Techno-economic investigation into nuclear centred steel manufacturing

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

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November 2011

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Keywords: Nuclear power; steel manufacturing; nuclear process-heat; co-generation; hydrogen production; techno-economic investigation;

Abstract

With the rising electricity, raw material and fossil fuel prices, as well as the relatively low selling price of steel, the steel industry has been put under strain to produce steel as cost-effectively as possible. Ideally the industry requires a cost-effective, stable source of energy to cater for its electricity and energy needs. Modern High Temperature Reactors are in a position to provide industries with not only electricity, but also process heat. Therefore, a study was conducted into the economic viability of centering the steel industry on nuclear power. This study considered 3 technology options: a nuclear facility to cater for solely the electricity needs of the steel industry; a nuclear facility producing hydrogen for the process needs of the steel industry; and a nuclear facility co-generating electricity and process heat for the steel industry.

An economic model for each of the 3 scenarios was developed that factored in the various cost considerations for each of the 3 options. In general, this included the construction costs, operational and maintenance cost, build time and interest rate of the financed amount. For each option, the model calculated the cost of production per unit output. The outputs were electricity for option 1, hydrogen for option 2, and both electricity and process heat for option 3. Each model was optimised based on a realistic best case scenario for the capital and operational costs and respective best case cost per unit outputs for each of the options were calculated.

Using the optimised cost model, it was shown that electricity produced from nuclear power was more cost effective than current electricity prices in South Africa. Similarly, it was shown that a nuclear facility could produce heat at a more cost-effective means than by the combustion of natural gas. Hydrogen proved to be not cost effective compared to reformed natural gas as a reducing agent for iron ore.

Based on the cost savings, a cash-flow analysis showed that the payback period for a nuclear power plant that produced electricity for the steel industry would be around 12 years at 0% interest and 15 years at 5% interest. Due to the long payback period and lack of certainty in the steel industry, any steel manufacturer would opt for purchasing electricity from a nuclear based electricity utility rather than building a facility themselves. Savings of over $70 million/year were achievable for a 2 million tonne/year electric arc furnace.

Overall this analysis showed that electricity generation is the only viable means for nuclear power to be integrated with the steel manufacturing industry.

Uittreksel

As gevolg van stygende elektrisiteits-, roumateriaal- en fossielbrandstofpryse asook die relatief lae verkoopsprys van staal, is die staalnywerheid onder druk om staalproduksie so koste-effektief moontlik te maak. Die nywerheid benodig 'n koste-effektiewe en stabiele bron van energie om aan elektrisiteits- en energievereistes te voldoen. Moderne Hoë Temperatuur Reaktors beskik oor die vermoë om nywerhede van beide elektrisiteit en proses-hitte te verskaf. Die moontlikheid om die staalnywerheid rondom kernkrag te sentreer is dus in terme van ekonomiese lewensvatbaarheid bestudeer. Hierdie studie het drie moontlike opstellings ondersoek: 'n kernaanleg om slegs aan die staalnywerheid se elektrisiteitsbehoeftes te voorsien; 'n kernaanleg wat waterstof produseer om aan die staalnywerheid se prosesbehoeftes te voorsien; en 'n kernaanleg wat beide elektrisiteit en proses-hitte aan die staalnywerheid verskaf.

'n Ekonomiese model wat die onderskeidelike kostes in ag neem is vir elk van die drie gevalle ontwikkel. Oor die algemeen sluit hierdie modelle konstruksie-, operasionele- en instandhoudingskoste, asook boutye en rentekoerse van finansiering in. Vir elke geval bereken die model produksiekoste per uitseteenheid. Die onderskeidelike uitsette is soos volg: elektrisiteit vir geval 1, waterstof vir geval 2, en beide elektrisiteit en proses-hitte vir geval 3. Elke model is ten opsigte van 'n realistiese beste-geval vir die kapitaal en operasionele kostes ge-optimeer en die onderskeidelike beste-geval koste per uitseteenheid vir elk van die drie moontlikhede is bereken.

Deur middel van die ge-optimeerde koste model, is aangetoon dat kern elektrisiteitsopwekking meer koste-effektief is as huidige oplossings (elektrisiteitspryse) in Suid-Afrika. Op 'n soortgelyke wyse is aangetoon dat kernaanlegte meer koste-effektiewe hitte kan verskaf in vergelyking met verbranding van natuurlike gas. Waterstof is egter nie 'n koste-effektiewe alternatief tot hervormde natuurlike gas as reduseermiddel vir ystererts nie.

Op grond van die koste besparing het 'n kontantvloei-ontleding aangetoon dat die terugbetalingstydperk vir 'n elektrisiteitsverskaffende kernkragaanleg vir die staalnywerheid ongeveer 12 jaar teen 'n 0% rentekoers en 15 jaar teen 'n 15% rentekoers sal wees. As gevolg van die lang terugbetalingstydperk en onsekerheid in die staalnywerheid behoort staalvervaardigers die aankoop van kernkrag bo die ontwikkeling van eie kernkragaanlegte te verkies. Besparings van meer as $70 miljoen per jaar is moontlik vir 'n 2 miljoen ton per jaar elektriese boog-oond.

As 'n geheel het die ontleding in hierdie studie aangetoon dat elektrisiteitsopwekking die enigste lewensvatbare moontlikheid is vir die integrasie van kernkrag in die staalvervaardigingsnywerheid.

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BF:	Blast Furnace
BOF:	Basic Oxygen Furnace
BWR:	Boiling Water Reactor
EAF:	Electric Arc Furnace
DR:	Direct Reduction
DRI:	Direct Reduced Iron
EUROPAIRS:	End User Requirements fOr industrial Process heat Applications with Innovative nuclear Reactors for Sustainable energy supply
GEN-IV:	Generation Four
HBI:	Hot Briquetted Iron
HTE:	High Temperature Electrolysis
HTGR:	High Temperature Gas-cooled Reactor
HTR:	High Temperature Reactor
IEA:	International Energy Agency
IPPC:	Integrated Pollution Prevention and Control
LWR:	Light Water Reactor
NERSA:	National Energy Regulator of South Africa
NSSS:	Nuclear Steam Supply System
PBMR:	Pebble Bed Modular Reactor
PWR:	Pressurised Water Reactor
SR:	Smelting Reduction
SI:	Sulphur Iodine
ULCOS:	Ultra Low CO_2 Steelmaking
VHTR:	Very High Temperature Reactor

1. Introduction

The Nuclear Renaissance has been a popular catch phrase within the industry over the last couple of years. There has been a level of cautious optimism that the perception of nuclear energy is improving and the revival of nuclear power is around the corner. However, with the recent nuclear crisis in Japan, the industry has had to re-evaluate the viability of this renaissance. Nuclear Power is at a delicate time in its existence and the industry has to broaden its potential uses away from just electricity generation.

While electricity generation remains the core of all commercial nuclear implementations, this alone cannot justify the large scale drive to increase nuclear power. While there is little doubt that electricity demands will continue to increase with an ever-increasing population and modernization of so-called third-world countries, there is enormous potential to diversify and make a truly significant impact in other industries. Therefore, the application of nuclear energy in industrial applications is an important step in the fruition of a Nuclear Renaissance.

Nuclear power has previously not been in a position to offer industries a viable alternative to their process requirements due to the limitations on the temperatures that the reactors operate at. However, with advances in technologies such as High Temperature Gas-Cooled Reactors (HTGRs), nuclear utilities can now design nuclear facilities for direct use in industrial applications.

From an industrial standpoint, concern about climate change has pushed various governments to opt towards implementing a tax on CO_2 emissions in the near future. In this scenario, it makes sense for many industrial companies to adapt to more environmentally friendly production methods that reduce overall emissions. The low carbon emission potential of nuclear power makes it a viable and attractive alternative for industries that are looking for change.

The nuclear industry has realized the importance of process heat applications and has been actively trying to get industries to come to the table to discuss viable means to incorporate nuclear power into their respective industries. One such initiative is the HTR-TN which has organized partnerships with non-nuclear industries in the EUROPAIRS project. This alone has the potential to open new avenues for nuclear research.

1.1 Background

The iron and steel making industry, one of the largest and most energy-intensive industries in the world, would serve as an ideal test bed to evaluate the viability of nuclear based alternatives for production. Contributions of greenhouse emission are significant and estimates of the industry's contributions vary significantly from the low estimates of about 4% (Chunbao & Da-qiang, 2010) to 7% (Kim & Worrell, 2002) to the high estimates of about 10% or greater (Kuramochi, Ramirez, Turkenburg, & Faaij, 2011) .

Over and above greenhouse gas emissions, solid waste and other by-products of the industry need to be handled. Overall, about half of the existing inputs to the steel making process end up as by-products or solid waste (Integrated Pollution Prevention and Control (IPPC), 2001, p. 10).

There are 4 main process routes that are followed in the production of steel (Integrated Pollution Prevention and Control (IPPC), 2001, p. 16):

1. The Blast Furnace/BOF Process route
2. The direct melting of scrap using Electric Arc Furnaces (EAFs)
3. Direct Reduction methods
4. Smelting Reduction methods

Out of these processes, the blast furnace/BOF route is the most predominant, accounting for about 65% of the steel produced in Europe (Integrated Pollution Prevention and Control (IPPC), 2001).

Chunbao & Da-qiang (2010) identify that the CO_2 emissions from the iron making side of the blast furnace/BOF process account for almost 90% of the emissions. The iron making side reduces iron ore into usable iron that is for steelmaking.

The Blast furnace accounts for the bulk of CO_2 emissions on the iron making side with sinter-making and coke making accounting for the remaining CO_2 emissions. The blast furnace/BOF technology will be one of the hardest hit if large “Carbon-taxes” are implemented.

Leaving out the use of scrap in steelmaking, the other methods described above hold potential to reduce CO_2 emission in the industry. However, out of these methods, only a few have been commercially proven and so far. In addition to this, these methods have not been able to make significant inroads as an alternative to producing iron. Smelting and direct reduction methods accounted for only about 4% of the steel produced in Europe (Integrated Pollution Prevention and Control (IPPC), 2001).

The most popular process in the direct reduction method is the MIDREX process and the only commercially viable smelting reduction method to date has been the COREX process.

These alternative iron-making process are generally of lower capacity than Blast Furnaces (although COREX plants with a production capacity of over 1 million tonnes DRI per year have been built), and on the other hand, blast furnaces are not cost efficient at lower capacity. Therefore these alternative processes are mostly implemented on smaller scales.

While the direct reduction and smelting reduction processes are definite improvements to the blast furnace based method, there is still room for improvement as shown by Botha (2009); where the viability of using hydrogen gas was assessed as an alternative in both the COREX and MIDREX processes. Botha (2009) showed that significant CO_2 reductions were possible in both processes, and that the MIDREX process could also be potentially cost effective.

1.2 Problem Statement

Currently the steel industry in South Africa has broadly 3 major concerns:

1. "Low" steel prices
2. The industry needs to reduce emissions
3. Electricity costs in the country are increasing

1.2.1 "Low" steel prices

The steel industry is by all respects a global industry and due to the great recession of 2008, this industry has been struggling. Prior to 2008 the industry saw an unprecedented growth and within South Africa specifically, various expansion projects were being considered. While the industry growth levels of pre-2008 are unlikely to be achieved again, local and international construction project will ensure that demand for steel is available. However, the low selling price of steel has put increased strain on the industry to reduce costs and with excess capacity in the industry, only the most cost effective plants will be viable to operate.

1.2.2 The industry needs to reduce emissions

The steel industry is the largest industrial greenhouse gas emitter in the world. With the imminent implementation of a "Carbon-Tax" in South Africa, the industry will require modifications to its current process route to ensure that it remains viable.

1.2.3 Electricity costs in the country are increasing

With the demand for electricity set to exceed supply in South Africa within the next few years, and with new power plants still to be built, the days of cheap electricity in South Africa will be coming to an end. Hints of this dilemma were seen prior to 2008 when load shedding became a reality and with industries being asked to cut down their consumption by 10%. With the recession, many industries were forced to slow production and electricity consumption was once again manageable, but with the country and industry slowly recovering from the recession, the load on Eskom will once again be difficult to manage.

1.2.4 Strategy to address these concerns

Within this context, the Steel industry could be an ideal environment where the application of nuclear generated electricity and process heat could be considered. This dissertation aims to determine if a nuclear centred steel industry could be economically and technically viable. The analysis was based on 3 scenarios:

1. Nuclear electricity generation for the industry
2. Defining a new process route for the industry such that nuclear process heat can be used
3. Co-generation of electricity and process heat for the steel industry

1.3 Research Methodology

A detailed literature study was undertaken as part of this research, with the aim to contextualize the dissertation within the Steel, Nuclear and South African perspectives.

With the context of the dissertation firmly established, a holistic model of each of the nuclear centred steel scenarios was developed. These models were then used to evaluate the economic viability of each scenario.

Once viable options were identified, externalities that affected the implementation of such projects were identified and evaluated. This included global steel prices, electricity price increases, global sentiment towards nuclear power, etc.

The results of the research allowed valid conclusions to be drawn on the viability of using nuclear power in the iron and steel industry.

1.4 Outline of the dissertation

The dissertation is structured into 4 broad subsections:

1. Introduction and Literature study
2. Techno-economic evaluation of the proposed scenarios
3. Risks, Management and Externalities
4. Conclusion and Recommendations

1.4.1 Introduction and Literature Study

Regarding the steel industry, the literature study includes details of existing iron/steel making processes as well as new processes that are being developed to achieve minimum emissions. Pertaining to the nuclear industry, process heat and co-generation potentials of nuclear energy were investigated, as well as delving into the costs involved with nuclear power. The Literature study concludes with the South African constraints and general context of the study, including details into the electricity crisis and the potential “Carbon-tax” that will be implemented.

1.4.2 Techno-Economic evaluation of the proposed scenarios

After going through the relevant literature, the dissertation details the technically viable means to incorporate nuclear power into the steel industry. The technical aspects of the 3 scenarios mentioned in the problem statement were evaluated in this section.

The costs involved with each of the technically viable alternatives were evaluated. This took various factors into consideration included the build costs, operational costs, energy savings costs, etc.

1.4.3 Risk, Management and Externalities

The dissertation then evaluates the risks of centering a steel industry on nuclear power and identified the best way to manage the redesigned process.

Finally, a sober look at the recent context that the nuclear industry finds itself in with the recent Fukushima incident was evaluated and the entire research was reassessed in light of a diminished outlook on nuclear power.

1.4.4 Conclusions and recommendations

This section summarises the conclusions and presents recommendations based on this research.

1.5 Research Objectives

The major research objectives of this study are as follows:

- Identifying viable means to incorporate nuclear power into the steel industry.
- Estimating the savings in resources (electricity, natural gas, etc.) that can be achieved through the identified processes.
- Estimating the reduction in greenhouse gases (especially CO_2).
- Determining if each of the technically viable options make economic sense.
- Identifying the additional risks on both the steel and nuclear industries with the potential merger of the two.
- Proposing how best the nuclear and steel areas of an integrated nuclear steel works will be managed.

1.6 Potential Impact

The impact of this research is 4-fold. Firstly, the research will identify if it is possible to and how to integrate the Iron and Steel industry in a way that is economically viable. If the research is found to be technically and economically viable, the steel industry would benefit by being largely independent of fluctuations in electricity, coal and natural gas prices.

Secondly, this research assists the nuclear industry to broaden its application to outside of electricity generation.

Thirdly, this research has the potential to reduce the emissions caused by the iron and steel industry.

Finally, if a technically and economically viable solution is available, South Africa has the potential to be at the forefront of nuclear and steel research. This will boost the country’s image and potential.

2. Literature Study

An analysis of the most common steel making technologies has been presented. Further to this, new low carbon processes that the industry is considering are briefly identified. Nuclear electricity, process heat and co-generation technologies are researched and existing initiatives to integrate the steel and nuclear industries are investigated. Finally the current South African context with respect to carbon taxes, nuclear power and electricity crisis has been presented. All these factors provide a thorough context in which the nuclear power for the South African steel industry can be evaluated.

2.1 Steelmaking

2.1.1 Existing Processes

Steel is and alloy of iron, consisting of up to 2% carbon. Various properties of steel can be achieved by altering the carbon content and by the addition of various other alloying materials (Nutting, Wente, & Wondris, 2008). The steel production industry accounts for roughly 20% of the industrial energy consumed in the world (Kuramochi, Ramirez, Turkenburg, & Faaij, 2011). The majority of commercial steel making processes emit large quantities of greenhouse gases into the atmosphere.

There are several methods by which steel is produced industrially. Literature differentiates these methods based on either the input materials that are used in the process or the method by which the iron and steel are produced.

From an input material point of view, steel production methods can be split into primary steelmaking or secondary steelmaking. Primary steelmaking is the process whereby steel is produced by first producing iron (in either solid or liquid form) from iron-ore. This form of steelmaking accounts for about 70% of steel produced globally. On the secondary steelmaking side, scrap steel is melted and further refined to produce usable steel. Steel produced by secondary steelmaking accounts for approximately 30% of steel produced globally.

It is obvious that primary steelmaking is more energy intensive than secondary steelmaking. This is mainly due to the reduction of iron from iron-ores. Various different methods are available for the reduction of iron from iron-ores.

This leads to the other classification of steel production based on the process technology. There are 4 main commercially viable production methods for steel:

1. Blast furnace (BF)/Basic oxygen furnace (BOF) route
2. Electric arc furnace (EAF) route
3. Direct reduction (DR) of iron
4. Smelting reduction of (SR) iron

The predominant technology that is used is the blast furnace/basic oxygen furnace, and this accounts for about 90% of iron produced in primary steelmaking. All secondary steelmaking is done via the electric arc furnace. This is due to the fact that the EAF is needed to melt solid scrap steel.

The output of the DR route and the Smelting Reduction processes also fall into the category of primary steelmaking as iron ore is reduced to iron in each case. The iron of the DR route generally requires the use of an EAF since this iron is solid and cannot be used in a BOF directly. However, direct reduced iron (DRI) can be used in a BOF provided that molten iron from other sources is available. The iron from the smelting reduction process can be used in either an electric arc furnace or a BOF.

Another classification that is very useful is the differentiation between the iron making and the steel making sides of the process. This will become apparent later when evaluating where the most benefits in term of greenhouse reductions can occur.

The classification of iron/steelmaking processes are graphically presented below:

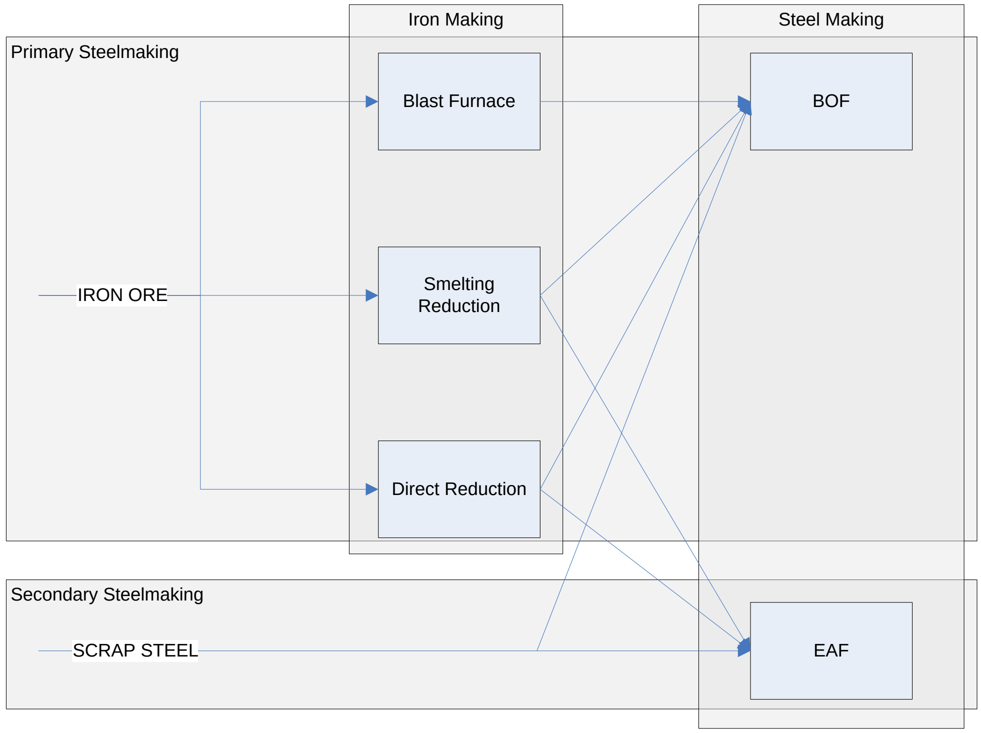

Figure 1: Steel making processes by category - derived (Wortswinkel&Nijs, 2010)

Figure 1 above is meant as a general indication of the processes and the classification of processes involved. After the steel making section, there are various rolling operations that produce the various products that are commercially sold.

For the purposes of this study, it is convenient to separate the iron making and steel making aspects of the industry. The following sections delve into a high level analysis of each of the 4 steelmaking production methods.

Before moving forward, it is important to note that the steel industry is a global industry, and changes in the global situation would affect the industry profoundly. Steel has historically been an accurate indicator of the economic situation at that time and market factors will greatly determine the most viable steel making process route. The existing install base should only be used as an indicatory tool and it is very likely that changes in this install base will occur.

2.1.1.1 The Blast Furnace/BOF process route

This production route is the most common in the world and comprises of the following components:

1. Coke Making Batteries
2. Sinter Making plant
3. Blast Furnace
4. Basic Oxygen Furnace

2.1.1.1.1 Coke Making Batteries

Coke production involves the oxygen starved heating of coal to remove all the volatile materials such as tar, water and various gasses from the coal. The coke is produced in large coke making batteries which heats the coal to temperatures of up to 1100°C for up to 24 hours (Botha, 2009, p. 11) (Wortswinkel & Nijs, 2010). Excess gasses produced in the coke making process are cleaned and can be used throughout the steelworks. Coke is an expensive commodity to produce and has significant environmental challenges associated with its production.

2.1.1.1.2 Sinter making plant

Sintering involves heating of the ore at relatively “low” (non-melting) temperatures until the particles adhere to one another. Iron ore, certain additives and recycled sinter are mixed together and sintered before it is fed into the blast furnace. Sintering enhances the blast furnace performance due to the high permeability of the sintered material. (Wortswinkel & Nijs, 2010)

2.1.1.1.3 Blast furnace

The blast furnace is a centuries old technology used for the production of what is termed “pig iron”. In a blast furnace, coke, sinter, limestone and dolomite are fed into a shaft like furnace from the top while hot air is blasted from the bottom of the furnace. The air is heated in stoves to produce the hot blast.

The coke reacts with the hot blast air in an exothermic reaction. The excess heat increases the temperature inside of the furnace and allows the excess carbon to produce carbon monoxide gas which acts as the reducing agent for the iron. The iron oxides in the ore react with the carbon monoxide gas in a series of reactions leading to the production of liquid iron at the bottom of the furnace. Other elements (impurities) in the ore react with the lime and dolomite and settle as slag above the liquid iron. The liquid pig iron and slag is then tapped from the bottom of the furnace. The excess gas produced heats the stoves and is used where needed.

The amount of coke utilized can be reduced to some degree by substituting it with an injection of pulverized coal to act as the heat source for the furnace. Adding pulverized coal instead of coke to the blast furnace reduces the overall cost of production. However, all blast furnaces require coke to some degree (Integrated Pollution Prevention and Control (IPPC), 2001) because it provides a burden support role for the iron ore that is being charged. The following figure illustrates a simplified schematic of a blast furnace:

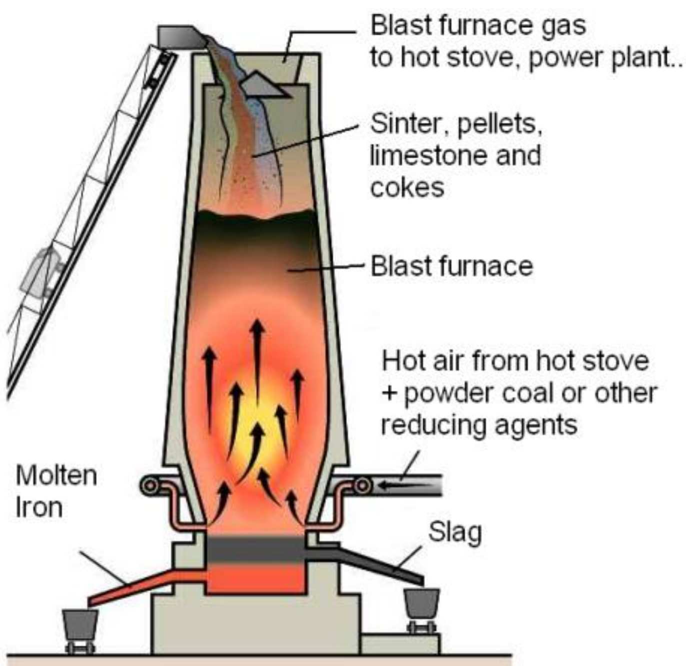

Figure 2: Simplified scheme of a blast furnace (Wortswinkel&Nijs, 2010)

The pig iron produced at the blast furnace has a typical composition of around 93.5 – 95% Iron; 4.1 – 4.4% Carbon and less than 1% of Silicon, Manganese, Sulphur, Phosphorous and Titanium (Botha, 2009).

2.1.1.1.4 Basic Oxygen Furnace

The hot pig iron from the blast furnace is fed into a basic oxygen furnace (BOF). The BOF is a large vessel that is lined with refractory material (Botha, 2009). Pig iron from the blast furnace is poured into the BOF and a lance is lowered into it and almost pure oxygen is blown into the mixture. The oxygen reacts with the carbon in the pig iron to produce carbon monoxide and carbon dioxide. The reaction is extremely exothermic and scrap steel and/or iron ore is added to the BOF to control the temperature. Other impurities such as silicon, phosphorus and manganese are also removed from the iron by adding lime to the BOF (Wortswinkel & Nijs, 2010).

The output of the BOF is steel with very low carbon content. Which is further refined according to specifications at the secondary metallurgical side of steel making. After a certain grade of steel is produced, the steel is cast and rolled into a final end product.

This steelmaking route is the primary route for the production of steel in the world accounting to close to two thirds of the world steel production.

2.1.1.2 Direct reduction

Alternate iron-making processes have the benefit of removing the environmentally problematic coke making from the steel making process., making these processes more environmentally friendly.

Direct reduction (DR) refers to processes that aim to remove oxygen from iron ore in the solid state (Wortswinkel & Nijs, 2010). The output of the DR is solid iron called direct reduced iron (DRI) or sponge iron. The DRI can sometimes spontaneously combust and therefore pose a fire hazard. Therefore, DRI is sometimes melted into briquettes called Hot Briquette Iron (HBI) (Integrated Pollution Prevention and Control (IPPC), 2001, p. 321). DR Iron is used predominantly in EAFs. Various restrictions come into play when scrap alone is used in EAFs, particularly to do with the scrap quality. Because of this, DRI is often used as a feedstock to EAFs.

The output of the DR has a high metallization rate of greater than 92% iron and less than 2% carbon (Integrated Pollution Prevention and Control (IPPC), 2001, p. 319). After the DRI is produced, it will still need to be processed into usable steel in either an EAF or a BOF.

Because of the low carbon content of DRI, more energy is required at the steelmaking side to refine the DRI. This is one of the main disadvantages for this process. However, as an alternative to DRI, iron carbide (Fe_3C), which is also produced by direct reduction, can be used. This has around 6% (by weight) carbon and can reduce the energy requirements at the steelmaking side.

There are a variety of direct reduction processes; the most popular among them is the MIDREX Process.

2.1.1.2.1 The MIDREX process

There are 4 main stages in the MIDREX process (Wortswinkel & Nijs, 2010):

1. Furnace
2. Reformer
3. Heat Recovery
4. Briquette making

In the furnace, iron ore is fed from the top. The ore slowly makes its way through the reduction zone of the furnace taking up to 6 hours. During this time the reformed gas reduces the iron ore and forms DRI. Some of the off gas from the furnace is recycled to the natural gas line feed and while the rest is used to heat the reformer.

At the reformer, heated natural gas flows through tubes where a catalyzing agent reforms the gas to greater than 90% H_2 or CO. The gas is fed into a shaft furnace as the reducing gas for the process (MIDREX, 2011).

The flue gas from the reformer can be used to pre-heat the natural gas feed and the air. This improves the efficiency of the process.

Finally, the end product, the DRI can be made into briquettes to produce the so called hot briquetted iron. Alternatively, the DRI can be immediately added to an EAF, or dried.

The following diagram from the MIDREX website shows the basics of the process.

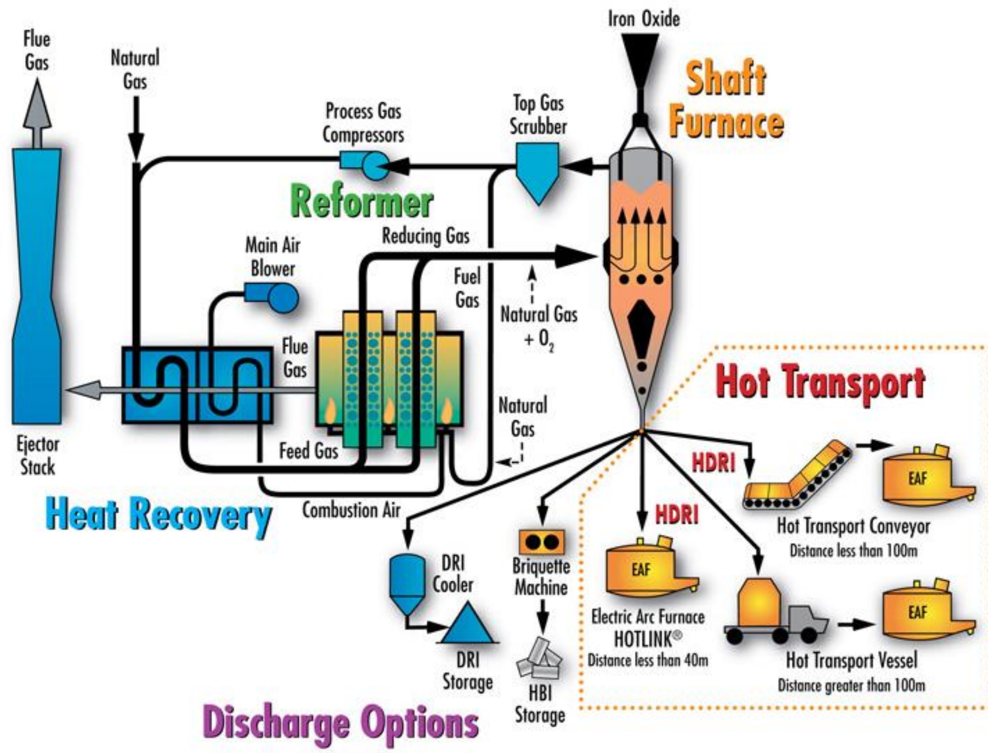

Figure 3: MIDREX flow diagram (MIDREX, 2011)

2.1.1.3 Smelting Reduction

In the smelting reduction process, the product is liquid pig iron – similar to what is produced from a Blast Furnace. The steelmaking side of this process can be either a BOF or an EAF.

The smelting reduction process is virtually synonymous with the COREX process developed by Siemens VAI. This is the first commercially implemented smelting reduction process.
This process is a 2 stage process:

1. Reduction shaft/unit
2. Meltergasifier chamber

This process can utilize a wide variety of coals due to the separation of the reduction and melting sections (Integrated Pollution Prevention and Control (IPPC), 2001).

At the reduction shaft iron ore, pellets or sinter is added to the unit. The iron pellets are reduced in this chamber in a similar manner to the direct reduction process. The reduced iron pellets are very similar to DRI and they move to the Meltergasifier chamber. For the COREX process specifically, the reduction shaft is situated on top of the Meltergasifier chamber. The reduction gas used in the reduction shaft comes from the Meltergasifier chamber and consists of up to 70% CO and 25% H_2 (Integrated Pollution Prevention and Control (IPPC), 2001). Top gas from the shaft can be collected and sold as export gas to various industries.

At the Meltergasifier chamber, coal and oxygen is added. The coal is gasified due to the reaction with oxygen and liquid iron ore (Wortswinkel & Nijs, 2010). The reaction is exothermic and melts the DRI that enters the Meltergasifier chamber. Final reduction of the DRI also occurs in this chamber. The off gas from the chamber is CO rich and acts as the reducing gas in the reduction shaft.

The gasified coal can further be oxidized to increase the heat delivered for smelting. This, however, diminishes the gas that can be used as a reducing agent in the reduction shaft. Therefore there is a tradeoff between the utilization of the gas for smelting and for reduction (Wortswinkel & Nijs, 2010). The hot metal output from the smelting reduction process is very similar in composition to pig iron output from a blast furnace (Integrated Pollution Prevention and Control (IPPC), 2001).

The process flow of the smelting reduction process is shown below:

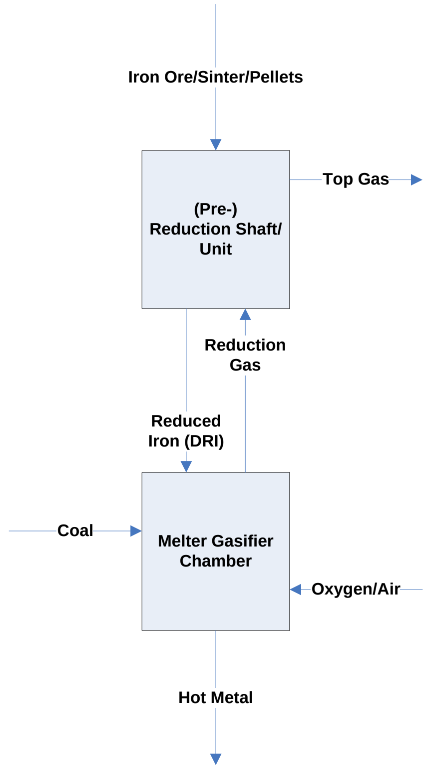

Figure 4: Smelting reduction flow diagram – derived (Wortswinkel&Nijs, 2010)

2.1.1.4 Electric Arc Furnace

The electric arc furnace (EAF) accounts for approximately 35% of all steel produced globally. Most of the steel produced using the EAF is from scrap melting and thus forms part of the secondary steel making line. However, the use of DRI as a feedstock into the EAFs has been increasing (Wortswinkel & Nijs, 2010). This is mainly due to the high iron content in DRI.

An EAF operates by using an electric arc to melt the scrap and or DRI. Charging of scrap occurs gradually in this furnace. Lime and burnt dolomite are charged together with the scrap to act as fluxes for the slag formation (Wortswinkel & Nijs, 2010).

Scrap/DRI is charged into the furnace to about 50% capacity. The electrodes are lowered until they have become shielded by the surrounding scrap/DRI. The power is then increased until an arc is formed to melt the steel. Oxygen lances and fuels are commonly used in the early stages of melting.

Oxygen is injected to remove excess carbon and undesired elements from the melted scrap (Integrated Pollution Prevention and Control (IPPC), 2001).

2.1.2 Drive for low carbon steel

The technologies presented in the previous section account for most of the commercially implemented technologies in the iron and steel industry. However, there is a major drive to develop new low CO_2 based technologies. A lot of these technologies focus on the primary steelmaking side and specifically in the iron making part of this. This is due to the fact that primary steelmaking accounts for around 70% of the steel produced in the world and the iron making phase specifically accounts for the majority of emissions in the industry.

The Coke Ovens, Sinter making plant and Blast Furnaces account for the majority of the emissions in the iron making bracket. There is a large environmental benefit by using alternative methods such as DR and SR. However, these processes are not widely used compared to Blast Furnaces, as they require large amounts of gas and very good quality, pelletised iron ore. Cost effective alternatives to Blast furnaces with low capital and operational costs are the focus of a lot of the initiates.

The ULCOS initiate is one such initiative. ULCOS is an acronym for Ultra Low CO_2 Steelmaking and is a consortium of several different steel manufacturers and countries from Europe with the goal to drastically reduce CO_2 emissions from the steel industry by at least 50%.

A similar initiate in Japan is the COURSE50 program, part of the Cool Earth 50 project, which aims to reduce CO_2 emissions in Japan (Matsumiya, 2011).

Several innovative ideas have been proposed by the industry such as (ULCOS, 2011):

1. ULCORED – a direct reduction process where the off gas is recycled as in the MIDREX process but where CO_2 is also captured and stored (CSS)
2. HIsarna – a smelting reduction process where a melting cyclone is used to melt the iron ore. The molten iron ore then drips into the converter chamber where it is reduced by the gases produced by the heated coal and oxygen reaction. Two separate units are not required for this process and the off gas from the process is almost completely CO_2 and therefore can be captured and stored without further processing.
3. ULCOWIN – a method to produce iron by electrolysis rather than reduction.

4. Top gas recycling blast furnace – a traditional blast furnace that captures the top gas from the furnace and separates CO_2 from the other gases and concludes by storing the captured CO_2.

All the technologies presented by ULCOS are still in the concept phase and require a lot of refinement before commercial implementations would be possible.

Over and above this most of the technologies suggest CO_2 capture as part of its aim of reducing emissions. While CO_2 capture and sequestration technologies are available, it is necessary to conduct a proper economic analysis to identify whether the viability of large scale implementations of such techniques are possible.

2.1.3 Identified integration with the nuclear industry

At this point, it is possible to identify, at least conceptually where the steel industry would benefit the most from nuclear integration.

On the primary steelmaking side, savings from nuclear power would predominantly be from the process heat applications. On the secondary steelmaking side, electricity becomes a major contributor to cost, and electricity generation applications from nuclear power would be beneficial.

For the co-generation perspective, process heat could be used to produce iron, either through direct or smelting reduction (Botha, 2009), and if an electric arc furnace (EAF) is used, electricity could be generated from the nuclear facility as well. Therefore a process route from DR or SR to EAF could benefit from co-generation applications of nuclear power.

2.2 Nuclear power analysis

Nuclear fission is the only large scale, green house emission free and commercially proven energy source available in the world at the moment. Commercial nuclear power currently caters almost exclusively for electricity generation.

In 2009, nuclear electricity generation accounted for 15% of global electricity generation (Simbolotti, 2010). It is estimated that the global share of nuclear energy will increase from current levels to between 19% and 23% by 2050 which will account for 6% of total CO_2 emission reductions (Simbolotti, 2010).

The energy sector (electricity and heating) is the major contributor to greenhouse gas emissions accounting for 41% of the total emissions worldwide with transport and manufacturing industries accounting for around 20% each (International Energy Agency, 2010, p. 9). Nuclear power will need to shift its focus away from electricity alone to make a significant impact on the reduction of anthropogenic CO_2 emissions.

2.2.1 Main technologies

The majority of the installed nuclear power plants around the world are the so called Generation II reactors. These reactors include basic pressurized water reactors (PWRs), boiling water reactors (BWRs), CANDU reactors and the VVER/RBMK reactors.

Generation II reactors helped establish the nuclear industry as a viable alternative to electricity generation. However, Gen-II reactors have 1 major flaw in that they rely on active safety mechanisms in case of an emergency, where operator intervention is required within less than an hour of the emergency.

Newer generation reactors, the so called Gen-III and Gen-III+ reactors have added additional safety mechanisms that allow any accident to remain contained without immediate operator interventions. Several Gen-III+ reactors are currently being built throughout the world. Gen-III+ reactors include the AP1000s, Advanced CANDU reactors, the European Pressurized Reactors (EPRs) and Advanced PWRs to name just a few.

In addition to these water cooled reactors, gas cooled reactors are once again being considered. High temperature gas-cooled reactors (HTGR) have the potential to extend the application of nuclear power into the industrial domain by providing process heat applications. These reactors are generally considered Gen-III+ reactors.

Most new reactors being built would be the Gen-III and Gen-III+ type reactors and with the broader industrial applicability of some designs, they have the potential to significantly impact the way many industries operate.

Over and above these reactors, the Gen-IV consortium has established several conceptual designs that could potentially increase efficiency and safety. These Gen-IV designs are still in the early design phases and would require several decades before they will become viable.

2.2.2 Electricity production

Electricity production has been the bread and butter of the commercial nuclear industry. Almost all of the reactors mentioned above follow the process of boiling water (either directly or indirectly) to run a turbine to generate electricity (also known as the Rankine Cycle). Currently most nuclear facilities operate at efficiencies of around 35% which is comparable to some coal fired stations. Superheated coal fired stations have achieved efficiencies in the mid 40% range, but superheating water is not possible with nuclear power due to safety restrictions. However, a lot of effort has been put into increasing the efficiency of the Rankine cycle using recuperators, intercoolers and other devices.

It is possible that a Brayton cycle (or gas turbine) could be used instead of the Rankine cycle. While this has not been commercially proven yet, efficiencies comparable to superheated coal fire stations are possible. The PBMR's original design incorporated a Brayton cycle. This allowed the efficiency of the PBMR to be around 45%.

Safety and material limitations prevent the temperatures of current nuclear reactors from exceeding 900°C, even for a high temperature reactor (HTR) like the PBMR. Conceptual designs such as the very high temperature reactors (VHTR) have the potential to further increase the allowable temperature and therefore the efficiency of generating electricity.

2.2.3 Process heat applications

Light water reactors generally limit the temperature that reactors can operate at to around 350°C due to material limitations and safety concerns. This is a major limiting factor for the application of nuclear power outside of electricity generation.

Modern Gen-III+ and Gen-IV gas cooled reactors are designed to operate at high temperatures. The coolant gas for the PBMR operates at around 900°C. At these temperatures, various process heat applications become feasible.

Very high temperature reactors (VHTRs), as suggested by the Gen-IV consortium, can operate at even higher temperatures (up to 1000°C) and there are very few applications that would require higher temperatures than this. For example, process steam at between 400°C and 600°C can supply about 80% of the heat required for an Oil Refinery (Groot, 2010).

Organisations such as the EUROPAIRS (End User Requirements fOr industrial Process heat Applications with Innovative nuclear Reactors for Sustainable energy supply) have been working hand in hand with industries to develop and promote nuclear applications in industry. This project is in conjunction with, and gets support from the EURATOM 7th Framework Programme, a European initiative to develop new technological ideas that will benefit the European continent in the future.

The vision of organisations like EUROPAIRS is to incorporate nuclear reactors in such a way that they sustain not only the electricity requirements of an area, but also the heating, water and process industries by means of hydrogen generations.

This is illustrated in the graphic below (derived from (Bogusch, 2011)):

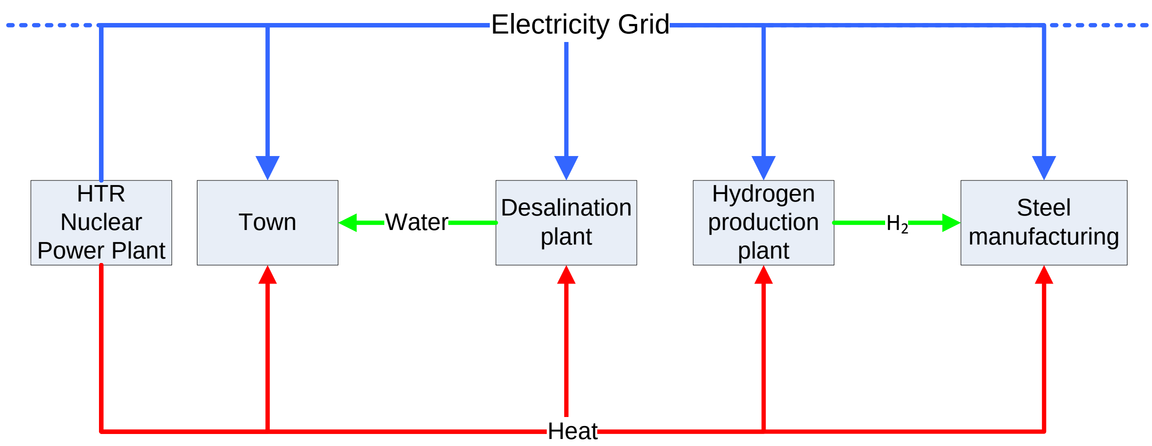

Figure 5: Vision of an integrated nuclear economy

2.2.3.1 *Hydrogen production*

Due to the potential use of hydrogen (H_2) gas in many industrial applications, hydrogen production is a major potential process heat application of nuclear power. Other process heat options are available for nuclear power, but for the purposes of this study, hydrogen production is the most important.

Several methods exist for the production of hydrogen from water and the most applicable processes that can be used with high temperature process heat are (Elder & Allen, 2009):

1. High Temperature Electrolysis (HTE)
2. Sulphur iodine (SI) thermochemical cycle
3. Hybrid sulphur cycle

2.2.3.1.1 *High temperature electrolysis*

This process uses normal electrolysis of high temperature steam to produce O_2 and H_2. There are several advantages in using high temperature steam instead of water, the most important of one being improved efficiencies. The normal low temperature electrolysis generally has an overall efficiency of 35%, while the high temperature electrolysis has an efficiency of up to 53%. However, there are several complications that need to be modified to make this process viable.

An applied potential difference (voltage) breaks down the steam into H^+ and O^{2-} ions at the cathode. The oxygen ions make its way to the anode where it gives up its excess electrons and to produce oxygen gas. The following figure shows the basic operation of this method:

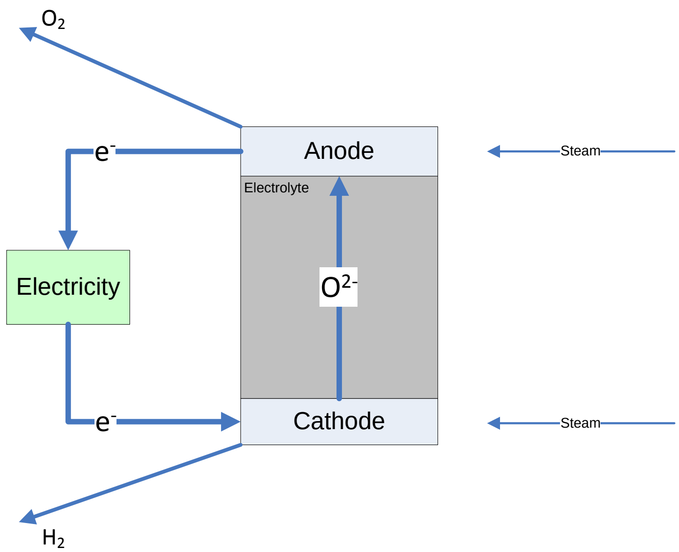

Figure 6: High temperature electrolysis (Elder & Allen, 2009)

An interesting derivation to this method was tested where a combination of carbon dioxide and steam were supplied for electrolysis. The output was then a combination of carbon monoxide gas and hydrogen. This process is termed syntrolysis and predictions of overall efficiencies of 43-48% have been suggested (Elder & Allen, 2009).

2.2.3.1.2 The sulphur iodine thermochemical process

This process has 3 phases. In the first phase, Iodine, sulphur dioxide and water react in an exothermic reaction to produce sulphuric acid and hydrogen iodide.

In the next phase, the sulphuric acid and the hydrogen iodide are separated and they are both decomposed by heat. Heat is added in the presence of a solid catalyst and decomposes the acid over a couple of steps into oxygen, sulphur dioxide and water. The water and sulphuric acid are fed back to the first reaction phase and the oxygen is collected. The temperatures needed for this reaction is about 800°C.

During the third and final phase, the Hydrogen Iodide is heated to 450°C which decomposes it to hydrogen gas and iodine. The iodine is fed back into phase one while the hydrogen is collected. The process is shown below. The overall efficiency of the process is between 35 and 45% (Elder & Allen, 2009).

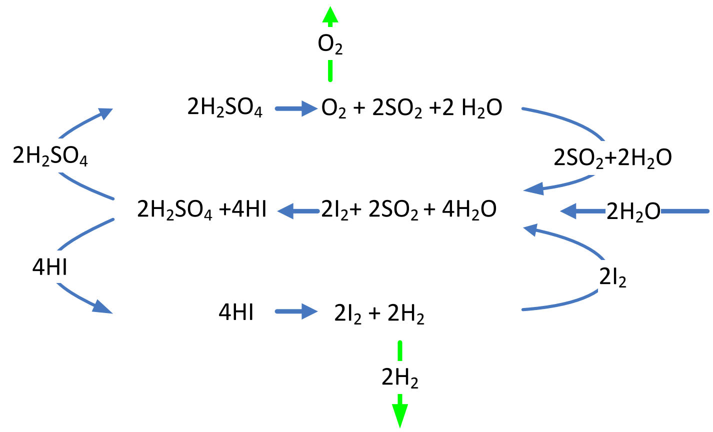

Figure 7: Idealized SI chemical cycle (Elder & Allen, 2009)

2.2.3.1.3 The hybrid sulphur cycle

This process uses a combination of electrolysis and thermochemical decomposition. Schematically, the process can be represented as follows:

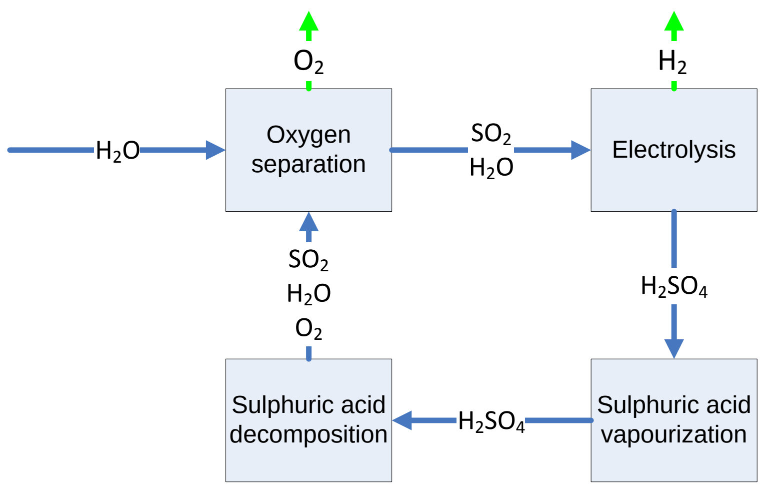

Figure 8: High level process flow of the hybrid sulphur cycle (Elder & Allen, 2009)

In the decomposition phase, the same reaction that takes place in the sulphur iodine cycle takes place. The sulphuric acid is converted into water, oxygen and sulphur dioxide over a series of reactions at around 800°C. During the electrolysis phase, sulphuric acid and H_2 gas are produced.

The H_2 gas is then captured. The efficiency of this cycle is currently predicted to about 47%, but it is possible that the efficiency could be closer to 50% (Elder & Allen, 2009).

This cycle could be very attractive to the steel industry in particular. Botha (2009) identified that a HTR such as the PBMR would be able to produce hydrogen using the hybrid sulphur cycle (HyS). The hydrogen produced would then be used as the reducing gas in the direct reduction process for iron making.

For the purposes of integration with nuclear power, many conceptual designs have been developed to take advantage of the various nuclear processes. With HTRs like the PBMR, efficient designs have been developed that can produce H_2 at a competitive price. There are couplings of HTRs and the SI process that estimate the production cost (including capital, maintenance and operating costs) at below \$2/kg H_2. The PBMR coupled hybrid sulphur cycle (also known as the Four Pack) estimates production costs to be between \$2/kg and \$3/kg of H_2 (Elder & Allen, 2009).

2.2.4 Costs involved with nuclear power

The economics of nuclear power presented here focus on existing facilities and are therefore limited to electricity generating facilities. However, almost all information presented here is applicable to process heat applications as well. There are various factors that need to be taken into consideration about the costs involved with nuclear power. Raw materials and fuels required for operations account for a large percentage of the costs of many industries. With nuclear power it is completely different. The bulk of nuclear power costs occur during the construction phase. Nuclear power requires significant upfront capital expenditure, with a near constant operational, maintenance, fuel and waste disposal costs during its operational life and finally another high expenditure for decommissioning. Qualitatively, the costs of each of these are summarized in the table below:

Cost Considerations	Required capital
Construction	Very High
Operation	Medium
Raw materials/fuel	Low
Waste storage/disposal	Medium
Decommissioning	High

Table 1: Qualitative capital requirements for different phases of nuclear plant operation

The other factor to take into consideration is the timelines involved with the different phases. Lead times for nuclear facilities are long, especially with new technology reactors. There have also been significant delays with the construction of these facilities. These overruns in nuclear builds have caused the construction costs for new facilities to steadily rise.

Post construction, nuclear facilities generally operate for 40 years, but extensions of up to 60 years are possible. Decommissioning of nuclear facilities are specialized tasks that require a significant amount of specialized expertise and therefore costs significantly more than with other facilities. The following graph indicates the capital expenditure on nuclear facilities over their lifetime.

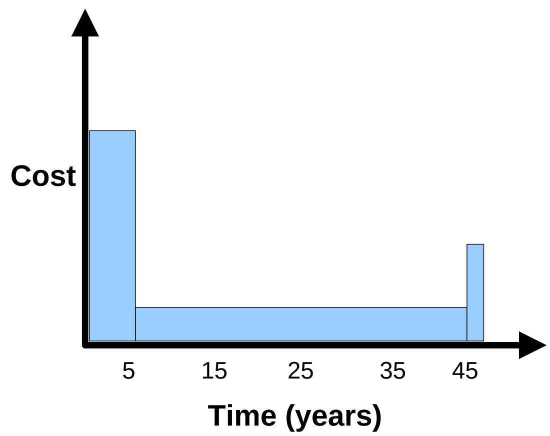

Figure 9: Qualitative illustration of nuclear power facility capital expenditure

It should be noted that in deregulated markets, nuclear power is not competitive against fossil fuel based power stations. Nuclear facilities would benefit from limited government initiatives and tax breaks (Deutch, Forsberg, Kadak, Kazimi, Moniz, & Parsons, 2009). While the construction costs of nuclear facilities are restrictive in many cases, governments guarantee loans to utilities to overcome this first hurdle should be available. This together with the long operating lives and low fuel costs make nuclear power a viable option. In addition to this, nuclear facilities have high availability of above 90% which makes them more reliable than other technologies.

With the introduction of a carbon tax to industries, nuclear power is more competitive, and with lessons learnt from current construction projects and improvements in efficiencies of facilities, nuclear power might even have the advantage (Deutch, Forsberg, Kadak, Kazimi, Moniz, & Parsons, 2009).

The following table (Deutch, Forsberg, Kadak, Kazimi, Moniz, & Parsons, 2009) shows the comparison of Nuclear power costs versus other technologies as of 2007.

	Overnight cost ($/kW)	**Fuel cost ($/mmBtu)**	**Electricity costs (c/kWh)**	**Carbon tax of $25/tCO$_2$ (c/kWh)**
Nuclear	4,000	0.67	8.4	
Coal	2,300	2.6	6.2	8.3
Gas	850	7	6.5	7.4

Table 2: Comparative costs of Nuclear, gas and coal

Nuclear power is seen as financially risky due to the high financial investment needed and the long return of investment period. Due to the high initial investment cost, the interest rate plays a major role in the returns of the utility. At high interest rates (e.g. 10%) coal and gas are more economically viable even with a carbon tax imposed (Simbolotti, 2010).

Most estimates of nuclear costs have an extremely broad range, and there is significant uncertainty about what actual costs of new builds will be. In addition to this, it is difficult to easily compare the generation costs of coal, gas and nuclear as different factors are considered in each case. For instance, nuclear facilities always include waste and decommissioning costs and estimate the lifetime of the facility to be 40 years. Such all-inclusive analysis is not usually undertaken in establishing the cost estimates for coal and natural gas.

From this analysis it is clear that nuclear power is a viable alternative to fossil fuel based technologies on electricity generation alone. However, with the possible applicability to process heat applications, nuclear facilities could offer greater return on investment.

2.3 South African context

South Africa is a country rich in natural resources including vast quantities of coal. This has allowed the country to produce electricity at extremely cheap rates in the past. Many industries have used this as one of the primary reasons to invest in South Africa.

After the country's first truly democratic elections in 1994, the economy of the country has been steadily increasing. Investment in the country has been strong and prospects are also positive. South Africa is the largest economy in Africa and has recently joined the BRICS group of developing countries and is seen as a gateway into the other economies in Africa.

2.3.1 Electricity price increases

The majority (around 80%) of the country's electricity is produced by coal fired power stations. Most of these power stations are in the eastern and north eastern parts of the country. The main reason for this is the proximity to coal reserves and mines. The only commercial nuclear power station in the country is in the Western Cape where distance to coal reserves makes coal fire stations a less attractive option.

In 2008 rolling blackouts occurred in the country due to the lack of sufficient capacity. The country's electricity provider, Eskom, is in the process of building new coal-fired power stations. These build projects are set to be completed within the next few years. Insufficient planning and government's initial plans to open the construction of electricity facilities to companies other than Eskom, prevented new power plants from being built in time to prevent the blackouts. Due to the urgency of the situation, several coal fired power stations are being built simultaneously. Eskom has increased tariffs for electricity to finance part of these projects.

Eskom requested an average tariff increase of 35% per year for 3 years. The National Energy Regulator of South Africa (NERSA) approved an average increase of 25% per year for 3 years. Specifically, the changes in tariffs are shown in the table below (NERSA, 2010):

	Baseline (Pre April 2010)	2010/2011	2011/2012	2012/2013
Average standard price (c/kWh)	33.6	41.57	52.3	65.85
Percentage increase	-	23.7%	25.8%	25.9%
Date of increase	-	Apr-10	Apr-11	Apr-12

Table 3: Approved Eskom tariff increases

2.3.2 Carbon Tax

From an environmental point of view, South Africa has been progressing steadily to become more environmentally friendly. Various laws, including the new Air Quality Act of 2005 put stringent restrictions on industrial emissions. Industries in the country now have to look for new innovative methods to become compliant with these laws.

The nuclear industry has the advantage in this context since they will not need to change the way they operate to comply with these laws. Over and above this, these new regulations put nuclear power as a far more attractive option.

South Africa is also committed to reducing CO_2 emissions in line with international measures to curb climate change. This leads to the strong possibility of the implementation of a Carbon tax on CO_2 emissions.

South Africa is in the top 20 countries in absolute CO_2 emissions. South Africa has volunteered to reduce domestic greenhouse emissions by 34% by 2020 and 42% by 2025 (National Treasury Department of South Africa, 2010). A Carbon tax is one of the main policy instruments available for the country to achieve these objectives. The government's discussion paper on carbon tax (National Treasury Department of South Africa, 2010) suggests that this tax should be imposed in a gradual basis, starting at around R75 per tonne CO_2, increasing to around R200 per tonne CO_2 over time.

Many industries, including the steel industry are wary of these taxes as many processes require fossil fuels to some extent. Although these proposals are in the discussion phase, the government has made it clear that it is committed to reducing emission. With the 17th United Nations framework on climate change (COP 17) being hosted in South Africa, the country seems poised to move forward with its emissions reduction plans.

2.3.3 IRP 2010

South Africa has finalized an integrated resource plan (IRP) for electricity and it is currently in the promulgation phase. This plan seeks to curb growing demand for electricity in the country while taking into account the country's goal to reduce emissions.

The plan has gone through 2 revisions, and the current policy-adjusted IRP suggests that the capacity be increased by building an additional:

1. 9.6 GW worth of nuclear power plants
2. 6.3 GW worth of coal power plants
3. 17.8 GW worth of renewable energy
4. 8.9 GW worth of other sources

This plan increases the energy share of nuclear facilities from 5% to 20% and of renewable energy sources from 0% to 9% while decreasing the share of coal from 90% to 65% by 2030 (South African Department of Energy, 2011). The plan aims to limit the carbon dioxide production from electricity to 275 million tonnes per year after 2025.

This plan is a boost for the nuclear industry in South Africa. However, it should be noted that the IRP does not include any high temperature reactors into the plan. The motivation behind this was that modern HTRs are yet to be fully commercialized while tried and tested light water reactors would be more appropriate for the electricity needs of the country. It is clear that HTR implementations in South Africa will be focused on the private sector and specifically on process heat applications.

3. Technological analysis of nuclear centred scenarios for the steel industry

3.1 Option 1 - Electricity only scenario

Electricity generation is the main industrial application of nuclear energy, and any analysis of the integration of nuclear power with any industry needs to include electricity as one of its considerations. The following section identifies the scenario that will be analysed in the study. Potential benefits that can be derived in using electricity from a nuclear facility will be identified in proceeding sections.

As with all major industries, electricity usage is a major expense that requires control. The specific usage, and therefore cost, of electricity in the industry depends on the process used. In all commercial steel manufacturing processes, the main consumption of electricity occurs in the steel-making side (where the iron is refined to achieve a certain grade/quality). Out of the technologies that are presently used for steel-making, the electric arc furnace (EAF) is the most electrically intensive.

For a proper economic analysis, it makes sense to focus on the most electricity intensive process. Therefore, this study will only focus on steel-making centred on electric arc furnaces. However, the models developed to analyse the EAF process can easily be customised to analyse other steel-making processes.

The percentage contribution of electricity costs in the EAF process route is important to identify. The higher the percentage cost of electricity, the more impact an alternative electricity production route will have on the profitability of the company. It is well known that the profitability of EAF based steel is closely coupled to electricity consumption.

For the analysis in this section, the cost of direct reduced iron (DRI) and scrap are assumed to follow the general global trends. Furthermore, it is assumed that equal amounts of scrap and DRI are used to charge the EAF. This assumption does not generally hold true in practice, as most electric arc furnaces are charged with up to 90% scrap. However with recent similarities in scrap and DRI prices, this assumption does not alter the accuracy of the analysis.

There are 2 possible options for how electricity generation for secondary steel-making can be integrated with the steel industry. The benefits and risks of these 2 options will be discussed in proceeding sections.

1. A nuclear power plant could be owned and run by a utility and provide electricity to an iron and steel works.
2. The steel plant could build a small nuclear facility for its own electricity needs.

The diagram below illustrates how a nuclear power facility integrates with an electric arc furnace.

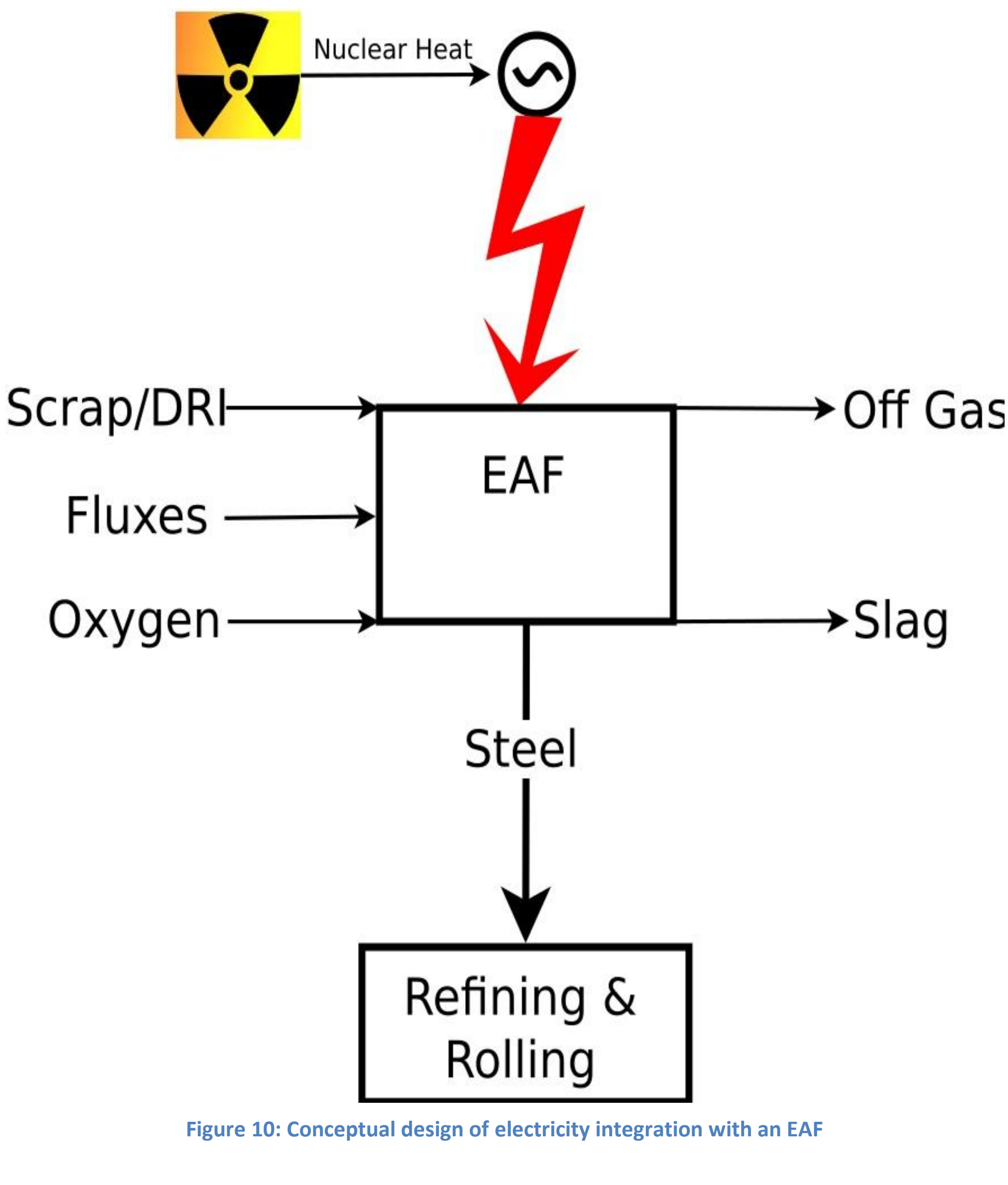

Figure 10: Conceptual design of electricity integration with an EAF

In this scenario, heat from a nuclear facility drives a turbine which runs an electric generator. Note that there is no requirement for any specific type of nuclear facility. The electricity produced (or part thereof) is used in an EAF to melt the scrap and DRI. Oxygen is blown to reduce the electricity requirements of the EAF. Fluxes are added as necessary to remove impurities, which are collected as slag during tapping. The steel is tapped from the furnace and sent for further refining and rolling into end products.

A significant quantity of off-gas is produced. While this by itself is an important environmental issue that needs to be addressed, this study does not focus on this. The industry itself needs to deal with these off-gasses regardless of its integration with the nuclear industry.

3.2 Option 2 - Process heat only scenario

The recent study (Botha, 2009) showed that a viable process route to integrate process heat applications of nuclear power with the steel industry involves using H_2 as a substitute reducing agent for the Midrex process instead of natural gas. This study will build on this work and proceeding sections will focus the economic viability of this process route.

Separating the hydrogen production aspect from the iron ore reduction side simplifies the economic analysis of the entire process. In addition to this, the economic analysis of a hydrogen substituted Midrex process would still be valid even if the hydrogen is not produced in conjunction with a nuclear facility.

The following diagram shows the overall process flow of iron ore reduction using hydrogen gas as the reducing agent.

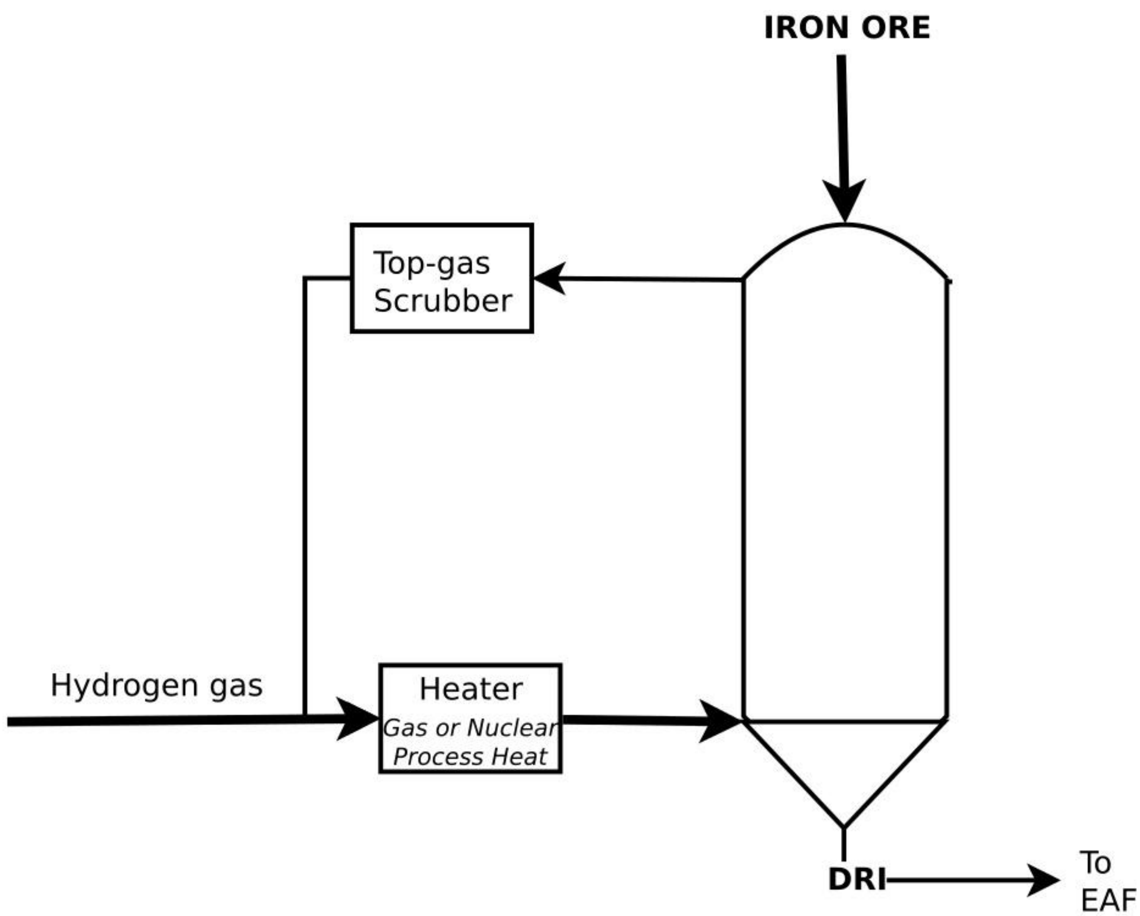

Figure 11: Hydrogen based Midrex process

Iron ore is fed from the top of a shaft furnace, while heated hydrogen gas rises through the furnace. The assumption is made that the iron ore is composed almost entirely of hematite (Fe_3O_2). This is a close enough approximation of most commonly used iron ores that are used for DRI production.

The hydrogen gas is fed through the bottom of the furnace and flows through the iron ore, reducing the ore over a few reactions, producing iron and water. The top gas exiting the shaft furnace goes through a scrubber to recover the unused hydrogen. This hydrogen is fed together with commercial hydrogen back into the heater.

H_2 is a powerful reducing agent, but the reaction with iron ore is endothermic and therefore requires an additional heat source to pre-heat the hydrogen before it can be used in the shaft furnace. The heater can be a gas-heater that will use natural gas to heat the hydrogen to the required temperatures. As an alternative to this, process heat from a nuclear facility can be used to heat the hydrogen gas. This would avoid the need for extra natural gas, but would also mean that the less process heat will be available to produce hydrogen gas. The analysis to follow will determine which option is the more cost effective. The following figure show a hydrogen generating facility coupled with a nuclear power plant.

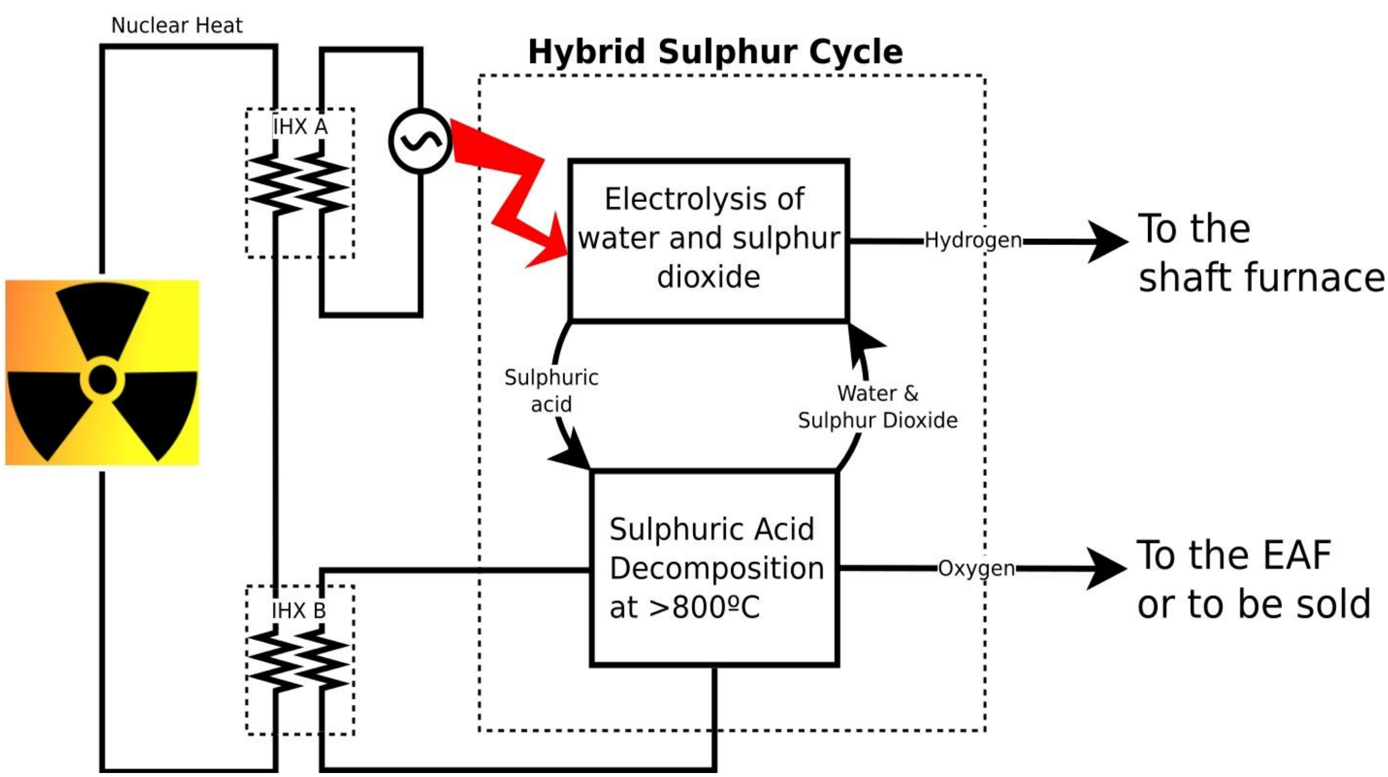

Figure 12: Hydrogen generating facility

For process heat applications, only high temperature reactors (HTRs) can be used. LWRs are limited in the temperatures that they can achieve. HTRs can achieve temperatures around 900°C and future VHTRs can even exceed this.

Note that the figure above would not represent the actual complexity of the nuclear heat removal facility and it is only meant as a conceptual flow diagram of the processes involved. The heat generated from the nuclear facility is used for:

1. Heating a coupled loop that will power a steam generator
2. Heating a coupled loop that will provide the required heat for the hydrogen production facility.

The specific hydrogen production technology shown above is the hybrid-sulphur cycle. While it is not necessary to use this specific technology, it has been used in this analysis due to the promising results obtained in a previous study (Botha, 2009).

The hydrogen produced by the facility will be sent to the H_2 based shaft furnace. The oxygen produced will be used at an EAF or sold.

For the steel industry specifically, there are 2 options in how hydrogen production can be managed.

Firstly, the nuclear power plant and associated hydrogen production facility could be separate from the steel works, providing hydrogen to the steel works. The nuclear facility merely ensures that sufficient heat is provided to the hydrogen production process. The steel works would merely buy hydrogen from a utility as they currently do for natural gas.

The second option is for the nuclear facility and associated hydrogen production facility to be tightly integrated with the steel works. In this scenario, some of the heat from the nuclear facility could be redirected to the steel works to maintain the required temperatures for the reduction process. The hydrogen production yield will be lower in this scenario, but it will ensure that no other, potential environmentally damaging, heating sources (coal, natural gas, etc.) are introduced into the process.

3.3 Option 3 - Co-generation (combined Electricity and process heat) scenario

Almost all iron produced using the Midrex process follows the EAF steel-making route. This is due to the fact that the output of the Midrex process is solid iron either in the form of sponge iron or Hot Briquetted iron. The BOF route requires a supply of molten iron in addition to DRI and therefore, cannot be used without another source of molten iron.

From the previous discussions, it should be clear that with EAFs, a significant portion of the cost of operation is due to electricity consumption. Therefore, the integration of process heat and electricity generation for the steel works makes sense. However, due to the requirements of process heat applications as described above, only HTRs can be used.

The modular nature of the recent HTR designs allow for scalability depending on the ultimate requirements of the industry. A depiction of the completely integrated nuclear centred steel works is illustrated in the picture on the following page.

In this scenario, heat from the nuclear facility drives both a hydrogen production plant and a turbine connected to a generator. The hydrogen from the hydrogen plant is used as a reducing gas in the hydrogen based Midrex plant. The DRI from the plant is used as feed-stock for the EAF facility.

The oxygen from the hydrogen plant is used at the EAF plant to reduce the electricity consumption. Electricity produced from the nuclear facility is used both at the hydrogen production plant and at the EAF facility.

It is possible that heat from the nuclear facility can be used in the Midrex plant instead of natural gas to heat the hydrogen to the required temperatures.

In a completely integrated plant, only one scenario is available for the management of the facility. The plant needs to be owned, managed and run with the sole purpose of being used for the steel works. This has various issues that will be explored in the later chapters. One of the major advantages is that transport losses in transporting the oxygen and hydrogen will be minimised in such an integrated facility.

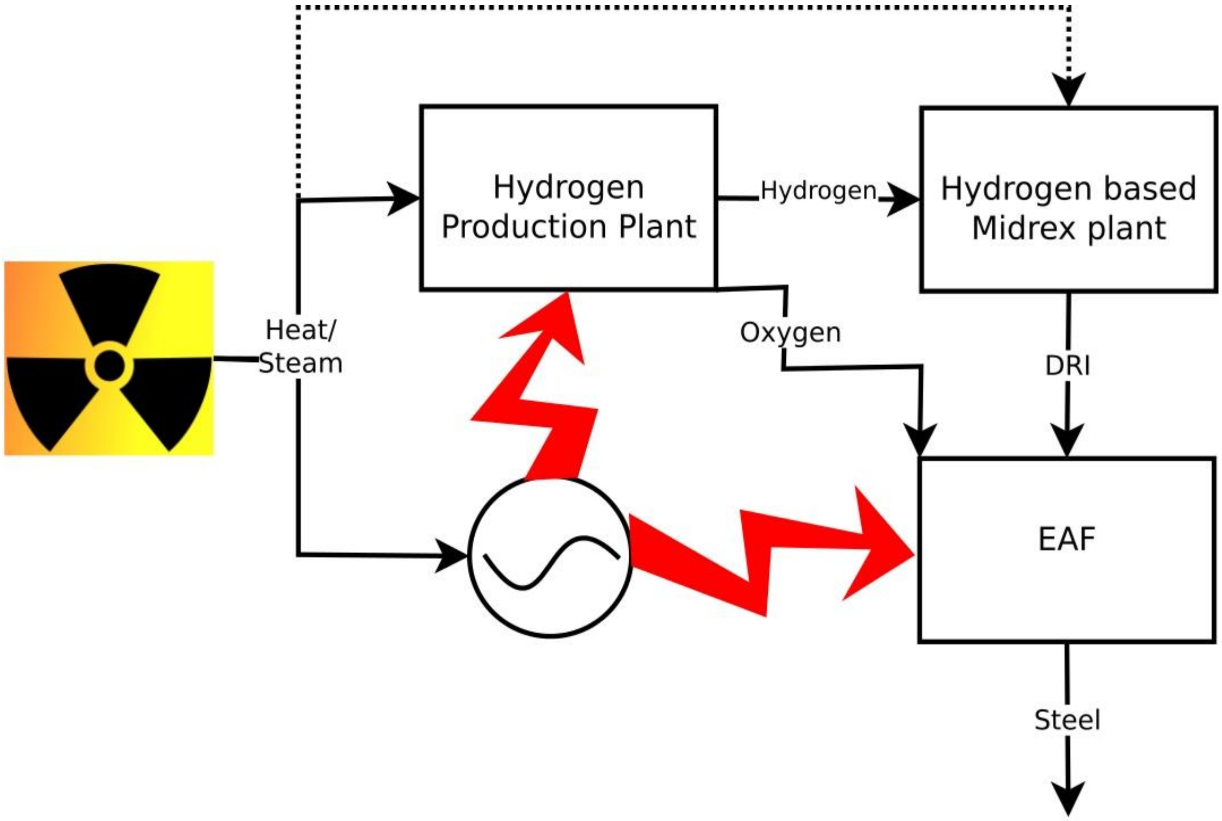

Figure 13: Nuclear co-generation in conjunction with the steel industry

3.4 Options not linked with nuclear facilities

The steel industry is a mature industry that has been refined over the last 2 centuries. Radical technology change is difficult in the industry due to the existing process efficiency for the existing Blast Furnace/BOF route. This technology would therefore likely remain the dominant technology in the steel industry for the foreseeable future.

Due to the fact that the global steel capacity is underutilised, new steel-plant builds are generally not the first choice for players in the industry. Instead, methods to contain carbon emissions within the framework of existing technologies are being intensely researched.

3.4.1 Carbon capture and sequestration

One of the major options that are being considered by the steel industry is to reduce carbon emissions by the use of carbon capture and sequestration. By collecting emissions, carbon dioxide can chemically or thermo-chemically be separated and stored directly or sent to a facility to be stored in a deep geological formation.

In addition to storage of CO_2, capturing of emissions allows for waste energy to be utilised to improve efficiencies in the entire steel-making process. The research conducted here has led to potential improvements in CO_2 emissions by up to 50%.

One of the main issues with carbon capture is that technologies are not very widely deployed and estimates for the costs involved with such technologies vary significantly. To date, commercial implementations of carbon capture in the steel industry has not been demonstrated.

However, given that carbon capture and sequestration techniques are young and that alternative solutions are not available in all situations, it is very possible that carbon capture will become cost effective in the near future as global carbon emissions become more legislated and taxes on carbon become law.

4. Cost analysis of viable nuclear centred solutions

4.1 Cost Analysis Context

In calculating the total cost of ownership for the 3 options identified above, the context of the proposed solutions must be made clear.

This analysis is based on the potential implementation of the 3 options mentioned previously within South Africa. Due to this, several important factors need to be taken into consideration. Firstly, electricity prices are based on local prices which has been one of the lowest in the world till recently.

Secondly, local inflation rates are used to normalise the collected data, to provide a more accurate price comparison.

Finally, the cost of many raw materials is referenced internationally and is priced in US dollars (USD). While most local industries source raw materials directly at reduced rates, the international price reference needs to be used in any analysis of this kind to balance discrepancies in the industry.

As such, the data used in this analysis has generally been normalised to 2011 values based on local inflation figures and is generally expressed in USDs. In addition to this all data except for electricity is based on the international reference prices of raw materials. Electricity prices are based on South Africa's local utility's (Eskom's) price projections. It is assumed that no special sourcing rates apply to any of the used resources.

4.1.1 Inflation

The following table illustrates South Africa's year on year inflation rates for the last decade. This data will be used throughout this study.

Table 4: Year on Year inflation for the last decade

Year	% Inflation (Jan-Jan)
2001	7.10%
2002	4.90%
2003	11.60%
2004	0.10%
2005	3.00%
2006	4.00%
2007	6.00%
2008	9.30%
2009	8.10%
2010	6.20%
2011	3.70%

4.1.2 Electricity Increases

The following table shows the actual and projected percentage price escalation for electricity prices since 2001.

Table 5: Electricity price escalation for the last decade

Year	Electricity price escalation (%)	Electricity price escalation (normalised to 2011 prices) (%)
2001	8.33%	1.23%
2002	3.85%	-1.05%
2003	3.70%	-7.90%
2004	7.14%	7.04%
2005	13.33%	10.33%
2006	5.88%	1.88%
2007	5.56%	-0.44%
2008	31.58%	22.28%
2009	32.56%	24.46%
2010	25.44%	19.24%
2011	25.81%	22.11%
2012	25.91%	25.91%

This data (until 2011) is graphically illustrated below with the inflation rates included as a baseline.

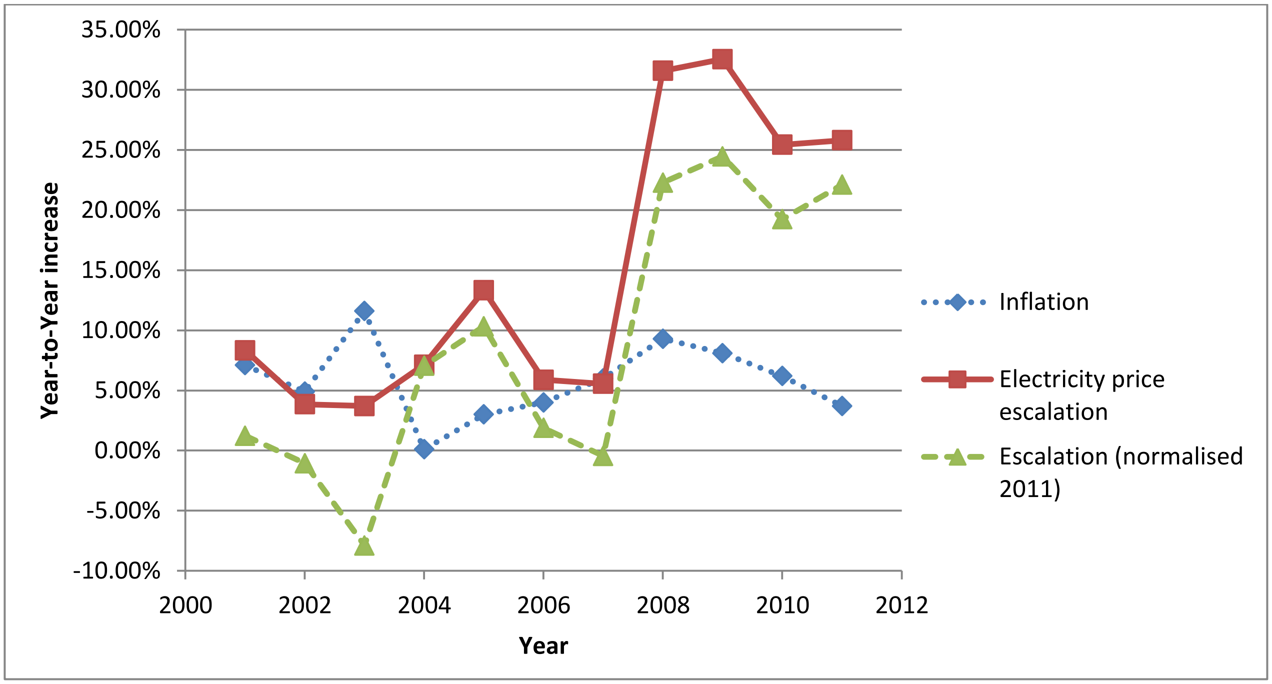

Figure 14: Electricity price escalation over the last decade

As is clearly seen from the figures above, electricity price increases have been quite stable at inflation levels or slightly more than inflation levels until about 2008. This was the start of the electricity crisis in South Africa. Recent projections suggest that this increase will continue till at least 2015.

4.1.3 Raw material prices

Another important factor that contributes significantly to the analysis is the price of raw materials. Although the increase in electricity prices in South Africa has been significant, worldwide electricity price growth has been less dramatic.

However, raw material prices used in steel manufacturing has increased significantly. Relevant to this study are the following materials:

1. Iron Ore
2. Natural gas
3. Steel scrap
4. DRI

The following graph shows the trend of the raw material prices over the last decade (Steelonthenet, 2011).

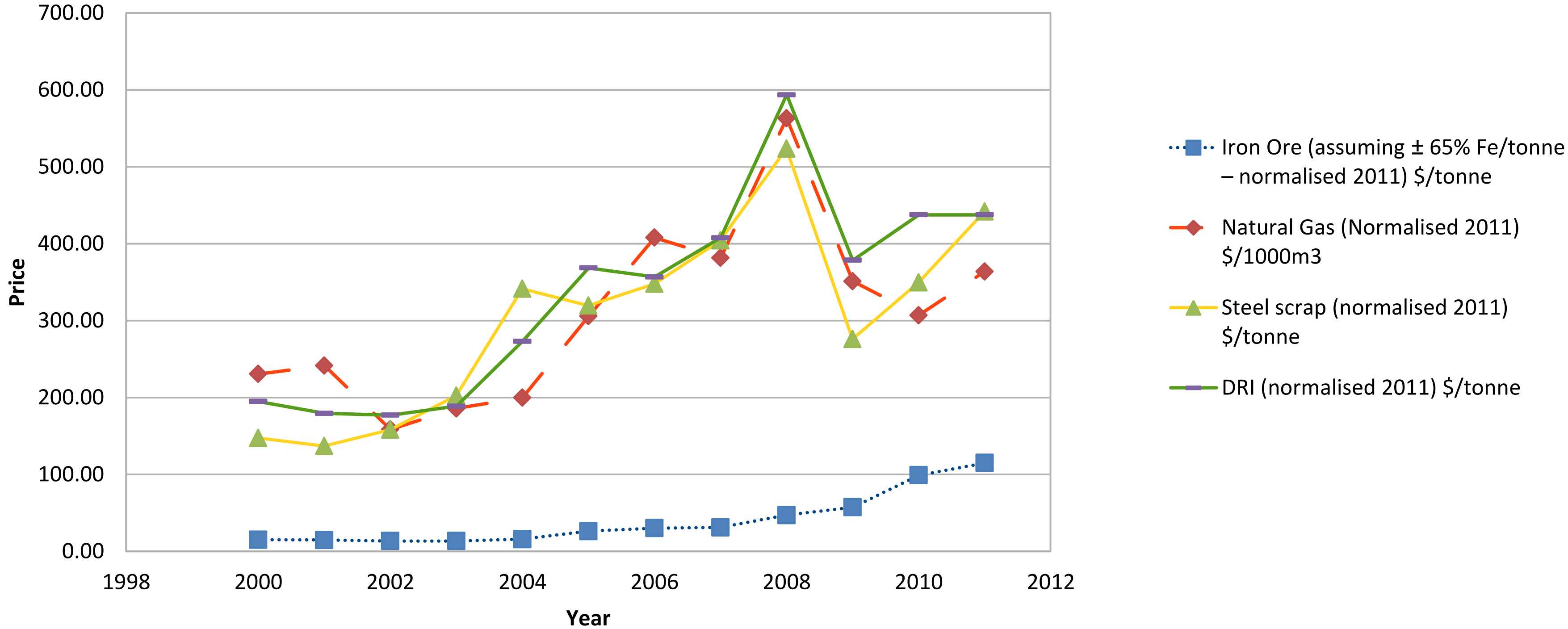

Figure 15: Raw material price escalation

The graph above clearly shows a steady upward trend for raw material prices. For all the resources except iron ore, the price peak was reached during 2008 before the global financial meltdown. Natural gas, steel scrap and DRI all appear to follow closely to one another over the years, while iron ore prices seem independent from the rest. The iron ore price has significantly affected global steel prices in recent years.

4.2 Option 1

4.2.1 Cost Contributions to EAF steelmaking

A 2001 study (Oosthuizen, 2001) of the economics of electric arc furnaces identified the following contributions of various operational costs as a fraction of total EAF operational costs in 2000. This table assumes that scrap to DRI is charged into the EAF at a 1:1 ratio.

Table 6: Contribution of different cost components to EAF steelmaking

Cost Component	% Contribution
Scrap	29.70%
DRI	22.30%
Electric power	14.90%
Maintenance and other costs	14.00%
Electrodes	7.50%
Refractories	3.70%
Flux	3.60%
Labour	1.90%
Investment	1.60%
Oxygen	0.70%
Graphite	0.10%

It can clearly be seen that in the year 2000, steel scrap, DRI and electric power accounts for two-thirds of the total operational costs for an EAF facility. With the escalation of raw material and electricity costs in the industry, especially in the last decade, the contribution of these 3 components has changed significantly.

The following table shows the increase in these contributions over the last decade (with the assumption that the remaining one-third of the costs increases according to inflation[1]).

Table 7: Escalation of contribution to EAF costs of electricity, scrap and DRI

Year	% contribution of costs from electricity	% contribution of costs from Scrap	% contribution of costs from DRI
2000	14.90%	29.70%	22.30%
2001	15.70%	28.61%	21.24%
2002	14.91%	31.92%	20.10%
2003	12.45%	37.99%	19.58%
2004	9.82%	47.22%	20.88%
2005	10.28%	41.83%	26.94%
2006	10.15%	44.29%	25.25%
2007	9.07%	46.61%	26.10%
2008	8.53%	47.39%	30.06%
2009	16.06%	35.05%	27.68%
2010	16.28%	38.24%	27.44%
2011	17.38%	42.86%	23.99%

This data is graphically represented in the graph below:

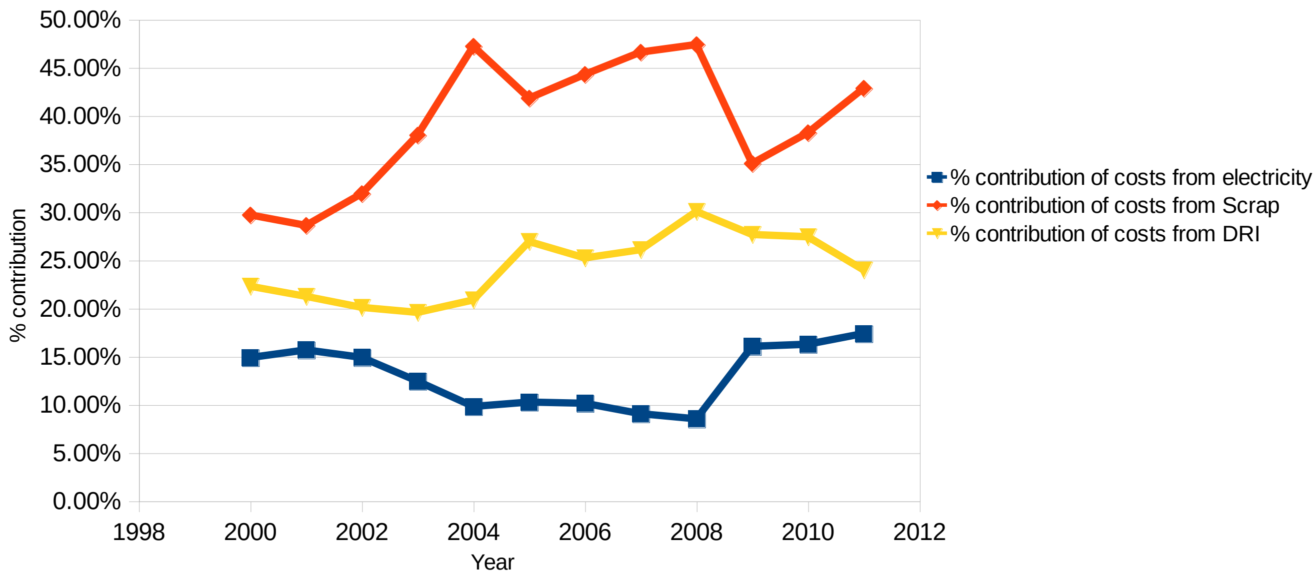

Figure 16: Change in percentage contributions of various components to EAF costs

Given the similarity in commodity prices for scrap and DRI shown in the previous section it may seem surprising to not see the trend lines of scrap and DRI being closer together. Especially when it is assumed that the same amount or scrap and DRI are charged into the EAF. The main contributing factor for this discrepancy is the transport cost involved with scrap.

1 Considering that maintenance, labour and investment costs account for a significant portion of the remaining costs, this consideration can generally be considered to be valid

DRI is mainly produced on the same premises as the EAF plant. Therefore no additional costs need to be added to the cost of production of DRI. However, most scrap is transported into the steel works and the extra transportation cost of scrap pushes the contribution of this component up.

It can clearly be seen that electricity contributions account for a significant portion of the total operating costs of an EAF facility. Given the planned increases in the price of electricity over the next few years this contribution will most likely increase.

While scrap prices are generally market controlled and not easily influenced by changes in technologies used in the steel industry, both the DRI costs and electricity costs have the potential to be controlled by reducing production costs of DRI and reducing electricity costs.

4.2.2 Pricing Model for a nuclear facility producing electricity

4.2.2.1 Base-line Model for electricity production

For the purpose of this study a model was developed to determine the production cost of electricity in a nuclear power facility. For this purpose the following factors were taken into consideration to calculate the cost of electricity production.

Table 8: Pricing model components for nuclear power facility

	Description	**Base values used in this study**
Overnight cost (USD/kW)	Typically between $1700 and $4000	4 000
Power (kW)	60,000 upwards, depending on purpose	100 000
Efficiency	33% upwards depending on technology	33.00%
Interest rate	This depends on the loan conditions and government backing	10.00%
Repayment period (years)	This depends on the loan conditions and government backing	20
Construction time (years)	4 – 6 years depending on type of nuclear power plant	6
Lifetime (years)	40 to 60 years	60
Load factor	Generally 95%	85.00%
Operational and Maintenance cost ($/MWh)	Typically between $10 and $16 per MWh	10
Decommissioning costs ($/MWh)	Cost set aside for decommissioning purposes (Typically between $2 - $3/MWh)	2
Cost/mmbtu	$0.6 to $1 per mmbtu	R 0.67
Operational cost/quarter (USD)	Calculated as total cost of fuel, operational and maintenance cost, and decomissioning cost	$3 851 519.87
Loan balance at end of construction (USD)	Total repayment necessary at end of the construction period	-$539 150 633.06
Quarterly loan repayment (USD)	Calculated payment based on loan balance at the end of the construction period, interest rate, quarterly repayments over the repayment period	$15 649 410.58
Cost of Electricity production (USD/kWh)	Total power produced in a quarter divided by total cost of production	$0.11
Cost of Electricity production (ZAR/kWh)	Cost of electricity production in $ multiplied by exchange rate	R 0.85

For the base scenario, shown above, the electricity generation costs exceed the current electricity costs of ZAR0.523/kWh by close to 63%. Given this situation, it is clear that the base scenario cannot be a viable option for an industrial corporation to reduce electricity expenses. Also it should be noted that the power of the facility does not affect the production costs at all. It mainly serves as a placeholder.

4.2.2.2 Sensitivity analysis of pricing model

To identify the impact on changes of various factors to the final electricity price, the following sensitivity analyses were conducted.

Firstly to assess the impact of loan interest rate to the cost of electricity production, the interest rate variable in the pricing model was varied while keeping the other variables constant. The following graph shows the result of this analysis. The interest rate was varied from 10% to 2%.

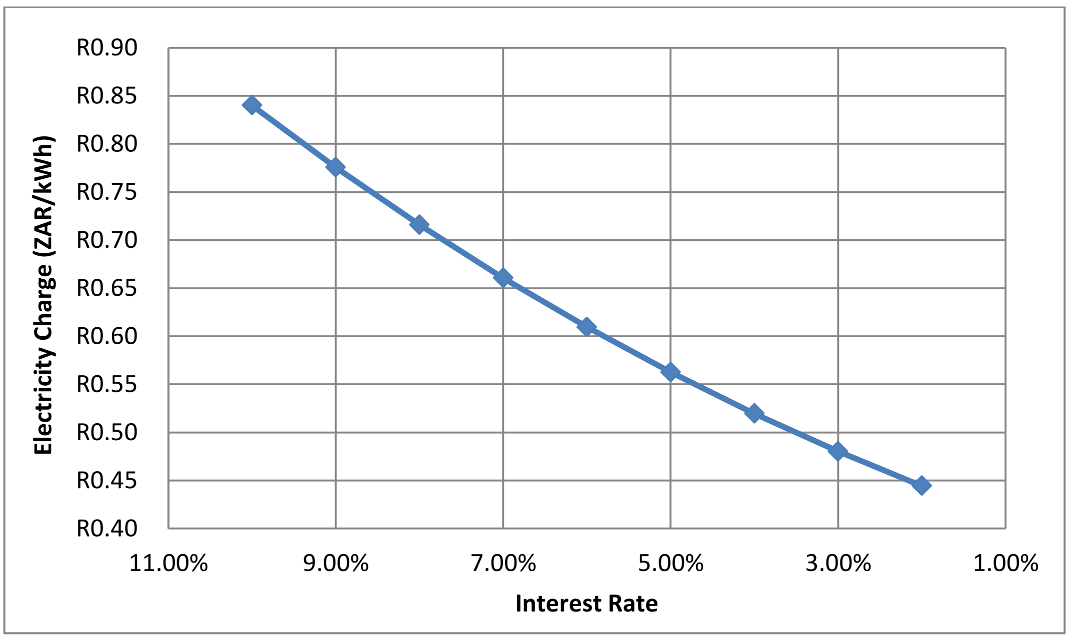

Figure 17: Effect of changing the interest rate on electricity cost

As can be clearly seen, changes in the interest rate are a significant contributor to the final price of electricity production in nuclear power. As the interest rate is lowered, the final production cost lowers significantly. While it is not easy to distinguish from the graph above, there is an exponential relation between interest rate and electricity production cost.

The next analysis that was conducted was around construction costs. The cost per kWh of the nuclear facility was varied from $1500 - $4500/kWh. The following graph shows the effect of this analysis on the final electricity production costs. A constant interest rate of 10% is used for this analysis.

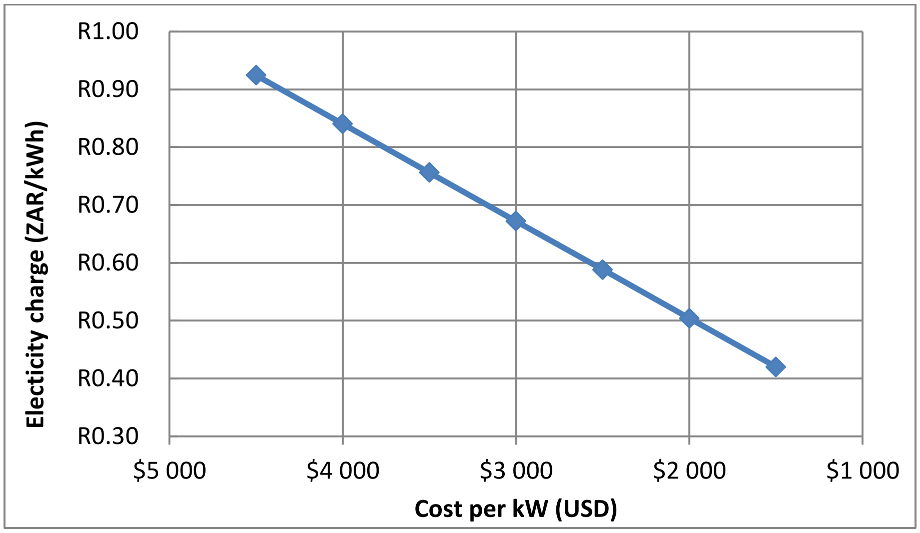

Figure 18: Effect of changing the construction costs (USD/kW) on electricity price

As the construction costs/kWh decreases, the production costs decrease. There is a linear relation between the cost per kWh and the final electricity production costs. Due to the high interest rate and construction costs, the final production cost of electricity is highly dependent on the cost per kWh.

The following graph shows the relation between plant efficiency and production costs:

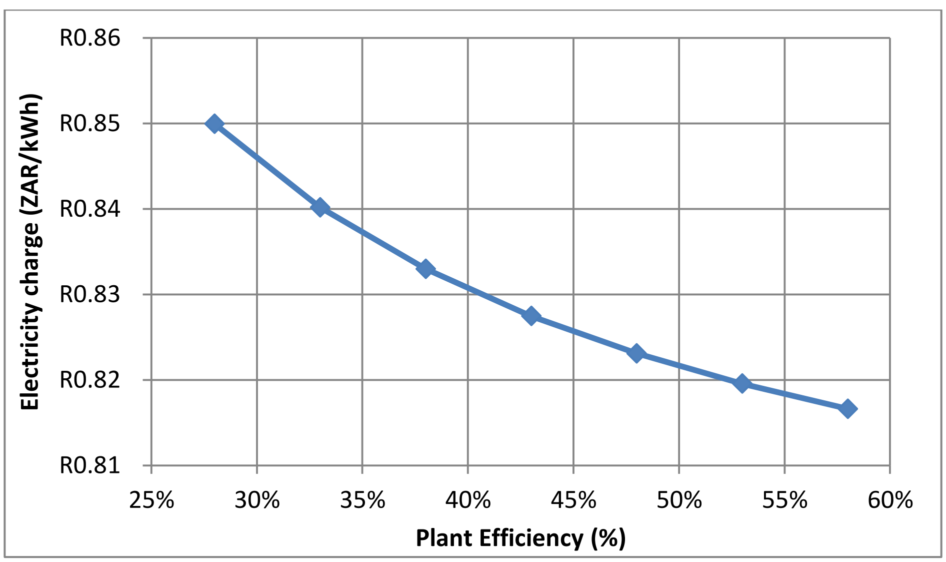

Figure 19: Effect of changing the plant efficiency on electricity cost

As efficiency increases, the production costs decrease accordingly. However, compared to interest rate and construction costs, the effect is minimal.

The following graph shows the same analysis for plant availability:

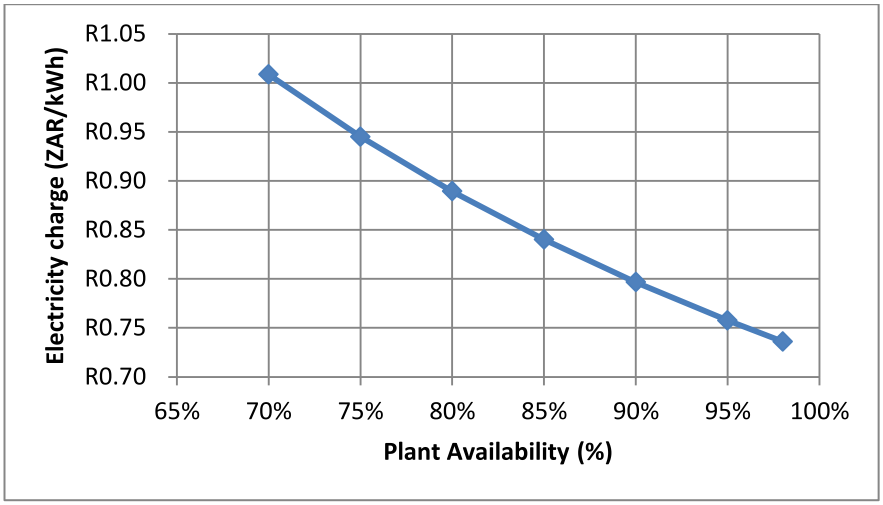

Figure 20: Effect of plant availability on electricity cost

As plant availability increases, production costs decrease. Next to interest rate and construction costs, plant availability produces the greatest effect on final prices.

Fuel prices changes for nuclear energy is potentially one other area that needs to be investigated. The following table shows how changes in the fuel price affect the total production costs.

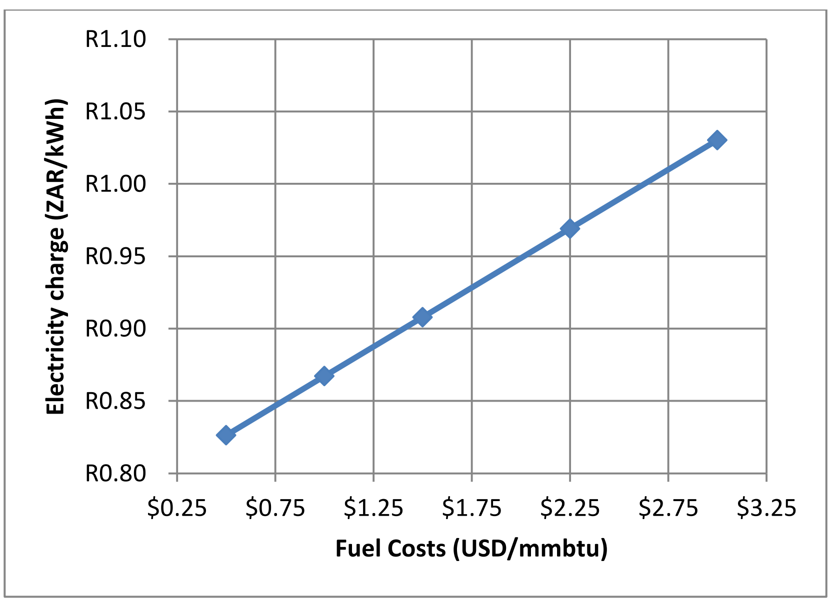

Figure 21: Effect of fuel price on electricity cost

As is clearly seen, electricity production costs follow the increase in fuel prices in a linear manner. However, a near 5 fold increase in fuel price is necessary to change the production cost by 25%. Fuel is therefore not one of the major contributors to cost in a nuclear facility.

The final sensitivity analysis that will be conducted is to determine the effect of construction time on electricity costs.

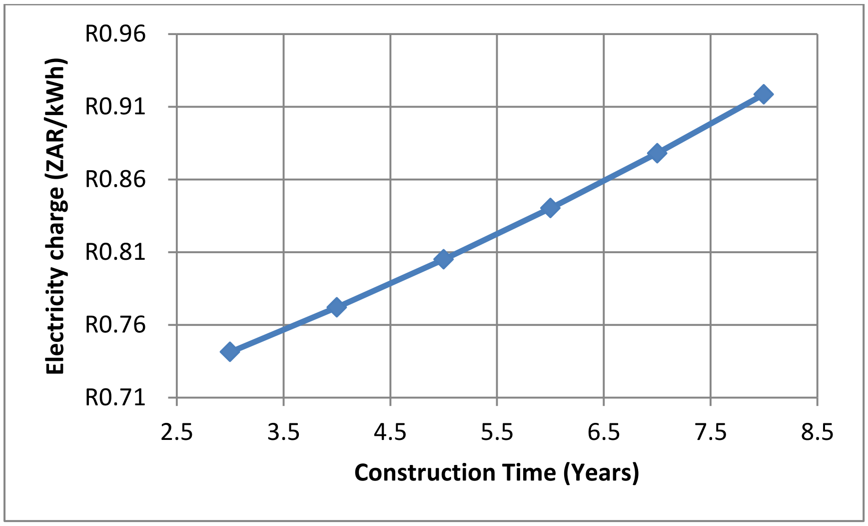

Figure 22: Effect of construction time on electricity cost

It is clear from the figure above that as the construction time increases, so too does the production cost.

4.2.2.3 Realistic best-case Model for electricity production

Based on these conclusions, a realistic best case scenario is provided below for the construction of nuclear facility to generate electricity to provide power to an EAF.

Table 9: Realistic best case model values

	Realistic best case scenario
Overnight cost (USD/kW)	3 000
Power (kW)	100 000
Efficiency	42.00%
Interest rate	5.00%
Repayment period (years)	20
Construction time (years)	4
Lifetime (years)	60
Load factor	95.00%
Operational and Maintenance cost ($/MWh)	10
Decommissioning costs ($/MWh)	2
Cost/mmbtu	R 0.67
Operational cost/quarter (USD)	$3 745 221.17
Loan balance at end of construction (USD)	-$329 834 321.55
Quarterly loan repayment (USD)	$6 546 064.79
Cost of Electricity production (USD/kWh)	$0.05
Cost of Electricity production (ZAR/kWh)	R 0.40

The calculated electricity cost from this best case scenario is more than 20% lower than that of the current electricity price from South Africa's electricity utility provider, Eskom. This confirms that electricity sourced from a nuclear facility can be a viable means for reducing electricity costs in industry.

4.2.3 Integrating Option 1 and the steel industry

As mentioned previously there are 2 primary scenarios regarding how a steel industry can source electricity via nuclear means.

4.2.3.1 Buy Electricity from a utility

The first option is to buy electricity from an external nuclear utility. The analysis above can then be utilised to provide a baseline from which a steelworks can negotiate with such a utility. Of course each facility will need to add its own mark-up to the production cost.

Given the following assumptions:

Utility mark-up	= 10%
Utility selling price	= R0.44/kWh
EAF electricity consumption/tonne	= 450kWh/tonne
EAF capacity	= 2 000 000 tonnes/annum
Electricity contribution for EAF steel-making	= 17.38%

The total electricity cost savings for the industry can then be calculated as follows:

Total electricity requirements per annum	= 450 x 2 000 000
	= 900 000 000 kWh
Current cost of electricity	= 900 000 000 x 0.523
	= R470 700 000 / annum
Utility Selling price of electricity	= 900 000 000 x 0.44
	= R396 000 000 / annum
Total savings	= R74 70 000 / annum
% Electricity savings	= 15.9%
% Savings/tonne steel produced	= Contribution for EAF steel making x % Savings
	= 2.75%

While this cost does not seem to be an exorbitant saving at first glance, buying electricity from a nuclear utility will ensure relatively long term stability regarding electricity prices. One of the other advantages of nuclear power is that the fuel price increases do not affect the price of electricity significantly, and therefore, more accurate cost forecasting for an industry would be available.

4.2.3.2 Build In-house

The alternative management option that a steel industry could take regarding nuclear power for electricity production is to build such a facility in house. This will allow the company to benefit for base level costs for electricity production as well as manage. For example, considering an EAF facility with the following attributes:

EAF electricity consumption/tonne	= 450kWh/tonne
EAF capacity	= 2 000 000 tonnes/annum
Electricity contribution for EAF steel-making (2011)	= 17.38%

Total electricity requirements per annum	= 450 x 2 000 000
	= 900 000 000 kWh

Size of Power Plant	= 900 000 MWh / (365 x 24)
	≈ 100 MW

Further if one can assume that the industry has sufficient capital to fund the project without a loan the subsequent analysis follows:

The following figure shows the income, expense summary of an in-house built facility where no external financing is used.

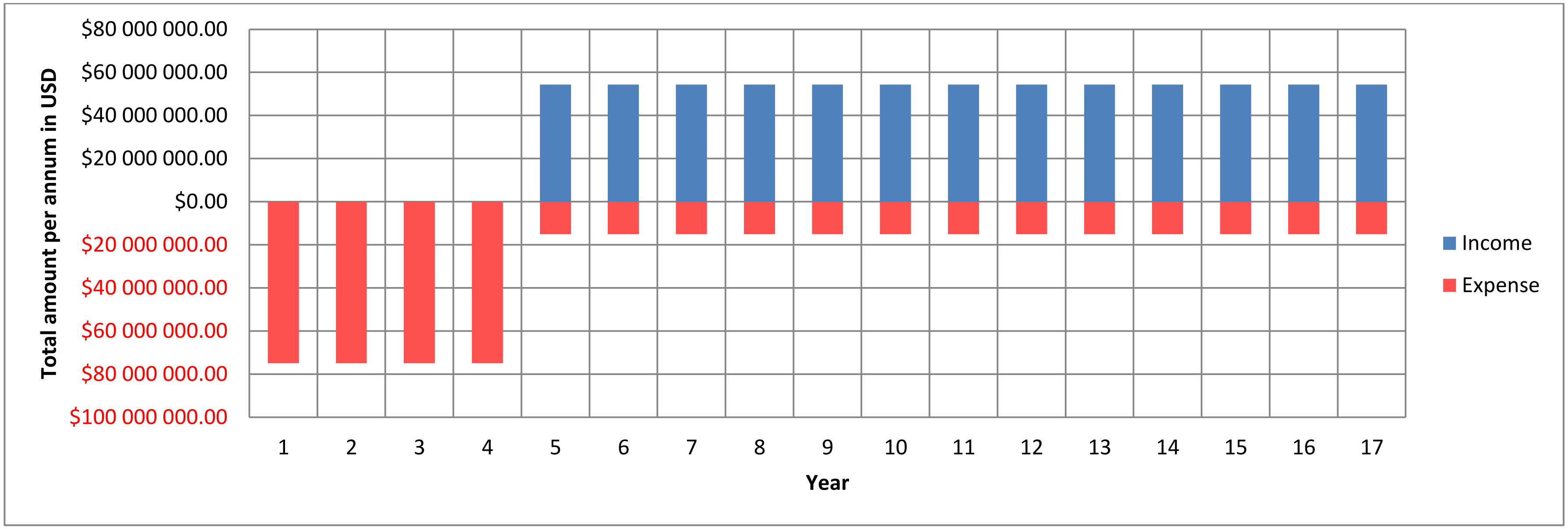

Figure 23: Cashflow for in-house financing of the nuclear electricity production facility

For the first 4 years, only the cost incurred in building the facility comes into the picture. After year 4, an "income" is added to the picture and the expenses include operational costs. Although the term income has been used, this actually represents the cost of electricity that the industry would otherwise have had to pay an electricity utility (like Eskom). Therefore, this is not an actual income, but rather a savings.

The following figure illustrates the "Bank balance" of the industry that would finance such a facility in house.

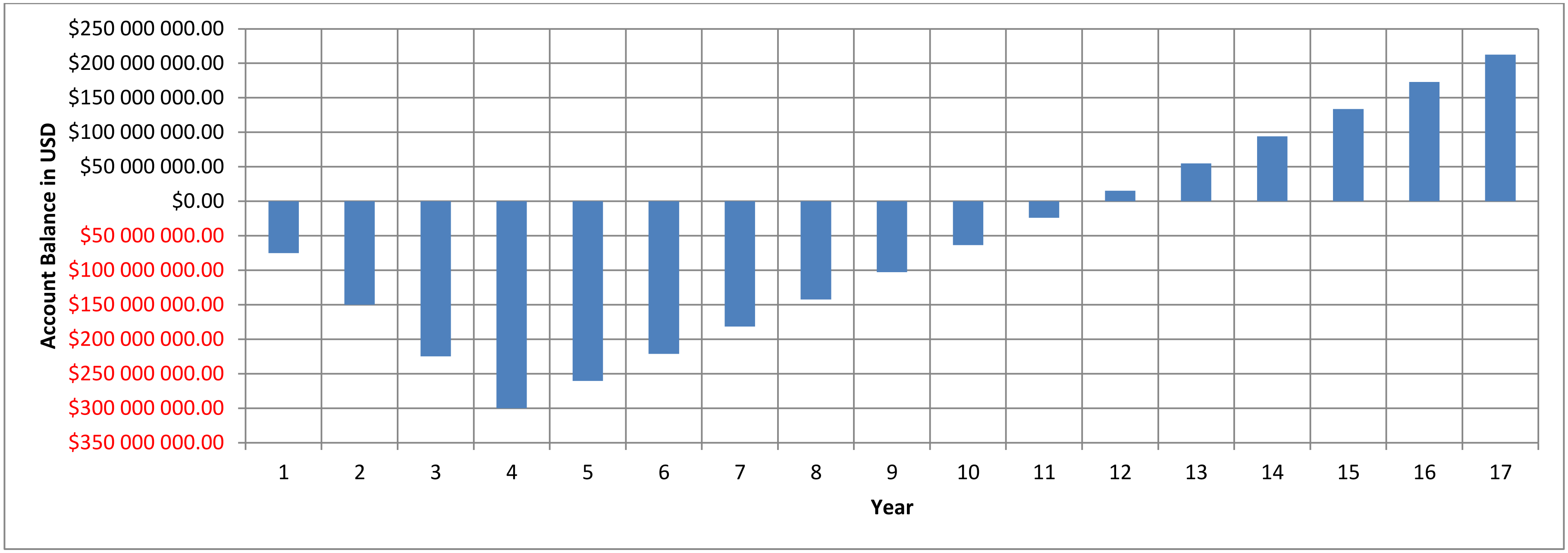

Figure 24: Bank Balance for a company financing the said nuclear facility in-house

As can clearly be seen in this figure, the costs involved escalate until year 4 after which the facility would pay back its start-up costs as savings incurred by the company. The positive "bank balance figures represent cumulative savings accumulated by not buying electricity from an outside utility. Apart from the income portion which continues steadily after year 5, the industry slowly pays off the debt incurred in the first 4 years over the next 8 years:- after which, only operational costs factor into the expense of the facility. The payback period is about 12 years for such a facility.

Of course the 2 graphs above assume that electricity prices would increase only by inflationary values. If steeper electricity increases occur, then the payback period will be pulled closer by a few years.

Although ideally, such a facility should be financed in house, practically this is unlikely. Therefore, the following 2 figures illustrate what the effect of influence would be on the industry's cashflow and bank balance when Option 1 is financed at a 5% interest rate:

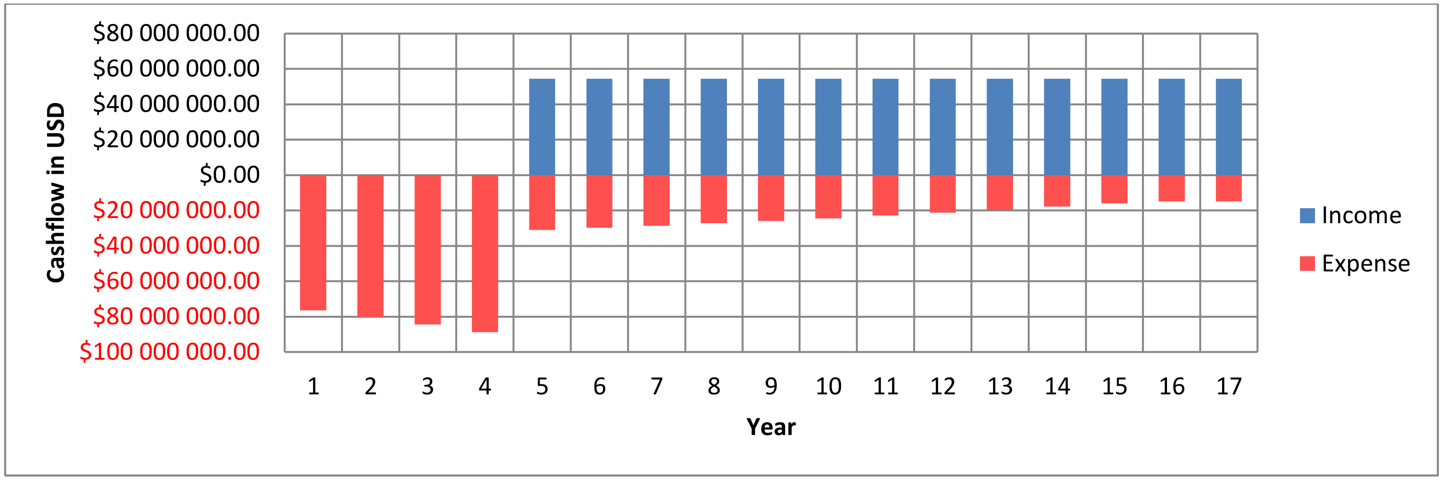

Figure 25: Cashflow when the facility is financed at 5% interest

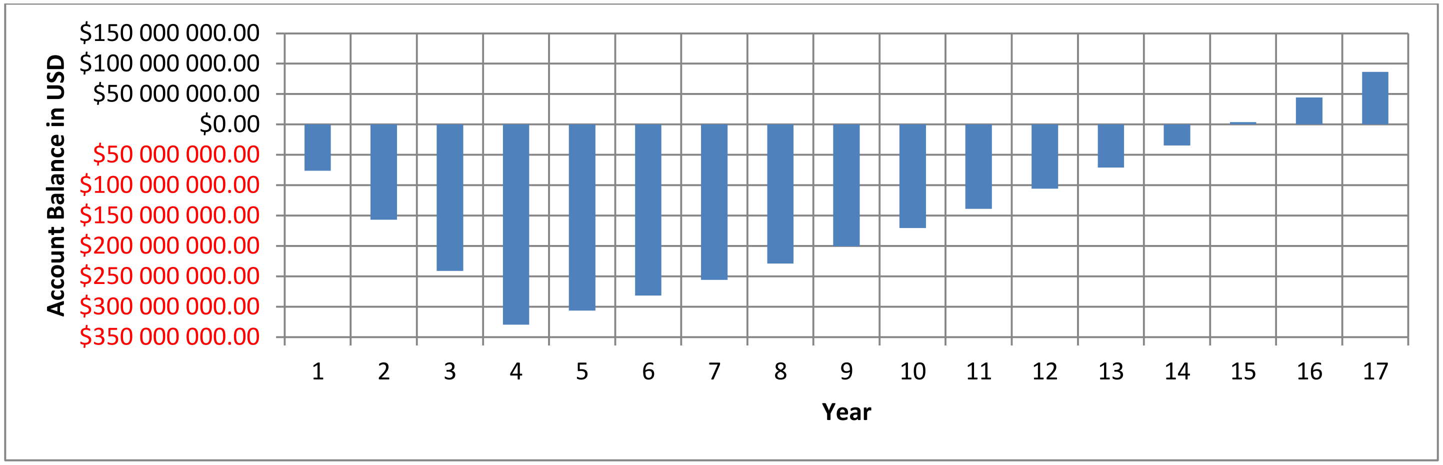

Figure 26: Bank balance of a company financing a nuclear facility at 5% interest

As is clearly illustrated in the figures above, an increase in the interest rate to 5% has pushed the payback period by over 3 years as compared to the ideal case. You can clearly see decreasing interest over time in the cashflow graph.

4.3 Option 2

This option considers the use of nuclear power to generate hydrogen. The hydrogen that is produced is then fed to a hydrogen based reduction process, similar to the Midrex process. As mentioned previously, it makes sense to separate the hydrogen production side and the reduction side of this analysis.

4.3.1 Reduction side

The general sequence of reactions that the iron ore undergoes is as follows:

$$3\,Fe_2O_3 + H_2 \rightarrow 2\,Fe_3O_4 + H_2O \quad \Delta H = -1\,kJ/mol$$
$$2\,Fe_3O_4 + 2H_2 \rightarrow 6\,FeO + 2H_2O \quad \Delta H = +24.9\,kJ/mol$$
$$6\,FeO + 6H_2 \rightarrow 6\,Fe + 6H_2O \quad \Delta H = +25.4\,kJ/mol$$

The reactions are balanced in such a way as to easily identify how much hydrogen gas is required to produce a certain amount of iron from iron ore. It has been easier to work with moles of a certain substance rather than volume or mass.

From the equations above, it is easily seen that 9 moles of H_2 is necessary to convert 6 moles of Fe. This translates to the following: 18g hydrogen is needed to reduce 335.07g of iron:- note that moles of H_2 gas are used and not the atomic H.

Typical DRI produced contains 90-94% iron content. Therefore, every tonne of DRI contains around between 900kg and 940kg iron. Therefore, between 48.35kg and 50.5kg of hydrogen is the minimum amount of hydrogen necessary per tonne DRI.

A recent study (Botha, 2009) calculated the hydrogen usage to around 51.5kg/tonne DRI. The extra hydrogen required is due to process efficiency losses. This calculated figure will be used for the remainder of this study.

From the studies by the ULCOS (ULCOS, 2011) consortium, a temperature of around 850ºC will produce good results both for a wide range of ore configurations.

Advantages of using H_2 instead of reformed natural gas are that the reduction rate is faster with hydrogen and therefore, smaller shafts are possible for the furnace. In addition to this, no CO_2 is produced in the reduction process.

4.3.2 Specifications for the hydrogen production facility

Before analysing the hydrogen production facility that will supply the required hydrogen to the reduction facility, the specific requirements of a facility needs to be calculated. Assuming a reduction shaft that produces 1 million tonnes / annum, the average production and consumption figures would be:

Production rate	= Annual Production / (hours in a year x plant availability)
	= 1 000 000 / (365 x 24 x 0.95)
	≈ 120 tonnes / hour

Hydrogen required to reduce iron	= Production rate x Hydrogen usage/tonne DRI
	= 120 x 51.5
	= 6180 kg/hour 6180
	= 148 320 kg/day
	≈ 148 tonnes/day

To determine the best option for the industry, a comparison of the gas heater and nuclear thermal heat exchanger needs to be done. For this purpose, the heating requirements need to be calculated. For the gas heater, the recent study (Botha, 2009) calculated that around 56.64 kg of natural gas is required per tonne DRI. Therefore:

Total Natural gas requirements	= Production rate x natural gas usage / tonne DRI
	= 120 x 56.64
	≈ 6797 kg/hour
	= 6457/0.717 m^3/hour
	≈ 9500 m^3/hour

Total energy used for heating the hydrogen	= Natural gas required x energy per unit
	= 9500 x 43000 kJ/hour
	= 408.5 GJ/hour

The calculated heat loss for the gas heater (Botha, 2009) was 22.5%, and assuming a heat exchanger efficiency of around 85%, the following analysis follows:

Heat required per hour	= total energy used for heating x (1 – heat loss)
	= 408.5 x (1 – 0.225)
	≈ 320 GJ/hour
Equivalent thermal power to heat hydrogen	= heat required per hour / heat exchanger efficiency
	= 320 / 0.85
	≈ 376.5 GJ/hour
	≈ 105 MWh/hour
	= 105 MW

Note that exact figures are not necessary as these values are used only to specify the requirements of the nuclear facility and associated hydrogen production plant.

4.3.3 Reference Hydrogen plant

Since a HTR nuclear facility is required for the production of hydrogen, the following analysis is based on a hybrid-sulphur cycle coupled to a PBMR. A detailed analysis of such a facility was conducted (Gorensek, Summers, Bolthrunis, Lahoda, Allen, & Greyvenstein, 2009) and this study will use their results as the reference model for hydrogen production. The reference system that they have proposed is a 500MWth PBMR power plant with coupled with a hybrid-sulphur cycle hydrogen generating facility capable of producing 160.1 tonnes of H_2/day.

For this facility, the plant performance summary is as follows (Gorensek, Summers, Bolthrunis, Lahoda, Allen, & Greyvenstein, 2009):

Table 10: Reference Hydrogen plant performance summary

	Reference
PBMR Power Rating, MWth	500
Plant electrical efficiency	41.2%
Hydrogen Output	
Mass flow rate, MT/day	160.1
Thermal Energy Requirements, MWth	
High-temperature heat to Decomposition	312.8
Steam to acid concentration	70.6
Steam for power generation	132.9
Electric Power Requirements, MWe	
Helium circulators	20.3
HyS electrolyzer power supply (AC)	110.8
HyS pumps, circulators, etc.	4.7
NHSS, PGS and BOP1	8.2
Total electric demand	144
Onsite power generation	54.8
Net electric power from grid	89.2
Overall Plant Efficiency	
Total thermal input, MWth	716.5
Hydrogen Thermal value (HHV), MWth	262.8
Overall plant efficiency (HHV basis)	36.7%

Assuming linear scaling of energy needs as the production rate changes, the following graph results:

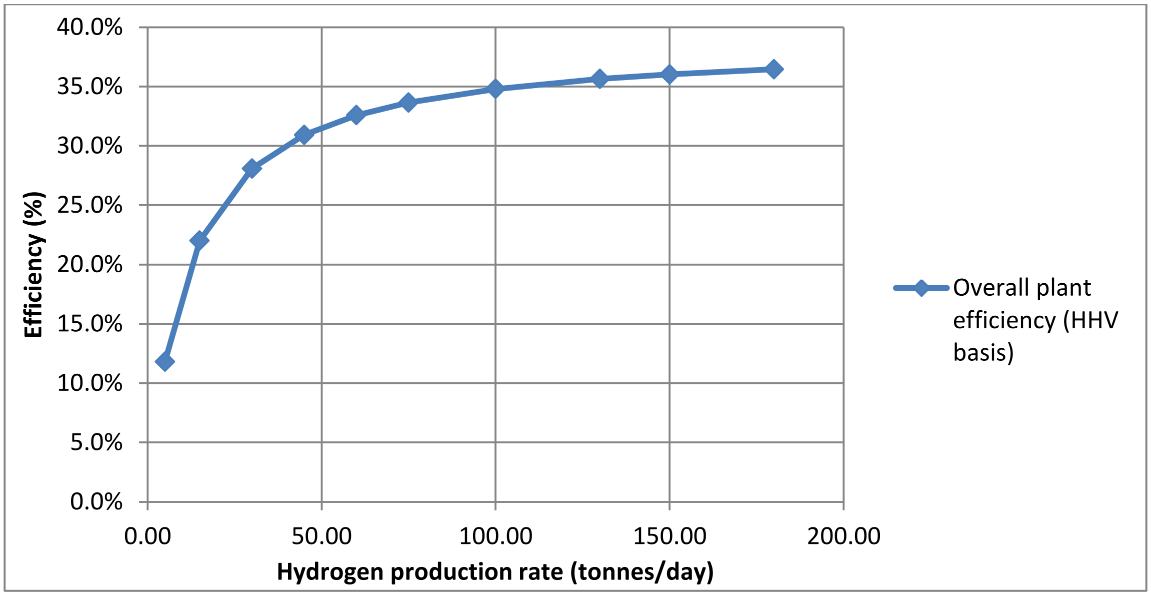

Figure 27: Hydrogen plant efficiency vs. Rate of production

This graph illustrates 2 things:- firstly, as production rate increases, so too does efficiency. Secondly very little efficiency gains are possible above 150 tonnes/day. Theoretically maximum efficiency would occur when all the facility's thermal power was used for heat requirements at the hydrogen-production side and a separate facility would then provide power for the system. It is also important to note that the maximum amount of hydrogen that can be produced in the proposed facility without needing to import electricity would be approximately 106.5 tonnes/day at an efficiency of 35%.

For the purposes of this study, it is irrelevant to ask where the required extra electricity for the facility comes from. The modular nature of the PBMR allows the plant to be scaled according to the user's requirement.

For the requirements calculated in the previous section, the following plant performance occurs:

Table 11: Hydrogen plant performance for the required specifications

	Calculated requirements
PBMR Power Rating, MWth	500.00
Plant electrical efficiency	42.0%
Hydrogen Output	
Mass flow rate, MT/day	150.00
Thermal Energy Requirements, MWth	
High-temperature heat to Decomposition	293.07
Steam to acid concentration	66.15
Steam for power generation	140.79
Electric Power Requirements, MWe	
Helium circulators	20.30
HyS electrolyzer power supply (AC)	103.81
HyS pumps, circulators, etc.	4.40
NHSS, PGS and BOP1	7.68
Total electric demand	136.20
Onsite power generation	59.13
Net electric power from grid	77.07
Overall Plant Efficiency	
Total thermal input, MWth	683.49
Hydrogen Thermal value (HHV), MWth	246.22
Overall plant efficiency (HHV basis)	36.0%

The important factors have been highlighted.

4.3.4 Pricing Model for a nuclear facility producing hydrogen

4.3.4.1 Base-line Model for hydrogen production

Given these requirements and factors mentioned, the following costing model for the facility has been developed, assuming a 150 tonnes/day hydrogen requirement, and scaling the consumption needs appropriately:

Table 12: Baseline pricing model for hydrogen production

	Description	Base value estimate
Interest Rate	Dependent on loan conditions	10.00%
Repayment period	Dependent on loan conditions	20
Construction time	Dependent on loan conditions	4
Lifetime	NSSS – up to 60 years. Hydrogen plant lifetime is uncertain	60
Availability	Typically 95%	95.00%
Overnight cost NSSS(MWth)	This is the construction cost per MWth	$900.00
Total Power (kW)	Cumulative power in kWth for process heat and electricity generation	683489.9
Decommissioning costs ($/Mwh)	Levy per MWth to cater for the end of life decommissioning of the NSSS	2
Cost per mmbtu		$0.67
Operational and Maintenance cost ($/MWh)		8
Loan balance at end of Nuclear power station construction	Total repayment necessary at the end of the loan period	-$745 098 105.75
NSSS Operational cost/quarter	Total operational and maintenance cost per quarter	-$8 241 179.96
Electricity generation construction cost (/kWe)	Cost per kW to generate only the electricity generating facilities	$1 000.00
Electrical Power Requirements (kW)	Electrical power necessary for hydrogen production	136196.3
Electrical Efficiency	Thermal efficiency of the process	42.00%
Operational and Maintenance cost ($/MWh)		2
Loan balance at end of electricity generating facility construction	Electrical facility repayments necessary at the end of the loan period	-$164 969 700.09
Electricity generation operational cost/quarter	Electrical facility operational and maintenance cost per quarter	-$1 420 333.00
Total Thermal Power Requirements (kW)	Total process heat required, including for hydrogen production and heating hydrogen	359213.0
Hydrogen construction cost (/kg.day)		$2 800.00
Hydrogen produced per day (kg)	Hydrogen production rate	150000
Thermal Power to generate hydrogen (kW)	Thermal power necessary to produce hydrogen at required rate	359213.0
Thermal Power to heat hydrogen (kW)	Thermal power necessary to heat the hydrogen	0
Natural Gas requirement (m3/h)	Gas required to heat the hydrogen	9500
Baseline Operational and Maintenance cost ($/year) Hydrogen Production	Yearly operational costs	$93 736 000.00
Loan balance at end of hydrogen production facility construction		-$508 730 901.69
Hydrogen production Operational cost/quarter		-$23 434 000.00
Total operational cost/quarter	Cumulative operating costs for station, power plant, and hydrogen production facility	-$33 095 512.96
Total Loan balance at end of total system construction	Total repayment necessary	-$1 418 798 707.53
repayment necessary for loan	Loan repayment neceassary for the conditions indicated above	-$41 182 115.25
Baseline Hydrogen generating Cost (USD/kg)	Cost in terms of hydrogen	5.427

It was necessary to separate the costs of the nuclear steam supply system (NSSS), the power generating system and the hydrogen production system to accurately model the facility. For the given baseline conditions, the hydrogen generating costs exceed what could be considered viable in the steel industry. The following sensitivity analyses make the situation clearer.

4.3.4.2 Sensitivity analysis

The sensitivity analyses provided for option 1 above holds true to this scenario as well. Especially the sensitivities relating to interest rate and build time. However, with the objective of producing hydrogen, the following additional sensitivities need to be analysed.

The following graph shows the dependence of the system on the hydrogen production rate.

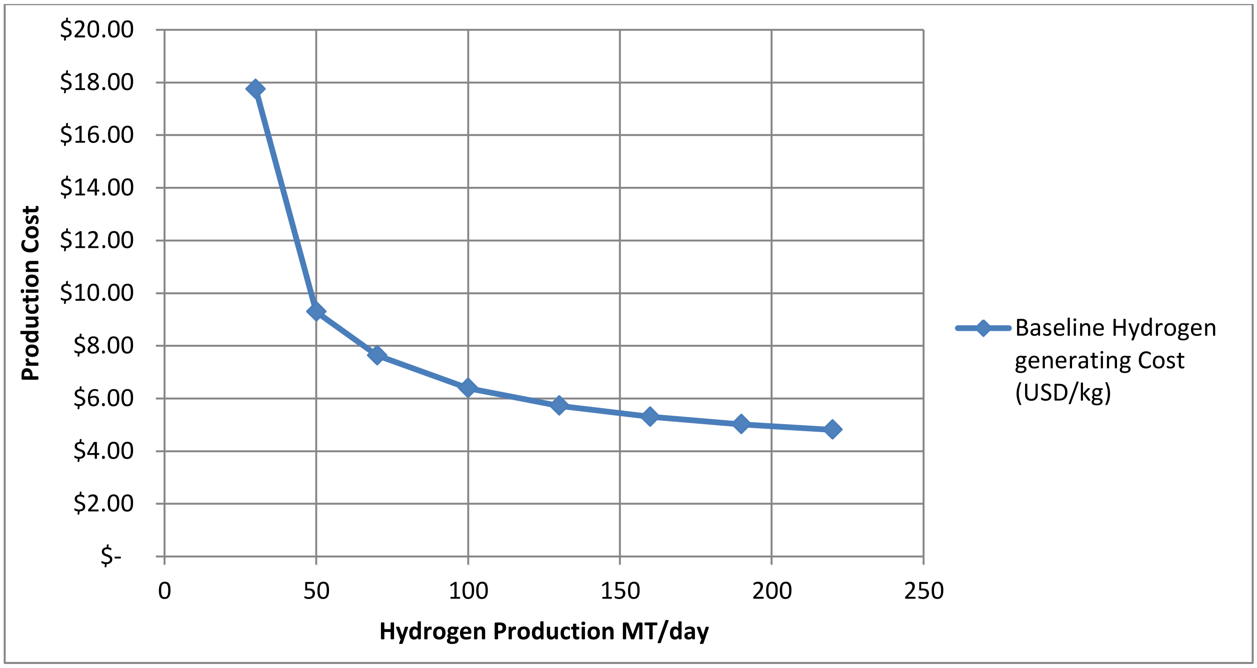

Figure 28: Effect of selling price of hydrogen on the production rate/day

As is clearly seen, as the production rate increases, the cost per unit of hydrogen drops. The strongly non-linear nature of this curve illustrates that the system is not easily scalable. Whether or not this will be a limiting problem will need to be investigated.

The following graph indicates the effect of construction cost of the Hydrogen production facility alone on the final cost per unit hydrogen.

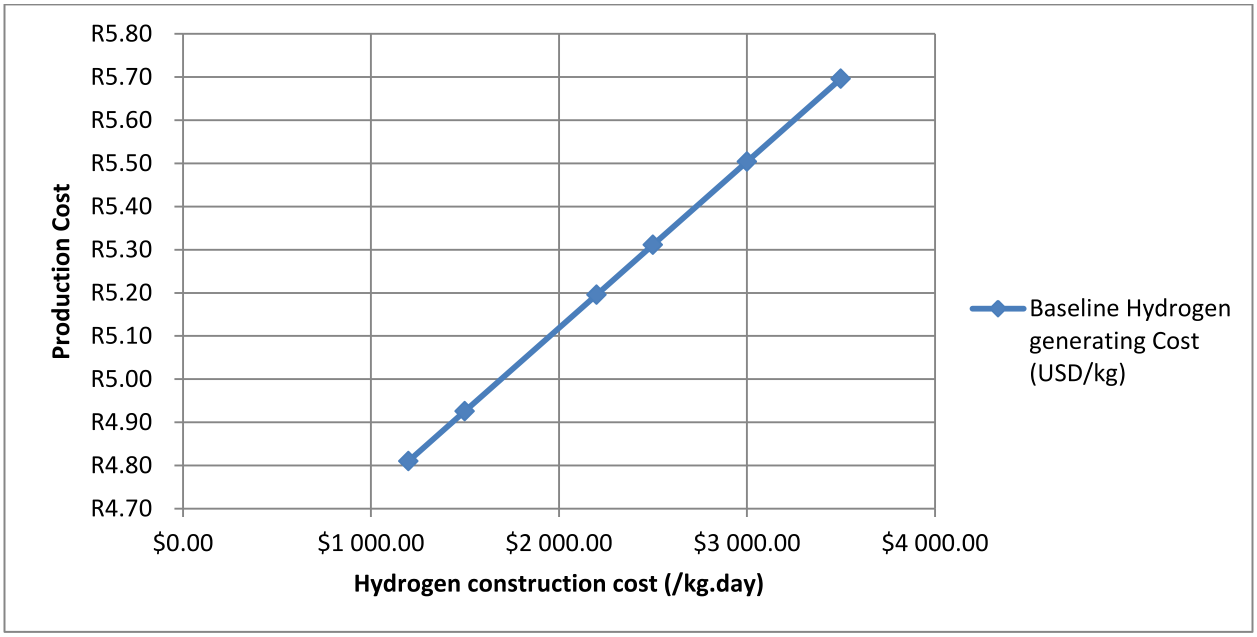

Figure 29: Hydrogen facility capital cost vs generating cost of hydrogen

As is clearly seen, the construction cost of the Hydrogen production facility does impact the cost of generating hydrogen. However, unlike with a nuclear facility, the impact is not as dramatic as one would expect. A 3-fold escalation in price only increases the price per kg of hydrogen by 1 dollar.

The main reason for this is the fact that each individual unit in the system contributes significantly to the final cost. This prevents any one factor from drastically altering the final cost.

Another interesting result is the dependence of the system on maintenance and operational costs as illustrated in the figure below.

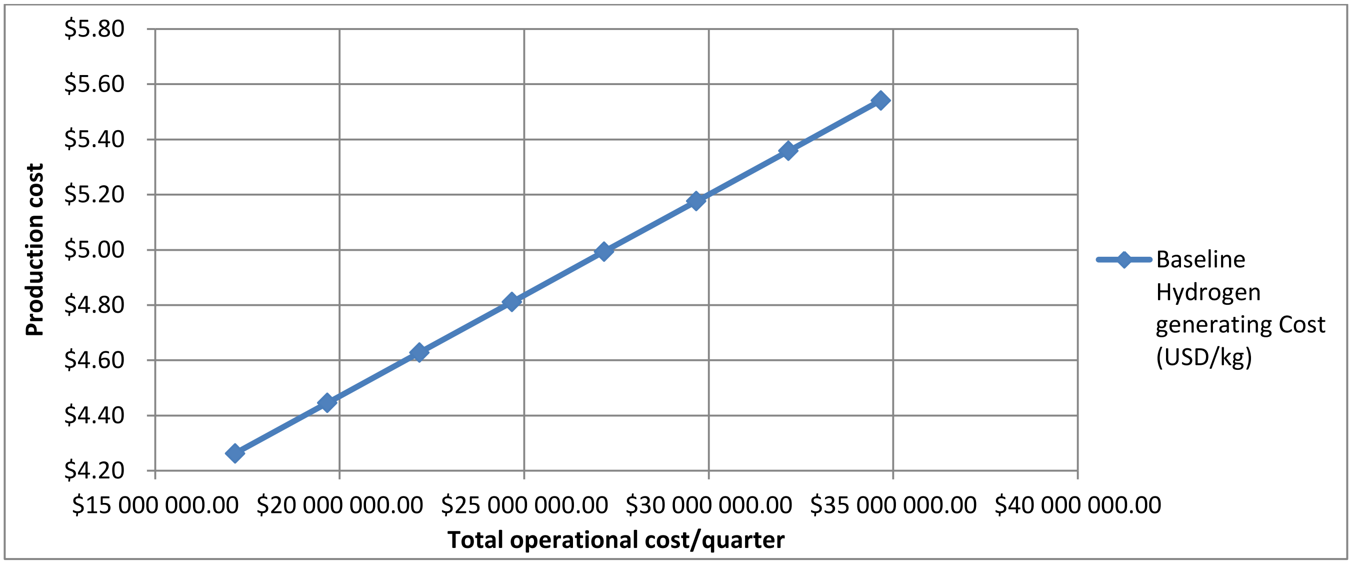

Figure 30: Maintenance cost vs hydrogen production cost

Unlike traditional nuclear facilities, savings in the operational and maintenance side of the hydrogen plant alone significantly benefit the final generating cost.

4.3.4.3 Realistic best-case Model for hydrogen production

Given these cost considerations, the following is a realistic best case scenario for hydrogen production:

Table 13: Best case scenario for hydrogen production

	Realistic Best case scenario
Interest Rate	5.00%
Repayment period	20
Construction time	4
Lifetime	60
Availability	95.00%
Overnight cost NSSS(MWth)	$900.00
Total Power (kW)	683489.9
Decommissioning costs ($/Mwh)	2
Cost per mmbtu	$0.67
Operational and Maintenance cost ($/MWh)	8
Loan balance at end of Nuclear power station construction	-$745 098 105.75
NSSS Operational cost/quarter	-$8 241 179.96
Electricity generation construction cost (/kWe)	$1 000.00
Electrical Power Requirements (kW)	136196.3
Electrical Efficiency	42.00%
Operational and Maintenance cost ($/MWh)	2
Loan balance at end of electricity generating facility construction	-$164 969 700.09
Electricity generation operational cost/quarter	-$1 420 333.00
Total Thermal Power Requirements (kW)	359213.0
Hydrogen construction cost (/kg.day)	$2 000.00
Hydrogen produced per day (kg)	150000
Thermal Power to generate hydrogen (kW)	359213.0
Thermal Power to heat hydrogen (kW)	0
Natural Gas requirement (m3/h)	9500
Baseline Operational and Maintenance cost ($/year) Hydrogen Production	$93 736 000.00
Loan balance at end of hydrogen production facility construction	-$363 379 215.50
Hydrogen production Operational cost/quarter	-$23 434 000.00
Total operational cost/quarter	$33 095 512.96
Total Loan balance at end of total system construction	-$1 273 447 021.33
repayment necessary for loan	-$25 273 496.91
Baseline Hydrogen generating Cost (USD/kg)	4.264

4.3.5 Comparison of cost per tonne of the reduction gas options

At this cost, the generating costs of hydrogen looks more attractive. However, in order to do a proper cost benefit analysis and cash-flow calculation, it is prudent to identify the potential cost benefit from using hydrogen instead of natural gas in the Midrex process. The calculations below compare the costs of using hydrogen and reformed natural gas (the two reducing agents) for reducing iron ore.

Efficient modern Midrex processes use between 9GJ and 10.5GJ of natural gas per tonne of DRI. This translates into between $210m^3$ natural gas/tonne DRI and $250m^3$ natural gas/tonne DRI. At 2011 prices, this would cost the steel company between \$76.37 and \$90.91/tonne DRI respectively.

Using the following values for the reduction gas in the Midrex process from (Botha, 2009),

$$\begin{aligned} Natural\ gas/tonne\ syn\ gas &= 704.83\,kg/tonne\ syn\ gas \\ Syn\ gas/tonne\ DRI &= 243.76\,kg/tonne\ DRI \end{aligned}$$

We get, the following results regarding cost of natural gas/tonne DRI:

$$\begin{aligned} Natural\ gas/tonne\ DRI &= Natural\ gas/tonne\ syn\ gas \times Syn\ gas/tonne\ DRI \\ &= 0.70483 \times 243.76 \\ &= 171.81\,kg/tonne\ DRI \\ &= 239.62\,m^3/tonne\ DRI \end{aligned}$$

The cost for this amount of natural gas is:

$$\begin{aligned} Cost\ of\ \ Natural\ gas/tonne\ DRI &= Natural\ gas/tonne\ DRI \times cost\ \ per\ unit\ volume \\ &= \$87.14/tonne\ DRI \end{aligned}$$

which is consistent with the cost for natural gas per tonne DRI estimated earlier.

By substituting hydrogen instead of natural gas, the cost per tonne DRI becomes:

$$\begin{aligned} Cost\ of\ \ Hydrogen/tonne\ DRI &= Hydrogen\ consumption/tonne\ DRI \times cost\ \ per\ kg \\ &= 51.46\,kg/tonne\ DRI \times \$\,4.265/kg \\ &= \$219.48/tonne\ DRI \end{aligned}$$

Note that only the reduction gas portion of the cost has been considered as the heating of hydrogen would require similar amounts of natural gas in a hydrogen based process and a natural gas based process.

The use of hydrogen instead of natural gas increases the cost of the reduction gas by more than a 150%. It is therefore difficult to justify the use of hydrogen gas as a viable substitute for natural gas in this process.

It is interesting to compare the reduction gas's cost per tonne to the selling price of DRI. As of 2011, the selling price stood at approximately $440/tonne. Considering the analysis above, when natural gas is the reducing agent, it accounts for about 20% of the selling price of DRI. By introducing hydrogen as the reducing gas, the selling price for DRI rises to approximately $570/tonne and the contribution of the reducing gas jumps to close to 40% of the selling price. This would just be unacceptable for the industry, especially when other raw materials have become so expensive.

4.3.6 Impact of carbon tax

The potential implementation of a carbon tax would be one of two reasons not to discard hydrogen based steel-making:- the other being the inevitable increase in fossil fuel prices. Fossil fuel price increases are unpredictable and therefore difficult to model, it is therefore easier to consider the effects of carbon tax on the viability of nuclear based hydrogen. In addition to this, the South African government is considering the implementation of a carbon tax within the next few years. Because of this, the effect of carbon tax will be a much more important consideration for the immediate future.

The following graph shows how the price of the reducing agent scales as the carbon tax increases.

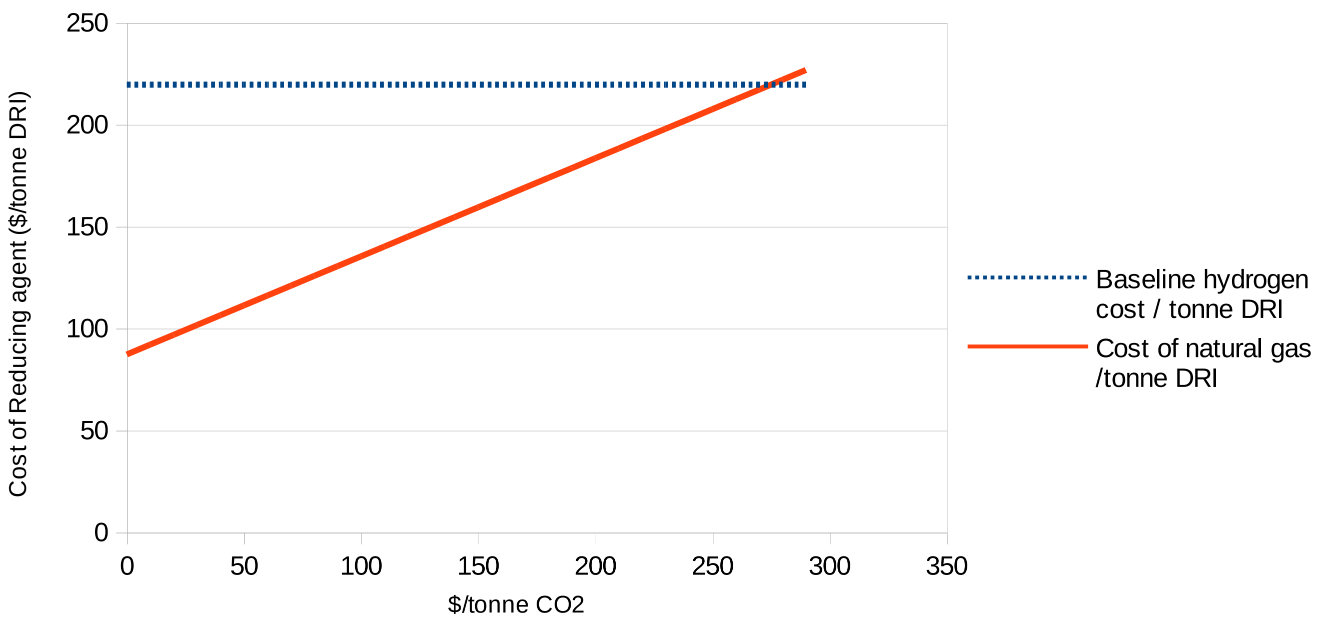

Figure 31: Effect of carbon tax on natural gas prices

As can be clearly seen, only a tax of $300/tonne CO_2 will make hydrogen based Midrex a viable option. This is much higher than any proposals for carbon tax currently on the table.

Due to this result, it is unnecessary to delve deeper into the cash flow and bank balance calculations for this option.

4.3.7 Heating of hydrogen gas

Although it is clear from the analysis above that hydrogen gas is unlikely to be a viable substitute as it is produced currently, we still need to answer the question about whether nuclear process heat can be substituted for natural gas to heat hydrogen. If it is shown to be possible, direct process heat could be used as a substitute for natural gas as a heat source for the reformer in the current Midrex process. This will be investigated further in the following section.

For this analysis, we go back to our earlier calculations where we demonstrated that around 105MWh/h of electricity is required to cater for the heating requirements of the process. Since the costing model described in this section separates the various phases of the hydrogen production system, we can easily calculate the average cost of NSSS heat production.

$$NSSS\ heat\ production\ cost = \frac{Loan\ repayments\ for\ construction + Operational\ costs}{Total\ Heat\ Generated}$$

Substituting the relevant values for the variables, gives the following:

$$NSSS\ heat\ production\ cost = \$19.95/MWh$$

Therefore, per hour, the cost of heating the hydrogen would be:

$$Cost\ of\ heating\ hydrogen = \$19.95/MWh \times 105\ MWh/h = \$1094.75/h$$

The equivalent heating from natural gas would cost

$$\begin{aligned} Heating\ costs\ of\ natural\ gas \quad &= cost/1000\,m^3 \times number\ of\ 1000\,m^3\ required\ per\ hour \\ &= \$363.68/1000\,m^3 \times 9500\mathrm{m}^3/hour \\ &= \$3454/hour \end{aligned}$$

Given this analysis, it seems clear that it would indeed be cost effective to use nuclear process heat to heat hydrogen. However, this could only be a viable option if the nuclear plant was integrated with the steel industry. The heating costs contribution to the total selling price is minuscule compared to the reduction gas needed, but savings gained from this option would make nuclear power a more viable option for the industry especially when it is integrated with the EAF electricity consumption cost savings.

4.4 Option 3

This option is to integrate a nuclear facility with the steel industry. It has already been shown that given the exorbitant increase in electricity prices in South Africa, nuclear power can potentially provide a viable means to keep electricity costs stable. The analysis showed a payback period of around 12 years (8 years after construction) when favourable interest rates and construction costs are used. However, due to the lack of stability of the steel industry, a 12 year payback is not as attractive as one would expect. Therefore, it makes sense to try and increase cost savings by introducing process heat applications.

The analysis in the previous section has shown that the original proposed idea of integrating hydrogen gas and electricity production to cater for the electricity and reduction needs for a steel industry is not viable.

However, the analysis has also shown that a substitute use for process heat is available. The current Midrex process requires a small portion of natural gas to be burned to heat the reformed natural gas. The reducing agent then enters a shaft furnace to reduce the iron ore into iron.

The revised integrated electricity/process heat option is shown in the figure below:

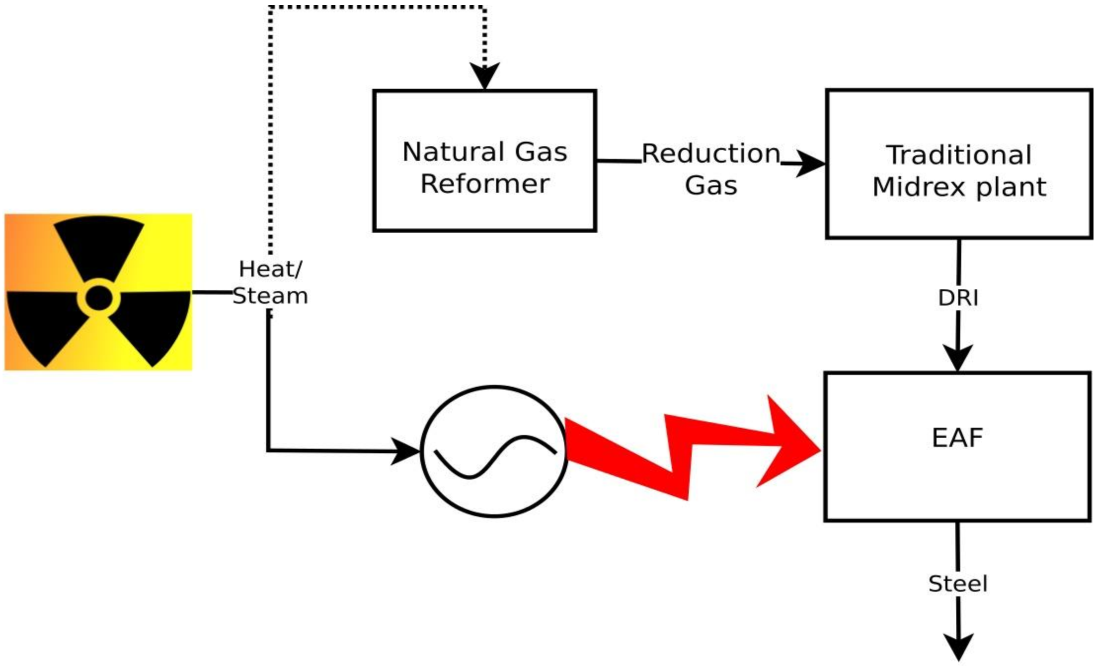

Figure 32: Revised co-generation option

In this scenario, process heat from a nuclear power generator provides heat to reform the natural gas to make the reducing gas for the Midrex plant. The majority of the heat would be used to power a turbine which would in turn generate electricity. The generated electricity will cater for the electricity needs of the EAF facility. The exit temperature of the reformed natural gas needs to be around 950ºC before it enters into the shaft furnace. With current technologies, the maximum process heat temperatures that can be generated from a nuclear facility are around 900ºC. Due to this fact, a nuclear powered facility will not completely replace the gas heaters, but can significantly reduce the amount of gas needed to heat the reformed gas. A safe estimate of around two-thirds of the heating needs can be catered for by nuclear process heat.

4.4.1 Thermal requirements for Option 3

Before delving into the financials, a revision of the energy requirements needs to be conducted. From (Botha, 2009) we see that the natural gas usage for heating the reformed gas is 48.09kg/tonne DRI and Assuming once again a 1 000 000 tonne/annum facility, it follows from there that:

Total Natural gas requirements	= Production rate x natural gas usage / tonne DRI
	= 120 x 56.64
	≈ 5771 kg/hour
	= 5771/0.717 m3/hour
	≈ 8000 m3/hour

Total energy used for heating	= Natural gas required x energy per unit
	= 8000 x 43000 kJ/hour
	= 346.1 GJ/hour

The calculated heat loss for the gas heater (Botha, 2009) was 15.4%, and assuming a heat exchanger efficiency of around 85%, the following analysis follows:

Heat required per hour	= total energy used for heating x (1 – heat loss)
	= 346.1 x (1 – 0.154)
	≈ 293 GJ/hour

Assuming that the nuclear facility will provide about two-thirds of this energy requirement, then,

Equivalent thermal power to heat Nat. gas	= heat required per hour / heat exchanger efficiency
	= 293 x 0.667/ 0.85
	≈ 230 GJ/hour
	≈ 64 MWh/hour
	= 64 MW

It is also important to calculate the cost per kWh for burning natural gas. The calculation is simple enough given that:

1 kWh = 3600 kJ

Energy density of natural gas = 43 000 kJ/m3

Therefore, 1 kWh = 0.083m3

The cost of natural gas = \$363.6778/1000m3
= \$0.363678/m3

Therefore, the cost of 1 kWh of natural gas =\$0.03045/kWh

Using these figures, an appropriate cost model for a steel facility can be developed.

4.4.2 Pricing Model for a nuclear co-production

4.4.2.1 Realistic best-case Model for co-production

To model the costs for this option, the cost analysis of option 2 was modified, resulting in the following:

Table 14: Co-generation costing model parameters

	Description	Base value estimate
Interest Rate	Dependent on loan conditions	5.00%
Repayment period	Dependent on loan conditions	20
Construction time	Dependent on loan conditions	4
Lifetime	NSSS – up to 60 years. Hydrogen plant lifetime is uncertain	60
Availability	Typically 95%	95.00%
Overnight cost NSSS(MWth)	This is the construction cost per MWth	$900.00
Total Power (kW)	Cumulative power in kWth for process heat and electricity generation	298095.2
Decommissioning costs ($/MWh)	Levy per MWth to cater for the end of life decommissioning of the NSSS	2
Cost per mmbtu	Fuel costs	$0.67
Operational and Maintenance cost ($/MWh)		8
Loan balance at end of Nuclear power station construction	Total repayment necessary at the end of the loan period	-$294 966 121.85
NSSS Operational cost/quarter	Total operational and maintenance cost per quarter	-$3 594 283.38
Electricity generation construction cost (/kWe)	Cost per kW to generate only the electricity generating facilities	$1 000.00
Electrical Power Requirements (kW)	Electrical power necessary for hydrogen production	100000.0
Electrical Efficiency	Thermal efficiency of the process	42.00%
Operational and Maintenance cost ($/MWh)		2
Loan balance at end of electricity generating facility construction	Electrical facility repayments necessary at the end of the loan period	-$109 944 773.85
Electricity generation operational cost/quarter	Electrical facility operational and maintenance cost per quarter	-$1 042 857.14
Thermal Power to heat reformed gas (kW)	Thermal power necessary to heat the reformed gas	60000
Natural Gas requirement (m3/h)	Total gas used to heat the hydrogen	9500
Repayment for Electricity	Repayment necessary for the electrcity portion of the facility	-$2 182 021.60
Repayment for nuclear process heat	Repayment necessary for the nuclear process heat portion of the facility	-$5 854 052.22
Baseline Electricity generating Cost (USD/kWh)	Production cost of electricity	$0.052
Baseline Heat generating costs (USD/kWh)	Production cost of process heat	$0.015

Note that the base value in this case shows an estimate more akin to a best case realistic construction scenario. Previous sensitivity analyses hold true for this facility, and the base values presented here will be used to determine the cashflow and "bank balance" estimates for a totally integrated facility.

4.4.2.2 In-house co-generation plant cashflow

When the facility is completely financed in house, the cash flow and bank balance for the facility look as follows:

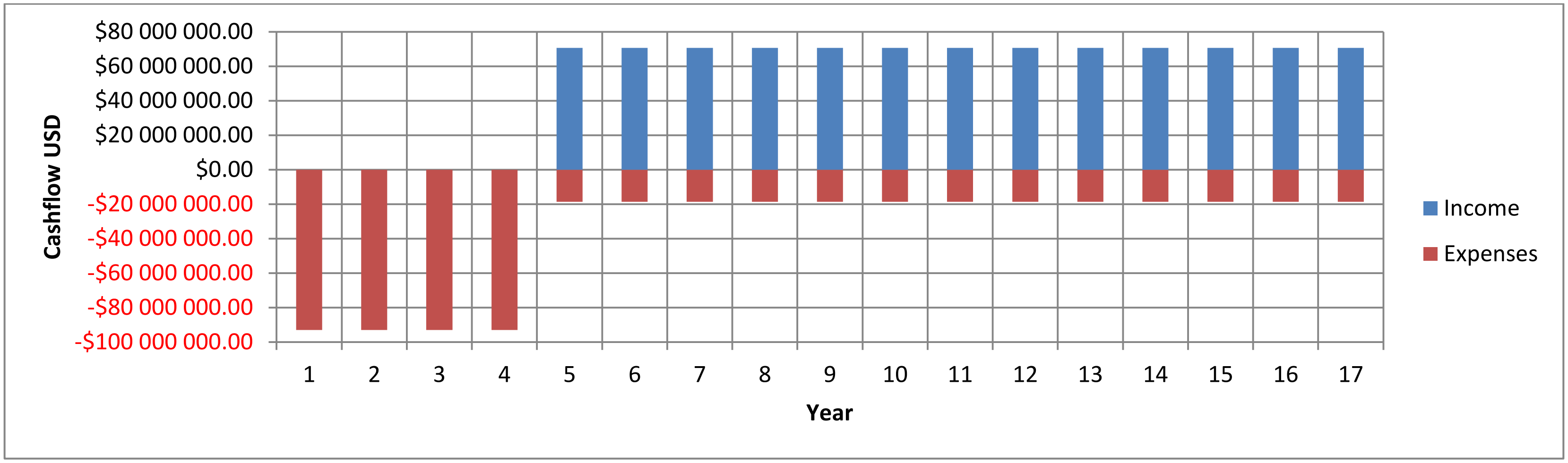

Figure 33: Cashflow for the co-generation facility build in-house (0% interest)

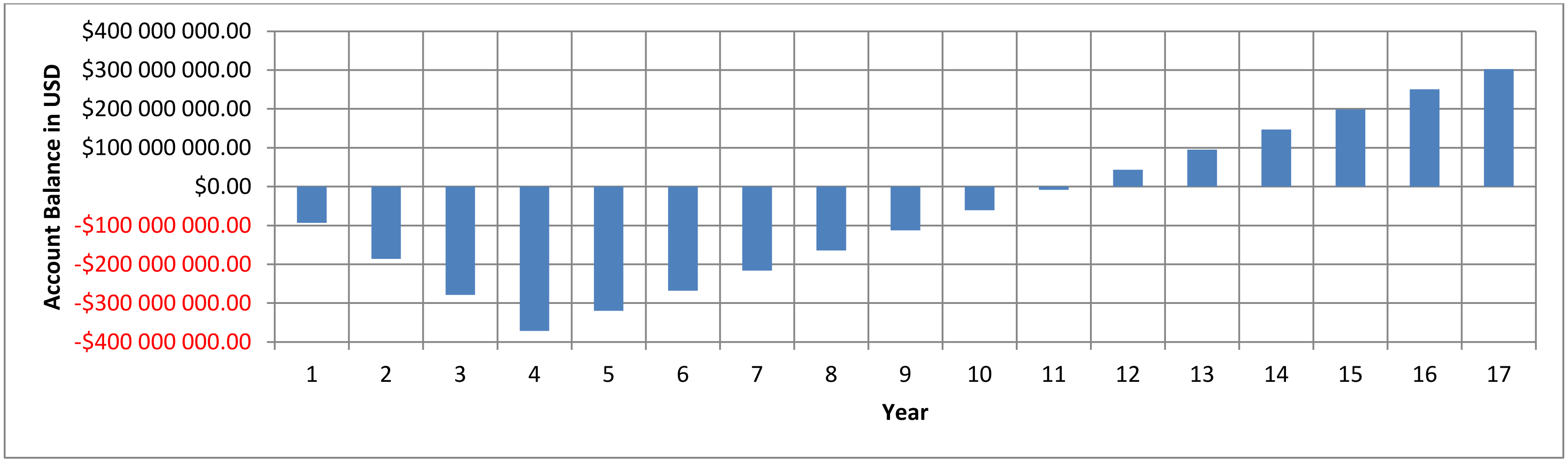

Figure 34: Bank balance for the co-generation facility build in-house (0% interest)

The payback period at 0% interest is just over 11 years. The process heat application contributes to this reduction in payback period. However, it should be noted that the change is not large enough to make a huge impact to the business.

When the facility is financed at 5% interest, the following financials ensue:

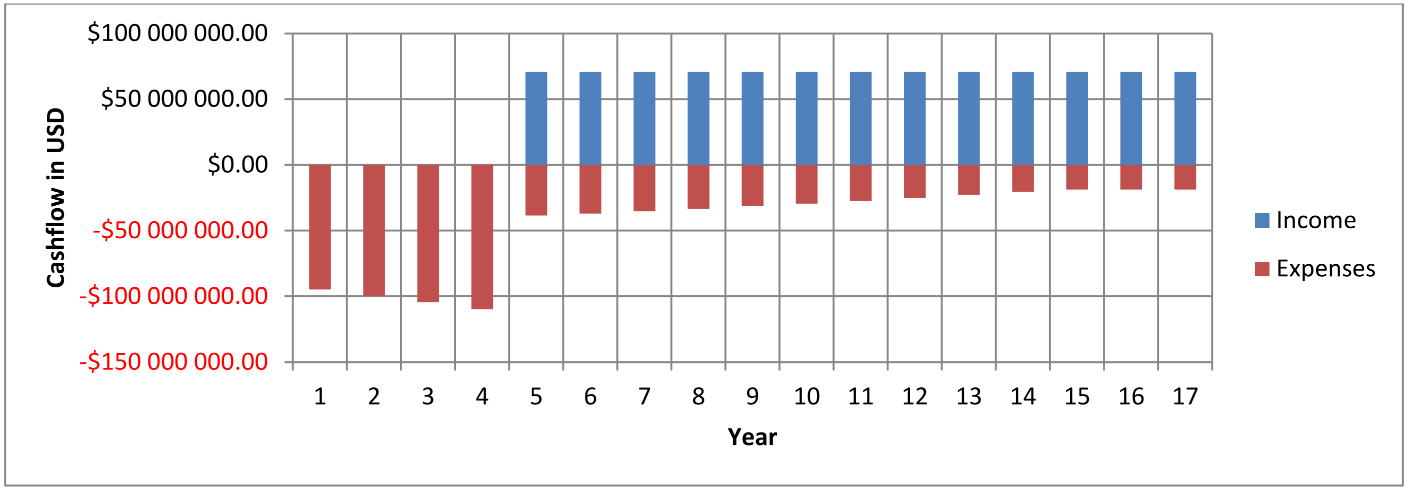

Figure 35: Cashflow for the co-generation facility build in-house (5% interest)

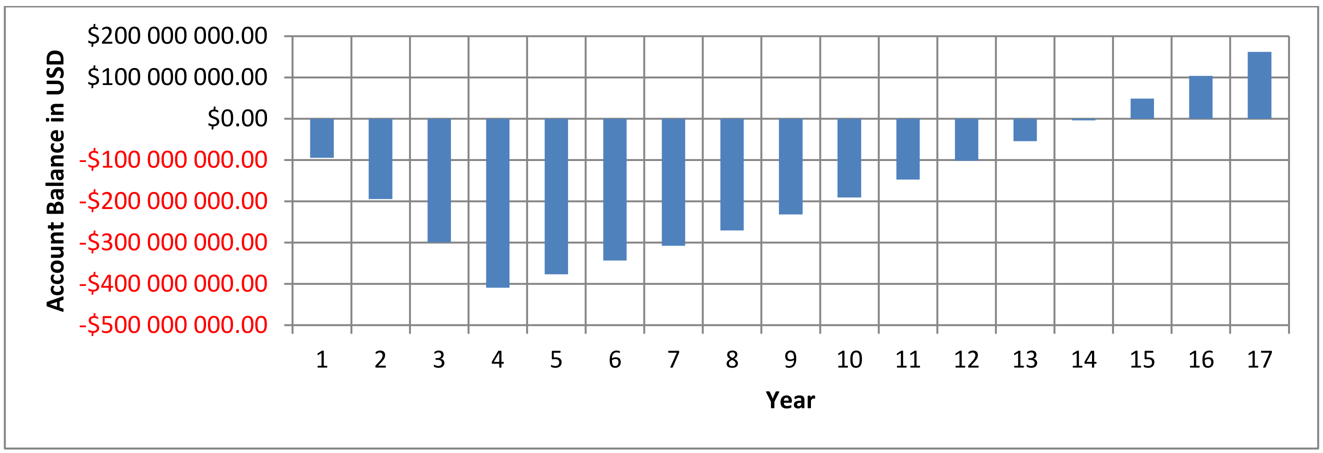

Figure 36: Bank balance for the co-generation facility build in-house (5% interest)

Once again, financing the facility with only a 5% interest rate pushes the payback period back by 3 years. It should be noted that after the facility has been paid back, it will undoubtedly remain an asset to the industry for probably longer than the lifetime of the industry that it is built around.

5. Externalities

This section will attempt to identify the various external factors that will influence the final decision about whether or not to integrate nuclear power with the steel industry. This section does not aim to be an exhaustive list of such externalities, but aims to put the options presented above into context so that the steel-making industry can make an informed decision about the topic.

5.1 Risks of centring the steel industry around nuclear power

Nuclear power comes packed with baggage. After the past accidents, the industry has tried to regain a name for itself. That being said, there are real risks that any industry considering nuclear power needs to take into account.

5.1.1 Spent fuel and nuclear waste management

One of the main issues regarding nuclear power is the safe storage and disposal of spent fuel and other forms of nuclear waste. Nuclear waste is classified in different levels according to level of contamination with radio-active substances. Most low level waste can be processed relatively safely in-house, but as the level increases, more specialised processing facilities need to deal with the waste. In addition to this long term storage options for waste needs to be identified.

Most nuclear facilities house spent fuel on site for a number of years before transporting it to a more permanent storage. There are many reasons for this, the primary amongst these being the latent heat that is released from spent fuel for a period of time. The heat released requires special cooling facilities to be built to deal with the fuel. The amount of heat generated from a spent fuel cell is proportional to the power density of the facility and the operating power of the facility. The heat generated decays exponentially over time and therefore can only be safely transported after some of the heat is dissipated.

Most of the integrated options described above require a PBMR of a similar HT reactor. Since these reactors are gas cooled, and the power density for the fuel is therefore lower than with LWRs. In addition to this, these reactors are characterised by lower power outputs than traditional facilities.

Hence, the active cooling period of the spent fuel for high temperature reactors is much shorter when compared to light water reactors.

In addition to this, since very few large scale, permanent storage facilities are available for the disposal of spent fuels, temporary on site storage often has to cater for the waste on a semi-permanent basis.

5.1.2 Security

There will always be proliferation concerns associated with nuclear power (a legacy inherited from the arms race). Due to this concern, security around any nuclear facility needs to be assured. This is usually not a serious issue for stand-alone utilities, as personnel flowing in and out of the facility can be carefully monitored and controlled. In addition to this, most nuclear facilities are built to withstand terrorist attacks.

That being said, when nuclear power is integrated with any industry, especially one with constant traffic flow to and from the industry (like the steel industry), extra precautionary measures need to be taken to maintain the security of the nuclear facility.

From a realistic perspective, this would require additional security measures for the entire facility. The additional cost for this has not been taken into account in deriving the cost models above.

It should also be noted that no process heat applications of nuclear power have been commercially tested to date. While the technology is definitely viable, providing process heat to areas that are geologically removed from the reactor itself could pose additional security risks. Since the cooling of the reactor is tantamount to its safe operation, if one of the cooling loops is destroyed due to an act of terrorism, then it could potentially risk the safe operation of the plant.

Of course, designs for HTRs on the table allow for passive safety of the reactor and therefore, even a major breach of one of the cooling loops would not catastrophically affect the reactor.

5.1.3 *Load following issues*

Nuclear power is not well geared for load following. This is true regardless of the technology being used. Changes in reactor power needs to occur gradually and the reactor needs to ideally operate in a continuous fashion.

This is a problem for the steel industry as EAF operations toggle between high power usages when arcing, to low and almost no power usage during tapping. In addition to this, one of the attractive advantages of EAFs is its ability to easily scale its production based on market conditions. This makes integration with nuclear power very difficult.

If a nuclear power generating facility provides the power for the EAF, drops in production equate to power reductions and in the worst case, a shut-down for a nuclear electricity generation plant. Since immediate start-ups of nuclear facilities after a shut-down are not possible, the flexibility that an EAF based steel-making enjoyed is reduced.

One way to counter this situation is for the nuclear facility to feed power into the grid at a fixed rate. When an EAF requires power, it will draw power from the grid as it currently does. This would allow the nuclear facility to operate at a more stable condition without affecting the flexibility of EAF operations. Of course practically, the nuclear facility would have to negotiate such that it would receive an income from providing power to the grid if an EAF is at reduced production. Negotiations with Eskom would be necessary for this solution to be implemented.

5.1.4 *Public sentiment*

Public sentiment regarding nuclear power has slowly been increasing over the last decade. However, with the recent accident in Japan, sentiment has dropped significantly. Any industry trying to implement nuclear power needs to be prepared for the negative sentiment that will arise from its construction. This will most likely be during the initial startup phases of the build but it could continue well into the lifetime of the plant, especially if normal operating procedures for the nuclear industry are not followed.

5.2 Management of the Nuclear/Steel industry integration.

As mentioned previously, there are 2 options regarding the integration of nuclear power with the steel industry. The nuclear facility can either be an independent organisation providing energy (electricity and/or process heat) to the steel industry and any other consumer, or the steel industry could build a nuclear facility solely for its own energy requirements.

Each option has its own advantages and disadvantages. This is listed in the table on the following page from the point of view of the steel industry (the consumer).

Table 15: Contrasting different management options for a nuclear build

	Buying energy from a utility	Building own nuclear plant for energy purposes
Cost to customer	Given the right conditions, electricity could be provided at cheaper rates than what is currently available. The utility will add its own markup.	The industry would be able to benefit from cost prices of electricity and heat production and given the right conditions, this would be cheaper than purchasing from a utility.
Operation of the facility	In general, nuclear power would be the core business of the utility and therefore, it would be well suited to manage and operate the plant efficiently.	There would be diversification of function away from the core business of the industry. Management and operational costs could be higher than at a utility.
Expertise	The expertise is usually available in-house.	Skills need to be sourced .
Liability	There would be no liability to a consumer if the nuclear facility experiences a catastrophic disaster.	The industry would be liable for any nuclear accident.
Changes to the industry	Consumer operation largely unchanged.	Plant security and efficiency would increase.
Upfront Capital	Low capital investment – immediate benefit.	High capital investment – delayed benefit.
Potential for growth	The consumer industry would remain largely static.	The consumer industry could potentially improve its processes to make it more focused around nuclear power.
Losses	As most utilities will be off site from a consumer, significant process heat losses will occur. Electricity production is the only realistic option.	Losses are minimised by having the facility on the same premises as the industry. Both process heat and electricity generation is possible.

5.2.1 Build as an integrated facility

The major benefit of building a facility in-house is that the total cost of ownership is much lower than if the energy is bought from a utility. In addition to this, process heat applications become more viable. However, even if the utility decides to construct a nuclear facility in-house, various management options regarding the operation of the facility are available. These include:

1. Have a nuclear utility build the facility and allow the steel industry to manage and operate the facility.
2. Have a nuclear utility build and operate the facility while the steel industry focuses on managing it.
3. Have a nuclear utility, build, operate and manage the facility, essentially becoming a utility providing the energy requirements for the industry. The only difference between this and having a separate utility is that the capital investment is provided by the steel industry.

The first option is not recommended, as a certain amount of expertise is required to properly operate a nuclear facility. Both the second and third option has the advantage of allowing the operational side of the nuclear facility to be left to a separate utility. The second option should, however, also be avoided as steel management the nuclear facility management requires different skills. While overall direction can be provided from the steel industry's side, the facility would best be run autonomously and therefore option 3 would be ideal if the steel industry is willing to build the facility for its private function.

5.2.2 Buy energy from a utility

From the perspective of the steel industry, the option of buying energy from a utility seems to be the more viable option. Unfortunately, only electricity purchase is viable due to geographic limitations on process heat applications. However, as was shown previously, process heat used to produce hydrogen is not currently viable for the industry. And using process heat to only heat natural gas does not provide a significant benefit over electricity generation alone. Therefore, having a utility providing a steel industry's electricity needs is attractive, especially if the industry can negotiate an adequate rate from said utility.

In addition to the analysis above, the steel industry generally follows cycles of high and low demand. The industry is presently still recovering from the recent recession, and investments in large capital projects are generally not considered unless the payback period is less than 6 years. In addition, if demand for steel decreases, the sunk cost for the construction of a facility cannot be directly recovered (unless, power from the facility is fed into the grid or sold elsewhere). From the perspective of the steel industry, a utility providing the energy service is the only real option.

5.3 Recent world context

An unavoidable point of discussion for all nuclear based studies is the Fukushima nuclear crisis that occurred earlier this year (2011) in Japan. This has been the largest nuclear accident since the Chernobyl accident in 1986, and the one of only two category 7 nuclear disasters. The crisis was triggered by a 9.1 magnitude earthquake off the coast of Japan. While the earthquake itself was not the cause of the accident, the subsequent tsunami cause by the earthquake destroyed critical equipment needed to maintain the emergency heat removal system.

The main question is how this disaster affects the future of nuclear power and the associated question of whether nuclear power can be kept safe. The second question is more relevant to an industry looking to privately build a nuclear facility. A facility built for local energy requirements should ideally not cause the industry any added headaches in terms of liabilities arising from a nuclear accident.

In general, modern designs of nuclear facilities provide adequate safety measures to prevent an accident similar to what occurred in Japan from repeating itself. Modern HTR designs incorporate passive safety mechanisms into the picture allowing the facility to be left standing for a couple of days before intervention is required. In addition, heat removal from such facilities is not dependent on external equipment. All in all, this would ensure that the facility does not release any radiation in the event of a catastrophic accident.

Even though a major natural disaster was necessary to cause the Fukushima accident, public sentiment regarding nuclear power has plummeted to such an extent that countries such as Germany decided to shut down all nuclear facilities in the country (overturning a previous decision to allow existing plants to continue operating). The impact has been significant, for the most part, for the industry, and at the very least, the Fukushima crisis has delayed the so called “Nuclear Renaissance”, and in the worst case scenario, it will put a permanent halt to the deployment of new nuclear power builds.

Luckily the disaster has been managed as well as possible and apart from complaints during the initial phases of the incident regarding lack of regular updates on the status of the Fukushima plants, most of the worst case scenarios predicted by anti-nuclear camps have not come to pass.

This is not to imply that the disaster has been trivial, it has shown several flaws in the backup safety features of nuclear power plants and stricter standards by regulatory agencies will almost certainly occur for new nuclear builds as well as for license renewals.

In addition to the negative sentiment arising from the public sphere due to this disaster, nuclear utilities themselves are wary of expanding nuclear power due to the price tag involved in clean up operations after a disaster. While capital costs for nuclear power is a major limiting factor for new builds, in all likelihood, this accident will ensure that build costs increase.

The only real option is to design new facilities that ensure the operational safety of the facility even in catastrophic accidents. Generation IV reactors show promise in achieving this. For now, the future of nuclear power is not clear.

5.4 Carbon Taxes

Due to the growing concern about climate change, South Africa is considering means to coerce industries to reduce their carbon emissions. One of the proposals that are being considered is the implementation of a carbon tax that will make industries pay a tax per tonne of CO_2 emitted.

Currently, these proposals are still in the vetting stages and implementation of a tax will most likely only occur a few years from now. However, a tax on carbon will affect almost all large scale industries.

5.4.1 In the context of electricity

For electricity in particular, South Africa is currently in a unique situation where a general tax on carbon emissions will affect all electricity consumers. This is due to the fact that South Africa only has a single electricity supplier. Therefore, the taxes that the company will incur from carbon emissions will be distributed across all technologies. In other words, the utility (Eskom) will just raise the price of electricity by a few percent over and above other planned increases and it would not matter if a consumer draws power from a nuclear power plant or from a coal fired one.

The only way that the consumer will benefit from not using electricity generated by coal is if other utilities enter into the arena or if they build a facility in-house. Unfortunately, for South Africa, new utilities are unlikely in the foreseeable future.

The following table shows the estimates for g/kWh CO_2 for coal fired power stations (world-nuclear.org, 2009). The estimates are based on studies conducted in various countries (indicated by column names).

Table 16: Carbon released per kWh for coal

	g/kWh CO2				
	Japan	**Sweden**	**Finland**	**UK: SDC**	**EU ExternE**
Coal	990	980	894	891	815

Based on the table above and taking the best case scenario of 815g/kWh CO_2, the following graph shows the increase in electricity prices based on the implementation of a carbon tax. Note that the costs are estimated here in Rand to bring it in line with the South African context:

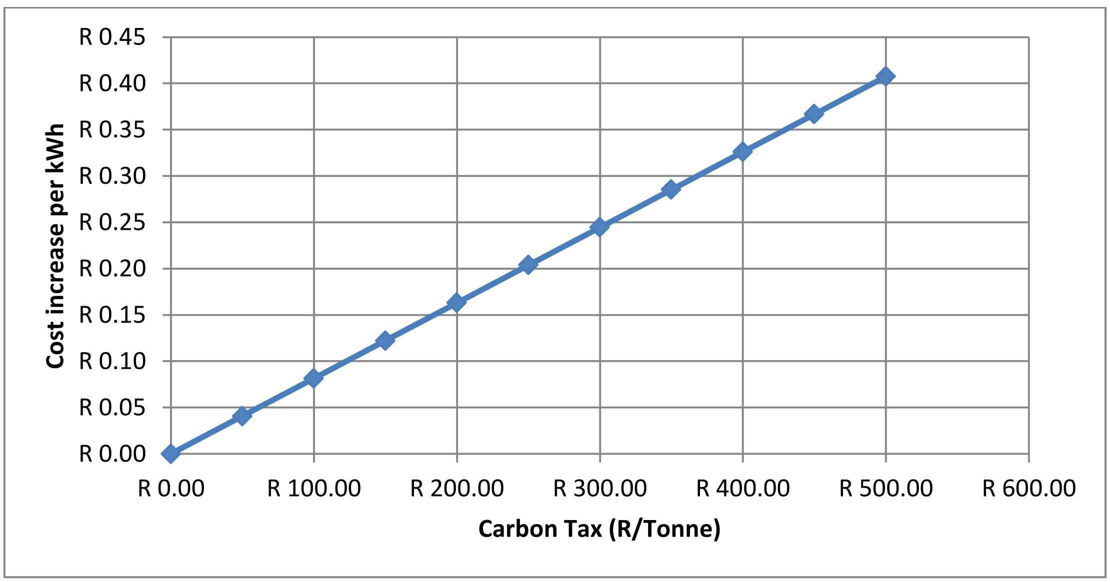

Figure 37: Effect of carbon tax on electricity generated from coal fired power plants

From a practical perspective, any carbon tax of over R200/tonne would put a huge burden on the consumer. Taking a realistic case of around R150/tonne CO_2, The following graphs show the cashflow and payback period for electricity generated from nuclear power (at 5% interest and \$3000/kWh installed):

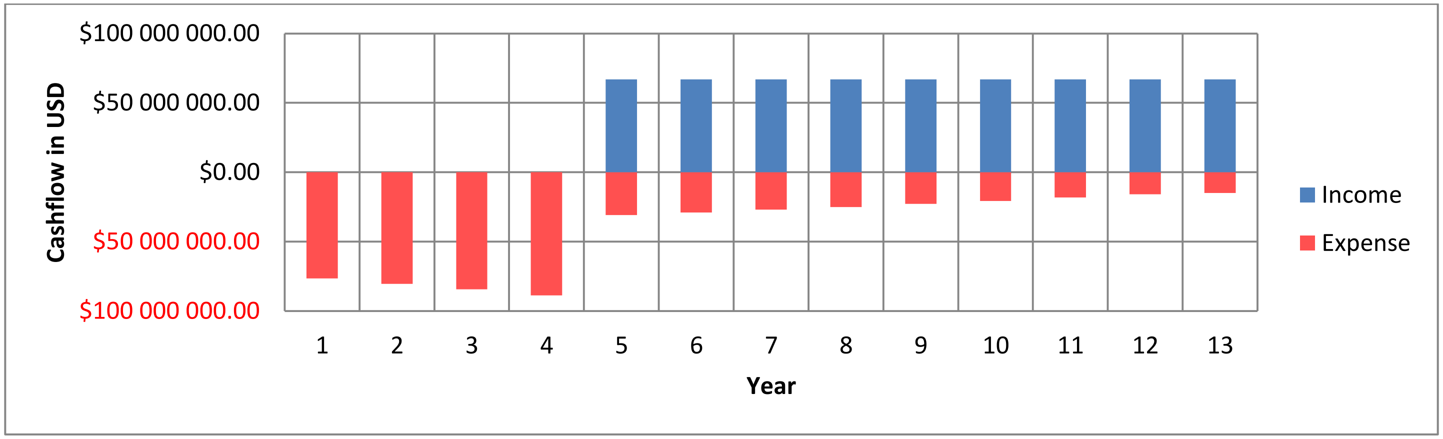

Figure 38: Cashflow for a nuclear facility if a carbon tax of R150/tonne CO2 is implemented

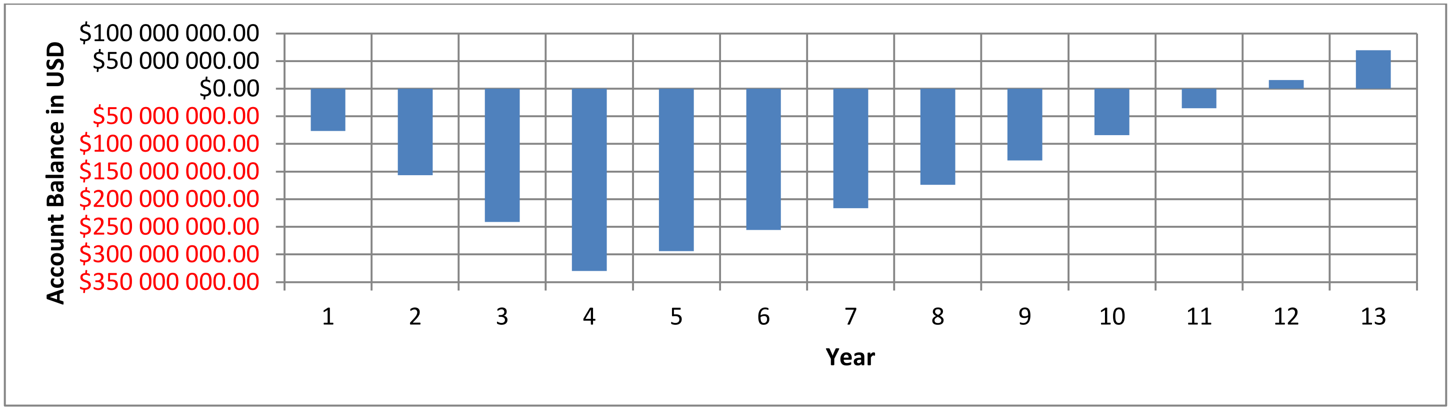

Figure 39: Bank balance for a nuclear facility if a carbon tax of R150/tonne CO2 is implemented

For comparison, the payback period for the same nuclear facility without the additional carbon tax on coal based electricity was around 15 years. By adding a carbon tax, this is reduced to less than 12 years. Carbon tax definitely makes nuclear power not only a viable, but also a recommended option.

6. Conclusions and summary

6.1 Context

The steel industry is one of the largest energy consumers in the world with most of its energy requirements coming from coal and other forms of fossil fuels. With the recent global drive to reduce carbon emissions, the production cost of manufacturing steel is set to increase. Electricity prices in South Africa in particular have been rising rapidly and are set to continue increasing until at least 2015. Of course, electricity production costs would also increase significantly with the introduction of a carbon tax.

It is apparent that the steel industry would benefit significantly from an alternative electricity source and by a reduction in carbon emissions either by process changes or by carbon capture and sequestration. This study investigated the viability of using nuclear energy to cater for these needs of the steel industry.

6.2 Evaluated Processes

From a very high level, steel making involves the reduction of iron ore into iron, followed by the refining of the iron into steel and the rolling of the steel into various end products.

Three separate investigations were conducted to analyse the potential to integrate the nuclear and steel industry. For the first option, the benefit of providing nuclear generated electricity alone for a steel industry was investigated.

The main consumers of electricity for steel production is in the steel-making (converting iron to steel) side, and out of the available processes, the electric arc furnace consumes the most electricity. A pricing model for a nuclear power plant was developed. The plant was specified to provide sufficient electrical power to cater for a two million tonne/annum EAF. Electricity costs account for more than 15% of the cost liquid-steel production from an EAF and therefore, even a small reduction in electricity costs translates to a huge cash savings.

The second option that was investigated was using a nuclear power plant to produce hydrogen to be used as a substitute reducing agent in the Midrex process. A recent study (Botha, 2009) concluded that the process of substituting hydrogen gas as a reducing agent instead of reformed natural gas provides a viable alternative to the existing Midrex process. A pricing model for a hydrogen production facility was developed and specified to produce sufficient hydrogen to produce one million tonnes/annum of DRI.

The final option that was investigated was the integration of process heat applications and electricity generation applications. Electrical power would be provided for the electric arc furnace and process heat would be available for the Midrex process.

6.3 Results

6.3.1 Electricity

The costing model was used to determine how nuclear based electricity relates to various factors involved with the construction and operation of the facility. The two largest contributors to the price of electricity is the capital required for the construction of the facility and the interest rate that the build is financed against. The next largest contributor to the final cost of production was plant availability. Fuel costs, plant efficiency and construction time all affect the final cost of production to a limited degree compared to other factors.

Given these factors, a model for a realistic best case scenario was drawn up. The calculations showed that the electricity produced in such a facility and sold to a steel manufacturer at a 10% markup would be more than 15% cheaper than the current selling price for electricity. At this rate a savings of 2.75% per tonne of steel was achieved. This translated into a savings of more than R37 million/year.

If such a facility was built by the steel plant in-house, the plant would pay itself back within 12 years, if sufficient capital was available to finance the build without a loan, and 15 years if a loan was taken at 5% per annum interest. In both these cases the payback period was calculated from the start of construction.

It is clear that nuclear power has the potential to improve the electricity costs for an industry. However, it is unlikely, given the long payback period, that any industry would build its own nuclear facility for electricity generation alone.

6.3.2 Hydrogen Production

A pricing model for a hydrogen production facility coupled with a nuclear power plant was developed. For the purposes of this model, it was assumed that sufficient hydrogen would be manufactured to produce about one million tonnes per annum of DRI. Each facility required for the hydrogen production was separated in the model and costs for construction, maintenance and operations were calculated in each case.

The sensitivities calculated previously also held true to this hydrogen production facility. However, several important factors such as the operational and maintenance cost and the hydrogen production rate impacted the cost of production significantly.

With the given analysis, the best case scenario for a hydrogen production facility was able to produce hydrogen at around \$4.26/kg H_2. At this cost, substituting hydrogen instead of reformed gas for the Midrex process would increase the selling price of DRI by about 40%.

Given this analysis, it is clear that if the costs of hydrogen production remain at such high levels, integration into the steel industry is not viable. One of the main reasons why the costs remain high is mostly due to the theoretical nature of the proposed hydrogen facility. In addition to this the high operational costs contribute significantly to the final cost of hydrogen. This counteracts one of the major benefits of the nuclear industry – the low running costs compared to start-up costs.

However, using the pricing model developed for this exercise, it was possible to calculate the cost per MWth produced from a nuclear facility, which was around \$20/MWth. It was calculated that this production cost was cheaper than the cost of burning an equivalent amount of natural gas.

Considering that H_2 was not viable, it made sense to consider the combined scenario of electricity and process heat.

6.3.3 Combined Scenario

The pricing model used for the hydrogen production facility was modified to cater for process heat directly. Using this model, the payback period for a nuclear facility that caters for the electricity and heating requirements for one million tonne/annum Midrex facility, and a 2 million tonne/annum EAF was calculated.

When the facility is financed without a loan, the total payback period is 11 years and when the facility is financed at 5% interest, the payback period is 14 years. In both cases a savings of a year occurred due to the extra process heat that was used.

It is however unclear as to whether the 1 year savings would justify the extra complexity on the nuclear facility to cater for the process heating side. It is most likely that it would be easier to just have a nuclear utility produce electricity that can be bought directly from then.

6.4 Carbon Tax

As a final note, it should be noted that the above analyses do not take into consideration the implementation of a carbon tax. If an extra tax on carbon were to be implemented, then the analysis shows that repayment for a nuclear facility that only produces electricity would be around 11 years when the facility is financed at 5% interest based purely on savings of not buying from a coal fired power station. This means that there could be a reduction in payback periods for a nuclear facility of about 1 year for every R40/tonne increase in carbon tax.

6.5 Conclusion

This study has demonstrated that currently, from a cost perspective, nuclear power is not ideal for integration into the steel industry for any function apart from electricity generation. If however, the production costs of hydrogen were to decrease significantly, this analysis should be revisited.

Further research should be conducted regarding the reduction of generation costs for hydrogen as well as increasing temperatures achievable by nuclear power facilities. To this end, industries in general and the steel industry specifically are encouraged to participate as part of a consortium to develop small, high temperature reactors.

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