Utilizing nuclear process heat to reduce the CO_2 generated by an SMR process in a GTL environment

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Mini-dissertation submitted in partial fulfilment of the requirements for the degree Master of Science in Nuclear Engineering at the Potchefstroom campus of the North-West University

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November 2010

Acknowledgements

Recognition must be given to a group of individuals who have provided technical guidance throughout this investigation.

Thanks to Johan Kirsten, who has been a mentor to me in my career thus far. His technical guidance and inspiration has allowed me to arrive at this document with an understanding that what is presented here is relevant and value adding.

Thanks also to Frans Le Roux who was an important resource with regards to his knowledge on reforming technology in general.

Professor P.W.E. Blom, without whom this document and its findings would not have been possible.

Ashwin Karma, a man who has dedicated his time to ensure that young minds do their best to understand and meet their true potential.

Keethan Kander
November 2010

Abbreviations and units

ATR - Auto-thermal reformer
ASU - Air separation unit
FT - Fischer Tropsch
GTL - Gas to liquids
HTGR - High temperature gas (cooled) reactor
HTR - High temperature reactor
HTTR - High temperature thermal reactor
LNG - Liquefied natural gas
PBMR - Pebble bed modular reactor
SMR - Steam methane reformer
Syngas - Synthesis gas

Units and symbols

^{o}C - Degree celcius
$ - Dollar (US)
kg/s - kilogram per second
$km^3{}_n/h$ – Kilonormal cubic meters per hour
MPa - Mega pascal
MW - Megawatt
MWe - Megawatt electric
MWh - Megawatt hour
MWt - Megawatt thermal
R - Rand (SA)
t/h - tons per hour

Abstract

Gas to liquids (GTL) technology, although an attractive method for meeting liquid fuel requirements into the future, has an inherent concern regarding the environmental impact of dealing with the large amount of carbon dioxide that is generated. In this investigation, the potential to reduce this carbon dioxide footprint by utilising process heat from high temperature helium at 950^{o}C downstream of a High Temperature Gas (cooled) Reactor (HTGR) is examined.

The study compares a base case steam methane reformer (SMR) heated by the combustion of natural gas to a nuclear heated steam methane reformer heated by hot helium from one HTGR. It has been shown that it is possible to reduce the carbon dioxide footprint almost entirely for the synthesis block of a GTL facility. Process heat integration from one HTGR has the potential to reduce the carbon dioxide footprint of an SMR by approximately 42 tons per hour.

The full potential of one HTGR in terms of carbon dioxide reduction for a GTL facility was also investigated. This was achieved by estimating the co-generation potential impact on carbon dioxide emissions where the residual heat in the helium stream downstream of the reformer was used for power generation. The overall amount of carbon dioxide reduction from both the reformer and power generation facility was then quantified and an economic study was completed. The study shows that with one HTGR it would be possible to reduce the carbon dioxide emissions of a GTL facility by almost 200 t/h if nuclear process heat was used in the reformer and nuclear power generation was used instead of conventional coal based power generation.
Results from the economic study show that industry would have to incur an operating cost increase of approximately R200, at current natural gas prices, to reduce their carbon dioxide emissions by one ton if nuclear energy was used as a process heat source and for power generation.

Table of contents

Table of tables

Table of figures

Chapter 1 - Introduction

1.1 Problem statement

GTL products, specifically GTL diesel, will have a substantial role to play in global energy requirements for the future. The conversion of natural gas into liquid fuels and other liquid products is referred to as Fischer Tropsch (FT) GTL conversion technology. This technology is proven not only in South Africa with SASOL and Petro SA, but also in Malaysia with Shell and most recently with the successful commissioning of ORYX in Qatar, a joint venture with SASOL. Feasibility of future ventures into this technology depends on natural gas markets and environmental legislation, particularly with regards to carbon dioxide emissions. Hydrogen and carbon monoxide are the critical feed stocks for this technology. The conversion of natural gas into these required components currently comes at the cost of the combustion of a substantial portion of the available natural gas to provide the energy required for the reforming reactions, and which leads to carbon dioxide production. Addressing the carbon dioxide impact of a GTL facility will make this attractive technology even more beneficial into the future. Efficiency improvements in terms of feedstock production from the available natural gas will also improve the feasibility of GTL technology.

This study will investigate the reduction of carbon dioxide generated in a steam methane reformer by utilising nuclear process heat in a GTL environment.

1.2 Objectives

The main objective of this study is to quantify the amount of carbon dioxide that can be reduced from a steam methane reforming process by nuclear heat integration. This study will also quantify the efficiency improvement impacts that may be possible due to improved natural gas utilisation. The feasibility of nuclear process integration with an SMR in terms of unit operating cost and the best case CO_2 reduction potential of an integrated nuclear co-generation plant, where nuclear process heat is used to provide reaction heat and for electricity generation, will also be quantified.

1.3 Literature overview

The literature survey conducted for the study focussed on the following areas:

- The case for gas to liquids technology
- Synthesis gas technology, issues and future potential
- The role of high temperature reactors in process heat applications
- Nuclear heat for hydrogen production
- Safety aspects for nuclear hydrogen production

The survey focussed on the future of GTL and this will be discussed in the following chapter as the promise of this technology puts the potential of nuclear heat integration into perspective.

The available literature addresses the potential for nuclear process heat integration for hydrogen production, but not specifically in a GTL environment. There was no literature found relating specifically to the quantification of carbon dioxide reduction and it is the purpose of this study to address this gap in the academic environment.

1.4 Method of approach

The study was initiated with a literature survey researching subject matter relevant to the topic. The study was then centred on comparing a base case SMR heated by the combustion of natural gas to a nuclear heated SMR, where process heat is supplied by hot helium at 950^{o}C downstream of a high temperature nuclear reactor. The carbon dioxide benefit of the nuclear case was then quantified. The next step was to assess the economic viability of the nuclear case. The study was then extended to investigate the full carbon dioxide benefit offered by a 500 MWt nuclear reactor in a co-generation analysis where electricity is generated with the remaining energy after heat integration with an SMR. This case was compared with a GTL facility that produces synthesis gas from a conventional SMR and that imports electricity from a coal based power plant. The final result of the study is the cost to reduce carbon dioxide emissions based on this last comparison.

1.5 Structure of thesis

Chapter 1 includes an introduction to the research topic, and the main objectives thereof. This chapter also contains a brief overview of the literature survey, method of approach for the study and concludes with an outline of the structure of this document.

Chapter 2 contains a summary of the literature survey with emphasis on GTL and its future, nuclear process heat integration for hydrogen production, hydrogen production in a GTL environment, and safety aspects specific to nuclear process heat integrated facilities.

Chapter 3 contains the results from the actions described by the method of approach. The main results presented in this chapter include:

- Carbon dioxide benefit for nuclear heated SMR
- Relative operating cost comparison
- Co-generation plant carbon dioxide reduction potential
- Relative operating cost for co-generation plant
- Cost of carbon dioxide reduction based on co-generation plant

Chapter 4 includes a detailed discussion of the results from chapter 3. The results of the mass and energy balances are considered from a GTL perspective. The carbon dioxide reduction impact is a focal point of the discussion. The feasibility of the nuclear heated SMR and co-generation plant is also discussed in detail.

Chapter 5 contains the final conclusions from the study including the quantification of carbon dioxide reduction potential and economic feasibility of an integrated nuclear/GTL facility.

Chapter 6 includes recommendations from this research. Areas which require further investigation before the potential of the outcomes of this study can be realised are outlined.

Chapter 7 captures the references of the material used in compilation of this document.

Chapter 8 contains the Appendices including the complete mass and energy balance results and the sample calculations that the results of the study was based on.

Chapter 2 – Literature survey

2.1 Gas to liquids

Gas to liquids technology produces a wide range of products for the petro-chemical industry. Low sulphur and low aromatic content diesel in particular make the environmental benefits for this technology for synthetic fuels production very attractive. Markets in Europe, North America and Asia see this technology as key to meet future energy requirements within expected legislation. Furthermore, the monetisation of natural gas reserves around the world is a great driver for the technology. (Goswami et al, 2003: 14-15)

GTL technology is one way of enabling the monetisation of stranded gas assets. Currently the Middle East offers the most attractive locations for future GTL plants. The main advantage of the region is the low-cost gas that is available. Iran's potential for gas reserve monetisation through GTL is also good. In the medium to long term, Australia, Indonesia and Latin America will also be suitable locations for GTL plants, but, in the near future it is Qatar that will be the focus of GTL development. (Goswami et al, 2003: 14-15)

Currently liquefied natural gas (LNG) is the preferred monetisation alternative for gas reserves. These markets are becoming harder to capture with multiple suppliers competing to secure markets. This trend will push the industry more toward GTL as the technology that makes gas the fuel of the future. (Goswami et al, 2003: 14-15)

A comparison between LNG and GTL-FT by Fleisch et al (2003: 41) stated that GTL-FT manufactures products that are 50% higher in value than LNG, through a 30% less energy efficient process. It was further stated that upstream economics are better for LNG mainly due to the lower cost of a liquefaction plant compared to a GTL plant but on a comparison of the full value chain the economics look better for GTL. It was also stated that with expected technology improvements in both sectors, GTL would have similar integrated returns compared to LNG on a non-risk basis.

Fleisch et al (2003: 41) also address the environmental drivers with respect to GTL. The energy efficiency of GTL-FT currently is approximately 60% while the carbon efficiency is close to 77%. The burning of methane to carbon dioxide in the reformer accounts for the relatively low carbon efficiency and this is considered a significant disadvantage for GTL-FT. Technology improvements focussed on improving the carbon efficiency of the process will do much for improving GTL feasibility.

There are three fundamental steps for a GTL process.
(Michael Waddacor, 2003: 5-7)

- The conversion of methane rich gas (natural gas) via gas reforming reaction into synthesis gas which is a mixture of hydrogen and carbon monoxide.
- The reaction of this “syngas” in a catalysed FT reactor for the production of liquid fuels and chemicals.
- The downstream refining of resulting liquid hydrocarbons into the required slate of liquid fuels.

2.2 Synthesis gas technologies for GTL

The production of synthesis gas for GTL plants is generally based on steam reforming, partial oxidation reforming or a combination of the two. The issue with GTL-FT is that the technology requires syngas with a hydrogen to carbon monoxide ratio of approximately 2. SMR alone achieves a higher ratio and partial oxidation technology achieves lower ratios than required for GTL. A solution has been to use both technologies in parallel to achieve the correct syngas compositions. An alternative approach is to use auto-thermal reforming which combines partial oxidation with catalytic steam methane reforming in one reactor. (I. B Dybkjaer, 2003: 16-17)

The most attractive technology for the production of synthesis gas is auto-thermal reforming (I. B Dybkjaer, 2003: 17). Oxygen from the air separation plant is pre-heated and fed to the reformer together with steam and raw materials. The energy required for the endothermic reaction is provided by the combustion of a large fraction of raw feed material which accounts for the poor carbon efficiency of a GTL facility. Oxygen is used to extinction with the product gas being a mixture of hydrogen, carbon dioxide, carbon monoxide and unreacted methane.

Industrial experience for GTL-FT comes from Shell's FT operation in Bintulu, Malaysia and from the operations of Mossgas and Sasol in South Africa. The Shell plant utilises an SMR in parallel with four partial oxidation reactors to provide syngas with the required composition. (M. Waddacor 2003: 8-10)
The Mossgas plant utilises Lurgi's two-step reforming process with an SMR followed by oxygen blown secondary reforming. A unique feature of the Mossgas installation is the bypassing of a fraction of the natural gas feed around the SMR to the secondary reformer to achieve correct feed compositions to the synthesis reactor. (M. Waddacor 2003: 8-10)
Sasol Secunda's operation is based primarily on coal based FT technology but also operates sixteen oxygen-blown auto-thermal reformers. These units represent the largest oxygen-blown auto-thermal reformers to have been commercially proven to date. A seventeenth reformer, that will be an SMR, is currently planned to be commissioned in 2011 to enable growth aspirations for the facility.

Syngas production costs account for about 50% of the capital investment for a GTL plant, mainly due to the significant capital cost of the air separation plant (Wilhelm et al, 2000). An alternative to oxygen blown auto-thermal reforming is air blown auto-thermal reforming. The advantage of using air instead of oxygen is that the air blown reformer does not require the service of an air separation unit (ASU). The disadvantages of this method however are that there is a requirement for large air compression units and the synthesis gas that is produced has a high fraction of nitrogen. The increased inert fraction in the feed to the synthesis block reduces its capacity to complete synthesis reactions and will affect yields negatively (I. B Dybkjaer, 2003: 18).

The most attractive technology presently is oxygen blown ATR and is the technology of choice for GTL projects in the near future. (I. B Dybkjaer, 2003: 19). The disadvantages of this technology into the future are:

- A large fraction of feed is required to be combusted for the energy requirements for the reforming reactions to occur, which leaves room for improvement in terms of natural gas efficiency.
- Carbon dioxide is produced as a result of this and this carbon dioxide must be dealt with in a CO_2 removal facility which inevitably will be vented to atmosphere. The legislative impacts of this carbon footprint into the future are considered a risk for GTL feasibility.
- ATRs require an ASU for oxygen production which carries a large fraction of the total capital cost for a GTL facility.

This study will address these issues offering a new technology for synthesis production that will improve the future aspirations for gas to liquids technology.

2.3 High temperature gas reactors and their role in process heat applications

High temperature nuclear reactors have opened up new doors for nuclear process heat integration opportunities due to the high temperature heat that is made available and the small, intrinsically safe reactor design that allows nuclear locations in close proximity to process plants. Currently, high temperature process heat applications are satisfied by the combustion of fuels like natural gas in the reforming environment. These combustion reactions lead to the emission of large amounts of carbon dioxide and the consumption of natural resources. HTR nuclear heat integration has the potential to lessen the requirement of these combustion reactions and reduce carbon dioxide emissions while also improving natural resource usage. Kuhr (2008)

The result by Kuhr (2008) is that the present value in 2020 of savings over a thirty year operation of displacing 500 MWt equivalent of natural gas can be 1-2 billion (2007) dollars. In many applications, the high initial investment in an HTR may be considered to represent a prepayment of a process plants future fuel gas costs. The feasibility of an HTR project will therefore depend on the perception of future natural gas pricing.

The economics and financing of the energy industry is currently under threat due to concerns regarding global warming. Carbon emissions taxes will severely impact the relative cost of energy and process feed stocks. The opportunity to implement advanced nuclear technology in mitigation of future uncertainties in this regard is an attractive long term strategic planning option for industry. Carbon dioxide emissions credits have been already defined in Europe, Canada and other countries with the US to follow suit in the next decade. Legislation passed in Canada has limited the cost penalty for carbon dioxide emissions to $20 per ton by 2015. Kuhr (2008) also calculated the potential value of displacing 500 MWt equivalent of coal based energy on reduced carbon dioxide emissions. A 500 MWt HTR could be worth 0.5-1 billion (2007) dollars if carbon emission credits are between $20-30 per ton. The assumptions here are again thirty year operation from 2020-2050.

Steam production, co-generation, steam methane reforming and the splitting of water for the production of hydrogen are areas that have the greatest potential for this technology. There are many challenges to be overcome before HTR can enter into process markets as presented by Kuhr (2008):

- Customer comfort with regards to nuclear safety and nuclear fuel cycle issues are a stumbling block. Public concerns include worker concerns related to radiation release and exposure, plans for spent fuel disposal, decommissioning requirement obligations, uncertain nuclear regulatory requirements and government response to new nuclear related initiatives. New HTR designs offer worker and public safety factors that are orders of magnitude improved compared to conventional nuclear reactors, but whether this enhanced safety will be appreciated by nuclear regulators is still to be seen. Current experience with nuclear regulatory bodies indicates a wanting to impose further safeguards to an intrinsically safe design, which will no doubt challenge HTRs economic viability in many proposed applications.

- The technical integration of nuclear reactors with process plants will also require the convergence of process industry and nuclear industry safety and risk management approaches. The hazards relating to operating a large hydrocarbon processing plant with its storage facilities in close proximity to HTRs must be carefully examined.

- Nuclear proliferation concerns must also be resolved, especially in countries where proliferation safeguards are not well developed, before this technology can enter mainstream industrial plans. HTR technology inherently is averse to nuclear proliferation due to the high fuel burn-ups that are possible. This safety feature will go a long way in improving sentiment around this nuclear technology.
  Government perceptions and their policies with regards to the deployment of HTRs for process heat applications will depend strongly on economic viability, the willingness of major private industries to invest in this technology, the demonstration of the carbon dioxide benefit that can be economically achieved via this technology, and confirmations that the enhanced safety features of HTRs are real and accepted by nuclear regulators.

- Other challenges that need to be addressed include the requirement for the development of new nuclear fuel cycles, construction and transportation requirements and the lack of business entities and models that can make the commercialisation of the technology possible.

- Technology advancements in heat exchanger design to handle high temperatures and pressures, convective process reactors, water splitting components and other specialised components specifically in the materials of construction must occur to enable the commercial use of this technology. New heat exchanger and related components capable of operating at temperature and pressures of around 900°C and 9 MPa respectively will be needed to interface high temperature gas from nuclear units with process units. The new equipment will have to be able to operate at conditions beyond currently achievable in current power and process plants.

- The drivers for the future of this technology lie in future availability and cost of fuel, and implementation of carbon emission taxes. Nuclear licensing frameworks that require the support of international energy and environmental policy will also be required to support private investment.

2.4 HTR process heat integration for hydrogen production

Hori et al (2005) detail the potential of heat integration of nuclear process heat with hydrogen production. Cost estimates from their contributions show that only a nuclear heated SMR process could compete economically with the fossil fuel combusting SMR process for hydrogen production. Their work also showed that the foremost feature of nuclear heated SMR is reduction in fossil fuels consumption and consequently the significant reduction in carbon dioxide emissions, per unit of hydrogen produced. As much as 30% of natural gas could be saved in the quest to produce the same amount of hydrogen according to Hori et al.

2.5 Safety aspects of the combined HTR/Steam reforming complex

In Oarai, Japan, the construction of a high temperature engineering test reactor has been completed. The reactor is a 30MWt graphite-moderated, helium cooled test reactor. This system was used by Verfonden et al (2005) to assess critical safety aspects for the merging of two technologies in the quest for hydrogen production to supply a new world hydrogen economy.

The HTTR consists of a primary and secondary helium loop. The two loops transfer heat in an intermediate heat exchanger. The secondary loop helium then flows outside the catalyst tubes of the SMR, transferring heat for the reforming reaction by forced convection.

If a nuclear power plant is to be directly connected with a chemical plant to provide electricity and process heat, particular safety aspects must be considered. The work of Verfonden at al (2005) concluded the following important results:

- The combustion of an unconfined LNG vapour cloud in the atmosphere will normally result in a flash fire and is very unlikely to produce damaging pressure waves.
- Gas mixtures typical for a gas factory cannot generate pressures beyond the design curve given in the German BMI guideline.
- Calculations have shown that under certain boundary conditions for release rate, methane vapour cloud explosions on the HTTR would have no significant influence on the building.

Chapter 3 – Results

3.1 Research methodology

The results in this chapter are based on a comparison between Aspen simulations of a steam methane reformer heated by the combustion of natural gas and a nuclear heated steam methane reformer. In the latter case, the heat was supplied by Helium at 950^{o}C downstream of a high temperature gas reactor. The simulation results give an indication to the amount of carbon dioxide that can be reduced if nuclear process heat is utilised for the heat of reaction instead of conventional combustion reactions. These results also form the basis of a techno-economic analysis where the relative operating costs of both scenarios are compared. The study was then extended to understand the full impact of an integrated nuclear process heat and electricity generation facility in a GTL environment in terms of carbon dioxide reduction and basic economic feasibility.

3.2 Process flow description

3.2.1 Aspen base case flow sheet

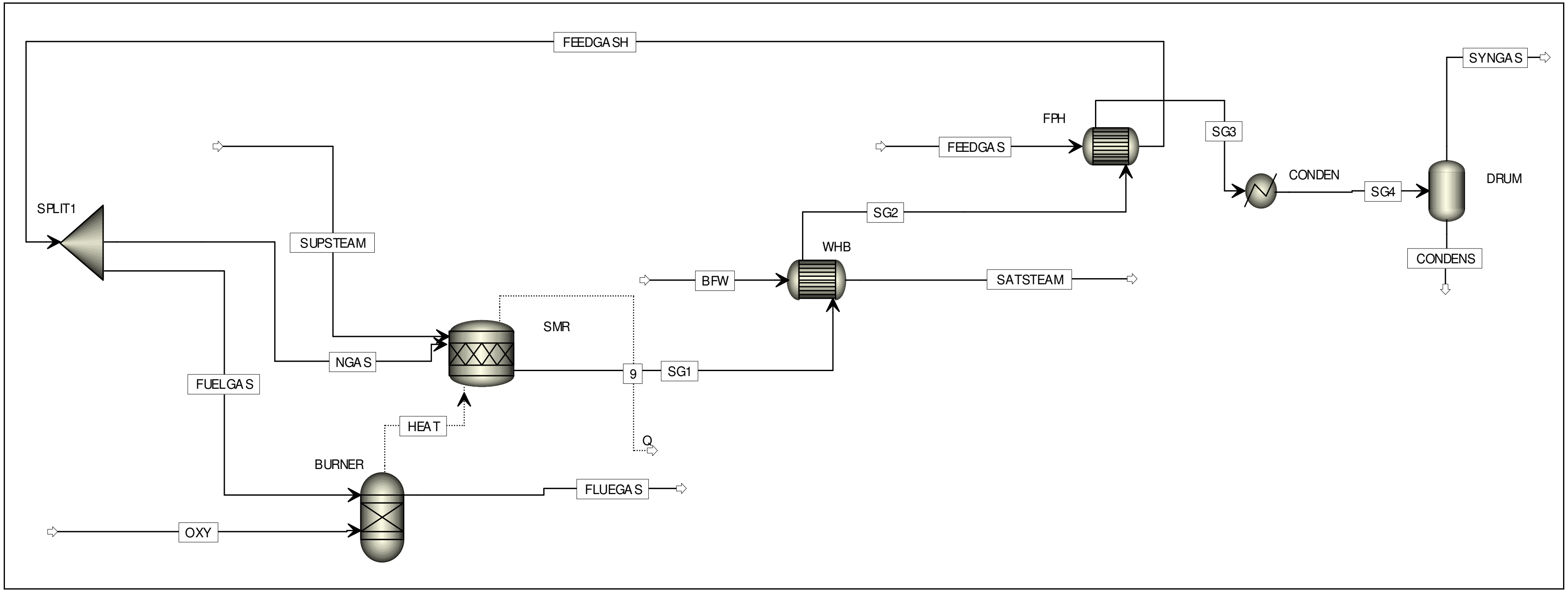

Figure 1: Base case flow sheet

3.2.2 Aspen nuclear case flow sheet

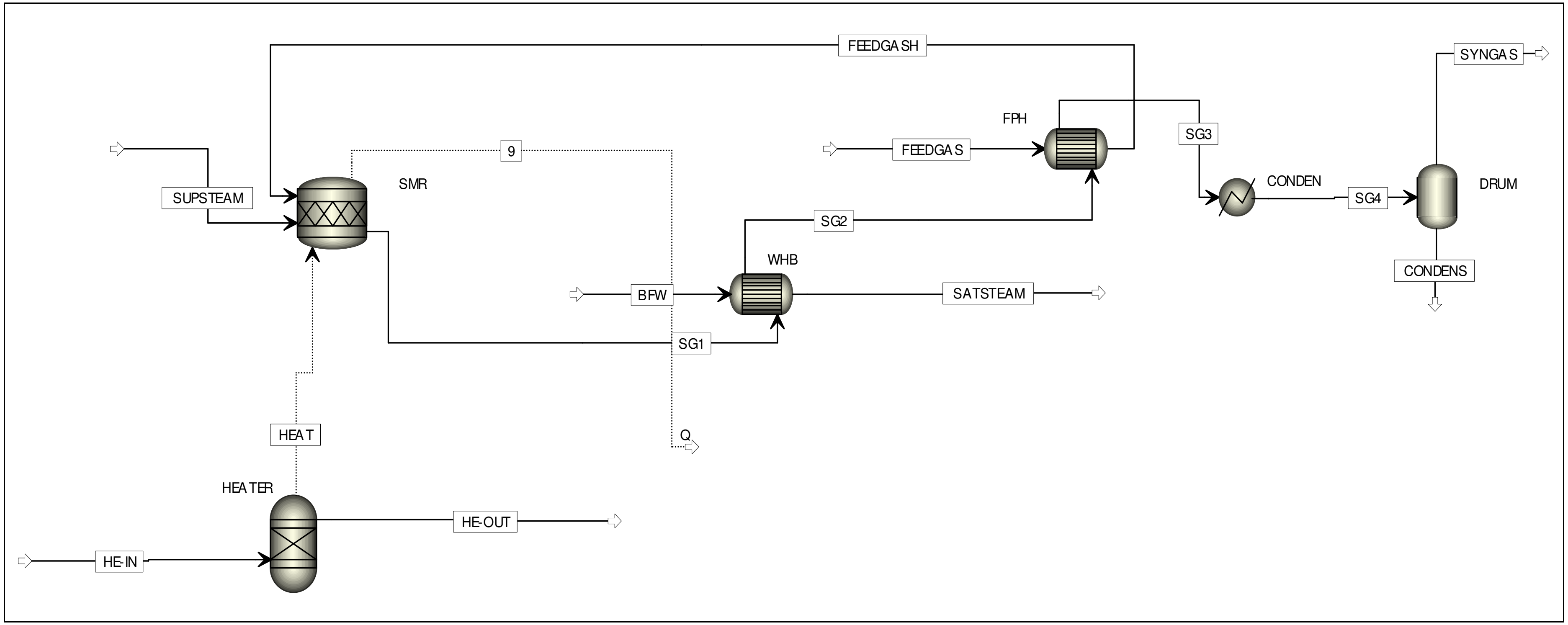

Figure 2: Nuclear case flow sheet

3.2.3 Assumptions

- Simulations were based on a steam methane reformer that converts 40 km^3_n/h of natural gas with 95% methane concentration into synthesis gas at an operating temperature of 800°C.[1]
- A methane conversion of 90% was assumed.
- A steam to natural gas ratio of 3:1 was utilised in both cases.
- The reactor model used for the comparison was a stochiometric reactor where two reactions occur in series namely:
    - Reforming reaction to 90% methane conversion.
    - Water gas shift reaction.
- The process flow and downstream heat integration for both cases were identical apart from the method of heating to supply reaction temperature.
    - Base case utilises an air blown furnace with a side stream of natural gas feed for fuel gas requirements at 65% efficiency consistent with industry standards.
    - Nuclear heated case utilises high temperature helium at a flow rate of 169 kg/s and at a cost of $113/MWh. The amount and cost of available high temperature helium is consistent with what can be currently supplied by a single HTGR. The value of $113/MWh was based on the cost of thermal energy from a 500 MWt HTGR at $30/MWh. The nuclear case requires 132 MW but the cost to supply the full 500 MWt was accounted for in the initial analysis.
- In comparison of full carbon dioxide reduction potential, it was assumed that 147MWe could be produced taking into account a 40% efficient power generation facility with the residual heat downstream of the SMR for the nuclear case. The power generation facility was not simulated. Results that are presented are based on the remaining heat of the 500 MWt in the helium stream downstream of the SMR being converted to electrical power at a thermal efficiency of 40%. The equivalent coal based power

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[1] Source for assumptions on base rates, compositions and conversions cannot be referenced due to confidentiality requirements

production impacts were then considered based on industry standard and available literature.

- High temperature helium (800°C – 950°C) would supply the process heat required for the reformer while the helium energy below 800°C would be available for power generation for the nuclear case in the final part of the study.

3.2.4 Base case process description

The feed stream (FEEDGAS) passes through a feed pre-heater where the natural gas feed is heated by the product stream (SG2) up to 450°C. The stream (FEEDGASH) then goes through a splitter block where a design specification was used to feed the burner with enough feed to achieve the required reactor duty of 132 MW with a steam methane reformer feed of 40 km^3_n/h. The heat was transferred to the SMR through the HEAT stream in the process flow diagram.

The burner was modelled as a furnace using the RYIELD model in Aspen. Excess oxygen was used to feed the burner for complete combustion of the natural gas feed.

The reformer was modelled as a steam methane reformer using the RSTOICH Aspen reactor model with the reforming reaction and water gas shift reaction occurring in series. Super heated steam with a flow of 120 km^3_n/h and a temperature of 420°C was fed to the SMR along with the pre-heated natural gas feed. The reactor temperature was 800°C at a pressure of 25 bar (g) and the methane conversion was 90% for the reforming reaction with 1% of the CO produced available for the shift reaction. The SMR reactions were respectively:

1. $CH_{4(g)} + H_2O_{(g)} \rightarrow CO_{(g)} + 3H_{2(g)} + 206kJ/mol$
2. $CO_{(g)} + H_2O_{(g)} \rightarrow CO_{2(g)} + H_{2(g)} - 41kJ/mol$

Downstream of the SMR, the product stream (SG1) transfers heat with 20 t/h of boiler feed water in a waste heat boiler that produces 20 t/h of saturated steam. The product stream (SG2) then passes through a feed pre-heater where it transfers heat to the natural gas feed to the SMR. The product stream (SG3) then feeds a condenser where un-reacted steam is condensed. The water is knocked out in the knockout drum (DRUM) and the dry product gas (SYNGAS) leaves the overheads of the unit with a hydrogen concentration of 72% and CO concentration of 24%.

3.2.5 Nuclear case process description

The nuclear case was modelled in the same fashion as the base case described above with the only difference being the source of reaction heat. This duty was supplied by a helium stream at 169 kg/s at 950^{o}C transferring heat to the SMR via the HEAT stream in figure 2. The helium leaves the process at 800^{o}C. Both simulation cases produce the same amount and composition of synthesis gas.[2]

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[2] Complete mass and energy balances available in Appendix A

3.3 Carbon dioxide benefit for nuclear heated SMR

To understand the full potential of carbon dioxide reduction for the integrated nuclear case, the study also considered the potential for power generation of this helium stream downstream of the SMR HEATER. This analysis was based on the fact that only 132 MWt of the available 500 MWt in the Helium stream was utilised by the SMR. At 800°C, it was assumed that the remaining 368 MWt could be converted to electrical power at an efficiency of 40%. The detail of the power generation facility was not considered as part of this study.

Table 1: Aspen simulation results

	Base case	Nuclear case
Steam [km^3_n/h]	120	120
Natural Gas to Reformer [km^3_n/h]	40	40
Hydrogen produced [km^3_n/h]	103	103
CO produced [km^3_n/h]	34	34
Synthesis gas H_2:CO ratio	3	3
CO_2 generated in reformer [km^3_n/h]	0.34	0.34
Natural Gas to Furnace [km^3_n/h]	21	-
CO_2 generated in Furnace [km^3_n/h]	21.49	-
Methane conversion [%]	90	90
Reformer duty [MWt]	132	132
Helium [kg/s]	-	169
H_2:Natural gas	1.7	2.6
H_2 efficiency improvement [%]	-	53

The table above captures the key assumptions, inputs and results from the simulation work for the study. The important results are the amount of carbon dioxide reduced by utilizing nuclear process heat as opposed to combustion heat and also the quantification of the natural gas utilisation improvement that is defined above by the H_2:Natural gas ratio increase for the nuclear case. These results will be expanded on in Chapter 4.

3.4 Relative operating cost comparison

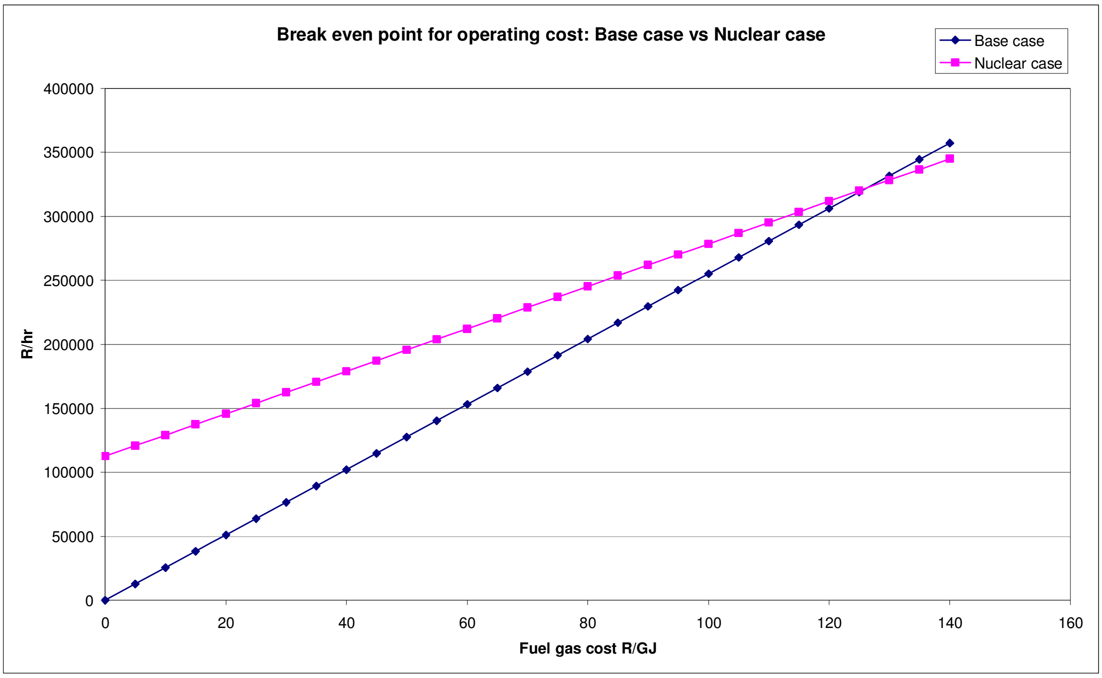

Figure 3: Relative operating cost comparison of base case vs nuclear case SMR

Figure 3 shows the relative operating cost for both SMR scenarios at varying fuel gas costs. The findings here show economic feasibility at ~ R130/GJ fuel gas cost based on relative operating costs for the nuclear case. The following assumptions were relevant for this part of the study:

- Nuclear heated case utilises high temperature helium at 950°C and a flow rate of 169 kg/s. The cost of thermal energy from a 500 MWt HTGR is \$30/MWh but the heat requirement for the reformer is 132 MWt. To arrive at a fair value of nuclear thermal energy for this case, the total cost of the thermal energy from the 500 MWt facility was used to supply the required 132 MWt to the reformer. The cost that was calculated was \$113/MWh.
- Rand to dollar exchange rate of R7.50:\$1
- Heating value of fuel gas: 41.5 GJ/ km^3_n

3.5 Co-generation plant carbon dioxide reduction potential

Table 2: Co-generation carbon dioxide reduction potential

	Base case	Nuclear case
SMR duty [MWt]	132	132
CO_2 produced in burner [t/h]	42	42
Electricity produced [MWe]	147	147
CO_2 footprint for electricity production [t/h]	145	-
Total CO_2 reduction [t/h]	-	187

The outcomes of the analysis of full carbon dioxide reduction potential including a co-generation plant where the residual heat downstream of the SMR is used for electricity production is shown in table 2. The assumption is that the power plant will operate at an efficiency of 40% to convert the remaining available heat (368 MW) to produce 147 MWe that will be used by the GTL facility. The 40% efficiency assumption is aligned with current industry expectations for nuclear power plants. The equivalent carbon dioxide produced in a conventional coal based power plant was calculated based on industry standard[3]. The cost of electricity was based on R334/MWh[4] for the coal based process and $30/MWht for the nuclear case.

3.6 Relative operating cost for co-generation plant

Figure 4 below extends the analysis of relative operating costs to include the cost implications related to the generation of 147 MWe in both the base and nuclear case. The break even point in terms of operating cost drops significantly to ~ R76/GJ for natural gas compared to the value of R130/GJ where power generation was not considered.

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[3] Sample calculation available in Appendix B section 8.2.2

[4] Current industry cost from Eskom

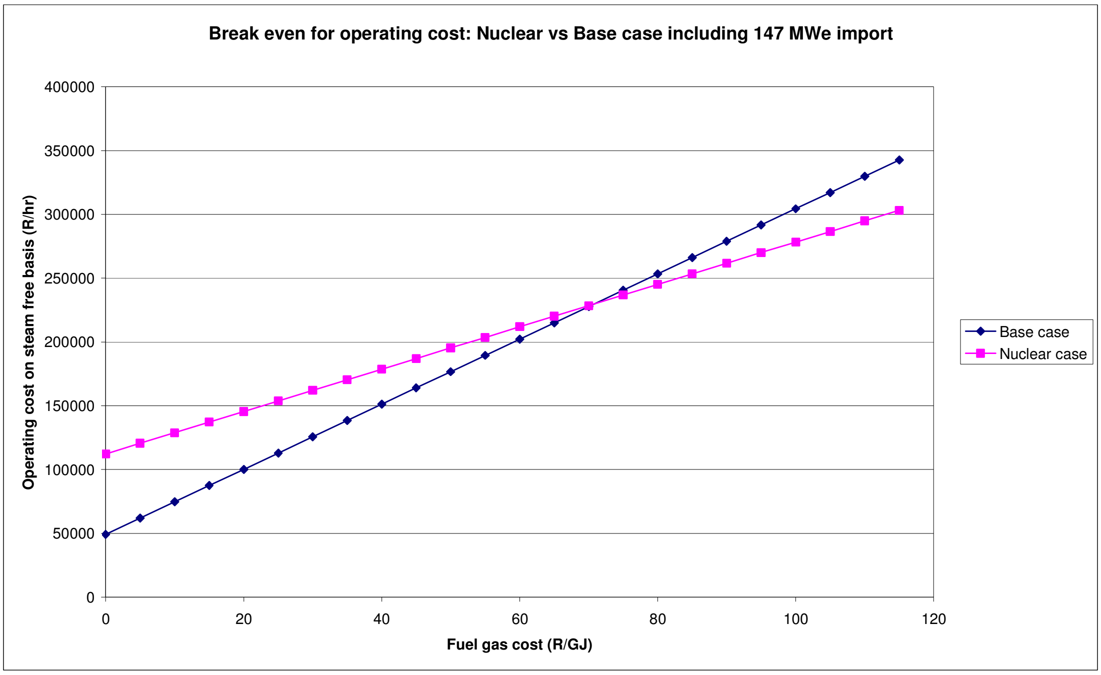

Figure 4: Relative operating cost for co-generation facility

Figure 5 below, goes further to estimate the cost per ton of carbon dioxide emission reduction. The data for this analysis was based on the previous results and does not include possible carbon dioxide emissions taxes. The figure was generated by understanding the difference in relative operating costs between the base case to produce synthesis gas using combustion reactions and power import at the current industrial rate of electricity, and the alternative, using nuclear energy to supply process heat for synthesis gas production and power generation. The total carbon dioxide savings were derived from the mass balance results and some understanding of the carbon dioxide footprint of a coal based power station. The important result is that at a natural gas cost of ~ R30/GJ it would cost industry in the region of R200 to reduce their carbon dioxide emissions related to a syngas production facility by one ton based on the assumptions of Table 2.

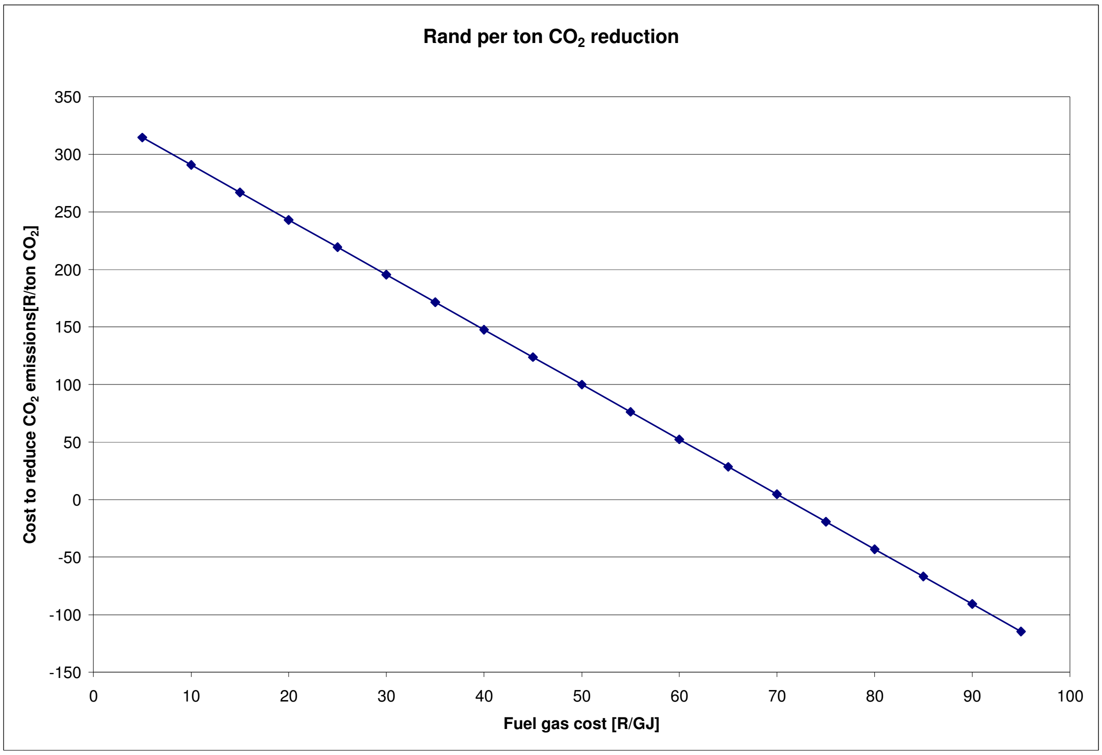

Figure 5: Cost (operating) of carbon dioxide reduction

Chapter 4 - Discussion

4.1 Mass and energy balance

The initial part of this study considered the detailed mass and energy balances that enabled the quantification of the reduction of the amount of carbon dioxide generated in an SMR that is heated by nuclear heat in a Gas to Liquids environment. The potential for the environmental impact of such an integration of technologies has been thought to be positive and the results presented in the previous chapter quantify that benefit in terms of carbon dioxide reduction and natural gas utilisation. These results are considered from a GTL perspective.

There are three main processing sections of a GTL facility namely:

- Synthesis gas preparation
- FT synthesis block
- Product work-up

The synthesis gas preparation block is the most important and is responsible for ~ 60% of the capital investment for a GTL facility. (I. B Dybkjaer, 2003: 16). The FT block requires different synthesis gas properties depending on the type of FT catalyst used. The generally accepted catalyst technology for new GTL ventures is based on a cobalt catalyst. The ideal hydrogen to carbon monoxide ratio for synthesis gas is ~ 2:1 and is critical for product conversion in the FT block.

The current industry tendency is to use oxygen blown auto-thermal reforming as the main unit operation to produce synthesis gas. The synthesis gas composition is controlled by utilizing a pre-reformer and recycling carbon dioxide rich product gas. These levers are manipulated to achieve a synthesis gas ratio of close to 2:1. (Wilhelm et al: 2001)

The key unit operation for the Aspen based comparison was a steam methane reformer. The choice of this technology was based on the fact that nuclear integration with a reformer is the only viable option in an SMR as the combustion of natural gas is not required in the reactor. Natural gas feed at 40 $km^3{}_n/h$ is converted to synthesis gas at a reformer temperature of 800^oC. A methane conversion of 90% via the steam methane reforming reaction and the water gas shift reaction occurring in series, produces synthesis gas with a hydrogen to carbon monoxide ratio of ~ 3:1. This composition of synthesis gas is not ideal for cobalt based FT conversion. This implies that although the potential for carbon dioxide reduction for an integrated nuclear and SMR block is good, a correction of the synthesis gas composition is required.

The mass and energy balances completed in Aspen yielded a reformer with a duty requirement of ~ 132 MW to achieve the required conversions with the defined stream inputs and reactor conversions. This energy is supplied by the combustion of ~ 21 $km^3{}_n/h$ of natural gas in the base case simulation and the heat transfer of nuclear heated helium at a flow rate of 169 kg/s and an inlet temperature of 950^oC for the nuclear case. The carbon dioxide produced via the water gas shift reaction in the reformer for both cases is identical but the nuclear case has the advantage of not requiring any sort of carbon dioxide producing combustion for heat requirements. The base case produces ~ 21.5 $km^3{}_n/h$ or, in mass terms, ~ 42 t/h of carbon dioxide. This is the amount of carbon dioxide reduction possible by the integration of one 500 MWt high temperature nuclear reactor with a basis of 169 kg/s and 950^oC and one SMR with a basis of 40 $km^3{}_n/h$ to produce synthesis gas with a H_2:CO ratio of ~ 3:1.

The other main outcome of the mass and energy balance section of this study is the quantified improvement in natural gas utilisation. H_2:Natural Gas ratio increases by 53% implying that the efficiency of a nuclear heated SMR in terms of natural gas utilisation for the block increases significantly. This efficiency improvement will be fully appreciated in the relative operating cost analysis that follows in the discussion.

4.2 SMR heat integration feasibility

The next part of the study investigated the relative feasibility of producing synthesis gas via the two cases described above. Figure 3 illustrates the results of this analysis and is based on the utility costs namely:

- 40 $km^3{}_n$/h of natural gas for feed gas in both cases
- 21 $km^3{}_n$/h of natural gas for fuel gas requirements for the base case
- 169 kg/s of helium at a cost of $113/MWh

Steam costs were not considered as this utility was constant in both scenarios. The flow sheet downstream of the reactor blocks in both cases uses the high temperature product gas to produce saturated steam in a waste heat boiler. The synthesis gas preparation block is therefore considered to be steam neutral as it produces steam in the same magnitude as it requires. The utility cost of steam was hence not required for the relative operating cost analysis illustrated by Figure 3.

The analysis shows the dependency of economic viability on the cost of fuel gas. The assumption for the base case is that the fuel gas required in the furnace is a side stream of the natural gas feed into the synthesis gas preparation block. In the conventional ATRs, the choice of fuel gas is not an option, as the feed gas undergoes oxidation in the burner section of the reformer to allow the reforming reactions to occur. The assumption of natural gas for fuel gas for the base case was hence justified as, in a GTL environment, this is currently the case if ATR technology is used.

The results of the relative operating cost analysis for both options showed that at a cost of fuel gas of ~ R130/GJ, the nuclear case becomes feasible. The driver for this result is the amount of fuel gas that is saved by utilising nuclear heated helium instead of natural gas. The results of the mass and energy balances show that the nuclear case has the potential to produce the same amount and quality of synthesis gas by using ~ 33% less natural gas by avoiding the combustion reactions of natural gas. This result is important for the future of GTL technologies where the price of natural gas is expected to increase with the depletion of resources.

Currently, GTL ventures are limited to areas of the world like the Middle East (Goswami, 2003: 15) where natural gas feed stock is considered stranded and low cost. The result also shows that GTL can be a competitive option in areas of the world where natural gas feed stock is more expensive, if the potential for nuclear integration is tapped.

The rising cost of oil and subsequent fuel prices together with tighter fuel specifications and other environmental constraints will also drive the feasibility of GTL technology into the future. The potential of the significant efficiency improvement with regards to natural gas utilisation should not be underestimated. Furthermore, life cycles of GTL facilities can be increased substantially due to the improvement in natural gas utilisation. Currently GTL technology consumes 12% more non-renewable resources by mass than traditional crude oil refining to produce the same spectrum of products (D. Dowdell, 2003: 23). The potential for GTL integration with nuclear heat changes this picture significantly making the technology more attractive in terms of a sustainable solution for the energy requirements of future generations.

The analysis has not included the expected legislation with regards to carbon dioxide emissions. Taxes are expected in the near future and this will force industry to consider cleaner options for the production of liquid products by reducing the viability of conventional technologies. The impact on the future of GTL technology will be significant with the feasibility of a nuclear heated reforming unit becoming more feasible than the results of the previous chapter. This issue will be developed further later on in this discussion.

The analysis up to now has two major shortcomings, namely:

- The total carbon dioxide impact that one high temperature nuclear reactor can have on a GTL facility has not been addressed fully. A GTL facility requires large quantities of electrical power with the main users being natural gas compressors to supply the feed to the synthesis gas preparation block and feed compressors to supply the synthesis gas to the FT block which operates at relatively high pressures. The energy requirement, supplied by conventional fossil fuel based power, results in a large carbon dioxide footprint which can be reduced significantly by utilizing the residual thermal energy in the helium stream downstream of the reforming unit to produce electricity.

- The relative operating cost analysis presented above includes the total cost of thermal energy from a 500 MWt reactor even though only 132 MW was required by the reformer. The above analysis does not show the full picture and shows the nuclear integrated case to be viable at high fuel gas prices. By better utilization of the residual heat in the helium stream, the viability of such a process would be greatly improved.

The study was extended to address the issues described above in an investigation that offers some results on a more integrated nuclear plant with a GTL facility.

4.3 Co-generation plant carbon dioxide reduction potential

The term co-generation refers to a combination of technologies where some of the thermal energy in the helium downstream of the nuclear reactor is used as process heat and the remainder of the thermal energy is used in an electricity generation facility. The more energy that is used as process heat, the higher the efficiency of the total process of nuclear thermal energy conversion to usable energy. Until now nuclear energy has been used only for the market of electricity where efficiencies are low (in the region of 40%). Nuclear power plants possess the potential to drastically reduce the carbon dioxide footprint of the power generation industry. There are several ways to generate electricity in combination with a modular high temperature reactor, including a:

- Steam cycle with high steam temperature and pressure;
- Closed helium cycle – Brayton cycle;
- Combined cycle using helium;
- Combined cycle using an intermediate heat exchanger;
- Combined cycle using air as working fluid; or a
- Combined cycle using air as working fluid and including additional fossil heat

The main aspects to consider for the selection of the different technologies are:

- Efficiency of electricity production;
- Complexity of plants;
- State of compressor and turbine technology; and the
- State of technology of high temperature heat exchangers[5]

For the purpose of this study, it was assumed that the remaining 368 MWt in the helium stream downstream of the reforming unit (where the heat is transferred to the reformer in the primary circuit) is converted in some way to electrical power. Although the detail of the electricity generation is not discussed here, the steam cycle with high steam temperature and pressure does look to be the most promising technology for the following reasons:

- It is a simple nuclear cycle compared with the other options.
- Efficiencies are ~ 43%.
- An outlet temperature of 800°C from the reforming unit will be sufficient to achieve required efficiencies.

An efficiency of 40% was assumed for the next part of the study to understand the impact that a co-generation plant could have on a GTL facility in terms of carbon dioxide reduction. Table 2 showed the results of the investigation. At the 40% efficiency it is possible to produce 147 MWe for the GTL facility. The

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[5] Information based on Thermo-fluid systems modelling – NWU 2009

equivalent amount of electrical energy from a coal based power plant would come at the cost of ~ 145 tons carbon dioxide per hour based on current industry standards. The implication of this result is that there is now a quantification of the amount of carbon dioxide that can be reduced by integration of a high temperature nuclear facility with a GTL facility. If a 500 MWt high temperature reactor with helium outlet temperatures of 950°C and flow rate of 169 kg/s was available for a co-generation plant, the amount of carbon dioxide reduction possible would be in the region of 187 t/h. The only carbon dioxide footprint of the GTL facility would be the amount of carbon dioxide produced via the shift reaction in the reformer and this is insignificant compared to what is saved by the introduction of nuclear technology.

The potential for carbon dioxide reduction has been shown to be good but it does come at a cost. This is due to the efficiency of the power generation plant where only 40% of the thermal energy is converted to electrical energy. The next part of the study focuses on understanding the cost implications required to reduce the carbon dioxide footprint by such a margin.

4.4 Co-generation plant feasibility

Figure 4 (section 3.6) showed the results for the relative operating costs for the co-generation facility. Section 3.6 described the inputs used to arrive at this graph, and the cost to produce 147 MWe was also accounted for. The cost of thermal energy used was \$30/MWh instead of the \$113/MWh for the development of Figure 3. This reduction in cost was due to the fact that all 500 MWt from the nuclear reactor could be utilised. Based on a nuclear power plant that takes 169 kg/s of hot helium at 800°C operating at an efficiency of 40% operating in conjunction with a reformer that utilises 132MW of high temperature energy, the nuclear case becomes more feasible and makes financial sense from an operating cost perspective at ~ R76/GJ for natural gas.

The next part of the investigation was the quantification of the cost to reduce carbon dioxide for a GTL facility. Figure 5 (section 3.6) showed the results of this analysis. If nuclear process heat is used to supply energy for the reforming stage to prevent the combustion of fuel gas, and the remaining thermal energy in the helium stream is used to produce electricity for the GTL facility to prevent the combustion of fossil fuels, the cost to reduce 1 ton of CO_2 is ~ R200 at current fuel gas costs of ~ R30/GJ. As the cost of fuel gas increases, the cost to reduce carbon dioxide emissions will reduce due to the natural gas utilisation improvements possible for a nuclear heated GTL facility.

Chapter 5 – Conclusions

- The amount of carbon dioxide that can be reduced from a steam methane reformer with a feed basis of 40 km^3_n/h natural gas if the energy for the reforming reaction is supplied by nuclear process heat is 21.5 km^3_n/h or, in mass terms, ~ 42 t/h.

- The natural gas utilisation improves when nuclear process heat is used instead of conventional combustion reactions. There is a 53% improvement in natural gas utilisation if natural gas is used for fuel gas in the reformer furnace. This is an important result because the implications are that producing synthesis gas in this way allows GTL technology to become feasible from an operating cost point of view, where fuel gas costs are high and into the future where the natural gas market becomes more competitive.

- The synthesis gas produced by an SMR needs to be adjusted to be a suitable feed to the FT block for a GTL facility. The study showed that a H_2:CO ratio of 3:1 is possible but the feed to the FT synthesis block must be closer to 2:1. This adjustment could be accomplished by a pressure swing adsorption unit for hydrogen separation. Hydrogen is always a precious commodity especially for the product work up stage of a GTL facility.

- Producing synthesis gas by a nuclear heated steam methane reformer will remove the need for an air separation unit and also a CO_2 removal facility, although a method of synthesis gas correction will be required.

- Based on relative operating costs with the assumption that natural gas is used for fuel gas, the nuclear heated SMR shows feasibility at natural gas costs of ~ R130/GJ. This result is conservative in that the total cost of the nuclear thermal energy was included in the 132 MW that the reformer utilises.

- The electricity producing potential of the helium stream downstream of the SMR is 147 MWe based on a 40% efficiency power generation plant. The helium temperature downstream of the SMR would be expected to drop from 800°C to 350°C. This amount of energy at 40% efficiency would convert to 147 MWe.

- The co-generation plant potential to reduce carbon dioxide emissions from a GTL facility is significant. It is possible to reduce the CO_2 footprint by ~ 187 t/h which includes 42 t/h from an SMR furnace and 145 t/h from conventional electricity production with one 500 MWt high temperature nuclear reactor.

- The break even point comparison between the nuclear and base case for the co-generation plant is ~ R76/GJ of fuel gas which is significantly lower than the initial R130/GJ, which was based on SMR economics alone.

- At current natural gas costs it would cost industry in the region of R200 to reduce their carbon dioxide emissions by 1 ton. This result is based on operating costs alone.

- The rising cost of natural gas will reduce the cost of carbon dioxide reduction.

- Nuclear/GTL integration is potentially viable, independent of expected legislation on carbon dioxide emissions depending on gas markets and their future.

- The expected legislation on carbon dioxide emissions can be based on what it will cost industry to reduce their carbon dioxide emissions and these values have been quantified in the discussion above.

Chapter 6 – Recommendations

- The method of synthesis gas correction needs to be further developed, and this should be focussed around hydrogen purification and product gas blending with other reforming technologies in an attempt to achieve ideal synthesis gas compositions for the FT block.

- Continued research and testing of high temperature and very high temperature reactors that can achieve the 950°C helium outlet temperatures, required for the heat integration opportunity around which this study is centred is suggested. Loss of government support of projects like PBMR is not a good indicator for the future of the technology and with the potential that has been described, money must be spent in the scaling up of proven technology.

- Further development of a helium heated steam methane reformer is important for the realisation of this opportunity.

- Development of materials for high temperature applications is important. Creep behaviour, fatigue properties, structural stability and corrosion resistance need to be understood for materials that can be used in these applications. Currently there are limited options and further advancements in the materials industry is a necessity.

- Government and public acceptance of a nuclear based energy economy for the future is critical. The inherent safety characteristics of the high temperature reactors will go far in addressing misconceptions based on past nuclear related accidents and this aspect of HTRs must be proven without reproach.

- A full economic analysis comparing the two cases should follow this study taking into account capital expenditure required. The fact that air separation and carbon dioxide removal units will not be required for a nuclear heated reforming plant is promising, but the capital investment of such a venture is expected to be expensive and this should be assessed.

- The HTR-10 has been built in China and has been in operation since 2002. This unit is a testing facility to ultimately test the possibility and concerns for a co-generation plant on a small scale. This type of investment is critical and should be supported especially by the world's GTL power houses in light of the potential that can be unleashed.

Chapter 7 – References

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Chapter 8 – Appendices

8.1 Appendix A – Mass and energy balances

8.1.1 Mass and energy balance – Base case

Table 3: Base case mass and energy balance

	BFW	CONDENS	FEEDGAS	FEEDGASH	FLUEGAS	FUELGAS	NGAS	OXY	SATSTEAM	SG1	SG2	SG3	SG4	SUPSTEAM	SYNGAS
	WHB		FPH	SPLIT1		BURNER	SMR	BURNER		WHB	FPH	CONDEN	DRUM	SMR	
		DRUM		FPH	BURNER	SPLIT1	SPLIT1		WHB	SMR	WHB	FPH	CONDEN		DRUM
	LIQUID	LIQUID	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	MIXED	VAPOR	VAPOR
Substream: MIXED															
Mole Flow scmh															
H2O	22573	85235	0	0	42140	0	0	0	22573	85458	85458	85458	85458	120000	223
H2	0	0	0	0	0	0	0	0	0	102942	102942	102942	102942	0	102942
CO	0	0	0	0	0	0	0	0	0	33858	33858	33858	33858	0	33858
CO2	0	0	0	0	21491	0	0	0	0	342	342	342	342	0	342
CH4	0	0	58017	58017	0	20016	38000	0	0	3800	3800	3800	3800	0	3800
N2	0	0	1221	1221	421	421	800	0	0	800	800	800	800	0	800
ETHAN-01	0	0	1221	1221	0	421	800	0	0	800	800	800	800	0	800
PROPA-01	0	0	611	611	0	211	400	0	0	400	400	400	400	0	400

O2	0	0	0	0	17439	0	0	60000	0	0	0	0	0	0	0
Mole Frac															
H2O	1.00	1.00	0.00	0.00	0.52	0.00	0.00	0.00	1.00	0.37	0.37	0.37	0.37	1.00	0.00
H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	0.45	0.00	0.72
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.15	0.15	0.15	0.00	0.24
CO2	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CH4	0.00	0.00	0.95	0.95	0.00	0.95	0.95	0.00	0.00	0.02	0.02	0.02	0.02	0.00	0.03
N2	0.00	0.00	0.02	0.02	0.01	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
ETHAN-01	0.00	0.00	0.02	0.02	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
PROPA-01	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
O2	0.00	0.00	0.00	0.00	0.21	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mass Flow kg/sec															
H2O	5.04	19.03	0.00	0.00	9.41	0.00	0.00	0.00	5.04	19.08	19.08	19.08	19.08	26.79	0.05
H2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.57	2.57	2.57	2.57	0.00	2.57
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.75	11.75	11.75	11.75	0.00	11.75
CO2	0.00	0.00	0.00	0.00	11.72	0.00	0.00	0.00	0.00	0.19	0.19	0.19	0.19	0.00	0.19
CH4	0.00	0.00	11.53	11.53	0.00	3.98	7.56	0.00	0.00	0.76	0.76	0.76	0.76	0.00	0.76
N2	0.00	0.00	0.42	0.42	0.15	0.15	0.28	0.00	0.00	0.28	0.28	0.28	0.28	0.00	0.28
ETHAN-01	0.00	0.00	0.46	0.46	0.00	0.16	0.30	0.00	0.00	0.30	0.30	0.30	0.30	0.00	0.30
PROPA-01	0.00	0.00	0.33	0.33	0.00	0.12	0.22	0.00	0.00	0.22	0.22	0.22	0.22	0.00	0.22
O2	0.00	0.00	0.00	0.00	6.92	0.00	0.00	23.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Flow scmh	2.3E+04	8.5E+04	6.1E+04	6.1E+04	8.1E+04	2.1E+04	4.0E+04	6.0E+04	2.3E+04	2.3E+05	2.3E+05	2.3E+05	2.3E+05	1.2E+05	1.4E+05
Total Flow kg/sec	5.04	19.03	12.75	12.75	28.19	4.40	8.35	23.79	5.04	35.14	35.14	35.14	35.14	26.79	16.11
Total Flow cum/sec	0.01	0.02	0.71	1.83	123.72	0.63	1.20	1.17	0.26	9.75	8.47	7.02	1.83	2.02	1.81
Temperature K	298.15	303.15	298.15	723.15	1473.15	723.15	723.15	473.15	523.09	1073.1	932.60	773.54	303.15	693.15	303.15

									5						
Pressure N/sqm	4.0E+06	2.5E+06	2.5E+06	2.5E+06	1.0E+05	2.5E+06	2.5E+06	2.5E+06	4.0E+06	2.6E+06	2.6E+06	2.6E+06	2.5E+06	4.0E+06	2.5E+06
Vapor Frac	0.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.63	1.00	1.00
Liquid Frac	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00
Solid Frac	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Enthalpy J/kmol	-2.9E+08	-2.9E+08	-7.4E+07	-5.3E+07	-1.8E+08	-5.3E+07	-5.3E+07	5.2E+06	-2.4E+08	-8.3E+07	-8.8E+07	-9.4E+07	-1.3E+08	-2.3E+08	-3.0E+07
Enthalpy J/kg	-1.6E+07	-1.6E+07	-4.4E+06	-3.2E+06	-6.5E+06	-3.2E+06	-3.2E+06	1.6E+05	-1.3E+07	-6.7E+06	-7.1E+06	-7.6E+06	-1.0E+07	-1.3E+07	-3.3E+06
Enthalpy Watt	-8.1E+07	-3.0E+08	-5.6E+07	-4.0E+07	-1.8E+08	-1.4E+07	-2.6E+07	3.9E+06	-6.6E+07	-2.4E+08	-2.5E+08	-2.7E+08	-3.6E+08	-3.4E+08	-5.3E+07
Entropy J/kmol-K	-1.7E+05	-1.7E+05	-1.1E+05	-6.6E+04	5.0E+04	-6.6E+04	-6.6E+04	-1.3E+04	-5.8E+04	1.9E+04	1.4E+04	7.4E+03	-6.4E+04	-4.7E+04	-2.6E+03
Entropy J/kg-K	-9324.02	-9247.55	-6437.91	-3928.42	1793.52	-3928.42	-3928.42	-405.31	-3228.20	1534.26	1123.59	593.31	-5138.81	-2582.28	-285.71
Density kmol/cum	55.12	54.85	1.07	0.41	0.01	0.41	0.41	0.63	1.08	0.29	0.33	0.40	1.55	0.74	0.98
Density kg/cum	993.03	988.19	18.00	6.97	0.23	6.97	6.97	20.31	19.46	3.60	4.15	5.01	19.25	13.24	8.92
Average MW	18.02	18.02	16.84	16.84	27.91	16.84	16.84	32.00	18.02	12.41	12.41	12.41	12.41	18.02	9.08
Liq Vol 60F cum/sec	0.01	0.02	0.04	0.04	0.04	0.01	0.03	0.04	0.01	0.11	0.11	0.11	0.11	0.03	0.10

8.1.2 Mass and energy balance – Nuclear case

Table 4: Nuclear case mass and energy balance

	BFW	CONDENS	FEEDGAS	FEEDGASH	HE-IN	HE-OUT	SATSTEAM	SG1	SG2	SG3	SG4	SUPSTEAM	SYNGAS
	WHB		FPH	SMR	HEATER			WHB	FPH	CONDEN	DRUM	SMR	
		DRUM		FPH		HEATER	WHB	SMR	WHB	FPH	CONDEN		DRUM
	LIQUID	LIQUID	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	MIXED	VAPOR	VAPOR
Substream: MIXED													
Mole Flow scmh													
H2O	22573	85235	0	0	0	0	22573	85458	85458	85458	85458	120000	223
H2	0	0	0	0	0	0	0	102942	102942	102942	102942	0	102942
CO	0	0	0	0	0	0	0	33858	33858	33858	33858	0	33858
CO2	0	0	0	0	0	0	0	342	342	342	342	0	342
CH4	0	0	38000	38000	0	0	0	3800	3800	3800	3800	0	3800
N2	0	0	800	800	0	0	0	800	800	800	800	0	800
ETHAN-01	0	0	800	800	0	0	0	800	800	800	800	0	800
PROPA-01	0	0	400	400	0	0	0	400	400	400	400	0	400
O2	0	0	0	0	0	0	0	0	0	0	0	0	0
HELIUM	0	0	0	0	3.41E+06	3.41E+06	0	0	0	0	0	0	0
Mole Frac													
H2O	1	1.00	0.00	0.00	0.00	0.00	1.00	0.37	0.37	0.37	0.37	1.00	0.00
H2	0	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	0.45	0.00	0.72
CO	0	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.15	0.15	0.15	0.00	0.24
CO2	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

CH4	0	0.00	0.95	0.95	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.00	0.03
N2	0	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
ETHAN-01	0	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
PROPA-01	0	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
O2	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HELIUM	0	0.00	0.00	0.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mass Flow kg/sec													
H2O	5.039915	19.03	0.00	0.00	0.00	0.00	5.04	19.08	19.08	19.08	19.08	26.79	0.05
H2	0	0.00	0.00	0.00	0.00	0.00	0.00	2.57	2.57	2.57	2.57	0.00	2.57
CO	0	0.00	0.00	0.00	0.00	0.00	0.00	11.75	11.75	11.75	11.75	0.00	11.75
CO2	0	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.19	0.19	0.19	0.00	0.19
CH4	0	0.00	7.56	7.56	0.00	0.00	0.00	0.76	0.76	0.76	0.76	0.00	0.76
N2	0	0.00	0.28	0.28	0.00	0.00	0.00	0.28	0.28	0.28	0.28	0.00	0.28
ETHAN-01	0	0.00	0.30	0.30	0.00	0.00	0.00	0.30	0.30	0.30	0.30	0.00	0.30
PROPA-01	0	0.00	0.22	0.22	0.00	0.00	0.00	0.22	0.22	0.22	0.22	0.00	0.22
O2	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HELIUM	0	0.00	0.00	0.00	169.25	169.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Flow scmh	22573.38	85235.81	40000	40000	3.41E+06	3.41E+06	22573.38	2.28E+05	2.28E+05	2.28E+05	2.28E+05	1.20E+05	1.43E+05
Total Flow kg/sec	5.039915	19.03041	8.349713	8.349713	169.249	169.249	5.039915	35.14188	35.14188	35.14188	35.14188	26.79217	16.11148
Total Flow cum/sec	5.08E-03	0.0192578	0.463981	1.197587	172.284	151.183	0.258978	9.748138	8.469086	7.523713	1.825498	2.023265	1.806241
Temperature K	298.15	303.15	298.15	723.15	1223.15	1073.15	523.091	1073.15	932.5966	829.0139	303.15	693.15	303.15
Pressure N/sqm	4.00E+06	2.50E+06	2.50E+06	2.50E+06	2.50E+06	2.50E+06	4.00E+06	2.60E+06	2.60E+06	2.60E+06	2.50E+06	4.00E+06	2.50E+06
Vapor Frac	0	0	1	1	1	1	1	1	1	1	0.626813	1	1
Liquid Frac	1	1	0	0	0	0	0	0	0	0	0.373187	0	0
Solid Frac	0	0	0	0	0	0	0	0	0	0	0	0	0
Enthalpy J/kmol	-	-2.87E+08	-	-5.34E+07	1.92E+0	1.61E+07	-2.36E+08	-	-	-	-	-2.29E+08	-

	2.88E+08		7.44E+07		7			8.32E+07	8.83E+07	9.19E+07	1.26E+08		3.01E+07
Enthalpy J/kg	-1.60E+07	-1.60E+07	-4.42E+06	-3.17E+06	4.81E+06	4.03E+06	-1.31E+07	-6.70E+06	-7.11E+06	-7.41E+06	-1.02E+07	-1.27E+07	-3.32E+06
Enthalpy Watt	-8.05E+07	-3.04E+08	-3.69E+07	-2.65E+07	8.14E+08	6.82E+08	-6.61E+07	-2.35E+08	-2.50E+08	-2.60E+08	-3.57E+08	-3.41E+08	-5.34E+07
Entropy J/kmol-K	-1.68E+05	-1.67E+05	-1.08E+05	-66167.38	2685.542	-34.50081	-58156.95	19047.64	13949.21	9778.97	-63797.95	-46520.42	-2594.399
Entropy J/kg-K	-9324.019	-9247.552	-6437.908	-3928.421	670.9493	-8.6196	-3228.201	1534.256	1123.586	787.68	-5138.821	-2582.276	-285.7074
Density kmol/cum	55.12148	54.8531	1.06843	0.4139409	0.245437	0.279693	1.08024	0.290376	0.3342298	0.376227	1.550602	0.735046	0.982301
Density kg/cum	993.0289	988.1924	17.99583	6.972111	0.982384	1.119497	19.46082	3.604984	4.14943	4.670817	19.25057	13.24205	8.919895
Average MW	18.01528	18.01525	16.84325	16.84325	4.0026	4.0026	18.01528	12.4149	12.4149	12.4149	12.4149	18.01528	9.080616
Liq Vol 60F cum/sec	5.05E-03	0.0190673	0.027026	0.0270256	2.264679	2.264679	5.05E-03	0.114471	0.1144708	0.114471	0.114471	0.026844	0.095403

8.2 Appendix B - Sample calculations

8.2.1 Relative operating cost - Excluding power generation

8.2.1.1 Base case

Fuel gas required = 21.49 km^3_n/h
Natural gas feed required = 40 km^3_n/h
Heating value of natural gas = 41.5 GJ/km^3_n
Cost of natural gas = *y* R/GJ
Fuel gas cost = Fuel gas required X Cost of natural gas X Heating value of natural gas
Natural gas feed cost = Natural gas feed required X Cost of natural gas X Heating value of natural gas
Relative operating cost *(base)* [R/h] = Fuel gas cost + Natural gas feed cost

Using the above method and varying the natural gas cost, the base case relative operating cost curve of *Figure 3* was developed.

8.2.1.2 Nuclear case

Natural gas feed required = 40 km^3_n/h
Heating value of natural gas = 41.5 GJ/km^3_n
Cost of natural gas = *y* R/GJ
Helium duty required = 132 MWt
Cost of helium thermal energy = $113/MWht
Rand per dollar exchange = R7.50
Helium heating cost = Helium duty required X Cost of helium thermal energy X Rand per dollar exchange
Natural gas feed cost = Natural gas feed required X Cost of natural gas X Heating value of natural gas
Relative operating cost *(nuclear)* [R/h] = Helium heating cost + Natural gas feed cost

Using the above method and varying the natural gas cost, the nuclear case relative operating cost curve of *figure 3* was developed.

8.2.2 Carbon dioxide generated by coal based power plant[6]

Power output = 147 MWe
Tons steam per MWh = 4.25
Tons of steam per ton of coal = 6
Carbon mass % in coal = 38%
Atomic weight of Carbon = 12 kg/kmol
Molecular weight of CO_2 = 44 kg/kmol

CO_2 generated [Tons CO_2/hr] = Power output X Tons steam per MWh / Tons of steam per ton of coal X Carbon mass % in coal / Atomic weight of Carbon X Molecular weight of CO_2

The results presented in Table 2 were arrived at by the above method to estimate the CO_2 emitted in the production of 147 MWe coal based electricity.

8.2.3 Relative operating cost - Including power generation

8.2.3.1 Base case

Cost of electricity = R334/MWh
Power requirement = 147 MWe
Electricity cost [R/h] = Cost of electricity X Power requirement

Relative operating cost with coal based power import [R/h] = Electricity cost + Relative operating cost *(as defined by section 8.2.1.1 above)*

The above definition was used to arrive at the Base case curve of *Figure 4.*

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[6] Source cannot be referenced due to confidentiality requirements

8.2.3.2 Nuclear case

Cost of helium thermal energy = \$30/MWht
Power requirement = 147 MWe
Power conversion efficiency = 40%
Rand per dollar exchange = R7.50
Cost of electricity [R/MWh] = Power requirement X Cost of helium thermal energy / Power conversion efficiency X Rand per dollar exchange
Electricity cost *(nuclear)* [R/h] = Cost of electricity X Power requirement

Relative operating cost with nuclear power generation [R/h] = Electricity cost *(nuclear)* + Relative operating cost *(as defined by section 8.2.1.2 above)*

The above definition was used to arrive at the nuclear case curve of *Figure 4*.

8.2.4 Cost per ton CO_2 reduction

CO_2 reduction for reformer = 42 t/h
CO_2 reduction for nuclear electricity production = 145 t/h *(as defined in section 8.2.2 above)*
Total CO_2 reduction using one HTR = CO_2 reduction for reformer + CO_2 reduction for nuclear electricity production
Relative cost to produce synthesis gas and 147 MWe [R/h] = Relative operating cost with nuclear power generation [R/hr] - Relative operating cost with power import [R/h] *(terms defined in section 8.2.3 above)*

Cost per ton CO_2 reduction [R/t CO_2] = Relative cost to produce synthesis gas and 147 MWe [R/h] / Total CO_2 reduction using one HTR [t CO_2/h]

The above calculation was the basis of the development of *Figure 5*.