to allow the development to proceed (SAOGA, 2017).

Government carries vary from five percent to forty percent of the production around the world (Daniel, *et al.*, 2017) In the USA, they are generally in the ten percent to fifteen percent range, as indicated in Table 22. In Canada, a sliding scale royalty is preferred.

Table 22 - Royalty Rates - adapted from (Daniel, *et al.*, 2017)

Comparative Royalty Rates for Shale Gas		
Country / Region	State / Country	Royalty
United States of America	North Dakota	16 %
	Oklahoma	18.75 %
	Pennsylvania	12.5 %
	Texas	20 %
Canada	Alberta	5 to 40 %
	Saskatchewan	0 to 40 %
International	Algeria	5 %
	China	11 %
	United Kingdom	0 %
	Australia	10 %

Finding a balance between an equitable government share and one that does not discourage investment is a major challenge for a potentially successful shale gas business.

Continued interest of participants

With the delays that have occurred in the move to the exploration phase of the licenses and the changed conditions in the gas market, there is some doubt that there is

as strong of an interest in pursuing this shale gas opportunity as there was when the licenses were issued.

Saturated world gas markets

In 2011, the world gas market appeared to need additional production to be balanced. World gas prices were high and there was a growing difference in the price between the United States of America with the shale gas development and other markets that depend on LNG imports (US EIA, 2018e). This difference peaked in 2009, with LNG delivered to Japan at 15 USD per GJ and the US Henry Hub price of less than USD 3 (BP, 2017). Since that time, sixteen LNG export projects have been constructed, adding 75 MTPA to the market (International Gas Union, 2017). World LNG prices have come into reasonable alignment along the lines of Henry Hub pricing plus liquefaction and shipping (Charles River Associates, 2018). Bloomberg concluded that the world gas market is currently over-supplied by twenty nine percent (Bloomberg New Energy Finance, 2018). The World Bank forecasts that the market will be over-supplied until at least 2030 (World Bank, 2018a).

Resource challenge

Several local studies had been performed to further define the resource size for Karoo shale gas. The studies have concluded that the US EIA estimate may be quite optimistic due to local geological conditions and the likely resource size is more on the order of 0.8 to 1.4 TCM (Scholes, *et al*., 2016). Further studies have indicated that the recoverable shale gas from the Karoo could be as low as 0.37 TCM (DeKock, *et al.*, 2018). Many questions remain about the size and commerciality of this resource.

The recent discovery of conventional gas in the deep ocean south of the country has also brought further challenges to shale gas development in South Africa as that gas would be competing for the limited market and should be significantly less costly to produce.

C.5. Conclusion

While the cautious approach being pursued by the South African government with the progress on shale gas development in the Karoo is probably warranted by the concerns raised about this activity, it would be best to allow exploration efforts to proceed in order to understand the value of the potential resource as this can only be defined after some exploration. It is unlikely that any of the companies involved will be pushing aggressively to proceed and a cautious forward path by all parties would be best. International gas prices are currently below USD 10 per GJ and are expected to stay in this range through to at least 2030. Unless costs are found to be significantly lower than anticipated and the resource per well much larger than estimated, it is unlikely that activities will move beyond exploration.

For long term planning purposes, it cannot be assumed that South African shale gas will ever be a factor in the supply of gas to the local or international power market. The timing of a potential development would be too far into the future for it to be considered. In addition, the potential for the cost of the gas to be economically competitive is too low to depend on this resource. For planning purposes, this must be considered as a strictly contingent resource.

Appendix D – Comparative Cost for Dispatchable Power

D.1 Background

It is essential for utility companies and policy makers to understand the cost of generation from the various technologies that are being considered. However, there are many complexities in these comparisons that make it challenging to determine the optimal comparison. In addition, there are different uses for the various technologies, whether it is for base generation, (i.e., generation that is "always on"), mid-merit, (generation that is generally in use but varies over daily use) or peaking power (which is only used to meet peak demand for short times). Each of the major technologies has a strong group of supporters that argue for the merits of their preferred technology. Utilities on the other hand, are generally just trying to reliability provide electricity at the lowest cost.

Until recently, renewable energy from wind and solar generation has only been supported because of the desire to produce power without greenhouse gas emissions. As costs from these generation sources decrease over time, they are potentially a lower cost alternative. The comparison of generation costs must also consider how these technologies can be used in conjunction with other generation sources.

The most common technique for comparing various technologies is the concept of levelised cost of electricity (LCOE). The concept is to try to synthesize all of the costs associated with the technologies considered, over the expected life of the project (thus requiring to account for the time value of money) into a simple equation (Comello, *et al*., 2017). However whenever a complex issue is simplified there are always issues that need to be ignored.

When comparing base load generation concepts to those based on wind and solar generation, it is essential to understand the overall system costs as the variability of these generation sources requires some level of redundant resources to back up the variable generation. LCOE does not do anything to address these concerns. LCOE also does not address the question of paying for dispatchable energy which is only used infrequently.

D.2 LCOE

LCOE brings all the elements of the cost of generation into one equation. These elements include the cost of building the facilities, the cost of operating the facility over the life of the project, fuel costs, the decline in generation capacity over time, as well as incidental costs such as financing and insurance costs. The equation and the analysis

can be simple or elaborate as need be. It is possible to include all tax and subsidies as well as external costs in the analysis (Comello, *et al.*, 2017). However, a simplified LCOE is best for comparing technologies.

LCOE Formation

In their comparison of LCOE calculations, J. Aldersey-Williams and T. Rubert noted that there are "Two main methods for calculating LCOE are in use; one suggested by the [UK] Department for Business, Energy and Industrial Strategy (BEIS) and one suggested by the [USA] Department of Energy's National Renewable Energy Laboratory (NREL)" (Aldersey-Williams and Rubert, 2019, pg. 170). In the UK formulation of LCOE, the calculation is net present value of project costs divided by the net present value of the energy produced, i.e.; LCOE= NPVcosts / NPVenergy. The authors indicate that "NREL defines LCOE in terms of the annual cost of energy, where the capital costs include an annuity-based capital recovery factor (CRF) which addresses the costs of financing the capital for the project " (Aldersey-Williams and Rubert, 2019, pg. 170). Both methodologies are in common usage around the world, including at Stellenbosch University. For this exercise, the NREL definition was used, with the formulation indicated in Equation 1.

$$LCOE_{NREL} = (C_o*CRF + O) / (8760*CF) + f*h + V \quad (1)$$

Where;

$$CRF = (i*(1+i)^n) / ((1+i)^n - 1) \quad (2)$$

C_o = overnight capital cost
O = fixed operating cost
i = interest rate
n = number of payments made to repay capital
CF = capacity factor
f = fuel cost
h = heating rate
V = variable operating cost

The authors indicate that both give similar results, which would be identical in simple analyses. However, it is essential that all comparisons are made using the same formulation.

LCOE for South Africa

In the IRP process, the technologies that are being considered are nuclear generation, coal generation, open and combined cycle gas generation as well as wind and solar PV. In the IRP 2018, hydropower from Inga is also considered, but will not be reviewed here as this is a unique generation source compared to generic sources that can be used

at locations and volumes as desired (SA DoE, 2018). These costs were not updated in the IRP 2019.

Summary of results

NREL and other entities, such as the World Nuclear Association, Lazard Associates and others have conducted extensive comparisons for the LCOE from various technologies (NREL, 2019;World Nuclear Association, 2019;Lazard Assoc., 2018b). It is important not so much to repeat these exercises but to confirm that the analyses are relevant to South Africa. the referenced analyses present their results with a range for each technology. For this analysis, specific numbers were generated based on IRP premises and publicly available information. The intent is to demonstrate that the LCOEs for South Africa are realistic compared to these references and demonstrate the comparison of the relative costs for each technology.

The comparison of LCOE for the various technologies is shown in Table 23. NREL publishes a comparison of LCOEs for various technologies on an annual basis for project completed in the US. These have a range of answers based on location, size and particularities of the projects considered. The ranges from their 2017 analysis are reported in this table (US EIA, 2017a). The numbers reported as RSA are based on the capital costs from the IRP and the premises discussed below.

Table 23 - Comparative LCOE for various technologies

LCOE – per kWh			
	NREL ($)	RSA ($)	RSA (Rand)
Nuclear – 1	0.09-0.12	0.10	1.47
Coal	0.07 – 0.15	0.10	1.39
Gas	0.033 – 0.15	0.09	1.26
Diesel	No data	0.16	2. 28
Wind	0.03 – 0.14	0.05	0.76
Solar PV	0.03 -0.06	0.07	0.99

(1) The NREL study did not include costs for nuclear. The LCOE quoted above comes from an analysis completed by the World Nuclear Association from 2013 (World Nuclear Association, 2019). The numbers have not been converted into current dollars. That study reported a comparative LCOE for coal as USD 0.07-0.09 and gas as USD 0.04-0.07.

For each of the elements in the LCOE as summarised in Table 24, the following describes the costs associated with each of technologies.

Table 24 - Generation Cost by Technology

IPR 2019 Generation Cost by Technology			
	Capital Cost	Fixed Operating Cost	Fuel
	Rand per kW	Rand per kW	Rand per kWh
Gas	10 449	148	1.40
LPG	9 499	148	1.92
Diesel	9 499	148	3.37
Coal	48 852	944	0.51
Nuclear	70 564	1 352	0.09
Wind	16 963	634	0
Solar PV	16 013	294	0
CSP	53 032	953	0

Capital cost

Capital cost is the major factor that goes into the comparison of generation costs. These costs vary considerably as shown in Figure 77. These are upfront costs so the investment must be made prior to generation of electricity and associated income from the project. These costs are spent over the years of project development, which can vary from one or two years for gas projects to six years or more for nuclear plants. The World Nuclear Association stated that "Nuclear power plant construction is typical of large infrastructure projects around the world, whose costs and delivery challenges tend to be under-estimated" (World Nuclear Association, 2019, pg. 1). As can be seen from the implementation of two new coal fired generation plants in South Africa, the same statement can be made for coal fired generation (Steyn, 2019).

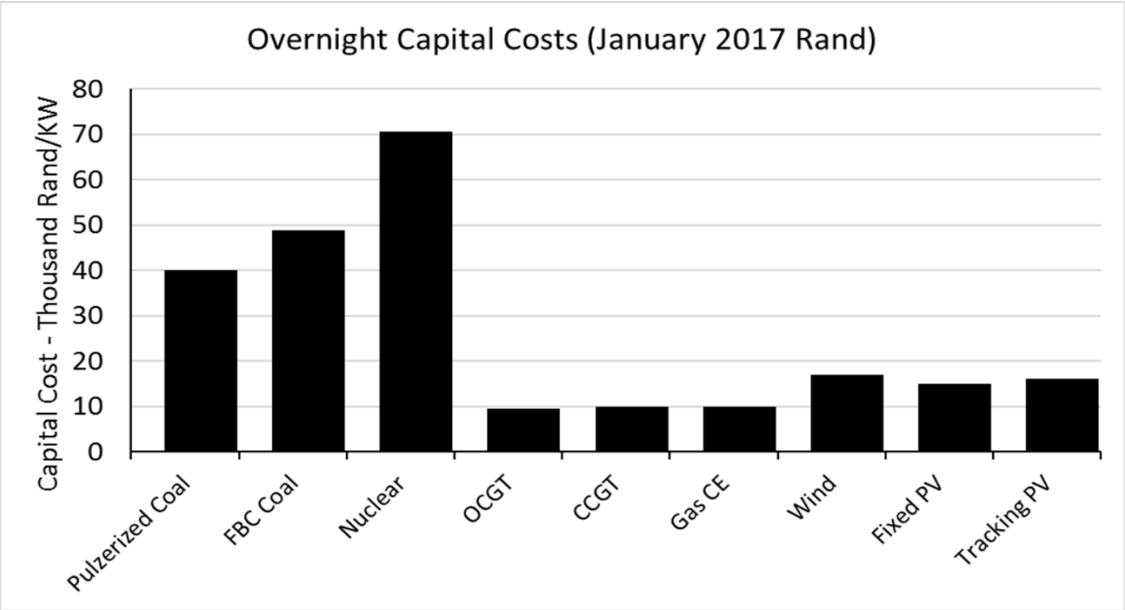

Figure 77 - IRP 2018 Capital Cost Comparisons – data (SA DOE, 2018)

Cost of capital or discount rate

The major difference between the two formulations of LCOE is the use of cost of capital, generally considered to be the weighted average cost of capital (WACC) in the NREL LCOE, versus a discount factor in the UK definition. Conceptually, the use of this factor is simple, but in practice it can be complicated and can have a significant impact on the results. In the UK definition, both costs and energy are discounted at a defined rate, giving the discounted energy and cash values. Normally, the discount factor is equal to the cost of capital or the WACC. In the NREL formulation, more assumptions must be made to use the WACC. Different technologies will likely have different financing rates based on assumed risks as well as political consideration. The percentage of the capital cost to be financed also affects the WACC as well as the expected return on equity that the investor requires on the non-financed portion (NREL, 2019). Generally, for comparison purposes, the assumption of complete financing and a consistent WACC for all projects is assumed. This brings the two LCOE calculation techniques close to one another.

In South Africa, there is exchange risk consideration that must also considered in cost of financing. The generally accepted WACC or discount factor for South Africa is 8.2 %, as noted in the IRP 2019 (SA DoE, 2019c, pg. 29). This is the rate that has been utilised in this analysis.

Project life and amortisation period

The lifespan of a generating project affects the costs in two ways. The first is the amortisation period. This is the period that the funding source expects the project to last to be able to recover the cost of development. The second is the time span that the project should be generating income to provide payback and profit to the project developers. This is one area that has elicited much debate and advocacy from the various project supporters. These considerations vary from the 20-year certification for wind plants, the 20 to 25-year warranties that solar panel manufactures provide for solar panels to 60-year safety licences that nuclear reactors are provided for their nuclear plant. None of these factors directly relates to project lifespan but are often used to frame the argument.

There is evidence which suggests the service that the generation unit provides, that is base load verses cycling use has more impact on the life of the facility than the technology. This is supported by engineering considerations where the failure modes of equipment are considered (Bergh & Delarue, 2015). For base load generation where facilities are used in an “always on use”, the primary design failure mode is creep failure. For cycling use, fatigue is as or more critical than creep in the failure of equipment (Shibli & Ford, 2014).

There have been several recent studies in the United States of America and Europe to compare actual lifespans of projects. All these studies have found that lifespans of projects vary considerably but centre around a design life of forty years. Farfan and Breyer made a lifetime analysis for different power plant types on a global scale (Farfan and Breyer, 2017). 900 power plant units which have been decommissioned worldwide were considered. The analysis shows that average lifetime (weighted with capacity of units) for different technologies is 34 years (gas-fired), 34 years (oil-fired), and 40 years (coal-fired). According to their analysis, nuclear plants have averaged only 29-year of life. Additionally, "in France, only 10-year extensions are granted and the safety authorities have made it clear that there is no guarantee that all units will pass the 40-year in-depth safety assessment" (Schneider and Froggatt, 2017, pg.14). In the USA, a study found the most common age of recently retired coal units was 50 to 60 years, natural gas steam turbine plants was 40 to 50 years, combustion turbine plants units was 40 to 50 years and nuclear units was 30 to 40 years (Wiser, Mills and Seel, 2017). These studies do not isolate the causes of project decommissioning but the rationale for decommissioning in general are economic considerations for whatever reasons. Type of service appears to be more of a factor than technology type, with peaking plants retiring sooner than plants used as base load. However, in all studies, nuclear plants have had significantly lower life spans than other technologies.

In terms of wind, projects in Europe have generally been given 20-year certification, after which they must be recertified. The history of the business is now reaching a point where projects are beginning to meet this time and require recertification. With improving technology and costs for larger wind turbines, many projects consider repowering versus life extension maintenance (Niewczas & Mcmillan, 2016). It will be many years before enough projects reach their ultimate life to determine how these lifespans compare to thermal plants.

For solar PV plants, there is even less history than there is for wind projects. Solar panel manufactures have historically provided warranties that their panels will provide over 80 % of design capacity by the 20th year. Recent high-quality panel providers are now offering twenty five year warranties at 85 % capacity and thirty year performance warranties over 80 % (Jordan & Kurtz, 2015). However, this should not be considered equal to project lifespan. A project producing 80 to 85 % of nominal capacity after 20 to 25 years is unlikely to stop generation at that time. The final lifespan of these projects is still unknown but is likely significantly more than the twenty-five years of the warranty period.

For project comparison, the US EIA uses a thirty year life for all projects (US EIA, 2019a). As per this comparison, this lifespan will be applied to all technologies.

Life time degradation of power plant performance

All projects suffer some level of performance degradation over time. A statistical review of coal plants from NETL in the United States of America showed an average capacity factor decrease from 80 % to 60 % by year 40 and a significant increased speed of decline after that, as seen in Figure 63 in Appendix B (Nichols, 2016). This implies an annual performance degradation of coal plants of 0.63 % per year. Most projects spend a majority of their operating cost repairing, replacing or upgrading systems to overcome this degradation over time (Parsons Brinkerhoff, 2014). Thermal plant operators describe the plant performance curves as saw patterns, where performance degrades until repairs are made, followed by an increase after repairs followed by degradation until the next repair. Coal plants normally have major maintenance overhauls every four years and minor overhauls every two years (Parsons Brinkerhoff, 2014). As for gas plants, the major overhauls occur every six years and the minor overhauls every three years (Parsons Brinkerhoff, 2014). After some time, it is more economically efficient to accept performance degradation rather than make the higher costs to bring the system back to original levels and utilities accepting a lower on time factor for the older plants. As most thermal plants have many components in common, degradation for thermal plants does not vary considerably by technology.

Wind generation facilities have a large percentage of moving parts and these are subject to wear and degradation with time. A study in the UK indicated that offshore wind turbines suffer about 1.6 % degradation in performance per year on average. Other studies indicate degradation averaging 1 % per year (Niewczas & Mcmillan, 2016).

Solar PV systems are much simpler than thermal plants and the major degradation that occurs is in the solar panels. This is covered for the first 20 to 25 years by panel manufactures' warranties. These warranties indicate a degradation of 15 % to 20 % over the warranty period or 0.66 % to 1 % per year. According to a study from NREL, actual degradation of solar PV plants has averaged about 0.5 % per year (Jordan & Kurtz, 2015).

Operating and maintenance costs

Operating and maintenance (O&M) may be divided into 'fixed costs', which are incurred whether or not the plant is generating electricity, and 'variable costs', which vary in relation to the output. Normally, these costs are expressed relative to a unit of electricity (for example, cents per kilo Watt hour) to allow a consistent comparison with other energy technologies. The variable operating costs used in this analysis are those generated by the US EIA (US EIA, 2017a). Nuclear generation has been shown in a number of studies from the United States of America, the UK, France and Australia to be approximately 30 % higher than the operating cost of coal fired plants in the same area. This is consistent with the estimates from US EIA as shown above in Table 24 (World Nuclear Association, 2019).

Coal generation has a lower operating cost than nuclear plants but significantly higher than gas plants due to the relative complexity of the plants. These expenses increase significantly over the life of the plant as more systems require refurbishment and replacement (Parsons Brinkerhoff, 2014). Cycling of these plants shortens the operational life and increases the operating expenses. A study of the operating cost of coal generation plants in Ireland indicates a 30 % increase in operating costs when the coal plant is used in cycling mode compared to base load use (Shibli & Ford, 2014).

Wind generation has a lower unit operating cost than coal or nuclear plants but higher than gas or solar PV generation. While wind power involves significant moving parts and therefore related maintenance, there has been less experience with these plants and less allowance in the operating costs of life extension as there is in larger base load plants.

Gas facilities, whether fuelled with natural gas or diesel, have low operating cost due to the low complexity of the plant.

Solar PV systems have a minimum of moving parts and therefore have low operating costs. Other than cleaning, there is minimal maintenance done on a solar PV plant (SunShot Group, 2016).

Fuel cost

Fuel cost varies considerably by technology and has a major impact on the ultimate cost. The cost of fuel is dependent on the heating value of the fuel in a particular usage. Based on US EIA estimates, a value of 10 000 kJ of fuel for 1 kWh of generation was used, which is the approximate requirement for an open cycle plant (US EIA, n.d.). Prices vary over time in the international market based on supply and demand, which indicates that fuel cost has a range rather than a fixed value. Since fuels internationally are not priced in Rands, there is an exchange rate factor for all fuels, including coal. For each of the fuels considered, the latest year average price was utilised.

The lack of fuel expenses is one of the prime advantages for generation from wind and solar. Nuclear plants use minimal quantities of fuel and therefore the fuel costs for nuclear generation is minimal as well. The cost of fuels for the different technologies is shown above in Table 24.

Coal has the lowest fuel cost in South Africa of any of the fossil fuel-based systems. Historical costs in South Africa of coal being used for generation have been based on long term contracts significantly below international or export pricing. This creates somewhat of a subsidy on the price compared to the option value that would be created if this coal was exported. It is apparent that this has also led to lower quality coal being used for local generation, with lower heating value from the coal plus additional challenges with increased ash and contaminates from the coal used (Eskom, 2016;

Evans, 2019). As these long-term contracts come to an end, the plant operators are facing increasing costs for the coal as well as increased logistics costs in getting the coal from sources not adjacent to the power plants. As shown in the cost information from the SA DoE, the cost of local usage is approaching export pricing (Motiang, 2018). Over the last ten years, the export price of coal from South Africa has been in the range of 0.3 to 0.65 R per kWh with an average of 0.45. The price for 2019 has averaged 0.51 R per kWh.

Diesel, while quite convenient regarding transport and storage, is the most expensive fuel for power generation. Diesel is a refined product from crude oil and its costs are directly related to oil price plus the cost of refining. With oil prices changing significantly over time, this means that diesel prices also vary accordingly. Over the last ten years, diesel has varied from below 2 R per kWh to over 4 Rand/kWh with an average of approximately 2.8 R per kWh (Motiang, 2018). In their 2019 integrated report, Eskom reported a diesel fuel cost of 3.13 R per kWh of generation for the financial year 2018 and 2.71 for 2017 (Eskom, 2019a). The Eskom costs from their report are shown in Table 25. For this analysis, an estimated diesel cost of 3.37 Rand, nearly equal to the Eskom target for 2021.

Table 255 - Eskom Reported Diesel Costs

Eskom Diesel Fuel Costs					
	Target 2021 / 22	Target 2091/20	Target 2018 / 19	Actual 2018 / 19	Actual 2017/18
Generation - GWh	3 710	2 174	211	1 202	118
Diesel Cost – million Rand	12 526	6 975	666	3 768	320
Fuel Cost – R per kWh	**R 3.38**	**R 3.21**	**R 3.16**	**R 3.13**	**R 2.71**

As per Eskom Integrated Report for 2019 (Eskom, 2019a, pg. 110)

Internationally, natural gas is the fuel most used for dispatchable power generation. Natural gas is more difficult to transport and store compared to liquid or sold fuels and traditionally is used only in vicinity to its production, within the distance it can be economically transported by pipeline. The market for natural gas was expanded to the entire world with the advent of liquefied natural gas (LNG) for transport and storage (International Gas Union, 2017). Where markets with pipeline gas have the product priced based on production costs for the gas, LNG prices have traditionally been based on the replacement of other fuels (particularly coal and oil) for power generation. On this basis, the price of natural gas supplied by LNG has been priced at a defined discount to these other fuels. The largest LNG market in the world is in Japan and the price is generally in the range of 60 % of the price of fuel oil delivered to Japan (Japan Office of Director for Commodity Market, 2018). Thus, gas pricing is related to oil pricing but maintains an advantage whatever the price of oil. Over the last ten years, LNG prices in Japan have varied from 0.7 Rand/kWh to 1.8 Rand/kWh and averaged approximately

1.3. The average cost in 2018 of 1.4 R per kWh has been utilised for this analysis. The only natural gas currently being sold in South Africa is that from Sasol. The SA DoE reported that the approved price for this gas ranged from 42 to 87 R per GJ in 2017 depending on the volume of use, corresponding to 0.4 to 0.9 R per kWh (Motiang, 2018). It is expected that in the next decade, the price of natural gas in South Africa will move to a price based on LNG import pricing as this becomes the dominant source of supply.

Gas pricing has lost some of its direct pricing to oil as the United States of America has entered the market to supply LNG (Charles River Associates, 2018). In the USA, gas pricing has long been distinct from oil pricing and is generally based on production costs with a reference price known as the Henry Hub price. The Henry Hub price is the price at a transit point in Louisiana where a number of pipelines intersect (US EIA, 2018c). Henry Hub price varies considerably from oil pricing. With the USA becoming a major LNG exporter, it is pricing LNG into the market related to the Henry Hub pricing plus costs to liquify and transport. This has resulted in international gas pricing becoming less tied to oil prices. It is expected that international gas pricing will reduce over time as more USA gas is on the market as was seen in Figure 24 (World Bank, 2018a).

Low fuel costs give nuclear energy an advantage in comparison to coal and gas-fired plants. In the assessment of the economics of nuclear fuel costs, allowances must be made for the management and the ultimate disposal of radioactive used fuel. According to analysis from the World Nuclear Association, even with these allowances, the fuel costs of a nuclear power plant are typically about one-third to one-half of those for a coal-fired plant (World Nuclear Association, 2019). For this analysis, the price of nuclear fuel of 0.0065 USD per kWh of generation was used (World Nuclear Association, 2019). At the exchange rate of 14 R per USD, this translates to 0.09 R per kWh.

Usage or capacity factor

Comparisons of LCOE use the capacity factor over the life of the plant. As noted above, all plants suffer performance degradation over the life of the operation. This must be built into the calculation of the average capacity factor over the life of the project. As noted in Figure 63, coal plants degrade from 80 % availability to 60 % over their life, thus 70 % represents a likely average capacity factor. This is normal for a base load plant, but for mid-merit or peaking use, there are other factors to be considered. The combination of creep and fatigue stresses lead to additional costs and downtime as well as decreased performance over time.

Studies have been conducted in the United States of America and in Europe on the cost of cycling large generation plants. These studies all show that the cost of cycling nuclear and coal thermal plants is three to five times the cost of cycling a gas turbine

plant and takes much longer for the plant to ramp up or down (Kumar, *et al.,* 2012; Bergh, *et al*., 2015). There are also indirect costs associated with cycling that are higher for thermal plants than for gas turbine plants. Due to the uncertainty of the number of cycles that should be considered at any given load factor, these costs were not considered in the comparison of LCOE as a function of capacity factor.

For peaking and mid-merit usage, fuel costs go down as the number of hours that plant is used decreases. This is one of the major advantages of gas fired turbine plants. The upfront capital costs for gas turbine plants are much less than for other plants and a much higher proportion of the cost of generation is the fuel cost. Figure 78 shows the comparison of LCOE over the range of a mid-merit facility. As can be seen in this graph, the fuel cost for a diesel power plants makes it more costly than coal or nuclear for anything above about a 30 to 40 % capacity factor. Gas fuelled generation remains competitive with coal and nuclear generation at any capacity. For peaking use, as demonstrated in Figure 79, over the range of 1 to 5 % capacity factors gas and diesel fuelled generation are significantly less costly than coal or nuclear. This is due to the cost of amortisation of the larger capital costs for these facilities. The higher cycling costs of nuclear and coal plants noted above would increase the difference in these costs at low capacity factors.

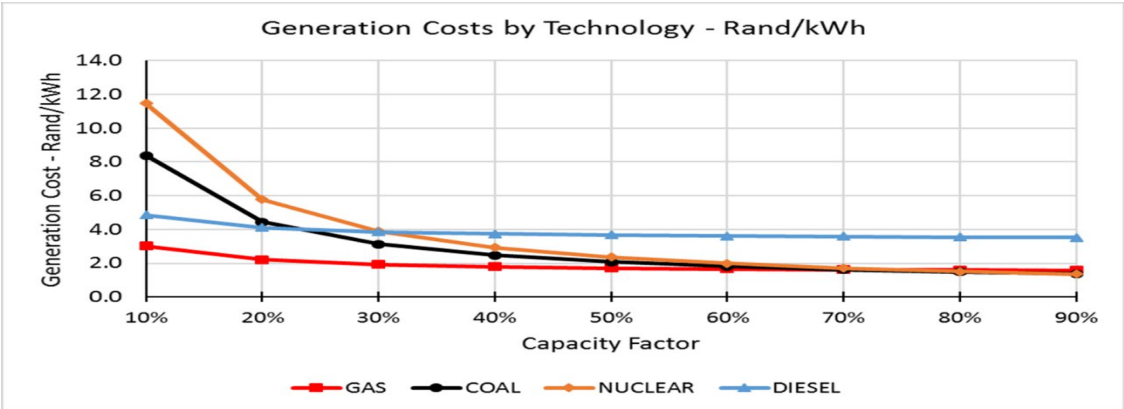

Figure 78 - LCOE by Generation Technology

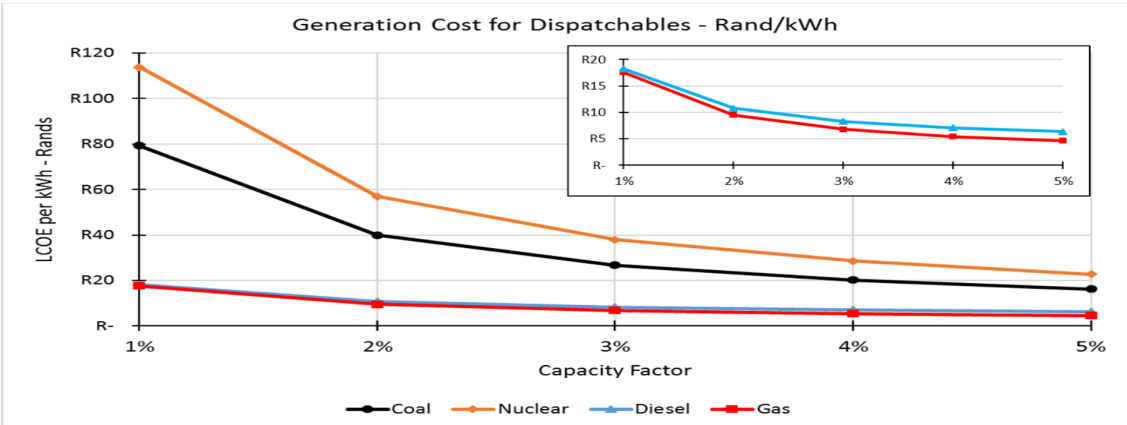

Figure 79 - LCOE for Dispatchable Usage by Technology

Limitations of LCOE

One of the major arguments utilised against the use of LCOE to compare generation technologies and against the use of renewable generation from wind and solar is the concern that a LCOE comparison ignores the overall system cost of a renewable based generation system. Wind and solar are intermittent generation sources and must be used as available, not necessarily when needed. This requires that there is significant available storage or dispatchable power to fill the gaps between supply and demand. This is a valid consideration that must be considered in comparing the costs of generation from various sources. The cost of comparative total development scenarios will be considered in the next section.

LCOE comparison and scenario comparisons also do not account for how the cost of dispatchable energy can be accounted for in the system. While the requirement for dispatchable power has been defined in renewable based systems and the overall cost of these systems is attractive, the question of how the customer pays for this dispatchable energy is not as clear. With utilisation factors in the range of 2 % to 5 %, the cost for energy from these plants will either be quite high or there must be a method of paying for the availability of these resources in their backup mode. This is a concept that is currently in discussion internationally and will be reviewed in section D.4.

D.3. Comparison of scenarios

In South Africa, there will be the requirement for major investments in new generation capacity in the coming years to replace the retiring generation facilities and meet the growth in demand. For comparison purposes, it was assumed that the current base load generation facilities would be decommissioned linearly from the current 43 GW down to 20 GW between 2020 and 2050. Additionally, it was assumed that demand would grow at 1.2 % per year in this period.

Input information

For this analysis, six cases were developed, four without the use of renewable generation and two with renewable generation. The four non-renewable generation cases assume that all new power is supplied by the relevant technology as needed. No specific costing for cycling of plants was added. Capital costs and operating costs are as those used in the IRP process reviewed in the previous discussion. Fuel costs are from the estimates used in the LCOE discussion. No inflation effects or cost improvements were considered.

US EIA estimates that the construction time for a nuclear plant is six years, four years for a coal plant and three years for a gas plant (US EIA, 2017a). Solar and wind plants have construction times below that of other technologies, however, for this analysis the three years as per gas plants was used. To level the comparison between technologies, in this analysis it was assumed in this analysis that the first generation

would come after six years in all cases. At that time 12 GW must go online, followed by an additional 2 GW each year over the study period until 2050.

Fuel costs are only considered for the amount of energy generation. No additional fuel allowance for start-up and shutdown during cycling was considered.

Summary of results

As expected, the renewable cases showed a significant increase in the need for installed capacity. For each of the non-renewable generation cases, 54 GW of new generation capacity was required to be installed over the period considered. For the case of renewables with 10 % dispatchable generation, the required capacity was 152 GW. These values were derived from the generation as indicated in the Dispatchable Energy Model meeting this energy from wind, solar and dispatchable generation sources.

This analysis compares the amount of money that must be expended for capital costs, operating costs, and fuel costs for each of these scenarios for the study period. It does not include the costs of providing the power from the existing base load facilities as this is the same in all cases. In addition, a net present value comparison was made for each scenario including all the capital, operating cost, and fuel costs for each scenario. This was discounted at 10 % giving an NPV @ 10 %.

Model output information

Table 26 summarises the results from each of these scenarios. There is a significant difference in the total cost of renewable based generation compared to any of the conventional based systems.

Table 266 - Generation Scenario Output

Generation Scenario Cost Comparison					
	Billion Rands from 2020 to 2050				
	Capital	O & M	Fuel	Total	NPV@ 8.2 %
Nuclear	4 368	1 050	490	5 908	2162
Coal	3 024	735	2 464	6223	1822
Gas	647	116	6 776	7 538	1652
Diesel	588	116	16 310	17 014	3591
Renew+ 10 % Gas	2 339	816	678	3 832	1155

Factors not considered

This is only a cost comparison between the various technologies and ignores several factors in comparing these generation sources. The most significant factor ignored in this analysis is the amount of greenhouse gas emissions and pollution production that each of these technologies' causes. Considering this factor or a cost associated would

provide further comparative value to the renewable case compared to coal, gas, or diesel.

In the case of nuclear generation, there are two factors that are not considered in this analysis or in most analyses. This is the cost of disaster insurance and the cost of waste disposal. Both of these costs are ignored by countries by choice. Insurance is specifically covered by the "Convention on Supplementary Compensation for Nuclear Damage". However, they are real costs that must be absorbed by someone, generally by society, outside of the scope of the project. There was one major incident at Three Mile Island in the USA in 1979 followed by two major disasters, Chernobyl in 1986 and Fukashima in 2011, in the nuclear industry out of a fleet of 450 units. The possibility of a major incident is not a trivial consideration. While it is expected that new nuclear technologies are safer than the current fleet, there is no movement to eliminate the liability limits. No direct subsidies were assumed for any generation source.

Grid integration for each of the technologies has been ignored. Each technology will have some issues with grid integration costs as the generation locations for each technology will have given geological considerations. Nuclear generation would likely require locations along the coast for cooling while coal would be built close to fuel sources to minimise transport costs. Gas would need to be located near gas sources while diesel generation could be generally sited where needed. This is an undefined cost that would be difficult to clearly compare between technologies.

Grid inertia has been raised as an issue with renewable based systems as wind and solar generation do not provide the spinning inertia provided by base load thermal plants. However, with the requirement to have dispatchable backup from diesel or gas in each of the renewable scenarios, this should not be a factor leading to any particular choice.

D.4. Capacity Market

As shown in the previous two sections, the generation costs from wind and solar based systems with appropriate dispatchable backup are lower than other alternatives whether considered from the system cost or the comparison of LCOE. With expected decreases in the cost of wind and solar generation, there is a distinct cost advantage to the renewable generation scenario. In addition there is the advantage of a short development schedule and without the need for large scale projects as required for nuclear and coal-based generation. This is the preferable solution, even ignoring decarbonisation considerations.

However, while the overall cost of generation is lower with a renewable based system with gas backup, this doesn't account for how to pay for the backup power. This

is a challenge that is being addressed around the world as the transition to renewable based generation systems continues. Two market methods have been considered and are in use (Ela, *et al.*, 2014).

The first concept for dispatchable energy is a pure energy market, where electricity supplied for any period, generally for the coming hour or shorter period, is bid to potential suppliers until all the demand is met. This can result in quite high rates on the few occasions of peak demand. The largest system where pure energy markets are being used is the Ercot grid in Texas (US EIA, 2020). In this market, the regulators have established a maximum price for peak supply. It is set at USD 9 000 per MWh or USD 9.0 per kWh, compared to a retail price in that market averaging USD 0.11 per kWh (Texas Public Utility Commision, 2019). There are some political limitations to this type of market as well as the potential that no investor will take the risk of building a plant that will meet this market but be idle with no income most of the year. This USD 9 per kWh would correspond to a price of electricity of R 153 per kWh at an exchange rate of R 17 per USD. It is unlikely that this would be accepted by the South African government or by the consumers, even if it was only for "insurance generation" periods as it is higher than the assumed cost of unserved demand.

The second market method that is being used in most markets is a capacity payment system. In their analysis, NREL states "Capacity markets can be defined as a means of providing revenue to owners of power plants who in return agree to stand ready to supply power when needed" (Jenkin, *et al.*, 2016, pg. 1). In Europe, capacity markets are being developed in most countries. In a review of these market developments, Timera Energy stated "Coal and nuclear closures cannot be offset by intermittent renewable generation alone. This underpins the need for investment in new flexible capacity across storage, gas, demand response, interconnectors, flexible renewables and hydrogen. Capacity payments will play a key role in delivering that investment" (Timera Energy, 2020, pg. 3) It is expected that most utilities will move to the use of capacity markets to meet the need for dispatchable energy.

Gas fuelled power plants have the lowest capital cost of any of the major forms of dispatchable generation as was shown above in Table 24. In addition, they can be ramped up and down quickly and can be built on modular sizes in a short period. This low capital cost and responsiveness makes them the ideal candidate for meeting this capacity need. Assuming the capital cost and fixed operating costs indicated from the review above, a gas fuelled power plant with a 25 year life and a 8.2 % cost of capital should be able to provide the installed capacity requirement at approximately R 2400 per installed kW per year or R 200 per month. As indicated above, the fuel cost for using this installed capacity would be in the range of R 1.4 per kWh (subject to the varying price of fuel).

Eskom is moving to a pricing structure for its customers with a peak use charge plus an energy charge. This concept it totally aligned to the idea of a capacity market for

generation with a separate charge for energy generation. According to analysis of peak rate charges for small-scale embedded generation (SSEG) users in South Africa, monthly peak charges range from R 229 to R 550 per kW with energy charges (excluding the subsidised rate below 600 kWh per month) ranging from R 1.49 to R 2.06 per kWh (Mashiri & Bekker, 2018). The two concepts of peak demand charges and capacity payments for dispatchable power seem to be complementary.

D.5. Conclusion

With the low cost from wind and solar resources, backed up with natural gas fuelled dispatchable power, South Africa will have the lowest cost generation system going forward. This system will also have the required responsiveness in planning and operation. With a capacity market payment system, this system can provide the required generation with payment to producers consistent with the way that it is being charged to customers. This should provide a workable format for low cost generation going forward. As wind and solar generation are greenhouse gas emission neutral and the dispatchable generation would be required at minimal levels, this should also be the ideal system for meeting climate change minimisation objectives.

Appendix E – Using LPG Fuel to Reduce the Operating Cost of the Ankerlig Peaking Power Plant

E.1. Introduction

Commencing in 2010, the South African government, through the Department of Energy (now the Department of Mineral Resources and Energy), developed a national long-term forecast and plan for electricity production in the country. The process used was the development of an Integrated Resource Plan (IRP) (SA DoE, 2011). Recognizing that the conditions assumed in the IRP process can change, the plan is for the IRP to be a living document that is updated periodically. Updates to the IRP were prepared in 2013, 2016 and 2018 (SA DoE, 2018)

In the 2018 IRP, it was stated that the short-term needs of the system were well provided for and no new generation capacity was needed until later in the coming decade. Eskom believed it was well on its way to improving the availability of its base load plants and was in the process of commissioning two new plants, Medupi and Kisule, which would add almost 20 % of new capacity (SA DoE, 2018). The 2018 update to the IRP was issued for comment in September 2018. Almost before the 2018 IRP was finalised, Eskom found significant problems with the new coal plants and performance challenges with the existing plants (SA DoE, 2019c). These problems led to load shedding in late 2018. Unfortunately, the problems increased in 2019 and so did load shedding. This resulted in level 6 load shedding for the first time in December 2019, with Eskom shedding over 6 GW of demand.

The short to medium term problems found with the 2018 update of the IRP led to another IRP update in 2019, just a few months after the 2018 IRP was released. As detailed in the 2019 IRP, the short-term problems will be challenging to resolve, and load shedding will be around for some years. In addition to significant load shedding due to the shortage of baseload generation, Eskom has been using their peaking generation facilities much more than they had planned. These plants are fuelled with diesel fuel which is quite expensive. Eskom has forecast in their latest integrated report that they expect to generate 3700 GWh of power from the two peaking plants, which corresponds to a 21 % usage factor and will necessitate the use of approximately 12 billion Rand of diesel fuel this year.

The two peaking plants are dual fuel plants and can be converted to gas fuel if it was available. As gas is significantly less expensive on an energy basis (per GJ), Eskom would like to make this change. However, they do not have access to gas. With minimal available local gas production, gas importation will be required to provide a source of this fuel. The assumption throughout the development of the various IRPs was that this gas would be provided through importation of liquified natural gas (LNG). This has

proven to be economically challenging due to the high upfront cost of importation facilities.

E.2. The LPG Option

Another option for diesel replacement for these peaking plants, which might not fully capture the cost advantage of natural gas but provide much of the benefit is the use of liquified petroleum gas (LPG). LPG is currently being imported into Saldanha Bay, has advantages of storage and transport much like diesel and is much less expensive than diesel. This is a solution that can be implemented in a short time frame.

Fuel costs

Diesel fuel is quite convenient, but it is expensive. It is readily available in South Africa and since it is a liquid it can be easily transported and stored. It can also be used in internal combustion engines as well as dual fuel gas turbines. It is less polluting than coal with lower sulphur dioxide, nitric oxide and particulate emissions as well as less CO_2 emissions during combustion, making it a cleaner option than coal fuelled generation (US EPA, 2013). However, it still has significant pollution and CO_2 production, so it is not a preferred fuel. The major issue for diesel, however, is its cost. Diesel fuel in South Africa currently has a price of approximately 14 R per litre, or 377 R / GJ (SA DMRE, 2020). Assuming a usage of 10,000 GJ per GWh of power generation, this implies a fuel cost for diesel generation of 3.8 R per kWh.

LPG is an alternate fuel that is also currently available in South Africa. Unlike methane, which is the major component of natural gas, LPG itself is not considered to be a greenhouse gas. However, it does produce about 20 % more CO_2 during combustion compared to natural gas. The CO_2 production from burning LPG is about 60 % of that from diesel fuel. It also produces less pollutants than diesel when burned (US EPA, 2013). However, the real advantage is low cost. The South African government regulated price for LPG is approximately 5 R per litre. This converts to 200 Rand/ GJ (SA DMRE, 2020). Using this fuel for power generation would imply a fuel cost of 2.0 R per kWh. Thus, a conversion from diesel fuel to LPG would reduce the fuel cost by almost 50 %.

Natural gas sourced by LNG importation is not currently available in South Africa, so the price for this fuel must be inferred from other sources. The major current market for LNG is Japan, so most LNG price comparisons are based on LNG imported into Japan. The current price for LNG into Japan is in the range of USD 8 per GJ (120 Rand), but most of the discussion of price for LNG importation has assumed USD 10 per GJ. (145 Rand) (Japan Office of Director for Commodity Market, 2018) (Delphos International Ltd., 2019). This would be 25 % less expensive than LPG. However, as noted below, this is the cost of LNG as it arrives at the terminal. The cost of LNG delivered to the power plant will be higher based on the cost of importation and

handling. LNG is only liquid when kept at -162 ºC. Therefore, storage and transport of LNG is a more difficult compared to diesel or LPG.

The major challenge for LNG usage, which has been the reason that the Saldanha Bay importation project is still in feasibility analysis is that the amortisation of the cost of the facilities must be absorbed by the amount of product. The cost of the LNG importation facilities in Saldanha is estimated to be between USD 600 million and USD 1 billion (8 to 14 billion Rand) (Delphos International Ltd., 2019). To have enough volume to bring this amortisation cost to a competitive level has led those proposing the project to the suggestion for use of Ankerlig as a mid-merit plant.

The Saldanha LNG terminal

An LNG importation terminal in Saldanha Bay has been a consideration for many years. In 2009, Gigajoule Corp conducted a pre-feasibility study for this project (Visagie, 2013). In 2012, the Western Cape government expressed an interest in building an LNG terminal at Saldanha Bay and conducted another pre-feasibility study (Visagie, 2013). This was followed by several other studies to understand the environmental considerations and the business case for the project. The latest step in the project was a business case feasibility analysis conducted by the Unites States Trade and Development Agency on behalf of the Western Cape government (Delphos International Ltd., 2019). This was completed in 2019.

While the project was conceived to provide gas for commercial and residential users in the Western Cape Area, as stated in the 2013 study "The market evaluation of the Cape West Coast region concluded that gas-fired power generation would play an enabling role to the viability of any of the gas importation options evaluated" (Visagie, 2013, pg. 20). In that study and the 2019 study, the assumption was conversion of the Ankerlig plant from its current peaking service with 5 % capacity factor to mid-merit usage with 40 to 50 % capacity factor. This change was necessary to provide enough throughput volume to make the project viable.

It is possible that the project might proceed, but the requirement to utilise Ankerlig in mid-merit usage is not consistent with the IRP planning (SA DoE, 2019a). Due to the cost of fuel, using these plants in mid-merit service results in an overall more expensive system than solar and wind-based generation with minimal peaking generation (Wright, *et al.*, 2017). In peaking use, the amount of gas that would be needed for the plant is not enough to justify the cost for the terminal. An LPG alternative fuel should be an option worth pursuing. South Africa risks that the LNG facility is never constructed, and we continue to rely on expensive diesel as the fuel for these plants.

The challenge of dispatchability

Importation of LNG for peaking power usage, as well as any other gas source, has a major challenge of balancing use of the gas for dispatchable power with any other usage. Most industrial gas usage has a flat demand profile, with the user needing a given amount of gas each day. Dispatchable power generation is the opposite. Very large rates of gas are needed for short periods and the total annual volume is quite small. However, when needed, the high rate must be available rapidly. This could be for several hours per day up to several days continuously in the highest demand period; followed by low usage for most months each year. Most gas delivery systems have challenges meeting this demand profile and the only solution is significant buffer storage. LPG stored as a liquid acts more like diesel in this regard and can be dispatched as needed.

The use of LPG in gas turbines

While LPG is a hydrocarbon gas, much like natural gas, it is necessary to confirm that this is a suitable fuel for gas turbine usage. This confirmation is provided by the turbine manufacturers. In their product brochures, Siemens confirms that their V94.2 turbines, as used in Ankerlig and Gourikwa, can utilise LPG fuel (Siemens, 2020).

LPG importation and storage

LPG is currently imported into Saldanha Bay and no new importation facilities would be needed to bring the required volumes of LPG into the area. The importation facility currently contains 5 500 tonnes of LPG storage (MOGs, 2020). As for all fuels, the challenge remains in the cost-effective storage and delivery of the fuel for dispatchable usage. Besides being locally available, one of the advantages of LPG is that it is normally in a liquid phase at ambient temperature under pressure slightly above atmospheric pressure. This is a significant advantage for this usage.

There is some question regarding the throughput capacity of the Sunrise LPG import facility in Saldanha Bay and its ability to meet the need for the Ankerlig demand. The issue to be determined is the amount of LPG storage that might be required. There is a relevant reference project in South Africa. In Richards Bay, Bidvest is in the process of commissioning an LPG storage and delivery project (Bidvest, 2020). The project has four LPG tanks which will store 10,000 cubic meter (5 500 tonnes) each of LPG. The cost of the plant was listed as less than 1 billion Rand as compared to an LNG importation facility approaching USD 1 billion (Delphos International Ltd., 2019). Bidvest commenced the project in June 2017, broke ground on the facility in June 2018 and will commission the plant in mid-year 2020 (Bidvest, 2020).

A duplicate of this plant would provide for 40,000 cubic metres of LPG storage or 1 PJ of fuel. Assuming 10,000 GJ/GWh, this stored volume would generate 100 GWh of power. This would be enough to run the 1.3 GW Ankerlig plant for 76 hours or slightly over 3 days, this compares to the current diesel storage at Ankerlig of 16.5 million litres, enough to run the plant for just less than two days.

It might also be possible to completely avoid the expenditure for any additional storage through the usage of a moored LPG tanker in Saldanha Bay providing the equivalent 40 000 cubic meters of LPG storage. The lease cost for an LPG tanker should be in the range of USD 5 million per year (Danish Ship Finance, 2019).

Fuel change economics

Assuming the 5 % usage factor for the Ankerlig plant, the fuel bill for Eskom for this plant running on diesel would be in the range of 2.2 billion Rand per year. LPG fuel would reduce this to 1.1 billion Rand. Thus, there is a saving of over 1 billion Rand per year in fuel with this shift. Assuming that the infrastructure cost to make this change would be the equivalent of a duplicate of the Bidvest Richards Bay LPG plant, the pay-out for Eskom for this change would be slightly less than one year. Higher usage of the plant as seen in 2019 and 2020 would reduce the pay-out time even more. Over a twenty-year period, this should have a fuel savings of over 20 billion Rand.

Other considerations

LPG fuel only gets about 75 % of the improvement in fuel savings that natural gas would give. There is a question of whether this change precludes the change to natural gas. With the minimum investment required to make this fuel change and the quick pay-out time, this change does not imply that the change to natural gas fuel via LNG importation would not be reasonable, but it means that the economic advantage is reduced.

This fuel change-over should not require any investment on the part of Eskom nor government guarantee to take the risk out of the project. Outside investors, like Bidvest or others, can be easily convinced to build the required infrastructure with a suitable fuel supply agreement for Ankerlig.

E.3. Recommendation

Given the probability of load shedding by Eskom continuing for the next several years, this concept should be followed up immediately with all interested parties, which should include potential investors, such as Bidvest or MOGS, Eskom as the customer and the government as the coordinating party. The first step should be a quick feasibility analysis conducted by a reputable local engineering company. Once this shows the feasibility and economic advantage of making this fuel shift, it be put out to bid by the government or Eskom for implementation. This can be conducted like the REIPPPP projects, where companies can bid on the supply of fuel to the Eskom Ankerlig plant, which can be done on a capacity plus usage payment or a simple competitive supply arrangement.

Appendix F – Publications and Presentations

The following is a listing of various publications and presentations where portions of the work in this thesis have been presented.

- The first technical paper related to this work was presented at SASEC 2018, discussing relevant international examples, entitled 'Review of large Independent Electricity Grid systems; Transition to renewable Generation and its Relevance for South Africa' (Clark *et al*., 2018).

- The second technical presentation of work from this research was made to SANEA in 2019 'Brulpadda – Game Changer? reviewing the size and development potential of the Brulpadda gas field (Clark *et al*., 2019).

- The research work related to the Brulpadda analysis was reviewed in an article in the Engineering News in 2019 'Brulpadda field unlikely to support a globally competitive chemicals industry, more exploration needed – experts', (Arnoldi, 2019).

- At the STERG Symposium 2019, a presentation was given related to the forecasting model developed for this work, as reviewed in Appendix B. This presentation was entitled '2030 – 2050 Dispatchable Power Requirement' (Clark *et al*., 2019).

- A technical paper related to South Africa Shale Gas Economics was submitted to the Journal of Energy in Southern Africa for publication in 2019. This paper is included as Appendix C.

- A technical paper discussing the potential to utilise LPG at the Ankerlig power plant has been shared with Eskom in 2020. This paper is included as Appendix E.

- As a representative of STERG, CRSES and Stellenbosch University, participated in the South Africa Gas Forum 1 March 2020 on a panel discussion of use of LPG (Africa Energy Indaba, 2020a).

- As a representative of STERG, CRSES and Stellenbosch University, participated in the South Africa Energy Indaba 2-3 March 2020 on a panel discussion on the transition from coal to gas (Africa Energy Indaba, 2020b).

- Technical input into the Energy Indaba was included in an article in Fin24. 'Numbers for developing an SA gas network still don't add up, Energy Indaba hears', (Smith, 2020).

Appendix G – Storage Patent

The following is the patent application for the Mine Shaft Storage Concept as drafted and submitted by the Law firm Von Seidels Intellectual Property Attorneys on behalf of the University of Stellenbosch. Not included in this section for purposes of space are the first four pages of the submitted document which are empty forms.

AS FILED

SOUTH AFRICAN PROVISIONAL
PATENT APPLICATION

Title: BULK FLUID STORAGE FACILITY AND PROCESS

Patent Application No: 2019/03690

Date of Filing: 10 June 2019

Applicant(s): STELLENBOSCH UNIVERSITY

Inventor(s): CLARK, Stephen Richard, VAN NIEKERK, Johannes Lodewikus

Von Seidels Ref No: P3677ZA00

Postal Address: PO Box 440, Century City (Cape Town) 7446, South Africa
Tel: +27 21 526 2800
Fax: +27 86 660 6208
E-mail: service@vonseidels.com

www.vonseidels.com

Von Seidels
Intellectual Property
Attorneys

BULK FLUID STORAGE FACILITY AND PROCESS

FIELD OF THE INVENTION

This invention relates to the bulk storage of fluids. It relates in particular, but not exclusively, to the bulk storage of gaseous fluids such as natural gas and hydrogen.

BACKGROUND TO THE INVENTION

Reliable generation of power for electrical grids depends upon the availability of dispatchable power, i.e. a source of electricity that can be used on demand to balance supply when this cannot be met by usual means of power generation. Dispatchable power is only used occasionally and when it is used, it must be available in significant volumes. Stored natural gas or hydrogen can serve as a fuel source to support dispatchable power generation.

Reservoir vessels of the displacement type are known for the storage of bulk fluids. For example, US 3360810 describes a floating reservoir which can be moored in an open body of water such as the ocean. Underground storage of gas in depleted oil and gas reservoirs, aquifers or salt domes is also known. However, geological formations of this type are not available in all geographic regions.

Certain types of mining are performed at significant depths, creating generally horizontal, excavated cavities such as stopes, drifts, adits and the like. Mined zones of this type may be large enough to provide sufficient volumes for storage. However, in certain circumstances they may lack adequate structural integrity to prevent leakage of gas. They can also be limited with respect to gas offtake rates on account of concerns relating to their structural integrity during rapid pressure depletion.

There is accordingly a need for additional types of systems and processes which can be used for the bulk storage of fluids.

The preceding discussion of the background to the invention is intended only to facilitate an understanding of the present invention. It should be appreciated that the discussion is not an acknowledgment or admission that any of the material referred to was part of the common general knowledge in the art as at the priority date of the application.

SUMMARY OF THE INVENTION

According to a first aspect of the invention there is provided a bulk fluid storage facility comprising:

an underground container formation defining a container cavity that is at least partially filled with a liquid; and

at least one storage vessel defining an interior fluid storage space and at least one port for filling the storage space with a storage fluid, the vessel being held within the container formation and in fixed relationship to it;

characterised in that the storage vessel is at least partially submerged in the liquid and configured to permit pressure of the liquid to be transferred to the interior fluid storage space.

In preferred embodiments of the invention the container formation may comprise a generally vertical or inclined underground passageway such as a mine shaft. It will be appreciated, however, that the container formation may instead, or in addition, comprise any other suitable underground formation capable of undergoing partial or complete flooding. Such formations may be selected from the group consisting of mine stopes, drifts, adits, galleries, caves and similar geological formations, quarries, wells and other bored or excavated subterranean formations defining cavities.

The storage vessel may be provided with force transfer means to permit the pressure of the liquid to be transferred to the interior fluid storage space. The force transfer means may comprise fluid communication means connecting the storage vessel with the container cavity, thereby to permit at least partial exchange of the liquid to take place between the cavity and the storage vessel. Other force transfer means may instead or in addition be provided for acting between the container cavity and the interior fluid storage space. For example, at least one bladder, piston or lever assembly may be provided, arranged to act between said cavity and said storage space.

The liquid in the container formation, e.g. the mine shaft, may comprise water or other generally aqueous liquid.

The interior fluid storage space of the storage vessel may be at least partially filled or fillable with the storage fluid. In a preferred embodiment of the facility, the storage fluid may comprise natural gas. It will be appreciated, however, that the storage fluid may instead or in addition comprise a suitable gas other than natural gas, or a liquid. Without limitation thereto, such gas may be selected from the group consisting of hydrogen, methane, propane, butane, pentane and other

gaseous hydrocarbons; and such liquid may be selected from the group consisting of crude oil, petroleum, diesel and other types of liquid which are suitable for storage in vessels of the displacement type, on account of their having a density lower than that of a reference liquid (typically water) that is intended to be displaced from the storage vessel.

The storage vessel may include a movable interface member. During operation, the interface member may be positioned between the liquid and the interior fluid storage space of the vessel. The interface member may comprise a movable floor or other suitable piston-like formation. The storage vessel may comprise an elongate vessel body defining a longitudinal axis, and the movable floor may be held captive within the vessel body and be movable along its longitudinal axis. The piston-like formation may be slideably movable inside the vessel body, and/or loosely held within it, and/or movably mounted on and within it.

The movable floor may comprise a float, i.e. it may be adapted to float on an aqueous liquid such as water. It may thus be manufactured from a material having a density lower than that of the liquid. Instead or in addition, the floor may incorporate a deballasting arrangement. Such an arrangement may, for example, comprise an inflatable ballast tank, bladder or the like to enable the overall density of the floor to be adjusted on demand after installation. The floor may serve as an interface between the natural gas and the liquid in the container formation.

Optionally, sealing means may be provided to limit ingress of liquid into the interior storage space of the vessel. The sealing means may comprise seal formations provided circumferentially around the movable floor. A ring-shaped seal or gasket may for example be used.

In other embodiments of the invention the movable floor may be omitted so that, in use, a direct interface is achieved between the liquid (e.g. water) and the storage fluid (e.g. natural gas) and pressure is transferred directly onto the storage fluid by the liquid.

The submersion of the storage vessel in the liquid may be sufficient to maintain a hydraulic head of the liquid above a vertical datum defined approximately by the bottom of the vessel in its normal operative condition.

The storage vessel may be mountable on a portion of the container formation, e.g. upon a wall or lining of a mine shaft, thereby to maintain the fixed relationship of the storage vessel to the container formation. The facility may thus include a mounting arrangement for mounting the

storage vessel on the container formation. The mounting arrangement may, for example, comprise an interstitial lining provided between the storage vessel and the container formation. The lining may be manufactured from concrete or any other suitable binding agent or adhesive. The mounting arrangement may, instead or in addition, comprise anchors, fixing fasteners or the like. While the outside water or other liquid may provide some pressure differential reduction, the relatively extreme lengths of the storage vessels contemplated herein may imply the presence of significant pressures inside each vessel. These pressures must be transferred evenly from the vessel into the surrounding formation to obviate the need to have an excessively thick vessel wall. Advantageously, therefore, mounting arrangements selected for implementation should be configured such that they enable this to occur.

Bypass means may be provided for making a fluid communication between regions of the container formation (e.g. mine shaft) that are separated by the mounting arrangement. The bypass means may, for example, comprise at least one passage or channel defined through the mounting arrangement, to permit liquid to pass between the separated regions. The bypass means may, for example, comprise piping set into a concrete lining positioned between the mine shaft and the storage vessel.

The storage vessel may be mounted such that the longitudinal axis of the vessel body is arranged in a generally upright orientation within the container cavity.

The storage vessel is typically a tank. The vessel body may include a roof region positioned towards one end, a basal region positioned towards an opposite end, and a tubular central portion connecting them.

The basal region may be open-ended, comprising an open skirt formation depending from the central portion. Instead, it may be substantially closed off by means of a ported closure member. In either case, the configuration of the basal region is typically such that liquid may pass, in use, between the storage vessel and a hydraulic head of liquid held within the mine shaft or other container formation. In the case of a ported closure member, apertures defined by the ports should be of sufficient size to permit liquid to flow freely through them so that rapid gas withdrawal can be achieved.

At least one stop formation may be provided within the storage vessel to delimit the range of travel of the movable floor within the vessel. The stop formation or formations may each comprise a

rim or an arcuate or concentric ridge projecting inwardly from the internal wall or walls of the storage vessel. The stop formations may be radially stepped to form a shoulder. Two sets of stop formations may be provided, a first set positioned towards the basal region and a second set positioned towards the roof region of the vessel.

The storage vessel may be mounted at a depth within the liquid such that its roof region is positioned below the surface elevation of the liquid, thereby to provide an operatively upper and an operatively lower liquid cushion of liquid at least partially surrounding the storage vessel. The upper and lower liquid cushions may be connected by the bypass means.

The roof region may include a domed roof formation.

Typically, the storage facility includes conduiting for making a fluid communication between the interior storage space of the storage vessel and a location remote the storage vessel, such as a surface facility, to permit filling and emptying of the vessel with the storage fluid and distribution of stored fluid to consumers. Advantageously the conduiting may comprise inlet and outlet piping or other fluid passages. Suitable valving may be mounted in-line within the piping to regulate flow in and out of the storage vessel. Appropriate secondary seals may also be provided to mitigate risks linked to possible surface incidents. Drawing on known oil field technology, such seals may, for example, comprise surface controlled downhole safety valves (SCDSV).

According to a further aspect of the invention there is provided a bulk fluid storage vessel for installation in an underground cavity, said vessel comprising

a vessel body having a roof region positioned towards one end, a basal region positioned towards an opposite end, a ported filler region positioned towards the roof region, and a tubular central portion connecting the roof and basal regions;

characterised in that the basal region includes an open skirt formation depending from the central portion.

The vessel body may define a longitudinal axis having a length (height) in a range from 100 metres to 1500 metres inclusive.

The storage vessel may include a movable interface member which may comprise a movable floor or other suitable piston-like formation. The movable floor may be held captive inside the vessel body and be movable along its longitudinal axis. The piston-like formation may be

slideably movable inside the vessel body, and/or loosely held within it, and/or movably mounted on and within it.

The movable floor may comprise a float as hereinbefore described.

At least one stop formation may be provided within the storage vessel to delimit the range of travel of the movable floor within the vessel. Two sets of stop formations may be provided, a first set being positioned towards the basal region and a second set being positioned towards the roof region of the storage vessel.

The storage vessel may further include a mounting arrangement for mounting the vessel on a container formation defining said underground cavity, for example a generally vertical or inclined passageway such as a mine shaft. The container formation may include the walls and/or lining of the mine shaft.

According to a further aspect of the invention there is provided a process for bulk storage of a storage fluid which comprises the steps of

utilising an underground container formation defining an underground cavity containing a liquid;

providing a storage vessel defining an interior fluid storage space, the vessel being configured to permit pressure of the liquid in the cavity to be transferred to the interior fluid storage space;

fixing the storage vessel in the underground cavity by mounting it on said container formation, at least partially submerged in the liquid; and

pumping said storage fluid into the interior fluid storage space of the storage vessel.

The storage vessel may be provided with force transfer means as hereinbefore described, to permit the pressure of the liquid to be transferred to the interior fluid storage space. Thus, fluid communication means may be provided for connecting the storage vessel with the container cavity, enabling at least partial exchange of the liquid to take place between the cavity and the storage vessel. Pumping of the storage fluid into the storage space may, during operation, displace at least some of the liquid from the storage vessel into the container cavity via the fluid communication means.

Instead of, or in addition to the fluid communication means, other types of force transfer means

as hereinbefore described may be provided for acting between the container cavity and the interior storage space. Such means may include assemblies comprising bladders, pistons, levers or the like.

In preferred embodiments of the invention, the container formation comprises a generally vertical or inclined passageway such as a mine shaft. The container formation may include the walls and/or lining of the mine shaft.

Further features of the process provide for the storage vessel to include a movable floor, conduiting, a skirt formation and at least one stop formation, and for details of those features and of the storage fluid and liquid to be as hereinbefore described.

An embodiment of the invention will now be described, by way of example only, with reference to the accompanying diagrammatic drawing.

BRIEF DESCRIPTION OF THE DRAWINGS

In the drawings:

Figure 1 illustrates, schematically, a cross-sectional side view a bulk fluid storage facility according to the invention.

DETAILED DESCRIPTION WITH REFERENCE TO THE DRAWINGS

A mine shaft is a vertical excavation which is typically sunk adjacent to an ore body, serving to connect horizontal stopes at different levels to the surface of the mine. A typical mine shaft may comprise a concreted or rock lined, generally vertical cylindrical formation having a depth of up to 3000 metres and a diameter of up to 20 metres. Upon abandonment, mine shafts often become partially flooded on account of water influx from mined-out zones.

Referring to Figure 1, a bulk fluid storage facility (10) is provided as a mine shaft storage system. A partially flooded, abandoned mine shaft (12) serves as an underground container formation and defines a vertical cylindrical cavity (14) (the interior of the mine shaft). An open-bottomed storage vessel or tank (16) of the displacement type is concreted into the mine shaft so that it is held in a fixed vertical relationship to the mine shaft. Thus, in the embodiment shown in the drawings, the

tank is mounted on the shaft's existing cylindrical concrete wall lining (18). A mounting arrangement is provided in the form of an interstitial concrete lining (20) set between the shaft wall and the tank. It will be appreciated that other means of mounting the tank to the shaft wall might be feasible. However, any such mounting arrangement should be capable of transferring pressures evenly from the vessel into the surrounding shaft wall, so that excessively thick vessel walls are not required. A concrete lining is advantageous in this regard.

The tank defines an interior fluid storage space (22) which, in use, may be at least partially filled with natural gas, hydrogen another suitable type of storage fluid as hereinbefore described. It will be appreciated that, in its normal operative condition when used for storing gases, the storage vessel should be substantially gastight.

The gas can be pumped into or out of the tank according to demand. Conduiting in the form of outlet piping (24) and inlet piping (26) communicates with the interior fluid storage space (22) of the tank via ports (28, 30). The conduiting connects the storage vessel with a surface facility (not shown) to permit filling and emptying of the vessel with the storage fluid and distribution of stored fluid to consumers. Surface equipment may include standard gas compression and processing systems.

The mine shaft (12) is partially flooded with water (32). The water may comprise a mixture such as that typically found in partially flooded mine shafts. It may comprise groundwater, rain water, mine water or a mixture of these. As shown in the drawing, the tank (16) is fully submerged in the water so that it is partially surrounded by upper and lower water cushions (34, 36). The water around the tank may provide a pressure buffer for the facility (10).

As shown, the mine shaft (12) and tank (16) are in fluid communication with each other so that water from the shaft can pass into and out of the tank.

In preferred embodiments of the invention, such as that shown in Figure 1, a movable floor or piston-like formation (38) is provided within the tank, positioned between the stored gas and the water. In the embodiment shown, the movable floor comprises a float. The floor may be manufactured, at least in part, from a material having a density lower than that of the liquid. Instead or in addition, it may include deballasting means such as a ballast tank, inflatable bladder or the like (not shown) provided within the float, or a sump pump arrangement (not shown).

Sealing means (not shown) such as a ring-shaped seal or gasket may be provided between the float and the inside of the storage vessel, to limit ingress of water into the interior storage space of the storage vessel. The sealing means may comprise seal formations provided circumferentially around the float.

The movable floor may offer certain advantages. For example, the floor may inhibit gas miscibility, i.e. mixing of stored gas with the water in the mine shaft.

Guide means (not shown) for guiding travel of the floor within the vessel may be provided. An important consideration is the need to keep the floor's central axis aligned with the longitudinal (upright) axis of the mine shaft and tank, i.e. to keep the floor horizontal as it travels. If it shifts from a horizontal orientation it could bind or be vulnerable to leakage. To mitigate this risk the floor may advantageously be provided as a relatively thick "float" type floor. In certain embodiments the guide means may include a rail system.

Although the inclusion of a movable floor is preferred in view of its ability to provide separation between the stored gas and the mine water, it will be appreciated that such a feature is not strictly essential to the operation of the facility. This is because natural gas has a density which is less than that of water. Thus, since the stored gas will float above the water, the water in the mine shaft can act directly upon the gas as a type of piston, and the water pressure may be transferred directly onto the stored fluid in the tank by the hydraulic head of water in the shaft. In certain embodiments, therefore, the movable floor may be omitted. However, this is a less preferred configuration on account of potential drawbacks relating to gas losses brought about by mixing of the stored gas with the water in the shaft.

Water bypass means (40) are provided to make a fluid connection between the upper and lower water cushions (34, 36), thereby to balance their respective pressures and to permit a substantially linear water pressure gradient to prevail between them. The water bypass means may comprise piping or other suitable channels defined from top to bottom through the interstitial concrete lining (20).

The tank (16) includes a vessel body (42) comprising the following components: a roof region (44) having a domed roof formation; a tubular central portion (46); and a basal region (48). The roof formation includes an access hatch (50) to facilitate access into the tank.

The basal region (48) of the tank includes an open skirt formation (52) depending from the central portion. During operation of the facility, water can pass into the basal region from the hydraulic head of water held within the mine shaft.

Two sets of floor stop formations (54, 56) are provided inside the tank to limit the range of travel of the movable floor (38). In the embodiment shown, the stop formations each comprise a rim projecting inwardly from the internal cylindrical wall of the storage vessel. Alternatively, each of the stop formations may comprise a concentric or arcuate ridge. The stops shown each have a radially stepped or frustoconical cross-section so that in each case they form a shoulder beyond which the floor cannot travel. In normal operative condition the first set of stop formations (54) is an upper set positioned towards the roof region (44) of the tank and the second set is a lower set (56) positioned towards the basal region of the tank. Downward and upward travel of the floor can accordingly be limited.

During operation of the facility (10), pressure acting on the outside of the tank (16) is provided by a water pressure gradient prevailing in the mine shaft and surrounding rock. Submersion of the tank (16) in the water maintains a hydraulic head of water provided by a water column extending between the surface of the water and a vertical datum defined approximately by the bottom of the tank. The pressure (58) provided by the water column acts upwardly against the bottom of the floating floor (38), which then transfers an equivalent pressure onto gas contained within the storage space (22) of the tank.

It will be appreciated that, in the case of a fully submerged tank, the pressure applied to the gas will exceed that of the ambient atmospheric pressure prevailing at the surface of the water filling the mine shaft. When the storage tank is full, the pressure near the bottom of the tank is balanced. However, there is a pressure differential inside the top of the tank equal to the difference between the internal gas pressure and the pressure of the outside water. This pressure is transferred into the surrounding rock. When the tank is empty, pressure differences are reduced to near zero.

The water pressure acting upwardly on the floating floor promotes delivery of gas as the tank supplies stored gas. On the other hand, when filling the tank, as more gas is supplied the gas progressively displaces the water in the tank. The water leaves from the bottom of the tank through its open (or ported) basal region.

The pressure rating of the tank will be determined by the depth at which it is intended to be

installed in a mine shaft. By way of example, the roof region of the tank may be set at a depth of 1000 metres into a mine shaft.

Depending upon factors relating to the particular configuration of a given mine shaft, the pressures of the liquid in the shaft, engineering tolerances and materials of construction of the tank, the length (height) of the tank may be expected to range from approximately 100 metres to approximately 1500 metres inclusive. Primary factors which can influence a tank's maximum feasible length may be expected to include, firstly, the maximum tolerable pressure that can be transmitted into the underground formation (e.g. the mine shaft wall) and, secondly, the ability of the formation to provide and maintain a shaft configuration which is aligned sufficiently vertically to allow the floating floor to transit from its lower positional limit to its upper positional limit inside the tank.

For facilities intended for the storage of gas, the removal of residual volumes of gas may be expected to be accomplished primarily by reduction of the pressure of the stored gas. In certain embodiments, final removal may be accomplished by exchange of residual gas and air. For facilities intended for liquid storage (a less likely application than gas storage) removal of residual volumes of stored liquid from the tank may be facilitated by, for example, a sump pump arrangement adapted to pump the final volumes of liquid from the tank.

To meet a requirement of 10 gigawatts of dispatchable energy it is estimated that 3 to 10 tanks would need to be installed depending on tank volumes. To restrict the number of installations that would need to be constructed, each tank may be built as large as is practically feasible, both in diameter and in length. The tank (16) shown in Figure 1 is depicted in schematically shortened configuration for clarity. In practical applications the ratio of a tank's height to its diameter may considerably exceed that depicted in the drawing. The dimensions of a storage tank will be limited by the dimensions of the particular mine shaft in which it is to be installed. Certain exemplary tanks may have a diameter in a range from about 10 to about 20 meters, e.g. 14 metres, and a vertical length of about 1000 metres.

The embodiment of the facility (10) shown in the Figure 1 is intended primarily for the storage of natural gas. However, it is anticipated that hydrogen production using renewable energy may, in the future, become sufficiently economically viable to replace gas-fuelled generation of dispatchable power with hydrogen-fuelled generation. In the event of a future transition to the widespread use of hydrogen for dispatchable power, it is expected that storage facilities of the

type described herein may continue to be utilized for the bulk storage of hydrogen. The facility may also be suitable for the bulk storage of numerous other gaseous and liquid fluids such as those hereinbefore listed.

Steel may be used as a material of construction for the tanks; however other suitable materials may be used such as plastics, polymers, composites, substantially gas-tight fabrics or other flexible materials), etc.

The storage facility described herein may provide certain advantages over other fluid storage facilities and systems. Pressurized gas storage systems are susceptible to leakage and explosion. The present invention may at least partially mitigate these drawbacks insofar as the tanks can be located deep underground. Furthermore, buffering can be provided by the water cushions or barriers above and below each tank. The water cushions can promote pressure maintenance and serve as a secondary control region for the detection of gas leakage. Monitoring for the presence of gas in the water surrounding the tank can be implemented as part of a leak detection and early warning system to facilitate correct scheduling of maintenance and repairs.

Additionally, since the facilities can be built into existing abandoned mine shafts, new aboveground areas do not need to be significantly affected. Installations of the facilities can provide a new use for problematic abandoned areas.

At the end of the life of a facility, the need for removal of equipment and infrastructure is reduced and much of the facility can be sealed into the mine shaft with concrete. With the stored gas removed from the storage vessel and utilized, environmentally harmful substances left behind can be reduced.

The foregoing description has been presented for the purpose of illustration; it is not intended to be exhaustive or to limit the invention to the precise forms disclosed. Persons skilled in the relevant art can appreciate that many modifications and variations are possible in light of the above disclosure.

The language used in the specification has been principally selected for readability and instructional purposes, and it may not have been selected to delineate or circumscribe the inventive subject matter. It is therefore intended that the scope of the invention be limited not by this detailed description, but rather by any claims that issue on an application based hereon.

Accordingly, the disclosure of the embodiments of the invention is intended to be illustrative, but not limiting, of the scope of the invention.

Throughout this specification unless the context requires otherwise:

- the word ‘comprise’ or variations such as ‘comprises’ or ‘comprising’ will be understood to imply the inclusion of a stated integer or group of integers but not the exclusion of any other integer or group of integers; and
- the word ‘fluid’ or variations such as ‘fluids’ will be understood to imply the inclusion of both gaseous and liquid fluids.

Dated this 10th day of June 2019

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Von Seidels Intellectual Property Attorneys

for the applicant

STELLENBOSCH UNIVERSITY
PROVISIONAL SPECIFICATION

1 Sheets / Sheet 1

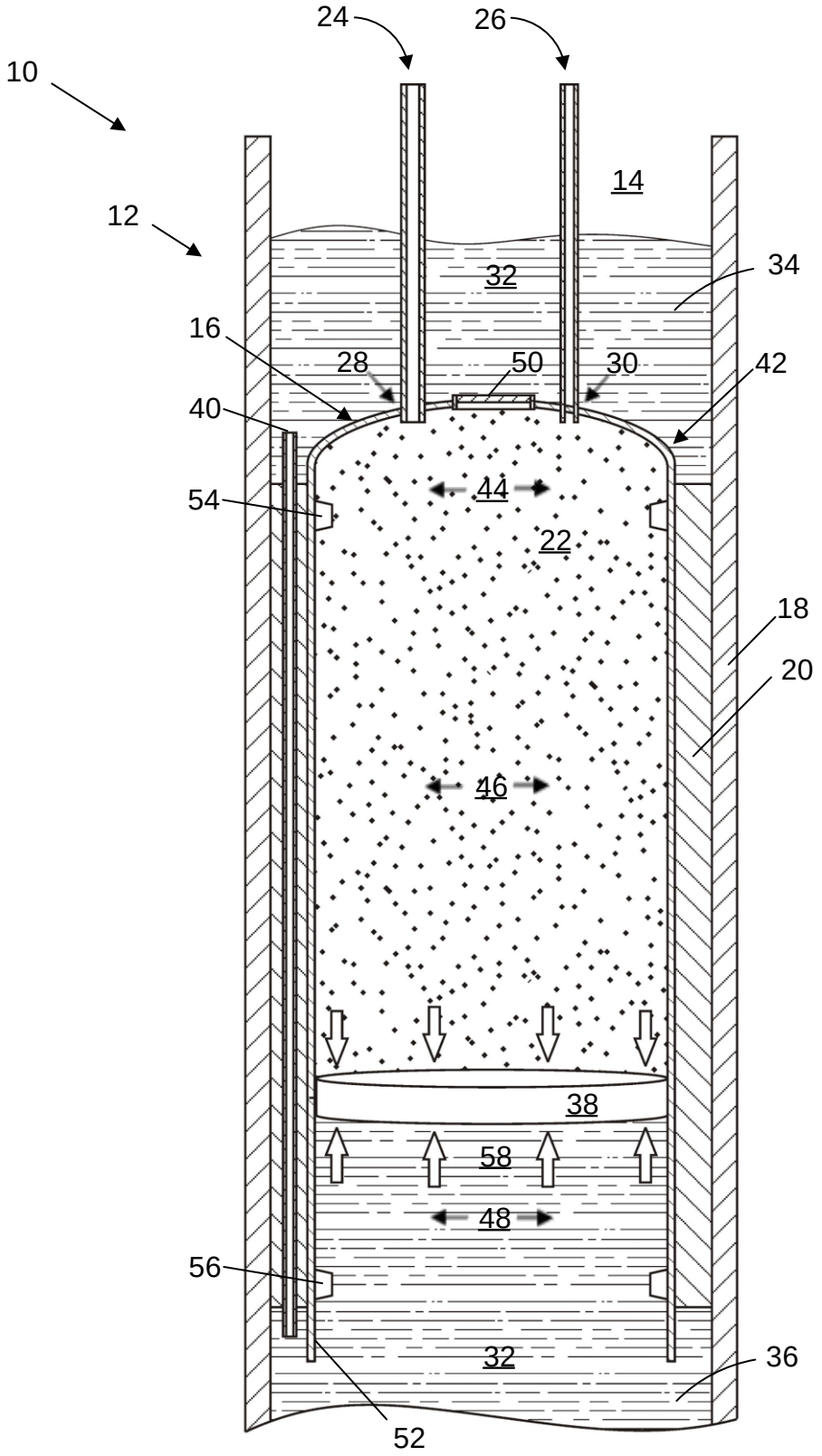

FIGURE 1

VON SEIDELS
FOR THE APPLICANT

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