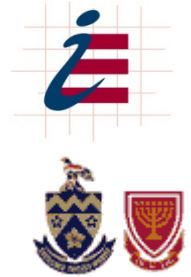


Faculty

Engineering



**Evaluation of the reduction of CO₂ emissions from a
coal-to-liquids utilities plant by incorporating PBMR energy**

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Dissertation submitted in partial fulfilment of the requirements for the degree

**Masters of Engineering
at the Potchefstroom campus
of the
North-West University**

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ABSTRACT

Title: Evaluation of the reduction of CO₂ emissions from a Coal-to-Liquids utilities plant by incorporating PBMR energy

Author: MM Gouws

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Due to the constantly growing environmental concerns about global warming, there is immense pressure on the coal-to-liquids (CTL) industry to lower carbon dioxide emissions. This study evaluates the cogeneration of electricity and process steam, using coal and nuclear heat obtained from a High Temperature Gas Cooled Reactor (HTGR) such as a Pebble Bed Modular Reactor (PBMR), for the use in a CTL plant. Three different cogeneration processes were investigated to resolve what influence nuclear cogenerated electricity and process steam would have on the carbon dioxide emissions and the unit production cost of electricity and process steam.

The first process investigated utilises coal as combustion medium and an extraction/condensing steam turbine, together with the thermodynamic Rankine cycle, for the cogeneration of electricity and process steam. This process was used as a basis of comparison for the nuclear-based cogeneration processes.

The second process investigated utilises nuclear heat generated by a HTGR and the same power conversion system as the coal-based cogeneration system. Utilising a HTGR as a heat source can decrease the carbon dioxide emissions to approximately zero, with a 91.6% increase in electricity production cost. The last process investigated is the nuclear-based closed cycle gas turbine system where a gas turbine and Brayton cycle is coupled with a HTGR for the cogeneration of electricity and process steam. It was found on technical grounds that this process would not be viable for the cogeneration of electricity and process steam.

The unit production cost of electricity and process steam generated by each process were determined through an economic analysis performed on each process. Overall it was found that the CTL industry could benefit a great deal from utilising nuclear heat as a heat source.

Keywords: Cogeneration, PBMR, CTL Plant, Process Steam, Electricity.

SAMEVATTING

Tittel: 'n Evalueering van die afname in koolstofdiksied uitlaat-gasse vanaf 'n Steenkool-tot Vloeistof utiliteite aanleg deur die aanwending van PMBR energie.

Outeur: MM Gouws

Studieleier: Prof. PWE Blom

Weens die groeiende kommer oor aardverwarming, is daar geweldige druk op die steenkool-tot-vloeistof industrie geplaas om hul koolstofdiksied uitlaatgasse te verlaag. Hierdie studie evalueer die gesamentlike opwekking van elektrisiteit en proses stoom (hitte), deur gebruik te maak van steenkool en kern hitte verkry vanaf 'n hoë temperatuur gas afgekoelde reaktor (HTGR) soos die korrelbed-modulêre-kern-reaktor (PBMR). Drie verskillende gesamentlike opwekking prosesse was bestudeer om die invloed van kern genereerde elektrisiteit en proses stoom (hitte) op die koolstof dioksied uitlaat-gasse en die eenheid produksie koste van elektrisiteit en proses hitte vas te stel.

Die eerste proses wat ondersoek was maak gebruik van steenkool as verbranding medium en 'n ekstraksie/kondensie stoom turbine tesame met die termodinamiese Rankine siklus vir die gesamentlike opwekking van elektrisiteit en proses stoom (hitte). Hierdie proses was gebruik as 'n basis van vergelyking vir die kern-gebaseerde prosesse. Die tweede proses maak gebruik van kern hitte verkry vanaf 'n HTGR en die dieselfde krag omskakeling stelsel as die steenkool-gebaseerde proses. Deur die gebruik van 'n HTGR as hittebron kan die koolstofdiksied uitlaatgasse verminder word tot ongeveer nul, met 'n styging van 82.6% en 62.2% in die eenheid koste van elektrisiteit en proses stoom (hitte) onderskeidelik.

Die laaste proses wat ondersoek is, is die kern-gebaseerde geslote gas turbine stelsel wat funksioneer op die termodinamiese Brayton siklus. Daar is gevind dat hierdie proses nie lewensvatbaar sou wees vir die gesamentlike opweking van elektrisiteit en proses stoom (hitte) nie. Die eenheid produksie koste van elektrisiteit en proses stoom verkry vanaf elke proses is

bepaal deur middel van 'n ekonomiese analise. In geheel kan dit gesien word dat die koolstof-tot-vloeistof bedryf sal kan baat by die gebruik van kern hitte as hitte bron.

Sleuteltermes: Gesamentlike opwekking, PBMR, Proses stoom, Steenkool-tot-Vloeistof, Elektrisiteit

TABLE OF CONTENTS

ACKNOWLEDGEMENTS.....	ii
ABSTRACT.....	iii
SAMEVATTING.....	v
LIST OF FIGURES.....	xi
LIST OF TABLES.....	xiii
LIST OF APPENDICES.....	xv
LIST OF ABBREVIATIONS.....	xvi
LIST OF SYMBOLS.....	xvix
CHAPTER 1. INTRODUCTION TO THE RESEARCH.....	1
1.1. Introduction.....	1
1.2. Background and current situation.....	6
1.2.1 <i>Process</i>	6
1.2.2 <i>Coal</i>	7
1.2.3 <i>Cogeneration (steam and electricity)</i>	7
1.3. Problem statement.....	8
1.4. Research methodology.....	9
1.5. Objective of the research project.....	9
1.6. Outline of the dissertation.....	10
CHAPTER 2. LITERATURE STUDY.....	12
2.1. Introduction.....	12
2.2. Cogeneration.....	12
2.2.1 <i>Classification of cogeneration systems</i>	14
2.2.1.1 <i>Topping Cycle</i>	14
2.2.1.2 <i>Bottoming Cycle</i>	17
2.2.2 <i>Technical options for cogeneration</i>	17
2.2.2.1 <i>Steam Turbines</i>	18

2.2.2.2 Gas Turbines	25
2.3. Nuclear heat applications.....	33
2.4. Chosen nuclear processes	36
2.4.1 Cycle naming convention	36
2.4.2 Indirect extraction/condensing steam turbine cogeneration system	37
2.4.3 Indirect closed-cycle gas turbine cogeneration system	38
2.5. Summary	40
CHAPTER 3. COAL-BASED PROCESS ROUTES	41
3.1. Introduction.....	41
3.2. Alternative A: Separate generation of electricity and steam by coal-fired boilers..	42
3.2.1 Process design criteria.....	42
3.2.1.1 Product specifications	42
3.2.1.2 Raw material specifications	42
3.2.2 Steam generation.....	44
3.2.2.1 Process description.....	44
3.2.2.2 Process flow diagram.....	46
3.2.2.3 Operating conditions	47
3.2.2.4 Mass balance.....	48
3.2.2.5 Energy balance	52
3.2.3 Electricity generation (conventional coal-fired power plant)	56
3.2.3.1 Process description.....	56
3.2.3.2 Process flow diagram.....	58
3.2.3.3 Operating conditions	59
3.2.3.4 Mass balance.....	60
3.2.3.5 Energy balance	64
3.2.4 Consumption and discharge figures.....	71
3.3. Alternative B: Coal-fired cogeneration process	73
3.3.1 Process design criteria.....	73
3.3.3.1 Product specifications	73
3.3.3.2 Raw material specifications	73
3.3.2 General process description	75
3.3.3 Process flow diagram.....	77

3.3.4	<i>Operating conditions</i>	78
3.3.5	<i>Mass balance</i>	80
3.3.6	<i>Energy balances</i>	84
3.3.7	<i>Consumption and discharge figures</i>	91
3.4.	Summary	94
CHAPTER 4. NUCLEAR HEAT PROCESS ROUTE		96
4.1.	Introduction	96
4.2.	Alternative A: Indirect extraction/condensing steam turbine cogeneration system	97
4.2.1	<i>Process design criteria</i>	97
4.2.2	<i>General process description</i>	98
4.2.3	<i>Process flow diagram</i>	100
4.2.4	<i>Operating conditions</i>	101
4.2.5	<i>Mass balance</i>	102
4.2.6	<i>Energy balance</i>	104
4.2.7	<i>Consumption and discharge figures</i>	110
4.3.	Alternative B: Indirect closed-cycle gas turbine cogeneration system	112
4.3.1	<i>Process design criteria</i>	112
4.3.2	<i>General process description</i>	113
4.3.3	<i>Process flow diagram</i>	115
4.3.4	<i>Operating conditions</i>	116
4.3.5	<i>Mass balance</i>	117
4.3.6	<i>Energy balance</i>	118
4.3.7	<i>Consumption and discharge figures</i>	125
4.4.	Summary	125
CHAPTER 5. PRODUCTION COST ANALYSIS		127
5.1.	Introduction	127
5.2.	Economic model	127
5.2.1	<i>Assumptions and methods used in the economic model</i>	128
5.2.2	<i>Fixed capital investment (FCI)</i>	128
5.2.3	<i>Production cost</i>	129
5.2.3.1	<i>Fixed operating costs</i>	129
5.2.3.2	<i>Variable operating costs</i>	131

5.2.3.3 Capital charges	131
5.2.3.3 Carbon penalties.....	131
5.2.4 Electricity and process steam unit production cost summary	137
5.3. Sensitivity analysis.....	142
5.4. Summary	146
CHAPTER 6. CONCLUSION AND RECOMMENDATIONS.....	147
6.1. Conclusion	147
6.2. Recommendations.....	150
REFERENCES	151
APPENDICES	157

LIST OF FIGURES

Figure 1-1 World marketed energy consumption (Time for change, n.d.)	2
Figure 1-2 World electricity generation by fuel, 2005-2030 (U.S. Department of Energy, 2008:63)	3
Figure 1-3 World CO ₂ emissions, 2005-2030 (U.S. Department of Energy, 2008:5)	4
Figure 1-4 South Africa: CO ₂ emissions by sector (International Energy Agency, 2010:25)	5
Figure 2-1 Energy use of conventional power plant (Naturalgas.org, 2011)	13
Figure 2-2 Energy usage of cogeneration plant (Naturalgas.org, 2011)	13
Figure 2-3 Combined cycle topping system (Bureau of Energy Efficiency, n.d.)	15
Figure 2-4 Steam turbine topping system (Bureau of Energy Efficiency, n.d.)	15
Figure 2-5 Heat recovery topping system (Bureau of Energy Efficiency, n.d.)	16
Figure 2-6 Gas turbine topping system (Bureau of Energy Efficiency, n.d.)	17
Figure 2-7 Boiler/steam turbine system (Energy Nexus Group, 2002)	19
Figure 2-8 Configuration of back-pressure steam turbines (Grote & Antonsson, 2009)	21
Figure 2-9 Different configurations of back-pressure steam turbine (Bureau of Energy Efficiency, n.d.)	22
Figure 2-10 Extraction/condensing steam turbine cogeneration system (Grote & Antonsson, 2009)	24
Figure 2-11 Regenerative gas turbine cycle (Weston, 1992)	27
Figure 2-12 Gas turbine cycle with inter-cooling (Milancej, 2005)	28
Figure 2-13 Gas turbine cycle with reheating (Weston, 1992)	28
Figure 2-14 Open-cycle gas turbine cogeneration system (Energy Efficiency Guide for Industry in Asia, n.d.)	30
Figure 2-15 Closed-cycle gas turbine cogeneration system (Energy Efficiency Guide for Industry in Asia, n.d.)	32
Figure 2-16 Fuel element design for the PBMR (Chetty, 2008)	34
Figure 2-17 Passive Heat Removal System (Strydom, 2007)	35
Figure 2-18 Indirect extraction/condensing steam turbine cogeneration process	38

Figure 2-19 Indirect closed-cycle gas turbine cogeneration system (Penfield <i>et al.</i> , 2006)	39
Figure 3-1 Process steam generation layout	46
Figure 3-2 Energy balance of coal mill (Steam generation process).....	52
Figure 3-3 Energy balance of boiler (Steam generation process).....	54
Figure 3-4 Layout of a conventional coal-fired power plant (electricity generation).....	58
Figure 3-5 Energy balance of coal mill (conventional coal-fired power plant)	64
Figure 3-6 Energy balance of boiler (Conventional coal-fired power plant).....	66
Figure 3-7 Energy balance of PCS (Conventional coal-fired power plant)	67
Figure 3-8 Layout of coal-fired cogeneration process.....	77
Figure 3-9 Energy balance of coal mill (coal-fired cogeneration process).....	84
Figure 3-10 Energy balance of boiler (coal-fired cogeneration process).....	86
Figure 3-11 Energy balance of PCS (Coal-fired cogeneration process)	87
Figure 4-1 Layout of extraction/condensing steam turbine cogeneration process.....	100
Figure 4-2 Energy balance of primary and intermediate cycle (extraction/condensing steam turbine cogeneration processes)	104
Figure 4-3 Energy balance of the PCS (Extraction/condensing steam turbine cogeneration system)	106
Figure 4-4 Layout of closed-cycle gas turbine cogeneration process	115
Figure 4-5 Energy balance of PHTS (closed-cycle gas turbine cogeneration process).....	118
Figure 4-6 Energy balance of PCS (closed-cycle gas turbine cogeneration process).....	120
Figure 5-1 Unit production cost of electricity and process steam via Alternative B: Coal-based Process Route	142
Figure 5-2 Efficiency of Alternative B: Coal-based process route	143
Figure 5-3 Unit Production Cost of Electricity and Process Steam via Alternative A: Nuclear-based Process Route.....	143
Figure 5-4 Efficiency of Alternative A: Nuclear-based process route	144
Figure 5-5: Unit production cost of electricity and process Steam via Alternative B: Nuclear-based process route	144
Figure 5-6 Efficiency of Alternative B: Nuclear-based process route	145

LIST OF TABLES

Table 2-1 Advantages and disadvantages of back-pressure steam turbines (Energy Efficiency Guide for Industry in Asia, 2006).....	23
Table 3-1 Composition of sub-bituminous coal.....	43
Table 3-2 Operating condition of steam generation process.....	47
Table 3-3 Mass balance of steam generation process	48
Table 3-4 Energy balance of coal mill (Steam generation process)	53
Table 3-5 Specific enthalpy of streams (Conventional coal-fired power plant)	55
Table 3-6 Energy balance of boiler (steam generation process).....	55
Table 3-7 Operating conditions of conventional coal-fired power plant.....	59
Table 3-8 Mass balance of conventional coal-fired power plant	60
Table 3-9 Energy balance of coal mill (conventional coal-fired power plant).....	65
Table 3-10 Energy balance of boiler (conventional coal-fired power plant).....	66
Table 3-11 Specific enthalpy and heat of each stream (conventional coal-fired power plant)	68
Table 3-12 Energy balance of PCS (Conventional coal-fired power plant)	68
Table 3-13 Efficiency of conventional coal-fired power plant	69
Table 3-14 Consumption figures of Alternative A: Coal-based process route	71
Table 3-15 Discharge figures of Alternative A: Coal-based process route	72
Table 3-16 Composition of sub-bituminous coal.....	74
Table 3-17 Operating conditions of a coal-fired cogeneration process	79
Table 3-18 Mass balance of a coal-fired cogeneration process.....	80
Table 3-19 Energy balance of coal mill (coal-fired cogeneration process)	85
Table 3-20 Energy balance of boiler (coal-fired cogeneration process)	86
Table 3-21 Specific enthalpy and heat of each stream (coal-fired cogeneration process)	88
Table 3-22 Energy balance of PCS (coal-fired cogeneration process)	89
Table 3-23 Efficiency of coal-fired cogeneration process	90
Table 3-24 Consumption figures of Alternative B: Coal-based Process Route	92
Table 3-25 Discharge figures of Alternative B: Coal-based process route	93

Table 3-26 Coal consumption and CO ₂ emissions of Alternative A and B: Coal-based process route	94
Table 3-27 Electricity and process heat of Alternative A and B: Coal-based process route	94
Table 4-1 Operating conditions of an extraction/condensing steam turbine cogeneration process	101
Table 4-2 Mass balance of the extraction/condensing steam turbine cogeneration process....	102
Table 4-3 Energy balance of PHTS and SHTS (extraction/condensing steam turbine cogeneration process)	105
Table 4-4 Specific enthalpy and heat load of each stream (extraction/condensing steam turbine cogeneration process)	107
Table 4-5 Energy balance of PCS (extraction/condensing steam turbine cogeneration process)	108
Table 4-6 Efficiencies of extraction/condensing steam turbine cogeneration process	109
Table 4-7 Consumption figures of extraction/condensing steam turbine cogeneration process	111
Table 4-8 Operating conditions of closed-cycle gas turbine cogeneration system	116
Table 4-9 Mass balance of a closed-cycle gas turbine cogeneration process	117
Table 4-10 Energy balance of PHTS (closed-cycle gas turbine cogeneration process).....	119
Table 4-11 Specific enthalpy (closed-cycle gas turbine cogeneration system)	121
Table 4-12 Heat load of each stream in the PCS	121
Table 4-13 Energy balance of the PCS (closed-cycle gas turbine cogeneration process)	122
Table 4-14 Efficiency of closed-cycle gas turbine cogeneration process	123
Table 4-15 Consumption figures of closed-cycle gas turbine cogeneration process.....	125
Table 4-16 Helium and steam consumption of Alternative A and B: Nuclear-based process routes.....	126
Table 4-17 Electricity and process steam production of Alternative A and B: Nuclear-based process routes	126
Table 5-1: Marshall and Swift Cost Indices (as cited in Chemical Engineering, 2011).....	128
Table 6-1 Cogeneration processes summary	148

LIST OF APPENDICES

Appendix A: Alternative A-Coal Based Process Route	157
Appendix B: Alternative B-Coal Based Process Route	168
Appendix C: Alternative A-Nuclear Based Process Route	175
Appendix D: Alternative B-Nuclear Based Process Route	184

LIST OF ABBREVIATIONS

AR	As Received
CV	Calorific Value
C	Carbon
CO₂	Carbon Dioxide
CTL	Coal-to-Liquids
CHP	Combined Heat and Power
DEL	Delivery
DAF	Dry and Ash Free
DB	Dry Basis
FT	Fischer-Tropsch
FCI	Fixed Capital Investment
g	Gas
GEN	Generator
HRSG	Heat Recovery Steam Generator
HPT	High Pressure Turbine
HTGR	High Temperature Gas Reactor
hr	Hour
H	Hydrogen
IHX	Intermediate Heat Exchanger
K	Kelvin
kg	Kilo Gram
kJ	Kilo Joule
kmol	Kilo Mol
kPa	Kilo Pascal
kW	Kilo Watt
l	Liquid

LPC	Low Pressure Compressor
LPT	Low Pressure Turbine
MJ	Mega Joule
MPa	Mega Pascal
MW	Mega Watt
MW_e	Mega Watt Electrical
MW_h	Mega Watt Hour
MW_t	Mega Watt Thermal
net	Netto
W_{net}	Net Work
N	Nitrogen
n.d.	No Date
Nm³	Normal Cubic Meter
O	Oxygen
PBMR	Pebble Bed Modular Reactor
PCS	Power Conversion System
PHTS	Primary Heat Transport System
PFD	Process Flow Diagram
P	Pump
sat	Saturated
SHTS	Secondary Heat Transport System
SiC	Silicate Carbon
SG	Steam Generator
S	Sulphur
SO₂	Sulphur Dioxide
t	Thermal
tot	Total
TCC	Total Capital Cost

North West University

US United States

H₂O Water

wt Weight

LIST OF SYMBOLS

S_a	Annual amount of working fluid generated in the PCS
Δ	Change
E	Delivered electricity
X_e	Delivered Electrical Ratio
S_d	Delivered steam
X_s	Delivered Steam Ratio
\$	Dollar
η	Efficiency
H	Enthalpy
Q	Heat
I	Internal Steam Usage
m	Mass Flow
n	Mole Flow
P	Pressure
C_p	Specific Heat Capacity
T	Temperature
A_{tot}	Total annual production cost
C_E	Unit cost of electricity delivered
C_S	Unit cost of delivered steam
C_{WF}	Unit cost of working fluid in the PCS
V	Volume Flow
W	Work

CHAPTER 1. INTRODUCTION TO THE RESEARCH

1.1. Introduction

One of the biggest environmental concerns of the 21st century is global warming which results in climate change. The growing increase of carbon dioxide (CO₂) and other greenhouse gases in the atmosphere, which result from the burning of fossil fuels, are slowly but surely heating the earth's atmosphere. The extent of the damage that climate change may cause, remains uncertain, but there is some risk that such damage could be large and perhaps even catastrophic (Congressional Budget Office, 2008:5).

Climate change will have the biggest impact on developing countries such as South Africa; it could undermine global poverty alleviation efforts and have severe implications on food security, clean water, energy supply, environmental health and human settlements (Coal Industry Advisory Board, 2005). South Africa currently relies heavily on fossil fuels as a primary energy source (90%); with coal providing most of it (Earthlife Africa & Oxfam International, 2009).

In terms of the Kyoto Protocol, South Africa, as a developing country, is not required to reduce its greenhouse gas emissions yet, but due to the high dependence on fossil fuels it could be beneficial to adapt a future strategy that is directed towards a cleaner future (Coal Industry Advisory Board, 2005).

Although South Africa is the largest emitter of greenhouse gases on the African continent, the 12th largest emitter of CO₂ in the world (Roos, 2009) and home to the biggest single emitter of CO₂ (SASOL Synfuels) (Earthlife Africa & Oxfam International, 2009), it represents only 1.1% of the global total emissions (International Energy Agency, 2010:25).

This rapid increase in CO₂ emissions is due to the world's dependency on fossil fuel as an energy source. The demand for energy is increasing worldwide, along with the growth in population and rises in the standard of living.

From Figure 1-1 it is clear that the global energy consumption will increase by 60% from 2002 to 2030 (2% per year), with the highest growth in consumption coming from Asia (3.8% per year) and Non-OECD countries (3% per year) (Time for change, n.d.).

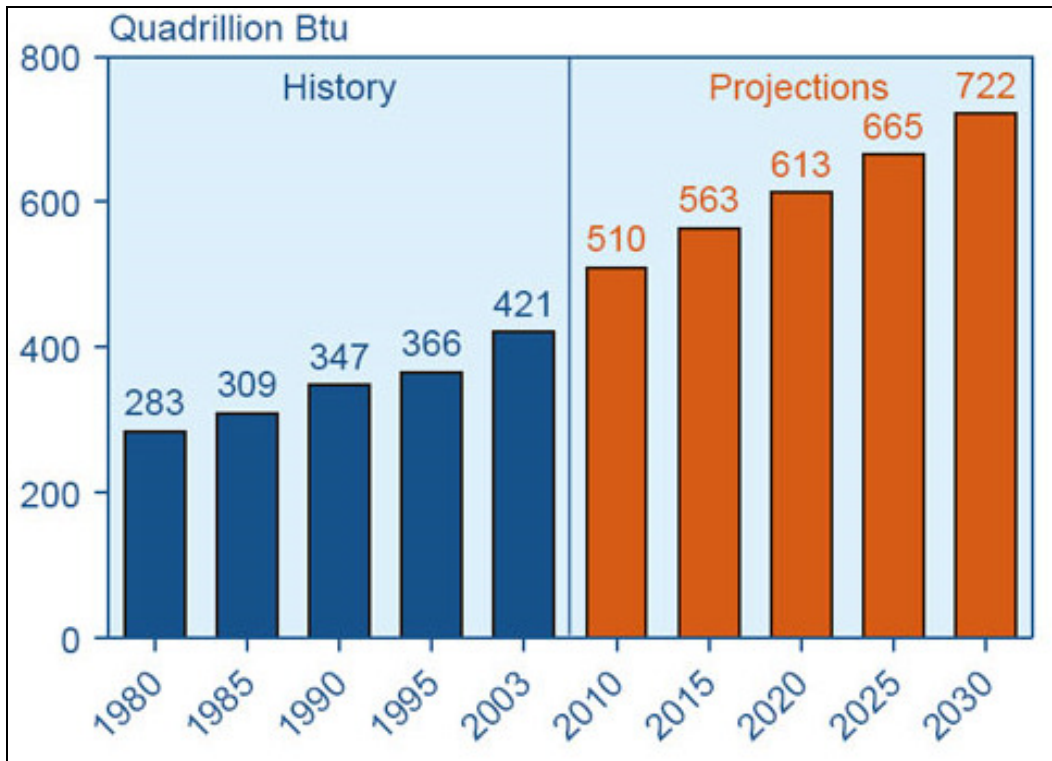


Figure 1-1 World marketed energy consumption (Time for change, n.d.)

With fossil fuels being the largest emitter of greenhouse gasses, it is important to know the predicted growth of energy consumption by fuel type. It is shown in Figure 1-2 that the highest increase in global energy consumption will be from coal, with the renewable and nuclear energies growing, but much less than the fossil fuels.

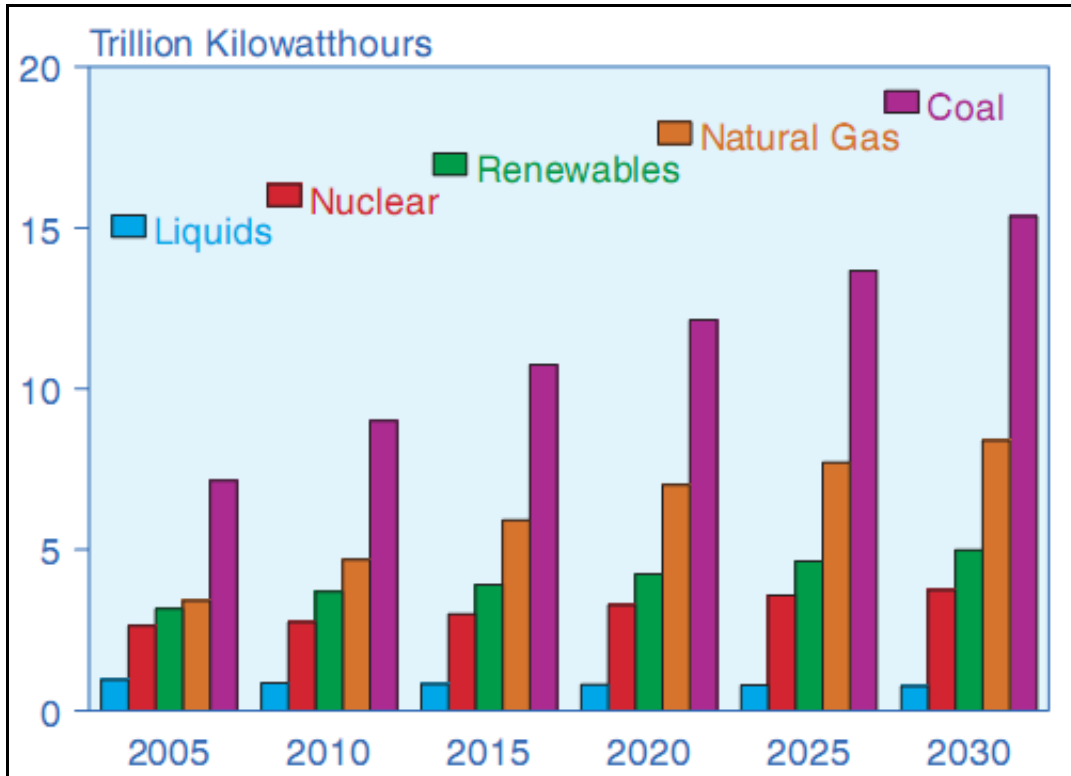


Figure 1-2 World electricity generation by fuel, 2005-2030 (U.S. Department of Energy, 2008:63)

In order to lower the CO₂ levels in the atmosphere and ultimately mitigate global warming, it is necessary to reduce the quantity of fossil fuels consumed as much as possible. In Figure 1-3 it is shown that the global CO₂ emissions will grow by 34% from the year 2005 to 2030. According to the International Energy Agency (2010:8), 43% of the total CO₂ emissions in 2008 were produced by the combustion of coal.

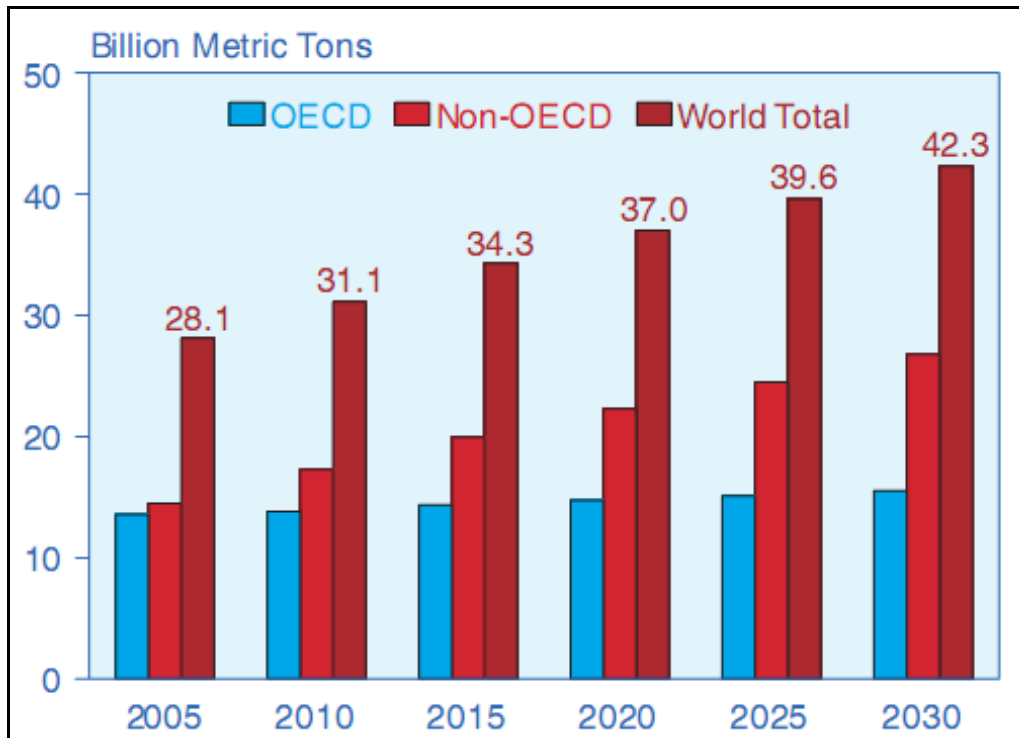


Figure 1-3 World CO₂ emissions, 2005-2030 (U.S. Department of Energy, 2008:5)

Reducing greenhouse gas emissions would have great advantages in reducing the scale of possible damage associated with climate change. On the other hand, decreasing these emissions would likely induce costs in the economy. Most economic activity in any nation involves the use of fossil fuels that consequently produce carbon dioxide (Congressional Budget Office, 2008:9).

The industrial sector's CO₂ emissions are a result of both electricity and steam generation and production processes. In total, the industrial sector accounts for almost a quarter of global carbon dioxide emissions (International Energy Agency, 2008:471). The electricity and steam sector produced 63% of South Africa's CO₂ emissions in 2008 (International Energy Agency, 2010:25), as can be seen in Figure 1-4.

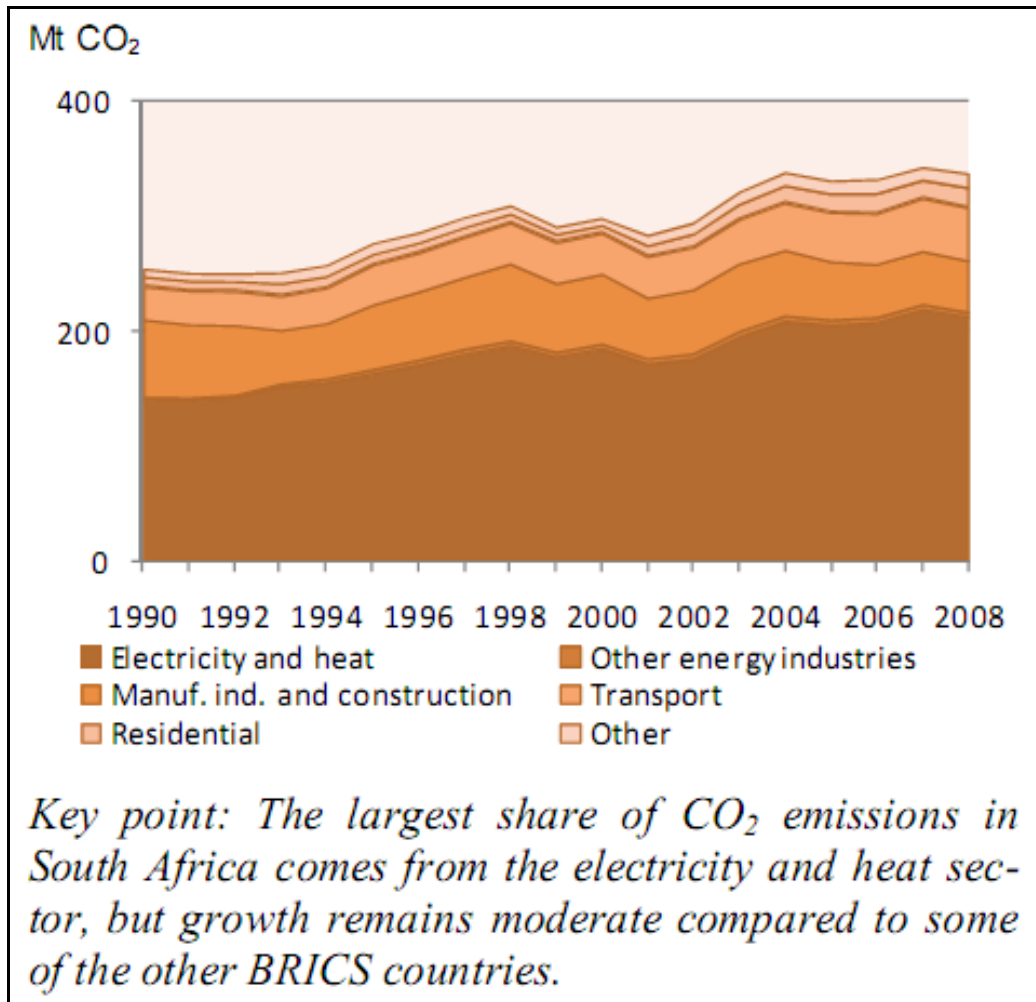


Figure 1-4 South Africa: CO₂ emissions by sector (International Energy Agency, 2010:25)

Carbon dioxide emissions are a direct by-product of industrial processes, especially in the coal-to-liquids process. The possibility of reducing these emissions is limited and will result in major technical challenges in the industrial sector. In the past there were no economical substitutes for fossil fuels or alternative processes that did not require the use of fossil fuels.

At present there is extensive research being done on alternative energy sources which includes nuclear energy. Nuclear energy is a promising option as it can supply sufficient energy for public and industrial demand. It will assist countries to reduce their greenhouse gas emissions and move towards a cleaner future. The use of a High Temperature Gas Reactor (HTGR) also makes nuclear energy much safer than before.

Furthermore, owners and operators of industrial and commercial facilities are always looking for ways to use energy more efficiently. One option is cogeneration; it is the simultaneous production of process steam and electricity from the same fuel or energy source. This process steam can then be applied as a heat source for a range of industrial uses (Renewable Energy Institute, n.d.). This ultimately reduces fossil fuel consumption and increases the efficiency of the process. Another option is to use nuclear heat generated by a HTGR as an energy source for cogeneration. This option will be studied in more detail in this mini-dissertation.

From this point of view, nuclear energy and cogeneration could be a viable option for reducing greenhouse gases emitted from the utility operations of a coal-to-liquids process.

1.2. Background and current situation

1.2.1 Process

SASOL Synfuels, an integrated energy and chemicals company, is the world's largest and only commercial coal-to-liquids (CTL) facility to date, producing about 21% of South Africa's liquid fuels (150 000 bbl/day) and consuming over 40 million tons of coal per annum (Mangena, 2009).

Electricity and steam generated at a CTL facility play a major role in the production process of liquid fuels and can be generated by making use of a number of different energy sources and processes. In this study the focus is on the production of electricity and steam by using coal and nuclear power respectively.

Coal is effectively utilised in a CTL facility for the generation of process steam and electricity and as feedstock for the gasification process to produce synthesis gas. The synthesis gas is converted into synthetic fuels and chemicals through the proprietary Fischer-Tropsch process (FT Process) (Mangena, 2009).

The large consumption of coal makes a CTL facility such as the SASOL plant at Secunda responsible for producing almost 72 million tons of CO₂ per year, making it the single largest CO₂ emitter on the planet (Earthlife Africa & Oxfam International, 2009). The biggest producer of greenhouse gases at a CTL facility is the gasification of coal to produce synthesis gas, followed by the burning of low grade coal to produce utilities such as electricity and steam needed by the operations (Sasol, 1998). In this study the focus will be on the supply of utilities required by a CTL plant.

1.2.2 Coal

There are a number of energy sources available for the generation of electricity and process steam, such as coal, natural gas, oil, nuclear power, renewable energy etc. Coal is the largest energy source used for the generation of electricity and steam, and the most abundant and reliable fossil fuel worldwide. It is also highly cost competitive compared with the other energy sources (Mangena, 2009).

Apart from coal's advantages as primary energy source compared with other fossil fuels, coal is also one of the largest contributors to the increase of CO₂ in the atmosphere, with oil and gas second inline and nuclear, hydro and wind energy about a 100 times lower (approximately zero CO₂) (Mangena, 2009). Coal comes in different ranks and consists mainly of carbon, water, hydrogen, oxygen and small amounts of nitrogen, sulphur and other minerals (Packer & Gray, 1998). The ranks of coal from those with the least carbon to those with the highest carbon content are lignite, sub-bituminous, bituminous and anthracite. Sub-bituminous coal is mostly used for the generation of electricity and steam, and is also used as the basis for this study (World Coal Association, 2011).

1.2.3 Cogeneration (steam and electricity)

The key determinant of whether or not cogeneration would be of use is the nearby need or purpose for the recovered thermal energy. The thermal energy generated by a cogeneration plant has many uses; the most common include industrial processes and water heating (Naturalgas.org, 2011).

The conventional method of power generation and supply is inefficient in the sense that only a third of the energy (36% efficiency) fed into the power plant is converted into electricity. The balance of the energy is lost to the environment. A cogeneration plant wastes about 35% less energy and uses 10 to 30% less fuel than a conventional power plant and on-site boiler (Naturalgas.org, 2011). The replacement of conventional power plants with cogeneration plants would yield numerous benefits, such as large cost savings, improved environmental quality, reduced energy consumption, and improved grid reliability (United States Clean Heat & Power Association, 2011).

Cogeneration is the simultaneous generation of two different forms of useful energy from a single primary energy source, and can have an overall energy efficiency of up to 85% and above in some cases (Bureau of Energy Efficiency, n.d.). A modern plant with a thermal efficiency of 50% implies a 28% cut in CO₂ emissions, compared with a typical plant of around 36% efficiency (Coal Industry Advisory Board, 2005).

Cogeneration systems have applications in centralised power plants, large industrial settings, large and medium sized commercial settings, and even smaller residential or commercial sites (Naturalgas.org, 2011).

1.3. Problem statement

A CTL plant is a large producer of carbon dioxide (CO₂) due to its dependency on coal. In an attempt to reduce the CO₂ emissions, research has been conducted on the possibility of replacing the coal-based utilities production at a coal-to-liquids plant with a HTGR as an energy provider and utilising the heat from the reactor to generate electricity and process heat. The advantages of using the heat from a nuclear reactor in cogeneration processes are that no CO₂ is emitted and higher steam temperatures can be achieved, thus higher efficiencies.

The question now arises; would the predicted advantages of using nuclear heat as the main heat source for the cogeneration process be substantial enough to justify its use?

The main focus of this research will be to determine if it is technically feasible and economically viable to use nuclear heat, obtained from a HTR as the main heat source, for the generation of electricity and process steam.

The aim of this project is also to recommend a means to reduce the CO₂ emissions and the use of energy at a coal-to-liquids plant more efficiently.

1.4. Research methodology

It is of utmost importance to firstly understand the problem and the motivation behind the problem. An in-depth literature study was performed on the process that is currently used by a CTL facility to produce electricity and process heat. Two nuclear processes that can possibly replace the current process in order to reduce CO₂ emissions were also identified and studied. These include the study of the related process units and the configuration thereof, the raw materials consumption, the process conditions under which these processes are operated, and the delivered steam conditions. All the mass- and energy balances were performed in Excel.

By applying the above mentioned information, it was possible to determine the production cost of electricity, steam and the disposal cost \$/ton of CO₂ for these different process routes. A final conclusion could be made whether the nuclear heat generated by a HTGR (PBMR) is a viable alternative heat source for the production of electricity and steam for a coal-to-liquids plant and what contribution it will make to the environment. A conclusion can also be made on which nuclear process suits the process better.

1.5. Objective of the research project

The objectives of this research project are as follows:

- Investigate the coal-based cogeneration process and conventional power plant.

- Examine whether the nuclear heat generated by a HTGR (PBMR) can be used as a heat source for the cogeneration process.
- Determine the amount of carbon dioxide produced for coal-based and the two nuclear-based process routes.
- Determine the production cost for the various process routes as well as the reduction in CO₂ emissions.
- Compare the above findings and establish whether the nuclear routes are technically and economically viable.
- Determine which nuclear process will be the better option.

1.6. Outline of the dissertation

In chapter 2 a thorough literature study on the current processes used to generate electricity and process steam is presented. The possibility of applying nuclear heat generated by a High Temperature Gas Reactor (HTGR) as the primary energy source for cogeneration, together with two proposed nuclear processes, are discussed in this chapter. An overview of the primary HTGR choice, i.e. the PBMR, is also given.

In Chapter 3 the technical evaluation of the coal-based process routes will be presented. In Chapter 4 the technical evaluation of the nuclear-based process routes; namely, the indirect closed-cycle gas turbine cogeneration system, as well as the indirect extraction/condensing steam turbine cogeneration system, will be presented. The following topics will be examined in depth in Chapters 3 and 4:

- Mass balance
- Energy balance
- Consumptions / discharge figures

The process design criteria, process description and process flow diagram (PFD) of the various process routes will be given in the respective sections.

In Chapter 5 the production costs of these various processes are presented, evaluated and compared. Chapter 6 addresses the conclusions that can be drawn from this research, as well as recommendations for further research studies.

CHAPTER 2. LITERATURE STUDY

2.1. Introduction

An in-depth study of cogeneration, together with the classification of these cogeneration systems and the different heat engines that can be applied to generate electricity and process heat (steam), are discussed in this chapter. This chapter is concluded with an overview of the application of nuclear heat generated by a High Temperature Gas Reactor (HTGR) as the primary heat source for cogeneration and the proposed nuclear cogeneration processes.

2.2. Cogeneration

Cogeneration or Combined Heat and Power (CHP) is the simultaneous generation of two different forms of useful energy from a single primary energy source at a facility located near the consumer; typically mechanical (electricity) and thermal (steam) energy. The thermal energy generated by cogeneration can be applied in a number of process applications as process heat (steam). These efficient systems recover the energy that would normally be lost to the environment and save the fuel that would otherwise be used to produce heat or steam in a separate unit (United States Clean Heat & Power Association, 2011).

Figures 2-1 and 2-2. show the energy usage of a conventional power plant and cogeneration system. A cogeneration plant uses 10 to 30% less fuel for the same amount of electricity and steam generated than a conventional power plant and on-site boiler (Naturalgas.org, 2011).

The conventional method of power generation is thermally inefficient in the sense that only about a third of the primary energy fed to the plant is converted into electricity with the excess energy being lost. Conventional power plants can reach thermal efficiencies up to 45% in the generation process, but with the addition of a waste heat recovery unit (Bureau of Energy Efficiency, n.d.), energy efficiencies of up to 80% or more can be achieved (Naturalgas.org, 2011).

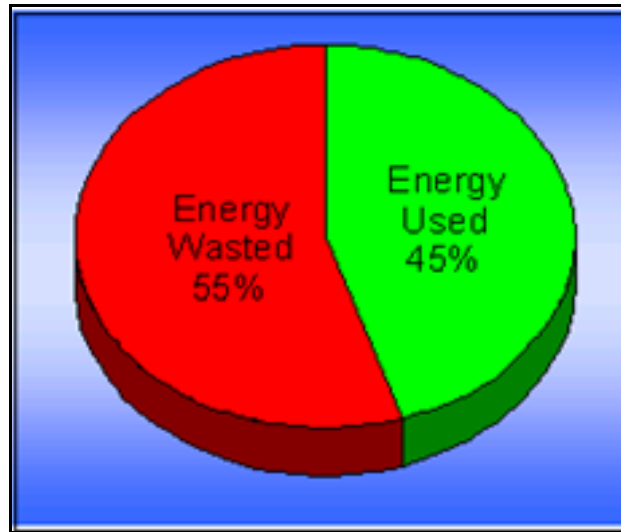


Figure 2-1 Energy use of conventional power plant (Naturalgas.org, 2011)

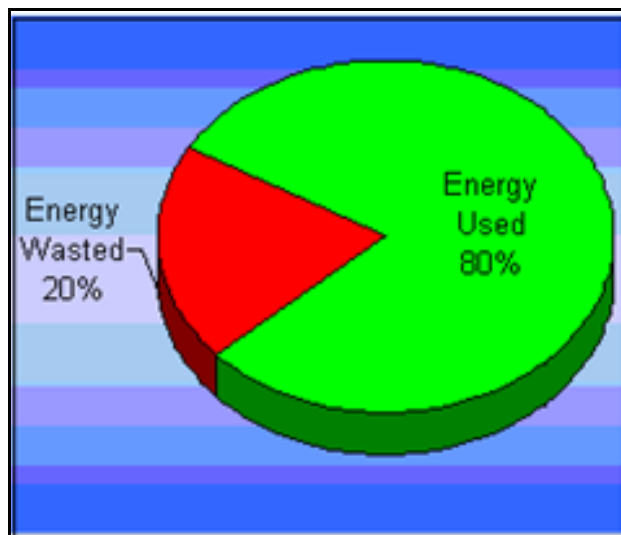


Figure 2-2 Energy usage of cogeneration plant (Naturalgas.org, 2011)

Cogeneration systems have applications in centralised power plants, large industrial settings, large and medium sized commercial settings, and even smaller residential or commercial sites (Naturalgas.org, 2011). The benefits of cogeneration include improved environmental quality, reduced energy consumption, and improved grid reliability (United States & Power Association, 2011). The classification of cogeneration systems together with the generating technologies will be discussed next.

2.2.1 Classification of cogeneration systems

The sequence of energy use in a cogeneration system normally classifies a cogeneration system as either a topping cycle or bottoming cycle and is discussed below (Bureau of Energy Efficiency, n.d.).

2.2.1.1 Topping cycle

In a topping cycle the primary energy source is utilised to first generate electricity, with the waste heat recovered in the form of useful thermal energy (steam) and supplied to the process. A topping cycle is widely used and is the most popular method of cogeneration. The topping cycle cogeneration system was chosen for this study. There are four types of cogeneration topping cycles as discussed below.

Combined cycle topping system

Figure 2-3 gives an example of a combined cycle topping system. In these systems the primary energy source is used to generate electricity, the waste heat goes to a heat recovery system (boiler) to generate steam to drive a secondary steam turbine (Bureau of Energy Efficiency, n.d.).

Steam can be extracted from the steam turbine as useful thermal heat and sent to the process as process heat. This cycle can be used with either an open or closed gas turbine cycle.

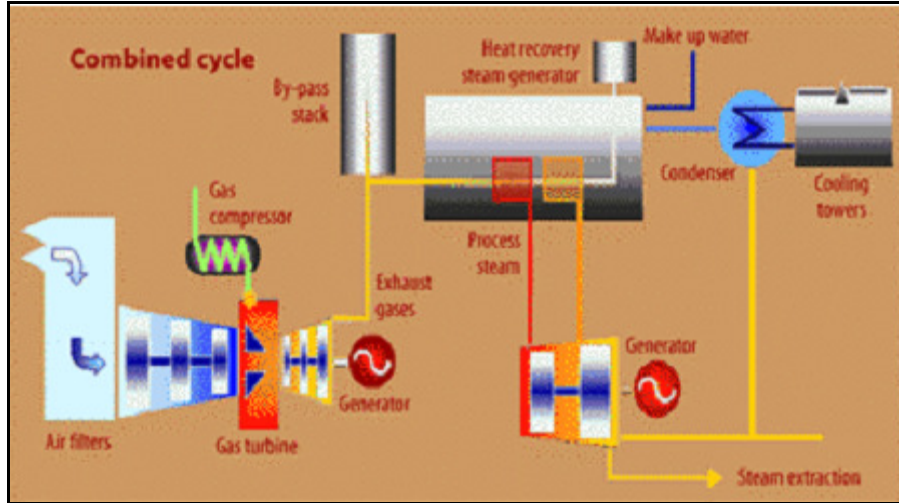


Figure 2-3 Combined cycle topping system (Bureau of Energy Efficiency, n.d.)

Steam turbine topping system

The steam turbine topping system is the most widely used cogeneration process. In this system the primary energy source is utilised to first produce high pressure steam which is expanded to a lower pressure over a steam turbine to produce electricity. The exhaust is recovered as low pressure process steam. The steam turbine topping system is shown in Figure 2-4 (Bureau of Energy Efficiency, n.d.)

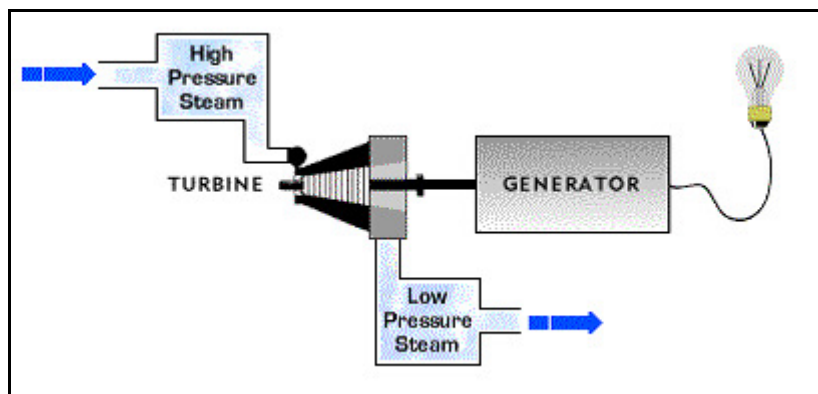


Figure 2-4 Steam turbine topping system (Bureau of Energy Efficiency, n.d.)

Heat recovery topping system

This system employs heat recovery from an engine exhaust and/or jacket cooling system flowing to a heat recovery boiler, where it is converted to process steam/hot water for further use (Bureau of Energy Efficiency, n.d.). The Bureau of Energy Efficiency (n.d.) gives the basics of a heat recovery topping system.

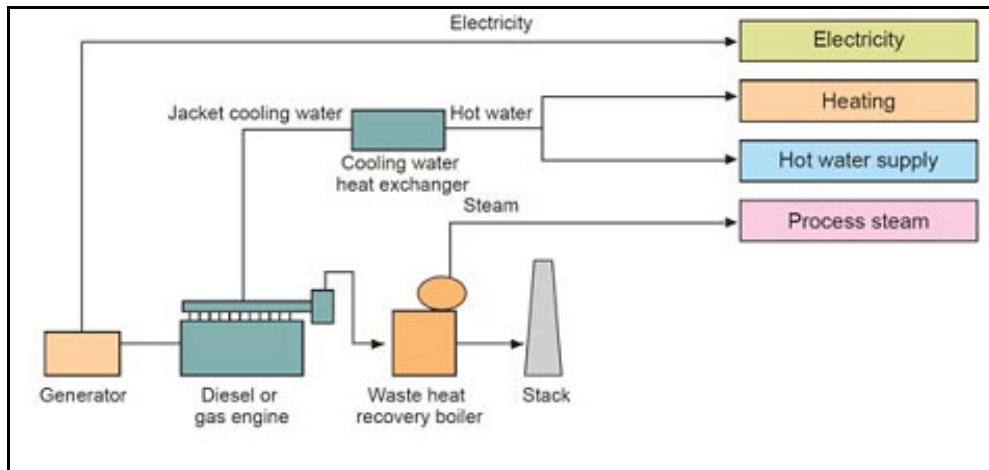


Figure 2-5 Heat recovery topping system (Bureau of Energy Efficiency, n.d.)

Gas turbine topping system

In this system a gas turbine drives an electrical generator to produce electricity, as can be seen in Figure 2-6. The exhaust gas goes through a heat recovery system where the waste heat is recovered in the form of useful thermal energy and applied as process steam.

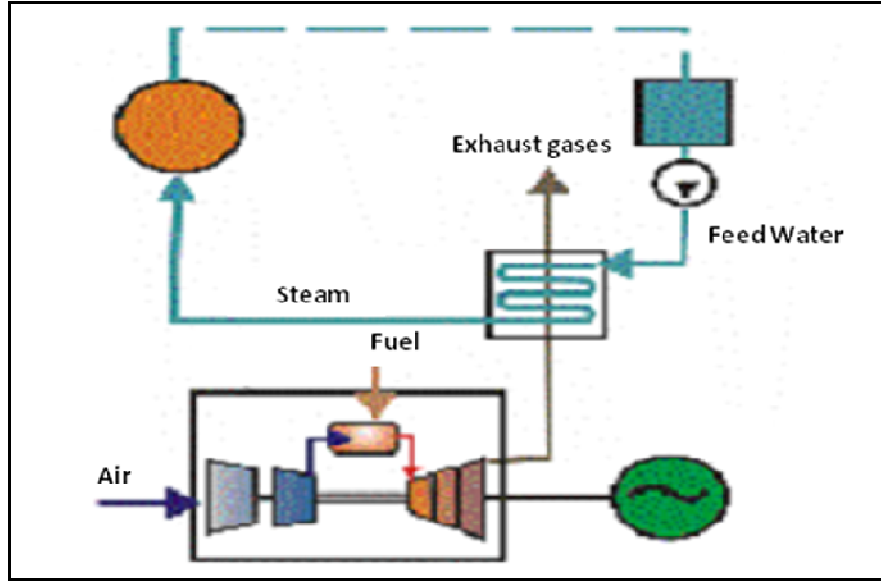


Figure 2-6 Gas turbine topping system (Bureau of Energy Efficiency, n.d.)

2.2.1.2 Bottoming cycle

Bottoming cycles are much less common than topping cycles and are suitable for processes that require high temperature process heat and reject heat at significantly high temperatures. In a bottoming cycle the primary energy source is first utilised to generate high temperature thermal heat for the process. The rejected heat of the process is then used to generate electricity through a heat recovery boiler and turbine generator. Typical areas where the bottoming cycle could be applied include cement, steel, ceramic, gas and petrochemical industries (Bureau of Energy Efficiency, n.d.).

2.2.2 Technical options for cogeneration

The power generating technologies (prime movers) for cogeneration include reciprocating engines, micro turbines, industrial turbines and fuel cells. A range of fuels can be used in conjunction with the cogeneration technologies including natural gas, coal, oil, nuclear fission etc. For the purpose of this study coal and nuclear fission will be used as the primary energy sources. Two types of industrial turbines namely steam turbines and gas turbine will be discussed in this section.

2.2.2.1 Steam turbines

Steam turbines are one of the most versatile and oldest power generating technologies and are commonly employed for cogeneration applications. Steam turbines differ from other prime movers in that they require a separate boiler or Heat Recovery Steam Generator (HRSG) to create its working fluid. They do not convert fuel directly into electrical power, but generate electricity as a by-product of heat (steam).

Due to this separation of functions it has the advantage, above other prime movers, to operate with a wide variety of fuels as primary energy source, such as coal, nuclear fission, natural gas, fuel oil etc. The capacity of steam turbines can range from 50kW to several hundred MW's for large utility power plants (Energy Nexus Group, 2002). Steam turbines can be modified to fit any cogeneration system, thus the steam turbine can be fitted to match the pressure and temperature requirements of a process.

The thermodynamic cycle for the steam turbine is the Rankine cycle, which is the basis for conventional power generating processes and consists of a heat source that converts water to high pressure steam (Energy Efficiency Guide for Industry in Asia, 2006). The Energy Nexus Group (2002) gives the primary components of a boiler/steam turbine system.

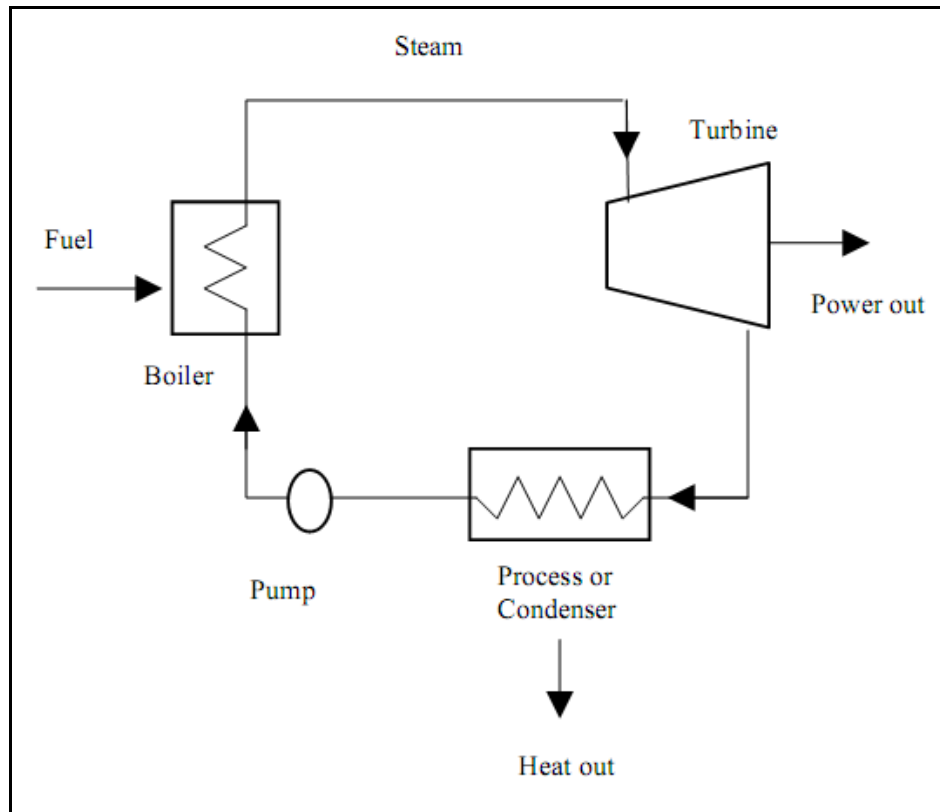
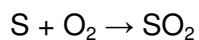
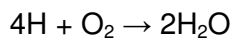
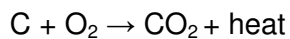


Figure 2-7 Boiler/steam turbine system (Energy Nexus Group, 2002)

In this cycle water is first pumped from medium to high pressure, after which it enters the boiler (a nuclear reactor can also be used as heat source). A variety of fuels can be used to supply the heat required in the boiler; in this case coal will be used as the primary energy source. The combustion of coal in the boiler is described by the following reactions (Biarnes *et al.*, 2009):



The combustion of coal generates CO_2 , water and heat. This heat is used to convert the high pressure water entering the boiler into high pressure superheated steam (first heated to saturation temperature, vaporised at constant temperature and pressure, and then superheated

to a temperature well above its saturation temperature). After leaving the boiler the high pressure steam expands in a steam turbine to a lower pressure and temperature.

The passing of the steam through the turbine blades causes the blades and the shaft of the turbine to spin, converting the thermal energy into kinetic energy or movement. The shaft of the turbine is connected to an electrical generator, where the kinetic energy is converted into electrical energy. Depending on the type of steam turbine used, the steam is either exhausted into a condenser at vacuum conditions or into an intermediate temperature steam distribution system that delivers the steam to the industrial or commercial application. The condensate from the condenser or the steam utilisation system returns to the feed water pump and then back to the boiler for continuation of the cycle (Energy Nexus Group, 2002).

Steam systems are classified according to the pressure of steam required, from low-pressure steam used primarily for space heating and food preparation, to medium-pressure used in industrial processes, and cogeneration to high-pressure used in utility power generation (Energy Nexus Group, 2002).

There are three types of steam turbines: condensing, back-pressure, and extraction/condensing steam turbines. The condensing steam turbine is solely used for the generation of electricity and results in a maximum electrical generation efficiency from the steam supply and boiler feed. In a conventional power plant (electricity only) the steam leaves the turbine as a saturated vapour at vacuum and is directly exhausted into a condenser where it is condensed into a liquid through the use of cooling towers etc. Back-pressure and extraction/condensing steam turbines are widely used for the purpose of cogeneration. The choice between these two types depends on the quantity and quality of heat and power required and economic factors (Energy Nexus Group, 2002).

Back-pressure (non-condensing) steam turbines

Back-pressure steam turbine cogeneration systems have the highest efficiency of all the cogeneration steam turbine processes. It can reach efficiencies of up to 90% if all the exhaust

steam is used to meet the industrial process steam demands (Bureau of Energy Efficiency, n.d.).

In a back-pressure steam turbine the steam is expanded over a turbine until it reaches a pressure required by the facility. The steam exits the turbine at a pressure higher or equal to atmospheric pressure. The exit pressure is established by the specific cogeneration application, with district heating requiring lower pressures and industrial processes higher pressures. Back-pressure steam turbines have a very simple configuration as can be seen in Figure 2-8.

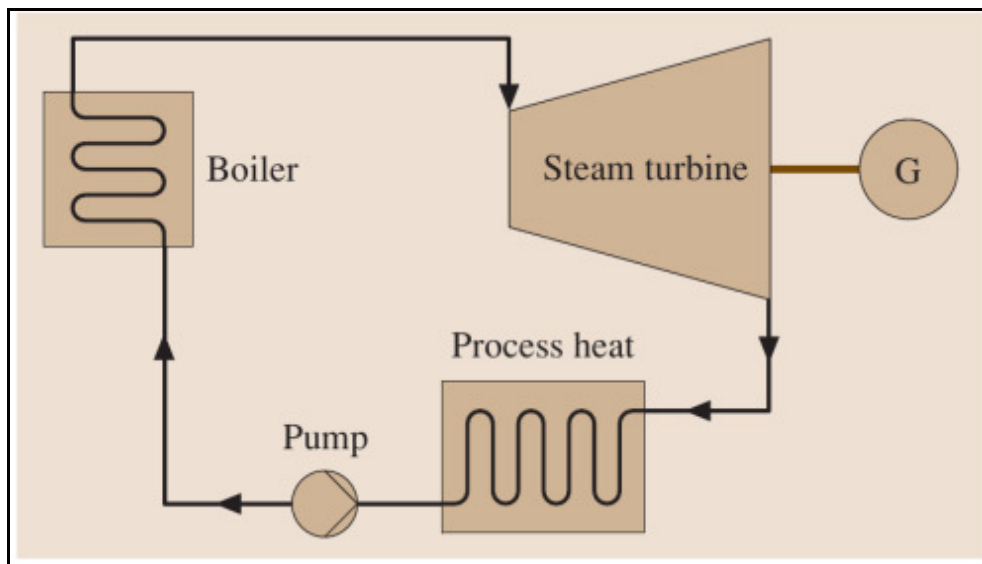


Figure 2-8 Configuration of back-pressure steam turbines (Grote & Antonsson, 2009)

After the steam exits the turbine it is sent to the industrial process where it releases its heat, is condensed, and sent back to the cogeneration process. The power generation capability of the steam turbine is dependent on the thermal requirements, and reduces significantly when steam is used at appreciable pressure rather than being expanded to vacuum in a condenser. The higher the pressure of the required steam, the lower the power generating capability (Energy Nexus Group, 2002).

Back-pressure steam turbines can have more than one configuration, including extraction back-pressure and double extraction back-pressure etc. depending on the process steam

requirements (temperature and pressure levels) of the industrial process. Figure 2-9 gives different configurations for back-pressure steam turbines (Bureau of Energy Efficiency, n.d.).

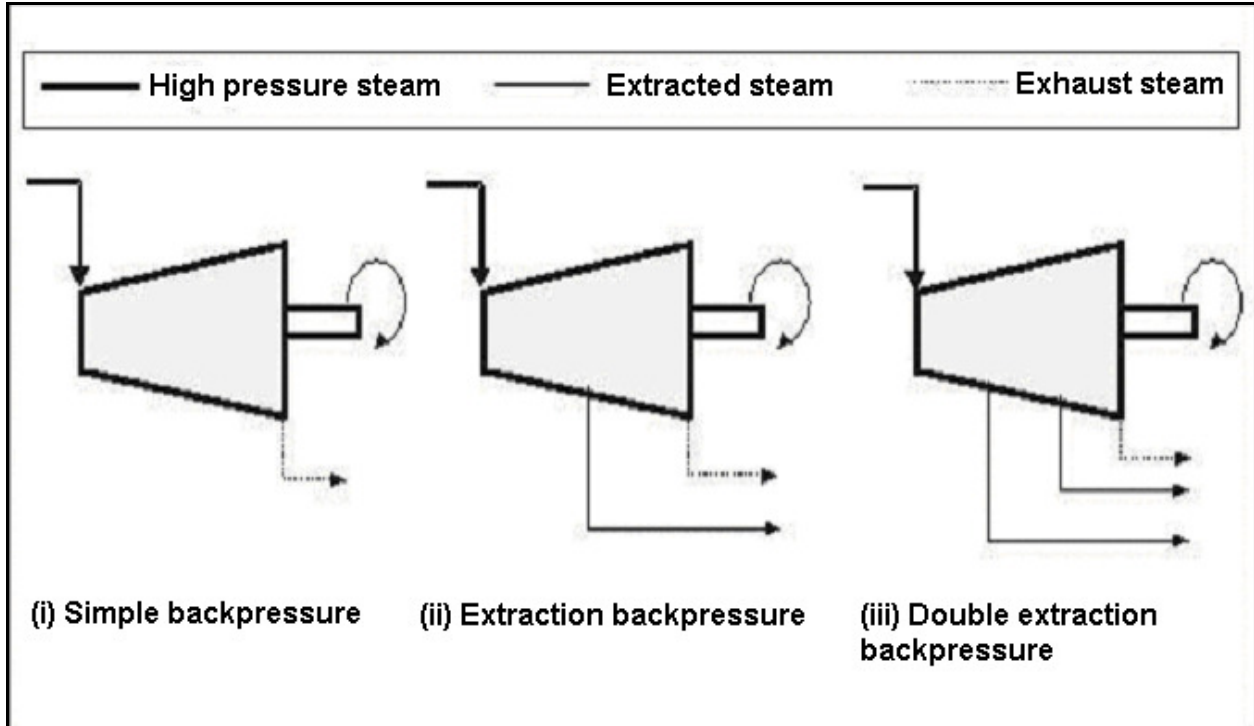


Figure 2-9 Different configurations of back-pressure steam turbine (Bureau of Energy Efficiency, n.d.)

In the extraction and double extraction back-pressure turbines, steam is extracted from the turbine after being expanded to a certain pressure level. The extracted steam meets the heat demands at pressure levels higher than the exhaust pressure of the steam turbine (Bureau of Energy Efficiency, n.d.). The advantages and disadvantage of using a back-pressure steam turbine for cogeneration applications are tabulated in Table 2-1.

Table 2-1 Advantages and disadvantages of back-pressure steam turbines (Energy Efficiency Guide for Industry in Asia, 2006)

Advantages	Disadvantages
Simple configuration	Larger steam turbine for the same power output because it operates under lower enthalpy differences of steam.
Low capital cost	The generated electricity is controlled by the thermal load.
Reduced or no cooling water required, thus no cooling towers etc.	No or little flexibility to match electrical output to electrical load.
High total efficiency as there is no heat rejection to the environment through a condenser.	

Extraction/condensing steam turbine

The extraction/condensing steam turbines are used when the process requires a constant pressure steam flow. This type of turbine has the flexibility to satisfy wide variations of process steam demand at a constant pressure while maintaining the power generated at a more or less steady state value to meet electricity demand (NS Turbo (P). Ltd, n.d.).

In extraction/condensing steam turbines, the steam for thermal load is extracted from the turbine from one or more intermediate stages at the appropriate pressure and temperature. Only a fraction of the steam is extracted for process use, while the rest of the steam continues to expand to the pressure of the condenser where it is condensed to water. The work in an extraction/condensing steam turbine continues until the steam reaches the pressure of the condenser. Figure 2-10 depicts the layout of an extraction/condensing steam turbine cogeneration system.

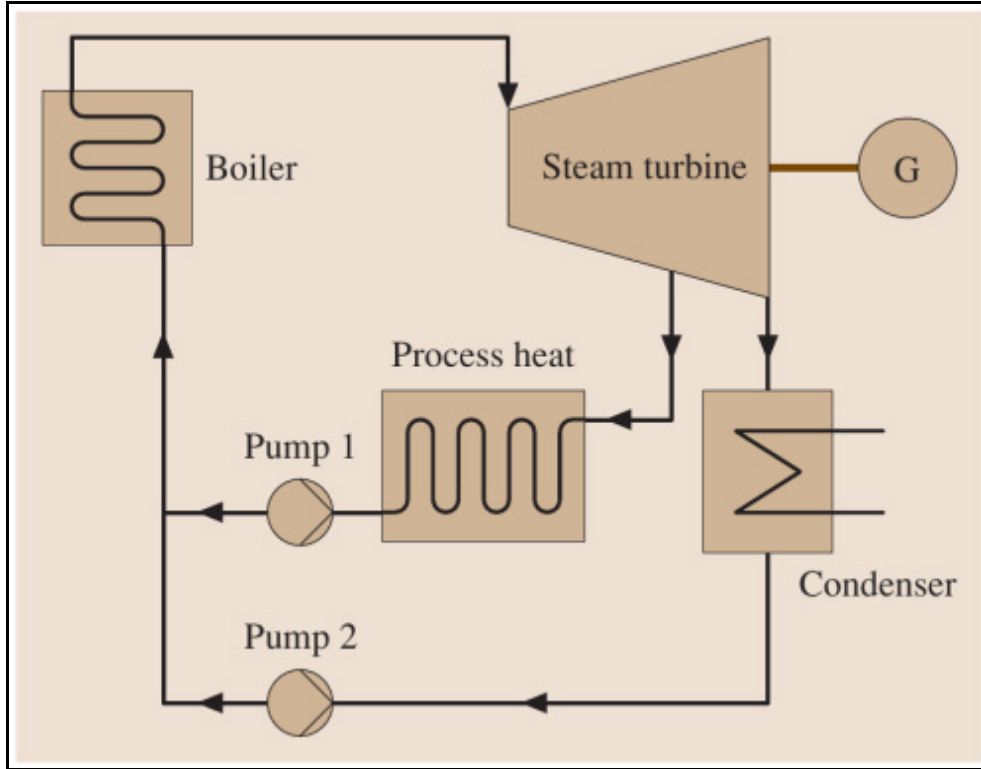


Figure 2-10 Extraction/condensing steam turbine cogeneration system (Grote & Antonsson, 2009)

Extraction/condensing steam turbines need more auxiliary equipment, such as the condenser and cooling towers, than back-pressure steam turbines, which contributes to increased capital costs. Although the overall efficiency of extraction/condensing steam turbine is lower compared with back-pressure steam turbines, it has a higher power to heat ratio and higher electricity generation efficiency. Better matching of electrical power and heat demand can be obtained by the extraction/condensing steam turbine where electricity demand is much higher than the steam demand and the load patterns are highly fluctuating (Bureau of Energy Efficiency, n.d.).

There are a number of modifications that can be applied to the system in order to increase the efficiency and/or output of the steam turbine cogeneration system, including: feed water heating and steam reheating. By heating the feed water before it enters the boiler or heat recovery steam generator, the heat that must be added to the system reduces, and thus the thermal efficiency increases.

By reheating the steam between the expansion stages, it increases the efficiency of the process and ensures that there is no drop formation in the turbine which can damage the turbine blades. Higher steam temperatures and pressures significantly improve thermal efficiency.

For the purpose of this study the extraction/condensing steam turbine was combined with a boiler with coal as the primary energy source. A nuclear reactor with nuclear fission as the energy source was also studied. A gas turbine was also coupled to a nuclear reactor for this study, and will be discussed next.

2.2.2.2 Gas turbines

Gas turbine cogeneration systems have the ability to produce all or part of the energy requirements of a process and meet the steam demand by recovering and applying the waste heat as useful thermal energy (steam). Gas turbines have a capacity ranging from 1MW to about 100MW, and operate on the thermodynamic cycle known as the Brayton cycle.

There are two types of gas turbine cogeneration systems; the open cycle and the closed cycle and these are discussed below. In the Brayton cycle the working fluid (usually helium or air) is compressed, heated and expanded over a gas turbine to produce electricity. The energy released at high temperature in the turbine exhaust, called waste heat, can be recovered by a heat recovery steam generator (HRSG) and applied for a variety of heating and cooling applications. Gas turbines have a lower heat to power conversion efficiency than steam turbines, but more heat can be recovered at high temperatures (Energy Efficiency Guide for Industry in Asia, n.d.).

In recent years gas turbines have experienced rapid developments due to the greater availability of natural gas, rapid progress in the technology, significant reduction in installation costs, and better environmental performance. They also have the following advantages (Energy Efficiency Guide for Industry in Asia, n.d.):

- Capable of producing large amounts of useful power for a relatively small size and weight.
- Mechanical life is long and corresponding maintenance cost is relatively low.
- Requires no coolant.
- Can be delivered in a modular manner.
- Shorter start-up time.
- Flexibility of intermittent operation.

If more electricity is required on-site, it is possible to combine the gas turbine with the steam turbine cogeneration system to adapt a combined cycle. This is where the exhaust from the gas turbine is applied to produce steam in a HRSG, as discussed in 2.2.1.1. The steam is then expanded over a back-pressure or extraction/condensing steam turbine to generate additional electricity, with the exhaust or extracted steam from the steam turbines meeting the process steam demands (Bureau of Energy Efficiency, n.d.). By combining the gas and steam turbine in a combined cycle, the efficiency of the process can be increased significantly. More ways to increase the efficiency and/or the output of gas turbine cycle additional equipment can be added; three such modifications include regeneration, inter-cooling and reheating.

Figure 2-11 shows the layout of a regenerative gas turbine cycle. Regeneration involves the installation of a heat exchanger through which the air entering the combustor is first heated by the exhaust gasses of the gas turbine. The increase in the air temperature means less heat needs to be added to the combustion process, thus increasing efficiency. Regeneration can increase the cycle efficiency by 5-6% (Langston & Opdyke, 1997).

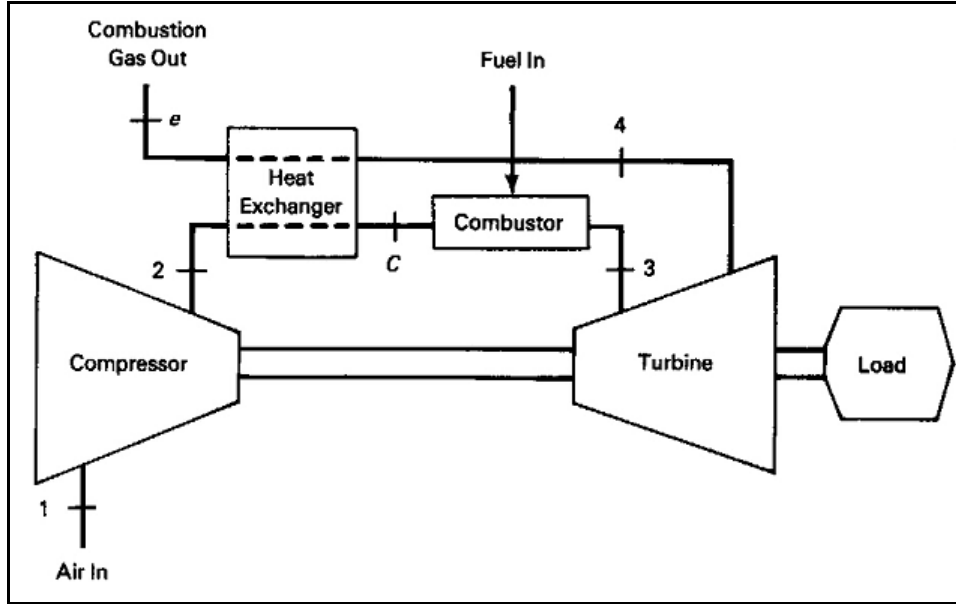


Figure 2-11 Regenerative gas turbine cycle (Weston, 1992)

In Figure 2-12 the layout of a gas turbine cycle with inter-cooling is indicated. One way to increase the output of the gas turbine is to reduce the work required by the compressor. Inter-cooling involves the use of a heat exchanger (inter-cooler) to cool the compressed gas between the compression stages. This reduces the temperature and increases the density of the gas making compression of the gas easier thus reducing the amount of work required by the compressor. One disadvantage of inter-cooling is that the combustor or external heat source must now provide the heat that was taken from the inter-cooler. Therefore while the gas turbine output increases, the heat input must also increase. Inter-cooling increases the gas turbine work output at the cost of efficiency (Langston & Opdyke, 1997).

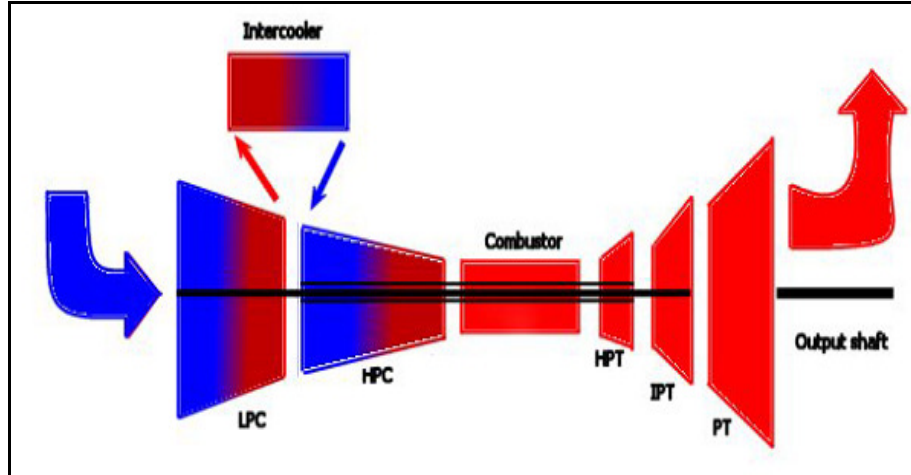


Figure 2-12 Gas turbine cycle with inter-cooling (Milancej, 2005)

Figure 2-13 shows the layout of a gas turbine cycle with reheating. Reheating works on the same principle as inter-cooling but is just applied in the turbine. It is a way to increase turbine output without changing the compressor work requirements or melting the materials from which the turbine is constructed. Reheating takes place between the expansion stages (Turbine 1 and Turbine 2) normally using another combustor or taking more heat from the external heat source. Reheating increases the efficiency by 1-3% (Langston & Opdyke, 1997).

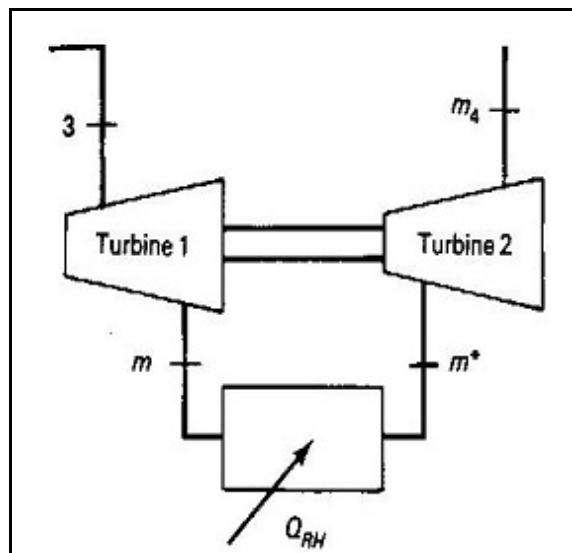


Figure 2-13 Gas turbine cycle with reheating (Weston, 1992)

The modification discussed above can also be combined to form a regenerated, inter-cooled and reheated cycle. These modifications are generally combined with either of the gas turbine cogeneration systems discussed in the next section.

Open-cycle gas turbine cogeneration system

The open-cycle gas turbine system has the advantage of simplicity and low capital cost, and is the most widely used gas turbine cycle in any sector of applications. Open-cycle gas turbine cycles are sensitive to component efficiencies and atmospheric temperature. Any reductions in turbine and compressor efficiencies can rapidly reduce the cycle efficiency. An increase in atmospheric temperature lowers the thermal efficiency (Vyga, 2010). Figure 2-14 gives the layout of an open-cycle gas turbine cogeneration system.

In order to avoid corrosion taking place under the extreme operating conditions (high speeds and high temperatures) of gas turbines, the hot gases supplied must be very clean, thus the minimal amount of contaminants must be present. High-premium fuels are therefore most often used, particularly natural gas. Other fuels such as fuel oil or diesel can also be employed (Energy Efficiency Guide for Industry in Asia, n.d.).

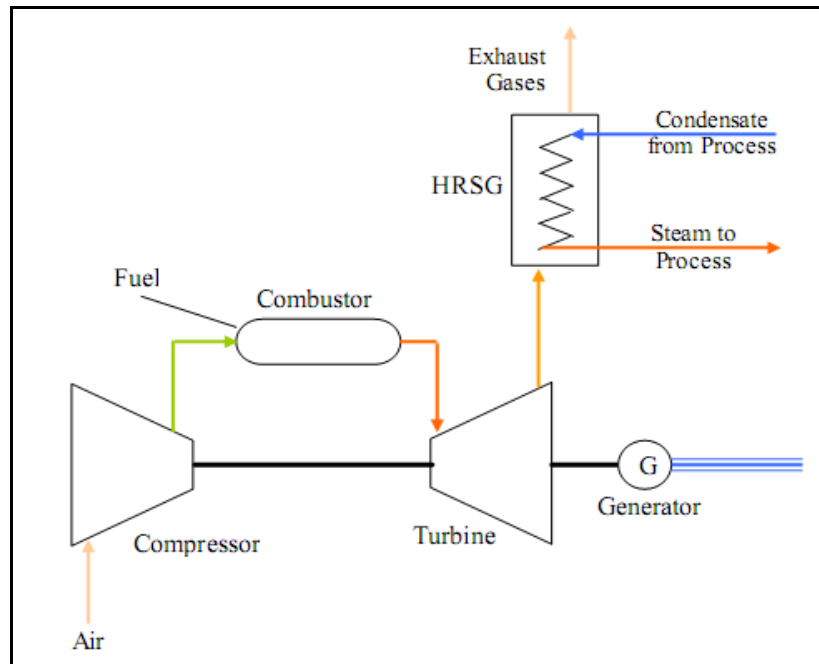


Figure 2-14 Open-cycle gas turbine cogeneration system (Energy Efficiency Guide for Industry in Asia, n.d.)

Air is taken from the atmosphere, compressed to a higher pressure and temperature and sent to a constant-pressure combustion chamber (combustor) together with fuel where it is combusted (burned). The combustion process takes place with a high excess air percentage. The air velocity is reduced to values acceptable in the combustor by sending the air through a diffuser to the combustion chamber. The combustion gas leaves the combustor at high temperature and pressure and with oxygen concentrations of up to 15-16% (Energy Efficiency Guide for Industry in Asia, n.d.).

The highest temperature in the cycle appears at the point where the combustion gas leaves the combustor. Higher gas temperatures results in higher cycle efficiency. The maximum operating temperature of the gas turbine is set by the material technology and cost and the efficiency of the cooling blades. The operating temperature achievable with the current technology is about 1300°C (Energy Efficiency Guide for Industry in Asia, n.d.). In a conventional gas turbine process the gas enters the turbine in the temperature range of 900°C to 1000°C and leaves the turbine in the range of 450°C to 550°C (Bureau of Energy Efficiency, n.d.).

The high temperature and pressure combustion gas leaving the combustor is expanded over a gas turbine to a lower pressure and temperature. The expansion of the gas over the turbine causes the blades and the shaft of the turbine to turn, producing mechanical work to drive the compressor and the electrical generator. The exhaust gas leaves the turbine at considerable temperatures making the recovery of waste heat, using a heat recovery steam generator, in the form of useful thermal energy (steam) possible. The steam produced can have high temperature and pressure and can be applied to a number of process heat applications (Energy Efficiency Guide for Industry in Asia, n.d.).

Another type of gas turbine cogeneration cycle is the closed-cycle gas turbine cogeneration system and will be discussed next.

Closed-cycle gas turbine cogeneration systems

In Figure 2-15 the layout of a closed-cycle gas turbine cogeneration system is shown. The closed-cycle gas turbine cogeneration system works on the same principles as the open-cycle gas turbine cogeneration system. Because of the confined and fixed amount of gas in a closed-cycle system, combustion cannot be sustained in the system. The combustor is replaced with an external heat source (nuclear reactor, combustion of coal etc.) and heat exchanger to heat the gas before it enters the turbine.

In a closed-cycle system the working medium is separated from the combustion process. The advantage is that the working medium does not have to support the combustion; therefore it does not have to be air. A gas with a higher density and specific heat such as helium can be used. An increase in these properties results in a reduction in the physical size of all the equipment for the same power output (Vyga, 2010).

Due to the separation, the working fluid does not contain any combustion products and therefore a number of fuels such as inexpensive coal can be used as the primary energy source. The separation also reduces the possibility of corrosion and erosion of the turbine blades (Vyga, 2010).

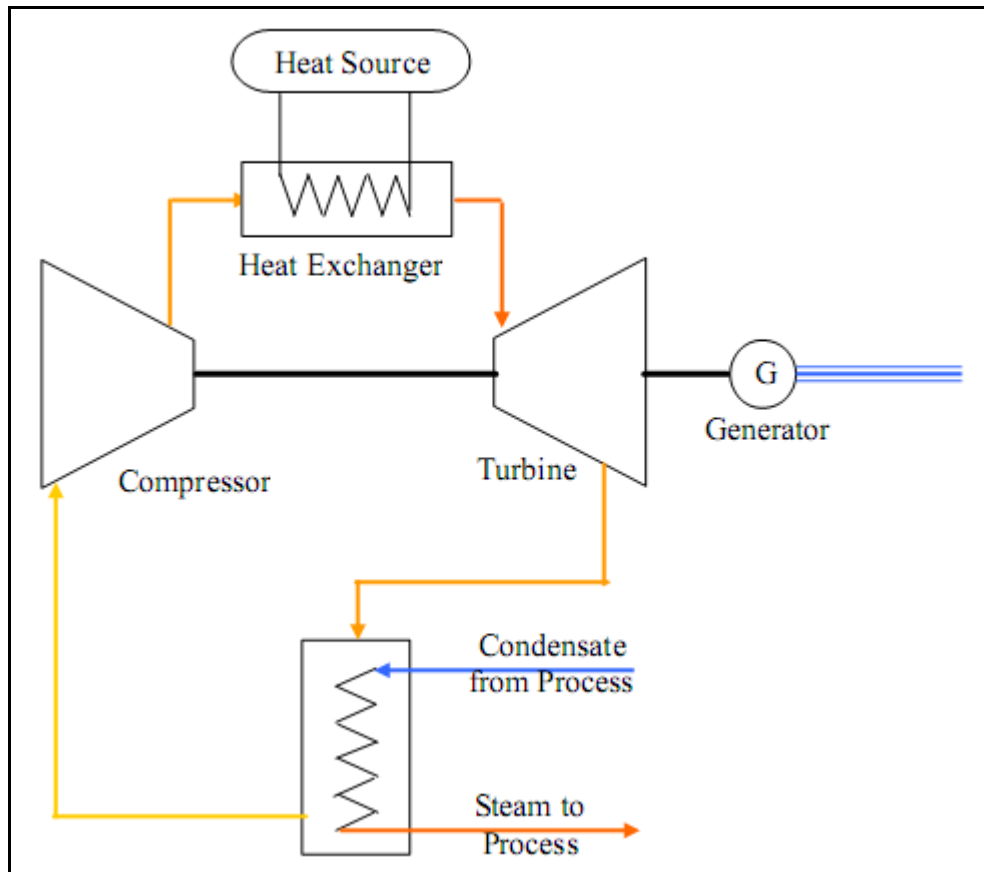


Figure 2-15 Closed-cycle gas turbine cogeneration system (Energy Efficiency Guide for Industry in Asia, n.d.)

In this cycle the working fluid circulates in a closed loop. It is first compressed, heated in an intermediate heat exchanger (IHX), and expanded over a gas turbine which is connected to an electrical generator to produce power. The exhaust gas leaves the turbine in the temperature range of 450°C - 550°C. It is sent through a HRSG where the waste heat is recovered as useful thermal energy (steam) and sent to the process.

The closed-cycle gas turbine cogeneration system together with the modifications discussed above can be combined with a nuclear reactor like the High Temperature Gas Reactor (HTGR). An overview of the HTGR will be given next, followed by the proposed nuclear cogeneration processes.

2.3. Nuclear heat applications

High temperature gas reactors (HTGR) make it possible to broaden the use of nuclear energy in the industrial and power generating sectors. These reactors are based on the concept that the new generation (generation IV) nuclear reactors must have high levels of passive safety, attractive economics, very high efficiency, minimal waste, and be proliferation resistant. It has the ability to be economical, environmentally safe, and reliably generate electricity and industrial process-heat without any greenhouse gas emissions (Sovereign Publications, 2008).

The Pebble Bed Modular Reactor (PBMR) technology is able to meet these requirements. This is a high-temperature helium gas-cooled, graphite moderated pebble bed reactor, with outlet temperatures of about 950°C which can be applied to various industrial processes (PBMR (Pty) Ltd., 2008). One example would be for the generation of electricity and process heat.

At present there are two proposed HTGR (PBMR) process heat configurations: the first generates intermediate temperature helium for the production of electricity and steam, and the second delivers high temperature helium for the production of hydrogen (PBMR (Pty) Ltd., 2008). The PBMR has a multi-pass fuelling scheme and graphite-lined annular core geometry (PBMR (Pty) Ltd., 2008). Helium gas is used as the primary working fluid in the PBMR due to its chemical and radiological inertness, and can experience very high operating temperatures without undergoing oxidation. Helium has a large heat capacity that allows more work to be done per mass of helium, and a large thermal conductivity that allows smaller heat transfer equipment (Kadak *et al.*, 1998).

The inherent safety of the PBMR is derived from the fuel sphere called TRISO fuel particles, as shown in Figure 2-16. These fuel particles are characterised by their inherently safe properties and are virtually indestructible. The fuel particles can withstand temperatures in the order of 2000°C, which is well above the operating temperatures of the reactor. The design of these particles combines the excellent fission product retention capabilities of the SiC coated fuel kernels with the large heat capacity of the graphite matrix material (Strydom, 2007).

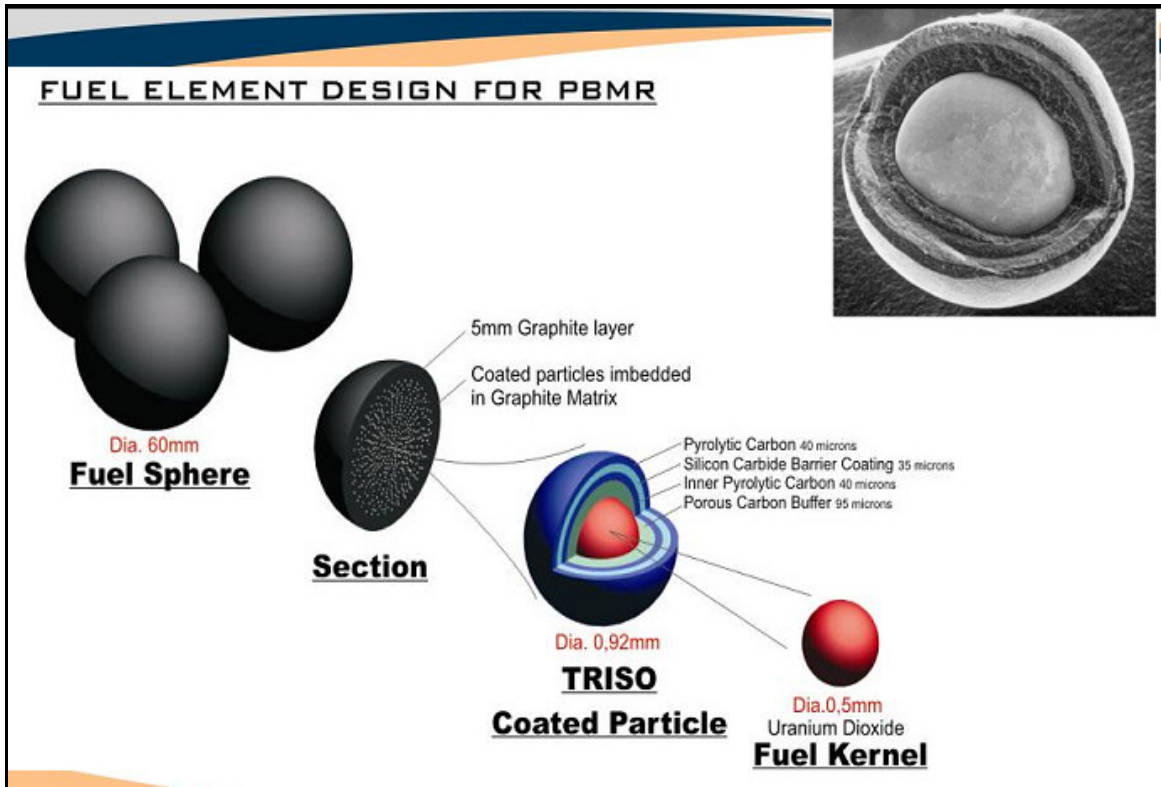


Figure 2-16 Fuel element design for the PBMR (Chetty, 2008)

The PBMR has passive safety systems which cannot be bypassed or rendered ineffective in anyway. In case a fault occurs during reactor operation, no safety control systems or operator intervention is required. The system will shut down by itself, thus no core failure or release of radioactivity to the environment is possible (PBMR (Pty) Ltd., 2008).

The PBMR makes use of passive heat removal systems, thus the reactor will be cooled naturally in the event of a total loss of cooling accident. The heat flow from the centre of the reactor to the outer boundaries will be ensured primarily through conduction, radiation and natural convection, as can be seen in Figure 2-17.

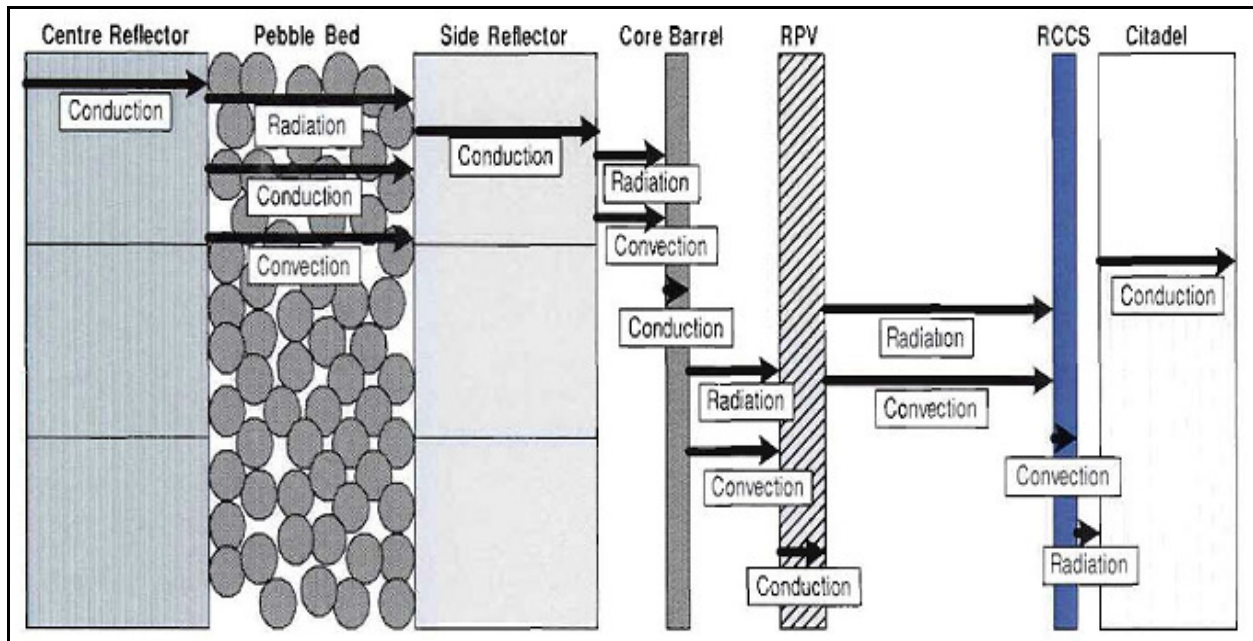


Figure 2-17 Passive Heat Removal System (Strydom, 2007)

HTGR's such as the PBMR have a number of other key features (PBMR (Pty) Ltd., 2008):

- Competitive economics
- Load-following characteristics
- Requires a small tract of land
- Can withstand significant external forces
- Requires relatively little water
- Can be placed near point of demand
- Highly proliferation resistant
- Can be refuelled online:
- Reduces greenhouse gasses:

- Has a modular design

The main driving factor for the development of applications for nuclear process heat is the opportunity to decrease the use of fossil fuels and to take action in reducing CO₂ emissions. An economic evaluation of HTGR such as the PBMR indicates that it will be competitive in several markets, especially those with high fuel costs and CO₂ emission constraints (PBMR (Pty) Ltd., 2008).

2.4. Chosen nuclear processes

By referring to the processes described above as baseline, two preferred processes have been chosen; one where an indirect closed-cycle gas turbine cogeneration system is used and the other where an indirect extraction/condensing steam turbine cogeneration system is used. These two concepts will be discussed separately, with the indirect closed-cycle gas turbine cogeneration system discussed first, followed by the indirect extraction/condensing steam turbine cogeneration system.

2.4.1 Cycle naming convention

These cycles consist of a HTGR such as a PBMR delivering heat to either a Rankine steam cycle coupled indirectly via an intermediate heat exchanger (IHX) and then a steam generator (SG) or a Brayton gas cycle coupled indirectly via an IHX. Heat is transported from either the Rankine steam cycle or the Brayton gas cycle to the CTL through a HRSG.

The circuit coupled to the reactor will be called the Primary Heat Transport System (PHTS). The intermediate helium loop in steam cycle process will be called the Secondary Heat Transport System (SHTS). The Rankine steam cycle or the Brayton gas cycle is termed the Power Conversion System (PCS). The heat exchanger connecting the PHTS and SHTS (steam cycle) or the PHTS and PCS (gas cycle) is called the Intermediate Heat Exchanger (IHX). The heat exchanger transporting heat from the helium circuit to the steam plant is called the Steam Generator (SG). The heat exchanger transporting heat to the CTL plant is called a Heat Recovery Steam Generator (HRSG).

2.4.2 Indirect extraction/condensing steam turbine cogeneration system

Figure 2-18 shows the layout and major components of the indirect extraction/condensing steam turbine cogeneration system. The fission heat generated in the PHTS is removed by using helium gas as working fluid. The primary helium coolant enters the top of the reactor at about 300°C and 5MPa, and leaves the bottom of the reactor at about 700°C and 5MPa. The high operating conditions of the HTGR results in a relatively high thermal efficiency of up to 41% and above (Ugeler & Mulder, n.d.).

The hot, high-pressure helium gas leaving the bottom of the reactor, transfers the heat to the SHTS helium through an IHX. The hot helium leaving the bottom of the IHX at about 650°C and 5MPa on the SHTS side transfers the heat to the PCS through a SG.

The PCS uses the extraction/condensing steam turbine cogeneration system to generate electricity and process steam. The pressure of the PCS is 7MPa and the temperature of the steam leaving the SG is about 550°C (Ugeler & Mulder, n.d.). The hot, high pressure steam is sent through a series of steam turbines that are connected to an electric generator to produce electricity.

In the cogeneration version steam is extracted simultaneously from the process for the application of process heat (through a HRSG), as can be seen below. In the last step of the cycle the steam is condensed to water by using a condenser. The water is pressurized and pumped back to the SG by using a series of pumps for the continuation of the cycle.

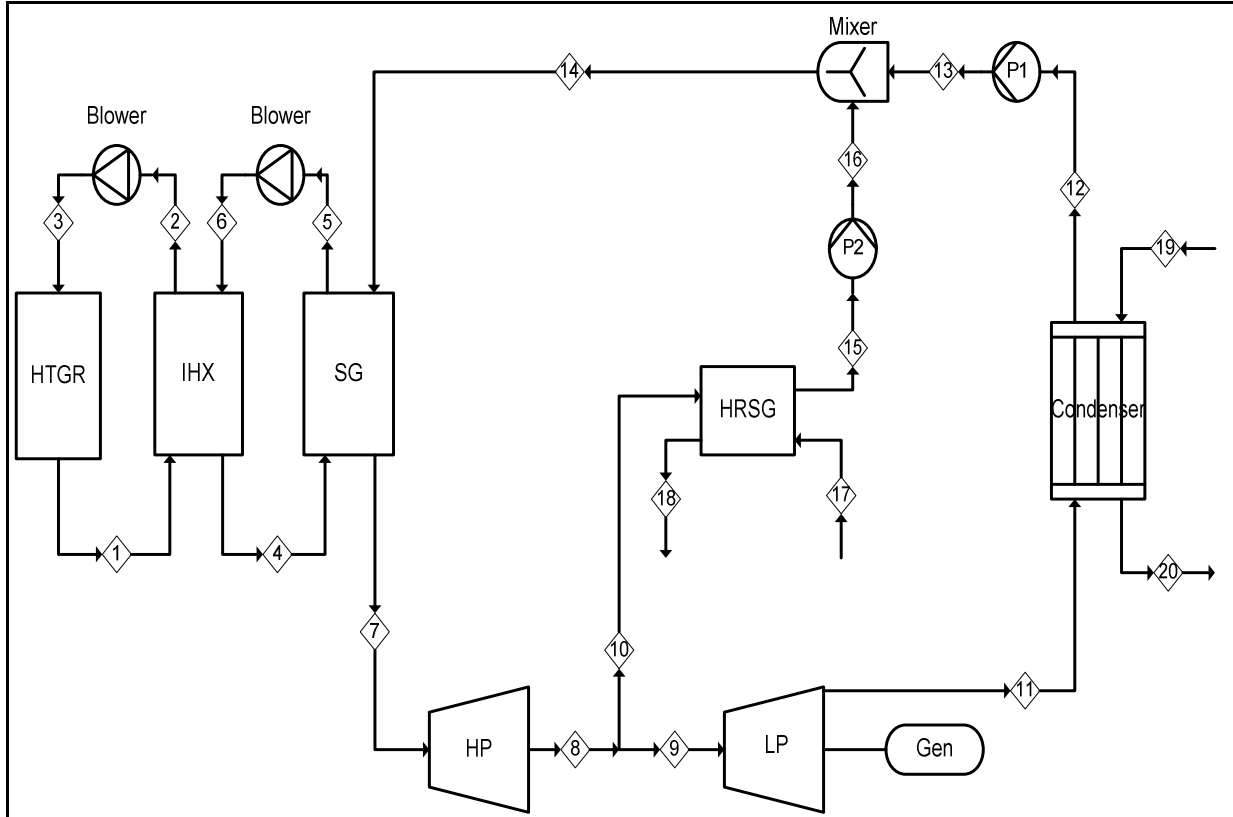


Figure 2-18 Indirect extraction/condensing steam turbine cogeneration process

2.4.3 Indirect closed-cycle gas turbine cogeneration system

In Figure 2-19 a schematic representation of the layout and major components of the indirect closed-cycle gas turbine cogeneration system is shown. To remove the fission heat generated in the reactor, the PHTS coolant helium enters the reactor from the top at about 340°C and 5MPa. The hot, high-pressure helium gas, leaving the bottom of the HTGR reactor at about 880°C and 5MPa, transfers the heat to the PCS helium through an IHX. The high operating conditions of the HTGR results in a relatively high thermal efficiency of up to 41% and above (Ugeler & Mulder, n.d.). The PCS uses a closed-cycle gas turbine topping cogeneration system for the generation of electricity and process steam. The gas turbine cogeneration system is a simplified variant of the gas turbine electricity (only) generation system.

The hot helium (about 830°C and 5MPa) leaving the IHX passes through a gas turbine which is mechanically connected to the generator through a speed-reduction gearbox on one-side and the gas compressor on the other side. The helium leaving the turbine is still at high temperature (470°C and 1.5MPa) (Ferreira, 2007). During the next step of the cycle the hot helium is used to generate process heat by converting water into steam through a HRSG.

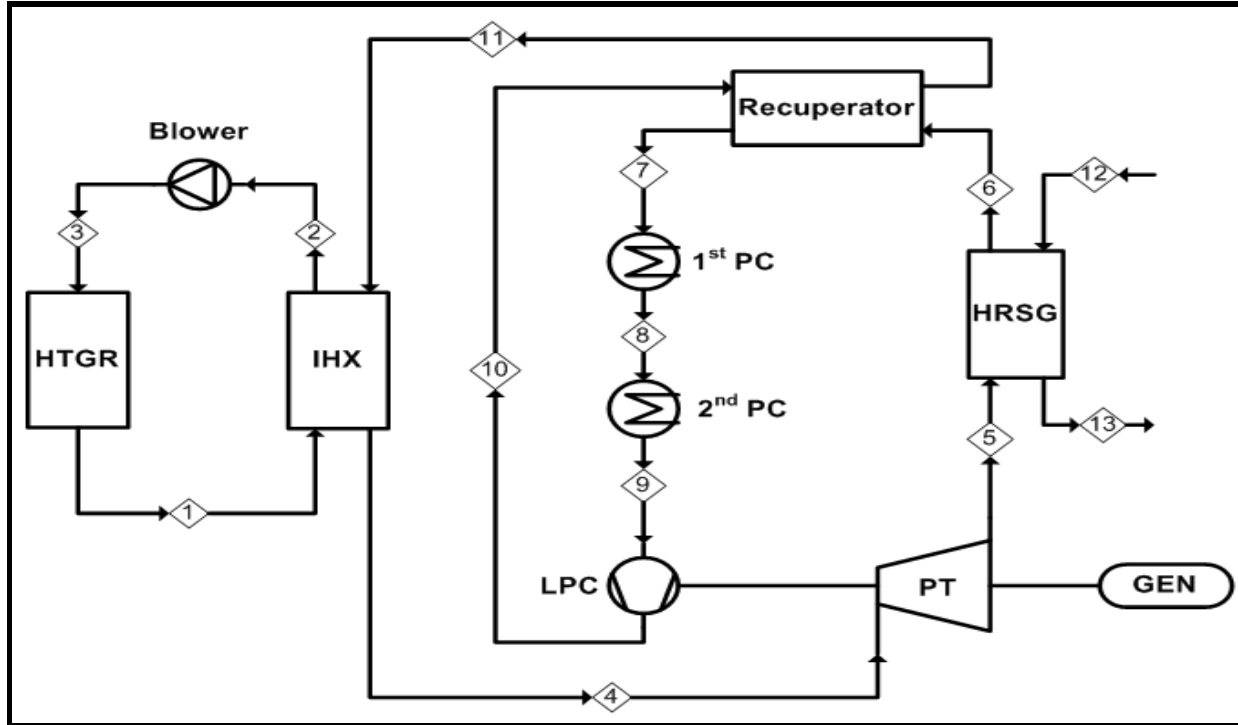


Figure 2-19 Indirect closed-cycle gas turbine cogeneration system (Penfield *et al.*, 2006)

After being blown through the HRSG, the helium passes through the primary side of the recuperator, where the heat is recuperated to the helium entering the IHX on the PCS side. The helium is further cooled by the pre-coolers before entering the compression stage, where it is compressed to about 5MPa. The cooling of helium before the compression stage increases the density of the gas and thus increases the efficiency of the compression process. The cold ($\pm 200^\circ\text{C}$), high pressure helium then flows through the secondary side of the recuperator, where it is heated before entering the IHX for the continuation of the cycle.

2.5. Summary

An overview of the heat engines, namely steam and gas turbines, which can be used to generate electricity and process heat for a coal-to-liquids facility, was given. The application of nuclear heat generated by a HTGR as the primary heat source for the cogeneration processes was also discussed in this section. The PBMR was chosen as the preferred HTGR due to its inherently safe properties and other key features.

The conclusion of this chapter is an overview of the two nuclear cogeneration processes that were proposed to replace the coal-based utilities at a CTL plant. The operating conditions and requirements of the coal-based processes (conventional power plant and cogeneration plant) and the proposed nuclear processes will be given in the next two chapters.

CHAPTER 3. COAL-BASED PROCESS ROUTES

3.1. Introduction

Two coal-based process routes for the generation of electricity and steam were studied in this dissertation. They include the separate generation of electricity and process steam by two separate boilers, and the simultaneous generation of electricity and process steam from a single energy source (cogeneration).

For the study of these coal-based process routes, the following topics are examined in depth:

- Mass balance
- Energy balance
- Boiler consumption/discharge.

The main focus points of this study are:

- CO₂ emissions compared, efficiencies and steam and electricity production to those of the nuclear-based cogeneration process route.

The process design criteria, operating conditions, process description and process flow diagram (PFD) of each coal-based route are also given in their respective sections.

3.2. Alternative A: Separate generation of electricity and steam by coal-fired boilers

The separate generation of electricity by a conventional power plant and process steam by an on-site boiler are discussed in this section. Both processes have the same design criteria. The generation of process steam will be discussed first, followed by the generation of electricity.

3.2.1 Process design criteria

3.2.1.1 Product specifications

Power plant availability	90%
Boiler availability	90%
Operational time	24 hr/day, 7 days/week
Operational days/year	328.5 days/year
Operational hours/year	7884 hrs/year
Electricity production rate	152.70 MW _e
Thermal energy production	146.34 MW _t
Steam production rate	249.44 ton/hr

3.2.1.2 Raw material specifications

Coal (Gray *et al.*, 1982).

The composition of coal can be given on one of the following basis:

As Received basis (AR),

Dry Basis (DB)

Dry and Ash Free (DAF) basis

Sub-bituminous coal with the following composition was used in this study:

Table 3-1 Composition of sub-bituminous coal

	AR (wt %)	DB (wt%)	DAF (wt%)
C	55.4%	58.6%	78.70%
H	3.0%	3.1%	4.20%
S	1.1%	1.2%	1.60%
N	1.3%	1.4%	1.90%
O	9.6%	10.1%	13.60%
Moisture	5.5%		
Ash	25.5%	26.984%	
Volatile Matter	23.6%	24.974%	34.2%
Fixed Carbon	45.4%	48.042%	65.8%
Net CV (MJ/kg)			28.44
Cp (kJ/kg K) (@ 25 °C) *	0.75 (Lee, n.d.)		
Cp (kJ/kg K) (@ 75 °C) *	0.80 (Lee, n.d.)		

*Dry and ash free basis (DAF)

The formula used to determine the heat capacity of coal at 25 °C and 75 °C can be seen in Appendix A.

Air

Air with the following composition is used for the drying and heating of the coal in the coal mill and as combustion medium in the boiler.

mol% O₂ : 21

mol% N₂ : 79

The following assumptions were made to simplify the Excel calculations:

- No significant pressure drops over the boiler, coal mill and condenser occurred.
- No significant pressure drop over the pipes occurred.
- No reheating or pre-heating of the steam in the PCS occurred.

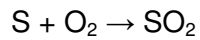
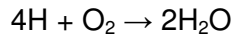
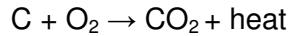
3.2.2 *Steam generation*

3.2.2.1 Process description

The process flow diagram of the steam generation process is given in section 3.2.2.2. The required process steam is generated separately from electricity by the combustion of coal in a coal-fired boiler.

Coal (AR) is first milled to a fine powder, which increases the surface area and allows it to burn more quickly. Coal (AR) is fed to the coal mill at ambient temperature of about 25°C with a 5.5% moisture content (1). Air is extracted from the atmosphere at about 25°C (2), heated in the boiler to 305°C (3) and mixed with tempering air (6) before it enters the coal mill at 250°C (7) (Subbarao, n.d.).

The air is used to dry the coal to 0% moisture content and to heat it to a temperature of 75°C (Liming Heavy Industry, n.d.) before leaving the coal mill. The pulverized coal is blown together with the air from the mill (8) into the combustion chamber of a boiler where it is burnt at high temperature. The combustion of coal is characterised by the following combustion reactions (Biarnes *et al.*, 2009):



The air required for complete combustion together with 50% excess air (assumed) enters the reactor at 305°C (5) (Subbarao, n.d.).

The combustion of coal produces heat, ash (9) and greenhouse gasses with CO₂ being the most significant of all (10). The heat produced in the boiler is used to turn saturated liquid (water) entering the boiler into superheated steam. A boiler efficiency of 87.3% was used in this study with 1.8% of the heat lost to the environment, 10.2% to the stack and 0.7% in the ash (Bureau of Energy Efficiency, n.d.).

Typical process steam conditions are 220°C and 1000 kPa (10 bar) with a return water temperature of 80°C and 1000kPa (10 bar) (Kikstra *et al.*, 2000). The superheated steam leaving the boiler (11) is sent to the process to meet the process steam demands before returning to the boiler as a saturated liquid (12).

The operating conditions are given in section 3.2.2.3 followed by the mass (section 3.2.2.4) and energy balances (section 3.2.2.5) of the steam generation process.

3.2.2.2 Process flow diagram

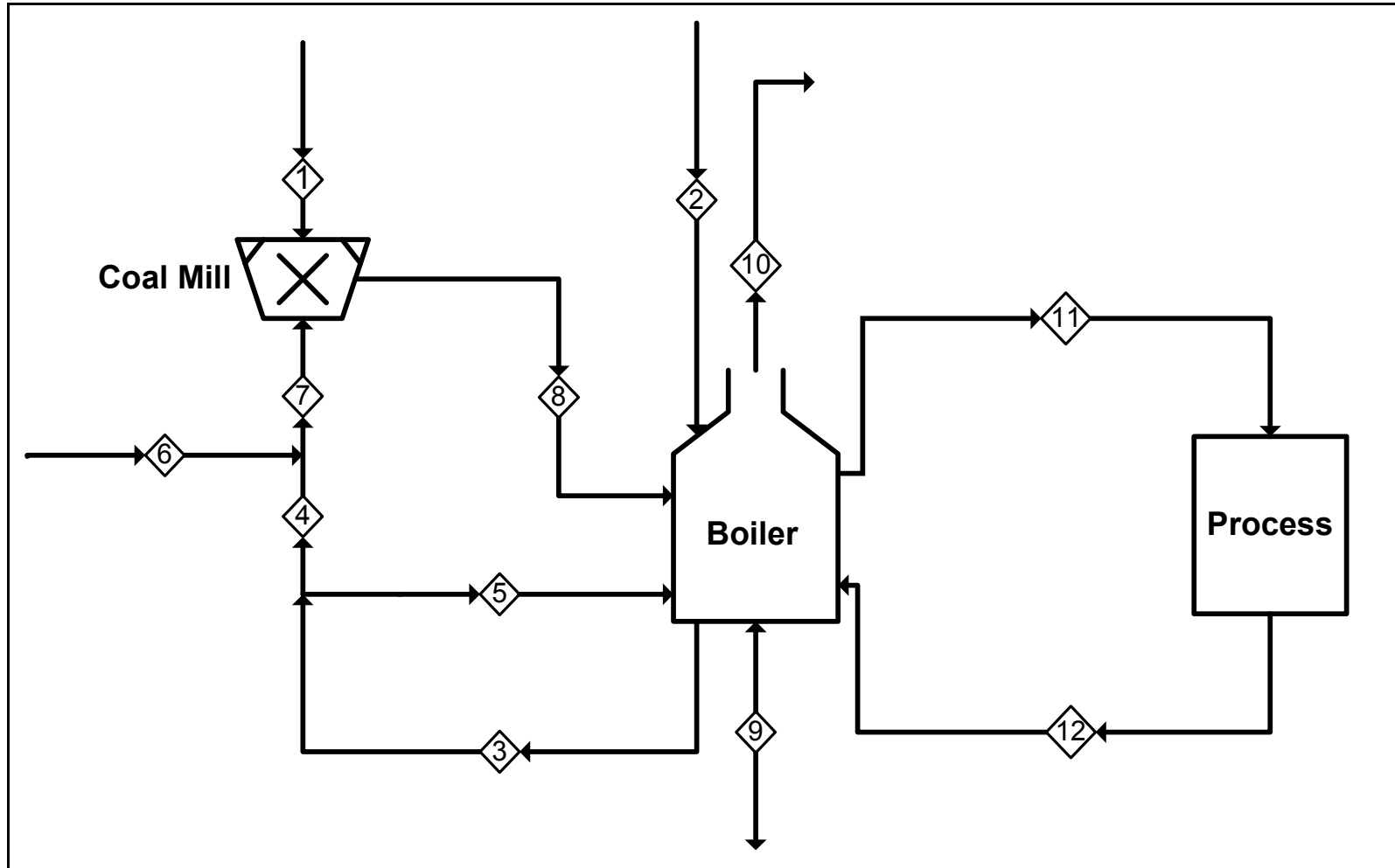


Figure 3-1 Process steam generation layout

3.2.2.3 Operating conditions

Table 3-2 gives the temperatures, pressures and reference conditions used by the steam generation process to generate process heat. The percentage excess air used together with a percentage breakdown of the energy usage in the boiler is also given below.

Table 3-2 Operating condition of steam generation process

Stream #	Composition	T (°C)	P (kPa)	Efficiencies	
1	AR Coal	25		<i>Boiler</i>	
2	Room Air	25	101.33	Excess Air ^a	50%
3	Hot Air	305		η_{Boiler}^b	87.3%
4	Primary Air	305		Energy Loss ^b	1.8%
5	Secondary Air	305		Energy loss from stack ^b	10.2%
6	Tempering Air	27		Energy loss from ash ^b	0.7%
7	Total Air	250			
8	Product stream	75		Reference conditions	
9	Ash			T(°C)	25
10	Stack gas			P(kPa)	101.325
11	Superheated steam	220	1,000		
12	Saturated liquid	80	1,000	T _{sat} (°C)	40

a: The amount of excess air was assumed, b: Bureau of Energy Efficiency (n.d.)

3.2.2.4 Mass balance

The mass balance of the steam generation process is given in Table 3-3.

Table 3-3 Mass balance of steam generation process

Stream #	Composition	m (ton/hr)	Mass %	n (kmol/hr)	Mol %	V(Nm ³ /hr)	Dry Vol%	Wet Vol%
1	AR Coal	30.75						
	Coal	29.06						
	H ₂ O	1.69						
2	Room Air	327.28		11,343.81		254,248.90		
	N ₂	251.05	0.77	8,961.61	0.79	200,856.63	0.79	0.79
	O ₂	76.23	0.23	2,382.20	0.21	53,392.27	0.21	0.21
3	Hot Air	327.28		11,343.81		254,248.90		
	N ₂	251.05	0.77	8,961.61	0.79	200,856.63	0.79	0.79
	O ₂	76.23	0.23	2,382.20	0.21	53,392.27	0.21	0.21
4	Primary Air	27.58		955.93		21,425.18		
	N ₂	21.16	0.77	755.18	0.79	16,925.89	0.79	0.79
	O ₂	6.42	0.23	200.74	0.21	4,499.29	0.21	0.21
5	Secondary Air	299.70		10,387.89		232,823.72		
	N ₂	229.89	0.77	8,206.43	0.79	183,930.74	0.79	0.79
	O ₂	69.80	0.23	2,181.46	0.21	48,892.98	0.21	0.21

6	Tempering Air	6.97		241.49		5,412.53		
	N ₂	5.34	0.77	190.78	0.79	4,275.90	0.79	0.79
	O ₂	1.62	0.23	50.71	0.21	1,136.63	0.21	0.21
7	Total Air	34.55		1,197.42		26,837.71		
	N ₂	26.50	0.77	945.96	0.79	21,201.79	0.79	0.79
	O ₂	8.05	0.23	251.46	0.21	5,635.92	0.21	0.21
8	Product	65.30						
	<i>Transport Air</i>	36.24		1,291.30		28,941.95		
	N ₂	26.50	0.73	945.96	0.73	21,201.79	0.79	0.73
	O ₂	8.05	0.22	251.46	0.19	5,635.92	0.21	0.19
	H ₂ O	1.69	0.05	93.88	0.07	2,104.24		0.07
	<i>Dry Pulverized coal</i>	21.22		2,494.24		55,903.36		
	C	16.70	0.787	1,390.31	0.557	31,160.95	0.557	0.557
	H	0.89	0.042	884.19	0.354	19,817.41	0.354	0.354
	N	0.40	0.019	28.78	0.012	645.09	0.012	0.012
	S	0.34	0.016	10.59	0.004	237.30	0.004	0.004
	O	2.89	0.136	180.37	0.072	4,042.60	0.072	0.072
	<i>Ash</i>	7.84						
9	Ash	7.84						
10	Stack gas	357.15		12,004.81		269,063.87		
	CO ₂	61.19	0.1713	1,390.31	0.1158	31,160.95	0.121	0.116

	H ₂ O	9.66	0.0270	535.98	0.0446	12,012.94	0	0.045
	SO ₂	0.68	0.0019	10.59	0.0009	237.30	0.001	0.001
	N ₂	256.80	0.7190	9,166.78	0.7636	205,455.08	0.799	0.764
	O ₂	28.84	0.0807	901.16	0.0751	20,197.60	0.079	0.075
11	Superheated steam	249.44		13,842.40		310,249.65		
12	Superheated steam	249.44		13,842.40		310,249.65		

The values in Table 3-3 were obtained from the simulation in Excel; the manual calculations can be seen in Appendix A. The mass balances were calculated according to the process design criterion, combustion reactions, and operating conditions. The mass balances are required to determine the amount of coal combusted, air required, steam generated, and CO₂ emitted by the process steam generation plant.

The amount of process steam generated by the boiler was assumed to be equal to the process steam generated in section 3.3, for the purpose of comparing the two. The coal required to generate the combustion heat necessary in the boiler to produce process steam was calculated by dividing the heat required in the boiler by the CV (DAF basis) of coal. The coal on DAF basis was then converted to an AR basis using equations given in (World Coal Institute, 2007).

Prior to the combustion process in the boiler, the coal is first pulverised and dried; 34.55 ton/hr (23,430.28 Nm³/hr) air is required to dry 30.75 ton/hr AR coal in the mill. At a temperature and pressure of 220°C and 1000kPa, 249.44 ton/hr process steam is generated by the combustion of 21.22 ton/hr DAF sub-bituminous coal. The combustion of coal takes place in the presence of 299.70 ton/hr (232,823.72 Nm³/hr) secondary air and 36.24 ton/hr (28,941.95 Nm³/hr, excluding H₂O) transport air.

A total of 334.25 ton/hr (259,661.43 Nm³/hr) air (stream 2 and 6) is extracted from the atmosphere to be used in the drying and combustion processes. The stack gas produced by the combustion of coal is mainly made up of nitrogen (76.4 mol%), CO₂ (11.6 mol%) and oxygen (7.5 mol%). The combustion of 21.22 ton DAF coal/hr produces about 61.19 tons/hr (31,160.95 Nm³/hr) CO₂ which amounts to 482,390.59 ton CO₂/year (245,672,938.18 Nm³/year).

3.2.2.5 Energy balance

Coal mill

The energy balance of the coal mill is given below:

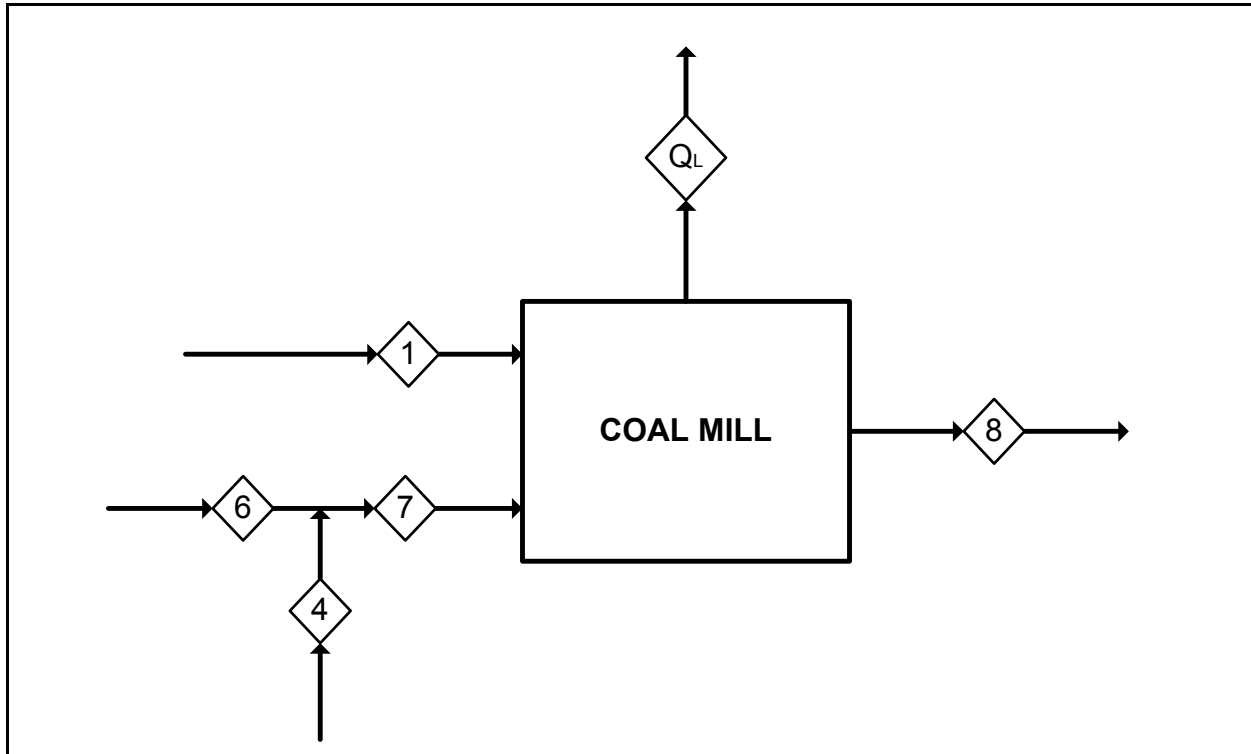


Figure 3-2 Energy balance of coal mill (Steam generation process)

Table 3-4 Energy balance of coal mill (Steam generation process)

		ΔH (kJ/mol)	Q (kJ/hr)	Q (MW)
1	AR Coal [#]	0.00	0.00	0.00
	Coal	0.00	0.00	0.00
	H ₂ O	0.00	0.00	0.00
4	Primary Air	16.90	7,977,065.69	2.22
	N ₂	8.63	1,732,104.45	0.48
	O ₂	8.27	6,244,961.23	1.73
6	Tempering Air	0.12	14,070.00	0.00
	N ₂	0.06	2,981.62	0.00
	O ₂	0.06	11,088.38	0.00
7	Total Air	13.50	7,991,135.69	2.22
	N ₂	6.88	1,728,877.39	0.48
	O ₂	6.62	6,262,258.30	1.74
8	Product Stream			2
	Transport Air	2.94	6,036,816.18	1.68
	N ₂	1.46	1,377,553.82	0.38
	O ₂	1.48	372,946.23	0.10
	H ₂ O		4,286,316.12	1.19
	Heat water(l) (T_1 to T_{sat}) [*]	1.12	105,149.45	0.03
	Evaporate water at T_{sat} [*]		4,069,372.94	1.13
	Heat water(g) (T_{sat} to T_g) [*]	1.19	111,793.73	0.03
	Dry Pulverized coal		1,155,205.94	0.32
	Q_{IN}			2.22
	Q_{OUT}			2
	Q_L (LOSS)			0.22
	Q_{TOTAL OUT}			2.22

Values are zero due to the inlet temperature and the reference temperature being the same; * Sum of these gives the total for H₂O

Boiler

The energy balance of the boiler is given below.

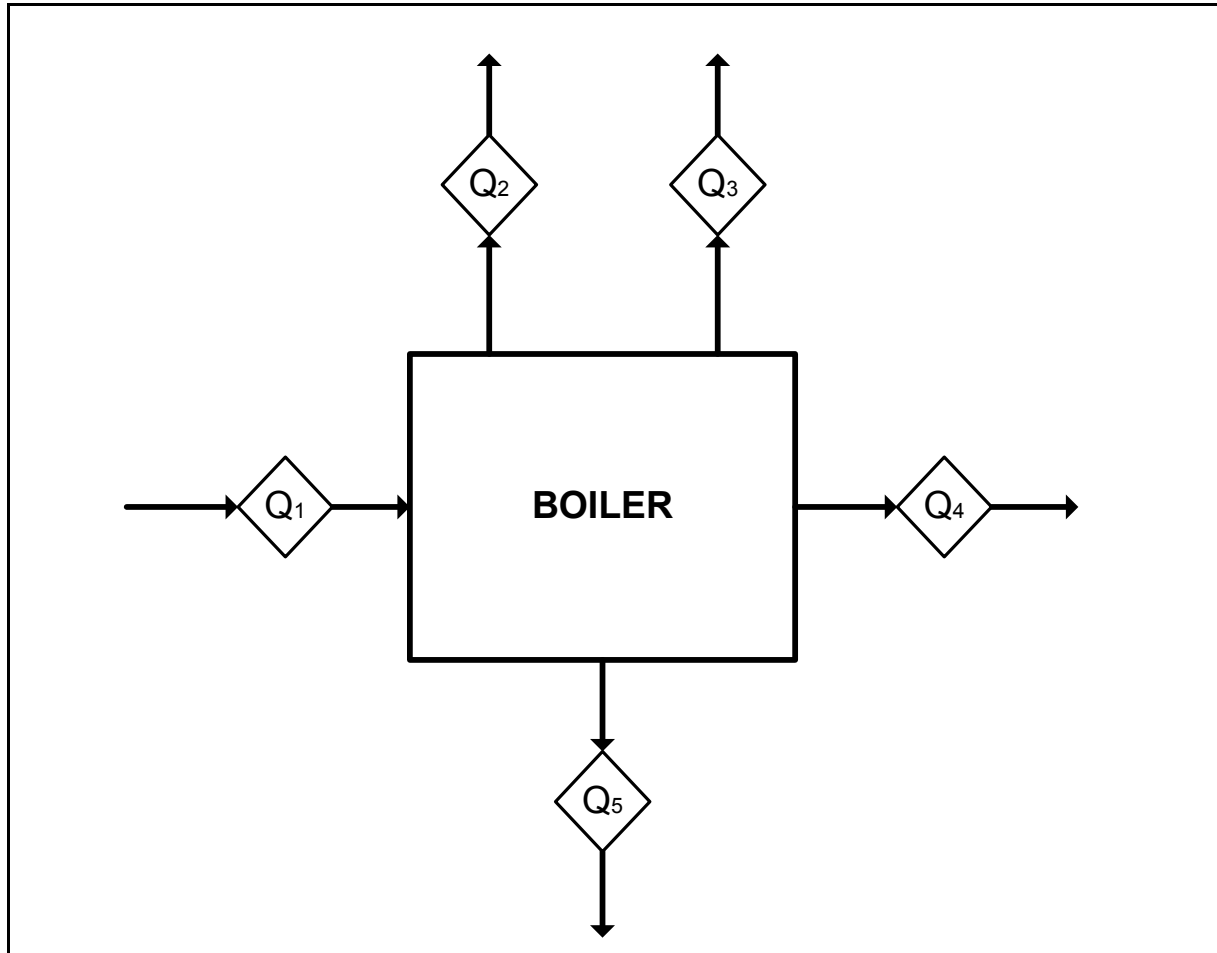


Figure 3-3 Energy balance of boiler (Steam generation process)

The specific enthalpy and heat load of each stream at their respective temperatures and pressures are given in Table 3-5. The enthalpies are either calculated using the equations from Smith *et al.* (2005) or obtained from the steam tables. The energy balance of the boiler is given in Table 3-6.

Table 3-5 Specific enthalpy of streams (Conventional coal-fired power plant)

Stream #	Composition	T (°C)	P (kPa)	H (kJ/kg)	Q(MW)
11	Superheated steam	220	1000	2874.60	199.18
12	Saturated liquid	80	1000	762.61	52.84

Table 3-6 Energy balance of boiler (steam generation process)

	Q(MW)
Q ₁	167.63
Q ₂	3.02
Q ₃	17.70
Q ₄	146.3
Q ₅	1.17
TOTAL	167.63

The symbols used in Table 3-6 represent the following:

Q₁ = Heat introduced into the boiler through the combustion process.

Q₂ = Heat loss from the boiler

Q₃ = Heat loss to the stack gas.

Q₄ = Heat transferred as process steam to the CTL facility.

Q₅ = Heat loss in the ash.

These tables were obtained from the simulation in Excel; the manual calculations can be seen in Appendix A.

The energy balances were calculated according to the design specifications, combustion reactions and operating conditions. The energy balances were used to determine the heat required to produce process steam and CO₂ emitted during the combustion process.

Using coal with a CV of 28.44 MJ/kg, 30.75 ton/hr coal (AR) (167.63 MW_t) is required to produce 146.3 MW_t (249.44 ton/hr process steam with a heat load of 199.18 MW_t) used as thermal energy in the process with 21.89 MW_t energy losses (see Table 3-6).

The process steam generation process has an efficiency of 87.3% due to the fact that there is no electrical energy generated. All the heat produced in a process steam generation process is applied as useful thermal energy in the form of process steam.

The mass and energy balances of the coal mill were performed simultaneously. An estimate for the total air flow required was used to determine the inlet and outlet energy for each stream. The specific enthalpy of each stream was calculated using the heat capacity equations given in Felder and Rousseau (2000) and the reference conditions in Table 3-2. The heat capacity of coal was determined by using the equation given in Lee (n.d.). These calculations can be seen in Appendix A. These values were then multiplied by the estimated mole values and converted into MW. The difference between the inlet and outlet energies were set equal to zero by changing the total air flow required using the Solver application in Excel. Using this stream the rest of the mass balance was calculated. Heat losses of 10% were assumed.

The mass balance over the boiler was performed using the combustion reactions and 50% excess air. The heat generated in the boiler is due to the combustion of coal. The efficiencies given in Table 3-6 were used to perform the energy balance over the boiler.

3.2.3 Electricity generation (conventional coal-fired power plant)

3.2.3.1 Process description

A conventional coal-fired power plant operates on the Rankine thermodynamic cycle and consists of a coal-fired boiler, steam turbine, condenser and pump.

The Rankine steam cycle is termed the Power Conversion System (PCS). The process flow diagram of a conventional power plant is given in section 3.2.3.2. For the purpose of the

generation of electricity, only a condensing steam turbine will be used, as discussed in section 2.2.2.1.

For the generation of electricity, coal is combusted in a coal-fired boiler to produce superheated steam which is used to drive a steam turbine that is connected to an electrical generator to produce electricity. The electricity will be used to meet the electrical demand of the plant. The operation of the coal mill and boiler of a conventional power plant is the same as for the steam generation process and thus will not be discussed again, refer to section 3.2.2.1.

A 500MW_t (heat transferred to the PCS, not total heat generated) boiler is used in this study for the purpose of comparing it to the coal-based and nuclear-based cogeneration processes. In this case the superheated steam leaves the boiler at 550°C and 7000kPa (11) (Energy Efficiency Guide for Industry in Asia, n.d.) and is expanded over a condensing steam turbine to generate electricity before leaving the turbine as a saturated vapour (13). Turbine and pump efficiencies of 80% are assumed (Smith *et al.*, 2005). The saturated vapour leaves the turbine at 10kPa (Eskom, 2011), consisting of 93.5% vapour and 6.5% liquid (13), and is directly exhausted into a condenser. It is condensed into liquid using cooling towers, before it is pumped back to the boiler for the continuation of the cycle (15). Generator and delivery efficiencies of 98% and 95% respectively were assumed (Ugeler & Mulder, n.d.). The operating conditions are given in section 3.2.3.3, followed by the mass (section 3.2.3.4) and energy (section 3.2.3.5) balances of the conventional power plant.

3.2.3.2 Process flow diagram

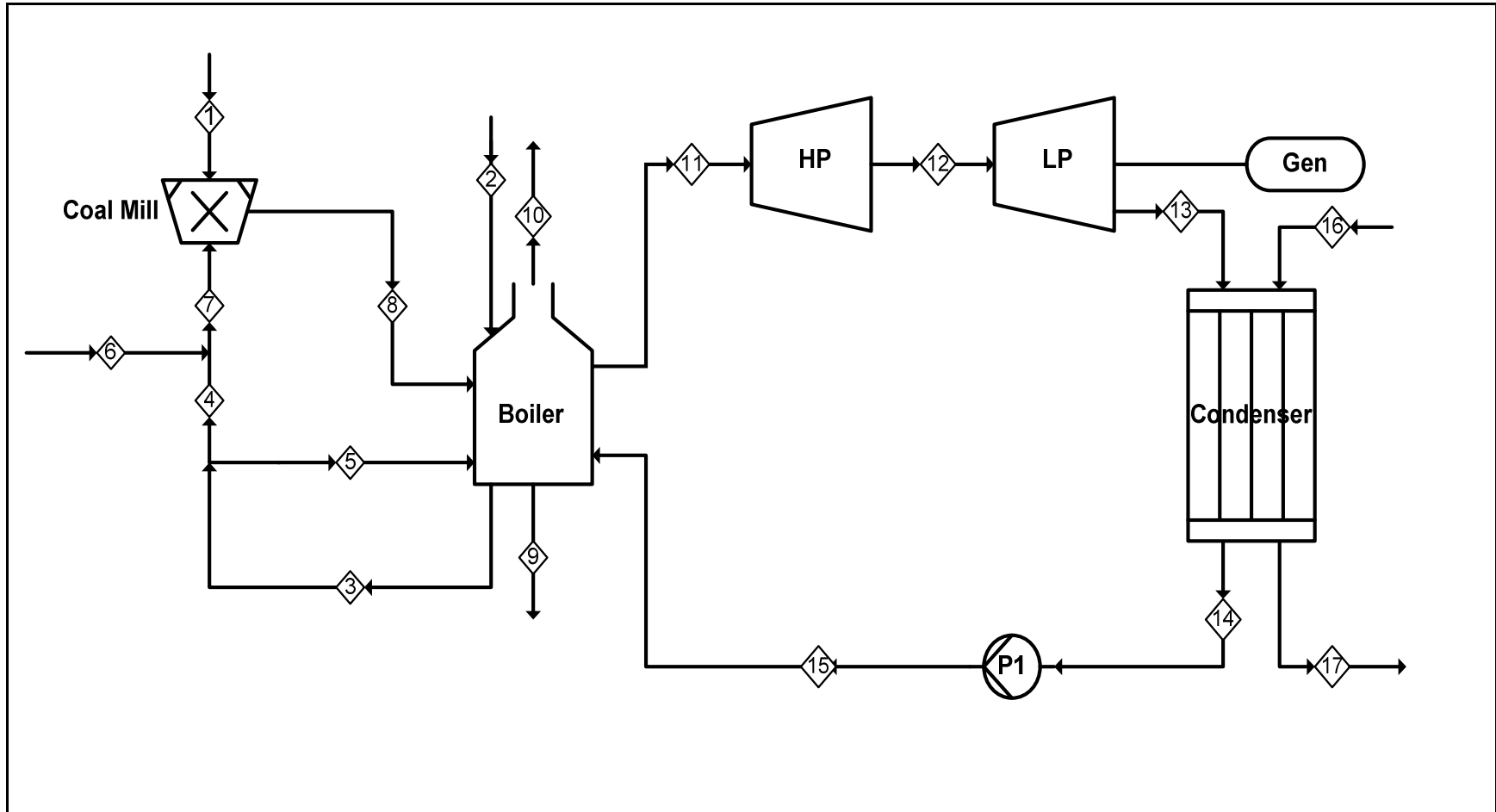


Figure 3-4 Layout of a conventional coal-fired power plant (electricity generation)

3.2.3.3 Operating conditions

In Table 3-7 the temperatures, pressures and reference conditions used for the generation of electricity by a conventional coal-fired power plant are given. The percentage excess air used, together with the efficiencies of the boiler, turbines, pump and generator, are also given below.

Table 3-7 Operating conditions of conventional coal-fired power plant

Stream #	Composition	T (°C)	P (kPa)	Efficiencies	
1	AR Coal	25		<i>Boiler</i>	
2	Room Air	25	101.33	Excess Air ^a	50%
3	Hot Air	305		η_{Boile}^b	87.3%
4	Primary Air	305		Energy Loss ^b	1.8%
5	Secondary Air	305		Energy loss from stack ^b	10.2%
6	Tempering Air	27		Energy loss from ash ^b	0.7%
7	Total Air	250			
8	Product	75		<i>PCS</i>	
9	Ash			η_{HPT}^c	80%
10	Stack gas			η_{LPT}^c	80%
11	Superheated steam	550	7,000	η_{GEN}^d	98%
12	Superheated steam	322.6	1,150	η_{DEL}^d	95%
13	Saturated steam	45.8	10	η_{P1}^c	80%
14	Saturated liquid	45.8	10	Reference Conditions	
15	Compressed liquid	46.5	7,000	T(°C)	25
16	Saturated liquid	25	101.33	P(kPa)	101.325
17	Saturated liquid	70	101.33	T_{sat} (°C)	40

a: Amount of excess air assumed, b: Bureau of Energy Efficiency (n.d.) c: Smith *et al.* (2005) d: Ugeler and Mulder (n.d.).

3.2.3.4 Mass balance

Table 3-8 Mass balance of conventional coal-fired power plant

Stream #	Composition	m (ton/hr)	Mass %	n (kmol/hr)	Mol %	V(Nm ³ /hr)	Dry Vol%	Wet Vol%
1	AR Coal	105.07						
	Coal	99.29						
	H ₂ O	5.78						
2	Room Air	1,118.22		38,759.00		868,705.57		
	N ₂	857.78	0.77	30,619.61	0.79	686,277.40	0.79	0.79
	O ₂	260.44	0.23	8,139.39	0.21	182,428.17	0.21	0.21
3	Hot Air	1,118.22		38,759.00		868,705.57		
	N ₂	857.78	0.77	30,619.61	0.79	686,277.40	0.79	0.79
	O ₂	260.44	0.23	8,139.39	0.21	182,428.17	0.21	0.21
4	Primary Air	94.23		3,266.16		73,204.54		
	N ₂	72.28	0.77	2,580.27	0.79	57,831.59	0.79	0.79
	O ₂	21.95	0.23	685.89	0.21	15,372.95	0.21	0.21
5	Secondary Air	1,023.99		35,492.84		795,501.02		
	N ₂	785.49	0.77	28,039.34	0.79	628,445.81	0.79	0.79
	O ₂	238.50	0.23	7,453.50	0.21	167,055.21	0.21	0.21
6	Tempering Air	23.81		825.11		18,493.28		
	N ₂	18.26	0.77	651.84	0.79	14,609.69	0.79	0.79

	O ₂	5.54	0.23	173.27	0.21	3,883.59	0.21	0.21
7	Total Air	118.04		4,091.28		91,697.83		
	N ₂	90.54	0.77	3,232.11	0.79	72,441.28	0.79	0.79
	O ₂	27.49	0.23	859.17	0.21	19,256.54	0.21	0.21
8	Product	223.11						
	<i>Transport Air</i>	123.81		4,412.06		98,887.48		
	N ₂	90.54	0.73	3,232.11	0.73	72,441.28	0.79	0.73
	O ₂	27.49	0.22	859.17	0.19	19,256.54	0.21	0.19
	H ₂ O	5.78	0.05	320.78	0.07	7,189.65		0.07
	<i>Dry Pulverized coal</i>	72.50		8,522.19		191,007.95		
	C	57.06	0.787	4,750.33	0.557	106,469.26	0.557	0.557
	H	3.04	0.042	3,021.07	0.354	67,711.20	0.354	0.354
	N	1.38	0.019	98.34	0.012	2,204.13	0.012	0.012
	S	1.16	0.016	36.17	0.004	810.78	0.004	0.004
	O	9.86	0.136	616.28	0.072	13,812.58	0.072	0.072
	<i>Ash</i>	26.79						
9	Ash	26.79						
10	Stack gas	1,220.30		41,017.47		919,324.66		
	CO ₂	209.06	0.171	4,750.33	0.116	106,469.26	0.121	0.116
	H ₂ O	32.99	0.027	1,831.31	0.045	41,045.25	0	0.045
	SO ₂	2.32	0.002	36.17	0.001	810.78	0.001	0.001

	N ₂	877.42	0.719	31,320.62	0.764	701,989.16	0.799	0.764
	O ₂	98.52	0.081	3,079.03	0.075	69,010.21	0.079	0.075
11	Superheated steam	540.71		30,006.24		672,529.95		
12	Superheated steam	540.71		30,006.24		672,529.95		
13	Saturated steam	540.71		30,006.24		672,529.95		
	Vapour	505.498	0.935	28,052.05	0.935	628,730.65		
	Liquid	35.215	0.065	1,954.19	0.065	43,799.30		
14	Saturated liquid	540.71		30,006.24		672,529.95		
15	Compressed liquid	540.71		30,006.24		672,529.95		
16	Saturated liquid	6,426.88		356,652.45		7,993,651.31		
17	Saturated liquid	6,426.88		356,652.45		7,993,651.31		

These tables are obtained from the simulation in Excel; the manual calculations can be seen in Appendix A. The mass balances were used to determine the amount of coal combusted, air used, steam generated and CO₂ emitted through the generation of electricity. The coal required to generate the combustion heat necessary in the boiler to produce steam used to drive the steam turbines was calculated as stated above in section 3.2.2.4.

For the drying of 105.07 ton coal/hr with 5.5% moisture content, 118.04 ton/hr (91,697.83 Nm³/hr) air is required in the mill. 540.71 ton/h superheated steam is generated from the heat produced by the combustion of 72.50 ton DAF coal/hr in the boiler. The combustion takes place in the presence of 1142.02 ton/hr air (secondary and transport air) (887,198.85 Nm³/hr).

The stack gas produced by the combustion of coal is mainly made up of nitrogen (76.4 mol%), CO₂ (11.6 mol%) and oxygen (7.5 mol%). The combustion of 72.50 ton DAF coal/hr (539,836 ton DAF coal/year) produces about 209.06 tons/hr (106,469.26 Nm³/hr) CO₂ which amounts to 1.65 million tons CO₂/year (839,403,627.06 Nm³/year).

3.2.3.5 Energy balance

Coal mill

The energy balance of the coal mill is given below.

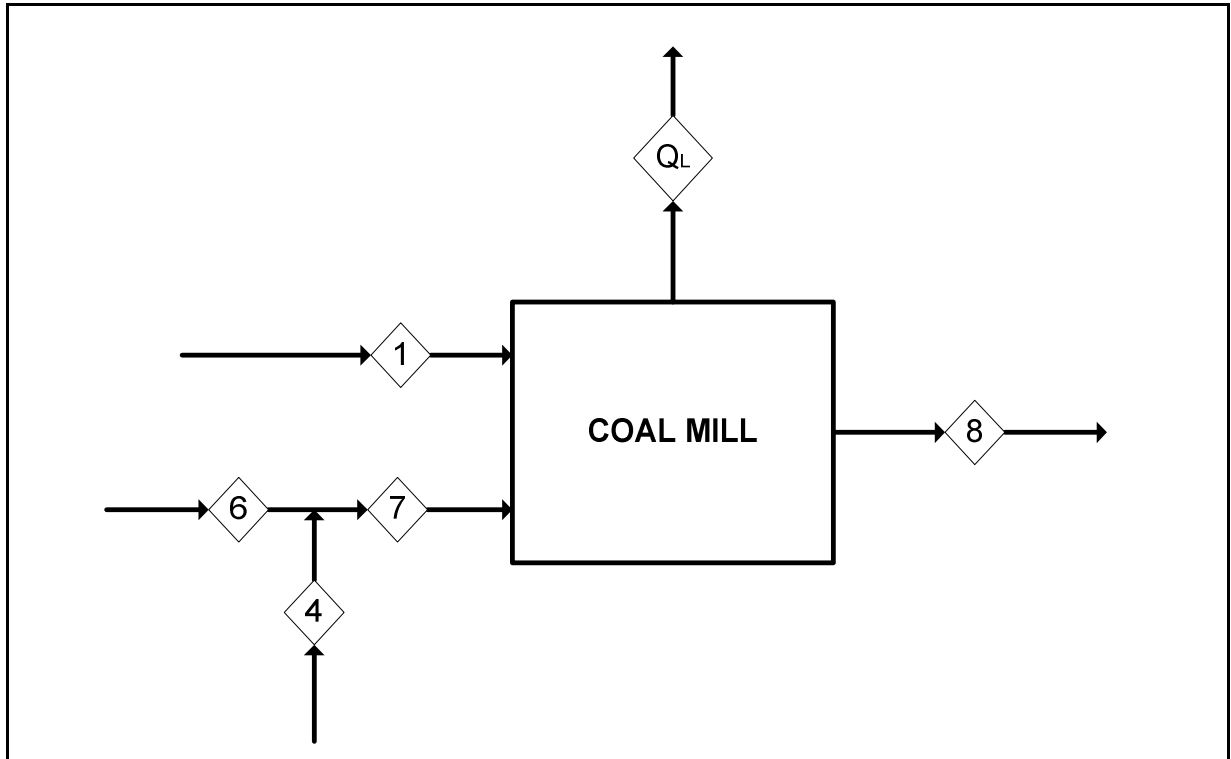


Figure 3-5 Energy balance of coal mill (conventional coal-fired power plant)

Table 3-9 Energy balance of coal mill (conventional coal-fired power plant)

		ΔH (kJ/mol)	Q (kJ/hr)	Q (MW)
1	AR Coal [#]	0.00	0.00	0.00
	Coal	0.00	0.00	0.00
	H ₂ O	0.00	0.00	0.00
4	Primary Air	50.69	27,255,659.17	7.57
	N ₂	25.89	5,918,172.22	1.64
	O ₂	24.81	21,337,486.95	5.93
6	Tempering Air	0.35	48,073.71	0.01
	N ₂	0.18	10,187.47	0.00
	O ₂	0.17	37,886.24	0.01
7	Total Air	40.49	27,303,732.88	7.58
	N ₂	20.63	5,907,146.16	1.64
	O ₂	19.86	21,396,586.72	5.94
8	Product Stream			6.83
	Transport Air	8.82	20,626,306.79	5.73
	N ₂	4.37	4,706,760.46	1.31
	O ₂	4.45	1,274,264.97	0.35
	H ₂ O		14,645,281.36	4.07
	Heat water(l) (T_1 to T_{sat}) [*]	3.36	359,269.66	0.10
	Evaporate water at T_{sat} [*]		13,904,040.18	3.86
	Heat water(g) (T_{sat} to T_3) [*]	3.57	381,971.52	0.11
	Dry Pulverized coal		3,947,052.80	1.10
	Q_{IN}			7.58
	Q_{OUT}			6.83
	Q_{LOSS}			0.75
	Q_{TOTAL OUT}			7.58

#Values are zero due to the inlet temperature and the reference temperature being the same; * Sum gives the total for H₂O

Boiler

The energy balance of the boiler is given below.

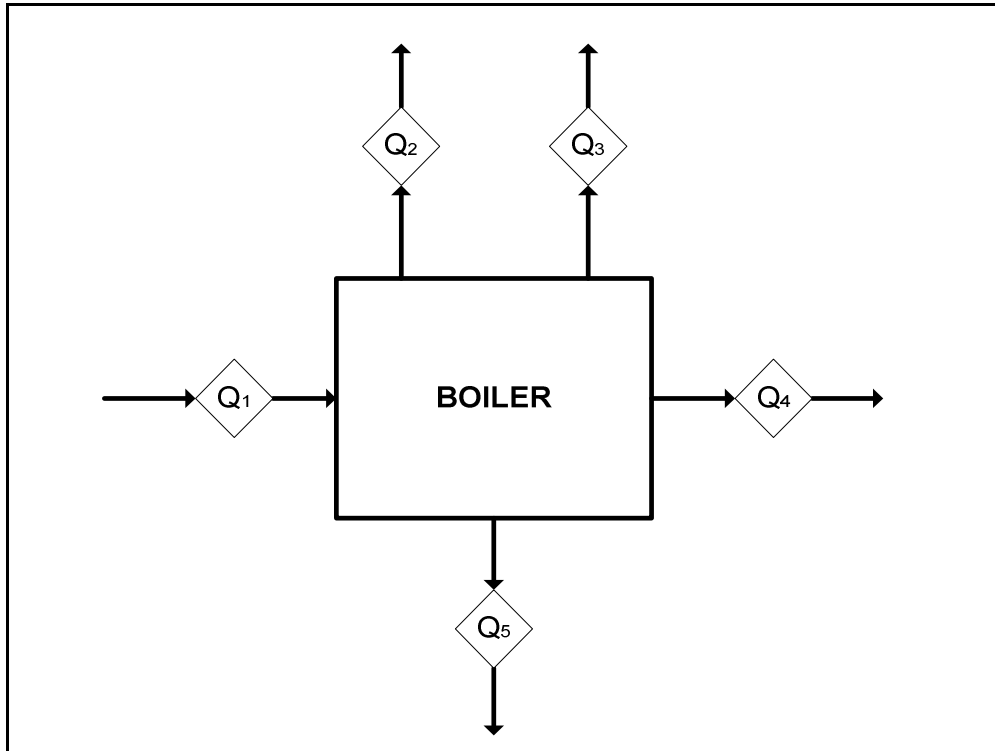


Figure 3-6 Energy balance of boiler (Conventional coal-fired power plant)

Table 3-10 Energy balance of boiler (conventional coal-fired power plant)

	Q(MW)
Q₁	572.74
Q₂	10.31
Q₃	58.42
Q₄	500
Q₅	4.01
TOTAL	572.74

Power conversion system (PCS)

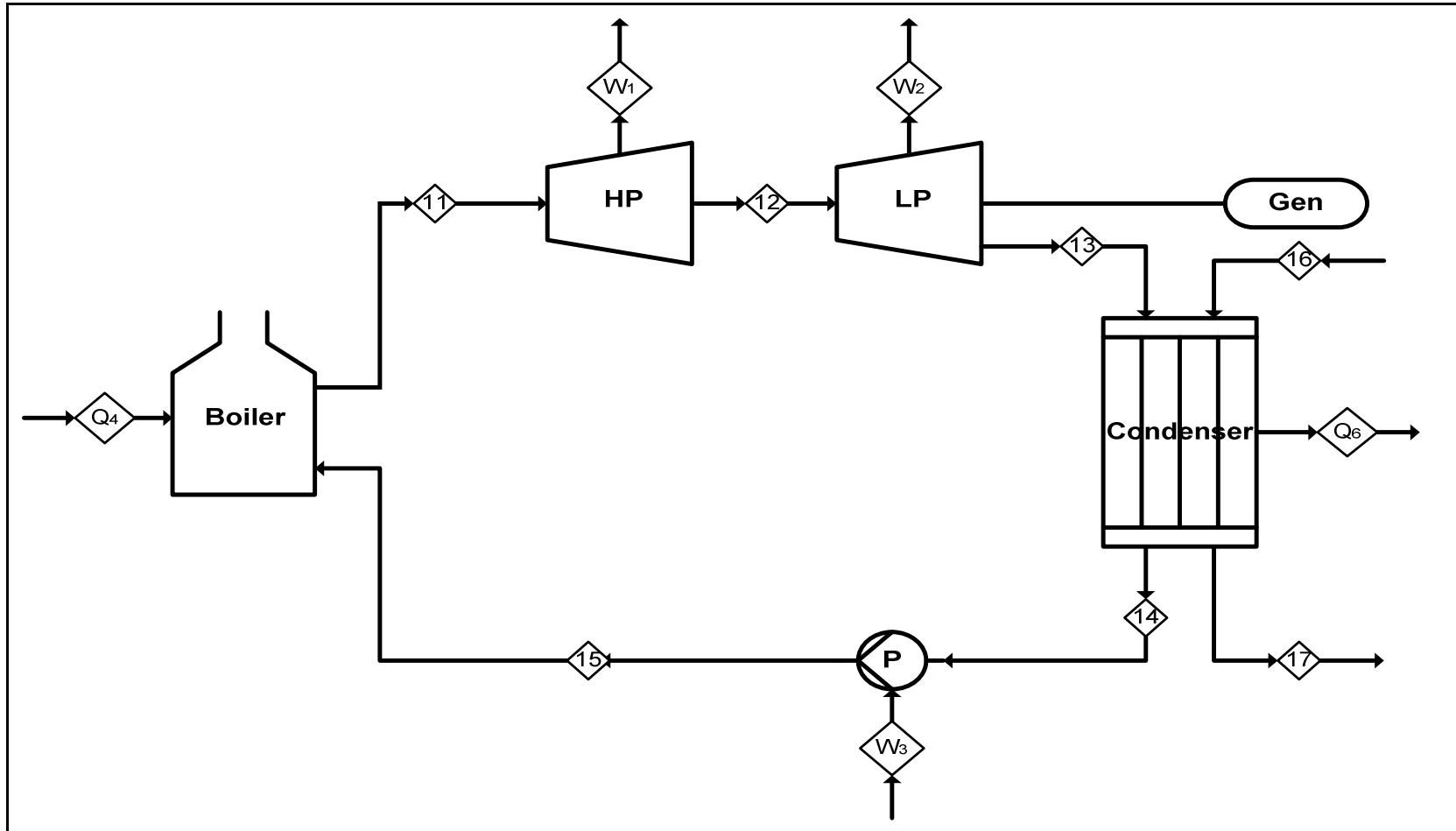


Figure 3-7 Energy balance of PCS (Conventional coal-fired power plant)

In Table 3-11 the specific enthalpy and heat load of each stream at the respective temperatures and pressures are given. The enthalpies are either calculated using the equations from Smith *et al.* (2005) or obtained from the steam tables. The energy balance of the steam cycle is given Table 3-12. The efficiency is also included in this section below.

Table 3-11 Specific enthalpy and heat of each stream (conventional coal-fired power plant)

Steam #	Composition	T (°C)	P (kPa)	H (kJ/kg)	Q(MW)
11	Superheated steam	550	7,000	3,529.60	530.13
12	Superheated steam	323	1,150	3,096.97	465.15
13	Saturated steam	46	10	2,428.77	364.79
14	Saturated liquid	46	10	191.83	28.81
15	Compressed liquid	47	7,000	200.66	30.13
16	Saturated liquid	25	101.33	104.80	15.74
17	Saturated liquid	70	101.33	293.00	44.01

Table 3-12 Energy balance of PCS (Conventional coal-fired power plant)

	$(\Delta H)_{\text{isentropic}}$ (kJ/kg)	ΔH (kJ/kg)	Q(MW)	$W_{\text{isentropic}}$ (MW)	W (MW)
Q_4	-	3,328.97	500	-	-
W_1	-540.78	-432.63	-	-81.22	-64.98
W_2	-835.26	-668.21	-	-125.45	-100.36
W_3	7.06	8.83	-	1.06	1.33
Q_6	-	-2,236.97	-335.98	-	-
TOTAL			164.02		-164.02

The symbols used in the energy balance represent the following:

Q_1 = Heat introduced into the boiler through the combustion process.

Q_2 = Heat loss from the boiler.

Q_3 = Heat loss to the stack.

Q_4 = Heat transferred to the PCS.

Q_5 = Heat loss it the ash.

Q_6 = Rejected latent heat by the condensation process to the environment.

W_1 = Power generated by the HP turbine.

W_2 = Power generated by the LP turbine.

W_3 = Power required by the pump.

Table 3-13 Efficiency of conventional coal-fired power plant

W_{net} (MW)	164.02
W_e (MW)	152.70
η_t	33%
η_{tot}	26.7%

The symbols used in Table 3-13 have the following meanings:

- W_{net} The net work produced by the PCS. The net work is the work generated by the turbine minus the work required by the pump
- W_e The electrical power (electricity) produced by the process. It is the net work multiplied by the generator and delivery efficiencies.
- η_t Thermal efficiency of the PCS. It is calculated by dividing the net work produced by the PCS with the heat that is introduced into the PCS (excluding the boiler efficiency).
- η_{tot} Total efficiency of the process. It is calculated by dividing the electrical power by the total heat input into the process (boiler efficiency included).

These tables are obtained from the simulation in Excel; the manual calculations can be seen in Appendix A.

The energy and mass balances were calculated according to the design specifications, combustion reactions and operating conditions. The energy balances are required to determine the electricity generated and the thermal and total efficiencies of the process.

Using coal with a CV of 28.44 MJ/kg, 105.07 ton/hr coal (AR) is required to produce 572.74 MW_t. From the energy entered into the process 500 MW_t is transferred to the PCS to generate superheated steam. Only 27% (152.70 MW_e) of the energy is converted into useable electrical energy with the balance lost due to mechanical and thermal efficiencies.

The mass and energy balances of the coal mill and boiler were performed as stated in section 3.2.2.5. Heat losses of 10% from the coal mill were assumed. The heat generated in the boiler is due to the combustion of coal. The efficiencies given in Table 3-7 were used to perform the energy balance of the boiler given in Table 3-10.

The mass and energy balances of the PCS were performed using the method and equations given in Smith *et al.* (2005) and can be seen in Appendix A. The water/steam flow rate required in the PCS was calculated by dividing the heat transferred from the boiler to the PCS by the specific enthalpy difference across the boiler.

The power generated and required in the PCS was also calculated using the formulas given in Smith *et al.* (2005). The actual power produced by each of the turbines in the PCS was calculated by multiplying the specific isentropic enthalpy difference ($(\Delta H)_{\text{isentropic}}$) over the turbines with the turbine efficiency and mass flow rate through the turbines.

The isentropic work ($W_{\text{isentropic}}$) given in Table 3-12 is the maximum work that can be produced by the turbines if the turbines were 100% efficient. It was calculated by multiplying the specific isentropic enthalpy difference over the turbine with the mass flow rate through the turbine. The actual power required by the pump was calculated by dividing the specific isentropic enthalpy difference ($(\Delta H)_{\text{isentropic}}$) over the pump with the pump efficiency and multiplying it with the mass flow rate through the pump. The heat output of the condenser was calculated by multiplying the specific enthalpy difference over the condenser with the mass flow rate through the condenser.

3.2.4 Consumption and discharge figures

This section states the amount of each commodity required and the amount of waste generated by each of the two processes for the separate generation of electricity (103.44 MW_e) and process steam (186.11 MW_t transferred to CTL process, 324.58 ton/hr, stream containing 254.87 MW_t). The consumption and discharge figures of the process steam generation plant and the conventional coal-fired power plant are given below.

Table 3-14 Consumption figures of Alternative A: Coal-based process route

	Process steam generation plant	Conventional coal-fired power plant
Coal (Ton/hr)	30.75	105.07
Coal (ton/year)	242,444.69	828,373.49
Coal (ton/MWh)	0.21	0.69
Air (ton/hr)	334.24	1,142.03
Air (ton/year)	2,635,175.38	9,003,742.09
Air (ton/MWh)	2.28	7.48
Process Steam (ton/hr)	249.44	
Process Steam (ton/year)	1,966,584.96	
Process Steam (ton/MWh)	1.70	
PCS Steam (ton/hr)		540.71
PCS Steam (ton/year)		4,262,936.53
PCS Steam (ton/MWh)		3.54
Cooling water (ton/hr)		6,426.91
Cooling water (ton/year)		50,669,736.89
Cooling water (ton/MWh)		42.09

The yearly consumption and discharge figures were calculated by using the *hr/year* operation figure given in section 3.2.1. The ton/MWh of each respective process was calculated by the dividing the ton/hr by the MW of that process.

Table 3-15 Discharge figures of Alternative A: Coal-based process route

	Process steam generation process	Conventional coal-fired power process
Ash (ton/hr)	7.84	26.79
Ash (ton/year)	61,823.40	211,235.24
Ash (ton/MWh)	0.05	0.18
Stack gas (ton/hr)	357.15	1,220.30
Stack gas (ton/year)	2,815,796.53	9,620,879.84
Stack gas (ton/MWh)	2.44	7.99
CO ₂ (ton/hr)	61.19	209.06
CO ₂ (ton/year)	482,390.59	1,648,209.26
CO ₂ (ton/MWh)	0.42	1.37
O ₂ (ton/hr)	28.84	98.52
O ₂ (ton/year)	227,336.56	776,752.74
O ₂ (ton/MWh)	0.20	0.65
H ₂ O (ton/hr)	9.66	32.99
H ₂ O (ton/year)	76,124.68	260,099.20
H ₂ O (ton/MWh)	0.07	0.22
SO ₂ (ton/hr)	0.68	2.32
SO ₂ (ton/year)	5,347.50	18,271.09
SO ₂ (ton/MWh)	0.00	0.02
N ₂ (ton/hr)	256.80	877.42
N ₂ (ton/year)	2,024,597.19	6,917,547.54
N ₂ (ton/MWh)	1.75	5.75

The separate generation of electricity and process steam generates about 270.25 ton of CO₂ per hour (2.13 million ton/year), and consumes about 1.07 million tons of coal per year. The simultaneous generation of process steam and electricity from a single source is discussed in the next section.

3.3. Alternative B: Coal-fired cogeneration process

The simultaneous generation of process steam (MW_t) and electricity (MW_e) from a single energy source called cogeneration is discussed in this section. For an overview of cogeneration please refer to section 2.2. The design criteria that were used in the study together with the mass and energy balances are given and discussed below.

3.3.1 Process design criteria

3.3.1.1 Product specifications

Cogeneration plant availability	90%
Operational time	24 hrs/day, 7 days/week
Operational days/year	328.5 days/year
Operational hours/year	7884 hrs/year
Electricity production	124.28 MW_e
Thermal energy production	146.34 MW_t
Process steam production	249.44 ton/hr

3.3.1.2 Raw material specifications

Coal (Gray *et al.*, 1982)

The composition of coal can be given on one of the following basis:

As Received basis (AR),

Dry Basis (DB)

Dry and Ash Free (DAF) basis

Sub-bituminous coal with the following composition was used in this study:

Table 3-16 Composition of sub-bituminous coal

	AR (wt %)	DB (wt%)	DAF (wt%)
C	55.4%	58.6%	78.70%
H	3.0%	3.1%	4.20%
S	1.1%	1.2%	1.60%
N	1.3%	1.4%	1.90%
O	9.6%	10.1%	13.60%
Moisture	5.5%		
Ash	25.5%	26.984%	
Volatile Matter	23.6%	24.974%	34.2%
Fixed Carbon	45.4%	48.042%	65.8%
Net CV (MJ/kg)			28.44
Cp (kJ/kg K) (@ 25°C) *	0.75 (Lee, n.d.)		
Cp (kJ/kg K) (@ 75°C) *	0.80 (Lee, n.d.)		

*Dry and ash free basis (DAF)

The formula used to determine the heat capacity of coal at 25°C and 75°C can be seen in Appendix A.

Air

Air with the following composition is used for the drying and heating of the coal in the coal mill and as combustion medium in the boiler.

mol% O₂ : 21

mol% N₂ : 79

The following assumptions were made to simplify the Excel calculations.

- No significant pressure drop over boiler, coal mill, HRSG, mixer and condenser.
- No significant pressure drop over pipes.
- No re-heating or pre-heating of the steam in the PCS.

3.3.2 General process description

A coal-fired cogeneration plant operates on the same principles as a conventional coal-fired power plant with the addition of process heat generation. Heat is sent to the CTL facility through a Heat Recovery Steam Generator (HRSG). The coal-fired cogeneration plant consists of a coal-fired boiler, an extraction/condensing steam turbine, condenser, two pumps and a HRSG for the generation of process heat. The process flow diagram of a coal-fired cogeneration plant is given in section 3.3.3. For the purpose of the generation of electricity and process heat, an extraction/condensing steam turbine will be used, as discussed in section 2.2.2.1. The turbine on the process flow diagram is split to simplify the calculations, but functions as an extraction/condensing steam turbine.

In a cogeneration process a fraction of the steam is extracted from the turbine (at the required temperature and pressure) for the purpose of generating process steam, while the balance of the steam continues to expand, generating electricity, until it reaches the pressure of the condenser.

A single boiler (thus a single energy source) is used to generate electricity and process heat. Coal is combusted in the coal-fired boiler to produce the heat required in the PCS. The steam turbines are connected to an electrical generator that converts mechanical energy into electrical energy. The electricity and process steam will be used to meet the electrical and heat demand of the CTL process. The operation of the coal mill and boiler of a coal-fired cogeneration process is the same as the processes discussed in section 3.2, and thus will not be discussed again.

A 500MW_t (heat transferred to the PCS, not total heat generated) boiler is used in this study for the purpose of comparing it with the nuclear-based cogeneration processes. The superheated steam leaves the boiler at 550°C and 7000kPa (11) (Energy Efficiency Guide for Industry in Asia, n.d.). The steam is expanded over a steam turbine, generating electricity, until it reaches the required temperature and pressure as required by the downstream process (12). It was assumed that 40% of the steam is extracted and sent to the HRSG (13) to generate process heat (steam), while the balance (14) of the steam continues to expand, further generating electricity.

The balance of the steam leaves the LP turbine as a saturated vapour (10 kPa) and consists of 6.5% moisture (15). Turbine and pump efficiencies of 80% were assumed (Smith *et al.*, 2005). The saturated steam is condensed (16) before being pumped to the required pressure of the boiler (17).

It was assumed that the HRSG will be 98% efficient (Ugeler & Mulder, n.d.), thus 98% of the heat sent to the HRSG is used to generate process steam while the balance is lost to the environment. Typical process steam conditions are 220°C and 1000 kPa (10 bar) with a return water temperature of 80°C and 1000 kPa (10 bar) (Kikstra *et al.*, 2000). The superheated steam leaving the HRSG (22) is sent to the process to meet the process steam demands before returning to the HRSG as a saturated liquid (21).

The extracted steam from the turbine used for the generation of process steam leaves the HRSG as a condensate (19). It is pumped to the required pressure of the boiler (20) before being mixed with the condensate of the condenser (16). The condensate from the condenser is mixed with the condensate from the HRSG before entering the boiler at 102.7°C and 7000 kPa (18).

Generator and delivery efficiencies of 98% and 95% respectively were used (Ugeler & Mulder, n.d.). The operating conditions are given in section 3.3.4, followed by the mass (section 3.3.5) and energy (section 3.3.6) balances of the coal-fired cogeneration plant.

3.3.3 Process flow diagram

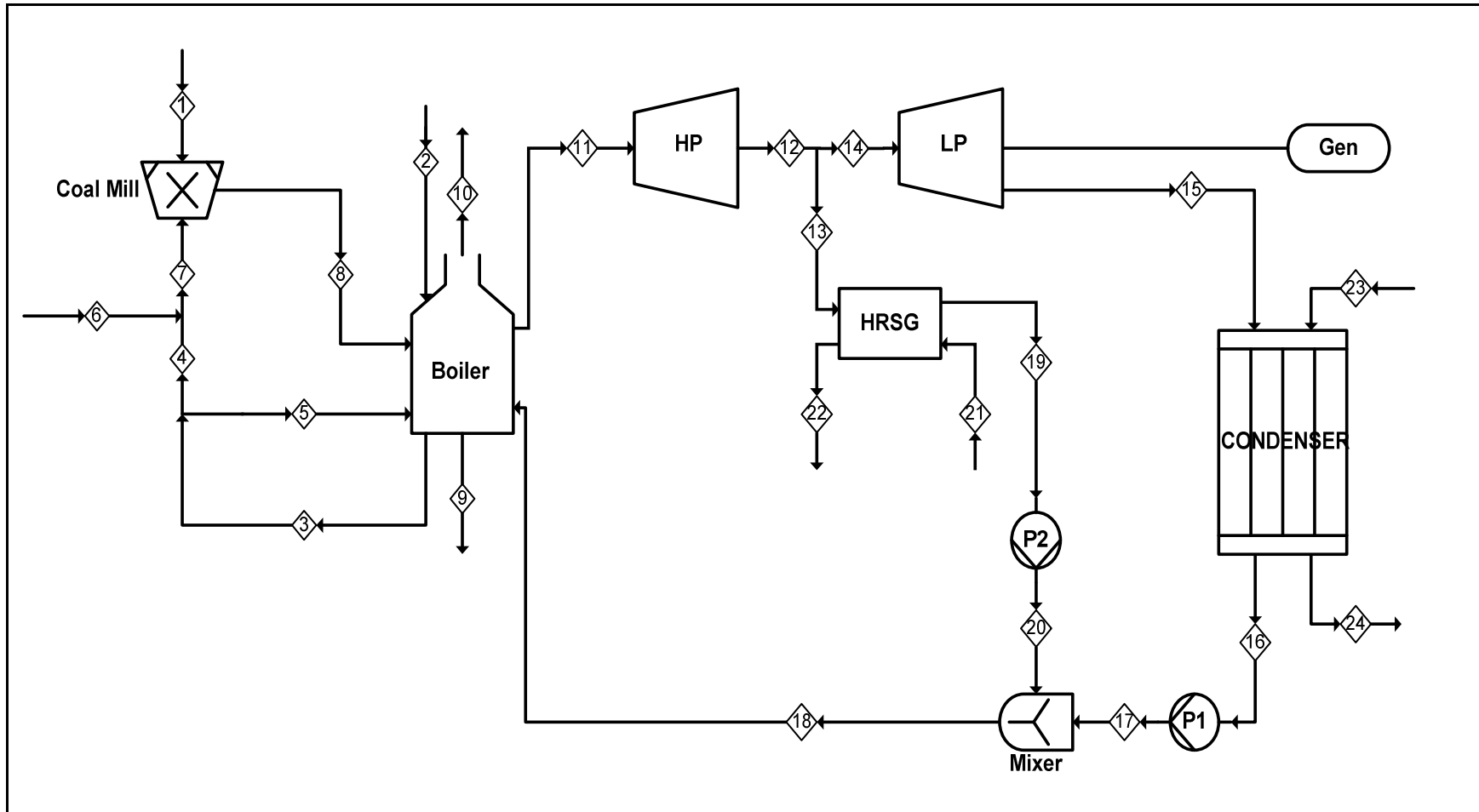


Figure 3-8 Layout of coal-fired cogeneration process

3.3.4 Operating conditions

Table 3-17 gives the temperatures, pressures and reference conditions used for the cogeneration of electricity and process steam. The percentage excess air used, together with the efficiencies of the boiler, turbines, pump, generator and HRSG, are also given in Table 3-17.

Table 3-17 Operating conditions of a coal-fired cogeneration process

Stream #	Composition	T (°C)	P (kPa)	Efficiencies	
1	AR Coal	25		<i>Boiler</i>	
2	Room Air	25	101.33	Excess Air ^a	50%
3	Hot Air	305		η_{Boiler}^b	87.3%
4	Primary Air	305		Energy Loss ^b	1.8%
5	Secondary Air	305		Energy loss from stack ^b	10.2%
6	Tempering Air	27		Energy loss from ash ^b	0.7%
7	Total Air	250			
8	Product stream	75		<i>PCS</i>	
9	Ash			η_{HPT}^c	80%
10	Stack gas			η_{LPT}^c	80%
11	Superheated steam	550	7,000	η_{P1}^c	80%
12	Superheated steam	322.6	1,150	η_{P2}^c	80%
13	Superheated steam	322.6	1,150	H_{HRSG}^d	98%
14	Superheated steam	322.6	1,150	η_{GEN}^d	98%
15	Saturated steam	45.8	10	η_{DEL}^d	95%
16	Saturated liquid	45.8	10		
17	Compressed liquid	46.5	7,000	Split Fraction	
18	Compressed liquid	102.7	7,000	Electricity	60%
19	Saturated liquid	186.1	1,150	Process steam	40%
20	Compressed liquid	187.1	7,000		
21	Saturated liquid	80	1,000	Reference Conditions	
22	Superheated steam	220	1,000	T(°C)	25
23	Saturated liquid	25	101.33	P(kPa)	101.325
24	Saturated liquid	70	101.33	T_{sat} (°C)	40

a: Amount of excess air assumed, b: Bureau of Energy Efficiency (n.d.), c: Smith *et al.* (2005), d: Ugeler and Mulder (n.d.)

3.3.5 Mass balance

Table 3-18 Mass balance of a coal-fired cogeneration process

Stream #	Composition	m (ton/hr)	Mass %	n (kmol/hr)	Mol %	V(Nm ³ /hr)	Dry Vol%	Wet Vol%
1	AR Coal	105.07						
	Coal	99.29						
	H ₂ O	5.78						
2	Room Air	1,118.22		38,759.00		868,705.57		
	N ₂	857.78	0.77	30,619.61	0.79	686,277.40	0.79	0.79
	O ₂	260.44	0.23	8,139.39	0.21	182,428.17	0.21	0.21
3	Hot Air	1,118.22		38,759.00		868,705.57		
	N ₂	857.78	0.77	30,619.61	0.79	686,277.40	0.79	0.79
	O ₂	260.44	0.23	8,139.39	0.21	182,428.17	0.21	0.21
4	Primary Air	94.23		3,266.16		73,204.54		
	N ₂	72.28	0.77	2,580.27	0.79	57,831.59	0.79	0.79
	O ₂	21.95	0.23	685.89	0.21	15,372.95	0.21	0.21
5	Secondary Air	1,023.99		35,492.84		795,501.02		
	N ₂	785.49	0.77	28,039.34	0.79	628,445.81	0.79	0.79
	O ₂	238.50	0.23	7,453.50	0.21	167,055.21	0.21	0.21
6	Tempering Air	23.81		825.11		18,493.28		
	N ₂	18.26	0.77	651.84	0.79	14,609.69	0.79	0.79

	O ₂	5.54	0.23	173.27	0.21	3,883.59	0.21	0.21
7	Total Air	118.04		4,091.28		91,697.83		
	N ₂	90.54	0.77	3,232.11	0.79	72,441.28	0.79	0.79
	O ₂	27.49	0.23	859.17	0.21	19,256.54	0.21	0.21
8	Product	223.11						
	<i>Transport Air</i>	123.81		4,412.06		98,887.48		
	N ₂	90.54	0.73	3,232.11	0.73	72,441.28	0.79	0.73
	O ₂	27.49	0.22	859.17	0.19	19,256.54	0.21	0.19
	H ₂ O	5.78	0.05	320.78	0.07	7,189.65		0.07
	<i>Dry Pulverized coal</i>	72.79		8,522.19		191,007.95		
	C	57.06	0.575	4,750.33	0.557	106,469.26	0.557	0.557
	H	3.04	0.031	3,021.07	0.354	67,711.20	0.354	0.354
	N	1.38	0.014	98.34	0.012	2,204.13	0.012	0.012
	S	1.16	0.012	36.17	0.004	810.78	0.004	0.004
	O	9.86	0.099	616.28	0.072	13,812.58	0.072	0.072
	<i>Ash</i>	26.79						
9	Ash	26.79						
10	Stack gas	1,220.30		41,017.47		919,324.66		
	CO ₂	209.06	0.171	4,750.33	0.116	106,469.26	0.121	0.116
	H ₂ O	32.99	0.027	1,831.31	0.045	41,045.25	-	0.045
	SO ₂	2.32	0.002	36.17	0.001	810.78	0.001	0.001

	N ₂	877.42	0.719	31,320.62	0.764	701,989.16	0.799	0.764
	O ₂	98.52	0.081	3,079.03	0.075	69,010.21	0.079	0.075
11	Superheated steam	582.54		32,327.23		724,550.13		
12	Superheated steam	582.54		32,327.23		724,550.13		
13	Superheated steam	233.01		12,930.89		289,820.05		
14	Superheated steam	349.52		19,396.34		434,730.08		
15	Saturated steam	349.52		19,396.34		434,730.08		
	Vapour	326.76	0.935	18,133.13		406,417.77		
	Liquid	22.76	0.065	1,263.21		28,312.31		
16	Saturated liquid	349.52		19,396.34		434,730.08		
17	Compressed liquid	349.52		19,396.34		434,730.08		
18	Compressed liquid	582.54		32,327.23		724,550.13		
19	Saturated liquid	233.01		12,930.89		289,820.05		
20	Compressed liquid	233.01		12,930.89		289,820.05		
21	Saturated liquid	249.44		13,842.67		310,255.67		
22	Superheated steam	249.44		13,842.67		310,255.67		
23	Saturated liquid	4,154.46		230,547.00		5,167,250.00		
24	Saturated liquid	4,154.46		230,547.00		5,167,250.00		

The values in Table 3-18 were are obtained from the simulation in Excel; the manual calculations can be seen in Appendix B. The mass balances are required to determine the amount of coal combusted, air used, steam generated and CO₂ emitted, through the generation of electricity and process steam. The coal required to generate the heat necessary in the process was calculated as stated above in section 3.2.2.4.

For the drying of 105.07 ton coal/hr with 5.5% moisture content, 118.04 ton/hr (91,697.83 Nm³/hr) air is required in the mill. The heat produced from the combustion of 72.79 ton DAF coal/hr in the boiler generates about 582.54 ton/h superheated steam in the PCS. Alternative B requires more steam in the PCS than alternative A due to the higher boiler inlet temperature (18) of alternative B. 40% (233.01 ton/hr) of the steam is extracted from the steam turbine at 322.6°C and 1,150 kPa to generate process heat (249.44 ton/hr steam) through a HRSG.

A total of 1142.03 ton/hr (887,198.85 Nm³/hr) air (stream 2 and 6) is extracted from the atmosphere to be used in the drying and combustion processes. The stack gas produced by the combustion of coal is mainly made up of nitrogen (76.4 mol%), CO₂ (11.6 mol%) and oxygen (7.5 mol%). The coal-fired cogeneration process produces about 209.06 tons/hr (106,469.26 Nm³/hr) CO₂ which amounts to 1.65 million tons CO₂/year (839,403,627 Nm³/year).

3.3.6 Energy balances

Coal mill

The energy balance of the coal mill is given below.

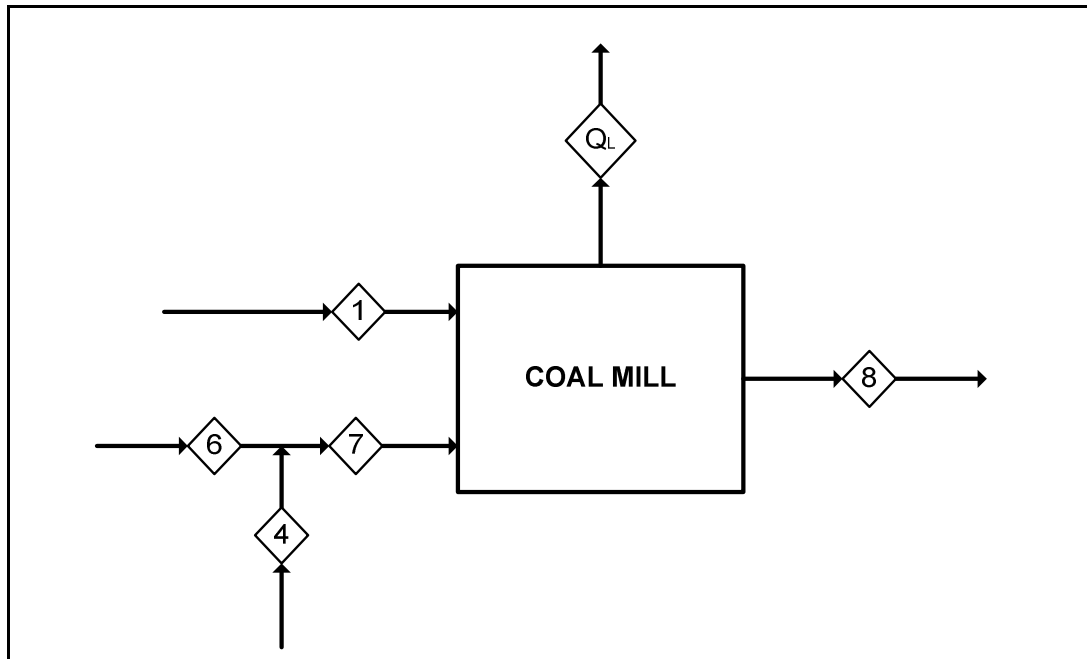


Figure 3-9 Energy balance of coal mill (coal-fired cogeneration process)

Table 3-19 Energy balance of coal mill (coal-fired cogeneration process)

		ΔH (kJ/mol)	Q (kJ/hr)	Q (MW)
1	AR Coal [#]	0.00	0.00	0.00
	Coal	0.00	0.00	0.00
	H ₂ O	0.00	0.00	0.00
4	Primary Air	50.69	27,255,659.17	7.57
	N ₂	25.89	5,918,172.22	1.64
	O ₂	24.81	21,337,486.95	5.93
6	Tempering Air	0.351	48,073.71	0.01
	N ₂	0.176	10,187.47	0.00
	O ₂	0.174	37,886.24	0.01
7	Total Air	40.49	27,303,732.88	7.58
	N ₂	20.63	5,907,146.16	1.64
	O ₂	19.86	21,396,586.72	5.94
8	Product Stream			6.83
	Transport Air	8.82	20,626,306.79	5.73
	N ₂	4.37	4,706,760.46	1.31
	O ₂	4.45	1,274,264.97	0.35
	H ₂ O		14,645,281.36	4.07
	Heat water(l) (T_1 to T_{sat}) [*]	3.36	359,269.66	0.10
	Evaporate water at T_{sat} [*]		13,904,040.18	3.86
	Heat water(g) (T_{sat} to T_8) [*]	3.57	381,971.52	0.11
	Dry Pulverized coal		3,947,052.80	1.10
	Q_{IN}			7.58
	Q_{OUT}			6.83
	Q_{LOSS}			0.75
	Q_{TOTAL OUT}			7.58

#Values are zero due to the inlet temperature and the reference temperature being the same; * Sum gives the total for H₂O

Boiler

The energy balance of the boiler is given below.

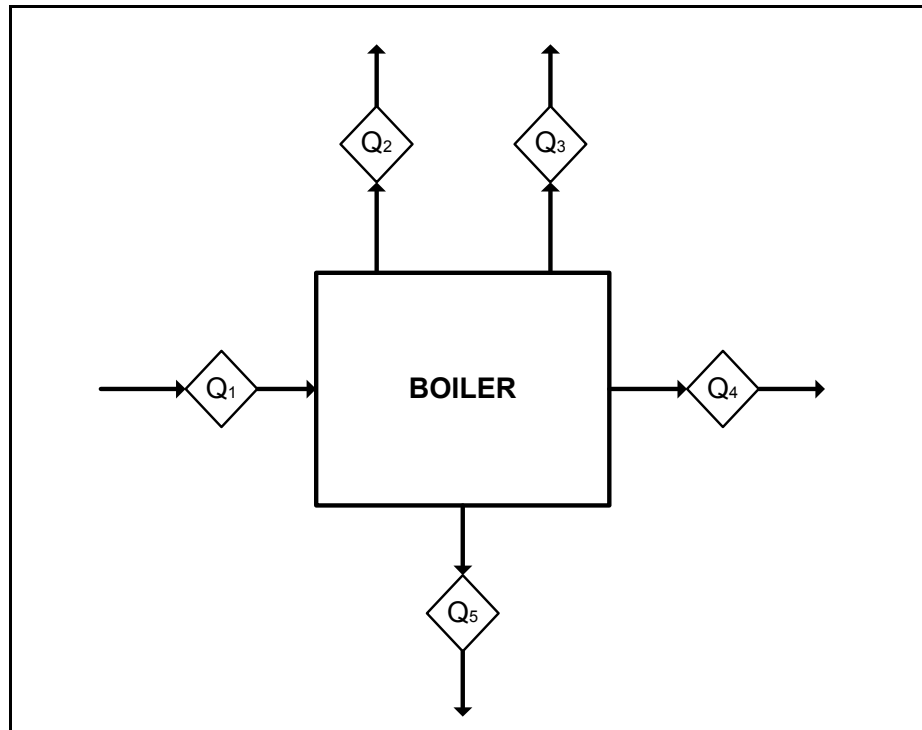


Figure 3-10 Energy balance of boiler (coal-fired cogeneration process)

Table 3-20 Energy balance of boiler (coal-fired cogeneration process)

	Q (MW)
Q₁	572.74
Q₂	10.31
Q₃	58.42
Q₄	500
Q₅	4.01
TOTAL	572.74

Power conversion system (PCS)

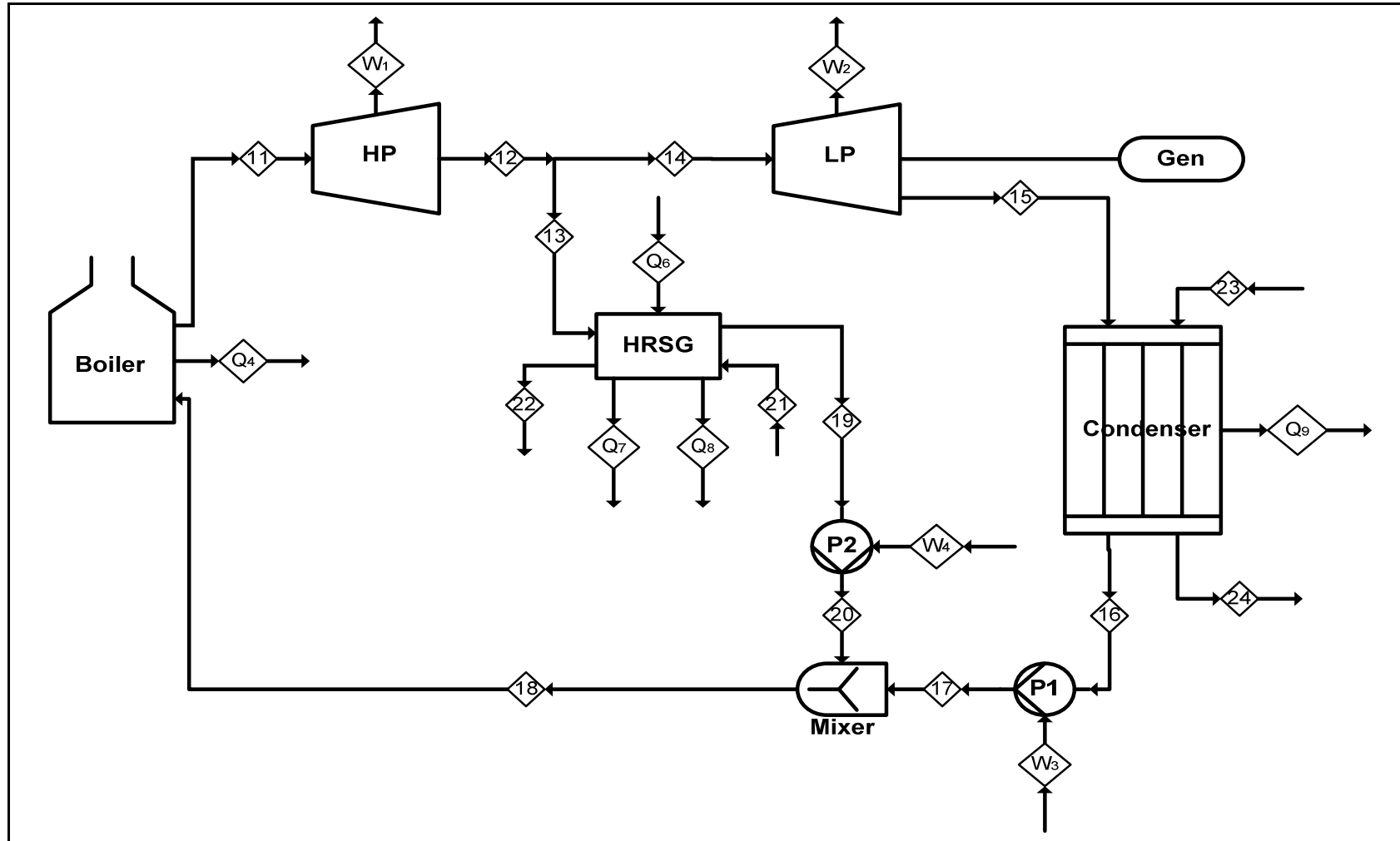


Figure 3-11 Energy balance of PCS (Coal-fired cogeneration process)

In Table 3-21 the specific enthalpies and heat load in each stream at the respective temperature and pressure are given. The energy balance of the PCS is given in Table 3-22. The efficiency of the process is also included in Table 3-23.

Table 3-21 Specific enthalpy and heat of each stream (coal-fired cogeneration process)

Stream #	Composition	T (°C)	P (kPa)	H (kJ/kg)	Q(MW)
11	Superheated steam	550	7,000	3,529.60	571.14
12	Superheated steam	322.6	1,150	3,096.97	501.14
13	Superheated steam	322.6	1,150	3,096.97	200.46
14	Superheated steam	322.6	1,150	3,096.97	300.68
15	Saturated steam	45.8	10	2,428.77	235.81
16	Saturated liquid	45.8	10	191.80	18.62
17	Compressed liquid	46.5	7,000	200.63	19.48
18	Compressed liquid	102.7	7,000	439.67	71.14
19	Saturated liquid	186.1	1,150	789.92	51.13
20	Compressed liquid	187.1	7,000	798.22	51.67
21	Saturated liquid	80	1,000	762.61	52.84
22	Superheated steam	220	1,000	2,874.60	199.18
23	Saturated liquid	25	101.33	104.80	120.94
24	Saturated liquid	70	101.33	293.00	338.13

Table 3-22 Energy balance of PCS (coal-fired cogeneration process)

PCS					
	Q (MW)	$(\Delta H)_{\text{isentropic}}$ (kJ/kg)	ΔH (kJ/kg)	$W_{\text{isentropic}}$ (MW)	W (MW)
Q₄	500	-	3,089.93	-	-
Q₆	-146.33	-	-2,307.06	-	-
Q₉	-217.19	-	-2,236.97	-	-
W₁	-	-540.78	-432.63	-87.51	-70.01
W₂	-	-835.26	-668.21	-81.09	-64.88
W₃	-	7.06	8.83	0.69	0.86
W₄	-	6.64	8.31	0.43	0.54
TOTAL	133.49				-133.49

HRSG balance	
Q₆	149.33
Q₇	-146.34
Q₈	2.99

The symbols used in the energy balance represent the following:

- Q₁ = Heat introduced into the boiler through the combustion process.
- Q₂ = Heat loss from the boiler.
- Q₃ = Heat loss to the stack.
- Q₄ = Heat transferred to the PCS.
- Q₅ = Heat loss in the ash.
- Q₆ = Heat input to the HRSG
- Q₇ = Heat output from the HRSG to the CTL process
- Q₈ = Heat loss from the HRSG to the environment
- Q₉ = Rejected latent heat by the condensation process to the environment.

W_1 = Power generated by the HP turbine.

W_2 = Power generated by the LP turbine.

W_3 = Power required by the pump 1.

W_4 = Power required by the pump 2.

Table 3-23 Efficiency of coal-fired cogeneration process

W_{net} (MW)	133.49
W_e (MW)	124.28
Q_t (MW)	146.34
η_t	56.56%
η_{tot}	47.25%

The symbols used in Table 3-23 have the following meanings:

- W_{net} The net work produced by the PCS. The net work is the work generated by the turbines minus the work required by the pumps.
- W_e The electrical power (electricity) produced by the process. It is the net work multiplied by the generator and delivery efficiencies.
- Q_t The thermal energy produced by the process. This energy is transferred to the CTL process in the form of process steam.
- η_t Thermal efficiency of the PCS. It is calculated by dividing the net work produced by the PCS with the heat that is introduced into the PCS (excluding the boiler efficiency).
- η_{tot} Total efficiency of the process. It is calculated by dividing the sum of the electrical power and thermal energy generated by the process by the total heat input into the process (including boiler efficiency).

These tables were obtained from the simulation in Excel; the manual calculations can be seen in Appendix B.

The energy and mass balances were calculated according to the design specifications, combustion reactions and operating conditions. The specific enthalpies were either calculated using the equations from Smith *et al.* (2005) or obtained from the steam tables. The energy balances are required to determine the electricity, process heat generated and the thermal and total efficiencies of the process.

Using coal with a CV of 28.44 MJ/kg, 105.07 ton/hr coal (AR) is required to produce 572.74 MW_t, with 500 MW_t transferred to the PCS to generate superheated steam. From the 500MW_t entered into the process only 56.56% is converted into useable energy (124.29 MW_e (electrical power) and 146.34 MW_t (process steam)) with the balance lost to the environment due to mechanical and thermal efficiencies.

The mass and energy balances of the coal mill and boiler were performed as stated above in section 3.2.2.5. Heat losses of 10% from the coal mill were assumed. The heat generated in the boiler is due to the combustion of coal. The efficiencies given in Table 3-17 were used to perform the energy balance of the boiler given in Table 3-22.

The mass balance and energy balances of the PCS were performed as stated above in section 3.2.3.5. The heat transferred to the CTL was calculated by multiplying the specific enthalpy difference over the HRSG on the PCS side with the mass flow rate through the HRSG. The mass flow rate of the process steam was calculated by dividing the heat transferred to the CTL through the HRSG with the specific enthalpy difference over the HRSG on the CTL side.

3.3.7 Consumption and discharge figures

In this section the amount of each commodity required and the amount of waste generated for the production of electricity (124.28 MW_e) and process steam (146.34 MW_t transferred to CTL process, 249.44 ton/hr with a heat load of 199.18 MW_t) is given. These quantities are essential for the production cost analysis and for comparing this process route with the alternative nuclear cogeneration processes.

The consumption and discharge figures of the coal-fired cogeneration process are given in Table 3-24.

Table 3-24 Consumption figures of Alternative B: Coal-based Process Route

	Coal-fired cogeneration plant
Coal (Ton/hr)	105.07
Coal (ton/year)	828,373.49
Coal (ton/MWh)	0.39
Air (ton/hr)	1,142.03
Air (ton/year)	9,003,742.09
Air (ton/MWh)	4.22
PCS Steam (ton/hr)	582.54
PCS Steam (ton/year)	4,592,718.77
PCS Steam (ton/MWh)	2.15
Process Steam (ton/hr)	249.44
Process Steam (ton/year)	1,966,623.08
Process Steam (ton/MWh)	0.92
Cooling water (ton/hr)	4,154.46
Cooling water (ton/year)	32,753,739.07
Cooling water (ton/MWh)	15.35

The yearly consumption and discharge figures were calculated by using the *hr/year* operation figure given in section 3.2.1. The ton/MWh was calculated by dividing the ton/hr value by the total MW's (MW_e plus MW_t) produced by the coal-fired cogeneration process.

Table 3-25 Discharge figures of Alternative B: Coal-based process route

	Coal-fired cogeneration plant
Ash (ton/hr)	26.79
Ash (ton/year)	211,235.24
Ash (ton/MWh)	0.10
Stack gas (ton/hr)	1,220.30
Stack gas (ton/year)	9,620,879.84
Stack gas (ton/MWh)	4.51
CO₂ (ton/hr)	209.06
CO₂ (ton/year)	1,648,209.26
CO₂ (ton/MWh)	0.77
O₂ (ton/hr)	98.52
O₂ (ton/year)	776,752.74
O₂ (ton/MWh)	0.36
H₂O (ton/hr)	32.99
H₂O (ton/year)	260,099.20
H₂O (ton/MWh)	0.12
SO₂ (ton/hr)	2.32
SO₂ (ton/year)	18,271.09
SO₂ (ton/MWh)	0.01
N₂ (ton/hr)	877.42
N₂ (ton/year)	6,917,547.54
N₂ (ton/MWh)	3.24

The cogeneration of electricity and process steam generates about 209.06 ton of CO₂ per hour (1.65 million ton/year), and consumes about 828,373.49 tons of coal per year.

3.4. Summary

A process overview, together with the mass and energy balances, and discharge and consumption figures of the two coal-based process routes for the generation of electricity and process steam are given in this chapter. Both of these processes function on the Rankine thermodynamic cycle and utilise a coal mill, coal-fired boiler, steam turbines, condensers and pumps with the addition of a HRSG in the cogeneration process.

These processes consume large quantities of coal and emit large quantities of CO₂ during the production of electricity and process steam. The coal consumption and CO₂ discharge of both processes are given in the table below.

Table 3-26 Coal consumption and CO₂ emissions of Alternative A and B: Coal-based process route

	Alternative A		Alternative B
	Process Steam Generation	Electricity Generation	Cogeneration
Coal Consumption (ton/hr)	30.75	105.07	105.07
CO₂ Discharge (ton/hr)	61.19	209.06	209.06

The electricity and process steam generation of both processes are given in the table below.

Table 3-27 Electricity and process heat of Alternative A and B: Coal-based process route

	Alternative A		Alternative B
	Process Steam Generation	Electricity Generation	Cogeneration
Electricity (MW_e)	-	152.70	124.28
Process heat (MW_t)	146.34	-	146.34
Process Steam (ton/hr)	249.44	-	249.44

It was assumed that complete combustion takes place in the boiler, thus the CO formed during the combustion process, is converted into CO₂. From these figures, it is quite obvious that these processes produce vast quantities of carbon dioxide, thus contributing a great deal towards the global warming problem.

Both alternatives A and B utilise a 500MW_t (heat transferred to the PCS, not total heat generated) boiler to generate electrical power, with the addition of process steam generation in Alternative B. Alternative B generates less electrical power than alternative A due to the fact that a fraction of the steam is extracted from the steam turbine to generate process steam, but has a higher thermal efficiency than Alternative A due to the simultaneous generation of process steam and electricity.

The simultaneous generation of process steam and electricity making use of nuclear heat generated by a HTGR will be discussed next. Two possible processes, a steam turbine and gas turbine process will be discussed.

CHAPTER 4. NUCLEAR HEAT PROCESS ROUTE

4.1. Introduction

Two nuclear-based process routes were chosen for the cogeneration of electricity and steam and will be discussed in this section. They include the indirect extraction/condensing steam turbine cogeneration system and the indirect closed cycle gas turbine cogeneration system.

The following topics are examined in depth for the two nuclear-based cogeneration process routes:

- Mass balance.
- Energy balance.
- Consumption/discharge figures.

The main focus points of this study are:

- To compare the CO₂ emissions, efficiencies, steam and electricity production with that of the coal-based process route.

The process design criteria, operating conditions, process description and process flow diagram (PFD) of each nuclear heat based route are also given in their respective sections.

4.2. Alternative A: Indirect extraction/condensing steam turbine cogeneration system

The simultaneous generation of electricity (MW_e) and steam (MW_t) utilising a HTGR as primary energy source and the conventional Rankine thermodynamic cycle will be discussed in this section. For an overview of cogeneration please refer to section 2.2.

The design criteria that were used in the study, together with the mass and energy balances, are given and discussed below.

4.2.1 Process design criteria

Plant availability	90%
Operational time	24 hrs/day, 7 days/week
Operational days/year	328.5 days/year
Operational hours/year	7884 hrs/year
Electricity production rate	113.27 MW_e
Thermal energy production	147.01 MW_t
Steam production rate	250.59 ton/hr

The following assumptions were made to simplify the Excel calculations.

- A constant helium heat capacity was assumed: 5.2 kJ/kg K
- No significant pressure drop over HTGR, IHX, SG, HRSG, mixer and condenser occurred.
- No significant pressure drop over pipes occurred.
- No heat loss over the HTGR to the environment occurred.

- The nuclear fuel used to generate the heat required in the HTGR will not be brought into account in this study due to the small influence it has on the production cost.
- No re-heating or pre-heating of the steam in the PCS.

4.2.2 *General process description*

The same steam cycle layout is used for the indirect extraction/condensing steam cogeneration process as for the coal-based cogeneration process.

In the extraction/condensing cogeneration system, a HTGR such as the PBMR is used as the primary heat source for cogeneration of electricity and process steam.

A 500 MW_t HTGR is used with helium as the working fluid in PHTS and SHTS and water as the working fluid in the PCS. The process flow diagram of the indirect extraction/condensing steam turbine cogeneration process is given in section 4.2.3. For the purpose of the cogeneration an extraction/ condensing steam turbine will be used, as discussed in section 2.2.2.1. The turbine used in the process flow diagram is split to simplify the calculations, but functions as an extraction/condensing steam turbine.

An indirect cycle was chosen due to the advantage of separating the nuclear reactor from the process. An indirect cycle has the disadvantage of lowering process efficiency. A Rankine PCS can only be coupled to a HTGR in an indirect fashion, due to the fact that the working fluid in a HTGR is a non-condensable gas, and in a Rankine cycle a condensable fluid is used (Van Eck, 2010). High pressure steam generated in the SG is expanded over a steam turbine, turning the shaft which is connected to an electrical generator, generating electricity.

One of the advantages of the HTGR is the high operating temperature conditions, but due to the fact that the temperature of the steam entering the steam turbine is limited by the material properties of the steam turbine, helium at 700 °C and 5000kPa will be used (Ugeler & Mulder, n.d.). IHX and SG efficiencies of 99% were assumed (Ugeler & Mulder, n.d.). The same

process steam conditions, efficiencies and steam split fraction as the coal-based cogeneration process will be used.

For a more detailed description of the indirect extraction condensing steam turbine process, please refer to section 2.4.2 and section 3.3.2. The operating conditions are given in section 4.2.4, followed by the mass (section 4.2.5) and energy (section 4.2.6) balances.

4.2.3 Process flow diagram

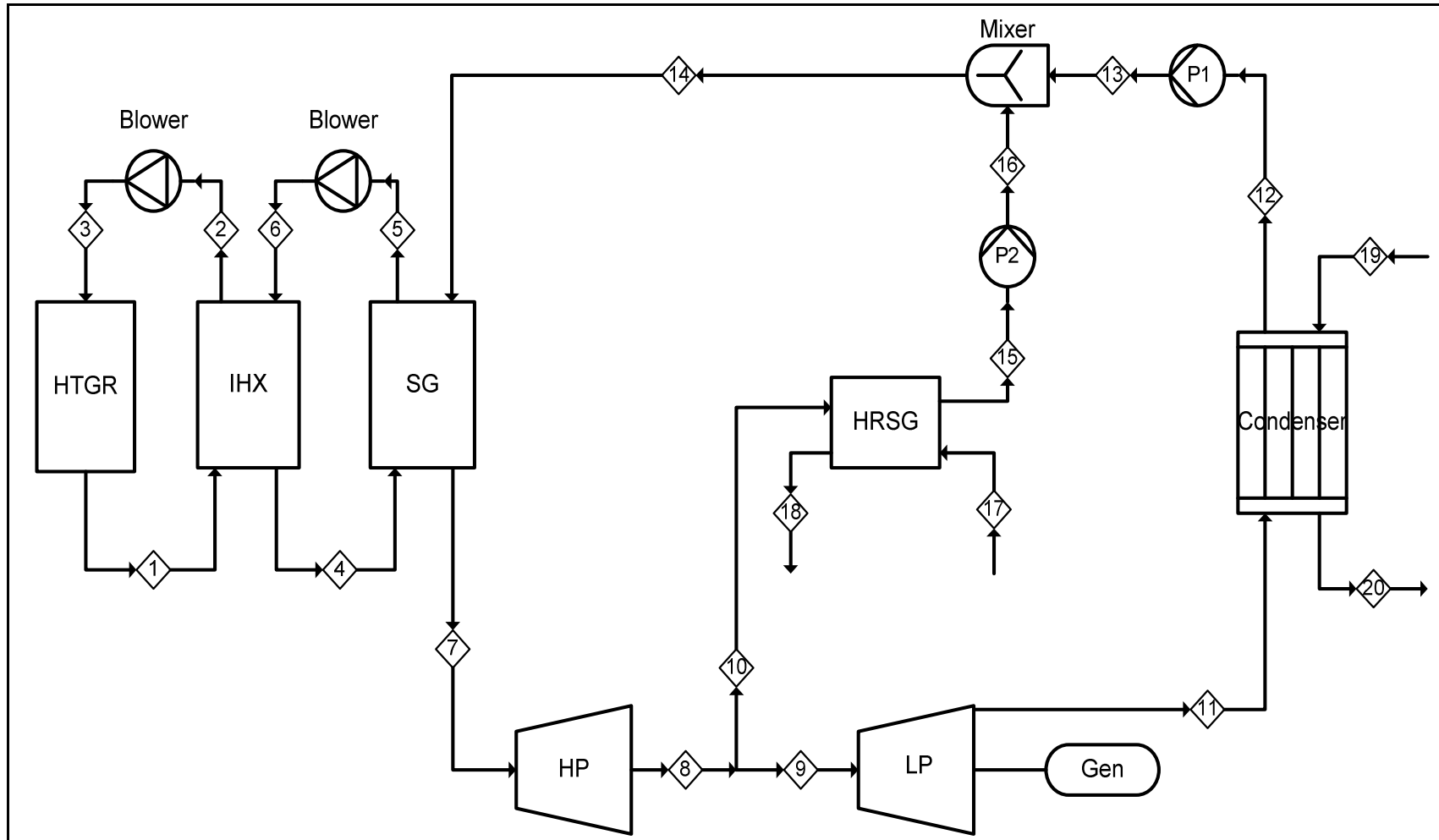


Figure 4-1 Layout of extraction/condensing steam turbine cogeneration process

4.2.4 Operating conditions

In Table 4-1 the temperatures, pressures and reference conditions used in the cogeneration process are given. The efficiencies together with the steam split fraction are also given below.

Table 4-1 Operating conditions of an extraction/condensing steam turbine cogeneration process

Stream #	Composition	T (°C)	P (kPa)	Efficiencies	
1	Helium	700	5,000	<i>PHTS</i>	
2	Helium	295	5,000	η_{IHX}^a	99%
3	Helium	300	5,000	η_{SG}^a	99%
4	Helium	650	5,000		
5	Helium	240	5,000	<i>PCS</i>	
6	Helium	245	5,000	η_{HPT}^b	80%
7	Superheated steam	550	7,000	η_{LPT}^b	80%
8	Superheated steam	322.6	1,150	η_{P1}^b	80%
9	Superheated steam	322.6	1,150	η_{P2}^b	80%
10	Superheated steam	322.6	1,150	η_{HRSG}^a	98%
11	Saturated steam	45.8	10	η_{GEN}^a	98%
12	Saturated liquid	45.8	10	η_{DEL}^a	95%
13	Compressed liquid	45.8	7,000		
14	Compressed liquid	102.7	7,000	Split Fraction^c	
15	Saturated liquid	186	1,150	Electricity	60%
16	Compressed liquid	187	7,000	Process Steam	40%
17	Saturated liquid	80	1,000		
18	Superheated steam	220	1,000	Temperature difference	
19	Saturated liquid	25	101	ΔT_{IHX} (°C)	50
20	Saturated liquid	70	101	ΔT_{SG} (°C)	100

a: Ugeler and Mulder (n.d.), b: Smith *et al.* (2005), c: The split fraction was assumed.

4.2.5 Mass balance

Table 4-2 Mass balance of the extraction/condensing steam turbine cogeneration process

Stream #	Composition	m (ton/hr)	Mass %	n (kmol/hr)	V (Nm ³ / hr)
1	Helium	865.38		216,205.62	4,845,816.57
2	Helium	865.38		216,205.62	4,845,816.57
3	Helium	865.38		216,205.62	4,845,816.57
4	Helium	856.73		214,043.56	4,797,358.40
5	Helium	856.73		214,043.56	4,797,358.40
6	Helium	856.73		214,043.56	4,797,358.40
7	Superheated steam	585.22		32,483.22	728,046.49
8	Superheated steam	585.22		32,476.01	727,884.88
9	Superheated steam	351.13		19,485.61	436,730.93
10	Superheated steam	234.09		12,990.41	291,153.95
11	Saturated steam	351.13		19,485.61	436,730.93
	Vapour	328.26	0.93	18,216.59	408,288.43
	Liquid	22.87	0.07	1,269.02	28,442.50
12	Saturated liquid	351.13		19,485.61	436,730.93
13	Compressed liquid	351.13		19,485.61	436,730.93
14	Compressed liquid	585.22		32,476.01	727,884.88
15	Saturated liquid	234.09		12,990.41	291,153.95
16	Compressed liquid	234.09		12,990.41	291,153.95
17	Saturated liquid	250.59		13,906.40	311,684.05
18	Superheated steam	250.59		13,906.40	311,684.05
19	Saturated liquid	4173.58		231,608.16	5,191,033.75
20	Saturated liquid	4173.58		231,608.16	5,191,033.75

The values given in Table 4-2 were obtained from the simulation in Excel; the manual calculations can be seen in Appendix C. The mass balances are required to determine the amount of helium and steam used and process steam generated.

The mass balance of the process was performed using the method and equations given by Smith *et al.* (2005). The helium flow rate required in the PHTS was calculated by dividing the heat input into the process through the HTGR by the heat capacity of helium and the temperature difference of the streams entering and exiting the HTGR. The helium required in the SHTS was calculated in the same manner in this case the heat input from the PHTS to the SHTS through the IHX was used.

To remove the heat generated in the HTGR, 856.73 ton/hr helium is required in the SHTS. This heat ultimately generates 585.22 ton/hr superheated steam which is used to generate electricity and process steam. 234.03 ton/hr superheated steam is extracted from the turbine to generate 250.59 ton/hr process steam which is sent to the CTL process.

One of the advantages of using a HTGR as the primary energy source is that no CO₂ is generated and emitted from the process, which assists to reduce the carbon foot print of a CTL process.

4.2.6 Energy balance

Primary cycle:

The energy balance of the primary and intermediate helium cycles are given below.

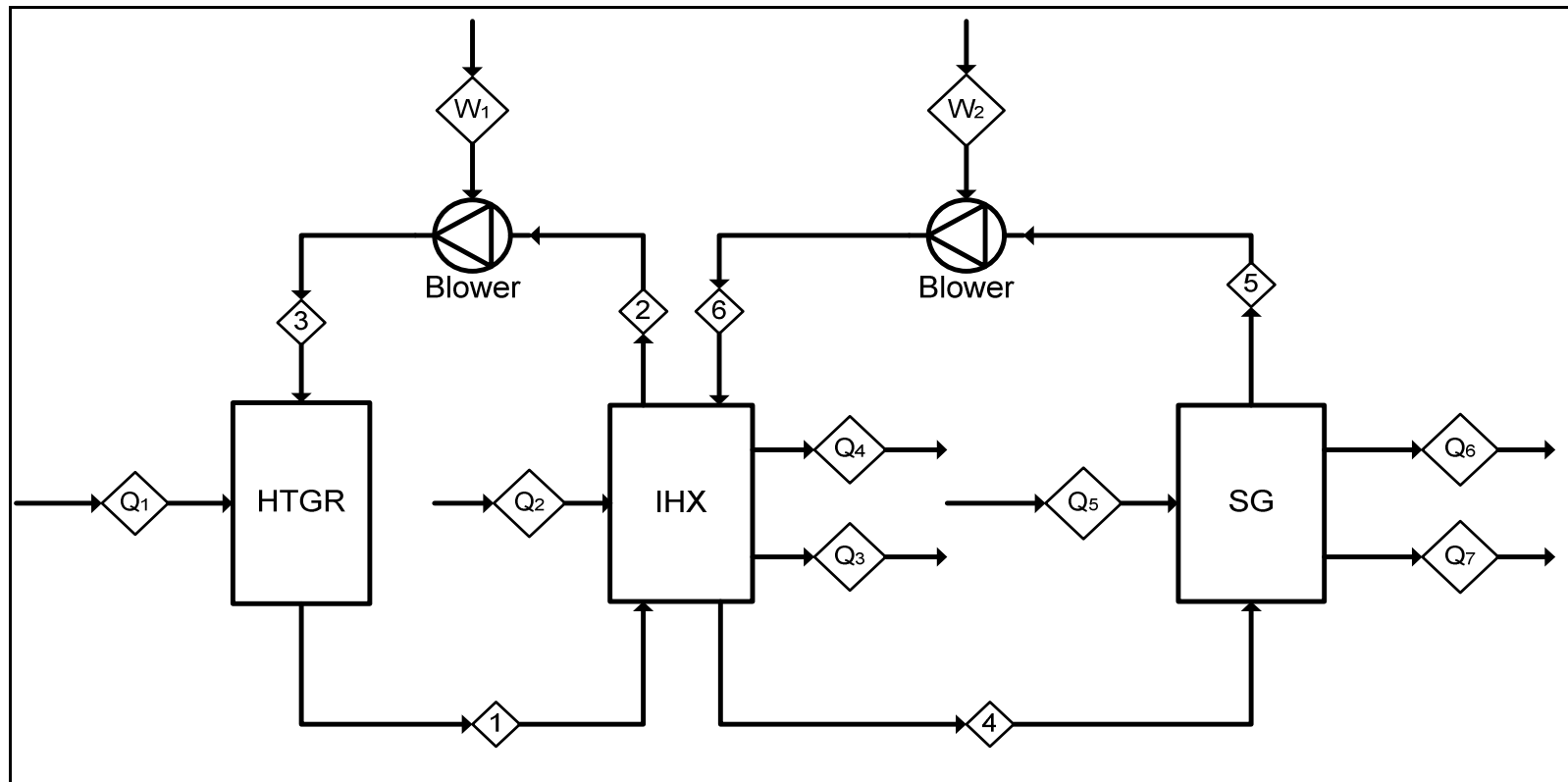


Figure 4-2 Energy balance of primary and intermediate cycle (extraction/condensing steam turbine cogeneration processes)

Table 4-3 Energy balance of PHTS and SHTS (extraction/condensing steam turbine cogeneration process)

PHTS		
	Q(MW)	W(MW)
Q₁	500	-
W₁	-	6.25
Q₂	-506.25	-
TOTAL	-6	6

SHTS		
Q₃	501.19	-
W₂	-	6.19
Q₅	-507.38	-
TOTAL	-6.19	6.19

IHX Balance	
Q₂	506.25
Q₃	-501.19
Q₄	5.06

SG Balance	
Q₅	507.38
Q₆	-502.37
Q₇	5.07

Power conversion system (PCS)

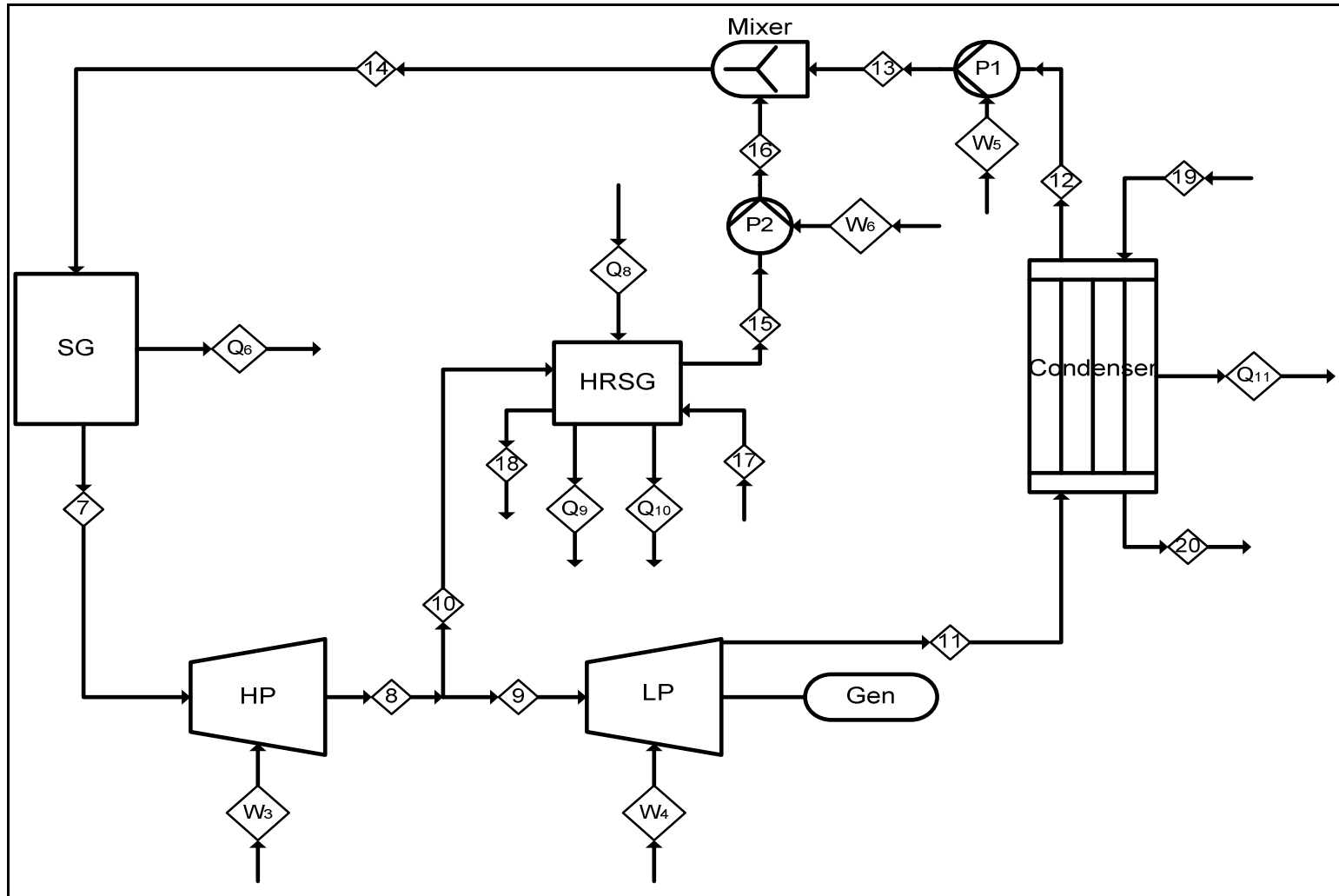


Figure 4-3 Energy balance of the PCS (Extraction/condensing steam turbine cogeneration system)

In Table 4-4 the specific enthalpies and heat load of each stream in the PCS at the respective temperature and pressure are given. The energy balance of the PCS is given in Table 4-5. The efficiency of the process is also included in Table 4-6.

Table 4-4 Specific enthalpy and heat load of each stream (extraction/condensing steam turbine cogeneration process)

Stream #	Composition	T (°C)	P (kPa)	H (kJ/kg)	Q (MW)
7	Superheated steam	550	7,000	3,529.60	573.77
8	Superheated steam	322.6	1,150	3,096.98	503.45
9	Superheated steam	322.6	1,150	3,096.98	302.07
10	Superheated steam	322.6	1,150	3,096.98	201.38
11	Saturated steam	45.8	10	2,428.77	236.89
12	Saturated liquid	45.8	10	191.80	18.71
13	Compressed liquid	45.8	7,000	200.63	19.57
14	Compressed liquid	102.7	7,000	439.67	71.47
15	Saturated liquid	186	1,150	789.92	51.36
16	Compressed liquid	187	7,000	798.22	51.90
17	Saturated liquid	80	1,000	762.61	53.08
18	Superheated steam	220	1,000	2,874.60	200.10
19	Saturated liquid	25	101.33	104.80	121.50
20	Saturated liquid	70	101.33	293.00	339.68

The symbols used in the energy balance represent the following:

Q_1 = Heat introduced by the HTGR.

Q_2 = Heat input from the PHTS to the IHX

Q_3 = Heat output from the IHX to the SHTS

Q_4 = Heat loss from the IHX to the environment

Q_5 = Heat input from the SHTS to the SG

Q_6 = Heat output from the SG to the PCS

Q_7 = Heat loss from the SG to the environment

Q_8 = Heat input to the HRSG

Q_9 = Heat output from the HRSG to the CTL process

Q_{10} = Heat loss from the HRSG to the environment

Q_{11} = Rejected latent heat by the condensation process to the environment.

W_1 = Power required by blower 1

W_2 = Power required by blower 2

W_3 = Power generated by the HP turbine.

W_4 = Power generated by the LP turbine.

W_5 = Power required by the pump 1.

W_6 = Power required by the pump 2.

Table 4-5 Energy balance of PCS (extraction/condensing steam turbine cogeneration process)

PCS					
W_3	-	-540.78	-432.62	-87.91	-70.3
W_4	-	-835.26	-668.21	-81.47	-65.2
W_5	-	7.06	8.83	0.69	0.9
W_6	-	6.64	8.31	0.43	0.5
Q_6	502.3	-	3,089.93	-	-
Q_8	-150	-	-2,307.06	-	-
Q_{11}	-218.2	-	-2,236.97	-	-
TOTAL	134.10				-134.10

HRSG Balance	
Q_8	150
Q_9	-147
Q_{10}	3

Table 4-6 Efficiencies of extraction/condensing steam turbine cogeneration process

$W_{\text{net PCS}}(\text{MW})$	134.10
$W_{\text{net TOT}}(\text{MW})$	121.66
$W_e(\text{MW})$	113.27
$Q_t(\text{MW})$	147.01
η_t	56.6%
η_{tot}	52.1%

The symbols used in Table 4-6 have the following meanings:

- $W_{\text{net PCS}}$ The net work produced by the PCS. The net work is the work generated by the turbines minus the work required by the pumps.
- $W_{\text{net tot}}$ The net work produced by the process. This is the net work of the PCS minus the work required by the blowers in the PHTS and SHTS.
- W_e The electrical power (electricity) produced by the process. It is the net work of the process ($W_{\text{net tot}}$) multiplied by the generator and delivery efficiencies.
- Q_t The thermal energy produced by the process. This energy is transferred to the CTL process in the form of process steam.
- η_t Thermal efficiency of the PCS. It is calculated by dividing the net work produced by the PCS ($W_{\text{net PCS}}$) with the heat that is introduced into the PCS (excluding the blower requirements).
- η_{tot} Total efficiency of the process. It is calculated by dividing the sum of the electrical power and thermal energy generated by the process by the total heat input into the process (including blower requirements).

These tables are obtained from the simulation in Excel; the manual calculations can be seen in Appendix C.

The energy and mass balances were calculated according to the design specifications and operating conditions. The energy balances are required to determine the electricity, process

heat generated and the thermal and total efficiencies of the process. The specific enthalpies were either calculated using the equations from Smith *et al.* (2005) or obtained from the steam tables.

From the 500MW_t entered into the process, only 52.1% is converted into useable energy (113.27 MW_e (electrical power) and 147.01 MW_t (process steam)) with the balance lost to the environment. The electrical output of this process is smaller than the electrical output of the coal-based cogenerations process (see Table 3.23) due to the extra requirements of the blowers.

The heat transferred and power required in the PHTS and SHTS were calculated using the formulas given by Smith *et al.* (2005). They were calculated by multiplying the helium flow rate by the heat capacity of helium and the temperature differences of the streams entering and exiting the specific section.

The mass balance and energy balances of the PCS were performed as stated above in section 3.2.3.5.

4.2.7 Consumption and discharge figures

In this section the amount of each commodity required to produce electricity (113.27 MW_e) and process steam (147.01 MW_t , 250.59 ton/hr with a heat load of 200.10 MW_t) is given. There is no discharge from this process due to the constant circulation of the working fluids, and no greenhouse gasses etc. are generated or emitted from a HTGR. These quantities are essential for the production cost analysis and for comparing this process route with the alternative nuclear and coal-based cogeneration processes.

The consumption figures of the extraction/condensing steam turbine cogeneration process are given in Table 4-7.

Table 4-7 Consumption figures of extraction/condensing steam turbine cogeneration process

	Extraction/condensing steam turbine cogeneration process
Helium (ton/hr)	856.73
Helium (ton/year)	6,754,465.38
Helium (ton/MWh)	3.29
PCS Steam (ton/hr)	585.22
PCS Steam (ton/year)	4,613,856.76
PCS Steam (ton/MWh)	2.25
Process Steam (ton/hr)	250.59
Process Steam (ton/year)	1,975,677.21
Process Steam (ton/MWh)	0.96
Cooling water (ton/hr)	4173.58
Cooling water (ton/year)	32,904,497.57
Cooling water (ton/MWh)	16.03

The yearly consumption figures and ton/MWh were calculated as stated above in section 3.3.7.

The cogeneration of electricity and steam using a HTGR, such as the PBMR, coupled to a closed cycle gas turbine will be discussed next.

4.3. Alternative B: Indirect closed-cycle gas turbine cogeneration system

The simultaneous generation of electricity (MW_e) and steam (MW_t) utilising a HTGR as primary energy source and the conventional Brayton thermodynamic cycle will be discussed in this section. For an overview of cogeneration please refer to section 2.2. The design criterion that was used in the study together with the mass and energy balances are discussed below.

4.3.1 Process design criteria

Plant availability	90%
Operational time	24 hrs/day, 7 days/week
Operational days/year	328.5 days/year
Operational hours/year	7886 hrs/year
Electricity production rate	115.13 MW_e
Thermal energy production	136.9 MW_t
Steam production rate	233.42 ton/hr

The following assumptions were made to simplify the Excel calculations.

- A constant helium heat capacity was assumed: 5.2 kJ/kg K.
- No significant pressure drop over HTGR, IHX, Recuperator and HRSG occurred.
- No significant pressure drop over pipes occurred.
- No heat loss over the HTGR to the environment occurred.
- The nuclear fuel used to generate the heat required in the HTGR will not be brought into account in this study due to the small influence it has on the production cost.

4.3.2 *General process description*

The closed-cycle gas turbine cogeneration process functions on the conventional Brayton thermodynamic cycle and uses a HTGR, such as the PBMR, as the primary heat source. One advantage of the Brayton cycle is that it can be operated directly coupled to a nuclear reactor which could further improve efficiencies.

However, there are other disadvantages associated with this, such as possible fission product contamination of the turbine blades and the fact that all the Brayton cycle components have to be designed to nuclear licensing codes. Thus an indirect cycle was chosen due to the advantage of separating the nuclear reactor from the process. Helium gas turbine technology holds some risk for near-term deployment as it needs development; it has not been demonstrated in a commercial nuclear power plant as yet (Van Eck, 2010).

A 500MW_t HTGR is used with helium as the working fluid in the PHTS and the PCS. The process flow diagram of the closed-cycle gas turbine cogeneration process is given in section 4.3.3. A closed-cycle gas turbine cogeneration process will be used for the simultaneous generation of electricity and steam as discussed in section 2.2.2.2. Helium at a temperature of 900°C is extracted from the HTGR and used for cogeneration (Ugeler & Mulder, n.d.).

The heat generated in the HTGR is removed by the helium in the PHTS (1) and transferred to the helium in the PCS using an IHX (4). It was assumed the IHX is 99% efficient and has a temperature drop of 50°C (Ugeler & Mulder, n.d.).

The high temperature and pressure helium leaving the IHX on the PCS side is expanded over a gas turbine to generate electricity. A gas turbine pressure ratio of 3.4 was assumed. The helium gas leaving the turbine is still at high temperature and pressure (6) and sent through a HRSG where the waste heat is recovered in the form of useful thermal energy. This recovered thermal energy is sent to the CTL process in the form of superheated steam (13) and returned to the HRSG as saturated liquid (12). The same process steam conditions as the coal and nuclear steam based cogeneration process will be used.

The energy in the helium leaving the HRSG (6) is recuperated exchanging heat by the helium entering the IHX (11) using a recuperator. It was assumed that the recuperator is 100% efficient and has a temperature drop of 30 °C (Ugeler & Mulder, n.d.). The helium leaving the recuperator (7) is cooled by two pre-coolers (PC)(9) to a temperature of 27 °C, compressed using a low pressure compressor (LPC) (10) and pre-heated in the recuperator before returning to the IHX for the continuation of the cycle (11). Efficiencies of 85% were assumed for both the gas turbine and LPC (Smith *et al.*, 2005). The same HRSG, delivery and generator efficiencies as the coal and nuclear steam based cogeneration processes were used.

For more on the closed-cycle gas turbine cogeneration process please refer to section 2.4.3. The operating conditions are given in section 4.3.4, followed by the mass (section 4.3.5) and energy (section 4.3.6) balances.

4.3.3 Process flow diagram

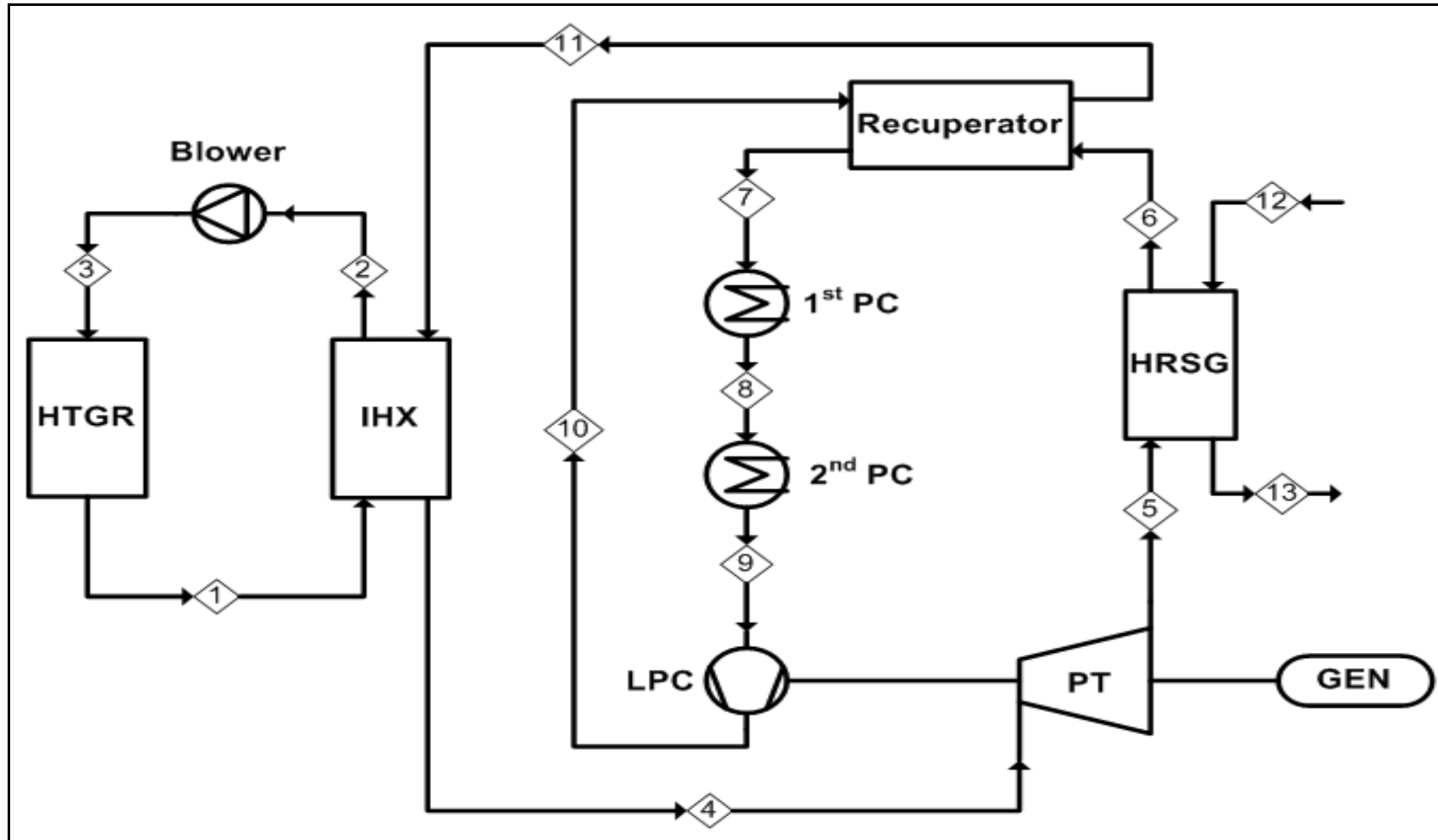


Figure 4-4 Layout of closed-cycle gas turbine cogeneration process

4.3.4 Operating conditions

In Table 4-8 the temperatures, pressures and reference conditions used in the cogeneration process are given. The efficiencies, together with the gas turbine pressure ratio, are also given below.

Table 4-8 Operating conditions of closed-cycle gas turbine cogeneration system

Stream #	Composition	T (°C)	P (kPa)	Efficiencies	
1	Helium	880	5,000	<i>PHTS</i>	
2	Helium	335	5,000	η_{IHX}^a	99%
3	Helium	340	5,000		
4	Helium	830	5,000	<i>PCS</i>	
5	Helium	467.44	1,471	η_T^b	85%
6	Helium	315.00	1,471	η_{LPC}^b	85%
7	Helium	279.61	1,471	η_{HRSG}^a	98%
8	Helium	153.31	1,471	η_{GEN}^a	98%
9	Helium	27	1,471	η_{DEL}^a	95%
10	Helium	249.61	5,000	$\eta_{RECUPERATOR}^a$	100%
11	Helium	285	5,000		
12	Saturated liquid	80	1,000	Temperature difference^a	
13	Superheated steam	220	1,000	ΔT_{IHX} (°C)	50
				$\Delta T_{RECUPERATOR}$ (°C)	30
				Pressure Ratio^c	
				P_4/P_5	3.4

a: Ugeler and Mulder (n.d.), b: Smith *et al.* (2005), c: Kikstra *et al.* (2000)

4.3.5 Mass balance

Table 4-9 Mass balance of a closed-cycle gas turbine cogeneration process

Stream #	Composition	m (ton/hr)	n (kmol/hr)	V(Nm ³ /hr)
1	Helium	641.03	160,152.31	3,589,493.75
2	Helium	641.03	160,152.31	3,589,493.75
3	Helium	641.03	160,152.31	3,589,493.75
4	Helium	634.62	158,550.79	3,553,598.81
5	Helium	634.62	158,550.79	3,553,598.81
6	Helium	634.62	158,550.79	3,553,598.81
7	Helium	634.62	158,550.79	3,553,598.81
8	Helium	634.62	158,550.79	3,553,598.81
9	Helium	634.62	158,550.79	3,553,598.81
10	Helium	634.62	158,550.79	3,553,598.81
11	Helium	634.62	158,550.79	3,553,598.81
12	Saturated liquid	233.42	12,956.12	290,385.59
13	Superheated steam	233.42	12,956.12	290,385.59

These tables were obtained from the simulation in Excel; the manual calculations can be seen in Appendix D. The mass balances are required to determine the amount of helium required in the PCS and process steam generated.

To remove the heat generated in the HTGR, 634.62 ton/hr helium is required in the PCS. The helium leaving the turbine in the PCS is sent through a HRSG to generate 233.24 ton/hr process steam, which is sent to the CTL process.

4.3.6 Energy balance

Primary cycle

The energy balance of the PHTS is given below.

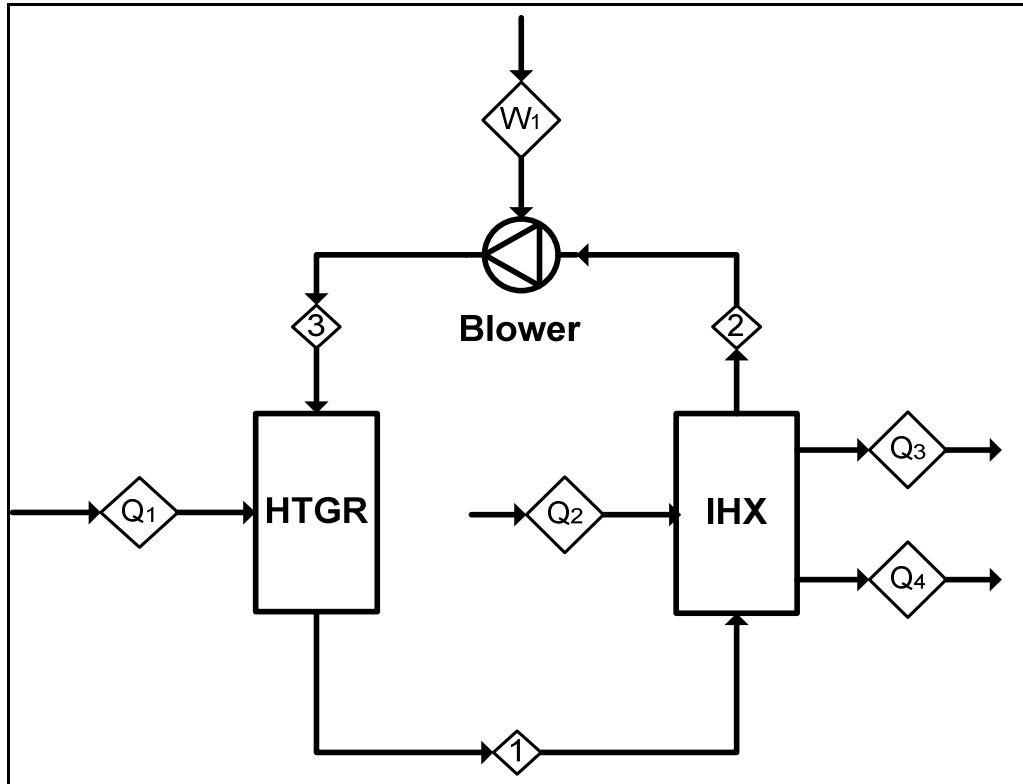


Figure 4-5 Energy balance of PHTS (closed-cycle gas turbine cogeneration process)

Table 4-10 Energy balance of PHTS (closed-cycle gas turbine cogeneration process)

PHTS		
	Q(MW)	W(MW)
Q₁	500	0
W₁	0	4.63
Q₂	-504.63	0
TOTAL	-4.63	4.63

IHX Balance		
Q₂	504.63	
Q₃	-499.58	
Q₄	5.05	

Power conversion system (PCS)

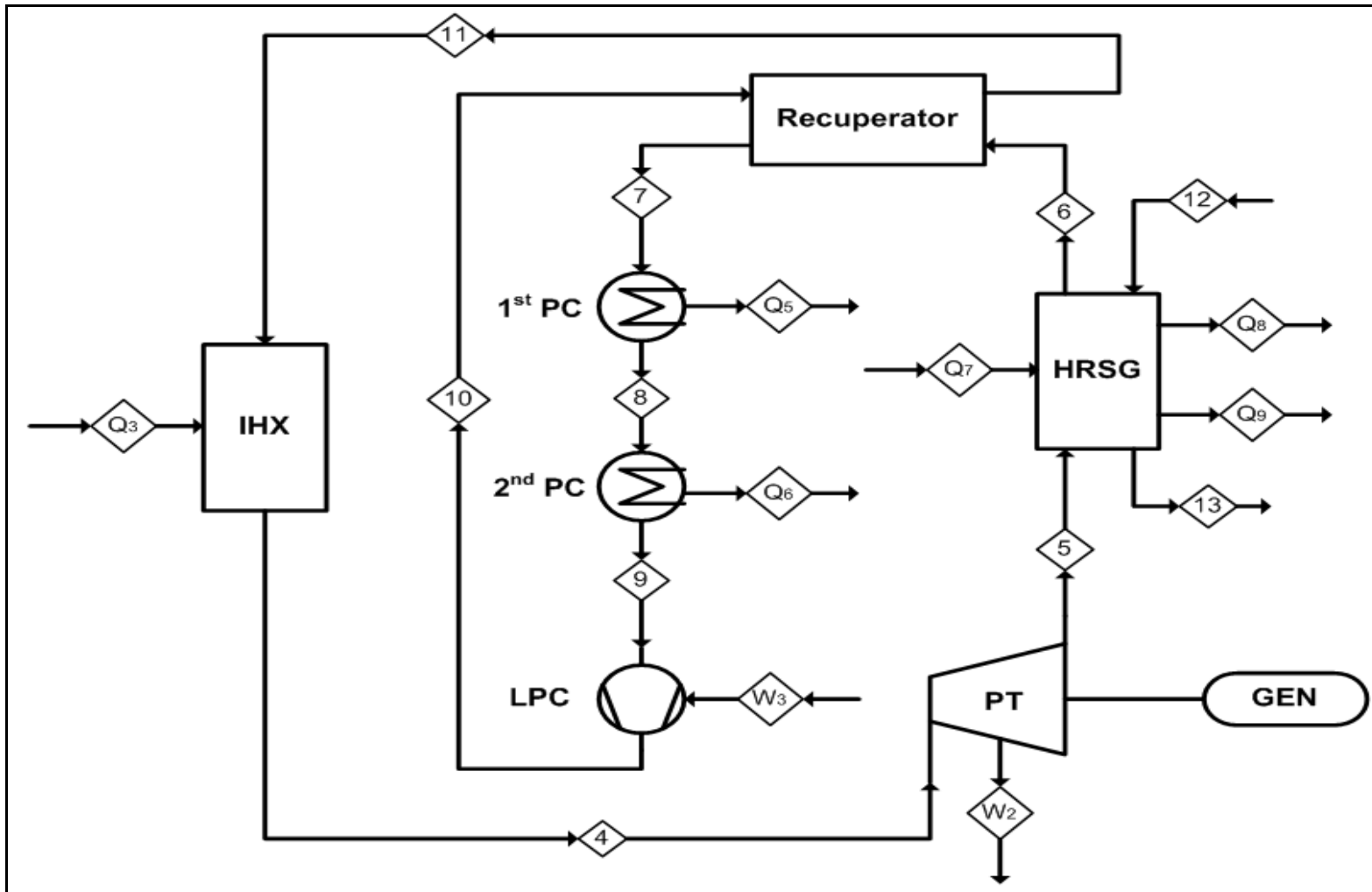


Figure 4-6 Energy balance of PCS (closed-cycle gas turbine cogeneration process)

In Table 4-11 the specific enthalpies of the process steam streams are given. These enthalpies were obtained from the superheated and saturated steam tables at the relevant temperature and pressure. The heat load (Table 4-12) of each stream in the PCS together with the energy balance (Table 4-13) of the PCS is also given below, followed by the efficiency of the process given in Table 4-14.

Table 4-11 Specific enthalpy (closed-cycle gas turbine cogeneration system)

Stream #	Composition	m (ton/hr)	n (kmol/hr)	V(Nm ³ /hr)
12	Saturated liquid	80	1,000	762.61
13	Superheated steam	220	1,000	2,874.60

Table 4-12 Heat load of each stream in the PCS

Q(MW)	
4	737.92
5	405.57
6	265.83
7	233.40
8	117.61
9	1.83
10	205.90
11	238.33
12	49.45
13	186.38

Table 4-13 Energy balance of the PCS (closed-cycle gas turbine cogeneration process)

PCS			
	Q(MW)	W_{isentropic} (MW)	W(MW)
Q₃	499.58	-	-
Q₅	-115.8	-	-
Q₆	-115.8	-	-
Q₇	-139.7	-	-
Recuperator_(Primary)	-32.4	-	-
Recuperator_(Secondary)	32.4	-	-
W₂	-	-391	-332.4
W₃	-	173.45	204.1
TOTAL	128.29		-128.29

HRSB Balance	
Q₇	140
Q₈	-136.9
Q₉	2.8

Recuperator Balance	
Recuperator	32.4
Recuperator_{primary to secondary}	-32.4
Recuperator_{heat loss}	0.0

The symbols used in the energy balance represent the following:

- Q_1 = Heat introduced through the HTGR.
- Q_2 = Heat input from the PHTS to the IHX
- Q_3 = Heat output from the IHX to the PCS
- Q_4 = Heat loss from the IHX to the environment
- Q_5 = Heat rejected by the 1st PC
- Q_6 = Heat rejected by the 2nd PC
- Q_7 = Heat input to the HRSG
- Q_8 = Heat output from the HRSG to the CTL facility
- Q_9 = Heat loss from the HRSG to the environment
- W_1 = Power required by blower
- W_2 = Power generated by the turbine.
- W_3 = Power required by the low pressure compressor (LPC).

Table 4-14 Efficiency of closed-cycle gas turbine cogeneration process

$W_{\text{net PCS}}(\text{MW})$	128.29
$W_{\text{net tot}}(\text{MW})$	123.66
$W_e(\text{MW})$	115.13
$Q_t(\text{MW})$	136.9
η_t	53.65%
η_{tot}	50.41%

The symbols used in Table 4-14 have the same meanings as stated above in section 4.2.6, with the only difference being the replacement of the pumps with the low pressure compressor. These tables were obtained from the simulation in Excel; the manual calculations can be seen in Appendix D.

The mass and energy balances were calculated according to the process design criterion and operating conditions. The energy balances are required to determine the electrical power, process heat generated and the thermal and total efficiencies of the process.

From the 500MW_t entered into the process, 50.41% is converted into useable energy (115.13MW_e (electricity) and 136.9MW_t (process steam)) with the balance lost to the environment. This alternative has the lowest generation of electricity compared with the alternatives discussed above, due to the large electrical requirements of the compressor.

The mass and energy balances of the process were performed using the method and formulas given in Smith *et al.* (2005). The helium flow rate required in the PHTR and PCS was calculated as stated in section 4.2.5. The process steam flow rate was calculated by dividing the heat transferred to the CTL facility through the HRSG by the specific enthalpy difference over the HRSG on the CTL side.

The actual power generated by the gas turbine was calculated by multiplying the isentropic work of the turbine with the turbine efficiency. The actual power required by the low pressure compressor was calculated by dividing the isentropic work of the compressor by the compressor efficiency. The heat transferred by a specific section in the PHTS and PCS was calculated by multiplying the helium flow rate through the section by the heat capacity of the helium and the temperature difference of the streams entering and exiting the specific section.

One of the advantages of using a HTGR as the primary energy source is that no CO_2 is generated or emitted from the process; this helps to reduce the carbon foot print of a CTL process.

4.3.7 Consumption and discharge figures

In this section the amount of each commodity required to produce electricity (115.13 MW_e) and process steam (136.9 MW_t, 233.42 ton/hr with a heat load of 186.38 MW_t) is given. There is no discharge from this process due to the constant circulation of the working fluids and no greenhouse gasses etc. are generated or emitted from a HTGR. These quantities are essential for the production cost analysis and for comparing this process route with the alternative nuclear and coal cogeneration processes.

The consumption figures of the closed-cycle gas turbine cogeneration process are given below.

Table 4-15 Consumption figures of closed-cycle gas turbine cogeneration process

	Closed-cycle gas turbine cogeneration system
Helium (Ton/hr)	634.62
Helium (ton/year)	5,004,576.92
Helium (ton/MWh)	2.52
Process Steam (ton/hr)	233.42
Process Steam (ton/year)	1,840,730.51
Process Steam (ton/MWh)	0.93

The yearly consumption figures and ton/MWh were calculated as stated above in section 3.3.7.

4.4. Summary

Two nuclear-based process routes for the cogeneration of electricity and process steam were discussed in this section. A process overview, together with the mass and energy balances and discharge and consumption figures of the two nuclear-based process routes, were given in this chapter.

These processes use a HTGR as the primary energy source for the cogeneration of electricity and process steam. Alternative A uses an extraction/condensing steam turbine and functions on the Rankine cycle, where alternative B uses a closed-cycle gas turbine cogeneration system and functions on the Brayton cycle. A 500 MW_t HTGR was used for both processes. Helium was used as the working fluid in the PHTS in both processes, with alternative A using water/steam, and alternative B using helium as the working fluid in the PCS. Table 4-16 gives the helium and steam consumption of each process.

Table 4-16 Helium and steam consumption of Alternative A and B: Nuclear-based process routes

	Alternative A	Alternative B
Helium (ton/hr)	856.73	634.62
PCS Steam (ton/hr)	585.22	-

Alternative B works on a closed-cycle gas turbine cycle and thus uses helium instead of steam in the production of electricity and process steam. Alternative B uses less helium than alternative A due to the high operating conditions of the gas turbine. The electricity and process steam generation of both processes are given in the table below.

Table 4-17 Electricity and process steam production of Alternative A and B: Nuclear-based process routes

	Alternative A	Alternative B
Electricity (MW _e)	113.27	115.13
Process heat (MW _t)	147.01	136.9
Process Steam (ton/hr)	250.59	233.42

No CO₂ is produced by either alternative A or B. This is due to the fact that nuclear heat is used as the primary energy source, and not coal. Coal is one of the largest producers of CO₂, and eliminating the use of coal can greatly reduce the carbon footprint of a CTL plant. The HTGR reactor has the ability to generate electricity and process heat without emitting CO₂ or any other greenhouse gases.

CHAPTER 5. PRODUCTION COST ANALYSIS

5.1. Introduction

The unit production cost of electricity and process steam for each of the processes are presented in this section. An economic model (production cost) for the coal-based cogeneration process route has been calculated as a basic cost analysis. This economic model will be used to determine the economic implications that the process will have on the cost of cogeneration of electricity and process steam.

A unit production cost of US\$30/MWh_t will be used in this study for both the nuclear-based cogeneration process routes. For the purpose of the study, only the coal-based and two nuclear-based (Alternative A and B) cogeneration processes will be compared. A sensitivity analysis will also indicate the effect that the unit cost of the working fluid will have on the electricity and process steam production costs.

5.2. Economic model

To determine the production cost of a specified product, one needs to develop a cost estimation of the proposed process plant. The purpose of the production cost analysis is to construct a benchmark to compare the coal-based cogeneration process route with the nuclear-based cogeneration process routes.

Production costs can be divided into fixed and variable operating costs (Sinnott, 2001):

- **Fixed operating costs:** The fixed operating costs are expenses which are independent of the production rate and dependent on the Fixed Capital Investment (FCI) of the process. These are the bills that have to be paid whatever the quantity produced. Typical expenditures are maintenance and repairs, operating labour, insurance etc.

- **Variable operating costs:** These costs are dependent on the production rate, meaning it that will differ with variations in electricity and steam production. The variable costs are costs for supplying process water, cooling water, nuclear fuel etc.

5.2.1 Assumptions and methods used in the economic model

The use of cost indexes was developed to update historical cost data used in the economic analysis to present (2011) values. The method used to update the values is as follows (Sinnott, 2001):

$$\text{Present Cost} = \text{Original Cost} \left(\frac{\text{Cost index in year A}}{\text{Cost index in year B}} \right) \quad (1)$$

The all industry Marshall and Swift (1926=100) cost indices were used to update the values Chemical Engineering, 2011).

Table 5-1: Marshall and Swift Cost Indices (as cited in Chemical Engineering, 2011)

1998	1061.9
2003	1123.6
2008	1449.3
2009	1468.6
2011	1512.5

5.2.2 Fixed capital investment (FCI)

The FCI of the coal-based process route was used to calculate the fixed operating cost of the process. A Total Capital Cost (TCC) of US\$1300/kWe was assumed for the coal-based cogeneration process (World Nuclear Association, n.d). The FCI was calculated based on the assumption that the cogeneration plant generates electricity only. This figure was used due to the limited information available on similar processes.

The TCC consists of the Fixed Capital Investment (80%) and Owner Cost (20%). The TCC given by World Nuclear Association (n.d.) is for 2003 values, and were update to present values using the cost index method given in section 5.2.1. The TCC and FCI for the coal-based processes are given in Table 5-4.

5.2.3 *Production cost*

The production cost consists of fixed and variable cost and capital charges. The expenses included in the production cost are explained in this section (Sinnott, 2001) and given in Table 5-4. The production cost of the coal-based process route is used to calculate the unit production cost of electricity and process steam generated by the process. A unit cost of US\$30/MWh_t (Cilliers, 2010) for the working fluid for each of the nuclear-based processes will be used to calculate the unit production cost of the steam and electricity generated by each process.

5.2.3.1 Fixed operating costs

The fixed operating costs are independent of the production rate but dependent on the FCI.

Operating labour: This is the manpower required to operate the plant and typically includes allowances for holiday, shift allowances, pension contributions etc. A labour rate of US\$34/hr was assumed (Brits, 2009).

Table 5-2 Labour requirements of each process

Coal-based process	
Operators	2 per shift x 3 shifts
Manual labour	3 per shift x 1 shift
Mechanical Maintenance	2 per shift x 1 shift
Control & Instrumentation maintenance	1 per shift x 1 shift
Electrical maintenance	1 per shift x 1 shift

Maintenance and repairs: This includes the cost of the labour and materials required for maintenance, and were taken as 5% of the FCI for the coal-based process route.

Laboratory costs: This is typically the annual cost required for the laboratory analysis required for process monitoring and quality control. The laboratory cost was taken as 20% of the operating labour costs for the coal-based process route.

Supervision: The supervision cost was taken as 20% of the operating labour costs for the coal-based process route.

Plant overheads: This is the general costs associated with operating the plant and includes general management, plant security, medical, canteen etc. The plant overhead cost was taken as 50% of the operating labour.

Insurance: This is the annual insurance premium paid to the insurers and was taken as 1% of the FCI.

5.2.3.2 Variable operating costs

The variable operating costs are dependent on the production rate of the process and given in Table 5-4.

Miscellaneous materials: This expenditure includes all the miscellaneous material required to operate the plant and typically include safety clothing, cleaning materials, pipe gaskets etc. The cost of the miscellaneous materials was taken as 10% of the maintenance and repair costs.

Utilities: The following utilities each with their respective costs were used in the coal-based process:

Coal: A coal price of US\$49.75/ton (2008 values (Afrisam, 2008)) was assumed for this study. This price was converted to 2011 values using the cost index ratio. Ultimately a coal price of US\$51.92/ton was used in the analysis.

Process and cooling water: The price of the process (US\$0.20/ton) and cooling (US\$0.01/ton) water were taken from Sinnott (2001) as a preliminary estimate. These values are for 1998 values and were updated to 2011 values using the cost index ratio. Ultimately process water at US\$0.28/ton and cooling water at US\$0.014/ton were used in the analysis.

5.2.3.3 Capital charges

The investment required for the processes is recovered as a charge, such as a depreciation charge. The capital charge for coal-based process was taken as 15% of the FCI.

5.2.3.4 Carbon penalties

In order to see the effect that carbon penalties will have on the production costs of the coal-based process route, a carbon tax of US\$25/ton CO₂ was assumed (Oehl, n.d.). The effect of

the carbon penalties on the production cost of the coal-based process route can be seen in Table 5-4.

The working medium in the PHTS, SHTS and PCS of each cycle was not included in the economic analysis due to the fact that it works on a closed cycle.

It was assumed that the process satisfies its own electrical needs, thus no extra electricity is imported. The total production of the coal-based cogeneration process is given in Table 5-4.

A comparison of the three cogeneration processes (Coal and Nuclear (Alternative A and B) based processes) can be seen in Table 5-3. The values given in the table below were used in the unit production cost analysis.

Table 5-3 Comparison of the cogeneration processes

Availability	90%			
Days/year	365			
Hours/year	8760			
Operating days/year	328.5			
Operating hours/year	7884			
	Units	Alternative B -Coal-based	Alternative A- Nuclear-based	Alternative B- Nuclear-based
Working Fluid in PCS		Water	Water	Helium
Heat introduced into PCS	MWt	500.00	502.30	499.13
	MWht/year	3,942,000.00	3,960,143.06	3,935,101.50
PCS working fluid		Stream 11	Stream 7	Stream 4
Mass flow (S_a)	ton/hr	582.54	585.22	634.62
	ton/year	4,592,718.77	4,613,856.76	5,003,307.69
Heat load	MWt	571.14	573.77	737.92
	MWht/year	4,502,905.60	4,523,630.22	5,817,735.00
Electricity (E)	MWe	124.28	113.27	115
	MWhe/year	979,795.50	893,011.72	907,655.93
X_e		0.002199	0.002873	0.0025435
Process Steam		Stream 22	Stream 18	Stream 13
Mass flow (S_d)	Ton/hr	249.44	250.59	233.42
	Ton/year	1,966,623.08	1,975,677.21	1,840,263.68

Heat load	MWt	199.18	200.10	186.38
	MWht/year	1,570,348.53	1,577,578.25	1,469,450.54
X_s		0.6	0.4	0.22901
I	Ton/year	1258291.20	1258291.20	2273248.73
Process heat transferred to CTL	MWt	146.3	147.01	233.59
	MWht/year	1,153,749.48	1,159,061.22	1,841,597.29
Overall Efficiency		47.2%	52.1%	50.4%
CO2 emitted	ton/hr	209.06		
	Ton/year	1,648,209.26		

For the economic analysis a plant availability of 90% was assumed which amounts to 7884 working hours/year.

The coal-based process route has the smallest overall efficiency, compared with the other alternatives, due to the low boiler efficiency and heat loss from the boiler. If the boiler efficiency were to increase the heat introduced into the PCS, ultimately the efficiency of the process will increase. A 500MW_t heat source was used for each of the three processes, with Alternative A: Nuclear-based process route introducing 502.30MW_t into the PCS. This is due to the heat addition of the two blowers in the PHTS and SHTS.

The X_e and X_s given in Table 5-3 are called the delivered electrical ratio and the delivered steam ratio respectively. These ratios are used to calculate the unit production cost of electricity and process steam and will be discussed in section 5.2.4. The “I” given above is called the internal steam usage and will also be discussed in section 5.2.4.

Table 5-4 Production cost of the coal-based process routes

Coal-based Cogeneration Process		
Total Capital Cost (TCC)	\$	267,218,204.88
Fixed Capital Cost (FCI 80% of TCC)	\$	213,774,563.90
Manufacturing Costs		
Variable Cost		
Miscellaneous materials	\$/year	1,068,872.82
Utilities		
Cooling water	\$/year	466,522.56
Process Water	\$/year	560,225.52
Coal	\$/year	43,008,705.43
Sub-Total A	\$/year	45,104,326.33
Fixed Costs		
Maintenance and repairs	\$/year	10,688,728.20
Operating labour	\$/year	1,097,044.00
Laboratory costs	\$/year	219,408.80
Supervision	\$/year	219,408.80
Plant overheads	\$/year	548,522.00
Insurance	\$/year	2,137,745.64
Sub-Total B	\$/year	14,910,857.43
Capital Charges	\$/year	32,066,184.59
Carbon Penalties	\$/year	41,205,231.59
Total Manufacturing Costs Without Carbon Tax (A_{tot})	\$/year	92,081,368.35
Total Manufacturing Costs With Carbon Tax (A_{tot})	\$/year	133,286,599.94

The coal-based process route has a FCI of US\$213.77 million and a production cost of US\$ 92.08 million/year. From Table 5-4 it is evident that the variable operating costs has the largest contribution to the production cost; this is due to the large dependence the coal-based process route has on coal, with the annual cost of coal amounting to US\$43.01 million/year.

5.2.4 *Electricity and process steam unit production cost summary*

A mathematical model for the production cost as a function of both steam and electricity delivered was developed by Sheikh and Hapse (2011) and solved using the Multiple Regression Least Squares method. This model was used to calculate the unit production cost of electricity and process steam generated by each process. This model is based on the assumption that the unit cost of electricity and process steam is derived from the unit cost of the working fluid in the PCS (Steam leaving the boiler or helium leaving the HTGR). The unit cost of the working fluid in the PCS was calculated using the following equation:

$$C_{WF} = A_{tot}/S_a \quad (2)$$

With,

C_{WF} = Unit cost of working fluid in the PCS (US\$/ton)

A_{tot} = Total annual production cost (US\$/year)

S_a = Annual amount of working fluid generated in the PCS (ton/year)

For both nuclear-based process routes (alternatives A and B,) a unit cost of US\$30/MWht (Cilliers, 2010) was assumed for the working fluid in the PCS.

In order to calculate the unit cost of electricity and process steam from the unit cost of the working fluid the amount of working fluid attributable to each of the two delivered utilities were calculated using the following mathematical model (Sheikh & Hapse, 2011):

$$S_a = I + X_s S_d + X_e E \quad (3)$$

With,

S_a = Annual amount of working fluid generated in the PCS (Ton/year)

I = Internal steam usage (ton/year)

X_s = Delivered steam ratio (Ton PCS working fluid per ton delivered steam)

S_d = Delivered steam (ton/year)

X_e = Delivered electrical ratio (Ton PCS working fluid per kWhe delivered electricity)

E = Delivered electricity (kWhe/year)

Sheikh and Hapse (2011) obtained the following equations through the Multiple Regression Least Square method for the calculation of I , X_s and X_e from equation 3.

$$S_a = nI + X_s \cdot S_d + X_e \cdot E \quad (4)$$

$$S_d \cdot S_a = I \cdot S_d + X_s \cdot S_d^2 + X_e \cdot S_d \cdot E \quad (5)$$

$$E \cdot S_a = I \cdot E + X_s \cdot S_d \cdot E + X_e \cdot E^2 \quad (6)$$

With, $n = 1$, years in operation.

The unit cost of electricity and process steam was calculated using the following equations:

$$C_E = C_{WF} \times X_e \quad (7)$$

$$C_S = C_{WF} \times X_s \quad (8)$$

With,

C_E = Unit cost of electricity delivered (US\$/kWhe)

C_S = Unit cost of delivered steam (US\$/ton)

The production cost of the working fluid, process steam and electricity is tabulated in Table 5-5. The calculations are based on the figures given in Table 5-3 and Table 5-4.

Table 5-5 Unit production cost of electricity and process steam

Production Cost Of Electricity and Steam				
Without Carbon Tax				
		Alternative B-Coal Based	Alternative A-Nuclear Based	Alternative B-Nuclear Based
C_{WF}		Stream 11	Stream 7	Stream 4
	\$/MWh _t	20.45	30.00	30.00
	\$/ton	20.049	29.41	34.88
C_E	\$/MWh _e	44.09	84.49	88.73
C_S		Stream 22	Stream 18	Stream 13
	\$/ton	12.03	11.77	7.99
	\$/MWh _t	15.07	14.73	10.00
Savings	\$/ton CO ₂		19.57	22.65
With Carbon Tax				
C_{WF}		Stream 11		
	\$/MWh _t	29.60		
	\$/ton	29.02		
C_E	\$/MWh _e	63.81		
C_S		Stream 22		
	\$/ton	17.41		
	\$/MWh _t	21.81		
Savings	\$/ton CO ₂		7.84	10.93

The unit cost of electricity and process steam for the coal-based cogeneration process without the carbon penalty implemented equals to US\$44.09/MWh_e for electricity, and US\$12.03/ton (US\$15.07/MWh_t) for process steam. If the carbon penalty of US\$25/ton CO₂ emitted is included in the production cost, the cost of electricity amounts to US\$63.81/MWh_e and process steam to US\$21.81/MWh_t and US\$17.41/ton.

For the indirect/extraction condensing steam turbine cogeneration process (Alternative A: nuclear-based process route) the unit cost of electricity amounts to US\$84.49/MWh_e (91.6% more than coal-based process) and process steam to US\$14.73/MWh_t and US\$11.77/ton.

Alternative B of the nuclear-based process route operates completely on helium gas as a working fluid and has an overall efficiency of (50.4%). The production cost of electricity via this process route amounts to US\$88.73/MWh_e, and process steam to US\$7.99/ton with the cost of steam per MWh_t amounting to US\$10/MWh_t. The unit production cost of electricity is 101.3% and 5% higher than the coal-based and Alternative A of the nuclear-based process routes respectively. The high unit cost of electricity is due to the fact that a large quantity of heat is used to generate electricity, but due to the large demand of the low pressure compressor the system has a much lower electrical output which leads to an increase in the unit production cost.

The coal-based process route has the lowest unit production cost for electricity and process steam but emits considerable amounts of CO₂ (1.68 ton CO₂/MWh_e) into the atmosphere which contributes to global warming. With the implementation of the carbon penalties it is clear that the cost of electricity and steam production will increase considerably which makes the nuclear processes more compatible.

By implementing the nuclear-based processes, a cost saving (based on US\$/ton CO₂ emitted) of US\$19.57/ton CO₂ and US\$22.65/ton CO₂ can be achieved with Alternative A and B respectively.

From the results given above it is evident that Alternative A: nuclear-based process route would be the most viable process of the nuclear-based processes to replace the coal-based cogeneration process, due to the fact that the unit production cost of electricity is only 91.6% higher and no CO₂ is generated and emitted, which contributes to the reduction of the carbon footprint of a CTL process.

5.3. Sensitivity analysis

The sensitivity analysis illustrates the effect that the unit cost of the working fluid in the PCS of each process has on the unit production costs of electricity and process steam. The effect of the electricity-steam split fraction on the overall efficiency is also evident through a sensitivity analysis. Sensitivity analyses for each process were performed and are presented in the figures below. A sensitivity analysis was performed on the coal-based process route without the implementation of carbon penalties, due to the fact that it is merely performed to see the effect on the production costs.

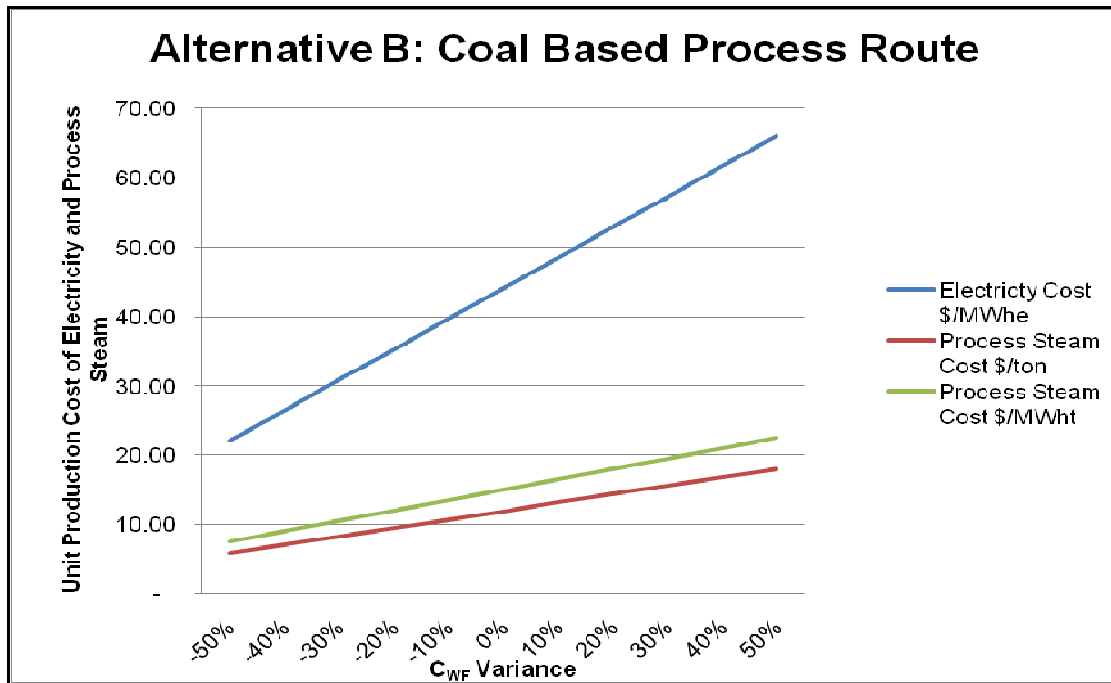


Figure 5-1 Unit production cost of electricity and process steam via Alternative B: Coal-based Process Route

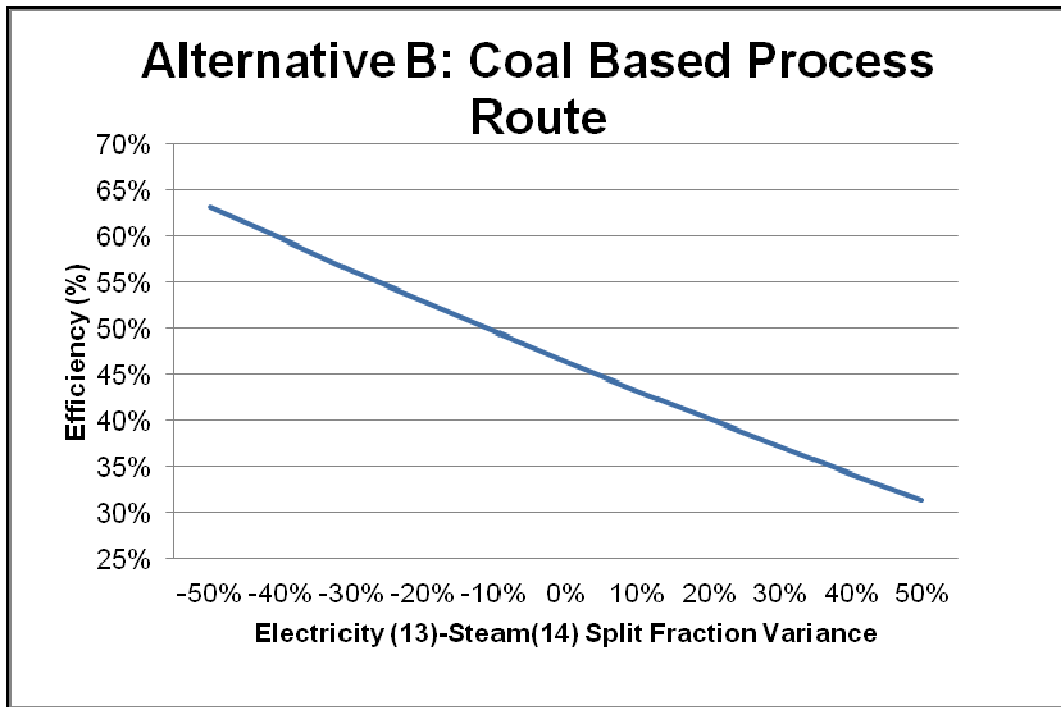


Figure 5-2 Efficiency of Alternative B: Coal-based process route

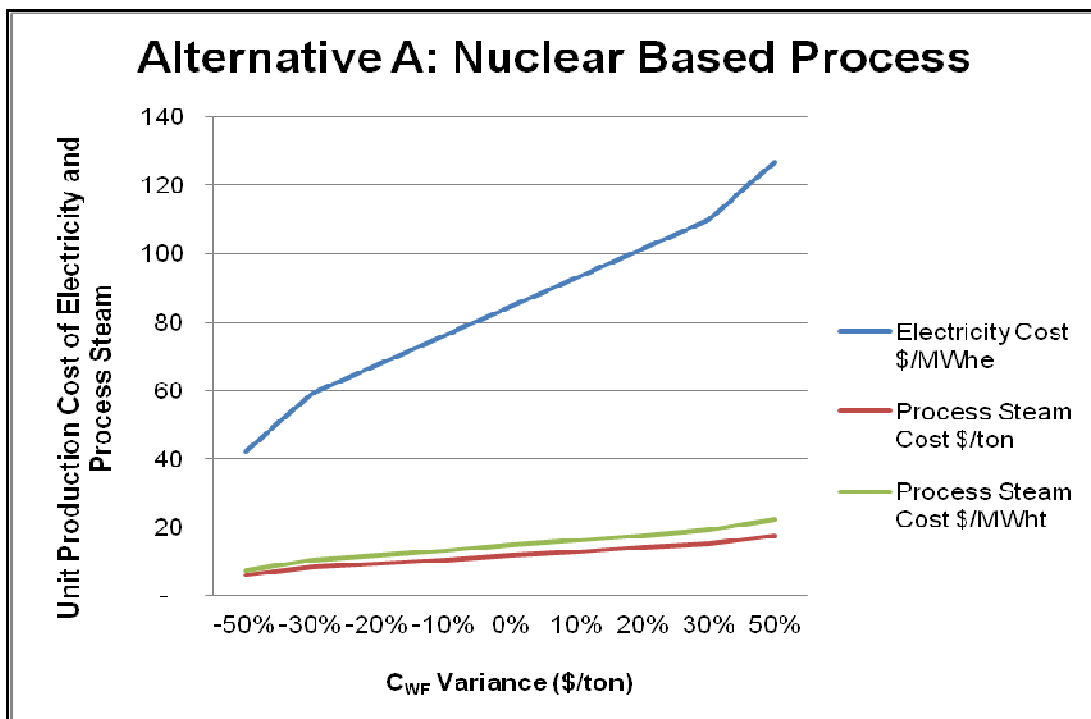


Figure 5-3 Unit Production Cost of Electricity and Process Steam via Alternative A: Nuclear-based Process Route

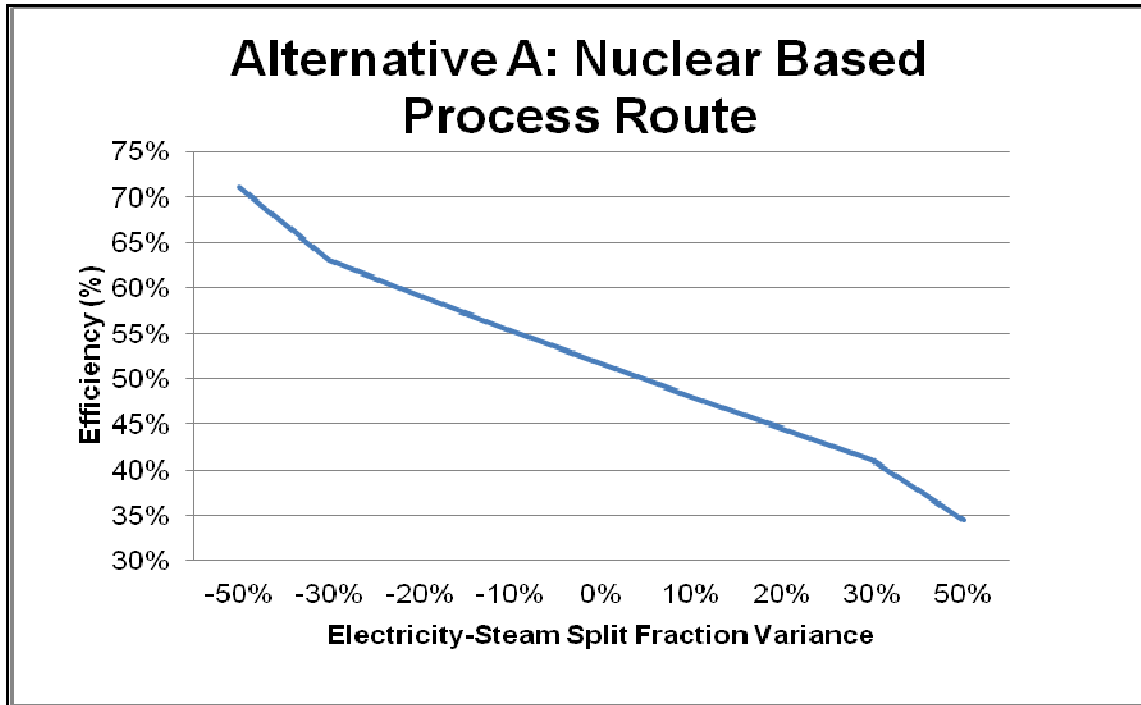


Figure 5-4 Efficiency of Alternative A: Nuclear-based process route

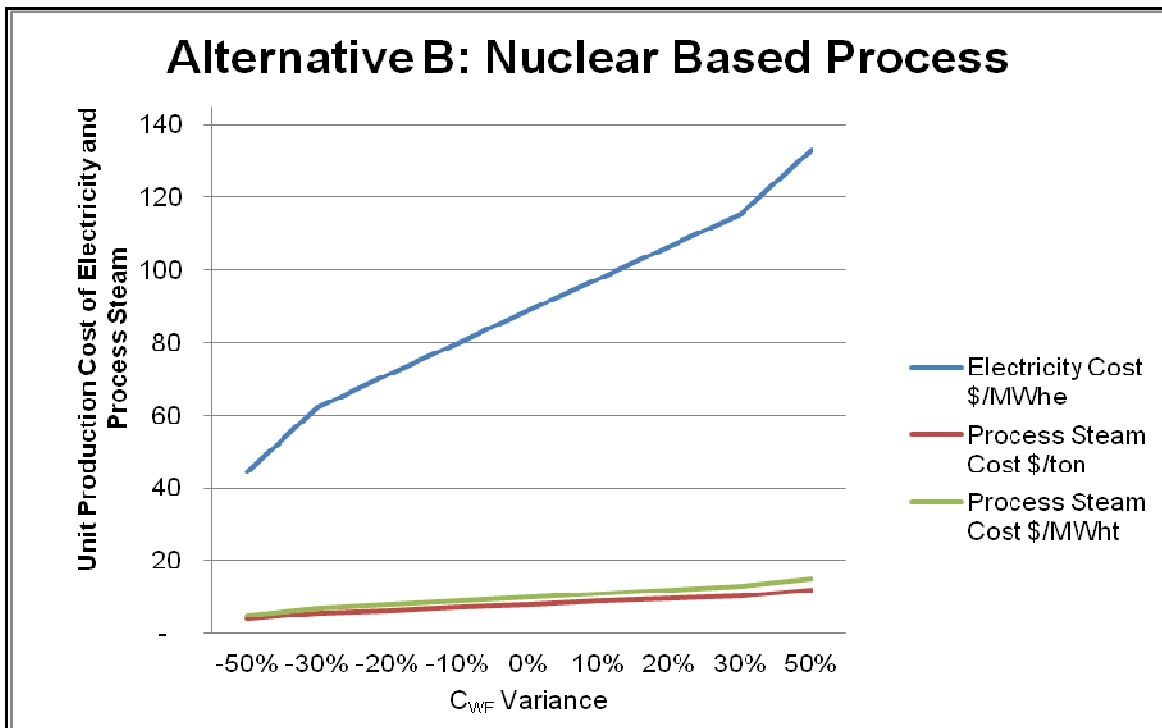


Figure 5-5: Unit production cost of electricity and process Steam via Alternative B: Nuclear-based process route

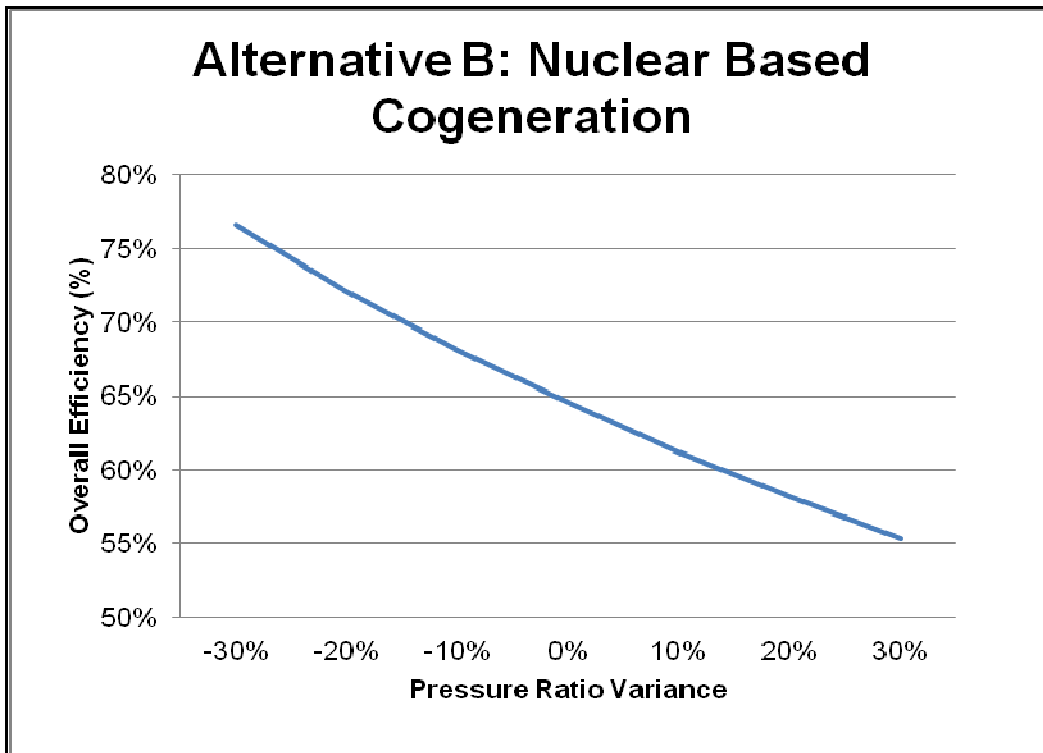


Figure 5-6 Efficiency of Alternative B: Nuclear-based process route

From this analysis it is evident that the unit cost of electricity is very sensitive to the unit cost of the working fluid; thus if the cost increases, the unit cost of electricity increases considerably. From the figures above it is also evident that the overall efficiency of the process decreases with the increase in the amount of electricity generated. The reason for this is that less heat is transferred to the CTL process as useable heat. Thus more heat is used for the generation of electricity and lost to the environment due to the low electrical efficiency of the turbines.

In order to reduce the unit cost of electricity one can try to increase the electrical efficiencies if the processes.

5.4. Summary

The total production cost of the coal-based process route was calculated in this section. The unit production cost of electricity and process steam for each of the processes were also calculated and compared.

From the economic analysis it is clear that with the carbon penalties, the nuclear-based process routes are very compatible with the coal-based process routes. The chapter was concluded with a sensitivity analysis of the effect of the unit cost of the working fluid in the PCS on the unit production cost of electricity and process steam.

CHAPTER 6. CONCLUSION AND RECOMMENDATIONS

6.1. Conclusion

The global energy sector is experiencing a significant increase in energy demand and carbon dioxide emissions, whilst the non-renewable energy sources are swiftly being depleted. This research project has therefore initiated an investigation into developing a means to address the demand, whilst also developing an energy source that will be clean and environmentally friendly.

This study was done to determine whether a cogeneration process utilising nuclear heat as a heat source could be the solution to the greenhouse gas emission problems of a CTL process. A CTL process is a large consumer of coal making it one of the single biggest emitters of CO₂ on the planet. The biggest producer of greenhouse gases at a CTL facility is the gasification of coal to produce synthesis gas, followed by the burning of low grade coal to produce utilities such as electricity and steam needed by the operations. This focus of this research was on the utility production such as electricity and process steam for a CTL process.

Cogeneration is the simultaneous generation of electricity and process steam from a single energy source and is a viable option for the reduction of greenhouse gas emissions. This study was performed to determine whether it would be economically viable to replace the coal-based power plant used with a nuclear reactor and utilise the nuclear heat for the cogeneration of electricity and steam. This nuclear technology includes the use of a HTGR, such as a PBMR, to supply the required heat to the cogeneration process for the production of electricity and process steam.

Three different cogeneration processes were evaluated in this study and include: coal-based cogeneration process utilising an extraction/condensing steam turbine system; nuclear-based cogeneration process utilising an extraction/condensing steam turbine and the thermodynamic Rankine cycle (Alternative A); and nuclear-based cogeneration process utilising a closed-cycle gas turbine system which functions on the thermodynamic Brayton cycle (Alternative B).

Both of the nuclear-based cogeneration processes are operated on an indirect cycle due the advantages of separating the working medium in the PCS from the nuclear reactor. Due to this separation possible fission product contamination of the turbine blades is avoided.

The main objective of this research was to determine the carbon dioxide emissions, the thermal and overall efficiencies, the electricity and process steam production rate, and ultimately the unit production cost of electricity and steam for each process. Comparisons could be made based on the unit production cost of electricity and steam and the disposal cost US\$/ton CO₂ between the different process routes.

A summary of the different cogeneration processes that were assessed is given in Table 6-1. It includes the production rate of electricity and process steam, overall efficiency, carbon dioxide emissions, and disposal cost and the unit production cost of electricity and process steam for each of the different processes.

Table 6-1 Cogeneration processes summary

		Coal-based Cogeneration	Nuclear-based Cogeneration (A)	Nuclear-based Cogeneration (B)
Electricity	MW _e	124.28	113.27	115.13
Process Steam	Ton/hr	249.44	250.59	233.42
C_E	\$/MWh _e	44.09	84.49	88.73
C_S	\$/ton	12.03	11.77	7.99
	\$/MWh _t	15.07	14.73	10.00
CO₂ emission	ton/hr	209.06	-	-
	ton/MW _e	1.68	-	-
Disposal cost of CO₂	\$/ton CO ₂	-	19.57	22.65

From a technical point of view, it was found that Alternative B of the nuclear-based cogeneration processes is not a viable option for the cogeneration of electricity and process steam, due to the high electricity unit production cost. The cost of electricity is 101% and 5% higher than the coal-based and Alternative A of the nuclear-based cogeneration processes respectively.

Helium gas turbine technology also holds some risk for near-term deployment as it needs development; it has not been demonstrated in a commercial nuclear power plant as yet. This alternative is thus not recommended for the cogeneration of electricity and process steam for a CTL process.

Alternative A of the nuclear-based cogeneration processes shows significant potential for the cogeneration of electricity and process steam for a CTL process. Although it has a 91.6% increase in electricity costs, this increase should be measured against the huge positive impact that the reduction of carbon dioxide emissions would have on the environment. Another advantage gained from utilising nuclear heat is that there is no generation of ash and other greenhouse gases, such as sulphur dioxide (SO₂), taking place in the process. The ash generated in the coal-based cogeneration process has its own significant consequences for the environment.

The advantage of utilising a HTGR as a heat source for the cogeneration of electricity and process steam is that it is inherently safe, can be placed near the point of demand, and constructed in a modular fashion to satisfy the process needs.

Thus, nuclear technology could be the solution to the greenhouse gas emission problems of a CTL process. The most promising process route for the cogeneration of electricity and process steam using nuclear heat would be the process utilising the extraction/condensing steam turbine cogeneration system.

6.2. Recommendations

The following recommendations are made with regard to a follow-up study:

- Develop detailed equipment costs and production costs for each of the processes. This will allow a more accurate calculation of the unit production cost of electricity and process steam, and thus a more accurate comparison between the processes.
- Investigate the possibility of utilising the heat lost by the condenser as possible process heat; this will increase the efficiency of the process and ultimately reduce the unit production costs of electricity and process steam.
- Investigate achieving an optimal thermal efficiency of the processes. This can be done by determining the optimum split fraction between the electricity and process steam. An optimum split fraction will positively affect the unit product costs of electricity and process steam.
- Investigate a means to increase the boiler and turbine efficiencies in order to increase the overall efficiencies of the processes, and ultimately reduce the unit production cost of electricity and process steam.
- Investigate the possibility of using a coal with a higher CV at the coal-based cogeneration process. Using a coal with a higher CV will reduce the amount of coal consumed, and thus the amount of greenhouse gases and ash generated and then emitted into the atmosphere.
- An optimization study of each of the process layouts would assist in achieving the maximum possible efficiency achievable by each of the processes. This can typically include reheating, feed water heating etc.
- The possibility of utilising more than one compressor in Alternative B of the nuclear-based cogeneration process is recommended, due to the high requirements of the low pressure compressor.
- An optimisation of the operating conditions of each of the processes is recommended. This will ensure that the most is achieved out of each process.

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APPENDICES

Appendix A: Alternative A-Coal Based Process Route

A.1. Process steam generation

Coal mill

Mass balance

- $\rho_{i,c} \text{ (kg/Nm}^3\text{)} = M_c \text{ (kg/kmol)} / 22.413$

$$\rho_i = \sum \rho_{i,c} \text{ (kJ/hr)}$$

$$V_i \text{ (Nm}^3\text{/hr)} = m_i \text{ (kg/hr)} / \rho_i \text{ (kg/Nm}^3\text{)}$$

$$V_{i,c} \text{ (Nm}^3\text{/hr)} = V_i \text{ (Nm}^3\text{/hr)} \times \text{Volume fraction}$$

$$\text{Dry volume fraction} = V_{i,c} / (V_i - V_{i,H2O})$$

$$\text{Wet volume fraction} = V_{i,c} / V_i$$

$$m_i \text{ (kg/hr)} = \text{Molecular Mass (kg/kmol)} \times n_i \text{ (kmol/hr)}$$

$$m_{i,c} \text{ (kg/hr)} = m_i \text{ (kg/hr)} \times \text{Mass fraction}$$

$$n_{i,c} \text{ (kmol/hr)} = n_i \text{ (kmol/hr)} \times \text{Mole fraction}$$

With i = stream number and c = the specific component.

- $m_{i,H_2O \text{ in coal}} \text{ (kg/hr)} = m_{AR \text{ Coal}} \text{ (kg/hr)} \times \text{Moisture Content (\%)}$, with $i = 1, 8$

Energy balance

- $Q_{i,c} \text{ (kJ/hr)} = n_{i,c} \text{ (mol/hr)} \Delta H_{i,c} \text{ (kJ/mol)}$

$$\Delta H_{i,c} \text{ (kJ/mol)} = \int_{T_{Ref}}^{T_{i,c}} C_{p,i,c} (T) dT$$

$$C_{p,i,c} \text{ [kJ/(mol } ^\circ\text{C)]} = a + bT + cT^2 + dT^3$$

$$\Delta H_{i,c} \text{ (kJ/mol)} = [aT + 1/2bT^2 + 1/3cT^3 + 1/4dT^4]_{T_{Ref}}^{T_{i,c}} - [aT + 1/2bT^2 + 1/3cT^3 + 1/4dT^4]_{T_{Ref}}$$

$Q_i \text{ (kJ/hr)} = \sum Q_{i,c} \text{ (kJ/hr)}$, With i = stream number and c = the specific component.

Table B.1: Heat Capacity Constants

	a	b	c	d
O₂	2.91E-02	1.16E-05	-6.08E-09	1.31E-12
N₂	2.90E-02	2.20E-06	5.72E-09	-2.87E-12
H₂O(g)	3.35E-02	6.88E-06	7.60E-09	-3.59E-12

H₂O(l)	7.54E-02			
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- $Q_{i,coal} \text{ (kJ/hr)} = m_{i,Dry\ Coal} C_{p,i,coal} (T^i - T^{ref})$, with $i = 1, 8$.

$$C_p \text{ of Coal (Btu/lb}^\circ\text{F)} = 0.17 + 1.1 \times 10^{-4} T + (3.2 \times 10^{-3} + 3.05 \times 10^{-6} T)V_m,$$

With, V_m = Volatile matter, dry basis, in weight percent

- Saturation Temperature Calculations (8):

$$\text{Humidity (kg H}_2\text{O/kg air): } m_{8,H_2O} / (m_{8,tot} - m_{8,H_2O})$$

$$M_{Dry\ gas} \text{ (kg/kmol)} = M_{O_2} \text{ (kg/kmol)} \times \text{Dry Vol Frac}_{O_2} + M_{N_2} \text{ (kg/kmol)} \times \text{Dry Vol Frac}_{N_2}$$

$$P^{Water,Actual} \text{ (kPa)} = (\text{Humidity} \times P_{ref}) / ((M_{H_2O} / M_{Dry\ gas}) + \text{Humidity})$$

Using the Antoine Equation to calculate the saturation temperature:

$$T^{sat} = B / (A - \ln(P^{water,Actual})) - C$$

Table B.2: Antoine Constants

Antoine Constants			
	A	B	C

Water	16.3872	3885.7	230.17
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$$Q_{8,H_2O} \text{ (kJ/hr)} = n(\text{kmol/hr})\Delta H_L(\text{kJ/kmol}) + m \text{ (kg/hr)}\Delta H_{\text{vap}}(\text{kJ/kg}) + n(\text{kmo/hr})\Delta H_V(\text{kJ/kmol})$$

$$\Delta H_L = \int_{T_{\text{Ref}}}^{T_{\text{sat}}} C_p(T) dT$$

$$= [aT + \frac{1}{2}bT^2 + \frac{1}{3}cT^3 + \frac{1}{4}dT^4]_{T_{\text{Ref}}}^{T_{\text{sat}}}$$

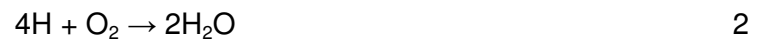
$$\Delta H_V = \int_{T_{\text{Sat}}}^T C_p(T) dT = [aT + \frac{1}{2}bT^2 + \frac{1}{3}cT^3 + \frac{1}{4}dT^4]_{T_{\text{Sat}}}^T$$

Boiler

Mass balance

An atomic mass balance was performed across the boiler.

Reactions used:



- Oxygen required for complete combustion:

$$n_{\text{O}_2,1} = \frac{e_{\text{O}_2}}{e_{\text{C}}} * n_{\text{C}}$$

$$n_{\text{O}_2,2} = \frac{e_{\text{O}_2}}{e_{\text{H}}} * n_{\text{H}}$$

$$n_{\text{O}_2,3} = \frac{e_{\text{O}_2}}{e_{\text{S}}} * n_{\text{S}}$$

$$n_{\text{O}_2,\text{Tot}} = n_{\text{O}_2,\text{C}} + n_{\text{O}_2,\text{H}} + n_{\text{O}_2,\text{S}}$$

- Stack gas composition:

$$n_{10,\text{N}_2} = (n_{8,\text{N}} \text{ (in coal)} + 2n_{8,\text{N}_2} \text{ (in Air)} + 2n_{5,\text{N}_2})/2$$

$$n_{10,CO_2} = \frac{c_{CO_2}}{c_C} * n_{8,C}$$

$$n_{10,H_2O} = (n_{8,H} \text{ (in coal)} + 2n_{8,H_2O} \text{ (in Air)})/2$$

$$n_{10,SO_2} = \frac{c_{SO_2}}{c_S} * n_{8,S}$$

$$n_{10,O_2} = [(n_{8,O} \text{ (in coal)} + 2n_{8,O_2} \text{ (in Air)} + n_{8,H_2O} \text{ (in Air)} + 2n_{5,O_2}) - (2n_{10,CO_2} - n_{10,H_2O} - 2n_{10,SO_2})]/2$$

With

n = Mole flow in kmol/s

C = reaction coefficient

Energy balance:

- $Q_4 \text{ (MW)} = \eta_{\text{Boiler}} Q_1$

$$Q_2 \text{ (MW)} = \text{Energy loss\%} \times Q_1$$

$$Q_3 \text{ (MW)} = \text{Energy loss from stack\%} \times Q_1$$

$$Q_5 \text{ (MW)} = \text{Energy loss with ash\%} \times Q_1$$

$$Q_4 \text{ (MW)} = m_{11} (H_{11} - H_{12}), \text{ with } m \text{ in kg/s and } H \text{ in kJ/kg.}$$

A.2. Electricity generation process

The same equations for the coal mill and boiler were used as given in Appendix A.1.

For all streams

- $Q_i(\text{kJ/s}) = m_i(\text{kg/s}) H_i(\text{kJ/kg})$

$$n_i(\text{kmo/hr}) = m_i(\text{kg/hr}) / \text{Mole mass}(\text{kg/kmol})$$

$$V_i(\text{Nm}^3/\text{hr}) = m_i(\text{kg/hr}) / \rho_i(\text{kg/Nm}^3) = m_i(\text{kg/hr}) / (\text{Mole mass}(\text{kg/kmol}) / 22.413),$$

With i = stream number

PCS

$$m_{11} = m_{12} = m_{13} = m_{14} = m_{15}$$

$$m_{16} = m_{17}, \text{with } m_i \text{ in kg/s}$$

$$P_{11} = P_{15}$$

$$P_{13} = P_{14}$$

$$P_{16} = P_{17}, \text{with } P \text{ in kPa}$$

Boiler

$$Q_4 = m_{11} \Delta H_{\text{Boiler}} = m_{11}(H_{11} - H_{15})$$

$$m_{11} = Q_4/\Delta H_{\text{Boiler}} = Q_4/(H_{11}-H_{15})$$

HPT

- Isentropic specific work of HPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_{12} - H_{11}$,

Assume HPT is isentropic, $S_{11} = S'_{12}$, with H'_{12} from steam tables at S'_{12} and P_{12} .

$$\text{Actual specific work of HPT: } W_1 \text{ (kJ/kg)} = \Delta H_{\text{HPT}} \text{ (kJ/kg)} = \eta_{\text{HPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{HPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$$

$$\text{Actual specific } H_{12} \text{ (kJ/kg)} = \Delta H_{\text{HPT}} + H_{11}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_{11} \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)} = m_{11} \text{ (kg/s)} \Delta H_{\text{isentropic}} \text{ (kJ/kg)}$$

$$W_1 \text{ (kJ/s)} = m_{11} \text{ (kg/s)} W_1 \text{ (kJ/kg)} = m_{11} \text{ (kg/s)} \Delta H_{\text{HPT}} \text{ (kJ/kg)}$$

LPT

- Isentropic specific work of LPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_{13} - H_{12}$,

$$\text{Actual specific work of LPT: } W_2 \text{ (kJ/kg)} = \Delta H_{\text{LPT}} \text{ (kJ/kg)} = \eta_{\text{LPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{LPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$$

$$\text{Actual specific } H_{13} \text{ (kJ/kg)} = \Delta H_{\text{LPT}} + H_{12}$$

To calculate H'_{13} :

Assume LPT is isentropic, $S_{12} = S'_{13}$,

$$\text{Calculate } X'_{\text{vap}} \text{ from } S'_{13} \text{ (kJ/kg K)} = S_{\text{liq}} (1-X'_{\text{vap}}) + X'_{\text{vap}} S_{\text{vap}}$$

$$\text{Calculate } H'_{13} \text{ using } H'_{13} \text{ (kJ/kg)} = H_{\text{liq}} (1-X'_{\text{vap}}) + X'_{\text{vap}} H_{\text{vap}}$$

At $P_{13} = 10\text{kPa}$ from steam tables:

$$S_{\text{vap}} = 8.151 \text{ kJ/kg}$$

$$S_{\text{liq}} = 0.649 \text{ kJ/kg K,}$$

$$H_{\text{vap}} = 2584.6 \text{ kJ/kg}$$

$$H_{\text{liq}} = 191.8 \text{ kJ/kg}$$

$$\text{Calculate } X_{\text{vap}} \text{ from } H_{13} \text{ (kJ/kg)} = H_{\text{liq}} (1-X_{\text{vap}}) + X_{\text{vap}} H_{\text{vap}}$$

$$\text{Calculate from } S_{13} \text{ (kJ/kg K)} = S_{\text{liq}} (1-X_{\text{vap}}) + X_{\text{vap}} S_{\text{vap}}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_{12} \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)} = m_{12} \text{ (kg/s)} \Delta H_{\text{isentropic}} \text{ (kJ/kg)}$$

$$W_2 \text{ (kJ/s)} = m_{12} \text{ (kg/s)} W_2 \text{ (kJ/kg)} = m_{12} \text{ (kg/s)} \Delta H_{\text{LPT}} \text{ (kJ/kg)}$$

Condenser

- $Q_6 \text{ (kJ/s)} = m_{13} \text{ (kg/s)} (H_{14} - H_{13}) \text{ (kJ/kg)} = m_{16} \text{ (kg/s)} (H_{17} - H_{16}) \text{ (kJ/kg)}$

$$m_{16} \text{ (kg/s)} = Q_6 \text{ (kJ/s)} / (H_{17} - H_{16}) \text{ (kJ/kg)}$$

P1

- Isentropic specific work of P1: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = V_{14} \text{ (m}^3\text{/kg)} (P_{15} - P_{14}) \text{ (kPa)}$

$$\text{Actual specific work of P1: } W_3 \text{ (kJ/kg)} = \Delta H_{P1} \text{ (kJ/kg)} = W_{\text{isentropic}} / \eta_{P1} = (\Delta H)_{\text{isentropic}} / \eta_{P1}$$

$$\text{Actual specific } H_{15} \text{ (kJ/kg)} = \Delta H_{P1} \text{ (kJ/kg)} + H_{14} \text{ (kJ/kg)}$$

To calculate T_{15} and S_{15} :

$$\Delta H_{P1} \text{ (kJ/kg)} = C_{p,14} \Delta T_{P1} + V_{14} (1 - \beta_{14} T_{14}) (P_{15} - P_{14})$$

$$T_{15} \text{ (}^\circ\text{C)} = \Delta T_{P1} \text{ (}^\circ\text{C)} + T_{14} \text{ (}^\circ\text{C)}$$

$$\Delta S_{P1} \text{ (kJ/kg K)} = C_{p,14} \ln(T_{15}/T_{14}) - \beta_{14} V_{14} (P_{15} - P_{14})$$

$$S_{15} \text{ (kJ/kg K)} = \Delta S_{P1} \text{ (kJ/kg K)} + S_{14} \text{ (kJ/kg K)}$$

At $P_{14} = 10 \text{ kPa}$

$$V_{14} = 0.00101026 \text{ m}^3\text{/kg}$$

$$C_{p,14} = 4.180 \text{ kJ/kg K}$$

$$B_{14} = 0.0004291 \text{ K}^{-1}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_{14} \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)} = m_{14} \text{ (kg/s)} \Delta H_{\text{isentropic}} \text{ (kJ/kg)}$$

$$W_3 \text{ (kJ/s)} = m_{14} \text{ (kg/s)} W_{P1} \text{ (kJ/kg)} = m_{14} \text{ (kg/s)} \Delta H_{P1} \text{ (kJ/kg)}$$

W_{net} , W_e , Efficiency

$$W_{net} = (W_1 + W_2) - W_3$$

$$W_e = W_{net} \times \eta_{Gen} \times \eta_{Del}$$

$$\eta_{th} = W_{net} / Q_4 \times 100$$

$$\eta_{tot} = W_e / Q_1 \times 100,$$

with W and Q in kJ/s

Appendix B: Alternative B-Coal Based Process Route

The same equations for the coal mill and boiler were used as given in Appendix A.1.

For all streams

- $Q_i(\text{kJ/s}) = m_i(\text{kg/s}) H_i(\text{kJ/kg})$

$$n_i(\text{kmo/hr}) = m_i(\text{kg/hr}) / \text{Mole mass (kg/kmol)}$$

$$V_i(\text{Nm}^3/\text{hr}) = m_i(\text{kg/hr}) / \rho_i(\text{kg/Nm}^3) = m_i(\text{kg/hr}) / (\text{Mole mass (kg/kmol)} / 22.413),$$

With i = stream number

PCS

$$m_{11} = m_{18} = m_{12}$$

$$m_{14} = y_{\text{electricity}} m_{12} = m_{15} = m_{16} = m_{17}$$

$$m_{13} = y_{\text{steam}} m_{12} = m_{19} = m_{20}$$

$$m_{21} = m_{22}$$

$$m_{23} = m_{24}, \text{ with } m_i \text{ in kg/s}$$

$$P_{11} = P_{18} = P_{17} = P_{20}$$

$$P_{12} = P_{13} = P_{14} = P_{19}$$

$$P_{15} = P_{16}$$

$$P_{21} = P_{22}$$

$$P_{23} = P_{24}, \text{ with } P \text{ in kPa}$$

Boiler

- $Q_4 = m_{11}\Delta H_{\text{Boiler}} = m_{11}(H_{11}-H_{18})$

$$m_{11} = Q_4/\Delta H_{\text{Boiler}} = Q_4/(H_{11}-H_{18})$$

HPT

- Isentropic specific work of HPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_{12} - H_{11}$,

Assume HPT is isentropic, $S_{11} = S'_{12}$, with H'_{12} from steam tables at S'_{12} and P_{12} .

$$\text{Actual specific work of HPT: } W_1 \text{ (kJ/kg)} = \Delta H_{\text{HPT}} \text{ (kJ/kg)} = \eta_{\text{HPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{HPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$$

$$\text{Actual specific } H_{12} \text{ (kJ/kg)} = \Delta H_{\text{HPT}} + H_{11}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_{11} \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)} = m_{11} \text{ (kg/s)} \Delta H_{\text{isentropic}} \text{ (kJ/kg)}$$

$$W_1 \text{ (kJ/s)} = m_{11} \text{ (kg/s)} W_1 \text{ (kJ/kg)} = m_{11} \text{ (kg/s)} \Delta H_{\text{HPT}} \text{ (kJ/kg)}$$

$$H_{12} = H_{13} = H_{14}, T_{12} = T_{13} = T_{14}$$

LPT

- Isentropic specific work of LPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_{15} - H_{14}$,

$$\text{Actual specific work of LPT: } W_2 \text{ (kJ/kg)} = \Delta H_{\text{LPT}} \text{ (kJ/kg)} = \eta_{\text{LPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{LPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$$

$$\text{Actual specific } H_{15} \text{ (kJ/kg)} = \Delta H_{\text{LPT}} + H_{14}$$

To calculate H'_{15} :

$$\text{Assume LPT is isentropic, } S_{14} = S'_{15},$$

$$\text{Calculate } X'_{\text{vap}} \text{ from } S'_{15} \text{ (kJ/kg K)} = S_{\text{liq}} (1 - X'_{\text{vap}}) + X'_{\text{vap}} S_{\text{vap}}$$

$$\text{Calculate } H'_{15} \text{ using } H'_{15} \text{ (kJ/kg)} = H_{\text{liq}} (1 - X'_{\text{vap}}) + X'_{\text{vap}} H_{\text{vap}}$$

At $P_{15} = 10\text{kPa}$ from steam tables:

$$S_{\text{vap}} = 8.151 \text{ kJ/kg}$$

$$S_{\text{liq}} = 0.649 \text{ kJ/kg K,}$$

$$H_{\text{vap}} = 2584.6 \text{ kJ/kg}$$

$$H_{\text{liq}} = 191.8 \text{ kJ/kg}$$

$$\text{Calculate } X_{\text{vap}} \text{ from } H_{15} \text{ (kJ/kg)} = H_{\text{liq}} (1 - X_{\text{vap}}) + X_{\text{vap}} H_{\text{vap}}$$

$$\text{Calculate from } S_{15} \text{ (kJ/kg K)} = S_{\text{liq}} (1 - X_{\text{vap}}) + X_{\text{vap}} S_{\text{vap}}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_{14}(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_{14}(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_2(\text{kJ/s}) = m_{14}(\text{kg/s}) W_2(\text{kJ/kg}) = m_{14}(\text{kg/s}) \Delta H_{\text{LPT}}(\text{kJ/kg}), \text{ with}$$

Condenser

- $Q_9(\text{kJ/s}) = m_{15}(\text{kg/s}) (H_{16}-H_{15})(\text{kJ/kg}) = m_{24}(\text{kg/s}) (H_{24}-H_{23})(\text{kJ/kg})$

$$m_{23}(\text{kg/s}) = Q_9(\text{kJ/s}) / (H_{24}-H_{23})(\text{kJ/kg})$$

P1

- Isentropic specific work of P1: $W_{\text{isentropic}}(\text{kJ/kg}) = (\Delta H)_{\text{isentropic}}(\text{kJ/kg}) = V_{16}(\text{m}^3/\text{kg}) (P_{17}-P_{16})(\text{kPa})$

$$\text{Actual specific work of P1: } W_3(\text{kJ/kg}) = \Delta H_{P1}(\text{kJ/kg}) = W_{\text{isentropic}}/\eta_{P1} = (\Delta H)_{\text{isentropic}}/\eta_{P1}$$

$$\text{Actual specific } H_{17}(\text{kJ/kg}) = \Delta H_{P1}(\text{kJ/kg}) + H_{16}(\text{kJ/kg})$$

To calculate T_{17} and S_{17} :

$$\Delta H_{P1}(\text{kJ/kg}) = C_{p,16} \Delta T_{P1} + V_{16}(1-\beta_{16} T_{16})(P_{17}-P_{16})$$

$$T_{17}(\text{°C}) = \Delta T_{P1}(\text{°C}) + T_{16}(\text{°C})$$

$$\Delta S_{P1}(\text{kJ/kg K}) = C_{p,16} \ln(T_{17}/T_{16}) - \beta_{16} V_{16}(P_{17}-P_{16})$$

$$S_{17}(\text{kJ/kg K}) = \Delta S_{P1}(\text{kJ/kg K}) + S_{16}(\text{kJ/kg K})$$

$$\text{At } P_{16} = 10\text{kPa}$$

$$V_{16} = 0.00101026 \text{ m}^3/\text{kg}$$

$$C_{p,16} = 4.180 \text{ kJ/kg K}$$

$$\beta_{16} = 0.0004291 \text{ K}^{-1}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_{16}(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_{16}(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_3 (\text{kJ/s}) = m_{16}(\text{kg/s}) W_3(\text{kJ/kg}) = m_{16}(\text{kg/s}) \Delta H_{P1}(\text{kJ/kg})$$

HRSG

- $Q_6(\text{kJ/s}) = m_{13}(\text{kg/s}) (H_{19}-H_{13})(\text{kJ/kg})$, with

$$Q_7(\text{kJ/s}) = \eta_{\text{HRSG}} Q_6(\text{kJ/s}) = m_{22}(\text{kg/s}) (H_{22}-H_{21})(\text{kJ/kg})$$

$$m_{22}(\text{kg/s}) = Q_7(\text{kJ/kg}) / (H_{22}-H_{21})(\text{kJ/kg})$$

P2

- Isentropic specific work of P2: $W_{\text{isentropic}}(\text{kJ/kg}) = (\Delta H)_{\text{isentropic}}(\text{kJ/kg}) = V_{19}(\text{m}^3/\text{kg}) (P_{20}-P_{19})(\text{kPa})$

$$\text{Actual specific work of P2: } W_4(\text{kJ/kg}) = \Delta H_{P2}(\text{kJ/kg}) = W_{\text{isentropic}}/\eta_{P2} = (\Delta H)_{\text{isentropic}}/\eta_{P2}$$

$$\text{Actual specific } H_{20}(\text{kJ/kg}) = \Delta H_{P2}(\text{kJ/kg}) + H_{19}(\text{kJ/kg})$$

To calculate T_{20} and S_{20} :

$$\Delta H_{P2}(\text{kJ/kg}) = C_{p,19} \Delta T_{P2} + V_{19}(1-\beta_{19} T_{19})(P_{20}-P_{19})$$

$$T_{20}(\text{°C}) = \Delta T_{P2}(\text{°C}) + T_{19}(\text{°C})$$

$$\Delta S_{P2}(\text{kJ/kg K}) = C_{p,19} \ln(T_{20}/T_{19}) - \beta_{19} V_{19}(P_{20} - P_{19})$$

$$S_{20}(\text{kJ/kg K}) = \Delta S_{P2}(\text{kJ/kg K}) + S_{19}(\text{kJ/kg K})$$

$$\text{At } P_{19} = 1150\text{kPa}$$

$$V_{19} = 0.0011359 \text{ m}^3/\text{kg}$$

$$C_{p,19} = 4.4368 \text{ kJ/kg K}$$

$$B_{19} = 0.00101 \text{ K}^{-1}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_{19}(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_{19}(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_4(\text{kJ/s}) = m_{19}(\text{kg/s}) W_4(\text{kJ/kg}) = m_{19}(\text{kg/s}) \Delta H_4(\text{kJ/kg})$$

Mixer

- $m_{18}(\text{kg/s}) H_{18}(\text{kJ/kg}) = m_{20}(\text{kg/s}) H_{20}(\text{kJ/kg}) + m_{17}(\text{kg/s}) H_{17}(\text{kJ/kg})$

$$m_{18} H_{18} = y_{\text{steam}} m_{18} H_{20} + y_{\text{electricity}} m_{18} H_{17}$$

$$H_{18}(\text{kJ/kg}) = y_{\text{steam}} H_{20} + y_{\text{electricity}} H_{17}$$

$$S_{18}(\text{kJ/kg K}) = y_{\text{steam}} S_{20} + y_{\text{electricity}} S_{17}$$

$$T_{18}(\text{°C}) = y_{\text{steam}} T_{20} + y_{\text{electricity}} T_{17}$$

$$m_{18}(\text{kg/s}) = m_{20} + m_{17}$$

W_{net} , W_e , Q_T and Efficiency

- $W_{\text{net}} = (W_1 + W_2) - (W_3 + W_4)$

$$W_e = W_{\text{net}} \times \eta_{\text{Gen}} \times \eta_{\text{Del}}$$

$$Q_T = Q_7 = \eta_{\text{HRSG}} Q_6$$

$$\eta_{\text{th}} = (W_{\text{net}} + Q_6) / Q_4 \times 100$$

$$\eta_{\text{tot}} = (W_e + Q_T) / Q_1 \times 100, \text{ with } W \text{ and } Q \text{ in kJ/s.}$$

Appendix C: Alternative A-Nuclear Based Process Route

For all the streams:

- $Q_i(\text{kJ/s}) = m_i(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg}) (T_i - T_{\text{ref}})$ (For the Helium streams)

$$Q_i(\text{kJ/s}) = m_i(\text{kg/s}) H_i(\text{kJ/kg}) \text{ (For the water streams)}$$

$$n_i(\text{kmo/hr}) = m_i(\text{kg/hr}) / \text{Mole mass (kg/kmol)}$$

$$V_i(\text{Nm}^3/\text{hr}) = m_i(\text{kg/hr}) / \rho_i(\text{kg/Nm}^3) = m_i(\text{kg/hr}) / (\text{Mole mass (kg/kmol)} / 22.413),$$

With i = stream number

PHTS

$$m_1(\text{kg/s}) = m_2(\text{kg/s}) = m_3(\text{kg/s})$$

$$P_1(\text{kPa}) = P_2(\text{kPa}) = P_3(\text{kPa})$$

HTGR

- $Q_1(\text{kJ/s}) = m_1(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg } ^\circ\text{C}) \Delta T(^{\circ}\text{C}) = m_1 C_{p,\text{He}}(T_1 - T_3)$

$$m_1(\text{kg/s}) = Q_1 / C_{p,\text{He}}(T_1 - T_3)$$

Blower

- $W_1(\text{kJ/s}) = m_2(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg } ^\circ\text{C}) \Delta T(^{\circ}\text{C}) = m_2 C_{p,\text{He}}(T_3 - T_2)$

SHTS

$$m_4 \text{ (kg/s)} = m_5 \text{ (kg/s)} = m_6 \text{ (kg/s)}$$

$$P_4 \text{ (kPa)} = P_5 \text{ (kPa)} = P_6 \text{ (kPa)}$$

IHX

- $Q_2 \text{ (kJ/s)} = m_1 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_1 C_{p,\text{He}} (T_2 - T_1)$

$$T_4 = T_1 - \Delta T_{\text{IHx}}$$

$$T_6 = T_2 - \Delta T_{\text{IHx}}$$

$$Q_3 \text{ (kJ/s)} = \eta_{\text{IHx}} Q_2 \text{ (kJ/s)} = m_4 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_4 C_{p,\text{He}} (T_4 - T_6)$$

$$m_4 \text{ (kg/s)} = Q_3 / C_{p,\text{He}} (T_4 - T_6)$$

Blower

- $W_2 \text{ (kJ/s)} = m_5 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_5 C_{p,\text{He}} (T_6 - T_5)$

SG

- $Q_5 \text{ (kJ/s)} = m_4 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_4 C_{p,\text{He}} (T_5 - T_4)$

$$Q_6 \text{ (kJ/s)} = \eta_{\text{SG}} Q_5 \text{ (kJ/s)} = m_7 \text{ (kg/s)} (H_7 - H_{14}) \text{ (kJ/kg)}$$

$$m_7 \text{ (kg/s)} = Q_6 \text{ (kJ/s)} / (H_7 - H_{14}) \text{ (kJ/kg)}$$

PCS

$$m_7 = m_{14} = m_8$$

$$m_9 = y_{\text{electricity}} m_8 = m_{11} = m_{12} = m_{13}$$

$$m_{10} = y_{\text{steam}} m_8 = m_{15} = m_{16}$$

$$m_{17} = m_{18}$$

$$m_{19} = m_{20}, \text{ with } m_i \text{ in kg/s}$$

$$P_7 = P_{14} = P_{13} = P_{16}$$

$$P_8 = P_9 = P_{10} = P_{15}$$

$$P_{11} = P_{12} = P_{13}$$

$$P_{17} = P_{18}$$

$$P_{19} = P_{20}, \text{ with } P \text{ in kPa}$$

SG

- $Q_6 \text{ (kJ/s)} = m_7 \text{ (kg/s)} (H_7 - H_{14}) \text{ (kJ/kg)}$

$$m_7 \text{ (kg/s)} = Q_6 / (H_7 - H_{14})$$

HPT

- Isentropic specific work of HPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_8 - H_7$,

Assume HPT is isentropic, $S_7 = S'_8$, with H'_8 from steam tables at S'_8 and P_8 .

Actual specific work of HPT: $W_3 \text{ (kJ/kg)} = \Delta H_{\text{HPT}} \text{ (kJ/kg)} = \eta_{\text{HPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{HPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$

Actual specific $H_8 \text{ (kJ/kg)} = \Delta H_{\text{HPT}} + H_7$

$W_{\text{isentropic}} \text{ (kJ/s)} = m_7 \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)} = m_7 \text{ (kg/s)} \Delta H_{\text{isentropic}} \text{ (kJ/kg)}$

$W_3 \text{ (kJ/s)} = m_7 \text{ (kg/s)} W_3 \text{ (kJ/kg)} = m_7 \text{ (kg/s)} \Delta H_{\text{HPT}} \text{ (kJ/kg)}$

$H_8 = H_9 = H_{10}$, $T_8 = T_9 = T_{10}$

LPT

- Isentropic specific work of LPT: $W_{\text{isentropic}} \text{ (kJ/kg)} = (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)} = H'_{11} - H_9$,

Actual specific work of LPT: $W_4 \text{ (kJ/kg)} = \Delta H_{\text{LPT}} \text{ (kJ/kg)} = \eta_{\text{LPT}} W_{\text{isentropic}} \text{ (kJ/kg)} = \eta_{\text{LPT}} (\Delta H)_{\text{isentropic}} \text{ (kJ/kg)}$

Actual specific $H_{11} \text{ (kJ/kg)} = \Delta H_{\text{LPT}} + H_9$

To calculate H'_{11} :

Assume LPT is isentropic, $S_9 = S'_{11}$,

$$\text{Calculate } X'_{\text{vap}} \text{ from } S'_{11} \text{ (kJ/kg K)} = S_{\text{liq}} (1-X'_{\text{vap}}) + X'_{\text{vap}} S_{\text{vap}}$$

$$\text{Calculate } H'_{11} \text{ using } H'_{11} \text{ (kJ/kg)} = H_{\text{liq}} (1-X'_{\text{vap}}) + X'_{\text{vap}} H_{\text{vap}}$$

At $P_{11} = 10\text{kPa}$ from steam tables:

$$S_{\text{vap}} = 8.151 \text{ kJ/kg}$$

$$S_{\text{liq}} = 0.649 \text{ kJ/kg K,}$$

$$H_{\text{vap}} = 2584.6 \text{ kJ/kg}$$

$$H_{\text{liq}} = 191.8 \text{ kJ/kg}$$

$$\text{Calculate } X_{\text{vap}} \text{ from } H_{11} \text{ (kJ/kg)} = H_{\text{liq}} (1-X_{\text{vap}}) + X_{\text{vap}} H_{\text{vap}}$$

$$\text{Calculate } S_{11} \text{ (kJ/kg K)} = S_{\text{liq}} (1-X_{\text{vap}}) + X_{\text{vap}} S_{\text{vap}}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_9(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_9(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_4(\text{kJ/s}) = m_9(\text{kg/s}) W_4(\text{kJ/kg}) = m_9(\text{kg/s}) \Delta H_{\text{LPT}}(\text{kJ/kg})$$

Condenser

- $Q_{11}(\text{kJ/s}) = m_{11}(\text{kg/s}) (H_{12}-H_{11})(\text{kJ/kg}) = m_{20}(\text{kg/s}) (H_{20}-H_{19})(\text{kJ/kg})$

$$m_{20}(\text{kg/s}) = Q_{11}(\text{kJ/s}) / (H_{20}-H_{19})(\text{kJ/kg})$$

P1

- Isentropic specific work of P1: $W_{\text{isentropic}}(\text{kJ/kg}) = (\Delta H)_{\text{isentropic}}(\text{kJ/kg}) = V_{12}(\text{m}^3/\text{kg}) (P_{13} - P_{12})(\text{kPa})$

$$\text{Actual specific work of P1: } W_5(\text{kJ/kg}) = \Delta H_{P1}(\text{kJ/kg}) = W_{\text{isentropic}}/\eta_{P1} = (\Delta H)_{\text{isentropic}}/\eta_{P1}$$

$$\text{Actual specific } H_{13}(\text{kJ/kg}) = \Delta H_{P1}(\text{kJ/kg}) + H_{12}(\text{kJ/kg})$$

To calculate T_{13} and S_{13} :

$$\Delta H_{P1}(\text{kJ/kg}) = C_{p,12} \Delta T_{P1} + V_{12}(1 - \beta_{12} T_{12})(P_{13} - P_{12})$$

$$T_{13}(\text{°C}) = \Delta T_{P1}(\text{°C}) + T_{12}(\text{°C})$$

$$\Delta S_{P1}(\text{kJ/kg K}) = C_{p,12} \ln(T_{13}/T_{12}) - \beta_{12} V_{12}(P_{13} - P_{12})$$

$$S_{13}(\text{kJ/kg K}) = \Delta S_{P1}(\text{kJ/kg K}) + S_{12}(\text{kJ/kg K})$$

At $P_{12} = 10\text{kPa}$

$$V_{12} = 0.00101026 \text{ m}^3/\text{kg}$$

$$C_{p,12} = 4.180 \text{ kJ/kg K}$$

$$\beta_{12} = 0.0004291 \text{ K}^{-1}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_{12}(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_{12}(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_5(\text{kJ/s}) = m_{12}(\text{kg/s}) W_5(\text{kJ/kg}) = m_{12}(\text{kg/s}) \Delta H_{P1}(\text{kJ/kg})$$

HRSG

- $Q_8(\text{kJ/s}) = m_{10}(\text{kg/s}) (H_{15}-H_{10})(\text{kJ/kg})$

$$Q_9(\text{kJ/s}) = \eta_{\text{HRSG}} Q_8(\text{kJ/s}) = m_{18}(\text{kg/s}) (H_{18}-H_{17})(\text{kJ/kg})$$

$$m_{18}(\text{kg/s}) = Q_9(\text{kJ/kg}) / (H_{18}-H_{17})(\text{kJ/kg})$$

P2

- Isentropic specific work of P2: $W_{\text{isentropic}}(\text{kJ/kg}) = (\Delta H)_{\text{isentropic}}(\text{kJ/kg}) = V_{15}(\text{m}^3/\text{kg}) (P_{16}-P_{15})(\text{kPa})$

$$\text{Actual specific work of P2: } W_6(\text{kJ/kg}) = \Delta H_{P2}(\text{kJ/kg}) = W_{\text{isentropic}}/\eta_{P2} = (\Delta H)_{\text{isentropic}}/\eta_{P2}$$

$$\text{Actual specific } H_{16}(\text{kJ/kg}) = \Delta H_{P2}(\text{kJ/kg}) + H_{15}(\text{kJ/kg})$$

To calculate T_{16} and S_{16} :

$$\Delta H_{P2}(\text{kJ/kg}) = C_{p,15} \Delta T_{P2} + V_{15}(1-\beta_{15} T_{15})(P_{16}-P_{15})$$

$$T_{16}(\text{°C}) = \Delta T_{P2}(\text{°C}) + T_{15}(\text{°C})$$

$$\Delta S_{P2}(\text{kJ/kg K}) = C_{p,15} \ln(T_{16}/T_{15}) - \beta_{15} V_{15}(P_{16}-P_{15})$$

$$S_{16}(\text{kJ/kg K}) = \Delta S_{P2}(\text{kJ/kg K}) + S_{15}(\text{kJ/kg K})$$

At $P_{15} = 1150\text{kPa}$

$$V_{15} = 0.0011359 \text{ m}^3/\text{kg}$$

$$C_{p,15} = 4.4368 \text{ kJ/kg K}$$

$$\beta_{15} = 0.00101 \text{ K}^{-1}$$

$$W_{\text{isentropic}}(\text{kJ/s}) = m_{15}(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg}) = m_{15}(\text{kg/s}) \Delta H_{\text{isentropic}}(\text{kJ/kg})$$

$$W_6(\text{kJ/s}) = m_{15}(\text{kg/s}) W_6(\text{kJ/kg}) = m_{15}(\text{kg/s}) \Delta H_{P2}(\text{kJ/kg})$$

Mixer

- $m_{14}(\text{kg/s}) H_{14}(\text{kJ/kg}) = m_{16}(\text{kg/s}) H_{16}(\text{kJ/kg}) + m_{13}(\text{kg/s}) H_{13}(\text{kJ/kg})$

$$m_{14}H_{14} = y_{\text{steam}}m_{14}H_{16} + y_{\text{electricity}}m_{14}H_{13}$$

$$H_{14}(\text{kJ/kg}) = y_{\text{steam}}H_{16} + y_{\text{electricity}}H_{13}$$

$$S_{14}(\text{kJ/kg K}) = y_{\text{steam}}S_{16} + y_{\text{electricity}}S_{13}$$

$$T_{14}(\text{°C}) = y_{\text{steam}}T_{16} + y_{\text{electricity}}T_{13}$$

$$m_{14}(\text{kg/s}) = m_{16} + m_{13}$$

W_{net} , W_e , Q_I and Efficiency

- $W_{\text{net PCS}} = (W_3 + W_4) - (W_5 + W_6)$

$$W_{\text{net TOT}} = (W_3 + W_4) - (W_5 + W_6) - (W_1 + W_2)$$

$$W_e = W_{\text{net}} \times \eta_{\text{Gen}} \times \eta_{\text{Del}}$$

$$Q_T = Q_9 = \eta_{\text{HRSG}} Q_8$$

$$\eta_{\text{th}} = (W_{\text{net PCS}} + Q_8) / Q_6 \times 100$$

$$\eta_{\text{tot}} = (W_e + Q_T) / Q_1 \times 100,$$

with W and Q in kJ/s

Appendix D: Alternative B-Nuclear Based Process Route

For all the streams:

- $Q_i(\text{kJ/s}) = m_i(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg}) (T_i - T_{\text{ref}})$ (For the Helium Stream)

$$Q_i(\text{kJ/s}) = m_i(\text{kg/s}) H_i(\text{kJ/kg}) \text{ (For the water streams)}$$

$$n_i(\text{kmo/hr}) = m_i(\text{kg/hr}) / \text{Mole mass (kg/kmol)}$$

$$V_i(\text{Nm}^3/\text{hr}) = m_i(\text{kg/hr}) / \rho_i(\text{kg/Nm}^3) = m_i(\text{kg/hr}) / (\text{Mole mass (kg/kmol)} / 22.413),$$

With i = stream number

PHTS

$$m_1(\text{kg/s}) = m_2(\text{kg/s}) = m_3(\text{kg/s})$$

$$P_1(\text{kPa}) = P_2(\text{kPa}) = P_3(\text{kPa})$$

HTGR

- $Q_1(\text{kJ/s}) = m_1(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg } ^\circ\text{C}) \Delta T(^{\circ}\text{C}) = m_1 C_{p,\text{He}}(T_1 - T_3)$

$$m_1(\text{kg/s}) = Q_1 / C_{p,\text{He}}(T_1 - T_3)$$

Blower

- $W_1(\text{kJ/s}) = m_2(\text{kg/s}) C_{p,\text{He}}(\text{kJ/kg } ^\circ\text{C}) \Delta T(^{\circ}\text{C}) = m_2 C_{p,\text{He}}(T_3 - T_2)$

IHX

- $Q_2 \text{ (kJ/s)} = m_1 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_1 C_{p,\text{He}} (T_2 - T_1)$

$$T_4 = T_1 - \Delta T_{\text{IHx}}$$

$$T_{11} = T_2 - \Delta T_{\text{IHx}}$$

PCS

$$m_4 = m_5 = m_6 = m_7 = m_8 = m_9 = m_{10} = m_{11}$$

$$m_{12} = m_{13}, \text{ with } m \text{ in kg/s}$$

$$P_4 = P_{11} = P_{10}$$

$$P_5 = P_6 = P_7 = P_8 = P_9$$

$$P_{12} = P_{13}, \text{ with } P \text{ in kPa}$$

IHX

$$Q_3 \text{ (kJ/s)} = \eta_{\text{IHx}} Q_2 \text{ (kJ/s)} = m_4 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} \Delta T \text{ (} ^\circ\text{C)} = m_4 C_{p,\text{He}} (T_4 - T_{11})$$

$$m_4 \text{ (kg/s)} = Q_3 / C_{p,\text{He}} (T_4 - T_{11})$$

PT

- Isentropic specific work of PT: $W_{\text{isentropic}} = C_{p,\text{He}} T_4 [(P_5/P_4)^{R/C_{p,\text{He}}} - 1]$, with W in J/mol, $C_{p,\text{He}}$ in J/mol K, T in K, P in kPa and R in J/mol K.

$$P_5 = P_4/PR, \text{ with } PR = \text{Pressure Ratio}$$

$$\text{Actual specific work of PT: } W_2 \text{ (J/mol)} = \eta_{PT} W_{\text{isentropic}} \text{ (J/mol)} = C_{p,\text{He}} (T_5 - T_4)$$

$$T_5(\text{K}) = W_2 / C_{p,\text{He}} + T_4$$

With,

$$C_{p,\text{He}} = 20.81352 \text{ J/mol K}$$

$$R = 8.314 \text{ J/mol K}$$

$$M_{\text{He}} = 4 \text{ g/mol}$$

$$W_{\text{isentropic}} \text{ (kJ/kg)} = W_{\text{isentropic}} \text{ (J/mol)} / M_{\text{He}} \text{ (g/mol)}$$

$$W_2 \text{ (kJ/kg)} = W_2 \text{ (J/mol)} / M_{\text{He}} \text{ (g/mol)}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_4(\text{kg/s}) W_{\text{isentropic}}(\text{kJ/kg})$$

$$W_2 \text{ (kJ/s)} = m_4(\text{kg/s}) W_2(\text{kJ/kg})$$

HRSG

- $Q_7(\text{kJ/s}) = m_5 \text{ (kg/s)} C_{p,\text{He}} \text{ (kJ/kg } ^\circ\text{C)} (T_6 - T_5)(^\circ\text{C)}$

$$Q_8(\text{kJ/s}) = \eta_{\text{HRSG}} Q_7(\text{kJ/s}) = m_{13}(\text{kg/s}) (H_{13} - H_{12})(\text{kJ/kg})$$

$$m_{13}(\text{kg/s}) = Q_8(\text{kJ/kg}) / (H_{13} - H_{12})(\text{kJ/kg})$$

Recuperator

- Recuperator (kJ/s) = m_6 (kg/s) $C_{p,He}$ (kJ/kg °C) $(T_7 - T_6)$ (°C) = m_{10} (kg/s) $C_{p,He}$ (kJ/kg °C) $(T_{11} - T_{10})$ (°C)

$$T_6 = T_{11} + \Delta T_R$$

$$T_7 = T_{10} + \Delta T_R$$

1st PC

- Q_5 (kJ/s) = m_7 (kg/s) $C_{p,He}$ (kJ/kg °C) ΔT (°C) = $m_7 C_{p,He} (T_8 - T_7)$

$$T_8 = T_7 - (T_7 - T_9)/2$$

2nd PC

- Q_6 (kJ/s) = m_8 (kg/s) $C_{p,He}$ (kJ/kg °C) ΔT (°C) = $m_8 C_{p,He} (T_9 - T_8)$

LPC

- Isentropic specific work of LPC: $W_{\text{isentropic}} = C_{p,He} T_9 [(P_{10}/P_9)^{R/C_{p,He}} - 1]$, with W in J/mol, $C_{p,He}$ in J/mol K, T in K, P in kPa and R in J/mol K.

$$\text{Actual specific work of LPC: } W_3 \text{ (J/mol)} = W_{\text{isentropic}} \text{ (J/mol)} / \eta_{\text{LPC}} = C_{p,He} (T_{10} - T_9)$$

$$T_{10} \text{ (K)} = W_3 / C_{p,He} + T_9$$

With,

$$C_{p,He} = 20.81352 \text{ J/mol K}$$

$$R = 8.314 \text{ J/mol K}$$

$$M_{He} = 4 \text{ g/mol}$$

$$W_{\text{isentropic}} \text{ (kJ/kg)} = W_{\text{isentropic}} \text{ (J/mol)} / M_{He} \text{ (g/mol)}$$

$$W_3 \text{ (kJ/kg)} = W_3 \text{ (J/mol)} / M_{He} \text{ (g/mol)}$$

$$W_{\text{isentropic}} \text{ (kJ/s)} = m_g \text{ (kg/s)} W_{\text{isentropic}} \text{ (kJ/kg)}$$

$$W_3 \text{ (kJ/s)} = m_g \text{ (kg/s)} W_3 \text{ (kJ/kg)}$$

W_{net} , W_e , Q_T and Efficiency

- $W_{\text{net PCS}} = W_2 - W_3$

$$W_{\text{net TOT}} = W_2 - W_3 - W_1$$

$$W_e = W_{\text{net}} \times \eta_{\text{Gen}} \times \eta_{\text{Del}}$$

$$Q_T = Q_8 = \eta_{\text{HRSG}} Q_7$$

$$\eta_{\text{th}} = (W_{\text{net PCS}} + Q_7) / Q_3 \times 100$$

$$\eta_{\text{tot}} = (W_e + Q_T) / Q_1 \times 100,$$

with W and Q in kJ/s