Financial and Economic Appraisal of a Biogas to Electricity Project

Govender, I.
Department of Engineering and Technology Management, University of Pretoria

Thopil, G.A.*
Department of Engineering and Technology Management, University of Pretoria

Inglesi-Lotz, R.
Department of Economics, University of Pretoria

*Corresponding author details:
email:george.alexthopil@up.ac.za

Abstract

Biogas generated through anaerobic digestion of organic waste, offers unique benefits compared to other renewables, by addressing environmental concerns relating to organic wastes together with creating electricity generation potential. Given the magnitude of benefits for biogas, the utilization of the technology has been increased exponentially worldwide. This study thus aims to identify constraining factors that limit investment in biogas to electricity projects in South Africa, by conducting a financial and economic appraisal of a biogas to electricity project that was proven to be unviable by a large petrochemical company, within the context of the country's renewable energy framework. The study was further benchmarked against a similar biogas to electricity project in Germany. The results indicate that the sale of thermal energy generated via the biogas combined heat and power process largely affects a positive appraisal outcome while the renewable energy policy framework incentivises investors for biogas. Irrespective of the non-viability of the project mainly attributed to high capital costs, the potential for biogas projects exists via the South African renewable energy programme. The financial viability of biogas projects can be improved if the policy frameworks are amended to cater for sale of heat and if independent smaller scale projects are allowed as part of the renewable programme.

Keywords: Biogas; Anaerobic Digestion; Financial viability; South Africa; CHP

1. Introduction

Greenhouse gas (GHG) emissions and global warming are now major concerns of the 21st century with carbon dioxide emission rates increasing 200% since 1970 (Huaman and Jun, 2014). Due to the negative impacts of GHGs, there has been a paradigm shift away from the reliance on fossil fuels to ensure the long term survival of the various ecosystems and species with more emphasis being placed on energy efficiency and reduction in GHG emissions (Huang et al., 2017). Globally, South Africa is the 12th largest emitter of CO_2 per capita intensity of close to 10 tonnes per person, with 95% of electricity generation originating from non-renewable mechanisms (Thopil and Pouris, 2015). Given these statistics and the fact that fossil fuels are being depleted yearly, it is clear that, there has to be a more concerted effort to reduce the GHG emissions.

The growing demands of human behaviour, depletion of earth's fossil fuels and the need for cleaner energy, has led to increased consciousness and extensive study on the obtainability of renewable energy resources (Dowling et al., 2012, Nie et al., 2016). In 2016, approximately 419.6 million tonnes (oil equivalent) of renewable energy (excluding hydro) was consumed globally (BP, 2017) and this figure is expected to rise. Increased fossil fuel consumption has led to growing concerns relating to human health and food safety calls for more sustainable solutions for handling and recycling of organic wastes (Huang et al., 2017). In relation to the growing concerns of energy and organic waste, biogas produced from organic matter, is increasingly becoming a renewable energy solution to mitigate the environmental and public health concerns of organic wastes (Garcia and You, 2018; Holm-Nielsen et al., 2009).

Biogas offers multifaceted benefits to the end user, when compared to other renewables such as wind, solar and hydroelectric (Hakawati et al., 2017)). Biogas, besides having the distinct advantage through its significance in controlling organic waste, can produce fertilizer, heat, carbon dioxide (food and beverage industry) and methane which can be used in various industrial applications (solvents, plastic and insecticide industry), including the production of electricity (Cheng et al., 2014, Bond and Templeton, 2011). In addition to the above, biogas has the second smallest Life Cycle Emissions (LCE) for renewable energy systems, with wind energy having the smallest LCE. Biogas LCE is also more than three times smaller when compared to conventional energy systems such as coal, gas and oil (Varun et al., 2009).

Recognising the positive link between renewable energy and GDP of a country (Chien and Hu, 2007; Roopnarain and Adeleke, 2017; Inglesi-Lotz, 2016; Abdeshahian et al., 2016), together with pressures from the Kyoto Protocol, many countries have developed renewable energy policy for electricity generation and distribution. The implementation of the various policy mechanisms has led to the effective and widespread implementation of biogas technology worldwide. China, Germany, India, United States, Italy are among the top five investors in renewable energy (Msimanga and Sebitosi, 2014) with the top three countries launching massive campaigns to popularize the use of biogas (Cheng et al., 2014). The efforts of these countries have resulted in China, Germany and India becoming leaders in biogas plants with approximately, 1900% growth in China, 380% growth in Germany and 1700% growth in India for biogas derived electricity, from 2010 to 2013 (Kummamuru, 2016).

Biogas is a methane rich gas produced by the fermentation of organic material in the absence of oxygen (referred to as anaerobic digestion). The organic material used for anaerobic digestion, is typically waste, generated from animal dung, aquatic weeds, sewage sludge, industrial waste and poultry litter (Wu et al., 2016a). Biogas, generated in methane concentrations of 45-75% (Aguilera and Gutiérrez Ortiz, 2016, Abdeshahian et al., 2016), is a GHG with energy content of up to 28 MJ/m3 which can be utilized as an energy carrier to generate electricity, heat as well as mechanical driving force (Chen et al., 2016). These properties have made biogas a popular alternative for industrial application in many countries (Lindkvist and Karlsson, 2018).

However despite the multiple advantages of biogas as resource and the contribution to global renewable portfolio, the growth has to been a lot slower (BP, 2017). Biofuels projects are still associated with high capital costs (Amigun and Blottnitz, 2007; Millinger and Thrän, 2018) in comparison with conventional alternatives and significant variation in efficiencies (Hakawati et al., 2017). Both these factors contribute to economic and financial un-competiveness. Beyond micro-conditions policy factors also play a crucial role in driving technological transitions (Huttunen et al., 2014). These challenges are intensified in developing countries due to the absence of institutional policy (Lönnqvist, et al., 2018). Biofuel waste in the petrochemical industrial provide multiple opportunities (Siddique, et al., 2015) but implementations are still limited (Hagman, et al, 2018).

The primary aim of this article is to aid policy debate within South Africa about the feasibility of biogas projects as part of the renewable energy programme. It is believed there is not been sufficient evidence to indicate financial viability of large scale biogas projects in South Africa, though the potential exists. This study aims to conduct an economic and financial appraisal on a biogas to electricity project in a large South African petrochemical company, to ascertain constraining factors that may hinder investment in biogas to electricity projects. The following section provides a background of the utility scale South African renewable energy sector and the current role of biogas within this sector. Section 3 provides the methodological components of the financial and economic analysis, taken into consideration to analyse the three cases. The first case (also called the base case) includes the analysis of the conditions that currently make utility scale investment unfeasible. The second case aims to further examine the base case within the context of South Africa's Renewable Energy Independent Power Producers Procurement Program (REIPPPP) and impending carbon tax bill. The third case takes into account factors related to a similar project under German market conditions, the market leaders in biogas technology (Hanekamp, 2014). Section 4 provides the analysis of the results of the three case, with conclusions being provided in Section 5.

It is believed the results will give insight into the investment viability of biogas to electricity projects and ascertain any shortcomings in South Africa's renewable energy policy when compared to Germany's successful biogas policy. It is expected that the findings will be useful in developing countries, particularly in Africa where investment in large scale biogas technology projects are accompanied with risk because of policy uncertainty (Investec 2004; Moody's 2017), thereby providing potential investors insight.

2. Research context

South Africa in particular finds itself in a precarious position with respect to electricity generation, with 95% of the country's electricity supplied via fossil fuel burning through the state owned power producer, Eskom (Dowling et al., 2012, Thopil and Pouris, 2015). Recognising the country's excessive dependence on fossil fuels together with the associated high carbon footprint has prompted government to promote the use of renewables (Dowling et al., 2012). After a decade's worth of somewhat incoherent policies, the REIPPPP, launched in 2011, represents South Africa's effort to promote the use of renewable energy (Pegels, 2010) via a competitive tendering process (Msimanga and Sebitosi, 2014).

The REIPPPP has been thus far considered a success, by diversifying the power generation sector from the single state owned power producer to 64 power independent power producers with 92 successful projects that incorporate more than 100 shareholders (Vallabhjee, 2015) in the three of four rounds of competitive bidding (Walwyn and Brent, 2015). For the individual renewable technologies listed in Table 1, caps were set on the total capacity to be procured with the largest allocations attributed to wind and photovoltaic (Eberhard et al., 2014), with smaller allocations for concentrated solar, biomass, biogas, landfill gas, and hydro.

Given all the benefits of biogas and the need for expansion in the renewable energy sector in South Africa; there have been no bids for the biogas allocation across all rounds of the REIPPPP (Qase et al., 2015). As part of the REIPPPP, low tariffs for biogas installations (as compared to wind and solar); the elevated cost of compiling bid documents for biogas (due to strict regulatory framework) and the minimum plant size limitation of 1MW under the REIPPPP, where average biogas installations are between 0.3-0.5MW; have all been listed as barriers for biogas adoption by potential developers (Roopnarain and Adeleke, 2017).

Table 1: Analysis of MW allocation and remaining for the REIPPPP

	MW Allocation per bidding round						
Technology	**Round 1**	**Round 2**	**Round 3**	**Round 3.5**	**Round 4**	**Round 4.5**	**MW capacity Remaining**
Solar photovoltaic	632	417	435	-	415	687	626.08
Wind	634	563	787	-	676	398	664
Concentrated solar	150	50	200	200	-	-	-
Small Hydro	-	14	0	-	5	-	115.6
Landfill gas	-	-	18	-	0	-	7
Biomass	-	-	16	-	25	-	19
Biogas	-	-	-	-	-	-	60
Total	1 416	1 044	1 456	200	1121	1085	2 808

Biogas has significant potential in South Africa (Baker, 2015), capable of generating 2.5GW of electricity with a market potential of R10 billion (Roopnarain and Adeleke, 2017). Stafford et al., (2013) estimates that roughly 3.2-9 GW_{th} energy can be recovered from wastewater sources, which is roughly 7% of South Africa's electrical supply.

South Africa has had limited growth (with a total of roughly 300 biogas producing plants as of 2013) in biogas adoption, compared with the likes of Germany (that has 1000 biogas plants built per year) (Munganga, 2013a). Germany recognised at the end of the last millennium the need to diversify away from fossil fuels and nuclear energy. The recognition of this necessity led to the creation of Germany's Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) which came into effect in April 2000 (Sösemann, 2007). This act was successor to the 1991 Electricity feed Act outlining commitments to renewable energy. As of 2006, the policy had resulted in a reduction of over 100 million tonnes in CO2 emissions, employing 230000 people and reducing the wholesale price of electricity within which biogas has been a major contributor (Sösemann, 2007).

Germany, alone contributed to roughly 42% to the global electricity production from biogas during the early part of this decade (Maghanaki et al., 2013). Over the period of 2001 to 2014, Germany's installed capacity for electricity generation from biogas grew from 182MW to 3000MW. This tremendous growth was largely due to positive legislative framework for renewable energy which was driven chiefly by Germany's Renewable Energy Sources Act. (Stauss et al., 2013). Motivating factors for biogas to electricity growth in Germany include higher remuneration for the electricity obtained from biogas plants and policies aiding the inclusion of smaller sized biogas facilities (Wagner, 2015). These reasons provide rationale to consider the German biogas industry as a benchmark case for comparison with South African cases.

From the South African perspective one of the most notable biogas facilities is the 4.2MW PetroSA project (Austin and Gets, 2009) expected to achieve 30 kilotonnes of certified emission reductions (Stafford et al., 2013) which was commissioned in 2007. Another notable example is the 4.6MW Bronkhorstspruit (Bio2Watt, 2016) biogas to energy plant commissioned in 2015 which has an industrial off taker.

Mwirigi et al. (2014), suggests that the regions inability to provide suitable feedstock for biogas production may be a hindrance for the technology adoption. Pegels (2010), faults the monopolistic nature of power producing companies and their inherent dependence on coal to produce energy together with their inability to foster environments fit for renewable energy utilization. Pegels (2010) also highlights risk and cost factors, together with South Africa's lack of experience in the biogas sector as possible hindrances for the adoption of the technology. However it is vital that South Africa diversifies and deregulate the electricity industry to ensure electricity security to enable technologies such as biomass and biogas (Khan et al, 2016).

3. Material and methods

The design parameters of the biogas power plant is discussed first after which components related to the financial analysis is analysed. The biogas project design basis on which the appraisal was performed is shown Table 2. The plant design is mesophilic in nature and uses wet digestion.

Table 2: Design Basis for Biogas to Electricity Plant

Feed: Industrial liquid waste flow rate	$600m^3/h$
Feed: Industrial liquid waste organic concentration	15000mg/l COD
Digester	95% COD removal efficiency
Methane concentration in Biogas	60%
Moisture content of Biogas	6%
Biogas Production Volume	$5000Nm^3/h$
CHP Heat Efficiency	38%
CHP Electric Efficiency	33%
Engine Capacity	2.74MW each
Engines Used	4
Plant Capacity	10MW
Plant Availability	90% of year
Potential Electricity Production	78840MWh
Plant Life Expectancy	20 years with no salvage value (plant will not be sold)

The feed to the biogas production plant is an industrial liquid waste which contains an organic rich stream (30% composition of organics with 6% moisture content and biogas production potential of 5000 Nm^3/h). The waste is already being produced by the company in question and hence a suitable feed stream for biogas production did not have to be purchased or transported to site, as is popularly done for biogas production plants (Mwirigi et al., 2014). The digester would have to also remove 95% organics in the feed stream due to the downstream requirements of the liquid product stream.

Methane concentration in the biogas was determined via lab scale anaerobic digestion of the feed stream, and usually varies between 45-75% methane in typical biogas production (Aguilera and Gutiérrez Ortiz, 2016). Typical biogas systems realise beneficiation in three ways, namely, biogas upgrading, combined heat and power (CHP) and biogas solid oxide fuel cells (Wu et al., 2016b). CHP technology was chosen for this study as it is widely regarded as one of the most robust technologies for electricity generation, not only being energy efficient with reductions in CO_2 emissions, but it also helps to increase the robustness of the energy infrastructure by means of decentralized generation (compared to the generation of heat and power in separate facilities) (Mitra et al., 2013). The efficiency of the CHP engines was attained from the supplier, via the request for proposal (RFP) that was sent to potential vendors. The biogas volume and electricity produced was calculated from equations 1 (Urbaniak-Hedley, 2011) and 2 (Abdeshahian et al., 2016) as shown:

$$\text{Biogas production rate}\left(\frac{\text{m3}}{\text{h}}\right) = \frac{\frac{\text{kg of COD}}{\text{h}} \text{x Methane yield}\left(\frac{\text{m3}}{\text{kg of COD removed}}\right) \text{x COD removal Eff of Digester(\%)}}{\text{\% CH4 in Biogas}} \qquad (1)$$

Where kg of COD[1]/h is the organic content of stream to be treated and methane yield (350 m^3/kg) is the specific volume at which organic compounds are removed, COD Removal Eff of digester (%) being the organic removal efficiency of digester and %CH4 in Gas being the percentage methane content in the biogas stream. The electricity produced from the production of biogas is expressed as follows:

$$Electricity\ Generated(kWh) = Energy\ content\ of\ biogas\left(\frac{kWh}{m3}\right)x\ Vol\ of\ biogas(m3)x\ Engine\ eff(\%) \qquad (2)$$

Where Vol of biogas (m^3) is the volume of biogas produced with Engine Eff (%) being the efficiency of engines used.

Accounting for statutory plant maintenance the plant was assumed to be 90% available. The lifetime of the investment is 20 years, which equals the economically useful life of the plant (Wu et al., 2016b) with zero salvage costs, since the plant will not be sold or scraped.

The appraisals will be based on the above criteria and will be analysed in three distinct cases, namely:

Case 1: This appraisal is based on the inputs from the petrochemical company concerned. This assessment is only based on a financial appraisal which was proven to be unfeasible by the petrochemical company and will serve as the base case to which the other cases will be compared to.

Case 2: This appraisal is based on the inputs from the base case and appraised within the scope of the REIPPPP. This case will also encompass an economic appraisal in the form of carbon tax avoidance.

Case 3: This appraisal will be conducted in the German context with financial inputs from German industry literature. This assessment will be based on a financial appraisal only, taking into account that Germany does not have carbon tax legislature (Grave et al., 2015).

The concept of the financial appraisal is the identification of all expenditures and revenues over the project lifetime, to ascertain the ability of a project to achieve financial viability and a

[1] COD = Chemical oxygen demand. COD is an index used to determine the content of organics in the medium (in this context the biogas stream)

reasonable rate of return. The appraisal is done in a cash flow statement format and is the difference of all revenues and expenditures at the time at which they are incurred.

3.1. Expenditure

Capital expenditure (CAPEX) is broken down into initial investment includes the capital costs of all fixed assets (plant and machinery) and non-fixed assets (design and commissioning costs). Other negative cash flows, classified as expenditure, are accounted for in terms of operating expenditure (OPEX), tax, and depreciation. Tax allowances, with respect to depreciation, assume that the company has a sufficient tax base to absorb these allowances; else they must be carried forward. Hence no tax will be paid for assessed losses.

Expenditure for all cases does not include the cost associated for feedstock or feedstock logistics. This is due to the fact that the petrochemical company does not incur any costs with respect to feedstock (feedstock is free of cost), hence for equivalence, the German case is also evaluated without feedstock costs. Additionally the cost of treatment of feedstock is also excluded based on the consideration that the petrochemical company has excess capacity to treat the industrial effluent within the feedback.

Interest payment and loan repayment are not included in any of the cases, because one of the major purposes of deriving the cash flow is to determine the rate of interest the project can bear (Skae, 2014). In addition, the company in question would not require loaned capital for this investment due to large capital reserves being available – hence for a viable project, any return must be greater than the current cost of borrowings for the entire company and greater than the required return from the company's shareholders.

Expenditures for Case 1 and 2

CAPEX was attained via the RFP submissions with OPEX and contingency being estimated at 6% and 15% of CAPEX respectively as per the petrochemical company's business model. Contingency estimates account for unforeseen elements in time and cost (Nicholas and Steyn, 2012) and in this case was based on the unstable political climate in South Africa during 2016 together with fluctuating exchange rates and South Africa's sovereign downgrade threat. The contingency was also justified due to the fact that the petrochemical company has not undertaken renewable energy projects and there was some uncertainty around project duration. OPEX, comprised of labour, repairs and maintenance (Skae, 2014), warrants yearly escalation, due to the price of goods and services increasing. Accordingly yearly escalations in OPEX was estimated at 6%, the average yearly inflation for South Africa (Lehohla, 2016). The RFP budget prices for CAPEX are listed in Table 3.

The appraisal for cases 1 and 2 are be based on the Company A’s budget quote, as it was the cheapest. Furthermore, the budget quotes above are within the range that is estimated by the Industrial Development Corporation (IDC) of South Africa. The IDC has a history investing in renewable energy projects and has estimated biogas facilities to cost between R15million-35million per MW (Munganga, 2013b)

Table 3: RFP Budget Pricing for Project

Summary of responses to the Biogas Facility RFQ (in million Rands)				
Company	**A**	**B**	**C**	**D**
Budget Prices				
Anaerobic Digester (x2)	R 85.14	R 125.25	R 90.10	R 120.48
Gas Turbine	R 168. 21	R 190.00	R 55.21	R 186.42
Piping			R 38.00	
Mechanical Engineering			R 2.00	
Electrical Engineering (including infrastructure)			R 82.00	
Civil Engineering			R 9.00	
Project Management			R 3.00	
Start-up & commissioning			R 2.50	
Total Cost	**R 253.36**	**R 315.25**	**R 281.81**	**R 306.90**
Contingency (15%)	R 38.00	R 47.28	R 42.27	R 46.03
Capital Estimate	**R 291.36**	**R 362.54**	**R 324.08**	**R 352.94**

Depreciation allowance and corporate tax is calculated in accordance with the tax rules of South Africa. South Africa allows assets to be depreciated for tax benefit as a percentage of CAPEX, over the first four years, in a 40%,20%,20%,20% ratio (SARS, 2016). All expenditures for cases 1 and 2 are summarized in Table 4.

Table 4: Expenditure for Cases 1 and 2

Item	**Expenditure (in million Rands)**	**Escalation**
CAPEX	R291.26	-
OPEX (6% of CAPEX)	R17.47	6% per year
Corporate Tax Rate	28% of taxable income	-

Depreciation	Year 1 - R116.50 Year 2 - R58.25 Year 3 - R58.25 Year 4 - R58.25	-

Expenditures for Case 3

CAPEX and OPEX were determined via investment literature for typical biogas facilities in 2011 (Hahn, 2011). It can be seen that CAPEX values, based on European experience (Hahn, 2011), tend to decrease proving economies of scale as opposed to cases in Africa which indicate diseconomies of scale (Amigun and Blottniz, 2007). The prices were then escalated to 2016 terms utilizing Germany's actual inflation from 2012 to 2016; averaged at 0.436% (Bundesamt, 2016). Yearly escalations in OPEX were also based on this average inflation.

Depreciation allowance and corporate tax is calculated in accordance with the tax rules of Germany. Germany allows assets to be depreciated for tax benefit equally over the useful life of the asset (Deloitte, 2015). The analysis was done in Euros, to ensure no distortion of evaluation through varying exchange rates. All expenditures for cases 3 are summarized Table 5.

Table 5: Expenditure for Case 3

Item	Expenditure (in million Euros)	Escalation
CAPEX (Hahn, 2011)	€26.00	-
OPEX (Hahn, 2011) Operational Cost (1€cent/kWh) Maintenance Cost (2.5€cent/kWh) Insurance (0.75% of CAPEX)	10MW plant €0.788 €1.971 €0.195 **€2.954**	0.436%
Corporate Tax Rate	30% of taxable income	-
Depreciation	Year 1 to 20 - €1.3	-

3.2. Revenue

Revenues, set out in the cash flow, can take different forms. The most identifiable are the products and services from the project sold through normal commercial channels as well as any commercially exploitable by-products and residues. Revenue valuation is then simply a matter of estimating the sales values of these products and services. The revenues streams for the respective cases are set out below:

Revenue for Case 1

The only revenue stream considered in the petrochemical company appraisal was that of lower electricity import due to electricity generated from the biogas plant. The revenue stream was hence priced according to the Eskom megaflex tariff for large industry, R763.8MWh. Hence a for a 10MW biogas plant with 90% yearly availability, the annual revenue amounts to R60 217 992. Although yearly escalation of electricity prices have exceeded South Africa's inflation rate (Eskom, 2017), yearly escalations were assumed to be that of inflation, at 6% (Lehohla, 2016), due to the 20 year project evaluation term.

Revenue for Case 2

Remuneration was based on the sale of electricity within the context of the REIPPPP including the sale of heat energy, which was priced according to the equivalent electricity cost for industry (as used in case 1) since no subsidy's exist for the heat generated through CHP. The tariff is priced at R1475MWh (Vallabhjee, 2015), hence for a 10MW biogas plant with 90% yearly availability, the annual revenue amounts to R116289000.

The quantity of heat generated from a 10MW biogas plant is equivalent to 14304kW (Kang et al., 2014). For the purposes of this study, it is assumed that 80% of the heat energy is recovered. Hence for a 90% yearly plant availability, the heat revenue (considering megaflex tariff of R763.8MWh) amounts to R68 908 508. Similar to case 1, yearly escalations were assumed to be 6% accounting for inflation (Lehohla, 2016).

Revenue for Case 3

Remuneration was based on the sale of electricity within the context of Germany's Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG), priced at 11.4 €cents/kWh (Graaf and Fendler, 2010). Hence for a 10MW biogas plant with 90% yearly availability, the annual revenue amounts to €8 987 760.

The sale of heat energy, which was priced according to the equivalent electricity cost according to the Germany's tariffs for industry. The industry tariff for electricity in Germany is 12.2 €cents/kWh (Grave et al., 2015). Hence, utilizing the same quantity of heat energy generated in case 2, for a 10MW biogas plant with 90% yearly availability, the annual revenue amounts to €11 006 619.18. Yearly escalations were assumed to be 0.436% accounting for inflation (Bundesamt, 2016).

3.3. Carbon tax consideration

Indications of financial profitability do not necessarily provide reliable estimates of the value of a project from a "social" point of view, as they focus rather on the investors' perspective. The economic appraisal considers costs or benefits that would arise as a direct consequence of a project, but which accrue to agents in the economy other than those who sponsor the project

In this case, the analysis was broadened to include the external benefits for a reduction in CO_2 emissions, in the form of carbon tax avoidance, which was due to be implemented in South Africa in 2017 (Swart, 2016) but has been subsequently delayed. The economic appraisal will only be applied to case 2, due to the fact that Germany does not have carbon tax policy (Grave et al., 2015).

Due to its infancy and to allow companies to adapt to low CO_2 environments, the impending carbon tax bill proposed allowances of up to 95%, 60% of which is the base threshold in the first phase (Swart, 2016). For the purposes of this study, an average of R27/tonne of CO_2 (Swart, 2016), amounting to a 77.5% allowance, is used in the evaluation (sensitivity of which is also analysed). Taking into account the GHG emission factor of biogas at 2700 kg CO_2e/tonne (Swart, 2016) and the volume of biogas produced per year (90% plant availability) at 39420000 Nm^3/year with a density of 1.15kg/m^3, the CO_2e produced, amounts to 122399.1 tonnes/year. Hence the year tax avoidance amounts to R3304773, with no yearly escalations due to the bill still in its infancy.

3.4. Cash flows

The annual cash flows (inflows and outflows) of the plant, applying the discounted cash flow (DCF) method were calculated. This method is used to evaluate the viability of the investment where all future cash flows over the 20 year plant life are discounted to yield the present day value of the investment.

The rate used to discount the cash flows to present day value must be greater than or equal to the cost of the company's equity (the return investors wish to make) and debt (interest the company pays on its borrowings), referred to as the weighted average cost of capital (WACC) (Skae, 2014). This is to ensure that the future cash flows of the investment are greater than the company's cost of capital (Skae, 2014). The discount rate that was hence used is taken from the petrochemical company's financial statements (year ended 2015), as WACC equal to 13%, together with the company's published hurdle rate of 1.3x WACC equal to 17%. The hurdle rate is a penalty imposed on any project, which must be overcome to warrant investment.

The discount rate for the German case evaluation, although expected to be between 6-12% due to the country being highly developed with lower interest rates and lesser perceived risk (Taylor et al., 2015), was taken to be the same as the South African case. This was done to evaluate the feasibility of the German case with imposed stricter viability criteria, since a lower cost of capital would make the project viable. The stricter criterion is imposed to evaluate if the same project in Germany would be viable with a South African discount rate. The imposed higher discount rate would negatively affect investment viability in the German case, but is used to evaluate the impact the discount rate might have on the bearing of the project.

The discount rate is used to calculate the net present value (NPV) of the future cash flows of the investment, which must be greater than zero to ensure a present day positive cash flow (Skae, 2014). A negative NPV hence does not warrant investment. The net present value (NPV) is defined as the sum of the present values of the yearly cash flows. The greater the NPV, the more profitable the project (Agostini et al., 2016). The NPV is expressed by:

$$NPV = CF0 + \frac{CF1}{(1+r)^1} + \frac{CF2}{(1+r)^2} + \frac{CF3}{(1+r)^3} + \cdots + \frac{CFn}{(1+r)^n} \qquad (3)$$

Where NPV is the net present value of the project, CFn is the cash flow at year n and r is the discount rate.

The internal rate of return (IRR) is defined as the discount rate at which the NPV becomes zero, which means that the present value of future revenues equals the present value of costs (Skae, 2014). Hence, the IRR must be greater than the discount rate to warrant investment. The IRR allows the judgement of the future performance of the investment to benchmark required rate of return (Agostini et al., 2016). The IRR is expressed by

$$When\ NPV\ is\ 0 = CF0 + \frac{CF1}{(1+IRR)^1} + \frac{CF2}{(1+IRR)^2} + \frac{CF3}{(1+IRR)^3} + \cdots + \frac{CFn}{(1+IRR)^n} \qquad (4)$$

In general, the higher the IRR, the more desirable it is to undertake the project (Agostini et al., 2016).

The payback period is defined as the time at which the NPV becomes zero. A payback calculation determines the length of time required to recoup the initial investment. The shorter the payback period, the more viable the investment becomes (Agostini et al., 2016).

From the results obtained using the capital budgeting techniques above the following rules will apply to analyse the appraisal:

- The payback period of the investment must be less than two years to be economically viable.
- If a net present value of zero and greater is achieved the investment will be deemed viable, if the NPV is less than zero the investment will not be viable and be rejected.
- If the internal rate of return (IRR) achieved is higher than the discount rate, the investment will be viable and should be accepted, based on the IRR decision rule. If lower than the discount rate is achieved, the investment would be considered not viable.

4. Results

The income and expenditure for the respective cases are shown in figures 1, 2 and 3, and represent the cash flows from the time of investment (year 0) to end of the economic life of the plant (year 20). Percentage escalations in sales and expenditure account for the outward bell shape in cases 1 and 2, which was 6% as opposed to 0.43% escalation in case 3.

The net cash flows over the 20 year term for the respective cases are shown in figure 4, with case three on the secondary euro millions axis. The payback period for case 1 was the longest at approximately 4 years with cases 2 and 3 reporting payback periods shorter than 1 year.

Figure 1: Income and Expenditure Cash Flows for Case 1 from Year 0 -20

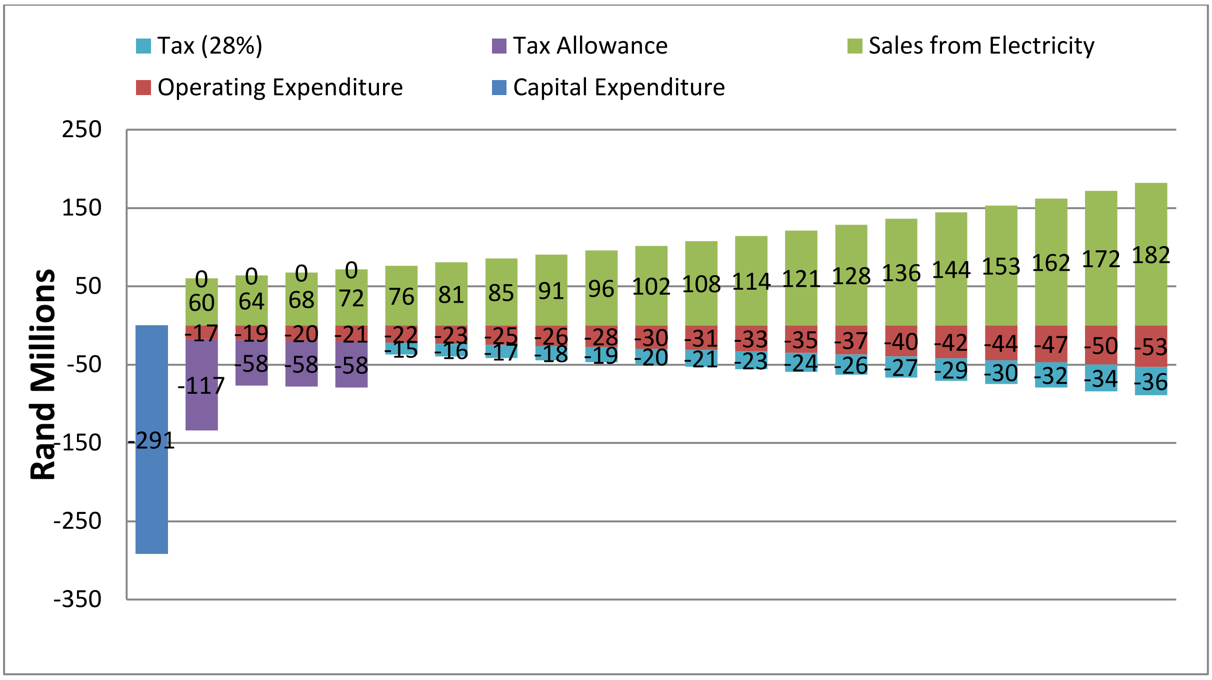


Figure 2: Income and Expenditure Cash Flows for Case 2 from Year 0 -20

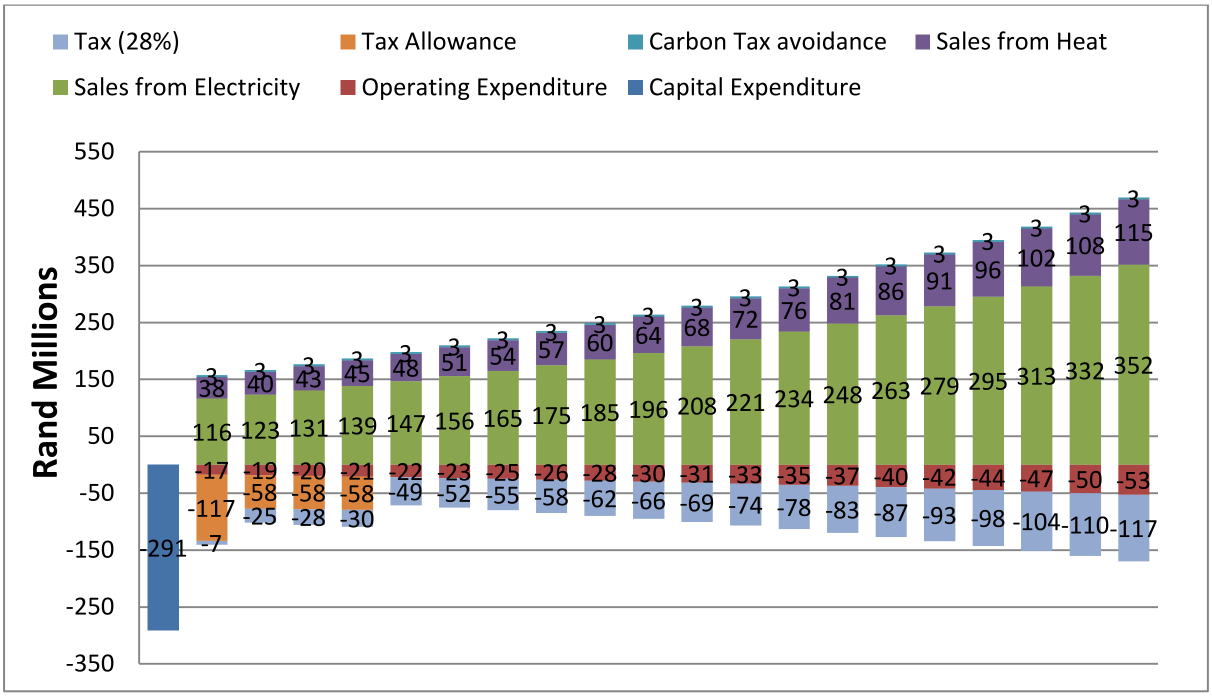


Figure 3: Income and Expenditure Cash Flows for Case 3 from Year 0 -20

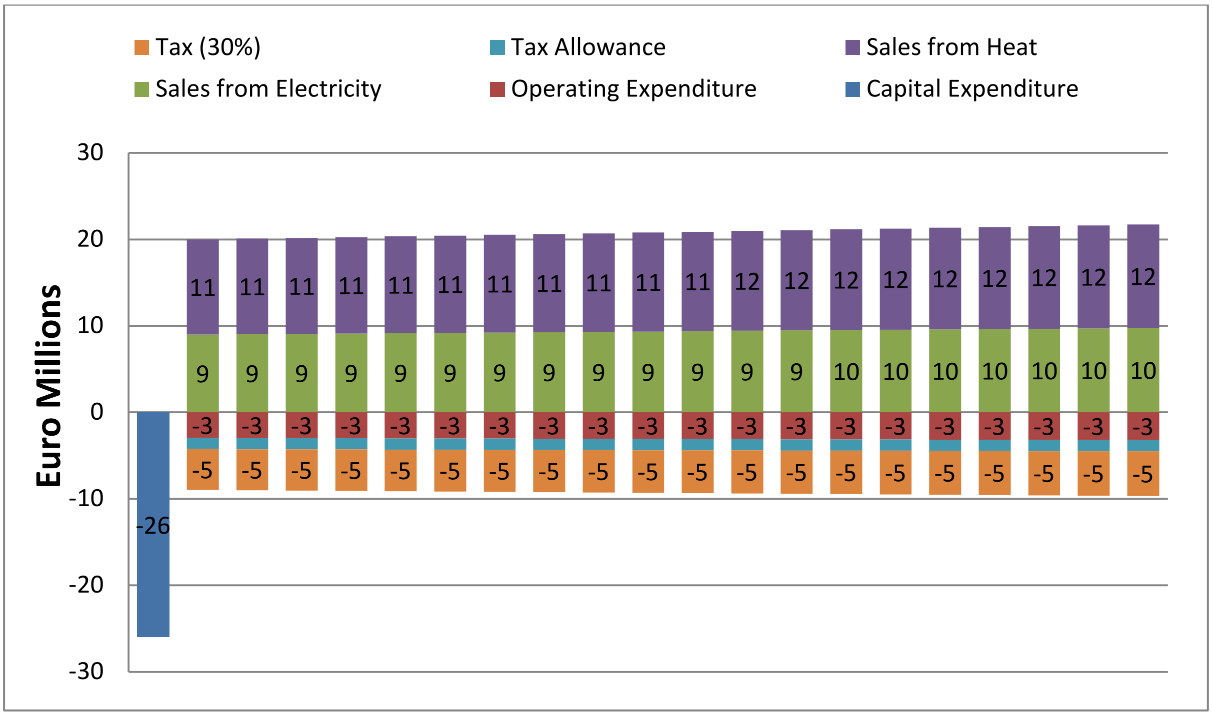
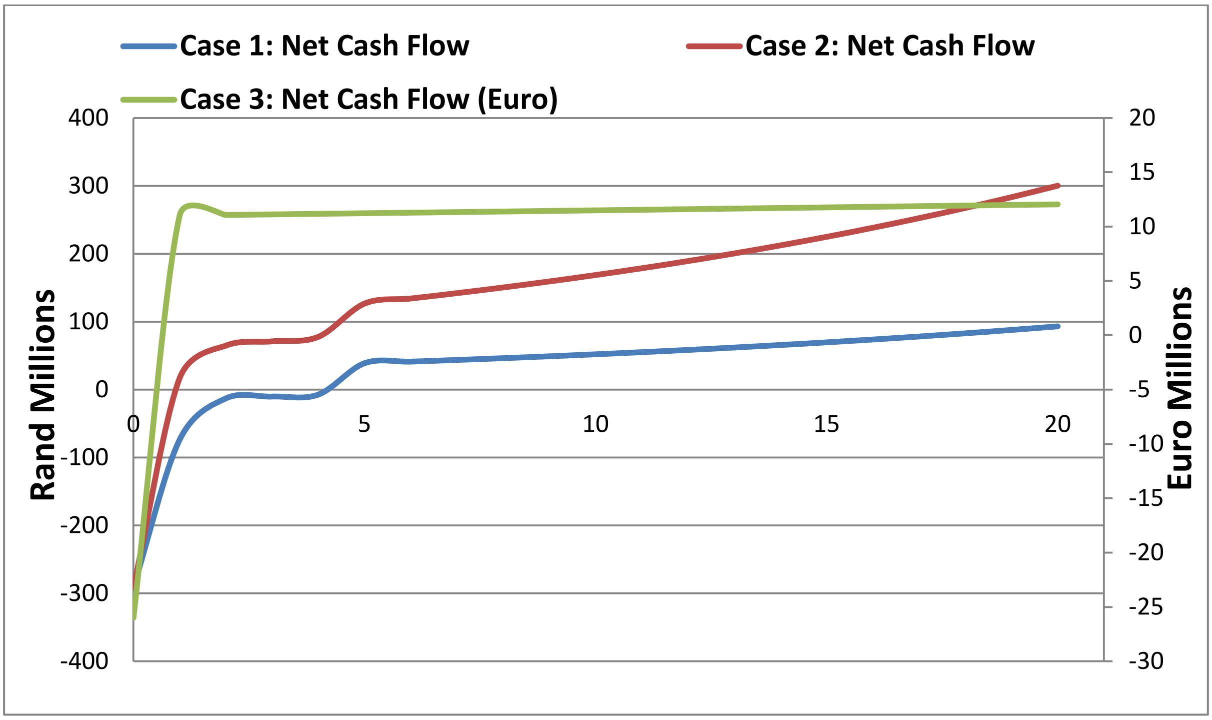


Figure 4: Net Cash Flow for Cases 1, 2 and 3

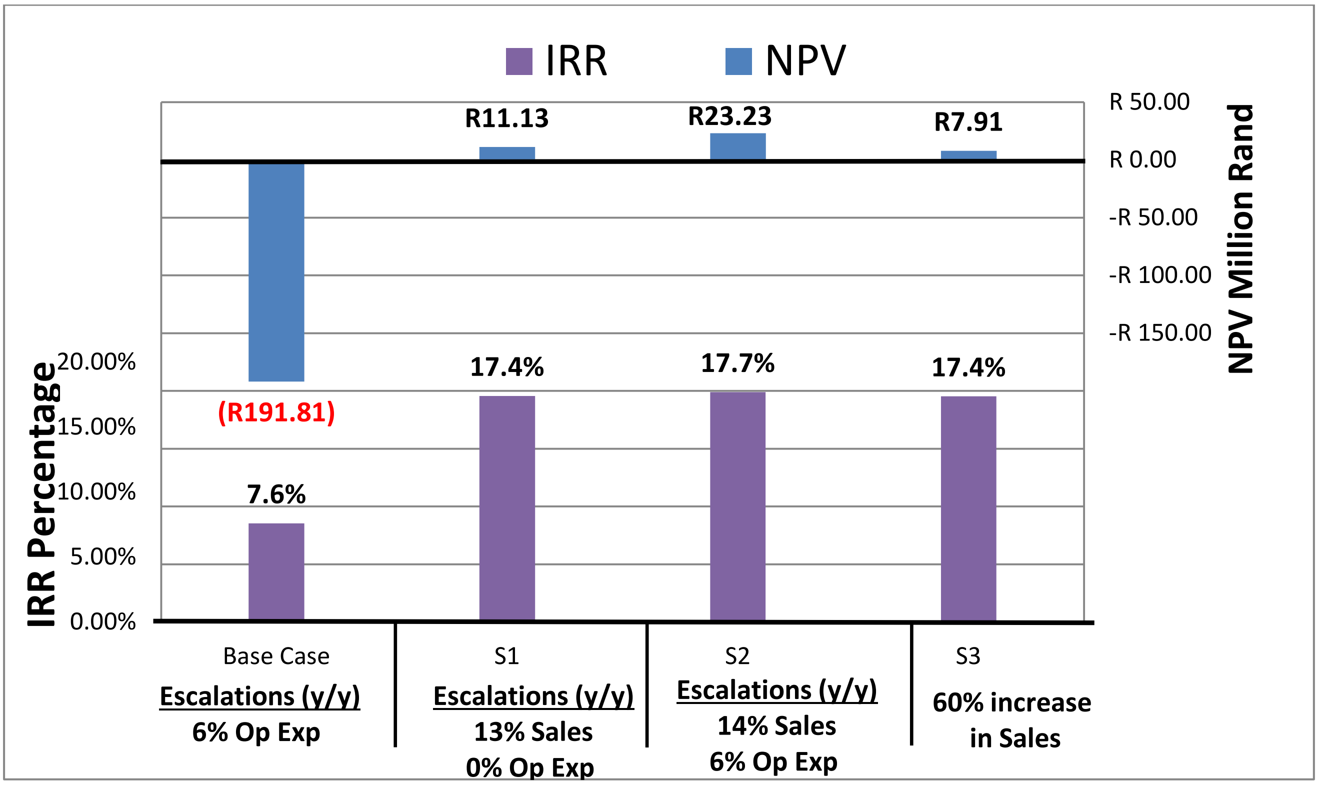


Figures 5, 6 and 7 summarize the NPV and IRR for the respective cases including the indicators sensitivity. Variations, through sensitivities (S1,S2…etc) in CAPEX, OPEX and sales was done to ascertain the income or expenditure that affects the investment decision the most and to gauge the extent to which the NPV and IRR in cases,1,2 and 3 can yield a positive investment decision. The sensitivities in the figures only describe the manipulation made to the original assumptions for that respective case (ceteris paribus).

4.1. Analysis of Case 1

The IRR of 7.6% is lower than the petrochemical company's discount rate of 17% and together with the NPV being negative makes the investment unwise. The lower than discount rate IRR means that the company is better off paying it's debtors since the company's cost of capital is 13%. The negative NPV shows that over the plants useful life, expenditure exceeds income.

Figure 5: Case 1 NPV and IRR with Sensitivity



The sensitivities, S1 and S2 suggest that a 13-14% or greater yearly escalation in sales must be maintained over the twenty year evaluation for the investment to be sound. This yearly escalation in sales is more than double South Africa's average inflation rate over the past five years, which puts the investment decision in even more in doubt, seeing that double digit inflation is highly unlikely. This is further supported by sensitivity, S3, which requires initial 60% additional revenue to make the investment sound.

4.2. Analysis of Case 2

The case examined within the context of the REIPPPP and impending carbon tax bill together with the sale of heat energy, yields an IRR greater than the company's discount rate together with a highly positive NPV, making the investment sound.

There were three differences between the case 1 and case 2. The major difference between case 2 and case 1 is the incorporation of electricity tariffs from the REIPPPP at R1475/MWh as opposed to the price that the company pays for electricity at the megaflex tariff of R763.8/MWh. This 51% difference resulted in a higher revenue stream which in turn made the appraisal highly positive. In addition to the above, the incorporation of heat energy that is also a by-product of the CHP process, which is sold at the equivalent electricity cost at the megaflex tariff mentioned above. The addition of this revenue stream also made the appraisal positive. The last difference was the economic appraisal of the project by taking into account carbon tax avoidance, although this was proven to have marginal impact on the outcome of the appraisal.

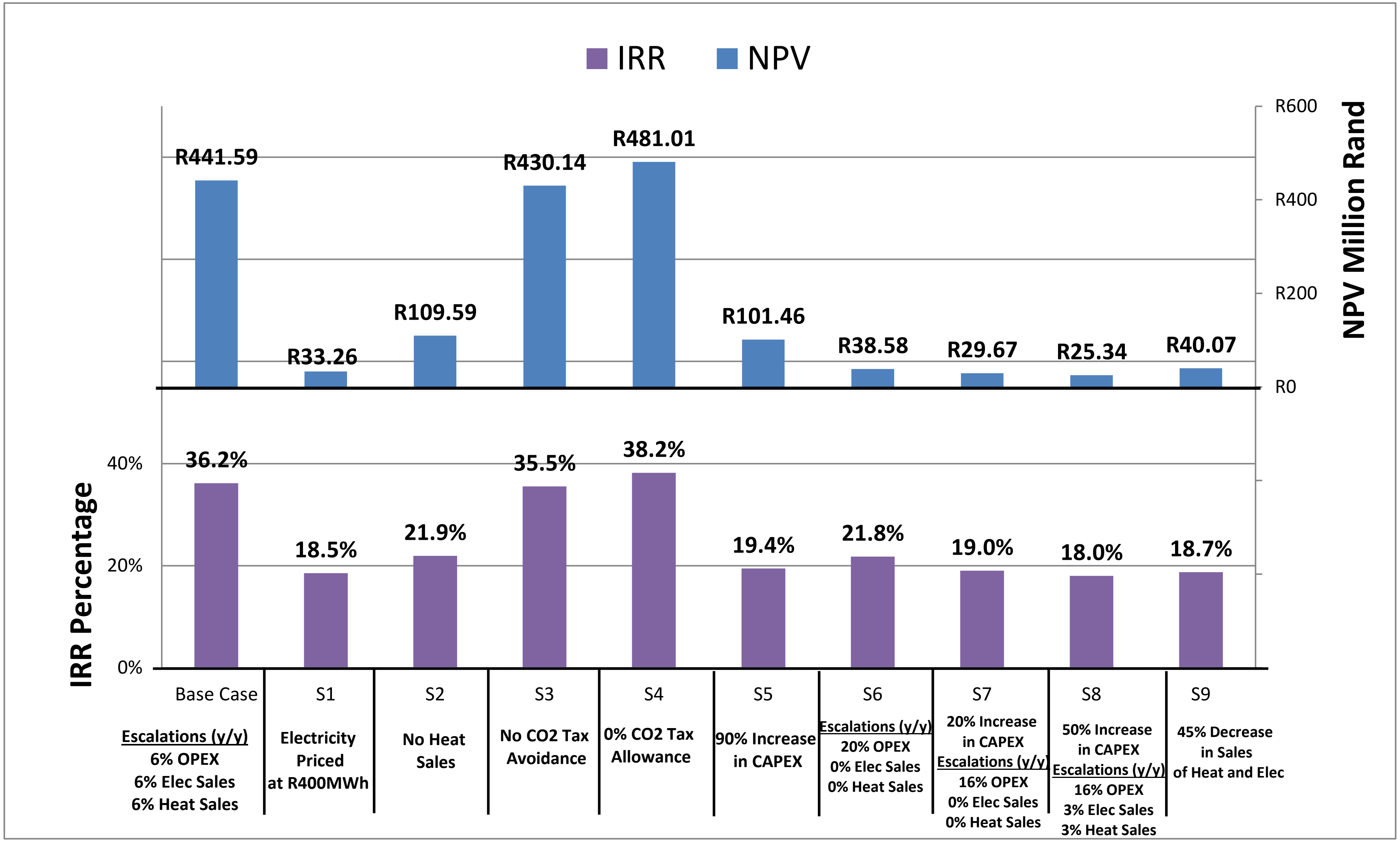
Sensitivities S1 to S9 are explained below:

S1: The investment decision is wise with the lower REIPPPP price.
S2: The investment decision remains wise with no heat sales
S3: The investment decision remains wise without the benefit of CO_2 tax avoidance. The case shows that the CO_2 tax has marginal negative effect on the investment decision.
S4: The investment decision indicators are marginally improved when compared to the original case 2, with the CO_2 tax avoidance increasing due to no allowances being given.
S5: The investment decision remains wise with a 90% increase in CAPEX.
S6: The investment decision remains wise with a yearly escalation of 20% in OPEX and no yearly escalations in heat and electricity sales
S7: The investment decision remains wise with a 20% increase in CAPEX and escalations of 16% in OPEX with no escalations in sales of heat and electricity.
S8: The investment decision remains wise with a 50% yearly escalation in CAPEX with 16% yearly escalation in OPEX and 3% yearly escalation in heat and electricity sales.
S9: The investment decision remains wise with a 45% decrease in sales of heat and electricity.

The sensitivities indicate that a REIPPPP price cap of R400/MWh sustain positive investment indicators, provided that heat sales and corresponding escalations remain the same. The analysis also indicates that the case is strongly dependent on the sale of heat, although the investment can be sustained with a 70% decrease in the sale of heat together with a 3% yearly escalation. The impending carbon tax bill, in the form of carbon tax avoidance, proves to have a marginal impact on the investment decision, even with no allowances granted.

Overall, case 2 investment indicators; prove to be much more robust than case 1, sustaining large increases in expenditure and smaller increases in revenue.

Figure 6: Case 2 NPV and IRR with Sensitivity



4.3. Analysis of Case 3

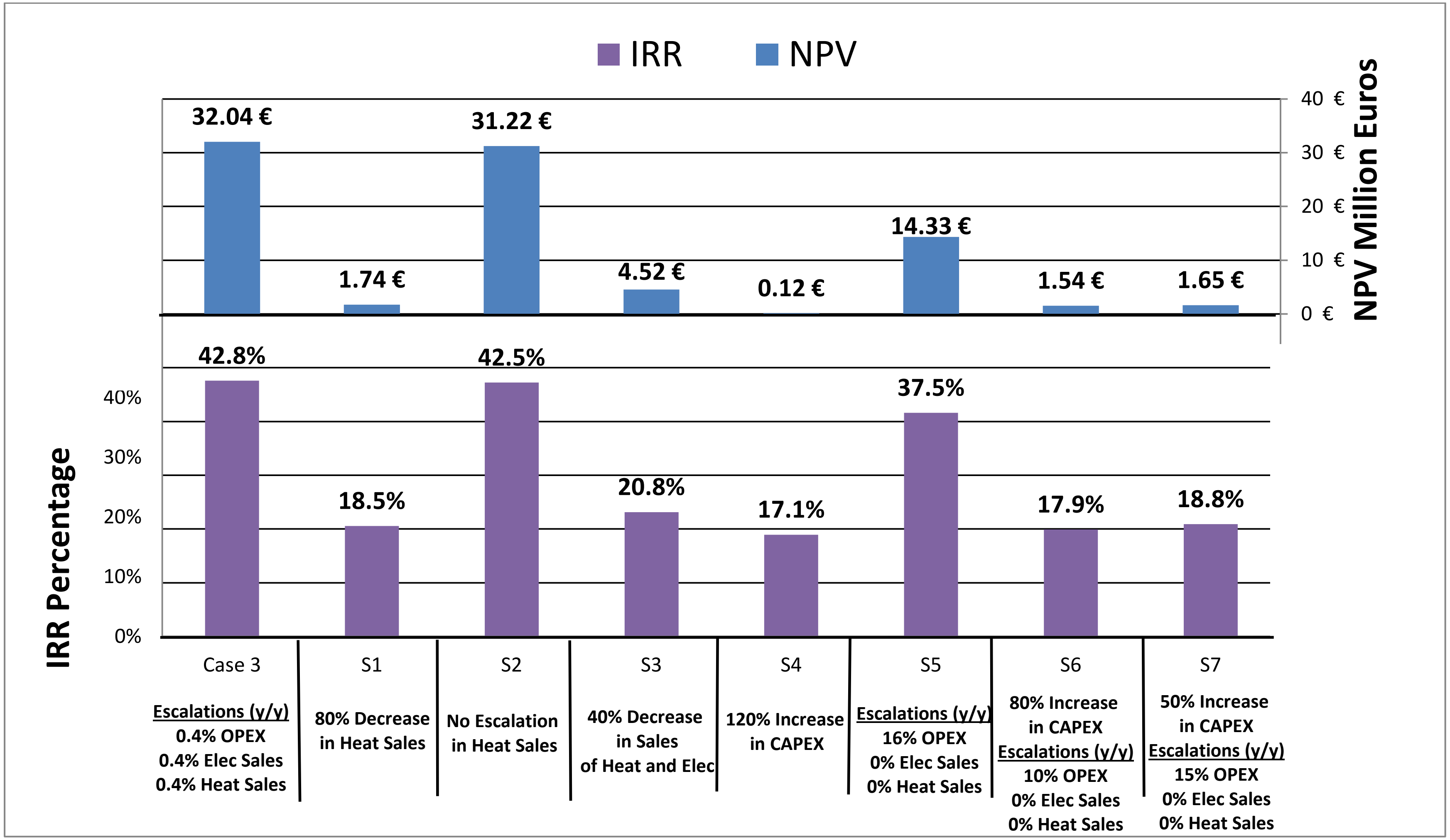
Case 3 was examined within the context of the German renewable energy act and the tariffs that have been afforded to independent power producers. Case 3 indicators prove the investment decision is highly beneficial, with an IRR greater than two times that of the petrochemical company's discount rate, and a highly positive NPV. A major difference between case 2 and case 3 is the large contribution of heat sales to the appraisal. This was due to the price of electricity being greater than that which was offered as part of Germany's Renewable Energy Sources Act (Sösemann, 2007) A noteworthy point in this case, is that the yearly escalations in expenditure and revenue were marginal, due to the country's average yearly inflation being 0.4%.

Sensitivities S1 to S7 are explained below:

S1: The investment decision remains wise with an 80% decrease in sales of heat.
S2: The investment decision indicators marginally decrease due to no yearly escalation of heat sales, but remain highly beneficial.
S3: The investment decision remains wise with a 40% decrease in sales of heat and electricity.
S4: The investment decision remains wise, marginally above qualifying criteria, with a 120% increase in CAPEX
S5: The investment decision remains wise with a yearly escalation of 16% in OPEX.
S6: The investment decision remains wise with an 80% increase in CAPEX and yearly escalation of 10% in OPEX and 0% in sales of heat and electricity.
S7: The investment decision remains wise with a 50% increase in CAPEX and yearly escalation of 15% in OPEX and 0% in sales of heat and electricity.

The sensitivities indicate that the NPV and IRR are heavily reliant on the sale of heat, but still viable with an 80% reduction in heat sales. The NPV and IRR also are also sensitive to fluctuations in OPEX when compared to case 2, due to OPEX contributing approximately 5% more of CAPEX in case 3. A noteworthy difference between cases 2 and 3 is the ability of case 3 meet minimum investment criteria with a 120% increase in CAPEX, as compared to 60% in case 2. This is again due to higher revenue streams in case 3 as compared to case 2, due to the higher cost of electricity in Germany. Overall, case 3 sensitivity proves to be highly robust, sustaining positive investment indicators with large variations in expenditure and revenue.

Figure 7: Case 3 NPV and IRR with Sensitivity



5. Discussion

This research sought to investigate the financial and economic feasibility of biogas projects within the context of having a biogas project that was proven unviable in a large petrochemical company. The research also aimed to understand the demotivating factors for investment in biogas technology, given the wide range of benefits the technology provides. Literature suggests that biogas technology adoption in South Africa has not seen the same growth when compared to the likes of Germany hence the tariffs afforded for renewable energy as per the renewable energy policy for the two countries was also examined to ascertain any shortcomings for the investment in biogas technology.

Under the specific conditions analysed, there is an indication that the low uptake rate of biogas technology in South Africa is related to deficient investment appraisals, in terms of identifying related revenue streams. Case 1, assessed within the petrochemical organisation, was proven unfeasible with a negative NPV and an IRR less than the WACC of the company; primarily due to not accounting for the sale of heat generated together with accounting for electricity sales using lower industry prices. There is also an indication that South Africa's low cost of electricity especially for large industry, where the megaflex tariff applies, may hinder investment in biogas to electricity projects if tariffs offered within the REIPPPP cease to exist.

Literature also suggests that biogas project appraisals are more beneficial with CHP technology, with the production of electricity and heat. As shown in case 2, appraisals become highly beneficial with the sale of heat. South Africa's REIPPPP also shows commitment to biogas to electricity projects offering a maximum of R1475MWh for electricity generated from biogas; approximately double the megaflex tariff used in case1. Most interestingly, South Africa's carbon tax bill that was due to be implemented in 2017 (but has been delayed), does not appear to have a large impact on the evaluation of a biogas to electricity project.

A typical biogas project in Germany on the other hand (case 3) is far more investment friendly than in cases 1 and 2; even taking account the stricter discount rate used; due to the robustness of the sensitivities and highly positive NPV and IRR. A major contributing factor to Germany's growth in the biogas sector as compared to South Africa is the higher price of electricity. Germany's high cost of electricity is directly linked to the incorporation of a renewable energy levy as specified within the EEG, which is used to subsidise renewable energy generation (Cox et al., 2014). It is also noteworthy to point out that, as of 2013, the renewable energy levy in Germany contributed ~48% of the electricity price (Cox et al., 2014). The higher the price of electricity, the higher the revenue streams and hence the more positive impact on the investment decision. Another reason that biogas technology is so widespread in Germany is due to the fact that the country's renewable energy policy caters for small biogas installations (400kW) whereas South Africa's smallest within the REIPPPP framework is 1MW. In addition to the lower cost of capital, Germany has benefited from years of investment in biogas technology due to governmental policy on renewable energy being developed in 1991, as compared to South Africa in 2001. The country's early adoption of a renewable energy strategy has yielded years of development on policy and technology, which also makes an investment decision easier.

In closing, though the project in the case of the petrochemical company was deemed unviable primarily due to the high WACC (as shown in case 1), the scope of financial viability via the REIPPPP still exists (as shown in case 2) based on certain existing conditions that would have to change. These conditions would include the option to sell heat even at current price of industrial electricity (R763.8/MWh) that will boost revenue streams for the participant. Additionally the option for smaller biogas capacity cap installations which would reduce capital costs, also corroborated by Amigun & Blottnitz (2007). The lower need for capital costs will therefore also reduce total repayments. Companies that want to invest in South African projects but are listed in developed markets or have diversified allocations may also be able to leverage lower borrowing costs (Investec, 2004). Furthermore, South Africa's developing nation status, with greater perceived risk, attracts a higher cost of capital than the likes of Germany, therefore require a larger yield of return (Moody's 2017).

6. Conclusion

It is expected that the findings and approach used within this research will aid the debate about allowing lower capacity caps for biogas technologies as part of the REIPPPP in South Africa. The findings also provide rationale to augment policy to aid sale of electricity back to the grid, either to other industrial users or the local municipality. The methodological approach used within this research can be used in other geographical areas or contexts that might have higher or lower risk portfolios depending on local political factors. Companies and organisations can also benefit from the methodological approach by using hurdle rates (WACCs) that might be less rigid. Additionally the analysis provides sensitivity analysis of possibly including and excluding revenue streams depending on sale of heat.

Future studies can take into consideration the sensitivity of engine sizes as well variations of WACC as part of the financial appraisal. Acquiring additional sources of feedstock such as household sewage or landfill waste with lower methane based feed streams can also be considered as part of future investigations. This can partially mitigate the challenge of landfilling in South Africa (Amsterdam & Thopil, 2017). Further synergies exist with other sectors of the industry where CO_2 output from the biogas plant can be captured and sold to the food and beverages industrial sector. Additionally, the feasibility of joint ventures where smaller companies that may have the human capacity but do not have the financial capacity for large scale installations, link with larger companies thereby increasing participation of smaller companies and stimulating the eco system.

References

ABDESHAHIAN, P., LIM, J. S., HO, W. S., HASHIM, H. & LEE, C. T. 2016. Potential of biogas production from farm animal waste in Malaysia. *Renewable and Sustainable Energy Reviews,* 60**,** 714-723.

AGOSTINI, A., BATTINI, F., PADELLA, M., GIUNTOLI, J., BAXTER, D., MARELLI, L. & AMADUCCI, S. 2016. Economics of GHG emissions mitigation via biogas production from Sorghum, maize and dairy farm manure digestion in the Po valley. *Biomass and Bioenergy,* 89**,** 58-66.

AGUILERA, P. G. & GUTIÉRREZ ORTIZ, F. J. 2016. Techno-economic assessment of biogas plant upgrading by adsorption of hydrogen sulfide on treated sewage–sludge. *Energy Conversion and Management,* 126**,** 411-420.

AMIGUN, B. & BLOTTNITZ, H. V. 2007. Investigation of scale economies for African biogas installations. *Energy Conversion and Management,* 48**,** 3090-3094.

AMSTERDAM, H. & THOPIL, G.A. 2017. Enablers towards establishing and growing South Africa's waste to electricity industry. *Waste Management*, 68, 774-785.

AUSTIN, G. & GETS, A. 2009. SUSTAINABLE CITIES: BIOGAS ENERGY FROM WASTE July 2009 ed. South Africa: SOUTH AFRICAN CITIES NETWORK.

BAKER, L. 2015. The evolving role of finance in South Africa's renewable energy sector. *Geoforum,* 64**,** 146-156.

BIO2WATT, 2016. Bronkhorstspruit Biogas Plant (Pty) Ltd. http://www.bio2watt.com/bio2watt%e2%80%99s-bronkhorstspruit-biogas-plant-(pty)-ltd.html. [Accessed, 10 November 2018]

BOND, T. & TEMPLETON, M. R. 2011. History and future of domestic biogas plants in the developing world. *Energy for Sustainable Development,* 15**,** 347-354.

BUNDESAMT, S. 2016. *Inflation Statis* [Online]. Statistisches Bundesamt. [Accessed 06 May 2016].

BP. 2017. *BP Statistical Review Of World Energy June 2017*

CHEN, C., GUO, W., NGO, H. H., LEE, D.-J., TUNG, K.-L., JIN, P., WANG, J. & WU, Y. 2016. Challenges in biogas production from anaerobic membrane bioreactors. *Renewable Energy,* 98**,** 120-134.

CHENG, S., LI, Z., MANG, H.-P., NEUPANE, K., WAUTHELET, M. & HUBA, E.-M. 2014. Application of fault tree approach for technical assessment of small-sized biogas systems in Nepal. *Applied Energy,* 113**,** 1372-1381.

CHIEN, T. & HU, J.-L. 2007. Renewable energy and macroeconomic efficiency of OECD and non-OECD economies. *Energy Policy,* 35**,** 3606-3615.

COX, M., PEICHL, A., PESTEL, N. & SIEGLOCH, S. 2014. Labor demand effects of rising electricity prices: Evidence for Germany. *Energy Policy,* 75**,** 266-277.

DOWLING, M., KIBAARA, S., CHOWDHURY, S. & CHOWDHURY, S. P. Economic feasibility analysis of electricity generation from landfill gas in South Africa. Power System Technology (POWERCON), 2012 IEEE International Conference on, Oct. 30 2012-Nov. 2 2012 2012. 1-6.

EBERHARD, A., KOLKER, J. & LEIGLAND, J. 2014. South Africa's Renewable Energy IPP Procurement Program: Success Factors and Lessons. Public-Private Infrastructure Advisory Facility (PPIAF).

ESKOM. 2017. *Eskom Tariff history* [Online]. Available: http://www.eskom.co.za/CustomerCare/TariffsAndCharges/Pages/Tariff_History.aspx [Accessed 18 January 2017].

GARCIA, D. J., & YOU, F. 2018. Addressing global environmental impacts including land use change in life cycle optimization: Studies on biofuels. *Journal of Cleaner Production,* 182**,** 313-330.

GRAAF, D. D. & FENDLER, R. 2010. Biogas production in Germany.

GRAVE, K., HAZRAT, M., BOEVE, S., BLÜCHER, F. V., BOURGAULT, C., BREITSCHOPF, B., FRIEDRICHSEN, N., ARENS, M., AYDEMIR, A., PUDLIK, M., DUSCHA, V., ORDONEZ, J., LUTZ, C., GROßMANN, A. & FLAUTE, M. 2015. Electricity Costs of Energy Intensive Industries: An International Comparison. Germany: ECOFYS Germany GmbH.

HAGMAN, L., BLUMENTHAL, A., EKLUND, M., & SVENSSON, N. 2018. The role of biogas solutions in sustainable biorefineries. *Journal of Cleaner Production,* 172**,** 3982-3989.

HAHN, H. 2011. Guideline for financing agricultural biogas projects-Training material for biogas investors. *Kassel, Germany: Fraunhofer Institute for Wind Energy and Energy System Technology (IWES)*.

HANEKAMP, E. 2014. International Biomass Business Opportunities Global biomass, bioenergy and bioplastics trends. Partners fro Innovation.

HOLM-NIELSEN, J. B., AL SEADI, T. & OLESKOWICZ-POPIEL, P. 2009. The future of anaerobic digestion and biogas utilization. *Bioresource Technology,* 100**,** 5478-5484.

HUAMAN, R. N. E., & JUN, T. X 2014. Energy related CO2 emissions and the progress on CCS projects: A review. *Renewable and Sustainable Energy Reviews,* 31**,** 368-385.

HUANG, W., CHEN, W., & ANANDARAJAH, G. (2017). The role of technology diffusion in a decarbonizing world to limit global warming to well below 2 °C: An assessment with application of Global TIMES model. *Applied Energy, 208*, 291-301.

HUTTUNEN, S., KIVIMAA, P., & VIRKAMAKIA, V. (2014, September). The need for policy coherence to trigger a transition to biogas production. Environmental Innovation and Societal Transitions, 12, 14-30.

INGLESI-LOTZ, R. 2016. The Impact of Renewable energy consumption to economic welfare: A panel data application. Ener*gy Economics*, 53, 58-63.

INVESTEC, 2004. OECD Development Centre Seminar: *"Cheaper Money for Southern Africa - Unlocking Growth".* Presentation by Michael Power, October 7, 2004. Paris

KANG, J. Y., KANG, D. W., KIM, T. S. & HUR, K. B. 2014. Comparative economic analysis of gas turbine-based power generation and combined heat and power systems using biogas fuel. *Energy,* 67**,** 309-318.

KHAN, M. T., THOPIL G. A., & LALK, J. 2016. Review of proposals for practical power sector restructuring and reforms in a dynamic electricity supply industry. *Renewable and Sustainable Energy Reviews,* 62**,** 326-335.

KUMMAMURU, B. 2016. WBA GLOBAL BIOENERGY STATISTICS 2016. Sweden: World Bioenergy Association.

LEHOHLA, P. 2016. *Consumer Price Index* [Online]. South Africa: Stats SA. Available: http://www.statssa.gov.za/publications/P0141/P0141January2016.pdf [Accessed 26 June 2016].

LINDKVIST, E., & KARLSSON, M. 2018. Biogas production plants; existing classifications and proposed categories. *Journal of Cleaner Production,* 174**,** 1588-1597

LONNQVIST, T., SANDBERG, T., BIRBUET, J. C., OLSSON, J., ESPINOSA, C., THORIN, E., GRONKVIST, S., & GOMEZ, M.F. 2018. Large-scale biogas generation in Bolivia – A stepwise reconfiguration. *Journal of Cleaner Production, 180*, 494-504.

MAGHANAKI, M. M., GHOBADIAN, B., NAJAFI, G. & GALOGAH, R. J. 2013. Potential of biogas production in Iran. *Renewable and Sustainable Energy Reviews,* 28**,** 702-714.

MILLINGER, M., & THRÄN, D. 2018. Biomass price developments inhibit biofuel investments and research in Germany: The crucial future role of high yields. *Journal of Cleaner Production,* 172**,** 1654-1663.

MITRA, S., SUN, L. & GROSSMANN, I. E. 2013. Optimal scheduling of industrial combined heat and power plants under time-sensitive electricity prices. *Energy,* 54**,** 194-211.

MOODY'S, 2017. Project finance bank loans in emerging markets show resilience. https://www.moodys.com/research/Moodys-Project-finance-bank-loans-in-emerging-markets-show-resilience--PR_377064. [Accessed 13 November 2018]

MSIMANGA, B. & SEBITOSI, A. B. 2014. South Africa's non-policy driven options for renewable energy development. *Renewable Energy,* 69**,** 420-427.

MUNGANGA, G. 2013a. Overview of biogas market in SA. Greencape Waste Economy Sector.

MUNGANGA, G. 2013b. Overview of biogas market in SA. *Greencape Waste Economy Sector*.

MWIRIGI, J., BALANA, B. B., MUGISHA, J., WALEKHWA, P., MELAMU, R., NAKAMI, S. & MAKENZI, P. 2014. Socio-economic hurdles to widespread adoption of small-scale biogas digesters in Sub-Saharan Africa: A review. *Biomass and Bioenergy,* 70**,** 17-25.

NICHOLAS, J. M. & STEYN, H. D. V. 2012. *Project Management for Business, Engineering and Technology*, Massachusetts: Butterworth- Heinemann.

NIE, P.-Y., CHEN, Y.-H., YANG, Y.-C. & WANG, X. H. 2016. Subsidies in carbon finance for promoting renewable energy development. *Journal of Cleaner Production,* 139**,** 677-684.

PEGELS, A. 2010. Renewable energy in South Africa: Potentials, barriers and options for support. *Energy Policy,* 38**,** 4945-4954.

QASE, N., BALMER, M., MASANGANE, P. & VAN DER WALT, M.-L. 2015. State of Renewable Energy in South Africa. Pretoria: Department of Energy.

ROOPNARAIN, A. & ADELEKE, R. 2017. Current status, hurdles and future prospects of biogas digestion technology in Africa. *Renewable and Sustainable Energy Reviews,* 67**,** 1162-1179.

SIDDIQUE, N. I., MUNAIM, M. S. A., & WAHID, Z. A. 2015. Role of biogas recirculation in enhancing petrochemical wastewater treatment efficiency of continuous stirred tank reactor. *Journal of Cleaner Production,* 91**,** 229-234.

SKAE, F. 2014. *Managerial Finance* ISBN: 978-0-409-12002-8, Lexis Nexis, South Africa.

SÖSEMANN, F. 2007. EEG – The Renewable Energy Sources Act - The success story of sustainable policies for Germany. *In:* GEHEEB, G. (ed.). Berlin, Germany: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU).

STAFFORD, W., COHEN, B., PATHER-ELIAS, S., VON BLOTTNITZ, H., VAN HILLE, R., HARRISON, S.T.L., & BURTON, S. 2013. *Journal of Energy in Southern Africa*, 24 (1), pp.15-26.

STAUSS, W., BIERNATZKI, R., BRAUN, J. & MERGENTHALER, M. The transformation of Germany's energy system: What is the role of biogas in the electricity market? Power Engineering Conference (UPEC), 2013 48th International Universities', 2-5 Sept. 2013 2013. 1-3.

SWART, I. 2016. *Draft Carbon Tax Bill released: South Africa moves to reduce greenhouse gas emissions* [Online]. Deloitte & Touche. Available: http://www2.deloitte.com/za/en/footerlinks/pressreleasespage/carbon-tax-bill.html [Accessed 05 May 2016].

TAYLOR, M., DANIEL, K., ILAS, A. & YOUNG, E. 2015. RENEWABLE POWER GENERATION COSTS. International Renewable Energy Agency

THOPIL, G. A. & POURIS, A. 2015. Aggregation and internalisation of electricity externalities in South Africa. *Energy,* 82**,** 501-511.

URBANIAK-HEDLEY, F. 2011. Biogas extraction : an alternative energy source for breweries : waste to energy. *ReSource.* SA ePublications.

VALLABHJEE, B. C. 2015. Overview of the Power Sector in South Africa. South Africa: Barclays Africa – Corporate & Investment Banking.

VARUN, BHAT, I. K. & PRAKASH, R. 2009. LCA of renewable energy for electricity generation systems—A review. *Renewable and Sustainable Energy Reviews,* 13**,** 1067-1073.

WAGNER, L. 2015. Trends from the use of biogas technology in Germany [Online]. Bangkok: German Biogas Association.

WALWYN, D. R. & BRENT, A. C. 2015. Renewable energy gathers steam in South Africa. *Renewable and Sustainable Energy Reviews,* 41**,** 390-401.

WU, A., LOVETT, D., MCEWAN, M., CECELJA, F. & CHEN, T. 2016a. A spreadsheet calculator for estimating biogas production and economic measures for UK-based farm-fed anaerobic digesters. *Bioresource Technology,* 220**,** 479-489.

WU, B., ZHANG, X., SHANG, D., BAO, D., ZHANG, S. & ZHENG, T. 2016b. Energetic-environmental-economic assessment of the biogas system with three utilization pathways: Combined heat and power, biomethane and fuel cell. *Bioresource Technology,* 214**,** 722-728.