ISTANBUL TECHNICAL UNIVERSITY ★ ENERGY INSTITUTE

TECHNO-ECONOMIC ANALYSIS OF HYDROGEN SUPPLY CHAINS AND HYDROGEN AIRCRAFTS FOR GAUTENG METROPOLITAN REGION OF SOUTH AFRICA

M.Sc. Thesis by
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Department : Energy Institute

Programme : Energy Science and Technology

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August 2013

ISTANBUL TEKNİK ÜNİVERSİTESİ ★ ENERJİ ENSTİTÜSÜ

GÜNEY AFRİKA'NIN GAUTENG METROPOLITAN BÖLGESİ İÇİN HİDROJEN TEDARİK ZİNCİRLERİNİN VE HİDROJEN YAKITLI UÇAKLARIN TEKNO-EKONOMİK ANALİZİ

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FOREWORD

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August 2013 Ömer Faruk Konar

(Mechanical Engineer)

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ABBREVIATIONS

ANC	: African national congress
CCS	: Carbon capture and storage
CMR	: Cryoplane medium range
CO_2	: Carbon dioxide
DOC	: Direct operating cost
FOM	: Fixed operating & maintenance (costs)
GHG	: Greenhouse gas
H_2	: Hydrogen
HHV	: Higher heating value
IGCC	: Integrated gasification combined cycle
INV	: Investment cost
LH_2	: Liquid Hydrogen
LHV	: Lover heating value
Nm^3	: Normal cubic meter
NO_X	: Nitrogen dioxide (NO2) and Nitric oxide (NO)
PEM	: Proton exchange membrane
pkm	: Passenger kilometer
R&D	: Research and development
RK	: Reference kerosene
SCF	: Standard cubic feet
SOFC	: Solid oxide fuel cell
UHC	: Unburned hydrocarbon
VOM	: Variable operating & maintenance (costs)
ZAR	: South African Rand

TECHNO-ECONOMIC ANALYSIS OF HYDROGEN SUPPLY CHAINS AND HYDROGEN AIRCRAFTS FOR GAUTENG METROPOLIAN REGION OF SOUTH AFRICA

SUMMARY

Climate change is only one of the issues that are results of greenhouse gas emissions. Air quality and climate change which are related to consumption of fossil fuels and which are not interest and concern of only policy makers but also the public. These issues concern authorities more intensely in the metropolitan regions where population density is high; hence, energy need is higher. An important portion of energy consumption in metropolitan regions is transportation. Transportation sector plays a significant role of consuming petroleum products including air transportation. Taking in to account that air transportation has a significant portion in total greenhouse gas emissions release and estimated high petroleum prices after a few decades; there are several attempts to substitute the conventional fuels with different alternatives.

Hydrogen is one of the potential alternative fuels for future aviation transportation. The most important argument about hydrogen as an alternative energy career is the source of production and the production process. It is criticized that obtaining hydrogen from fossil fuels does not serve greenhouse gas emission reduction targets in every case. Even though hydrogen seems like a promising alternative fuel, climate change mitigation tendency and commercially competitiveness of hydrogen are not proved yet and still under investigation.

The purpose of this thesis is to evaluate future availability of hydrogen air transportation in Gauteng metropolitan region of South Africa estimating costs and efficiencies comparing with the current statue. In order to assess entire hydrogen life cycle costs in Gauteng metropolitan region, current and future hydrogen production costs from coal, natural gas, biomass and electrolysis are analyzed. Distribution costs of hydrogen from centralized production fields to the international airport and onsite liquefaction costs are also analyzed for hydrogen. The conversion of a conventional airplane to a hydrogen fuel airplane design costs are determined and compared with the conventional aircraft. Finally, overall hydrogen utilization in air transportation is analyzed with a techno-economic approach.

In addition to all, there are some obstacles for transition to hydrogen technology. The main obstacle is high costs of hydrogen production and hydrogen infrastructures. The result of the current and future comparisons of production and transportation costs shows that operating a hydrogen aircraft might be doable earliest around 2040 after competing hydrogen fuel prices with kerosene.

Until 2040, hydrogen production methods require further research to decrease provision costs. Meanwhile, high investment and operating costs of hydrogen production and accelerated research and development on this field should be supported by policy makers and more passionate climate change mitigation targets.

GÜNEY AFRİKA'NIN GAUTENG METROPOLİTAN BÖLGESİ İÇİN HİDROJEN TEDARİK ZİNCİRİNİN VE HİDROJEN YAKITLI UÇAKLARIN TEKNO-EKONOMİK ANALİZİ

ÖZET

İklim değişikliği, sera gazı salınımı sonucu oluşan sorunlardan sadece biridir. Fosil yakıtların tüketimiyle bağlantılı olan hava kalitesi ve iklim değişikliği gibi sorunlar, sadece politika oluşturan karar mekanizmalarının değil aynı zamanda halkın da kaygı duyduğu konulardır. İklim değişikliği konusu özellikle nüfusun yoğun ve enerji gereksiniminin yüksek olduğu metropol bölgelerde, otoriteleri daha fazla ilgilendirmektedir. Metropol bölgelerde enerji tüketiminin büyük bir bölümünü ulaşım oluşturmaktadır. Hava ulaşımı dahil olmak üzere tüm ulaşım çeşitleri, petrol ürünleri tüketiminde önemli rol oynar. Özellikle hava ulaşımının sera gazı salınımına önemli ölçüde olumsuz katkısı ve gelecek yıllar için yapılan yüksek petrol fiyatı tahminleri dikkate alındığında, geleneksel yakıtların yerini alması planlanan alternatif yakıtlar ön plana çıkmaktadır.

Hidrojen, diğer alternatiflerin yanı sıra, fosil yakıtlarla yarışabilecek termal karakteristiği ve yanma verimi, düşük emisyon oranları, doğada bulunan en yaygın element olması sebebiyle çeşitli üretim seçenekleri sunması gibi özellikleriyle ulaşım için önemli bir potansiyel yakıttır. Emisyonlar ve sera gazı etkisi noktasında ele alındığında, hidrojenin alternatif yakıt olarak kullanılmasındaki en önemli tartışma, üretim kaynağı ve üretim yöntemidir. Hidrojenin, fosil kaynaklardan üretilmesinin, her zaman sera gazı azaltma hedeflerine hizmet etmediği tartışma konusu olmuştur. Hidrojen her ne kadar ümit veren bir alternatif yakıt olarak gözükse de, iklim değişikliğine olan etkisi ve ticari rekabet özelliği kanıtlanmamış ve hala araştırma konusu durumundadur.

Bu çalışmada, hava ulaşımının enerji yoğun bir ulaşım çeşidi olduğunu göz önünde bulundurarak, hidrojenin hava ulaşımında alternatif bir yakıt olarak kullanımı incelenmektedir. Örnek bir çalışma olarak Güney Afrika'nın Gauteng Metropoliten bölgesinde hava ulaşımında kullanımı değerlendirilmektedir. Hidrojenin üretilmesi ve kullanılması ile bağlantılı tüm maliyet ve verimlilik tahminlerini günümüz koşulları ile kıyaslayarak, hidrojenin gelecekte, Gauteng bölgesi için tüm ömür maliyetinin belirlenmesi hedeflenmiştir. Hidrojenin üretim kaynağı olarak, kömürden, doğal gazdan, biokütleden ve elektroliz yöntemi ile sudan üretilmesi yakından incelenmektedir.

Tekno-ekonomik bir çalışma olan bu tezde, güncel ve gelecek global hidrojen üretim maliyetleri analiz edilmektedir. Üretim maliyetleri ile hidrojen kaynaklarının Gauteng metropolitan bölgesindeki yerel yakıt fiyatları girdi olarak göz önüne alınarak, hidrojenin bu bölgeye özgü yerel üretim maliyetleri elde edilmiştir.

Merkezi olarak üretilmiş hidrojenin, uluslar arası havalimanına dağıtım ve yerinde sıvılaştırma maliyetleri de analiz edilmiştir. Bu bağlamda, bu metropolitan bölgedeki bazı potansiyel hidrojen üretim tesisleri seçilerek, hava alanına uzaklıkları optimize edilmiş ve bu uzaklıklar için hidrojenin taşınma ve dağıtım maliyetleri kıyaslanmıştır. Hidrojenin taşınması ve dağıtılmasında, kamyon taşımacılığı, boru hattı taşımacılığı ve bu iki yöntemin birlikte kullanılabileceği combine taşımacılık yakından incelenmiştir. Hidrojenin bu yöntemler ile, ilgili teknolojiye bağlı olarak, sıvı yada gaz fazında taşınabileceği varsayılmaktadır. Üretilen ve havaalanına taşınan hidrojenin uçaklarda kullanımının analizi yapılmaktadır. Geleneksel bir uçağın, hidrojen yakıtlı bir uçağa dönüştürülmesindeki tasarım maliyetleri ve hidrojenin hava ulaşımında kullanılması için detaylı maliyetler tekno-ekonomik yaklaşım ile incelenmektedir. Hidrojenin üretilmesi, taşınması ve uçaklarda kullanımının maliyet kıyaslarında günümüz için belirlenen veriler için 2010 senesi, gelecek için 2040 senesi kıyas referansı olarak seçilmiştir.

Hidrojen teknolojisine geçişte bazı engeller de bulunmaktadır. Hidrojen üretiminin ve hidrojen altyapısının yüksek maliyeti bu engellerin başında gelir. Hidrojen üretimi ve dağıtımının günümüz ve gelecek maliyetleri kıyaslaması, hidrojen yakıtlı uçağın, hidrojenin kerosen yakıtı ile ekonomik olarak rekabet edebilmesinin ardından, en yakın 2040 yıllarında uygulanabilir olduğunu ön görmektedir. Hava ulaşımı bağlamında, Hidrojenin maliyet olarak rekabet edebilecek bir yakıt seviyesine gelmesi gerekliliğinin yanısıra, havacılık alanındaki teknolojik gelişmeler de, hidrojenin yakıt olarak kullanılmasında en başta gelen gereksinimlerdendir.

2040 yılına kadar, üretim maliyetlerinin düşürülmesi için, hidrojen üretim teknikleri üzerinde ileri araştırmalar yapılması gerektirmektedir. Bunun yanı sıra, yüksek maliyetli hidrojen üretimi ve bu alanda hız kazanmış araştırma ve geliştirme, karar mekanizmaları ve daha açık iklim hedefleri tarafından desteklenmelidir. Hidrojen temelli teknolojiler için, özellkle hidrojen yakıtlı uçaklar gibi hidrojen bağlantılı ulaşım teknolojieri için, hidrojenin yakıt olarak kullanılabileceği noktada teknoloji kabiliyeti olarak yeterli seviyeye ulaşmak için gerekli araştırma ve teknoloji geliştirme faaliyetlerine hız kazandırılmalıdır.

1. INTRODUCTION

1.1 Problem Statement

Energy issue has been one of the key factors for economic growth, social well being and global development recently (ExxonMobil, 2012). Therefore, energy consumption in the world mainly deepens on fossil fuels in recent decades. Depending on fossil fuels, causes unfavorable results. One of these results is unreliable market and fluctuant prices of fossil fuels. Beside the economical aspect, from environmental aspect, fossil fuels release greenhouse gas emissions, especially CO2 emissions (Gül, 2008). The terms of Global warming, climate change and energy security became the common concerns, which obligate nations and organizations to take measures as alternative energy solutions.

Transportation sector has an important role in energy consumption with the increasing demand on transportation and with the increasing number of population worldwide (Ernst&Young, 2012). Metropolitan regions have more obvious impact and results of this high-energy consumption rate with their high density of population. Out of whole transportation systems, air transportation is the second largest energy consuming transportation after road transportation with a share of 13% (EC, 2013). Economical and environmental point of view, metropolitan regions requires alternative energy solutions and fuels with depleting fossil fuel sources. Hydrogen economy studies including transportation challenges accelerated in recent decade.

Serving to alternative energy and transportation solutions, alternative transportation and fuel technologies has become a focus of research (EERE, 2007). One of these fuel alternatives is hydrogen with its wide range of productivity and inoffensive environmental characteristics. Hydrogen applications in aviation have been also studied to offer alternative energy solutions to this energy-dense transportation by the leadership of Airbus and this project was named Cryoplane (Airbus, 2003).

Hydrogen in aviation in metropolitan region of Gauteng - South Africa is a part of a regional energy solution project named EnerKey. For this aim, hydrogen cycle in Gauteng metropolitan region will be analyzed in this study.

As a case study in Gauteng metropolitan region, hydrogen production, transportation, hydrogen infrastructure at the airport and hydrogen airplanes are the significant points of understanding future statue of hydrogen in megacities and in transportation.

1.2 Methodology and Outline of The Study

The method of this dissertation consists in the literature. The global costs and efficiencies of all hydrogen related values rely on the economic evaluation in the literature. Currency and exchange rate changes follow the basic data collection from the literature. After conversion all monetary values into the common currency of South African Rand in 2007, the curves were modeled for each technology of hydrogen production or delivery technologies. Numerical functions were gained from the data pool in a year or capacity based comparison graphics. These functions were run for the years 2010 and 2040 in order to project current and future costs. Finally, production and delivery functions were used to estimate total costs. In hydrogen delivery paths, different factors such as delivery distance, hydrogen demand, hydrogen pipeline diameter, the phase of delivered hydrogen etc. were taken into consideration. In addition to all, efficiencies for each technology were projected. Therefore, regional fuel prices and delivery options such as possible hydrogen production plants and distances are applied with scenario analysis approach. Hydrogen airplane costs and efficiencies were estimated for future and compared with the conventional kerosene airplane costs.

The structure of the dissertation proceeds in a techno-economical order. Chapters firstly present the technologies and subsequently presenting cost estimations in the following chapter.

In the Chapter 2, methods of hydrogen production from coal, natural gas, biomass and electrolysis are depicted in detail.

In the Chapter 3, the investment costs, fixed operating and maintenance costs, variable operating and maintenance costs and efficiencies are presented on the year based graphics. Finally, the production costs were projected for 2010 and 2040.

In the Chapter 4, methods of hydrogen delivery by pipeline, by truck or combined delivery are explained in detail.

In the Chapter 5, the investment costs, fixed operating and maintenance costs, variable operating and maintenance costs and efficiencies are presented on the year based graphics and as final step the production costs were projected for 2010 and 2040.

In the Chapter 6, hydrogen airplane applications and the necessary systems and technologies in order to demonstrate hydrogen airplanes in Gauteng region are presented.

In the Chapter 7, the costs for hydrogen airplane per seat for 2040 is projected.

Consequently, in the Chapter 8, result related to techno-economic analysis of hydrogen fuel and hydrogen airplane for Gauteng region is interpreted and recommendations are suggested.

1.3 Gauteng Metropolitan Region and EnerKey

The EnerKey project, comprising of German and South African researchers and businesses, undertakes to assist the region to tackle these energy challenges and develop measures to improve and optimize the sustainable development of megacities while meeting economic, social and environmental objectives.

An integrated energy and climate protection concept for the metropolitan region of Gauteng, South Africa is developed within an international research project, EnerKey. The Gauteng megacity region, one of the 30 largest agglomerations worldwide, has a high economic output and high population density.

Johannesburg, Ekurhuleni and Tschwane form part of the Gauteng Global City Region in South Africa. Together the population exceeds 10 million. With an average annual population growth rate of approximately 2.4% the population is projected to grow to 14.6 million by 2015, ranking it the 14th largest urban region in the world (IER, 2012a). Gauteng city region is presented in Figure 1.1.

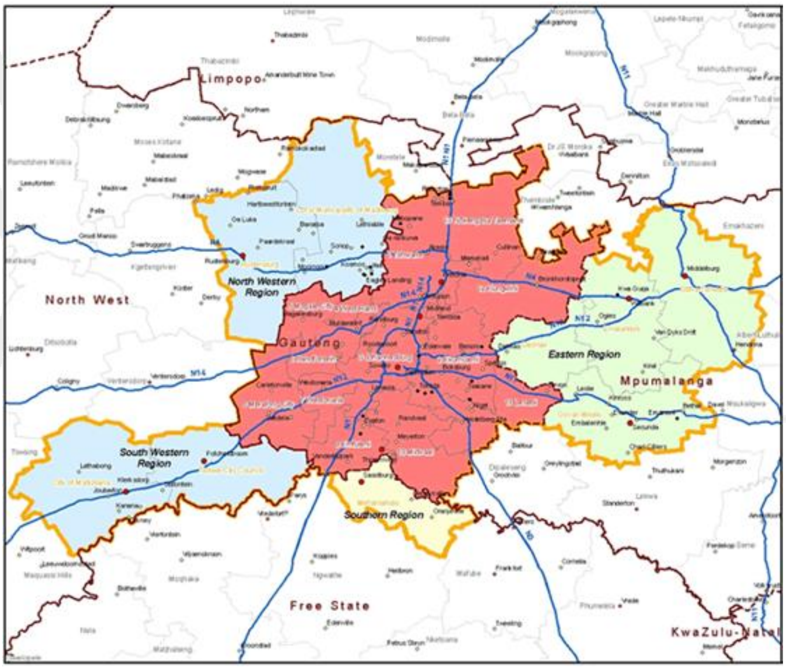

Figure 1.1: Map of Gauteng city region (IER, 2012a).

The industry sector in Gauteng accounts for about 48.7% of the total provincial final consumption rates are 9.0% for commerce, 8.5% for residence, 0.5% for governmental facilities respectively. Therefore, industry and transportation play a significant role in this region. Furthermore, the likely growth of transport demand due to private car ownership and recent industrial development causes increase energy demand and related environmental impacts.

The project covers all relevant fields of energy sources and energy systems. In order to support this project and assist sustainable development of the metropolitan region of Gauteng, particularly in this study hydrogen energy supply chain will be considered for Gauteng region as a part of EnerKey Project. Consequently, comprehension of feasibility of hydrogen energy supply, transportation and usage of hydrogen as aircraft fuel in this metropolitan area is analyzed.

1.4 O.R. Tambo International Airport

O.R. Tambo International Airport is South Africa's principal airport, with more than 50 percent of the country's air passengers passing through the airport.

The airport was renamed in 2006 to the memory of Oliver Reginald Tambo. An anti-apartheid politician and central figure in the African National Congress (ANC)

O.R. Tambo International Airport services airlines from all five continents and plays an important role in serving the local, regional, national, continental and intercontinental air transport needs of South Africa. It is the biggest and busiest airport in Africa with 28 million passengers a year.

O.R. Tambo International Airport is located in Gauteng, South Africa's commercial and industrial hub, and has road infrastructure linked to Johannesburg, Pretoria and the national road network. The Gauteng rapid rail system has had its first section opened, linking the airport with Sandton, and the extention is expected to Johannesburg and Pretoria (ACSA, 2013).

1.5 Aim of the study

This study aims to analyze hydrogen energy feasibility for Gauteng region of South Africa. In this study hydrogen air transportation is focused with the analysis of hydrogen fuel chain. Future of hydrogen related technologies in the region are studied to find alternative energy solutions for Gauteng region. Central aspects of this study are explained below:

1. Description of hydrogen sources and investigation of production methods from coal, natural gas, biomass and electrolysis for Hydrogen supply in Gauteng/South Africa.

2. Comparison of transportation methods of hydrogen considering transportation ways as truck transportation and pipeline.

3. Examination of hydrogen usage processes for air transportation in hydrogen aircrafts.

4. Comparison of cost parameters of conventional energy utilization and hydrogen energy utilization.

5. Application of supply chain integrated into the study and analysis of the system.

6. Estimation and investigation of hydrogen energy solutions for Gauteng region from today till the year 2040.

2. HYDROGEN PRODUCTION

Hydrogen is already produced in the world. Advanced R&D about production technologies are promising larger amounts and lower costs. Total annual production of hydrogen from all sources is around 40.5 million tones globally in 2010. Furthermore, it is expected to increase 3.5 % every year until 2013 (Lipman, 2011). Hydrogen can be produced from variety of sources. Hydrogen production shares were 48% from natural gas, 30% from oil, 18% from coal and 4% from electricity by electrolysis in 2009 (Balat & Balat, 2009). Even though 4% of hydrogen production comes from electrolysis and electricity also come from some fossil fuels, it is mostly accepted that this electricity source necessary for electrolysis should be produced from renewable energy systems. Principally, 96% of hydrogen produced from fossil fuel-based processes. Annual global hydrogen production is shown roughly in Table 2.1. as billion cubic meters at 21°C and 1 atm (Balat & Balat, 2009).

Table 2.1: Annual global hydrogen production by source (Balat & Balat, 2009).

Source	**10^9 m^3/year**
Natural gas	240
Oil	150
Coal	90
Electrolysis	20
Total	500

However, there are several potential hydrogen production paths. In this study the technologies which are promising globally and suitable to examine for the metropolitan region of Gauteng will be considered. In this section, technologies for hydrogen production from coal, natural gas and biomass resources and also from water electrolysis will be presented.

2.1 Hydrogen Production from Coal Gasification

Coal gasification or with the other name partial coal oxidation is one of the mostly commercialized technologies in order to produce electricity and hydrogen. This technology is mostly used in Integrated Gasification Combined Cycles (IGCC) for electricity production. Recent technologies allow combined production of electricity and hydrogen (IEA, 2010).

Gasification is a flexible technology according to the feedstock energy career. A solid feedstock such as biomass, coal or any petroleum based source and also a fuel mix can be converted to syngas. In the chemical process of coal gasification basically steam and oxidant are used. Furthermore operating conditions will be different for each kind of carbon based feedstock (Anantharaman, Hazariki, Tufai, Nagvekar, Ariyapadi, & Gualy, 2012). The principle of gasification process for hydrogen production is represented in Figure 2.1.

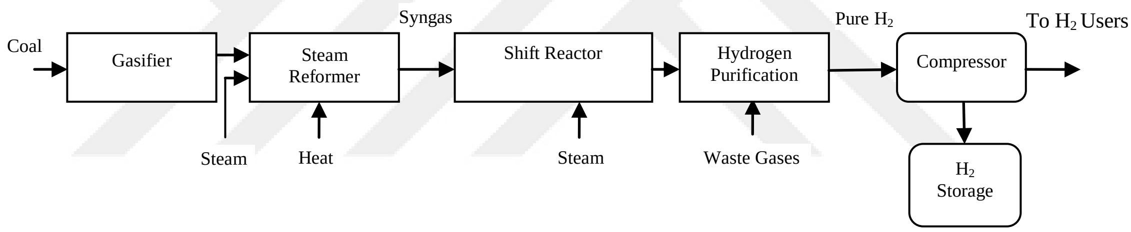

Figure 2.1: Coal gasification process for hydrogen production (Gül, 2008).

Hydrogen production primarily occurs by means of the reaction of coal with oxygen, steam under high pressure and the formation of syngas. The first mixture after chemical reaction is carbon monoxide and hydrogen as seen in the equation 2.1 (EERE, 2012a). Next step is removing impurities from the syngas.

$$CH_{0.8} + O_2 + H_2O \rightarrow CO + CO_2 + H_2 + \text{other species} \quad \textbf{(2.1)}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \quad \textbf{(2.2)}$$

After the reaction of carbon monoxide with steam by the water gas shift reaction as seen in the equation 2.2 (EERE, 2012a), additional hydrogen and carbon dioxide are gained. Consecutively hydrogen should be removed by a separation system and highly concentrated carbon dioxide can be captured by carbon capture and sequestration system (EERE, 2012a).

The process generally requires high temperatures and high pressures for gasification to occur. Even though conditions depend on the type of the process, mostly temperature should be between 750 to 840 °C and pressure might be between 1 MPa and 4.5 MPa (Wang, 2012)

2.2 Hydrogen Production from Natural Gas Reforming

Natural gas is a common methane source for steam reforming process in order to produce hydrogen. In steam methane reforming process, methane reacts with steam in an endothermic reaction. The reaction takes place under pressure with a help of catalyst, see equation 2.3, whereas in another production process called partial oxidation, reaction is exothermic and unlikely steam reforming, producing heat as seen in equation 2.4 (EERE, 2012b). In steam methane reforming, after methane and steam reaction, hydrogen, carbon monoxide and very small amount of carbon dioxide are obtained (Crews & Shumake, 2006). The whole process is presented in Figure 2.2.

Water-gas shift reaction occurs to obtain additional carbon dioxide and hydrogen from carbon monoxide and steam as seen in the equation 2.5. The last step is removing impurities and carbon dioxide from the syngas in order to obtain pure hydrogen (EERE, 2012b).

$$CH_4 + H_2O + (\text{heat}) \rightarrow CO + 3H_2 \quad \textbf{(2.3)}$$

$$CH_4 + 1/2O_2 \rightarrow CO + 2H_2 + (\text{heat}) \quad \textbf{(2.4)}$$

$$CO + H_2O \rightarrow CO_2 + H_2 + (\text{small amount of heat}) \quad \textbf{(2.5)}$$

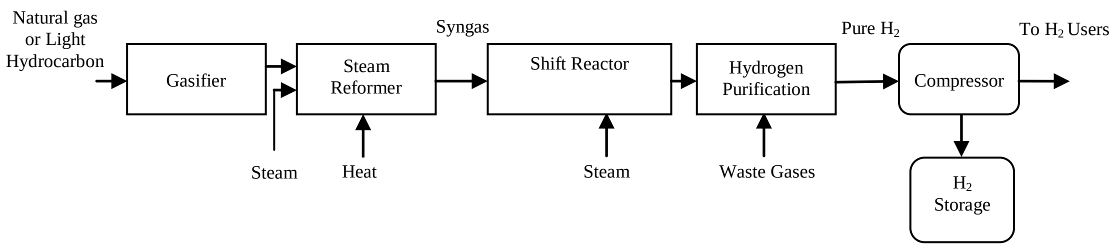

Figure 2.2: Steam-methane reforming process for hydrogen production (Gül, 2008).

According to Molburg (2003), a steam-methane reforming process operating conditions are between 20-30 atm pressure and 800-880 °C temperature. Shifting reaction also may require 345-370°C operating temperature.

2.3 Hydrogen Production from Biomass Gasification

Biomass gasification is the gasification of renewable organic sources. These sources can be variety of residues ranging from corn stover, wheat straw, switch grass, willow trees to animal wastes. This technology is considered as a suitable process for large-scale and centralized hydrogen production means of investment costs. Dealing with big amounts of biomass and large scale of production procures benefit economically. (EERE, 2012c).

As seen in Figure 2.3, the whole process for the biomass gasification is similar to the coal gasification process except operating conditions (NNFCC, 2009).

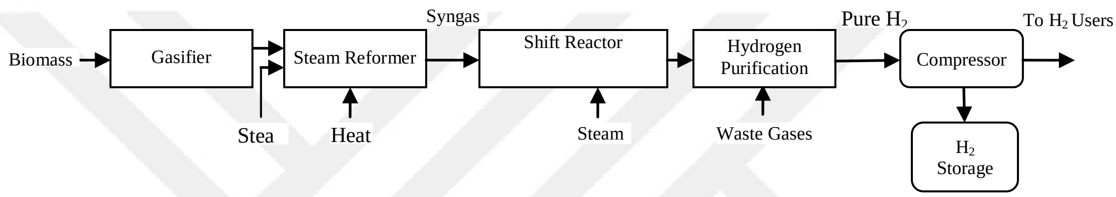

Figure 2.3: Biomass gasification process for hydrogen production (Gül, 2008).

In the gasifier, biomass is chemically converted into carbon monoxide, carbon dioxide, hydrogen and other species. The process takes place under pressure and heat with help of steam and oxygen. This primary syngas reacts with water to form additional carbon dioxide and hydrogen. This is the same water-gas shift reaction.

$$C_6H_{12}O_6 + O_2 + H_2O \rightarrow CO + CO_2 + H_2 + \text{other species} \quad \textbf{(2.6)}$$

$$CO + H_2O \rightarrow CO_2 + H_2 + \text{small amount of heat} \quad \textbf{(2.7)}$$

In general sense, biomass requires higher temperatures then coal gasification. Operating conditions such as temperature and pressure are respectively: from 500 to 1200 °C and from 1 up to 100 atm (Xcel Energy, 2007).

2.4 Hydrogen Production from Electrolysis

Electrolysis is a process which separates water into hydrogen and oxygen using an electrical current (NEED, 2005). Electrolyzer is a unit where electrolysis process takes place. The size of electrolyzer is flexible and still there are several ongoing researches to design a largescale electrolyzer connected to renewable energy electricity production facilities such as wind or solar farms (EERE, 2011). Electricity production source is an argument in order to consider electrolysis as near zero emission for hydrogen production process. Electricity input necessary for the process should be produced from low-green house gas releasing renewable energy technologies such as wind turbines, solar photovoltaic, geothermal energy, hydropower or wave power. The principle of an alkaline electrolysis is shown in Figure 2.4.

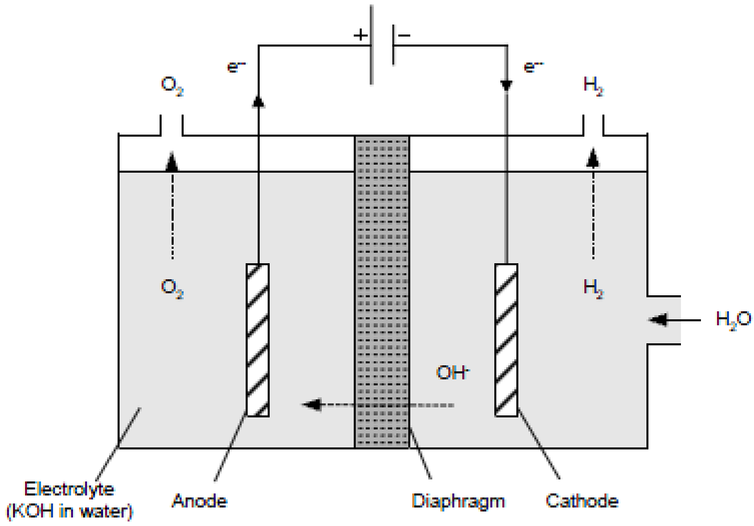

Figure 2.4: Alkaline electrolysis for hydrogen production (Gül, 2008).

Theoretically, water reacts at the anode and hydrogen ions charge positively, seen in equation 2.8. Electrons across with an external circuit to the cathode. On the cathode with electrons, hydrogen ions form hydrogen gas, seen in equation 2.9 (EERE, 2011) (Take, Tsurutani, & Umeda, 2006).

$$2H_2O \rightarrow O_2 + 4H^+ + 4e^- \quad \textbf{(2.8)}$$

$$4H^+ + 4e^- \rightarrow 2H_2 \quad \textbf{(2.9)}$$

There are three main electrolyzer types; polymer electrode membrane (PEM) electrolyzer, alkaline electrolyzers and solid oxide electrolyzers. PEM electrolyzers work with solid polymer electrolyte. However, in principle alkaline electrolyzers are similar to PEM electrolyzers. They work with sodium or hydroxide alkaline electrolyte. Solid oxide electrolyzers work with solid ceramic electrolyte and with a selective ion transmission (EERE, 2011) (Özdemir, 2011).

Alkaline electrolysis is the mostly commercialized electrolysis. PEM electrolysis is in production and development level, whereas, solid oxide electrolysis is under research level (Jensen, Jensen, & Tophoj, 2008).

Operating temperature of alkaline electrolyzers is between 100-150°C. PEM electrolyzers' operating temperature is between 80-100°C and solid oxide electrolyzers work between 500-800°C (EERE, 2011).

2.5 Carbon Capture and Sequestration

Carbon capture and sequestration is capturing of the CO_2 which is released during the processes of using fossil fuels (CCSa, 2012). In another general aspect, it is physical process of capturing manmade carbon dioxide before releasing to atmosphere. Its benefit is to reduce greenhouse gas emissions while using fossil fuels in power plants or industrial applications (Folger, 2012a). 90% of the carbon dioxide produced during the electricity production from fossil fuels can be captured by carbon capture and storage technology (CCSa, 2012). There are three main methods that carbon dioxide can be captured. These methods are seen in Table 2.2.

Carbon capture and storage systems consist of three main steps; capturing, transporting and storing. Capturing and separating carbon dioxide from other gasses at the power plants or industrial facilities is the first step. As mentioned in this section and in the Table 2.2, there are three possible methods to capture carbon dioxide.

Table 2.2: Carbon capture methods (CCSa, 2012) (Folger, 2012b).

Method	Process
Pre-combustion capture	Converting solid, liquid or gaseous fuel into a mixture of hydrogen and CO_2 using gasification or reforming.
Post-combustion capture	Absorbing CO_2 in a solvent or using high pressure membrane filtration, adsorption, cryogenic separation
Oxy-fuel combustion capture	Oxygen separation from air, combustion in oxygen diluted recycled flue-gas, concentrated CO_2 stream for purification.

Then, this gas should be compressed and transported. Transportation of CO_2 is one of the main costs of carbon capture and storage technology. Pipeline and ship transportation are choices for transport captured CO_2. Pipeline seems more suitable for domestic transportation because of the similarity of natural gas and oil transportation. Moreover, ship transportation is considered more suitable for cross-continental transportation (Folger, 2012b). Storing the captured carbon dioxide in the oceans or injecting it in geological reservoirs is the last step of the system (Folger, 2012b) (IPCC, 2005).

Carbon capture and sequestration technologies are appropriate to be used in industrial production, electricity production, hydrogen production or co-production (hydrogen and electricity) plants. (Cortes, Tzimas, & Peteves S, 2009)

It should be emphasized that benefits of carbon capture and storage technologies are more obvious in the countries which have more production or consumption rates of coal, oil and gas (IEA, 2012).

3. TECHNO-ECONOMIC ANALYSIS OF HYDROGEN PRODUCTION IN GAUTENG - SOUTH AFRICA

This section compares the costs of possible hydrogen production routes for Gauteng region of South Africa. The possible routes of hydrogen production for Gauteng region by the reasons of availability of natural sources and developing alternative fuels and technologies are from coal, natural gas, biomass and electrolysis. An overview of literature of production costs for these paths will be presented. The current and future costs will be compared for each technology. The future costs are be estimated for the year 2040 and these results are calculated for Gauteng region as conclusive hydrogen production costs. All costs are estimated for central hydrogen production facilities. The local fuel costs are applied into the calculations and estimations of hydrogen production costs for today and future. The current and future fuel costs are taken from (Tomaschek, 2012). Fuel costs for Gauteng metropolitan region are shown in Table 3.1. All fuel costs are for industrial level including transportation and delivery costs, excluding taxes.

Table 3.1: Fuel costs for Gauteng region (Tomaschek, 2012).

ZAR_{2007}/GJ_{output}	2010	2040
Coal	9.3	17.0
Natural Gas	71.6	138.4
Biomass	46.3	46.6
Electricity	146.7	207.0

In this study, all hydrogen related energy values are based on LHV. It is assumed that all technologies use electricity as input for the processes since electricity is a relatively cheap fuel in South Africa compared to the world market; however, in hydrogen production, electricity may be by product as it may be input for the production process. Positive auxiliary electricity values are taken into account in the literature research. Besides, it is assumed that electricity costs for the processes are included in the variable operation and maintenance costs. Electric efficiency is considered as electrolysis fuel efficiency. In addition, water costs and cleaning costs are included into variable operating and maintenance costs.

All costs in the literature are converted into South African Rand (ZAR) in 2007 currency. In the conversion of the currency, Table G 1, Table G 2 and Table G 3 are used which can be seen in Appendix G. Conversion rates and years are applied as a part of system analysis worksheet of EnerKey (Energy as a Key Element of an Integrated Climate Protection Concept for the City Region of Gauteng), (IER, 2012b)

All production costs for hydrogen is based on the relation (Gül, 2008):

$$COST = \frac{INVCOST}{AF} \cdot CRF + \frac{FIXOM}{AF} + VAROM + \frac{FeedstockCost}{\eta} \qquad \textbf{(3.1)}$$

INVCOST = Specific investment cost [ZAR_{2007}/kW]

CRF = Capital recovery factor [-]

AF = Availability factor [-]

FIXOM = Fixed operation and maintenance cost [ZAR_{2007}/kW/year]

VAROM = Variable operation and maintenance cost [ZAR_{2007}/GJ]

η = Process efficiency

The capital recovery factor is formulated as:

$$CRF = dr \times \frac{1+dr\ ^{n}}{(1+dr)^{n}-1} \qquad \textbf{(3.2)}$$

dr = Discount rate [%]

n = Plant life time [years]

In this section discount rate is assumed 8% and capital recovery factor is calculated for the life time of each technology separately. Plant life time approximated with 30 years for coal and natural gas technologies, 20 years for biomass and electrolysis technologies.

3.1 Cost Analysis of Hydrogen Production from Coal Gasification

This section compares the investment costs, fixed operation and maintenance costs (FOM), variable operation and maintenance costs (VOM) and efficiency values for the hydrogen production from coal gasification technologies. These values are taken from different sources for different production capacities and for different years in the literature. In order to compare the costs, this study considers two coal gasification technologies which are coal gasification with carbon capture and sequestration and without carbon capture and sequestration. Hydrogen production costs from coal gasification in the literature can be seen in Table A 1 and Table A 2 respectively for the technologies using CCS and without CCS, respectively. In these tables, the original costs and converted values into ZAR can be compared.

According to the investment costs in the literature, current and future investment costs were estimated. Decrease of the investment costs by years can be seen Figure 3.1. Exponential method is used to estimate future cost of hydrogen production from coal gasification for 2040. On the other hand, investment costs for the different capacities of the production are presented in Figure 3.2. In the graphic, the values are taken from Table A 2 which can be examined in Appendix A.

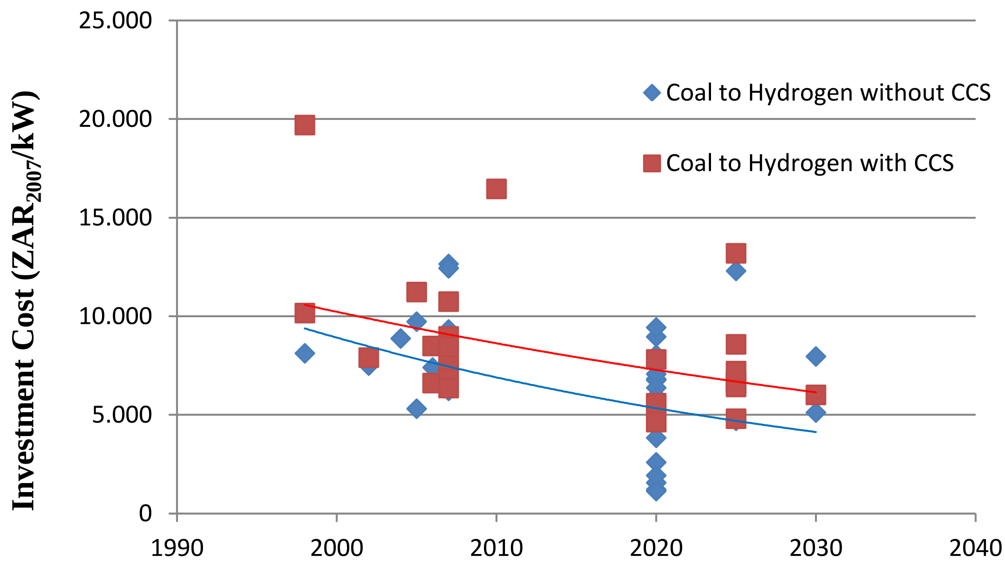

Figure 3.1: Investment costs of hydrogen production from coal gasification.

In the graphics which gives the future estimations as a result of exponential approach, investment cost for hydrogen production from coal gasification with carbon capture and sequestration is 8,661 ZAR_{2007}/kW_{output} for 2010 in Gauteng. Moreover, for the same technology which is coal gasification with carbon capture storage, investment cost of hydrogen production is projected to be about 5,205 ZAR_{2007}/kW_{output} for 2040. In thirty years, around 39.9% decrease in investment cost is projected.

The same way, investment cost for hydrogen production from coal gasification without carbon capture storage is 6,877 ZAR_{2007}/kW_{output} for 2010 and 3,185 ZAR_{2007}/kW_{output} for 2040 with an expected decrease of 53.5%.

Capacity of the production plant has effect on the efficiency of the plant and the investment cost inherently. The technology, which is used in hydrogen production plants, has also further effect on the costs. The plants, which use advanced technologies, have higher efficiencies and lower VOM and FOM costs as well.

Figure 3.2 shows capacity range of coal gasification hydrogen production plants for both the ones with carbon capture and without carbon capture and sequestration technology.

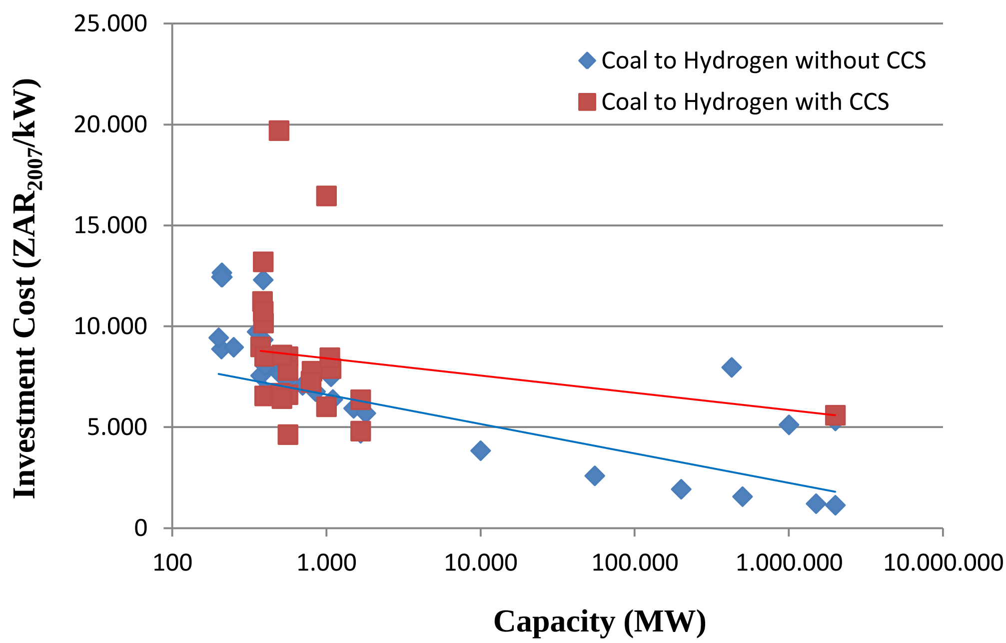

Figure 3.2: Investment costs of hydrogen production from coal gasification depending on plant capacity.

Future costs are related to capacity increase as mentioned in the graphic above and technology development. Thus, Depending on the year, all costs decrease with the developing production technologies (Özdemir, 2011). The reason of the disordered progress of the values by years is the technology learning in commercial level.

Fix operation and maintenance costs also follow the same trend. Because of additional costs of carbon capture storage along the graphic as seen in Figure 3.3, FOM cost of hydrogen production coal gasification plant without carbon capture is lower for both current and future years. In 2010, FOM cost of hydrogen production from coal gasification without carbon capture and sequestration is 362.54 ZAR2007/kWoutput and future FOM is estimated about 250.07 ZAR2007/kWoutput, whereas the production FOM with CCS is 390.58 ZAR2007/kWoutput for the year 2010 and estimated 251.14 ZAR2007/kWoutput for the year 2040. It is estimated that FOM costs of the coal gasification without CCS will approach to FOM costs of the technology with CCS in 2040.

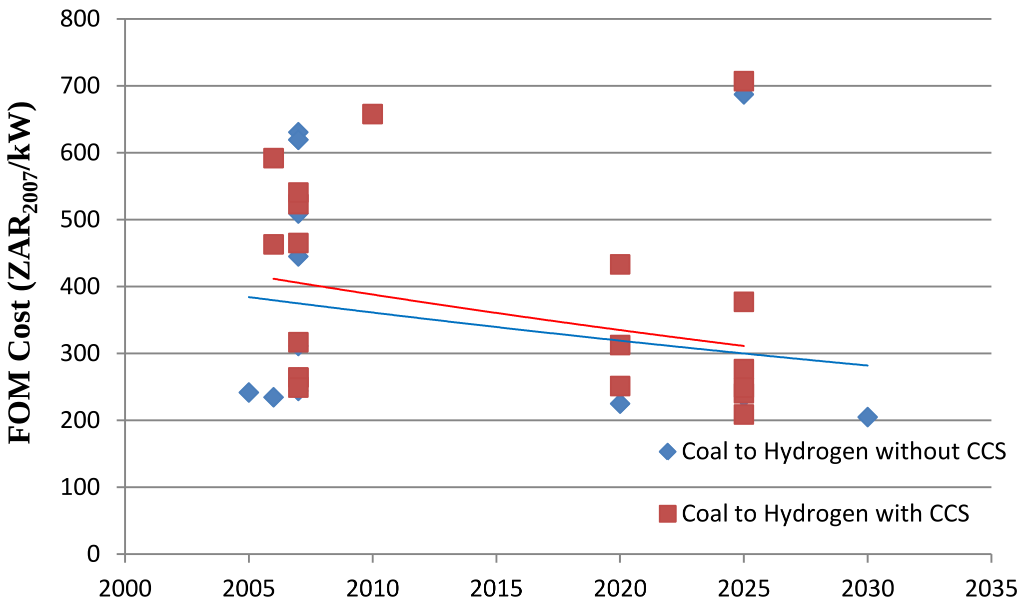

Figure 3.3: Fix operation & maintenance costs of hydrogen production from coal gasification.

Variable operation and maintenance costs of hydrogen production from coal gasification with CCS are estimated 3.74 ZAR_{2007}/GJ_{output} for 2010 and 2.58 ZAR_{2007}/GJ_{output} for 2040 in Figure 3.4. Variable operating and maintenance costs of hydrogen production from coal gasification without CCS are projected 2.46 ZAR2007/GJoutput for 2010 and 0.93 ZAR2007/GJoutput for 2040.

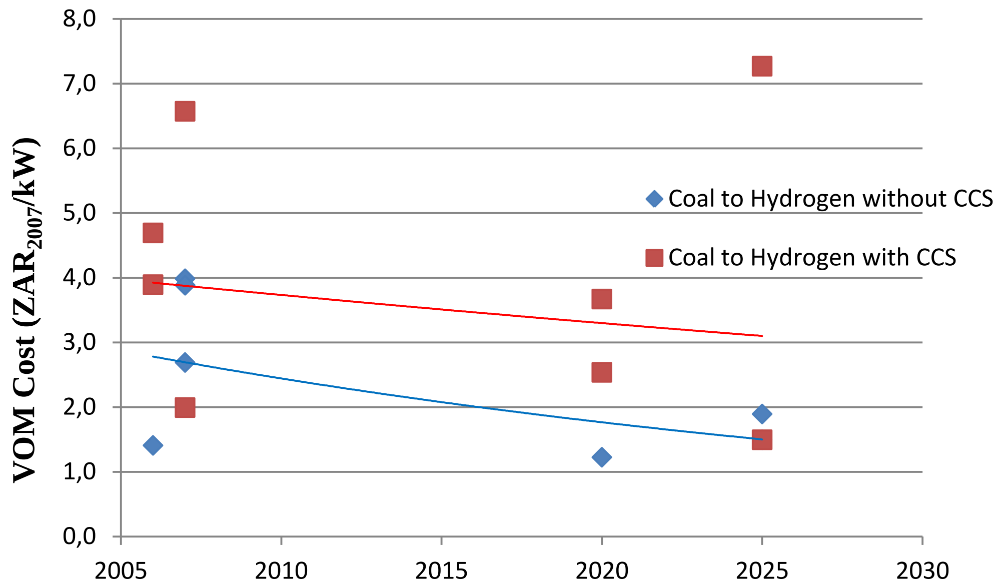

Figure 3.4: Variable operation & maintenance costs of hydrogen production from coal gasification.

Figure 3.5 Shows efficiencies of hydrogen production from coal for both with CCS and without CCS technologies.

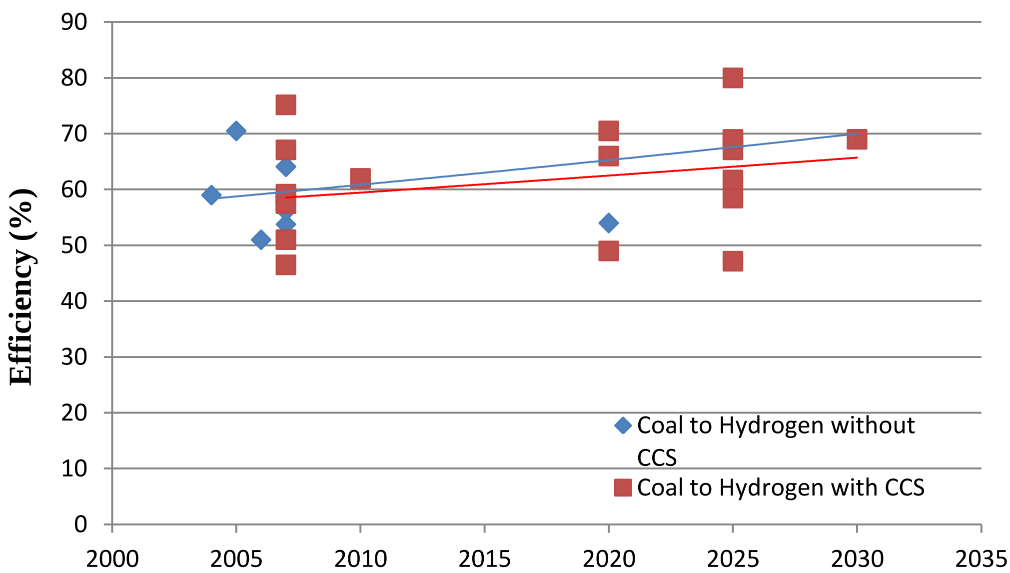

Figure 3.5: Efficiency of hydrogen production from coal gasification.

The efficiencies of hydrogen production from coal gasification reforming are respectively 60% in 2010 and 69% in 2040 for the technologies with CCS, and 64% in 2010 and 80% in 2040 for the technologies without CCS.

Current hydrogen production costs for 2010 and future hydrogen production costs for 2040 are calculated using the relation mentioned in this chapter. In the calculations of current and future, investment, FOM, VOM costs, the fuel costs for Gauteng region play important role.

All costs are converted to the currency of ZAR in 2007 per GJ in order to compare them effectively. The costs can be seen as ZAR2007/GJoutput in Table 3.2.

Table 3.2: Costs of hydrogen production from coal gasification.

ZAR_{2007}/GJ_{output}	Technology	2010	2040
Investment Cost	With CCS	274.64	165.07
	Without CCS	218.07	101.02
FOM Cost	With CCS	12.39	7.96
	Without CCS	11.50	7.93
VOM Cost	With CCS	3.74	2.58
	Without CCS	2.46	0.93
Production Cost	With CCS	1,308.16	819.98
	Without CCS	1,098.45	614.58

Hydrogen productions from coal gasification with carbon capture and sequestration technology costs are higher than the same production technology without carbon capture and storage. The additional costs, obviously, are the results of carbon capture and storage technologies.

Coal gasification has a few challenges to be used in hydrogen production with lower costs, higher efficiencies and more environmental friendly process. Advanced research and development is necessary for carbon capture and sequestration, which procure lower carbon dioxide, as new technologies for the process that separate the needed oxygen from air and new membranes which separate and purify hydrogen from gas stream.

3.2 Cost Analysis of Hydrogen production from Natural Gas Reforming

Hydrogen production from natural gas reforming also has two main technologies commonly in use. These two technologies differ from each other having carbon capture sequestration and without carbon capture and sequestration. Investment cost, operation and maintenance cost, variable operation and maintenance cost and efficiencies of both hydrogen production technologies from natural gas reforming will be projected for 2010 and 2040 in order to compare techno-economically. Literature values and the costs for Gauteng region can be seen in Table A 9 and Table A 10 in Appendix A.

Change in the investment cost can be seen in Figure 3.6. As for all estimations, the same method is applied to find today and future values of investment cost.

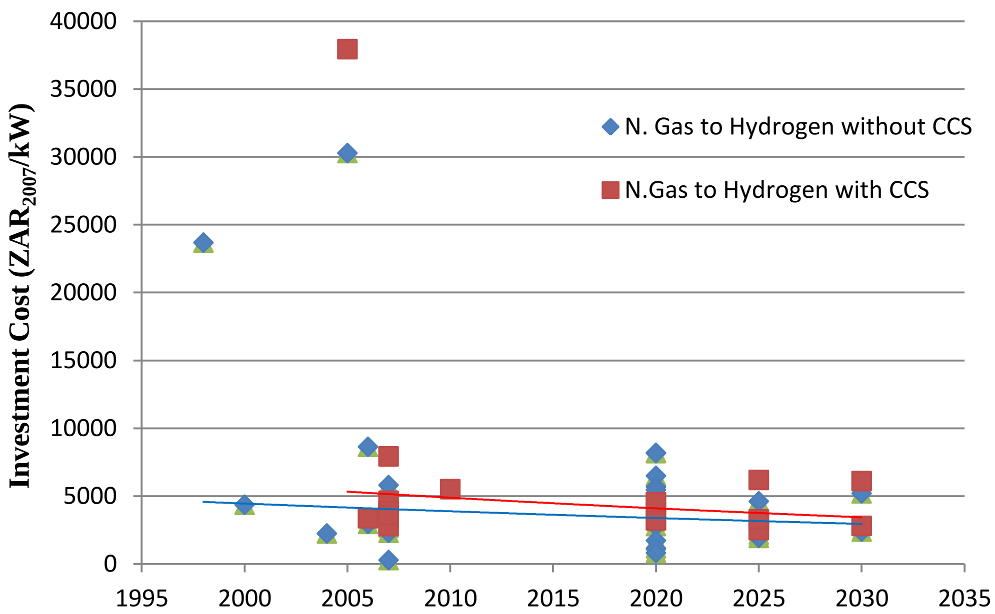

Figure 3.6: Investment costs of hydrogen production from natural gas reforming.

In Figure 3.6, estimations show the investment cost for hydrogen production from natural gas reforming with carbon capture and storage is 4,791 ZAR_{2007}/kW_{output} for 2010 and 2,885 ZAR_{2007}/kW_{output} for 2040 with approximately decrease of 40.9%.

Investment cost for hydrogen production from natural gas reforming without carbon capture is 3,867 ZAR_{2007}/kW_{output} for 2010 and 2,563 ZAR_{2007}/kW_{output} for 2040 with a decrease of 33.7%.

In Figure 3.7, the capacity range of hydrogen production technologies in the literature are compared with the investment costs.

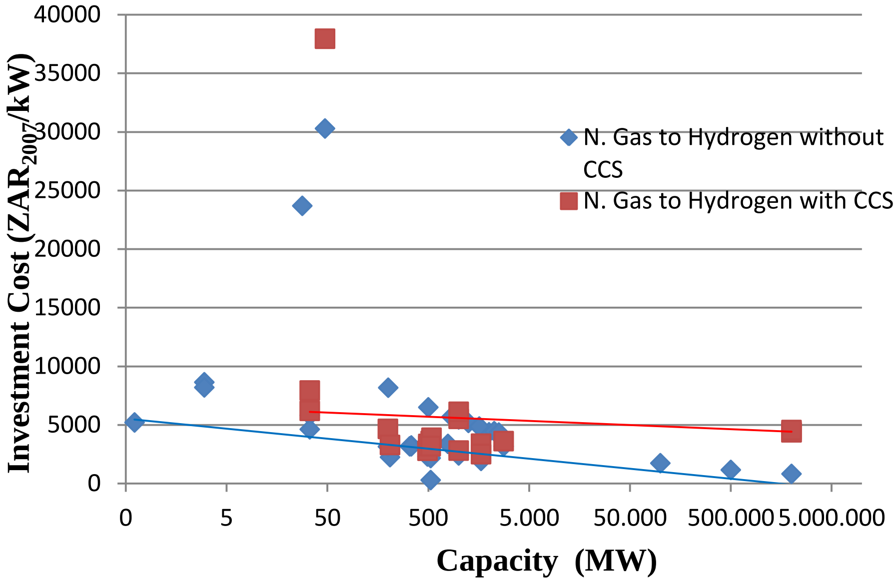

Figure 3.7: Investment costs of hydrogen production from natural gas reforming depending on plant capacity.

As mentioned in the section for coal gasification technologies, capacity of the production plant has impact on the costs and efficiency of the plant. The technology, which is used in hydrogen production plant, has also further effect on the costs.

The effect of carbon capture storage on the costs can be seen that fix operation and maintenance cost of hydrogen production from natural gas reforming with CCS is higher than the one without CCS. The FOM cost of hydrogen production from natural gas reforming with CCS is 208 ZAR_{2007}/kW_{output} for 2010 and 131 ZAR_{2007}/kW_{output} for 2040. Therefore, FOM cost of hydrogen production from natural gas reforming without CCS is 134 ZAR_{2007}/kW_{output} for 2010 and 97 ZAR_{2007}/kW_{output} for 2040. The change in the costs can be seen in Figure 3.8.

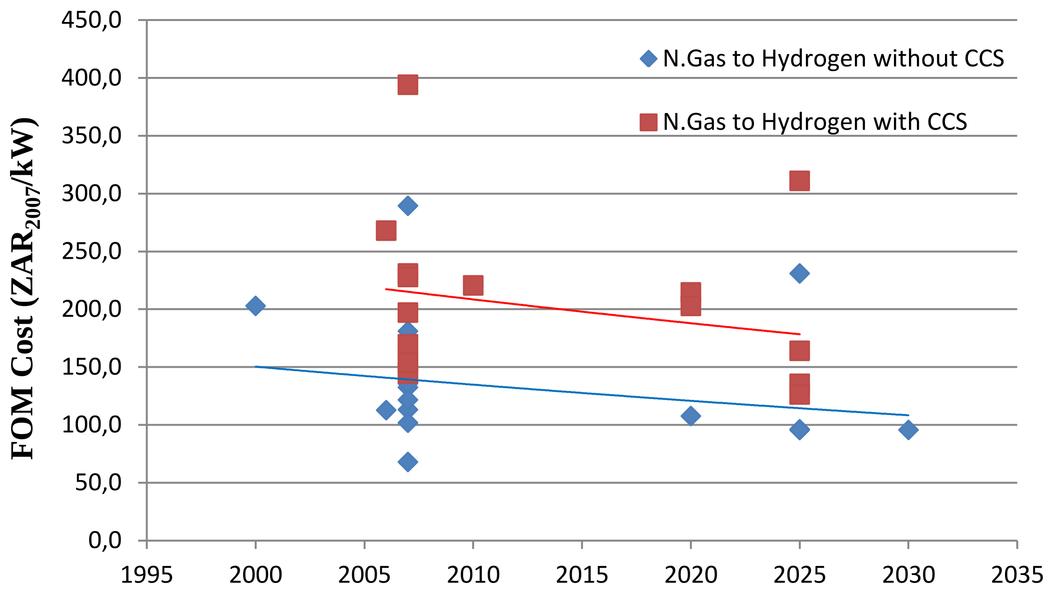

Figure 3.8: Fix operation & maintenance costs of hydrogen production from natural gas reforming.

Variable operation and maintenance costs of hydrogen production from natural gas reforming with CCS is projected as 2.15 ZAR2007/GJoutput for 2010 and 1.37 ZAR2007/GJoutput for 2040. Hydrogen production from natural gas reforming without CCS is projected 1.77 ZAR2007/GJoutput for 2010 and 1.12 ZAR2007/GJoutput for 2040, as seen in Figure 3.9.

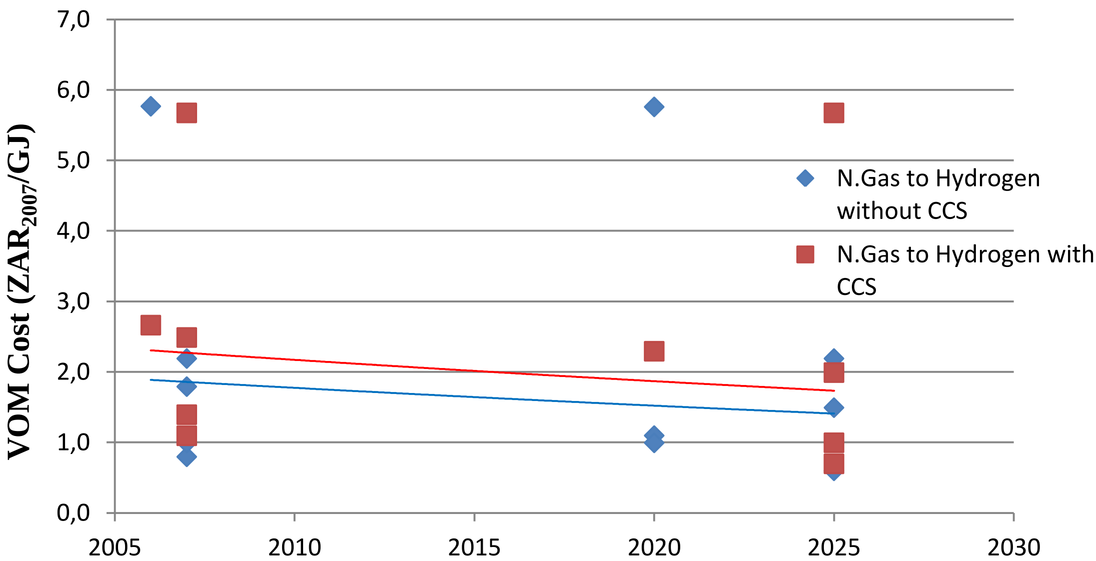

Figure 3.9: Variable operation & maintenance costs of hydrogen production from natural gas reforming.

The projected efficiencies are respectively 73% in 2010 and 77% in 2040 for the technologies with CCS, and 74% in 2010 and 81% in 2040 for the technologies without CCS as shown in Figure 3.10.

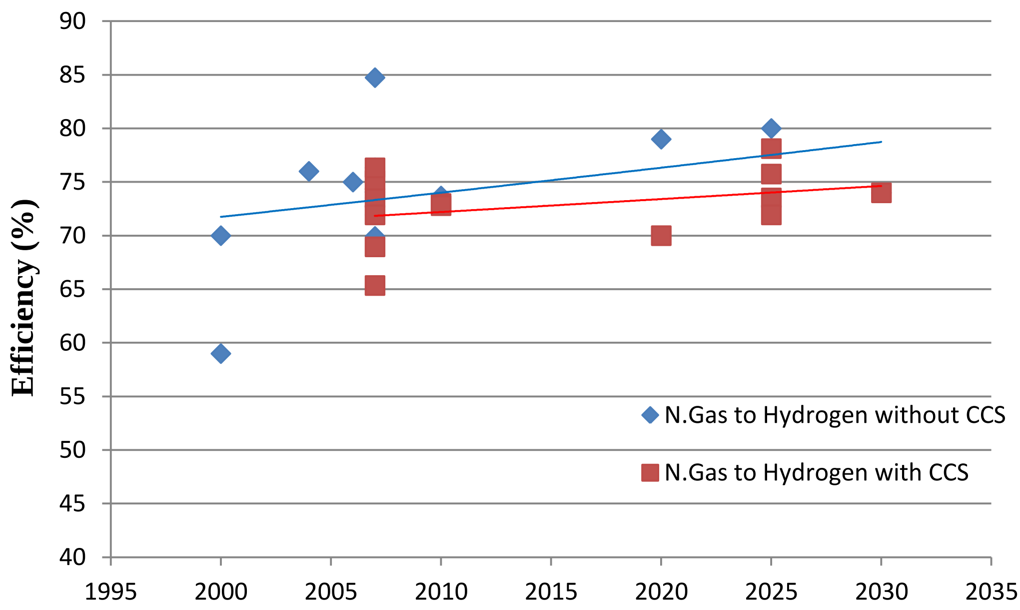

Figure 3.10: Efficiency of hydrogen production from natural gas reforming.

The total hydrogen production costs from natural gas reforming with and without CCS, also investment, FOM and VOM costs can be seen as ZAR_{2007}/GJ_{output} in Table 3.3.

Table 3.3: Costs of hydrogen production from natural gas reforming.

ZAR_{2007}/GJ_{output}	Technology	2010	2040
Investment Cost	With CCS	151.92	91.50
	Without CCS	122.65	81.29
FOM Cost	With CCS	6.62	4.16
	Without CCS	4.27	3.08
VOM Cost	With CCS	2.15	1.37
	Without CCS	1.77	1.12
Production Cost	With CCS	805.42	612.66
	Without CCS	629.64	532.97

3.3 Cost Analysis of Hydrogen Production from Biomass Gasification

The estimation of current and future values of investment costs of hydrogen production from biomass gasification project that the investment costs are 4,573 ZAR2007/kWoutput in 2010 and 2,232 ZAR2007/kWoutput in 2040 with 51% decrease as seen in Figure 3.11

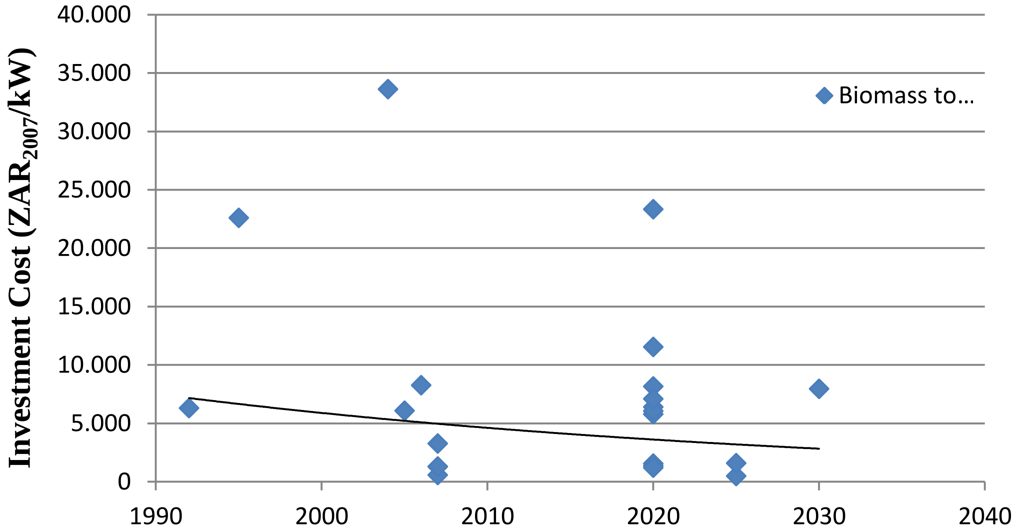

Figure 3.11: Investment costs of hydrogen production from biomass gasification.

In Figure 3.12, the capacity range of hydrogen production technologies in the literature are compared with the investment costs.

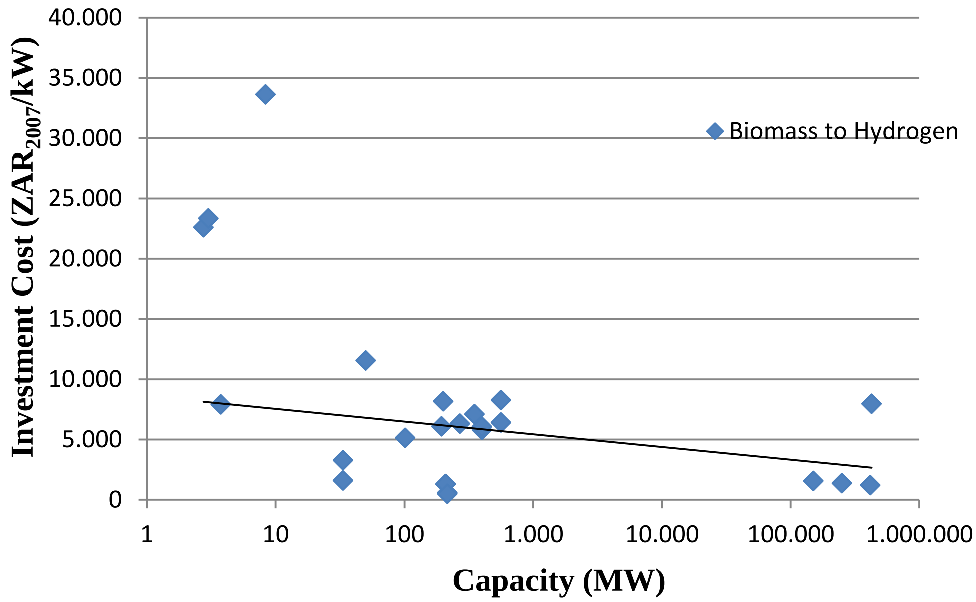

Figure 3.12: Investment costs of hydrogen production from biomass gasification depending on plant capacity.

Biomass gasification technology is considered as using no carbon capture storage technology because of having no wide diversity of costs in the the literature.. In Figure 3.13, FOM costs are projected for biomass gasification. As result of cost estimation of biomass gasification, the FOM costs of hydrogen production are 397 ZAR2007/kWoutput in 2010 and 181 ZAR2007/kWoutput in 2040.

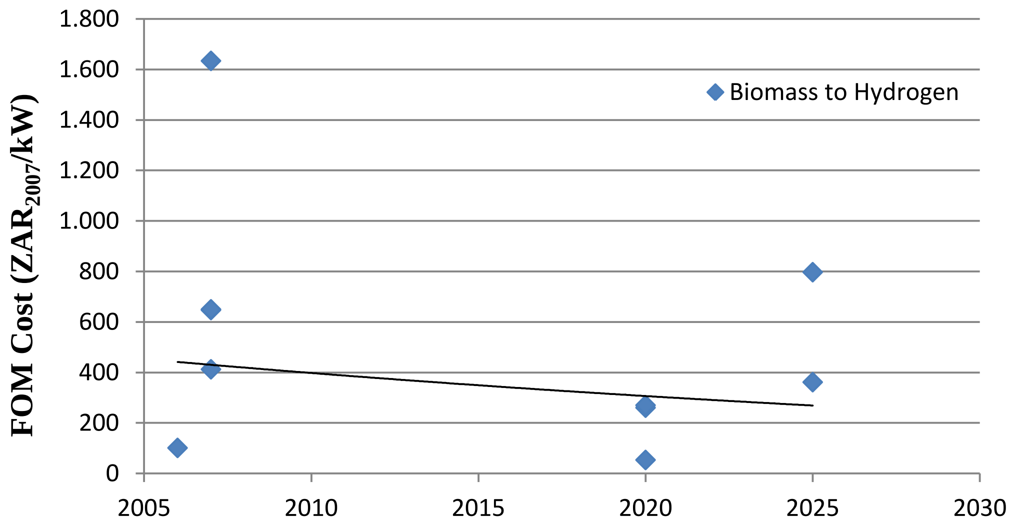

Figure 3.13: Fix operation & maintenance costs of hydrogen production from biomass gasification.

Variable operation and maintenance costs of hydrogen production from biomass gasification are projected as 6.84 ZAR2007/GJoutput for 2010 and 4.37 ZAR2007/GJoutput for 2040. These costs are shown in Figure 3.14.

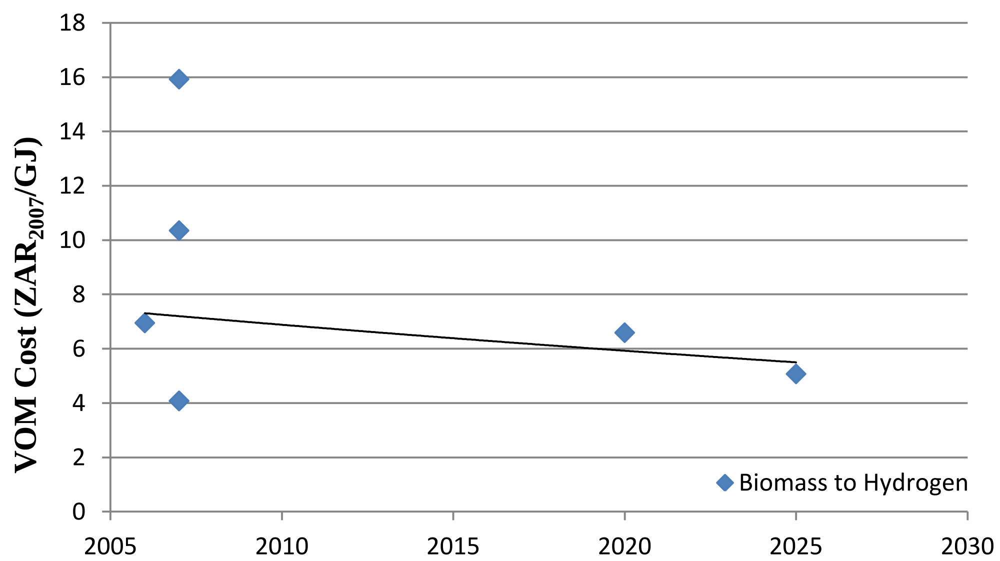

Figure 3.14: Variable operation & maintenance costs of hydrogen production from biomass gasification.

Projected efficiencies for hydrogen production from biomass gasification for 2010 and 2040 are 56% and 74%, respectively. The efficiency estimations can be seen in Figure 3.15.

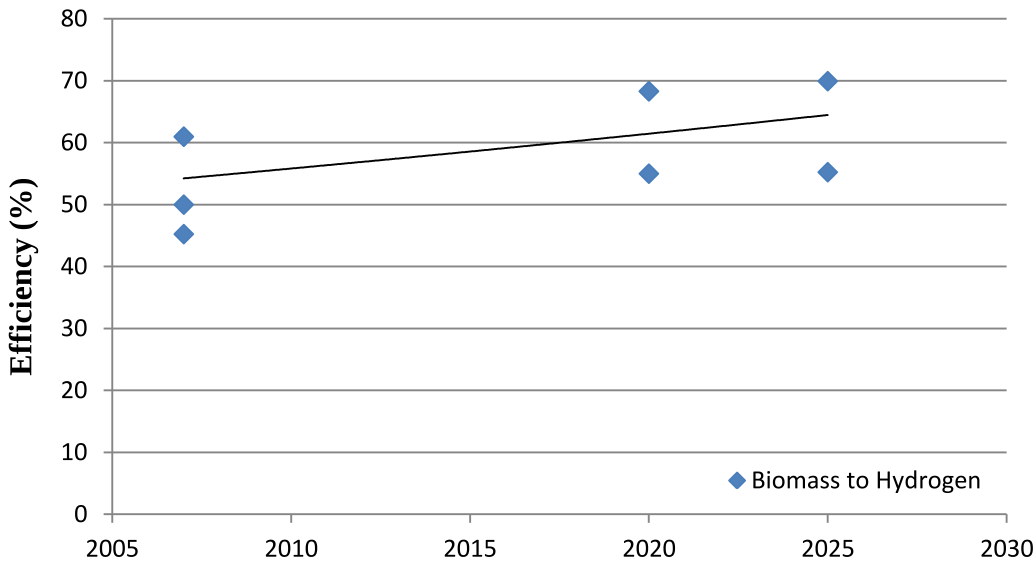

Figure 3.15: Efficiency of hydrogen production from biomass gasification.

All costs related to biomass gasification in order to produce hydrogen including total production cost can be seen as ZAR2007/GJoutput in Table 3.4.

Table 3.4: Costs of hydrogen production from biomass gasification.

ZAR_{2007}/GJ_{output}	2010	2040
Investment Cost	145.03	70.79
FOM Cost	12.59	5.76
VOM Cost	6.84	4.37
Production Cost	1,048.73	521.41

3.4 Cost Analysis of Hydrogen production from Electrolysis

The cleanest and one of the most promising methods, electrolysis has couple of different technologies for hydrogen production (Herraiz-Cardona, González-Buch, & Ortega, 2013). All technologies in the literature are considered and can be seen in Table A 21, Table A 22, Table A 23 and Table A 24 in Appendix A. The change in investment cost depending by years can be seen in Figure 3.16.

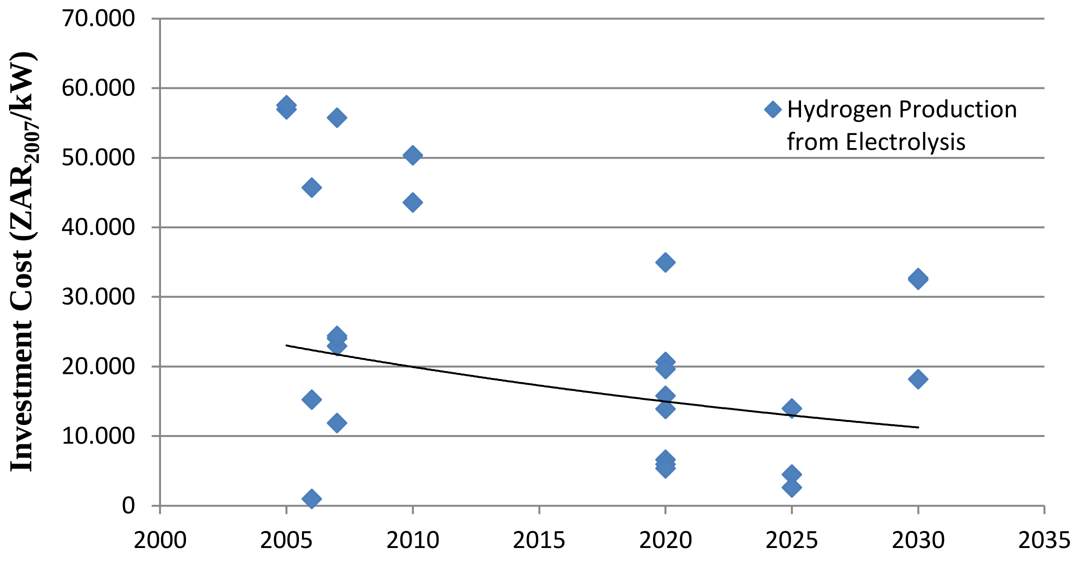

Figure 3.16: Investment costs of hydrogen production from electrolysis.

In the figure, investment costs of hydrogen production from electrolysis for 2010 and for 2040 are estimated as 19.780 ZAR2007/kWoutput and 8.376 ZAR2007/kWoutput, respectively with a decrease of 57%. The change in investment cost by capacity of plant can be seen in Figure 3.17.

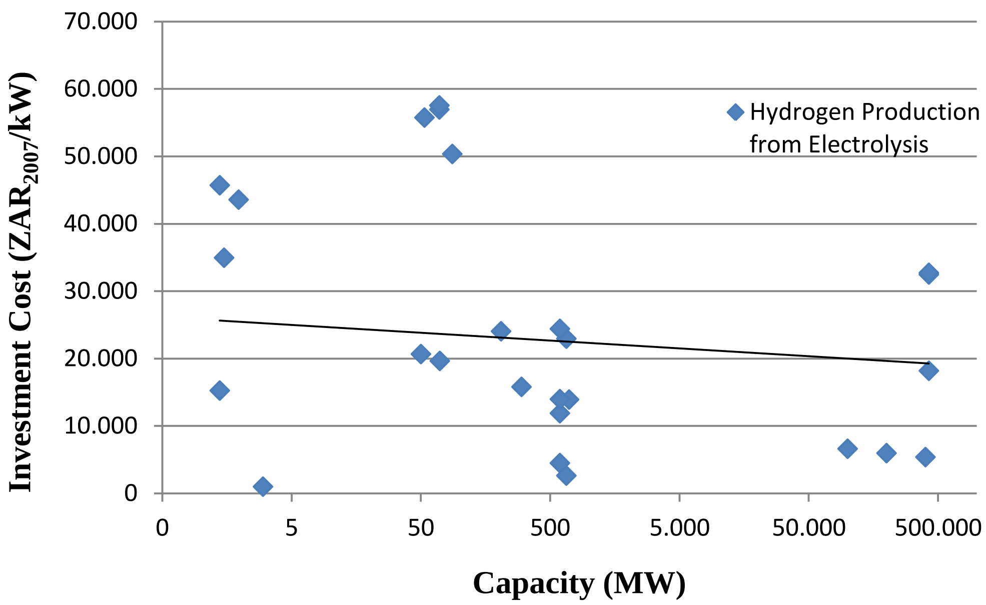

Figure 3.17: Investment costs of hydrogen production from electrolysis depending on plant capacity.

It is estimated that FOM costs of hydrogen production from electrolysis are 799 and 89 ZAR_{2007}/kW_{output} for 2010 and 2040, respectively. The change in FOM costs are shown in Figure 3.18

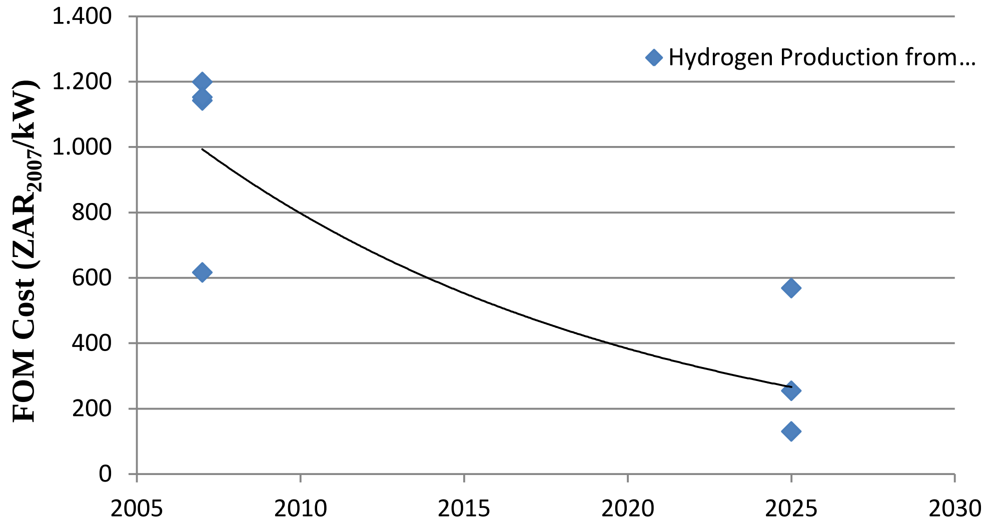

Figure 3.18: Fix operation & maintenance costs of hydrogen production from electrolysis.

Variable operation and maintenance costs of hydrogen production from electrolysis by years can be found in Figure 3.19. Estimations show that VOM costs are 3.85 and 0.83 ZAR2007/GJoutput for 2010 and 2040, respectively, as seen in Figure 3.19.

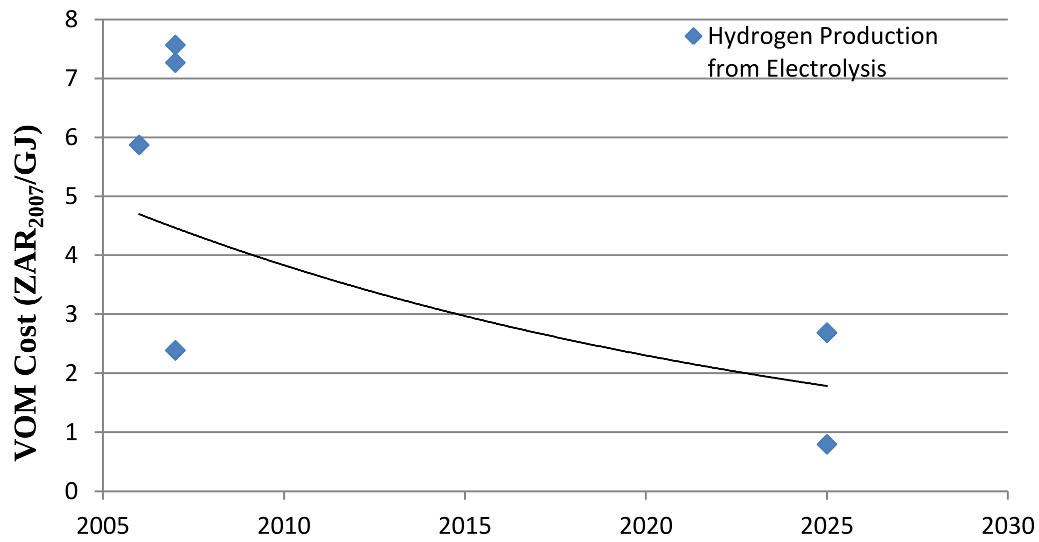

Figure 3.19: Variable operation & maintenance costs of hydrogen production from electrolysis.

As seen in Figure 3.20, the current and future efficiencies of electrolysis for hydrogen production are 66% and 82% in 2010 and 2040, respectively.

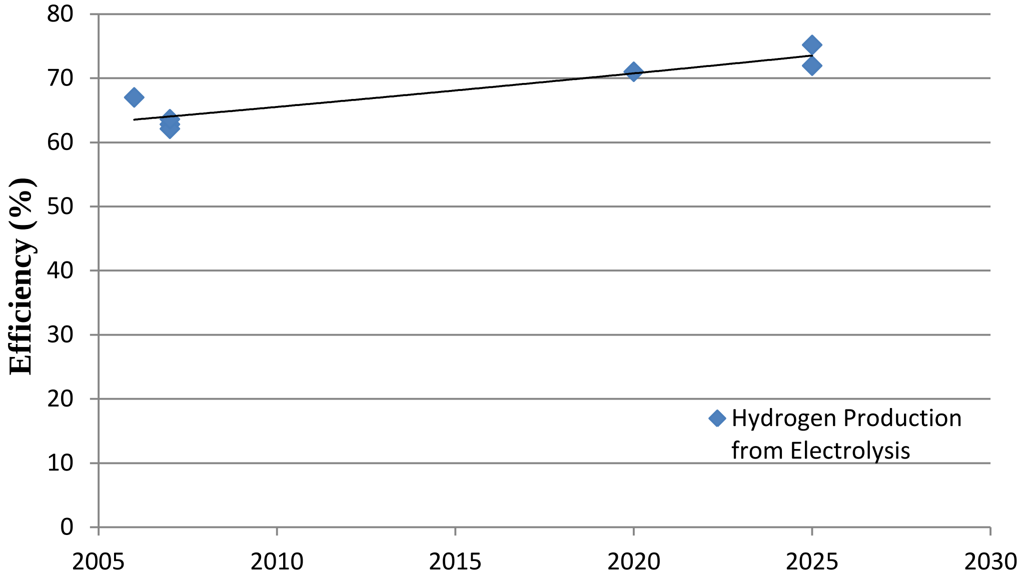

Figure 3.20: Efficiency of hydrogen production from electrolysis.

The total hydrogen production cost, FOM, VOM costs are presented in ZAR2007/GJoutput in Table 3.5: Costs of hydrogen production from electrolysis

Table 3.5: Costs of hydrogen production from electrolysis

ZAR_{2007}/GJ_{output}	2010	2040
Investment Cost	627.22	265.63
FOM Cost	25.35	2.82
VOM Cost	3.85	0.83
Production Cost	3,354.59	1,298.61

Electrolysis shows a promising decrease in investment cost, fix and variable operation maintenance costs and increase in efficiency. Despite the high investment costs, electrolysis, being one of the environmental friendly hydrogen production paths, seems like a key factor of future hydrogen production with the technology development studies.

The comparison of hydrogen production efficiencies is shown in Table 3.6.

Table 3.6: Efficiencies of hydrogen production technologies

Hydrogen Production Method	Technology	Efficiency (%)	
		2010	2040
Coal Gasification	With CCS	60	69
	Without CCS	64	80
Natural Gas Reforming	With CCS	73	77
	Without CCS	74	81
Biomass Gasification	-	56	74
Electrolysis	-	66	82

4. HYDROGEN DELIVERY

Hydrogen, which is centrally produced, needs to be delivered to hydrogen fueling stations for any demand. This demand could be for stationary power needs, for fuel cell vehicles or any other needs.

The aim of this study is to analyze the hydrogen utilization in liquid hydrogen airplanes. Therefore, hydrogen delivery paths for an airport from production facility until fueling stations should be considered.

A combination of hydrogen delivery infrastructure for an airport is presented in Figure 4.1.

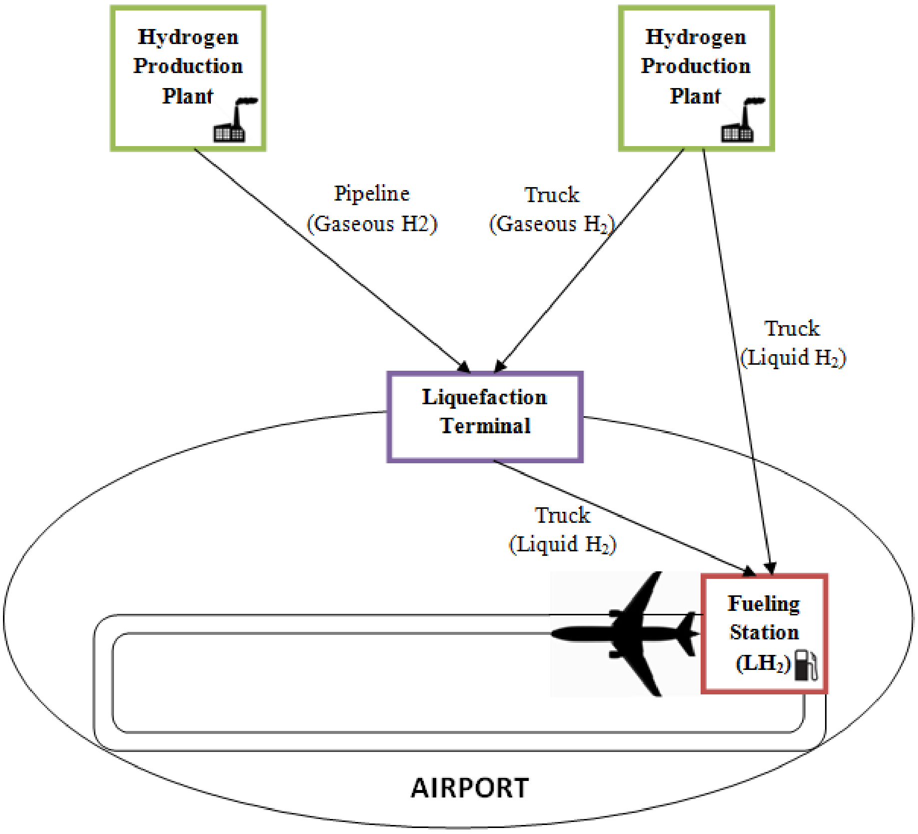

Figure 4.1: Hydrogen delivery infrastructure.

It is possible to deliver hydrogen in gaseous or liquid form. There are several ways of liquid or gaseous hydrogen transportation. Some of these methods are by truck, tube trailers, pipeline, rail, ship or carrier materials transport in form of liquid hydrocarbons or metal hydrides (Freedom Car & Fuel Partmership, 2005).

Gaseous hydrogen is able to be transported by either pipeline or truck. Gaseous hydrogen transmission by pipeline is the lowest cost method for large amounts of hydrogen. Truck transmission of gaseous hydrogen is generally used for industry use far from main pipelines. Currently, tube trailers about under 182 can transmit small amount of gaseous hydrogen with approximate capacity of 300-400 kg. Gaseous hydrogen needs to be cooled to below -253°C to be liquefied. Liquid hydrogen is stored in insulated tanks at liquefaction terminals. Today's liquefaction plats in capacity is ranging from 5,400 to 32,000 kg hydrogen per day with small scale, for minimal needs (Freedom Car & Fuel Partmership, 2005).

In this study, truck and gas pipelines, which are the most common paths of hydrogen transportation in industrial level, are examined. For this purpose, three possibilities of hydrogen delivery combinations exist.

First way is to deliver hydrogen by truck to the fueling station directly in liquid form.

Second way is to deliver hydrogen by truck in gaseous form to the liquefaction terminal and again by truck in liquid form to fueling station.

Third way is to deliver hydrogen by pipeline in gaseous form to the liquefaction terminal and by truck in liquid form to fueling station.

In order to analyze all possibilities, transportation by truck, pipeline and combined delivery by pipeline and truck are considered.

4.1 Hydrogen Delivery by Pipeline

Hydrogen can be delivered in gaseous form in pipelines. As well as hydrogen pipelines, hydrogen can be delivered in natural gas pipelines about 20% of total gas (Melaina, Antonia, & Penev, 2013). In order to transport hydrogen in natural gas pipelines, small scale of modifications are sufficient. In this study; however, capital investment costs of hydrogen pipelines are high, in order to transport large amounts of hydrogen reliably, particular hydrogen pipelines are examined. The usage of pipelines to transport hydrogen to liquefaction terminal is presented in Figure 4.2.

Figure 4.2: Hydrogen pipeline delivery (Paster, Hydrogen Delivery Options and Issues, 2006).

Hydrogen pipeline diameter is determined by the following equation (Ruth, Laffen, & Timbario, 2009):

$$q_{sc} = 737.\left(\frac{T_{sc}}{P_{sc}}\right)^{1.02} . \left(\frac{P_1^2 - P_2^2 \quad d^{4.961}}{\gamma^{0.961} L T_m Z_m}\right)^{0.51} . E \qquad \textbf{(4.1)}$$

q_{sc}	= Gas rate at standard conditions [scf/d]
T_{sc}	= Temperature at standard conditions [°R]
P_{sc}	= Pressure at standard conditions [psia]
P_1	= Inlet pressure [psia]
P_2	= Outlet pressure [psia]
d	= Inside pipe diameter [in]
γ	= Mean gas relative density [air=1]
L	= Pipeline length [mile]
T_m	= Mean temperature of pipeline [°R]
Z_m	= Mean compressibility factor
E	= Pipeline efficiency [kg]

It is concluded that no energy is required for pipeline hydrogen delivery and some assumptions are made for the pipe line diameter, such as: T_{sc} =530 R, P_{sc} =14.7 psia and E =0.92 (Ruth, Laffen, & Timbario, 2009).

4.2 Hydrogen Delivery by Truck

Hydrogen can be delivered in compressed gaseous or cryogenic liquid form by truck. The location of compressors or the terminal of liquefiers depend on the delivery path. In case of gaseous delivery by truck, a compressor at production facility and liquefaction terminal at a nearby site of fueling station are needed. Besides, in case of liquid hydrogen delivery by truck, a liquefaction terminal is necessary at production facility (Gül, 2008).

Figure 4.3: Hydrogen truck delivery (Bonner, 2008).

In current technology, gaseous hydrogen can be transported in tube trailers about at 200 bar but not cost effective for more than 320 km. Because of being an expensive method, transportation under higher pressures are being researched for further cost effective methods. Furthermore, liquefied hydrogen can be transported in super insulated cryogenic tank trucks, after gaseous form is cooled to below -253°C and liquefied in the liquefaction plants (EERE, 2008).

The amount of liquid hydrogen to deliver by truck can be calculated with and equation as described below (Ruth, Laffen, & Timbario, 2009) :

$$H_2 = V_{\tan k} . \rho_{LH_2} . A_{LH_2 truck} \tag{4.2}$$

H_2 = Hydrogen [kg]

V_{tank} = Water volume of the trailer [m3]

ρ_{LH_2} = Density of liquid hydrogen [g/L]

$A_{LH_2 truck}$ = Availability of the liquid truck

Although liquefying hydrogen consumes more than 30% of energy content of hydrogen and hydrogen losses take place because of evaporation, transporting liquid hydrogen by truck is less costly than transporting gaseous hydrogen (Klell, 2010)

The boil-off losses while the delivery of liquid hydrogen can be calculated. In order to calculate the losses, the loaded hydrogen is used in the equation below (Ruth, Laffen, & Timbario, 2009):

$$H_{2,boil\ off} = H_{2,prev}.B_r.T \tag{4.3}$$

H_2 = Hydrogen [kg]

$H_{2,prev}$ = Hydrogen in truck from previous station [kg]

B_r = Boil off rate [fraction of a day]

T = Travel time [d]

In truck delivery case, for this study, two ways of truck transportation are possible. First option is to deliver liquid hydrogen directly by truck, and second option is to transport the gaseous hydrogen to a liquefaction terminal and after the terminal deliver liquid hydrogen to a fueling station. In Figure 4.4, two different ways of hydrogen delivery by truck are presented.

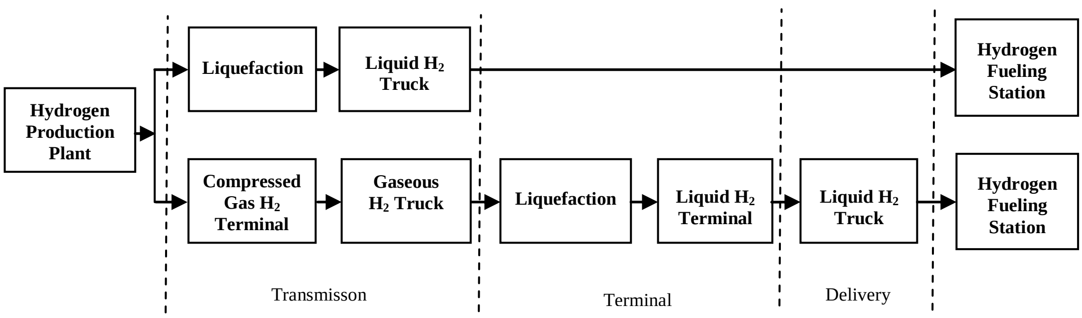

Figure 4.4: Hydrogen delivery by truck.

Truck delivery presents couple of advantages such as being flexible that trucks can deliver for any amount of demand and to any distance of delivery in any form of hydrogen either liquid or gaseous. Truck delivery is advantageous when there are multiple points of demand. In case of increase in demand, it is easy to increase the numbers of trucks. (Altmann, Schmidt, Wurster, Zetra, & Zittel, 2004).

4.3 Combined Hydrogen Delivery by Truck and Pipeline

Addition to truck and pipeline delivery, in some specific cases, combined delivery of hydrogen is necessary. In the case of this study, hydrogen is used in liquid state in airplanes. For this reason hydrogen needs to reach to fueling station in liquid state. In combined delivery of airport usage, hydrogen is considered to be transmitted to the boundary of the airport in liquid form by pipelines. After transmission, at the boundary, hydrogen is liquefied in liquefaction terminal. In the airport, as a last step, hydrogen is delivered in gaseous form to the refueling station by trucks. Figure 4.5 shows possible combined hydrogen delivery paths.

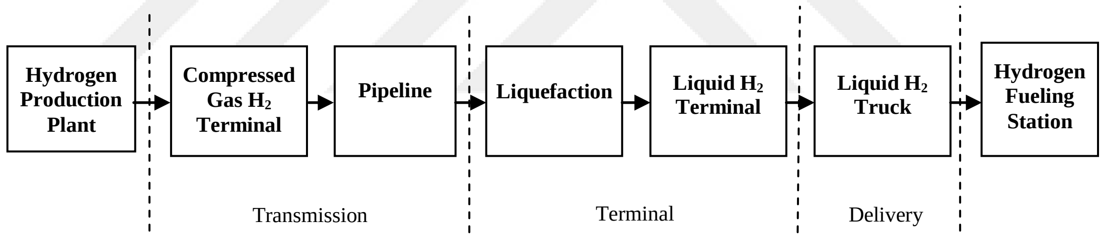

Figure 4.5: Combined hydrogen delivery paths**.**

4.4 Hydrogen Compression

Gaseous hydrogen should be compressed if it is aimed to be delivered by tube trailer or hydrogen pipelines (Dodds & McDowall, 2012). In gaseous tube trailer delivery means, it is important to compress hydrogen to a high pressure in order to have higher capacity of a tube trailer (Paster, 2006). A compressor is needed centrally at the production facility or in some cases integrally in the pipeline system (Ruth, Laffen, & Timbario, 2009) (Devold, 2010).

The capital cost of compressor depends on the maximum peak flow rate of hydrogen. Besides, annual energy requirement of a hydrogen compressor is a function of flow rate. Annual energy requirement of a hydrogen compressor can be defined with the following equation (Ruth, Laffen, & Timbario, 2009):

$$E_{ann} = 8760 \frac{F_{avg}}{\eta_{isentrop}} ZRT_1 N_{st} \left(\frac{k}{k-1} \right) \left[\left(\frac{P_2}{P_1} \right)^{\frac{k-1}{kN_{st}}} - 1 \right] \tag{4.4}$$

E_{ann}	= Annual energy requirement [kWh]
F_{avg}	= Average hydrogen flow rate [kg/h]
$\eta_{isentrop}$	= Isentropic compressor efficiency [-]
R	= Gas constant [J/mol.K]
T_1	= Inlet gas temperature [K]
N_{st}	= Number of compression stages [-]
k	= Ratio of specific heats [-]
P_2	= Outlet pressure [Pa]
P_1	= Inlet pressure [Pa]

4.5 Hydrogen Liquefaction

Hydrogen as alternative fuel for transportation has a low density according to other conventional fossil fuels. Hydrogen should be more attractive as energy content for transportation (IEA, 2007). Depending on the amount of hydrogen, in most of the cases, transportation of hydrogen in liquid form is more cost efficient. Besides, total costs of hydrogen distribution decreases with the increasing capacity of hydrogen liquefaction plants (Staats, 2008). In liquid state hydrogen has about 5 times more energy than its compressed gaseous state at 200 bar and 15°C (Walnum, et al., 2012). Figure 4.6 shows the energy density of hydrogen in different forms.

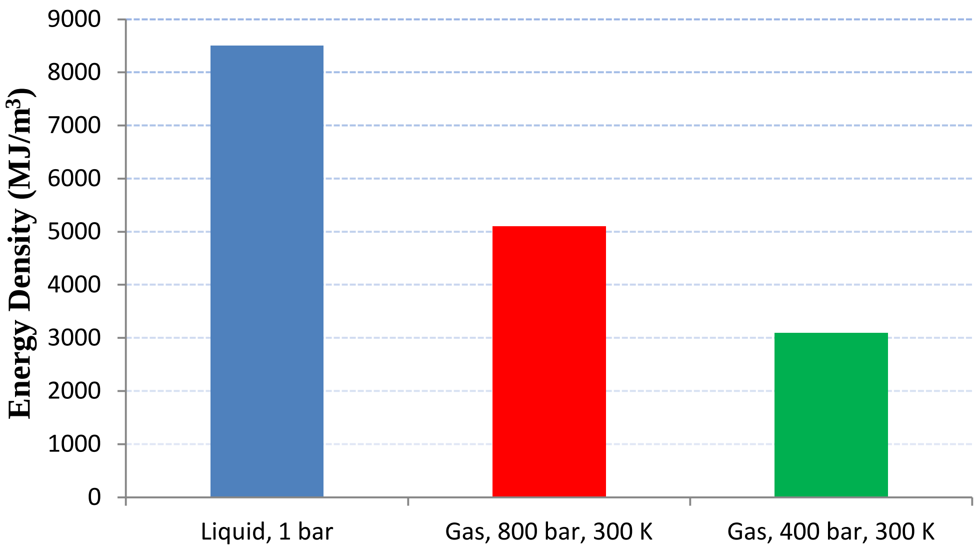

Figure 4.6: Energy density of hydrogen in liquid and in compressed gaseous forms (Staats, 2008).

Liquefaction of hydrogen can be achieved by an efficient pump to reach the required pressure values. Liquefaction of hydrogen has a few steps (McGuiness & Pirnat, 2011). Liquefaction steps follow each other respectively; pre-compression at ambient conditions to 80 bar (79 atm) pre-cooling at ambient conditions to about 80 K (-193.15°C), cryo-cooling from 80 K to 30 K (-243.15°C), liquefaction at 30 K to liquid H2 at 1 atm (Walnum, et al., 2012).

The theoretical power requirement of hydrogen liquefier is determined by the following function (Ruth, Laffen, & Timbario, 2009):

$$-\frac{\dot{W}_{net}}{\dot{m}} = T_1(s_{in} - s_{out}) - (h_{in} - h_{out}) \tag{4.5}$$

$\dot{W}_{net}$ = Idealized net work required by the liquefier [kWh/(kg/d)]

$\dot{m}$ = Design capacity of the liquefier [kg/d]

T_1 = Inlet temperature to the liquefier [K]

s_{in} = Hydrogen entropy at the inlet temperature [kWh/K(kg/d)]

s_{out} = Hydrogen entropy at the outlet temperature [kWh/K(kg/d)]

h_{in} = Hydrogen enthalpy at the inlet temperature [kWh/(kg/d)]

h_{out} = Hydrogen enthalpy at the outlet temperature [kWh/(kg/d)]

4.6 Hydrogen Fueling Infrastructure

Hydrogen should be stored in liquid form in cryonic tanks at the airport. For storage, liquid hydrogen should be kept below 25 K (-248.15°C) (van Zon, 2012). Refueling stations for hydrogen depends on the phase of hydrogen delivered to the refueling station. In this study, only liquid hydrogen is considered at the refueling station according to the demand of LH2 Airplanes. Capacity of refueling stations depends on the capacity of airport. Besides, in this chapter, refueling stations are considered large refueling stations, which provide 1,500 kg H2/day. Figure 4.7 presents a schematic liquid hydrogen refueling station.

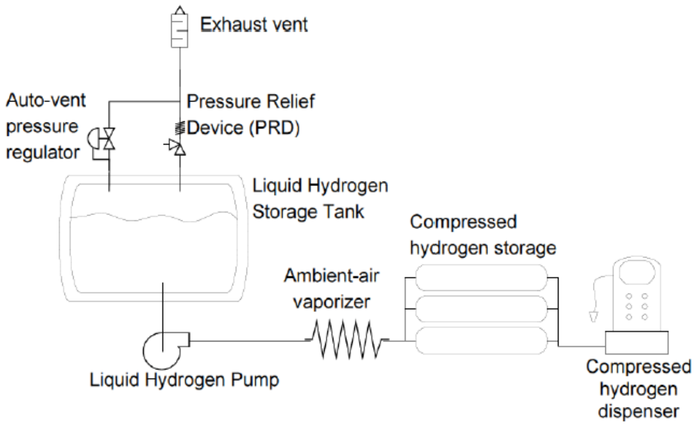

Figure 4.7: Schematic presentation of liquid hydrogen station (Doods & McDowall, 2012).

Hydrogen reaches to refueling stations by two pathways. The first way is combined delivery that brings gaseous hydrogen in pipelines to the liquefaction station and then delivering liquid hydrogen by trucks to the refueling stations. The second way is direct truck delivery of liquid hydrogen by truck from production plant to refueling stations. Refueling stations can be a fixed station at the gates of airport or it can be a refueling tanker stations as shown in Figure 4.8.

Figure 4.8: Hydrogen fueling alternative for aircrafts (Klug, 2000).

Airport hydrogen refueling stations can be converted by increasing their capacity in order to refuel LH_2 Airplanes.

5. TECHNO-ECONOMIC ANALYSIS OF HYDROGEN DELIVERY IN GAUTENG - SOUTH AFRICA

According to the case study in the technical report of Airbus (2003), the hydrogen demand of Stockholm-Arlanda airport would be 50 t/d LH2 for transition to hydrogen fuel in aviation in 2050. The demand of hydrogen projected with the consideration of the air traffic growth assumptions that the number of the passengers would increase three to four times by 2050 (Airbus, 2003). The same approach for O.R. Tambo international airport can be made with the comparison of the number of passengers of Stockholm-Arlanda airport and O.R. Tambo international airport in 2011. The number of passengers had reached to 19 million in 2000 and 2011 at Stockholm-Arlanda airport (Swedavia, 2013). The number of passengers is 19,004,001 at O.R. Tambo international airport in 2011-2012 (ACSA, 2012). In Africa, average 5.7% annual growth in air passenger traffic is projected (Kuuchi, 2009). The number of passengers in O.R. Tambo international airport will increase approximately five times by 2040 then 2011 responding to annual growth rate. The demand of hydrogen in O.R. Tambo international airport can be also estimated as around 65 t/d (90.25 MW) in 2040.

The peak demand of hydrogen is determined to design liquefiers, terminals, storage tanks and hydrogen refueling stations for transition to hydrogen in O.R. Tambo international airport. The land required for liquefier terminal is assumed 25,000 m^3 for 30 t/d demand according to Ruth, Laffen, & Timbario (2009). It can be calculated that approximately 42,000 m^3 area will be required at the airport borders in order to liquefy gaseous hydrogen for aviation.

The possible hydrogen delivery options for different demands are presented in million standard cubic feet (SCF) per day in Figure 5.1.

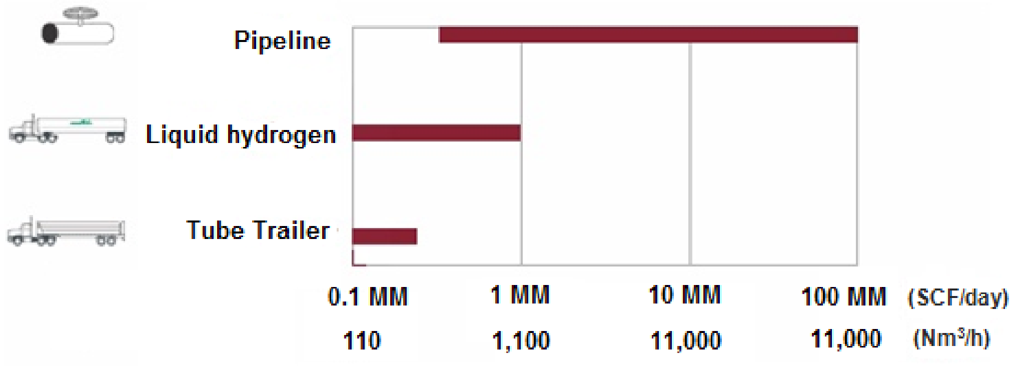

Figure 5.1: Hydrogen delivery options according to demand (Air Products and Chemicals Inc., 2013).

As mentioned before, the costs of hydrogen delivery can be considered for three paths. Hydrogen can be delivered directly by trucks in liquid form to the fueling stations or two combined delivery paths; by pipeline or by truck in gaseous form until the liquefaction terminal and then by trucks in liquid form until the fueling stations. Finally hydrogen in liquid form is utilized in aircrafts.

The delivery costs of hydrogen can be basically calculated by a simple equation as described below (Yang & Ogden, 2006):

$$LC_{H_2} = \frac{AC_{equipment} + AC_{operations}}{\dot{M}_{H_2} + CF} \tag{5.1}$$

LC_{H_2} = Levelized cost [ZAR_{2007}/kW]

$AC_{equipment}$ = Annual equipment cost [ZAR_{2007}/kW]

$AC_{operations}$ = Annual operations and maintenance cost [ZAR_{2007}/kW]

$\dot{M}_{H_2}$ = Annual mass flow of hydrogen [kg/h]

The energy requirement of hydrogen delivery paths for liquid or compressed gaseous hydrogen can be determined as a function of energy requirements for delivery fuel, liquefier or compressor as an equation given below (Yang & Ogden, 2006):

$$W_{\%input} = \frac{\dot{W}_{fuel} + \dot{W}_{liq} + \dot{W}_{comp}}{LHV_{H_2} . \dot{M}_{H_2}} \quad \textbf{(5.2)}$$

$W_{\%input}$	= Energy input requirement of hydrogen delivery [kWh]
$\dot{W}_{fuel}$	= Energy requirement for the fuel [kW]
$\dot{W}_{liq}$	= Electricity requirement for the liquefier [kW]
$\dot{W}_{comp}$	= Electricity requirement for the compressor [kW]
LHV_{H_2}	= Lower heating value of hydrogen [MJ/kg]
$\dot{M}_{H_2}$	= Hydrogen mass flow [kg/h]

5.1 Hydrogen Pipeline Delivery Costs

Hydrogen is delivered in the pipelines in gaseous form to the utilization sites. Pipeline delivery requires extra compression costs. Compression costs are mentioned in the following subchapters. There are two main factors affecting pipeline investment costs; diameter of the pipelines and distance of the pipelines. The alteration in hydrogen pipeline investment cost can be seen in Figure 5.2.

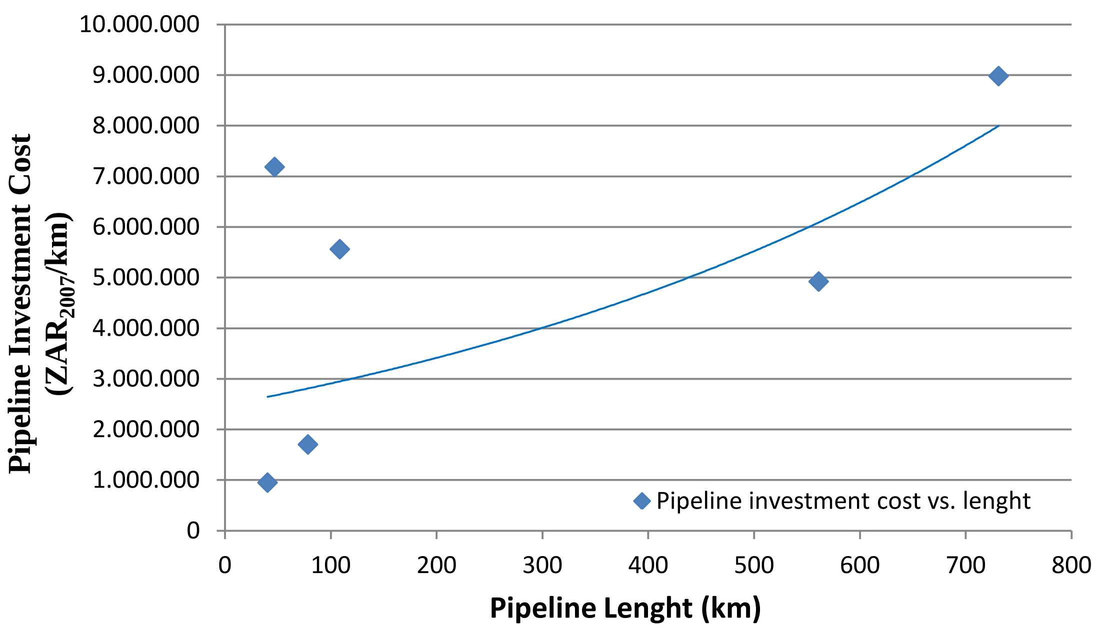

Figure 5.2: Hydrogen pipeline investment cost by pipeline lenght (Amos, 1998).

The change in hydrogen pipeline investment cost by diameter can be seen in Figure 5.3. for a 500 km hydrogen pipeline. It can be projected that investment cost per energy content of carried hydrogen for the higher mass flow hydrogen pipelines is lower than the pipelines for small amount of hydrogen delivery.

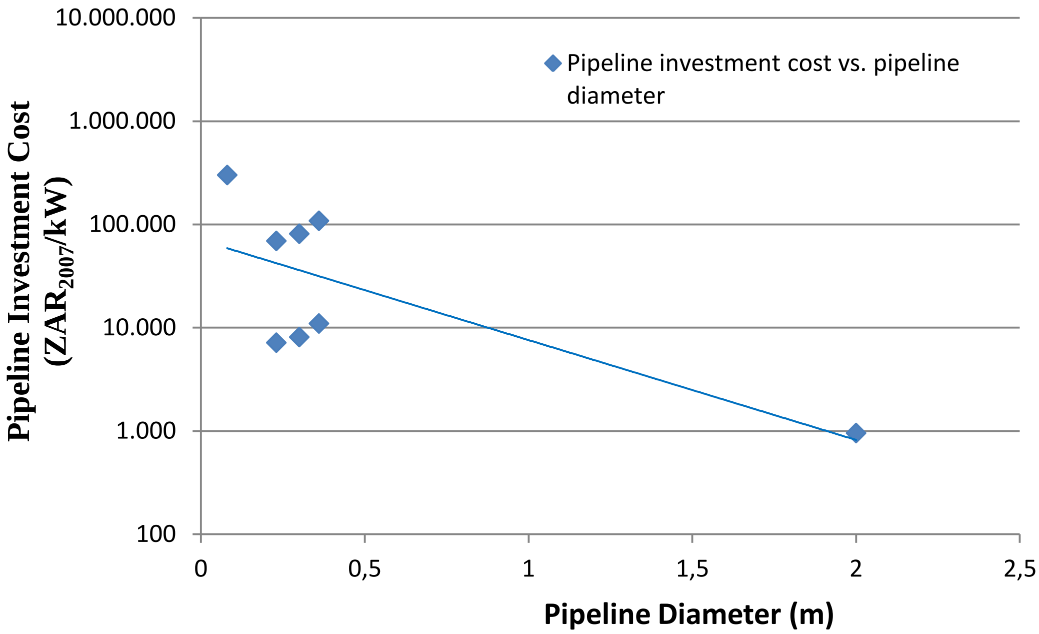

Figure 5.3: Hydrogen pipeline investment cost by pipeline diameter (Doods & McDowall, 2012).

The increase in investment cost of hydrogen by years can be seen in Figure 5.4.

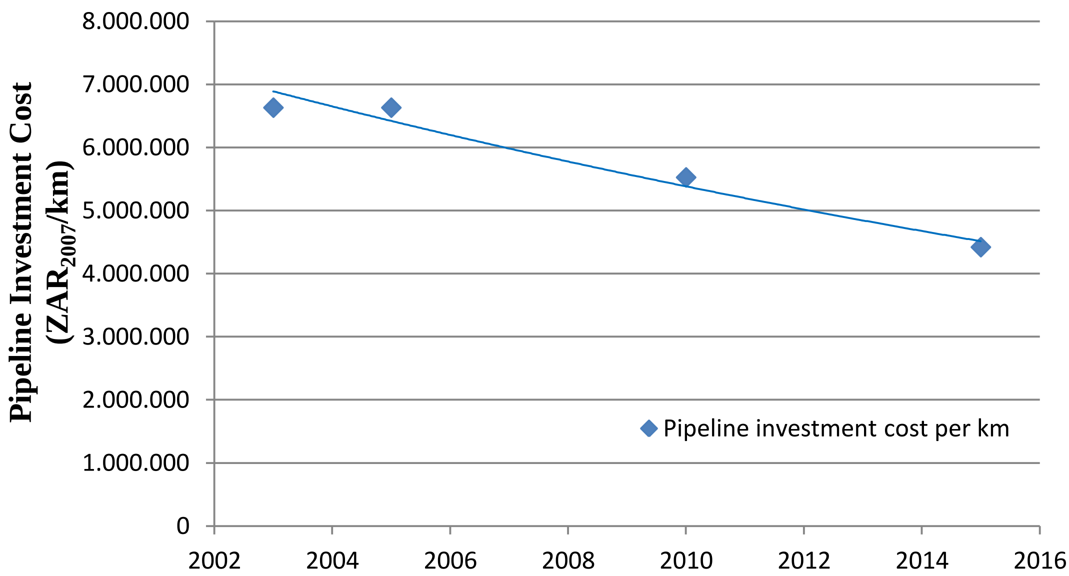

Figure 5.4: Hydrogen pipeline investment costs (FCFP, 2005).

Whereas, the investment cost of hydrogen pipeline is 5,526,537 ZAR2007/km in 2010, it will decrease to 1,871,004 ZAR_{2007}/km in 2040 in Figure 5.4.

The same curve can be applied to the investment cost per power output The investment cost in 2002 is given as 7489 ZAR2007/kW for a 150 km pipeline (Simbeck & Chang, 2002). An important decrease can be seen from 5,610 ZAR2007/kW in 2010 to 1,963 ZAR2007/kW in 2040 for 150 km long hydrogen pipeline. The efficiencies of hydrogen pipeline delivery by pipeline diameter are presented in Figure 5.5.

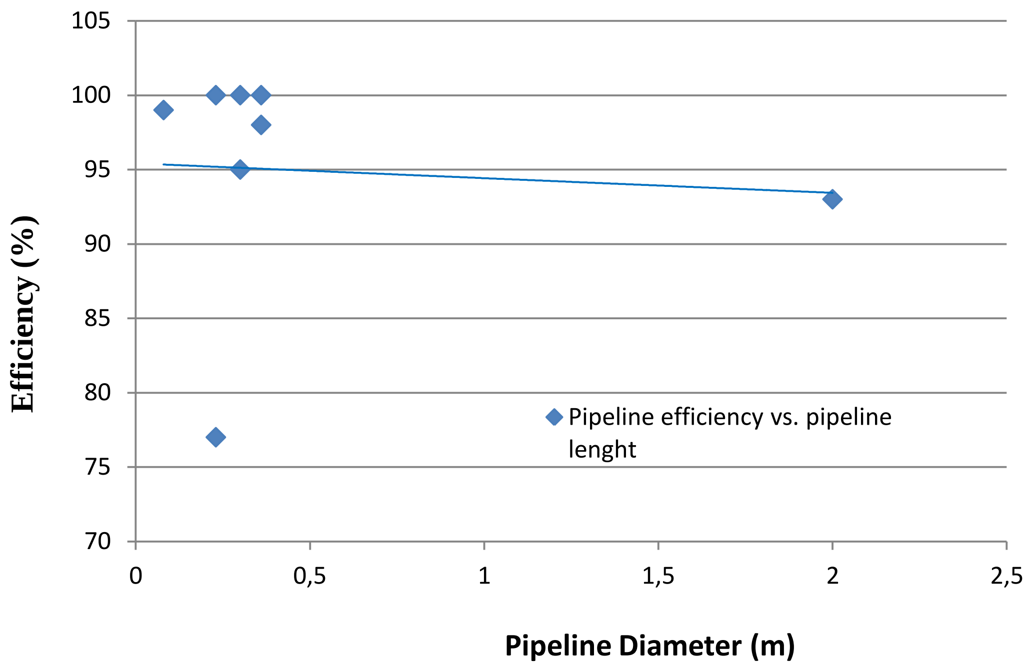

Figure 5.5: Efficiency of hydrogen pipeline delivery by pipeline diameter (Doods & McDowall, 2012).

5.2 Compressed Gaseous Hydrogen Tube Trailer Delivery Costs

The US Department of Transportation regulates compressed gaseous hydrogen truck trailers. DOT regulations limit the gas pressure on the trucks to 160 atm. The hydrogen carried by tube trailers is approximately 300 kg. Capacity of trailers would increase with higher tube trailer pressure. Some assumptions are made for compressed gaseous hydrogen tube trailer delivery (Yang & Ogden, 2006). Tube trailer investment costs are presented in Figure 5.6.

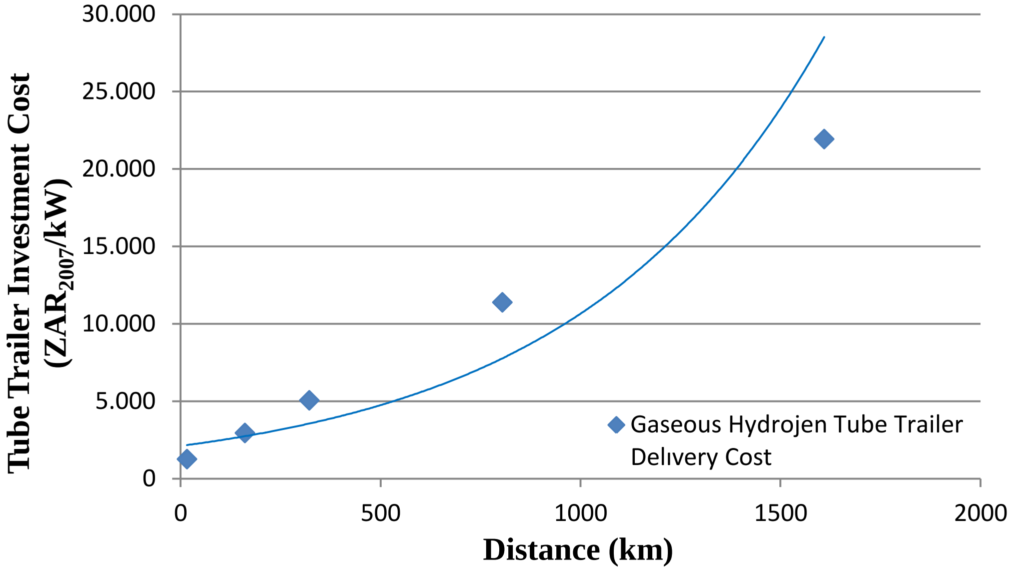

Figure 5.6: Tube trailer investment cost by distance (Berridge, 2010).

In Figure 5.7, the distance for tube trailer delivery is given as 100 km, and in Figure 5.9, the distance for liquid hydrogen truck delivery is given 200 km.

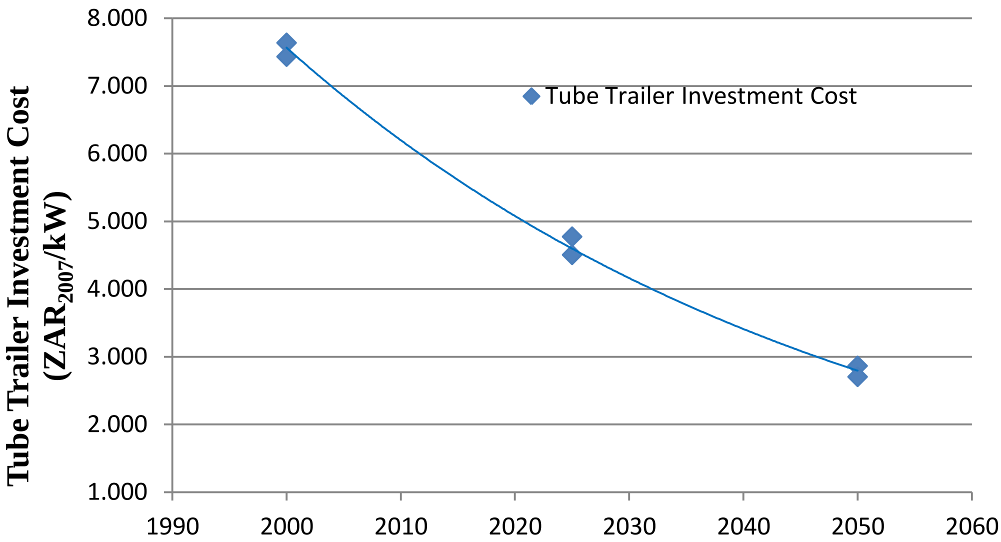

Figure 5.7: Tube trailer investment cost for 100 km hydrogen delivery (Doods & McDowall, 2012).

5.3 Liquid Hydrogen Truck Delivery Costs

Hydrogen is produced centrally at the production plants in this study. In this section of the study, hydrogen is liquefied after production at the plants and this liquefied hydrogen is transmitted and delivered in trucks to the fuelling stations at the airport directly. The investment costs of liquid hydrogen delivery includes the number of delivery trucks, distance traveled, size of liquefiers, pumps, storage terminals, vaporizers and other related factors in this case (Berridge, 2010) (Ruth, Laffen, & Timbario, 2009) . Investment costs of liquid hydrogen truck delivery are presented in Figure 5.8.

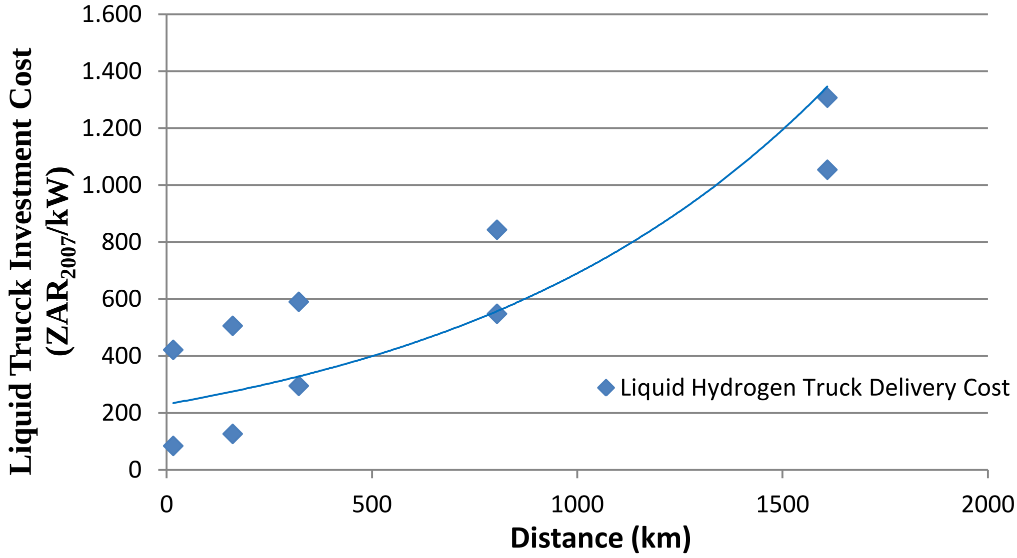

Figure 5.8: Liquid truck investment cost by distance (Berridge, 2010).

Liquid hydrogen truck delivery investment costs by years are presented in Figure 5.9. It can be assumed that there is no expected change in investment cost of liquid hydrogen truck delivery in 2040.

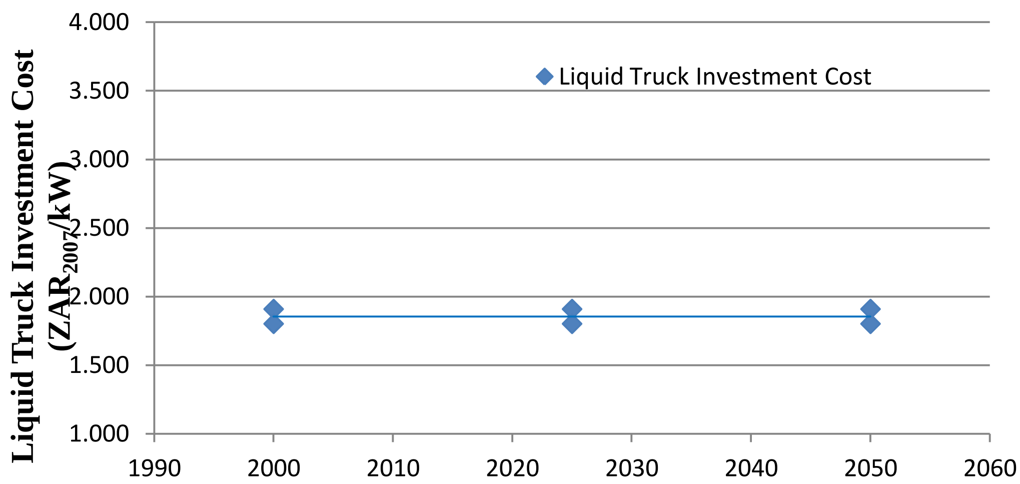

Figure 5.9: Liquid truck investment cost for 200 km hydrogen delivery (Doods & McDowall, 2012).

5.4 Hydrogen Compression, Liquefaction and Fueling Station Costs

In this study, individual compressor design for each hydrogen production plant is considered. It is projected that equal amount of hydrogen is compressed in case of gaseous hydrogen delivery from each production technology. It is assumed that 16.25 t/d (22.56 MW total capacity of compressors) hydrogen is compressed at the production sites as a proportion of the total demand of 65 t/d hydrogen for OR International Airport. As a scenario analysis 1,000 kW capacity compressors are analyzed for the production sites. In Figure 5.10 the chance in investment cost by the capacity of compressor is presented.

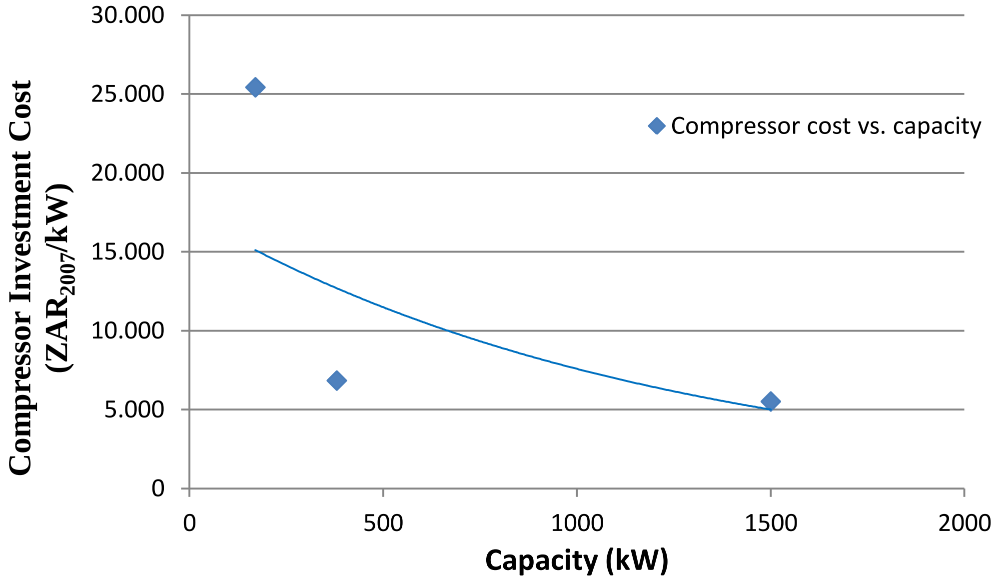

Figure 5.10: Compressor investment cost by capacity (Amos, 1998).

In Figure 5.11, it is estimated that the investment cost of the compressor is 7,582 ZAR2007/kWoutput in 1998. In addition to the capacity curve, the investment cost change by year approach for hydrogen liquefier is applied because of limited data in the literature. Consequently, investment cost of 6,061 ZAR2007/kWoutput for 2010 and 3,463 ZAR2007/kWoutput for 2040 is projected for hydrogen compressor.

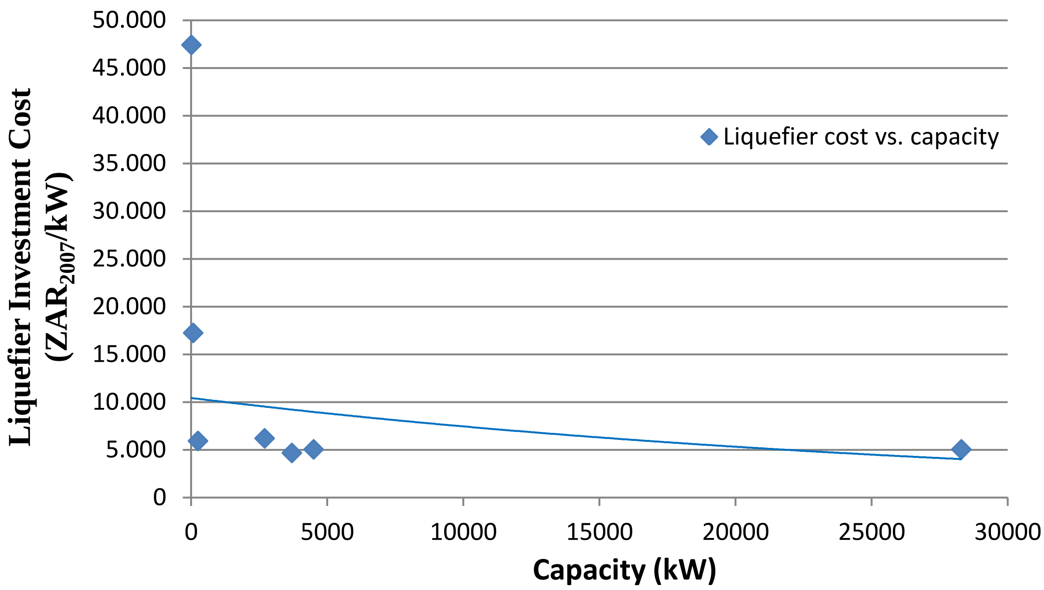

Figure 5.11: Liquefier investment cost by capacity (Amos, 1998).

The similar approach can be made in order to estimate liquefier investment cost. In this case, it is assumed that at least half of the hydrogen demand is delivered in gaseous form until the liquefaction terminal. The capacity of liquefier is 32.5 t/d (45,134 kW total capacity). As a scenario analysis, it is assumed that at least three liquefiers (capacity of 15,000 kW) exist at the terminal. In Figure 5.12, it can be estimated that liquefier investment cost is 6,300.87 ZAR2007/kWoutput in 1998. In Figure 5.12, it is estimated that investment cost of hydrogen liquefier is 5,037 ZAR2007/kWoutput for 2010 and 2,878 ZAR2007/kWoutput for 2040.

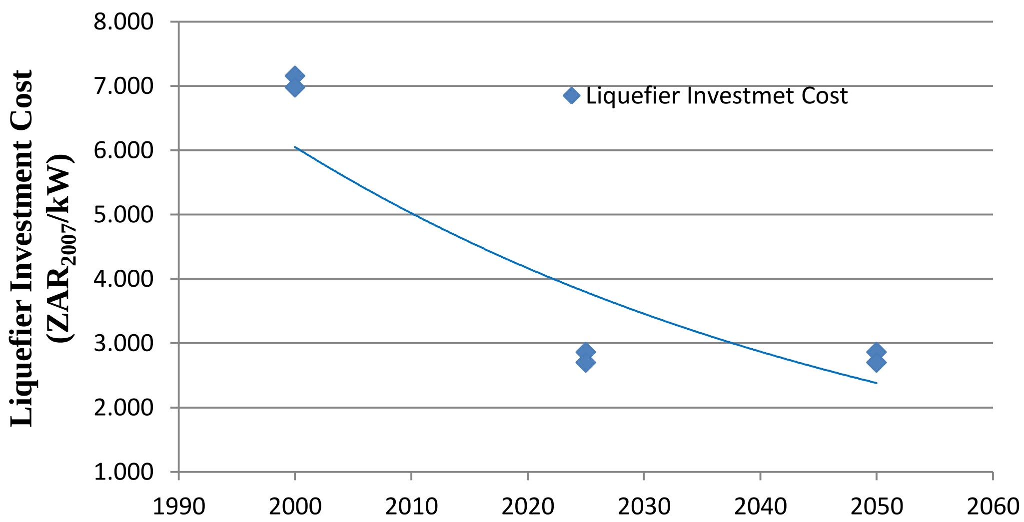

Figure 5.12: Liquefier investment cost (Doods & McDowall, 2012).

In this study, 1,500 kg/d large hydrogen fueling stations from the literature are considered. In this case, there are more than 40 fueling stations for airplanes for the airport demand of 65 t/d hydrogen. In the study of Gül (2008), investment cost for hydrogen fueling stations is given as 687 ZAR_{2007}/kW_{output} for 2007. It can be estimated, using Figure 5.13 with the given cost to estimate future cost, that the investment cost of liquid hydrogen fueling stations is 667 ZAR_{2007}/kW_{output} for 2010 and 493 ZAR_{2007}/kW_{output} for 2040.

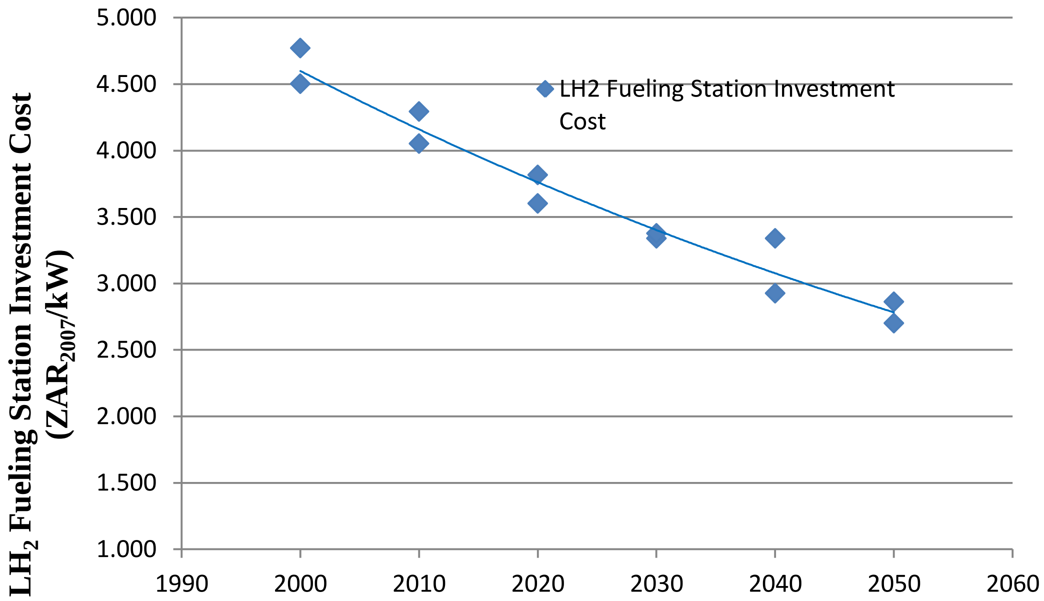

Figure 5.13: LH2 fueling station investment cost (Doods & McDowall, 2012).

The fixed O&M costs are projected as 4% of capital cost for compressors and liquefiers (Yang & Ogden, 2006). The fixed O&M costs for hydrogen compressor are 242 ZAR_{2007}/kW_{output} for 2010 and 138 ZAR_{2007}/kW_{output} for 2040.

The fixed O&M costs for hydrogen liquefier are 201 ZAR_{2007}/kW_{output} for 2010 and 115 ZAR_{2007}/kW_{output} for 2040.

For the liquid hydrogen fueling stations, the Fixed O&M costs are projected as 5% of investment cost and for compressors, liquefiers and fueling stations variable O&M are considered as 50% of fixed O&M costs (Doods & McDowall, 2012). The fixed O&M costs for hydrogen fueling stations are 33 ZAR_{2007}/kW_{output} for 2010 and 24 ZAR_{2007}/kW_{output} for 2040. The costs of hydrogen compressor, liquefier and fueling station can be compared in Table 5.1.

Table 5.1: Delivery costs of compressor, liquefier and fueling stations

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compressor	Investment Cost	192.21	109.84
	Fixed O&M Costs	7.69	4.39
	Var. O&M Costs	3.84	2.19
	Delivery Cost	203.74	116.45
Liquefier	Investment Cost	159.73	91.27
	Fixed O&M Costs	6.39	3.65
	Var. O&M Costs	3.19	1.82
	Delivery Cost	169.31	96.74
Fueling Station	Investment Cost	21.15	15.65
	Fixed O&M Costs	1.06	0.78
	Var. O&M Costs	0.53	0.39
	Delivery Cost	22.74	16.82

5.5 Delivery Scenarios and Costs

Hydrogen delivery is favorable to be produced from coal, natural gas, biomass and electrolysis in this study as mentioned in the first chapter. In order to deliver hydrogen produced from these production plants, four possible example production sites and delivery scenarios are considered in order to estimate the lowest-cost delivery option.

For the first production technology, which is coal gasification technology, the nearest coal power plant to the airport is selected as a case scenario. Kelvin power station, which has 600 MW installed capacity and uses primarily coal as fuel, is mostly 15 km far from the surroundings of OR Tambo international airport. (Aldwych, 2007). The location of Kelvin power station and a possible coal to hydrogen production plant can be seen in Figure 5.14.

Figure 5.14: Kelvin power station and OR Tambo international airport (Googel maps, 2013).

A liquefaction terminal should be built in the surroundings of airport. Taking into account that the diameter of the airport field is approximately 10 km, a liquefaction terminal can be build in a distance of around 10 km from the fueling stations.

In this case, the total cost consists of a 15 km delivery path (pipeline or tube trailer) of hydrogen from Kelvin power plant or a hydrogen production plant nearby, a liquefaction terminal and 10 km liquid truck delivery at the airport and refueling station cost.

It can be again taken into account that in Figure 5.7, the distance for tube trailer delivery is given as 100 km, and in Figure 5.9, the distance for liquid hydrogen truck delivery is given 200 km. The estimation of costs according to distances and years are illustrated in Figure 5.15, Figure 5.16, Figure 5.17 and Figure 5.18.

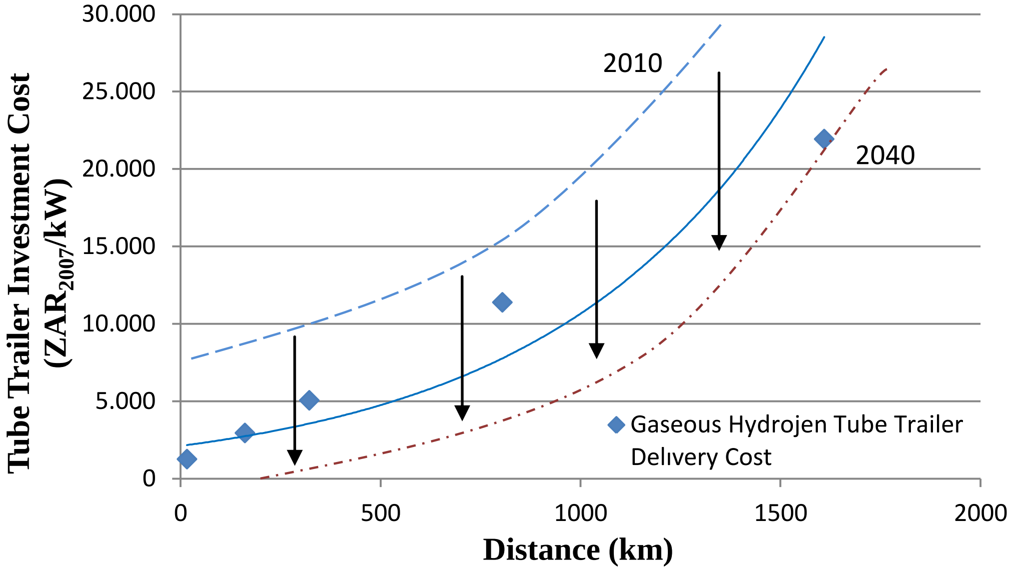

Figure 5.15: Tube trailer investment cost by distance (Berridge, 2010).

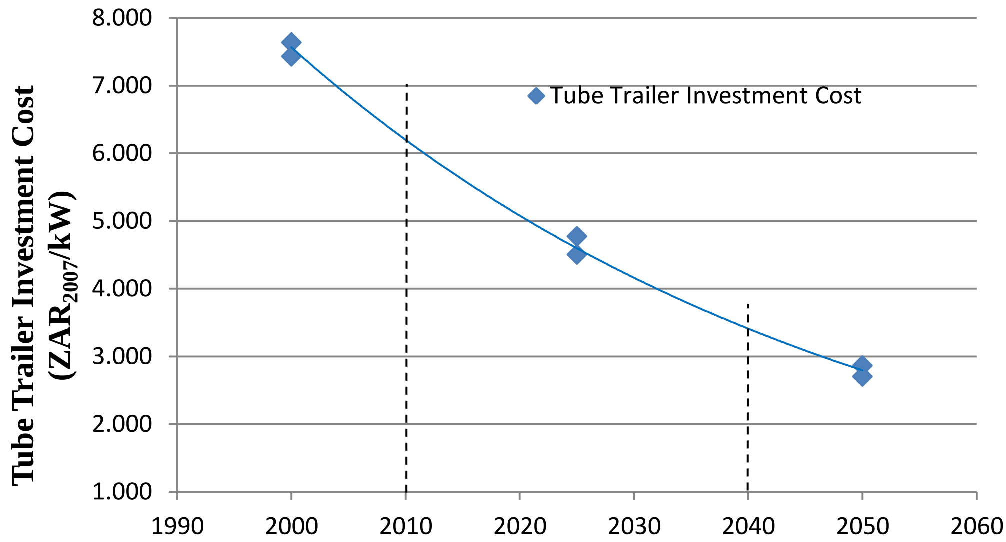

Figure 5.16: Tube trailer investment cost for 100 km hydrogen delivery (Doods & McDowall, 2012).

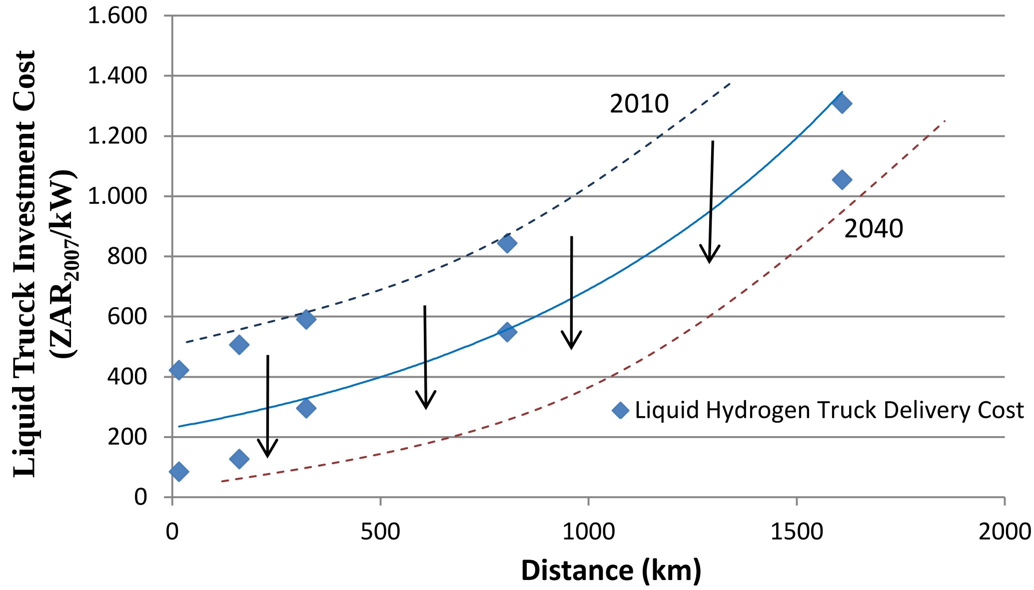

Figure 5.17: Liquid truck investment cost by distance (Berridge, 2010).

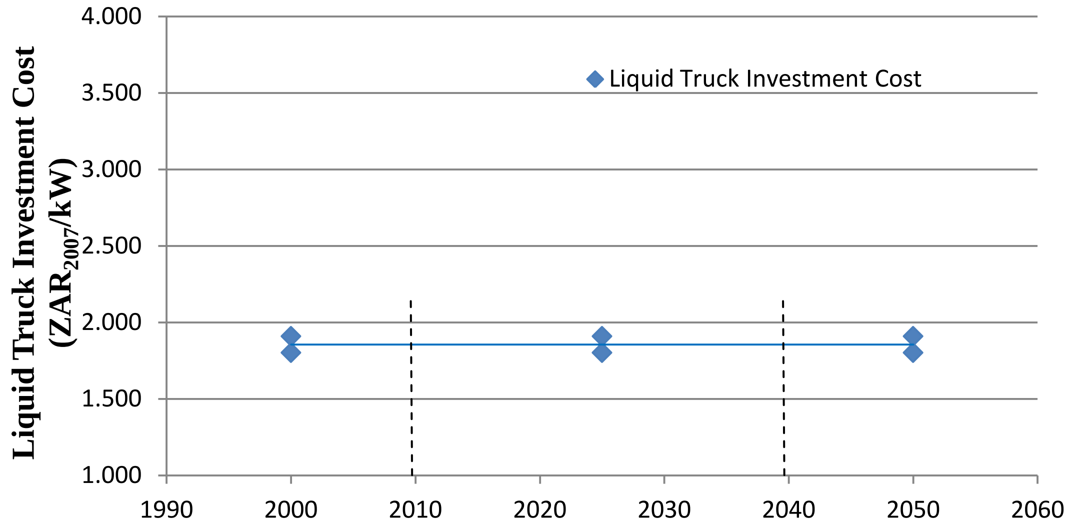

Figure 5.18: Liquid truck investment cost for 200 km hydrogen delivery (Doods & McDowall, 2012).

Considering the investment cost change by years curve, hydrogen delivery investment costs for both tube trailer in gaseous form and truck delivery in liquid form can be estimated for 15 km distance with an approach using Figure 5.6 and Figure 5.8, which give investment cost by distance relations.

The investment costs of 15 km gaseous tube trailer delivery from production plant to liquefaction terminal are 5,402 ZAR_{2007}/kW_{output} for 2010 and 2,971 ZAR_{2007}/kW_{output} for 2040.

The investment costs of pipeline 15 km long from the production plant to the liquefaction terminal, taking Figure 5.2 and Figure 5.4 into account, are 4,518 ZAR_{2007}/kW_{output} for 2010 and 1,581 ZAR_{2007}/kW_{output} for 2040

The investment cost of 10 km truck delivery from liquifection terminal to fueling station directly is 1,506 ZAR_{2007}/kW_{output} for 2010 and for 2040 with no change.

In other option, the total cost consists of a 15 km direct liquid hydrogen truck delivery and fueling station cost is 1,514 ZAR_{2007}/kW_{output} for 2010 and for 2040. Fixed O&M costs are defined as 20% of investment cost for gaseous and liquid truck delivery. O&M costs of pipeline delivery is considered as 5% of the investment costs. All variable O&M costs are considered as 50% of the fixed O&M costs (Dodds & McDowall, 2012) (Berridge, 2010).

In the first delivery scenario, hydrogen is compressed and delivered 15 km by pipelines from the coal to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.2: Delivery scenario 1 (combined delivery with pipeline and truck) for coal to hydrogen production.

ZAR_{2007}/GJ_{output}	**Costs**	**2010**	**2040**
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Pipeline (15 km)	Inv. Cost	143.29	50.14
	Fixed O&M	7.16	2.51
	Var. O&M	3.58	1.25
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	601.17	335.23

In the second delivery scenario, hydrogen is compressed and delivered 15 km by gaseous tube trailers from the coal to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5. 3: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for coal to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Tube Trailer (15 km)	Inv. Cost	171.33	94.24
	Fixed O&M	8.57	4.71
	Var. O&M	4.28	2.36
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	631.31	382.64

In the third delivery scenario, hydrogen is liquefied and delivered 15 km by liquid hydrogen trucks from the coal to hydrogen production plant to the fueling stations directly.

Table 5. 4: Delivery scenario 3 (Truck delivery in liquid form) for coal to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-15 km)	Inv. Cost	48.03	48.03
	Fixed O&M	2.40	2.40
	Var. O&M	1.20	1.20
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	243.68	165.19

The same approach can be used for natural gas to hydrogen production. A natural gas to hydrogen production plant can be built on the region where natural gas source can be supported by Mozambique-Secunda natural gas pipe extension in Secunda. The location of pipe extension can be seen in Figure 5.19 and the natural gas company’s whole pipe lay out can be seen in Appendix C. The distance between OR Tambo international airport and the natural gas pipeline is approximately 125 km.

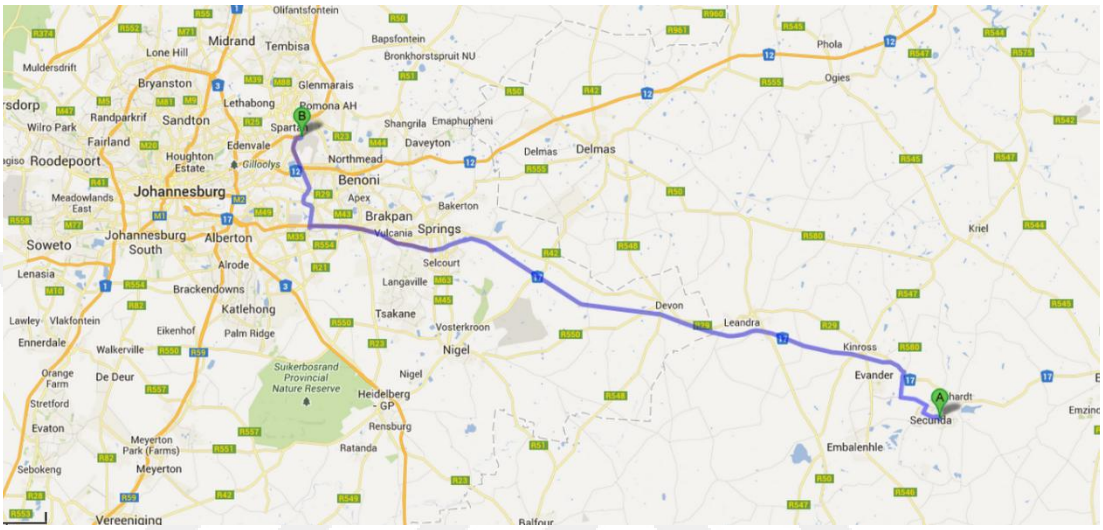

Figure 5.19: Mozambique-Secunda natural gas pipeline extension (Google Map, 20013).

The three scenarios for delivery costs can be considered with the same method of investment cost change by distance and years. The scenario analysis can be seen in Table 5.5, Table 5.6 and Table 5.7. The investment costs for determined distances are 5,389 ZAR_{2007}/kW_{output} in 2010 and 1,885 ZAR_{2007}/kW_{output} for 2040 for hydrogen pipeline, 6,453 ZAR_{2007}/kW_{output} in 2010 and 3,549 ZAR_{2007}/kW_{output} in 2040 for gaseous hydrogen tube trailer, 1,708 ZAR_{2007}/kW_{output} in 2010 and 1,708 ZAR_{2007}/kW_{output} in 2040 for Liquid hydrogen truck delivery. Detailed delivery costs can be seen in Table 5.5.

In the first delivery scenario, hydrogen is compressed and delivered 125 km by pipelines from the natural gas to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.5: Delivery scenario 1 (combined delivery with pipeline and truck) for natural gas to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Pipeline (125 km)	Inv. Cost	170.91	59.80
	Fixed O&M	8.55	2.99
	Var. O&M	4.27	1.50
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	630.86	345.62

In the second delivery scenario, hydrogen is compressed and delivered 125 km by gaseous tube trailers from the natural gas to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.6: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for natural gas to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Tube Trailer (125 km)	Inv. Cost	204.64	112.57
	Fixed O&M	10.23	5.63
	Var. O&M	5.12	2.81
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	667.13	402.34

In the third delivery scenario, hydrogen is liquefied and delivered 125 km by liquid hydrogen trucks from the natural gas to hydrogen production plant to the fueling stations directly.

Table 5.7: Delivery scenario 3 (Truck delivery in liquid form) for natural gas to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-125 km)	Inv. Cost	54.18	54.18
	Fixed O&M	2.71	2.71
	Var. O&M	1.35	1.35
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	250.30	171.81

For biomass to hydrogen production, the closest dense forest region can be selected as an example to build up a production plant. Althoug Kuger National Park region is out of Gauteng, it is the closest high capacity national flora, which is close to Mozambique border. This national park is 1,336,981 km2 wide with various plant cover. The distance between National park and airport can be seen in Figure 5.16.

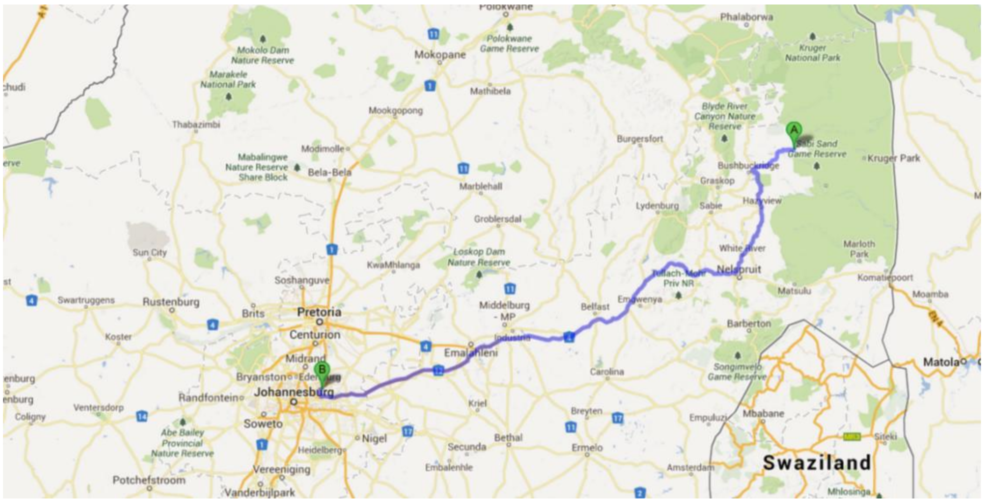

Figure 5.20: Dense forests nearby Kruger National Park (Google Map, 20013).

This scenario-based biomass to hydrogen production plant is located about 450 km away from OR Tambo international airport.

The scenario of three possible delivery paths with the given distances of delivery routh determines the following investment costs are projected; 9,072 ZAR_{2007}/kW_{output} in 2010 and 3,174 ZAR_{2007}/kW_{output} for 2040 for hydrogen pipeline, 10,910 ZAR_{2007}/kW_{output} in 2010 and 6,001 ZAR_{2007}/kW_{output} in 2040 for gaseous hydrogen tube trailer, 2,440 ZAR_{2007}/kW_{output} in 2010 and 2,440 ZAR_{2007}/kW_{output} in 2040 for Liquid hydrogen truck delivery. Detailed delivery costs can be seen in Table 5.8, Table 5.9, Table 5.10.

In the first delivery scenario, hydrogen is compressed and delivered 450 km by pipelines from the biomass to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.8: Delivery scenario 1 (combined delivery with pipeline and truck) for biomass to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Pipeline (450 km)	Inv. Cost	287.69	100.67
	Fixed O&M	14.38	5.03
	Var. O&M	7.19	2.52
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	756.41	389.54

In the second delivery scenario, hydrogen is compressed and delivered 450 km by gaseous tube trailers from the biomass to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.9: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for biomass gas to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Tube Trailer (450 km)	Inv. Cost	345.96	190.30
	Fixed O&M	17.30	9.51
	Var. O&M	8.65	4.76
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	819.04	485.90

In the third delivery scenario, hydrogen is liquefied and delivered 450 km by liquid hydrogen trucks from the biomass to hydrogen production plant to the fueling stations directly.

Table 5.10: Delivery scenario 3 (Truck delivery in liquid form) for biomass to hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-450 km)	Inv. Cost	77.38	77.38
	Fixed O&M	3.87	3.87
	Var. O&M	1.93	1.93
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	275.23	196.74

In the case of electrolysis hydrogen production, Bronkhortstspruit dam in Gauteng can be selected as an example place to build up an electrolysis to hydrogen production plant. This dam is 35.3 m high ad 152.4 m long with 57,913,000 m3 capacity. The dam is 68 km far from OR Tambo international airport. The location of Bronkhortstspruit dam is shown in Figure 5.17.

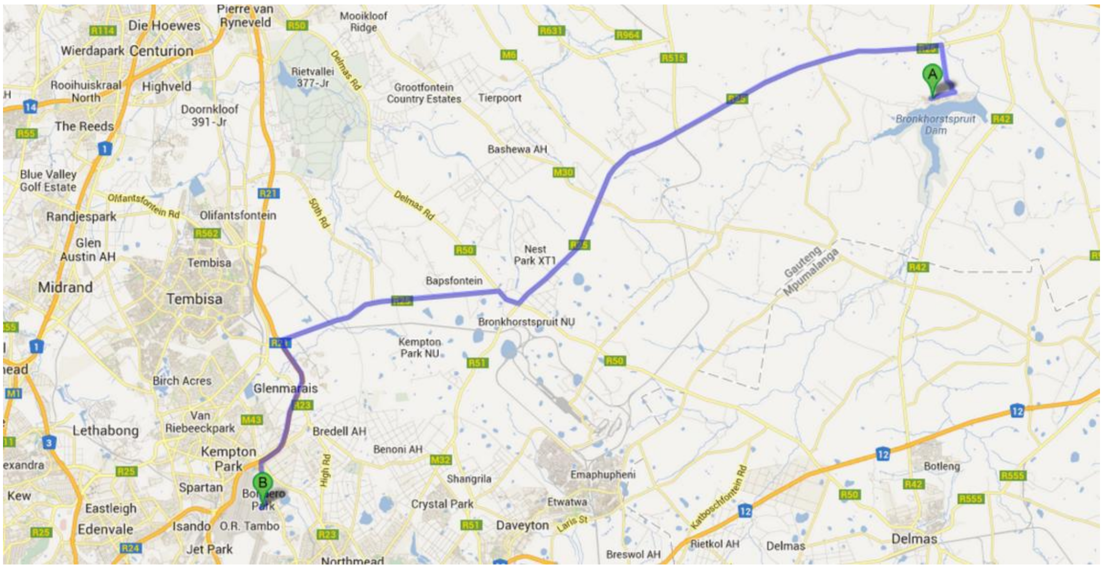

Figure 5.21: Bronkhorstspruit dam in Gauteng (Google Map, 20013).

The cost analysis of three possible hydrogen delivery are made and consequently, according to the three scenarios of three possible delivery paths with the given distances, the investment costs are found as 4,919 ZAR_{2007}/kW_{output} in 2010 and 1,721 ZAR_{2007}/kW_{output} for 2040 for hydrogen pipeline, 5,885 ZAR_{2007}/kW_{output} in 2010 and 3,237 ZAR_{2007}/kW_{output} in 2040 for gaseous hydrogen tube trailer, 1,605 ZAR_{2007}/kW_{output} in 2010 and 1,605 ZAR_{2007}/kW_{output} in 2040 for Liquid hydrogen truck delivery. Detailed delivery costs can be seen in Table 5.11, Table 5.12, Table 5.13.

In the first delivery scenario, hydrogen is compressed and delivered 68 km by pipelines from the electrolysis hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.11: Delivery scenario 1 (combined delivery with pipeline and truck) for electrolysis hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Pipeline (68 km)	Inv. Cost	155.99	54.58
	Fixed O&M	7.80	2.73
	Var. O&M	3.90	1.36
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	614.83	340.00

In the second delivery scenario, hydrogen is compressed and delivered 68 km by gaseous tube trailers from the electrolysis hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 5.12: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for electrolysis hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	192.21	109.84
	Fixed O&M	7.69	4.39
	Var. O&M	3.84	2.19
Tube Trailer (68 km)	Inv. Cost	186.64	102.66
	Fixed O&M	9.33	5.13
	Var. O&M	4.67	2.57
Liquefaction (Terminal)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-10 km)	Inv. Cost	47.77	47.77
	Fixed O&M	2.39	2.39
	Var. O&M	1.19	1.19
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	647.78	391.69

In the third delivery scenario, hydrogen is liquefied and delivered 68 km by liquid hydrogen trucks from electrolysis hydrogen production plant to the fueling stations directly.

Table 5.13: Delivery scenario 3 (Truck delivery in liquid form) for electrolysis hydrogen production.

ZAR_{2007}/GJ_{output}	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	159.73	91.27
	Fixed O&M	6.39	3.65
	Var. O&M	3.19	1.82
Truck (Liquid-68 km)	Inv. Cost	50.90	50.90
	Fixed O&M	2.55	2.55
	Var. O&M	1.27	1.27
Fueling Station (LH_2)	Inv. Cost	21.15	15.65
	Fixed O&M	1.06	0.78
	Var. O&M	0.53	0.39
Delivery Cost	Total	246.77	168.28

Current and future life time and efficiency values for truck, tube trailer, pipeline, liquefier and fueling station can be found in Table 5.14. LH2 fueling station lifetime is considered as the same of gaseous fueling station (Doods & McDowall, 2012).

Table 5.14: Energy input and lifetime of the delivery technologies (Doods & McDowall, 2012).

Delivery Technology	Energy Input		Lifetime (years)
	Hydrogen	Electricity	
Pipeline	100%	0%	80
LH2 Truck	83%	0%	15
Tube Trailer	100%	0%	15
Liquefier	83%	17%	20
Fueling Station	96%	4%	20

6. HYDROGEN IN AVIATION

Hydrogen looks like a promising alternative fuel for most kinds of transportation (Hemighaus, et al., 2006). Besides the other types of transportation, hydrogen is yet the only known suitable alternative fuel for aviation, produced from renewable energy systems (Klug, 2000).

Addition to 4-5% annual traffic increase predictions for next decades, recent rapid growth in civil aviation also attracted attentions to alternative fuel research for aviation (Westenberger, 2007a). Furthermore, estimations were showing 2% annual increase in fuel consumption and CO_2 emissions pointed hydrogen fuel because far less low emissions might be helpful to lessen dependency of aviation on oil resources and catch greenhouse gas emission targets (Klug, 2000).

Hydrogen airplane was investigated in the project named “cryoplane” by a European consortium of thirty-five partners from industry, research establishments and universities from eleven countries led by Airbus Deutschland (EC, 2012). In the project, an overall system analysis of hydrogen as an aviation fuel was investigated including configuration, system and components, propulsion, safety, environmental compatibility, fuel sources and infrastructure, transition. The project started in 2000 and planned for 24 months with 4.5 million Euro total budget and 550 person-months total effort (Fass, 2001).

Even though hydrogen is advantageous alternative fuel for aviation, it has some technical challenges to be achieved. In this chapter, some of these challenges such as hydrogen fuel storage, hydrogen airplane design, safety and cost challenges will be discussed. A model of cryoplane is shown in Figure 6.1.

Figure 6.1: A model of cryoplane hydrogen fuelled aircraft (Klug, 2000).

6.1 Hydrogen versus Kerosene

Research and development studies show that there are only a few alternative fuels or systems for energy solution of future transportation in a way environmental friendly and feasible. (Saynor, Baue, & Leach, 2003) Whereas electrical power and fuel cell applications present clean and applicable energy solutions for road transportation but these solutions are not power-intensive or they are too heavy for aircrafts requiring high power. However, electricity produced from renewable energy sources can pose a reasonable option to produce hydrogen by electrolysis in order to use in aircrafts (EC, 2003) (DOE, 2011).

The reason total fuel cell propulsion is not applicable; the convenient way of use of hydrogen is to burn it in turbofan power plants. The main product of burning hydrogen in engines is water after the process. Hydrogen can be carried and stored only in liquid form practically in aircrafts. The reason of this limitation is the tank weight and size and high volume of hydrogen in gaseous form (Saynor, Baue, & Leach, 2003). Figure 6.2 compeares energy content rates of hydrogen and kerosene in the same weight and volume.

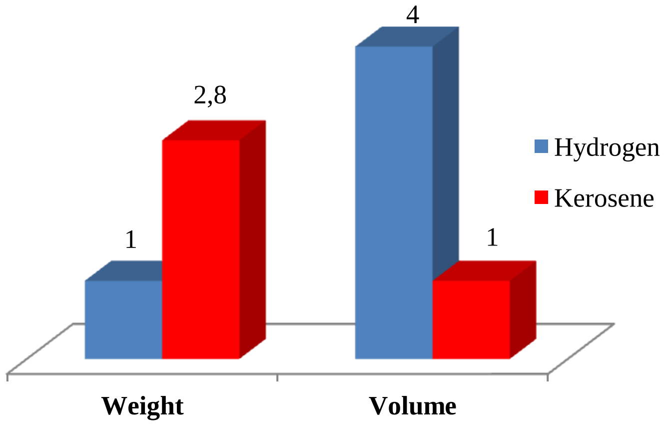

Figure 6 2: Weight and volume rates of hydrogen and kerosene by the masses of equal energy content (Fass, 2001).

Hydrogen contains 2.8 times more energy in the same weight, comparing to kerosene fuel. (Krijinen & Astaburuaga, 2002) Therefore, a disadvantage in transition to hydrogen is that some part of energy content of hydrogen will be consumed by the increasing weight of complex fuel systems and fuel tanks, however, an increase in payload at a certain takeoff weight is also expected (Edwards, 2003). Figure 6.3 compares emissions of the same energy content of hydrogen and kerosene.

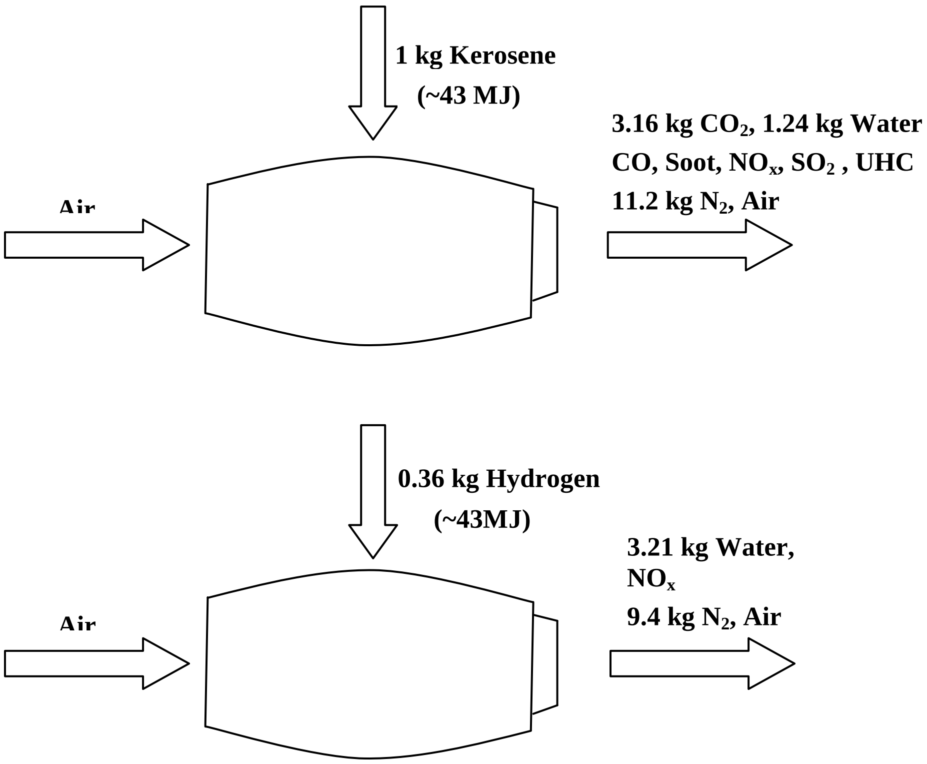

Figure 6.3: Emissions of masses of equal energy content (van Zon, 2012).

The only primary product after combustion of hydrogen in airplanes is water. The secondary existing emission is Nitrogen Oxides (NO_x). Other greenhouse gases are not emitted by combustion of hydrogen (Momirhan & Veziroğlu, 2002). The emission of Nitrogen Oxidants can be also reduced by lean combustion to the lower level than of kerosene. Additionally, hydrogen combustion releases 2.6 times more water amount compared the kerosene of the same energy content. However, water vapor contributes to greenhouse gas effect, it is less residence in the stratosphere compared to CO_2 (Klug, 2000).

6.2 Liquid Hydrogen Fuelled Aircraft

6.2.1 Configuration

The physical disadvantage of hydrogen transition of airplanes is that hydrogen requires four times bigger volume to store the same energy content comparing to kerosene (EERE, 2011). These tanks, at the same time, should enable isolation and differential pressure with a cylindrical shape. (Juanos, 2008). Depending on the liquid hydrogen tanks, two main configurations for hydrogen aircraft were focused. The first configuration named conventional configuration includes some the aircraft types of commercial operation. Unconventional configuration requires design of new aircrafts for hydrogen tanks (Saynor, Baue, & Leach, 2003).

Three main types of aircrafts for conventional configuration were projected; small regional aircraft, short-medium range aircraft and long-range aircraft. The concept of small regional aircraft is presented in Figure 6.4.

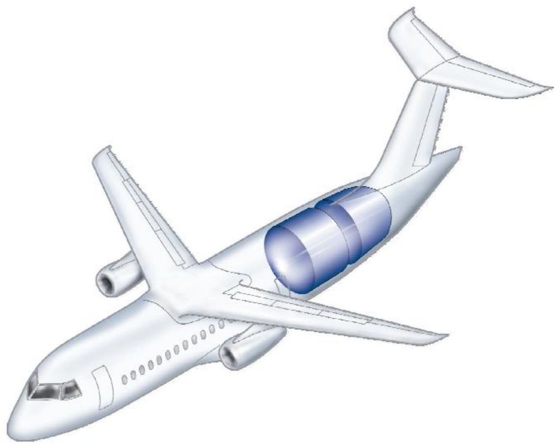

Figure 6.4: Small range aircraft (Westenberger, 2007b).

The configuration for small regional aircraft is considered as the simplest configuration having the tank behind the aft pressure bulkhead. This configuration requires wider fuselage. This configuration is appropriate for only small regional aircraft and business aircraft. For larger fuel needs like regional aircrafts including turbo-prop or turbo-jet aircrafts up to hundred seats, aft tank must be balanced with a forward tank. This type of tank configuration is considered less efficient but safer for the passengers because hydrogen tanks are on the top of the fuselage and hydrogen can boil off in case of defect (Airbus, 2003). This configuration is presented in Appendix E, in Figure E 4.

The design of medium range aircraft requires the hydrogen tanks on the top of the fuselage. Hydrogen tanks in ticker inner wings were considered at the first proposal of small/medium range aircraft. Based on lower aerodynamic efficiency, configuration was revised as an alternative configuration which is presented in Figure 6.5, with a larger tail cone and top tanks. Another configuration was considered as the most efficient one with two tanks balancing each other, one in the front and one in the rear (Westenberger, 2007a).

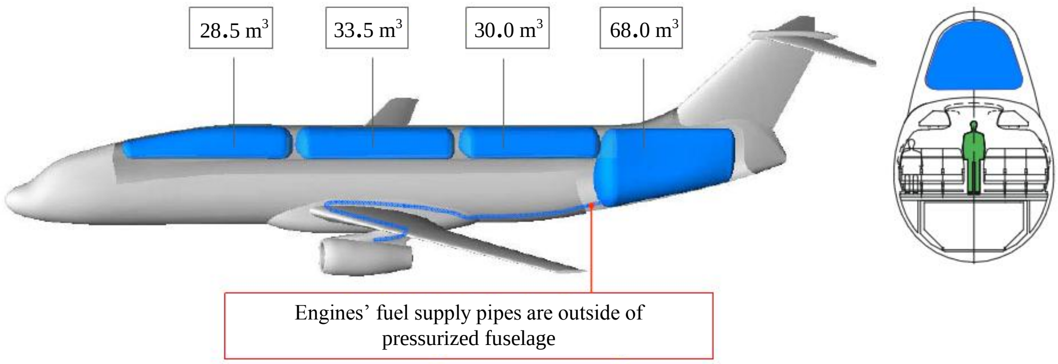

Figure 6.5: Medium range aircraft (Westenberger, 2007b).

The configuration of long range aircraft and very large long range aircraft allows a catwalk between cockpit and cabin through the front tank with wider fuselage diameter. The Configuration can be seen in Figure 6.6. This configuration is appropriate for very large long range aircraft except three-deck layout (Airbus, 2003).

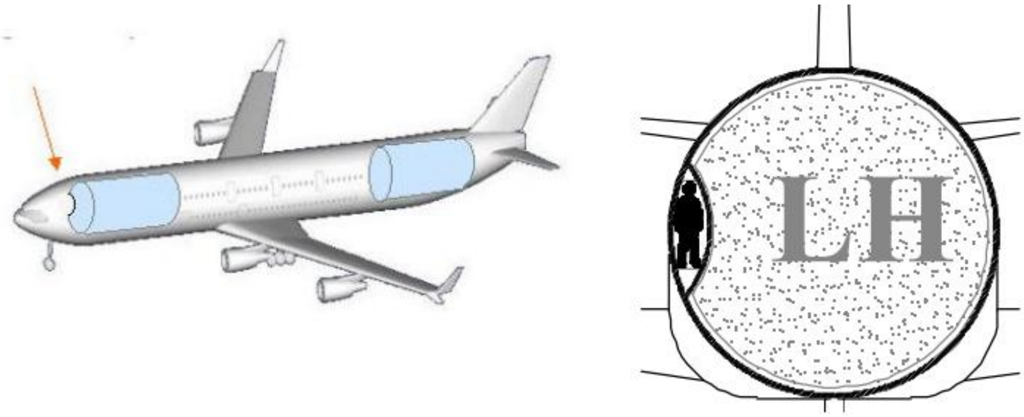

Figure 6.6: Long-range aircraft (Airbus, 2003).

As unconventional configurations, varieties of alternatives were studied. Two of them appeared reasonable. The twin boom configuration, which can be seen right down in Figure 6.7, causes high profile and interference drag with external tanks. The blended wing body configuration creates much unused volume. Consequently, no advantage against the conventional configurations was discovered (Westenberger, 2007a).

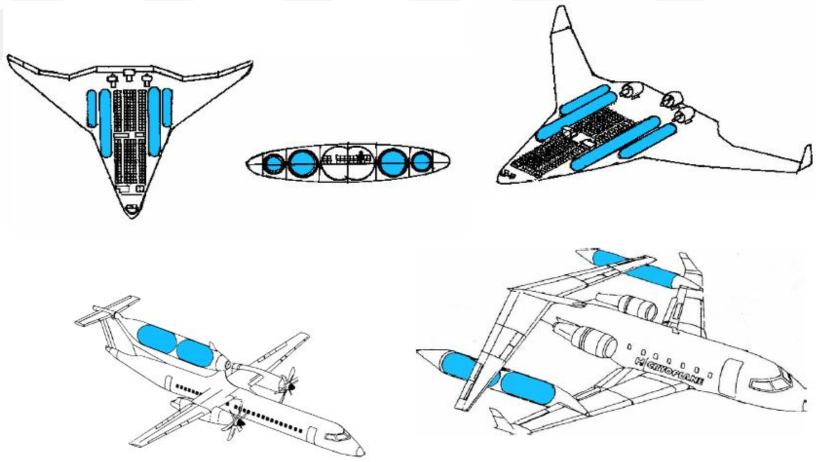

Figure 6.7: Unconventional aircraft configurations (Westenberger, 2007b).

6.2.2 Structure

The structural parts as insulated tanks should be enduring under low and high temperature working conditions as well as they should be light (Koroneos & Moussiopoulos, 2001). Airplane fuselage should be able to stretch under more payload. (Airbus, 2003). Cross section of a cryoplane can be seen in Figure 6.8.

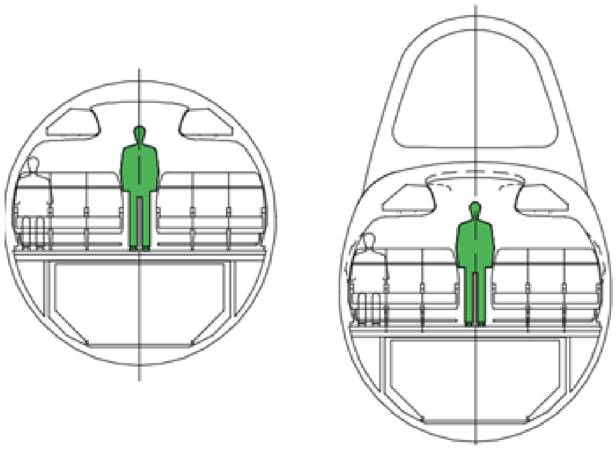

Figure 6.8: Cryoplane cross section (Westenberger, 2007a).

6.2.3 New Systems

Hydrogen airplanes will require more complex fuel system because of characteristic that hydrogen can evaporate and fuel system can include both liquid and gaseous form of hydrogen. Life cycle of airplane components should be longer and these components should be durable enough (Klug, 2000). A possible fuel system is presented in Figure 6.9.

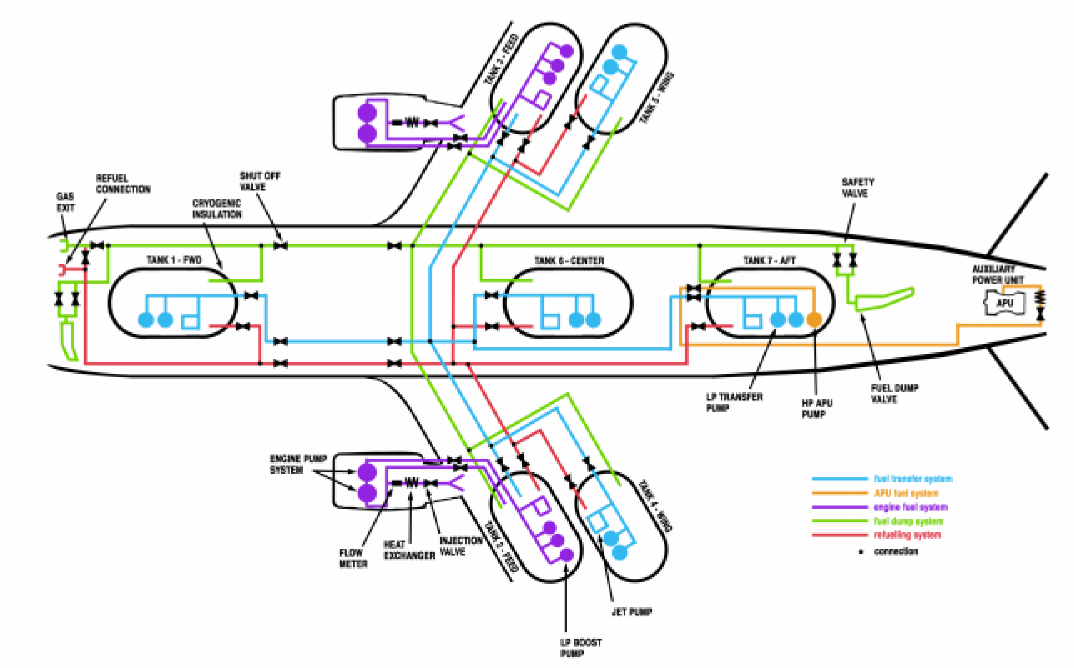

Figure 6.9: Possible fuel supply system for an Airbus A300 with liquid hydrogen (van Zon, 2012).

6.2.4 Power Plant

Hydrogen airplane design will cause operational developments in airplane engines (Corchero & Montanes, 2005). New engine configurations will be necessary such as heating combustion chamber must be heated before the hydrogen injected. New systems such as a heat exchanger, flow control valve and high-pressure pump should necessarily be developed (Juanos, 2008). Figure 6.10 presents a type of hydrogen engine system.

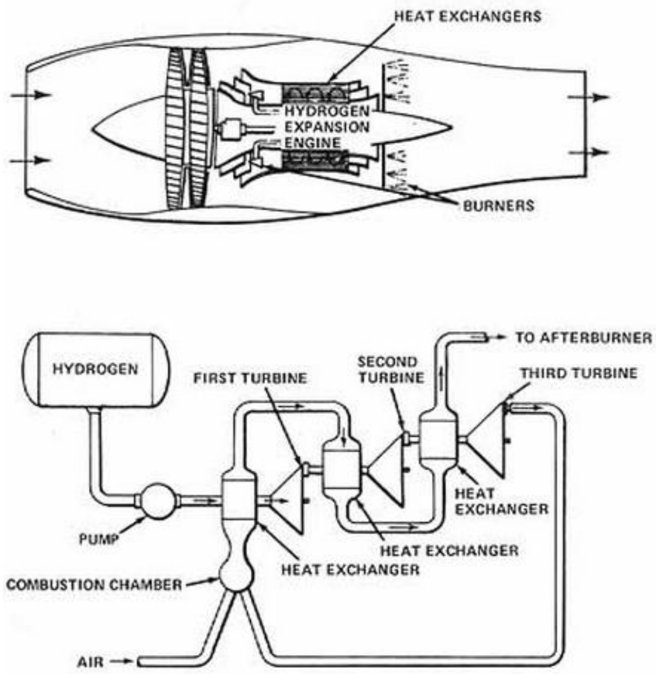

Figure 6.10: NASA’s Rex III hydrogen engine system (NASA, 2013).

6.2.5 Safety

Hydrogen cannot detonate in free atmosphere because it rises faster than other gases such as Propane or Natural Gas. Hydrogen burns at below detonation limit and that means the danger zone of hydrogen is so small in case of leak or it is spilled (Pritchard, Royle, & Willoughby, 2009) (Klug, 2000). The danger zone of hydrogen in comparison with other gases is presented in Figure 6.11.

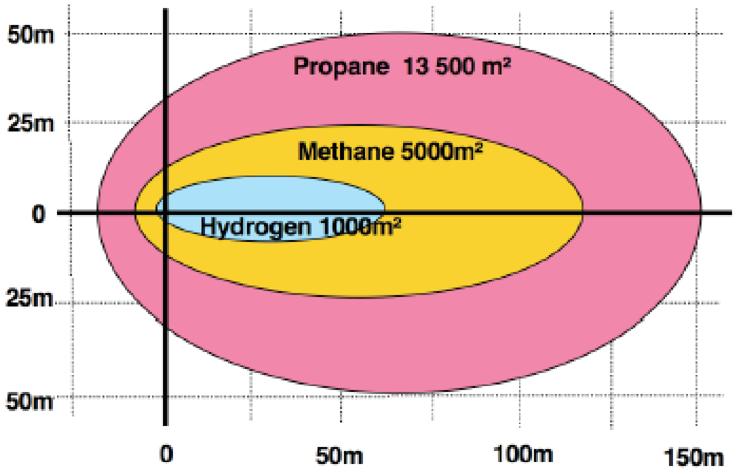

Figure 6.11: Danger zones of spilled liquid gases (Verstraete, 2009).

Hydrogen does not form a fire carpet with its volatility in the air unlike kerosene. From the aspect of a crash, passengers may survive because of the characteristics of hydrogen that even if it burns fast, it burns with a low heat radiation and does not produce toxic by-products while burning (Klug, 2000).

7. TECHNO-ECONOMIC ANALYSIS OF HYDROGEN FUELED AIRCRAFT

Transition to hydrogen in aviation is expected to occur when it is economically advantageous for airlines (FAA, 2005). From the economical aspect, fuel prices are the focus depending on the expectation of the balance of payload fraction and operating cost of more complex fuel systems (Edwards, 2003) (Klug, 2000). Figure 7.1 shows world airline route map of 2007. It can be seen that South Africa is one of the points in the world where air traffic increased with a high acceleration since 1990 (Forbes, Patel, Cone, Valdez, & Komerath, 2011).

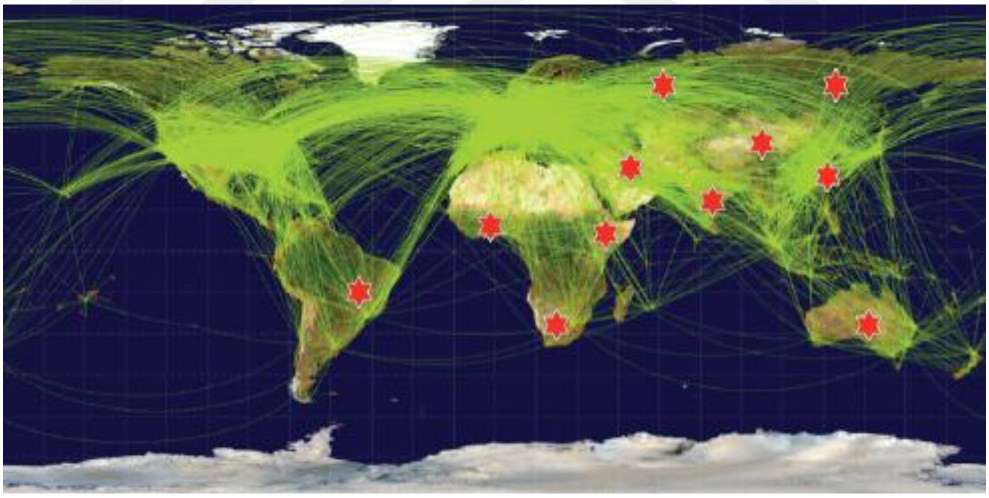

Figure 7.1: World airline route map of 2007.

Investment costs per passenger kilometer for airplanes with different fuels are presented in Table 7.1.

Table 7.1: Investment costs of kerosene plane and hydrogen plane (IEA, 2005).

Investment cost per passenger.km	Unit	Cost
Kerosene plane	(ZAR_{2007}/1000 pkm)	571
Hydrogen plane	(ZAR_{2007}/1000 pkm)	642

Even if hydrogen is stored as liquid in storage tanks, because the liquid hydrogen still requires four times greater volume, big liquid hydrogen tanks will cause between 9-34 % higher energy consumption. In cost calculations, 12% annuity per seat is used. Fuel cost for kerosene is assumed 35.70 ZAR_{2007}/GJ and fuel cost of hydrogen is assumed 142.82 ZAR_{2007}/GJ. Besides, it is projected that 20% less fuel is used per seat in hydrogen airplane (IEA, 2005). Fuel and capital cost per seat occupied for both type of airplanes can be seen in Table 7.2.

Table 7.2: Fuel and capital costs per seat occupied of kerosene plane and hydrogen plane (IEA, 2005).

Fuel and capital per seat occupied	Unit	Cost
Kerosene plane	(ZAR_{2007}/seat)	357,043
Hydrogen plane	(ZAR_{2007}/seat)	1,428,172

The payload of hydrogen airplanes will be between 20-30 % lower comparing to kerosene airplane, however; it affects the number of passengers not that importantly (Jolley, 2006). Costs per seat for the airplanes can be seen in Table 7.3. The load factor is 75% for both of the planes and hydrogen airplane has 15% fewer passengers then the kerosene airplane. Costs per seat occupied includes investment costs and direct operational costs for airplanes. DOC (direct operating cost) can be determined as in the equation below:

DOC = Flight Crew + Cabin Crew + Airframe Maintenance +Engine Maintenance + Depreciation + Insurance + Interest (ADAC, 2011)

Table 7.3: Costs per seat occupied of kerosene plane and hydrogen plane with load factor (IEA, 2005).

Cost per seat occupied	Unit	Cost
Kerosene plane	(ZAR_{2007} 1000/seat)	3,998
Hydrogen plane	(ZAR_{2007} 1000/seat)	4,927

As it is mentioned in the previous chapter, although hydrogen airplane's waste products such as water vapor and NO_X also have greenhouse effect depending on the level of altitude in the stratosphere (IEA, 2005). Emissions of the airplanes bring some emission cost to airlines (Clements, Wilkins, & Beyzh, 2011). Whereas 0.073 ton of CO_2/GJ is considered for kerosene, H_2O and NO_X are not considered for hydrogen fuel in emission costs calculations (IEA, 2005). In this study additional greenhouse mitigation costs are not included to product cost related to hydrogen. Table 7.4 shows the costs of emissions for the airplanes.

Table 7.4: Emission costs of kerosene plane and hydrogen plane (IEA, 2005).

Emission costs	Unit	Cost
CO_2 emissions for kerosene	(t/used seat/yr)	730
Hydrogen plane CO_2 emissions mitigation cost	(ZAR_{2007}/t of CO_2)	1,471

While flying at higher cruising altitudes contribute to fuel saving for airplanes, on the other hand water vapor, which is by product of hydrogen fuelled airplane has higher greenhouse impact at higher altitudes (NASA, 2010). The optimum cruising altitude is 10 km for hydrogen, whereas kerosene airplanes can fly at up to 11 km altitude. Hydrogen airplane may consume 15% more fuel while flying at 11 km than flying at 10km (IEA, 2005). The current and future efficiencies of kerosene and hydrogen airplanes at different altitudes can be seen in Table 7.5.

Table 7.5: Fuel efficiencies of kerosene airplane and hydrogen airplane (IEA, 2005).

Fuel efficiency	2000	2040
Kerosene at 10 km altitude (1,000 pkm/GJ)	0.45	0.53
Kerosene at 11 km altitude (1,000 pkm/GJ)	0.53	0.62
Cryoplane at 10 km altitude (1,000 pkm/GJ)	0.38	0.44

The break-even point for hydrogen airplane and kerosene airplane is projected for 2040, and the break-even point of DOC can be seen in Figure 7.2.

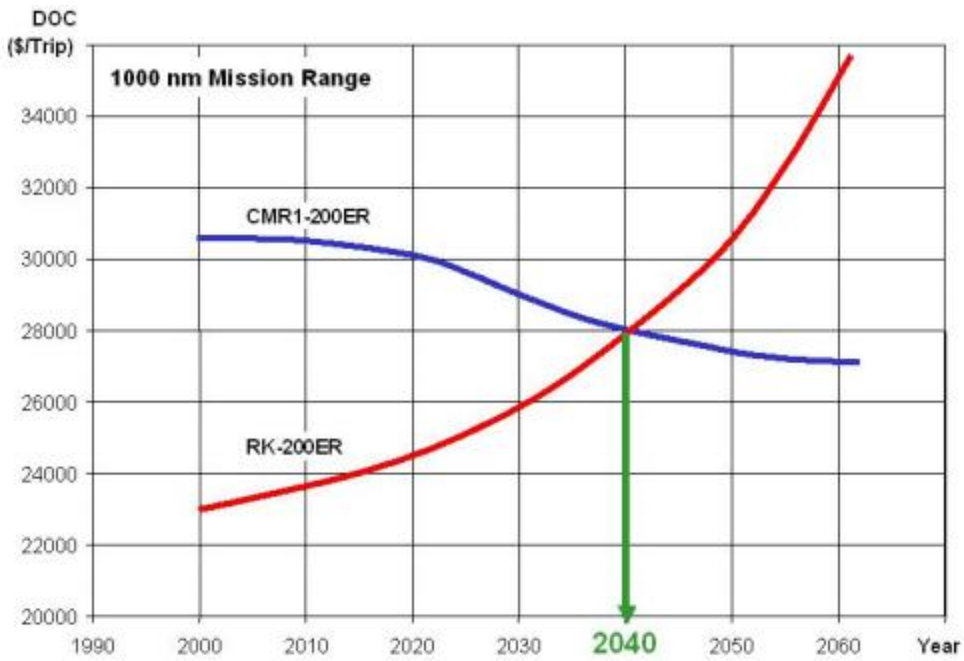

Figure 7.2: Break-even point of DOC (Direct operating cost) for CMR (Cryoplane Medium Range) and RK (Reference a/c Kerosene) (Westenberger, 2007a).

8. CONCLUSIONS AND RECOMMENDATIONS

The purpose of this study was to evaluate the future role of hydrogen as an alternative aviation fuel in Gauteng metropolitan region of South Africa in terms of costs and efficiencies.

Variations of hydrogen production and delivery pathways, besides liquid hydrogen airplanes were investigated from technological aspect.

The costs of each scenario for production and delivery technologies as well as hydrogen airplane costs were projected for current date and for the year 2040 as future estimations.

In order to perform current and future costs, scenario analysis applied to each case. Costs from the literature were utilized and estimations for the years were undertaken with the curves of cost optimization. While cost estimations took place, specific local characteristics and details of Gauteng region were taken into consideration. The estimation results were interpreted and submitted as a life cycle assessment for each technology and for each scenario.

8.1 Conclusions

Hydrogen production costs for Gauteng metropolitan region of South Africa is analyzed for each hydrogen production technology of coal gasification, natural gas reforming, biomass gasification and electrolysis. Coal gasification and natural gas reforming technologies considered as two pathways of hydrogen production, which involves the production methods with carbon capture storage technology and without carbon capture storage technology. Hydrogen production cost of each production technology is projected and compared in Table 8.1.

Table 8.1: Hydrogen production costs.

Hydrogen Production Method	Technology	Production Cost (ZAR_{2007}/GJ_{output})	
		2010	2040
Coal Gasification	With CCS	1,308.16	819.98
	Without CCS	1,098.45	614.58
Natural Gas Reforming	With CCS	805.42	612.66
	Without CCS	629.64	532.97
Biomass Gasification	-	1,048.73	521.41
Electrolysis	-	3,354.59	1,298.61

As in Table 8.1, the current and future costs of hydrogen production technologies can be compared for today and future. After comparison, it can be commented that the lowest-cost production technology for Gauteng region is natural gas reforming with CCS with the price of 805.42 ZAR2007/GJoutput for 2010 and 612.66 ZAR2007/GJoutput for 2040, and natural gas reforming without CCS with the price of 805.42 ZAR2007/GJoutput for 2010 and 612.66 ZAR2007/GJoutput for 2040. As it is expected, the natural gas reforming without CCS is lower than the one with CCS like in other production technologies as well. Although the local fuel prices for coal is the cheapest option in the region, the relative investment cost for natural gas reforming hydrogen production is 55% of the production cost of coal gasification with CCS currently and in the future. Furthermore, in the future, the investment cost of hydrogen production from natural gas reforming without CCS is 80% of coal gasification without CCS. Briefly, it can be presumed that the lower relative investment cost, fixed operating and maintenance cost and variable operating cost are the main reason of the lowest-cost hydrogen production from natural gas reforming , despite the higher fuel cost comparing to the cheapest coal fuel prices. Assuming the environmental effect is ignorable in this study, hydrogen production from natural gas reforming without CCS is the lowest-cost production path from the economic aspect.

All delivery scenario costs are given as a comparison in Table 8.2. In each case, direct liquid truck delivery is estimated as the lowest-cost hydrogen delivery scenario according to the local distances and the technologies used in the delivery paths.

Table 8.2: Cost comparison of delivery scenarios.

ZAR_{2007}/GJ_{output}	Total Delivery Costs	2010	2040
Coal to Hydrogen Production Plant	**Scenario 1 (Compressor, Pipeline, Liquefier, Liquid Truck, Fueling Station)**	601.17	335.23
	Scenario 2 (Compressor, Gaseous Tube Trailer, Liquefier, Liquid Truck, Fueling Station)	631.31	382.64
	Scenario 3 (Liquefier, Liquid Truck, Fueling Station)	243.68	165.19
Natural Gas to Hydrogen Production Plant	**Scenario 1 (Compressor, Pipeline, Liquefier, Liquid Truck, Fueling Station)**	630.86	345.62
	Scenario 2 (Compressor, Gaseous Tube Trailer, Liquefier, Liquid Truck, Fueling Station)	667.13	402.34
	Scenario 3 (Liquefier, Liquid Truck, Fueling Station)	250.30	171.81
Biomass to Hydrogen Production Plant	**Scenario 1 (Compressor, Pipeline, Liquefier, Liquid Truck, Fueling Station)**	756.41	389.54
	Scenario 2 (Compressor, Gaseous Tube Trailer, Liquefier, Liquid Truck, Fueling Station)	819.04	485.90
	Scenario 3 (Liquefier, Liquid Truck, Fueling Station)	275.23	196.74
Electrolysis Hydrogen Production Plant	**Scenario 1 (Compressor, Pipeline, Liquefier, Liquid Truck, Fueling Station)**	614.83	340.00
	Scenario 2 (Compressor, Gaseous Tube Trailer, Liquefier, Liquid Truck, Fueling Station)	647.78	391.69
	Scenario 3 (Liquefier, Liquid Truck, Fueling Station)	246.77	168.28

As it can be compared in the Table 8.2, the lowest-cost hydrogen delivery option is Scenario 3 for each case. In Scenario 3, direct hydrogen delivery by liquid hydrogen trucks is the main delivery step. In order to deliver hydrogen by liquid trucks, firstly liquefiers required at the production site. After liquefaction, there is no need for a terminal at the airport until fueling stations. Liquefiers and fueling stations are additional costs to total delivery cost in this case. In these results, model hydrogen production plants are essential key factor for costs by their distances to the airport. While these scenarios are modeled, the closest possible hydrogen production plants are considered as case models. In this case of hydrogen delivery in Gauteng region, delivery by liquid trucks from coal gasification hydrogen production is 243.68 ZAR2007/GJoutput for 2010 and 165.19 ZAR2007/GJoutput for 2040, from natural gas reforming hydrogen production plant is 250.30 ZAR2007/GJoutput for 2010 and 171.81 ZAR2007/GJoutput for 2040, from biomass gasification hydrogen production plant is 275.23 ZAR2007/GJoutput for 2010 and 196.74 ZAR2007/GJoutput for 2040, from electrolysis 246.77 ZAR2007/GJoutput for 2010 and 168.28 ZAR2007/GJoutput for 2040

The reason why truck delivery for liquid hydrogen is the lowest-cost delivery path for each production technology is because of a few reasons. The first reason is high investment cost of pipeline plays an important role of determining total delivery costs. Investment cost of pipeline decrease with wider diameter of the pipeline, which is related to big amount of hydrogen flow through the pipeline, and the longer length of the pipeline. In these delivery paths pipeline delivery options do not exceed the pay off limit of 500 km length. The second reason of the lowest prices of liquid hydrogen truck delivery comparing to gaseous tube trailer delivery is that the gaseous tube trailers have lower hydrogen capacity as weight and their trip per year rate is higher for the same amount of hydrogen demand. These reasons cause higher FOM and VAROM costs for gaseous tube trailer hydrogen delivery. The third reason is liquid hydrogen truck delivery is the only liquid hydrogen delivery that unlike pipeline delivery and tube trailer delivery, it does not require compressors and extra liquefaction terminal at the airport borders. The unnecessary extra investment costs are avoided so that the liquid hydrogen truck delivery is the lowest-cost hydrogen delivery path for Gauteng region with selected model hydrogen production plants.

In Table 8.3, kerosene airplane and hydrogen airplane cost per seat occupied are presented for the year 2040.

Table 8.3: Costs per seat occupied of kerosene plane and hydrogen plane with load factor (IEA, 2005).

Cost per seat occupied	Unit	Cost
Kerosene plane	(ZAR_{2007} 1000/seat)	3,998
Hydrogen plane	(ZAR_{2007} 1000/seat)	4,927

It can be concluded that hydrogen airplane has higher cost then kerosene airplane because of a main reason that the fuel cost of hydrogen is approximately 4 times higher than that of kerosene. Even though 2040 is break-even point of DOC for both kerosene and hydrogen middle range airplanes and the energy efficiency of hydrogen airplane is higher than the kerosene airplane, still it is challenging to overcome the high investment cost of hydrogen airplane. The production and delivery costs of hydrogen are compared in Table 8.4.

Table 8.4: Production and delivery cost of hydrogen.

Hydrogen Production Method	Production Technology	Delivery Technology	Production+Delivery Cost (ZAR_{2007}/GJ_{output})	
			2010	2040
Coal Gasification	With CCS	Pipeline+LH_2 Truck	1,909.33	1,155.21
		Tube Trailer+ LH_2 Truck	1,939.47	1,202.62
		LH_2 Truck	1,551.84	985.17
	Without CCS	Pipeline+LH_2 Truck	1,699.62	949.81
		Tube Trailer+ LH_2 Truck	1,729.76	997.22
		LH_2 Truck	1,342.13	779.77
Natural Gas Reforming	With CCS	Pipeline+LH_2 Truck	1,436.28	958.28
		Tube Trailer+ LH_2 Truck	1,472.55	1,015.00
		LH_2 Truck	1,055.72	784.47
	Without CCS	Pipeline+LH_2 Truck	1,260.50	878.59
		Tube Trailer+ LH_2 Truck	1,296.77	935.31
		LH_2 Truck	879.94	704.78
Biomass Gasification	-	Pipeline+LH_2 Truck	1,805.14	910.95
		Tube Trailer+ LH_2 Truck	1,867.77	1,007.31
		LH_2 Truck	1,323.96	718.15
Electrolysis	-	Pipeline+LH_2 Truck	3,969.42	1,638.61
		Tube Trailer+ LH_2 Truck	4,002.37	1,690.30
		LH_2 Truck	3,601.36	1,466.89

Because of the whole life cycle of hydrogen fuel, the lowest-cost production and delivery cost will be 704.78 ZAR2007/GJoutput in 2040 by natural gas reforming without CCS and liquid hydrogen truck delivery. The cost of hydrogen airplane will be 4,927 ZAR_{2007}.1000/seat in 204 additional to the hydrogen cost.

8.2 Recommendations

Regarding the aspect of hydrogen energy and hydrogen economy, production of hydrogen plays an essential role in the lifecycle cost assessment of hydrogen. The costs of hydrogen production technologies which were examined in this study, mostly rely on the local fuel costs. The fuel costs are the result of the abundance of these sources in the region. From techno-economical point of view, hydrogen should be produced from the cheapest source considering the total production cost of hydrogen. At the same time, amount and future statue of these sources in the region should not be ignored. Developing the natural gas pipeline network in South Africa, natural gas is the lowest-cost option among production technologies. At this point the production costs have an influence on the decision of hydrogen production path. Even if this study does not include emissions, natural gas reforming with CCS could be also applied as a cheaper and environmentally friendly method of all.

The delivery of hydrogen requires further technology comparing to natural gas delivery. Among the delivery technologies, liquid hydrogen delivery should be the most appropriate one because of having liquid hydrogen fueling stations at the airport and avoiding combined delivery additional costs as transportation change and terminal investments. However, liquid transportation provide opportunity to use either pipelines or liquid hydrogen trucks, because of the fact that the investment costs of hydrogen pipelines are high, direct liquid hydrogen truck delivery is basic path for Gauteng region for hydrogen delivery. Except the sample hydrogen production plants which were suggested in this study, in the case that there is a big demand and further hydrogen production plant opportunity, pipeline could be also considered the lowest-cost delivery solution according to the distance of delivery.

Hydrogen airplane utilization can be a demonstration in Gauteng region for future use of hydrogen airplanes in worldwide air traffic. In order to carry this technology into practice in the future, understanding of the demand, technology use and hydrogen infrastructure in Gauteng region are the basic requirements.

8.3 Outlook on Future Research

This dissertation aims to analyze the future role of hydrogen as an energy solution and alternative fuel in aviation in Gauteng metropolitan region of South Africa. While evaluating the future of hydrogen in aviation, costs of production and delivery paths were analyzed locally in Gauteng region. This study approached to hydrogen by a regional aspect different then (Gül, 2008) and (Dodds & McDowall, 2012) and (Airbus, 2003), taking the cost effects of Gauteng metropolitan region.

In this study, hydrogen production from coal, natural gas, biomass and electrolysis were analyzed. These production methods were decided according to national sources and local availability of production. These technologies can be diversified and hydrogen production from renewable technologies such as direct solar, solar PV, wind, geo-thermal and algae can be examined and as a conventional source oil can also be included in further studies.

For the delivery of hydrogen, in this dissertation, only specific pipeline and truck delivery methods were analyzed. In further studies, other technologies, which allow hydrogen delivery with lower-cost, can be examined. These technologies can be natural gas pipelines which allow to blend hydrogen into natural gas pipelines or other methods can be studied in order to reduce costs of road delivery of hydrogen.

In This study, hydrogen airplanes and the previous studies about hydrogen airplanes were analyzed and future costs were projected. In order to accelerate the demonstration of hydrogen aviation fuel and hydrogen airplanes, new systems and new engines and unplanned storage tank configurations can be studied in further research. Hydrogen storage as liquid form in the airplanes is the focus of challenges about usage of hydrogen in aviation. Thus, hydrogen storage techniques in cryogenic tanks can be new focus of further research.

This dissertation has a techno-economical approach to hydrogen energy solution. Therefore, environmental aspect is another key factor for future development of metropolitan regions that further research can review hydrogen fuel also considering the greenhouse gas emissions.

Finally, this study focuses on energy solution in aviation in Gauteng but also this approach can be applied other metropolitan regions in the world in further studies

8.4 Case Study For Istanbul

8.4.1 Hydrogen Production Costs for Istanbul

According to Kaya & Kılıç (2012), energy production from natural gas will decrease 41.1 % and energy production from biomass will decrease 15.1% between 2010 and 2030 in Turkey. Considering these values inversely proportional, biomass feed stock price in 2040 can be projected as 0.00804 \$2010/GJ. This approach can be made according to biomass feedstock price of biomass in 2010 as 0.00422 \$2010/GJ in the study Karataş & Gül (2012) and Kaya & Kılıç (2012) with the consideration that feedstock prices can follow decreasing trend line with increasing energy production capacity. All fuel prices are estimated for current and future prices according to (IGDAS, 2013). The change in fuel prices are shown in Figure 8.1.

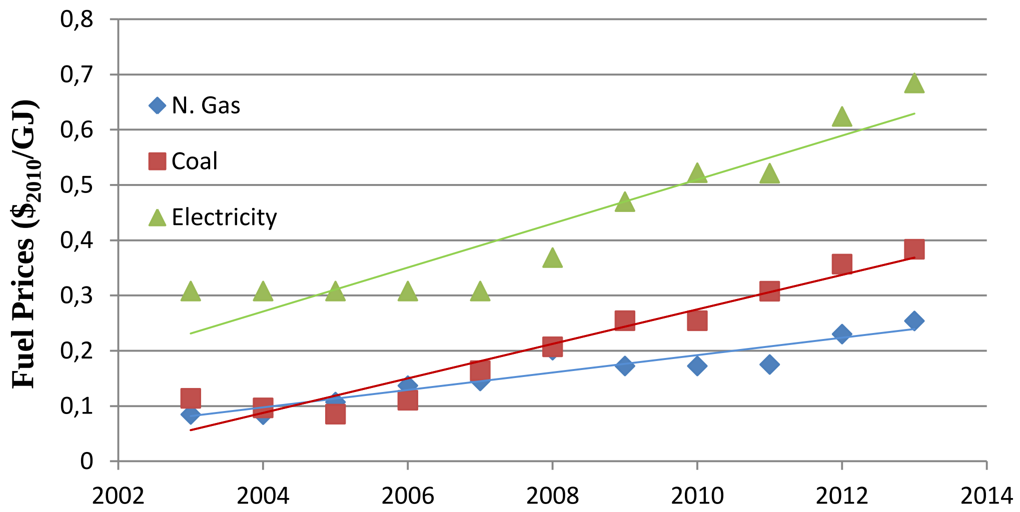

Figure 8.1: Fuel Prices by Years (IGDAS, 2013).

In fuel cost estimations, lignite prices are assumed as coal prices for Turkey. Biomass comprises solid biomass, biogas, industrial and municipal wastes. In addition to all, USD/TRY= 1.5443 currency rate for December 31, 2010 is used in the calculations. Fuel prices for Istanbul can be seen in Table 8.5.

Table 8.5: Fuel prices for Istanbul.

$\$_{2010}/GJ_{output}$	2010	2040
Coal	0.27	1.21
Natural Gas	0.19	0.66
Biomass	0.00422	0.00804
Electricity	0.50	1.70

The same as in the previous chapters, hydrogen production costs are calculated with the same relation below. (Gül, 2008):

$$COST = \frac{INVCOST}{AF} \cdot CRF + \frac{FIXOM}{AF} + VAROM + \frac{FeedstockCost}{\eta} \qquad \textbf{(8.1)}$$

INVCOST = Specific investment cost [ZAR_{2007}/kW]

CRF = Capital recovery factor [-]

AF = Availability factor [-]

FIXOM = Fixed operation and maintenance cost [ZAR_{2007}/kW/year]

VAROM = Variable operation and maintenance cost [ZAR_{2007}/GJ]

η = Process efficiency

The capital recovery factor is formulated as:

$$CRF = dr \times \frac{1+dr\ ^{n}}{(1+dr)^{n}-1} \qquad \textbf{(8.2)}$$

dr = Discount rate [%]

n = Plant life time [years]

In the calculations, discount rate is assumed 8% and capital recovery factor is calculated for the lifetime of each technology separately. Plant lifetime approximated with 30 years for coal and natural gas technologies, 20 years for biomass and electrolysis technologies.

The costs of hydrogen production from coal gasification in Istanbul can be seen in Table 8.6.

Table 8.6: Costs of hydrogen production from coal gasification.

$\$_{2010}/GJ_{output}$	Technology	2010	2040
Investment Cost	With CCS	43.15	25.94
	Without CCS	34.26	15.87
FOM Cost	With CCS	1.95	1.25
	Without CCS	1.81	1.25
VOM Cost	With CCS	0.59	0.41
	Without CCS	0.39	0.15
Production Cost	With CCS	203.54	126.73
	Without CCS	170.75	94.73

The costs of hydrogen production from natural gas reforming in Istanbul can be compared in Table 8.7.

Table 8.7: Costs of hydrogen production from natural gas reforming.

$\$_{2010}/GJ_{output}$	Technology	2010	2040
Investment Cost	With CCS	23.87	14.38
	Without CCS	19.27	12.77
FOM Cost	With CCS	1.04	0.65
	Without CCS	0.67	0.48
VOM Cost	With CCS	0.34	0.22
	Without CCS	0.28	0.18
Production Cost	With CCS	111.36	68.71
	Without CCS	84.04	57.69

The costs of hydrogen production from biomass gasification in Istanbul can be seen in Table 8.8.

Table 8.8: Costs of hydrogen production from biomass gasification.

$\$_{2010}/GJ_{output}$	2010	2040
Investment Cost	22.79	11.12
FOM Cost	1.98	0.91
VOM Cost	1.08	0.69
Production Cost	151.76	72.10

The costs of hydrogen production from electrolysis in Istanbul are shown in Table 8.9.

Table 8.9: Costs of hydrogen production from electrolysis.

$\$_{2010}/GJ_{output}$	2010	2040
Investment Cost	98.55	41.74
FOM Cost	3.98	0.44
VOM Cost	0.60	0.13
Production Cost	491.91	164.62

8.4.2 Hydrogen Delivery Scenarios and Costs for Istanbul Atatürk Airport

Çayırhan Park coal thermal power plant can be selected as the closest available place to Istanbul in order to built a coal to hydrogen production plant to Istanbul. This location is approximately 330 km far from Istanbul Atatürk international airport as seen in Figure 8.2.

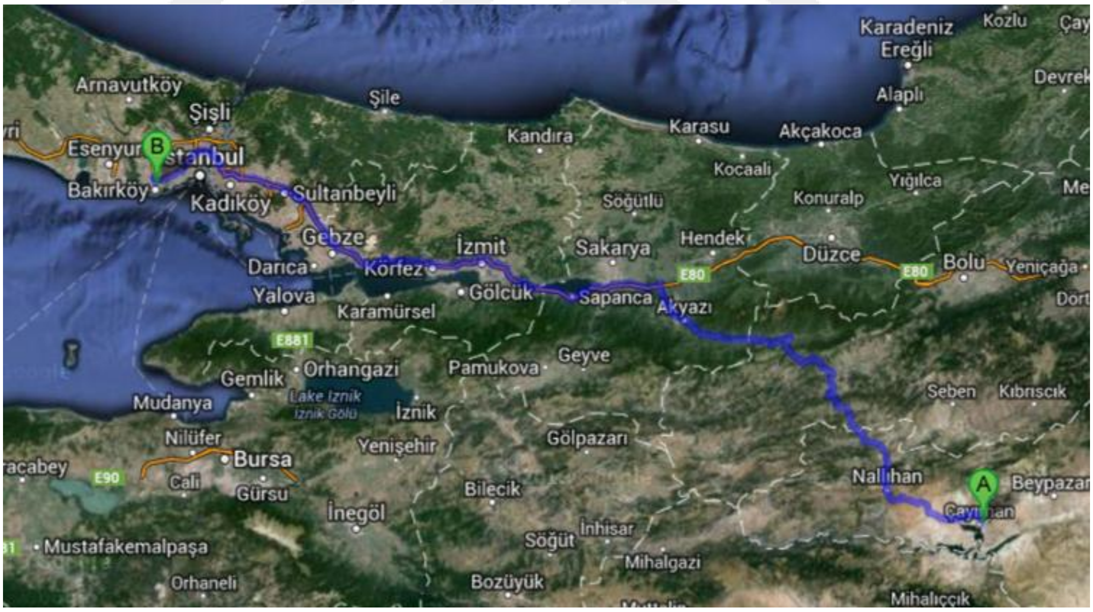

Figure 8.2: Çayırhan Park thermal power plant location (Google Map, 2013).

In the first delivery scenario, hydrogen is compressed and delivered 330 km by pipelines from the coal to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks. Three delivery scenarios for

Çayırhan Park thermal power plant are presented in Table 8.10, Table 8.11, and Table 8.12.

Table 8.10: Delivery scenario 1 (combined delivery with pipeline and truck) for coal to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Pipeline (330 km)	Inv. Cost	37.30	13.05
	Fixed O&M	1.86	0.65
	Var. O&M	0.93	0.33
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	110.35	58.23

In the second delivery scenario, hydrogen is compressed and delivered 330 km by gaseous tube trailers from the coal to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.11: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for coal to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Tube Trailer (330 km)	Inv. Cost	44.78	24.63
	Fixed O&M	2.24	1.23
	Var. O&M	1.12	0.62
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	118.39	70.68

In the third delivery scenario, hydrogen is liquefied and delivered 330 km by liquid hydrogen trucks from the coal to hydrogen production plant to the fueling stations directly.

Table 8.12: Delivery scenario 3 (Truck delivery in liquid form) for coal to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-330 km)	Inv. Cost	10.66	10.66
	Fixed O&M	0.53	0.53
	Var. O&M	0.27	0.27
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	41.63	29.30

The location of Ambarlı natural gas thermal power plant is suitable place for a natural gas to hydrogen production plant. The location is approximately 22 km far from Istanbul Atatürk international airport.

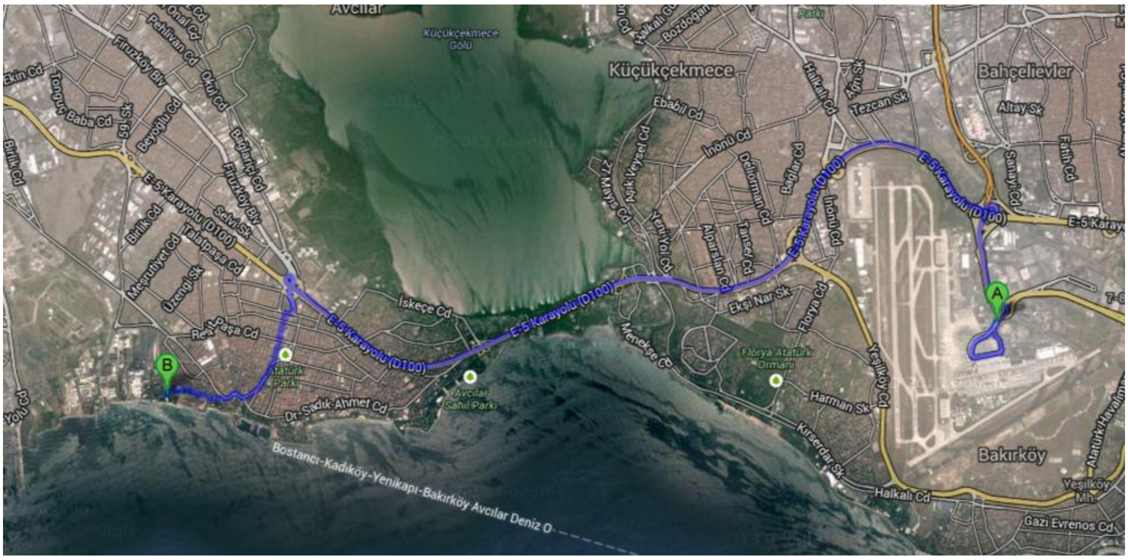

Figure 8. 3: Ambarlı natural gas thermal power plant location (Google Map, 2013).

Three delivery scenarios for Ambarlı natural gas thermal power plant are presented in Table 8.13, Table 8.14, and Table 8.15.

In the first delivery scenario, hydrogen is compressed and delivered 22 km by pipelines from the coal to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.13: Delivery scenario 1 (combined delivery with pipeline and truck) for natural gas to hydrogen production.

$\$_{2010}/GJ_{output}$	**Costs**	**2010**	**2040**
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Pipeline (22 km)	Inv. Cost	22.77	7.97
	Fixed O&M	1.14	0.40
	Var. O&M	0.57	0.20
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	94.73	52.77

In the second delivery scenario, hydrogen is compressed and delivered 22 km by gaseous tube trailers from the natural gas to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.14: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for natural gas to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Tube Trailer (22 km)	Inv. Cost	27.23	14.98
	Fixed O&M	1.36	0.75
	Var. O&M	0.68	0.37
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	99.52	60.30

In the third delivery scenario, hydrogen is liquefied and delivered 22 km by liquid hydrogen trucks from the natural gas to hydrogen production plant to the fueling stations directly.

Table 8.15: Delivery scenario 3 (Truck delivery in liquid form) for natural gas to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-22 km)	Inv. Cost	7.60	7.60
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	38.35	26.02

The location of Kemerburgaz-Ekolojik Enerji biomass thermal power plant is appropriate location for a biomass to hydrogen production plant. The distance between its location and Istanbul Atatürk international airport is around 32 km.

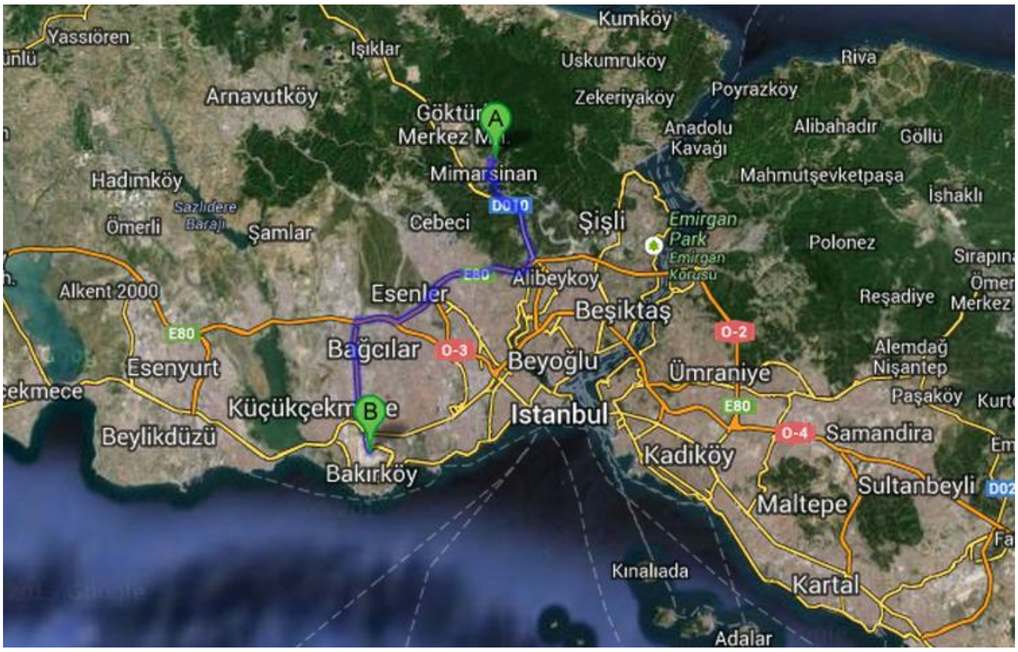

Figure 8.4: Kemerburgaz, Ekolojik Enerji Biomass and Waste Thermal Power Plant location (Google Map, 2013).

Three delivery scenarios for Kemerburgaz-Ekolojik Enerji biomass thermal power plant are presented in Table 8.16, Table 8.17, and Table 8.18.

In the first delivery scenario, hydrogen is compressed and delivered 32 km by pipelines from the biomass to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.16: Delivery scenario 1 (combined delivery with pipeline and truck) for biomass to hydrogen production.

$\$_{2010}/GJ_{output}$	**Costs**	**2010**	**2040**
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Pipeline (450 km)	Inv. Cost	23.14	8.10
	Fixed O&M	1.16	0.40
	Var. O&M	0.58	0.20
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	95.13	52.91

In the second delivery scenario, hydrogen is compressed and delivered 32 km by gaseous tube trailers from the biomass to hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.17: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for biomass gas to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Tube Trailer (450 km)	Inv. Cost	27.67	15.22
	Fixed O&M	1.38	0.76
	Var. O&M	0.69	0.38
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	100.00	60.56

In the third delivery scenario, hydrogen is liquefied and delivered 32 km by liquid hydrogen trucks from the biomass to hydrogen production plant to the fueling stations directly.

Table 8.18: Delivery scenario 3 (Truck delivery in liquid form) for biomass to hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-450 km)	Inv. Cost	7.69	7.69
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	38.44	26.11

Alibey Dam is approximately 24 km far from Istanbul Atatürk airport and it is a suitable location for an electrolysis hydrogen production plant.

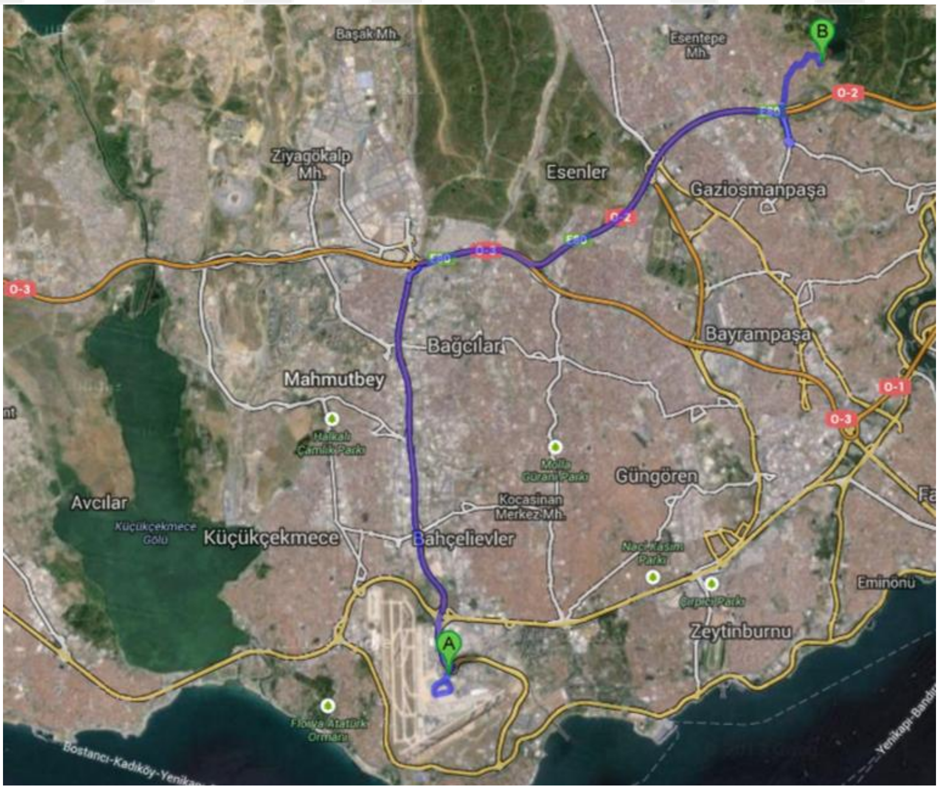

Figure 8.5: Alibey Dam location (Google Map, 2013).

Three delivery scenarios for Alibey Dam are presented in Table 8.19, Table 8.20, and Table 8.21. In the first delivery scenario, hydrogen is compressed and delivered 24 km by pipelines from the electrolysis hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.19: Delivery scenario 1 (combined delivery with pipeline and truck) for electrolysis hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Pipeline (68 km)	Inv. Cost	22.84	7.99
	Fixed O&M	1.14	0.40
	Var. O&M	0.57	0.20
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	94.81	52.80

In the second delivery scenario, hydrogen is compressed and delivered 24 km by gaseous tube trailers from the electrolysis hydrogen production plant to the liquefaction terminal at the border of the airport. After liquefaction process, liquid hydrogen is delivered 10 km to the fueling stations by liquid hydrogen trucks.

Table 8.20: Delivery scenario 2 (truck delivery in gaseous and liquid forms) for electrolysis hydrogen production.

$\$_{2010}/GJ_{output}$	**Costs**	**2010**	**2040**
Compression (Production Plant)	Inv. Cost	30.20	17.26
	Fixed O&M	1.21	0.69
	Var. O&M	0.60	0.34
Tube Trailer (68 km)	Inv. Cost	27.31	15.02
	Fixed O&M	1.37	0.75
	Var. O&M	0.68	0.38
Liquefaction (Terminal)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-10 km)	Inv. Cost	7.51	7.51
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	99.62	60.35

In the third delivery scenario, hydrogen is liquefied and delivered 24 km by liquid hydrogen trucks from electrolysis hydrogen production plant to the fueling stations directly.

Table 8.21: Delivery scenario 3 (Truck delivery in liquid form) for electrolysis hydrogen production.

$\$_{2010}/GJ_{output}$	Costs	2010	2040
Liquefaction (Production Plant)	Inv. Cost	25.10	14.34
	Fixed O&M	1.00	0.57
	Var. O&M	0.50	0.29
Truck (Liquid-68 km)	Inv. Cost	7.62	7.62
	Fixed O&M	0.38	0.38
	Var. O&M	0.19	0.19
Fueling Station (LH_2)	Inv. Cost	3.32	2.46
	Fixed O&M	0.17	0.12
	Var. O&M	0.08	0.06
Delivery Cost	Total	38.37	26.04

Current and future life time and efficiency values for truck, tube trailer, pipeline, liquefier and fueling station can be found in Table 5.14. LH2 fueling station lifetime is considered as the same of gaseous fueling station (Doods & McDowall, 2012).

8.4.3 Hydrogen Aircraft Utilization Costs for Istanbul

Hydrogen airplane costs can be considered as globally fixed for transition to hydrogen air transportation. Conversion of conventional aircraft has taught to have no effect on local economical values. The only effect, which is production costs of hydrogen as aviation fuel, can be assumed as approximately calculated in direct operating costs of aircraft.

The investment costs of airplanes comparison can be seen in US Dollar in Table 8.24.

Table 8.22: Investment costs of kerosene plane and hydrogen plane (IEA, 2005).

Investment cost per passenger.km	Unit	Cost
Kerosene plane	($\$_{2010}$/1000 pkm)	89.7
Hydrogen plane	($\$_{2010}$/1000 pkm)	100.9

Fuel and capital cost comparison of airplanes can be seen in Table 8.25.

Table 8. 23: Fuel and capital costs per seat occupied of kerosene plane and hydrogen plane (IEA, 2005).

Fuel and capital per seat occupied	Unit	Cost
Kerosene plane	($\$_{2010}$/seat)	56,100
Hydrogen plane	($\$_{2010}$/seat)	224,401

Cost per seat occupied for airplanes can be seen in Table 8.26.

Table 8.24: Costs per seat occupied of kerosene plane and hydrogen plane with load factor (IEA, 2005).

Cost per seat occupied	Unit	Cost
Kerosene plane	($\$_{2010.}$1000/seat)	628.3
Hydrogen plane	($\$_{2010}$.1000/seat)	774.2

Efficiencies for both of kerosene and hydrogen airplanes can be seen in Table 8.27.

8.4.4 Conclusions

In this part of the study, hydrogen lifecycle is examined for Istanbul and it is concluded that the lowest-cost option for hydrogen production and hydrogen delivery to Istanbul Atatürk airport is the production of hydrogen from natural gas reforming without CCS technology and deliver the hydrogen by liquid hydrogen trucks.

Table 8.25: The lowest-cost option of hydrogen Production and Delivery.

Hydrogen Production Method	Production Technology	Delivery Technology	Production+Delivery Cost ($\$_{2010}/GJ_{output}$)	
			2010	**2040**
Coal Gasification	With CCS	Pipeline+LH_2 Truck	313.89	184.96
		Tube Trailer+ LH_2 Truck	321.93	197.41
		LH_2 Truck	245.17	156.03
	Without CCS	Pipeline+LH_2 Truck	281.1	152.96
		Tube Trailer+ LH_2 Truck	289.14	165.41
		LH_2 Truck	212.38	124.03
Natural Gas Reforming	With CCS	Pipeline+LH_2 Truck	206.09	121.48
		Tube Trailer+ LH_2 Truck	210.88	129.01
		LH_2 Truck	149.71	94.73
	Without CCS	Pipeline+LH_2 Truck	178.77	110.46
		Tube Trailer+ LH_2 Truck	183.56	117.99
		LH_2 Truck	122.39	83.71
Biomass Gasification	-	Pipeline+LH_2 Truck	246.89	125.01
		Tube Trailer+ LH_2 Truck	251.76	132.66
		LH_2 Truck	190.2	98.21
Electrolysis	-	Pipeline+LH_2 Truck	586.72	217.42
		Tube Trailer+ LH_2 Truck	591.53	224.97
		LH_2 Truck	530.28	190.66

In the comparison of hydrogen production and delivery costs, it is estimated that, the cost of hydrogen production form natural gas without CCS and delivery by liquid hydrogen trucks is 12.39 \$2010/GJoutput for 2010 and it will decrease to 83.71\$2010/GJoutput in 2040. Additionally, the production and delivery costs, the costs of hydrogen utilization in aircrafts are projected to be 774.2 \$2010.1000/seat in 2040 whereas the cost of kerosene aircrafts is 628.32010.1000/seat in 2040.

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APPENDIX A (Costs of Hydrogen Production)

Table A 1: Investment costs of hydrogen production from coal gasification without carbon capture technology in literature.

Technology	Investment Cost (ZAR_{2007}/kW)	Capacity (kW)	Innvest-ment Cost in Source	Investment Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
CG without Seq.	**8,123**	**429,861**	495	$m	309,500	kg_{H2}/d	1998	(Bartels, Pate, & Olson, 2010)
CG without Seq.	**7,501**	**1,070,417**	1,138.2	$m	770,700	kg_{H2}/d	2002	(Bartels, Pate, & Olson, 2010)
Coal Gasification	**8,875**	**208,333**	247.4	$m	150	tonne/d	2004	(Ewan & Allen, 2005)
Coal Gasification	**5,313**	**354,722**	489.2	€/kW	255,400	kg_{H2}/d	2005	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
CG without Seq.	**9,728**	**2,000,000**	550	$m	2	GW	2005	(Bartels, Pate, & Olson, 2010)
Coal Gasification	**7,403**	**450,000**	834	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**9,331**	**388,889**	1.98	$/GJ	280	tonne/d	2007	(Gül, 2008)
Coal Gasification	**6,221**	**1,666,667**	1.76	$/GJ	1,200	tonne/d	2007	(Gül, 2008)
Coal Gasification	**12,441**	**208,333**	3.52	$/GJ	150	tonne/d	2007	(Gül, 2008)
Coal Gasification	**12,653**	**209,722**	3.58	$/GJ	151	tonne/d	2007	(Gül, 2008)
Coal Gasification	**12,441**	**211,111**	3.52	$/GJ	152	tonne/d	2007	(Gül, 2008)
Coal Gasification	**7,557**	**434,722**	4.51	$/GJ	313	tonne/d	2007	(Gül, 2008)
Coal Gasification	**7,775**	**400,000**	4.64	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
Coal Gasification	**6,820**	**397,139**	4.07	$/GJ	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
Coal Gasification	**6,818**	**450,000**	768	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**8,962**	**250,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**8,044**	**400,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**7,476**	**550,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**6,764**	**850,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**9,434**	**200,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**7,642**	**500,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**7,072**	**700,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)

Table A 2: Investment costs of hydrogen production from coal gasification without carbon capture technology in literature (Cont.).

Coal Gasification	**6,374**	**1,100,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**5,935**	**1,500,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**5,692**	**1,800,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**1,560**	**500,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**1,212**	**1,500,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**1,134**	**2,000,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**3,837**	**10,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**2,592**	**55,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**1,926**	**200,000,000**	-	-	-	-[1]	2020	(Konda, Shah, & Brandon, 2011)
Coal Gasification	**12,300**	**388,889**	2.61	$/GJ	280	tonne/d	2025	(Gül, 2008)
Coal Gasification	**4,701**	**1,666,667**	1.33	$/GJ	1,200	tonne/d	2025	(Gül, 2008)
Coal Gasification	**7,964**	**425,000,000**	474	Billion $	6	Mboe/d	2030	(Mason, 2007)
Advanced CG	**5,119**	**1,000,000**	600	€/kW	1,000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)

Table A 3: Investment costs of hydrogen production from coal gasification with carbon capture technology in literature.

Technology	Investment Cost (ZAR_{2007}/kW)	Capacity (kW)	Invest-ment Cost in Source	Invest-ment Cost Unit in Source	Capacity in Source	Capacity Unit in Sources	Year	Source
CG with Seq.	10,163	492,222	1374.5	$m	354,400	kg_{H2}/d	1998	(Bartels, Pate, & Olson, 2010)
Adv. CG with CCS	19,698	390,417	562.5	$m	281,100	kg_{H2}/d	1998	(Bartels, Pate, & Olson, 2010)
CG with Seq.	7,905	1,070,417	1199.5	$m	770,700	kg_{H2}/d	2002	(Bartels, Pate, & Olson, 2010)
CG with Seq.	11,231	384,583	612.3	$m	276,900	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
CG with CCS	8,495	450,000	745	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Adv. CG with CCS	6,613	450,000	957	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	8,981	388,889	2.28	$/GJ	280	tonne/d	2007	(Dincer, 2012)
CG with CCS	10,745	1,666,667	1.8	$/GJ	1,200	tonne/d	2007	(Gül, 2008)
CG with CCS	8,512	400,000	4.64	$/GJ	400	MW	2007	(Gül, 2008)
CG with CCS	7,289	441,389	5.36	$/GJ	317.8	tonne/d	2007	(Gül, 2008)
CG with CCS	7,775	794,278	4.35	$/GJ	6.8	Mil. Nm^3/d	2007	(Gül, 2008)
CG with CCS	8,445	397,139	5.08	$/GJ	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
CG with CCS	6,362	400,000	5.04	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
CG-Selexol (CCS)	16,461	1,000,000	1640	€/kW_{H2}	1,000	MW_{H2}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
CG with CCS	7,812	450,000	522	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Adv. CG with CCS	4,634	450,000	880	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	5,593	2,000,000	579	€/kW	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
CG with CCS	13,195	388,889	2.8	US$/GJ	280	tonne/d	2025	(Gül, 2008)
CG with CCS	6,552	1,666,667	1.36	US$/GJ	1,200	tonne/d	2025	(Gül, 2008)
CG with CCS	6,686	502,264	3.99	$/GJ	4.3	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	6,418	441,389	3.83	$/GJ	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	8,579	441,389	5.12	$/GJ	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	7,222	794,278	4.31	$/GJ	6.8	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	4,807	397,139	3.91	$/GJ	3.4	Mil. Nm^3/d	2025	(Gül, 2008)
Adv. CG-Selexol (CCS)	6,015	1,000,000	600	€/kW_{H2}	1,000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)

Table A 4: Fixed operation and maintenance costs of hydrogen production from coal gasification without carbon capture technology in literature.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Coal Gasification	**241.5**	**2,000,000**	25	€/kW/a	2	GW	2005	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Coal Gasification	**234.4**	**450,000**	17,310	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**509.0**	**388,889**	1.8	$/GJ	280	tonne/d	2007	(Gül, 2008)
Coal Gasification	**311.0**	**1,666,667**	1.1	$/GJ	1,200	tonne/d	2007	(Gül, 2008)
Coal Gasification	**619.2**	**208,333**	2.19	$/GJ	150	tonne/d	2007	(Gül, 2008)
Coal Gasification	**630.6**	**209,722**	2.23	$/GJ	151	tonne/d	2007	(Gül, 2008)
Coal Gasification	**619.2**	**211,111**	2.19	$/GJ	152	tonne/d	2007	(Gül, 2008)
Coal Gasification	**243.8**	**434,722**	0.97	$/GJ	313	tonne/d	2007	(Gül, 2008)
Coal Gasification	**263.9**	**400,000**	1.05	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
Coal Gasification	**444.9**	**397,139**	1.77	$/GJ	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
Coal Gasification	**224.8**	**450,000**	16,290	1000€/a	450	MW_{th}	2020	(Gül, 2008)
Coal Gasification	**687.1**	**388,889**	2.43	$/GJ	280	tonne/d	2025	(Gül, 2008)
Coal Gasification	**234.7**	**1,666,667**	0.83	$/GJ	1,200	tonne/d	2025	(Gül, 2008)
Advanced CG	**204.8**	**1,000,000**	24	€/kW	1,000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)

Table A 5: Fixed operation and maintenance costs of hydrogen production from coal gasificationwith carbon capture technology in literature.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
CG with CCS	591.8	450,000	44,850	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Adv. CG with CCS	462.9	450,000	35,760	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	523.1	1,666,667	1.85	$/GJ	1200	tonne/d	2007	(Gül, 2008)
CG with CCS	316.7	400,000	1.12	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
CG with CCS	263.9	794,278	1.05	$/GJ	6.8	Mil. Nm^3/d	2007	(Gül, 2008)
CG with CCS	263.9	388,889	1.05	$/GJ	280	tonne/d	2007	(Gül, 2008)
CG with CCS	248.8	441,389	0.99	$/GJ	317.8	tonne/d	2007	(Gül, 2008)
CG with CCS	540.4	400,000	2.15	$/GJ	400	MW	2007	(Gül, 2008)
CG with CCS	465.0	397,139	1.85	$/GJ	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
CG-Selexol (CCS)	657.7	1,000,000	65.6	€/kW_{H2}	1000	MW_{H2}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
CG with CCS	433.0	450,000	33,100	1000€/a	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Advanced CG with CCS	312.4	450,000	23,740	1000€/a	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	251.1	2,000,000	26	€/kW/a	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
CG with CCS	706.9	388,889	2.5	$/GJ	280	tonne/d	2025	(Gül, 2008)
CG with CCS	240.3	397,139	0.85	$/GJ	3.4	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	208.6	441,389	0.83	$/GJ	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	276.5	441,389	1.1	$/GJ	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	248.8	794,278	0.99	$/GJ	6.8	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	377.0	1,666,667	1.5	$/GJ	1200	tonne/d	2025	(Gül, 2008)

Table A 6: Variable operation and maintenance costs of hydrogen production from coal gasification without carbon capture technology in literature.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Coal Gasification	**1.4**	**450,000**	38	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**2.7**	**388,889**	0.27	$/GJ	280	tonne/d	2007	(Gül, 2008)
Coal Gasification	**2.0**	**1,666,667**	0.2	$/GJ	1,200	tonne/d	2007	(Gül, 2008)
Coal Gasification	**3.9**	**208,333**	0.39	$/GJ	150	tonne/d	2007	(Gül, 2008)
Coal Gasification	**4.0**	**209,722**	0.4	$/GJ	151	tonne/d	2007	(Gül, 2008)
Coal Gasification	**3.9**	**211,111**	0.39	$/GJ	152	tonne/d	2007	(Gül, 2008)
Coal Gasification	**1.2**	**450,000**	36	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**1.9**	**388,889**	0.19	$/GJ	280	tonne/d	2025	(Gül, 2008)
Coal Gasification	**1.5**	**1,666,667**	0.15	$/GJ	1,200	tonne/d	2025	(Gül, 2008)

Table A 7: Variable operation and maintenance costs of hydrogen production from coal gasification with carbon capture technology in literature.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
CG with CCS	**4.7**	**450,000**	100	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Advanced CG with CCS	**3.9**	**450,000**	79	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	**6.6**	**388,889**	0.66	$/GJ	280	tonne/d	2007	(Gül, 2008)
CG with CCS	**2.0**	**400,000**	0.2	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
CG with CCS	**3.7**	**450,000**	74	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Advanced CG with CCS	**2.5**	**450,000**	53	1000€/MW_{th}	450	$MW_{th\ 2}$	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	**7.3**	**388,889**	0.73	$/GJ	280	tonne/d	2025	(Gül, 2008)
CG with CCS	**1.5**	**1,666,667**	0.15	$/GJ	1200	tonne/d	2025	(Gül, 2008)

Table A 8: Efficiencies of hydrogen production from coal gasification without carbon capture technology in literature.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
Coal Gasification	**59.0**	**208,333**	150	tonne/d	2004	(Ewan & Allen, 2005)
Coal Gasification	**51.0**	**450,000**	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Coal Gasification	**54.0**	**450,000**	450	MW_{th}	2020	(Mueller-Langer, Tzimas, Kaltschmitt, & Peteves, 2007)
Advanced CG	**69.0**	**1,000,000**	1,000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)
Coal Gasification	**70.5**	**2,000,000**	2	GW	2005	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Coal Gasification	**53.8**	**388,889**	280	tonne/d	2007	(Gül, 2008)
Coal Gasification	**75.2**	**1,666,667**	1,200	tonne/d	2007	(Gül, 2008)
Coal Gasification	**64.1**	**208,333**	150	tonne/d	2007	(Gül, 2008)
Coal Gasification	**64.1**	**209,722**	151	tonne/d	2007	(Gül, 2008)
Coal Gasification	**64.1**	**211,111**	152	tonne/d	2007	(Gül, 2008)
Coal Gasification	**56.2**	**434,722**	313	tonne/d	2007	(Gül, 2008)
Coal Gasification	**51.3**	**400,000**	400	MW_{H2}	2007	(Gül, 2008)
Coal Gasification	**51.3**	**397,139**	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
Coal Gasification	**80.0**	**1,666,667**	1,200	tonne/d	2025	(Gül, 2008)

Table A 9: Efficiencies of hydrogen production from coal gasification with carbon capture technology in literature.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
CG with CCS	**59.2**	**388,889**	280	tonne/d	2007	(Gül, 2008)
CG with CCS	**75.2**	**1,666,667**	1,200	tonne/d	2007	(Gül, 2008)
CG with CCS	**51.0**	**794,278**	6.8	Mil. Nm^3/d	2007	(Gül, 2008)
CG with CCS	**57.5**	**434,722**	313.8	tonne/d	2007	(Gül, 2008)
CG with CCS	**57.8**	**794,278**	6.8	Mil. Nm^3/d	2007	(Gül, 2008)
CG with CCS	**46.5**	**400,000**	400	MW	2007	(Gül, 2008)
CG with CCS	**67.1**	**397,139**	3.4	Mil. Nm^3/d	2007	(Gül, 2008)
CG-Selexol(CCS)	**62.0**	**1,000,000**	1,000	MW_{H2}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
CG with CCS	**49.0**	**450,000**	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Advanced CG-with CCS	**66.0**	**450,000**	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
CG with CCS	**70.5**	**2,000,000**	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
CG with CCS	**47.2**	**1,666,667**	1,200	tonne/d	2025	(Gül, 2008)
CG with CCS	**80.0**	**400,000**	400	MW_{H2}	2025	(Gül, 2008)
CG with CCS	**67.1**	**502,264**	4.3	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	**69.0**	**513,944**	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	**69.0**	**434,722**	317.8	tonne/d	2025	(Gül, 2008)
CG with CCS	**58.5**	**794,278**	6.8	Mil. Nm^3/d	2025	(Gül, 2008)
CG with CCS	**61.7**	**400,000**	400	MW	2025	(Gül, 2008)
Advanced CG-Selexol(CCS)	**69.0**	**1,000,000**	1,000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)

Table A 10: Investment costs of hydrogen production from natural gas reforming without carbon capture technology in literature.

Technology	Investment Cost (ZAR_{2007}/kW)	Capacity (kW)	Investment Cost in Source	Investment Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
SMR	**23688.9**	**328**	94.4	\$m	236.24	kg_{H2}/d	1998	(Bartels, Pate, & Olson, 2010)
Natural Gas Ref.	**4366.1**	**2,000,000**	452	€/kW	2	GW	2000	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
SMR	**2245.6**	**208,333**	62.6	\$m	150	tonne/d	2004	(Ewan & Allen, 2005)
SMR	**30286.5**	**474**	202.8	\$m	341.448	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
Steam Reforming	**2956.0**	**450,000**	333	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Steam Ref. (Small Scale)	**8637.3**	**3,000**	973	1000€/MW_{th}	3	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	**287.5**	**527,778**	0.61	\$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**2694.1**	**1,666,667**	0.7	\$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**5811.5**	**33,333**	1.51	\$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**3145.7**	**208,333**	0.89	\$/GJ	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**2299.8**	**580,278**	1.22	\$/GJ	417.8	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**3242.3**	**338,736**	1.72	\$/GJ	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**3166.9**	**327,056**	1.68	\$/GJ	2.8	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**3166.9**	**338,736**	1.68	\$/GJ	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**3374.2**	**782,597**	1.79	\$/GJ	6.7	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**3166.9**	**2,791,653**	1.68	\$/GJ	23.9	Mil. Nm^3/d	2007	(Gül, 2008)
Steam Ref.	**2796.3**	**450,000**	315	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Steam Ref. (Small Scale)	**8193.5**	**3,000**	923	1000€/MW_{th}	3	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
SMR	**8169.7**	**200,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**6497.2**	**500,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**5690.0**	**850,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**5463.4**	**1,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**5167.0**	**1,250,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**4857.8**	**1,600,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**4460.9**	**2,250,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**4344.9**	**2,500,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**1727.7**	**100,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**1155.4**	**500,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
SMR	**817.0**	**2,000,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)

Table A 11: Investment costs of hydrogen production from natural gas reforming without carbon capture technology in literature (Cont.).

Natural Gas Ref.	**2167.8**	**527,778**	0.46	\$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	**1924.3**	**1,666,667**	0.5	\$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	**4618.4**	**33,333**	1.2	\$/GJ	24	tonne/d	2025	(Gül, 2008)
Advanced ATR	**2388.9**	**1,000,000**	280	€/kW$_{H2}$	1000	MW$_{H2}$	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)
Membrane Ref.	**5204.3**	**2,000**	610	€/kW$_{H2}$	2	MW$_{H2}$	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)

Table A 12: Investment costs of hydrogen production from natural gas reforming with carbon capture technology in literature.

Technology	Investment Cost (ZAR2007/kW)	Capacity (kW)	Investment Cost in Source	Investment Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
SMR with Seq.	**37947.8**	**474**	254.1	$m	341.448	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
SMR with Seq.	**3373.3**	**450,000**	380	1000€/MWth	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	**3628.7**	**527,778**	0.77	$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**3393.1**	**1,666,667**	0.96	$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**7928.2**	**33,333**	2.06	$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**4656.9**	**208,333**	1.21	$/GJ	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**3900.0**	**400,000**	1.9	$/GJ	400	MW_{th}	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**2791.6**	**580,278**	1.36	$/GJ	417.8	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**3612.6**	**2,791,653**	1.76	$/GJ	23.9	Mil. Nm^3/d	2007	(Gül, 2008)
SMR -MEA (CCS)	**5514.0**	**1,000,000**	550	€/kWH2	1000	MW_{H2}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
Steam Ref. with CCS	**3204.6**	**450,000**	361	1000€/MWth	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	**4559.3**	**2,000,000**	472	€/kW	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Natural Gas Ref. with CCS	**3181.6**	**527,778**	0.62	$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**2501.6**	**1,666,667**	0.65	$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**6196.3**	**33,333**	1.61	$/GJ	24	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**3287.1**	**208,333**	0.93	$/GJ	150	tonne/d	2025	(Gül, 2008)
MR with Membrane (CCS)	**6115.6**	**1,000,000**	610	€/kWH2	1000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
Advanced ATR-MDEA (CCS)	**2807.1**	**1,000,000**	280	€/kWH2	1000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)

Table A 13: Fixed operation and maintenance costs of hydrogen production from natural gas reforming without carbon capture technology in literature.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Natural Gas Ref.	**202.9**	**2,000,000**	21	€/kW/a	2	GW	2000	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Steam Ref.	**112.7**	**450,000**	7930	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	**113.1**	**527,778**	0.4	$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**132.4**	**1,666,667**	0.43	$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**289.4**	**33,333**	0.94	$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**158.3**	**208,333**	0.56	$/GJ	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**101.8**	**580,278**	0.36	$/GJ	417.8	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**161.2**	**338,736**	0.57	$/GJ	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**135.7**	**327,056**	0.48	$/GJ	2.8	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**121.6**	**338,736**	0.43	$/GJ	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**67.9**	**782,597**	0.24	$/GJ	6,7	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**181.0**	**2,791,653**	0.64	$/GJ	23,9	Mil. Nm^3/d	2007	(Gül, 2008)
Steam Reforming	**107.6**	**450,000**	7680	1000€/a	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	**96.1**	**527,778**	0.34	$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	**95.4**	**1,666,667**	0.31	$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	**230.9**	**33,333**	0.75	$/GJ	24	tonne/d	2025	(Gül, 2008)
Advanced ATR	**95.6**	**1,000,000**	11.2	€/kW_{H2}	1000	MW_{H2}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)

Table A 14: Fixed operation and maintenance costs of hydrogen production from natural gas reforming with carbon capture technology in literature.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Steam ref. with CCS	**267.9**	**450,000**	19,440	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	**144.2**	**527,778**	0.51	$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**169.7**	**1,666,667**	0.6	$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**394.1**	**33,333**	1.28	$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**230.9**	**208,333**	0.75	$/GJ	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**227.8**	**400,000**	0.74	$/GJ	400	MW_{H2}	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**153.9**	**580,278**	0.5	$/GJ	417.8	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	**197.1**	**2,791,653**	0.64	$/GJ	23.9	Mil. Nm^3/d	2007	(Gül, 2008)
SMR -MEA (CCS)	**220.6**	**1,000,000**	22	€/kW_{H2}	1000	MW_{H2}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
Steam ref. with CCS	**214.5**	**450,000**	15,540	1000€/a	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	**202.9**	**2,000,000**	21	€/kW/a	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Natural Gas Ref. with CCS	**135.5**	**527,778**	0.44	$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**126.2**	**1,666,667**	0.41	$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**311.0**	**33,333**	1.01	$/GJ	24	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	**164.0**	**208,333**	0.58	$/GJ	150	tonne/d	2025	(Gül, 2008)

Table A 15: Variable operation and maintenance costs of hydrogen production from natural gas reforming without carbon capture technology in literature.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Steam Ref. (Small Scale)	5.8	3,000	208	1000€/MW_{th}	3	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	2.2	527,778	0.22	$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	0.8	1,666,667	0.08	$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	1.8	33,333	0.18	$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	1.0	208,333	0.1	$/GJ	150	tonne/d	2007	(Gül, 2008)
Steam Ref.	1.1	450,000	18	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Steam Ref.	1.0	450,000	17	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Steam Ref. (Small Sale)	5.8	3,000	207	1000€/MW_{th}	3	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	2.2	527,778	0.22	$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	0.6	1,666,667	0.06	$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	1.5	33,333	0.15	$/GJ	24	tonne/d	2025	(Gül, 2008)

Table A 16: Variable operation and maintenance costs of hydrogen production from natural gas reforming with carbon capture technology in literature.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Steam Ref. with CCS	2.7	450,000	43	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	5.7	527,778	0.57	$/GJ	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	1.1	1,666,667	0.11	$/GJ	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	2.5	33,333	0.25	$/GJ	24	tonne/d	2007	(Gül, 2008)
Natural Gas ref. with CCS	1.4	208,333	0.14	$/GJ	150	tonne/d	2007	(Gül, 2008)
Steam Ref. with CCS	2.3	450,000	35	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref. with CCS	5.7	527,778	0.57	$/GJ	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	0.7	1,666,667	0.07	$/GJ	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	2.0	33,333	0.2	$/GJ	24	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	1.0	208,333	0.1	$/GJ	150	tonne/d	2025	(Gül, 2008)

Table A 17: Efficiencies of hydrogen production from natural gas reforming without carbon capture technology in literature.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
Steam Ref.	**59.0**	**233,611**	2	Mil. Nm^3/d	2000	(Spath & Margaret, 2001)
Natural Gas Ref.	**70.0**	**2,000,000**	2	GW	2000	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
SMR	**76.0**	**208,333**	150	tonne/d	2004	(Ewan & Allen, 2005)
Steam Ref.	**75.0**	**450,000**	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	**73.5**	**527,778**	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**76.3**	**1,666,667**	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**71.9**	**33,333**	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**76.3**	**208,333**	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**69.9**	**580,278**	417.8	tonne/d	2007	(Gül, 2008)
Natural Gas Ref.	**74.1**	**338,736**	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**74.1**	**327,056**	2.8	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**74.1**	**338,736**	2.9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**74.1**	**782,597**	6,7	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**84.7**	**2,791,653**	23,9	Mil. Nm^3/d	2007	(Gül, 2008)
Natural Gas Ref.	**73.7**	**2,000,000**	2	GW	2010	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Steam Ref.	**79.0**	**450,000**	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Natural Gas Ref.	**73.5**	**527,778**	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref.	**80.0**	**1,666,667**	1200	tonne/d	2025	(Gül, 2008)
Advanced ATR	**74.0**	**1,000,000**	1000	MW_{th}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2007)

Table A 18: Efficiencies of hydrogen production from natural gas reforming with carbon capture technology in literature.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
Natural Gas Ref. with CCS	73.5	527,778	380	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	71.9	1,666,667	1200	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	69.0	33,333	24	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	65.4	208,333	150	tonne/d	2007	(Gül, 2008)
Natural Gas Ref. with CCS	75.2	400,000	400	MW_{th}	2007	(Gül, 2008)
Natural Gas Ref. with CCS	76.3	580,278	417.8	tonne/d	2007	(Gül, 2008)
SMR -MEA (CCS)	73.0	1,000,000	1000	MW_{th}	2010	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)
Natural Gas Ref. with CCS	72.8	2,000,000	2	GW	2010	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Natural Gas Ref. with CCS	70.0	2,000,000	2	GW	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Natural Gas Ref. with CCS	73.5	527,778	380	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	78.1	1,666,667	1200	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	71.9	33,333	24	tonne/d	2025	(Gül, 2008)
Natural Gas Ref. with CCS	75.8	208,333	150	tonne/d	2025	(Gül, 2008)
Advanced ATR-MDEA(CCS)	74.0	1,000,000	1000	MW_{th}	2030	(Damen K. , van Troost, Faaij, & Turkenburg, 2006)

Table A 19: Investment costs of hydrogen production from biomass gasification.

Technology	Investment Cost (ZAR_{2007}/kW)	Capacity (kW)	Investment Cost in Source	Investment Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Gasification (Low Estimate)	**6,315.13**	**269,640**	241.4	\$m	194	kg_{H2}/d	1992	(Bartels, Pate, & Olson, 2010)
Gasification (High Estimate)	**22,606.78**	**2,746**	8.8	\$m	1977	kg_{H2}/d	1995	(Bartels, Pate, & Olson, 2010)
Solar Biomass (Via Gas.)	**33,630.00**	**8,333**	37.5	\$m	6	tonne /d	2004	(Ewan & Allen, 2005)
Gasification	**6,089.49**	**194,028**	167.5	\$m	140	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
Gasification	**8,273.38**	**450,000**	932	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**584.37**	**215,278**	1.24	\$/GJ	155	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**3,279.99**	**33,333**	9.28	\$/GJ	24	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**1,297.15**	**208,333**	3.67	\$/GJ	150	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**1,307.76**	**209,722**	3.7	\$/GJ	151	tonne /d	2007	(Gül, 2008)
Gasification	**6,409.21**	**450,000**	722	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**5,795.76**	**400,000**	600	€/kW	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification with CCS	**6,066.23**	**400,000**	628	€/kW	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification	**23,344.54**	**3,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**11,553.76**	**50,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**8,169.74**	**200,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**7,103.11**	**350,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**1,561.14**	**150,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**1,373.98**	**250,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**1,210.47**	**415,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Biomass Gasification	**494.83**	**215,278**	1.05	\$/GJ	155	tonne /d	2025	(Gül, 2008)
Biomass Gasification	**1,597.58**	**33,333**	4.52	\$/GJ	24	tonne /d	2025	(Gül, 2008)
Cellulosic Bio.Gasification	**7,964.16**	**450,000**	474	Billion \$	450	MW_{th}	2030	(Mason, 2007)

Table A 20: Fixed operation and maintenance costs of hydrogen production from biomass gasification.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Gasification	**101.53**	**450,000**	17,380	1000€/a	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**412.83**	**215,278**	1.46	$/GJ	155	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**1,634.34**	**33,333**	5.78	$/GJ	24	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**647.52**	**208,333**	2.29	$/GJ	150	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**650.34**	**209,722**	2.3	$/GJ	151	tonne /d	2007	(Gül, 2008)
Gasification	**53.76**	**450,000**	14,170	1000€/a	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**260.81**	**400,000**	27	€/kW/a	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification	**270.47**	**400,000**	28	€/kW/a	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification	**361.93**	**215,278**	1.28	$/GJ	155	tonne /d	2025	(Gül, 2008)
Biomass Gasification	**797.38**	**33,333**	2.82	$/GJ	24	tonne /d	2025	(Gül, 2008)

Table A 21: Variable operation and maintenance costs of hydrogen production from biomass gasification.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Biomass Gasification	**6.95**	**450,000**	39	1000€/MW_{th}	450	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**15.93**	**215,278**	1.6	$/GJ	155	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**10.35**	**33,333**	1.04	$/GJ	24	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**4.08**	**208,333**	0.41	$/GJ	150	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**4.08**	**209,722**	0.41	$/GJ	151	tonne /d	2007	(Gül, 2008)
Gasification	**6.60**	**450,000**	31	1000€/MW_{th}	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**5.08**	**33,333**	0.51	$/GJ	24	tonne /d	2025	(Gül, 2008)

Table A 22: Efficiencies of hydrogen production from biomass gasification.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
Biomass Gasification	**45.24**	**215,278**	155	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**50.00**	**33,333**	24	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**60.97**	**208,333**	150	tonne /d	2007	(Gül, 2008)
Biomass Gasification	**60.97**	**209,722**	151	tonne /d	2007	(Gül, 2008)
Gasification	**55.00**	**450,000**	450	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Biomass Gasification	**68.30**	**400,000**	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification	**68.30**	**400,000**	400	MW_{th}	2020	(van Vliet, van den Broek, Turkenburg, & Faaij, 2011)
Biomass Gasification	**55.24**	**215,278**	155	tonne /d	2025	(Gül, 2008)
Biomass Gasification	**69.93**	**33,333**	24	tonne /d	2025	(Gül, 2008)

Table A 23: Investment costs of hydrogen production from electrolysis.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Investment Cost in Source	Investment Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Wind Electro.without Electricity Coprod	**56,943.74**	**69,444**	$m	560.6	50	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
Wind Electro.with Electricity Coprod	**57,543.04**	**69,444**	$m	566.5	50	kg_{H2}/d	2005	(Bartels, Pate, & Olson, 2010)
Wind electrolysis	**15,236.47**	**1,389**	$m	3	1000	kg_{H2}/d	2006	(Bartels, Pate, & Olson, 2010)
Wind Electrolysis	**45,700.94**	**1,389**	$m	0.9	1000	kg_{H2}/d	2006	(Bartels, Pate, & Olson, 2010)
Water electrolysis. (smal scale)	**976.47**	**3,000**	1000€/MW_{th}	110	3	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Power Tower Electrolysis	**55,745.74**	**53,272**	$m	421	38.356	kg_{H2}/d	2007	(Bartels, Pate, & Olson, 2010)
Alkaline Water Electrolysis	**11,875.84**	**594,444**	$/GJ	2.52	428	tonne/d	2007	(Gül, 2008)
Alkaline water Electrolysis	**22,938.75**	**666,667**	$/GJ	6.49	480	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	**24,034.44**	**208,333**	$/GJ	6.8	150	tonne/d	2007	(Gül, 2008)
Wind+AW Electrolysis	**24,393.13**	**594,444**	$/GJ	13.31	428	tonne/d	2007	(Gül, 2008)
Photovoltaic Electrolysis	**43,563.86**	**1,943**	$m	12	1399	kg_{H2}/d	2010	(Bartels, Pate, & Olson, 2010)
Power Tower Electrolysis	**50,341.26**	**87,436**	$m	624	62.954	kg_{H2}/d	2010	(Bartels, Pate, & Olson, 2010)
Water Electrolysis	**34,949.65**	**1,500**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**20,654.33**	**50,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**19,637.76**	**70,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**15,786.59**	**300,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**13,902.47**	**700,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**6,604.75**	**100,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**5,952.54**	**200,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**5,364.73**	**400,000,000**	-	-	-	-	2020	(Konda, Shah, & Brandon, 2011)
Water Electrolysis	**4,477.00**	**594,444**	$/GJ	0.95	428	tonne/d	2025	(Gül, 2008)
Water Electrolysis	**2,615.51**	**666,667**	$/GJ	0.74	480	tonne/d	2025	(Gül, 2008)
Wind+AW Electrolysis	**13,965.11**	**594,444**	$/GJ	7.62	428	tonne/d	2025	(Gül, 2008)
Nuclear Electrolysis	**18,171.77**	**425,000,000**	Billion $	870	6	Mboe/d	2030	(Mason, 2007)
PV Electrolysis	**32,458.55**	**425,000,000**	Billion $	1554	6	Mboe/d	2030	(Mason, 2007)
Wind Electrolysis	**32,709.19**	**425,000,000**	Billion $	1566	6	Mboe/d	2030	(Mason, 2007)

Table A 24: Fixed operation and maintenance costs of hydrogen production from electrolysis.

Technology	Fix O&M Cost (ZAR_{2007}/kW)	Capacity (kW)	Fix O&M Cost in Source	Fix O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Water Electrolysis	616.41	594,444	2.18	$/GJ	428	tonne/d	2007	(Gül, 2008)
Water Electrolysis	1,142.34	666,667	4.04	$/GJ	480	tonne/d	2007	(Gül, 2008)
Water Electrolysis	1,198.89	208,333	4.24	$/GJ	150	tonne/d	2007	(Gül, 2008)
Wind+AW Electrolysis	1,152.40	594,444	10.48	$/GJ	428	tonne/d	2007	(Gül, 2008)
Alkaline water Electrolysis	254.48	594,444	0.9	$/GJ	428	tonne/d	2025	(Gül, 2008)
Alkaline Water Electrolysis	130.07	666,667	0.46	$/GJ	480	tonne/d	2025	(Gül, 2008)
Wind+AW Electrolysis	568.50	594,444	5.17	$/GJ	428	tonne/d	2025	(Gül, 2008)

Table A 25: Variable operation and maintenance costs of hydrogen production from electrolysis.

Technology	Var. O&M Cost (ZAR_{2007}/GJ)	Capacity (kW)	Var. O&M Cost in Source	Var. O&M Cost Unit in Source	Capacity in Source	Capacity Unit in Source	Year	Source
Water Elec. (Smal Scale)	5.87	3,000	211	1000€/MW_{th}	3	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Alkaline Water Electrolysis	2.39	594,444	0.24	$/GJ	428	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	7.27	666,667	0.73	$/GJ	480	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	7.57	208,333	0.76	$/GJ	150	tonne/d	2007	(Gül, 2008)
Wind+AW Electrolysis	2.39	594,444	0.24	$/GJ	428	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	2.69	594,444	0.27	$/GJ	428	tonne/d	2025	(Gül, 2008)
Alkaline Water Electrolysis	0.80	666,667	0.08	$/GJ	480	tonne/d	2025	(Gül, 2008)
Wind+AW Electrolysis	2.69	594,444	0.27	$/GJ	428	tonne/d	2025	(Gül, 2008)

Table A 26: Efficiencies of hydrogen production from electrolysis.

Technology	Efficiency (%)	Capacity (kW)	Capacity in Source	Capacity Unit in Source	Year	Source
Water Elec. (Smal Scale)	**67.00**	**3,000**	3	MW_{th}	2006	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Alkaline Water electrolysis	**62.80**	**594,444**	428	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	**62.11**	**666,667**	480	tonne/d	2007	(Gül, 2008)
Alkaline Water Electrolysis	**63.60**	**208,333**	150	tonne/d	2007	(Gül, 2008)
Water Electrolysis (Smal Scale)	**71.00**	**3,000**	3	MW_{th}	2020	(Mueller, Tzimas, Kaltschmitt, & Peteves, 2007)
Alkaline Water Electrolysis	**75.18**	**594,444**	428	tonne/d	2025	(Gül, 2008)
Alkaline Water Electrolysis	**71.94**	**666,667**	480	tonne/d	2025	(Gül, 2008)

APPENDIX B (Costs of Hydrogen Production)

All costs for hydrogen production routes in the literature are converted into South African Rand (ZAR) in 2007 currency. In the conversion of the currency, Table G 1, Table G2 and Table G 3 are used which can be seen in Appendix G. Conversion rates and years are applied as a part of system analysis worksheet of EnerKey (Energy as a Key Element of an Integrated Climate Protection Concept for the City Region of Gauteng), (IER, 2012b)

In this Appendix, current (2010) and future (costs) and efficiencies for the hydrogen production from coal gasification, natural gas reforming, biomass gasification and electrolysis can be found. These costs and efficiencies depend on years and capacities on the graphics.

All production costs for hydrogen is based on the relation (Gül, 2008):

$$COST = INVCOST \times \frac{CRF}{AF} + \frac{FIXOM}{AF} + VAROM + \frac{FeedstockCost}{\eta}$$

INVCOST	= Specific investment cost [ZAR_{2007}/kW]
CRF	= Capital recovery factor [-]
AF	= Availability factor [-]
FIXOM	= Fixed operation and maintenance cost [ZAR_{2007}/kW/year]
VAROM	= Variable operation and maintenance cost [ZAR_{2007}/GJ]
η	= Process efficiency

The capital recovery factor can be formulized as:

$$CRF = dr \times \frac{{1+dr}^{\;n}}{(1+dr)^n - 1}$$

dr = Discount rate [%]

n = Plant life time [years]

The current and future fuel costs are taken from Tomaschek (2012). The fuel costs are the costs of input materials for hydrogen production paths. Fuel costs for Gauteng metropolitan region are shown in Table 2.3. All Fuel costs are for industrial level including transportation and delivery costs, excluding taxes.

Table B 1: Fuel costs for Gauteng region.

ZAR_{2007}/GJ_{output}	**2010**	**2040**
Coal	9.3	17.0
Natural Gas	71.6	138.4
Biomass	46.3	46.6
Electricity	146.7	207.0

In this study, all hydrogen related energy values are based on LHV. It is assumed that all technologies use electricity as input for the processes since electricity is a relatively cheap fuel in South Africa compared to the world market; however, in hydrogen production, electricity is may be by product as it may be input for the production process. Positive auxiliary electricity values are taken into account in the literature research. Besides, it is assumed that electricity costs for the processes are included in the variable operation and maintenance costs. Electric efficiency is considered as electrolysis fuel efficiency. In addition, water costs and cleaning costs are included into variable operating and maintenance costs.

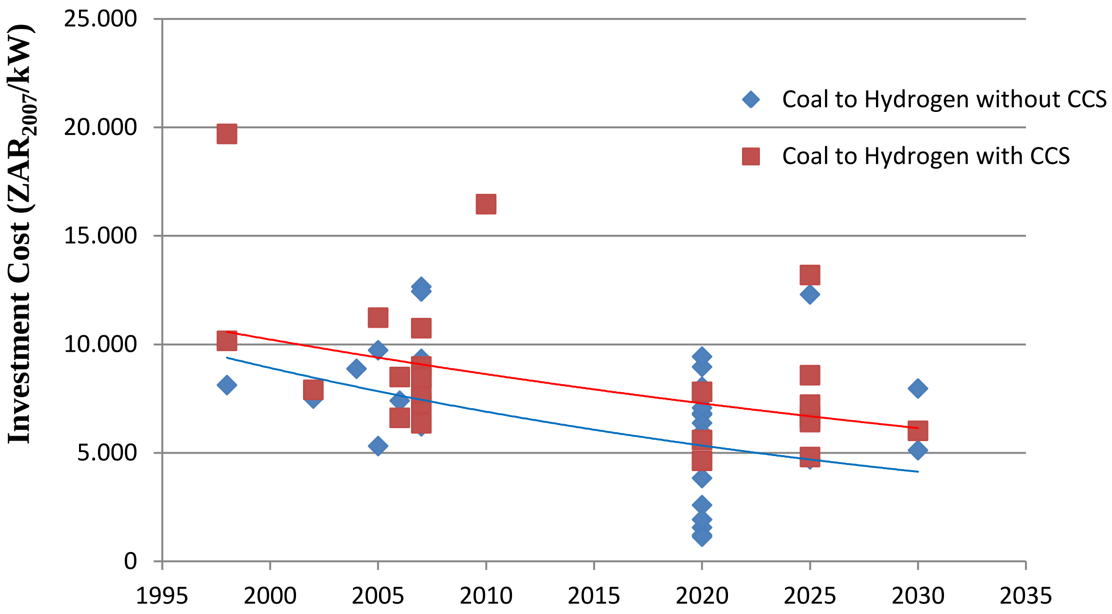

Figure B 1: Investment costs of hydrogen production from coal gasification.

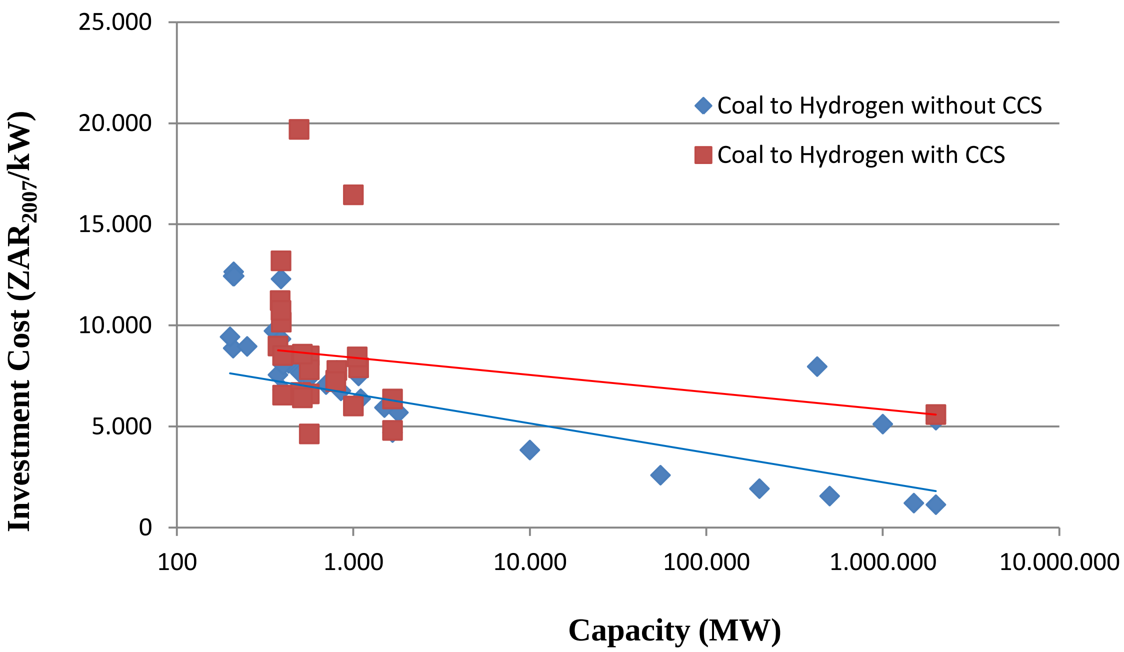

Figure B 2: Investment costs of hydrogen production from coal gasification depending on plant capacity.

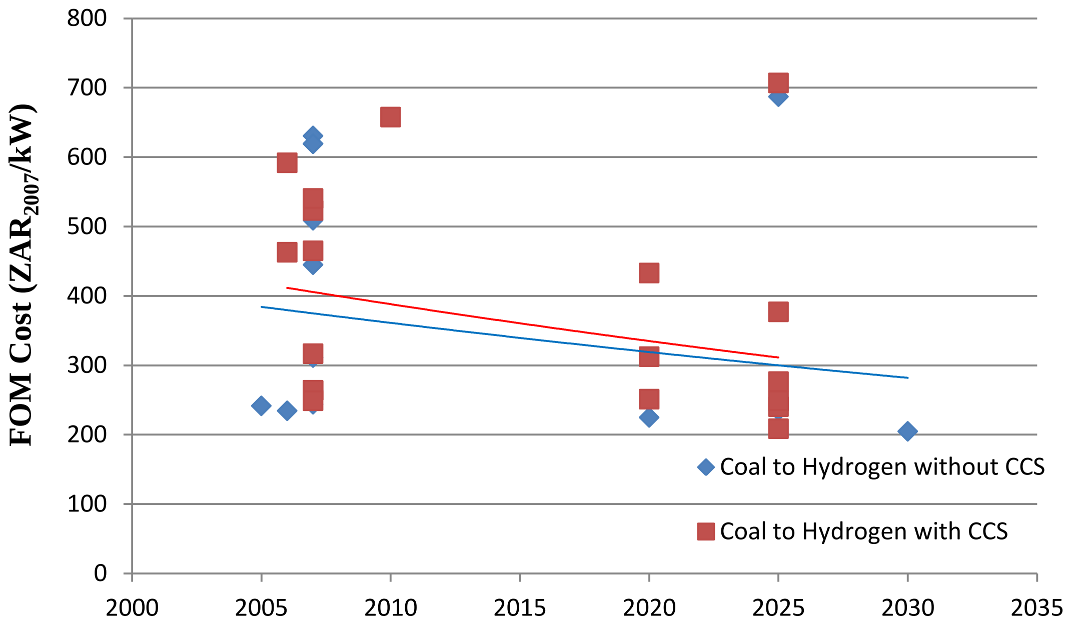

Figure B 3: Fix operation & maintenance costs of hydrogen production from coal gasification.

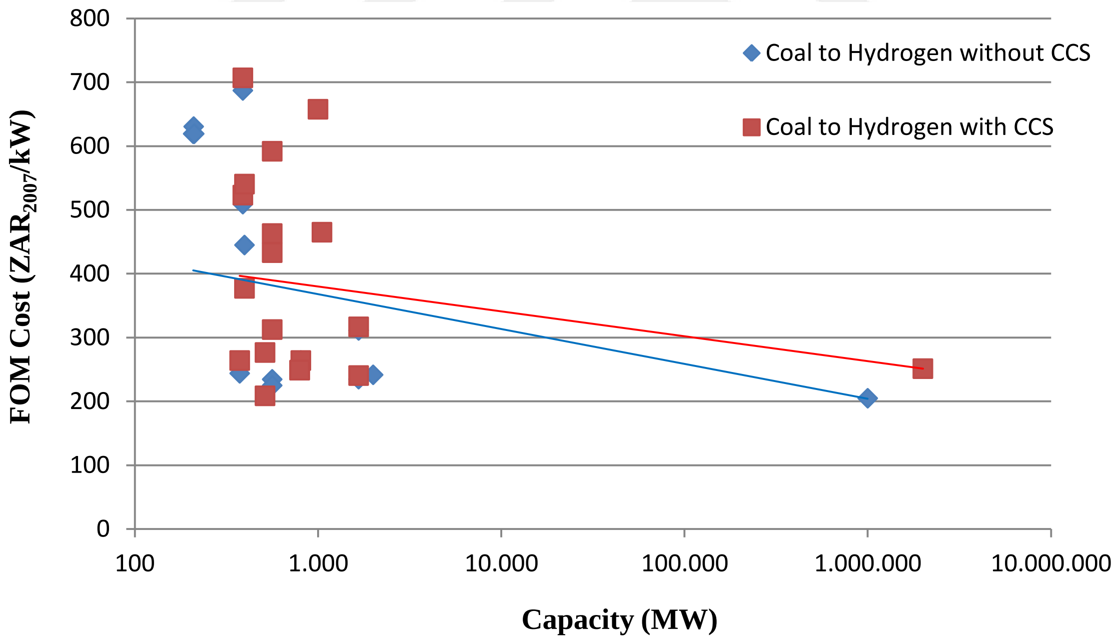

Figure B 4: Fix operation & maintenance costs of hydrogen production from coal gasification depending on plant capacity.

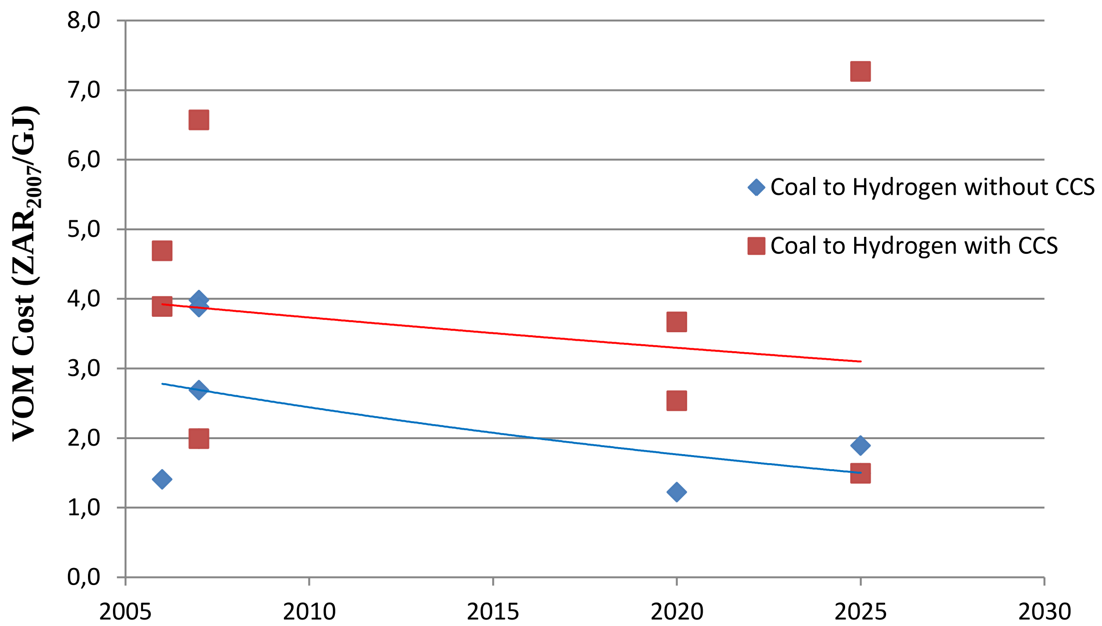

Figure B 5: Variable operation & maintenance costs of hydrogen production from coal gasification depending on plant capacity.

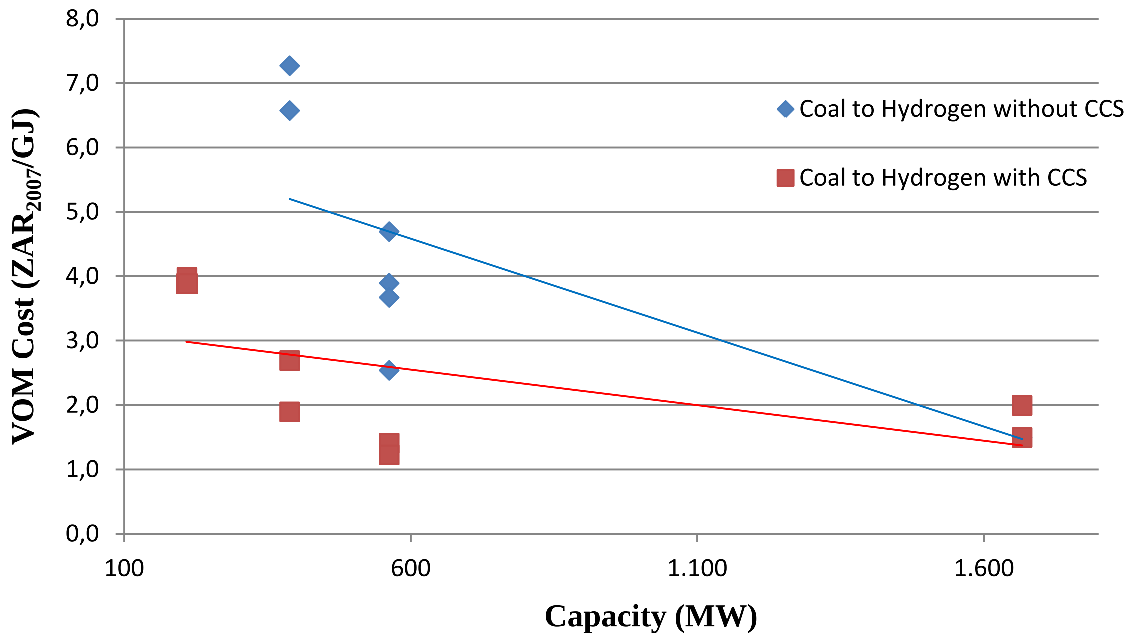

Figure B 6: Variable operation & maintenance costs of hydrogen production from coal gasification depending on plant capacity.

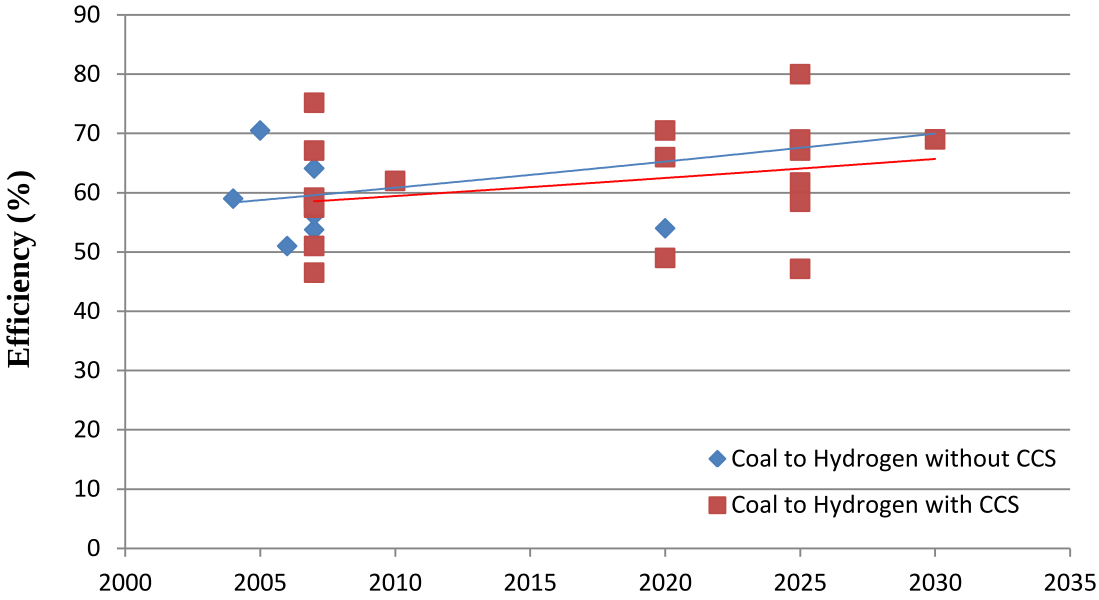

Figure **B 7:** Efficiency of hydrogen production from coal gasification.

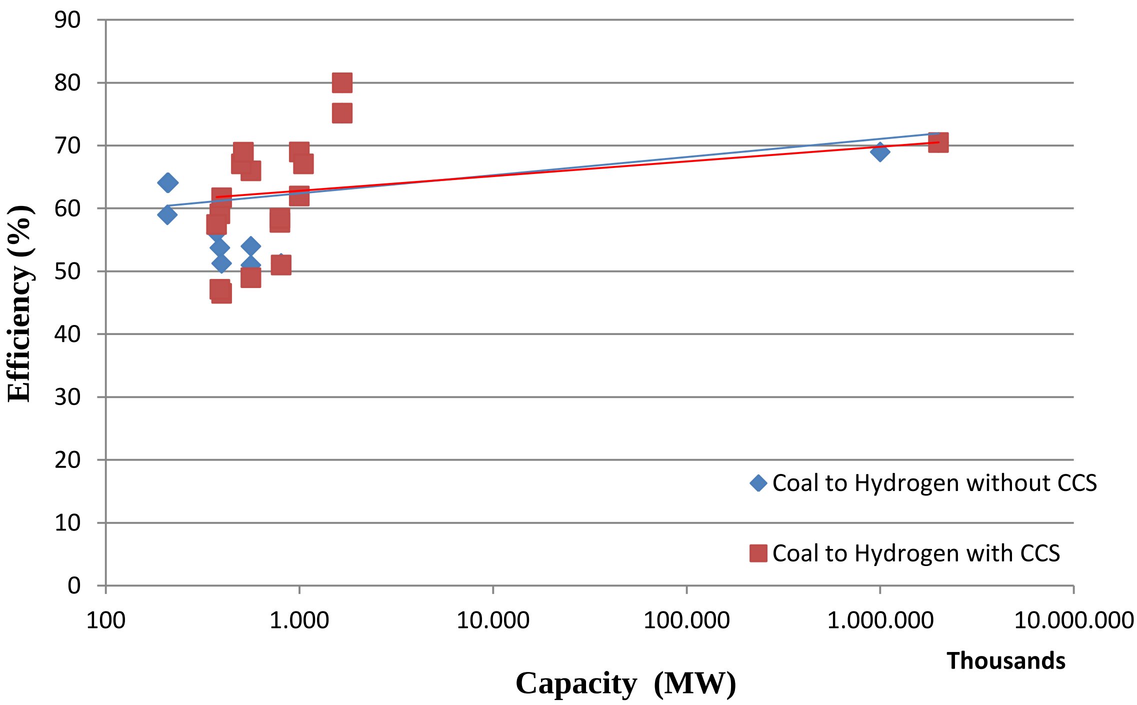

Figure B 8: Efficiency of hydrogen production from coal gasification depending on plant capacity.

Table B 2: Costs and efficiency of hydrogen production from coal gasification.

ZAR_{2007}/GJ_{output}	Technology	2010	2040
Investment Cost	With CCS	274.64	165.07
	Without CCS	218.07	101.02
FOM Cost	With CCS	12.39	7.39
	Without CCS	11.50	7.93
VOM Cost	With CCS	3.74	2.58
	Without CCS	2.46	0.93
Production Cost	With CCS	60.23	52.29
	Without CCS	51.17	41.08
Efficiency (%)	With CCS	60	69
	Without CCS	64	80

COSTS AND EFFICIENCY OF HYDROGEN PRODUCTION FROM NATURAL GAS

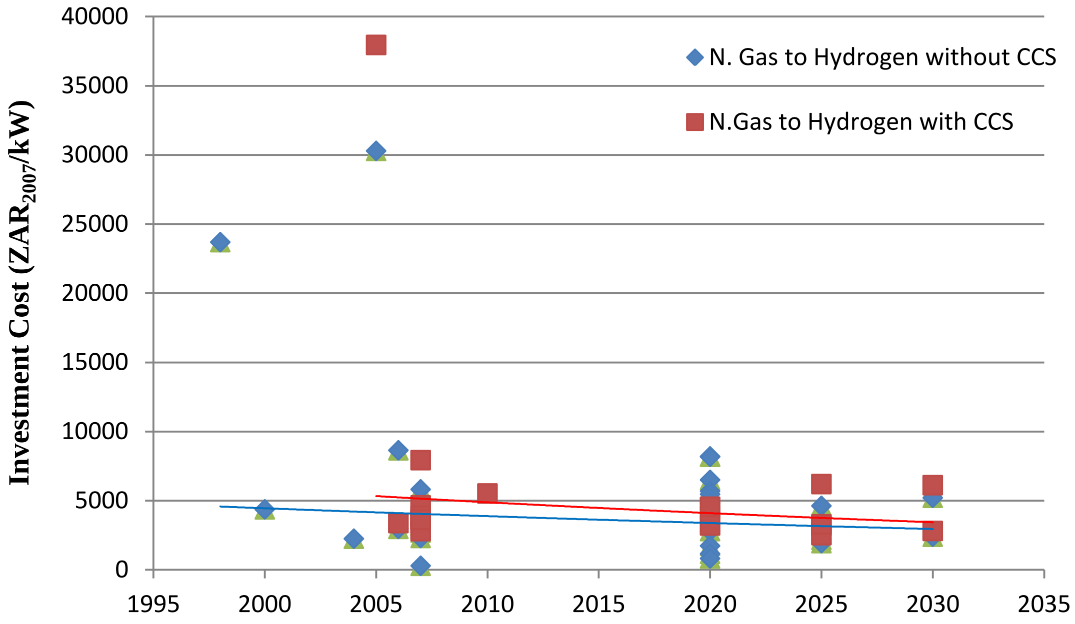

Figure B 9: Investment costs of hydrogen production from natural gas reforming.

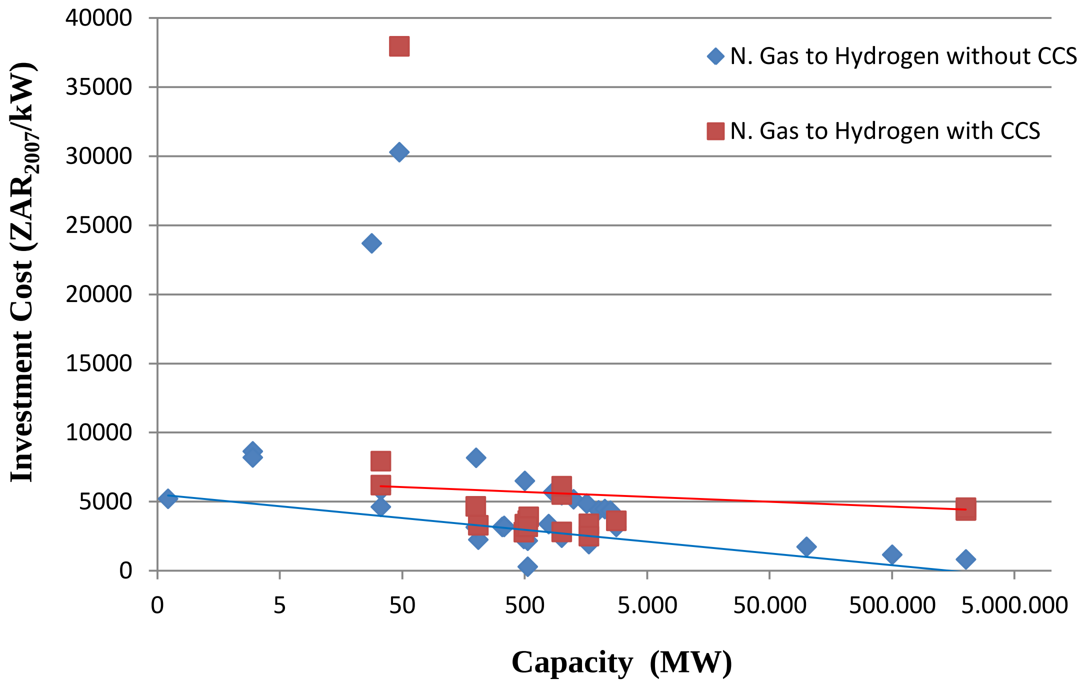

Figure B 10: Investment costs of hydrogen production from natural gas reforming depending on plant capacity.

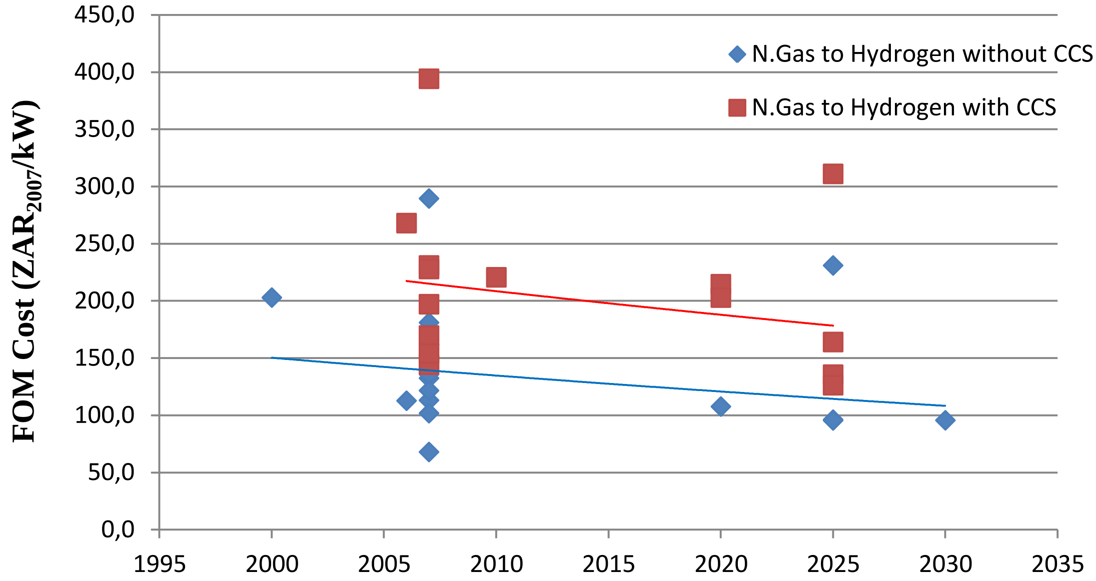

Figure B 11: Fix operation & maintenance costs of hydrogen production from natural gas reforming.

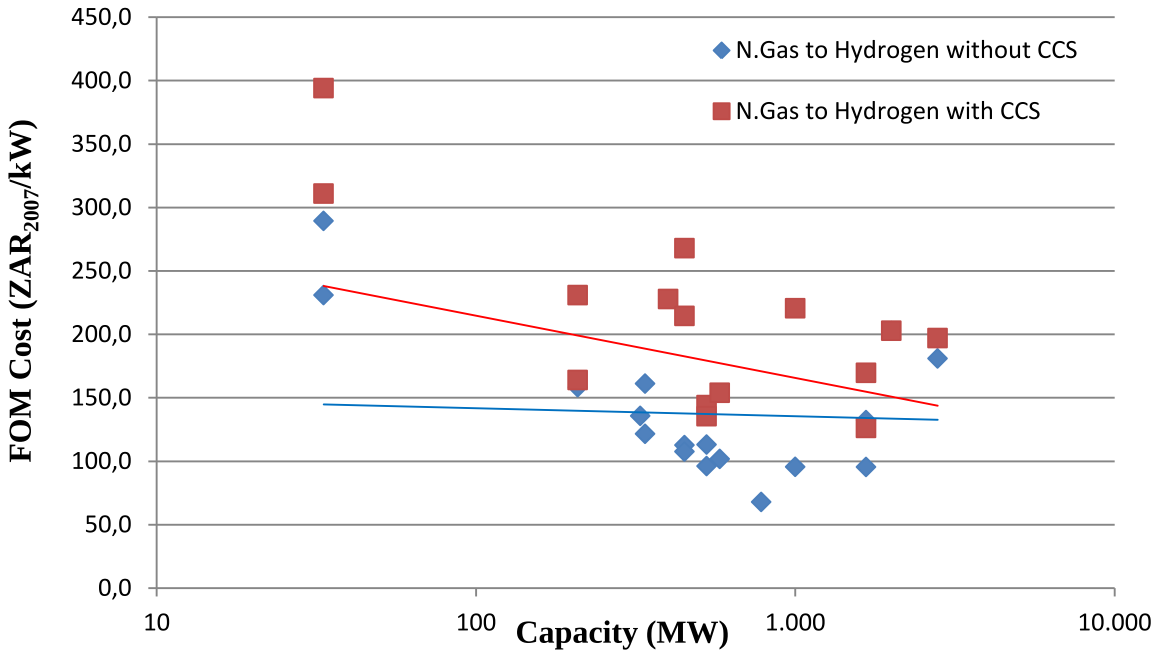

Figure B 12: Fix operation & maintenance costs of hydrogen production from natural gas reforming depending on plant capacity.

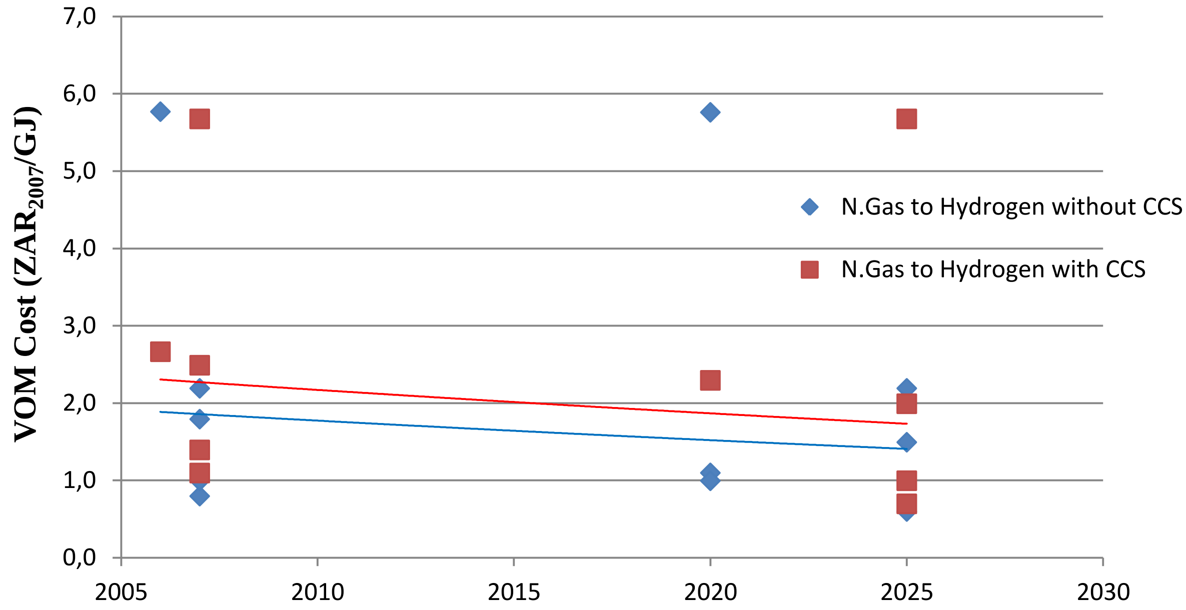

Figure B 13: Variable operation & maintenance costs of hydrogen production from natural gas reforming.

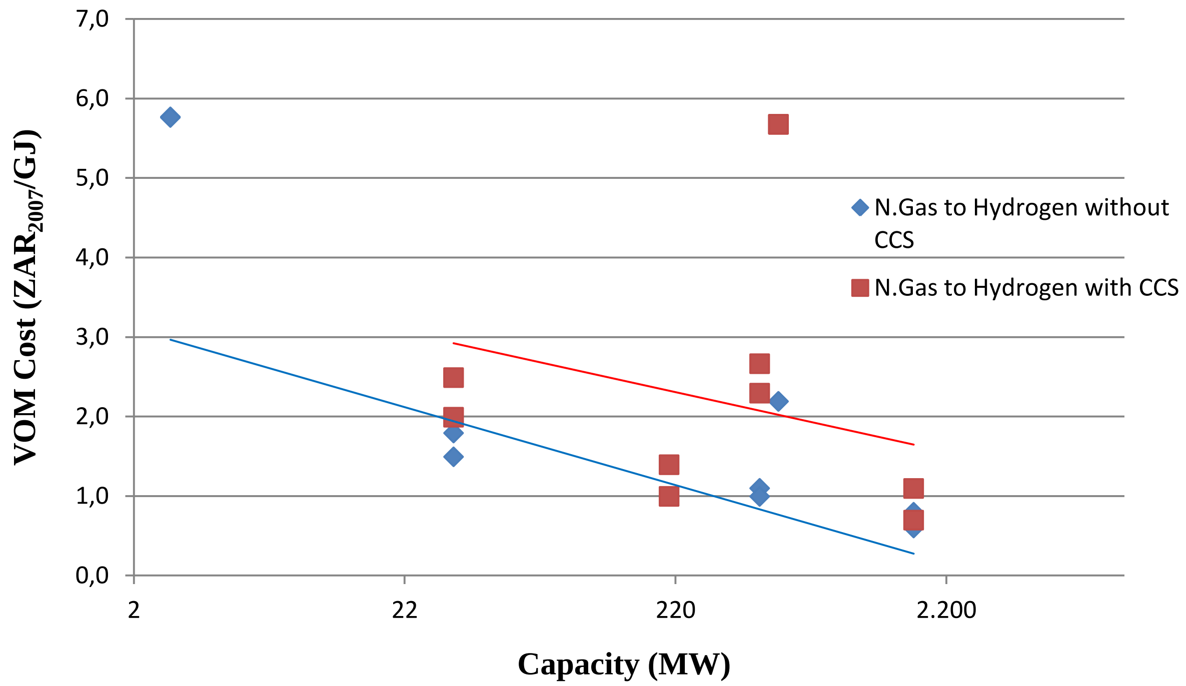

Figure B 14: Variable operation & maintenance costs of hydrogen production from natural gas reforming depending on plant capacity.

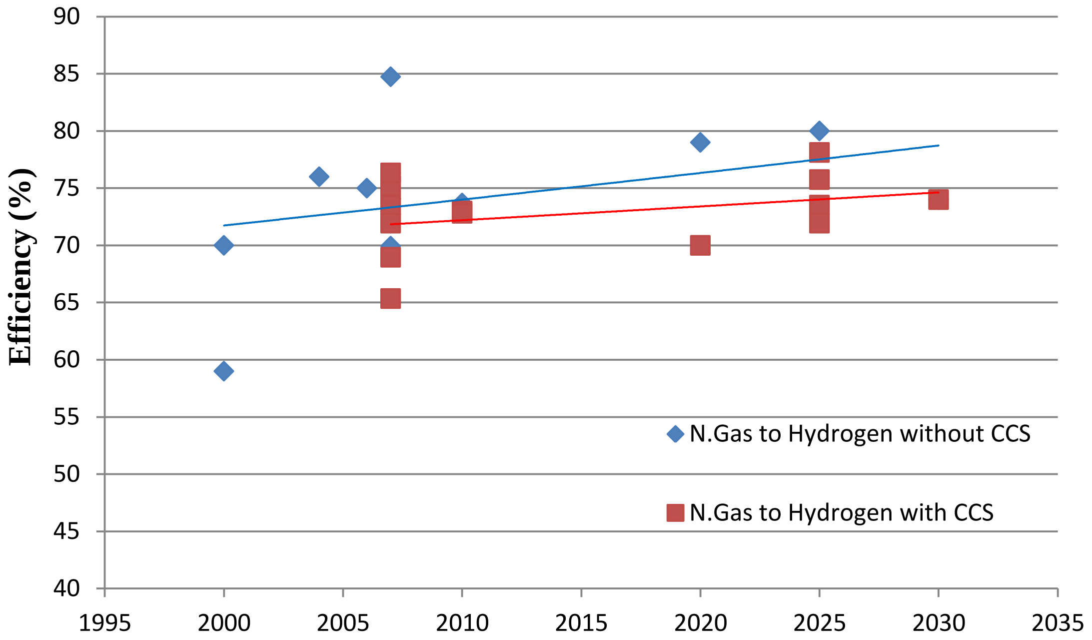

Figure B 15: Efficiency of hydrogen production from natural gas reforming.

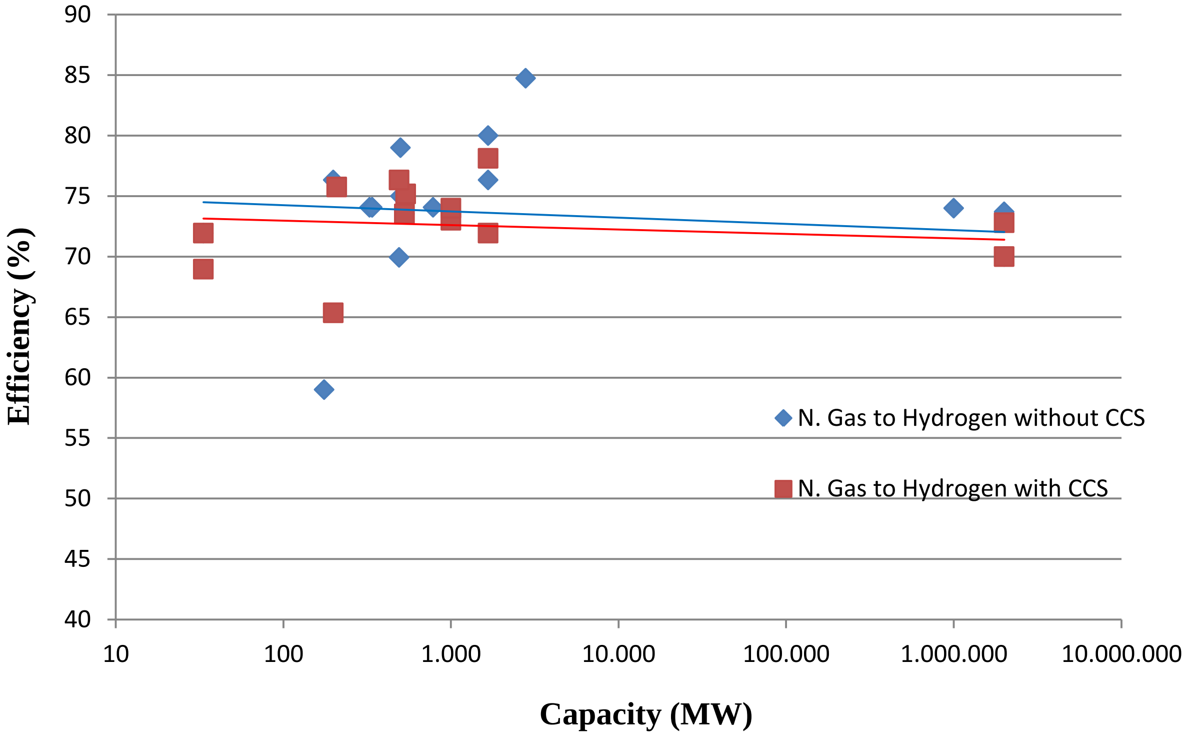

Figure B 16: Efficiency of hydrogen production from natural gas reforming depending on plant capacity.

Table B 3: Costs and efficiency of hydrogen production from natural gas reforming.

ZAR_{2007}/GJ_{output}	Technology	2010	2040
Investment Cost	With CCS	153.74	90.86
	Without CCS	122.65	81.29
FOM Cost	With CCS	6.62	4.16
	Without CCS	4.27	3.08
VOM Cost	With CCS	2.15	1.37
	Without CCS	1.77	1.12
Production Cost	With CCS	123.02	195.80
	Without CCS	115.04	183.55
Efficiency (%)	With CCS	73	77
	Without CCS	74	81

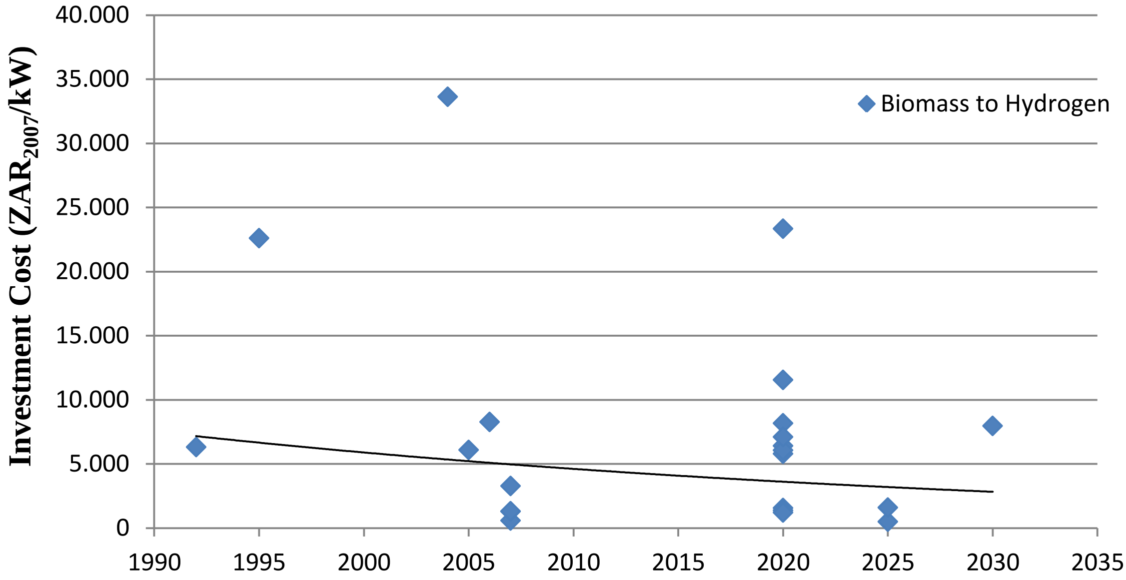

Figure B 17: Investment costs of hydrogen production from biomass gasification.

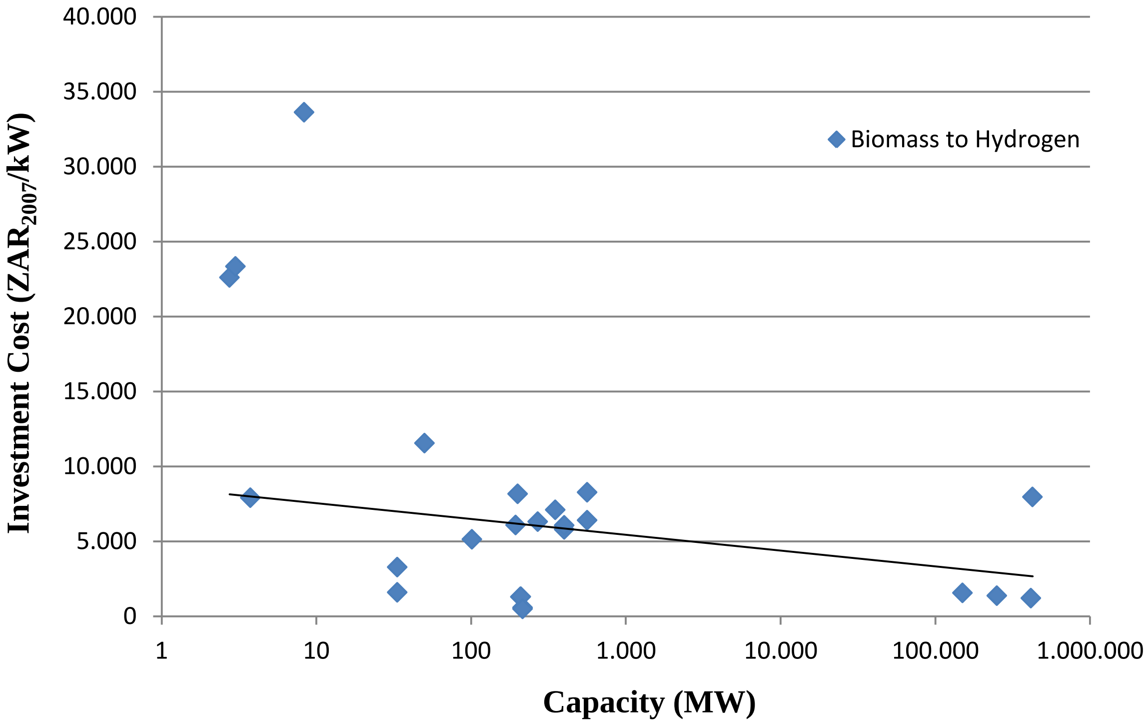

Figure B 18: Investment costs of hydrogen production from biomass gasification depending on plant capacity.

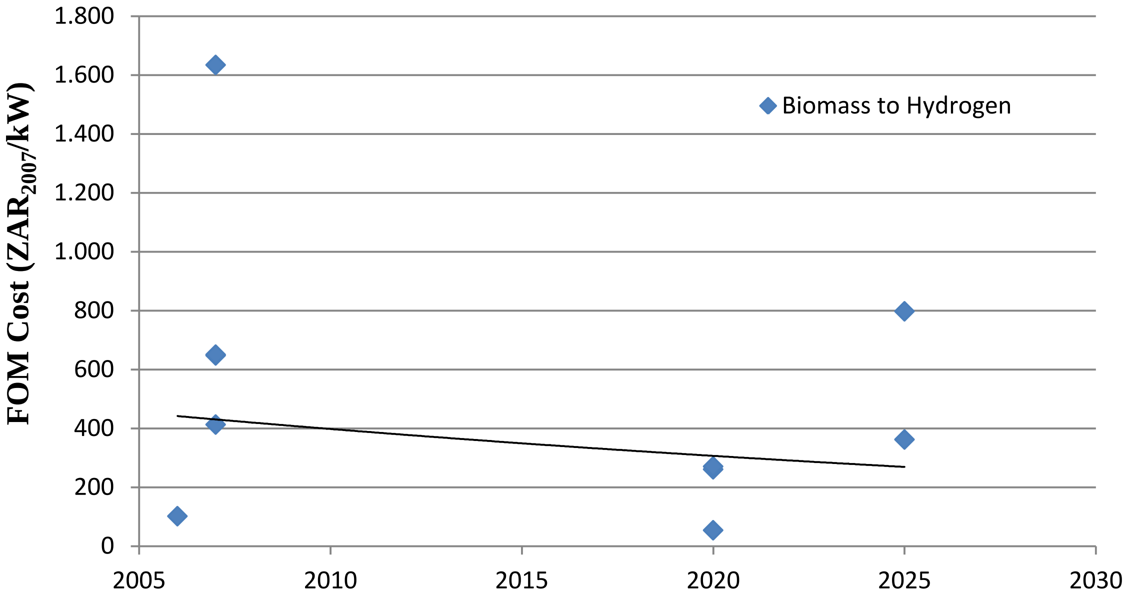

Figure B 19: Fix operation & maintenance costs of hydrogen production from biomass gasification.

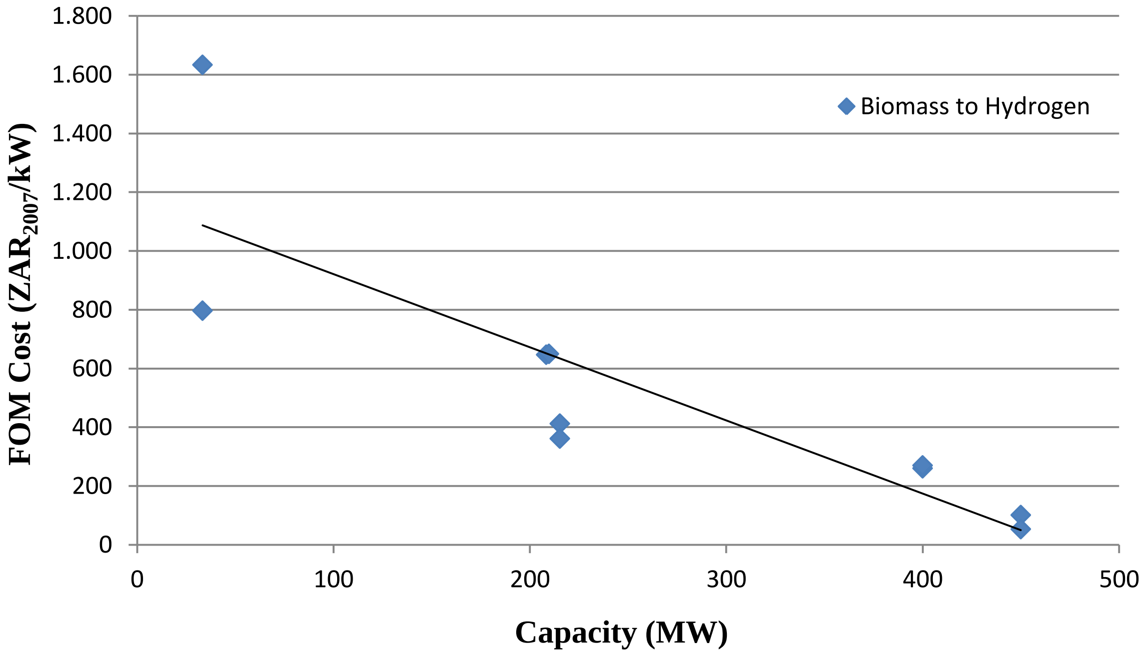

Figure B 20: Fix operation & maintenance costs of hydrogen production from biomass gasification depending on plant capacity.

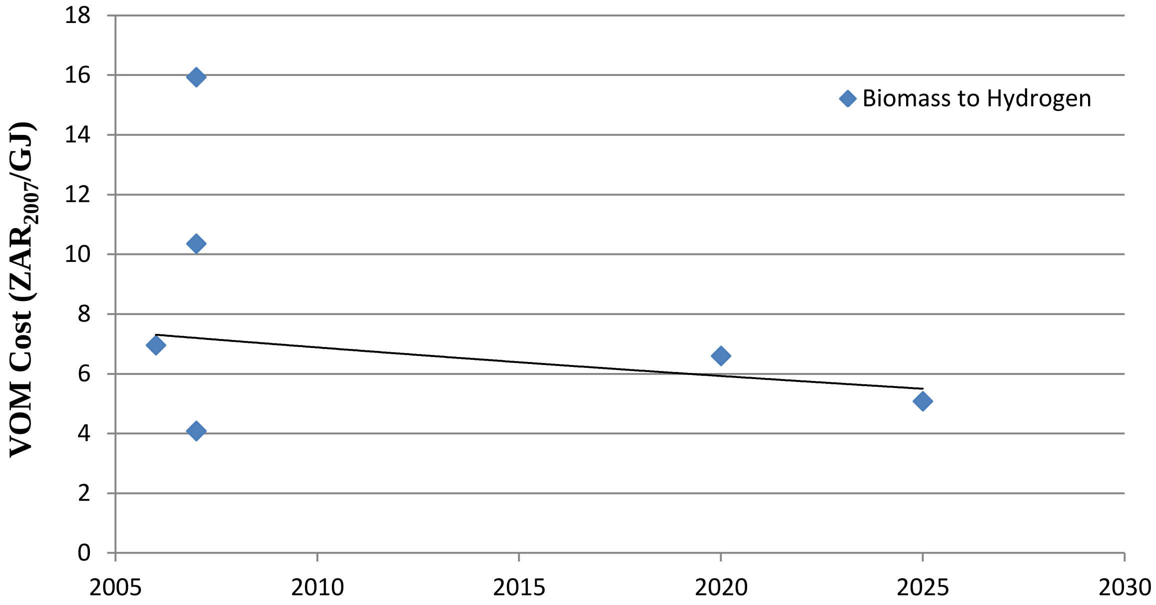

Figure B 21: Variable operation & maintenance costs of hydrogen production from biomass gasification.

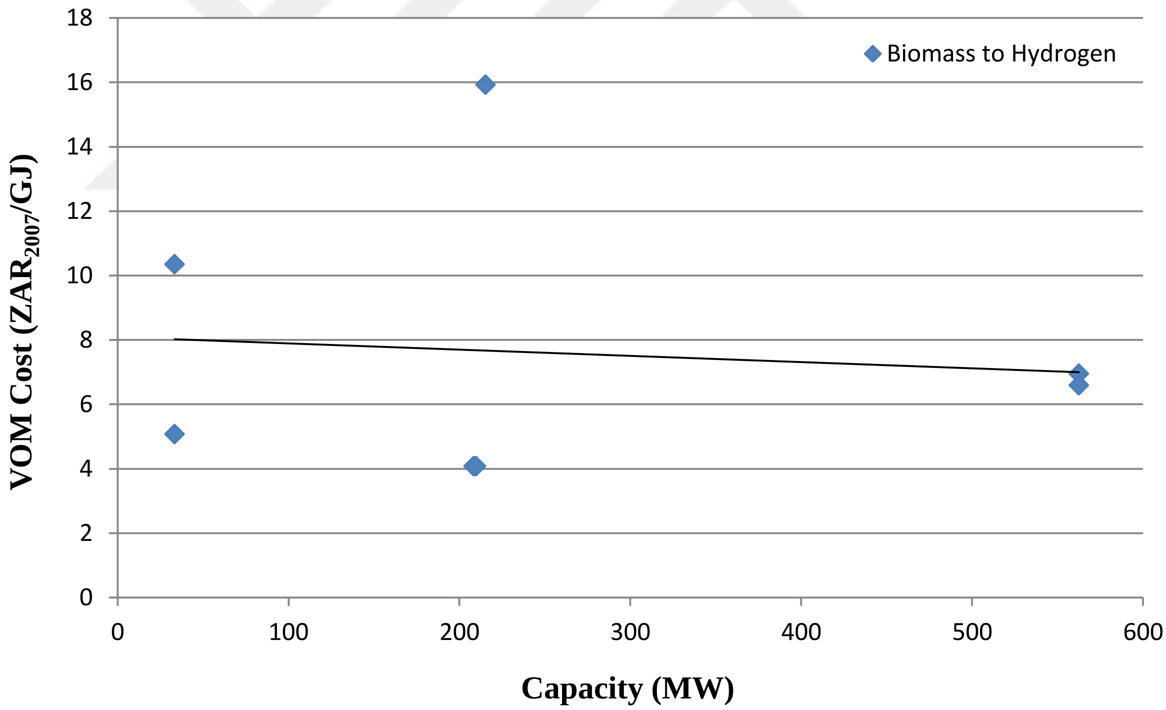

Figure B 22: Variable operation & maintenance costs of hydrogen production from biomass gasification depending on plant capacity.

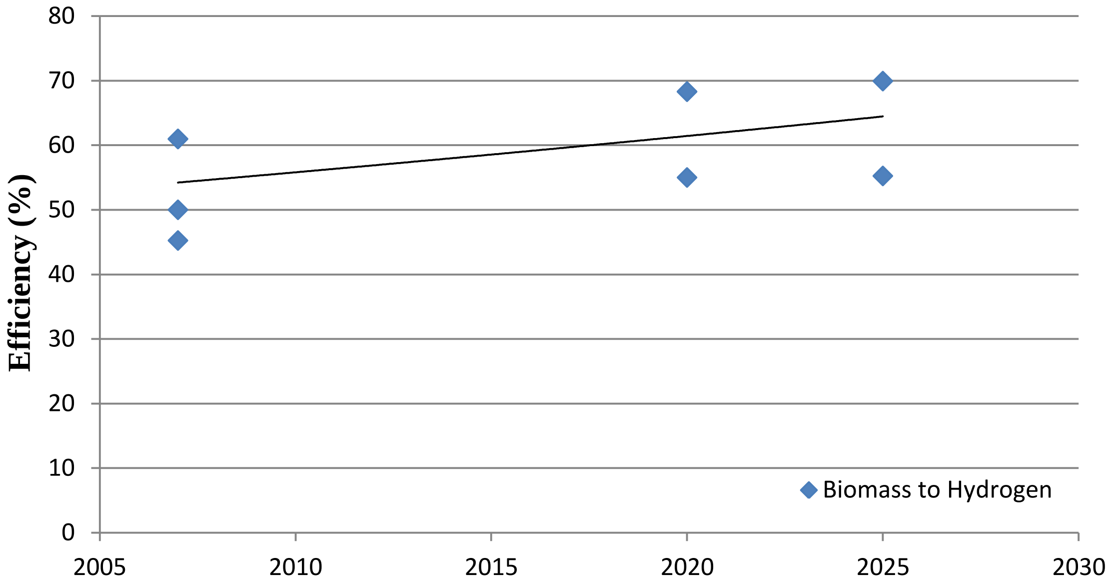

Figure B 23: Efficiency of hydrogen production from biomass gasification.

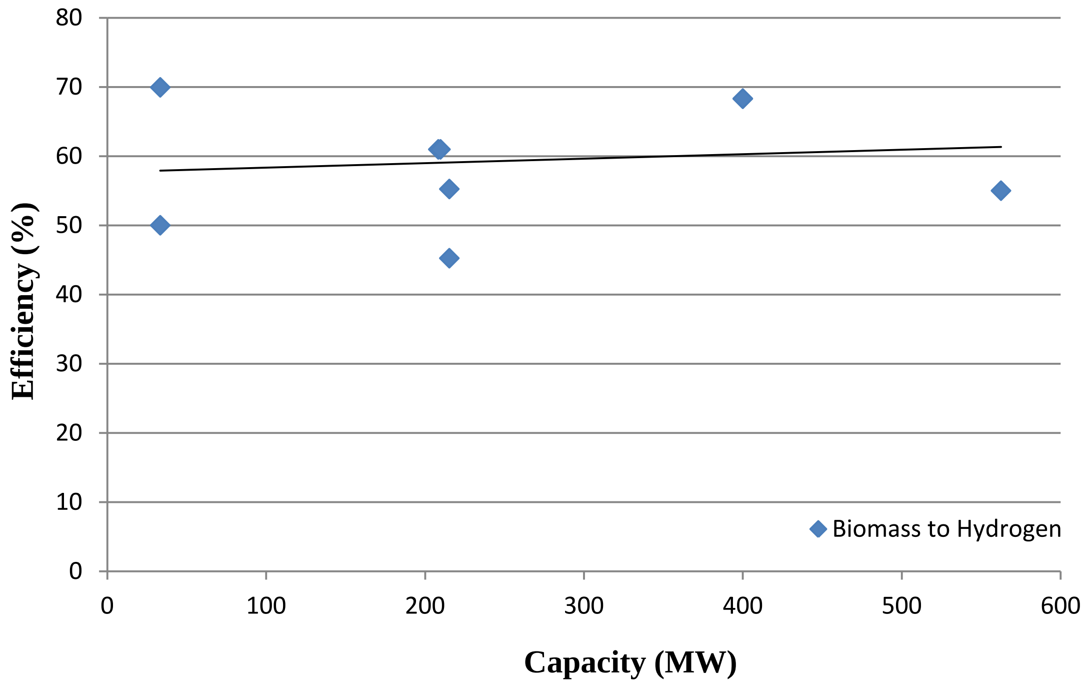

Figure B 24: Efficiency of hydrogen production from biomass gasification depending on plant capacity.

Table B 4: Costs and efficiency of hydrogen production from biomass gasification.

ZAR_{2007}/GJ_{output}	2010	2040
Investment Cost	144.94	69.58
FOM Cost	12.59	5.76
VOM Cost	6.84	4.37
Production Cost	120.18	81.23
Efficiency (%)	56.00	74.00

COSTS AND EFFICIENCY OF HYDROGEN PRODUCTION FROM ELECTROLYSIS

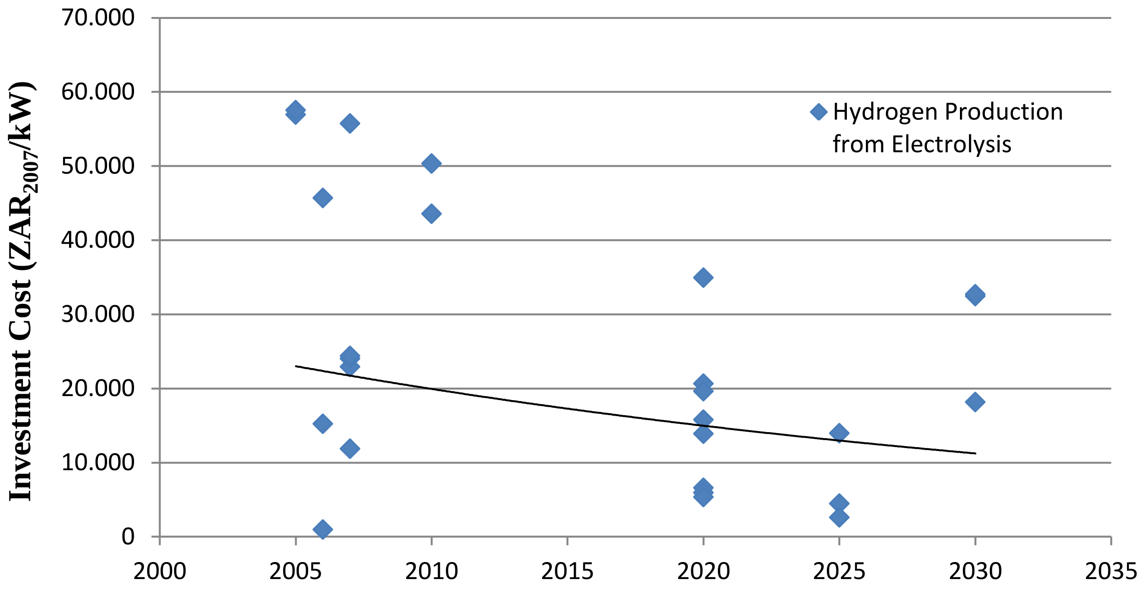

Figure B 25: Investment costs of hydrogen production from electrolysis.

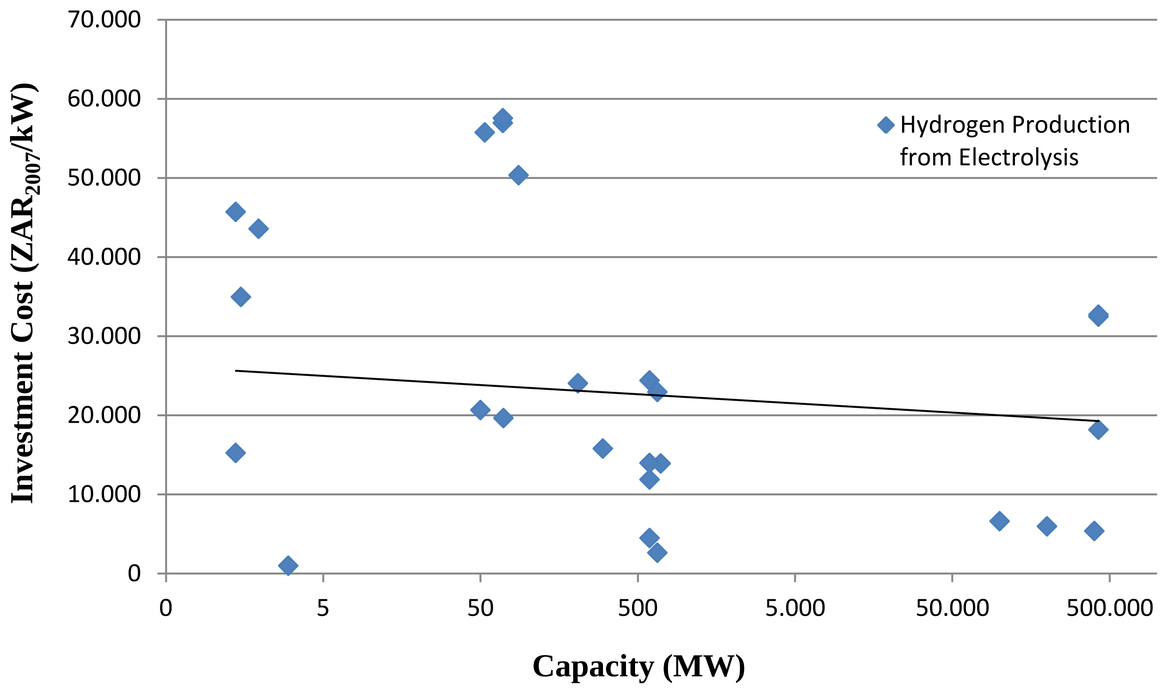

Figure B 26: Investment costs of hydrogen production from electrolysis depending on plant capacity.

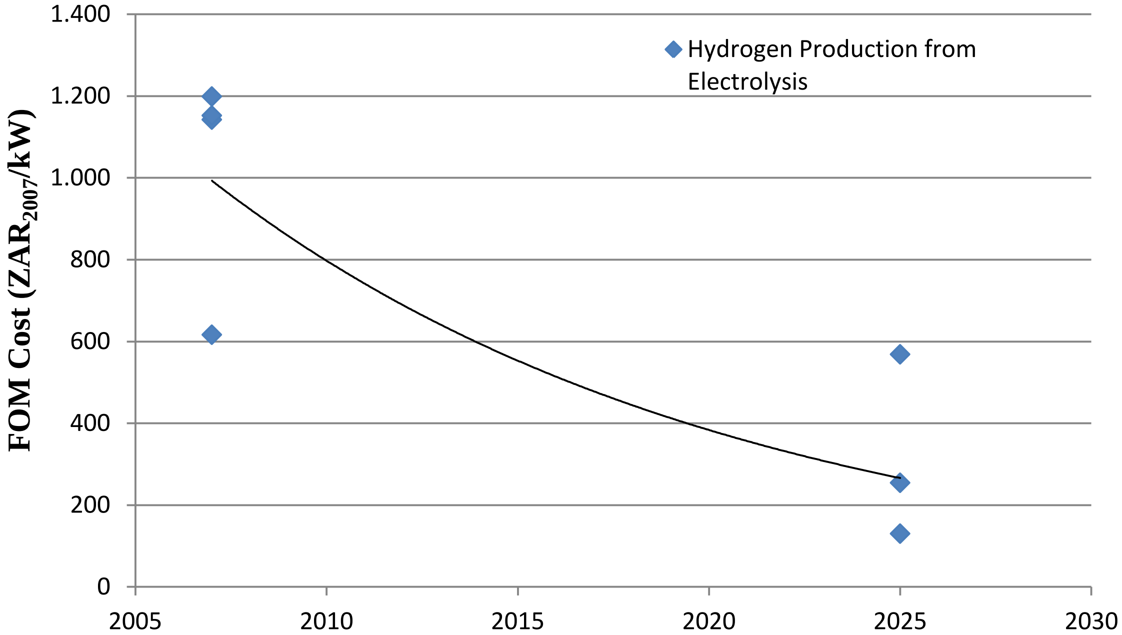

Figure B 27: Fix operation & maintenance costs of hydrogen production from electrolysis.

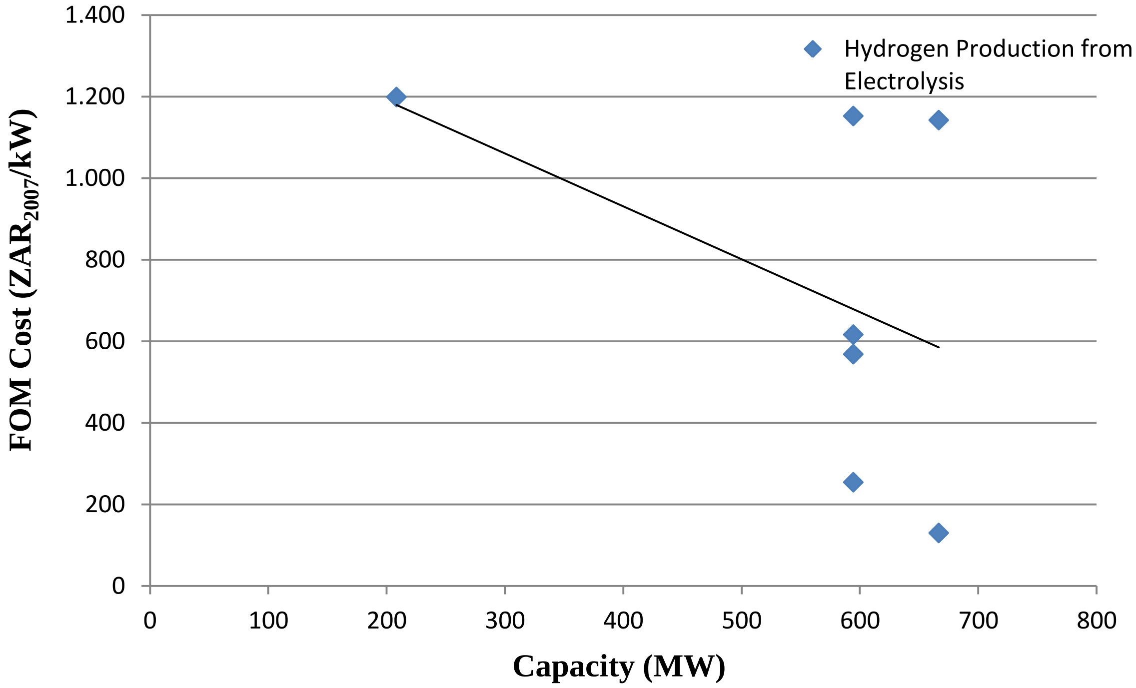

Figure B 28: Fix operation & maintenance costs of hydrogen production from electrolysis gasification depending on plant capacity.

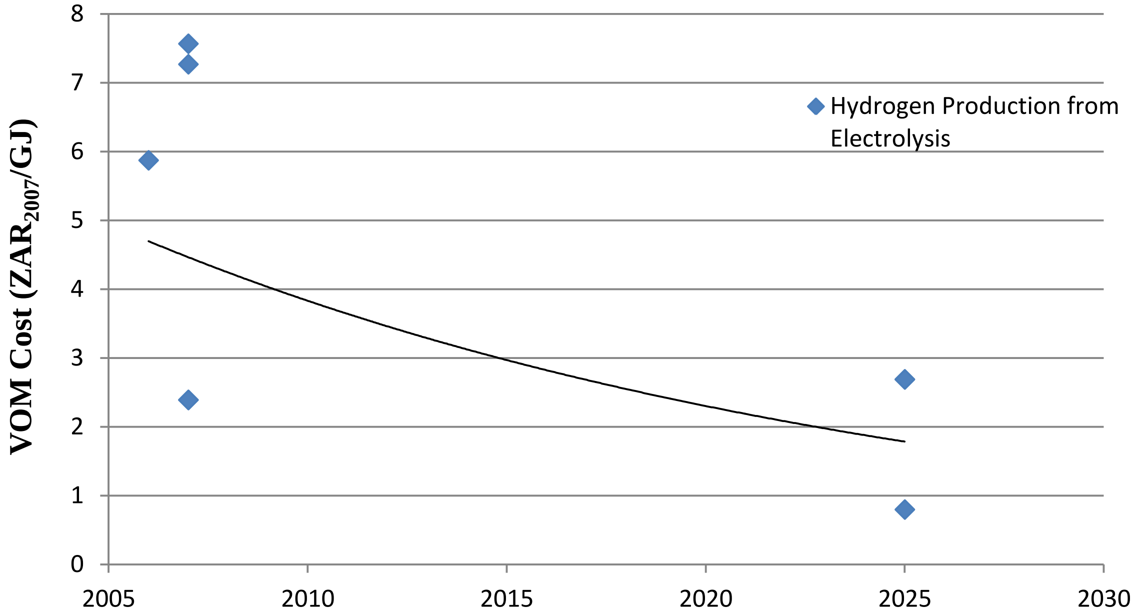

Figure B 29: Variable operation & maintenance costs of hydrogen production from electrolysis.

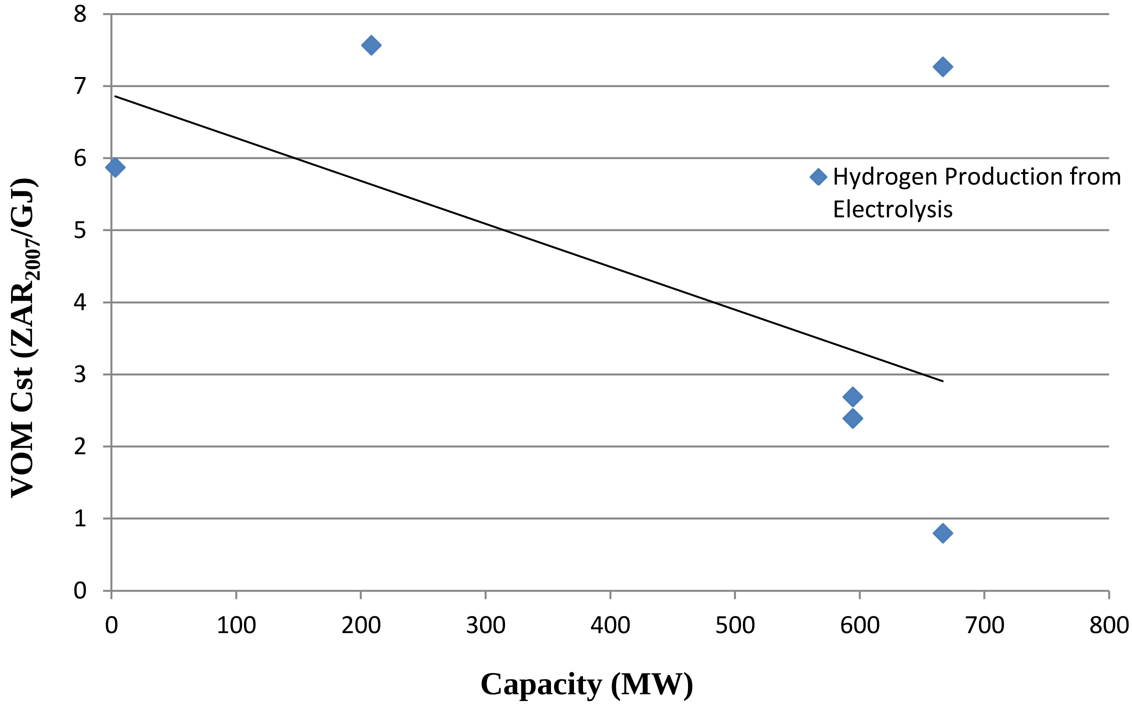

Figure B 30: Variable operation & maintenance costs of hydrogen production from electrolysis gasification depending on plant capacity.

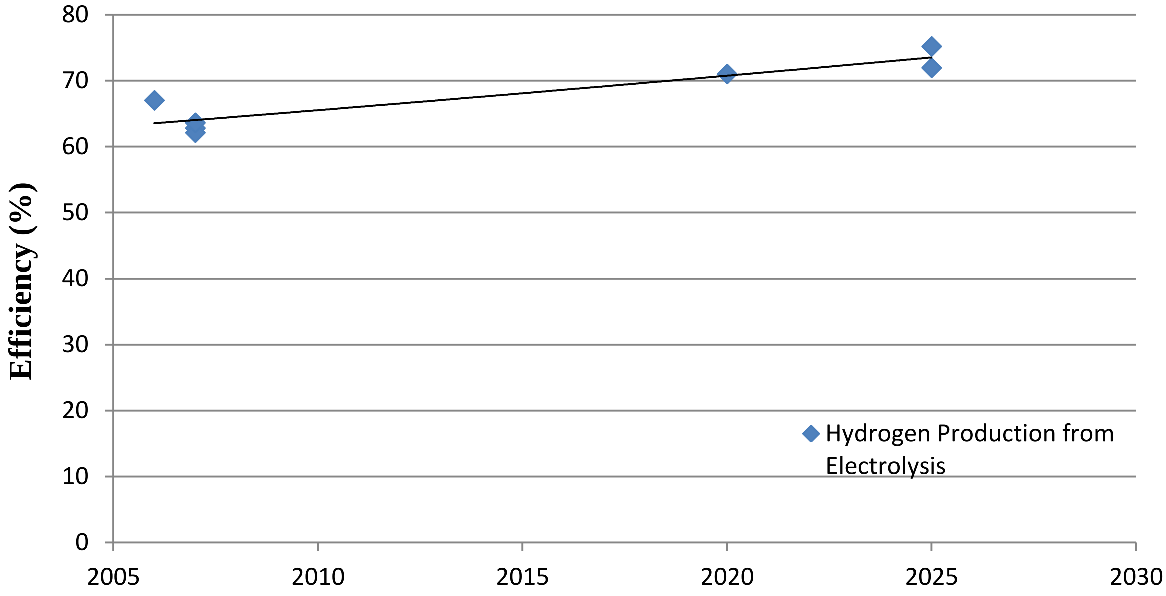

Figure B 31: Efficiency of hydrogen production from electrolysis.

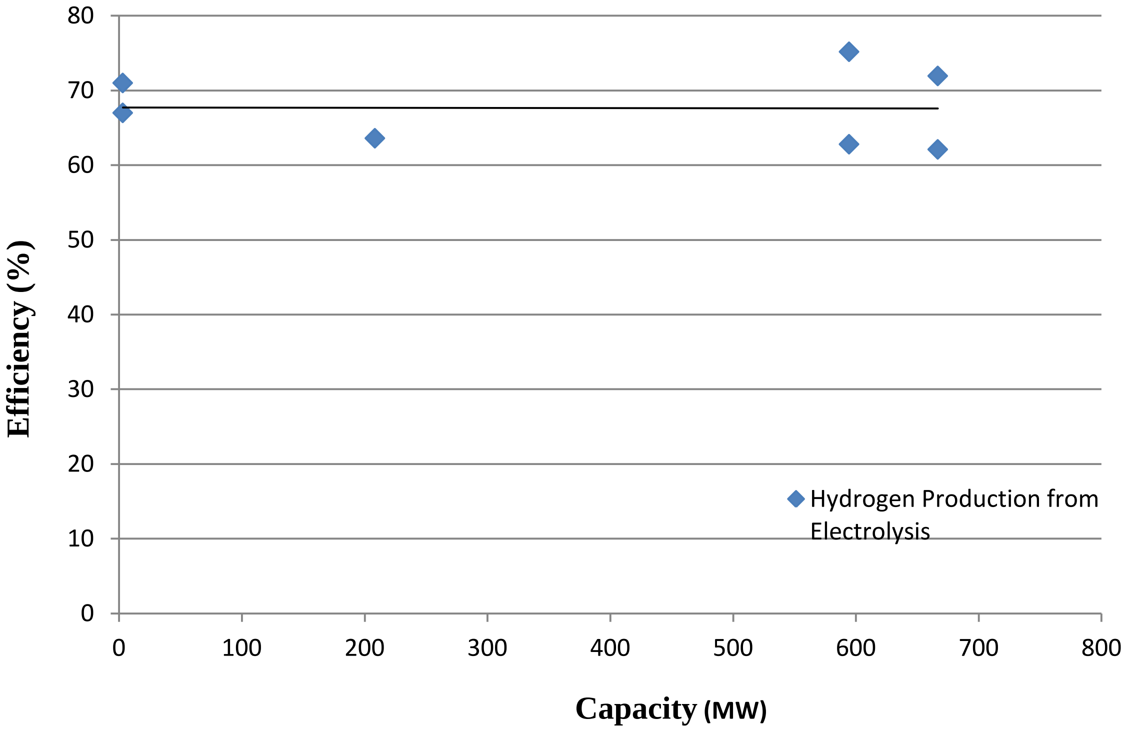

Figure B 32: Efficiency of hydrogen production from electrolysis depending on plant capacity.

Table B 5: Costs and efficiency of hydrogen production from electrolysis.

ZAR_{2007}/GJ_{output}	2010	2040
Investment Cost	627.22	265.63
FOM Cost	25.35	2.82
VOM Cost	3.85	0.83
Production Cost	326.88	284.94
Efficiency (%)	66	82

APPENDIX C (Hydrogen Delivery Costs)

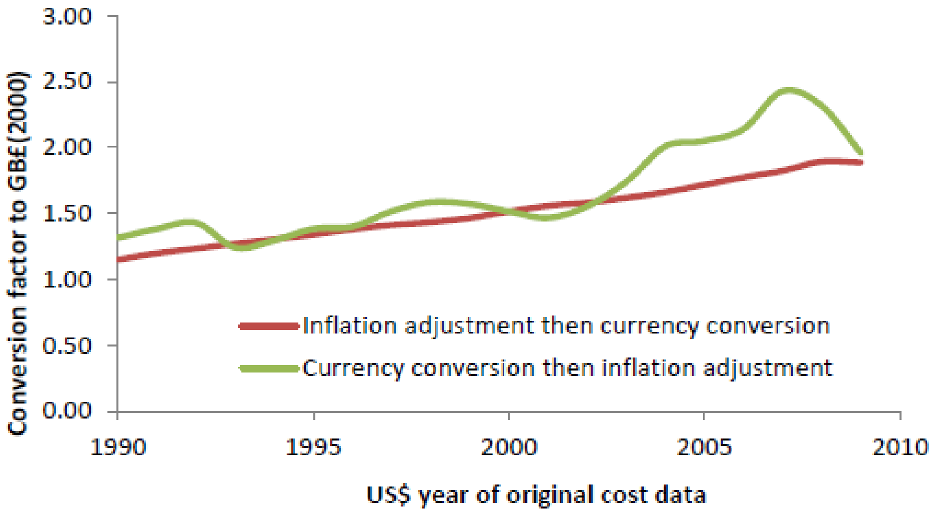

Figure C 1: Conversion of £/$ in the year 2000 (Dodds & McDowall, 2012).

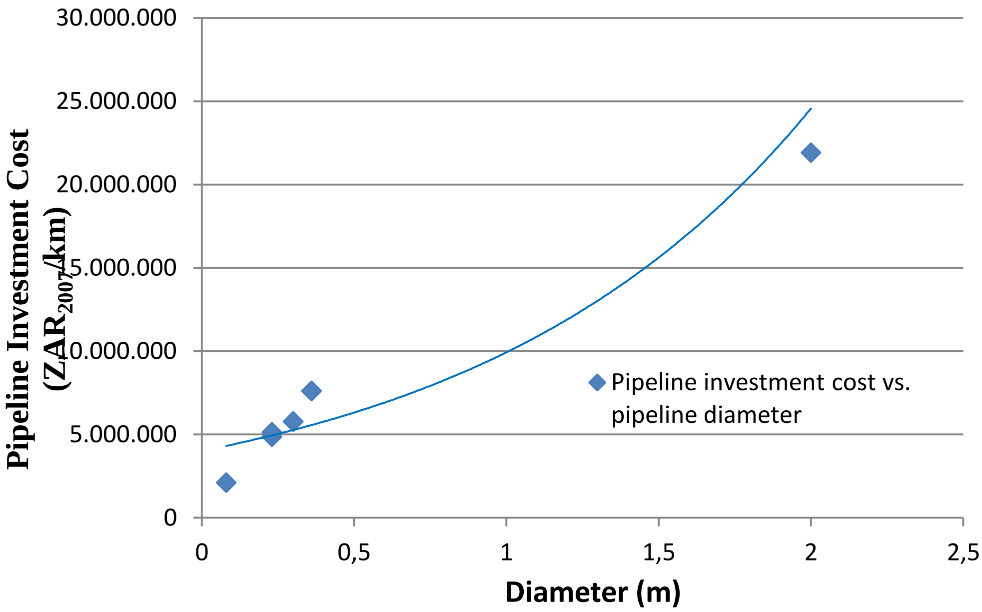

Figure C 2: Hydrogen pipeline investment cost by pipeline diameter (Doods & McDowall, 2012).

In the source Doods & McDowall (2012), for the currency conversion of Great British Pound, the rate of 1£=1.52$ is applied according to inflation and currency rates of the year 2000. In the source Berridge (2010), 1£=1.90$ conversion rate is ued for the year 2009.

Table C 1: Liquefier investment costs by years (Doods & McDowall, 2012).

Model	Cost	2000	2025	2050
UK MARKAL	£$_{2000}$/(GJ.a)	15.00	6.00	6.00
TIAM-UCL	$$_{2005}$/(GJ.a)	31.00	12.00	12.00
UK MARKAL	ZAR$_{2007}$/kW	7,158	2,863	2,863
TIAM-UCL	ZAR$_{2007}$/kW	6,981	2,702	2,702

Table C 2: Liquid hydrogen truck investment costs by years (Doods & McDowall, 2012).

Model	Cost	2000	2025	2050
UK MARKAL	£$_{2000}$/(GJ.a)	4.00	4.00	4.00
TIAM-UCL	$$_{2005}$/(GJ.a)	8.00	8.00	8.00
UK MARKAL	ZAR$_{2007}$/kW	1,908	1,908	1,908
TIAM-UCL	ZAR$_{2007}$/kW	1,801	1,801	1,801

Table C 3: Gaseous tube trailer investment costs by years (Doods & McDowall, 2012).

Model	Cost	2000	2025	2050
UK MARKAL	£$_{2000}$/(GJ.a)	16.00	10.00	6.00
TIAM-UCL	\$$_{2005}$/(GJ.a)	33.00	20.00	12.00
UK MARKAL	ZAR$_{2007}$/kW	7,635	4,772	2,863
TIAM-UCL	ZAR$_{2007}$/kW	7,431.	4,503	2,702

Table C 4: Liquid hydrogen fueling station investment costs by years (Doods & McDowall, 2012).

Model	UK MARKAL	TIAM-UCL	UK MARKAL	TIAM-UCL
Cost	**£$_{2000}$/(GJ.a)**	**\$$_{2005}$/(GJ.a)**	**ZAR$_{2007}$/kW**	**ZAR$_{2007}$/kW**
2000	10.00	20.00	4,772	4,503
2010	9.00	18.00	4,294	4,053
2020	8.00	16.00	3,817	3,603
2030	7.00	15.00	3,340	3,377
2040	7.00	13.00	3,340	2,927
2050	6.00	12.00	2,863	2,702

Table C 5: Efficiencies of delivery technologies (Doods & McDowall, 2012).

Model	Efficiency	2000	2025	2050
UK MARKAL	Liquefier	0.82	0.85	0.85
TIAM-UCL		0.82	0.85	0.85
UK MARKAL	Gaseous Tube Trailer	0.98	0.98	0.98
TIAM-UCL		0.98	0.98	0.98
UK MARKAL	Liquid Truck	0.95	0.95	0.95
TIAM-UCL		0.95	0.95	0.95
UK MARKAL	Hydrogen Pipeline	100	100	100
TIAM-UCL		100	100	100

Table C 6: Liquefier investment costs by capacity (Amos, 1998).

Size	Cost	
kW	$\$_{1995}$/kW	ZAR_{2007}/kW
10	6600	47,408
75	2400	17,239
250	825	5,926
2700	863	6,199
3700	650	4,669
4500	702	5,042
28300	702	5,042

Table C 7: Compressor investment costs by capacity (Amos, 1998).

Size	Cost	
kW	$\$_{1995}$/kW	ZAR_{2007}/kW
170	118000	3,540
380	31750	952
1500	25600	768

Table C 8: Pipeline investment costs by pieline diameter (Amos, 1998).

Diameter	Energy Efficiency	Total Investment cost		
m	%	ZAR_{2007}/kW	£$_{2000}$/(GJ.a)	m€$_{2000}$/km
0.08	99	300,648	630.00	0.23
0.23	100	69,196	145.00	0.53
0.3	100	81,127	170.00	0.63
0.36	100	108,328	227.00	0.83
0.23	77	7,158	15.00	0.56
0.3	95	8,112	17.00	0.63
0.36	98	10,976	23.00	0.83
2	93	954	2.00	2.39

Table C 9: Hydrogen pipeline installation costs by pipeline length (Amos, 1998).

Length	Installation Cost	
km	$\$_{1995}$/km	ZAR_{2007}/km
78.4	237000	1,702,395
108.5	774000	5,559,722
46.9	1000000	7,183,104
731	1250000	8,978,880
561	685000	4,920,426
40.2	132000	948,169

Table C 10: Hydrogen pipeline installation costs by years (FCFP, 2005).

Year	Installation Cost	
	$m\$_{2003}$/km	ZAR_{2007}/km
2003	1.2	6,631,844
2005	1.2	6,631,844
2010	1.0	5,526,537
2015	0.8	4,421,229

Table C 11: Investment costs of hydrogen truck delivery by distance (Berridge, 2010).

Length	Investment Cost	
km	£$_{2009}$/GJ	ZAR$_{2007}$/kW
16	0.2	84
16	1	422
161	0.3	127
161	1.2	506
322	0.7	295
322	1.4	590
805	1.3	548
805	2	844
1,609	2.5	1,054
1,609	3.1	1,307

Table C 12: Investment costs of gaseous hydrogen tube trailer delivery by distance (Berridge, 2010).

Length	Investment Cost	
km	£$_{2009}$/GJ	ZAR$_{2007}$/kW
16	3	1,265
161	7	2,952
322	12	5,061
805	27	11,388
1,609	52	21,932

APPENDIX D (Hydrogen Delivery Distances)

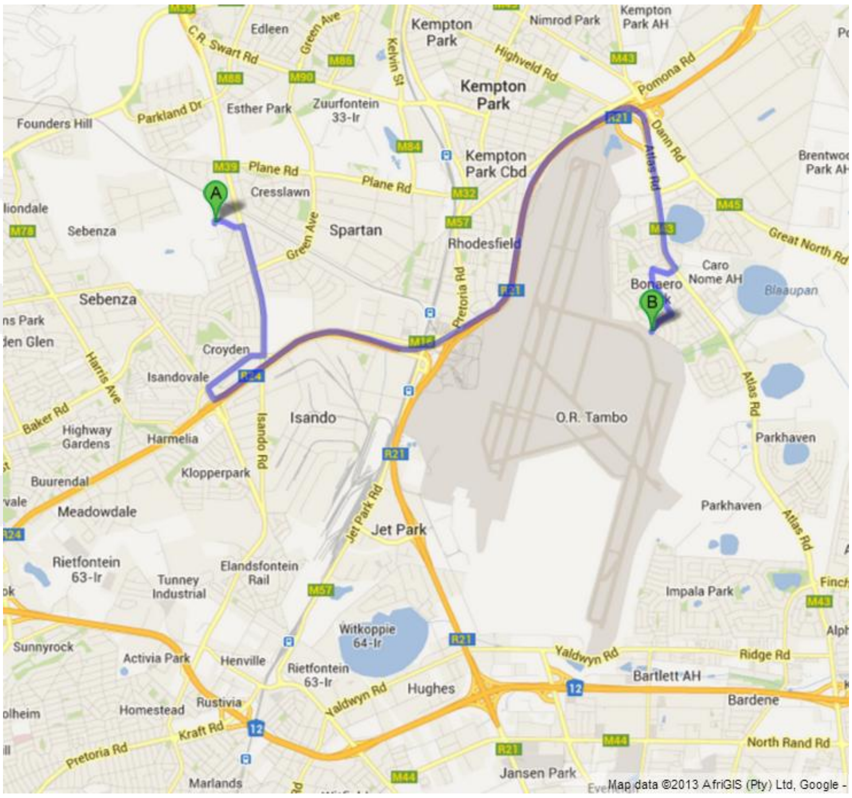

Figure D 1: Kelvin power plant in Gauteng (Google Map, 20013).

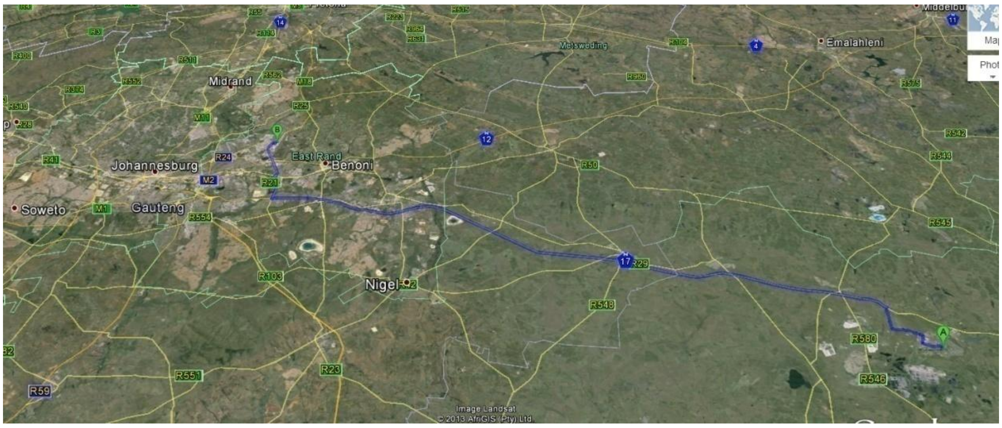

Figure D 2: Distance between OR Tambo International Airport and Sasol Mozambique-Secunda natural gas pipeline.

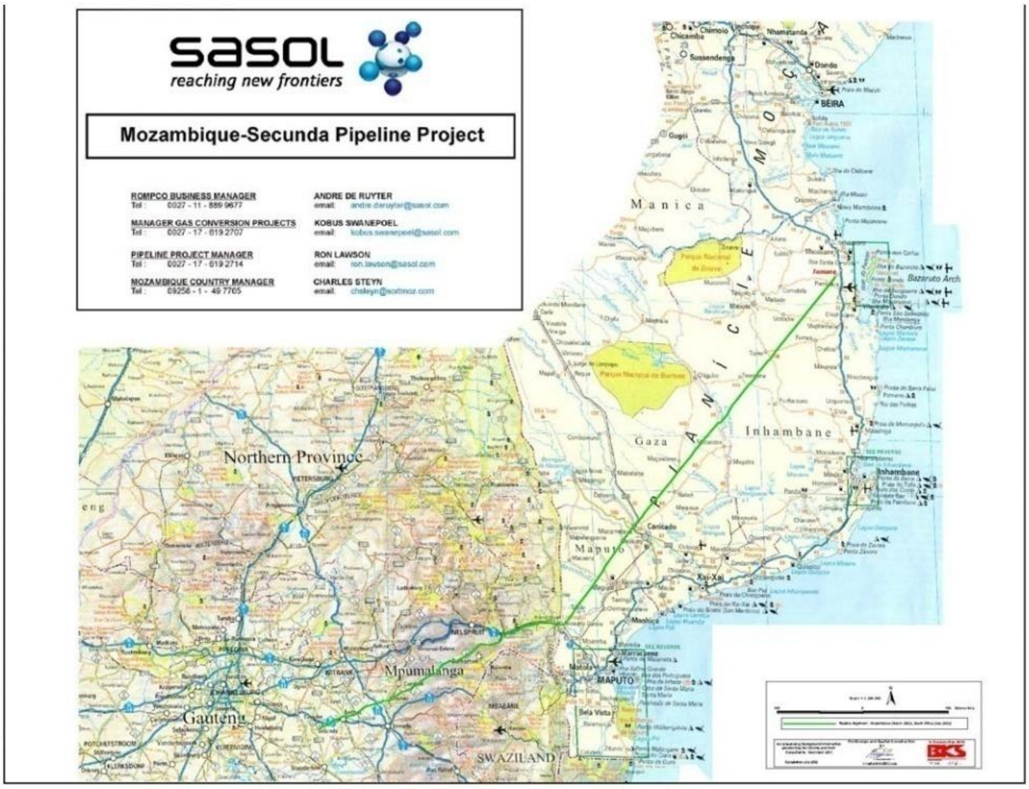

Figure D 3: Mozambique-Secunda natural gas pipeline extension of Sasol in Secunda, South Africa (SASO, 2003).

APPENDIX E (Liquid Hydrogen Aircraft Configurations)

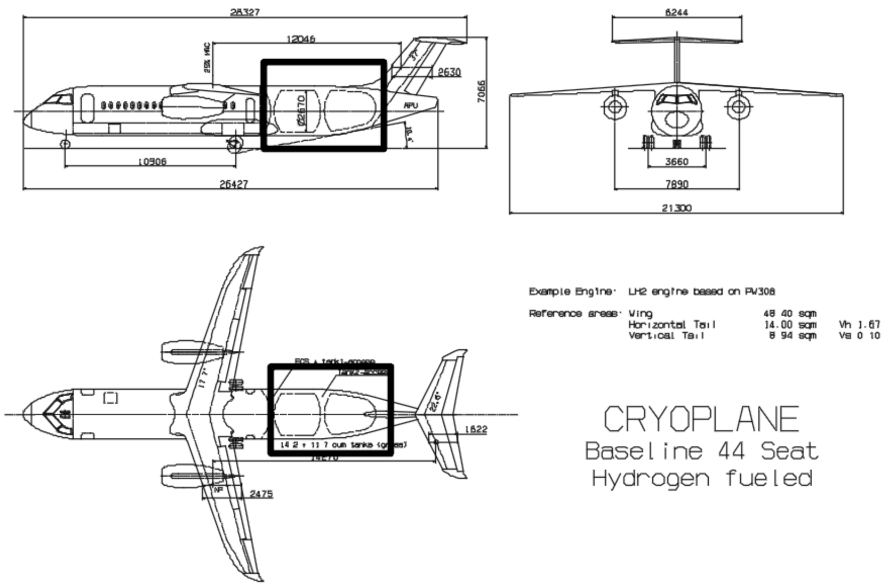

Figure E 1: Small regional aircraft (Westenberger, 2003).

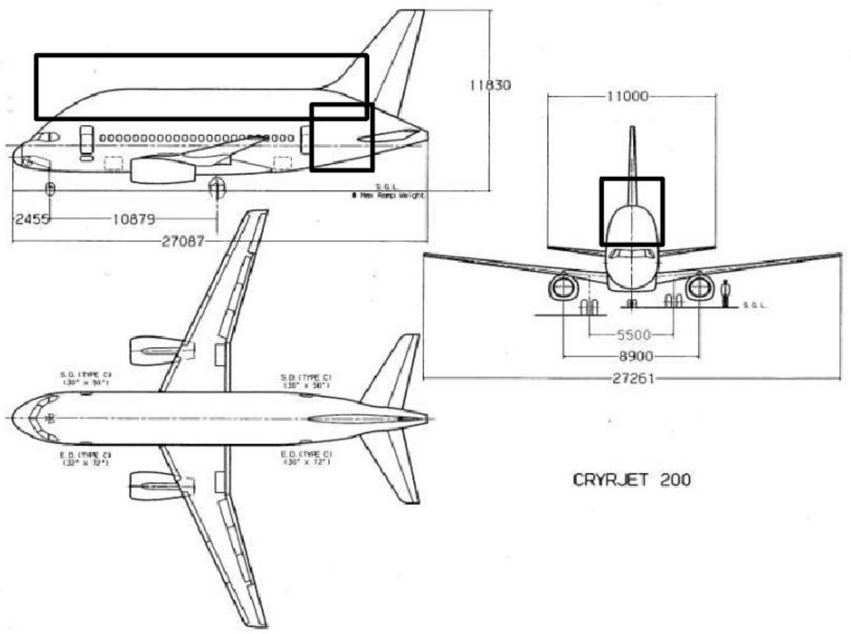

Figure E 2: Standard regional jet (Westenberger, 2003).

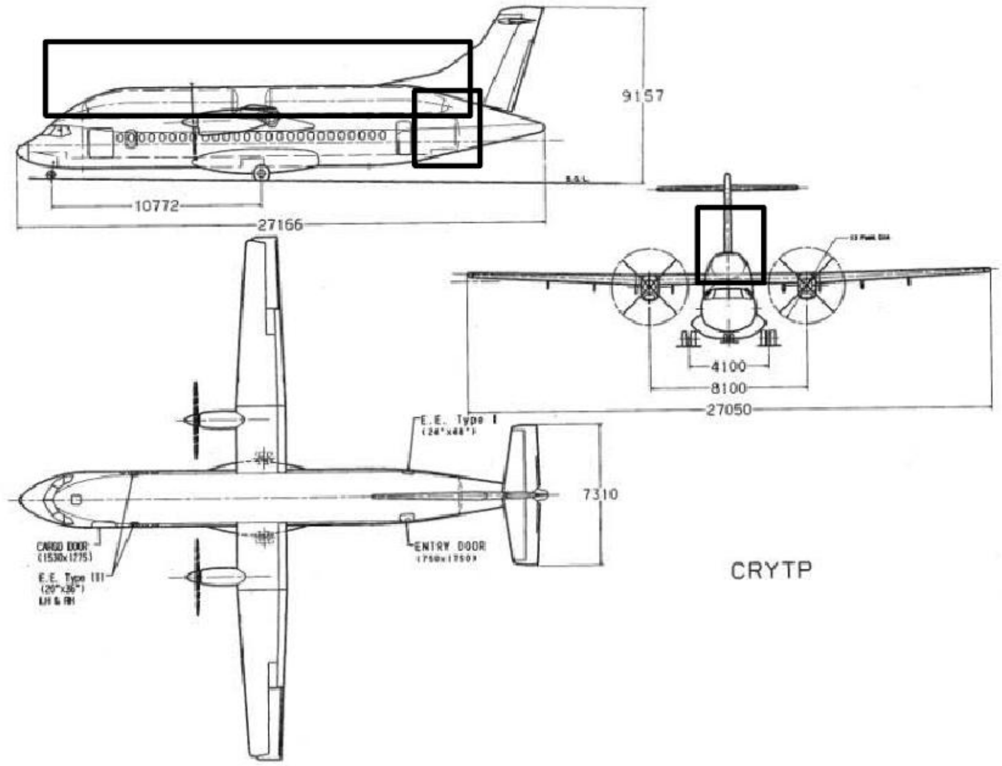

Figure E 3: Standard regional turboprop (Westenberger, 2003).

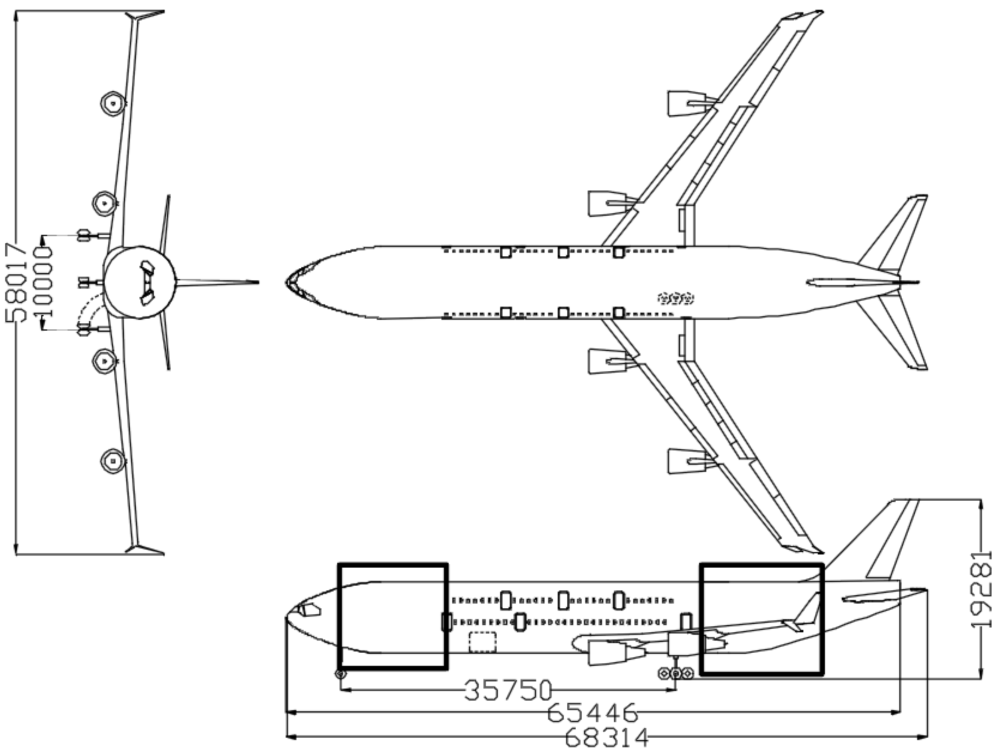

Figure E 4: Long-range aircraft (Westenberger, 2003).

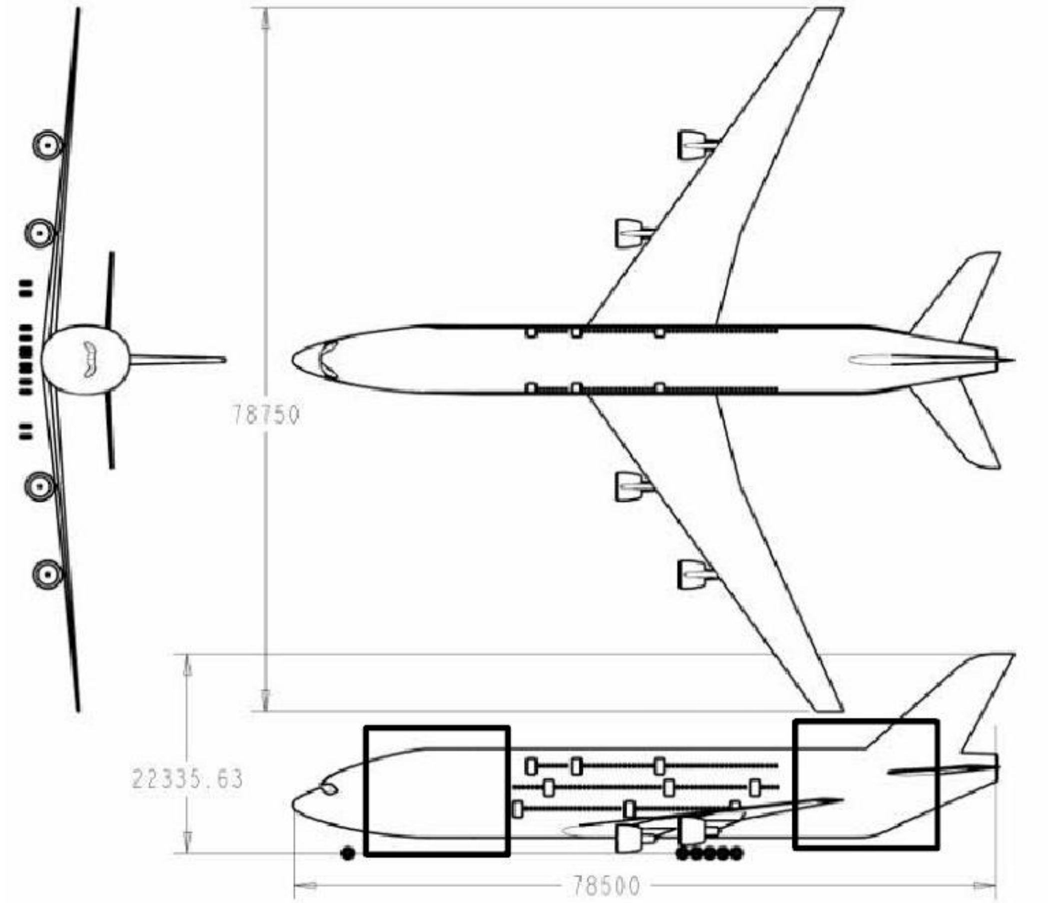

Figure E 5: Large long range aircraft (Westenberger, 2003).

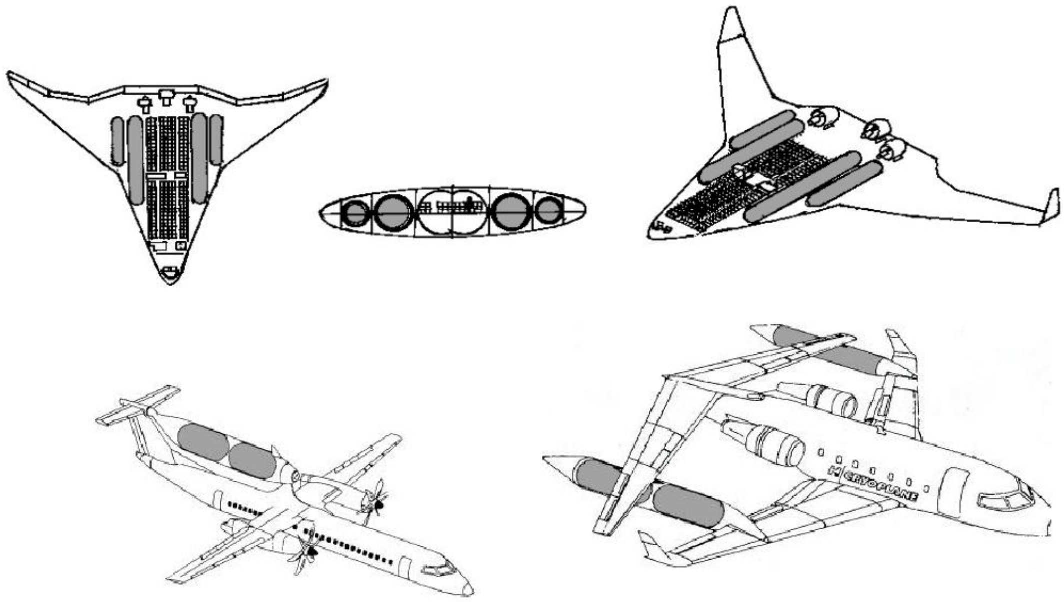

Figure E 6: Unconventional tank configurations for liquid hydrogen (Westenberger, 2003).

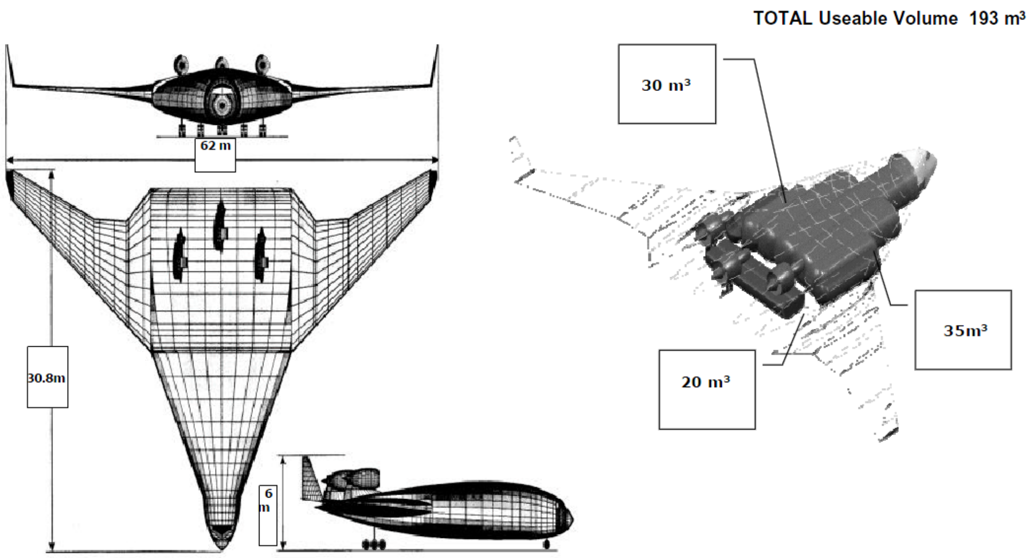

Figure E 7: Unconventional configuration alternative (Westenberger, 2003).

Total usable volume is 193 m3

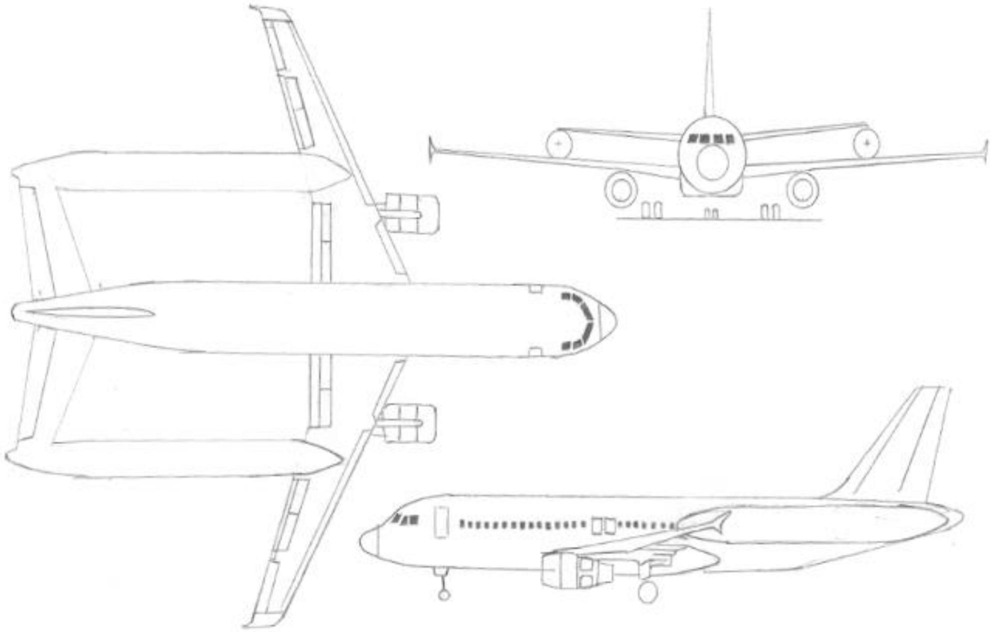

Figure E 8: Unconventional configuration alternative (Westenberger, 2003).

Weight/tank 2,722 kg, total volume 173.6 m^3, diameter per tank is 2.80 m length per tank is 14.0 m (Westenberger, 2003).

APPENDIX F (Hydrogen Aircraft Costs)

Table F 1: Investment costs of kerosene plane and hydrogen plane.

Investment cost passenger.km	Unit in Source	Cost in Source	Unit	Cost
Kerosene plane	(USD /1000 pkm)	80	(ZAR_{2007}/1000 pkm)	571
Hydrogen plane	(USD /1000 pkm)	99	(ZAR_{2007}/1000 pkm)	642

Table F 2: Costs per seat occupied of kerosene plane and hydrogen plane with load factor.

Cost per seat occupied	Assumptions	Unit in Source	Cost in Source	Unit	Cost
Kerosene plane	75% load factor	(USD 1000/seat)	560	(ZAR_{2007} 1000/seat)	3,998
Hydrogen plane	75% load factor, 15% fewer passengers	(USD 1000/seat)	690	(ZAR_{2007} 1000/seat)	4,927

Table F 3: Fuel and capital costs per seat occupied of kerosene plane and hydrogen plane.

Fuel and capital per seat occupied	Assumptions	Unit in Source	Cost in Source	Unit	Cost
Kerosene plane	12% annuity of cost per seat and USD 5/GJ kerosene	(USD/seat)	50,000	(ZAR_{2007}/seat)	357,043
Hydrogen plane	12% annuity, 20% increase in fuel use per seat and USD 20/GJ liquid hydrogen	(USD/seat)	200,000	(ZAR_{2007}/seat)	1,428,172

Table F 4: Emission costs of kerosene plane and hydrogen plane.

Emission costs	Assumptions	Unit in Source	Cost in Source	Unit	Cost
CO_2 emissions for kerosene	0.073 t of CO_2/GJ kerosene	(t/used seat/yr)	730	(t/used seat/yr)	730
Hydrogen plane CO_2 emissions mitigation cost	H_2O and NO_X not considered	(USD/t of CO_2)	206	(ZAR_{2007}/t of CO_2)	1,471

APPENDIX G (Conversion of Monetary Values into ZAR_{2007})

In Appendix G, tables of conversion of all monetary value in to south African Rand in currency of 2007 is explained with related tables. This explanation is a summary of consideration of the various costs related to energy production paths, energy transmission and energy utilization cases. These costs include capital investment, operating costs such as fixed and variable, specific investment costs, interest costs during construction, carbon capture and storage costs. An example of conversion shows how inflation rate and currency conversion are applied. Conversion rates are taken from (IER, 2012b)

Table G 1: Long-term exchange rate for Euro to Rand.

Year	Value
2010	9.6984
2009	11.6737
2008	12.0590
2007	9.6596
2006	8.5312
2005	7.9183
2004	8.0092
2003	8.5317
2002	9.9072
2001	7.6873
2000	6.3899
1999	6.5188

Table G 2: Long-term exchange rate for US Dollar to Rand.

Year	Value
1970	0.71644
1971	0.71265
1972	0.77302
1973	0.69478
1974	0.67944
1975	0.73987
1976	0.86960
1977	0.86960
1978	0.86960
1979	0.84177
1980	0.77898
1981	0.87925
1982	1.08795
1983	1.11420
1984	1.47763
1985	2.23100
1986	2.29021
1987	2.03682
1988	2.27874
1989	2.62563
1990	2.58712
1991	2.76286
1992	2.85061
1993	3.27097
1994	3.54876
1995	3.62747
1996	4.29539
1997	4.60924
1998	5.54328
1999	6.11469
2000	6.93907
2001	8.58327
2002	10.52194
2003	7.56888
2004	6.44949
2005	6.36965
2006	6.78342
2007	7.05392
2008	8.25675

Table G 3: Long-term exchange rate for US Dollar to Rand (Cont.).

2009	**8.41170**
2010	**7.93000**

Table G 4: Cost estimates and baseline year (2005 -> 2007) (Inflation rates).

Year	Index 2007	Index 2007 (old)
1990	29.6	29.6
1991	34.1	34.1
1992	38.9	38.9
1993	42.6	42.6
1994	46.4	46.4
1995	50.5	50.5
1996	54.2	54.2
1997	58.8	58.8
1998	62.9	62.9
1999	66.2	66.2
2000	69.7	69.7
2001	73.7	73.7
2002	80.4	80.4
2003	85.1	85.1
2004	86.3	86.3
2005	89.2	89.2
2006	93.4	93.4
2007	100.0	100.0
2008	111.5	111.5
2009	119.5	119.6
2010	124.6	127.0
2011	130.8	133.5
2012	138.3	139.5
2013	145.9	145.8
2014	153.2	152.3
2015	160.2	
2016	167.4	

Example of monetary conversion:
$50\ US\$_{2003}/\text{unit}$ (Commodity price)

1.Exchange in ZAR_{2003}
$= 50\ US\$_{2003}\, x 7.555$ ZAR/US$ (2003)
$=377.7\ ZAR_{2003}/\text{unit}$

2.Inflation Index
$377.7\ ZAR_{2003}/CPI(2003)x100$
$=377.7/85.1x100$
$=443.9\ ZAR_{2007}/\text{unit}$

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