

CRANFIELD UNIVERSITY

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**ADVANCED LOW-CARBON POWER PLANTS:
THE T.E.R.A. APPROACH**

SCHOOL OF MECHANICAL ENGINEERING

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ABSTRACT

It is widely accepted that climate change is a very serious environmental concern facing the world today. Levels of carbon dioxide (CO₂) in the global atmosphere have risen by more than a third since the industrial revolution and are now rising faster than ever before. Power generation accounts for a large proportion of GHGs emissions.

Many different options are being proposed for CO₂ emissions mitigation from the power generation sector. They have been extensively investigated in the scientific literature, but selection of better candidates for future investments is difficult and uncertain.

The main aim of this investigation is to provide an insight into the possibilities of using power generation plants with CO₂ capture in a long-term perspective by means of the application of the T.E.R.A. (Techno-economic Environmental and Risk Analysis) approach. The present work offers a solid base for the establishment of such a methodical approach for the unmitigated power generation case and subsequently for the CO₂ capture case.

Five low-carbon gas turbine based power plants have been identified as promising options satisfying future requirements for reduced CO₂ emissions, and a conventional gas turbine combined cycle has been designated as the baseline of the whole analysis. A study of each selected cycle has been initiated in terms of many aspects according to the T.E.R.A. approach (technical solution, technology readiness level, effort required for its deployment, environmental impact, costs and risks involved). A first version of a computer tool for analysing CO₂ capture power plants based on the suggested methodology has been implemented.

The applicability of the methodology has been demonstrated in three case studies (a conventional power plant and two pre-combustion power plants, the ATRCC and the IRCC), showing the potential of the approach applied to advanced low-carbon projects' assessment, and testing the utility and the functionality of the related tools developed. The transparent and consistently based picture of the three power plants considered allowed highlighting clearly advantages and disadvantages of each scheme over the others from a fourfold point of view (performance, costs, pollutant emissions and technological readiness level). Results are presented in terms of specific economic and cost indices that are commonly used to measure cost against technical performance. Both deterministic methods and stochastic perturbation are compared as a way of examining uncertainty in assigned parameter values for cost and technology readiness level. The implementation of coupled models into a consistently-based code is the overall achievement of the project and forms an initial coherent model for plant assessment.

From the performance perspective, the two advanced schemes with fuel decarbonisation result in thermal efficiencies well below that of the conventional combined cycle. The ATRCC with removal of CO₂ presents a net efficiency of 37 %, which corresponds to a reduction of about 19%-points with reference to the baseline. The net efficiency of the IRCC is about 11 percentage points lower than for the conventional combined cycle.

The two advanced technologies investigated can make an indisputable contribution toward lowering carbon dioxide emissions and the associated global warming potential. The specific emissions are about 64g_{CO2}/kWh for the ATRCC and 53g_{CO2}/kWh for the IRCC, ensuring a reduction with respect to the baseline of 82% and 85% respectively. However, it has been shown also that the two layouts investigated may not keep NO_x in the common range for a conventional combined cycle.

The ability of removing CO₂, provided by the two pre-combustion cycles, leads to a significant increase in the Capital and O&M costs, which impinges on the electricity cost: the CoE rises from 2.92p/kWh, value estimated for the baseline, to 4.72p/kWh and 4.16p/kWh for the ATRCC and the IRCC respectively (in the case of no carbon tax). The economic analysis showed also the advantage in the economic performance of the pre-combustion cycles with respect to the baseline if a carbon tax is stipulated. The analysis performed through the application of Monte Carlo method highlighted a higher variability of the economic indices of the conventional combined cycle resulting from the uncertainty surrounding the carbon tax. Both the low-carbon power plants, instead, are less influenced by the introduction of the tax, but are critically sensitive to the uncertainty in the fuel price.

The technology risk analysis showed that, due to the plant configuration adopted, no particular concerns exist regarding the gas turbine, and the other components present a high maturity level. The CO₂ compression and the CO₂ capture section are characterised by a lower maturity level, therefore may not match the power plant requirements.

Between the two advanced schemes, the more integrated solution (the IRCC power plant) emerged as a viable option for new power generation capacity to be installed in the near future under a high carbon dioxide emission constraint. Improvements in the CO₂ capture and compression (due to their low maturity level) and reduction in NO_x emissions, along with the costs contribution, would provide a very competitive solution to reduce substantially CO₂ emissions from power plants.

The T.E.R.A. exercise developed in the present investigation showed clearly how the carbon tax levy looms as a market factor through which CCS deployment can be incentivised. On the other hand, combined with the volatile price of natural gas, this additional cost will be certainly transferred from power producers to the consumers of electricity, with a negative impact on national economic growth.

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Cranfield, April 2010

G. D. L.

... καὶ ἀποκριθεὶς Σίμων εἶπεν ὅτι ἐπιστάτα
δι' ὅλης νυκτὸς κοπιάσαντες οὐδὲν ἐλάβομεν
ἐπὶ δὲ τῷ ῥήματί σου χαλάσω τὰ δίκτυα".

κατὰ Λουκᾶν 5,5

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LIST OF ABBREVIATIONS AND SYMBOLS

A Area
ASU Air Separation Unit
ATR Auto-Thermal Reformer
ATRCC Auto-thermal Reforming Combined Cycle
AZEP Advanced Zero emission power Plant
BFW Boiler Feed Water
C Heat capacity rate
CCGT Combined Cycle Gas Turbine
CC Combined Cycle
CCS Carbon Capture and Storage
CLC Chemical Looping Combustion
COT Combustor Outlet Temperature
 C_p Specific Heat Capacity
DTI Department of Trade and Industry
GHG Greenhouse Gas
GT Gas Turbine
HRSG Heat Recovery Steam Generator
IAPWS International Association for the Properties of Water and Steam
IGCC Integrated Gasification Combined Cycle
IRCC Integrated Reforming Combined Cycle
IRR Internal Rate of Return
LHV Lower Heating Value
LMTD Log Mean Temperature Difference
M Mach number
Me Metal
MeO Metal Oxide
NDN Non-dimensional rotational speed
NDW Non-dimensional mass flow
NG Natural Gas
NPV Net Present Value
P Pressure
PBT Pay-Back Time
PC Pulverized Coal
PLF Pressure Loss Factor
PM Particulate Matter
POX Partial Oxidation
Pr Prandtl number
PR Pressure Ratio
R Gas Constant
Re Reynolds number
SFT Stoichiometric Flame Temperature
SMR Steam Methane Reforming
ST Steam Turbine
T Temperature
TERA Techno-economic Environmental Risk Analysis
TET Turbine Entry Temperature

List of Abbreviations and Symbols

TLI Technology Level Indicators
TRL Technology Readiness Level
U Overall heat transfer coefficient
VGV Variable Guide Vanes
W Mass flow
WGS Water Gas Shift

CHAPTER 1

INTRODUCTION

1.1 Climate Change and Electric-power Generation

There is a broad consensus that climate change is an environmental issue of present and critical global significance. The increased concentration of man-made emissions of greenhouse gases (GHGs), with the consequent greenhouse effect, is at the centre of the climate change debate, motivating global actions.

The first use of the term ‘greenhouse effect’ dates back to the beginning of the 19th century, when the term was used to express the naturally-occurring function of trace gases in the atmosphere without any negative implications. The greenhouse effect is in fact the warming of the Earth because of the presence of greenhouse gases in the atmosphere, and indeed this natural effect is essential for the Earth. The negative connotation of the term is related to the possible impacts of an enhanced greenhouse effect - caused by a man-made increase of greenhouse gases concentration - which will make the Earth warmer than usual, thereby disturbing the natural course of meteorological phenomena and creating troubles for the living beings.

The significant greenhouse gases are water vapour, carbon dioxide, nitrous oxide, methane and ozone [1]. According to evaluations made in non-industrialised zones around the world, the concentrations of greenhouse gases in the atmosphere today are much larger than pre-industrial levels (i.e. at 1750 A.D.), as can be seen in Table 1-1 below. The cause of these increases can be found in fossil fuel combustion and in the reduction of carbon accumulated in biomass as a result of the transmutation of natural forests and woodlands into housing and farm land as well as other anthropogenic activities [1].

The dominant anthropogenic global warming contribution is from CO₂ emissions because of its extended lifetime in the atmosphere¹ [2, 3]: carbon dioxide is the predominant man-made greenhouse gas, contributing about 70% of the potential global warming effect of man-made emissions [7]. The concentration of CO₂ in the atmosphere has increased from a pre-industrial level of about 280 ppm to the current concentration of about 387 ppm, rising at a faster rate recently (Figure 1.1) [8, 9]. Figure 1.2 shows that the level of CO₂ in the atmosphere increased by about 10 ppm during the period 2005 and 2009 only. Such increased concentration of CO₂, thereby adding up to the overall negative impact of the greenhouse effect, has already led to a dangerous warming of the Earth and disastrous changes in the world around us. It is believed that the mean global temperature has considerably increased over the past 100 years due to the growing man-made greenhouse effect, as shown in Figure 1.1. Without any significant actions to reduce emissions of CO₂ and other greenhouse gases in the atmosphere, according to the Stern Review [8], a global average temperature rise exceeding 2 °C is almost certain to occur within the next 50 years.

Table 1-1 *Most influential greenhouse gases* [9]

<i>Greenhouse gases</i>	<i>Concentration (1750 A.D.)</i>	<i>Recent Concentration²</i>
Carbon dioxide	280 ppm	384.8 ppm
Methane	700 ppb	1865 ppb
Nitrous Oxide	270 ppb	322ppb
Ozone	25 ppb	34 ppb

International efforts, symbolised by the Kyoto Protocol of December 1997, have been made in order to reduce emissions. An initial consequence of the protocol was an agreement by the majority of industrialised countries to reduce their CO₂ emissions from the 1990 level by 2012.

¹ Other non-CO₂ ‘Kyoto gases’, such as methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride are expected to produce as much warming as 125 Gt of carbon in the form of CO₂ would [4], or one-third of total CO₂ equivalent [5]. Consequently, a focus on CO₂ may prove insufficient in the near term if pollutants with shorter lifetimes do not gain comparable attention [2, 6].

² Atmospheric concentrations of gases change during the course of a year. Values reported in the table are averages over a 12-month period for all gases except for ozone, for which a current global value has been estimated by the IPCC. For carbon dioxide, the figure displayed is the 2008 average, whereas for methane and nitrous oxide it refers to the year October 2006 to September 2007 inclusive [9].

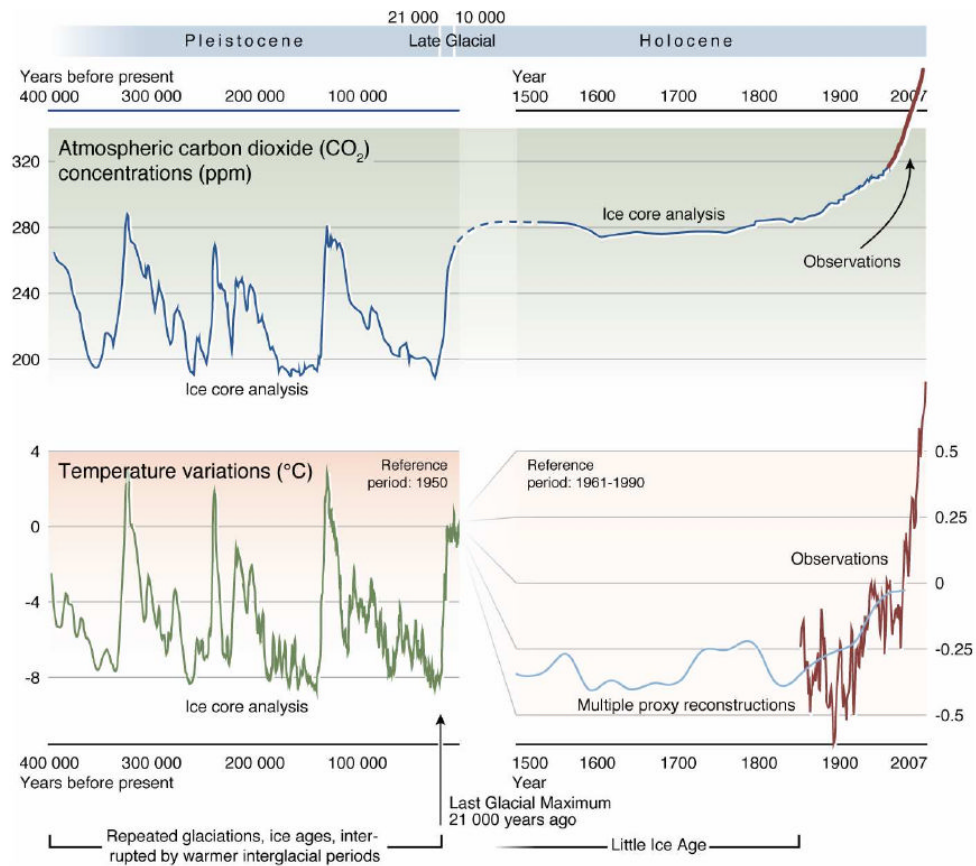


Figure 1.1 Historical trend of CO₂ concentration in the atmosphere versus its temperature [10]

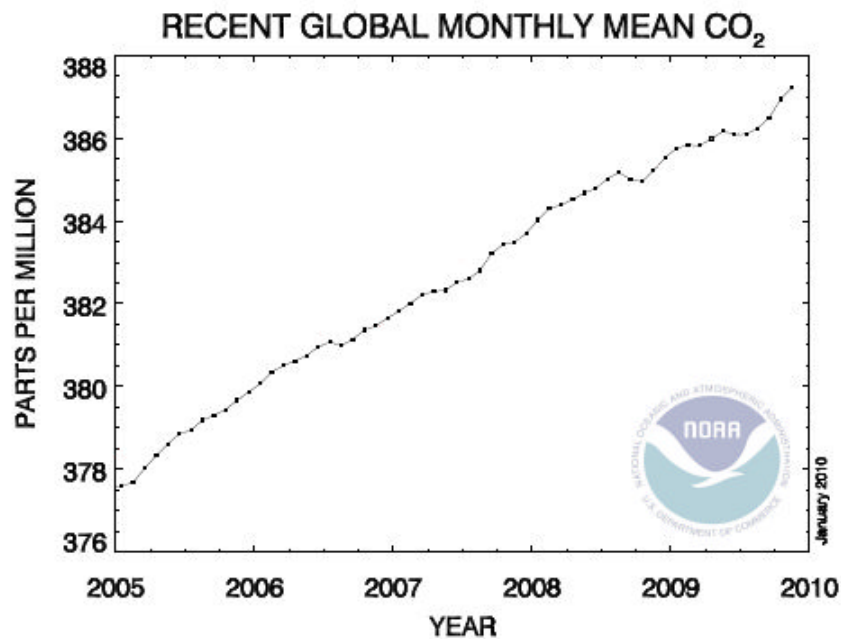


Figure 1.2 CO₂ concentration in atmosphere at sea level for Mauna Loa [11]

CO₂ emissions are directly related to the economic trends of the world: the world's economy to a large extent relies on the combustion of fossil fuels whose consumption results in huge amounts of CO₂ being emitted into the atmosphere each year. In 2007 the total world consumption of fossil fuels corresponded to an equivalent of 409,000,000,000,000,000 J (409 exajoule) [12].

Energy use and energy conversion are at the heart of the problem. Approximately 81% of the globe's primary energy comes from carbon-based fuels, with 13% from renewable energy and 6% from nuclear energy sources [IEA 2008[13] in 14]. As Table 1-2 below illustrates, energy use is by far the predominant source of CO₂ emissions, accounting for 72.9% of the world's total CO₂ emissions in the year 2000 [15]. However, land-use change and deforestation account for nearly a quarter of annual emissions globally. The main contributor to total anthropogenic CO₂ emissions is the power generation industry [3], which accounts for the largest proportion of the energy sector's GHG emissions. Among the energy sectors listed in Table 1-2, in fact, power-generating plants dominate the data by having the largest share of 33.7% of all identified CO₂ emissions sources. This is quite understandable considering that electricity drives the industrial and commercial sectors and even various means of transportation in many countries.

Table 1-2 CO₂ emissions by sources in 2000 [15]

World		
Sector	MtCO₂	%
Energy	25,097.6	72.9
Electricity & Heat	11,581.5	33.7
Manufacturing & Construction	4,748.4	13.8
Transportation	5,089.0	14.8
Other Fuel Combustion	3,488.1	10.1
Fugitive Emissions	190.6	0.6
Industrial Processes	828.1	2.4
Land-Use Change & Forestry	7,618.6	22.1
International Bunkers	862.7	2.5
Total	34,406.9	



The world's electricity demand has increased by over 50% since 1980 and will tend to increase sharply in the 21st century: the International Energy Agency (IEA) forecasts that global electricity generation will nearly double from 2005 to 2030 [16]. Fossil fuels are a key ingredient in meeting global electricity demand, as illustrated by Figure 1.3. Despite the increasing use of renewables, fossil fuels are expected to remain dominant for the next 30 years at least, both globally and for Europe, comprising roughly 70% of global and 60% of European electricity generation [16].

Therefore the power generation sector presents a particularly important potential source of carbon savings. According to the Stern Review "the power sector around

the world will have to be at least 60%, and perhaps as much as 75%, decarbonised by 2050” in order to stabilise the CO₂ concentration³ in the atmosphere [8].

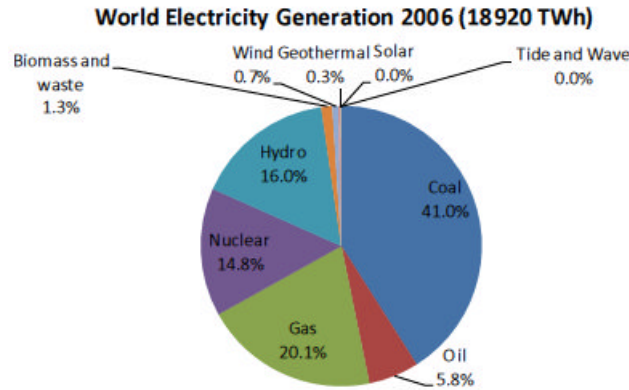


Figure 1.3 World electricity generation in 2006 [23]

1.2 The U.K. Electricity-generation sector and its contribution to tackling Climate Change

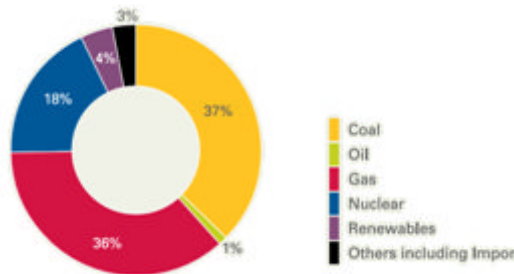
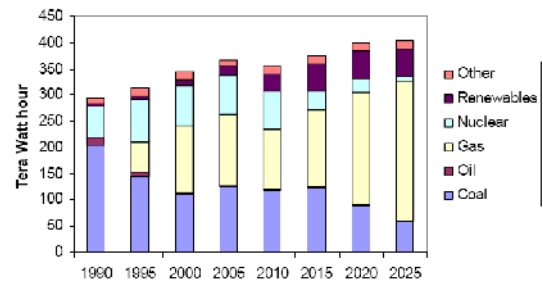
The U.K. power generation sector is under increasing pressure as nowadays it is faced with the difficulty of addressing climate change challenge, when a number of constraints arise.

Power generation is the major source of emissions in the U.K., being responsible for about one third of the total CO₂ release [24, 25]. It is expected to make a major contribution to the overall reductions of the U.K. [26-29], which according to the Kyoto Protocol, is required to deliver a 12.5% reduction in GHG emissions from the 1990 levels by 2008-2012. It seems likely also that the major part of the CO₂ reduction will take place in the power generation sector – globally and in U.K. - because of the variety of lower carbon alternatives to current technologies and its inherent easiness compared to the transport sector case. The achievement of this substantial reduction might be obtained in fact by a more economical and rapid action in this sector rather than in others, without requiring the need for changes in infrastructures of supply and final use (‘at its point of use electricity would “look” the same’) [30, 31]. The EU emission trading scheme (EU-ETS) and the electricity

³ Proposals to limit atmospheric CO₂ to a concentration that would prevent most damaging climate change have focused on a goal of 500±50 ppm [17, 18]. However, leading environmental scientists suggest a limit of not more than 350 ppm [19]. In such case CO₂ levels already exceed those that would provide long-term safety. Therefore it would need to do more than just stop, it would need to reverse course [19]. In this respect photosynthesis is currently the only practical form of air capture [20]. Canada, the United States and Switzerland have further developed air capture in form of prototypes [21, 22].

renewable obligation (RO) are among the ongoing policies that include electricity in the British energy policy agenda as its foremost concern. [32].

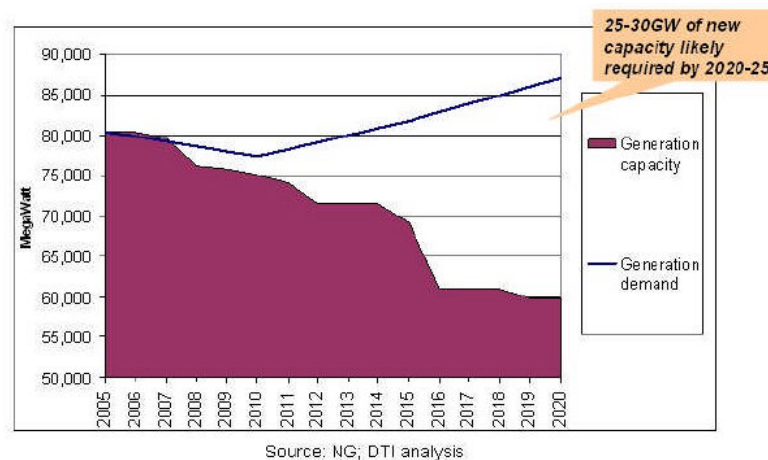
The difficulty of shifting toward a low-carbon energy society is exacerbated by the dependency of the U.K. economy on fossil fuels. Power generation in the United Kingdom is currently supplied primarily by fossil-fuel fired power plants (Figure 1.4). Because of the issues of ensuring energy supplies and low unit purchase prices, the predominant source of energy in the future will still remain fossil fuels and the resulting fuel mix, according to a DTI forecast [33], may end up in the recent future being dominated by gas-fired capacity (Figure 1.5).



Source: DTI analysis

Figure 1.4 U.K. Electricity generation mix (2006) [34] **Figure 1.5** A generation mix scenario to 2020 [33]

The next 10-15 years will be critical in the U.K. with respect to energy supply (Figure 1.6), as many nuclear-power stations and coal-fired power stations will reach their decommissioning stages, thus leaving an estimated gap of about 20 GW to be met by 2020 [33].



Source: NG; DTI analysis

Figure 1.6 Estimated power generation capacity to 2020, DTI analysis [33]

Tackling the combined challenges of climate change, energy affordability and security of supply requires significant modifications of the U.K. power generation sector in terms of upgrading and replacement [29]. There is a widespread consensus that substantial investments in new power generation plants are required urgently. Advanced technologies development and deployment are among the most frequently advocated keys to solve this dilemma.

1.3 Novel Low-Carbon Power Plants

Five fundamental options can be identified in the portfolio of mitigation methods for accomplishing the reduction of carbon dioxide arising from the power generation sector [35] (Figure 1.7):

- reducing fossil-fuel consumption through increased efficiency of power plants;
- using fossil fuels with lower Carbon/Hydrogen ratio (for instance by replacing coal and oil with natural gas);
- using power sources with intrinsically very low CO₂ emissions, such as renewable sources;
- resorting to nuclear-power generation;
- designing new fossil-fuel fired power plants to include the capture and storage of carbon dioxide that would otherwise be emitted.

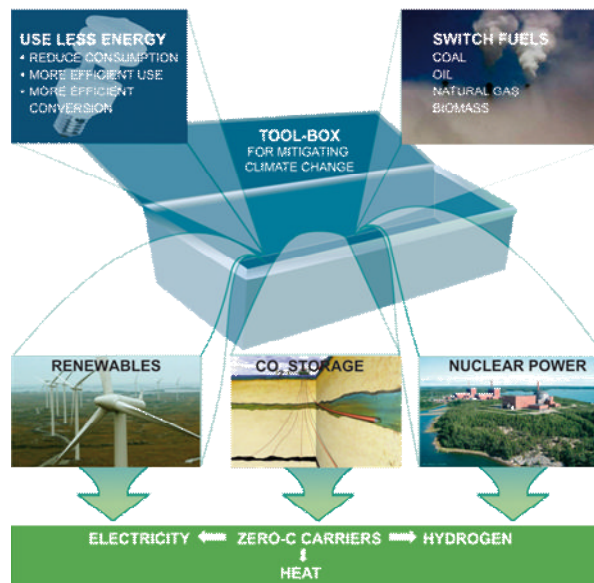


Figure 1.7 Tool-box for mitigating climate change [35]

The development of carbon capture and storage (CCS) plants has emerged as crucial for the achievement of U.K. energy and climate change goals [36]. Reducing CO₂ emissions associated with power production by measures such as efficiency improvements or switching to low-carbon fuels are limited by the residual carbon content of the fuel and the availability of the primary energy sources respectively [37]. The utilization of renewable energy sources also is restricted by capacities, as well as by the high cost of the present state of this technology [37]. Although nuclear power plants are CO₂-emissions free, radioactivity related concerns hinder further development of nuclear power in many countries. Typically, nuclear-power plants also have high capital costs and long construction periods, both of which inhibit their adoption.

CCS involves extracting CO₂ from power plants, thereby avoiding its release into the atmosphere, and then injecting it into an underground store. Even with a considerable increase in renewable energy and other low-carbon energy sources, “extensive carbon capture and storage will be necessary to allow the continued use of fossil fuels without damage to the atmosphere” [8]. A major advantage of this approach is that it enables the use of fossil fuels without contributing to greenhouse gases increasing [37]. A large potential for the reduction of CO₂ emissions, not considering nuclear energy, is presented by the capture and storage of CO₂ rather than the harnessing of other more expensive renewable energy sources [Strömberg [38] in [37]].

There are three basic approaches for CO₂ capture from fossil fuel-based power plants: (i) the post-combustion approach, (ii) the pre-combustion approach and (iii) the oxy-fuel combustion approach. In **post-combustion** capture fuel is burned in air and the carbon dioxide generated in the combustion process is subsequently removed from the flue gas [3]. The CO₂ capture process from post-combustion power plants has the advantage that it can be applied to existing plants. But some major disadvantages include the large-size equipment and the production of toxic by-products during the regeneration process of the CO₂ solvent, along with the substantial energy penalty associated with such regeneration. In the **pre-combustion capture** process, the fuel reacts with an oxidiser to produce a synthetic gas with high concentrations of carbon monoxide, hydrogen, water vapour and CO₂. After a CO shift conversion, the CO₂ is separated and the hydrogen-rich fuel is burnt in a power plant [3]. Such processes allow the use of cheaper capture technologies compared with the post-combustion case. However, pre-combustion capture is expected to have decreased short-term flexibility, since the extended chemical process plant in front of the turbine appears to be best operated under relatively steady state conditions. In the **oxy-fuel combustion** power plants, fuel is burned in an almost stoichiometric atmosphere, with oxygen of purity exceeding 95% [3]. Consequently, the main components of the flue gas are water vapour and CO₂. This enables simple

and low-cost CO₂ purification methods to be used: by cooling the flue gas, the water vapour condenses thereby creating an almost pure CO₂ stream. The characteristic features of this approach are the recycling of products (water vapour and CO₂), in order to moderate the combustion temperature, and the production of pure oxygen which can be a high energy-intensive process. Further details on CO₂ capture approaches and technologies are provided in Chapter 3.

The research community's response to the call for technology development in low-carbon power systems, and in particular for CCS, has been promising: there is a voluminous literature investigating and studying them and numerous research and development projects have been undertaken.

A common statement has resonated throughout the scientific community: although all of the proposed alternatives allowing CO₂ capture may offer great advantage with respect to CO₂ reduction, these options are quite different from each other and their large-scale deployment is fraught with a wide range of uncertainties. Different approaches and criteria have necessarily emerged to assess these technologies: in the last few years a plethora of publications dealing with their thermodynamic performances, their technological maturity and improvement potential, costs and process complexities have appeared. Nevertheless, these criteria cannot alone rule out any of the proposed concepts. Selection of the better candidates to pursue for investment is difficult and uncertain. The liberalisation of the power sector combined with the long-term nature of power plant investment imposes that the correct choice be made as the effects of the investment decision will remain with the organisation for the lifetime of the plant and will determine significantly its competitiveness.

From this standpoint, there is a line in which research efforts have been recently intensified: comparative assessments of novel low-carbon power plants concepts in terms of many criteria.

1.4 Project's Aim and Objectives

The main aim of this work, sponsored by the Engineering and Physical Sciences Research Council (EPSRC) and by E.ON U.K. Engineering Ltd, is to provide an insight into the possibilities of using power generation plants with CO₂ capture in a long-term perspective by means of the application of the T.E.R.A. approach. T.E.R.A. is the acronym for "Techno-economic Environmental and Risk Analysis". As its acronym reveals, T.E.R.A. provides a methodical approach which incorporates multidisciplinary aspects of modelling power plant performance, estimation of the environmental impact, assessment of the economic feasibility and the identification of the potential risks and critical elements associated with each proposed technological solution.

In a broader view, the main objectives of this investigation are the following:

- After identifying a number of suitable gas turbine based technologies each satisfying future requirements for reduced CO₂ emissions, a study of each selected cycle is undertaken in terms of technical solution, technology readiness level, effort required for its deployment, environmental impact, costs and risks involved, according to the T.E.R.A. method.
- Implement a framework for techno-economic assessments to evaluate the most competitive solutions in different scenarios, contributing in this way to future investment planning in CCS plants and related R&D.

The aforementioned objectives are required to establish a solid foundation for the unmitigated power generation case, from which to proceed to the CCS case.

It would be misleading to see this investigation as providing a definitive complete solution to such a delicate and general problem like the problem of CO₂ emissions reduction from power generation sector. Rather its contribution is to provide the outline of a useful guide to support the strategic decision-making process for future investments in advanced-technology low-carbon power plants. Underlying this study is the belief that by obtaining a transparent and accurate picture of these technologies, based on a common basis including configuration and definition of system boundaries, simulation tools, methods and assumptions, future investors will be able to get a fair estimation of the magnitude of the benefit achievable with each technology. Thus a consistent T.E.R.A. comparison across the technologies will sharpen investors' knowledge by showing the competitiveness of each investment option. Planning future investments in advanced low-carbon power systems would be a relatively straightforward task if a single technology were superior to others in all areas of interest (e.g. economic, technical performance, environmental impact...). Unfortunately no such "silver bullet" technology exists at present. However, the present methodical T.E.R.A.-approach proposed can increase the visibility of risks and enables examination of trade-offs between expected returns and key risks deriving from each area imposed on the decision makers. In addition, the result of a T.E.R.A. exercise can inform investors, legislators and other stakeholders of market and political instruments that can be critical factors for the profitable development and deployment of such radically innovative technologies. Such a method can be used to channel CCS related research and the investment of scarce research-and-development funds towards the projects with the largest potential of cost reduction and technical improvement.

1.5 Thesis Structure

The thesis comprises of eight chapters and three appendices. The subsequent chapters have the following content and purpose.

Following this introduction, Chapter 2 presents the basic philosophy of the T.E.R.A. approach. The purpose of the systematic method is described and its steps are analyzed. A review of the main approaches and studies for CCS cycle comparison available in the open literature is reported in order to highlight the novelty features of T.E.R.A. The structure of the T.E.R.A. Framework is also illustrated.

Chapter 3 reports an overview of carbon capture and storage technologies and introduces the cycles selected for the present investigation as well as the conventional cycle designated as the baseline for comparison purposes. After reviewing previous pertinent studies, focus is on their working principles, design options and operational characteristics.

Thermodynamic performance models for the configurations to be investigated are then described in Chapter 4, where details concerning the mathematical modelling and simulation basis are also discussed. The chapter also reports the results obtained for the on-design case and the work carried out for the off-design performance analysis.

The environmental behaviour of the cycles selected for this investigation is discussed in Chapter 5 to a preliminary extent. Due to the breadth of this research project, the environmental assessment focuses solely on CO₂ emissions.

The outcomes of the performance and environmental analyses are used in the subsequent economic evaluation, to which the Chapter 6 is dedicated. The study encompasses two parts. The first stage of the assessment draws attention to a discounted cash flow evaluation, quantifying performance indices that give an indication of the attractiveness of a proposed investment. The financial risk analysis is then performed through the use of the Monte Carlo method.

The T.E.R.A. assessment of the power plants, which is the object of the present analysis, is completed in Chapter 7 with a risk analysis taken from the perspective of the technology employed. The aim of this assessment is to identify the critical issues related to the viability of the power plant, with a focus on technological maturity. One of the main aspects that affect the selection of new low-carbon gas turbine cycles for future investments is the novelty of some of the incorporated components. Therefore, this risk examination will provide for each proposed solution an evaluation of the technological maturity and the relative development potential through a combination of the Monte Carlo method and the so-called Technology Readiness Levels (TRLs) of its components.

Chapter 8 concludes this study and proposes the author's recommendations for future developments.

The diversity of topics covered by the T.E.R.A. approach did not allow the combination of a single literature review, methodology or discussion section for the whole thesis. Instead, each of the chapters includes details on computational tools applied and presents the respective results and discussion. The comparison of the cycles with the conventional one chosen as the baseline is presented for each step of the T.E.R.A. approach.

1.6 Papers and Posters Published during Thesis Work

The following papers and posters originate from the thesis work:

Paper I

G. Di Lorenzo, V. Friconneau, P. Brandt, V. Lonneux, L. Marinai, P. Pilidis, G. Ruiz-Olalla, “Techno-economic Environmental Risk Analysis-Technological Perspective Application To Low Carbon Plant”, Proceedings of the Fourth IDGTE Gas Turbine Conference “Gas Turbine Technology in a Carbon Constrained World”, 13-14 November 2007 U.K., Paper 6

Paper II

G. Di Lorenzo and P. Pilidis, “Advanced Low Carbon Power Systems: the T.E.R.A. Approach”, Proceedings of the Cranfield University Multi-Strand Conference “Creating Wealth through Research and Innovation”, 6-7 May 2008, Cranfield, United Kingdom

Poster I

G. Di Lorenzo, S. O. T. Ogaji, P. Pilidis, “Assessing Low Carbon Power Technologies as the Key to Deployment”, Poster Presentation, British-French Flame Days 2009: Challenges in Combustion Technology: Security of Supply, Efficiency and Development, organised by British Flame and IRFR, 9-10 March 2009, Lille, France

Poster II

P. Barbera, G. Di Lorenzo, G. Ruggieri, P. Pilidis, M. Adams, “The T.E.R.A. Approach for clean power technologies: an IGCC case”, Poster Presentation, 5th Trondheim Conference CO₂ Capture and Storage, 16-17 June 2009, Trondheim, Norway

Paper III

Pagone, E., Di Lorenzo, G., Ogaji, S.O.T., Goodger, E.M., Pilidis, P., Adams, M., A sensitivity analysis for Advanced Zero Emissions Power plants. Part A: Short-medium term technology, (in preparation).

Paper IV

Pagone, E., Di Lorenzo, G., Ogaji, S.O.T., Goodger, E.M., Pilidis, P., Adams, M., A sensitivity analysis for Advanced Zero Emissions Power plants. Part B: Long-term technology, (in preparation).

CHAPTER 2

THE T.E.R.A. METHODOLOGY

This chapter describes the methodology of T.E.R.A. (Techno-economic Environmental and Risk Analysis) with a focus on the emerging low-carbon power concepts. Studies at Cranfield University concerning the development and adaptation of T.E.R.A. models for complex mechanical systems can be traced back to the early 90s. Tools implementing the “T.E.R.A. approach” are being used to explore the design space available in novel aero-engine configurations during the conceptual design phase. The methodology can be used to assess advanced power generation schemes to support the strategic decision-making process in low-carbon technology investments. The purpose of the methodology is described here, and its steps analyzed. A review of the pertinent literature is also presented to highlight the beneficial use of T.E.R.A. in the CCS case.

2.1 The T.E.R.A. Methodology

“Techno-economic Environmental and Risk Analysis” (T.E.R.A.) is an appraisal and optimisation method that can be applied to any mechanical systems and provide the insight necessary for preliminary design decisions [39]. Attempting to provide a strict and concise definition of T.E.R.A., Kyprianidis et al. [39] argue: “*T.E.R.A. is an adaptable decision support system for preliminary analysis of complex mechanical systems.*” It can examine, in depth, the design space in order to achieve an optimal-design solution (Figure 2.1). Introducing single and multi-objective optimization techniques, T.E.R.A. will essentially identify the most promising system configuration and provide the optimal design parameters values associated with it [39].

Concerning the desirability to adopt this procedure for system design, Kyprianidis et al. [39] argue:

“A T.E.R.A. approach during the preliminary design process of complex mechanical systems will soon become the only affordable, and hence, feasible way of producing optimized and sound designs, if the whole spectrum of possible impacts (economic, environmental etc) is to be taken into account.”

Work at Cranfield University on T.E.R.A.-oriented developments on aircraft and weight models were initiated by Vicente [40] in an attempt to study the effect of bypass ratio on commercial aero-engines designed for long-range subsonic aircraft.

This original conception of T.E.R.A. for applications in the aerospace field was soon however also applied to gas turbine systems in the industrial and marine sectors. With its ongoing development, assessment of environmental impact, which had always been a key element, continued to be an important part of T.E.R.A. [39, 41].

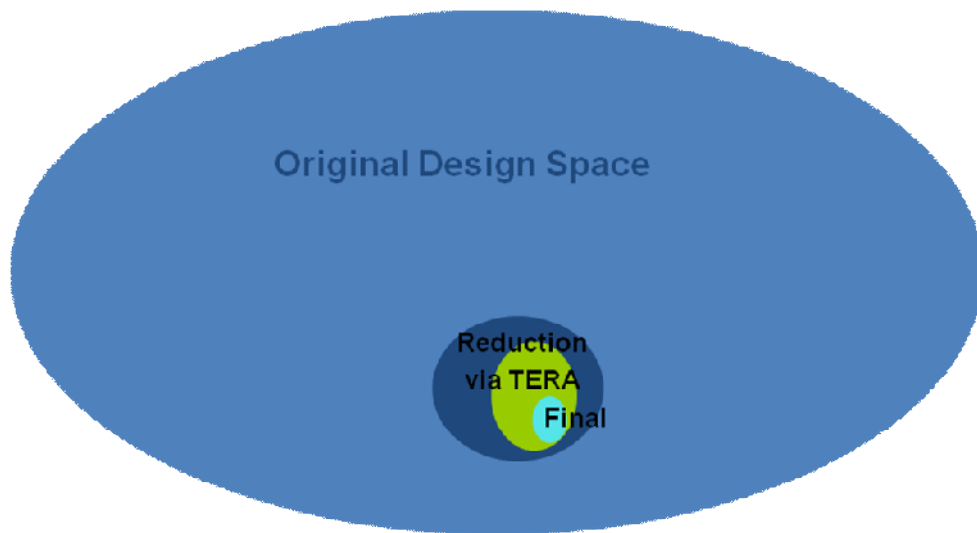


Figure 2.1 Reduction of original design space through T.E.R.A.

2.1.1 Aviation Application

The origins of T.E.R.A. date from studies of engine choices for civil aircraft: it was formulated as a decision-making framework to conceive and assess engines with respect to achieving low global warming impact and least cost of ownership in a variety of emission legislation scenarios, emissions taxation policies, fiscal and Air

Traffic Managements environments [42]. Within the European projects VITAL⁴ and NEWAC⁵, T.E.R.A. has been used for the evaluation of advanced aircraft engine concepts intended to meet the ACARE⁶ goals.

The proposed structure of a T.E.R.A. scheme for evaluating novel propulsion cycles is illustrated in Figure 2.2. The multidisciplinary aspect of the “T.E.R.A. approach” can be observed: the T.E.R.A. tool is based essentially on a robust engine performance model coupled with a large variety of modules (emissions, environmental, direct operating cost with risk analysis, plant cost, weights and dimensions) [39]. The top layer of the T.E.R.A. structure is the engine-performance model, which initiates information exchange. Performance data are exchanged with the following models: engine weight and dimensions, aircraft, emissions, noise and direct operating cost. The plant production (unit) cost model receives data from the weights and dimension models while the environmental model communicates with the emissions model.

The principal output parameters from the proposed T.E.R.A. scheme are: total fuel burn, global warming potential, emissions, noise, cost of acquisition and cost of operation. The heart of the structure is the optimisation of the engine design with respect to any given output [39]. Multi-objective and/or constrained optimisation may also be performed, thus reducing the initial engine design-point [39].

⁴ The VITAL (Environmentally Friendly Aero Engine) project, supported by the European Union (EU) within its Framework Programme 6 (FP6), aims at a 6dB noise reduction per aircraft operation and 7% reduction in CO₂ emissions compared to engines in-service prior to 2000. VITAL investigated new technologies for the low pressure shaft of the engine, which will enable the development of low noise and low weight fan architectures for very high bypass ratio engines.

⁵ NEWAC (NEW Aero Engine Core concepts) is an European-level programme, under the leadership of MTU Aero Engines, in which major European engine manufacturers, assisted by universities, research institutes and enterprises, focus on new core engine concepts. The NEWAC core configurations include an inter-cooled recuperative aero engine operating at low overall pressure ratio (OPR), an inter-cooled core configuration operating at high OPR, an active core and a flow controlled core operating at medium OPR. NEWAC project aims to further close the gap between the current emissions and the ACARE targets, enabling a strong reduction in CO₂ emissions and in NO_x emissions.

⁶ The Advisory Council for Aeronautical Research in Europe (ACARE) identified the research needs for the aeronautics industry for 2020. Concerning the environment, ACARE fixed, amongst others, the following objectives for 2020 for the overall air transport system, including the engine, the aircraft and operations: 1) a 50% reduction in CO₂ emissions per passenger-kilometre (assuming kerosene remains the main fuel in use) with the engine contribution corresponding to a reduction of 15 to 20 % in specific fuel consumption, whilst keeping specific weight constant; 2) a reduction in perceived noise (EPNdB) to one half of the current average level, considered as equivalent to a 10 dB reduction per aircraft operation, taking into account that the engine is the major contributor to noise.

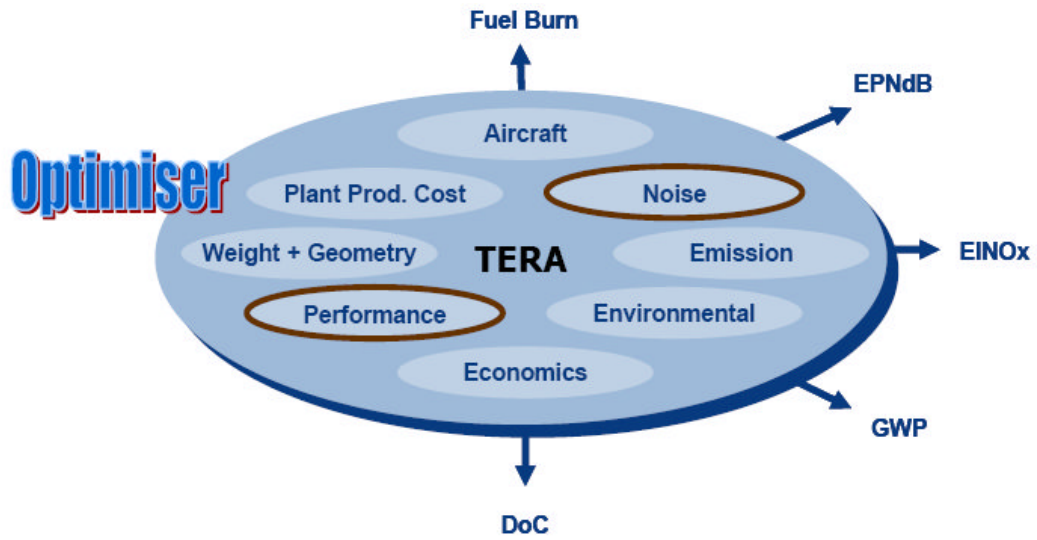


Figure 2.2 T.E.R.A. scheme for Aviation [42]

Various aspects of T.E.R.A. modelling are discussed in Kyprianidis et al. [39], Colmenares et al. [43], Pascovici et al. [44], and Laskaridis et al. [45], whereas more details on the architecture of a T.E.R.A. tool as it was designed for assessing novel propulsion cycles within the VITAL project are presented in Bretschneider et al. [46] and Ogaji et al. [42].

Sample results on how the tool can be used to identify those gaseous pollutants and flight phases that contribute the most to global warming are presented in [39], whereas an example of how to assess the trade-off between operating costs and environmental requirements of the future aero-engines for short range commercial aircrafts is illustrated in Colmenares Quintero et al. [43].

For more information on the historical development of T.E.R.A. over the past two decades the reader is referred to Kyprianidis et al. [39].

2.1.2 Marine Application

A T.E.R.A.-oriented computational method has been developed for marine gas-turbine-based power plants (Figure 2.3) within the AMEPS (Advanced Marine Electric Propulsion Systems) project [47].

The marine gas turbines selected for the investigation were: existing simple cycle, novel twin-mode intercooled cycle, hypothetical intercooled cycle, hypothetical recuperated cycle and partly based on an existing design, intercooled/recuperated cycle. Three marine vessel types, requiring the same power plant output power and configuration but utilising different operational profiles, have also been realistically

modelled for Destroyer, RoPax fast ferry and Liquefied Natural Gas (LNG) carrier application [47, 48].

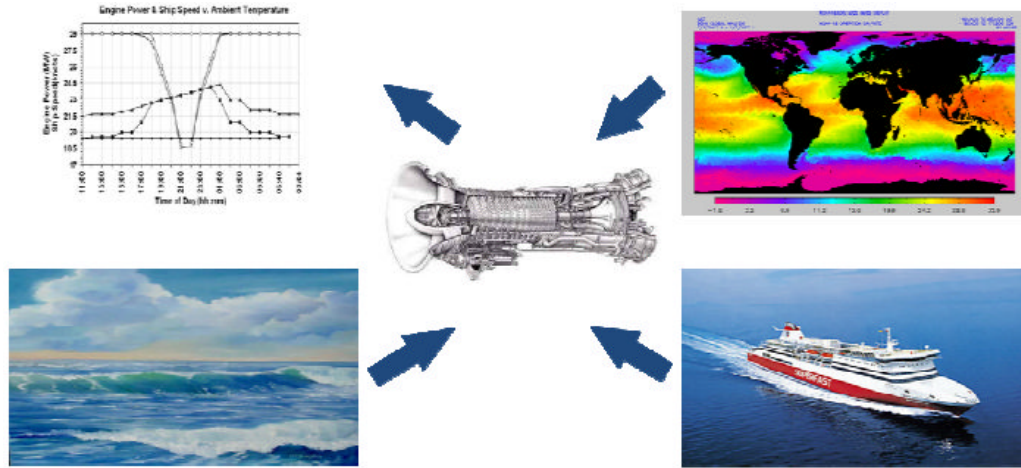


Figure 2.3 *T.E.R.A. for Marine Application* [47]

Three case studies, defined by each of the marine vessels, were analysed in order to examine the economic feasibility of the advanced cycle gas turbine power plants in comparison with the power plant based on existing gas turbines, in a possible future scenario where all four modelled exhaust emission rates of nitric oxide, carbon monoxide, carbon dioxide and unburned hydrocarbon are accurately measured and taxed. Further details can be found in Tsoudis [48].

2.1.3 Industrial Application

Although T.E.R.A. was originally conceived for aerospace applications, research interest soon also spread to industrial gas turbine systems. Gayraud [49-51] identified issues in gas turbine selection for power generation and addressed the problem through techno-economic assessments. His subsequent investigation [50, 51] focusing on more complicated systems, set the foundation for a decision support system for combined cycle schemes. Along this route, a techno-economic performance simulation and diagnostics computational system for the operations optimisation and risk management of a combined cycle gas turbine (CCGT) power station has been developed by Mucino [52]. The study concluded that the use of techno-economic advanced tools can improve the way an operator manages a power generation asset, protecting the operations of a power generator with respect to the main technical and economic risk variables.

T.E.R.A. is also being applied successfully in the cogeneration field. The development of power generation technologies and the deregulation of the power market have led to an increasing interest in combined heat and power (CHP) systems. As a consequence of the highly competitive power market and increasing environmental concerns, distributed power generators have to make choices at different levels of complexity. Key to successfully approaching these problems is the development of decision-making support tools that rely on service life prediction, intelligent economic dispatch optimisation techniques and condition monitoring. The development of a multidisciplinary decision-making support tool for a mini-pool nerve centre based on distributed gas turbine generation units has been carried out by Gomes [53, 54] as a first step in the application of T.E.R.A. to the cogeneration field. T.E.R.A. for gas turbine-based cogeneration systems for use associated with thermally-developed oil fields is also being developed. Oil field thermal developments facilitate extracting heavy oil that cannot be extracted using conventional oil recovery techniques: it operates by injecting a significant quantity of steam into the oil bearing reservoir and hence reducing the oil's viscosity. Approximately 50% of the operating cost is attributed to steam generation and therefore gas-turbine based cogeneration is seen as an opportunity to reduce the overall cost and environmental footprint. The T.E.R.A. concept has been applied to assess the impacts of gas turbine performance and technology level on project economics and environmental impacts. Financial risk associated with investing in a capital-intensive system such as cogeneration is also examined according to the T.E.R.A. approach.

Recent work addresses the concept of conducting a T.E.R.A. on gas turbines used for mechanical drive in the field of LNG production [55, 56]. The role of gas turbines in this field is fundamental because they are used as drivers for the compressors that cool the refrigerants for the natural gas liquefaction. Two state-of-the-art types of gas turbines are being used for this purpose and currently investigated at Cranfield University: Heavy Duty Industrial and Aeroderivative Gas Turbines. In such application of gas turbines, the risk associated with downtime is of vital importance and more reliable configurations investigated will be compared and assessed according to the T.E.R.A. approach and ranked with regard to their benefits and contributions to the reduction of downtime.

2.2 A Portrait of Methodologies and Approaches to CCS

In recent years world-wide research concerning CO₂ capture and storage has been carried out. The research community has responded promptly to calls for technological development of low-carbon power systems: there exists a voluminous

literature investigating and studying such systems and numerous research and development projects have been undertaken. Although the above-mentioned studies, as well as others summarised in Chapter 3, present thermodynamic analyses of some CO₂ capture cycles, the comparison and benchmarking of such cycles still remain a challenging task.

Cycle studies found in the literature have been carried out on a range of models and computational assumptions, and with the application of different software tools with various thermodynamic property models [3, 57, 58]. Thus a worthwhile comparison of the results is very difficult to achieve. Moreover, it is challenging to interpret and compare results due to incomplete documentation of applied parameters values: varying level of documentation of underlying data and assumptions complicates the evaluation of the results. Problems can also originate when comparing results from various sources due to fundamental differences in the scope of the studies. On the other hand, the performance characteristics or advantages of one cycle over another should be legitimate and transparent and not simply the result of different assumptions or methods used in process models.

Furthermore, conducting fair and rational comparisons and benchmarking between such advanced power plant concepts is often complicated by their inherent and characteristic complexity and diversity. Several studies on CCS plants have highlighted how CO₂ capture power plants can be compared by means of different criteria. Plant efficiency is one criterion, but not necessarily the most decisive. The systems envisaged are more extensive and complex than the current state-of-the-art technology. All of them will be characterized first by an increase in the cost of the plant and then by an increased challenges with respect to reliability and availability. Therefore, qualitative aspects, such as costs for investment and operation and maintenance, and technological maturity will impact when selecting a low-carbon technology. These aspects will need to be addressed when evaluating investment performance, enabling a fair estimation of the actual and potential benefit from each concept.

The following is a review of the main studies, which have been selected for the purpose of exemplifying the types of investigations undertaken. Such a literature review, though non- definitive due to the continuing new developments and updates, nevertheless highlights the main criteria and approaches typically included in CO₂ capture related research activities currently carried out around the world.

Nine different concepts for natural gas-fired power plants with CO₂ capture have been investigated, and a comparison undertaken based on net plant efficiency and emission of CO₂ by Bolland et al. [58]. The cycles are:

- one post-combustion capture concept (based on a conventional combined cycle (CC) with CO₂ separation from the exhaust gas by chemical absorption);
- six oxy-fuel capture concepts (the oxy-fuel combined cycle, the water cycle, the Graz cycle, the advanced zero emissions power plant (AZEP), one solid oxide fuel cell (SOFC) integrated with a gas turbine, one chemical looping combustion (CLC))
- two pre-combustion capture concepts, both of them involving natural gas reforming, with an auto-thermal reformer (ATR) and a membrane reactor (MSR-H₂) respectively.

This analysis gives a coherent picture of the cycle performance of these concepts. The authors pointed out as a common challenge for all these approaches the reduced plant efficiency compared to conventional power plants. On the other hand, the model parameters applied in the concepts that make use of units comprising emerging technology (SOFC+GT, AZEP, CLC, MSR-H₂), “may involve higher uncertainty in the calculations as these are based on unverified data” [58]. On conclusion of their work, the authors argue that the plant efficiency and the CO₂ emissions avoidance cannot alone rule out any of the proposed concepts: “development of this sort of technology is both costly and potentially risky” [58].

As a follow-up to this quantitative comparison, based on net plant efficiency and emission of CO₂, the same nine concepts for natural gas-fired power plants with CO₂ capture have been examined and compared with regard to technological maturity and operational challenges [59]. The analysis illustrated how the concepts facing high operational challenges and requiring technological breakthroughs are to be realized to exhibit the best plant efficiencies. Thus in order to determine the most promising concept, it will be important to address further the potential of relative plant efficiency improvement as well as other important factors such as the risk of not succeeding in the technology development, relative cost reduction potential, and time to plant realization [59].

Several projects have also been conducted to draft the improvement potential of specific CO₂ capture technologies. As an example, A.N.M. Peeters, A.P.C. Faaij and W.C. Turkenburg performed a detailed analysis of the potential future costs and performance of post-combustion CO₂ absorption in combination with a natural gas combined cycle [60]. After researching state-of-the-art technology, an Excel model was created by the authors to analyze possible developments in the performance of energy conversion, CO₂ capture, and CO₂ compression, selecting for each input parameter a value for three different time frames (short term, medium term and long

term⁷) in relationship to the development stage of technologies to which the input parameters are referred [60]. The amine-based post-combustion cycle concept has also been an object of study and investigation for Rao et al. [61]. Rao et al. examined the potential for future cost reductions that may result from continued process development: using the method of '*expert elicitation*' the authors tried to appreciate what experts in this field believe about possible improvements in some of the key underlying parameters that govern the performance and cost of this technology [61]. By means of the experts' responses a picture of how the overall performance and cost of amine-based systems might improve over the next few decades has been obtained.

Various economic data concerning the new low CO₂ emission power generation processes are available in the recent literature. The literature also discloses a number of different measures used to characterize CO₂ capture and storage costs, such as capital cost, cost of electricity, and cost of CO₂ avoidance. Due to the absence of a standard framework for the economic assessments there is considerable potential for misunderstanding [62]. Furthermore, for any given cost measure, different assumptions about the technical, economic and financial parameters used in cost calculations can also give rise to large differences in the final capture cost figures [3].

Recently, an innovative method for the comparison of power-generating plant concepts including CO₂ capture has been put forward by Olav Bolland and Henriette Undrum [63]: instead of using extensive thermodynamic calculations for these concepts, reaction equations for the conservation of molecular species together with specific energy consumption numbers for the different process sections are used to characterize the concepts with respect to fuel-to-electricity conversion efficiency. This method has been successfully applied by the authors to three concepts for capturing CO₂ from natural gas-fired combined cycle power plants (a post-combustion cycle, using chemical absorption by amine solutions; a gas turbine combined cycle with a semi-closed gas turbine with near to stoichiometric combustion using oxygen from an air separation unit as an oxidizing agent; and a pre-combustion cycle, which comprises an auto-thermal reforming reactor with air-blown catalytic partial oxidation of gas natural gas), revealing itself as an easier approach to achieving an understanding the relation between loss mechanisms and total efficiency. However, the authors concluded that efficiency is unlikely to be the primary deciding factor in selecting one of these three concepts, because it is probable that investment costs would be more than twice that for a large conventional CC plant. Reduced efficiency will increase fuel costs, operating costs will raise and there is likely to be reduced availability. Moreover, the commercial readiness of such innovative concepts will also need to be considered.

⁷ Short term, medium term and long term are represented by the years 2010, 2020 and 2030 respectively.

Lombardi [64] proposed an environmental life cycle assessment (LCA) which focuses on CO₂ production through the three phases of plant life, namely construction, operation and decommissioning, in order to ascertain if the process is effective regarding CO₂ reduction. In addition to the classic LCA, the author also carried out an exergetic life cycle assessment (ELCA) to assess the cost, in terms of exergy losses, of the life cycle of the plants. Both ELCA and LCA have been performed for three carbon dioxide low emission power cycles: a semi-closed gas turbine combined cycle with CO₂ reduction from the exhausts by means of amine solution chemical absorption; an integrated gasification combined cycle with CO₂ reduction from the synthesis gas by means of amine solution chemical absorption; and O₂/CO₂ innovative cycle where, burning methane in oxygen, CO₂ becomes the cycle working fluid, and the CO₂ excess, produced in the combustion, is removed in liquid phase without any additional system [64]. The results have explained that the main contribution to the total life cycle greenhouse effect comes from the operation phase. The operation phase has proven itself as the dominant phase with respect to the total exergy destruction. Therefore, Lombardi has concluded that, for both LCA and ELCA, the attention must be focussed on the operation phase, while the other phases, construction and maintenance, are almost negligible when compared to it. Lombardi underlined also that “the final decision of adopting one or the other solution will be determined by several factors, among which are the fuel availability and economic feasibility” [64].

Essentially, different authors chose different viewpoints and strategies in their analyses. All these studies on CCS plants conclude that they can be analysed from various perspectives and different kinds of analyses are needed, depending on the objective and the required level of detail. All concluded that their studies are not exhaustive and any of the adopted criteria cannot alone rule out any of the proposed concepts. In order to conduct a complete assessment of these diverse concepts, many criteria for comparison should also be included and taken in account.

During recent years much effort has been put into comparative assessments of novel low-carbon power plants concepts in terms of many criteria. As an example, various studies have been carried out to attempt a techno-economic comparison of some concepts [65-69]. Among them is the latest “Techno-Economic Evaluations and Benchmarking of Pre-combustion CO₂ Capture and Oxy-fuel Processes Developed in the European ENCAP Project” [70]. ENCAP (ENhanced CAPture of CO₂) is a major technological development project under the 6th Framework Programme of the European Commission, involving leading European power and energy industries and equipment suppliers, along with some research institutes and universities [71]. Among several concepts for power plants with CO₂ capture developed in ENCAP, the most promising have been evaluated, compared and benchmarked with respect to technical performance –in terms of net electric

efficiency-, costs –with emphasis on electricity generation costs and CO₂ avoidance costs- and level of technical maturity versus needs for further R&D and technical risks.

An excellent basis for comparison between competing CCS technologies, which take into account the most significant costs and emissions factors, is the Integrated Environmental Control Model (IECM) tool developed by the Carnegie Mellon University for the Department of Energy [72]. The IECM was initially developed as a tool to assess the impact of fossil-fuel power plants on acid rain with respect to emissions and pollution control options. The IECM originally focused on post-combustion options to control emissions of criteria air pollutants (SO₂, NO_x, and PM) from coal combustion systems. Interest moved on to a natural gas combined cycle and a gasification system, whose models were added to the tool, and then to CCS, with the addition of an amine system for post-combustion capture systems and selexol for pre-combustion capture systems. An oxy-fuel model has been added as an additional option in a coal-fired furnace for the CCS part, along with simple transport and storage models. For each of these technologies the IECM includes a process performance model to account for mass and energy flows associated with the process being considered. Coupled to each performance model, an economic model is also present to estimate the capital cost, annual operating cost and total levelized cost of each technology. Details of the performance and cost models originally developed for the IECM are available in [69, 73]. A unique feature of the IECM is the ability to characterize uncertainty in probabilistic terms, in contrast to conventional deterministic analysis. This capability offers special advantages in analyzing advanced technologies at an early stage of development, and in comparing them with conventional systems where uncertainties typically are smaller [74].

Another tool which is relevant for CO₂ capture technology assessment is an Excel-based calculator developed by a team from the IEA GHG R&D Programme in U.K. [75]. It is a tool for low-cost but consistent comparison of novel CO₂ capturing power generation processes, thus allowing such comparisons “to be done by an experienced process engineer in just a few working days” [75]. This tool assesses the overall commercial performance on a multi-criteria scoring basis taking into account CO₂ emissions, fuel consumption, capital and operating costs as well as the process complexity and severity, construction material and natural resource requirements, development requirements, safety and environmental impacts. Credit is given in the scoring for good performance whilst use of exotic materials, extreme process conditions, dangerous processes or toxic materials is penalised. The tool also makes an assessment of the likelihood of success on a comparative (i.e. not absolute) scale. This allows results to be plotted in a two dimensional way so that the competitive position of process can be visualised both in terms of likely commercial performance and risk. The tool has been tested with several conventional baseline

processes both with and without capture, such as the coal fired process with cryogenic expansion system for CO₂ recovery, the gas fired oxy-combustion using the “Clean Energy Systems” (CES) water recycling process, the gas fired CO₂ separating Solid Oxide Fuel Cell (SOFC) concept based on a pressurised hybrid system, and the gas fired fluid bed chemical looping system using Barium Oxides [75]. Such a tool offers a means of giving new insights into the relative merits of different capture processes: it is able to distinguish those processes which have little chance of successful development, while for promising processes it helps identify key development issues and important parameters from a commercial as well as a technical viewpoint.

The T.E.R.A. methodology likewise provides a methodical approach for this kind of investigation as it incorporates multidisciplinary aspects in its approach.

2.3 The T.E.R.A. for CCS

The T.E.R.A. approach has been applied in the present work to advanced power generation schemes for conceptual design, similar to aviation, but with different objectives in mind. The prime role of such a multidisciplinary approach in this case is related to strategic decision-making in low-carbon technology investments.

Figure 2.4 presents the basic philosophy of T.E.R.A., which emerges as a four-step decision support procedure. The starting point of T.E.R.A. is a detailed thermodynamic model of the power plant. This delivers a representative view of the components and the whole plant performance in a wide range of operating conditions.

Off-design evaluation is an essential and vital step during the development process of a power cycle. A power plant is designed and built for maximum capacity or full-load when it is operating at STP, i.e. standard ambient temperature and pressure. However, in real applications, a power plant generally operates at off-design conditions during most of its lifetime, being subject to load- and ambient temperature-variations during the seasons of the year. The off-design evaluations not only provide information regarding the efficiency and flow conditions at different operating points but also indicate the operational problems that may be encountered by the plant. The control strategies for the plant should be devised in order to cope with such problems while maintaining the plant's efficiency as high as possible.

One of the objectives of T.E.R.A. methodology, therefore, is to base the analysis on the off-design performance of these advanced low-carbon power cycles, addressing the operating requirements and local conditions. This is a key characteristic of this methodology that make its results significantly different from others: it provides an accurate and detailed understanding of the off-design

behaviour of the plant under a wide range of operating conditions and so facilitates a consistent and transparent performance comparison of the technologies being investigated. The CCS-research carried out across the world so far includes few investigations of the off-design behaviour of some CO₂ capture power plant concepts. On the other hand, such off-design studies rely on various models and computational assumptions and make use of different software tools with various thermodynamic property models. As a consequence, their final results are difficult to compare.

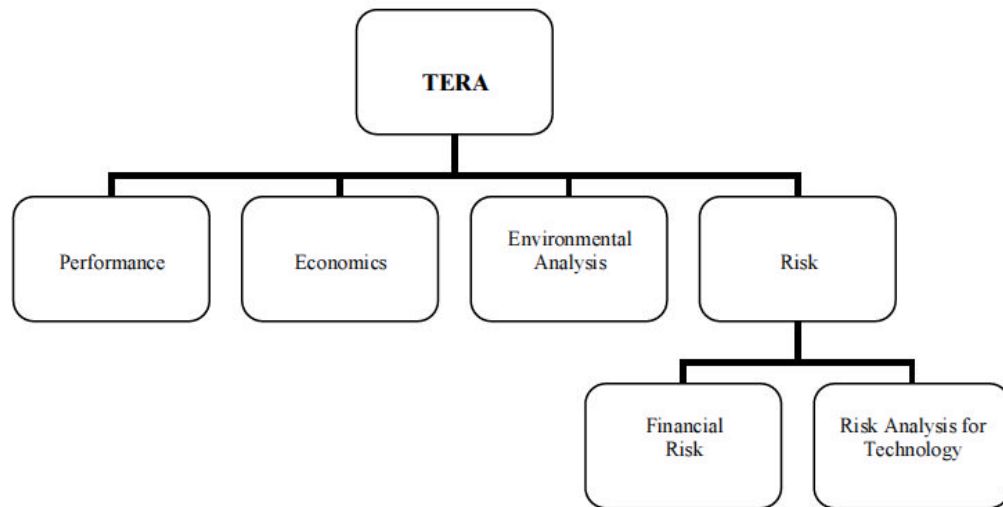


Figure 2.4 *Basic philosophy of T.E.R.A.* [76]

Additional analyses, such as economic and environmental, then follow. The economic analysis draws attention to a discounted cash flow evaluation, quantifying indices, such as Net Present Value (NPV), Pay-Back Time (PBT), Internal Rate Return (IRR), that give an indication of the attractiveness of the proposed investment whereas the environmental analysis is focused on the assessment of NO_x, CO and CO₂ emissions.

Risk analysis is subsequently carried out at two levels in order to identify risks and challenges arising from each technology. Financial risk is initially examined by the Monte Carlo method in order to identify the impact that changes in income, costs and prices can have in the decision-making process. This is another key characteristic of the methodology, being a first application of the Monte Carlo method to an evaluation of CCS investment proposals. The second level of risk examined is from the perspective of the technologies employed. The success of a low-carbon future is highly dependent on technology. All low-CO₂ emissions power plant cycles differ in technological maturity and operational challenges: some technologies are very near state-of-the art, whereas others tend to be more innovative but less-developed. A risk

analysis becomes necessary to understand the readiness level of new technologies and to address the risk of not achieving the goals in the technology development. The original model, adopted within T.E.R.A. methodology to assess the uncertain characteristics of CCS power plants, couples Monte Carlo simulation technique and the concept of TRLs, “a discipline-independent, programmatic figure of merit” introduced by the National Aeronautics and Space Administration (NASA) in 1970s to allow “more effective assessment of, and communication regarding the maturity of new technologies”

T.E.R.A. methodology presents itself therefore as a tool for taking the joint impact of several criteria into account and enables a consistent and systematic evaluation of alternative CO₂ capture concepts. A techno-economic optimisation is also provided for by T.E.R.A. methodology in this application to CCS concepts, in similar manner to the Aviation application, and it is the object of another Ph.D. project.

The investigation presented in this thesis serves as a basis for establishing the T.E.R.A. methodology. In order to analyse a power cycle under off-design mode, it is essential to have a detailed and reasonable thermodynamic representation of the power plant. Once the thermodynamic design is achieved, the key cycle components can be dimensioned for the design-point. The cycle dimensions are fixed in the off-design mode and only the load and the ambient temperature conditions are varied. The robustness of the design-point evaluation is of critical importance if both an optimisation process and an off-design evaluation are undertaken. Moreover, the quality of thermodynamic models is one of the main determinants of the credibility of the overall T.E.R.A. results, since the subsequent analyses use the detailed and reliable thermodynamic results produced. In the light of this consideration and with the breadth of the methodology and the complexity of CO₂ capture technologies in mind, the present investigation has been narrowed to the design-point case, while keeping unchanged the other steps of the T.E.R.A. as described earlier. The off-design analysis has been only initiated and the first advance is described in Chapter 4.

2.4 T.E.R.A. Framework

The implementation of the T.E.R.A. methodology proposed for this investigation has generated a framework for techno-economic assessments to evaluate technologies for medium- and long-term investments, thus also achieving the second objective of this project. The author recognises that the development of a fast and robust decision support framework is a difficult and time-consuming project, of which the present research work can only be considered a first step.

Reflecting the basic multidisciplinary philosophy of the T.E.R.A. approach, the Framework is organised as a serial connection of four modules, with the power plant performance module playing the role of central information exchange. The modules included in the current structure of T.E.R.A. Framework (Figure 2.5) are as follows:

- Performance Module
- Economic Module
- Emissions Module
- Technology Risk Analysis Module

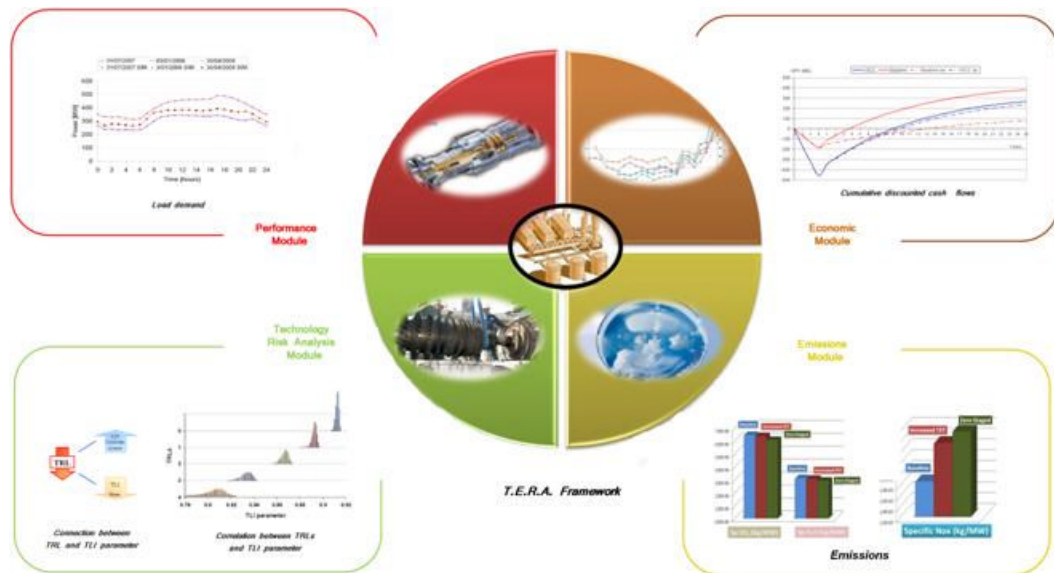


Figure 2.5 Structure of T.E.R.A. Framework (adapted from [77])

The internal structure of the T.E.R.A. Framework, in particular how the four modules are serially linked, is illustrated in more detail in Figure 2.6. The Performance Module covers the power plant performance: after specifying the plant configuration, along with the main plant's technical parameters, it delivers as principal outputs the thermal efficiency, the power output and the fuel flow. These outputs, along with the composition of the fuel, are fed into the Emissions Module, which in the current version evaluates the carbon dioxide emissions. The output of the Performance and Emissions Module are exploited in the Economic Module

which carries out both economic and financial risk analyses. Finally the Risk Module embeds the other three Modules into a multi-run simulation environment, applying the Monte Carlo technique for the technology risk analysis. It is clear how the power plant performance module undertakes the most critical role during the T.E.R.A. simulation by forming the centre of all information exchange. Therefore, as already outlined, the robustness of the power plant performance code is of critical importance.

The framework is straightforward and transparent. The level of data requirement is medium, but the application can result in complexity due to the interdisciplinary character of the tool.

The framework has been tested on the three case studies selected for the present work. These case studies will be outlined in Chapter 3. The relative results, along with more details concerning each module, will be given in the following chapters.

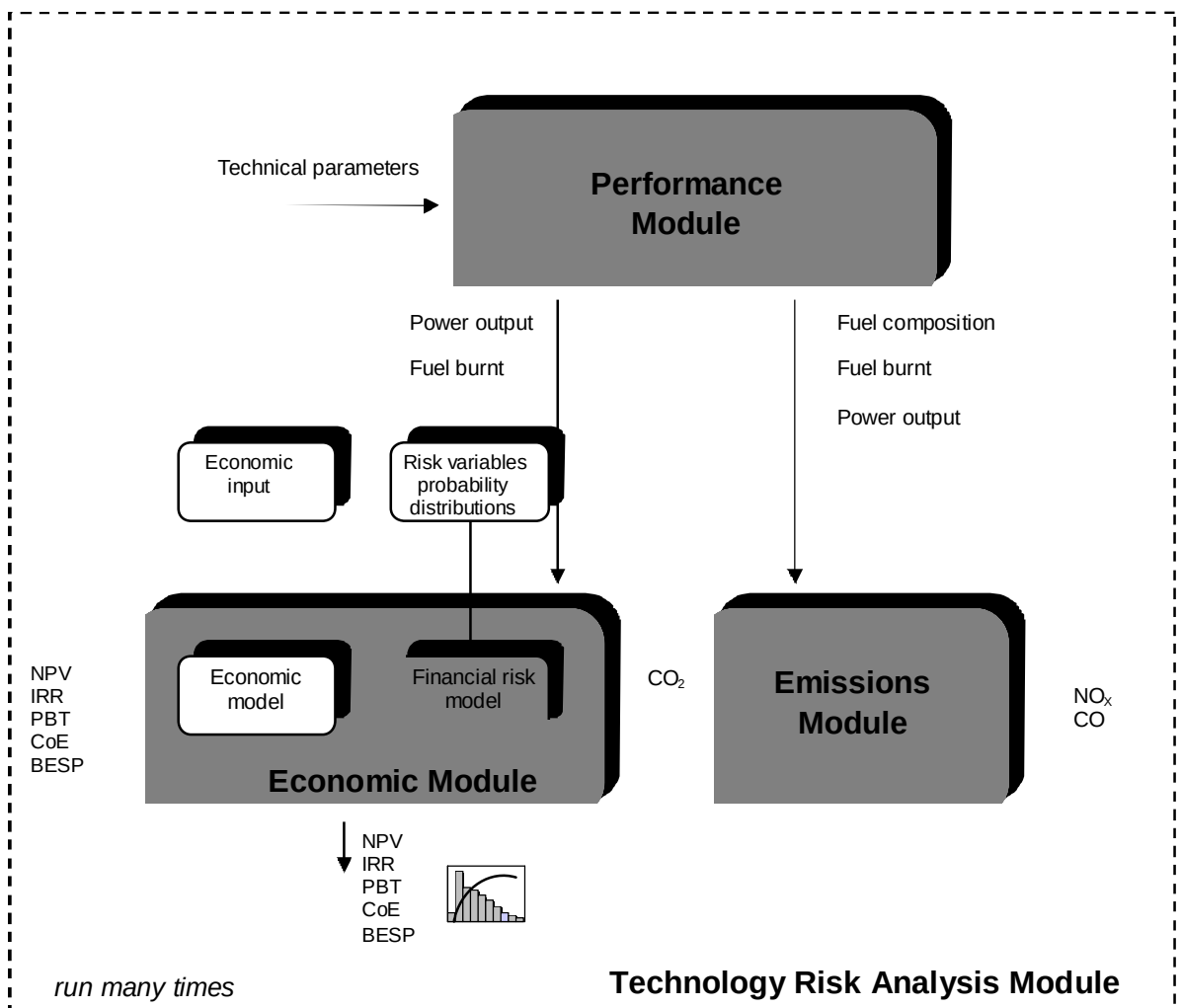


Figure 2.6 Internal structure of T.E.R.A. Framework

CHAPTER 3

CO₂ CAPTURE AND STORAGE

The concern about the increasing rate of CO₂ emissions presents a great challenge to the power generation sector worldwide. Accordingly, several solutions have been proposed and developed to address this issue. Among them CO₂ Capture and Storage has emerged as a promising option. After outlining the basic principle of the CO₂ capture and storage, a concise literature review of major CO₂ capture technologies is presented in this chapter. Case studies selected for this investigation along with the conventional natural gas-fired combined cycle designated as the reference cycle are described. The boundary conditions and the main assumptions employed in this investigation are also highlighted.

3.1 CO₂ Capture & Storage in the Power Generation Sector

According to the definition provided by the International Panel on Climate Change “CO₂ Capture and Storage (CCS) is a technology aimed to prevent the CO₂ generated by large stationary sources from being released into the atmosphere” [3]. As illustrated in Figure 3.1, CCS attempts to achieve this purpose via three steps: CO₂ is first captured and compressed at the emission source and then it is transported to a storage location, where, finally, it is permanently stored. Each of these three phases can be accomplished in several ways. Some of the main aspects of each phase are outlined in the following paragraphs. Particularly the main processes and challenges involved in CO₂ capture step are presented.

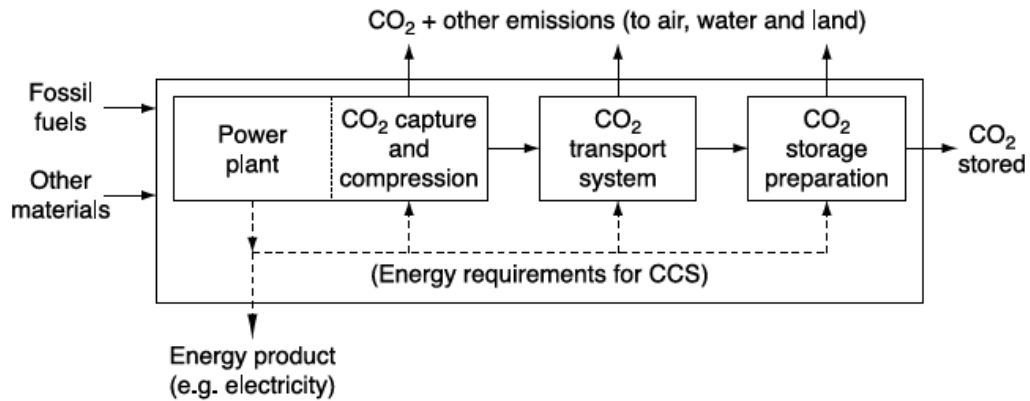


Figure 3.1 Main stages of the CCS chain [3]

3.2. CO₂ Capture

The purpose of CO₂ capture is to produce a concentrated stream that can be readily transported to a CO₂ storage site. At present, three main approaches for CO₂ capture from power plants are under consideration: (i) pre-combustion decarbonisation, (ii) oxy-fuel combustion and (iii) post-combustion CO₂ capture. These approaches are shown in simplified form in Figure 3.2.

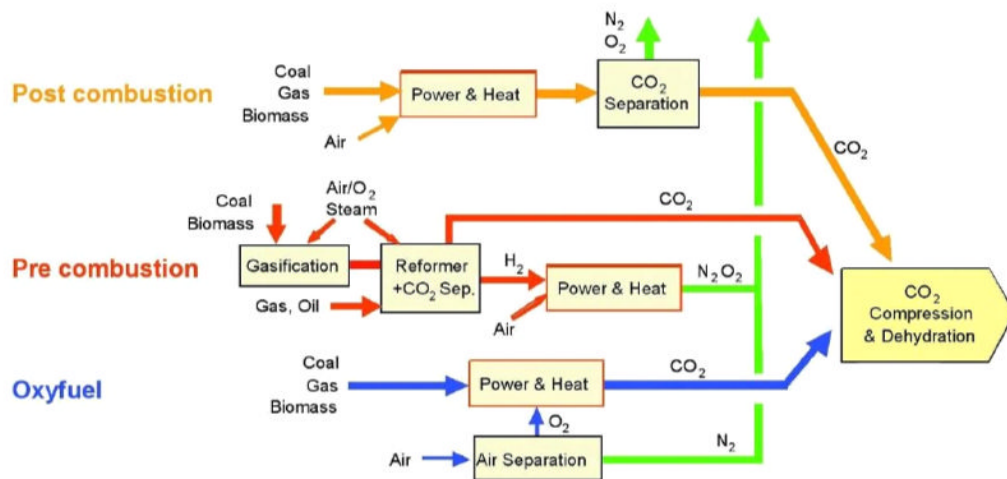


Figure 3.2 CO₂ capture approaches [3]

A broad variety of technologies, based on different physical and chemical processes (absorption, adsorption, membranes and cryogenic separation) are currently available

to separate and capture CO₂ from gas streams. However, such technologies have not been designed and demonstrated yet for power-plant-scale operations.

Figure 3.3 reports a schematic representation of them. They can be summarised briefly as below:

- **Absorption-based separation:** CO₂ is removed from the flue gases by selective absorption in a liquid phase, either by means of solubility differences (physical solvents) or by chemical interaction with the solvent (chemical solvents);
- **Adsorption-based separation:** CO₂ is removed by adsorption onto a solid medium (molecular sieves or activated carbon) and subsequently removed by pressure-swing adsorption (PSA) or temperature-swing adsorption (TSA);
- **Membrane separation:** in practice membranes can be coupled with absorption, acting as a permeable barrier between gas/liquid phases, because the flue gas CO₂ concentration is too low to provide a sufficient driving force (due to the concentration difference across a permeable membrane).
- **Cryogenic separation:** CO₂ is liquefied and separated by cooling the gases to a low temperature and exploiting difference in points of condensation. This is also known as low temperature distillation: it is a commercial process commonly used to liquefy and purify CO₂ from relatively high purity (> 90%) sources.

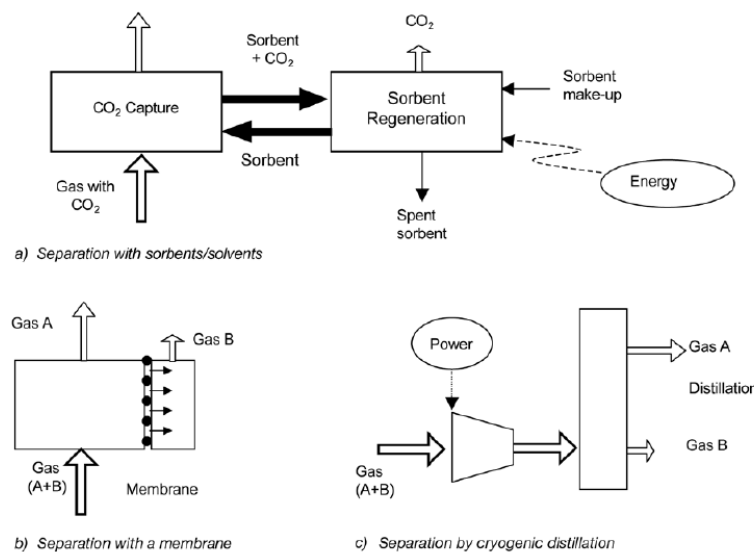


Figure 3.3 General schemes of the main technologies used to achieve carbon dioxide separation [3]

These technologies for gas-separation can be cross-referenced with the three basic approaches for CO₂ capture of Figure 3.2, taking in account that the selection of a suitable gas-separation technology is motivated by the characteristics of the gas stream.

3.2.1 Post-combustion capture

In **post-combustion** capture a large fraction of the CO₂ generated in the combustion process is removed from the flue gas [3]. Separating the CO₂ from the flue gas stream is challenging for several reasons: CO₂ is present at dilute concentrations (13-15vol% in coal fired systems, 7-8vol% in gas-fired boilers and 2-4vol% in gas-fired gas turbines) and at low pressure which dictates that a high volume of gas be treated.

Among the several known technologies for gas-separation, the CO₂ chemical absorption technique based on amine-scrubbing is at present the lead contending technology for the post-combustion approach. Amines are available in three forms (primary, secondary and tertiary), each with its advantages and disadvantages as CO₂ solvent [78]. Being effective for low CO₂ partial pressures (dilute CO₂ streams), the amine-based CO₂ absorption systems are the most suitable for combustion-based power plants

A schematic sketch of an absorption process for the removal of CO₂ from flue gases is shown in Figure 3.4. The process is based on the interaction between an aqueous (basic) amine and CO₂-containing flue gases and on the reversible nature of the chemical reaction between CO₂ and the solvent. The system consists of two main elements: an *absorber*, where CO₂ is absorbed into the sorbent, forming a weakly-bonded compound, and a *stripper* (or regenerator), where the weakly-bonded compound, formed during absorption, is broken down by the application of heat, so releasing CO₂ (in concentrated form) and the original sorbent can be recovered.

CO₂ separation from flue gas streams dates back to the 1970s, when it was introduced mainly for enhanced oil recovery (EOR) operations and for other industrial applications (such as the carbonation of brine and production of products, such as dry ice, urea, and beverages). Despite these applications, only limited large-scale operating experience has been obtained to date and a ten-times scaling-up is required for economic use in power generation [79]. At present, the largest operating unit has a capacity of 800 tonne CO₂ per day (IMC Global Inc. in Trona, California, USA (Herzog [80] and IEA GHG [81] in [79])), while a 500 MWe pulverized-coal (PC) power plant produces circa 8000 tonnes CO₂/day (Damen [82] in [79]). However, because it has been proven on a small scale and it is similar to other end-

of-pipe environmental-control systems used at power plants [69], it has the potential to be retrofitted to existing power plants.

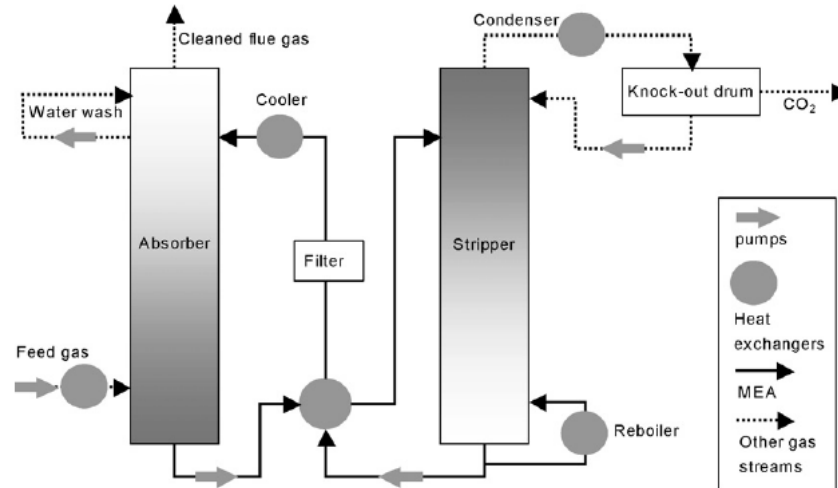


Figure 3.4 Process flow diagram for a flue-gas CO₂ absorption process [60]

One of the main drawbacks of amine systems is the energy penalty associated with solvent recirculation and the heat required to regenerate large quantities of solvent. The heat requirement for the current regeneration of solvents is high (i.e. between approximately 3.0MJ/kgCO₂ for recent initiatives and 4.2 MJ/kgCO₂ for a conventional Mono-Ethanol-Amine (MEA) based solvent [79]). This heat is typically provided by the steam cycle, thereby penalising considerably the net efficiency of the power plant. There are also several other improvements needed: e.g. long-term amine stability, improved pre-absorption treatment of flue gas in order to remove solvent-detrimental components and the development of new solvents with improved CO₂ selectivity and capacity are the most important present challenges [60, 83]. Nevertheless, at present it is regarded as the most mature and the less risk approach among the three ones proposed.

Longer-term research will focus on other techniques of CO₂ capture from flue gases including the use of membranes, adsorption and low temperature distillation [84].

3.2.2 Pre-combustion capture

Pre-combustion capture is a method for capturing carbon in the form of CO₂ from the fossil fuel before burning the fuel in a combustor. Applicable to natural gas as well as coal-fired combined cycles, this concept comprises two main steps (Figure 3.5):

- conversion of fossil fuel to syngas - a mixture containing hydrogen, CO₂ and CO - that subsequently undergoes the water-gas shift (WGS) reaction, thereby converting the remaining CO to CO₂;
- separation of CO₂ and hydrogen in order to feed the power conversion unit with a hydrogen-rich and carbon-free fuel.

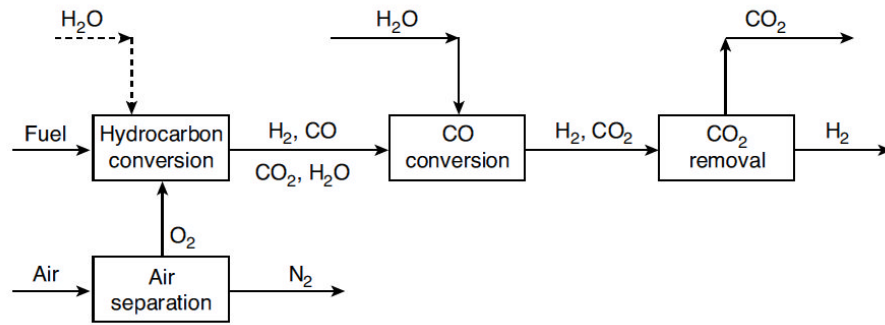


Figure 3.5 The basic steps of a pre-combustion decarbonisation process [85]

Several technologies (such as steam reforming, partial oxidation and auto-thermal reforming) exist to produce syngas from natural gas while for coal and biomass applications the most-popular relevant technology adopted is gasification. The resulting syngas composition varies with the process utilised and with operating parameters, but the two basic steps mentioned above remain the same.

Steam reforming is an endothermic process which is commercially important and can be regarded as a mature industrial process. Equation 3.1 describes the steam reforming process for a light weight hydrocarbon with a low tendency for coke formation:



Steam methane reforming (SMR) is a highly endothermic catalytic process. A portion of the natural gas, which can be regarded as the secondary fuel, is burnt outside the reaction tubes for supplying the necessary heat of reaction.

Partial oxidation (POX), contrary to steam reforming, is an exothermal process. The fuel is oxidised to CO and hydrogen by supplying pure oxygen. Equation 3.2 symbolises the partial oxidation process:



The need for a cryogenic air separation unit (ASU) for oxygen production leads to high investment costs and energy demands. However, this energy demand is compensated by the higher reforming efficiency and the elimination of nitrogen from the syngas. These two factors significantly reduce the costs associated with the subsequent separation of CO₂.

Auto-thermal reforming is a stand-alone and single-step process, in which the entire hydrocarbon conversion is completed in one reactor. Auto-thermal reforming can be viewed as a combination of steam reforming and partial oxidation, as both processes occur within different sections of the same reactor. The process is *auto-thermal* in the sense that, by combining the exothermic oxidation reaction with the endothermic reforming reaction, the heat generated by the former is directly exploited in the latter, in contrast to the external combustion of fuel which is characteristic of conventional tubular reforming.

The *gasification* process converts a carbon-based feedstock (e.g. coal, biomass, petcoke or oil residual) in the presence of steam and oxygen to form syngas. The gasification process occurs at temperatures in the range of 800 °C to 1800 °C. In the practical realisation of gasification processes a broad range of reactor types is being used. They can be grouped into three main categories: moving-bed gasifiers, fluid-bed gasifiers and entrained-flow gasifiers [86]. For power plants of large capacity the entrained-bed gasifier is generally used because of its higher rate of production. The gasification process finds application in the so-called Integrated Gasification Combined Cycle (IGCC) (Figure 3.6), which has emerged as a technology offering the potential for achieving higher efficiencies compared with conventional coal-burning technologies as well as reduced costs for pollutant-emissions control [86]. Applying this concept effectively is the aim of worldwide research activity [87, 88]: there is, in fact, still some concern at the excessive capital costs, the high operation and maintenance costs, the long time required to start the plant and the low availability of IGCC plant.

The fuel decarbonisation strategy, whose the aforementioned processes are only some examples, may be more attractive than the other two strategies, because the separation treatments are concentrated on the fuel, rather than on exhausts or the oxidizer [89, 90] so that some authors (Chiesa [91] and Doctor [92] in [89]) recognized a certain superiority of this process, compared to ones based on the other strategies. A strength of pre-combustion capture approach compared to post-combustion one is represented in fact by a reduced volume of gas for treatment, richer in CO₂ and at high pressure, which in turn reduces the size of the gas-separation plant and therefore also capital costs. The higher concentration of CO₂ also enables less selective gas-separation techniques to be used which require less energy to operate (e.g. current state-of-the-art being a physical glycol-based solvent

like Selexol, or methanol-based Rectisol). Furthermore, since CO₂ is generated under pressure, less energy is required for compression.

Like post-combustion technologies, pre-combustion technology is also a proven industrial-scale technology, widely applicable within syngas production for obtaining methanol, synfuel, ammonia and hydrogen. However it needs three times scale-up for power plants [79]. Another attractive feature of this approach is represented by the possibility of producing H₂ along with electricity [93-95].

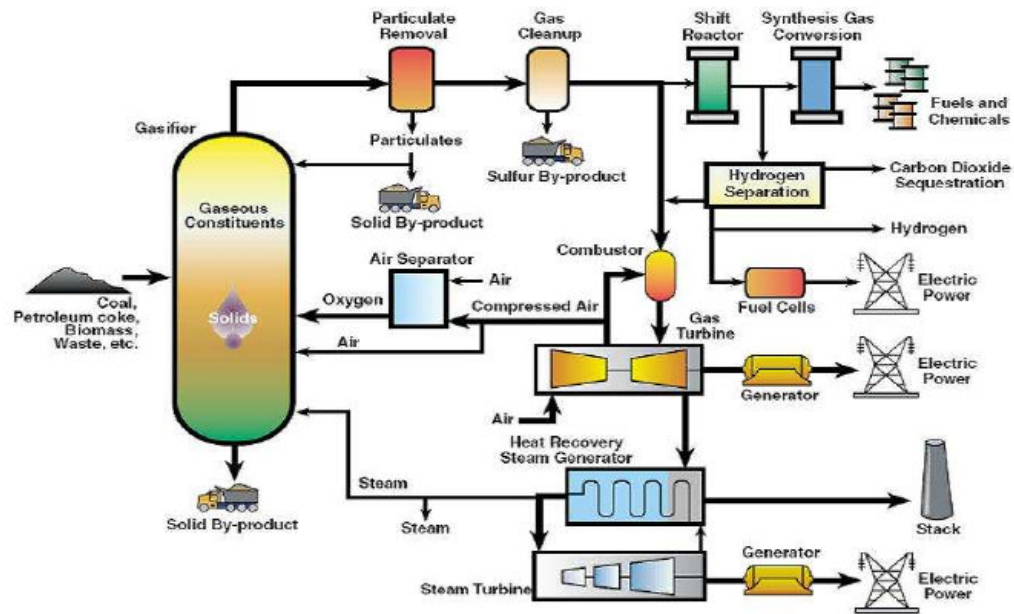


Figure 3.6 General IGCC layout and possible products [96]

Pre-combustion decarbonisation technology is complex involving many components in addition to the conventional power-conversion section and several catalytic steps, heating to high temperatures and cooling to low temperatures. What might favour one part of the process might be a disadvantage for another part. [85] As an example, energy efficiency is favoured by low rate of steam-addition from the steam plant (also called steam-to-carbon ratio), but hydrogen production is favoured by high rate of steam-addition. This extended chemical plant in front of the turbine, involving complicated chemical processes, may cause extra shut-downs of the plant, resulting in a lower power output, and affect load-following capability. Other disadvantages are that for non-gaseous feedstocks, the gas stream must generally be cleaned [79, 86], and possible high rates of NO_x emissions might require removal by expensive scrubbing and/or the use of a low-NO_x burner.

For energy losses and costs to be reduced, integration and coalescence among the several processes are strongly pursued [79, 85]. Mid-term to long-term opportunities to reduce capture costs could be achieving via the use of membranes [97] and sorbents currently at the laboratory stage of development [79, 83].

3.2.3 *Oxy-fuel combustion*

Oxy-fuel combustion, as its name implies, involves burning the fuel in almost pure oxygen at near-to-stoichiometric conditions. Oxy-fuel combustion has been used for several years in the metal and glass manufacturing industries. The resulting commercial demonstration has led to the key process principles being well understood, but for large-scale power generation other (new) technological challenges have still to be met [98].

The advantage of oxy-fuel combustion is that it produces a nitrogen free flue gas containing water vapour and a high concentration of carbon dioxide as its main components [98]. This enables simple and low-cost CO₂ purification methods to be devised. The flue gas is cooled to remove water, followed by the separation of non-condensable gases (Ar, O₂ and N₂) from CO₂. This will significantly reduce the energy demand and capital cost incurred in the CO₂ capture. Oxy-combustion also offers several other benefits [98, 99]: namely a 60-70% reduction in NO_x emissions compared with air-fired combustion, mainly due to flue-gas recycling, but also due to lower available nitrogen; increased mercury removal for the coal application case and few other harmful emissions due to more complete combustion; potential for 100% CO₂ capture; and potential to be operated at high pressure, involving less CO₂ compression-energy being required.

The stoichiometric combustion of fuel, however, may lead to combustion temperatures significantly higher than those which current materials can withstand, so requiring recirculation of the flue gases or steam injection in the combustor.

The Figure 3.7 represents the schematic of the so-called “oxy-fuel combined cycle” in which flue gas is recycled, compressed and the resulting CO₂-rich fluid is subsequently expanded in a gas turbine. The residual heat in the exhaust is utilised in a Rankine steam cycle. Proposed variants of this principle include MATIANT cycle [100] and Graz-cycle [101]. The main technical obstacle to the implementation of oxy-fuel combustion is the complete redesign of turbomachinery components and combustor, for them to be compatible with a CO₂-rich working fluid [98, 99].

An important area of improvement for the oxy-fuel combustion concept is to be found in the air separation unit: producing pure oxygen results in an energy penalty that, together with the energy demand for CO₂ compression and conditioning, results in a significant efficiency penalty. An ASU producing 95% pure oxygen would

require 200 kWh/tonne O₂ (David [101] in [79]). Research to improve the performance of ASUs is not very promising: long-term development of the technology has resulted in only a few significant technical breakthroughs that would lead to reduction of costs and power consumption [99].

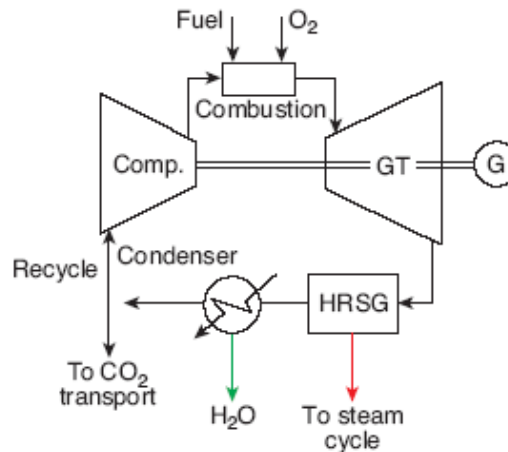


Figure 3.7 A schematic of oxy-fuel combined cycle with CO₂ recycle [98]

Consequently, other air separation technologies, based on mixed oxygen conducting membranes [102-104] or on chemical looping combustion process [29-30], are gaining interest.

Chemical-looping combustion (CLC) is a combustion technology with inherent separation of CO₂: it was proposed originally by Richter and Knoche [105] and developed further by Ishida and Jin [106]. CLC involves “combustion without direct contact between air and fuel” [106]. The combustion process is split into intermediate oxidation and reduction reactions occurring in two reactors, namely a fuel reactor and an air reactor, between which a metal oxide circulates as an oxygen carrier (Figure 3.8). Consequently no air separation is required. The output from the fuel reactor consists of CO₂ and H₂O, and an almost pure stream of CO₂ is obtained when the water is condensed. Considerable research has been conducted concerning CLC during the last decade with respect to oxygen-carrier development, reactor design, system efficiencies and prototype testing, modelling and simulation/cycle studies [107]. The technique has been demonstrated successfully with both natural gas and syngas as fuel in continuous prototype reactors based on interconnected fluidized beds within the size range 0.3 – 50 kW, using different types of oxygen carriers based on the metals Ni, Co, Fe, Cu and Mn. From these tests it can be established that almost complete conversion of the fuel can be obtained and 100% CO₂ capture is possible.

The limitation of the Turbine Entry Temperature (TET), imposed by the oxygen carriers, and the integration of the two reactors in a conventional gas turbine represent important challenges to the further development of the CLC. However, studies on this concept have shown that it is theoretically possible to achieve reasonable thermal efficiencies using CLC integrated with CO₂ capture. This together with the added advantage that no new separation equipment is needed makes CLC a highly-interesting technology for further study [58].

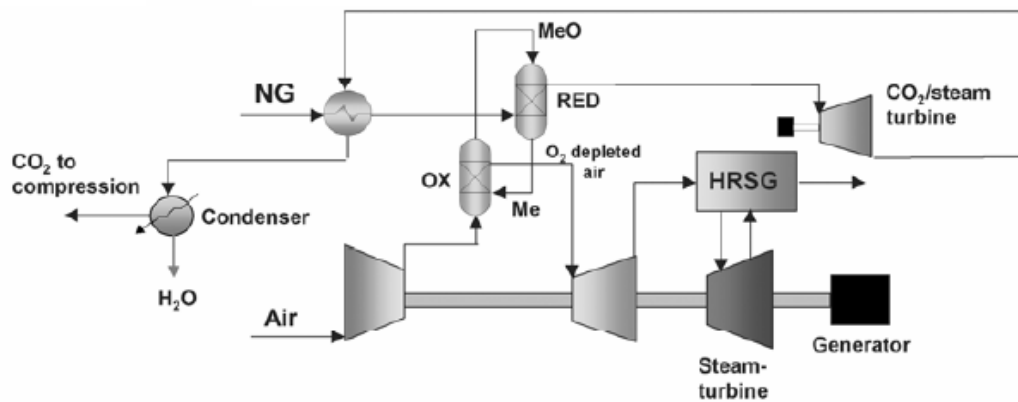


Figure 3.8 CLC cycle layout [58]

The mixed conducting membrane (MCM) reactor is a radically innovative device that can replace the conventional combustor in a gas turbine. It includes: a combustor, an air preheater, a membrane section, and a high temperature heat exchanger section. This MCM reactor accomplishes several functions, among which are the separation of O₂ from air and the combustion of fuel in a near-to-stoichiometric condition. It finds application in the so-called Advanced Zero Emission Power Plant (AZEP) concept, whose process flow diagram is shown in Figure 3.9. Several configurations have been proposed and investigated. In the AZEP model shown in Figure 3.9, both the CO₂/steam stream and the flue gas from the main gas turbine are supplied to the heat recovery steam generator (HRSG) where steam is generated for the bottoming cycle [102].

Other alternatives include an afterburner with extra fuel added prior to the gas turbine in order to raise the TET (AZEP 85%) or the presence of a CO₂/steam turbine (Figure 3.10). The AZEP concept development relies heavily on the successful development of the mixed conducting membrane and on the development of a heat exchanger which is stable at high temperatures (about 1100 °C) in the presence of steam and carbon dioxide. The membrane's mechanical integrity issue imposes an upper limit for the TET of about 1200 °C with important repercussions

for the whole plant's efficiency. Other important challenges are represented by the combustion of natural gas in the highly-diluted exhaust gas stream and the integration of the MCM-Reactor in the gas turbine system, start-up philosophy and gas turbine trips [102].

Such radically-innovative concepts are the focus of considerable development effort, but they are not yet suitable for large scale applications.

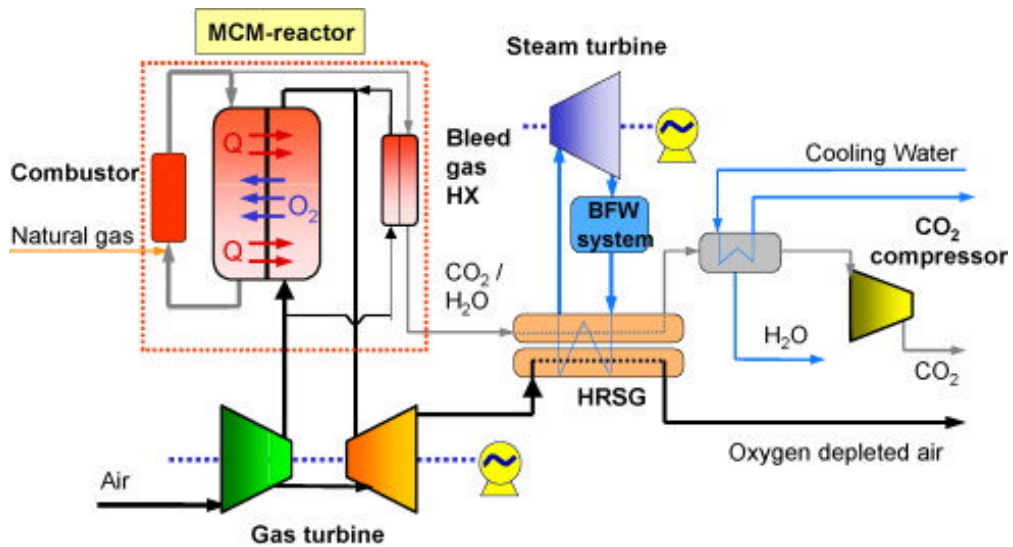


Figure 3.9 AZEP process flow sheet [102]

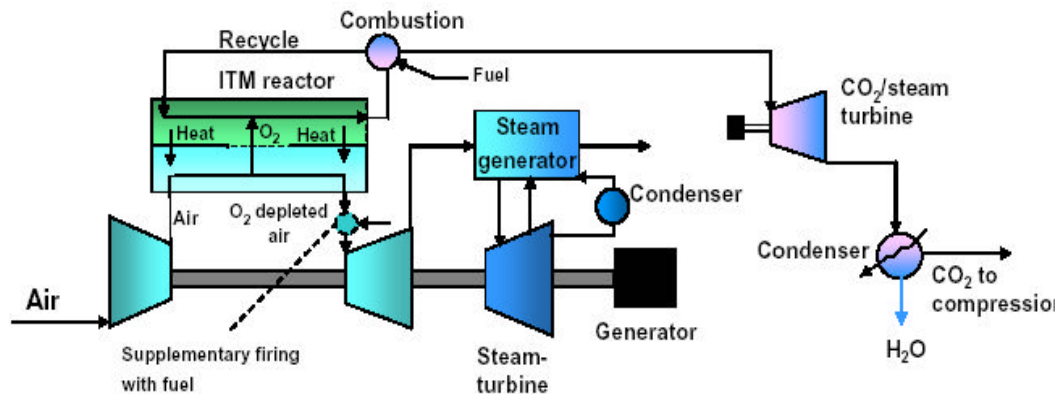


Figure 3.10 AZEP 85 % with a CO₂/steam turbine [58]

3.3 CO₂ Transport

Transport is the second phase in the carbon capture and storage chain; beginning with the conditioning of the carbon dioxide stream sequestered by the capture process and ending with injection to a reservoir, it links sources and storage sites. Transport can be undertaken by pipeline or on ships, as shown in Figure 3.11.

For the large gas volumes usually involved in a CCS scheme, transport through pipelines is the primary option [108]. It is a well established practice in the chemical and petroleum industries and is comparable with the transportation of natural gas. As an example, most experience of pipeline transport of CO₂ has been gained in the USA which has more than 2,500 km of such pipelines for Enhanced Oil Recovery (EOR) [3, 109]. The utilisation of ships for transporting CO₂ is also a possibility, even though this is at an embryonic stage [3]. Some dedicated CO₂ ships are in operation today, but they are not suitable for large-scale operations [109]. Carbon dioxide, in fact, is sometimes transported like liquefied natural gas and petroleum gases, but on a smaller scale because of its limited demand. On the other hand, given the similarity between the properties of liquefied carbon dioxide and those of liquefied petroleum gases, the technology could be scaled up to large carbon dioxide carriers [3]. As illustrated in Figure 3.11, for transport via ships intermediate storage is required, since CO₂ can be assumed to be captured with a more or less continuous process, which is usually inappropriate to the CO₂ being loaded onto a ship [110].

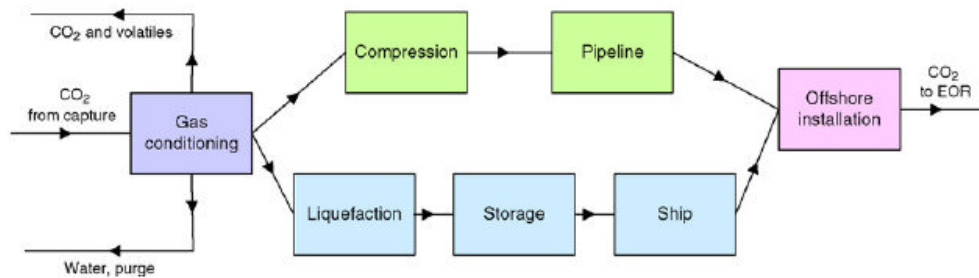


Figure 3.11 The CO₂ transport chain [110]

For both transport options illustrated in Figure 3.11, conditioning and compression of the CO₂-rich gas stream, often considered the concluding phase of the CO₂ capture process, are required [110].

In order to transport efficiently large amounts of CO₂, it must be transformed into a high-density form, i.e. transport is accomplished in liquid, solid or in supercritical phases [109, 110]. In pipeline transport, the CO₂ will be transported at supercritical pressure, most likely in the range of 80–150 bar.

Transport at lower densities (i.e., as gaseous CO₂) is inefficient because of the low density of the CO₂ and relatively high pressure drop per unit length of pipeline [110, 111]. Moreover, by operating the pipeline at pressures exceeding the CO₂ critical pressure of 7.38 MPa, temperature fluctuations along the pipeline will neither result in the formation of gaseous CO₂ nor the difficulties encountered with two-phase flow [111], as the phase diagram in Figure 3.12 illustrates.

The main technical constraints will be the maximum allowable impurity content in the CO₂ to be injected and the impurities that can be allowed with respect to transport via pipeline or ship [110].

In particular, the compressibility of CO₂ is greatly affected by any impurities (such as hydrogen sulfide (H₂S) or methane (CH₄)) (Figure 3.13). Water, hydrocarbons and CO₂, as well as forming corrosive carbonic acid, may combine to form hydrates that could block the system (Barrie [112] in [109]).

Such demanding requirements for the carbon dioxide purity, dictated by several factors such as safety and operation in the transport chain, reservoir requirements and regulations, have to be guaranteed by the CO₂ capture and conditioning process, thereby imposing a further requirement on the CO₂ capture phase [110].

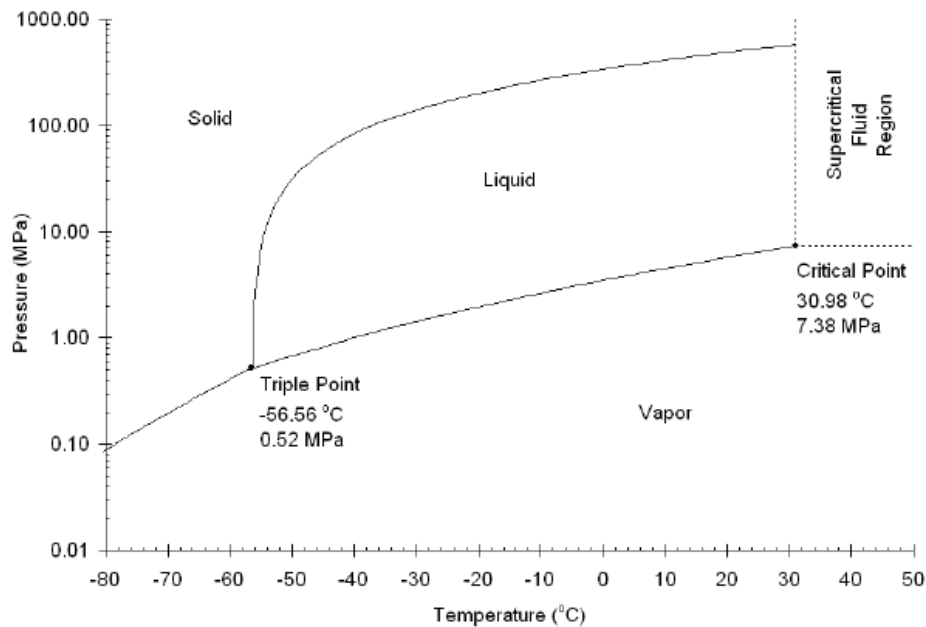


Figure 3.12 Phase diagram for CO₂ [111]

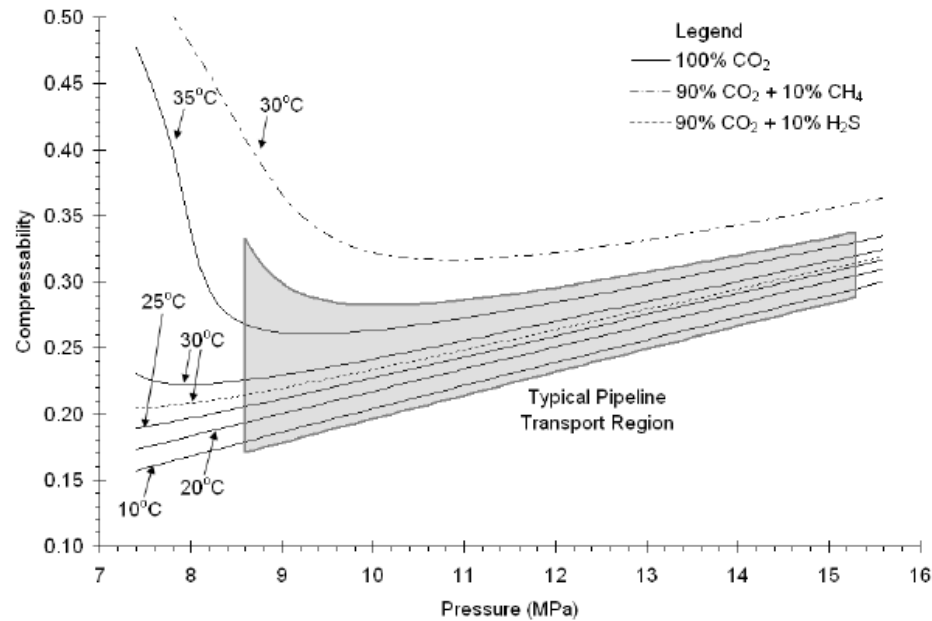


Figure 3.13 The compressibility of CO₂ affected by impurities [111]

3.4 CO₂ Storage

Following the capture and transport processes, CO₂ needs to be securely held in a store that will not permit leakages to the ambient. Essentially two options are usually considered for storage of sequestered CO₂, namely geological and ocean storage [3, 108, 109].

Geological storage of CO₂ makes use of techniques commonly employed in the oil and gas industry: this option involves injecting the CO₂ at depths exceeding about 1 km into porous sedimentary formations [113]. Depleted oil and gas reservoirs, possibly coal formations, and particularly saline formations, can be used for the storage of CO₂.

The enhanced oil recovery (EOR) method is already used particularly in the United States, where carbon dioxide is injected into the oil field to increase the extraction of the remaining oil. The final benefit can result in an increase of 10-15% of oil recovery. When the oil field is completely depleted, CO₂ can be injected and therefore stored for thousands of years.

Storage in gas fields has not been implemented to date, but no technical barriers seem to exist. A pilot project for CO₂ storage in gas fields has started in the Dutch sector of the North Sea (K12-B gas field).

An alternative possibility is to use deep saline aquifers for CO₂ storage. Rocks present in aquifers are rich in calcium, magnesium and iron, which tend to react with the CO₂ to form carbonates, so resulting in a long-lasting effective storage. There are some examples, notably in Norway: Statoil has the world's first CO₂ store in a saline

aquifer. From its creation in October 1996, about 1 million tons of CO₂ have been injected annually.

The use of CO₂ for the so-called Enhanced Coal-Bed Methane Recovery (ECBM) has been put forward recently as another geological storage option [114]. The Earth's sedimentary basins contain an enormous amount of coal. The challenge is to unlock the coal-bed methane resources in an economically viable manner. One of the attractive aspects of ECBM is that for each molecule of methane gas produced at least two CO₂ molecules can be absorbed in the coal matrix. The coal seams in question must be recognised as being unminable, otherwise the stored CO₂ might be released by subsequent mining, thereby negating the purpose of the original injection.

Figure 3.14 indicates the CO₂ storage potential by type of reservoir. The global capacity of depleted oil and gas formations for storing CO₂ has been estimated to be 900 gigatons of carbon dioxide (Gt CO₂). A considerable capacity is provided also by deep saline formations [115, 116].

The ocean plays a critical role in the global carbon cycle as a natural means of CO₂ absorption, both exchanging carbon rapidly with the atmosphere and taking up a substantial portion of anthropogenically-generated carbon from the atmosphere [109]. For CCS application some researchers have proposed storage in deep oceans aimed to inject liquid CO₂ at the ocean floor and to make a “lake” of CO₂ that will be absorbed little by little. However, this is only as yet a theoretical concept since it cannot be experimented and very hazardous impacts on the ecosystem could not be predictable. For instance, some experts state that CO₂ injection could cause a locally acidification of the ocean and damage to ocean ecosystem.

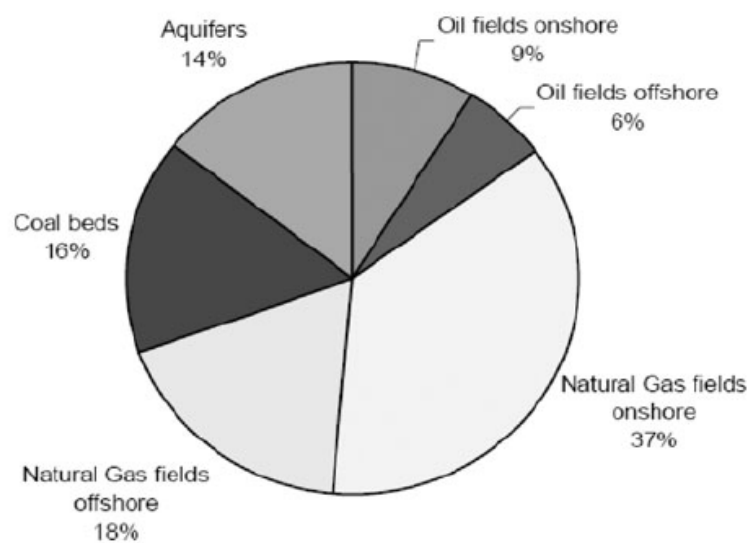


Figure 3.14 CO₂ storage per type of underground reservoirs [109]

Currently, CO₂ storage of a large volume of CO₂ that could result from large-scale CCS implementation is still fraught with uncertainty. The most substantial risk associated with CCS is the leakage of CO₂ from storage sites via gradual and long-term release or sudden release of CO₂ caused by disruptions of the reservoir [109]. Concerns have been expressed regarding the long-term storage of CO₂ [109]. While there is some experience with geological storage of CO₂ and natural gas for periods of approximately 10-20 years, long-term storage over many hundreds or thousands of years has not been proven [109].

3.5 Cycles selected for TERA Analysis

Five low-carbon gas turbine technologies for the further analyses have been identified after a thorough literature review of relevant papers and previous works on this subject, and have been agreed with the industrial sponsor⁸. They include three oxy-fuel concepts and two pre-combustion concepts:

- Auto-thermal Reforming Combined Cycle;
- Integrated Gasification Combined Cycle;
- Advanced Zero Emissions Power Plant Cycle;
- Chemical Looping Combustion Cycle;
- Oxy-fuel Combined Cycle.

A conventional gas turbine combined cycle has been added to this list: its performance acts as a benchmark for the subsequent analyses.

Among the five power plant concepts selected for the present study, four are natural gas-fired units and one is a coal-fired unit. The reasons underlying this choice are several.

Natural gas remains the least-polluting of mainstream fuels. It has the lowest carbon/hydrogen ratio among all the fossil fuels. Moreover, it has been argued that a natural gas fired combined cycle is much more suited to pilot plants with CO₂ capture than plants with coal gasification [117]. In fact, the specific cost of CO₂ sequestration is expected to be lower in an NG-fired plant than in a coal –fuelled

⁸ Technical review meetings with Mr Paul Jeffreys and Mr Martyn Adams from E.ON U.K. Ltd. on the 6th March 2007, on the 20th June 2007 and on the 21st February 2008 at Cranfield University.

plant [118]. Last, but not least, the motivation for the present study is the specific situation of United Kingdom power sector, which, as outlined in Chapter 1, is forecast to be dominated by natural gas fired-power plants.

On the other hand, as reported in a DTI report [119], an appropriate mix of energy sources for the U.K. is of paramount importance with respect to guaranteeing secure supplies. Among all fossil fuels, coal is the most abundant [120] and the one dominating power production applications. Another attraction of coal is its relatively low unit price. Furthermore, as already highlighted, much of the investigations on CO₂ emissions reduction is related to coal-fired plants, often with integrated gasification of the fuel.

Table 3.1 summarises schematically the work done on the selected cycles. It is evident that due to the breadth of the present study, the T.E.R.A. analysis, according to the first objective of the project, has been completed for three cycles (the baseline, and two configurations of the Auto-thermal Reforming Combined Cycle) which represent the three case studies of this discussion. Appendix A provides an overview of the other selected cycles and the work done on each of them.

It emerges clearly also that this project has been conducted as a collaborative research activity, receiving some external inputs that however needed to be supported, overseen and channeled by the author in order to finalise the whole investigation.

3.5.1 Reference-Conventional Combined Cycle

The choice of a reference power plant to provide a benchmark performance for the CO₂ capture plants being studied has a significant impact on the comparison. Without a well-defined reference power-plant the efficiency of a power cycle with CO₂ capture technology has little meaning, since there is no possibility of determining how large is the penalty of including CO₂ capture. This concept is essential for establishing the effectiveness of each option. It also has a great impact on the evaluation of the so-called CO₂ capture avoidance cost, a parameter which takes into account the additional energy (and emissions) resulting from capturing the CO₂. In fact, as a means of comparing mitigation options, the CO₂ capture avoidance cost can be confusing because the answer depends on the base case chosen for the comparison (i.e., what is being avoided).

In the present study the most common approach adopted when comparing CO₂ capture power plants has been applied: it involves comparing the performances of identical plants with and without CO₂ capture. This approach gives a clear insight as to which technologies enable inherent low-cost CO₂ capture to be achieved.

Table 3-1 *Summary of the work done on the cycles selected for T.E.R.A. study*

Cycles	Performance Analysis	Economic Analysis/ Financial Risk Analysis	Environmental Analysis	Risk Analysis for Technology
Conventional GT Combined Cycle	Model developed and integrated in the T.E.R.A Framework ^a	Completed ^a	CO ₂ Emissions evaluation ^a	Partially Completed ^a
Auto-thermal reforming Combined Cycle (two configurations: ATRCC / IRCC)	Preliminary Model of the ATRCC ^b Models of the ATRCC and IRCC developed and integrated in the T.E.R.A Framework ^a	Completed ^a	CO ₂ Emissions evaluation ^a	Literature Review ^{a,c} Partially completed ^a
IGCC	Preliminary model ^d Partial integration of the model in the T.E.R.A. Framework ^a	Literature Review ^c	CO ₂ emissions evaluation ^a SO _x emissions evaluation ^d	Literature Review ^{a,c}
CLC	Preliminary model ^e	-	-	Literature Review ^{a,c}
Oxy-fuel CC	Preliminary model ^f	-	-	Literature Review ^{a,f}
AZEP	Preliminary model ^g	-	-	Literature Review ^{a,g}

^a By the author

^bIn collaboration with Giancarlo Ruggieri [121]. This preliminary model has been developed in part in Excel based environment and does not take in account the pre-heating of the all process streams in the heat recovery steam generator.

^cCollection of some data and information performed by M.Sc. students.

^d In collaboration with Paolo Barbera [122]. This preliminary model has been developed in part in Excel based environment

^e In collaboration with Noel Glaenzer [123]. The model does not cover the whole combined cycle power plant but only the gas turbine.

^f In collaboration with Festus Agbonzikilo [124]. The model does not cover the whole combined cycle power plant but only the gas turbine.

^g In collaboration with Emanuele Pagone [125]. The model does not cover the whole combined cycle power plant but only the gas turbine.

Figure 3.15 presents the schematic of the conventional single-pressure natural gas-fired combined cycle designated as the reference cycle. The single-pressure level combined cycle is the simplest form of combined gas/steam cycle. Even if many improvements have been introduced to improve the performance, leading to multiple-pressure combined cycles, single-pressure cycles remain on the market because of their relative cheapness [126]. Moreover, a single-pressure level simulation gives a good idea of the kind of the efficiency achievable by a gas turbine combined cycle compared with that of the simple gas turbine [127].

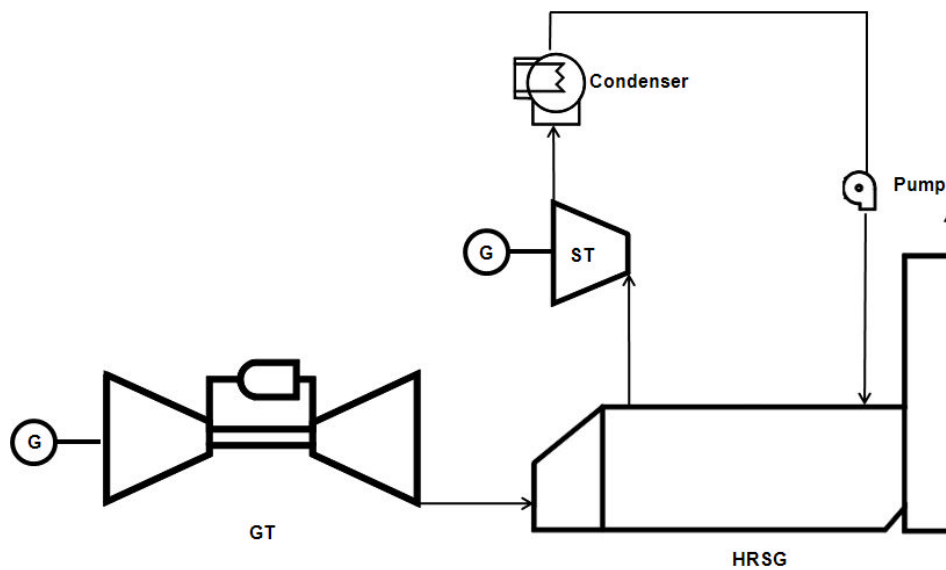


Figure 3.15 Schematic of the conventional GT combined cycle

3.5.2 The Auto-thermal Reforming Combined Cycle and the Integrated Reforming Combined Cycle

As already mentioned in paragraph 3.2.2, auto-thermal reforming is a stand-alone process which combines steam reforming and partial oxidation processes.

In general, there are two types of ATR systems. The first is compact and useful for fuel cell applications: it consists of just a catalyst bed on which combustion and steam reforming reactions take place at the same time. The second has two separate sections: in the first section fuel is first partially oxidised by air or oxygen in a partial oxidation non-catalytic burner and steam reforming is carried out in the downstream catalyst bed by the introduction of steam, without requiring secondary fuel. The latter one is ideal for gas-to-liquid (GTL) applications and is now being proposed for power generation applications among the CCS options.

The internal combustion or oxidation of a portion of the feed hydrocarbons can occur in the auto-thermal reformer using as oxidiser pure oxygen or air. In industrial applications oxygen is more often preferred to air, in order to reduce plant size and costs because it has the advantage of being able to use smaller reactors. However, it leads to the requirement of a further additional component, the ASU to produce the O₂. Air is used instead of O₂ in ammonia plants, where it feeds a secondary reformer (an ATR placed after the steam methane reformer), and provides the ammonia synthesis with the necessary nitrogen [129]. If air is used as oxidizer, the gas leaving the ATR contains a large amount of nitrogen.

Figure 3.16 shows a simplified conceptual representation of a combined cycle power plant including fuel auto-thermal reforming and CO₂ removal. The fuel treatment section includes a pre-reformer, an auto-thermal reformer, two water-gas shift reactors, a CO₂ capture section. In the pre-reformer the heavier hydrocarbons in the natural gas feed are converted to CO₂ and H₂. The syngas produced in the ATR from pre-reformer output, air (or oxygen) and steam is cooled down and enters the shift reactors whereby CO₂ and H₂ are formed by consuming steam, previously added to syngas. Shift reaction is exothermic and heat is removed by steam production. To enhance CO conversion to CO₂ a second shift reactor is usually used at lower temperatures, favouring shift advancement. Furthermore, the low temperature stage of the WGS requires a more active catalyst. Consequently, it is better to use a standard catalyst at the higher temperature range and then have a separate reactor with a more active catalyst for the low end temperature. Decarbonised syngas is used in a combined cycle. Separated CO₂ is eventually liquefied by compression and made available for long-term storage.

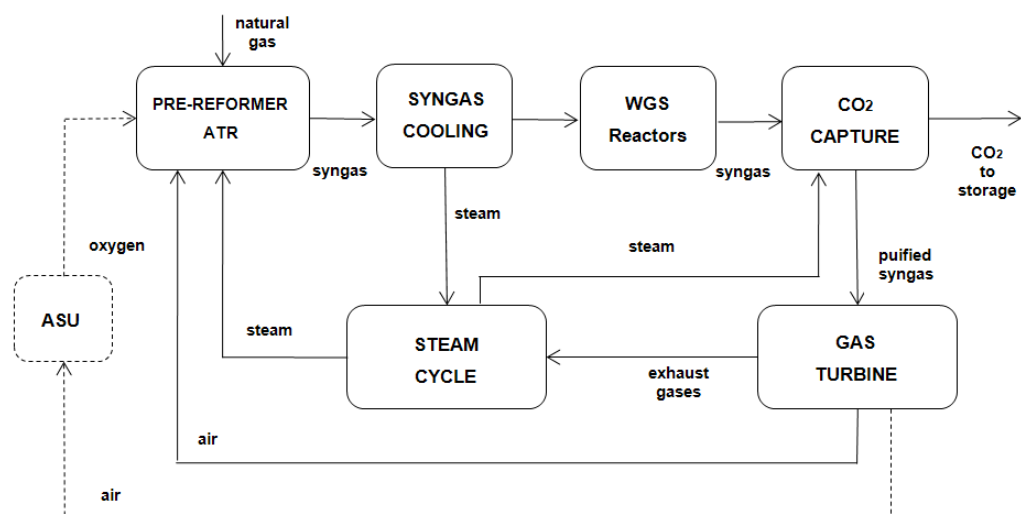


Figure 3.16 Conceptual representation of a combined cycle power plant including fuel auto-thermal reforming and CO₂ removal

Certainly there are several configurations for this power plant concept. For example, an oxygen-blown auto-thermal reformer can be used, calling for an air separation unit for the oxygen supply. It has been highlighted, however, that air-blown reactors are perfectly suitable for integration with a combined cycle [129, 130]. Indeed, in combination with a natural gas fuelled power plant, such auto-thermal reforming process can be of great interest. Preheated air can be extracted from the air compressor of the gas turbine and correspondingly steam from the steam turbine. An air-blown ATR, together with water gas shift reactors and CO₂ removal process, produces a fuel with about 50% hydrogen. Modern gas turbines with low-NO_x combustors are restricted regarding the hydrogen concentration of the fuel. Traditional steam reforming processes would, in this application, produce a fuel for the gas turbine with significantly higher hydrogen content [131].

In air-blown ATR case, it could be possible to operate the ATR system at a higher pressure by boosting the air pressure from the gas turbine compressor with an additional compressor. In this case a fuel compressor would not be necessary. This option has been studied by Andersen [130] who concluded that operating at a lower system pressure and having a fuel compressor improve the overall efficiency of the cycle. The air necessary for the fuel reforming can be totally or partially provided by the gas turbine's compressor. In the latter case, an additional air compressor needs to be included. Different degree of integration between the fuel decarbonisation section and the power conversion unit can also be attractive. Both chemical and physical absorption could be used according to the characteristics of the gas stream.

Based on the literature findings presented above, in the present investigation two layouts of this pre-combustion concept employing auto-thermal reforming are investigated: the ATRCC and the IRCC. They are characterised by a different degree of integration between the fuel-treatment section and the power-conversion unit.

Their schematic layouts are shown in Figure 3.17 and 3.18 respectively, revealing how the IRCC scheme presents a higher degree of process integration compared with the ATRCC scheme case. It is understood that the efficiency of a process plant normally increase with the degree of integration. Such consideration led to extend the analysis of the Auto-thermal reformer combined cycle from the ATRCC layout, investigated preliminarily in collaboration with Ruggieri [121], to a more integrated solution. The aforementioned increase in efficiency, however, is coupled with an increased complexity which can give rise to operability and risk issues [132].

Both schemes consist of an air-blown auto-thermal reformer for which the necessary air is totally provided by the GT compressor, so as to benefit from the aforementioned advantages provided by the combination of air-blown ATR and a power plant. In the light of Andersen et al. [130] findings, the air pressure from the gas turbine compressor is not boosted with an additional compressor and therefore the ATR system does not operate at a higher pressure.

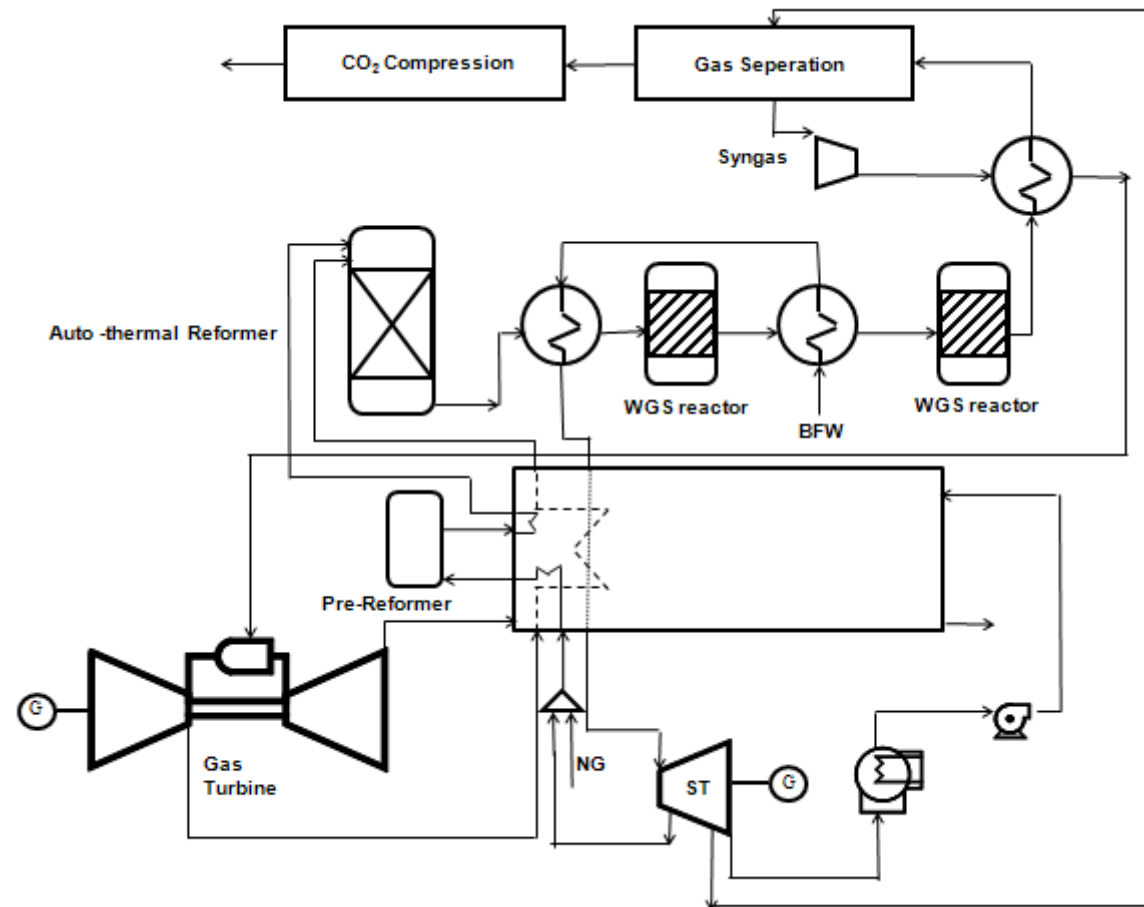


Figure 3.18 Process flow diagram for the IRCC (adapted from [135])

The heat recuperated downstream of the auto-thermal reformer and the WGS is used to produce steam: in the ATRCC case, this steam is partially exploited in the reformer and partially superheated in the HRSG at the turbine's admission temperature. Regarding the IRCC, the steam generated by the heat recovery in the pre-combustion section is totally expanded in the steam turbine, which in turn is penalised by the extraction of steam required for the reforming process.

For both schemes the pre-heating of the process streams is provided by the heat recovery steam generator. The CO₂ sequestration is accomplished by the chemical absorbent, whose regeneration is achieved by means of the steam extracted from the steam turbine. The chemical absorption has been adopted in both schemes due to the low operative pressure of the fuel treatment section.

The feasibility of producing power in natural gas reforming based power plants (with the integration of such technologies with the power section) has been investigated previously. Several process configurations have been studied by a number of authors [89, 129, 130, 133-135]. Their thermodynamic analyses display net plant efficiencies of approximately 46% to 49%. This type of plant also offers the interesting opportunity of hydrogen and electricity co-production [93,136]. Consonni and Viganò performed a thermodynamic and exergetic analyses of a steam cycle and combined cycle integrated with tubular reformers and auto-thermal reformers with CO₂ capture.

3.6 Definition of the boundary conditions and assumptions

A transparent comparison urges, together with the choice of cycles to investigate and the designation of an appropriate baseline case, the selection of the so-called boundary conditions and the computational assumptions along with the maturity level of the power plant technology to be studied, features that need to be applied to all power plants so that the effect of CO₂ capture is clearly visible [137].

The boundary conditions delineate how the power plant is interfaced with its surroundings [137]. The introduction of CO₂ capture in the power plant involves that extra-processes and components need to be taken in account, so that the power plant boundary will alter and may be extended to consider the purification and compression of CO₂ or sometimes also the transport and storage phases. The system boundary of the present analysis has been set at the production plant, i.e. only energy conversion, CO₂ capture and compression have been included.

Boundary conditions refer also to composition, properties and conditions of the feed streams, such as temperature and humidity, fuel composition, cooling water temperature and final pressure of the captured and compressed carbon dioxide [137]. In this regard, two options are available: standard boundary conditions and site-specific conditions, referring the former to standard values and the latter to a specific site's conditions [137]. Standard-

boundary conditions allow the comparison to provide a portrait of performance of different concepts, relative to each other, and characterised by a more general validity than the site-specific conditions. Therefore, this option has been used in this work and all values are specified in Chapter 4. However, site-specific conditions would give a better description of different alternatives once the location of a power plant with CCS has been decided on (in particular if the plant is located in a very cold or very hot zone) [137].

The computational assumptions define the technology level of the plant and describe the operating conditions inside the power plant. The combined cycle models of the present study are based on the technology level of the GE9FA gas turbine.

Two alternatives exist regarding the choice of the computational assumptions, i.e. the input data for the components in the power cycles being analysed: the first, for which the present work has opted, is to reflect present level of technological maturity, in which case more certain data are known and can be adopted. The second alternative is to assess somehow the input data that indicate future technology levels, trying to anticipate the performance of different power cycles when the CO₂ capture could be better developed and more widely deployed. The future development potential for CO₂ capture technology is highly relevant and will be the subject of attention and scrutiny in Chapter 7, after having studied, as first step in the TERA approach, the performance of the three case studies selected, to which the next chapter is dedicated.

CHAPTER 4

MODELLING BASIS, SIMULATION TOOLS AND PERFORMANCE ANALYSIS

This chapter deals with the thermodynamic performance analysis of the investigation. Firstly, requirements on process modelling in general are formulated. Later, thermodynamic models of the main unit-operation components in the power plant cycles analysed are described. The methodology of analysing and benchmarking various power cycle concepts is to keep a similar and consistent definition of work and efficiency which are defined in this chapter. Most of the models are implemented in the Cranfield simulation tool VARIFLOW, the simulation tools are mentioned otherwise. A common basis for the cycle analysis is established in the form of computational assumptions, included in the chapter, which enables a transparent comparison of the three power plants, also reported in this chapter.

4.1 Modelling Approach

A large variety of approaches to modelling a physical-chemical process exists. The variations include, among others, the level of detail in modelling the phenomena occurring as well as simplification or neglect of side effects.

As illustrated in Chapter 3, the advanced low-carbon power plants are in general complex technical systems, characterised by phenomena that span a large range of scientific disciplines, such as chemical engineering, material science and process engineering. Underlying any model there are inevitably strong interactions between these disciplines which brings about a certain complexity in the model itself.

As a matter of fact, a main quality indicator of any model is indisputably its degree of accuracy in reproducing the true behaviour of a system. The more detailed model is expectedly the more reliable model in terms of accuracy. However, the

purpose of the model and the simulation approach often decide and restrict the detailing level, leading to some simplifications. For example, if an optimisation using a genetic algorithm or a stochastic simulation is to be performed, a high number of model evaluations and thus a fast model is required. Likewise, if the controllability of a system is to be investigated, linear or linearised models with a low number of state variables are advantageous. On the other hand, the acceptability of each simplification must be verified⁹ according to the so-called “principle of optimum sloppiness” [138]: *“Make as many simplifying assumptions as reasonable without throwing out the baby with the bath water”* [138].

Another important feature of a model is the flexibility with which the problem may be posed. A classical model has input and output variables. But for some applications it is advantageous if the model is flexible in terms of input and output variables. Using a classical sequential solving approach, this may be realised by adding additional iteration loops for each output variable which is to be changed to an input variable. However, as this increases simulation time, a better solution can be a simultaneous, equation-oriented solving approach.

Summarising, general requirements on the modelling approach are:

- Accuracy of reproducing the true behaviour of a system
- Quick and stable solution
- Flexibility in input-output structure

These requirements are to some extent contradictive. The purpose of the model and the way it should be applied play an important role in determining the importance of each aforementioned single point and thus in the selection of the modelling approach.

T.E.R.A. methodology, as stated in Chapter 2, aims to apply the performance model of a system for many purposes. First of all, the model should help to understand phenomena observed in a real system and allow analysis of the system behaviour at different conditions. The model needs to cover the phenomena that should be analysed and those they depend on in a sufficient level of detail. Once a system is understood, its components need to be designed to achieve an optimum performance. Efficiency, specific power output, specific costs are only some of the several objectives that may contribute to the optimum. Various numerical optimisation approaches exist, but they all require a large amount of model evaluations in order to proceed to the optimum. Having designed the system and

⁹ It can also be stated as follows: “A good theoretical model of a complex system should be like a good caricature: it should emphasize those features which are most important and should downplay the inessential details” [139].

fixed a design-point, the next step is to investigate and optimise the behaviour of the system at off-design situations. For this purpose, many model evaluations are typically required; hence the model should be lean enough to provide quick and stable solution. However, for performing different kinds of simulations and evaluating different operation strategies, flexibility of input-output structure is a great advantage.

The present investigation, as initiation of TERA methodology, has focused on developing models of these complex systems which are simplified but still representative of the main phenomena occurring inside the system itself to obtain fundamental insights into such power plants behaviour.

4.2 Gas Turbine Simulation Tool: the VARIFLOW Code

The gas turbine cycle is analysed using the VARIFLOW code developed at Cranfield University by previous PhD and M.Sc. students [140-143] and widely used in the studies contracted to Cranfield University by “The IEA Greenhouse R&D Programme” within a project related to CO₂ abatement in gas turbine power cycles [144].

Written in Fortran 77 and 90, this computer-based code is able to perform both on-design and off-design calculation of the gas cycle of single shaft engines. Figure 4.1 shows a scheme of the kind of a gas turbine that can be modelled by the VARIFLOW code.

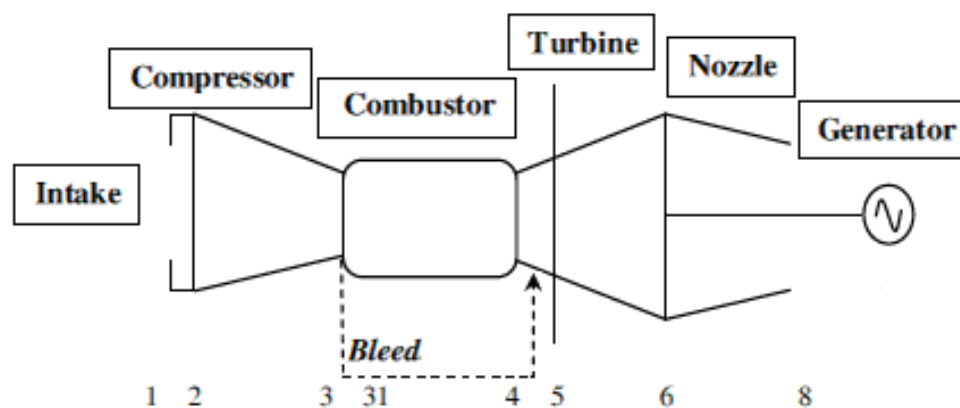


Figure 4.1 Gas turbine model in the VARIFLOW code (modified from [142])

VARIFLOW is a flexible gas turbine simulation tool that allows consideration of the performance effects of several fuels and working fluids. The fuel is defined as a mixture of CH_2 , CH_4 , C_2H_6 , C_3H_8 , CO , CO_2 , H_2 , H_2O , N_2 and the working fluid is defined as a mixture of N_2 , O_2 , CO_2 and H_2O . This last feature is of relevance for this study as the gas turbine can be fuelled with an hydrogen enriched synthetic fuel artificially produced from coal or from natural gas or can work with a working fluid different from the conventional one.

Mixtures of different compounds are present, therefore the evaluation of mixture properties ($\widetilde{a}_m$) is necessary. This is calculated using the following general formulas:

$$\widetilde{a}_m = \sum_i x_i \widetilde{a}_i \quad (4.1)$$

$$a_m = \widetilde{a}_m / MM_m \quad (4.2)$$

where x_i indicates the molar fraction of the species and $\widetilde{a}_i$ is a generic molar property. With this method the molar property sought is obtained. The mass based property can be obtained dividing the molar based one by the molecular mass of the mixture (Eq. 4.2). The thermodynamic properties of all the species considered are based on polynomial equations given by McBride et al. [145].

The performance calculations are based on the following assumptions [140-142]:

- The working fluid across the engine is treated as an ideal gas with the following thermodynamic equation of state:

$$PV = mR_{gas}T = nRT \quad (4.3)$$

- The compressor characteristic is mapped by using non-dimensional parameters:

$$\text{Non-dimensional mass flow: } NDW = \frac{w\sqrt{T}}{P} \sqrt{\frac{R}{\gamma}} \quad (4.4)$$

$$\text{Non-dimensional rotational speed: } NDN = \frac{N}{\sqrt{\gamma RT}} \quad (4.5)$$

The pressure ratio (PR) and the polytropic efficiency (η_{poly}) depend on NDW and NDN . However, the compressor polytropic efficiency is assumed constant in the code.

- The combustion is assumed complete and the pressure loss factor is expressed as:

$$PLF_{comb} = \Delta P_{comb} \frac{2}{\gamma_3 (M_{31})^2} \quad (4.6)$$

PLF_{comb} keeps the same value for design-point and off-design calculations.

- The mean temperature method is used to calculate pressure and temperature ratios across the components.
- The turbine is choked, leading to a constant non-dimensional mass flow through the turbine.

In the design-point calculations, all the thermodynamic parameters, i.e. W , P , T , C_p , γ and R , as well as the non-dimensional mass flow are calculated. The areas at which the code needs to iterate in the off-design algorithm (stations 2, 31, 8 and 5) are also calculated with the equation below:

$$A = \frac{QP}{W\sqrt{T}} \quad (4.7)$$

The parameters below are chosen as input data for the design-point, and they are typical of the design considered:

- M_2 Mach number at compressor inlet
- M_{31} Mach number at combustor inlet
- M_5 Mach number at turbine nozzle guide vane
- M_8 Mach number at the nozzle
- ΔP_{comb} combustor pressure drop

Additional information about the VARIFLOW code can be found in [140-142] where a description of the matching calculation procedure used by the code is also reported.

The VARIFLOW code was validated by Codeceira Neto [140] through comparisons with published data of commercial gas turbines (ABB GT13E2 and GE PG9351 FA). Results given by the code have been validated also by comparison with TURBOMATCH [121, 122, 142, 143], the Cranfield University in-house gas turbine performance simulation software that has been refined and developed over a number of decades. Such validation procedure has showed that the differences in the main output data are small, demonstrating the accuracy of VARIFLOW code [121, 122, 140, 142, 143].

4.3 Off-design Matching Procedure

The matching procedure of VARIFLOW for off-design calculations of the gas turbine has been widely described and detailed in previous M.Sc. and Ph.D. theses [140-142]. For completeness reasons a summary is hereafter presented.

Off-design calculations are based on a thermodynamic procedure as follows. Iterations are performed on the following parameters:

- A_2 compressor inlet section area
- A_{3f} combustor section area
- A_5 turbine nozzle guide vane section area
- A_8 nozzle throat section area
- ΔP_{comb} combustor pressure drop

The iterative method used for off-design calculations is the following [140-142]:

1. The values of M_2 , M_{3f} , M_8 and ΔP_{comb} used for the design-point are estimated values for the off-design.
2. The non-dimensional rotational speed is calculated. As the ambient temperature is known, the speed line is set on the compressor map.
3. A value for the compressor pressure ratio is estimated.
4. The non-dimensional mass flow can be deduced from the compressor map; thus the mass flow at the compressor inlet is calculated.
5. The thermodynamic parameters are calculated at all the stations of the gas turbine.
6. New values of A_5 and A_8 are calculated and compared to the ones obtained from the design-point. If they have converged, the algorithm proceeds to step 7. Otherwise, a method is used to make A_5 and A_8 converge. It is based on finite differences; it uses differential values of the compressor pressure ratio (PR) and the Mach number at the nozzle exit (M_8) with the following equation:

$$\begin{bmatrix} \frac{\partial A_5}{\partial CPR} & \frac{\partial A_5}{\partial M_8} \\ \frac{\partial A_8}{\partial CPR} & \frac{\partial A_8}{\partial M_8} \end{bmatrix} \begin{bmatrix} \Delta PR \\ \Delta M_8 \end{bmatrix} = \begin{bmatrix} \Delta A_5 \\ \Delta A_8 \end{bmatrix} \quad (4.8)$$

The calculated values of ΔPR and ΔM_8 enable to determine new values for PR and M_8 :

$$M_{8,new} = M_8 + \Delta M_8 \quad (4.9)$$

$$PR_{new} = PR + \Delta PR \quad (4.10)$$

The algorithm returns to step 4.

7. The thermodynamic parameters are recalculated at all the stations of the gas turbine.

8. The new value of M_{31} is calculated and compared to the one obtained from the design-point calculations. If it has converged, the algorithm goes to step 9. Otherwise, a method is used to make M_{31} converge. This is a finite difference method using differential values of the Mach number at the combustor inlet (M_{31}) with the following equation:

$$\left[\frac{\partial A_{31}}{\partial M_{31}} \right] [\Delta M_{31}] = [\Delta A_{31}] \quad (4.11)$$

The calculated value of ΔM_{31} enables to determine a new value for M_{31} :

$$M_{31,new} = M_{31} + \Delta M_{31} \quad (4.12)$$

The algorithm returns to step 7.

9. The new value of ΔP_{comb} is calculated.

10. The latter value is compared to the one obtained from design-point calculations. The convergence criterion is:

$$\left| \frac{(\Delta P_{comb}) - \Delta P_{comb}}{\Delta P_{comb}} \right| < 0.0001 \quad (4.13)$$

If it has converged, the algorithm proceeds to step 11. Otherwise, a new value is assigned to ΔP_{comb} and the algorithm returns to step 5.

11. The thermodynamic parameters are recalculated at all the stations of the gas turbine.

12. The new value of A_2 is calculated and compared to the one obtained from design-point calculations. If it has converged, a finite difference method is used. It uses differential values of the Mach number at compressor inlet (M_2) and is based on the following equation:

$$\left[\frac{\partial A_2}{\partial M_2} \right] [\Delta M_2] = [\Delta A_2] \quad (4.14)$$

The calculated value of ΔM_2 enables to determine a new value for M_2 :

$$M_{2,new} = M_2 + \Delta M_2 \quad (4.15)$$

The algorithm returns to step 11.

13. Final calculations are performed, including thermal efficiency, power output and

fuel consumption.

4.4 Steam Plant Simulation Tool

A computer-based routine has been written in Fortran 90 to simulate the bottoming steam plant and has been combined and integrated with the VARIFLOW code to produce a complete computer-based code for combined cycle performance analysis.

The program is able to simulate multi-pressure systems in cascade arrangement¹⁰ (single, dual and triple pressure levels without reheat). Nevertheless, the single pressure combined cycle scheme has been considered in the present investigation. The schematic diagram for the combined cycle power plant on which the simulation is based is depicted in Figure 3.15, whereas the T-Q diagram for the HRSG is shown in Figure 4.2.

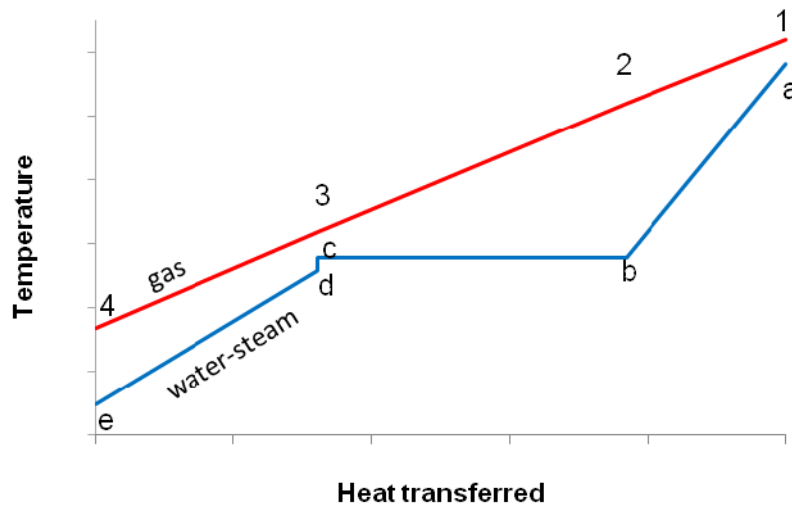


Figure 4.2 T-Q diagram and notation for one pressure level

For each pressure level the HRSG model consists of an economizer, an evaporator and a superheater. A counter-flow¹¹ heat exchanger model, which is represented in Figure 4.3 along with the notation used in this paragraph, is applied

¹⁰ The cascade arrangement implies the high pressure level in the heat recovery steam generator is fed from the low pressure drum. As a consequence, the inlet temperature of the high pressure economiser is precisely the low pressure drum saturation temperature and the mass flow of the low pressure economiser is the sum of the low pressure steam mass flow plus the high pressure steam mass flow. The advantages of this configuration, compared with the parallel one, are the simplicity of the heat recovery steam generator itself and the ease of the performance calculations.

¹¹ The counter-flow heat exchanger arrangement (in which the fluids enter the exchanger from opposite ends) has been adopted because for a given inlet condition it has a greater potential for heat transfer than the parallel arrangement [146].

for each part of the HRSG. Once the heat and mass balances at on-design conditions for each heat exchange element have been evaluated, using the log-mean temperature difference (Eq. 4.16), the thermodynamic size (UA) of each tube bank and heat exchanger can be calculated as indicated by equation 4.17, where U is the overall heat transfer coefficient and A is the heat transfer area [147-148]:

$$\Delta T_{ln} = \frac{\Delta T_{hot} - \Delta T_{cold}}{\log\left(\frac{\Delta T_{hot}}{\Delta T_{cold}}\right)} \quad (4.16)$$

$$UA = \frac{Q}{\Delta T_{ln}} \quad (4.17)$$

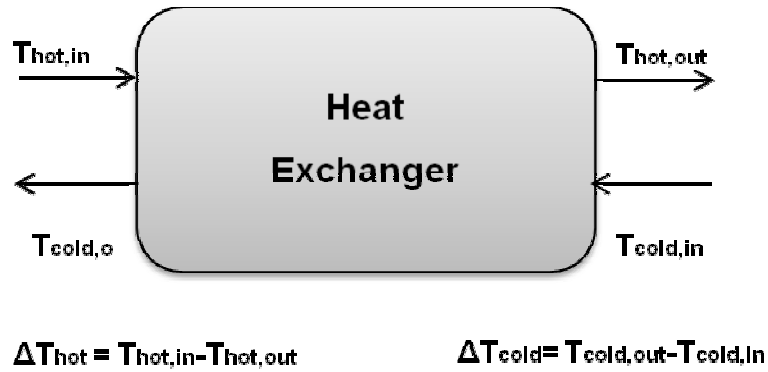


Figure 4.3 Counter-flow heat exchanger disposition and notation

The design values are used as reference values for the off-design calculation. Each heat exchanger is subsequently characterised by its number of transfer units NTU, according to the following equation:

$$NTU = \frac{UA}{C_{min}} \quad (4.18)$$

where C_{min} indicates the smaller heat capacity rate (i.e. flow rate multiplied by specific heat) between the hot and cold fluid ones. The model of counter-flow heat exchanger outlined is applied also to the condenser model, which is assumed to be a river/sea water cooled condenser.

The author recognises that the model implemented for the heat exchangers in the current version of the steam plant simulation tool is simplified. A more appropriate model should have evaluated the overall heat transfer coefficient U , which is related to the convection heat transfer coefficient between the steam and the internal tube

walls and the heat transfer coefficient between the gas flow and the external tube surface according to the following equation¹²:

$$\frac{1}{U} \approx \frac{1}{h_i} + \frac{1}{h_o} \quad (4.19)$$

where h_i and h_o are the individual convection heat transfer coefficients inside and outside the tubes respectively and it is assumed that the inner and outer surface areas of the tube are almost identical ($A_i \approx A_o$). This assumption is not appropriate in case of finned surface, since the surface area of the finned area side is several times that of the unfinned side [146]. The convection heat transfer coefficients h depend on all the variables influencing convection such as the surface geometry, the nature of fluid motion, the properties of the fluid, and the bulk fluid velocity and can be expressed in relation to the Reynolds¹³ (Re) and Prandtl (Pr) numbers on the basis of the fluids' thermal conductivity (λ), viscosity and specific heat [146]:

$$h = c Re^m Pr^n \frac{\lambda}{D} \quad (4.20)$$

In the previous equation c , m , n are experimental parameters and D represents the hydraulic diameter of the tubes. The restricted time frame available to address the steam plant simulation issue and the lack of knowledge regarding some parameters (such as c , m , n in the equation 4.20, and the number of fins) to be used in the conventional scheme and especially in the advanced schemes (as for example in the oxy-fuel concepts due to the different composition of the GT exhaust gases) led to use of the model described above.

The steam turbine expansion is divided into a number of sections which correspond to the number of HRSG pressure stages. Each section is computed by individual dry isentropic step efficiency (η_{st}). The steam turbine model does not take in account throttle valve losses, steam leakages through the steam turbine seals, low pressure section leaving loss.

There are a number of ways of modelling the steam turbine. Much effort has been devoted to the implementation of the so-called Cotton-Spencer model. This model evaluates the efficiency of each section (condensing and not-condensing) of the steam turbine through experimental correlations in relation to the inlet steam's volumetric flow, the expansion ratio, and the condition of the steam at group inlet [149-151]. Generally, a steam turbine can have one impulse stage at inlet, followed by a series of reaction stages [149]. The impulse stage may be a governing stage which

¹² This equation neglects the thermal resistance of the tube since usually the wall thickness of the tube is small and the thermal conductivity of the tube material is high.

¹³ In case of forced convection.

allows partial admission for load control or a wide open stage. Most steam turbines in combined-cycle plants operate in sliding pressure operation and generally do not have control stage nozzle groups [127]. The Cotton-Spencer model apparently assumes a governing stage for the high-pressure section since it was developed from steam plant experimental data.

Due to lack of information about the model, its implementation was not completed, but this is not considered critical in the scope of this work because it represented an attempt to refine the steam turbine model, which is not an explicit objective of this study.

A preliminary correction for the efficiency of the low pressure section because of moisture has been implemented: if the low pressure expansion crosses into the wet region, the efficiency is corrected for moisture when the exit quality is below that for the onset of condensation [152]. The so-called Wilson Line¹⁴ quality is normally between 0.95-0.98. The occurrence of the Wilson line has been fixed to a steam quality of 0.97 in this implementation. The efficiency degradation is assumed to be an exponential function of mean step steam quality:

$$\eta_{is} = \eta_{dry} [1 - (1 - x_{step\ mean})^c] \quad (4.21)$$

where η_{dry} is the isentropic efficiency for dry steam and $x_{step\ mean}$ is the mean steam quality for each computational step. The exponent c is typically in the range 1.0-1.3 and is chosen to be 1.15 in the present implementation. However, because of lack of time, this model of moisture correction has not been validated and therefore will not be used in the performance analyses reported hereafter. As this is a preliminary model, the inaccuracy in derived efficiency has been accepted.

For the design-point the computational procedure is quite straightforward. The results of the performance calculation of the gas turbine cycle are fully utilized as the input condition to the steam cycle calculation. These are: molar composition of exhaust gas from the gas turbine, exhaust gas temperature (T_1), exhaust gas pressure and exhaust mass flow (W_{gas}). No water extraction in the steam drum is considered, hence the flow-rates of the economizer and superheater are equivalent. For the HRSG-calculations, once the gas inlet temperature, the exhaust gas-live steam approach temperature difference ($\Delta T_{sup,a}$), pinch-point temperature difference (ΔT_{pp}), economizer approach temperature difference (ΔT_a), live steam pressure (P_a) are given

¹⁴ When steam passing through a nozzle crosses the saturation line into the two-phase region, condensation would be normally expected to begin the instant the saturation line is crossed. The transition is so rapid in a nozzle that condensation does not actually take place until a lower temperature and pressure are reached. Condensation may then take place suddenly with the formation of multitudinous minute droplets. The Wilson Line is the locus of points in Mollier diagram where condensation ultimately occurs [153, 154].

as inputs, all other remaining temperatures and mass flows are calculated with the aid of the energy balance equations.

The temperature of the pinch-point on the water side can be determined using the saturation relation between pressure and temperature:

$$T_c = T_b = \text{saturation temperature } (P_a) \quad (4.22)$$

The pinch-point temperature on the gas side is

$$T_3 = T_b + \Delta T_{pp} \quad (4.23)$$

Similarly, the economiser outlet temperature is:

$$T_d = T_c - \Delta T_a \quad (4.24)$$

Therefore, the heat exchanged above the pinch is:

$$Q_{13} = (T_1 - T_3) c_{p,gas} W_{gas} \quad (4.25)$$

This amount of heat is captured by the water/steam circuit in the evaporator and superheater sections, so that, using the water and the steam enthalpy, the steam mass flow W_{steam} can be found:

$$W_{steam} = \frac{Q_{13}}{(h_a - h_d)} \quad (4.26)$$

The amount of heat exchanged below the pinch is given by the water side energy balance:

$$Q_{34} = Q_{ed} = W_{steam} (h_d - h_e) \quad (4.27)$$

This can give the stack temperature which is a very important parameter:

$$T_4 = T_3 - \frac{Q_{34}}{(c_p W_{gas})} \quad (4.28)$$

Knowing the steam mass flow W_{steam} by the Equation 4.26, the expansion in the steam turbine can be calculated with the following procedure: from the superheated steam temperature and pressure, the correspondent enthalpy h_a and entropy s_a can be estimated. Assuming an isentropic expansion and knowing the condenser pressure p_c ,

the corresponding isentropic outlet enthalpy $h_{o(is)}$ can be evaluated and thus the actual steam turbine output is:

$$Work_{st} = \Delta h_{st(is)} W_{steam} \eta_{st} \quad (4.29)$$

All temperature-dependent thermodynamic properties of gas turbine flue gases are calculated by considering them mixtures of ideal gases, with the same model used in VARIFLOW [140, 145]. In addition, both the thermodynamic and transport properties of water and steam are calculated with the aid of FLUIDPROP¹⁵ [155], a calculation routine, which has been adopted as a sub-programme of the main calculation routine.

The more complex systems (with two and three pressure levels) included in the current version of the steam plant simulation tool essentially make use of the model just described: they can be broken into several modules, each corresponding to a pressure level and composed of three heat exchangers, i.e. an economiser, an evaporator and a superheater.

4.4.1 Steam Plant Off-design Model

The equations necessary to describe the off-design behaviour of a single-pressure steam plant are here reported as they have been implemented in the current version of the steam plant simulation tool introduced in the previous section. It is assumed that the combined cycle power plant operates in sliding-pressure mode.

The energy balance for the superheater can be written as:

$$Q_{su} = UA_{su} \Delta T \ln_{su} \quad (4.30)$$

$$Q_{su} = W_{gas} (h_1 - h_2) \quad (4.31)$$

$$Q_{su} = W_{steam} (h_a - h_b) \quad (4.32)$$

The same set of equations applies for the evaporator (4.33-4.35) and for the economiser (4.36-4.38):

$$Q_{eva} = UA_{eva} \Delta T \ln_{eva} \quad (4.33)$$

$$Q_{eva} = W_{gas} (h_2 - h_3) \quad (4.34)$$

$$Q_{eva} = W_{steam} (h_b - h_d) \quad (4.35)$$

¹⁵ FluidProp implements models for the thermodynamic and transport properties of water and steam according to the IAPWS -IF97 industrial standard and documented in [156].

$$Q_{ec} = UA_{ec} \Delta Tln_{ec} \quad (4.36)$$

$$Q_{ec} = W_{gas} (h_3 - h_4) \quad (4.37)$$

$$Q_{ec} = W_{steam} (h_d - h_e) \quad (4.38)$$

These nine heat balance equations are completed by the saturation relation:

$$T_s = \text{saturation temperature } (P_d) \quad (4.39)$$

and by the Stodola choking relation at the steam turbine inlet:

$$\frac{W_{steam} \sqrt{T_a}}{P_a} = \text{constant} \cdot \text{steam turbine inlet area} \quad (4.40)$$

in which the right hand side is known from the design-point calculation.

The aforementioned equations constitute a system of 11 non-linear equations with the same number of unknown (i.d. P_a , T_s , T_d , T_a , T_2 , T_3 , T_4 , W_{steam} , Q_{sis} , Q_{eva} , Q_{ec}) which can be solved if the inlet conditions for the gas and the feed-water are known. The former is provided by the gas turbine performance simulation, whereas the latter derives essentially from the condenser off-design model (taking in account that the pump does not increase considerably the feed-water temperature). In the model implemented condensation pressure slides down to a minimum of 0.03 bar, keeping constant mass flow of refrigerated water. Further reductions of condenser thermal power are accommodated by decreasing the refrigerated flow rate. Therefore, an iterative procedure between condenser and steam turbine has been included.

This system of equations has been implemented in the current version of the steam plant simulation tool. As illustrated in the Figure 4.4, an attempt was made to solve sequentially the equations with some estimates and checks when an equation has one unknown variable at the time it has to be solved, as suggested by Dechamps [157]. The solving methods applied were the successive substitutions method and the Brent method [125, 158]. However, such solving strategies turn out to be not suitable because they did not reliably reach convergence.

After describing the model and tools developed for the performance analysis of the conventional combined cycle, the thermodynamic models of the advanced low-carbon power plants, which represent the ATRCC and the IRCC, are reported in the next paragraphs. The schematic diagrams for these two pre-combustion power plants are reported in Figure 3.17 and 3.18.

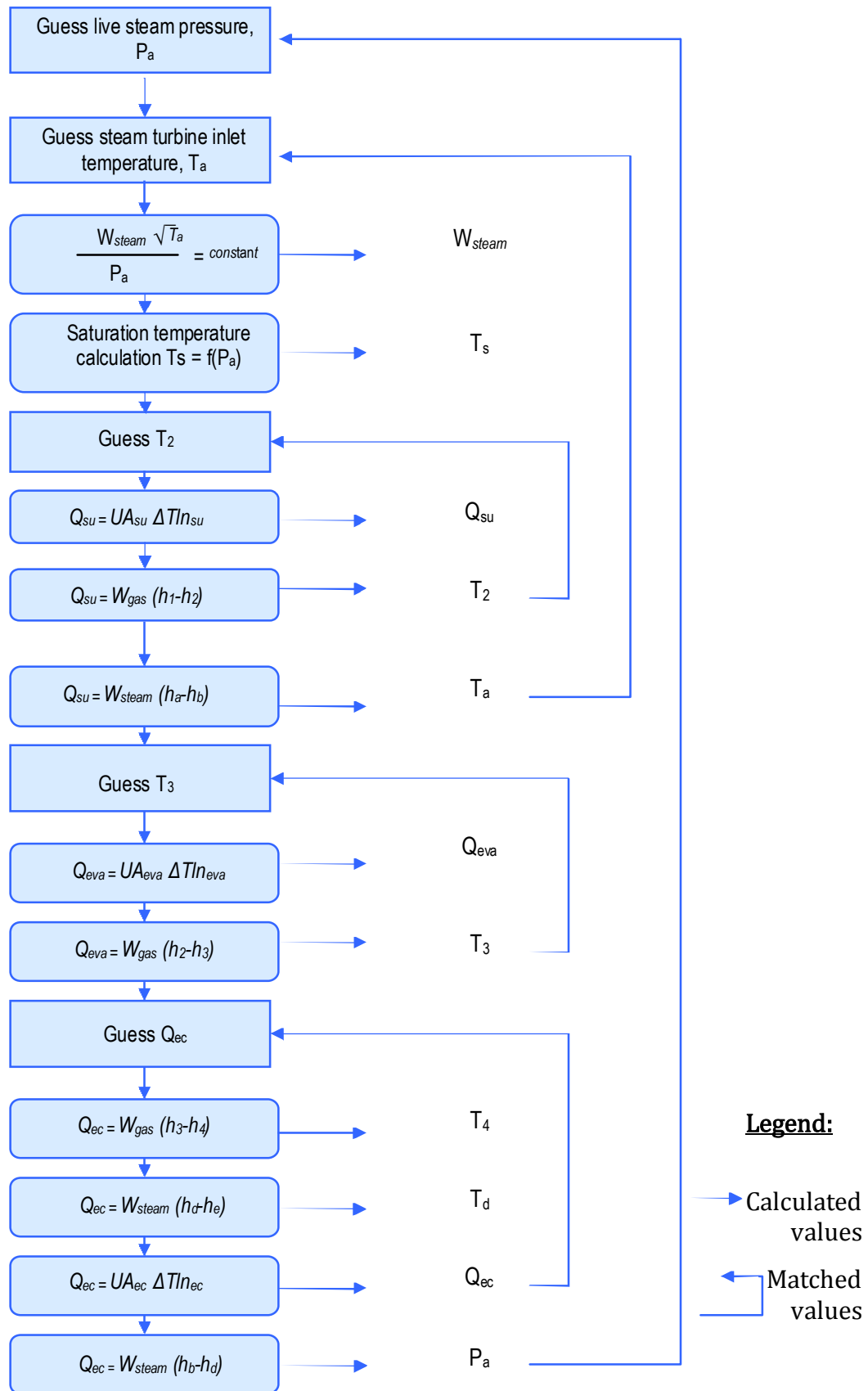


Figure 4.4 Off-design performance calculation (modified from [157])

4.5 The Auto-thermal Reforming Combined Cycle and the Integrated Reforming Combined Cycle

The reforming of natural gas involves a complex set of physical and chemical transformations. However, the gas composition downstream the ATR and the other reactors can be considered, with a satisfactory approximation, to be that resulting from chemical equilibrium [134, 135]. Therefore, a simplified chemical model based on chemical equilibrium of the main reactions which best represent the whole process has been implemented in collaboration with Ruggieri [121]. The low calorific value of fuel gas is also calculated.

4.5.1 Minimisation of Gibbs Free Energy

Generally speaking, the Gibbs free energy (G) is an important thermodynamic property, defined in terms of other thermodynamic properties, according to the equation [159]:

$$G = H - TS \quad (4.41)$$

The Gibbs free energy is a function of temperature, pressure and composition [159]:

$$G = G(P, T, n_i) = G(P, T, n_i^0 + \lambda) \quad (4.42)$$

where n_i and n_i^0 are the number of moles at equilibrium and the initial number of moles respectively, whereas λ is the reaction's degree of advancement.

Therefore its differential can be expressed as follows:

$$dG = \frac{\partial G}{\partial T} dT + \frac{\partial G}{\partial P} dP + \frac{\partial G}{\partial \lambda} d\lambda \quad (4.43)$$

If it is assumed that temperature and pressure are constant, as is possible for reactors under steady state conditions, then the previous equation becomes:

$$dG = \frac{\partial G}{\partial \lambda} d\lambda \quad (4.44)$$

From entropy considerations, it is understood that the equilibrium condition is achieved when the Gibbs free energy is at a minimum, therefore when dG is zero. In a broader view it can be stated that [159]:

- $\Delta G = 0$ suggests that the reaction is at equilibrium, so it has reached the minimum Gibbs energy;
- $\Delta G < 0$ suggests that the forward reaction is spontaneous;
- $\Delta G > 0$ suggests that the reverse reaction occurs spontaneously.

where Δ indicates still the variation of the Gibbs free energy with the reaction degree of advancement.

The variation of the Gibbs free energy can be expressed also as [159]:

$$\Delta G = \Delta G_R^0 + RT \ln k_{eq} \quad (4.45)$$

where k_{eq} is the equilibrium constant and ΔG_R^0 is the standard Gibbs free energy of reaction. The latter can be obtained using the following formula:

$$\Delta G_R^0 = \Delta H_R^0 - T\Delta S_R^0 \quad (4.46)$$

Hence the equilibrium condition $\Delta G = 0$ becomes:

$$\Delta G_R^0 = -RT \ln k_{eq} \quad (4.47)$$

From the previous relation the value of the equilibrium constant can be worked out. Such value needs to match the following one:

$$k_{eq} = \prod_i x_i^{v_i} \quad (4.48)$$

The values of the equilibrium constant obtained with equations 4.47 and 4.48 have to be equal. Such condition is achieved by changing the value of the degree of advancement of each reaction determining the equilibrium of each reaction and the outlet composition.

Furthermore, the thermal balance of the reactor needs to be verified. This balance is expressed by the following relation:

$$Q_{IN} - Q_{OUT} - Q_{Reactions} = 0 \quad (4.49)$$

where

$$Q_{IN} = c_{P_{in}} n_{tot_{in}} T_{in} \quad (4.50)$$

$$Q_{OUT} = c_{P_{out}} n_{tot_{out}} T_{out} \quad (4.51)$$

$$Q_{Reactions} = \sum_{i=1}^r \Delta H(T_{out})_i \lambda_i \quad (4.52)$$

In the equation 4.52 r indicates the number of reactions occurring in the reactor, assumed to occur at the outlet temperature T_{out} .

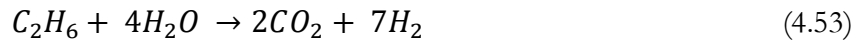
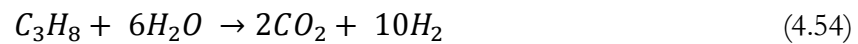
The set of equations 4.49 - 4.52 provides the thermal balance of the reactor as a function of the outlet temperature. Changing the outlet temperature of the reactor it is possible to impose the adiabaticity of the reactor. As the outlet temperature of the reactor is changed, the equilibrium condition has to be calculated again leading to different values of the reactions' degree of advancement. By means of an iterative procedure, the degrees of advancement of all the reactions involved and the outlet temperature is obtained so that the formers can satisfy the equations 4.47 and 4.48 and the latter the adiabaticity of the reactor being considered.

The minimization model of the aforementioned equations has been solved by using Microsoft Excel Spreadsheet's Solver feature [121], which applies the Generalized Reduced Gradient (GRG) method to solve nonlinear programming problems. This yields the composition and the temperature at outlet of the reactor being considered.

4.5.2 Syngas Production: Chemical Model of Pre-Reformer, Auto-Thermal Reformer and Water Gas Shift Reactors.

The reactions assumed to take place in the pre-reformer, in the auto-thermal reformer and in the water gas shift reactors are the following:

- Pre-reformer:



- ATR:



- Shift Reactors:



In the pre-reforming reactor the hydrocarbons heavier than methane are converted to protect against coking in the primary reformer according to the reactions 4.53 - 4.55. In accordance with the literature the third reaction can be discounted due to the low reactor exit temperature [130]. In the ATR reactor a combination of partial and total oxidation is considered to supply the required heat for the endothermic reaction of the steam reforming.

Most of the remaining CO is converted into CO₂ according to reaction 4.60. The conversion of the CO into CO₂ is assumed to occur in two reactors, a high temperature reactor and a low temperature one because of conversion rate and catalysts. To get a higher degree of such conversion two reactors are favourable compared to a one-reactor setup due to the exothermic nature of the reaction itself. Moreover more catalyst is required at the lower region of the temperature range [135]. Hence, the use of a standard catalyst at the higher temperature range and then a more active catalyst for the low end temperature in a separate reactor appears a good solution [135].

The chemical composition at each reactor outlet, along with the final temperature, is obtained using the procedure described in paragraph 4.5.1.

4.5.3 Capture of Carbon Dioxide

The model of the CO₂ capture system, within the cycle boundaries as established in the Chapter 3, is in this work limited to the following characteristics. The regeneration temperature and the MEA heat demand is kept constant (proportional to the mole-flow of captured CO₂). Given the composition of the inlet gas, the composition of the separated gases is calculated, as well as steam requirement for the regeneration of the amine solvent in the absorber.

The latter, to be bled from the steam turbine, leading to a reduction of the power produced in the expansion process, is calculated using the following expression, in accordance with [58]:

$$W_{steam} = \frac{H_{capture} W_{CO_2}}{bleed\ enthalpy} \quad (4.61)$$

$H_{capture}$ is the amine re-boiler steam requirement [58]. It is evident that the amount of steam required depends on the amount of CO₂ to compress and on the enthalpy at which it is bled.

4.5.4 CO₂ Compression

Most of the power cycles integrated with CO₂ capture result in CO₂ at atmospheric pressure saturated with water vapour, while others do it at above-atmospheric pressure. The same CO₂ dehydration and compression model has been used in all the calculations, by changing the input at the inlet conditions in case of different pressure.

The pressure to which CO₂ is compressed depends on how it will be transported and the nature of the storage reservoir. Four compressor stages including aftercoolers compress the CO₂ up to the critical pressure, while water is removed simultaneously in between the compression stages. Finally, the dense CO₂ is pumped up to the final pressure by the CO₂ delivery pump. The pressure ratio is equally distributed between the four compressor stages. The single stage pressure ratio is calculated with the following expression:

$$\pi_i = \pi^{N-1} \quad (4.62)$$

where N is the number of inter-refrigerated stages.

Assuming a polytropic efficiency for each stage, the temperature at each of the four compression stage outlets can be derived as:

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{(\gamma-1)/\gamma\eta_{poly}} \quad (4.63)$$

along with enthalpy of the CO₂ flow at each compressor exit. The calculation of the compression power therefore can be obtained as follows:

$$Work_{CO_2} = \sum_1^N W_{CO_2} \Delta h_i + v(P_{final} - P_{cr}) \quad (4.64)$$

where:

- W_{CO_2} is the carbon dioxide mass flow, obtained from the CO₂ separation unit;
- h_i is the enthalpy change in the i -th compression stage in kJ/kg;
- v is the specific volume at the critical pressure of CO₂ at 30°C;
- P_{final} is the final compression pressure obtained with a pump;
- P_{cr} is the critical pressure of the carbon dioxide, assumed to be the pressure at pump inlet.

The carbon dioxide compression process is estimated using the thermodynamic properties obtained from FluidProp¹⁶.

The plants do not all produce the same purity of CO₂. Some technologies inherently produce high purity CO₂ and others inherently produce lower purity CO₂, which has to be refined if a higher purity is required [66]. Some other components than CO₂ and H₂O can be present in the stream sent to storage. In the case of natural gas as fuel, these may comprise nitrogen, oxygen, argon, and nitrous oxides. Hence, it might be necessary to remove these components prior to transportation, as mentioned in the Chapter 3. It was found that purifying the CO₂ implies a power cycle efficiency reduction up to 0.4%-points and hence the effect on the overall efficiency has been neglected [58]. Therefore the presence of non condensable gases like N₂, H₂, Ar and O₂ and other impurities is not taken in account and not considered further in the present analysis.

4.5.5 Off-design operation of the auto-thermal reforming section

To take into account the off-design operation of the power plant it is necessary to consider the operation of the whole syngas production chain. It is possible to identify the following mass flows as input and output of the syngas production chain:

- natural gas fed to the pre-reformer, $\dot{W}_{ng}$
- steam fed to the pre-reformer, $\dot{W}_{pre}$
- air bled from the gas turbine compressor and fed to the auto-thermal reformer, $\dot{W}_c$
- syngas ready for the gas turbine combustion chamber, $\dot{W}_{syngas}$

For every off-design condition it is possible to calculate the fuel required by the gas turbine. It is assumed that the outlet to input ratio of the syngas production chain is constant as a result of mass balance. Knowing the required output from the syngas production chain, it is possible to know the input. All the mass flows listed above are expressed as a function of the air mass flow bled from the gas turbine compressor. Consequently, all the ratios between the air bleed and the other input to the syngas production chain are kept constant. Hence, all the flows are expressed as a function of the air bleed and are therefore linearly changing during the off-design operation. It

¹⁶ FluidProp provides thermodynamic and transport properties for some components, among which is the CO₂. These components can be used as pure fluids or in a mixture. Details of the theory and fluid data implemented in FluidProp can be found in [160-162].

is proper to underscore that the chemical composition of the syngas produced is assumed to be constant for every off-design condition.

The following equations are considered to describe the syngas production chain with reference to the assumptions enunciated:

$$W_{TOT} = W_{ng} + W_{pre} + W_c \quad (4.65)$$

$$\frac{W_{syngas}}{W_{TOT}} = k \quad (4.66)$$

$$W_{ng} + W_{pre} + W_c - \frac{W_{syngas}}{k} = 0 \quad (4.67)$$

During the off-design the amount of fuel required changes and, consequently, also the amount of air bled changes. Hence, it is necessary to perform an iterative loop to match the fuel flow necessary to obtain the required combustor outlet temperature (COT) for an air mass flow entering the combustion chamber. This iterative loop is implemented in VARIFLOW as reported in section 4.5.6.

4.5.6 Modification of VARIFLOW Code

The code originally developed for the baseline combined cycle, described in the paragraphs 4.2- 4.4, has been modified in order to take into account the composition of the synthesis gas derived from the decarbonisation section of the plant and the air extracted from the gas turbine compressor to feed the auto-thermal reformer. The models of the other components, reported in the previous paragraphs, have been included in the combined cycle simulation tool in order to close the thermodynamic balance of the whole plant. Such modifications have been accomplished according to the following steps.

The subroutine “LHV” has been modified implementing the following formula to enable VARIFLOW to calculate the lower heating value (LHV) for a fuel of any composition¹⁷, providing the molar composition and the molecular weight of the fuel being considered:

$$LHV = \sum_P x_P H_P^0 - \sum_R x_R H_R^0 \quad (4.68)$$

¹⁷ In this regard the original version of VARIFLOW code has a certain flexibility, as stated in the paragraph 4.2. However, the composition of fuels (natural gas, kerosene, a syngas from a biomass gasification process) and the relative LHV are fixed and saved in the subroutine LHV.

In the previous formula x is the molar fraction of each component, H^0 is the enthalpy of formation whereas the subscript P and R indicate respectively products and reactants. The molar composition of the syngas, as obtained from the chemical model described in paragraphs 4.5.1 and 4.5.2, is fed in the VARIFLOW code by means of a data file.

The second modification deals with the integration of the fuel treatment section with the gas turbine compressor. As at the combustor inlet less air is delivered, there is a lower fuel requirement to achieve the same combustor outlet temperature. On the other hand, as the fuel flow reduces, the air to be bled from the compressor reduces as well. Therefore, an iteration loop has been implemented in the subroutine “GASPWR1S” to perform a new calculation of the fuel flow for a given air bleed. The code calculates the air to fuel ratio at the combustor inlet and then the fuel flow. Subsequently, the equation 4.67 is applied. If the value obtained is not zero, the code calculates a new value of mass flow to be bled for the auto-thermal reformer. The calculation iterates until the convergence criterion is not satisfied.

A data file was introduced with all data regarding the other components as generated from the reforming section model developed in Excel based environment.

Four subroutines have been written and integrated in the main code:

- 1) The subroutine “SPECIFIC_HEAT” reports values of the specific heat of the syngas constituents at constant pressure for several ranges of the temperature. Through linear interpolations it provides the value of c_p researched as a function of the temperature.
- 2) The subroutine “CO₂_COMPRESSION” to implement the model for CO₂ compression reported in paragraph 4.5.4;
- 3) The subroutine “FUEL_COMPRESSION” to take into account the fuel compression work according to the following expression:

$$CW = \frac{W_{fuel} \times c_p \times T_{in} \times \left[\left(\frac{P_2}{P_1} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right]}{\eta_{comp}} \quad (4.69)$$

The work required by this compressor, according to this equation, clearly depends on the value of the pressure at the compressor outlet, on the temperature of the syngas, and especially on the amount of fuel that is necessary to compress. For the aim of

the present model it is assumed that the pressure at which the syngas is injected into the combustor is 20% higher than the combustor operating pressure.

- 4) The subroutine “STEAM” to evaluate the heat recuperated from the syngas cooling downstream the main reactors in the reforming section of the plant.

The steam plant model has been modified to take in account the steam extractions required by the reforming and the CO₂ capture processes, and the pre-heating of the process streams in the HRSG. Appendix C reports an example of the Input data file of the Performance Module.

4.6 Basis of plant assessments: Definitions of Work and Efficiency

The net efficiency of the combined cycle is here defined by the following equation:

$$\eta_{Net\ Plant} = \frac{Work_{Net\ Plant}}{W_f \times LHV} \quad (4.70)$$

where:

$Work_{Net\ Plant}$ = net plant work

$\eta_{Net\ Plant}$ = net plant efficiency

W_f = fuel flow rate

LHV = lower heating value

The net plant work is calculated according to the following:

$$Work_{Net\ Plant} = (Work_{GT} + Work_{SP})\eta_g - \sum Work_{consumers} \quad (4.71)$$

where:

$Work_{GT}$ = net gas turbine work

$Work_{SP}$ = steam plant work

η_g = generator efficiency

$Work_{consumers}$ = Work related to consumers as auxiliaries, CO₂ compression and so on.

4.7 Results and Discussion

This paragraph reports the results obtained for the three case studies of this investigation by applying the models described in the first part of the chapter. Before proceeding with presentation and discussion of such results, a preliminary validation of the Performance Module is firstly shown.

In order to validate the model implemented in the Performance Module for analysing the performance of combined cycle power plants, a single pressure combined cycle power plant has been simulated using the Performance Module and GTPRO. The main results derived from the simulations set are then compared. The input data to accomplish this validation are reported in Table 4-1, whereas the overall results from both codes (Performance Module and GTPRO) are presented in Table 4-2. The results obtained are quite promising, diverging only slightly from the commercial software ones. Such results, with differences in the main output parameters lower than 2%, provide a demonstration of the satisfactoriness of the whole model developed and implemented in the Performance Module.

Table 4-1 *Input data for validation of the Performance Module*

INPUT DATA			
Parameter [Unit]	GT PRO	Performance Module	Δ (%)
W_1 [kg/s]	647.7	647.7	0
PR [-]	15.8	15.8	0
$\eta_{\infty,c}$ [%]	-	89	-
Compressor Bleed Air [%]	-	10	-
$\Delta P_{0-1}/P_0$ [%]	1	1	0
COT [K]	1600	1600	0
ΔP_{3-4} [%]	-	6	-
$\eta_{\infty,t}$ [%]	-	88.5	-
Steam Pressure [bar]	70	70	0
Condenser Pressure [bar]	0.05	0.05	0
Steam Temperature [K]	833	833	0
ΔT_{pp} [K]	10	10	0
$\Delta T_{sup,a}$ [K]	20	20	0
ΔT_a [K]	2.8	2.8	0
$\eta_{is,t}$ [%]	90	90	0
$\eta_{is,pump}$ [%]	85	85	0
Inlet Cooling Water T [K]	284	284	0
Cooling Water T Rise [K]	10	10	0
Generator Eff. [%]	98.5	98.5	0

Table 4-2 Comparison of performance results (Performance Module and GT PRO)

RESULTS			
Parameter [Unit]	GT PRO	Performance Module	Δ (%)
Power [MW]	385	389	1.04
η_{th} [%]	55	55.9	1.6
Stack Temperature [K]	415	412.2	0.67

The assumptions used for evaluating the energy balance and thus predicting the on-design performance of the conventional combined cycle designated as baseline of this investigation are reported in Table 4-3. As anticipated in the Chapter 3, the power section is based on a heavy-duty gas turbine of the technology referred as “FA”. In particular, the gas turbine model is the MS9001FA characterised by pressure ratio 17, air flow of 641 kg/s and power output of 255 MW [163]. The steam cycle presents one pressure level with steam pressure of 70 bar and condensing pressure of 0.05 bar. The net efficiency and the power output of the reference combined cycle - without any CO₂ removal technique – display a value of 55.7% and 378.6 MW respectively.

The main assumptions for calculating the on-design performance are kept unmodified for the advanced plants configurations here analysed, based on the same gas turbine engine and the same steam plant of the reference combined cycle.

The additional assumptions used in the performance simulations of the ATRCC and the IRCC are summarised in Table 4-4 as derived from the information available in the public literature [129, 130, 135, 164].

Among the parameters reported in Table 4-4 the value selected for the steam-to-carbon ratio (S/C) requires a comment. The selection of this value is, as matter of fact, quite questionable due to its conflicting effects on the pre-combustion power plant’s behaviour. The rate of conversion of CH₄ in the auto-thermal reformer and the rate of conversion of CO to CO₂ in the shift reactors are favoured by elevated steam concentration in the syngas, which would imply a high S/C ratio. On the other hand, high steam consumption is damaging to the cycle efficiency and power output because of the correspondent steam cycle power loss. The selected value of 2.5 kg of steam per kg of natural gas has been stipulated as good compromise between the two contradictive features, even if further investigation would be greatly beneficial to appreciate the best compromise between thermodynamic efficiency and elevated CO₂ removal.

Table 4-3 *Conventional power plant assumptions*

GAS TURBINE		
Parameter	Unit	Value
M_2		0.45
M_{3f}		0.10
M_5		1.00
M_8		0.25
$\Delta P_{0-1}/P_0$	[%]	3
W_1	[kg/s]	641
PR	[-]	17
$\eta_{\infty,c}$	[%]	90.8
$W_{cooling}$	[%]	12
ΔP_{3-4}	[%]	6
η_{comb}	[-]	1
COT	[K]	1610
$\eta_{\infty,t}$	[%]	87
STEAM PLANT		
Parameter	Unit	Value
Steam Pressure	[bar]	70
Condenser Pressure	[bar]	0.05
Steam Temperature	[K]	833
ΔT_{pp}	[K]	10
$\Delta T_{sup,a}$	[K]	30
ΔT_a	[K]	5
$\eta_{is,t}$	[%]	90
$\eta_{is,pump}$	[%]	85
AUXILIARIES		
Parameter	Unit	Value
Generator Mechanical Efficiency	[%]	98.5

Table 4-4 *Assumptions for ATRCC and IRCC*

ATRCC & IRCC		
Parameter	Unit	Value
CO ₂ Critical pressure	[bar]	74.64
Final CO ₂ Pressure	[bar]	150
CO ₂ compressor stages	[-]	4
CO ₂ compressor $\eta_{\infty,c}$	[%]	80
CO ₂ compression intercooler temp.	[K]	303
Carbon-to-Steam Ratio	[-]	2.5
Carbon capture effectiveness	[%]	90
ATR operating pressure	[bar]	15
Decarbonisation reactors pressure drop	[bar]	0.5
Fuel temperature	[K]	278
Steam turbine pressure first extraction	[bar]	20
Steam turbine pressure second extraction	[bar]	4
Absorber outlet pressure	[bar]	1.05
Stripper outlet pressure	[bar]	1.5
Amine re-boiler steam requirement	[M]/kg CO ₂	3.4
Fuel compressor $\eta_{is,c}$	[%]	87

The inlet temperature for the pre-reformer is assumed as 773 K and for the ATR as 873 K. The inlet temperatures for HTS and LTS are fixed to 673 K and 473 K respectively. The outlet temperatures, calculated according to the thermodynamic model described in paragraphs 4.5.1 and 4.5.2, are shown in Table 4-5: in particular, the estimated ATR exit temperature results in a value of 1163 K that slots in the range found in the literature and is below the maximum temperature imposed by the current state-of-the-art materials [130, 135, 165].

Table 4-5 *Inlet and outlet temperatures of each reactor in the fuel treatment section of the ATRCC and IRCC*

Reactor	Inlet Temperature [K]	Outlet Temperature [K]
Pre-reformer	773	726.96
Auto-thermal reformer	873	1163
HTGS	673	717.47
LTGS	473	471.84

From the data listed in Table 4-6 the variation of the syngas chemical composition after each step in the decarbonisation process, from the reforming to the final composition after the carbon dioxide sequestration, is clear. In particular, it is evident how the H₂ yield - the molar percentage of H₂ in the reformat stream - increases during the whole process, whereas the CO yield - the molar percentage of CO in the reformat stream - reduces in the two water gas shift reactors.

Table 4-6 *Composition of the syngas produced after each step of the decarbonisation process*

Species	Natural Gas [%vol]	Pre-R Outlet [%vol]	ATR Outlet [%vol]	HTGS Outlet [%vol]	LTGS Outlet [%vol]	Final Comp. [%vol]	Final Comp [129, 130, 135] [%vol]
CH ₄	0.94	23.91	1.53	1.53	1.53	2.35	0.11-0.8
C ₂ H ₆	0	0.00	0.00	0.00	0.00	0.00	0.00
C ₃ H ₈	0.043	0.00	0.00	0.00	0.00	0.00	0.00
N ₂	0.015	0.38	27.26	27.26	27.26	41.90	40.8-45.6
O ₂	0	0.00	0.00	0.00	0.00	0.00	0.00
H ₂ O	0	61.41	32.48	26.49	24.55	1.13	0.19-0.8
H ₂	0	10.96	26.25	32.24	34.18	52.53	52.3-56
CO	0	0.00	8.04	2.04	0.12	0.18	0.3-0.4
CO ₂	0.002	3.33	4.43	10.44	12.36	1.91	0.64-2.0

Calorific Value = 10.2MJ/kg SFT¹⁸ = 2347 K

The syngas fed to the combustion chamber is characterised by a hydrogen content of 52.53 vol% with about 41.90 vol% of nitrogen. The calorific value of the final syngas is about 10.2 MJ/kg, since this syngas is essentially made up of H₂, which is characterised by LHV of 10.8 MJ/kg (versus 35.8 MJ/kg of CH₄), and a considerably amount of inerts (N₂, CO₂, H₂O). Hence, the fuel flow would result to be much higher than for a natural gas case, assuming the same compressor operating conditions and the same COT. The values reported in terms of hydrogen molar fraction and lower heating value are well aligned with some data available in the literature. The molar fraction obtained can be compared to the range of values indicated in other studies [129, 130, 135] and reported in the last column of Table 4-6. It could be argued that a comparison among the final compositions can not be appropriate since these compositions depend on the CO₂ capture effectiveness. Indeed, the comparison at any stage of the pre-combustion section can not be considered exhaustive since the final values depend on many assumptions (temperature and pressure, composition of natural gas, configuration of the fuel treatment plant). On the other hand, it was not possible to reproduce the values

¹⁸ More information about the Stoichiometric Flame Temperature (SFT) can be found in Chapter 5.

available in the literature using the model developed for the present study due to the lack of information about input data and operating parameters. However, the public literature provides ranges of values that can be used as a first validation of the model developed. The comparison with the data available in the public domain shows that the results obtained from the current version of the model are quite encouraging: it is possible, in fact, to note a good agreement of the values calculated for the different species considered and the data obtained from the literature. In particular, the hydrogen content in the syngas seems to be fairly well predicted, whereas the methane conversion appears to be slightly underestimated. However, the main purpose of the analysis reported in this chapter (obtaining fundamental insights into such power plants behaviour), combined with the breadth of the whole investigation, has led to assume that such a model is reasonably adequate for this first stage of the T.E.R.A. implementation.

Table 4-7 reports the main results of the on-design overall performance as resulting from the heat and mass balances of the plant: it presents a comparison of the two different concepts with CO₂ capture being investigated and the conventional combined cycle. Such comparison shows that the cases with fuel decarbonisation, as expected, result in efficiencies well below that of the conventional combined cycle. The ATRCC with removal of CO₂ presents a net efficiency of 37 %, which corresponds to a reduction of about 19%-points with reference to the baseline. The net efficiency of the IRCC is about 11 percentage points lower than for the conventional combined cycle. Figures 4.5-4.6 are a graphical presentation of the main performance results.

Table 4-7 *Main results for the three case studies*

Main Results	Baseline	ATRCC	IRCC
Natural gas LHV Input [MW]	679.7	821.72	821.72
GT Power output [MW]	256.5	260.4	260.4
ST Power output [MW]	122.1	71.5	132.22
Fuel compression [MW]	-	10.7	10.7
CO ₂ compression [MW]	-	16.4	16.4
Net power output [MW]	378.6	304.8	365.5
Net efficiency [%]	55.7	37.0	44.4

The factors which contribute to the efficiency and power output reductions for the CO₂ capture power plants are summarised and commented on in the following.

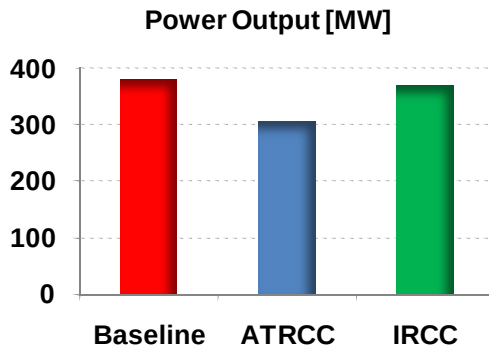


Figure 4.5 Power output of the three case studies

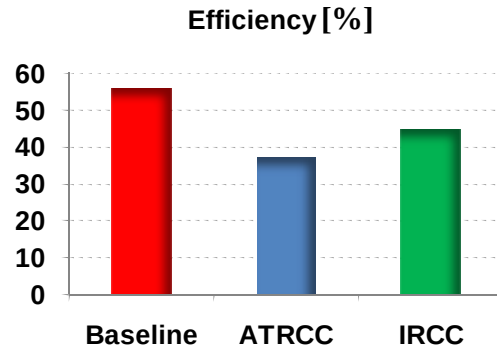


Figure 4.6 Net efficiency of the three case studies

The use of hydrogen –rich fuel gas in the two plants with CO₂ capture has important impacts on the combined cycle performance. Among them is the higher steam concentration in the expansion gas, which implies an enhancement of the c_p and thus in the enthalpy drop. The power output of the gas turbine is slightly increased compared to the conventional combined cycle. The air required by the fuel treatment process is assumed to be bled from the gas turbine compressor. Without bleed, the very large fuel flow (due to the reduced LHV) would enhance significantly the turbine flow and the power production (calling for a larger turbine nozzle area). The higher steam concentration in the expansion gas increases also the rate of heat transfer to the turbine blades. It is argued that the combustor outlet temperature has to be reduced [166], in order to maintain the same blade temperature. The rationale underlying this strategy is that “the same lifetime of a machine running on natural gas can be preserved in hydrogen operations by maintaining the same maximum metal temperature” [166]. Without such a reduction, the O&M costs, along with the availability of the whole plant, can be affected.

The steam turbine cycle shows the consequences of the extended interactions with the decarbonisation process. A considerable amount of the heat recoverable from the gas turbine exhaust is used for heating the streams to the fuel treatment sections (pre-reforming streams and reforming streams), thereby reducing the production of steam. Moreover, the steam turbine presents extractions of steam along the expansion path, which diminish its performance. On the other hand, heat is removed by steam production between reactors in the decarbonisation sector of the plant (due to the exothermic nature of the water gas shift reactions).

Compared to the IRCC case, the power balance of the ATRCC shows a similar gas turbine performance but a severe reduction of the steam turbine output. This difference is due to the fact that the steam produced by syngas cooling between the reactors and available at the turbine admission is much less compared to the IRCC case, since it is partially exploited in the ATR process. Furthermore, a lower

preheating inlet temperature of the natural gas in the HRSG implies more heat required to reach the desired temperature at the inlet of the pre-reformer reactor.

In the IRCC, even if a large steam extraction is needed for the amine regeneration (42.6 kg/s) and for the ATR process (45.6 kg/s), a relevant high pressure steam flow comes from the high temperature recovery from syngas (76.78 kg/s): the steam mass flow at turbine admission is therefore as large as 128 kg/s versus 97 kg/s of the reference combined cycle, resulting in a larger power output compared to the conventional combined cycle.

To appreciate the variations occurring in the HRSGs, Figures 4.7 – 4.9 display the on-design temperature profiles. In the IRCC case the temperature of the flue gases at the outlet of the HRSG is significantly lower than that of the conventional combined cycle and the ATR combined cycle. Compared to the conventional power plant, such reduction in the stack temperature can be attributed to the lower exhaust gases temperature, whereas compared to the ATRCC is due to the higher steam mass flow generated, and therefore to the much higher thermal power recovered from the flue gas in the HRSG. However, it is worth noting that the stack temperature needs to be above the dew point of the stack gases otherwise condensation of acid gases could occur on the tube with subsequent corrosion. The dew point is function of the water content and of sulphur content. The natural gas composition used in these simulations does not contain any sulphur but the flue gas will be characterised by a large quantity of water due to the high percentage of H_2 in the syngas. The water dew point of gas turbine exhaust gas is typically around 313.15 K, which is below the values estimated for the two advanced schemes being considered.

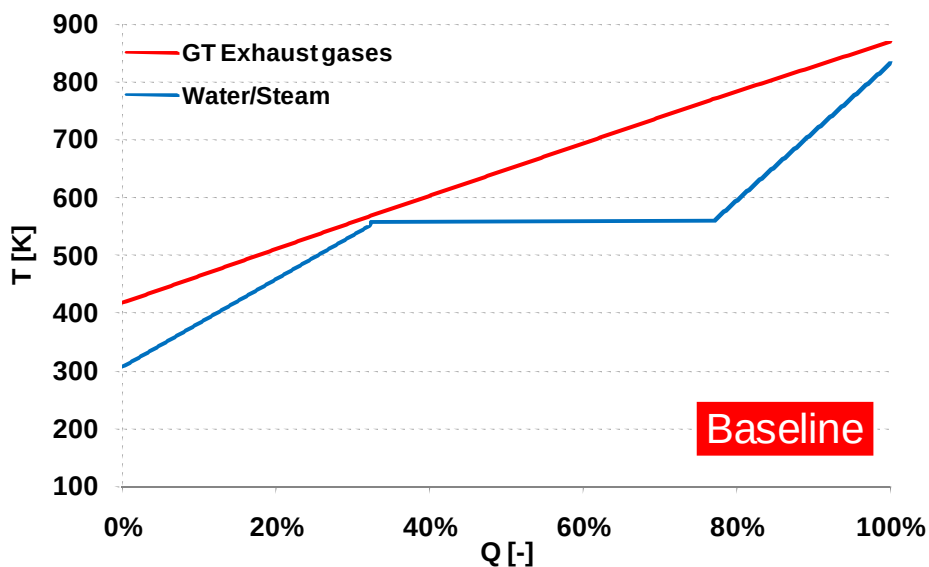
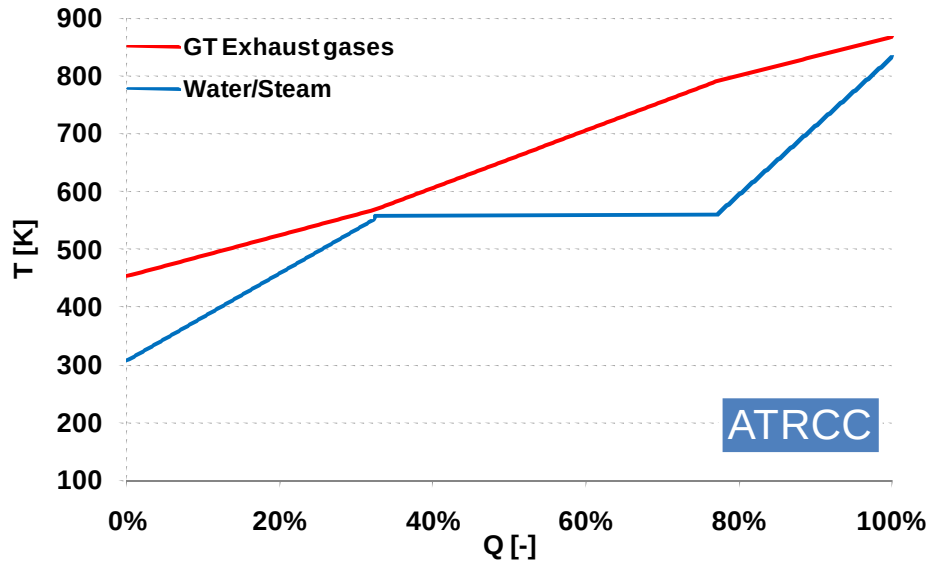
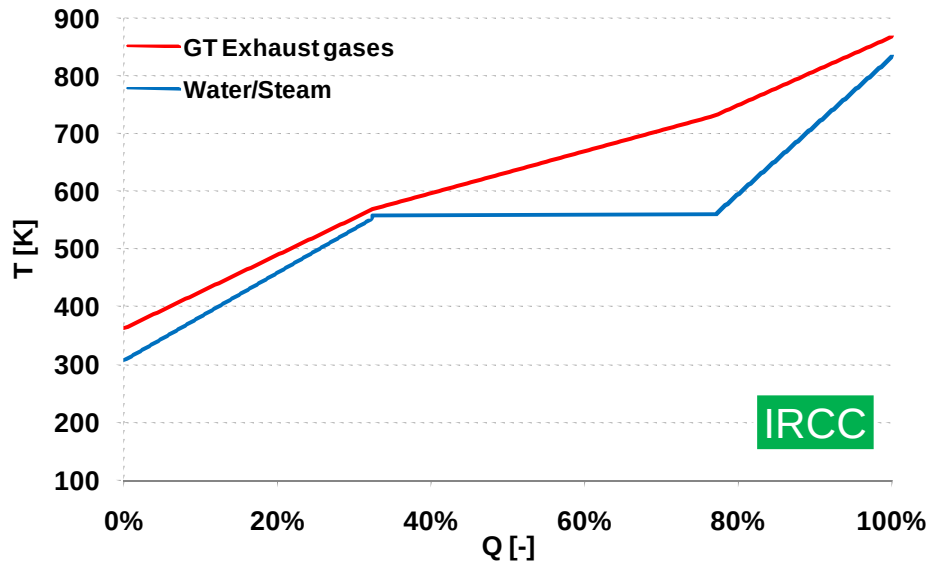


Figure 4.7 T - Q diagram for the conventional combined cycle

Figure 4.8 T - Q diagram for the ATRCCFigure 4.9 T - Q diagram for the IRCC

Large power consumption is caused by the CO_2 compression and by the hydrogen compressor. The CO_2 compression consumption is quite significant (16.4 MW) due to the operating pressure assumed equal to the atmospheric one. The not negligible power demand from the syngas compression (10.7 MW) is due to its large volumetric flow and its different properties compared to the natural gas case. As a matter of fact, the heat capacity ratio of the syngas is higher than the natural gas one:

$$\gamma_{syngas} > \gamma_{NG} \quad (4.72)$$

The relation (4.73) implies that:

$$\left(\frac{\gamma}{\gamma-1}\right)_{syngas} > \left(\frac{\gamma}{\gamma-1}\right)_{NG} \quad (4.73)$$

Therefore, for the same pressure ratio it derives that:

$$\left(\frac{T_2}{T_1}\right)_{syngas} > \left(\frac{T_2}{T_1}\right)_{NG} \quad (4.74)$$

which will bring about an increase in the compressor work.

Despite the efforts of the author, it was not possible to completely validate the results estimated for the two advanced low-carbon power plants. The configuration of the IRCC scheme considered in this investigation is similar to those reported in two studies carried out by SINTEF and NTNU [130, 135]: the analysis performed by Andersen et al. [130] provides a net efficiency of about 47% and a power output of about 400 MW, while the one carried out by Nord [135] shows a net efficiency of about 42% and a power output of about 360 MW. However, a direct comparison with these results can not be performed due to the substantial differences of the layout investigated, along with the computational assumptions and input data not completely available. Andersen considered a more advanced steam turbine cycle (three pressure levels with reheat and supplementary firing) and not extractions from steam turbine for the regeneration of CO₂ capture solvent. Nord considered an IRCC with a partial integration of the GT compressor with the reforming section and a three level pressures steam plant, and he stipulated a reduction of the COT by 30 K.

Simulations of this type are, to a large extent, dependent on the choice of assumptions regarding the additional components that any CO₂ capture process includes, whose performance should be fairly realistic. In this way an advanced low-carbon power cycle can be compared to a conventional cycle. However, the sparse availability of real experimental data on operation of such systems may result in unrealistic assumptions. That may result in simulations becoming prone to errors, unrealistic and idealised with regard to the possible downsides of CO₂ capture power plants. Nevertheless, for the analysis of power processes with CO₂ capture modelling and simulation play a vital role: simulation results help setting ‘benchmarks’ for component development, as they indicate reaction temperatures, conversion rates and operating conditions at which reasonable cycle efficiencies can be achieved.

Moreover, they add value to CO₂ capture-research by indicating the challenges in tailoring such advanced systems toward state-of-the-art power plant machinery.

CHAPTER 5

ENVIRONMENTAL ANALYSIS

In Chapter 4 it was shown that advanced low-carbon power plants cannot be attractive and competitive from the performance point of view alone. The T.E.R.A. approach provides for the appraisal of the environmental impact so as to include it as another criterion in the decision-making process on future investments. This investigation is aimed at assessing different advanced low-carbon power plants. Hence, the environmental impact does, indeed, play an important role in the selection of the type of power plant. The environmental analysis of the power plants being considered in the present investigation centres on the emissions of carbon dioxide. The amount of carbon dioxide emitted by each power plant is evaluated and compared with each other. Apart from a preliminary assessment of NO_x emissions, no alteration to the statutory emission limits for other compounds are assumed or foreseen.

5.1 Pollutant Emissions

Several pollutants are emitted by combined cycle power units. Such emissions arise from the combustion process occurring either in the gas turbine engine itself, or in the duct burners that are typically located in the HRSG [127]. The emissions produced in combined cycle applications, as in the cases herein considered, include carbon dioxide (CO₂), water vapor (H₂O), and others designated as criteria pollutants like carbon monoxide (CO), unburned hydrocarbons (UHC), particulate matter (PM), oxides of nitrogen (NO_x) and oxides of sulfur (SO_x). The negative effects of such pollutants are summarized in Table 5-1. Their concentration in the exhaust gases is function of the firing temperature, the composition of the fuel, the type of equipment being used and the time and the species' concentration in the combustor.

Carbon monoxide is dangerous since it reduces the capacity of the blood to absorb oxygen and is higher at low power conditions along with unburned hydrocarbons. The CO emissions are higher than the amount predicted by equilibrium calculation. A large amount of CO, in fact, derives from incomplete combustion of the fuel due to several reasons: low fuel-air ratio, short residence time and poor mixing of fuel and air are some of them. On the other hand, the UHC are associated with poor fuel/air mixing, inadequate burning rates or the chilling effect of film cooling air (which is however a major source of CO) [167]. The amounts of CO and UHC emitted are strongly dependent in a complex way on several engine parameters such as equivalence ratio, pressure, compressor delivery temperature, combustor wall cooling air and fuel preparation.

Table 5-1 *Main pollutant emissions produced by gas turbines* [167]

Pollutant	Effect
Carbon Monoxide (C)	Toxic
Unburned hydrocarbons (UHC)	Toxic
Particulate matter (PM)	Visible
Oxides of nitrogen (NO _x)	Toxic, precursor of chemical smog, depletion of ozone in stratosphere
Oxides of sulphur (SO _x)	Toxic, corrosive

Exhaust smoke derives from the finely-divided soot particles that are produced in fuel-rich regions of the flame. Part of it is consumed in the secondary zone while the remaining stays in the stream. Smoke is mainly formed by carbon up to 96% and because it is not a product of equilibrium combustion it is very difficult to predict its final concentration.

Other pollutants that are formed during combustion are represented by NO_x. The two main products that compose NO_x emissions are NO₂ and NO. There are four mechanisms that explain their formation [167]: Thermal NO, Nitrous Oxide N₂O,

Prompt NO and Fuel NO. Most of the NO_x emissions are produced with the first mechanism which is the oxidation of nitrogen present in the comburent air in high temperature areas of the flame and is based on the Zeldovich mechanism [167]. NO_x is toxic, contributes to the formation of chemical smog, and enhances the depletion of ozone in the stratosphere. Together with smoke¹⁹ the amount is higher at a higher temperature therefore at high power conditions. The NO_x formation is strongly affected by the combustor inlet temperature, the residence time, the pressure and the fuel atomization.

The chemical reactions governing the formation of these pollutants are quite complex. Various correlations have been proposed and validated and serve as a very useful means of predicting emissions from gas turbines. More precisely, there are three different strategies for predicting emissions from gas turbine engines [168]: empirical correlations, stirred reactor models and extended numerical simulations involving detailed Computational Fluid Dynamics (CFD) calculations. Concerning this, a model has been developed in collaboration with Samaras [169], by applying the second approach. The model has been essentially aimed to predict the pollutant emission trends from industrial gas turbines, since accurate predictions of their concentrations cannot be reached without experimental data (which are available for the conventional gas turbine case but not for all the advanced cycle being considered). Such model is based on the idea of simulating the various combustor zones using different types of stirred reactors, incorporating the processes of mixing, combustion heat release and pollutants formation [170]. A stochastic representation of turbulent mixing has been included in order to allow for various inhomogeneities in gas composition and temperature [170]. The model is not complete and has not been integrated into the T.E.R.A Framework.

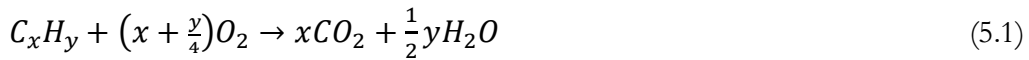
Carbon dioxide and water, which are the natural consequence of combustion, have never been considered as pollutants. Although over the last few years attention has always concentrated on pollutants related to human health hazards, emissions of carbon dioxide, a greenhouse gas thought to be responsible for global warming, are currently at the heart of the climate change challenge. Carbon dioxide emissions are not regulated at the moment but there is increasing momentum for establishing its reduction through a regulatory mechanism. This remark, together with the aforementioned incompleteness of the Emission Module, has led to narrowing the environmental analysis down only to the CO₂ emissions evaluation.

Even if partial, the results obtained can be used, however, as a guideline for an introductory environmental assessment.

¹⁹ In the case of gaseous fuels the amount of smoke produced will be not significant.

5.2 CO₂ Emissions

The CO₂ emissions are the result of the complete oxidation of the carbon present in the fuel. The prediction of CO₂ is relatively straightforward. In the case of the conventional combined cycle chosen as baseline of the analysis, knowing the carbon-hydrogen ratio of the fuel and assuming a complete oxidation of the fuel, the CO₂ emissions can be readily calculated according to the following equation [171]:



where

x/y is the carbon-hydrogen atomic ratio of the fuel.

In the case of ATRCC and the IRCC, the CO₂ emission evaluation takes into account the carbon dioxide not sequestered in the amine absorber²⁰ and the oxidation of methane and carbon monoxide contained in the syngas fed to the gas turbine combustion chamber.

A computer-based routine was written by the author in Fortran 90 to implement the aforementioned CO₂ evaluation model. Although this program represents a very preliminary version of the Emissions Module inside the T.E.R.A. Framework, it allows the analysis to proceed and to lay the foundations of the general structure of the Framework itself. Using data from the Performance Module (power output, composition of fuel, fuel flow) the Emissions Module evaluates for all case studies under consideration carbon dioxide emissions for unit of electricity produced (see Appendix C for example of Input data file). Such results are then stored in a data file, ready for the subsequent analysis performed by means of the Economic Module.

5.3 NO_x Emissions

The single most important factor affecting the formation of NO_x is the flame temperature. This is, theoretically, a maximum at stoichiometric conditions and will fall off at both rich and lean mixtures. Unfortunately, while NO_x could be reduced by operating well away from stoichiometric, this results in increasing formation of both CO and UHC. The formation of NO_x is slightly dependent on the residence time of the fluid in the combustor; an increase in residence time, however, has a favorable effect on reducing both CO and UHC emissions. The rate of formation of NO_x varies exponentially with the flame temperature, so the key to reducing NO_x is the

²⁰ This amount of carbon dioxide has been evaluated according to the model described in paragraph 4.5.2.

reduction of the flame temperature. There are, basically, three major methods of minimizing emissions: water or steam injection into the combustor, selective catalytic reduction and dry low NO_x (so-called because no water is involved) [167].

Being a major parameter of the various reactions describing NO_x formation, the flame temperature can also be considered a good indicator of the NO_x emissions when comparing different fuels²¹ [172].

The NO_x emissions are of great importance in the case of pre-combustion cycles. It is understood that hydrogen-rich fuel combustion with air brings about an unacceptable level of NO formation because of the higher flame temperature [166, 172, 173].

In light of these remarks, a preliminary evaluation of the SFT (Stoichiometric Flame Temperature) is performed for the ATRCC and the IRCC cases. Assuming that the combustion process is complete, in the absence of any external heat transfer, all the energy deriving from the combustion reactions brings about an increase in the temperature of the gas stream. For the energy balance during the combustion process to be respected, the following equation needs to be satisfied [159]:

$$\sum_i (\Delta h_i^0 + \Delta h_{T,i})_{Reactants} = \sum_j (\Delta h_j^0 + \Delta h_{T,j})_{Products} \quad (5.2)$$

In the equation 5.2 Δh^0 indicates the enthalpy of formation, Δh_T is the variation of enthalpy associated with the temperature above the reference value, i indicates the generic reactant whereas j indicates the generic product. In the equation 5.2 the right hand side is dependent on temperature and therefore is unknown, while the left hand side can easily be evaluated. Therefore, by an iterative calculation, which has been implemented in Excel, the SFT can be obtained as the solution of the equation 5.2 (e.g. see [122]). The chart shown in Figure 5.1 can then be used to appreciate whether or not the NO_x level falls within the allowable limits for industrial gas turbines. Figure 5.1 shows, in fact, an empirical relation between stoichiometric flame temperature and NO_x emission for gas turbine combustion with different fuels and steam and nitrogen dilution (nitrogen is the balance gas for data at 56% and 95% hydrogen fuel) [173]. It relies on the interpretation of the experimental results of Todd and Battista [173] which demonstrated that pure hydrogen combustion in typical gas turbine applications presents NO_x emission in the range of 600-800 ppmvd (15% O₂) with a stoichiometric flame temperature of 2700 K and that to

²¹ For the same air flow and fuel flow to a combustor, NO_x production is also determined by other factors, such as combustor design technology, air and fuel distribution and so on. Such factors have not been considered in this preliminary assessment of NO_x emissions.

achieve an acceptable emission in the range of 20-40 ppmvd SFT must be reduced to 2250-2350 K by nitrogen or steam dilution of the fuel [173].

Therefore, in this investigation, a SFT of 2350 K has been assumed as the reference value for an acceptable NO_x emission in the range of 25-50 ppmvd [173].

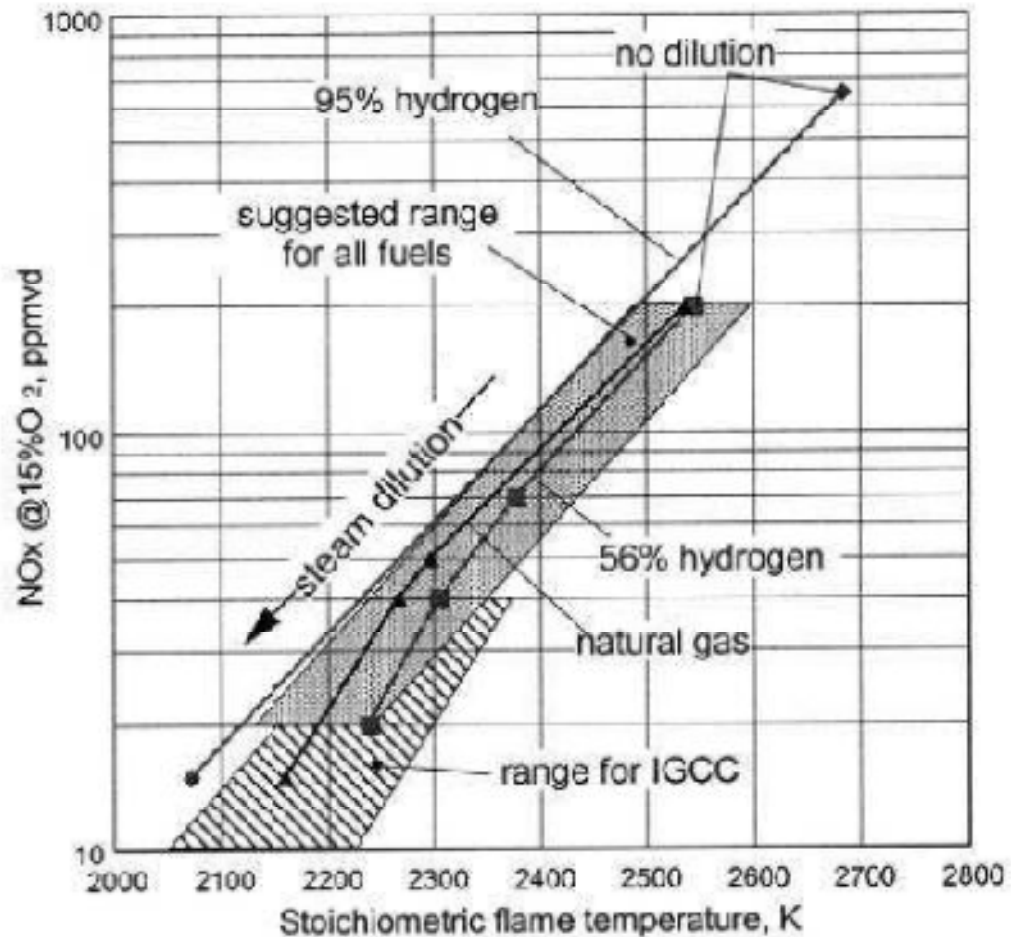


Figure 5.1 NO_x emission for different adiabatic flame temperatures [173]

5.4 Results and Discussion

The comparison of the carbon dioxide emission rates relative to the baseline combined cycle and two pre-combustion cycles is shown in Figure 5.2. The overwhelming superiority of the advanced power plants over the conventional one in the environmental performance - in terms of CO_2 emissions reduction - is quite clear: for the on-design case 361 g/kWh, 64 g/kWh and 53 g/kWh represent the

emission of carbon dioxide for the conventional combined cycle, the ATR combined cycle and the integrated reforming combined cycle respectively.

As a consequence of the reduced thermal efficiency, as explained in Chapter 4, the ATRCC and the IRCC produce much more CO₂ than the conventional combined cycle. However, thanks to the CO₂ capture technology the 90% of this carbon dioxide is removed, resulting in a significantly reduced CO₂ release level.

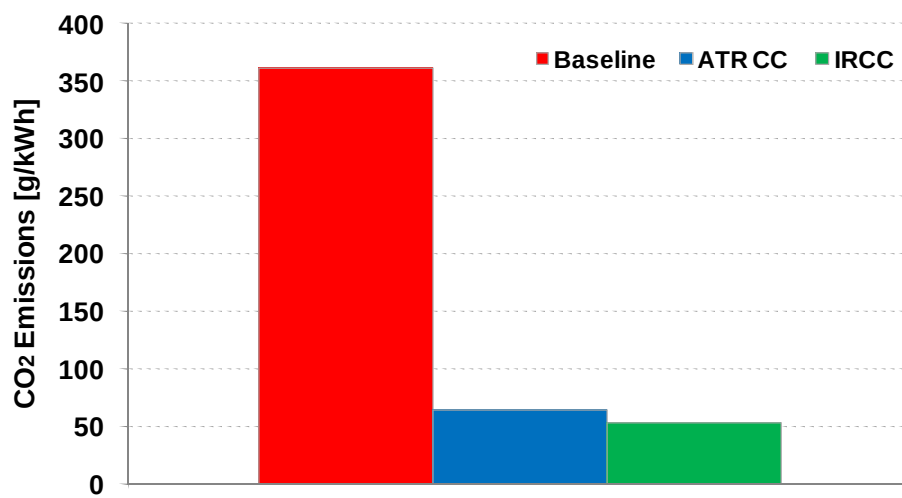


Figure 5.2 Carbon dioxide emissions for the power plants analysed

Figures 5.3 and 5.4 illustrate graphically for the ATRCC and for the IRCC the difference between the carbon dioxide *captured* and the carbon dioxide *avoided* with reference to the conventional combined cycle chosen as the baseline²². In the light of the previous comments, the carbon dioxide avoided (297 g/kWh for the ATRCC and 307 g/kWh for the IRCC) is lower than the removed one (435 g/kWh and 363 g/kWh), with such a difference that reduces in the case the efficiency of the advanced low-carbon power plant increases.

²² The CO₂ avoided is represented by the difference between the amount of CO₂ emitted by the reference cycle and the CO₂ emitted by the advanced cycle being considered.

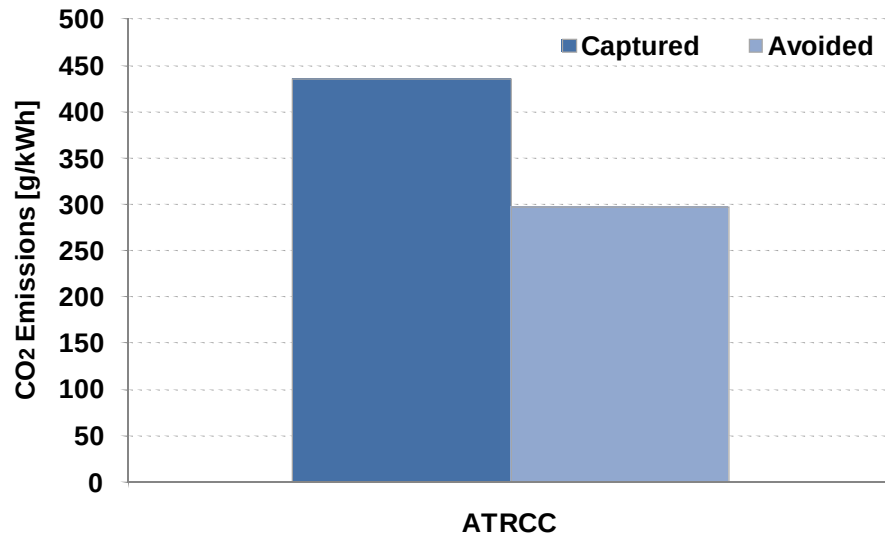


Figure 5.3 CO₂ captured and avoided for the ATRCC

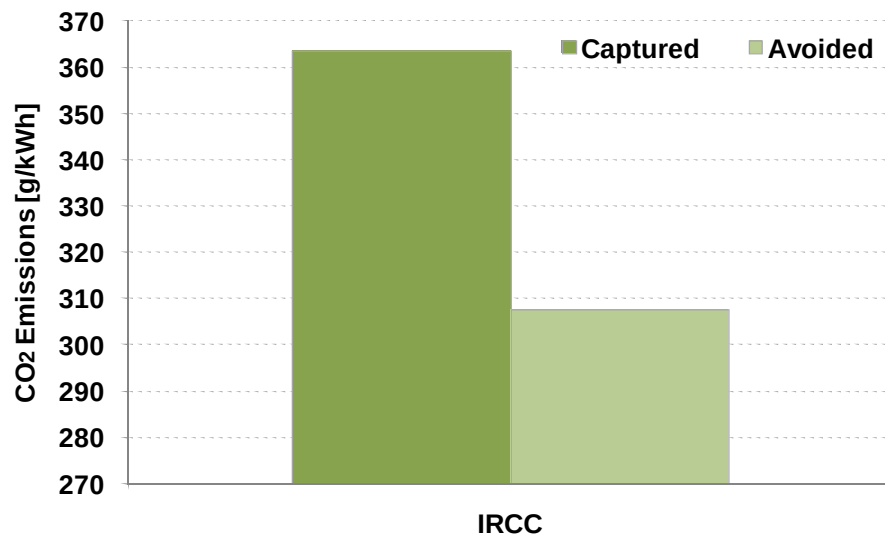


Figure 5.4 CO₂ captured and avoided for the IRCC

These figures just illustrated depend considerably on the CO₂ capture efficiency stipulated in the performance analysis (90%), on the rate of conversion of CH₄ in the auto-thermal reformer and the rate of conversion of CO to CO₂ in the shift reactors (which are favoured by an elevated carbon-to-steam ratio).

As far as the NO_x emissions are concerned, the estimation of SFT, according to the procedure described in paragraph 5.3, displayed a value of 2346 K. It is worth

noting that such value is a preliminary estimation of the real stoichiometric flame temperature, useful, however, to foresee the range of nitrogen oxides produced. Considering the above established limit of 2350 K, the SFT of 2346 K evaluated leads to the conclusion that the NO_x emissions may not fit into the range of nitrogen oxides that are compatible with environmental concern. If so, they will stand on the fringe of such a range. Consequently, the dilution of syngas using steam could be taken into account. Such operation can have important impact on the thermodynamic performance of the power plant and, therefore, negative and positive effects in terms of both aspects have to be weighed and compared carefully.

CHAPTER 6

ECONOMIC ANALYSIS

The decision-making process for a new investment comprises different aspects. One of them is related to the profits generated at the end of the project. Economic evaluation provides information for making good investment decisions, with the purpose of ensuring that a project is “worthwhile”, that is, the expected future profits justify the prior expenditure of resources. Power generation projects, and especially advanced low-carbon power projects, are long-term projects whose appraisal necessarily involves a degree of uncertainty and risk attached to assumptions and projections. The aim of this chapter is to present the tool developed within the T.E.R.A. Framework for assessing both economic attractiveness and financial risk during projects’ evaluation. This chapter presents the economic modelling methodology and states the assumptions used in the model. It describes the elements that the model can look at, and demonstrates the potential for the model to be used in advanced low-carbon projects assessment applying it to the three case studies selected for the present investigation.

6.1 Investment Appraisal Methodology

Generally speaking, “the purpose of investment appraisal is to assess the economic prospects of a proposed investment project” [174]. The project or investment meets the viability requirements if the project’s return is greater than the cost of capital and the risk associated to the venture is tolerable.

One of the conventional methods for engineering economics to support the decision-making process is the so-called “discounted cash flow technique” (DCF) [175]. This approach, taking in account the time value for money, involves recording the cash inflow and outflow in the project being considered over its lifespan [175]. All cash inflows and outflows that happen in the project’s future are discounted back

to their present-worth value at the beginning of the project. DCF allows the complexity of large-scale investments to be summarized in single figures, such as for example NPV.

The approach widely applied in investment appraisal involves calculating a “best estimate” based on the available data and using it as an input in the evaluation model [174]. By doing so, it is implicitly assumed that it is possible to associate to each input of great significance a single value and that such values used in the appraisal are certain. The result of the project is also presented as a certainty with no possible variance or margin of error associated with it. However, it is well known that actual cash flows could be considerably dissimilar from the forecast ones [176-178]. All projects are influenced by variables subject to substantial levels of uncertainty regarding costs, prices, completion time and the level to which original objectives of the project will be achieved, and as such, hardly summarisable in a single value. Traditional deterministic economic analysis does not provide alone sufficient information for an informed decision. Therefore, any investment appraisal should include a comprehensive understanding and awareness of the risks associated with the project of interest [174].

Several approaches could be used for incorporating uncertainty in deterministic evaluation of new projects.

Sensitivity analysis involves varying the value of a variable in order to appreciate its impact on the final outcome. Simple and informative, it assists the evaluator to identify the variables that significantly affect the outcome and correspondingly needs more information and investigation [179]. One of the major weaknesses of sensitivity analysis is that changes are, most of the time, *ad hoc*, without regard to the expectancy and probability of these happening. Such *ad hoc* assumptions do not assist decision makers to examine the likelihood of the event [180].

A step forward from sensitivity analysis is *scenario analysis*. It enables the contemporaneous variation of values for a number of key project variables thereby constructing mutually exclusive scenarios for the project, the sum of probabilities of these scenarios adding up to unity. In its simplest form it requires usually a base scenario, an optimistic scenario and a pessimistic scenario. The base scenario will demonstrate the most likely inputs and outputs from the point of view of the project evaluator. The optimistic scenario will incorporate future parameters that are more favourable to the project success than they appear at the time of evaluation, while the pessimistic scenario will have an opposite view expecting that future events may be less favourable than they appear today. Setting up mutually exclusive scenarios with a probability distribution assigned to each is a rather difficult task. These are usually based mainly on the judgement of experts and other project designers.

Probability descriptions of input variables permit further improvement of the analysis of economic risk and provide the pursued answer with a probability

distribution. *Monte Carlo simulation* enables construction of random scenarios, consistent with the analyst's key assumptions about risk, including the feature of dynamic analysis to investment appraisal [174]. Ho and Pike [181] state that “proponents of risk analysis argue that increased risk information improves management’s understanding of the nature of risks, helps identify the major threats to project profitability and reduces forecasting errors”. They also state that “the risk analysis approach provides useful insights into the project, improves decision quality and increases decision confidence” [181].

6.2 Aspects of Investments in Advanced Low-Carbon Power Plants

Investment in the power sector has some important features. Beyond being a long-term venture, the investment is partially or completely irreversible [182]. Once the choice is made, the effects of the investment decision remain with the organisation for the lifetime of the plant. Second, there is always uncertainty over the future return from the investment [182]. Future energy price, fuel price and carbon price are unpredictable which makes cash flows of the project return uncertain. Third the investors have choices to invest at flexible timing [182]. They can invest in a power plant now if they think the return of the investment is high enough to recover all the investment risks, or they can postpone the investment to get better information on the future prices.

Investments in CCS power plant options are characterised by a high degree of complexity which makes more uncertain and sometimes volatile the results of this kind of investments analysis.

The systems envisaged are larger and more complex than current state-of-the-art technology. The majority have in common a very large balance of plant around the PCU (power conversion unit) and more complex PCUs. Inevitably all carbon abatement opportunities will carry a cost penalty: increased costs will arise through reduced overall plant efficiency (pointed out for the case studies of the present investigation in Chapter 4) followed by an increased challenge in reliability and availability and combined with increased capital and operational costs. Most of these CO₂ capture techniques, in fact, have not been developed or optimised originally for this type of application and, since the majority of them have not been built and operated yet in full-scale commercial plants, the absence of historical antecedents and the lack of knowledge about reductions in the construction cost per unit of capacity for large size plants results in uncertainty associated with the capital cost and O&M costs.

In order to take into account not only the economic benefits of advanced low-carbon power plants options, but also the substantial level of uncertainty in evaluating such projects, many authors have been induced to adopt different

approaches. It is proper to remember that taking into account risks and uncertainty is not a substitute for normal investment appraisal methodology but rather a means that enhances its results and supports the investment decision by giving the investor a measure of the variance associated with a project appraisal return estimate [174].

Using sensitivity analysis, Corradetti and Desideri have evaluated hydrogen plants based on natural gas reforming [183]. After determining the optimum size for each configuration studied, they have investigated the influence of some parameters, such as electricity, natural gas, and steam costs. The effect of the fuel price and interest rate on the cost of electricity and the cost of CO₂ avoided have been determined through sensitivity analysis by Abu-Zahra et al. for a power plant with CO₂ capture based on mono-ethanolamine [184]. One example of scenario analysis application to low-carbon power plants is provided by Singh and Gabbielli [62]. Singh and Gabbielli have explored the effect of uncertainty in some investment parameters (as the discount rate, the plant life and the equivalent full load operative hours of the plant) on the cost of electricity and the break-even carbon tax for innovative gas-turbine combined cycles with no emissions of carbon dioxide and nitrogen oxides [62]. Some authors have reviewed the use of real option analysis to the CCS investment decisions [182]. The real options analysis, incorporating a learning model, takes into consideration the strategic managerial options that certain projects create under uncertainty and the management's flexibility in exercising or abandoning these options at different points in time, when the level of uncertainty has decreased or has become known over time [185].

Lastly, as already stated in Chapter 2, in literature several economic data concerning the new low CO₂ emission gas turbine-based power generation processes are available. On the other hand, the reliability of these cost estimates for plants with CCS is most uncertain both due to the absence of historical antecedents [186], as already highlighted, and due to the wide range of economic factors and assumptions as well as standard assumptions about plant performance and availability which underlie them. Moreover, several criteria are being used for comparing the economic performance of power generation schemes. The absence of a systematic framework for analysis exacerbates the difficulty of the economic assessments: reliable comparisons across technologies turn out really arduous and dubious.

6.3 The Economic Module

A computer program in Fortran 90 language has been developed by the author for a transparent and consistent assessment of the economic feasibility of long-term investments in competing advanced low-carbon power systems: the Economic

Module. The evaluation model, around which the computer code was structured, is based on a two-stage investigation²³.

The first stage of the assessment draws attention to a discounted cash flow evaluation, quantifying performance indices that give an indication of the attractiveness of a proposed investment. As second stage, the Economic Module allows the user to take in account uncertainty into the economics of the power generation scheme. Decision-making under uncertainty is performed through the use of Monte Carlo method which subjects the economic future of the project to random variations centred on the no-risk data used in the first stage of the assessment.

6.3.1 The Discounted Cash Flow Model

The period of the economic study is assumed to start in the year the plant is going to be installed and to end in the year the plant is taken out of service permanently (Figure 6.1). Thus, two distinct phases, the construction and the operational phases, can be identified in the period object of the study. The line of demarcation, often referred to as “time zero”, is taken as the date of commissioning, i.e. the year in which the plant is commissioned to start up. Time-zero is selected as start-up²⁴ since this approach is useful for cases when a new project is being considered [187]. All cash amounts are then discounted back to equivalent amounts at this reference date.

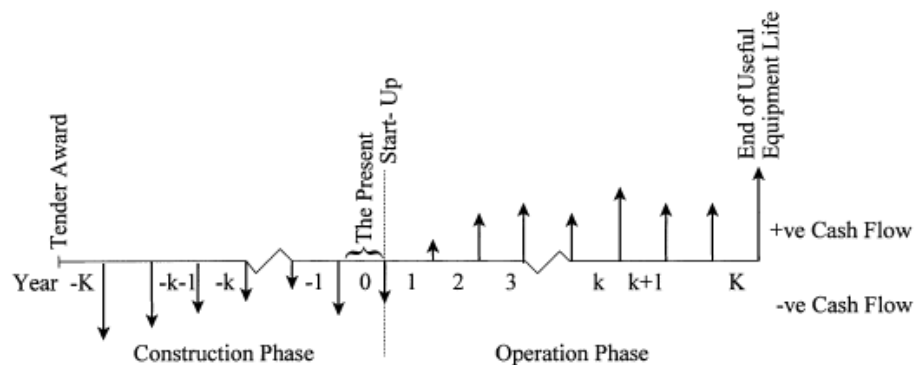


Figure 6.1 Period of economic study [188]

The starting point of the assessment is represented by the estimation of the capital cost of the project. The total capital invested in the project is expressed as sum of direct bare equipment costs and of various indirect costs that are estimated as fractions of the total direct cost following the Electric Power Research Institute

²³ The Appendix C contains an example of Input file.

²⁴ As an alternative, it may be convenient to select time zero when the first funds are spent. Such approach is frequently more convenient for cases when equipment is being added to an existing plant or an expansion of an already existing plant is to be made. The selection of either time base is satisfactory for economic analysis as long as consistency is maintained [187].

(EPRI) cost estimating guidelines [189]. The direct bare equipment costs are expressed as £/kW and are a function of the plant size. The indirect costs are represented by the general facilities costs (which is the total construction cost of the general facilities, including roads, office buildings and others), engineering and home office overhead, and contingencies (project and process). The project contingency is a capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design and an actual site. The process contingency is a capital cost contingency factor applied to a technology to reflect its level of maturity. Such capital costs, incurred during the construction phase, are assumed to be spread over the construction period, which may last for a number of years in power plants projects, and they make up the invested capital or initial investment I_0 .

The cash flows model applicable yearly over the investment time horizon is shown in Figure 6.2. The cash flow derives from the joint estimation on the annual basis of the fixed and variable costs, as well as the revenue, for the whole time horizon of the evaluation. In addition, the calculation of cash flows takes into account the payment of taxes and depreciation, as shown in Figure 6.2. It is stressed that technical parameters, including fuel consumption, CO₂ emissions and power produced by the power plant, are fed in the model developed after being calculated as explained in the paragraph 6.3.3 by means of the Performance and the Emissions Modules.

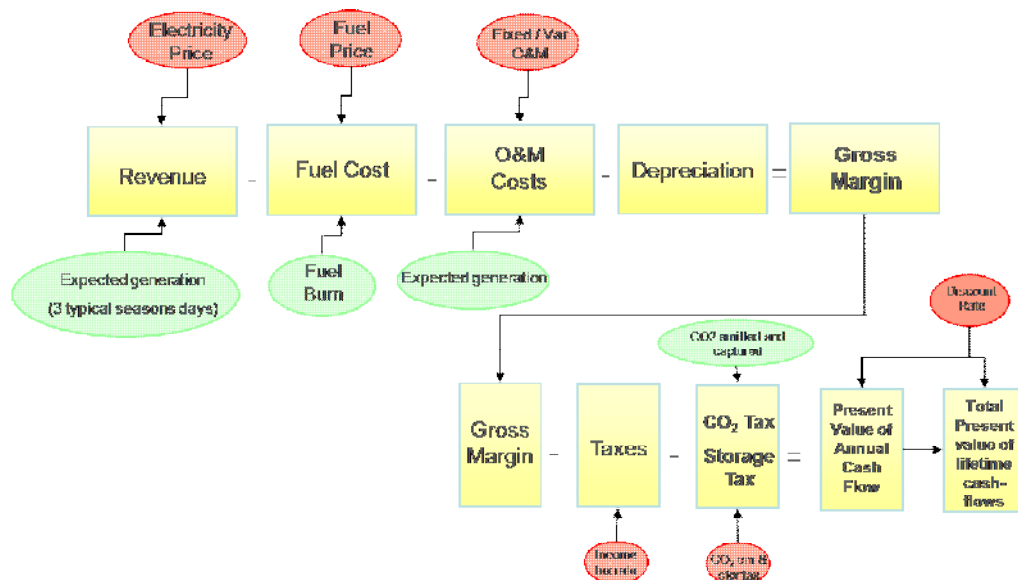


Figure 6.2 Structure of cash-flow model (adapted from [190])

For a specific year, the annual net cash flows (ANCF) can be expressed in the following manner:

$$ANCF = \text{annual operation profit} - \text{annual loan repayment} - \text{annual tax} \quad (6-1)$$

The annual operation profit can be defined as the revenue generated by the electricity sold minus the cost of the fuel consumed by the power plant minus the operation and maintenance cost:

$$\text{Annual operation profit} = \text{electricity sold} - \text{fuel cost} - \text{O\&M cost} \quad (6-2)$$

The operation and maintenance (O&M) charge comprises a fixed and a variable charge. The fixed portion, C_f , does not depend on the output of the plant in a year, but rather it is set by considerations relating to the operation and maintenance of the plant, fixed by the decision to keep the plant in service. The fixed operating and maintenance cost are estimated on annual basis (£/yr). They are assumed to be a function of plant size only and include the cost of maintenance (materials and labour) and labour (operating labour, administrative and support labour). The variable costs depend on the performance of the plant. They include costs of chemicals consumed (for example CO₂ capture solvent if required), utilities (water, steam, power) and services used. The variable charge varies in direct proportion to the yearly output. The constant of proportionality, C_v , is given in monetary units per kilowatt hour. Among the variable costs, the fuel cost is accounted separately since it is the single largest cost item.

Annual tax payment is made up of two parts: the first part is the tax on the profit and the second part is the possible tax on emitted CO₂. Consequently,

$$\text{Annual tax} = \text{Tax rate} \cdot \text{taxable income} + \text{emission tax rate} \cdot \text{emissions} \quad (6-3)$$

It is reasonable to assume that the tax rate will remain constant throughout the lifetime of the investment. The carbon dioxide emissions are not currently regulated. However, there is possibility that carbon limits will be imposed in the future. Hence a carbon tax has been assumed as one possible environmental regulatory mechanism and it has been supposed to be proportional to the carbon dioxide emitted in the atmosphere.

The taxable income in the equation (6-3) is determined considering depreciation. Depreciation reflects the fact that the value of an asset tends to decrease with age and use due to physical deterioration, technological advances, and other factors that ultimately will lead to the retirement of the asset. In addition, depreciation is an important accounting concept serving to reduce taxes during plant operation [191]:

$$\text{taxable income} = \text{annual operation profit} - \text{depreciation} \quad (6-4)$$

Among the many methods for depreciating the value of an asset (straight-line, sum-of-the-years-digits, sinking fund and double-declining balance methods) [191], the depreciation method called “straight-line depreciation” has been adopted, since widely used by the electric industry [189]:

$$\text{depreciation} = \text{plant price} / \text{book life} \quad (6-5)$$

6.3.2 Economic Parameters

The cash flows evaluation leads to calculating the following parameters:

- net present value, NPV
- pay-back period, PBP
- internal rate of return, IRR

The NPV is calculated according the following expression:

$$\text{NPV} = \sum_{t=0}^n CF_t \cdot (1 + i)^{-t} \quad (6-6)$$

where:

CF_t is the net cash flow at time t ;

i is the discount rate;

t is the time of the cash flow;

n is the lifetime of the investment.

The net present value represents an estimate of the wealth generated by a project: higher NPV, higher the net profit will be, so the investment may have favorable economic performance [192].

The IRR is defined as the discount rate that gives the cash flows for a project a zero net present value:

$$\text{IRR} = i^* \quad \exists' \text{NPV}(i^*) = 0 \quad (6-7)$$

A project is acceptable if its IRR is greater than the required rate of return on the project [177]. It can be considered as a measure of the financial risk related to the variation of the interest rate: the IRR must be greater than the opportunity cost of capital, or in another words, the most profitable risk-free investment, otherwise the investment is not viable and as such is not worth considering. When considering an individual project, the IRR decision-rule will always give exactly the same results as the NPV decision-rule: from the NPV curve in Figure 6.3 it can be seen that when the discount rate is less than IRR, the NPV will be positive, and vice versa. NPV and

IRR may not give the same result for accept or reject decisions when a choice has to be made between two or more projects²⁵.

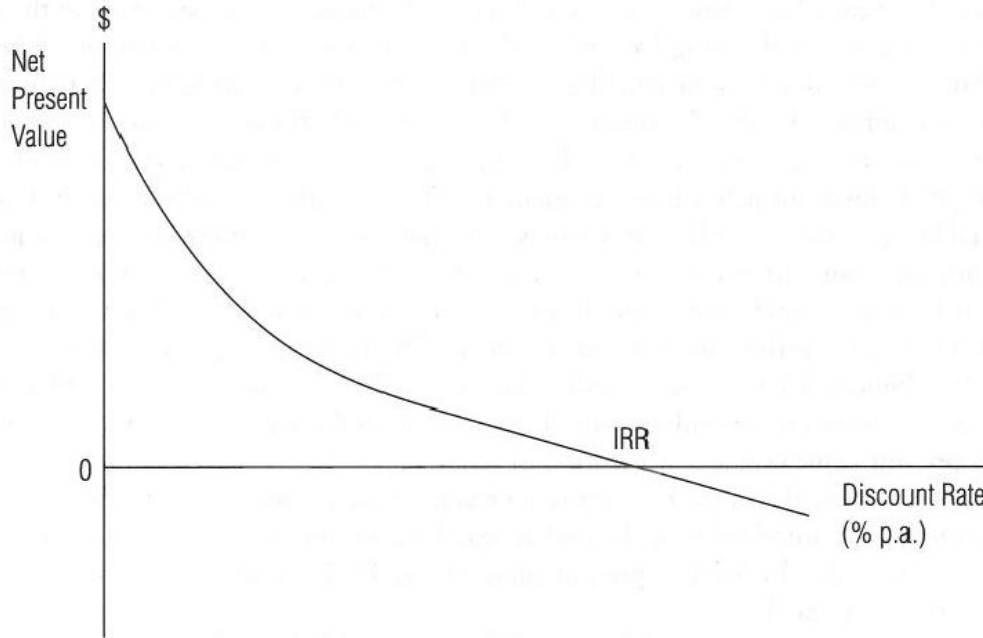


Figure 6.3 *NPV in relation to the discount rate* [193]

The pay-back period is a measure of the time required to recover the initial investment and it is defined as the minimum period of time n' which satisfies the following equation:

$$\min_{[0,n]} \{n'\} \quad \exists' \quad \sum_{t=0}^{n'} CF_t \times (1+i)^{-t} \geq 0 \quad (6-8)$$

Contrary to the other two indices, the pay-back time is not a profitability measure. It can be considered rather a measure of liquidity warranted by the investment, since it gives the analyst a 'feel' as to the length of time cash is at risk [177]. Shorter the pay-back time, shorter the time that needs to elapse before recovering the initial investment outlay. However, a profitable investment, characterised by high value of NPV and IRR could present a high pay-back time, which makes the investment quite risky. This turns out to be important when comparing investment options to quantify the period of exposure of risk, although it is a good practise to associate it to the two other indexes [177].

²⁵ In this case it is possible to apply the so-called Fisher's criterion: to consider the incremental project, defined as the difference between cash flows of the two project being considered, and then apply the NPV and IRR criteria on the incremental cash flows [193].

The cost of electricity and the mitigation cost are also considered in the economic evaluation.

The unitary Cost of Electricity (CoE) is calculated according to the levelized cost methodology, considering the total electrical energy that the power plant will produce in its lifetime and dividing between the total cost generated by construction investment plus the operation and maintenance cost [194]:

$$CoE = \frac{\beta \cdot C_0 + C_{fuel} + C_{O\&M}}{W \cdot H} \quad (6-9)$$

where:

C_0 is the capital cost of the plant (£);

$\beta(i, n)$ is the capital charge factor which is related to the discount rate (i) on capital and the life of the plant (N years) according to the following equation:

$$\beta = \frac{i \times (1+i)^n}{(1+i)^n - 1} \quad (6-10)$$

where:

C_{fuel} is the annual cost of fuel supplied (£ per annum);

$C_{O\&M}$ is the annual cost of operation and maintenance (£ per annum);

W is the rating of the plant (kW) and H is the plant utilisation (hours per annum).

As it is a mean value, it allows the immediate comparison among different technologies.

For comparisons of CO₂ mitigation costs of different plants, an established economic indicator proposed by David and Herzog [195] is the Cost of Avoided CO₂ (CAC, in £/tonne CO₂ avoided), given in the following equation:

$$CAC = \frac{CoE_{cap} - CoE_{ref}}{E_{ref} - E_{cap}} \quad (6-11)$$

where CoE is the cost of electricity (p/kWh), E is the CO₂ emissions (tonne/kWh) and the indices ref and cap represent the reference and capture plants respectively.

Another criterion the Economic Model can compute and use for estimating the economic performance of new power generation schemes is the break-even electricity selling price (BESP). The break-even electricity selling price is the price that the generator must charge for the electricity that is sent out to the grid in order that, over the lifetime of the station, its net present value is zero [196]:

$$BESP = \sum_{t=0}^n [(I_t + M_t + F_t) \times (1+i)^{-t}] / \sum_{t=0}^n [E_t \times (1+i)^{-t}] \quad (6-12)$$

where:

I_t = investment expenditures in the year t ;

M_t = Operations and Maintenance expenditures in the year t ;

F_t = Fuel expenditures in the year t ;

E_t = Electricity generation in the year t ;

i = discount rate.

6.3.3 Analysis Approach and Key Assumption

A critical aspect of estimating the costs of CCS is represented by the set of economic assumption made [197]. The key assumptions underlying the DCF model of the Economic Module are here briefly summarized. They include how the following aspects have been treated in the model and subsequently in the analysis carried out: (1) inflation, (2) discount rate and time period used as a basis for developing estimates, (3) the capacity factor, (4) degradation of the plant and (5) CO₂ transport and storage costs.

The economic analysis is conducted in *constant currency units* by excluding inflation and considering only real escalation²⁶ rates in cost projections and the real cost of money. The Economic Module is able to take in account also inflation. Escalation rates are applied to the fuel cost, to the electricity price, as well as the fixed and variable operating and maintenance costs, to forecast their values during the years of operation. This approach has its strengths and weaknesses [189]: a constant currency units analysis gives a clear picture of real cost trends, enables engineers to get a better understanding of the costs involved, and makes levelized costs appear close to today's values. Such a method, however, appears to understate all cost values and leads to cash flows that may be significantly less than the actual values, presenting the project as less costly than it ultimately will be. The results of studies involving more than 10 years, as in the case of a power plant, may be best presented in constant currency units so that the effect of many years of inflation does not distort the costs to the point that they bear no resemblance to today's cost values [189]

The choice of a discount rate can significantly affect the present value of future costs and benefits [192, 193]. Recently it has been stressed how the actual discount rate employed by a company in investing in CCS can have a significant impact on the total CCS cost [66, 198] and in general on the cost of electricity generation [180]. As an example, coal-fired plants are more sensitive to discount rate than gas-fired plants because they are more capital intensive [66, 180]. Typically, in an investment analysis, the discount rate value is selected by the decision maker, taking into account the risk

²⁶ The real escalation rate of expenditure is the annual rate of expenditure change caused by factors such as resource depletion, increased demand and technological advances [189]. The first two factors lead to a positive real escalation rate whereas the third factor results in a negative rate. The real escalation rate is independent and exclusive of inflation [191].

of the investment. When using cash-based investment appraisal tools such as net present value (NPV), there can be an artificial compensation for the volatility of the industry by increasing the discount rate used in the analysis [199]. If the investor wants to reduce the investment risk associated with non-standard technologies of power generation, a high i value may be used [186]. In less risky conditions, as for example in case of government supports, it is possible to adopt a low discount rate. This approach has the disadvantage of channelling all the risk through the discount rate. The value of the analysis itself is also reduced. Conversely, a fundamental duty of investment appraisal is to deal with risk effectively rather than providing against it by using an artificially high cost of capital [200]. Previous studies have used a value of discount rate in the range between 5% and 15% [197]. In this analysis a discount rate of 10% is assumed. The model developed allows addressing this issue calculating also the IRR as a measure of the investment profitability²⁷, which is independent from the interest rate used for discounting the cash flows [199]. As already stated, the IRR is, by definition, the break-even discount rate on a project, the highest discount rate at which the project would be worthwhile [192]. Therefore it indicates the margin of error in estimating the discount rate and may be a useful subsidiary calculation for that purpose. It does not, however, indicate the sensitivity of the profitability of a project to errors or uncertainty of estimates of the cash flows [192]. As explained in the paragraph 6.4, Monte Carlo simulation technique will address such aspect.

Another assumption which can play an important role in cost comparisons involving CCS plants, especially natural gas-fired power plants, is the so-called *plant utilisation factor* or *capacity factor* [186]. The capacity factor is defined as the ratio of the actual output of a power plant over a period of time and its output if it had operated for the same time at full load. In the short to medium term, it is presumable that CCS power plants will work in base load conditions, in order to get the most out of the investment in CO₂ capture system. In the longer term the requirement of reducing CO₂ emissions will entail a wider use of variable renewable electricity generation sources. Since these renewable sources (such as wind and solar energy) should operate whenever they are available, other plants will be expected to operate at lower annual load factors in order to satisfy the variable demand for electricity from the grid (Smith [201] in [66]). Plants with CO₂ capture, particularly gas-fired plants, should be more appropriate than other generation technologies such as nuclear power (more capital intensive and less flexible) to operate in conjunction with unstable renewable electricity sources. Nevertheless, the capability of power plants with CO₂ capture to operate with frequent and rapid variations in output needs to be further studied and assessed [66, 202].

²⁷ In the case of a “non conventional “ investment multiple solutions are possible for solving the internal rate of return equation. It may also be the case that no internal rate of return can be found. Under these circumstances the internal rate of return method can not be easily used for assessing projects [177].

In the analysis here presented a scenario has been taken into account, corresponding to a base load utilisation of the power plants. The correspondent capacity factor amounts at 85%. It is assumed that the plants would be contributing when they are available and would be capable of generating maximum capacity when online. Therefore capacity factor and availability are equal. Using the technical information provided by the Performance and the Emissions modules, the data required by the Economic module, as illustrated in Figure 6.2, have been evaluated. Extra start-ups and shut-downs are not accounted in the costs.

Allison et al. [197] highlighted how the project lifetime can have a considerable impact on the economic evaluation: a reduction in the project time horizon can turn out in an increase in the mitigation cost, whereas a longer project could require for example the installation of new equipments to be taken in account in the cash flows estimate. In the open literature usually a value of 25 years for the plant life with standard power generation technologies is adopted [62, 66, 196, 203, 204] and a construction time which ranges between 2 years and 5 years [62, 66, 196, 203]. If the power plant is innovative, a lower value of the plant life [62] and a longer construction time could be more suitable. All the three projects investigated in the present work are assumed to have the same lifetime equal to 25 years [66, 196, 203, 204] and the same construction time of three years²⁸.

Another important assumption assumed to perform the economic evaluation is that no plant performance degradation is considered during the plant life. The system boundaries for the economic analysis are the same for the whole T.E.R.A. evaluation as stated in Chapter 3: the costs of CO₂ transport and disposal are excluded from the capital estimation of the plants and from the operational costs. The exclusion of transport and storage costs, however, can greatly affect the comparative ranking of different CO₂ capture systems, since they account for a large proportion of the total outlay.

6.4 Risk Analysis: Monte Carlo Simulation

In a broad view, simulation is a method meant to study a system's behaviour. In a simulation controlled sampling experiments are conducted, assuming that the results of such experiments represent a sufficiently accurate reproduction of the behaviour the system would have. Such approach is aimed to better understand performance of system, to verify or to deny hypotheses on it, to collect information in order to be able to formulate potential forecasts.

²⁸ Assuming that all projects options have equal lives allows to compare them by means of NPV and IRR, without resorting to a more complex analysis, such as the Annual Equivalent Cost [193].

An interesting use of the simulation's method is represented by Monte Carlo technique. This technique is widely used to reproduce and provide approximate solutions to several mathematical problems which would be too complicated or impossible to solve analytically [205]. Perhaps the historical origins of Monte Carlo method could be traced back even to 1700, that is well before the advent of computers. In 1900 the method was widely used in nuclear research and today Monte Carlo simulation method finds application in several scientific fields and, in general, it can also be developed into a powerful decision-making device in any ambits in which relationships that are based on uncertain variables are modelled to facilitate and enhance the decision-making process.

The first application to the investments' evaluation is probably due to David Hertz who in his paper "*Risk Analysis in capital investment*" of 1964 proposes this technique to evaluate an expansion investment of a chemical plant [206]. A basic example of how Monte Carlo simulation can support economic evaluation of projects in electricity supply industry can already be found in Gayraud [49, 50]. An application to coal gasification is given by Xander [207]: Xander has applied Monte Carlo technique to allow for future economic and technological uncertainties associated with producing an high BTU gas from coal. As already mentioned in Chapter 2, the Integrated Environmental Control Model, developed by Carnegie Mellon University for the National Energy Technology Laboratory, adopts Monte Carlo method to quantify cost uncertainties in the estimation of the capital cost, annual operating and maintenance (O&M) costs, total levelized cost of some options for coal-fired power plants employing CO₂ capture methods [69].

Monte Carlo Simulation follows the steps shown in Figure 6.4. The first stage of Monte Carlo simulation is simply the implementation of a model consisted of a set of equations, which define the interdependence between components of the system under evaluation and describe the mathematical relationship between output and input variables. The model needs to include all the significant variables and postulate the correct relationship between them. Among them there are those that are known to have deterministic values and those that are subjected to uncertainty. The second stage of Monte Carlo Simulation requires the selection of the "risk variables" of the model, whose trend can be described in probabilistic terms. After identifying and modelling potential correlations between the selected risk variables, a probability distribution needs to be specified for each of them. The selection of the most appropriate distribution is of paramount importance: such probability distributions describe quantitatively the uncertainty marking the key project variables and quantify the probability that the forecast deviates from its base value by a random amount.

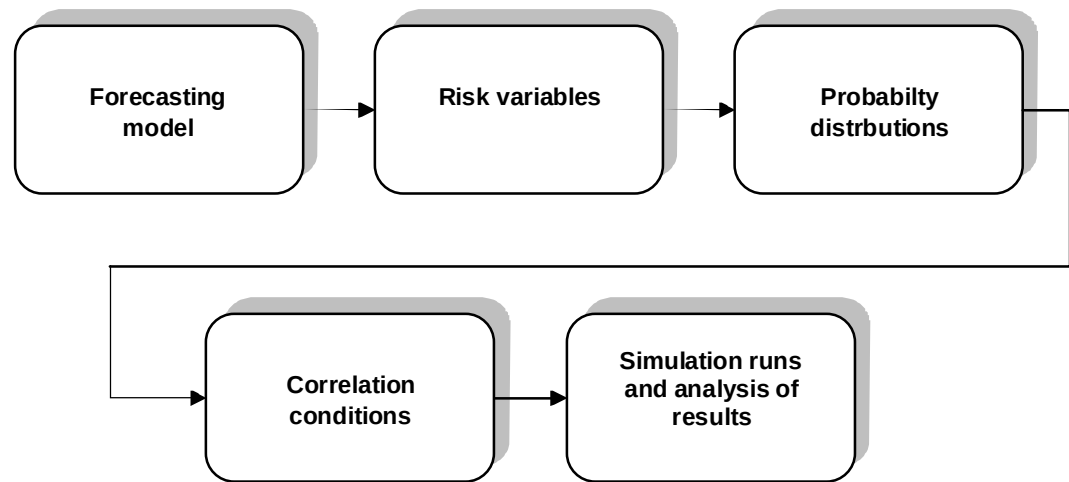


Figure 6.4 *Risk Analysis process (adapted from sak [174])*

The basic idea of using the Monte-Carlo simulation technique is to carry out a large number of individual project evaluations, each with different input values, selected from their probability distribution in random combinations (Figure 6.5). These selected values, along with other fixed input data, are used in the evaluation model to calculate a value for the project's performance indicator. As iterations are repeated more and more times, the frequencies with which particular values are selected from the input distributions approach more and more closely to their probabilities and the frequency with which the resulting output indicator falls within the specified output indicator steps approaches a stable distribution. The output of a risk analysis is therefore a probability distribution of all possible expected values of the output variable. In the case of a new investment's appraisal, this allows somehow to provide the investor with a measure of risk profile of the project on the basis of statistical dispersion of the project profitability indicator.

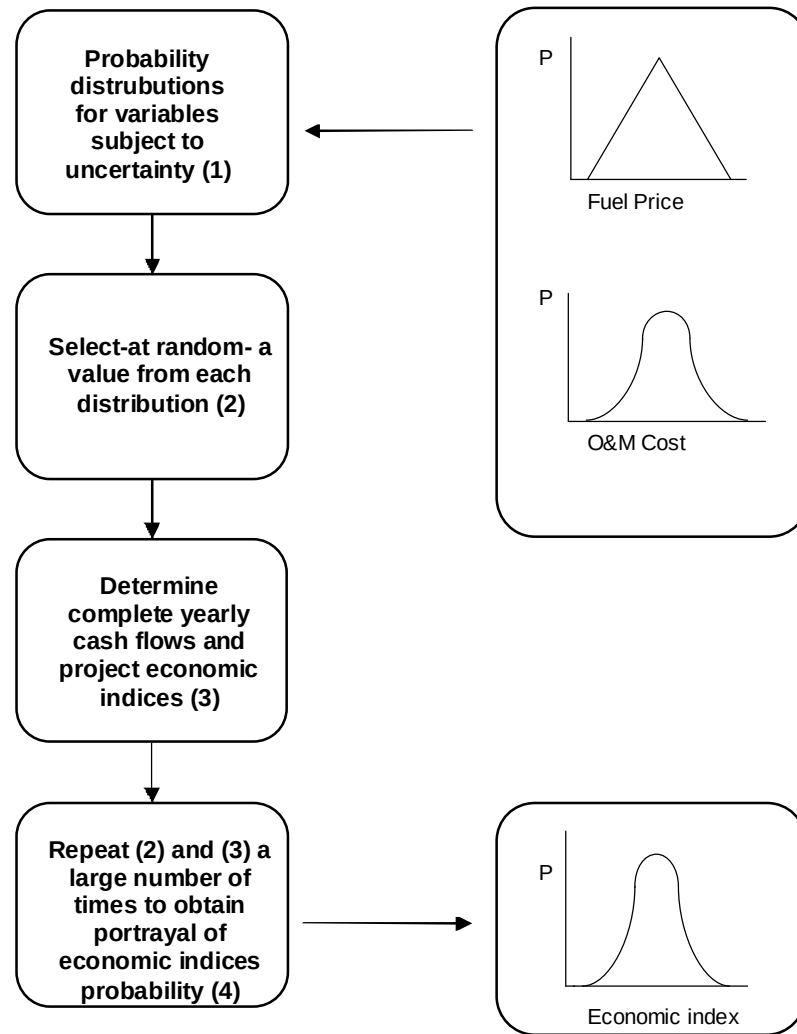


Figure 6.5 Risk Analysis procedure using Monte Carlo simulation technique (adapted from [49, 50])

6.4.1 Model

As stated above, the first step of a Monte Carlo analysis application is a complete model capable of including all relevant project's variables and defining the mathematical relationships between them. In the present analysis, the model is represented by the discounted cash flow model described in the paragraph 6.3.1 and the Monte Carlo simulation is built on top of it.

6.4.2 Risk Variables

Among the key parameters which are subject to uncertainty and can considerably affect the economic performance of low-carbon power systems, the plant construction cost, the operating and maintenance cost (fixed and variable), the fuel price and the CO₂ emission tax have been selected to carry out the Monte Carlo simulation.

Despite every effort made to validate the capital cost estimation data, using published information, the accuracy of this type of capital cost estimation is not absolute. No full-scale plants with CO₂ capture are currently in existence and construction cost is definitely a function of plant size. For all existing conventional power plants, it has been observed that reductions in construction cost per unit of capacity are realized as larger plants are built, but the nature of this function is not exactly known for CCS based power plants.

Among all the risk cost components, operating and maintenance costs are subject to the greatest degree of uncertainty. While it is possible to categorize O&M costs, it is not always possible to obtain reliable data for use in economic studies. The operation and maintenance costs are really difficult to predict even for conventional power plants [49, 50, 208]. This is because costs are indeed a function of the type of unit, its size or rating, and the disparate O&M practices of utility organizations, particularly with respect to preventive maintenance [208]. The future technological advancements, especially in the area of CO₂ capture, may have an important role in the determination of these costs.

Fuel price uncertainty is included in the model: the price of fuel is usually market-driven and could vary considerably. It does not only add its own uncertainties into the equation, but influences the relative costs of carbon abatement opportunities [66, 184, 186, 209]. As already underlined in paragraph 6.3.1, fuel cost is one of the most critical cost components for any combined cycle schemes since it accounts for a large portion of all the operating and maintenance costs. It has been showed that a variation in the price of fuel could affect considerably the final cost per kWh produced [197, 210]. The fuel cost is directly related to the price of fuel and is inversely related to the efficiency of the conversion process. Efficiency is determined by the applied state of the technology and is also a function of the plant size and plant utilization.

The environmental challenge has increased the level of uncertainty in the investment decision process introducing also another new factor: the emissions cost [184]. One problem of incorporating these emission costs into financial appraisal is that the status of climate change policy in most countries is uncertain. Despite the mechanism through which the climate change policies are introduced, they will impose “extra” costs on investors and users which need to be considered in any

investment appraisal [184]. In the present model, as already pointed out, a CO₂ tax has been introduced and is taken to be stochastic.

It is clear how the full range of investment risks is not however modelled. For example, technical risks such as demand or load factor uncertainty are not included and other parameters are technologically constrained or their values are assumed constant. The uncertainty related to technological maturity is studied through the model described in Chapter 7. Over time, the costs associated with CO₂ capture from power plants are expected to decrease as increasing adoption for large-scale applications drives down costs. Costs will also decline as a consequence of the various technical developments and as a result of the “*learning-by-doing*”, thus increasing the overall attractiveness of such CO₂ capture systems [8, 198]. This aspect is not included in the current version of the Economic Module.

6.4.3 Probability distributions

The probability distribution expresses the relative chances that the variable being estimated will turn out to have any particular value. Different types of subjective probability distributions are available (Figure 6.6) - normal, triangular, lognormal, beta and so on - and in theory, according to the perception of the situation, a subjective probability distribution may be any of them. Subjective probability distributions for the key parameters need to be developed using a wealth of information from secondary sources, such as knowledge of past performance and data, and experts’ experience and judgement.

There is a common tendency to use the normal distribution because of its neatness. It is characterised by a mean and a standard deviation, where the mean is taken by default as being the no-risk value of the parameter and the standard deviation is specified by the decision maker. Previous studies, however, have shown that this is not the distribution curve in every case [180]. The actual distributions, for example, could show some skewness, ignoring the assumption of normality [180, 207]. If there are no reliable historical information about the variable in question and no information beyond the range of the values the variable could reasonably be expected to take, the analyst can assume a triangular or three-point distribution: the distribution is described by a high, low and best-guess estimate, which provide the maximum, minimum and modal values of the distribution respectively [193].

The Economic Module offers the analyst a wide range of probability distributions to choose from²⁹.

²⁹ The random numbers to be fed into the Economic Module are generated by means of dedicated functions available in Excel and then stored in a data file which represents an input file for the Economic Module.

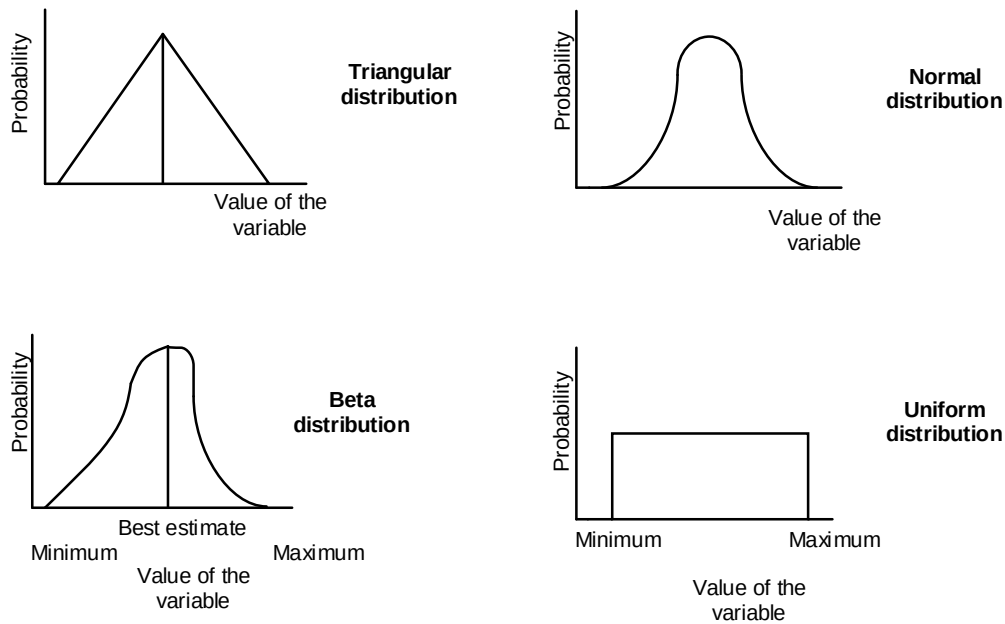


Figure 6.6 *Examples of probability distributions (e.g. see [180])*

6.4.4 Simulation and Results of Risk Analysis

The output parameters of Monte Carlo simulation are NPV, IRR, PBP, CoE and BESP. Unbiased results are gathered by using a large number of samples. The accuracy of estimate of outcome parameters, in fact, depends on the observations' size [211, 212]. As will be detailed in paragraph 6.7, the number of trials has been selected equal to 15000, since at 15000 simulation's runs results become stable reaching convergence.

Results take the form of charts, more precisely of cumulative probabilistic distributions. These distributions are set up for the key outcome parameters. The output distributions feature bars which are a measure of the frequency of a particular range of outputs, and a curve which stands for the cumulative probability function of each of the output ranges. The range of values of the variable are given on the abscissa, and the corresponding fractile from the probability distribution is shown on the ordinate, giving the probability of a parameter being at or below a given value. One minus the cumulative probability gives the probability of exceeding the corresponding parameter value.

Beside the cumulative probability, which is also the most important result of the Monte Carlo analysis (because it is a measure of the risk of achieving or not a particular project target), the means, standard deviations and the ratio of standard

deviation to the mean value of each output are evaluated gauging the riskiness of the venture being considered [211, 212].

6.5 Limitations of risk analysis through Monte Carlo simulation technique

Monte Carlo simulation technique serves a useful purpose of making uncertainty manageable. However, it is not without its own potential drawbacks. They have been widely discussed in the literature and are here briefly summarised.

The subjectivity of the qualitative evaluation - which however represents an uneliminable component of any evaluation - has a significant impact in the approach adopted. The successful application of Monte Carlo technique relies heavily on the judgement of the evaluators, which are required to specify a suitable probability distribution for each input variable. This step, which is one of the most important in the risk analysis, can be turn out a demanding and difficult task, even deterring sometimes the application of the Monte Carlo method itself.

Another issue to be considered in risk analysis is represented by the disaggregation. It refers to the extent of detail in which an input has to be analysed. For example, the cost of a power station involves many types of equipment and items, each of them can be disaggregating into further details. Disaggregation of input variables brings about better cost estimates and in turn more complete and accurate results. On the other hand an excessive disaggregation would require the evaluators to construct too many probability distribution curves. This remark, along with the difficulty of predicting the costs of CCS systems, underlies the simplified approach of the discounted cash flow model developed for the present investigation.

The adoption of Monte Carlo technique is complicated also by the so-called *correlation*. Correlated variables are variables that are likely to move together in a systematic way [180]. To the extent that dependency exists among variables, it must be specified. Such interrelationships are not always clear and are frequently complex to model. It is not possible to give a general rule for the electricity supply industry, particularly the movement of fuel price and its relationship with other inputs [180]. Each project should be studied separately, and its features, disaggregation and correlation adequately dealt with. The model described above and implemented in the Economic Module assumes that the four risk variables selected are independent.

The last consideration deals with the value of discounted rate to be used when applying risk analysis, which is object of a debate in the specialized literature [174, 180]. Some authors have suggested that a more accurate study of the project through Monte Carlo simulation could reduce investment risk and imply a reduction in the discount rate: the most suitable discount rate would be the free-risk interest [174]. Other authors have argued that the discount rate should signify the market risk but not the project risk. It is not author's purpose to discuss and examine such a

thoughtful issue. In the present work, the discount rate adopted in Monte Carlo simulations is the same applied in the deterministic analysis, following the approach of Savvides [174]: Monte Carlo technique allows appreciation of the level and the order of the project risk, but doing so does not imply by itself that the project's risk is lowered or cancelled.

It has been also proposed that, instead of calculating the NPV through simulation, it would be more useful to calculate the IRR and represent it in a probability distribution curve. The current version of the Economic Module allows choosing the IRR as project's output in Monte Carlo simulations. This solution overcomes the problem of choosing a discount rate for the evaluation of the project to calculate the NPV. On the other hand, in some cases, the IRR cannot be easily calculated (e. g., see note 27 at page 111). Moreover, the mean of the IRR will need still to be compared with a discount rate that reflects the risk of the project. The estimation of the most appropriate discount rate that signifies risk of the project is still, therefore, of significant interest and relevance to future economic assessment and selection of advanced low-carbon power plants investments, but it is well beyond the scope of this study.

6.6 Economic Analysis: Results and Discussion

The scope of this paragraph is the evaluation of the economic performance of the three power plants under investigation. The possibility for the two advanced low-carbon power systems under investigation to play an important role in the mitigation of the greenhouse problem will fundamentally rely on the cost of electricity they can deliver. An increase of the cost of electricity of the two pre-combustion schemes compared to the conventional combined cycle can be predicted, due to additional hardware and lower efficiency pointed out in the previous chapters.

To assess its amount, along with the other economic parameters mentioned in the paragraph 6.3.2, the cost of the various components needs firstly to be estimated. For this purpose an extensive literature review has been performed to get figures of cost of the technologies considered here, with and without CO₂ capture.

Since capital costs depend strongly on the capacities considered, which vary substantially among studies, capital cost figures found in the literature have been scaled to the capacity of interest applying the following generic scaling relation (6-12):

$$\text{Costs } C = \text{Costs } C_0 * (S / S_0)^f \quad (6-12)$$

in which the cost C of a component of size S is related to the cost C_0 of a reference component of size S_0 by means of a scaling factor f [213]. Furthermore, costs are converted to £₂₀₀₈ through U.K. GDP³⁰ deflators [214] and annual currency exchange rates³¹. For each study reviewed an average exchange rate has been stipulated for the year of reference of the economic analysis that the study reported. Where not specified, the year of reference is assumed to be the year of publication of the study reviewed.

The values used for capital cost estimation of each component are summarised in Table 6-1, whereas investment costs for the three case studies of this investigation are detailed in Table 6-2. The large variety of the components present in the advanced cycles entails the larger investment costs that are required in order to build (and also to operate) a natural gas combined cycle with pre-combustion capture plant compared to a conventional power plant. The capital costs exclude interests during construction, owner's costs and start-up costs but they include project and process contingencies. A higher process contingency (10%) has been added for the two advanced power plants due to the presence of non-mature technologies.

Since the cost of single component is highly variable from one author to another, the resulting capital cost for the plants under investigation is compared to other values available in literature and reported in Tables 6-3 and 6-4.

Table 6-1 *Parameters used for estimating capital costs*

Component	Scale Parameter	Base Specific Cost C_0	Base Size S_0	Scale factor f	Note
Gas turbine	MW _e	57.123 10 ⁶ \$ ₂₀₀₈	255	0.67	a
ST/gen, BFW & CW	MW _e	220 \$ ₁₉₉₇ /kW _e	132	0.67	b
HRSG boiler	MW _t	144 \$ ₁₉₉₇ /kW _t	342	0.67	b
Pre-reformer	CH ₄ Input (MW _{LHV})	3.862 10 ⁶ \$ ₂₀₀₅	890.82	0.6 ^c	d
ATR	kmol total /h	4.7 10 ⁶ US \$ ₂₀₀₁	1390	0.6 ^c	c
Shift ^e	Mmol/hr CO+H ₂	11.275 10 ⁶ US \$ ₁₉₉₁	8.819	0.65 ^f	f
Fuel Compressor	MW	11.1 10 ⁶ US \$ ₂₀₀₁	13.2	0.85 ^c	c
CO ₂ capture	kg/s CO ₂	13.9 10 ⁶ US \$ ₂₀₀₀	44.58	0.67	d
CO ₂ compression	MW	400 \$ ₂₀₀₀ /kW	30 MW	0.67 ^g	h

^a Gas Turbine world [215]

^b Simbeck [216]

^c Hamelinck and Faaij [217]

^d [218] Lozza & Chiesa in Corradetti & Desideri [183]

^e A dual shift is costed as a shift of twice the capacity [217]

^f Williams [219]

^g Browne [213]

^h Lozza & Chiesa, Steam Reforming, Part II [133]

³⁰ The GDP (Gross Domestic Product) deflator can be defined as a measure of general inflation in the domestic economy. It reflects movements of hundreds of separate deflators for the individual expenditure components of GDP. The deflator is usually expressed in terms of an index, i.e. a time series of index numbers. More details about the GDP deflator and its use are available in [214]. The GDP deflator series used in the present study can be found in Appendix B.

³¹ The exchange rates used in this investigation can be found at: www.x-rates.com.

Table 6-2 *Estimated capital costs*

Plant Configuration	Baseline	ATRCC	IRCC
Gas turbine, £ ₂₀₀₈ M	31.24	31.5	30.9
ST/gen, BFW & CW, £ ₂₀₀₈ M	22.26	15.11	22.88
HRSG boiler, £ ₂₀₀₈ M	38.16	31.87	46.68
Pre-reformer, £ ₂₀₀₈ M	-	3.92	3.92
ATR, £ ₂₀₀₈ M	-	23.47	23.47
Shift ^b , £ ₂₀₀₈ M	-	14.36	14.36
Fuel Compressor, £ ₂₀₀₈ M	-	7.47	7.47
CO ₂ capture, £ ₂₀₀₈ M	-	9.95	9.95
CO ₂ compression, £ ₂₀₀₈ M	-	6.52	6.52
Cost of Process Facilities, £₂₀₀₈M	91.66	144.17	166.15
Cost of Engineering	7 % Cost of Process Facilities		
General Facilities	10 % Cost of Process Facilities		
Project Contingencies	10 % Cost of Process Facilities and General Facilities		
Process Contingencies (% of Process Facilities)	5 %	10 %	
Total Cost, £₂₀₀₈M	121.93	199.0	230.17
Specific Cost, £₂₀₀₈/kW	322.07	657.61	634.74

Table 6-3 and Table 6-4 summarise the range of investment costs for conventional power plants and for power plants using several pre-combustion CO₂ capture technologies respectively. The original capital costs figures, as collected from the literature, are presented in Appendix B. It is evident that there is a substantial variability concerning the capital cost of these plants. First of all, the range of the reported values is wide, since the plants considered vary greatly in terms of their capacity. For each case, different assumptions about the technical parameters used in cost calculations, as illustrated in the two tables, give rise to large differences in the final cost figures. Furthermore, as already stated in the first part of the chapter, due to the absence of a standard framework for the economic assessment comparisons across technologies turn out arduous and dubious. In fact, not every study includes the same cost items: generally Total Plant Cost is reported, but some studies also include owner's costs and interests during construction. However, it is challenging to interpret and compare results due to incomplete documentation of applied parameters values. Last but not least, the location of plant contributes to the variability characterising the capital cost figures collected. Despite such considerable uncertainty, the values estimated in the present study and reported in Table 6-2, even if preliminary, are quite well aligned with the ones available in the technical literature.

Tables 6-3 and 6-4 show also that O&M cost figures are considerably dissimilar across the different studies reviewed. The original O&M costs figures, as collected from the literature, are presented in Appendix B. Differences in O&M costs can be primarily ascribed to process related differences. This variability, which emerges from Tables 6-3 and 6-4, arises also from many different influencing assumptions about the performance and the operation of the plant such as plant size, plant efficiency, plant capacity factor. Moreover, in the O&M costs case, like in the capital cost case, varying level of documentation underlying data and assumptions adopted in the studies reviewed complicates the screening of the values.

Despite the efforts of the author, no indication about the distinction between fixed O&M costs and variable O&M costs has been found for the two pre-combustion schemes. Most of the reviewed studies, in fact, consider O&M costs as a percentage of the capital cost or just specify a value for such costs. The final values assumed in the present analysis are reported in Table 6-5. They derive from a study [220] that accounts for an IGCC power plant with CO₂ capture. Such assumption implies that the O&M costs will totally amount to about £10M/year and £12M/year for the ATRCC and the IRCC respectively. Such values appear to be an average of the values reported in Table 6-4. For the conventional combined cycle the values stipulated derive from the same study carried out by EPRI [220]: the total O&M costs aggregate about £7M/year and appear to be in the same range of others values proposed in the literature and reported in Table 6-3.

Other assumptions relevant to cost evaluation are listed in Table 6-5: a relatively high natural gas cost has been considered (the common value used in the literature is 3\$/GJ which corresponds to about £0.08/kg) to conform to midterm projections, and a typical price paid for base-load electricity generation has been adopted as electricity price. It is worth noting, however, that these parameters are quite volatile and therefore difficult to estimate.

The financing of the three investments being considered has been assumed 100% equity.

Table 6-3 Data collected for the conventional combined cycle

Data Description / Source	GT World 2007-08 [216]	Lozza & Chiesa [133]	Simbek [216]	IEA [221]	Parsons NETL [222]	Rezvani et al. [203]
Power Output	380 MW	373.2 MW	400 MW	485 MW	379 MW	380 MW
Decarbonisation process	-	-	-	-	-	-
CO ₂ capture technology	-	-	-	-	-	-
CO ₂ compression	-	-	-	-	-	-
Yearly operating hours	-	7000	6570	7884	7446	7446
Capital cost	270 ^a £/kW	126.3 ^b M£ (338 £/kW) 156.4 ^c M£ (418.2 ^c £/kW)	84.28 ^d M£ (264.29 £/kW) 101.4 ^e M£ (318.4 £/kW)	High Base Cost scenario ^f : 487 £/kW Low Base Cost scenario ^f : 308 £/kW	105.341 ^g M£ (277.8 £/kW) 135.547 ^h M£ (357.3 £/kW)	152.95 ⁱ M£ (402 £/kW)
O&M costs	-	0.17 c£/kWh	4% of capital per yr	5.57 M£/year	8.340 M£	Fixed operating cost: 19.3 £/kWe Variable operating cost: 0.22 £/kWh
Year of reference	2007	2000	1997	1998	1 st Quarter 2002	2005

a This figure includes cost of GT, ST, Unfired HRSG, Electric Generator, Balance of Plant (standard plant controls and auxiliary systems)

b Cost of process facilities

c Total Cost (balance of plant, cost of engineering, contingencies included)

d Cost of process facilities

e General Facilities included (costs exclude contingencies, “soft costs”, sales tax, VAT, interest during construction, owner’s costs)

f Fixed investment including reforming block, CO₂ block, combined cycle block, utilities block, contingencies. As the estimated cost of the base case combined cycle plant is considered to be subject to significant variation, depending on the location of the plant and information source, economic summaries are given for two cost scenarios (High Base Cost scenario and Low Base Cost scenario).

g Process Plant Cost

h Total Plant Cost (engineering fees, process contingency and project contingency included)

i Engineering and procurement costs (excluding contingencies and working capitals). Some indirect costs included.

Table 6-4 Data collected for the two pre-combustion cycles

Data Description / Source	Damen et al. [94]	Lozza & Chiesa [133]	IEA [221]	IEA [221]	IEA [221]	Parsons NETL [222]	Bolland et al. [223]
Power Output	600 Mwe	394 MW	479 MW	475 MW	489 MW	413 MW	1263 MW
Decarbonisation process	SMR/POX/ATR	Partial oxidation	SMR Recycle ^o	SMR Pressurised ^q	Catalytic POX ^r	Steam reforming	ATR
CO ₂ capture technology	Chemical/physical absorption	Chemical absorption	Chemical absorption	Chemical absorption	Chemical absorption	PSA	Chemical absorption
CO ₂ capture efficiency	85-90%	90%	85%	85%	85%	-	85-90%
CO ₂ compression	110 bar	80 bar	80 bar	80 bar	80 bar	145 bar	150 bar
Yearly operating hours	-	7000	7884	7884	7884	7446	-
Capital cost	709.5-1159 ^l £/kWe	179 ^m M£ (454 £/kW) 230.8 ⁿ M£ (586 £/kW)	High Base Cost scenario ^p : 800 £/kW Low Base Cost scenario: 619 £/kW	High Base Cost scenario ^p : 931 £/kW Low Base Cost scenario: 749.2 £/kW	High Base Cost scenario ^p : 723.7 £/kW Low Base Cost scenario: 547 £/kW	308.78 ^s M£ (747.7 £/kW) 397 ^t M£ (961 £/kW)	1079.8 ^u £/kW
O&M costs	3-6 % of TPC (Total Plant Cost)	0.205 c£/kWh	9.73 M£/year	10.87 M£/year	8.89 M£/year	21.874 M£	-
Year of reference	2003	2000	1998	1998	1998	1 st Quarter 2002	2000

^l Total Capital Requirement (TCR) includes TPC (Total Plant Cost), owners costs and interest of construction.

^m Cost of process facilities

ⁿ Total Cost (balance of plant, cost of engineering, contingencies included)

^o Conventional steam reforming but with gas turbine exhaust used as combustion medium for the reformer furnace

^p Fixed investment including reforming block, CO₂ block, combined cycle block, utilities block, contingencies. As the estimated cost of the Base Case combined cycle plant is considered to be subject to significant variation, depending on the location of the plant and information source, economic summaries are given for two cost scenarios.

^q Combustion air for the pressurised reformers is extracted from the discharge of the air compressor of the combined cycle gas turbine and the spent combustion air is returned to the gas turbine upstream of the combustion zone.

^r Catalytic partial oxidation of natural gas, using air extracted from gas turbine air compressor discharge.

^s Process Plant Cost

^t Total Plant Cost (engineering fees, process contingency and project contingency included)

^u Specific total installed cost

Table 6-5 *General assumptions for economic analysis*

Parameter	Unit	CC	ATRCC Value	IRCC
Plant lifetime	[year]		25	
Capacity factor	[hr/year]		7446	
Revenue tax rate	[%]		40	
Time period for depreciation	[years]		20	
Discount Rate	[%]		10	
Natural gas cost	[£/kg]		0.12	
Electricity price	[£/kWh]		0.03	
Fixed O&M costs	[£/kW]	5	12	12
Variable O&M costs	[p/kWh]	0.00191	0.00284	0.00284
Fuel price escalation	[%]		2	
Electricity price escalation	[%]		2.5	
O&M costs escalation	[%]		2	

The cumulative discounted cash flow trend against years of the lifetime is shown in Figure 6.7 for all the power plants being analysed in the case of no emission tax introduced. From this picture the advantage in the economic performance of the conventional combined cycle is quite evident: the baseline case, in fact, presents a much higher NPV (£131.7M) compared to the ATRCC (£-137.6M) and the IRCC (£-72.9M). This statement is further confirmed by the IRR evaluation, as summarised, along with the other results of the economic analysis, in Table 6-6. The baseline power plant appears to be convenient also in terms of PBP, with a value of approximately 7 years, whereas the ATRCC and the IRCC result to be characterised by a longer PBP³², exposing therefore the investor to the risk of not recovering the capital expenditure during the lifetime of the power generation plant.

Table 6-6 *Main economic results*

Economic Parameter	Unit	CC	ATRCC Values	IRCC
NPV	[£ ₂₀₀₈ M]	131.7	-137.6	-72.9
IRR	[%]	20.8	0.46	6.05
PBP	[years]	7.3	35 ³²	35 ³²
CoE	[p/kWh]	2.92	4.72	4.16
BESP	[p/kWh]	2.31	3.82	3.39
CAC	[£/ton]	-	60.7	40.5

³² The Economic Module attributes automatically to the PBP a value equal to the lifetime risen by ten years when the investment ends up with a negative NPV, indicating that the investors will not be able to recover the initial investment outlay during the investment lifetime.

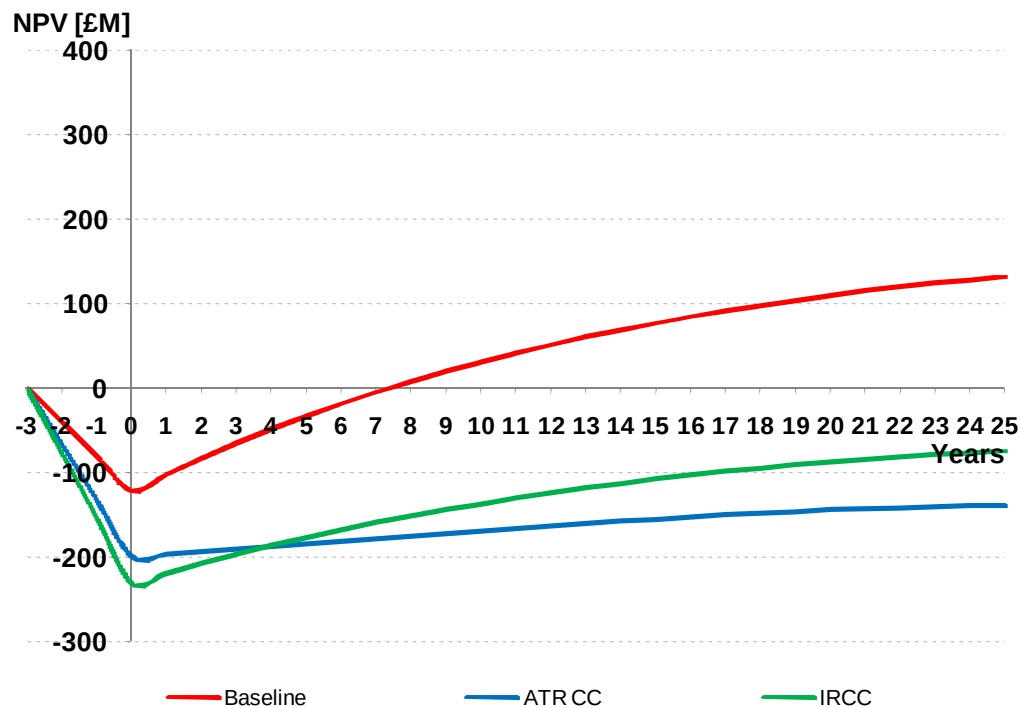


Figure 6.7 Cumulative discounted cash flows without carbon tax

It is proper to underscore that the preliminary model implemented in the Economic Module, as illustrated in Figure 6.2, assumes that all electricity produced is sold, without taking in account any spark-spread factor (i.e. the gross margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity). Under free-market trading conditions, such as in the U.K. power market, power generation firms would not operate plant under non-profitable conditions (for any significant length of time). If the commercial conditions are such that a particular plant is not profitable, other plant is used in preference. For the power generation market, plant is traded as the commercial situation dictates, without a contract to deliver specific amounts of power. This situation is different in CHP-type applications where plant is dedicated to a specific customer. On the other hand, to the knowledge of the author, in the case of long-term perspective, as in this investigation, it is quite common to assume a (constant or with some trend) price for the electricity³³. The modelling details dealing with periods in which the electricity price will be lower than the operational costs of the power plants are only included in short-term models (with hourly steps). This modelling approach would require eventually to consider the power plant as participating in a

³³ Personal communication with Mr Mauro De Angelis from Tirreno Power (Rome-Italy) and Adela Pages from NTNU (July 2009).

market, and thus to model somehow the competitors. This approach is beyond the objective of the present study and therefore plausible assumptions have been made on the generation of a particular power plant.

To address this issue and to guide the analyst in stipulating the aforementioned assumptions, the Economic Module offers the investors the possibility of evaluating the BESP, as discussed in the following in this chapter, to give a view of the conditions of competitiveness to which the firm can be subjected to.

As anticipated at the opening of this paragraph, CoE becomes considerably higher when fuel decarbonisation and CO₂ sequestration sections are included in the plant due to the higher capital costs, the higher O&M costs and the higher fuel consumption compared to the baseline case. The ability to remove CO₂, provided by the two pre-combustion cycles, yields to an increase of the electricity cost from 2.92 p/kWh, value estimated for the baseline, to 4.72 p/kWh and 4.16 p/kWh for the ATR and the IRCC respectively. The values provided are averaged over the 25 years of the lifespan of the plant and therefore are greatly affected by the stipulated escalation. The two pre-combustion schemes have electricity costs substantially higher than the baseline combined cycle due to their higher capital costs and lower net efficiencies.

In Figures 6.8 – 6.10 the costs of electricity generation for the first year of operation of the three power plants being considered are broken down into capital charges, operation and maintenance and fuel costs, showing the relative importance of the costs met to produce electricity. It is shown that the main cost for the conventional power plant is represented by the fuel cost. This is confirmed also for the CO₂ capture power plants being considered, for which however the capital charges become more significant. Such evaluation of the CoE relies on the important assumption of equal capacity factor for the three plants. It is highly likely that the two advanced plants will be characterised by a lower capacity factor, especially for the first years of operation. Therefore, the picture given in Figures 6.8 – 6.10 may change significantly. The CoE during the lifetime of the plant is affected in the model here applied by fuel price escalation and O&M cost escalation; however the relative importance of these costs, shown in Figure 6.8 – 6.10, is substantially confirmed.

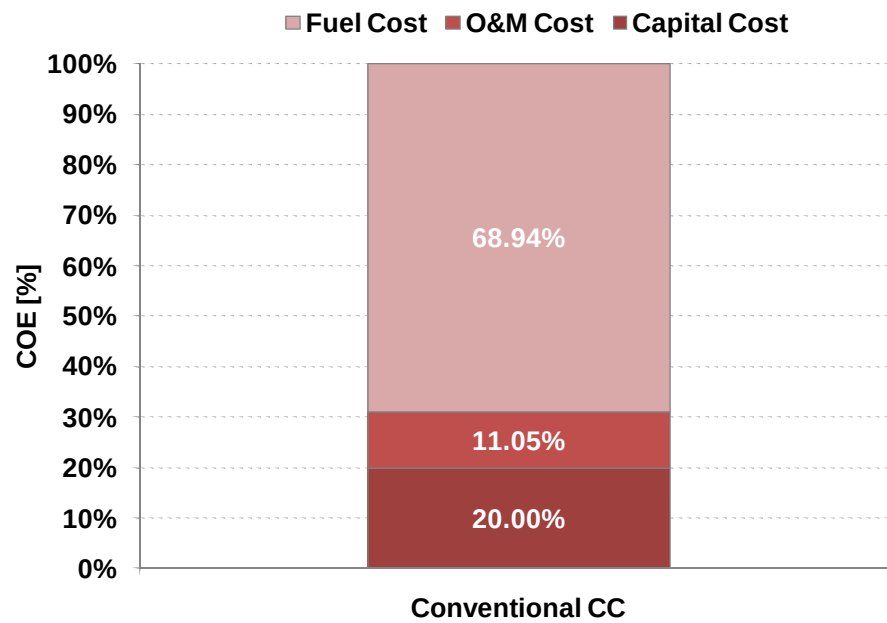


Figure 6.8 Breakdown of CoE for the conventional combined cycle.

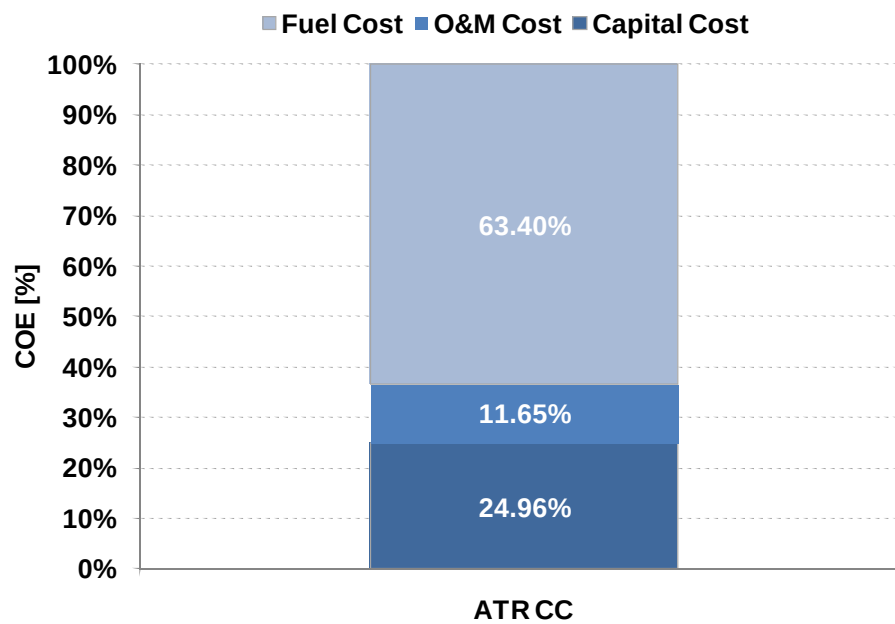


Figure 6.9 Breakdown of CoE for the ATRCC.

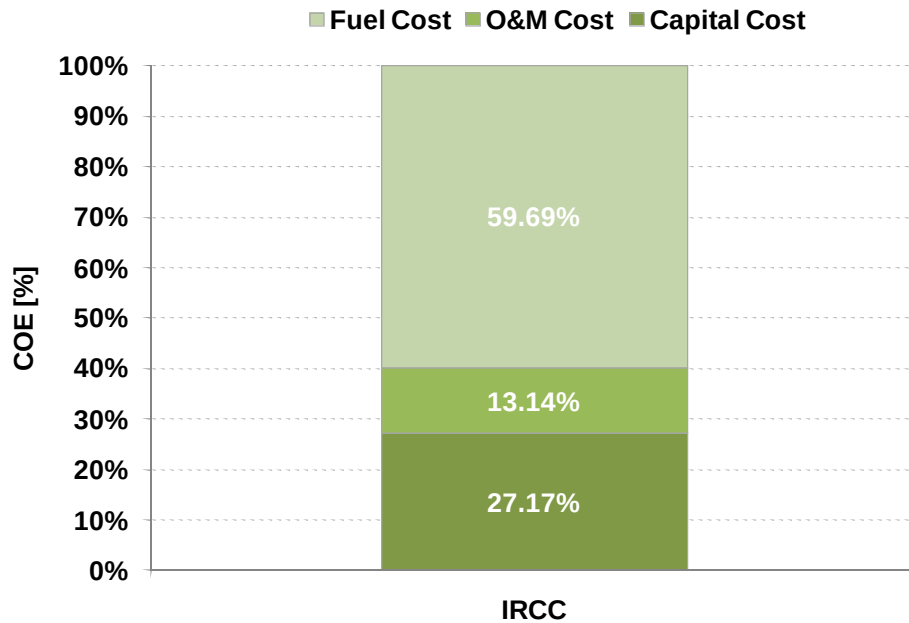


Figure 6.10 Breakdown of CoE for the IRCC.

A first outcome of the economic analysis, therefore, shows the current inconvenience and infeasibility of producing and selling electricity by reforming natural gas at the assumed value of selling electricity price for base load applications (3p/kWh).

Among the economic parameters evaluated and listed in Table 6-6, the CAC turns out to be particularly meaningful. The CAC, calculated according to the equation 6.11, represents the minimum carbon tax necessary for the ATRCC and the IRCC to be economically competitive with the reference plant: in other words it represents practically the tax to pay for each ton of CO₂ emitted into the atmosphere by the conventional reference CC owner so that the baseline CoE results equal to that produced with the advanced cycles proposed. The CAC can be read directly from Figure 6.11, which illustrates clearly this concept. Figure 6.11 shows, in fact, the cost of electricity of each candidate power plant for different values of carbon tax, illustrating how for all power plants being considered the electricity unit cost increases as the carbon tax increases. In the CC case the CoE results to be much more sensitive than the two pre-combustion schemes due to the considerable amount of CO₂ emitted (361g_{CO2}/kWh against 64g_{CO2}/kWh for the ATRCC and 53g_{CO2}/kWh for the IRCC). Figure 6.11 shows the so-called break-even point between the imposition of a carbon tax and the use of a sequestration plant for the power plants being considered. Such value corresponds to the CAC evaluated and displayed in Table 6-6. The break-even with the conventional combined cycle can be found for a carbon tax of about £40/ton and £60/ton for the ATRCC and IRCC

respectively. Therefore, if the carbon tax is higher than that corresponding to these points, then the plant being considered would be cost-effective with respect to the reference plant³⁴; the opposite occurs if the carbon tax is lower. The results reported in Figure 6.11, along with the other results reported in Table 6-6, are not very encouraging for the ATRCC scheme, because the carbon tax needed to make it competitive is higher than that required for the competitiveness of the IRCC scheme. This is mainly because of its smaller power production and lower efficiency.

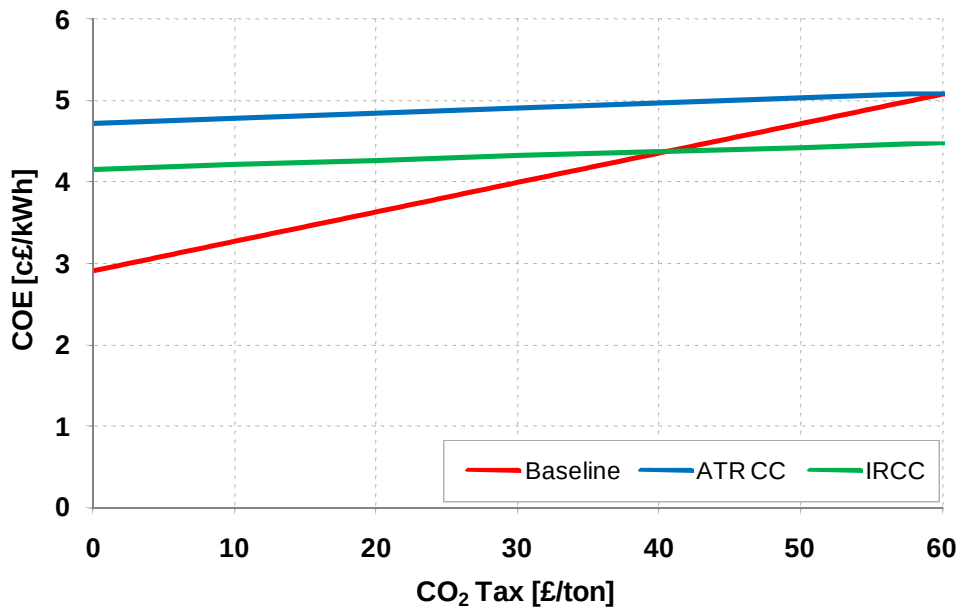


Figure 6.11 Cost of electricity versus Carbon Tax

The introduction of a carbon tax however will call for an increase of the electricity selling price, as Figure 6.12 clearly exemplifies. This figure, in fact, shows the rise of BESP for the three case studies due to the introduction of a carbon tax. The IRCC scheme appears more attractive in terms of BESP since electricity can be selling at lower price than CC or ATRCC plants in presence of a considerable carbon tax. The values of BESP shown in Figure 6.12 are quite lower than the average CoE shown in Figure 6.11 and therefore could lead to a sort of misinterpretation. It must be noted that the CoE values represented in Figure 6.11 are average figures over the 25 years lifetime of the power plant and, therefore, as already mentioned, they are significantly affected by escalation applied to fuel price and O&M costs. Contrarily, the BESP value reported in Figure 6.12 refers at the “time zero” of the investment, without the

³⁴ The value of CAC depends significantly on the choice of the reference plant, as already highlighted in Chapter 3.

application of the escalation stipulated for the electricity price (2.5%), and thus is lower than the average CoE. To avoid any misleading, in Appendix B, the cost of electricity is compared with the BESP averaged over the lifetime of the plant, showing the validity of the model's calculation.

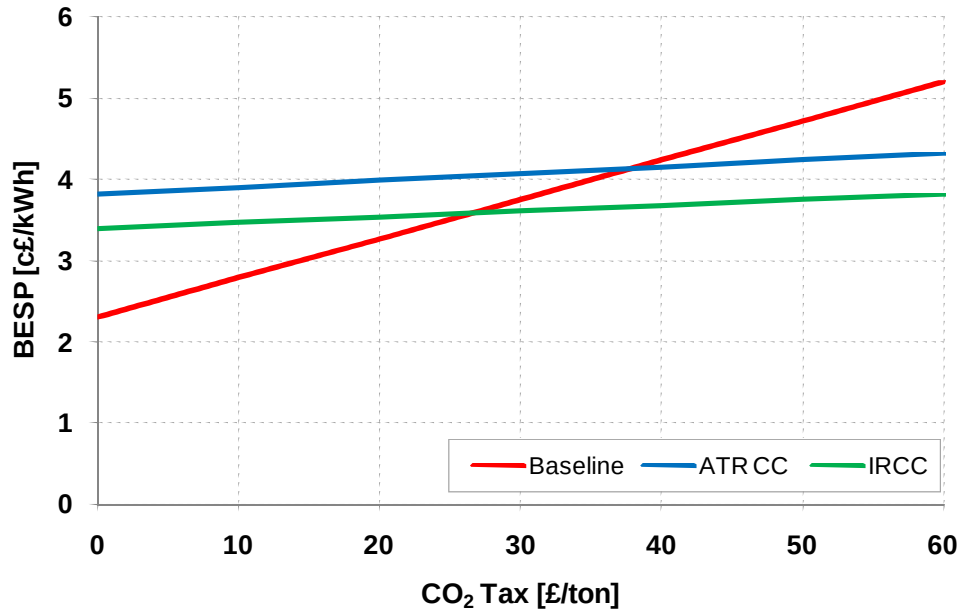


Figure 6.12 Break-even selling price versus carbon tax

With these remarks in mind a new scenario (NS) has been considered in which a carbon tax of £50/ton³⁵ and an electricity price of £0.05/kWh have been stipulated. Figure 6.13 reports the NPV trends as depicted by Figure 6.7 (for electricity price of £0.03/kWh and no emissions tax) and the NPV trends in the new scenario, providing a comparison among the three schemes being considered. In the case of no emission tax, as already stated, it is clear that the baseline has higher NPV, but, in the new scenario, the NPVs are subjected to a variation that is quite pronounced. The NPV achieved from the IRCC at the end of the plant life is much higher than the CC one (£228M against £53M). Figure 6.13 also reveals the increase in payback time related to the introduction of the tax, in particular for the conventional combined cycle. Table 6-7 summarises the economic results for the new scenario being considered and demonstrates clearly the better economic performance of the two advanced cycles – in particular the IRCC – compared to the conventional one. It is proper to highlight that the CoE and the BESP increase in proportion to the

³⁵ Even if a carbon tax greater than £50/ton had been stipulated, the final outcome would have confirmed the economic superiority of the IRCC scheme over the ATRCC one.

power plant carbon dioxide release, that for the CCS based plants depends on the carbon capture rate³⁶.

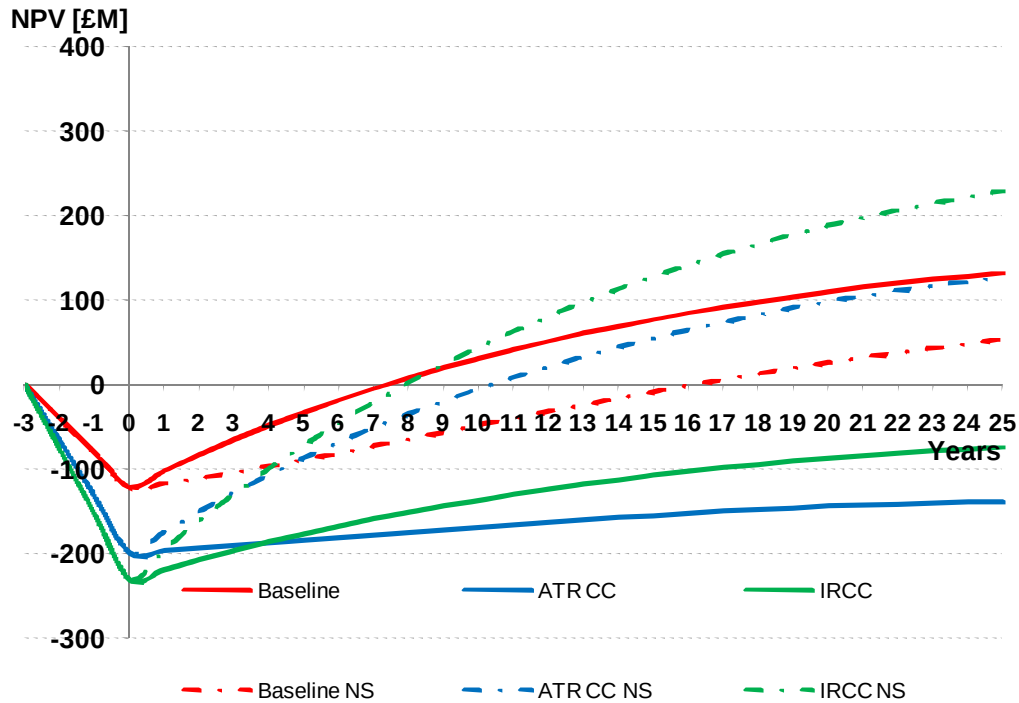


Figure 6.13 Cumulative discounted cash flows with a carbon tax of £50/ton

Table 6-7 Main economic results (with a carbon tax of £50/ton)

Economic Parameter	Unit	Values		
		CC	ATRCC	IRCC
NPV	[£ ₂₀₀₈ M]	53	115.6	228.7
IRR	[%]	13.43	15.9	19.9
PBP	[years]	16	10.9	7.8
CoE	[p/kWh]	4.72	5.04	4.4
BESP	[p/kWh]	4.73	4.24	3.75

The elaboration of the above results clearly highlights that carbon dioxide sequestration realised by the two pre-combustion schemes becomes economically feasible and sustainable in a deregulated energy market only if a heavy carbon-tax (£40/ton for the IRCC and £60/ton for the ATRCC) is imposed on power plant carbon dioxide emissions and an higher electricity selling price is accounted for.

³⁶ In this respect, a techno-economic optimisation of the power plant being considered, as mentioned in Chapter 2, could deliver useful insight regarding trade-off between efficiency penalty, costs and carbon capture rate.

However, it is worth noting also that capital and O&M cost estimates are very preliminary, due to the great variability surrounding them, and that the figures given in this study may change significantly once more accurate estimates will be available or if such uncertainty is taken into account. The analysis presented hinges also on the capacity factor assumption and above all on the hypothesis that the addition of CO₂ capture technology to a power plant does not impact the capacity factor. This assumption appears to be preliminary especially if the implications of running a power plant which is characterised by O&M cost as double as a conventional one is considered.

Despite the efforts of the author, no direct validation can be provided for the economic figures here reported: the CoE values estimated by other studies are not suitable for such a comparison due to the enormous difference in plant layout and economic assumptions (e.g., the power plant designated as the baseline). To the author's knowledge, no data regarding the financial indices considered in the present study are available in the public domain.

6.7 Financial Risk Analysis: Results and Discussion

A preliminary comparative estimate giving a sense of the conditions under which the advanced power plants being investigated can be competitive with each other and with a conventional power plant has been performed and the main results have been reported in the previous paragraph. Nevertheless, as already outlined in the first part of the chapter and showed through the literature review reported in the previous paragraph, at the current stage of CCS development, costs are very uncertain, because of the limited experience gained so far. Moreover, the fuel price is subject to fluctuations and the pollution control regulations are not clearly defined. These factors introduce inaccuracies to any cost analysis of power generation projects. In the present analysis these ambiguities are minimised by the application of Monte Carlo method.

As already stated in Paragraph 6.4.4, a sufficiently large number of samples are necessary to achieve undistorted results. As a matter of fact, the value of outcome parameters dampens and stabilises as the number of iterations increases. The iterations are carried out according to the procedure represented in Figure 6.5. In the present analysis the number of iterations has been set at 15000: at 15000 simulation's runs results become stable reaching convergence and presenting very small variation (less than 10^{-4}) in the mean and standard deviation values. Figure 6.14 shows the convergence for the CoE mean case. Moreover the shape of the resulting probability distribution does not change increasing the number of sample above 15000. Appendix B reports the same plot for the other output parameters (NPV, IRR, PBP,

BESP), confirming the size of samples required to ensure satisfactory convergence of the simulations' results.

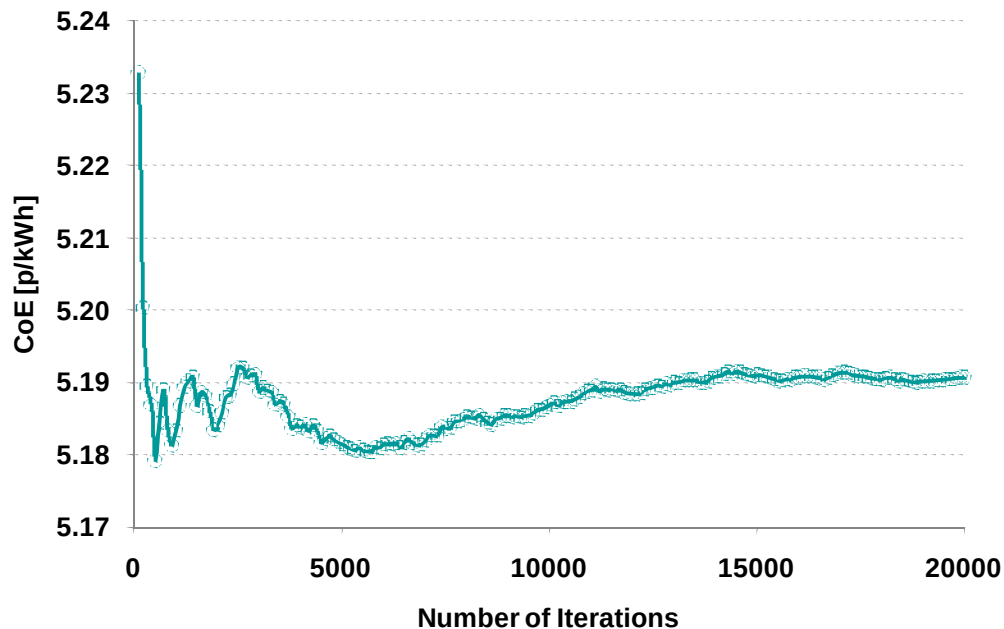


Figure 6.14 *CoE convergence*

Tables 6-8 and 6-9 describe the main features of the probability distributions selected in the present analysis for the capital costs, the fuel price, the O&M costs and CO₂ tax³⁷. As it is revealed in Table 6.8, the parameters of these distributions correlate very closely with the input parameters originally applied to carry out the deterministic analysis presented in the previous paragraph. Such subjective probability distributions for the key parameters were developed making use of results gathered through the literature review and reported in Tables 6-3 and 6-4.

Since no precise information is currently available, the carbon tax has been assumed to be normally distributed around the value of £50/ton adopted in the second scenario investigated in the previous paragraph. The normal distribution, in fact, is often assumed for future predictions.

³⁷ Another important risk variable is represented unquestionably by the electricity price. This variable is included in the current version of the Economic Module. However, the difficulty of modelling long-term projects highlighted in paragraph 6.6 deterred the author from including electricity price in the present analysis.

Table 6-8 *Probability distributions for the risk variables: range of values simulated*

Risk Variables	Baseline			ATRCC			IRCC		
	Minimum Value	Deterministic Value	Maximum Value	Minimum Value	Deterministic Value	Maximum Value	Minimum Value	Deterministic Value	Maximum Value
Specific Capital Cost (£/kW)	270	322.07	450	400	657.61	950	400	634.74	900
Total Capital Cost (£M)	102.23	121.93	170.37	121	199	287.5	145	230.17	326.3
Fuel Price (£/kg)	0.08	0.12	0.16	0.08	0.12	0.16	0.08	0.12	0.16
Carbon Tax (£/ton)	28.6	50	72	28.6	50	72	28.6	50	72
O&M delta	-0.4	0	0.45	-0.55	0	1.5	-0.55	0	1.5
O&M Costs (£M/year)	5	7.2	8.5	6.8	10.2	18.8	7.9	12.2	23.3

Table 6-9 *Probability distributions for the risk variables: characteristics*

Risk Variables	Probability Distribution	Parameters of probability Distribution
Capital Cost	Triangular	Optimistic, pessimistic and most likely values as specified in the previous table
Fuel Price	Beta ³⁸	$\alpha = 12$ $\beta = 20$
Carbon Tax	Normal	Mean = £50/ton Standard deviation = 5
O&M Costs	Beta ³⁸	$\alpha = 12$ $\beta = 20$

³⁸ The general formula for the probability density function of the beta distribution is: $f(x) = \frac{(x-a)^{(\alpha-1)}(b-x)^{(\beta-1)}}{B(\alpha,\beta)(b-a)^{\alpha+\beta-1}}$, where α and β are the shape parameters, a and b are the lower and upper bounds of the distribution, and $B(\alpha,\beta)$ is the beta function. The shape parameters are reported in Table 6-9, while the lower and upper bounds are detailed in Table 6-8.

The fuel price subject to uncertainty was simulated using a beta distribution positively skewed. Such distribution presents a tail toward high values to take in account future projections and a lower value equal to £0.08/kg (3 \$/GJ), which has been widely used in several economic studies [183, 196]. The mean of this distribution is coincident to the value of £0.12/kg stipulated in the first part of the analysis.

A triangular probability distribution was developed and used to reflect forecasts of the capital cost: in Table 6-9 the estimates of the optimistic, most likely, and pessimistic values of capital costs - input parameters for the probability distribution- are illustrated for the three alternatives, assuming that the deterministic value used in the first step of the analysis coincide with the most likely value.

O&M costs uncertainty³⁹ was simulated again using a beta distribution, whose characteristic parameters were specified in order to reproduce the range of O&M costs found in the literature and summarised in Table 6-4: in the CC case the O&M costs resulting from the probability distribution vary between £5M/year to £8.5M/year, while for the ATRCC scheme they cover a range between £6.8M/year to £18.8M/year. Regarding the IRCC, the random value they can assume results to be included between £7.9M/year and £23.3M/year.

Given the paramount importance held by the selection of probability distributions in any Monte Carlo simulation, it must be highlighted that the probability distributions estimation in this investigation is introductory and valid only for a preliminary analysis, since expert judgments could not be obtained in the time frame available and the author offered her own judgments based on literature review and data analysis. However, the exercise of estimating distributions had the benefit of encouraging the author to think in terms of uncertainty during the analysis and to handle a stimulating risk management approach. On the other hand, despite the preliminary choice of probability distributions, the method still keeps its validity as a means to gain understanding into the role that uncertainty surrounding key factors can play in determining the failure or the success of a project, along with the advantage to scrutinize scenarios not valuable by sensitivity analysis.

As anticipated in paragraph 6.5, the model implemented in the Economic Module assumes that the risk variables selected are independent. It is highly likely that there will be no any strong interrelationships between the variables here considered. There could be some relationships between Capital cost and O&M costs, in that if economies are made to minimise Capital cost it is likely that more maintenance and

³⁹ The model receives as input the *degree of variation* of the specific O&M costs (variable and fixed), which is generated by the selected probability distribution, and applies the following relationship to the deterministic values: Specific O&M Cost = Specific O&M Cost_{Deterministic} + (Specific O&M Cost_{Deterministic} × *degree of variation*).

component replacements will be necessary⁴⁰. However, if appropriate specification of plant is carried out, this should not be the case. In the future it is likely that power produced from renewable sources will be highest in the merit order⁴⁰ and that plant fuelled by other sources will not be used for extended base-load operation. Therefore the intervals between maintenance may increase. However, field-experience indicates that operating plant in flexible regimes significantly increases the rate of component deterioration, so that O&M costs are likely to be influenced by both the total number of hours (capacity factor) and the number of start-stop cycles the plant does.

Other input parameters correspond to the ones applied in the scenario with a carbon tax (new scenario) investigated in the first part of the analysis. They are listed in Table 6-5, with the exception of the carbon tax that is assumed equal to £50/tonne.

Results related to the all five output parameters of the model could be presented and commented on, but the limited space available in this dissertation required choices driven by the relevance. However, results related to the other output parameters are collected in Appendix B. Among the output parameters of the Economic Module, the cost of electricity is a comprehensive measure of a plant's economic viability, because it is based on and sensitive to all of the performance and cost factors which affect the economics of a power generation plant. On the other hand, the investment-oriented approach of the present investigation suggests also to address more specific financial indices. In the light of this remark, the uncertainty in the CoE and the NPV estimation due to the four risk variables being considered is illustrated and discussed in the following.

6.7.1 The Conventional GT Combined Cycle

As far as the conventional power plant designated as the baseline of the present investigation is concerned, in Figures 6.15-6.19 the CoE related results are displayed as cumulative probabilities, whereas the distributions parameters are summarised in Table 6-10.

As it is shown in Figure 6.15, the risk of fuel price volatility is manifested in a long upward tail of the cost of electricity probability distribution. From the probabilistic simulation for the fuel price uncertainty (Table 6-10) it derives that the range of possible values for the CoE is from 4.27 p/kWh to 5.616 p/kWh. The mean value, approximately 4.8 p/kWh, is higher than the deterministic estimate of 4.72 p/kWh. There is about a 68% chance that cost of electricity would be higher than the deterministic estimate.

⁴⁰ Personal communication with Mr Martyn Adams from E.ON U.K. Ltd (July 2008, January 2010).

Table 6-10 *CoE results for the baseline*

CoE					
	Mean Value	Standard Deviation	Coefficient of Variation	Minimum Value	Maximum Value
Fuel Price	4.810	0.177	0.037	4.270	5.616
Carbon Tax	4.720	0.181	0.038	3.979	5.609
Capital Cost	4.760	0.056	0.012	4.647	4.910
O&M Costs	4.696	0.024	0.005	4.619	4.788
All Variables	4.817	0.258	0.053	3.830	5.903

Among the uncertain variables being taken into account, the uncertainty in the carbon tax gives rise to the highest variability of the CoE value which ranges from about 3.979 p/kWh to over 5.6 p/kWh. There is almost a 50% chance that the cost of electricity would be higher than the “best guess” estimate evaluated in the deterministic part of the analysis.

The range of uncertainty in the CoE varies by a factor of 1.05 from the lowest to the highest values if capital cost uncertainty is taken in account. In addition, the mean value of the probability distribution is higher than the deterministic estimate, with a considerable probability (approximately a 70%) that the CoE could be higher than such deterministic estimate. As for capital costs, the inclusion of uncertainties for operating and maintenance cost broaden the CoE value range from 4.619 p/kWh to 4.788 p/kWh and determine a 13% chance that the final value of the cost of electricity could be higher than the deterministic one. Interactions among uncertainties in the four cost parameters selected as risk variables lead to a significant uncertainty in the cost of electricity. Taking into account the uncertainty distributions for all risk variables, the CoE varies from 3.83 p/kWh to 5.903 p/kWh, with a more than 65% likelihood of exceeding the deterministic estimate. Therefore, Figure 6.19 suggests that use of the deterministic cost estimate would expose the decision-maker to a substantial chance of a cost increase.

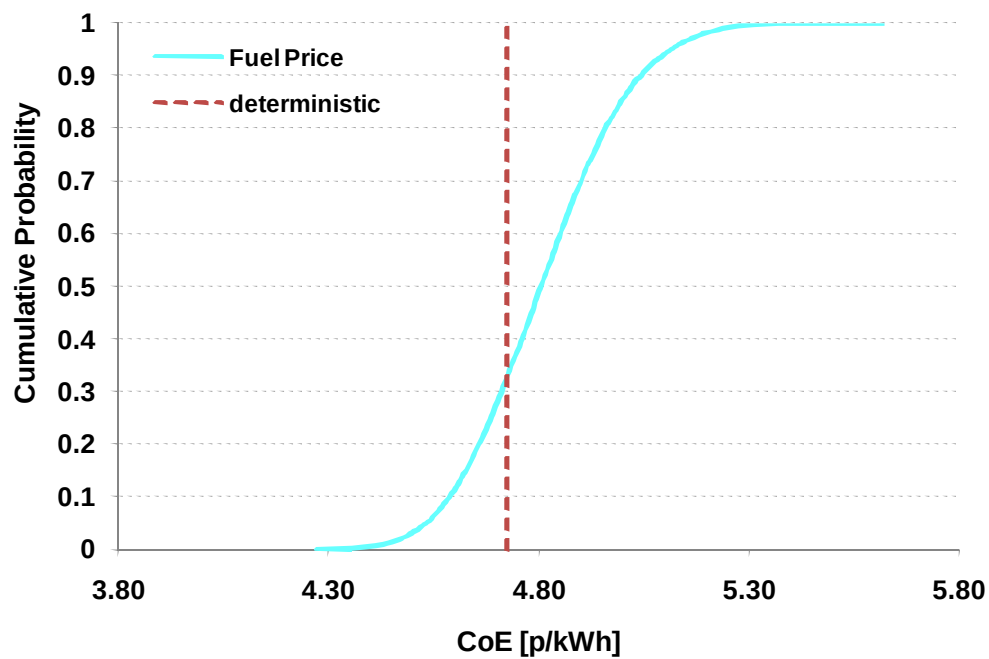


Figure 6.15 CoE for the baseline: effect of uncertainty of fuel price

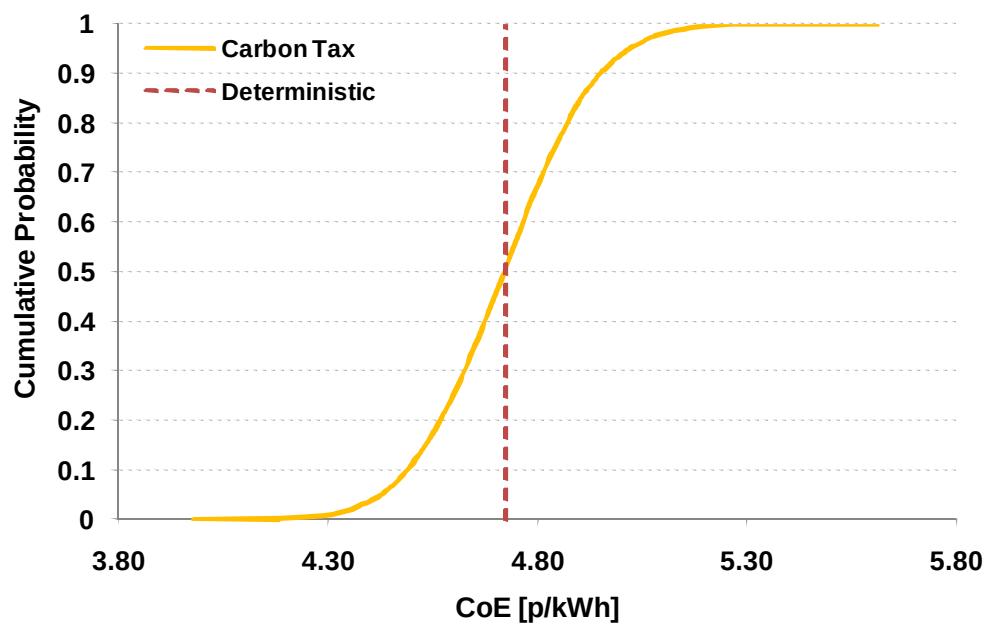


Figure 6.16 CoE for the baseline: effect of uncertainty carbon tax

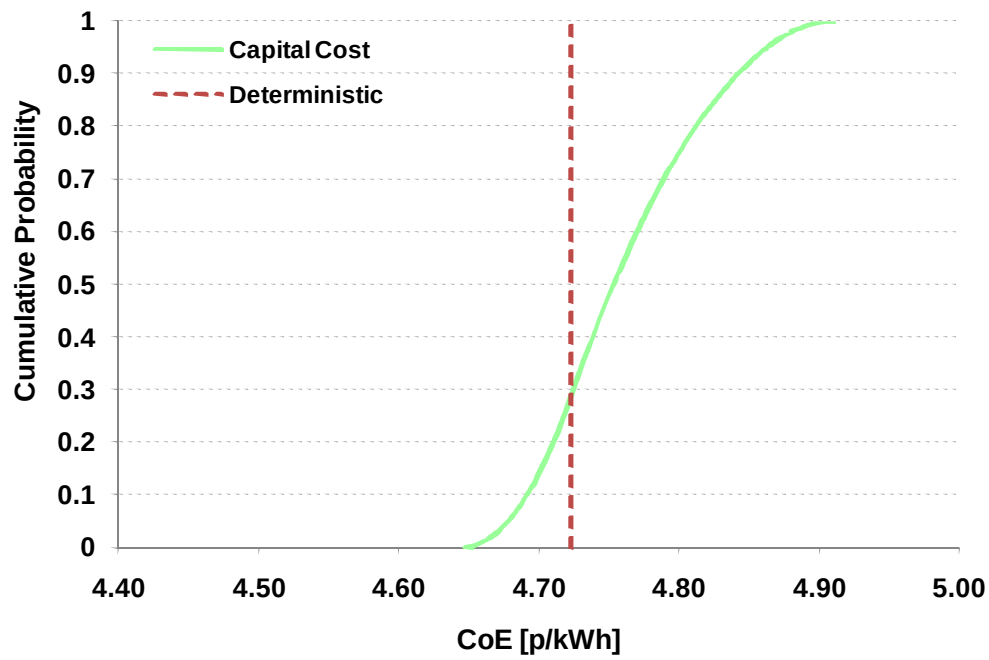


Figure 6.17 CoE for the baseline: effect of uncertainty of Capital Cost

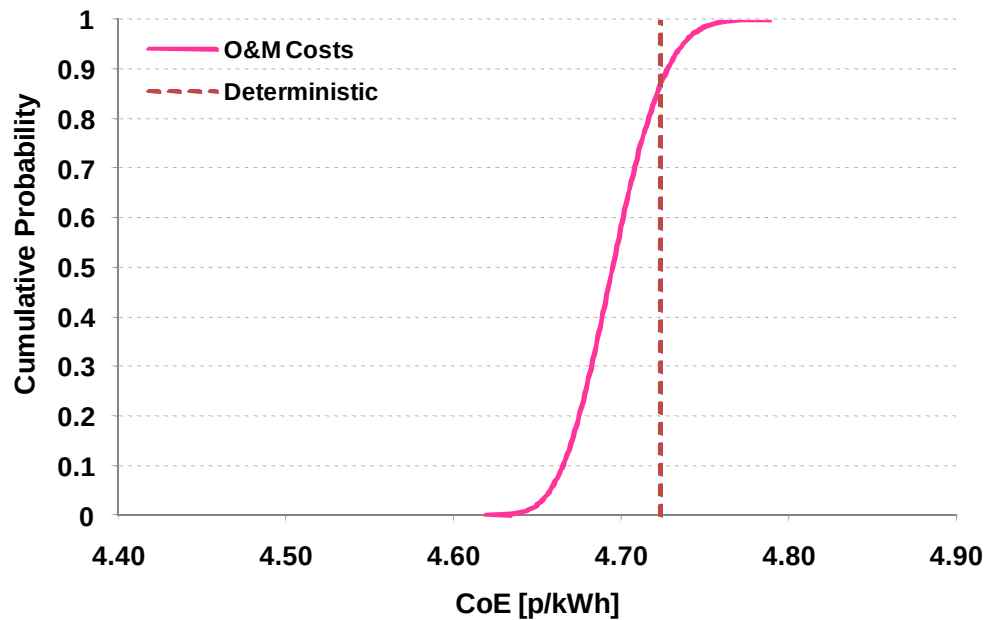


Figure 6.18 CoE for the baseline: effect of uncertainty of O&M Costs

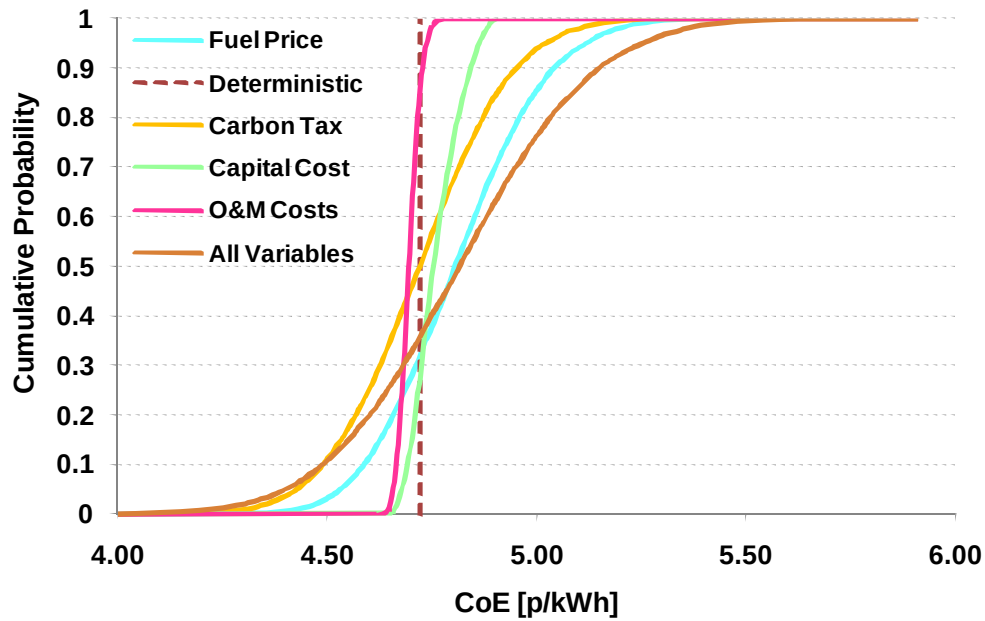


Figure 6.19 CoE for the baseline: effect of uncertainty of all risk variables

6.7.2 The ATRCC

The results of the financial risk analysis reveal meaningful information also with respect to the economic feasibility of the two pre-combustion schemes being investigated. The cumulative probability distributions for the cost of producing electricity by reforming natural gas in the ATRCC scheme are displayed in Figures 6.20-6.24. The indicative distribution parameters are summarised in the Table 6-11.

Table 6-11 CoE results for the ATRCC

	CoE				
	Mean Value	Standard Deviation	Coefficient of Variation	Minimum Value	Maximum Value
Fuel Price	5.172	0.266	0.051	4.359	6.386
Carbon Tax	5.041	0.032	0.006	4.910	5.199
Capital Cost	5.057	0.167	0.033	4.666	5.469
O&M Costs	5.169	0.099	0.019	4.842	5.571
All Variables	5.315	0.330	0.062	4.319	6.654

From the probability distribution shown in Figure 6.20, it can be determined that there is more than 70% chance that the annual cost of producing electricity will lie between 5.042 p/kWh (deterministic value) and 6.386 p/kWh, if the fuel price is treated as uncertain. Table 6-11 highlights quite high standard deviation in the simulated CoE values, which are included between 4.359 and 6.386 p/kWh.

The results reported in Table 6-11 show also a substantial increase in the standard deviation to 0.167, as a result of the capital cost variability. The expected CoE increases slightly to 5.057 p/kWh (mean value) from the deterministic value of 5.042 p/kWh. The standard deviation of the Capital cost effect is also higher than that of the O&M case, indicating that the uncertainty associated with CoE due to variability of capital cost is greater than uncertainty associated with CoE due to O&M costs variability. In the Capital cost case, in fact, the CoE value varies between 4.67 p/kWh and 5.47 p/kWh, with a 52% chance that the CoE could be higher than the deterministic figure. The chance of exceeding the deterministic value is quite marked in the case of O&M costs' uncertainty (about 90 %) since the resulting CoE mean value is quite higher than the deterministic one (5.169 p/kWh against 5.042 p/kWh).

The assumed carbon tax variability contributes least to the total uncertainty of the CoE. The shape of the resulting probability distribution, almost vertical and very close to the deterministic value, reveals a certain insensitivity of the CoE to the carbon tax. Such feature is further elucidated by the distribution parameters reported in Table 6-11: the standard deviation (0.032) is the lowest one and the mean results to be quite close to the deterministic estimate. The interactions among uncertainties are illustrated graphically: Figure 6.24 shows the uncertainty in the CoE resulting from the four variables uncertainties only and from the combined interactions simultaneously. The likelihood that the forecasted CoE value can exceed the deterministic value is quite marked (about 80%) in the case of simultaneous variation of the risk variables. Fuel price-related uncertainties are seen to be the dominant source of the positive skewness in the cost of electricity.

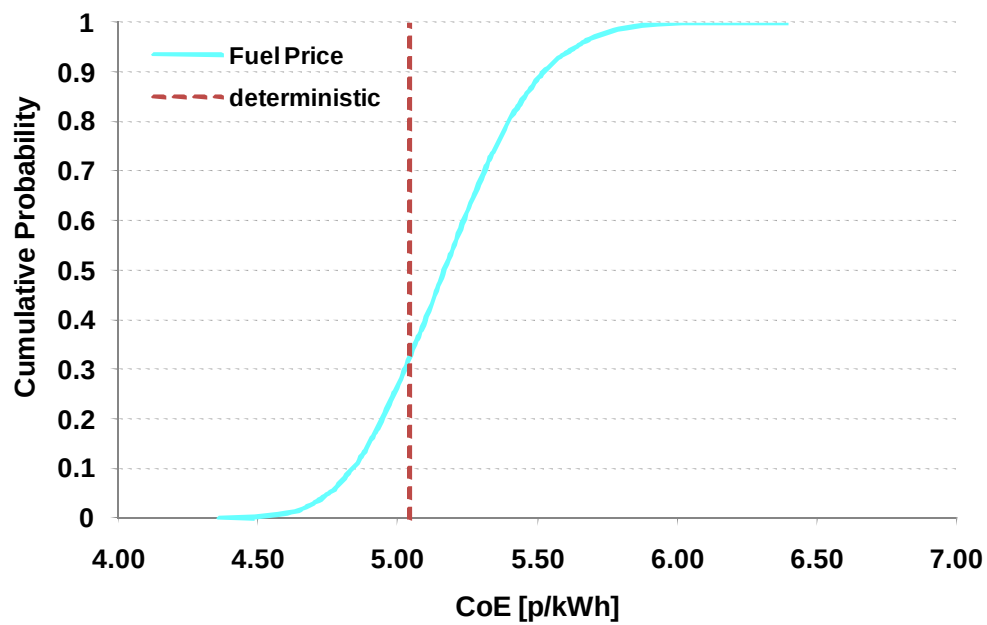


Figure 6.20 CoE for the ATRCC: effect of uncertainty of fuel price

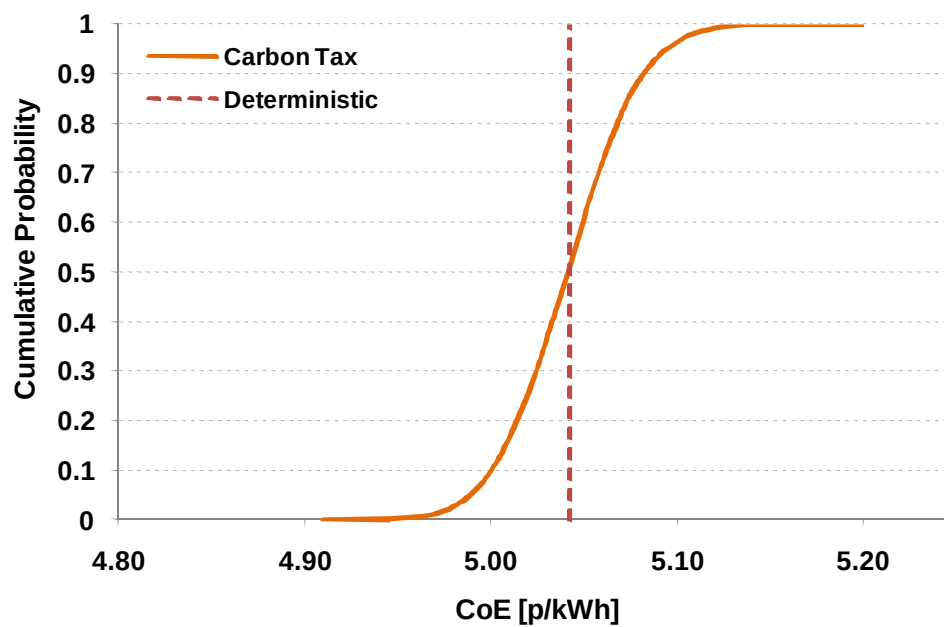


Figure 6.21 CoE for the ATRCC: effect of uncertainty of carbon tax

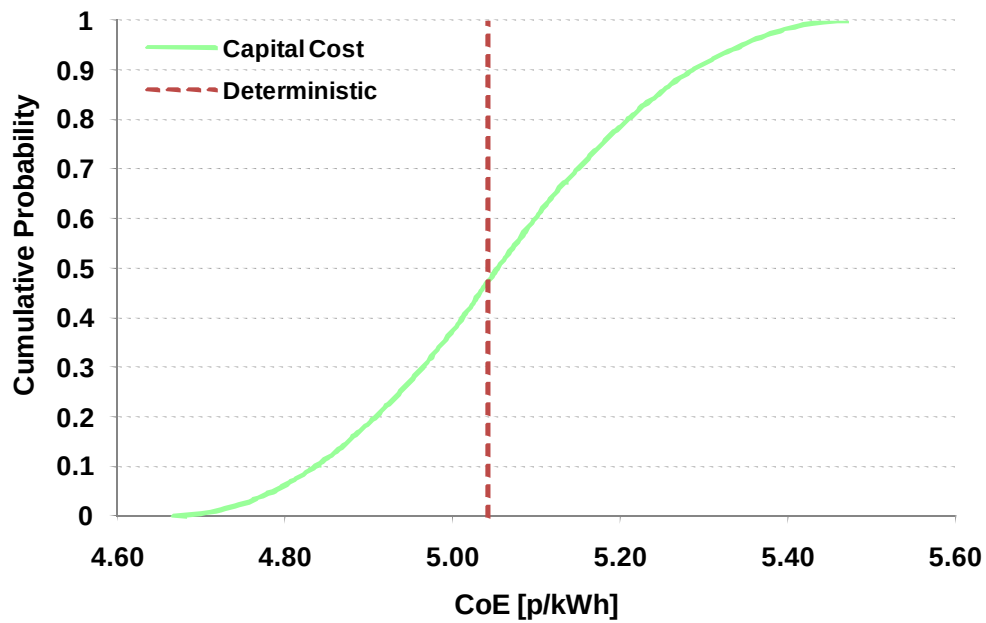


Figure 6.22 CoE for the ATRCC: effect of uncertainty of Capital Cost

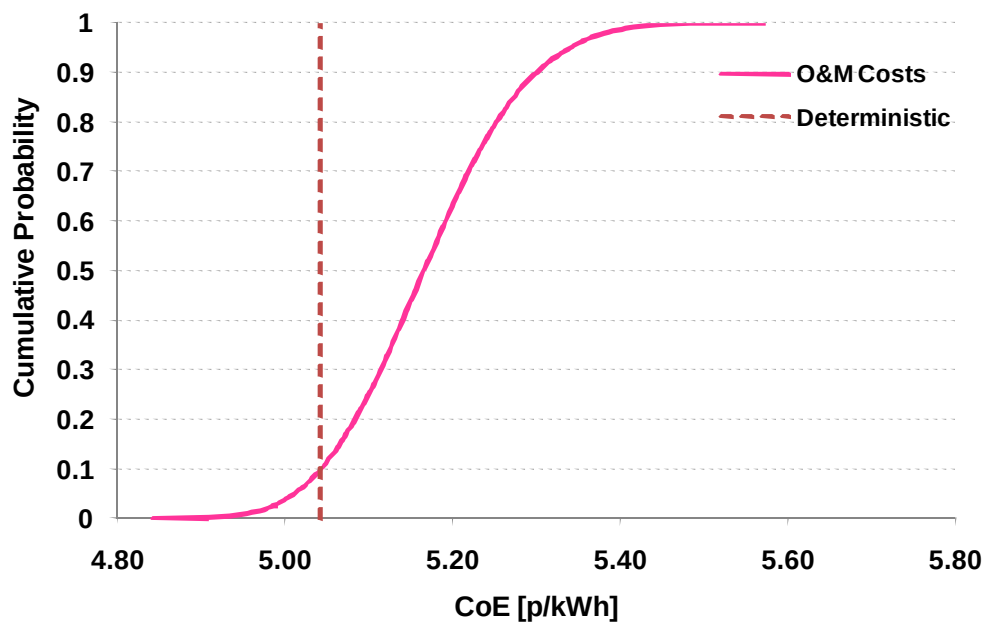


Figure 6.23 CoE for the ATRCC: effect of uncertainty of O&M Costs

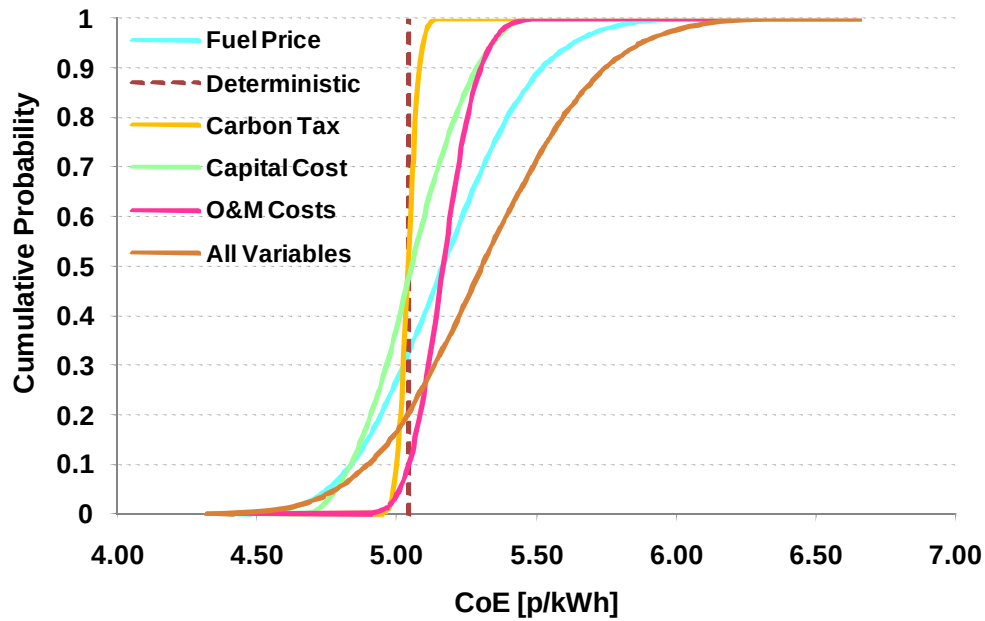


Figure 6.24 CoE for the ATRCC: effect of uncertainty of all risk variables

6.7.3 The IRCC

Table 6-12 reports the characteristics of the resulting probability distributions for the CoE in the IRCC scheme case. The cumulative probability distributions are instead represented graphically in Figures 6.25-6.29.

Table 6-12 CoE results for the IRCC

	CoE				
	Mean Value	Standard Deviation	Coefficient of Variation	Minimum Value	Maximum Value
Fuel Price	4.540	0.222	0.049	3.861	5.553
Carbon Tax	4.430	0.027	0.006	4.321	4.562
Capital Cost	4.447	0.151	0.034	4.085	4.819
O&M Costs	4.558	0.099	0.022	4.231	4.960
All Variables	4.683	0.286	0.061	3.696	5.766

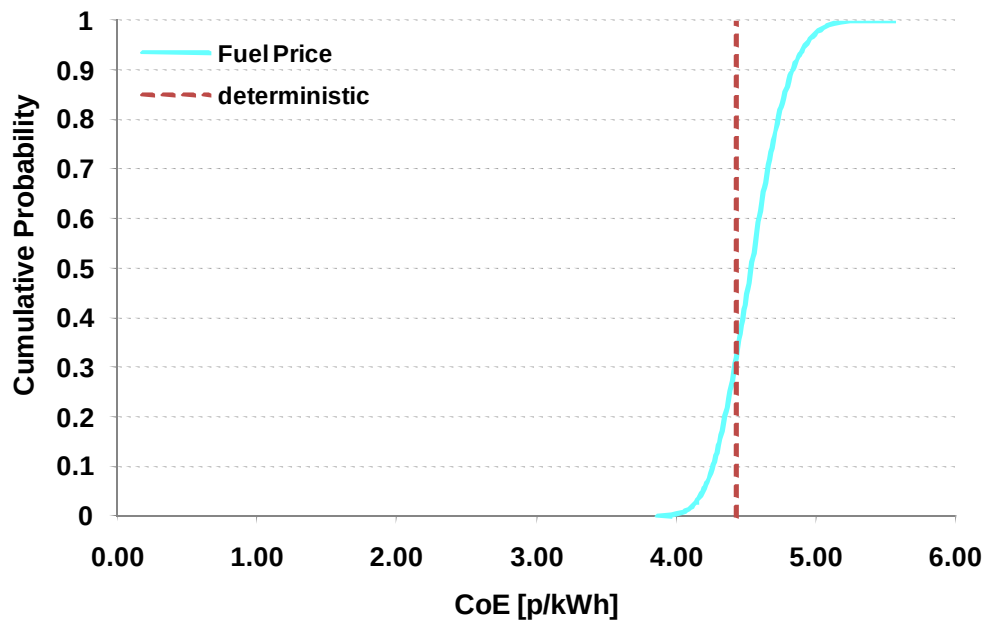


Figure 6.25 CoE for the IRCC: effect of uncertainty of fuel price

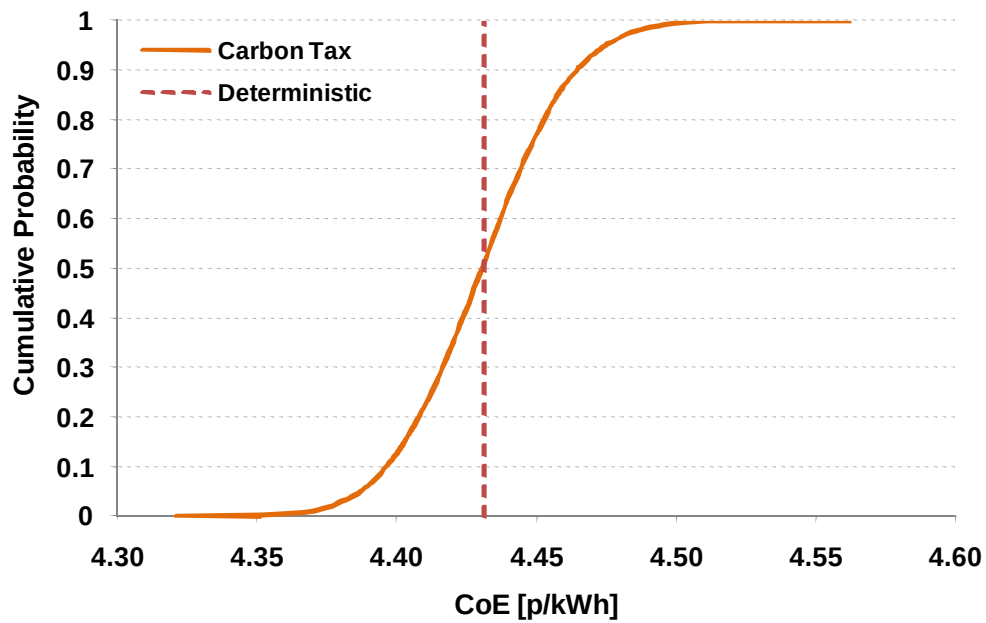


Figure 6.26 CoE for the IRCC: effect of uncertainty of carbon tax

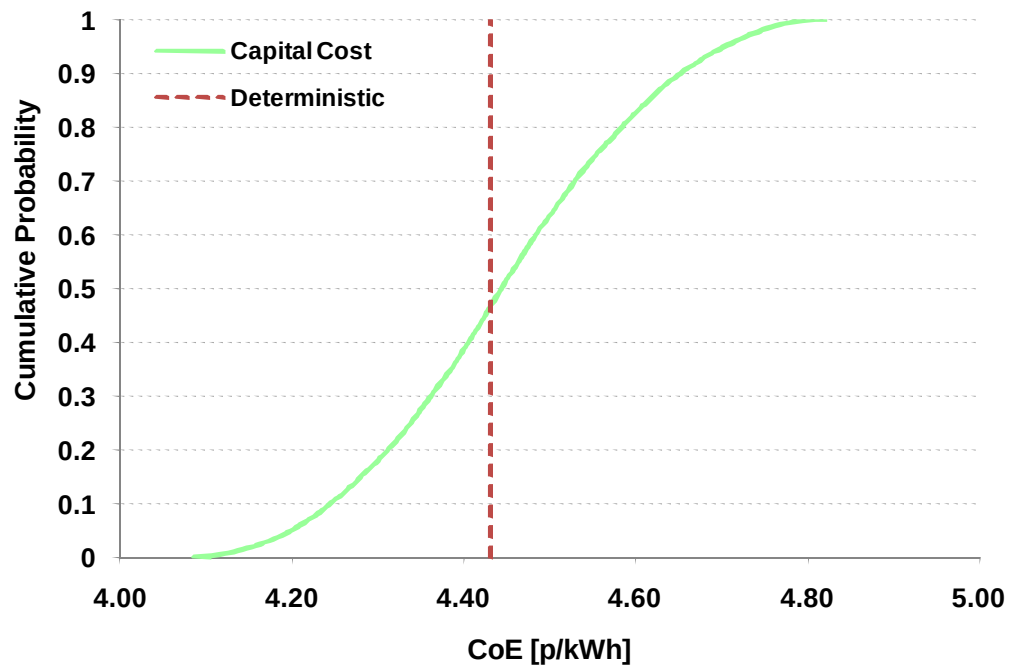


Figure 6.27 CoE for the IRCC: effect of uncertainty of Capital Cost

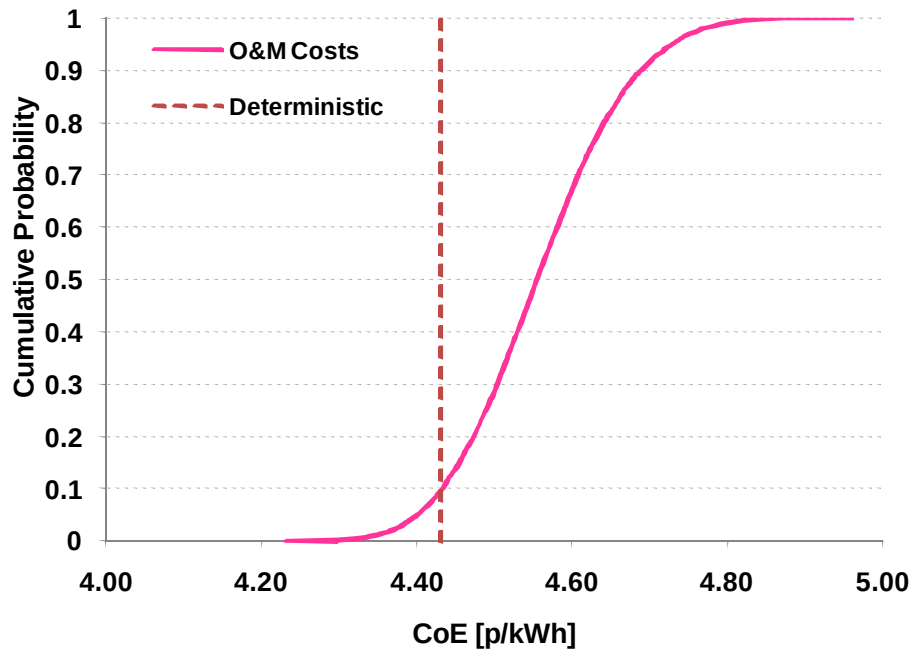


Figure 6.28 CoE for the IRCC: effect of uncertainty of O&M Costs

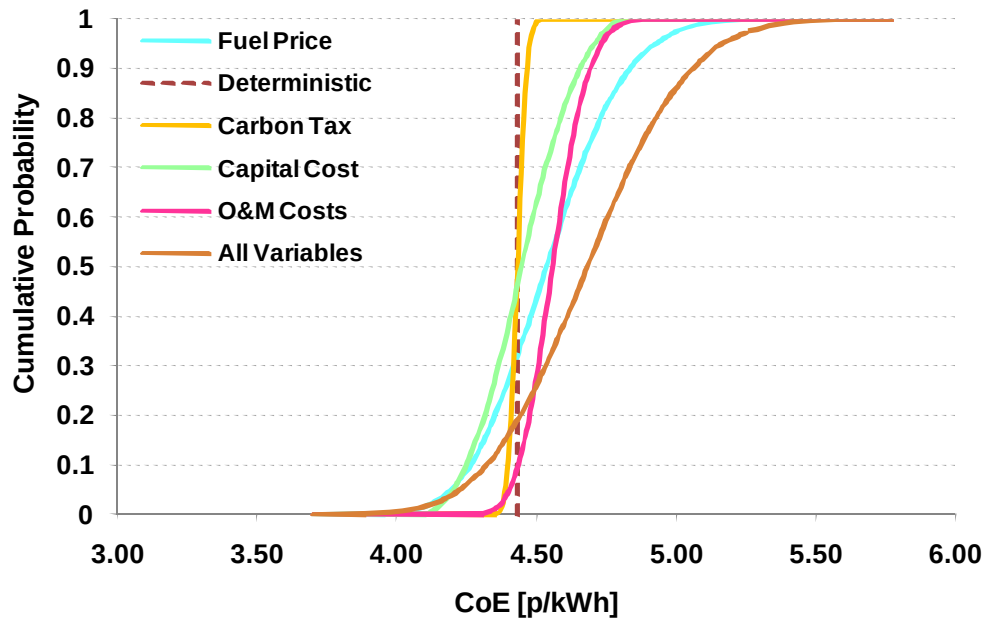


Figure 6.29 CoE for the IRCC: effect of uncertainty of all risk variables

The remarks that can be made for the IRCC case are qualitatively similar to the ones made for the ATRCC case. The results indicate that the greatest level of uncertainty is associated with variation in fuel price. Such variability in fuel price alone causes the CoE to vary between 3.861 p/kWh and 5.553 p/kWh, with a 68% chance that the mean value would be higher than the deterministic estimate. Uncertainty is also quite high with regard to the capital cost variability: the CoE value lies between 4.085 p/kWh and 4.819 p/kWh. The results show a CoE higher than the deterministic value in the 52% of the cases simulated. Treating the O&M costs as uncertain variable exposes the decision-maker to a 90% probability to exceed the deterministic value of the cost of electricity. The CoE of the IRCC being analysed is fairly independent from the carbon tax, as the emissions are fairly low.

The fuel price seems to have a major effect on the cost of electricity produced by the IRCC, in particular on the disposition of the final cumulative distribution further to the right. Like for the ATRCC, the likelihood that the forecasted CoE value can exceed the deterministic value is about 80% in the case of simultaneous variation of the risk variables.

6.7.4 NPV Results

Figure 6.30 presents the results of the cumulative probability distribution of the NPV for the three alternatives considered with all the risk variables treated as uncertain. All the other results are collected in Appendix B. Figure 6.30 poses itself as the risk-analysis oriented version of the information provided by the plot reported in Figure 6.13.

Before proceeding in commenting on this chart, it is proper to make a statement. As stated in paragraph 6.3.2, the basic decision rule for a deterministic project appraisal, like the one reported in the previous paragraph, is simply to accept or reject the project depending on whether its NPV is positive or negative respectively. Similarly, when choosing among alternative projects, the decision rule is to select the one with the highest NPV, provided that it is positive. However, because risk analysis presents the decision maker with an additional aspect of the project – the so-called “risk/return profile” – the investment decision may be reconsidered. The final decision is therefore subjective and rests to a large extent on the investor’s attitudes toward risk. Assuming a “rational” behaviour of the analyst the following remarks can be done.

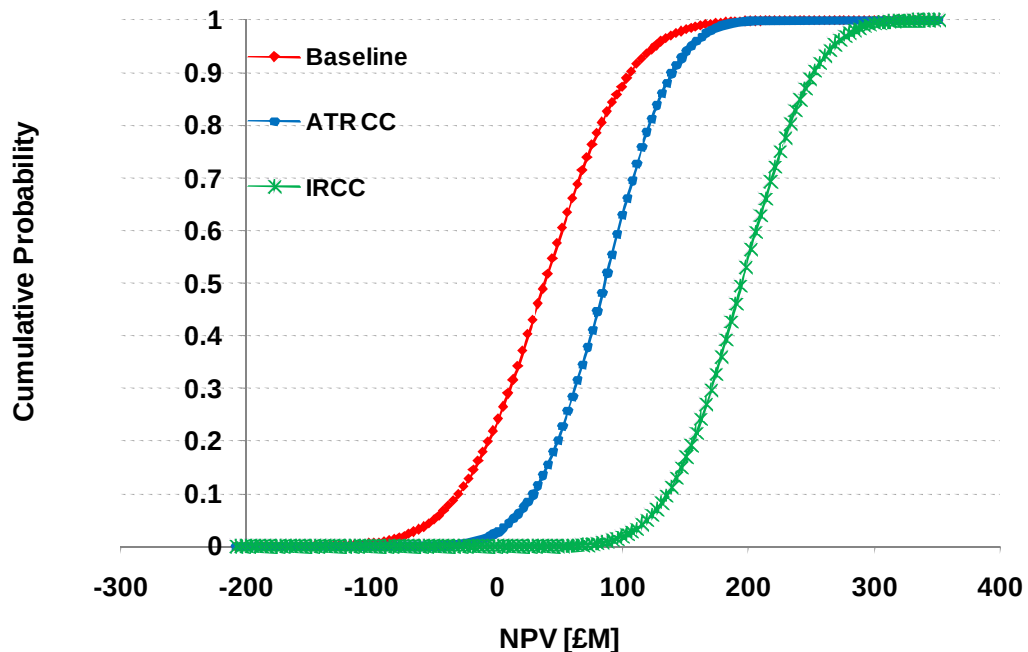


Figure 6.30 NPV results considering the effect of all risk variables

The minimum point of the NPV probability distribution is higher than zero for the IRCC while for the baseline and for the ATRCC there is a likelihood of about

20% and few percent-points respectively that the NPV would assume a negative value. The plot reported in Figure 6.13 provided the decision maker only with the information of deterministic NPV values (£53M for the baseline, £115M for the ATRCC, £228M for the IRCC), without suggesting at all the just mentioned likelihood of a negative final return. On one hand, given the low probability of NPV negative, the decision rests on the risk predisposition of the investor. On the other hand, the IRCC always shows a positive NPV even under the worst scenarios that can arise from the random combinations of the all risk variables. The project, therefore, represents a very interesting alternative.

Moreover, the three cumulative probability distributions of the NPV do not intersect at any point; therefore the IRCC project whose probability distribution curve is further to the right should be preferred. As a matter of fact, given a particular return's target, the probability that it will be achieved or exceeded is always higher for the IRCC than for the other two cases being considered: as an example, establishing a NPV target of £150M, the IRCC presents a probability of about 80% to arrive at the end of its lifetime with an NPV equal or higher than such target; for the ATRCC and for the baseline the probability is much lower (less than 10%), or in other words for the baseline and the ATRCC the probability to have a lower final NPV is quite considerable. By analogy, stipulated a certain level of confidence, this will correspond to a higher NPV value for the IRCC than for the other two alternatives. As an example, stipulating a confidence level of 90% (which corresponds to a cumulative probability of 10%), from the chart it is possible to appreciate that the IRCC will generate a NPV of about £130M. Therefore, the final NPV will exceed such a value with a probability of 90%. In the ATRCC case the cumulative probability distribution predicts a 90% probability that the NPV would be higher than about £25M, while for the baseline the corresponding value is negative.

Therefore, from a financial point of view the IRCC investment can be considered quite secure, bearing in mind that such a conclusion hinges on the assumptions of this analysis, above all on the probabilistic distributions chosen for the risk variables taken into account.

CHAPTER 7

TECHNOLOGY RISK ANALYSIS

The success of a low-carbon future is highly dependent on technology. All low-CO₂ emissions power plant cycles differ in technological maturity and operational challenges: some technologies are very near state-of-the art, whereas others tend to be more innovative but less-developed. T.E.R.A. methodology intends to assess the uncertain characteristics of CCS power plants coupling Monte Carlo simulation technique and the concept of TRLs. The T.E.R.A. assessment of the three power plants is completed in this chapter with a risk analysis aimed to provide an evaluation of the maturity level of the technology employed. The original model adopted within T.E.R.A. methodology is applied to the conventional combined cycle.

7.1 Technological Maturity effects on CO₂ Capture plants' performances and costs

As already highlighted in previous chapters, CO₂ capture power plants are complex chemical processing and energy conversion systems. The technical maturity of specific CCS system components varies greatly: some technologies are extensively deployed in mature markets, primarily in the oil and gas industries, while others are still in the research, development or demonstration phase. Large-scale commercial experience with this kind of power technologies and systems for CO₂ capture is still limited.

Consequently, there are major uncertainties associated with using the limited performance and cost data of new CO₂ capture power plant facilities. Uncertainties, as well as variability in design assumptions, may apply to different aspects of the process, including performance variables, equipment-sizing parameters, capital costs and maintenance costs. Chapter 6 has already dealt with uncertainties concerning

capital costs and maintenance costs, along with some key economic market parameters. Thermodynamic model parameters may be uncertain or variable, depending on the state of technology development, as well as on other factors, such as the accuracy of the values of the performance parameters [58, 137]. As described in Chapter 3, some of these power plants incorporate many components in addition to the conventional power conversion section and others more complex power conversion units themselves. The challenging integration of such complicated and numerous chemical process components involved, along with their low technological maturities, may cause extra shut-downs of the plant, resulting in an initially lower availability and reliability and more complex operating procedures.

While the literature on CCS power plants covers a range of applications and technologies, most studies of CO₂ capture and storage for power plants have focused on currently available technology. This approach has the advantage of avoiding subjective judgments of what may or may not happen in the future, or what the performance will be of advanced technologies still in the early stages of development. On the other hand, reliance on performance estimates for current technology has the disadvantage of not taking into account the potential for improvements that can affect the overall role of CCS as a climate-mitigation strategy and thus the long-term competitiveness of CO₂ capture systems in different applications [65, 73, 137].

The success of a low-carbon future relies heavily on technology. Because of the significant reliance on technology in the advanced low-carbon power systems and the uncertainties of their performances, innovation is needed to take place in the area of CO₂ capture technology.

With several development pathways and multiple technology options to choose from within each pathway, resources must be properly dedicated and adequately focused. Therefore, the optimal technologies mix to be actively developed to provide future options needs to be clearly identified, without squandering scarce resources on too many low-priority projects and, as a result, starving the truly deserving ones. Such a problem requires determining which ones should receive high priority and be accelerated and which instead should be neglected. As pointed out in the open literature, prioritizing research advancements in CO₂ capture technology emerges essentially as a *portfolio management problem* [224].

The portfolio management – the ability to pick the most rewarding projects and make the right investments – can be formally defined as follows [225]:

“Portfolio management is a dynamic decision process, whereby a business’s list of active new product (and development) projects is constantly up-dated and revised. In this process, new projects are evaluated, selected and prioritised; existing projects may be accelerated, killed or de-prioritised; and resources are allocated and re-allocated to active projects. The portfolio decision process is characterised by uncertain and changing information, dynamic opportunities, multiple goals and

strategic considerations, interdependence among projects, and multiple decision-makers and locations.”

The optimal technology portfolio will have several projects at different stages of completion, and will balance risk versus returns and short-term versus long-term advancements [225, 226]. Such a problem can be depicted as a pipeline, with raw concepts at one end and useable technologies produced at the other end (Figure 7.1). Research and development efforts move potential technologies from one extreme to another, from simple concepts to completed and usable products, and the portfolio management process can be used to determine which technologies are pushed through the pipeline and how fast, and which are abandoned and when [224].

However, the variety and different maturities of these competing technologies make technical comparison largely subjective, but objective insights can be gained through the development and application of structured approaches or analytical techniques. Such structured approaches to understanding each technology will identify its place in the technology development pipeline, and deciding what to do with it [224]. Generally speaking, several approaches for assessing the technology maturity and potential of development have been proposed and experimented with, each having its own purpose and its unique strengths and weaknesses. Regarding uncertainties for the CO₂ capture power systems, some analyses and studies have been undertaken to characterize their effects on plant performance and cost and rank the importance of different factors in terms of their contribution to the overall uncertainty.

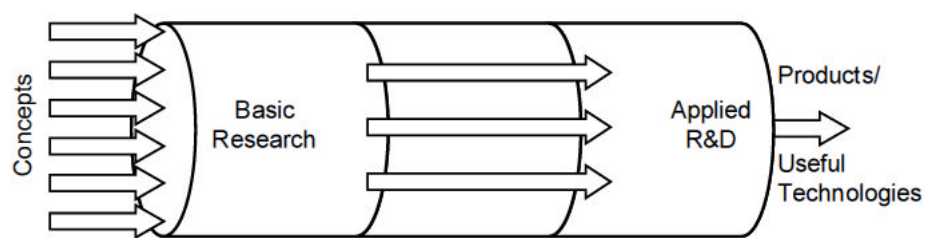


Figure 7.1 *Technology Development Pipeline* [224]

In 1970s The National Aeronautics and Space Administration (NASA) introduced the concept of “technology readiness levels” (TRLs) as “a discipline-independent, programmatic figure of merit to allow more effective assessment of, and communication regarding the maturity of new technologies” [227]. In 1995 the TRL scale was further strengthened by the articulation of the first definitions of each level,

along with examples [227]. Since then the TRL concept has been embraced and are being considered for use by numerous other organizations. Overall, TRLs have proved to be highly effective in communicating the status of new technologies among sometimes diverse organisations: TRL is a measure widely used to assess the maturity of each evolving technology prior to incorporating that technology into a system.

As shown in Figure 7.2, the NASA TRL system has nine levels. Technologies are advanced from level 1 up through level 9 as they develop. The specific language of TRLs shows how they are tailored for typical NASA technologies, which are related primarily to the aeronautical field especially in the space environment, but can be applied potentially for every kind of technology where large R&D investments are needed [227].

Using the NASA model as a basis, a first-attempt TRL model specific to CO₂ capture technologies is shown in Table 7-1 [224]. It includes the progression of the technology from a scientific principle and technological concept to laboratory-scale, bench scale and full-scale prototypes, and then to full deployment. These steps are intended to reflect the actual course that a CO₂ capture technology would go through as it is developed and deployed. The final TRL incorporates the demonstration of economic viability, which is not included in the NASA TRLs model, but it is an important factor for CO₂ capture technologies [224].

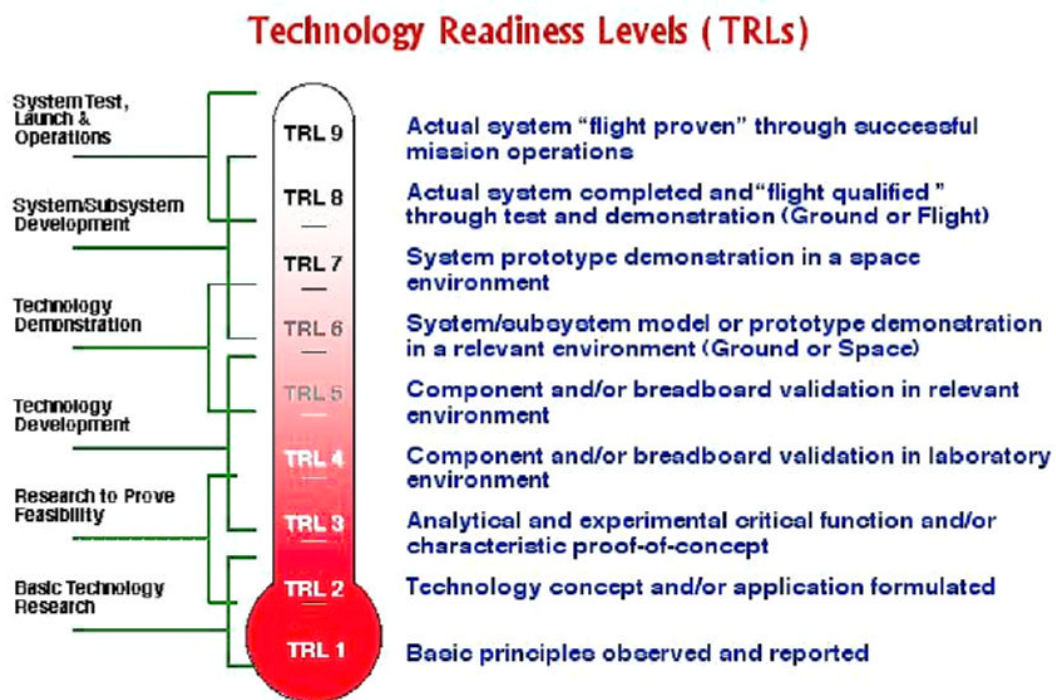


Figure 7.2 TRLs scale proposed by NASA [227]

Table 7-1 *TRL Model adapted for assessment of CCS technologies* [224]

TRL 1	Basic scientific principles observed and reported
TRL 2	Technology concept and/or application formulated
TRL 3	Analytical and experimental critical function and/or proof-of-concept validated
TRL 4	Component and/or process validated at laboratory scale
TRL 5	Component and/or process validated at pilot scale
TRL 6	System/subsystem model or prototype demonstrated at pilot scale
TRL 7	System prototype demonstrated at full scale
TRL 8	Actual system integrated into a full-scale plant and successfully deployed
TRL 9	Actual system market proven through economically successful industrial operations

A transparent methodology, based on TRL concept, for a qualitative evaluation of CO₂ capture power plant concepts has been presented by authors from NTNU and SINTEF [59]. Such methodology involves a breakdown of the power plant into its main blocks. A block is defined as a distinct unit operation or an integrated unit consisting of two or more unit operations, which can be developed independently of surrounding blocks. Each block is then classified and characterised with a numeric classification according to a 5 maturity levels system introduced by IPCC [3] and reported in Table 7-2. This scale ranks every block from zero to 4, where 4 represent a component which has not yet been tested and zero a component with proven characteristics (in an inverse order compared with the NASA metric). Such methodology has been applied to nine different gas turbine-based cycles with CO₂ capture which were evaluated against a reference combined cycle without CO₂ capture [59]. The cycles constitute one post-combustion, six oxy-fuel and two pre-combustion concepts.

Table 7-2 *Technology Readiness Level Scale* [59]

Maturity level	Description
0	Mature technology with multiple commercial replications for this application and scale of operation; considerable operating experience and data under a variety of conditions.
1	Commercially deployed in applications similar to the system under study, but at a smaller scale and/or with limited operating experience; no major problems or issues anticipated in this application; commercial guarantees available
2	No commercial application for the system and/or scale of interest, but technology is commercially deployed in other applications; issues of scale-up, operability and reliability remain to be demonstrated for this application.
3	Experience and data based on pilot plant or proof-of-concept scale; no commercial applications or full-scale demonstrations; technical issues or cost-related questions still to be resolved for this application.
4	Component or sub-system not yet tested, or with operational data limited to the laboratory or bench-scale level; significant issues of operability, effectiveness, reliability and manufacturability remain to be demonstrated.

The sum of occurrences of the maturity levels for each of the concepts revealed the number of immature blocks, thereby indicating an initial view of the required effort to realize the different concepts. The representation of the qualitative evaluations in combination with quantitative results represented by the plant efficiency (Figure 7.3) show how the concepts involving complex operating procedures and demanding substantial improvements to be fully developed and deployed look attractive in terms of plant efficiency.

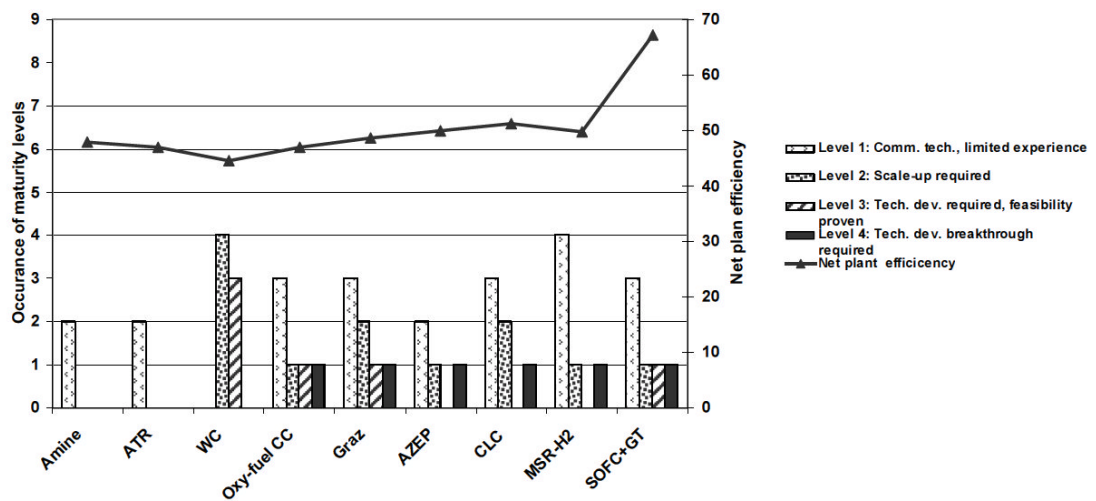


Figure 7.3 Example of application of the NTNU-SINTEF TRL scale [59]

The TRL concept, in both versions herein proposed and described, represents a “figure of merit” which provides a *language* – not dependent on any specific technology – by which it can be possible to communicate concerning what is the current level of maturity of the technology and the maturation objective [228, 229]. The coordination offered by the TRL concept is necessary to ensure that the same metric is used, thus not leaving space for ambiguity [228, 229]. Therefore, TRLs can be used by specialists developing the technology itself to determine research priorities and communicate with non-specialists. Moreover, they can be beneficial also when integrating a technology for system development as a means of deciding whether to use or integrate the technology, with sufficient knowledge of any risks relating to the degree of maturity [228, 229].

It is stressed that the TRL concept is mainly used with respect to technology and equipment (they do not apply to systems and system integration maturity) and are not suited to take into account industrial production-capacity and procurement-limitations [228, 229]. In this regard, the level nine inserted by MIT does not appear to suit this general requirement. The economically successful industrial operations

rely so heavily on many factors (like market conditions, local-government support and operators' expertise) that could be hardly represented by a systematic indicator like TRL without losing its objectivity.

Furthermore, by comparing the MIT's and the NTNU-SINTEF's scales, the difference in levels' number is immediately evident. The former, increasing the resolution, implies that complexity of the model representing TRLs also rises. The many differentiated levels, within the same metric, make the application of such a model a difficult exercise to accomplish. The scope of assessment, in fact, could turn out to be enormous, involving probably six or seven orders of magnitude in cost terms from the laboratory scale to the prototype: consequently the confidence of the analyst might progressively wane as the levels rise. It is a well-worn rule of thumb that costs rise through around four orders of magnitude from lab scale to pre-production prototype

The technology readiness level concept can provide the framework for assessing the maturity levels of the different technologies, but analytical methods can yield a deeper understanding of the potential development of such advanced technologies in order to underpin the decision of which technologies to pursue. The tools can vary greatly in their purpose, applicability and format, but generally they seek to quantitatively analyse technologies, or in general activities, to understand the dynamics of cost, performance, and reliability [224].

A broadly used tool is represented by the so-called "risk matrix", which relies on a graphical representation of uncertainties and consequences [230]. An example is given by the multi-criteria methodology and tool proposed by the IEA: it includes in the evaluation of advanced low-carbon power plants the technology maturity level and the consequent potential capability of these plants to contribute to the mitigation of climate change [75]. As already pointed out in Chapter 2, the tool offers a standardised assessment of some features, providing a set of standard responses (in drop down menus) among which the most suitable response needs to be picked. Every answer is attributed a score between 1 and 100, which indicates the need for greater or less financial investment to reach a fully workable and saleable component. An additional response, which helps to assess the risk of not succeeding in the technological development, is provided for some aspects, among which process novelty is included. An example of the above mentioned standard responses' menu is shown in Figure 7.4. In the case reported in Figure 7.4, the feature taken into account is "materials of construction". The first menu asks the user to select the most advanced materials of construction which will be used widely in the plant, whereas the supplementary menu asks for an indication of the state of development of the necessary materials as planned in the power plant under investigation. Results are then plotted on a chart with two axes (Figure 7.5): the vertical axis reports the

“performance score” and the horizontal axis the “likelihood of success”, allowing the competitive position of the process to be visualised in terms of both aspects.

The IECM Framework, developed by Carnegie Mellon University as a part of the USDOE’s Carbon Sequestration Program and already described in its overall rationale and structure in Chapter 2, presents a stochastic simulation capability to illustrate the effect of uncertainty or variability in key process parameters, as well as in key cost items. The framework makes use of parameter uncertainty analysis, which provides a quantitative way to estimate the uncertainty in model results. The term uncertainty is used loosely to include variability (for example, in nominal process design values) as well as true uncertainty in the value of a particular parameter. The general approach to perform the parameter uncertainty analysis is detailed elsewhere [231]. In particular, the parameter uncertainty analysis assumes that the total uncertainty affecting a performance/costs model can be calculated from an estimate of uncertainty in each of the parameters used as input into the model. Making use of published judgements in the literature, statistical analysis of published data and elicitation of judgements from technical experts, parameters uncertainty or variability can be evaluated and subsequently translated as probability distributions [232]. Latin Hypercube sampling⁴¹ is then used to generate values of each uncertain input according to the probability assigned to it. The model is run repeatedly, using different values for each of its uncertain inputs each time. Thus the effects of parameter uncertainties are propagated through the engineering model to yield an explicit indication of the uncertainty in output variables, which do not assume single values but are represented by probability distributions of all the expected values [74].

Example of multi-criteria analysis menu structure Materials of construction

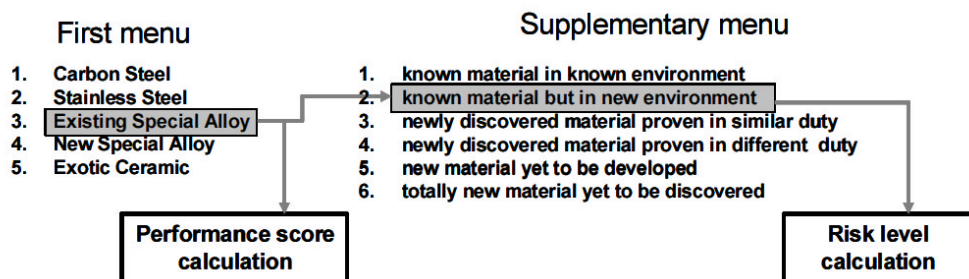


Figure 7.4 Example of standard responses menu [75]

⁴¹ Latin Hypercube sampling (LHS) uses a technique known as 'stratified sampling without replacement'. The probability distribution is split into n intervals of equal probability, where n is the number of samples that are to be performed on the model. As the simulation progresses each of the n intervals is sampled once. The LHS has the advantage of generating a set of samples that more precisely reflects the shape of a sampled distribution than pure random (Monte Carlo) samples.

The model was applied to an IGCC case [74, 233]. Among the many performance parameters that could be regarded as uncertain, carbon loss in the gasifier, heat loss in the gasifier, sulphur-removal efficiency, shaft/generator efficiency, and some parameters of the CO₂ capture system (selexol system performance parameters, like selexol pump efficiency, CO₂ compressor efficiency) were selected to carry out the analysis. Such an exercise enabled an accurate evaluation of performance uncertainties and a ranking of the various factors according to their contributions to the resulting uncertainty on the cost of electricity and plant thermal efficiency [74, 233].

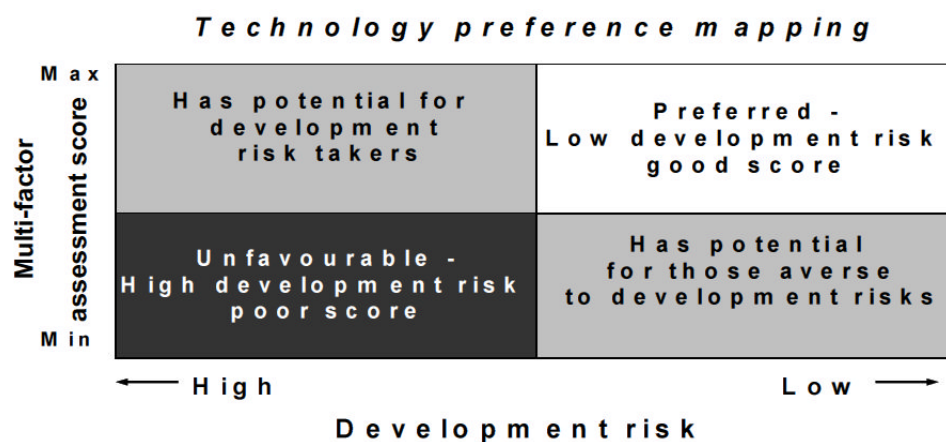


Figure 7.5 *Risk matrix* [75]

The IECM tool requires a preliminary computer-intensive phase. The period required to choose among the standardised responses of the IEA tool is shorter than the time necessary to develop estimates of uncertainty and the derived probabilistic distributions. The IEA tool is aimed, in fact, at a “rapid” assessment, as the authors defined the assessment performed by the tool. On the other hand, it demands a thorough chemical and mechanical engineering appraisal and thus the tool is intended for use by professionals experienced in the field. The graphical representation of uncertainty and consequences - in terms of commercial performance and risk - provided by the risk matrix serves as an immediate awareness of comparative advantages of the different CO₂ capture technologies. However, the results obtained from the IECM application are suitable for a straightforward and relevant analysis compared with that from the IEA matrix, so providing quantitative insights into potential payoffs from the technological development. On the other hand, the IECM model lacks a systematic approach to addressing the effects of technology improvements resulting from further R&D efforts.

7.2 The Technology Risk Analysis Module

The aim of this module of T.E.R.A. Framework is to provide a methodology and a tool for evaluation of the various CCS cycles with the focus being placed on their technological maturities. Such a risk assessment within the T.E.R.A. Framework finds its strength by virtue of capturing and coupling the systematic character of the TRLs and the quantitative approach of the Monte Carlo method.

As already stated in this chapter, one of the main aspects that affects the selection of novel low-carbon gas turbine-based cycles for future investments is the novelty of some of the incorporated components. The various concepts have reached different levels of technological maturity. In particular, it can be argued that the newer a component, the more uncertain is its performance. Such uncertainty will reflect on the whole system, with important consequences on its costs, its performance and its availability. Performance, costs and availability assessments of a novel system are fraught with uncertainty due to the limited large-scale experience available. Such uncertainties might not be resolved until commercial-scale demonstration plants are built and fully tested.

The model proposed here is aimed at characterising only the impact (i.e. effect) that technology maturity has on the power plant's performance, and in turn, on CO₂ emissions and economics. The RAM (Reliability Availability Maintainability) is not taken into consideration in the current version of the Module, although the author recognises the paramount importance that it holds in the applications, so determining the financial competitiveness of the organisation.

For a systematic description of maturity, this method starts by decomposing each power plant being considered into major “blocks” or “main process operation units”, following the approach proposed by NTNU and SINTEF [59].

As already explained in the previous paragraph, a block is defined as a distinct unit operation or an integrated unit consisting of two or more unit operations, which can be developed independently of surrounding blocks [59]. Each of the main process operation units or blocks is then classified in accordance to the 5 maturity levels scale reported in Table 7-2, which ranks the component from zero to 4 where 4 represents a component which has not yet been tested and zero a component with proven performance. Each block is characterised by one or more parameters (such as maximum temperature, efficiency and so on), which are involved in the thermodynamic model of the plant's behaviour and, therefore, play an important role in the performance analysis of the whole concept. Among them there are the parameters relating to the innovative blocks, whose values are influenced by the technological maturity level attained. These parameters are referred to in the following as *technology level indicators* (TLIs). The performance evaluation, reported in Chapter 4, assumed constant deterministic values for all the input variables. In reality,

the values of the input parameters referring to the novel components may be uncertain, being influenced by the level of technology maturity: as stated above, an innovative component implies a dubious performance. The method proceeds by using Monte Carlo simulation technique to evaluate the performance of the whole plant (in terms of power output, thermal efficiency and fuel consumption) according to the variation of TLI parameters that could be modified by undelivered or delivered technologies.

The Monte Carlo technique approach, as illustrated in the previous chapter, is useful when, as in this case, the decision-making process is facilitated and enhanced by modelling uncertain variables not as a single figure but as a range of values described by probabilistic distributions.

The main steps of Monte Carlo simulation have been described in the previous chapter. They are briefly reported once again here for completeness reasons, with reference to their specific application to the technological maturity analysis herein illustrated. The Monte Carlo simulation requires the following five steps:

- a) *Forecasting model*
- b) *Risk Variables*
- c) *Probability distributions*
- d) *Correlations conditions*
- e) *Simulation runs and analysis of results.*

The Monte Carlo method is based on the implementation of a model consisting of a set of equations, which define the interdependence between components of the system under evaluation and describe the mathematical relationship between output and input variables. In the present risk analysis, the model is represented by the Performance Module (Figure 7.6).

Among the input parameters there are those that are subjected to uncertainty because they reflect the low-state of development of the technologies of the components to which they are referred.

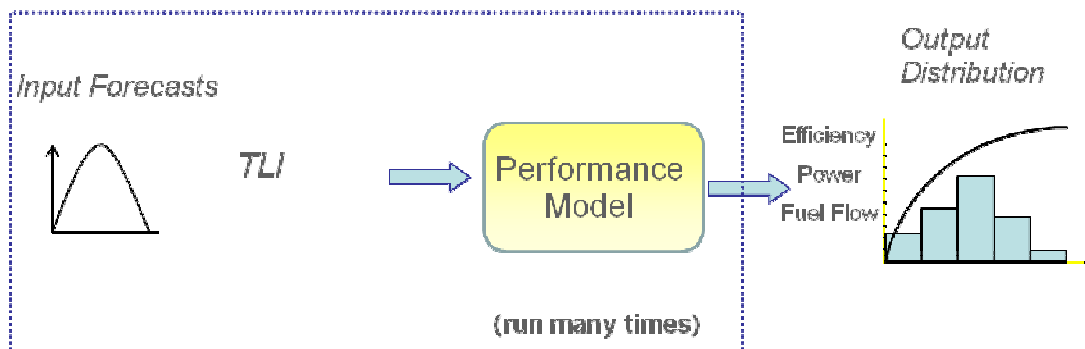


Figure 7.6 Monte Carlo method applied to the Risk Analysis for technology

For each of the TLIs, which represent the “risk variables” of the model, whose trend can be described better in probabilistic terms, a probability distribution needs then to be specified. Such probability distributions describe quantitatively the uncertainty marking the key project variables and quantify the probability that the forecast deviates from its base value, which was used in the deterministic analysis reported in Chapter 4, by a random amount.

The Monte Carlo simulation technique implies drawing a value from this distribution randomly and using it, along with any other deterministic values, in the model. The effects of this choice on the output variables, used as indicators of the behaviour of the system, are recorded. If this process is repeated for n times, different values will be picked from the distribution and different related effects will be recorded, so generating an entire probability distribution of all the values which the output variables will be assuming. Hence, the effects of the variation of the TLI parameters on the whole plant performance can be evaluated.

At this point, a question would spontaneously arise: where does the correlation of the Monte Carlo method and the TRLs, mentioned in the opening of this paragraph, fill its place?

The TRL of each block will determine the choice of the probabilistic distribution of the input variables that are referred to the block itself. In order to assess and link the TRL of a block to its own distribution, a case has been considered as benchmark: a TRL of zero has been assigned to the baseline plant’s blocks already available and operating in the market. Therefore, if a certain mean and a standard deviation level exist for the distributions that characterize the blocks of the baseline power plant, these values will be varied by a certain percentage related to the level at which the alternative power plant’s blocks have been allocated.

In particular if the TRL level decreases, the model entails that the standard deviation of the parameter has to increase due to the greater uncertainty of its data. Regarding the mean value of the parameter used as the technology readiness level indicator, the model assumes that it will decrease or increase according to whether a decrease in the maturity level corresponds to a lower or a higher TLI value respectively. Figure 7.7 schematically summarises this concept. A view of the paradigm underlying the variation of means and standard deviation is shown in Figure 7.8, including both the process of technological risk reduction and the simultaneous course of performance improvement and overall technology maturation.

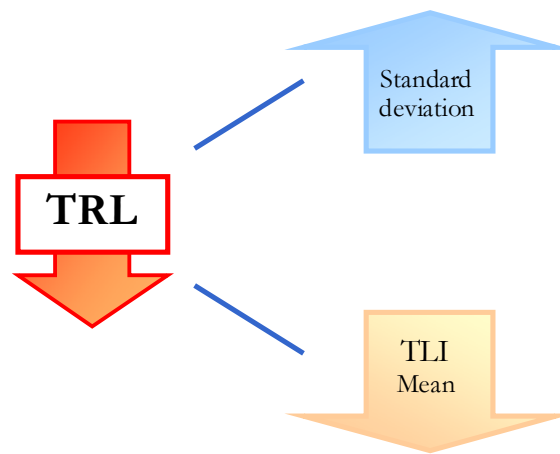


Figure 7.7 The connection between TRL and TLI parameter (adapted from [77])

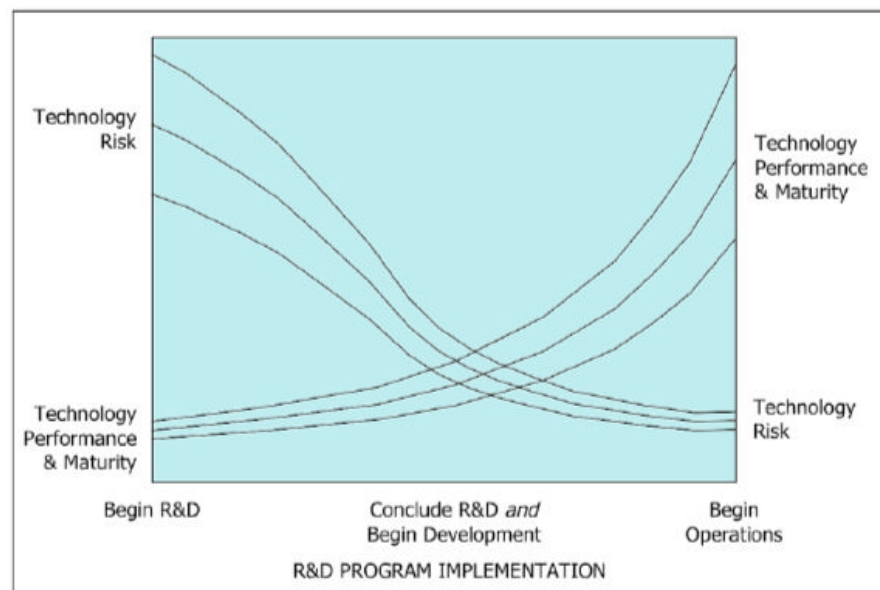


Figure 7.8 Paradigm of the connection between TRL and TLI parameter [230]

By changing the distributions' parameters for all levels, the TLI parameters distributions for all five levels have been plotted on a common graph, shown in Figure 7.9. The case reported in the plot refers to the compressor block with its polytropic efficiency designated as TLI. For the level zero, the mean value assumed is 90.8% with a slight uncertainty (the value can range between 89% and 91.5%). The lower the TRL, the smaller is the mean (79.5%) and the higher the uncertainty about the value of the efficiency (for the last level the values vary between 78% and 82.3%).

Underlying this model, there is the hopeful assumption that key performance parameters are improving concurrently with improvements in the TRL. It may well prove, in many cases, that the technological performance can be improved or its maturity advanced but not both simultaneously [229, 230].

The probability distributions are negatively skewed, with a tail toward lower values (Figure 7.9). Such a tail shortens when the TRL rises. Such attributes reflect how the degree of confidence improves when the state of technological development is higher. Reduction in uncertainty, with the subsequent reduction of the range of possible values, can be regarded as a plausible outcome from further research [74] and technological developments.

Because Monte Carlo analysis requires numerous iterations of the model before the results are stabilised, the analysis has been limited to the design-point case. Hence, the simulation of the Technology Risk Analysis model is relatively cheap in terms of computational requirements.

A thorough literature review facilitates the selection of the parameters (mean and standard deviation) of the probability distributions for each TLI. Depending on the availability of information, estimates of parameter uncertainties or variabilities can be based on published information in the literature that can be used to infer judgments about uncertainty, statistical analysis of data, or elicitation of judgments from technical experts. However, a significant limitation inherent in this model is represented by the difficulty in some cases of developing estimates of uncertainty based on classical statistical analysis. Particularly for new process technologies, data may be lacking regarding some types of uncertainty. Moreover, this approach could be not suitable to take into account the effect of scale-up on process performance, which may not be fully understood [74, 229, 230], and how TRLs and TLIs are function of time.

7.3 Economic Module

The state of development of some of the technologies deployed in CCS power plant concepts brings about a certain ambiguity about the plant cost estimates. The cost estimates for new technologies are inherently dubious because of the lack of commercial-plant-scale experience for such forecasts to be confirmed. In this regard, the Rand Corporation argued that: “Accurate assessment of the costs of advanced technologies has always been one of the most difficult and uncertain tasks facing an R&D planner” [74].

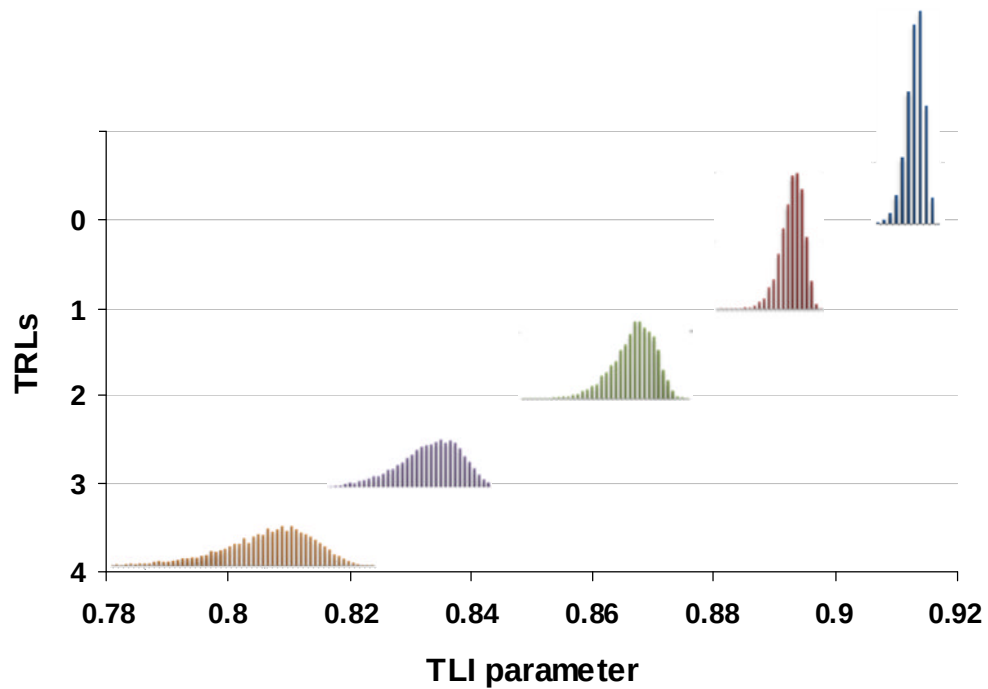


Figure 7.9 *Correlation between TRLs and TLI parameter
(for the compressor case with polytropic efficiency as TLI) (e. g. see [77])*

In the public domain it is pointed out how costs of such innovative technologies can significantly decline by virtue of several factors [198]. The so-called learning-by-doing effects, R&D investment, improvements in technological designs, materials product standardisation, system integration or optimisation are some beneficial opportunities. Several authors have used historical trends in costs of various technologies to predict future costs of power generation with CO₂ capture [234-238]. First they assessed the rates of cost reductions achieved by *other energy and environmental-process technologies in the past* and then, by analogy with leading capture plant designs, future cost reductions that might be achieved by power plants employing CO₂ capture were estimated [234-238].

As anticipated in Chapter 2, the Technology Risk Module embeds not only the Performance Module but also the Economic and the Emissions Modules into a multi-run simulation environment. The outcome of the whole T.E.R.A. exercise is then no longer represented by single values, but rather by probability distributions of the main output indicators (i.e. emissions of CO₂ from the Emissions Module and NPV, IRR, PBT, CoE and BESP from the Economic Module) (Figure 7.10). The potential cost reduction deriving from continuous TRL improvements has not been fully taken into account in this analysis. Consequently, the relationship between each

TLI and relative economic parameters was not modelled. The capital costs adopted in the analysis, in fact, are the specific ones (£/kW) as estimated in the paragraph 6.6 for the deterministic economic study, regardless of the new plant capacity derived from the variation of the TRLs. All the other economic parameters remain essentially fixed.

Nevertheless, the final results are considerably informative as they reflect changes in economic expectations based on technology process improvements.

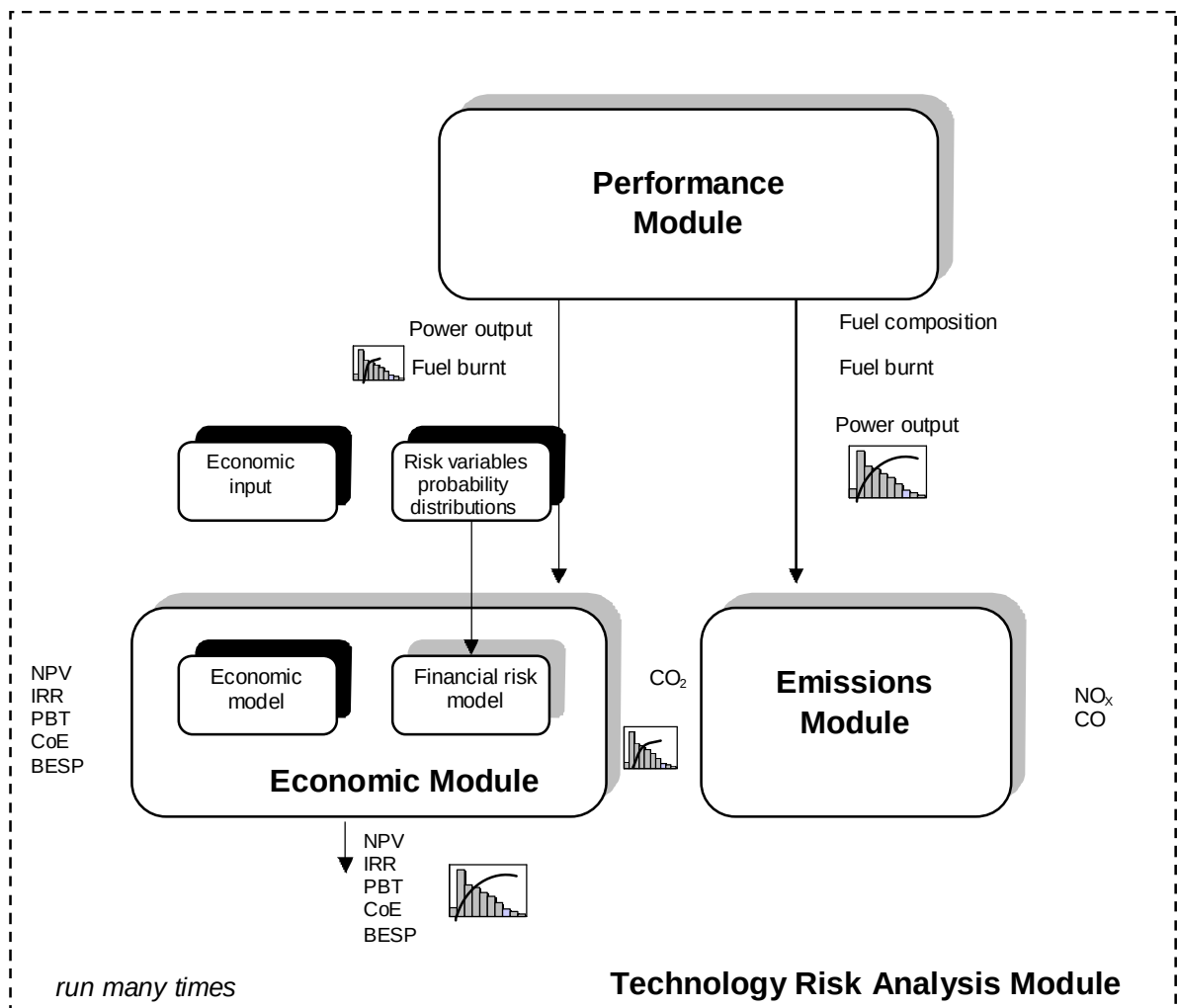


Figure 7.10 *Technology Risk Analysis Module outcomes*

7.4 Combined Cycle Gas Turbine

Combined cycle power plants operate by combining the gas cycle and the steam cycle for higher efficiency. Current commercially available power generation combined cycle plants achieve net plant thermal efficiency typically of some 55-59%.

The commercial development of combined-cycle power plants has proceeded in parallel with gas turbine development. As a matter of fact, such development has led to the breakthrough of the combined-cycle plant in the past few years, increasing power and efficiency while decreasing emissions and lifecycle costs without sacrificing reliability [127, 239].

Given the positive effect of a high turbine inlet temperature on the efficiency of a gas turbine and a combined-cycle plant, further improvement mainly in the direction of higher turbine inlet temperatures are pursued [127]. This improvement has become possible through the development of new materials and improved cooling systems [127]. Parallel to this, improvements are also being made to the turbomachinery items. The advantages offered by the higher TET cannot be fully exploited only if the pressure ratio of the machine is increased to an appropriate level. High unit ratings are also being attained by increasing the air flow through the compressor. With the use of transonic stages, it is already possible to attain equivalent outputs and pressure ratios with many fewer compressor stages [127, 239].

Further developments of the gas turbine, along the aforementioned route, show promise for near-term future power generation combined-cycle plants capable of reaching 60% or greater thermal efficiency [239].

Steam cycle improvements that include increased steam pressure and temperature with supercritical steam cycles have near-term application. Current economic analysis indicates, however, that the thermodynamic gain associated with steam cycles that have steam temperatures and pressures above the current levels may be unjustified in most cases because of the added costs [127].

7.5 The ATRCC and the IRCC

In this paragraph an evaluation of the technological maturity level of the main components utilised in the ATRCC and IRCC power plants, along with considerations about their integration and operational challenges, is reported. Preliminary results obtained by means of the application of the Technology Risk Analysis Module, described in the first part of the chapter, are also described.

The following *blocks* have been identified, with classification supported by literature review and discussion of some experts. Due to the multidisciplinary character of the systems including components whose application spans a large range of uses, no opinion of experts from each specific field has been obtained. Therefore,

the author recognises that the following treatment is not exhaustive but still illustrative of the main challenges posed to the deployment of such complex systems.

ATR and Pre-reformer

The auto-thermal reformer is the key component for the reforming process. It elaborates an original feedstock to produce a synthesis fuel. The ATR process has been used for synthesis gas production since the late 1950s when it was applied mainly for ammonia and methanol syntheses, and for production of pure H_2 and CO . New developments have been made in the 1990s, including operation at lower steam-to-carbon ratios, new burner designs for safer operation and higher on-stream factors. It is currently used in conjunction with WGS reactors for the production of H_2 , even if the commercial experience is still limited [128]. However, it has emerged from this understanding that ATR has relevant attributes—relative compactness, lower capital cost, and greater potential for economies of scale [128].

Nonetheless, it is stressed that the distinction between ATR and secondary reforming is not consistently drawn by technology users and vendors, with the result that secondary reformers often are referred to as ATRs [128].

As already illustrated in Chapter 3, a typical scheme of an ATR reactor consists of a burner, a combustion chamber, and a refractory-lined pressure vessel where catalysts are placed (Figure 7. 11). The key elements in the reactor are the burner and the catalyst.

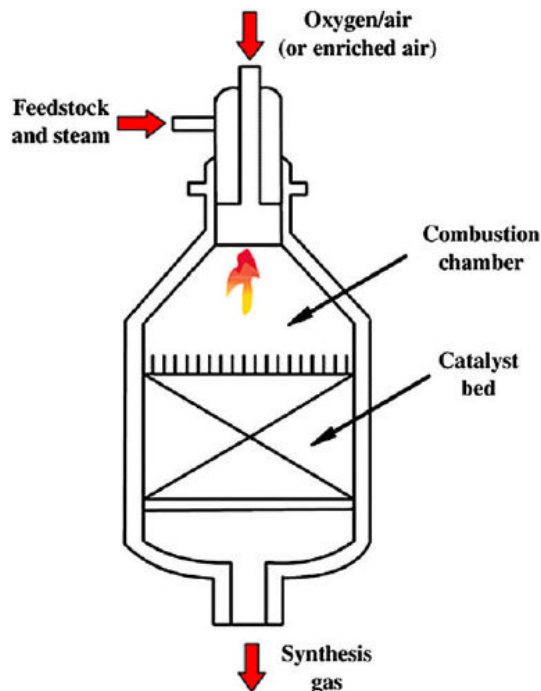


Figure 7.11 *Diagram of an ATR reactor* [241]

The burner provides a proper mixing of the feed streams in a turbulent diffusion flame. This extensive mixing is essential to avoid soot formation. In addition, it must maintain low temperature at the refractory walls of the reactor and an outlet gas with constant flow and temperature. The operating conditions in the burner foresee pressures above 12 atm⁴² and temperatures up to 2300 K. The burner nozzles must be designed to avoid excessive metal temperatures. Heat transfer from the flame core to the burner by radiation and hot gas recirculation must be minimised to maintain a safe operation and a satisfactory equipment lifetime [128, 240].

The severe operation conditions in the ATR necessitate catalysts with good mechanical properties, which are stable at the high temperature of the reaction (1200-1400 K) and at the high steam partial pressure. Catalysts based on nickel supported on magnesia-alumina spinel carriers have shown high stability and activity for this process. The selection of high operation temperatures and suitable steam/carbon and oxygen/carbon ratios are fundamental to avoid soot formation in the process. Soot formation may occur during start-up when low pressure and temperatures ranges are encountered [240].

In addition, the reactor design and its geometry are key factors used to avoid large pressure drops due to the process gas flow through the catalytic bed, to operate in conditions of turbulence, and to produce and transfer enough heat for the reforming reactions. Different geometries for ATR reactors have been proposed considering fixed beds, fluidised beds, and monolithic catalysts.

A pilot plant mentioned by Christensen [165] was built to test and demonstrate ATR technology and reaction engineering. The plant operated on natural gas at a capacity corresponding to 100 Nm³/hr producing syngas (CO+H₂) from 250 to 300 Nm³/hr with pure oxygen (O₂>99.5%). This pilot plant has operated for three years. Test-data have verified trouble-free operation is possible at very low H₂O/C feed ratios, high equilibrium temperatures and high CO₂ addition⁴³. The pilot plant tests proved ATR flexibility and reliability with short start-up periods and fast load changes. The start-up period was 90 minutes from hot standby to operation at 100% capacity. The auto-thermal reforming requires, however, careful control-system design to balance exothermic and endothermic processes during load changes and start-up [242].

Air-blown secondary reforming is well established, being commonly utilized for syngas production for ammonia plants. The chief proponent of the air-blown approach is Syntroleum. On the other-hand, it has been stated that air-blown reforming technology is unlikely to be competitive with oxygen-blown systems and appears much less flexible [128]. Reasons are found in lower thermal efficiency, high air compression power requirements, and the larger downstream equipment sizes and

⁴² Low pressures (<12 atm) may not be applied due to soot formation, which cannot be eliminated through steam addition or burner design.

⁴³ Operations with CO₂ addition were done to yield very CO-rich syngas.

pressure drop associated with handling the much larger volumetric flow of gas [128].

Issues regarding the auto-thermal reformer concern catalyst degradation due to coking [243, 244], i.e. formation of carbonaceous deposits, which leads catalyst cracking. Consequently, catalyst life is shorter than expected, which would require more frequent catalyst regeneration, catalyst purchases or both, thereby increasing operation costs.

Another important challenge for this reactor, as for the others herein analysed, is metal dusting, a corrosion phenomenon that leads to the disintegration of the alloy [243]. It particularly happens when the metal surface is exposed to a gas containing hydrogen. Since it is necessary to keep the temperature of the metal low, as the material properties are strongly dependent on the temperature, a solution adopted is to exchange heat with water (in this way it is also possible to produce more steam for the steam turbine). Another solution could also be feasible: coatings or advanced materials, but these are still under investigation [245].

Adiabatic pre-reforming is used for reforming of hydrocarbon feed-stocks ranging from natural gas to heavy naphtha with final boiling points above 200 °C [246]. The process is carried out in a fixed bed reactor upstream the tubular reformer [246]. The reactor is loaded with a highly active reforming catalyst. In the pre-reformer, higher hydrocarbons are completely converted into a mixture of carbon oxides, hydrogen and methane. The pre-reformer will act as a guard for the reformer, and it will facilitate changes in operating conditions (e.g. reduction of steam-to-carbon ratio) and variation in feedstock [246].

From the data available in the literature (Figures 7.12 - and 7.13) the range of H_2 plant capacity for which the auto-thermal reformer technology can be suitable is doubtful. However, the auto-thermal reformer section included in the two pre-combustion schemes of this investigation is characterised by a size of about 200,000 Nm^3h^{-1} , which lies in both ranges reported in Figures 7.12-7.13.

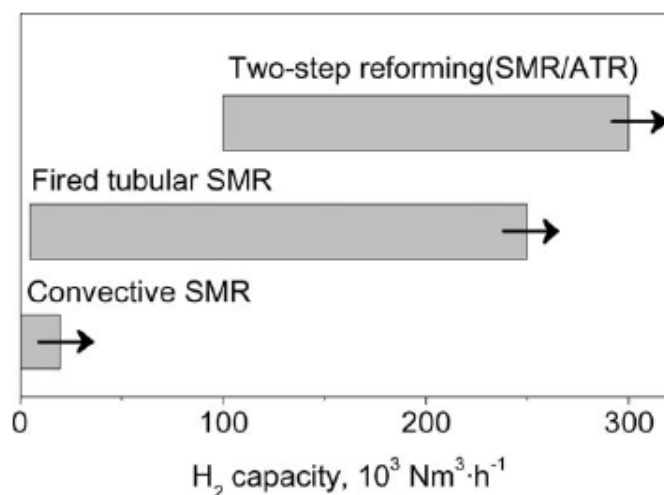


Figure 7.12 Suitability ranges for reforming technologies as a function of the H_2 plant capacity [245].

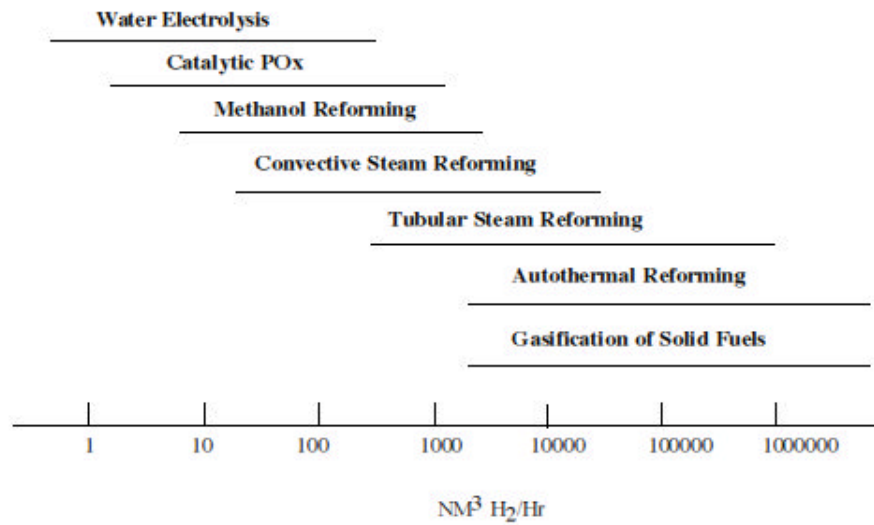


Figure 7.13 Choice of technologies based on the scale of hydrogen demand [247]

Therefore, considering the present day development of the reforming systems as emerged from the information collected, it seems reasonable to consider the maturity level for this component to be equal to zero.

Water Gas Shift reactors and Syngas coolers

In order to reduce as much as possible the amount of carbon dioxide emitted, it is necessary to reduce as much as possible the carbon fed to the gas turbine combustor. It is, therefore, necessary to convert the carbon monoxide produced during the reforming process into hydrogen and carbon dioxide. The latter is captured while the former is used to fuel the gas turbine. This process is accomplished by one or two water gas shift reactors. To get a higher degree of conversion of CO to CO₂, two reactors are favourable compared to one reactor setup. As already stated, the reasons behind dividing the water-gas shift reaction into a high temperature reactor and a low temperature one are due to conversion rate and catalyst.

At the moment, there are two main classes of materials being used in industry as CO-shift catalysts: Fe-based and Cu-based catalysts.

Catalysts can deactivate via two methods, sintering and poisoning, both of which are a concern in WGS reactors [242]. *Sintering* is a process in which the surface area of a catalyst decreases under the influence of high temperatures. Exposed to high temperatures, catalyst particles try to achieve a lower energy state by merging together to reduce their surface area. Over time, the reactor's catalyst loses its activity [242]. For example, a WGS reactor may use a copper and zinc oxide catalyst supported on alumina. The zinc oxide molecules create a physical barrier that impedes the copper molecules from merging together. However, if the temperature is too high, the copper molecules can merge anyway. Thus, even a single high-

temperature event can inactivate a reactor. For example, exposed to operating temperatures of 700 °C, a catalyst's active surface area can decrease by a factor of 20 within the first days of operation. Lower temperature of operation reduces sintering because the copper molecules are less mobile. *Poisoning* is essentially the chemical deactivation of a catalyst surface [242]. For example, chemical impurities like sulphur can aggregate onto catalyst particles and deactivate them by blocking reaction sites. Poisoning reduces the activity of the catalysts at the front of the reactor first. The WGS reactor is particularly susceptible to sulphur poisoning [242].

The syngas is cooled before entering the water-gas shift reactors. Both schemes investigated use a convection-based HRSG to cool down the syngas at the outlet of the reactors and to produce saturated high-pressure steam for extra power generation. Saturated steam is generated to avoid high tube wall temperatures and metal dusting [164, 243].

These equipments have been used for many years for the production of pure hydrogen for different industries and have found application in the IGCC power plants currently operating. It is possible, therefore, to assume that it is already technologically mature, hence being at a maturity level of zero.

Carbon dioxide capture

In Chapter 3 it is stated that it is preferable to perform the capture of carbon dioxide from the syngas, where high concentration are available at higher pressure, using physical absorbents. In the ATRCC and IRCC schemes considered in the present investigation the operative pressure of the fuel treatment section (in particular the auto-thermal reformer) is quite low. Therefore, the CO₂ capture by chemical absorption has been adopted.

One problem related to the carbon capture section is represented by the eventual entrainment of traces of amine in the clean fuel that are likely to be corrosive for blades and combustor. In the case of chemical absorption applied to the fuel treatment, like the cases here investigated, the possible presence of residual amine in the cleaned fuel is marginal [134]. Literature data about the corrosive effects of amine solutions is lacking when such low concentrations are encountered, being mainly focused on the analysis of specific chemical plants where the concentrations are much higher [134].

The main concerns with MEA are corrosion in the presence of O₂ and other impurities, high solvent degradation rates from reaction with SO_x, NO₂, and O₂, the large amounts of energy required for regeneration, and the possibility of emissions of solvent and decomposition products to the environment. Proprietary inhibitors are used to reduce corrosion, enabling use of conventional materials of construction, mostly carbon steel, and higher solvent concentrations. The SO_x concentration in the feed to an MEA scrubber needs to be reduced to typically 10 ppm or even lower.

This technology appears to be quite developed because of the previous utilisation in the pure hydrogen production industry. The only concern related to this equipment is therefore related to the scale-up required, hence a maturity level equal to one is selected. At present, the largest operating unit has a capacity of 800 tonne CO₂ per day, as detailed in Chapter 3, while the two power plants being investigated would produce about 3000 tonne CO₂ per day. However, scale-up issues have been addressed in the oil and gas industry where amine scrubbing technology was developed and they are not expected to be an obstacle to this kind of application. Recently it has been stated that with absorber diameters of 12–15 m considered feasible, CO₂ recovery plant capacities of up to 8000 tonne/day are achievable, depending on the inlet flue gas CO₂ concentration [209].

CO₂ Compression

Once separated from the main flow, the carbon dioxide needs to be compressed before its storage or transportation. The compression is realised with dedicated compressors. Despite the large experience in air compressors, little experience in design of compressor for large carbon dioxide mass flow and pressure ratio has been achieved⁴⁴. This leads to a maturity level of one⁴⁴.

Compressor

As previously described, in the ATRCC and IRCC it is necessary to bleed air from the gas turbine to provide the auto-thermal reformer with the required air mass flow. Considering the difference existing in lower calorific value between syngas and natural gas, a much larger fuel flow is required. Without any bleed from the compressor outlet, the turbine inlet mass flow would be larger than the value relative to the natural gas case. This would lead to a higher pressure ratio reducing the surge margin of the compressor and increasing the stresses the shaft would have to withstand because of the increased power. Bleeding air and using it in the auto-thermal reformer is therefore beneficial for the operational condition of the compressor. As it is possible to assume that the design procedure of the compressor is understood, it seems reasonable to assume a maturity level of zero for the gas turbine compressor⁴⁴.

Combustor

Due to high hydrogen molar fraction, a large amount of water is produced during the combustion process. Due to the thermo-physical properties of water, the heat transfer coefficient is higher in comparison with the natural gas case, leading to concerns about the combustor cooling system. This has to be redesigned also

⁴⁴ Personal communication with Mr Martyn Adams and Prof. Pericles Pilidis on the 22th May 2008 (Technical review Meeting at Cranfield University).

considering that the combustion of hydrogen at this concentration is in a turbulent diffusion flame; a larger amount of air is available to cool the liner [167]. Moreover, it is stressed that the combustor will need to be more fuel flexible; therefore special attention needs to be dedicated to the burner design and the control system [132].

Turbine

The same considerations apply also to the gas turbine expander: the main concerns relate to the increased metal temperature of the blades. The turbine needs an improved cooling system and/or augmented cooling mass flow but the degree of knowledge is high so a maturity level of zero has been allocated⁴⁴.

Heat Recovery Steam Generator

The hot gas exhausted from the gas turbine is used to produce additional power in a bottoming Rankine cycle. The heat recovery steam generator takes advantage of the experience related to the well known water/steam cycle technology. The main concern for the HRSG is related to the increasing complexity due to the heating of the streams to the fuel treatment sections. The maximum temperature and pressure are not a concern being limited by the gas turbine exhaust temperature and well within current boiler practice for large utility steam plant.

For the remaining components a technology level equal to zero is stipulated, given the present knowledge and experience related to them.

In the following table (Table 7-3) a summary of the technology maturity level is reported.

Table 7-3 *Technology maturity levels for ATRCC and IRCC components*

Block	Maturity Level
Pre-reformer	0
ATR	0
Shift reactors	0
CO ₂ capture system	1
CO ₂ compression	1
Compressor	0
Turbine	0
Combustor	0
Heat exchanger (HRSG and syngas cooling)	0
Steam turbine	0

Before proceeding with the analysis of the results obtained by the application of the Technology Risk Analysis Module a remark deserves attention. As highlighted in Table 7-3, the number of components and subsystems utilised in these power plants are quite considerable. The single sub-systems maturity seems to be very good. All of these subsystems are integrated together to form the final configuration of the ATRCC and the IRCC. As a result, the operability and the availability of the power plants, in particular of the IRCC, can be affected by its complexity. The higher the number of subsystems the more difficult will be the operation, the control and the maintenance of the plant. However, a medium level of operational challenges can be predicted due to the knowledge of these subsystems [59, 132]. Moreover, the experience gained from IGCC plants currently in operation has shown how the availability has been improving since their first introduction to the market. Nevertheless, the maturity of the whole system integration and subsequent operation can not be measured in terms of TRL since it has been stressed that the TRL concept does not apply to systems and system integration maturity.

7.6 Preliminary Results

As already stated in Chapter 6 for the financial risk analysis, a sufficiently large number of samples are necessary to achieve undistorted results. As a matter of fact, the value of outcome parameters dampens and stabilises as the number of iterations increases. In the present analysis the number of iterations has been fixed at 8000: at 8000 simulation runs results become stable reaching convergence, as showed in Figure 7.14 for the efficiency case. Appendix B reports the same plot for the other output parameters (power output, fuel flow), confirming that the number of samples selected guarantee convergence of the simulations' results. Appendix C reports an example of Input file of this Module.

The Technology Risk Analysis Module has been applied to the baseline case for illustrative purposes. The attention focused on the following gas turbine components, since the gas turbine contributes most to the overall performance of a combined cycle: compressor and combustor. The TLIs proposed for these components are the polytropic efficiency for the turbomachinery component and the COT for the combustor.

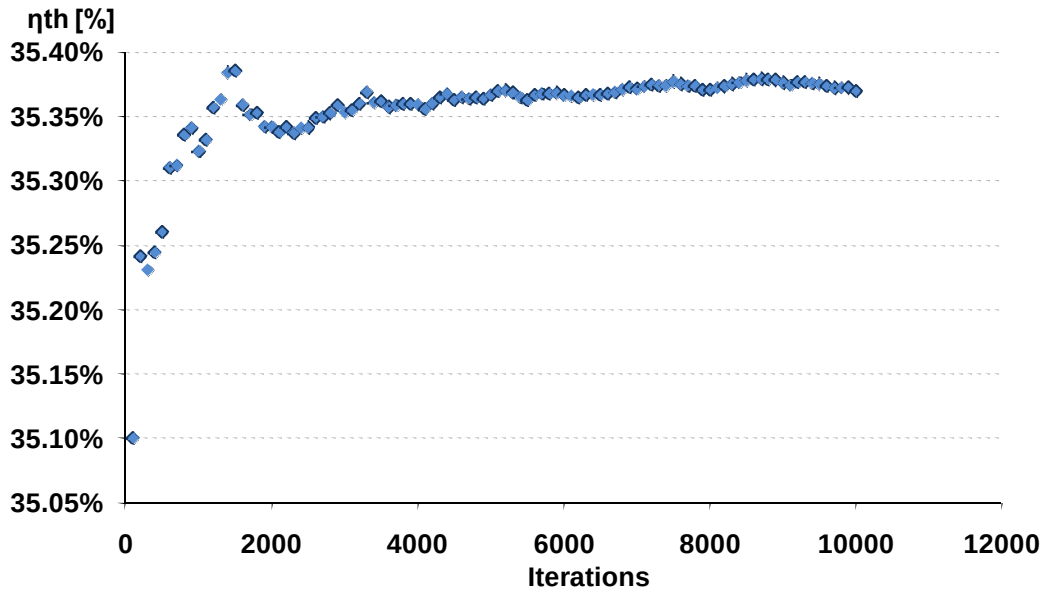


Figure 7.14 Convergence of the Technology Risk Model

As described in the first part of the chapter, the model implemented in the Technology Risk Analysis Module proposes that the selection of the probability distributions to be attributed to the TLIs follow the trend depicted in Figure 7.9. Many probability distributions could be selected to satisfy such requirement. In the present analysis, the beta distribution was selected to simulate all TLI parameters of interest. The general formula for the probability density function of the beta distribution is:

$$f(x) = \frac{(x-a)^{(\alpha-1)}(b-x)^{(\beta-1)}}{B(\alpha,\beta)(b-a)^{\alpha+\beta-1}} \quad (7.1)$$

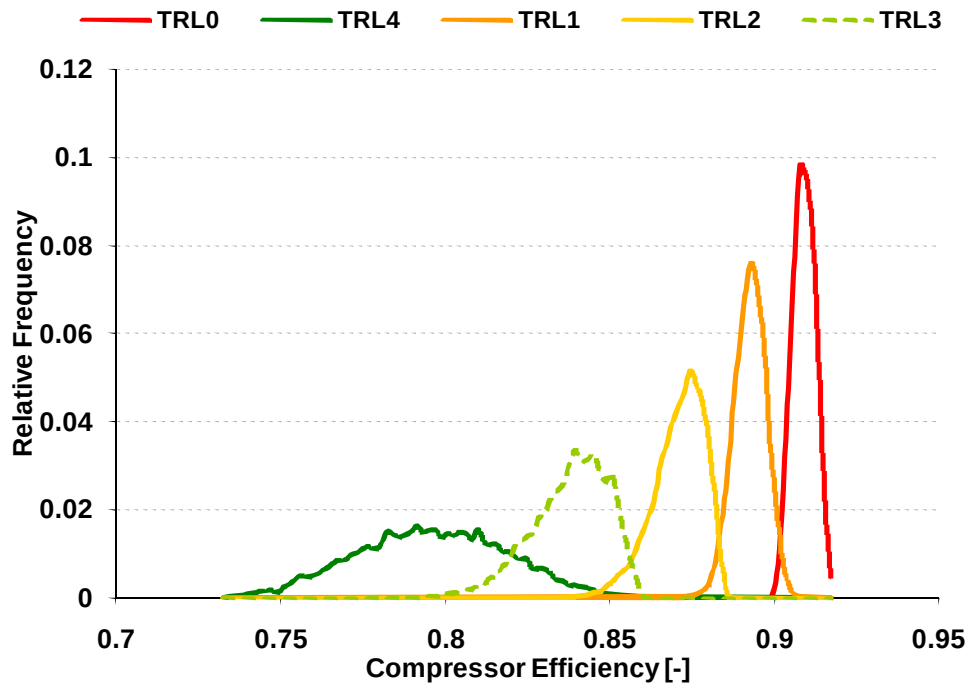
where α and β are the shape parameters, a and b are the lower and upper bounds of the distribution, and $B(\alpha, \beta)$ is the beta function. Tables 7-4 and 7-5 report values of the main parameters of the beta probability distributions chosen in the present analysis for the selected TLIs (Figures 7.15-7.16). Likewise in the financial risk analysis and in any Monte Carlo simulation, the selection of probability distributions is of great relevance. Due to the limited data and time frame available and the breath of this investigation, detailed expert judgments about such probability distributions could not be obtained. The author compensated this lack, bringing forward her own evaluation and suggesting values within the range of public material for illustrative purpose.

Table 7-4 Probability distributions for the TLIs: range of values simulated

TRL	Compressor (η_{∞})			Combustor (COT)		
	Minimum Value	Mean Value	Maximum Value	Minimum Value	Mean Value	Maximum Value
TRL 0	90%	90.8%	91.5%	1593 K	1610 K	1627 K
TRL 1	87.1%	89.1%	90.7%	1606 K	1580 K	1546 K
TRL 2	83.1%	87%	88.4%	1469 K	1542 K	1568 K
TRL 3	77.2%	83.7%	85.9%	1380 K	1483 K	1524 K
TRL 4	72.6%	79.5%	86.1%	1292 K	1409 K	1526 K

Table 7-5 Probability distributions for the TLIs: characteristics

TRL	Parameters of probability distribution
TRL 0	$\alpha = 4$ $\beta = 4$
TRL 1	$\alpha = 37$ $\beta = 16$
TRL 2	$\alpha = 18$ $\beta = 3$
TRL 3	$\alpha = 15$ $\beta = 3$
TRL 4	$\alpha = 5$ $\beta = 5$

**Figure 7.15** Relative frequency of random numbers for compressor polytropic efficiency

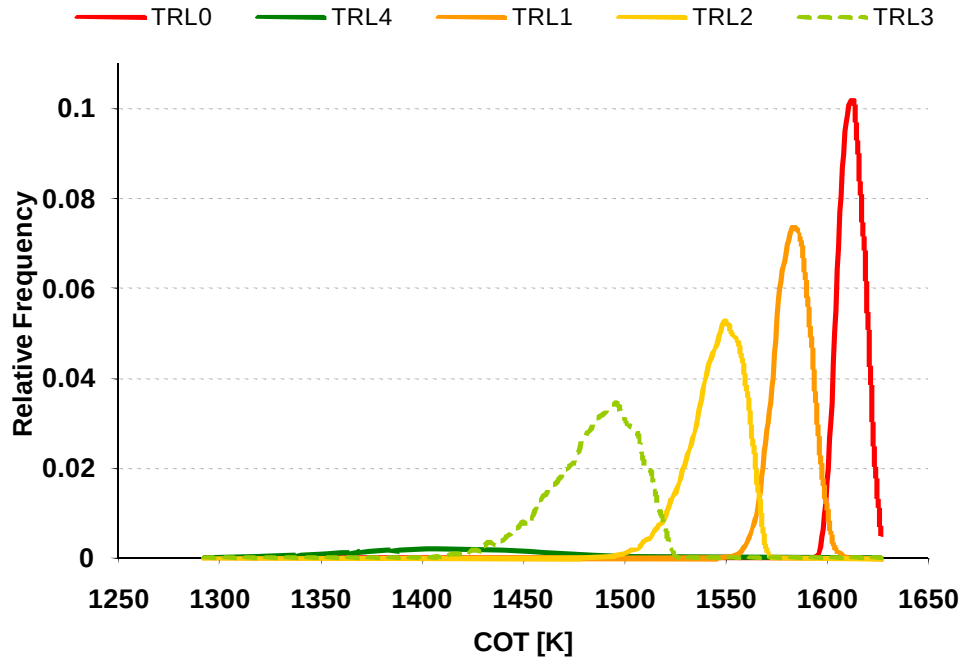


Figure 7.16 Relative frequency of random numbers for combustor outlet temperature

As shown in Table 7-4 the value of the TRL 0 is equal to 1610 K. It is understood that the COT of a modern gas turbine engine can assume values well higher than 1610 K. Such a value has been stipulated as characterising the TRL 0 (mature technology) since it refers to the conventional combined cycle designated as the baseline of the analysis.

Figures 7.17 – 7.20 present the results for the cumulative probability distributions of the power output and the thermal efficiency of the baseline in the case of an improvement of the level of technological maturity of the compressor and combustor alone. The results derived from a simultaneous enhancement of the TRL of the two components being considered are instead reported in Figures 21-22.

All graphs show the same trend: an improvement of the technology readiness level (which corresponds by hypothesis to an improvement of the performance of the component itself) implies a considerable increase of the thermal efficiency and the power output. The higher the technological maturity level, the further to the right is the cumulative distribution, ensuring thus higher value for the output variable being analysed. Assuming a confidence level of 90% (which corresponds to a cumulative probability of 10%), from the chart it is possible to appreciate that the TRL 0 will generate an higher power output and an higher thermal efficiency, while for the lowest TRLs the corresponding values are not encouraging. The cumulative distributions of the lowest TRLs present a quite pronounced negative skewness,

which is determined from high standard deviation (expression of an higher uncertainty) characterising the TLI in an immature state of development.

Hence, an overview of how a power plant (in this case a conventional combined cycle) can possibly benefit from ongoing or future technology development is shown.

Figure 7.23 reports the impact that improvement in the development of such components can eventually have on the economic performance of the conventional power-plant project considered.

For the ATRCC and the IRCC, the regeneration enthalpy and the polytropic efficiency of the CO₂ compressor have been included in the current version of the Technology Risk Module as TLI of the CO₂ capture block and the CO₂ compression block respectively, but some computational instability prevented the full analysis.

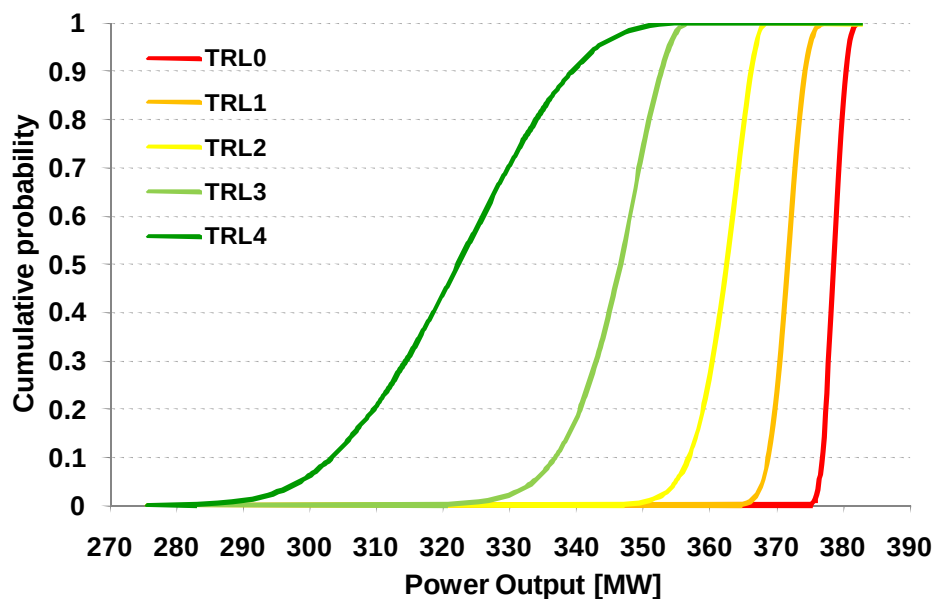


Figure 7.17 Effect of improvement of compressor TRL on power output

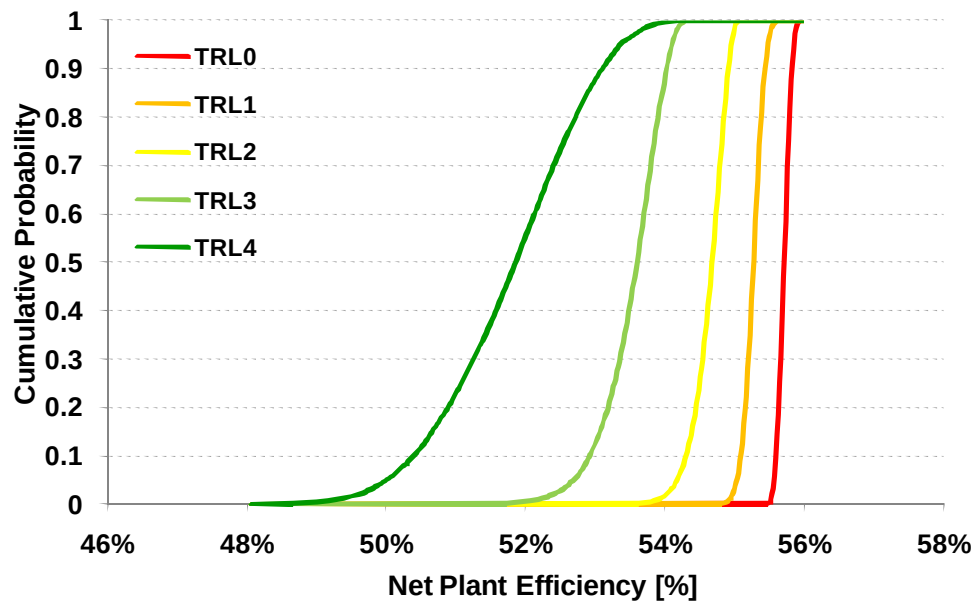


Figure 7.18 *Effect of improvement of compressor TRL on thermal efficiency*

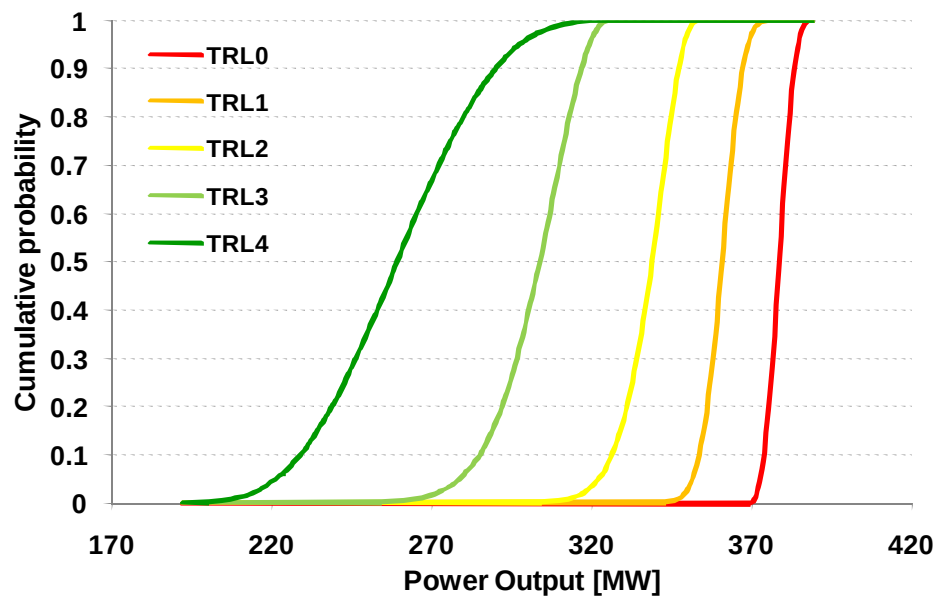


Figure 7.19 *Effect of improvement of combustor TRL on power output*

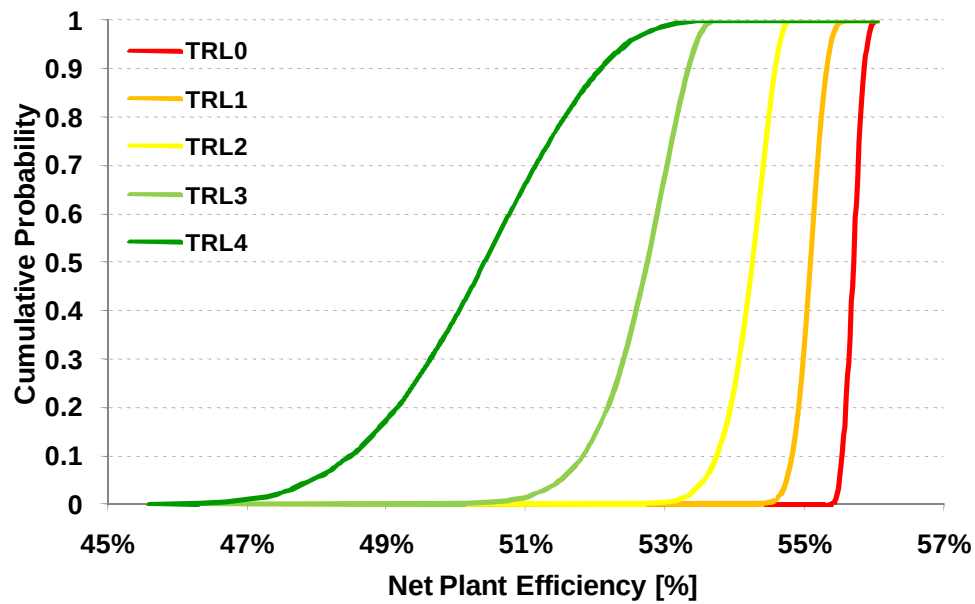


Figure 7.20 *Effect of improvement of combustor TRL on thermal efficiency*

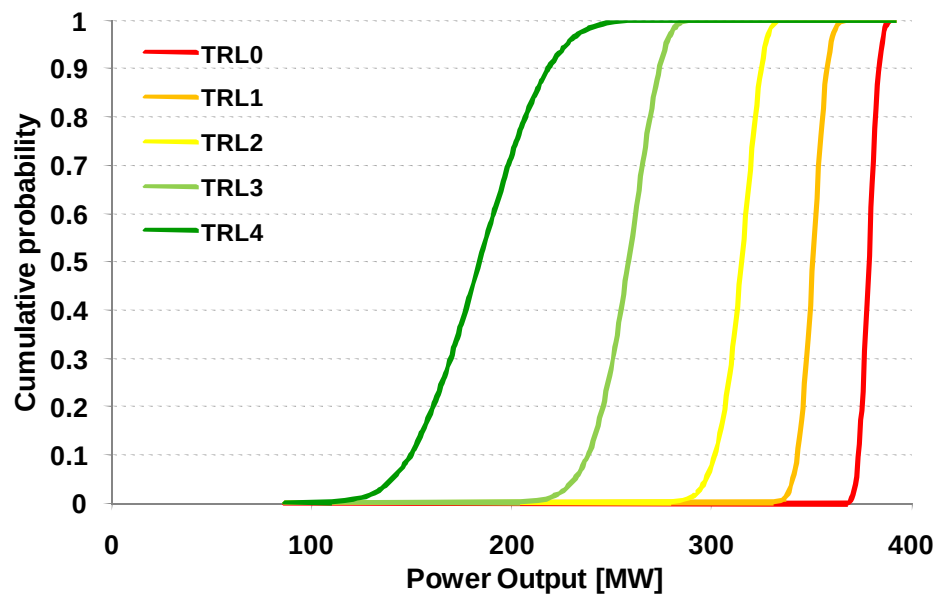


Figure 7.21 *Effect of improvement of all TRLs considered on power output*

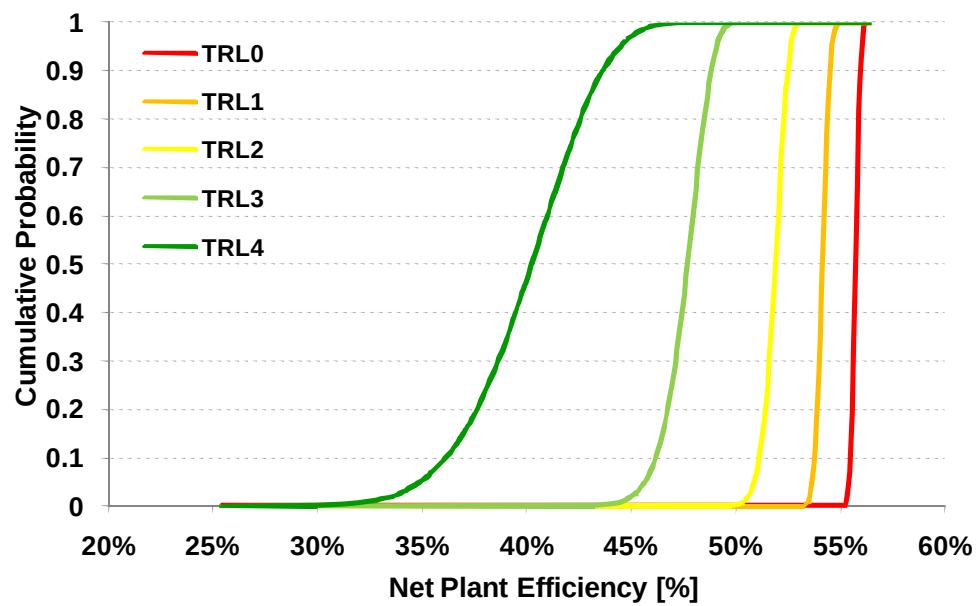


Figure 7.22 *Effect of improvement of all TRLs considered on thermal efficiency*

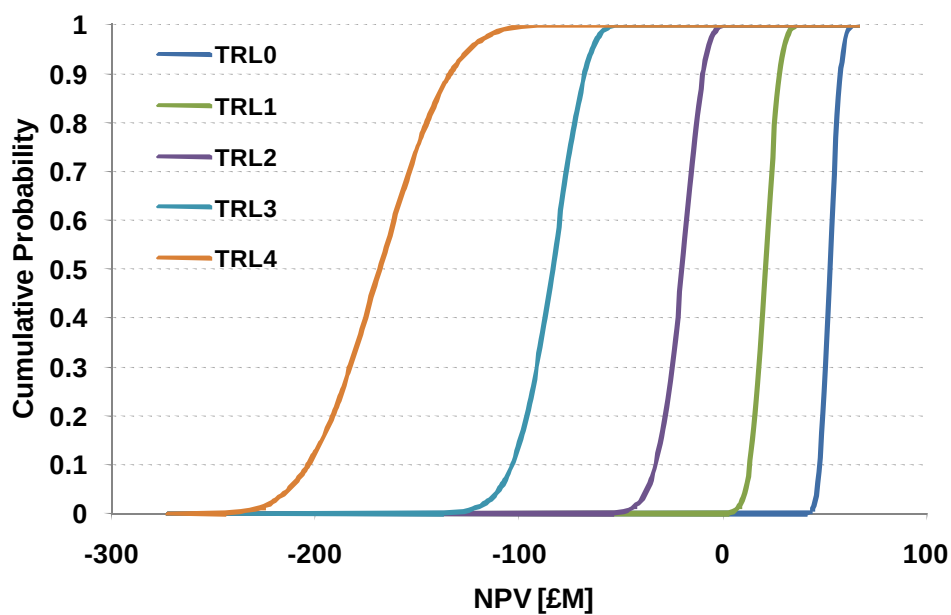


Figure 7.23 *Economic consequences of an increase of the TRLs*

CHAPTER 8

CONCLUSION AND FURTHER WORK

8.1 Final Discussion

The work presented in this thesis has contributed to the development of the multidisciplinary T.E.R.A. methodology for assessing CO₂ capture based power plants, with the principal target of offering a useful guide to support the strategic-decision-making process for future investments.

T.E.R.A. methodology applied here intends to screen technologies for capturing CO₂ from power generation from a fourfold point of view (performance, costs, pollutant emission and technological readiness level), offering a transparent, consistent and systematic approach.

Five low-carbon gas turbine based power plants have been identified as promising options satisfying future requirements for reduced CO₂ emissions, and a conventional gas turbine combined cycle has been designated as the baseline of the whole analysis. A study of each selected cycle has been initiated in terms of many aspects according to the T.E.R.A. approach (technical solution, technology readiness level, effort required for its deployment, environmental impact, costs and risks involved). Due to the breadth of the present study, the T.E.R.A. analysis, according to the first objective of the project, has been completed for three cycles (the baseline, the ATRCC and the IRCC), while, as detailed in Appendix A, encouraging results have been achieved for the development of thermodynamic models of the other selected cycles and their consequent performance analysis.

A first version of a computer tool for analysing CO₂ capture power plants based on the suggested methodology has been implemented, achieving thus the second objective of this investigation. Reflecting the basic multidisciplinary philosophy of T.E.R.A., the current version of this tool comprises four modules: Performance Module, Economic Module, Emissions Module and Technology Risk Analysis Module.

The Performance Module covers the power plant performance, in particular the gas and the steam cycles. A computer-based routine was written by the author in Fortran 90 to simulate the bottoming steam plant and was combined and integrated with the VARIFLOW code, a flexible Cranfield in-house gas turbine simulation tool, to produce a complete computer-based code for combined cycle performance analysis. Thermodynamic models of the selected advanced low-carbon power systems have been developed and some of them (ATRCC, IRCC) have been integrated in the Performance Module. Such models are simplified but still representative of the main phenomena occurring inside the systems considered.

A computer-based routine was written by the author in Fortran 90 to implement a CO₂ emissions evaluation model. Although this program represents a very preliminary version of the Emissions Module inside the T.E.R.A. Framework, it allowed the analysis to proceed and to lay the foundations of the general structure of the Framework itself. Using data from the Performance Module, the Emissions Module evaluates carbon dioxide emissions for unit of electricity produced. Such results are then stored and used in the subsequent analysis performed by means of the Economic Module.

The Economic module, a computer program in Fortran 90 language developed by the author, performs a two-stage investigation. It allows to calculate some parameters useful to assess the financial prospects of investments and support decision-making process, making use of the technical data provided by the previous Modules. In addition to this capability, the Economic Module allows the user to take in account uncertainty into the economics of the power generation scheme through the use of Monte Carlo method, which subjects the economic future of the project being considered to random variations centred on the no-risk data used in the first stage of the assessment.

The Technology Risk Module provides a methodology and a tool for evaluation of various CCS cycles with focus on technological maturity, capturing and coupling the systematic character of TRLs and the quantitative approach of the Monte Carlo method. The Risk Module embeds the Performance Module, the Economic and the Emissions Modules into a multi-run simulation environment. The whole TERA analysis delivers, therefore, no longer single values, but rather probability distributions of the main output indicators as representation of the impact that uncertainty, deriving from different levels of technological maturity, can have on the technical performance and in turn on the economic performance.

The present work offers a solid base for the establishment of such a methodical approach for the unmitigated power generation case and subsequently for the CCS case. The applicability of the methodology has been demonstrated in the three case studies, showing the potential of the approach applied to advanced low-carbon

projects' assessment, and testing the utility and the functionality of the related tools developed.

The T.E.R.A. analysis applied in this investigation to the three case studies delivered the following insights, discussed under the headings of power plant performance, carbon capture potential, investment analysis, technology readiness level.

1. Power plant performance

From the performance perspective, pre-combustion CO₂ capture capability reduces considerably the thermal efficiency and the power output of the two advanced schemes. The ATRCC power plant is predicted to produce a power output of about 304.8 MW with a thermal efficiency of 37%, while the IRCC solution is characterised by a power output of 365.5 MW and a thermal efficiency of 44.4%. The reduction in both power output and efficiency appears to be quite significant if these results are compared to the conventional combined cycle which is forecast to deliver a power output of 378.6 MW with a thermal efficiency of 55%. Between the two advanced power plants, the advantage in terms of power and efficiency of the combined cycle using the more integrated layout (IRCC) is clear.

2. Carbon capture potential

The T.E.R.A. approach highlighted the indisputable contribution the two advanced technologies investigated can make toward lowering carbon dioxide emissions and the associated global warming potential. The specific emissions are about 64g_{CO2}/kWh for the ATRCC and 53g_{CO2}/kWh for the IRCC, ensuring a reduction with respect to the baseline of 82% and 85% respectively. However, it has been shown also that the two layouts investigated may not keep NO_x in the common range for a conventional combined cycle, urging the necessity of a proper fuel treatment or improved combustor design to achieve NO_x emissions compatible with environmental protection.

3. Investment analysis

The ability of removing CO₂, provided by the two pre-combustion cycles, leads to a significant increase in the Capital and O&M costs, which impinges on the electricity cost: the CoE rises from 2.92p/kWh, value estimated for the baseline, to 4.72p/kWh and 4.16p/kWh for the ATRCC and the IRCC respectively (in the case of no carbon tax).

The economic analysis carried out highlighted clearly that carbon dioxide sequestration realised by the two pre-combustion schemes becomes economically feasible and sustainable in a deregulated energy market only if a heavy carbon-tax

(£40/ton for the IRCC and £60/ton for the ATRCC) is imposed and a higher electricity selling price is accounted for.

The economic analysis showed also the advantage in the economic performance of the IRCC cycle with respect to the other two cycles if a carbon tax of £50/ton is stipulated: the IRCC plant, in fact, presents a much higher NPV (£ 228M) compared to the ATRCC (£ 115M) and the baseline (£53M). This statement is further confirmed by the IRR evaluation, which revealed a value of 19.9% for the IRCC versus 15.9% and 13.43% for the ATRCC and the baseline respectively.

The application of Monte Carlo method revealed that considering uncertainties surrounding four key parameters (Capital Cost, O&M Cost, Fuel Price, and Carbon Tax) a substantial risk that the economic performance indices could exceed (or be lower in the case of NPV and IRR) the deterministic estimate found in the first part of the analysis is more prominent. The analysis performed showed a higher variability of the economic indices of the conventional combined cycle resulting from the uncertainty surrounding the carbon tax. This is related to the higher amount of CO₂ emitted. Both the low-carbon power plants, instead, are less influenced by the introduction of the tax, but are critically sensitive to the uncertainty in the fuel price. All economic and financial risk outcomes of the present investigation are subject on plant design assumptions as well as economic and financial parameters selected.

4. Technology Readiness Level

The T.E.R.A. analysis also provides insight into the potential requirements for the commercial readiness of advanced technology. The technology risk analysis showed that, due to the plant configuration adopted, no particular concerns exist regarding the gas turbine, and the other components present a high maturity level. The CO₂ compression and the CO₂ capture section are characterised by a lower maturity level, therefore may not match the power plant requirements. Furthermore, an appreciation of how the two power plants can possibly benefit from future development of these two technologies can be gained by means of the application of the Technology Risk Analysis Module, as it has been showed for the conventional combined cycle case. Taking in account the IGCC power plant experience, the high number of subsystems in which the plants can be divided, along with the less-mature technology used, may represent some concern about the availability and maintenance in their first years of operation, especially for the IRCC case due to the higher degree of integration between the power island and the fuel decarbonisation section.

This transparent and consistently based picture of the two pre-combustion power-plants, based on a common basis (configuration and definition of system boundaries, simulation tools, methods and assumption), allows highlighting the aforementioned

advantages of the IRCC scheme compared to the ATRCC one, drawing thus the following conclusion: the IRCC power plant can be a viable option for new power generation capacity to be installed in the near future under a high carbon dioxide emission constraint. Improvements in the CO₂ capture and compression (due to their low maturity level) and reduction in NO_x emissions, along with the costs contribution, would provide a very competitive solution to reduce substantially CO₂ emissions from power plants.

The T.E.R.A. exercise developed in the present investigation highlighted clearly how the carbon tax levy looms as a market factor through which CCS deployment can be incentivised, since it offers the opportunity for power plants to profit from investments in CCS. On the other hand, combined with the volatile price of natural gas, this additional cost will certainly be transferred from power producers to the consumers of electricity. Therefore, the carbon tax will inevitably have a negative impact on national economic growth.

8.2 Further Work

The experience gained during implementing the case studies confirms that the suggested methodology for CO₂ capture power plant analysis may become very useful for analysing and comparing alternative solutions for CCS under various conditions. However, due to the simplified models and analyses set up in the initial implementation, the reported case studies revealed several properties of the tool that could be refined.

Given the central role and paramount relevance that the performance analysis holds in any T.E.R.A. exercise, the Performance Module requires special attention. The VARIFLOW code could be more complete allowing for the simulation of the engine for different IGV angles. This can be done implementing the standard compressor map for different IGV angles. The steam cycle model represents a preliminary model and needs to be improved in order to obtain a more flexible and powerful tool. This objective could be reached introducing more detailed models for each component (e.g. HRSG, steam turbine and condenser) as suggested in Chapter 4, completing the off-design model of the single pressure level power plant and extending it to multi-pressure level systems.

Regarding the two advanced pre-combustion schemes analysed in this investigation, the model implemented for the fuel treatment section aimed to provide an estimation of the chemical composition of the mass flows exiting the reactors. In this context, a more detailed description of the reforming chain can be developed. This is of relevance for the prediction of the exact pressure of the flows exiting the components modelled. The integration of such a model in a computer-based code

could be useful for the calculation of the composition also for off-design operations (removing the assumption of linearity between the fuel flow required from the gas turbine and all the input streams used in the reforming process). Moreover, it has been said that the steam-carbon ratio plays an important role in the performance of the ATRCC and IRCC. A value of 2.5 has been stipulated in this study as good compromise between the thermodynamic efficiency of the whole plant and elevated CO₂ removal; it would be interesting to optimise it taking into account the whole spectrum of possible impacts (economic, environmental etc) implied by the T.E.R.A. approach. Another scenario that could be taken into account is the possibility to store H₂ along with the production of electricity. In this way the reactors could always process the same amount of syngas while the engine is working in off-design, without needing to modulate the syngas production. In case of variation of the load required from the grid, the plant will reduce the electricity produced but will increase the production of hydrogen. However, a careful investigation and analysis of the risks and the complexity related to the storage of H₂ has to be carried out.

In the further development of the methodology and related Framework it is relevant to include the thermodynamic models of the other selected cycles, and thus complete the T.E.R.A. analysis for all of them.

In the long-term perspective, the advanced power plant models could be developed with greater consideration of optimal system design and the off-design behaviour, providing thus a better understanding of the potential advantages of such advanced low-carbon power systems and completing the implementation of T.E.R.A. methodology, as described in Chapter 2.

The off-design analysis will be beneficial also for the economic analysis, providing more realistic figures of the thermodynamic performance of the power plant during its lifetime. The calculation of the electricity sent out could be performed considering the power plant performance evolution during its lifespan under various ambient conditions and load demand, considering the impact that changes at the same time in both parameters can have on the plant performance. Moreover, the probability distributions for the risk variables are at present based on simplified assumptions (derived from the literature) and they should be estimated on a more profound basis, benefitting from the experience of experts and/or historical data. Such refinement could deliver a more tailored appreciation using the general T.E.R.A. platform. Third, the economic analysis could facilitate inclusion of parameters such as extra start-ups and shut-downs, other risk variables (e.g. escalation rates) and other financial solutions with different debt-to-equity ratio in order to evaluate capital subsidy schemes to support construction of CCS plants. The analysis could be extended also to other capacity factor cases (given the importance held by this parameter) and eventually include capacity factor as a risk variable, taking in account

potential correlation between the capacity factor and the other risk variables (in primis O&M costs).

In the further development of the methodology and the related tool it is highly relevant to substitute the current version of the Emissions model to extend the environmental analysis to the estimation of other emission pollutants. In particular the modelling related to the carbon dioxide and oxides of nitrogen needs to be implemented or improved.

The Technology Risk Analysis Module could be strengthened by an accurate selection of the TLI parameters that reflect the low state of development of the technology of the components which are referred to, and thus being applied also to the CCS power plant concepts. It would be highly beneficial for the whole analysis to dispose of information (statistical analysis of data and/or elicitation of judgments from technical experts) that can be used to infer judgments about uncertainty. The entire model could be improved also to take into account the effect of scale-up on process performance and the potential cost reduction deriving from continuous TRL improvements, which was not included in the current version of the Economic Module.

Further developments would require also automated data flows between models and a user interface.

In the long-term perspective, it would be relevant to study the interfaces between the CCS power plant and the surrounding markets and identify whether and to what extent it is possible to forecast key input parameters of the methodology such as energy prices and CO₂ quota prices.

The evaluation method, to whose development this work contributed, represents only a part of the extraordinarily complex and multidisciplinary approach necessary for evaluating the relative merits and risks embodied in investments in advanced low-carbon power systems.

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Appendix A

A.1 Integrated Gasification Combined Cycle

The IGCC investigated in this work in collaboration with Barbera [122] is composed of the following main components:

- entrained flow gasifier
- integrated elevated pressure air separation unit (ASU)
- high and low temperature water gas shift reactors (HTSR and LTSR)
- acid gas removal (AGR)
- gas turbine (GT)
- heat recovery steam generator (HRSG)
- steam turbine (ST)

Figure A.1 shows the schematic representation of the final arrangement of the components of the power plant. The gasifier processes the injected coal, transforming it into a gaseous flow.

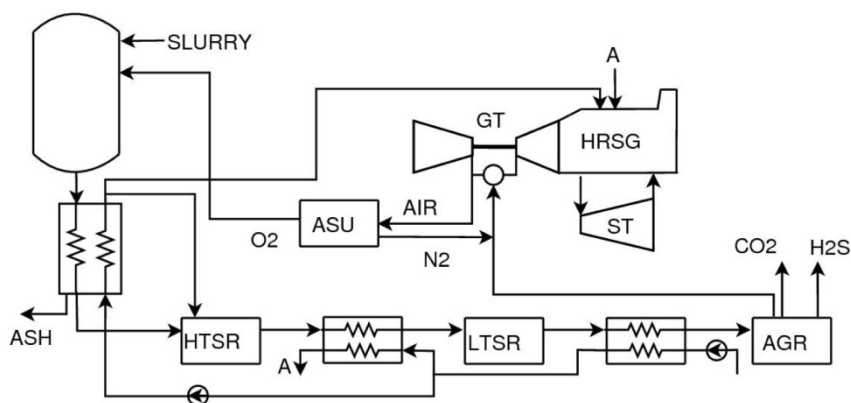


Figure A.1 *IGCC plant layout analysed*

As a strong reduction in carbon dioxide is desired, it is necessary to convert the carbon monoxide formed in the gasifier. This is obtained in the water gas shift reactors which convert the CO to additional hydrogen and carbon dioxide consuming steam. As the WGS reaction is exothermic, it benefits from low temperature. Hence, the very high temperature raw syngas produced in the gasifier has to be cooled to recover its sensible energy. The heat recovered in the heat exchanger is used for the production of high pressure steam. The steam produced is partly injected into the high temperature water gas shift reactor and the remaining part is added to the high pressure steam produced in the HRSG.

As stated previously, the WGS reaction is exothermic; therefore, the temperature of the syngas at the outlet of the first shift reactor is increased. Prior to the low temperature shift reactor, the syngas is cooled, generating intermediate saturated steam to be superheated in the HRSG.

At this point the syngas is highly enriched in hydrogen and must be purified from the acid gases including hydrogen sulphide and carbon dioxide. This is performed in the acid gas removal (AGR) section of the power plant (a double column Selexol process for the removal of the acid gases, hydrogen sulphide and carbon dioxide), which requires the syngas almost at ambient temperature. Hence the temperature of the syngas is cooled at the low temperature shift reactor outlet, preheating the water for the following heat recoveries.

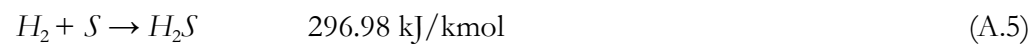
The gasifier needs a highly oxygen enriched oxidiser. This is generated in an integrated high pressure air separation unit that is fed mainly with air bled from the gas turbine compressor (75% integration) but also, in small part, from a dedicated compressor.

From the AGR, the syngas is expanded to a pressure suitable for the gas turbine combustor. The nitrogen produced in the ASU is compressed and used to dilute the syngas for an effective control of oxides of nitrogen.

At this point the diluted and purified syngas is used to fire the gas turbine. The engine is producing power and delivers a high temperature mass flow to the HRSG which recovers the gas turbine exhaust energy, producing the steam used to generate power.

A simplified chemical model based on chemical equilibrium, using the minimisation of the Gibbs free energy as described in Chapter 4 of this dissertation, has been implemented to provide an estimation of the composition of the syngas produced. This chemical model is applied both to the gasifier and to the water gas shift reactors.

A bituminous coal is assumed to be fed to the gasifier. The mass fractions are 61.27% of C, 3.41% of S, 1.1% of N, 8.83% of O₂, 12% of H₂O, 4.69% of H₂, 8.7% of ash. The coal is mixed with water and fed as slurry into the gasifier. The following reactions are taken into account for the determination of the composition at the gasifier outlet [122]:



The performance of the power plant is analysed simulating the gas cycle with an adapted release of the VARIFLOW code. The code has been modified to account for the air bled from the gas turbine compressor for the air separation unit (see Chapter 4). The steam cycle considered (double pressure with reheat), along with the other components outlined in Figura A.1, have been modelled in an Excel based environment [122]. A preliminary study of the off-design behaviour of the plant has been carried out by the application of the model described in Chapter 4 [122].

A.2 Advanced Zero Emissions Power plant

As stated in Chapter 3, the Advanced Zero Emissions Power plant (AZEP) is a novel thermodynamic cycle in which the conventional GT combustor is replaced by a mixed conducting membrane (MCM) reactor. This new device operates the separation of the oxygen from the air, the combustion of the fuel with pure oxygen and, finally, transfers the heat of combustion to the oxygen-depleted air.

The MCM reactor is actually made up of three parts: a Low and High Temperature Heat Exchanger (respectively LTHX and HTHX) and the membrane itself, that performs at the same time the oxygen mass transfer and the heat exchange. The insertion of the LTHX and the HTHX, respectively before and after the membrane is necessary to keep its temperature as constant as possible at the optimal value for the oxygen transport. Basically the higher is the temperature of the membrane, the higher is the mass of the oxygen depleted from the compressed air; consequently, it would be desirable to boost it as much as possible also to reduce the exchange area. Unfortunately the aforementioned temperature is limited to about 1200 °C by the degradation of the device and the HTHX is necessary to reduce the difference between the combustor outlet temperature of a conventional power plant and the turbine inlet temperature of the AZEP cycle. This limitation turns out in the constitutional disadvantage of the AZEP concept versus the reference thermodynamic cycle.

The process flow diagram of the AZEP plant selected for the T.E.R.A. study is shown in Figure A.2. A flexible and modular computational tool, called *eAZEP*, was developed by Pagone [125] in collaboration with the author.

As already stated, the Mixed Conductive Membrane is the most important and complicated device of the power plant. It performs the extraction of the oxygen (the light blue line in Figure A.2) from the compressed air flow (dark blue and grey line) transferring it to an almost oxygen-free gas stream (the red line). The peculiarity of this device is that, at the same time of the mass transfer, takes place the counter-current heat exchange between the two flows, turning out in a remarkable increase of the model complexity.

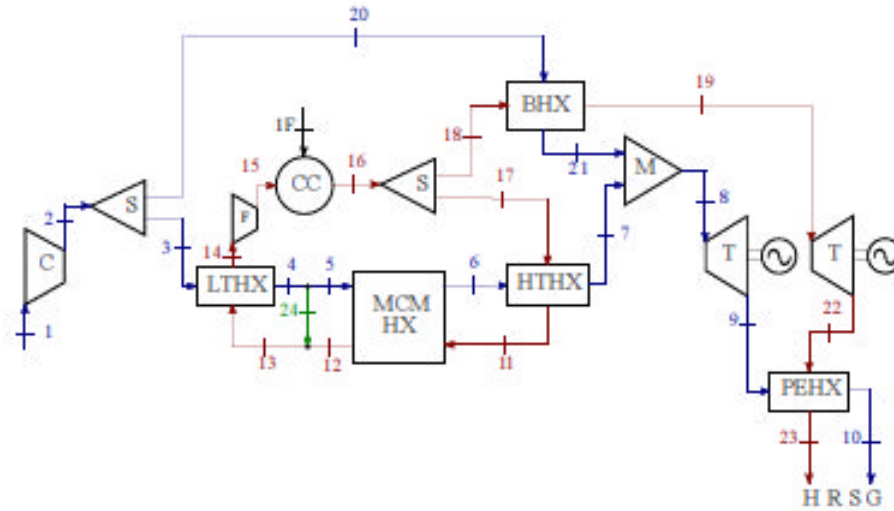


Figure A.2 Process flow diagram of the AZEP cycle [125]

In order to take into account the complex thermodynamic transformations of the device, it has been considered consistent with the aim of the whole T.E.R.A. analysis the application of the *superimposition principle*: the corresponding process flow diagram is shown in Figure A.3. Applying the superimposition principle, the membrane process is divided into two sub-processes: 1) an adiabatic transfer of oxygen from the feed flow (compressed air) to the permeate flow (flue gas stream) and 2) the heat exchange.

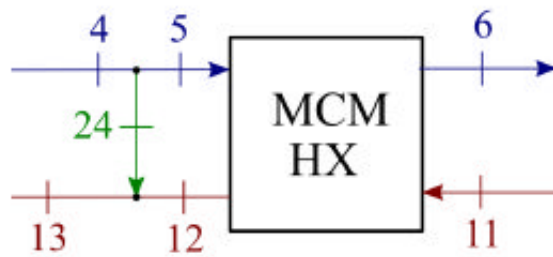


Figure A.3 The eAZEP Mixed Conductive Membrane process flow diagram [125]

The membrane surface A_{mcm} must satisfy, at the same time, the mass transfer and the heat transfer constraint. Thus the number of thermal units for the MCM NTU_{mcm} cannot be regarded as a design parameter, but it is determined by the equation that drives the mass transfer through the membrane, which is the Nernst-Einstein

formula, a simple case of integration of the Wagner equation ([248-250] in Pagone [125]):

$$j_{O_2} = \frac{\sigma RT}{4Ln^2F^2} \ln \frac{p_{O_2}^F}{p_{O_2}^P} \quad (A.6)$$

where:

j_{O_2} is the oxygen flux;

σ is the membrane electric conductivity;

R is the ideal gas constant;

T is the membrane temperature;

L is the membrane thickness;

N is the valency number of the element permeated (in the case of oxygen $n=2$);

F is the Faraday constant;

$p_{O_2}^F$ is the partial pressure of the oxygen on the feed side;

$p_{O_2}^P$ is the partial pressure of the oxygen on the permeate side.

Four different layouts of the AZEP concept as stand-alone gas turbine-based power plants have been investigated. The performance evaluation of the long-term potential for these gas turbines has been also evaluated considering the effect of the operative pressure of the membrane. For more information the reader is referred to Pagone [125].

A.3 Chemical Looping Combustion

A Chemical Looping combustion model for the on-design and off-design performance study has been developed in Fortran 90 language by Noel Glaenzer [123] in collaboration with the author.

Figure A.4 depicts the principle of Chemical Looping Combustion. The fuel conversion is accomplished by virtue of the two intermediary reactions: oxidation and reduction. The oxygen needed by the fuel is supplied by employing an intermediate agent, which is a certain metal oxide (MeO). In a reduction reactor, the metal oxide reacts with the fuel. As a result of the reduction reaction, the fuel reacts with the oxygen in the metal oxide thereby reducing the metal oxide to metal (Me) (Equation A.7). The reduced metal then circulates to a separate oxidation reactor, transports the chemical energy of the fuel to the air in the form of sensible heat, reacts with oxygen in the air, and gets regenerated to MeO (Equation A.8). The metal oxide then circulates back to the reduction reactor to react with the fuel.

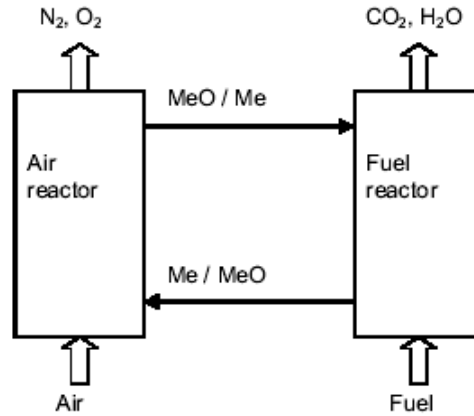
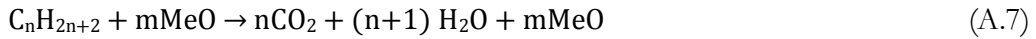


Figure A.4 Basic principle of CLC [107]



The preliminary model developed is based on heat mass balance occurring between the two reactors, completed by the evaluation of the reactors dimensions. Three different oxygen carriers' performance has been assessed: iron, nickel and copper. The model has been integrated in the VARIFLOW code. Further details are available in Glaenzer [123].

A.4 Oxy-fuel Combined Cycle

As stated in Chapter 3, the Oxy-fuel Combined Cycle concept employs a semi-closed loop gas turbine with near-to-stoichiometric combustion of fuel in a mixture of CO_2 and oxygen to produce a mixture of CO_2 and steam (e.g., Figure 3.7). The exhaust gases are expanded through the turbine for power generation and provide heat for the bottoming steam cycle. The CO_2/H_2O stream goes through the condenser where most of the H_2O is recovered by cooling and condensation. Approximately 90% of the CO_2 is recycled back to the combustor in order to keep the TET at a required level. The excess produced during the combustion can be easily removed to be compressed for an efficient storage. The working fluid in the gas turbine cycle is CO_2 .

Although VARIFLOW code offers the flexibility of choosing CO_2 as working fluid, some modifications have been implemented in the main code: a cooler has

been added between the turbine outlet and the compressor inlet to close the cycle; an additional bleed at the end of the compressor is required to simulate the excess CO₂ removal; two simple routine take into account the work required by the CO₂ compression and the power consumed by the air separation plant. The aforementioned modification of the VARIFLOW code has been carried out in collaboration with F. Agbonzikilo [124].

APPENDIX B

Table B-1 *U.K. GDP deflator series* [214]

Calendar year			
GDP deflator at market prices		Money GDP	
Calendar year 2008 = 100	per cent change on previous year	Cash £ million	
1955	4.914	19,490	
1956	5.235	20,956	
1957	5.432	22,105	
1958	5.646	23,050	
1959	5.719	24,348	
1960	5.793	25,977	
1961	5.974	27,413	
1962	6.190	28,711	
1963	6.286	30,409	
1964	6.512	33,228	
1965	6.880	35,888	
1966	7.183	38,189	
1967	7.394	40,281	
1968	7.691	43,656	
1969	8.115	47,023	
1970	8.726	51,696	
1971	9.535	57,670	
1972	10.307	64,621	
1973	11.092	74,545	
1974	12.742	84,513	
1975	16.191	106,717	
1976	18.666	126,274	
1977	21.222	146,973	
1978	23.687	169,344	
1979	27.139	199,220	
1980	32.441	233,184	
1981	36.132	256,279	
1982	38.809	281,024	
1983	40.941	307,207	
1984	42.824	329,913	
1985	45.325	361,758	
1986	46.876	389,149	
1987	49.384	428,665	
1988	52.485	478,510	
1989	56.329	525,274	
1990	60.683	570,283	
1991	64.602	598,664	
1992	67.031	622,080	
1993	68.959	654,196	
1994	70.050	692,987	
1995	71.926	733,266	
1996	74.529	781,726	
1997	76.606	830,094	
1998	78.305	879,102	
1999	79.949	928,730	
2000	80.897	976,533	
2001	82.616	1,021,828	
2002	85.174	1,075,564	
2003	87.791	1,139,746	
2004	90.004	1,202,956	
2005	91.832	1,254,058	
2006	94.392	1,325,795	
2007	97.111	1,398,882	
2008	100.000	1,448,392	

Table B-2 *Capital costs and O&M costs for conventional combined cycle power plants*

Data Description / Source	GT World 2007-08 [216]	Lozza & Chiesa [133]	Simbek [216]	IEA [221]	Parsons NETL [222]	Rezvani et al. [203]
Power Output	380 MW	373.2 MW	400 MW	485 MW	379 MW	380 MW
Decarbonisation process	-	-	-	-	-	-
CO ₂ capture technology	-	-	-	-	-	-
CO ₂ compression	-	-	-	-	-	-
Yearly operating hours	-	7000	6570	7884	7446	7446
Capital cost	525 ^a US\$/kW	151 ^b M\$ (404 \$/kW) 187 ^c M\$ (500 ^c \$/kW)	133 ^d M\$ (332 \$/kW) 160 ^e M\$ (400 \$/kW)	High Base Cost scenario ^f : 632 \$/kW Low Base Cost scenario ^f : 400 \$/kW	128.551 ^g M\$ (339 \$/kW) 165.412 ^h M\$ (436 \$/kW)	205.4 ⁱ M€ (540 €/kW)
O&M costs	-	2.04 millUS\$/kWh	4% of capital per yr	7.23 M\$/year	10.170 M\$	Fixed operating cost: 26 €/kWe Variable operating cost: 0.3 €/kWh
Year of reference	2007	2000	1997	1998	1st Quarter 2002	2005

^a This figure includes cost of GT, ST, Unfired HRSG, Electric Generator, Balance of Plant (standard plant controls and auxiliary systems)

^b Cost of process facilities

^c Total Cost (balance of plant, cost of engineering, contingencies included)

^d Cost of process facilities

^e General Facilities included (costs exclude contingencies, “soft costs”, sales tax, VAT, interest during construction, owner’s costs)

^f Fixed investment including reforming block, CO₂ block, combined cycle block, utilities block, contingencies. As the estimated cost of the base case combined cycle plant is considered to be subject to significant variation, depending on the location of the plant and information source, economic summaries are given for two cost scenarios (High Base Cost and Low Base Cost)

^g Process Plant Cost

^h Total Plant Cost (engineering fees, process contingency and project contingency included)

ⁱ Engineering and procurement costs (excluding contingencies and working capitals). Some indirect costs included.

Table B-3 Capital costs and O&M costs for pre-combustion decarbonisation combined cycle power plants

Data Description / Source	Damen et al. [94]	Lozza & Chiesa [133]	IEA [221]	IEAv [221]	IEA [221]	Parsons NETL [222]	Bolland et al. [223]
Power Output	600 Mwe	394 MW	479 MW	475 MW	489 MW	413 MW	1263 MW
Decarbonisation process	SMR/POX/ATR	Partial oxidation	SMR Recycle ^o	SMR Pressurised ^q	Catalytic POX ^r	Steam reforming	ATR
CO ₂ capture technology	Chemical/physical absorption	Chemical absorption	Chemical absorption	Chemical absorption	Chemical absorption	PSA	Chemical absorption
CO ₂ capture efficiency	85-90%	90%	85%	85%	85%	-	85-90%
CO ₂ compression	110 bar	80 bar	80 bar	80 bar	80 bar	145 bar	150 bar
Yearly operating hours	-	7000	7884	7884	7884	7446	-
Capital cost	900-1470 ^l €/kWe	214 ^m M\$ (543 \$/kW) 276 ⁿ M\$ (701 \$/kW)	High Base Cost scenario ^p : 1038 \$/kW Low Base Cost scenario: 803 \$/kW	High Base Cost cenario ^p : 1208 \$/kW Low Base Cost scenario: 972 \$/kW	High Base Cost scenario ^p : 939 \$/kW Low Base Cost scenario: 710 \$/kW	376.813 ^s M\$ (912.4 \$/kW) 484.476 ^t M\$ (1173.06 \$/kW)	1291 ^u \$/kW
O&M costs	3-6 % of TPC (Total Plant Cost)	2.45 millUS\$/kWh	12.62 M\$/year	14.11 M\$/year	11.54 M\$/year	26.694 M\$	-
Year of reference	2003	2000	1998	1998	1998	1st Quarter 2002	2000

^l Total Capital Requirement (TCR) includes TPC (Total Plant Cost), owners costs and interest of construction.

^m Cost of process facilities

ⁿ Total Cost (balance of plant, cost of engineering, contingencies included)

^o Conventional steam reforming but with gas turbine exhaust used as combustion medium for the reformer furnace

^p Fixed investment including reforming block, CO₂ block, combined cycle block, utilities block, contingencies. As the estimated cost of the Base Case combined cycle plant is considered to be subject to significant variation, depending on the location of the plant and information source, economic summaries are given for two cost scenarios.

^q Combustion air for the pressurised reformers is extracted from the discharge of the air compressor of the combined cycle gas turbine and the spent combustion air is returned to the gas turbine upstream of the combustion zone.

^r Catalytic partial oxidation of natural gas, using air extracted from gas turbine air compressor discharge.

^s Process Plant Cost

^t Total Plant Cost (engineering fees, process contingency and project contingency included)

^u Specific total installed cost

Table B-4 *Comparison of CoE and BESP (without carbon tax)*

Case	CoE_average (p)	BESP_average (p)
Baseline	2.918	3.330
ATRCC	4.722	5.500
IRCC	4.164	4.893

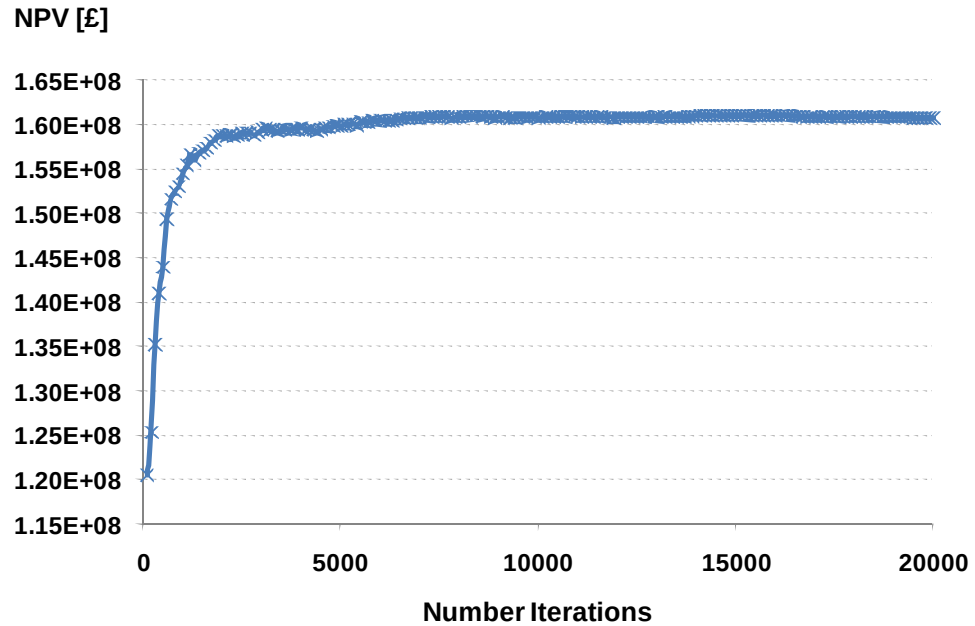


Figure B.1 *NPV convergence*

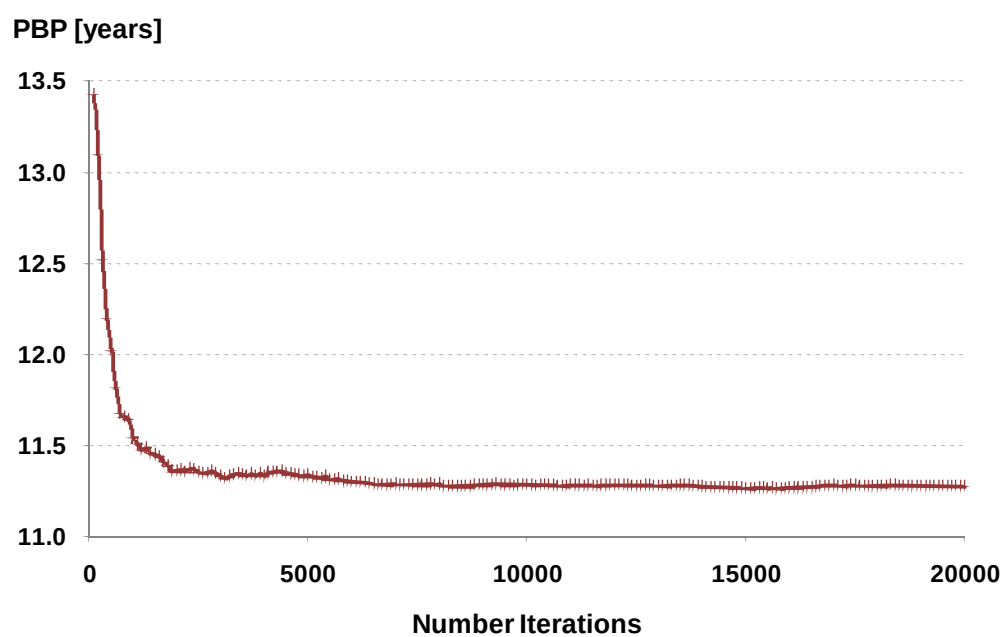


Figure B.2 *PBP convergence*

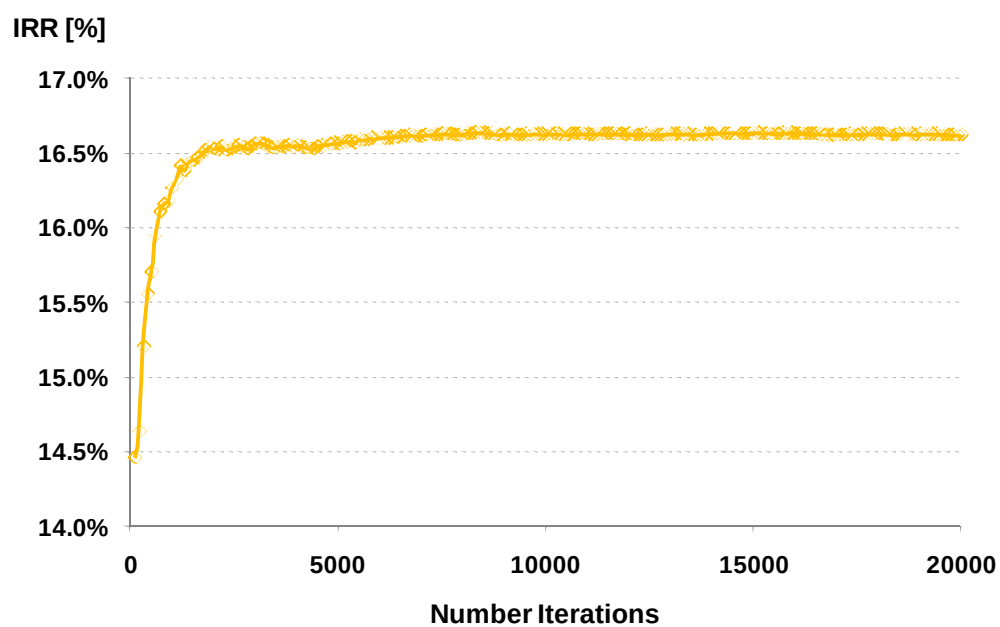
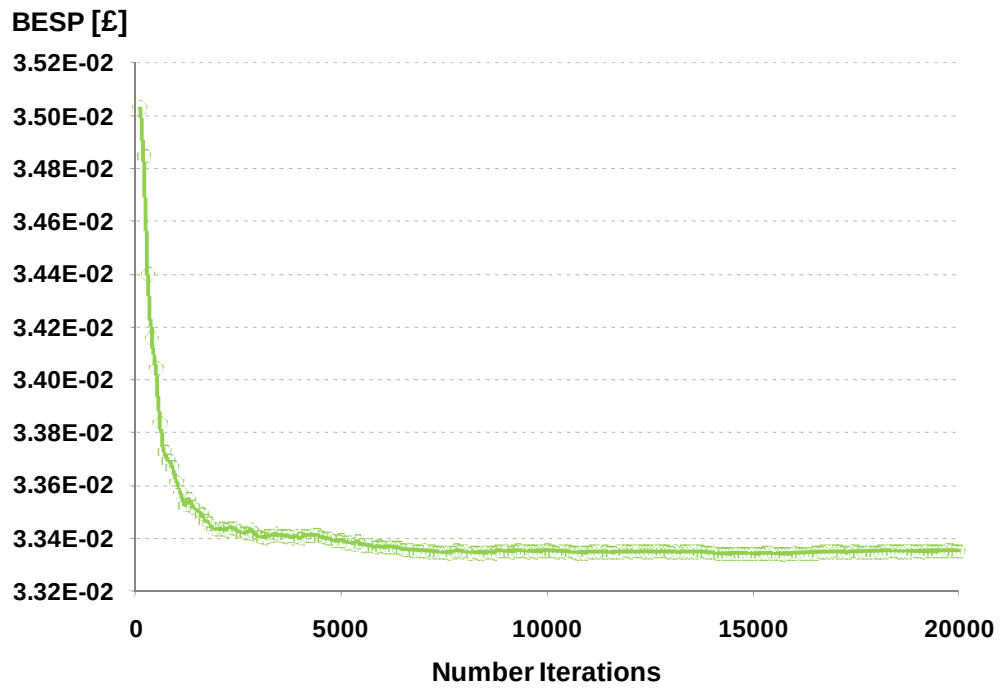
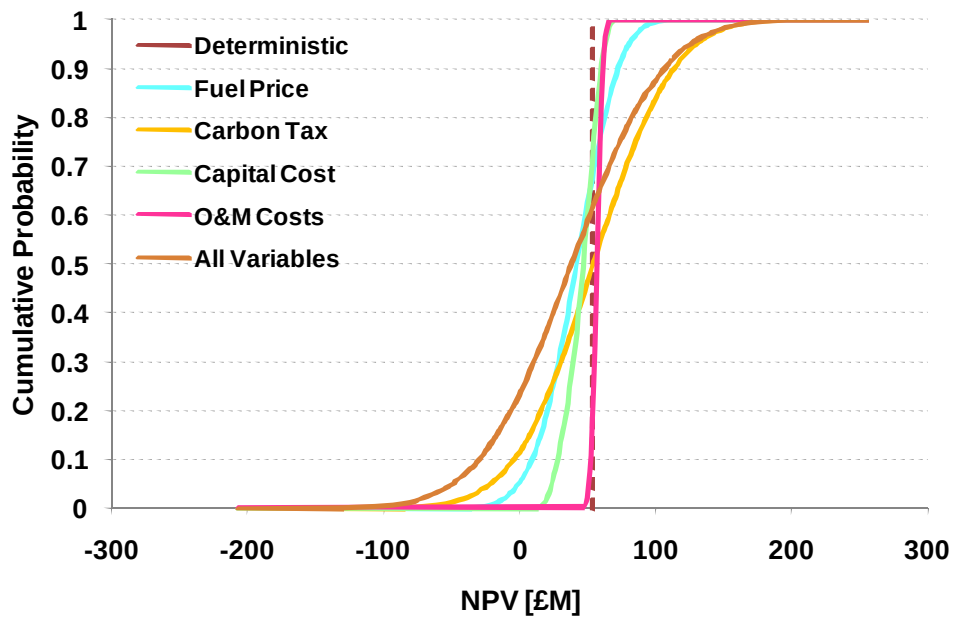


Figure B.3 *IRR convergence*

Figure B.4 *BESP convergence*Figure B.5 *Baseline case: effect of uncertainty of all risk variables on NPV*

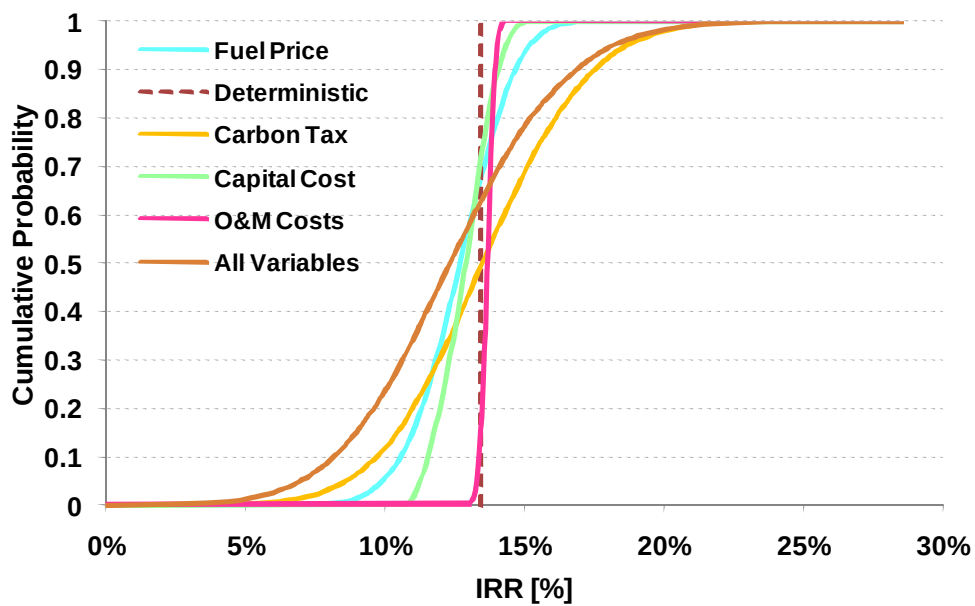


Figure B.6 Baseline case: effect of uncertainty of all risk variables on IRR

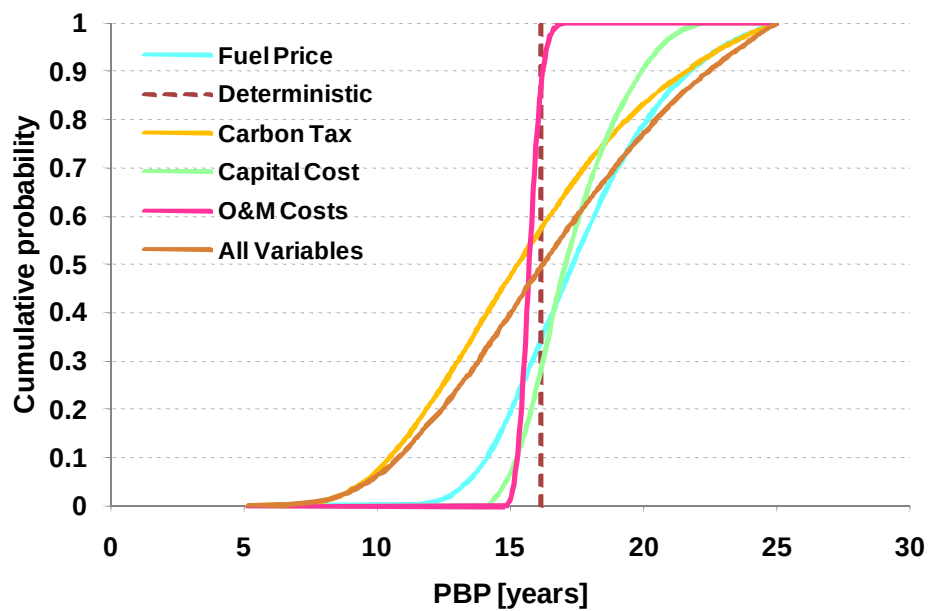


Figure B.7 Baseline case: effect of uncertainty of all risk variables on PBP

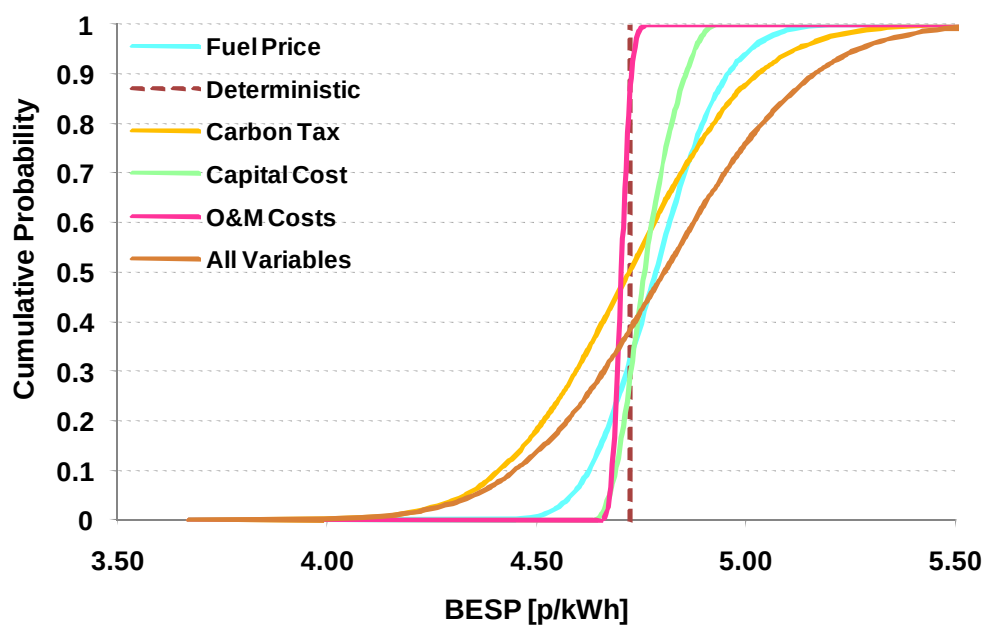


Figure B.8 Baseline case: effect of uncertainty of all risk variables on BESP

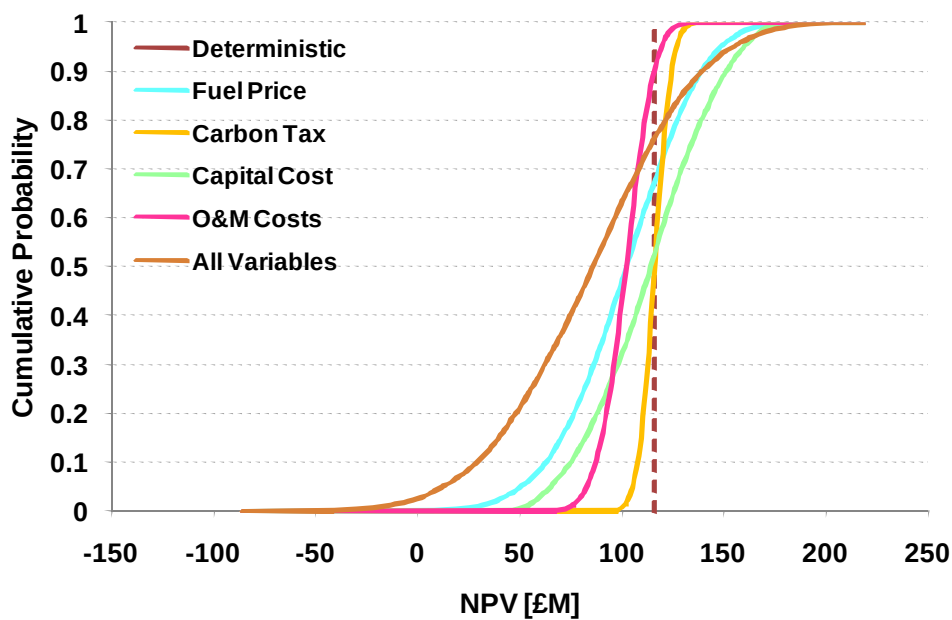


Figure B.9 ATRCC case: effect of uncertainty of all risk variables on NPV

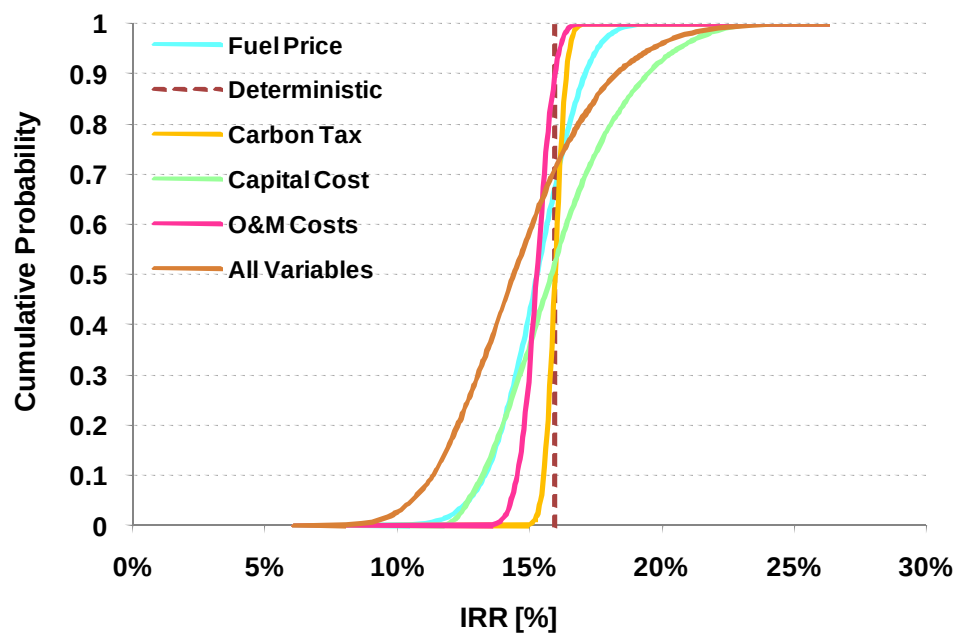


Figure B.10 ATRCC case: effect of uncertainty of all risk variables on IRR

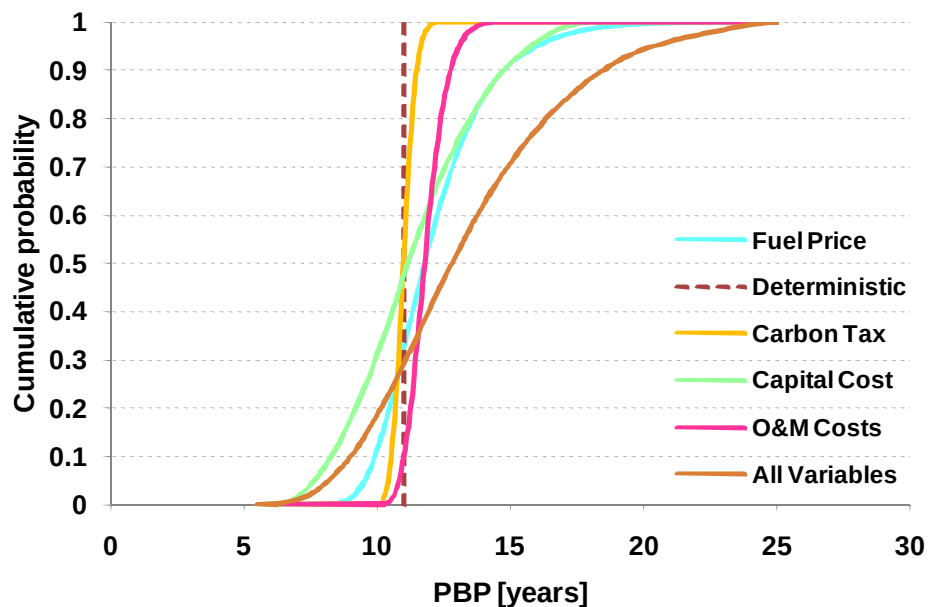
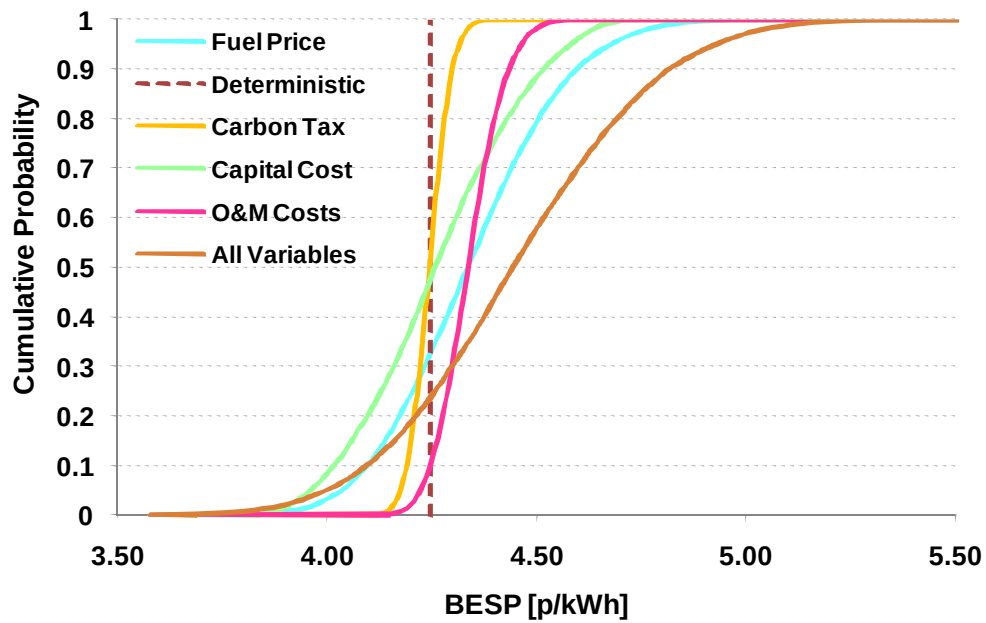
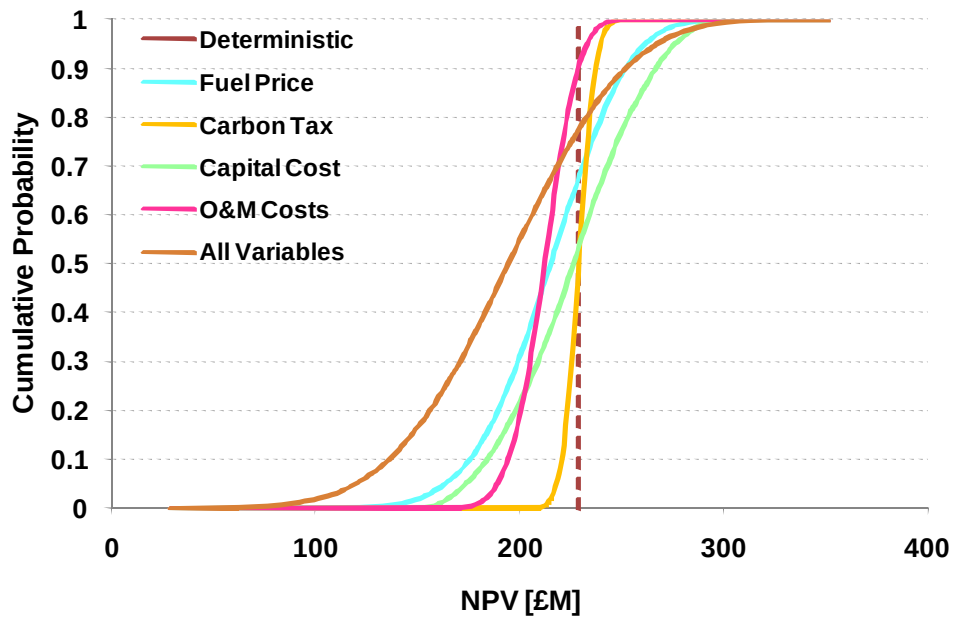


Figure B.11 ATRCC case: effect of uncertainty of all risk variables on PBP



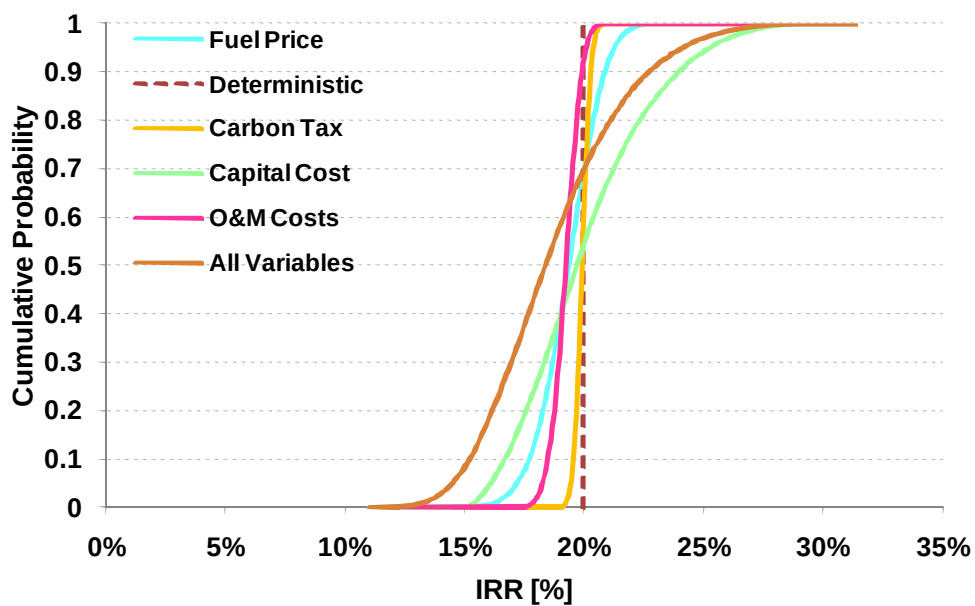


Figure B.14 IRCC case: effect of uncertainty of all risk variables on IRR

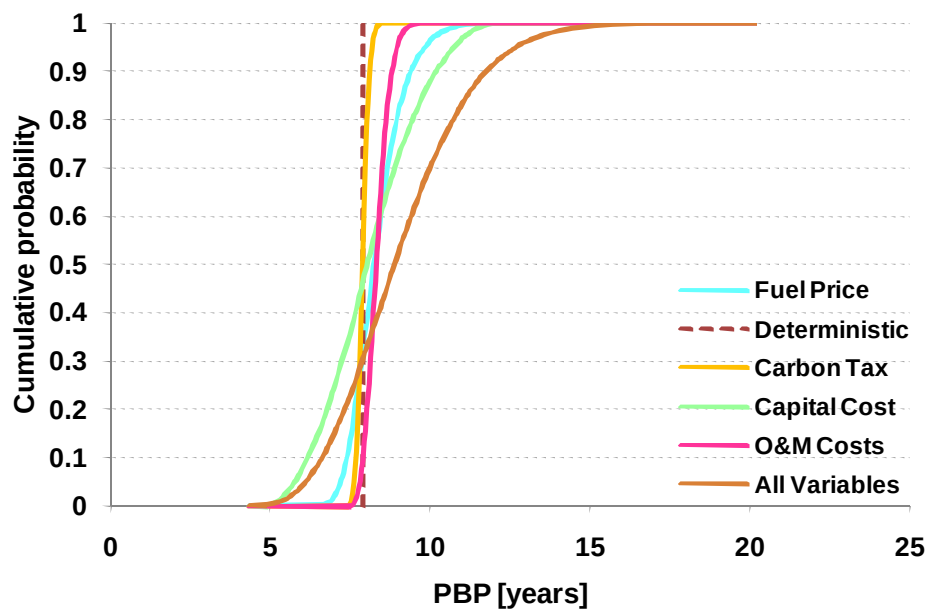


Figure B.15 IRCC case: effect of uncertainty of all risk variables on PBP

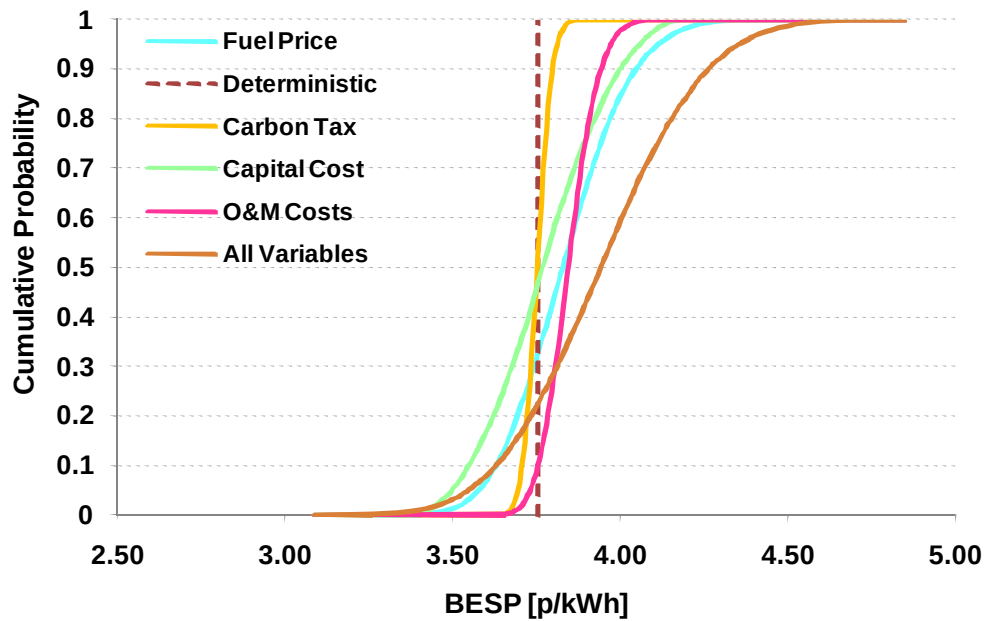


Figure B.16 IRCC case: effect of uncertainty of all risk variables on BESP

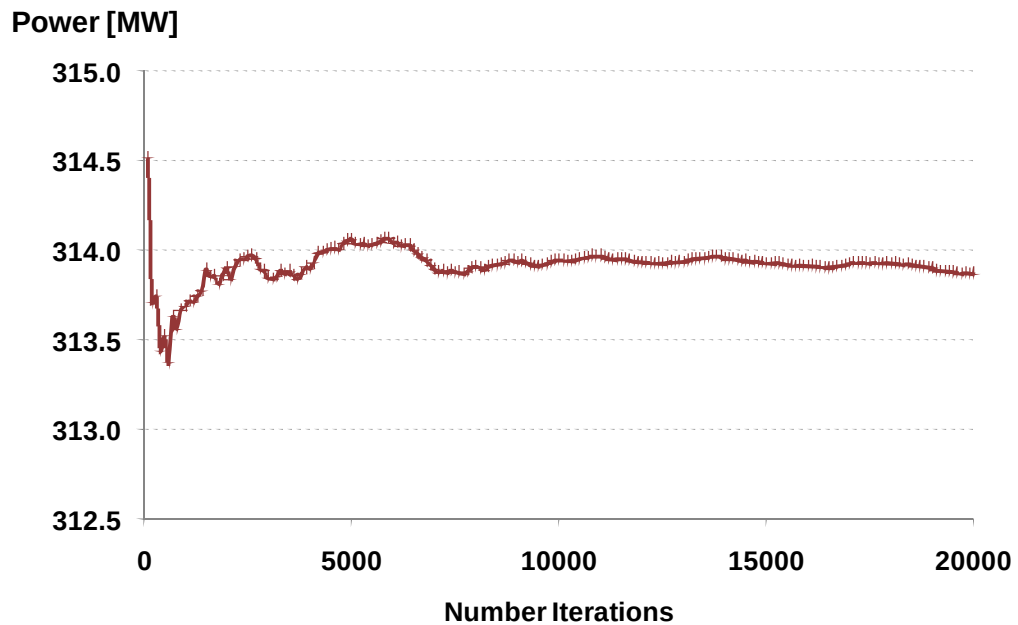


Figure B.17 Technology Risk Module: convergence for the power output

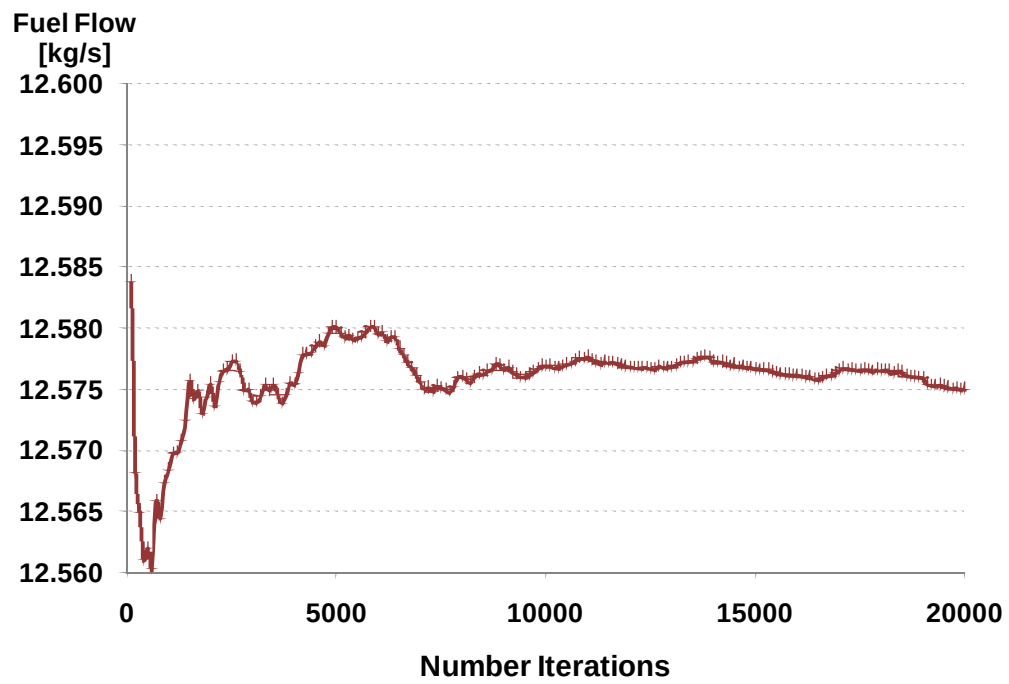


Figure B.18 *Technology Risk Module: convergence for the fuel flow*

APPENDIX C

C.1 INPUT FILES FOR THE PERFORMANCE ANALYSIS

C.1.1 BASELINE CASE

2 !1=GT, 2= GTCC
BASELINE !OR ADVANCEDCYCLE
1 !WORKING FLUID 1=Air, 2= CO2
2 !FUEL SELECTOR FOR DP, 1=KEROSENE, 2=NG, 3=ATR, 4=IGCC
2 !FUEL SELECTOR FOR OD
3000.0 !NDP
641.0 !W1DP
101325.0 !P1DP
288.15 !T1DP
0.03 !INTPLOSSDP
0.45 !M2DP
0.908 !CPOLYDP
17.0 !CPRDP
3.0 !CMapNb
0.12 !CBLFDP
0.00 !OBLFDP
0.10 !M91DP
0.06 !CCPLOSSDP
1610. !COT
0.87 !TPOLYDP
0.22 !M14DP
360. !UDP
65. !ALFANOZ
3 !NSTTRB
-3 !DP/OD SELECTOR
0 !Risk ANALYSIS SELECTOR

70.00 ! LIVE STEAM PRESSURE(BAR)
30.0 ! SUPERHEATER PINCH POINT DIFF.(K)
10.0 ! EVAPORATOR PINCH POINT DIFF. (K)
5 ! EVAPORATOR APPROACH POINT DIFF. (K)
0.9 ! ST BASE EFFICIENCY
0.75 ! PUMP ISENTROPIC EFFICIENCY (%)
0.0 !EXTRACTION PRESSURE
0.0 !EXTRACTION PRESSURE
0.05 ! CONDENSER PRESURE (BAR)
288.0 ! INLET COOLING WATER TEMPERATURE, T7w (K)
10.0 ! COOLING WATER TEMPERATURE RISE, TR (K)

C.1.2 ATRCC CASE

2 !1=GT, 2= GTCC
ADVANCEDCYCLE !
1 !WORKING FLUID 1=Air, 2= CO2

3 !FUEL SELECTOR FOR DP, 1=KEROSENE, 2=NG, 3=ATR, 4=IGCC
 3 !FUEL SELECTOR FOR OD
 3000.0 !NDP
 641.0 !W1DP
 101325.0 !P1DP
 288.15 !T1DP
 0.03 !INTPLOSSDP
 0.45 !M2DP
 0.908 !CPOLYDP
 17.0 !CPRDP
 3.0 !CMAPNb
 0.12 !CBLFDP
 0.00 !OBLFDP
 0.10 !M91DP
 0.06 !CCPLOSSDP
 1610. !COT
 0.87 !TPOLYDP
 0.22 !M14DP
 360. !UDP
 65. !ALFANOZ
 3 !NSTTRB
 -3 !DP/OD SELECTOR
 0 !Risk ANALYSIS SELECTOR

ATRCC !PLANT CONFIGURATION
 150.D0 !P STORAGE [BAR]
 1.50D0 !P USCITA ABSORBER [BAR]
 303.15 !T INTEREFR [K]
 0.80 !EFF. CO2 COMPRESSOR
 0.80 !
 0.80 !
 0.80 !
 70.8043940721 !MASS OF SYNGAS
 2.6725 !MOLES WATER FOR ATR
 4.973783295 !USCITA ABSORBER MOLES
 7.645327249 !USCITA LTS MOLES
 0.948069007 !KMOL DI CO2 PRIMA ABSORBER
 15 !P AT INLET OF PreREFORMER
 773.15 !T AT INLET OF PreREFORMER
 1160.17 !T OUT ATR
 673.15 !T INLET OF HTS
 717.51 !T OUTLET HTS
 473.15 !T INLET OF LTS
 471.83 !T OUTLET OF LTS
 1050000 !P SYNGAS TO FUEL COMPRESSOR
 0.87 !FUEL COMPRESSOR EFFICIENCY
 0.85 !EFFICIENCY PUMP FOR WATER Pre-REFORMER
 0.9 !ABSORBER EFFICIENCY
 0.023540707 !CH4 TO THE COMBUSTOR

```

0          !C2H6
0          !C3H8
0.418996944 !N2
0          !O2
0.011306387 !H2O
0.525919552 !H2
0.001175085 !CO
0.019061325 !CO2
0.015314763 !CH4 EXIT LTS
0          !C2H6
0          !C3H8
0.2725848   !N2
0          !O2
0.245184713 !H2O
0.34214492   !H2
0.000764469 !CO
0.124006334 !CO2
0.015314763 !CH4 EXIT HTS
0          !C2H6
0          !C3H8
0.2725848   !N2
0          !O2
0.264852487 !H2O
0.322477146 !H2
0.020432243 !CO
0.104338561 !CO2
0.015314763 !CH4 EXIT ATR
0          !C2H6
0          !C3H8
0.2725848   !N2
0          !O2
0.324804779 !H2O
0.262524854 !H2
0.080384535 !CO
0.044386268 !CO2
3400000 ! [J/KGCO2] AMINE RE-BOLER STEAM REQUIREMENT

70.00      ! LIVE STEAM PRESSURE(BAR)
30.0       ! SUPERHEATER PINCH POINT DIFF.(K)
10.0       ! EVAPORATOR PINCH POINT DIFF. (K)
5          ! EVAPORATOR APPROACH POINT DIFF. (K)
0.9        ! ST BASE EFFICIENCY
0.75       ! PUMP ISENTROPIC EFFICIENCY (%)
0.0        ! EXTRACTION PRESSURE
4.0        ! EXTRACTION PRESSURE
0.05       ! CONDENSER PRESURE (BAR)
288.0      ! INLET COOLING WATER TEMPERATURE, T7W (K)
10.0       ! COOLING WATER TEMPERATURE RISE, TR (K)

```

C.1.3 IRCC CASE

2 !1=GT, 2= GTCC
 ADVANCEDCYCLE !
 1 !WORKING FLUID 1=AIR, 2= CO2
 3 !FUEL SELECTOR FOR DP, 1=KEROSENE, 2=NG, 3=ATR, 4=IGCC
 3 !FUEL SELECTOR FOR OD
 3000.0 !NDP
 641.0 !W1DP
 101325.0 !P1DP
 288.15 !T1DP
 0.03 !INTPLOSSDP
 0.45 !M2DP
 0.908 !CPOLYDP
 17.0 !CPRDP
 3.0 !CMAPNb
 0.12 !CBLFDP
 0.00 !OBLFDP
 0.10 !M91DP
 0.06 !CCPLOSSDP
 1610. !COT
 0.87 !TPOLYDP
 0.22 !M14DP
 360. !UDP
 65. !ALFANOZ
 3 !NSTTRB
 -3 !DP/OD SELECTOR
 0 !Risk ANALYSIS SELECTOR

IRCC !PLANT CONFIGURATION
 150.D0 !P STORAGE [BAR]
 1.50D0 !P USCITA ABSORBER [BAR]
 303.15 !T INTEREFR [K]
 0.80 !EFF. CO2 COMPRESSOR
 0.80 !
 0.80 !
 0.80 !
 70.8043940721 !MASS OF SYNGAS
 2.6725 !MOLES WATER FOR ATR
 4.973783295 !USCITA ABSORBER MOLES
 7.645327249 !USCITA LTS MOLES
 0.948069007 !KMOL DI CO2 PRIMA ABSORBER
 15 !P AT INLET OF PREREFORMER
 773.15 !T AT INLET OF PREREFORMER
 1160.17 !T OUT ATR
 673.15 !T INLET OF HTS
 717.51 !T OUTLET HTS
 473.15 !T INLET OF LTS
 471.83 !T OUTLET OF LTS
 1050000 !P SYNGAS TO FUEL COMPRESSOR

0.87 !FUEL COMPRESSOR EFFICIENCY
 0.85 !EFFICIENCY PUMP FOR WATER PRE-REFORMER
 0.9 !ABSORBER EFFICIENCY
 0.023540707 !CH4 TO THE COMBUSTOR
 0 !C2H6
 0 !C3H8
 0.418996944 !N2
 0 !O2
 0.011306387 !H2O
 0.525919552 !H2
 0.001175085 !CO
 0.019061325 !CO2
 0.015314763 !CH4 EXIT LTS
 0 !C2H6
 0 !C3H8
 0.2725848 !N2
 0 !O2
 0.245184713 !H2O
 0.34214492 !H2
 0.000764469 !CO
 0.124006334 !CO2
 0.015314763 !CH4 EXIT HTS
 0 !C2H6
 0 !C3H8
 0.2725848 !N2
 0 !O2
 0.264852487 !H2O
 0.322477146 !H2
 0.020432243 !CO
 0.104338561 !CO2
 0.015314763 !CH4 EXIT ATR
 0 !C2H6
 0 !C3H8
 0.2725848 !N2
 0 !O2
 0.324804779 !H2O
 0.262524854 !H2
 0.080384535 !CO
 0.044386268 !CO2
 3400000 ! [J/KGCO2] AMINE RE-BOLER STEAM REQUIREMENT

 70.00 ! LIVE STEAM PRESSURE(BAR)
 30.0 ! SUPERHEATER PINCH POINT DIFF.(K)
 10.0 ! EVAPORATOR PINCH POINT DIFF. (K)
 5 ! EVAPORATOR APPROACH POINT DIFF. (K)
 0.9 ! ST BASE EFFICIENCY
 0.75 ! PUMP ISENTROPIC EFFICIENCY (%)
 20.0 !EXTRACTION PRESSURE
 4.0 !EXTRACTION PRESSURE

0.05 ! CONDENSER PRESURE (BAR)
 288.0 ! INLET COOLING WATER TEMPERATURE, T7W (K)
 10.0 ! COOLING WATER TEMPERATURE RISE, TR (K)

C.2 INPUT FILES FOR ECONOMIC ANALYSIS

C.2.1 BASELINE CASE

BASELINE : POWER PLANT CONFIGURATION
 378602 : POWER AT DESIGN-POINT (kW)
 1017808.632 : ANNUAL CO2 PRODUCED (TON/YEAR)
 0.0 : ANNUAL CO2 CAPTURED (KG/YEAR)
 2819070492 : ANNUAL ELECTRICITY PRODUCED (kWh/YEAR)
 378227016 : ANNUAL MASS FLOW CONSUMPTION (KG/YEAR)
 1 : AVAILABILITY
 0 : CONSTRUCTION TIME
 25 : POWER PLANT LIFESPAN
 0.10 : INTEREST RATE
 121936350 : CAPITAL COST (£)
 0.05 : ELECTRICITY PRICE (£/kWh)
 0.025 : REAL ELECTRICITY PRICE ESCALATION RATE
 0.12 : FUEL PRICE (£)
 0.02 : REAL FUEL PRICE ESCALATION RATE
 5 : SPECIFIC FIXED O&M COST PER UNIT OF POWERDP (£/kW)
 0.00191 : SPECIFIC VARIABLE O&M COST PER UNIT OF ELECTRICITY
 PRODUCED (£/kWh)
 0.02 : REAL O&M COST ESCALATION RATE
 0.0 : UNIT COST OF CO2 TRANSPORT
 0.0 : REAL COST OF CO2 TRANSPORT ESCALATION RATE
 0.0 : UNIT COST OF CO2 STORAGE
 0.0 : REAL COST OF CO2 STORAGE ESCALATION RATE
 0.0 : TRANSPORTATION DISTANCE OF CO2 CAPTURED
 50.0 : CO2 EMISSION TAX (£/TONCO2)
 0.0 : REAL CO2 EMISSION TAX ESCALATION RATE
 0.0 : CO2 STORAGE TAX (£/KGCO2)
 0.0 : REAL CO2 STORAGE TAX ESCALATION RATE
 20 : TIME PERIOD FOR DEPRECIATION
 0.0 : SALVAGE VALUE (£)
 0.00 : LOAN (£)
 0 : TIME PERIOD FOR LOAN REPAYMENT
 0.0 : LOAN RATE
 0.4 : TAX RATE

C.2.2 ATRCC CASE

ATRCC : POWER PLANT CONFIGURATION
 304819 : POWER AT DESIGN POINT (kW)
 144168 : ANNUAL CO2 PRODUCED (TON/YEAR)
 0.0 : ANNUAL CO2 CAPTURED (KG/YEAR)
 2269540800 : ANNUAL ELECTRICITY PRODUCED (kWh/YEAR)

455041252	: ANNUAL MASS FLOW CONSUMPTION (KG/YEAR)
1	: AVAILABILITY
0	: CONSTRUCTION TIME
25	: POWER PLANT LIFESPAN
0.10	: INTEREST RATE
199006435	: CAPITAL COST (£)
0.05	: ELECTRICITY PRICE (£/kWh)
0.025	: REAL ELECTRICITY PRICE ESCALATION RATE
0.12	: FUEL PRICE (£)
0.02	: REAL FUEL PRICE ESCALATION RATE
12.0	: SPECIFIC FIXED O&M COST PER UNIT OF POWERDP (£/kW)
0.00284	: SPECIFIC VARIABLE O&M COST PER UNIT OF ELECTRICITY PRODUCED (£/kWh)
0.02	: REAL O&M COST ESCALATION RATE
0.0	: UNIT COST OF CO ₂ TRANSPORT
0.0	: REAL COST OF CO ₂ TRANSPORT ESCALATION RATE
0.0	: UNIT COST OF CO ₂ STORAGE
0.0	: REAL COST OF CO ₂ STORAGE ESCALATION RATE
0.0	: TRANSPORTATION DISTANCE OF CO ₂ CAPTURED
50.0	: CO ₂ EMISSION TAX (£/TONCO ₂)
0.0	: REAL CO ₂ EMISSION TAX ESCALATION RATE
0.0	: CO ₂ STORAGE TAX (£/KGCO ₂)
0.0	: REAL CO ₂ STORAGE TAX ESCALATION RATE
20	: TIME PERIOD FOR DEPRECIATION
0.0	: SALVAGE VALUE (£)
0.00	: LOAN (£)
0	: TIME PERIOD FOR LOAN REPAYMENT
0.0	: LOAN RATE
0.4	: TAX RATE

C.2.3 IRCC CASE

IRCC	: POWER PLANT CONFIGURATION
365527	: POWER AT DESIGN POINT (kW)
144168.0491	: ANNUAL CO ₂ PRODUCED (TON/YEAR)
0.0	: ANNUAL CO ₂ CAPTURED (KG/YEAR)
2721714042	: ANNUAL ELECTRICITY PRODUCED (kWh/YEAR)
455041143	: ANNUAL MASS FLOW CONSUMPTION (KG/YEAR)
1	: AVAILABILITY
0	: CONSTRUCTION TIME
25	: POWER PLANT LIFESPAN
0.10	: INTEREST RATE
230175611	: CAPITAL COST (£)
0.05	: ELECTRICITY PRICE (£/kWh)
0.025	: REAL ELECTRICITY PRICE ESCALATION RATE
0.12	: FUEL PRICE (£)
0.02	: REAL FUEL PRICE ESCALATION RATE
12.0	: SPECIFIC FIXED O&M COST PER UNIT OF POWERDP (£/kW)
0.00284	: SPECIFIC VARIABLE O&M COST PER UNIT OF ELECTRICITY PRODUCED (£/kWh)

0.02 : REAL O&M COST ESCALATION RATE
0.0 : UNIT COST OF CO2 TRANSPORT
0.0 : REAL COST OF CO2 TRANSPORT ESCALATION RATE
0.0 : UNIT COST OF CO2 STORAGE
0.0 : REAL COST OF CO2 STORAGE ESCALATION RATE
0.0 : TRANSPORTATION DISTANCE OF CO2 CAPTURED
50.0 : CO2 EMISSION TAX (£/TONCO2)
0.0 : REAL CO2 EMISSION TAX ESCALATION RATE
0.0 : CO2 STORAGE TAX (£/KGCO2)
0.0 : REAL CO2 STORAGE TAX ESCALATION RATE
20 : TIME PERIOD FOR DEPRECIATION
0.0 : SALVAGE VALUE (£)
0.00 : LOAN (£)
0 : TIME PERIOD FOR LOAN REPAYMENT
0.0 : LOAN RATE
0.4 : TAX RATE

C.2.4 MONTE CARLO ANALYSIS INPUT FILE

1 : SELECTOR OF MONTE CARLO (0 = NO MC, 1 FOR MC, 2 FOR RISK
ANALYSIS FOR TECHNOLOGY)
20000 : NUMBER OF SCENARIOS
1 : SELECTOR OF FUEL PRICE (1 FOR MONTE-CARLO ANALYSIS,
OTHERWISE 0)
0 : SELECTOR OF ELECTRICITY PRICE
1 : SELECTOR OF CO2 TAX
0 : SELECTOR OF O&M COSTS
0 : SELECTOR OF CO2 STORAGE TAX
1 : SELECTOR OF CAPITAL COSTS
0 : SELECTOR OF NPV
0 : SELECTOR OF IRR
0 : SELECTOR OF PBP
1 : SELECTOR OF COE
0 : SELECTOR OF BESP

C.3 EXAMPLE OF INPUT FILE FOR EMISSION MODULE

0 !CH2
0.94 !CH4
0 !C2H6
0.043 !C3H8
0 !CO
0.002 !CO2
0 !H2
0 !H2O
0.015 !N2
0 !O2

378602 !POWER

13.757 !FUEL (KG/S)

C.4 EXAMPLE OF INPUT FILE FOR TECHNOLOGY RISK ANALYSIS MODULE

1000 :SCENARIO
0 :SELECTOR FOR COMPRESSOR
0 :SELECTOR FOR TURBINE
0 :SELECTOR FOR COMBUSTOR
0 :SELECTOR FOR STEAM TURBINE
1 :SELECTOR FOR AMINE REGENERATION
0 :SELECTOR FOR CO2 COMPRESSION