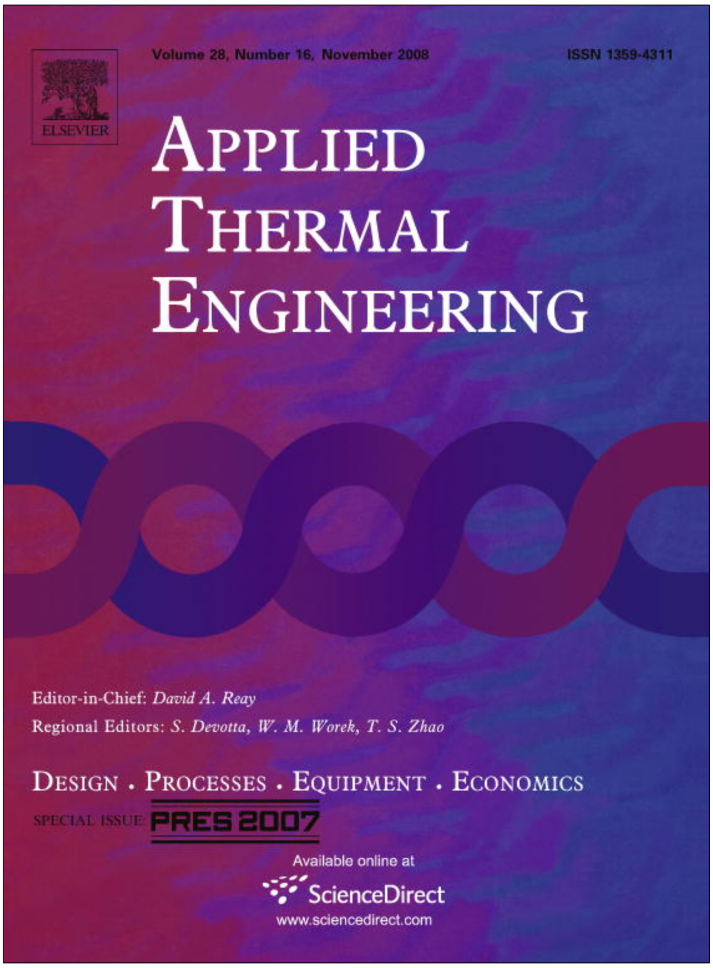
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Assessment of a fully integrated SARGAS process operating on coal with near zero emissions

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ABSTRACT

This paper presents a novel advanced clean-coal technology, *Sargas that* facilitates capture and storage of carbon dioxide (CCS). The technology combines the ABB Carbon P200 PFBC power cycle[1] characterised by pressurised post-combustion acid gas cleaning. This article describes the conceptual idea and working principle of this technology, and provides some reference data for further assessment studies to be performed under two consecutive EU-based projects entitled EMINENT and EMIENT-2. For this survey process simulation data have been made available by technology owner, Sargas AS, for a coal-fired *Sargas* block rated at 100 MW_e. The modelling and calculations have been performed by Sargas, using the HYSYS Mass and Energy Balance Model. The main results have been verified by a third party (Siemens). Recently the Finnish company SWECO PIC has developed the design basis for the first-of-its-kind coal-based *Sargas* plant planned for Husnes, Norway.

1. Introduction

According to BP Statistical Review of World Energy [1] fossil fuels account for 87.7% of the global primary energy demand. This corresponds to 9.24 Gtoe per year,[2]). and implies that 28 Gtpa CO_2 is directly attributed to the use of fossil fuels.[3] This vast amount of CO_2 suggests that solutions that include CCS have to be pursued and adapted to numerous power plants, especially those burning coal.

In this setting *Sargas* responds to the UN Framework Convention on Climate Change (UNFCCC) and to the pronounced needs of most Annex-I countries for reducing their greenhouse gas emissions.

According to Sargas AS, recent assessment studies suggest that the *Sargas* technology is capable of meeting a capture rate of 95% at a capture cost of around 15 Euro per tonne CO_2 on terms that applies to a coal-fired plant (in Norway). Could this be confirmed and validated by testing and large-scale demonstration, one may assume that a considerable market will pay interest in this particular technology throughout the world.

2. Sargas idea

By combining the virtue of the pressurised fluidised bed combustion technology (PFBC) with pressurised post-combustion carbon dioxide capture Sargas AS has proposed an innovative clean-fossil fuel technology made up by technologies that are well established and proved per se, although individually and in two quite different applications. The clue is a) to provide a high partial pressure of the CO_2 to allow for low-cost chemicals (e.g. carbonates) for efficient flue gas cleaning, and b) to apply a high degree of process integration to form an integral power scheme to facilitate CCS.

The technology (named *Sargas)* belongs to the Norwegian-based company Sargas AS, who is the owner of the intellectual property rights pertaining to the *Sargas* concept. So far the *Sargas* capture process has been functionally tested and partly verified. The core technology is (in 2007) subjected to further testing and optimisation against a hot pressurised bleed stream from a coal-based

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Abbreviations: CCS, Capture and storage of CO_2; COP, Coefficient of performance; EPC, Engineering procurement and construction; Gtoe, Giga tonne oil equivalents; Gtpa, Giga tonne per year; HPC, High-pressure compressor; HPT, High-pressure turbine; IGCC, Integrated coal gasification combined cycle; ktpa, Kilo tonne per year; LNG, Liquid natural gas; LPC, Low-pressure compressor; LPT, Low-pressure turbine; MEA, Mono-ethanol amine; Mtpa, Mega tonne per year; NGCC, Natural gas combined cycle; PFBC, Pressurised fluidised bed combustion; TIT, Turbine inlet temperature; tpa, Tonne per year; Eta, Efficiency; PI, Pressure ratio.

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[1] PFBC: pressurised fluidised bed combustion, developed by ABB Carbon in the 1980s. ABB Carbon has licensed the PFBC technology to Babcock & Wilcox Company (USA) and IHI (Japan).

[2] 2005: Global total primary energy demand (PED) reached 10537.1 Mtoe whereof 9241.3 were from fossil fuels. 2004 showed 10291.0 and 9022.7, respectively, hence, a total increase in PED of 246.1 Mtoe, whereof fossil fuels accounts for 218.6 Mtoe (i.e. 88.9% of the growth). (Source: BP Statistical Review of World Energy 2006).

[3] Gtpa: Gigatonne per annum. The formation of CO_2 from the burning of oil is roughly 3 kg/kg oil.

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combined heat power plant, Värtan, in Stockholm, Sweden. Since 1991 the Värtan plant generates 135 MW electric power and 220 MW heat for Stockholm Energi. Furthermore, Värtan is coined the first coal-fired PFBC plant in the world. Although it lacks the provision for carbon dioxide capture, its power cycle is essentially the same and similar to that of the proposed *Sargas* concept. Basis is the ABB Carbon P200 PFBC power cycle that (per se) has been verified in industrial operations in Europe, the US, and Japan for more than 15 years [2,3].

What is new is basically the way that *Sargas* is combining current needs with prior knowledge and proven technologies in forming a complete CCS scheme that has been protected by intellectual property rights. Jointly with early customers the owners of the *Sargas* technology have declared that sufficient confidence has been gained in the technology to having signed a letter of intent (in 2006) aimed at entering into an EPC contract[4] for a 4 × 100 MW_e coal-based CCS plant to be located at an aluminium smelter at Husnes in Southern Norway.[5] If realised, this plant will become the first of its kind anywhere in the world.

Provided that suitable storage sites and appropriate related infrastructure for the CO_2 could be decided and organised in due time – this plant could be urged (as judged by mid 2007) to go on stream probably by 2011/2012 – depending, however, on site permits and other concessionary approvals. The investment cost of the referred plant is estimated to amount to some EUR 560 million (NOK 4500 million). The annual yields will be roughly 3 TWh electricity output and some 2.5 Mtpa CO_2 captured. This implies that the decision to build is scheduled to take place during spring 2008, aimed at start-up during 2011/2012. The timeframe may be considered somewhat optimistic, not least owing to the general industrial acticity level at global scale, which may largely affect the lead time for deliveries from the major supplier industry.

3. Sargas concept

The *Sargas* concept is a closed loop made up in unit blocks rated at 100 MW_e. Each block includes:

1. One heavy-duty gas turbine engine characterised by external combustion.
2. One pressurised fluidised bed combustion unit with integrated steam generation.
3. One sub-critical steam cycle operating at 16.5 MPa (165 bar) and 565 °C, with reheat to 565 °C.
4. One steam turbine with five steam extractions and one crossover.
5. One pressurised capture unit using a hot potassium carbonate process for chemical CO_2 absorption.

As partly depicted in Fig. 1 the high-pressure compressor of the gas turbine unit diverts the compressed air to the external fluidised-bed combustor unit (PFBC) with typical air properties at 300 °C and 1.2 MPa (12 bar). This airflow is first used to fluidise the solid particles, thus providing an efficient mixing regime represented by the fluidised bed itself. Then the air will intrinsically mix and react with the solid fuel particles in the combustion zone and jointly undergo the combustion reactions, and thereby release the heat required by the process. The PFBC unit generates superheated live steam for the steam cycle, and diverts a hot flue gas stream to the capture unit. From the capture unit the cleaned pressurised gas is further directed to the power turbine. The way that this process is arranged results in a combined cycle that obviously offers an electric efficiency that is higher than just a conventional steam cycle [3]. According to calculations this gain represents about 3% points of efficiency. The steam properties of the *Sargas* power cycle at nominal rating are typically 565 °C and 16.5 MPa (165 bar) referred to the inlet duct of the steam turbine. The expansion line ends at 0.002 MPa (0.02 bar) and 17.9 °C, which corresponds to 88.6% steam quality. In order to reach this end point, a rather low cooling-water temperature is required. This is, however, usually available in coastal areas in Northern Europe most of the year.

So far commercial as well as demonstration units based on the ABB Carbon P200 PFBC module have been built in Europe, the US and Japan [4,5]. One of the European plants is the Cottbus PFBC project, which became part of the EU-based THERMIE programme. In 2001 Jansson [6] summarised the experience from Cottbus in the following way: "*As all other P200 plants, it has a GT35P gas turbine. The plant was designed to operate at high plant efficiency and with very low emissions of sulphur and nitrogen oxides, carbon monoxide. Because of its high electric and total efficiencies the emission of carbon dioxide is also low*". In his paper Jansson further deals with positive and negative experiences: Among the former he mentions the excellent environmental performance, and concludes that all guarantees regarding emission levels and thermal performance were met. Among the negative experiences some unexpected problems are mentioned – primarily linked with the nature of brown coal, whereof the most severe was said to be the formation of ash deposits in the cyclone subsequent to the combustion unit.

Furthermore, Meyer in 2004 [7] reported some other disadvantages like cost, efficiency, and he also gave a mention to CCS, which according to him would be complicated to employ to the P200 concept. He also indicated operational problems in the fluidised bed combustor and the gas turbine, which seemingly are linked with those reported by Jansson [6]. Nevertheless, for the Cottbus P200 unit fired with lignite an efficiency of 41.5% has been reported by Rombrect et al. [8], whereas state of the art in lignite-fired power cycles with advanced steam data is 42.5%. The latter plants, however, are probably some 5–8 times larger than the P200 block.

In 2001 a larger version of the PFBC concept rated at 360 MW_e using supercritical steam properties was delivered by IHI on the basis of the larger ABB Carbon P800 module. This plant is known as the Karita project in Japan [3]. Although this module is significantly larger, it is still based on the same principle as the ABB carbon P200 PFBC power cycle.

However, according to Meyer [7] Alstom – the current owner of the ABB Carbon technology – has temporarily suspended further development of its PFBC programme. This is probably one of the reasons for Sargas AS to embark on this technology in providing its CCS concept without support from Alstom.

The power cycle is interfaced with the gas cleaning unit via a recuperating heat exchanger. The purpose of this heat exchanger is to shift the temperature from a high level to a lower level and vice versa, when diverting the flue gas to and from the CO_2 capture unit (refer Fig. 2). Hence, this also represents the key of the *Sargas* concept, as it affects the diversion of the hot flue gas from the PFBC combustor unit to the power turbine: This diversion is routed through the low-temperature capture unit. Thereby the flue gas has to pass twice through the recuperating heat exchanger: Once first to drop the temperature in front of the capture unit (from typically 854 to below 200 °C), and then (2) – after CO_2 removal – to expose the cleaned gas to the hot section of the heat exchanger in front of the power turbine in order for the gas to roughly recover its initial temperature potential – up to a level that corresponds almost to the PFBC outlet temperature (814 °C). Between the recuperator and the hot potassium carbonate unit, heat is further exchanged in order to minimise the heat loss, as the hot potassium carbonate process operates around 90 °C. Hence, as the CO_2 is re-

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[4] EPC: Engineering, procurement and construction.

[5] According to Sargas AS information: Consortium: SørAl AS (Alcan and Hydro Aluminium), Eramet Norway, and Tinfos.

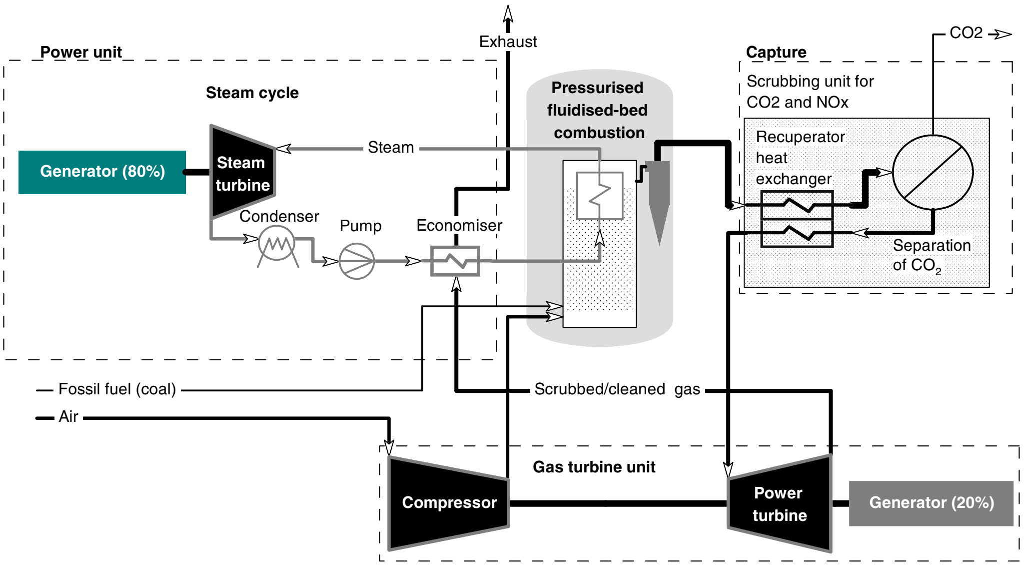

Fig. 1. Simplified outline of the Sargas technology with pressurised fluidised-bed combustion technology (ABB Carbon PFBC) interlinked with the CO_2 capture process and the power turbine via a recuperating heat exchanger.

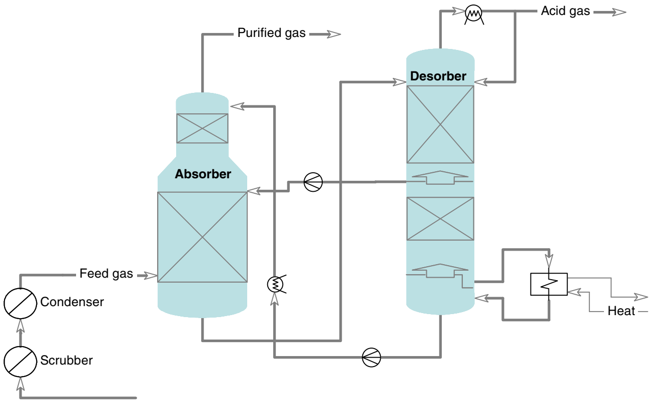

Fig. 2. The hot potassium carbonate capture process for CO_2 absorption.

moved from the gas stream, the heating profile is somewhat steeper than the cooling profile of the recuperator. Upon leaving the recuperator the cleaned gas is diverted to the power turbine that drives the compressor and the gas turbine generator (refer Fig. 1).

In this combination, the recuperator is for two reasons considered to represent the far most critical element of the *Sargas* concept, as it (1) interlinks the power cycle and the pressurised capture unit, and (2) because the thermal load of the heat exchanger is considered to be relatively high. For this reason verification and design optimisation of the recuperating process of *Sargas* has been supported by active testing during 2007. Further tests are scheduled to continue throughout 2008.

3.1. Gas turbine

The current *Sargas* technology rests on the SIEMENS GT35P gas turbine rated at 14–17 MW_e depending on fuel properties (coal). The machine is regarded as a turbocharged, constant speed gas turbine characterised as follows: Pressure ratio 13:1. Number of stages: LPC: 11, HPC: 12, HPT: 4, LPT: 1. The turbine inlet temperature is about 820 °C with cleaned flue gas. Owing to the high system pressure the compressor includes an intercooler that is not shown in Fig. 1 [2,3,9,10].

The GT35P machine was developed in the late 1980's originally intended for operations with flue gas from various coals. This implies that it was specially designed to withstand erosion, fouling and corrosion. The reliability is reportedly high with a down-time of just 2% [11].

3.2. Pressurised fluidised-bed combustion

The *Sargas* cycle involves combustion of the solid fuel in the PFBC unit, in which live steam for the steam cycle is generated in boiler tubes immersed in the fluidised bed. The combustion pressure is around 1.2 MPa (12 bar) [2]. Hence, the fluidisation of the PFBC bed material requires compressed air supplied by the high-pressure compressor of the gas turbine. Usually the fuel is introduced as a coal–water slurry. Particles from the fluidised bed combustion will be trapped by cyclones (up to 98%). The remaining part is removed by the capture unit.

Inherently, the PFBC technology is associated with very low air polluting emissions. Owing to the low bed temperature, typically around 850–880 °C, the formation of nitrogen oxides will be kept low (thermal $NO_x < 5$ ppm). Furthermore, sulphur capture may be facilitated by adding some dolomite or other additives. Sulphur capture may even improve as the temperature goes beyond 850–880 °C, although a high bed temperature may increase other risks such as bed agglomeration – depending, though, on the fuel [3].

3.3. Power cycle

It is known that in conventional natural-gas-combined-cycle power generation (NGCC) the electricity generated by the gas turbine versus the steam turbine is roughly 2/1 – meaning that roughly two-thirds of the power is generated by the gas turbine and one third by the steam turbine. In contrast, the duty sharing of the *Sargas* concept is quite different, as less than 20% of the net power output owes to the gas turbine because a large portion of the gross turbine work is used to maintain a high system pressure of the combined power and capture cycle. However, despite the low duty, the gas turbine is claimed to offer an advantage over other clean coal technologies (IGCC) in terms of versatility, availability and turbine life. The reason is that the gas turbine of the *Sargas* cycle operates at a fairly low turbine-inlet temperature (TIT about 820 °C), which implies a significant turbine life in comparison with the highly loaded top cycles in advanced gas turbines with a TIT around 1300 °C. The sub-critical steam cycle, employed for the P200 units, operates at 16.5 MPa (165 bar) and 565°C, with reheat to 565 °C.

Furthermore, the *Sargas* power plant offers large quantities of low-grade heat that is readily available for surrounding industries or district heating, thus envisaging a high total energy utilisation index (maybe as high as 90%).

3.4. Capture unit

The CO_2 capture unit employs the hot potassium carbonate process,[6] which is a chemical absorption, thermally regenerated cyclical solvent process that uses an activated hot potassium carbonate solution for removing the CO_2 [12]. The capture rate may be as high as 98% for CO_2 capture compared with 85–90% for MEA in combined cycles using post-combustion schemes. The practical capture rate will be determined, however, on commercial terms. Furthermore, hot potassium carbonate is regarded less sensitive to degradation than amines that are used in physical absorption processes [11].

One of the hot potassium carbonate processes, Benfield, belongs to the US-based company UOP LLC. The process is claimed to be a simple, stable and oxygen tolerant capture process that has been used by the industry for around 40 years – especially in treating synthesis gas in ammonia plants. It is also used to pre-treat natural gas to achieve either LNG or pipeline specifications. The key driving force for this process is the partial pressure of the CO_2. According to supplier information [12], typical feed conditions may range from 1 to 12.5 MPa (10 to 125 bar) with acid gas concentration ranging from 5% to more than 35% by volume. In the study case of *Sargas* the CO_2 concentration amounts to 16.4% for coal fired systems. The high partial pressure is prone to reduce the heat demand for the regeneration process [11]. According to UOP the typical heat consumption is 70–90 MJ/kmol of CO_2 removed.[7] This corresponds to 1.58–2.1 GJ/tonne CO_2 captured, usually supplied as low-grade steam extracted from the low-pressure steam turbine. For comparison in post combustion natural gas plants using a generic 30% amine solution a heat demand of around 4 GJ/tonne CO_2 is frequently used in simulations – although significant research efforts are made to reduce this energy demand.

In order to keep pace with the rate of processing demands, the hot potassium carbonate process operates at a relatively high temperature (90 °C plus), in contrast to conventional (atmospheric) post-combustion absorption units that operate at typically 50 °C.

Moreover, the *Sargas* capture process does not necessarily rely on just carbonates. Other absorber types with different characteristics may apply as well, which are being indicated and discussed in Table 1 (Dons, [10]).

4. Liquefaction and pressurisation of the CO_2 gas

The captured CO_2 will leave the hot potassium carbonate process at a pressure and temperature of roughly 0.15–0.2 MPa (1.5–2 bar) and 40 °C. Nevertheless, the conditioning of the gas must involve compression – either to a sub-critical pressure level that is higher than the triple point (0.581 MPa (5.81 bar), −56.558 °C) prior to condensation (Fig. 3). Or, the gas must be compressed to a pressure close to the critical point (7.38 MPa (73.8 bar) and 31.03 °C), and then cooled down to atmospheric temperature (20 °C) as shown in Fig. 4. In both cases the pressure can subsequently be raised to comply with the pipeline pressure simply by pumping. For this study the back-pressure is assumed at 12 MPa (120 bar).

4.1. Compression and sub-critical liquefaction by condensation

As shown in Fig. 5 the conditioning of the CO_2 stream (in Fig. 3) starts at thermodynamic state A (0.15 MPa or 1.5 bar, and 40 °C). From this state it is first pre-cooled to 25 °C before it is compressed through two stages with inter-cooling to reach state E at 1.2 MPa (12 bar) and 125 °C. From this point the gas is cooled down in two steps: first to state F at near ambient temperature level (20 °C) until it is diverted to the second step that includes a low-temperature cycle that suppresses the temperature from state F to G via refrigeration.

Depending on actual pressure the liquefaction will take place when the cooling trajectory F–G intersects the saturation line. With a gas pressure of 1.2 MPa (12 bar) saturation will occur at around −27 °C. However, in order to avoid cavitation at the suction side of the CO_2 pump, the liquid CO_2 should preferably be subcooled by say 5–10 °C below the boiling point (to reach state G). In the liquefaction process (F–G) an amount of heat corresponding to 100.8 kWh must be removed by cooling – the duty being determined in kWh per tonne CO_2. A COP of 2.24 has been assumed for this duty, which implies that a power input of 45 kWh per tonne CO_2 would be required to remove the heat from the gas.

From liquid state (G) the pressure of the CO_2 is easily lifted to H just by pumping, and the temperature may gradually increase towards ambient temperature level (I) depending, however, on the transport system. In the calculations the end pressure of the pump (H) is determined by the backpressure set by the CO_2 transfer system, which could be higher or lower than the 12 MPa (120 bar) that has been chosen for the purpose of this assessment. Simple calculations show that the power needed by the pump is 5.2 kWh per tonne CO_2 (assuming 60% pump efficiency). Hence, by this condensation scheme the aggregated power demand amounts to 99.4 kWh per tonne CO_2.

4.2. Densification at near critical state

In this approach the gas will be compressed further to a pressure close to critical level. By selecting a pressure ratio of 2.7 a four-stage compressor will be required to increase pressure from 0.15 MPa (1.5 bar) to super-critical pressure at 8.0 MPa (80 bar). The gas will enter at 40 °C and pass through a pre-cooler to bring the compressor inlet temperature down to 25 °C and leave the first stage at 0.405 MPa (4.05 bar) and 119 °C and then the temperature will be dropped to 25 °C in the inter cooler. These temperatures will prevail after all stages, as indicated in Fig. 6.[8] The gas from the last stage is cooled by a subsequent cooler as depicted in Fig. 4, in which the temperature is reduced from 119 to 20 °C at super-critical state (or near critical pressure), and hence as the gas becomes dense it behaves almost like a liquid, however, with the distinction that it is somewhat compressible.[9] The entire scheme corresponds to the trajectory A–B: cooling, B–C: compression, C–D: inter-cooling, D–E: compression, E–F: inter-cooling, F–G: compression, G–H: inter-cooling, H–I: compression to near-critical pressure, I–J: densification of the gas by cooling, and J–K: pressurisation of the dense CO_2 by pumping in order to sustain the system pressure of the pipeline (here assumed at 12 MPa (120 bar)).

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[6] Supplied by the US-based UOP LLC.

[7] Quoted "30–40 kBtu/lbmol" by UPO LLC.

[8] Isentropic efficiency of 0.82 and mechanical efficiency at 92%. Kappa is set at 1.3026 and $c_{p,CO_2} = 0.816$ kJ/kg K.

[9] For this reason it is possible to monitor possible leakage from the geological structures underneath the seabed in which CO_2 is being injected, by means of echo sounding. Owing to the compressibility of the "liquid" CO_2 the echo will vanish in contrast to structures that contain water because water at this state is termed incompressible.

Table 1
Cleaning alternatives for flue gas under pressure [11]

Absorber type	Characteristic of absorber
Amines	More efficient than other absorbents at atmospheric pressure (Fluor Econamine, MHI KS-1). Challenge: Control of corrosion and amine degradation. Limited references for this application, at least two major amine vendors remain apprehensive.
Carbonates	Stable, simple process. Oxygen tolerant without solution degradation. Many relevant references from industrial applications, 90 to 99% CO_2 absorption possible with standard plant design. Requires pressurized system (1 MPa+(10 bar and more), partial pressure CO_2 0.05 MPa+or more than 0.5 bar)
Amino acids	Old and well-known process. Oxygen tolerant, biodegradable. Possibly a future candidate for *Sargas*
Other physical absorption	Difficult to achieve 90% CO_2 absorption. Low CO_2 loading capacity, low selectivity.

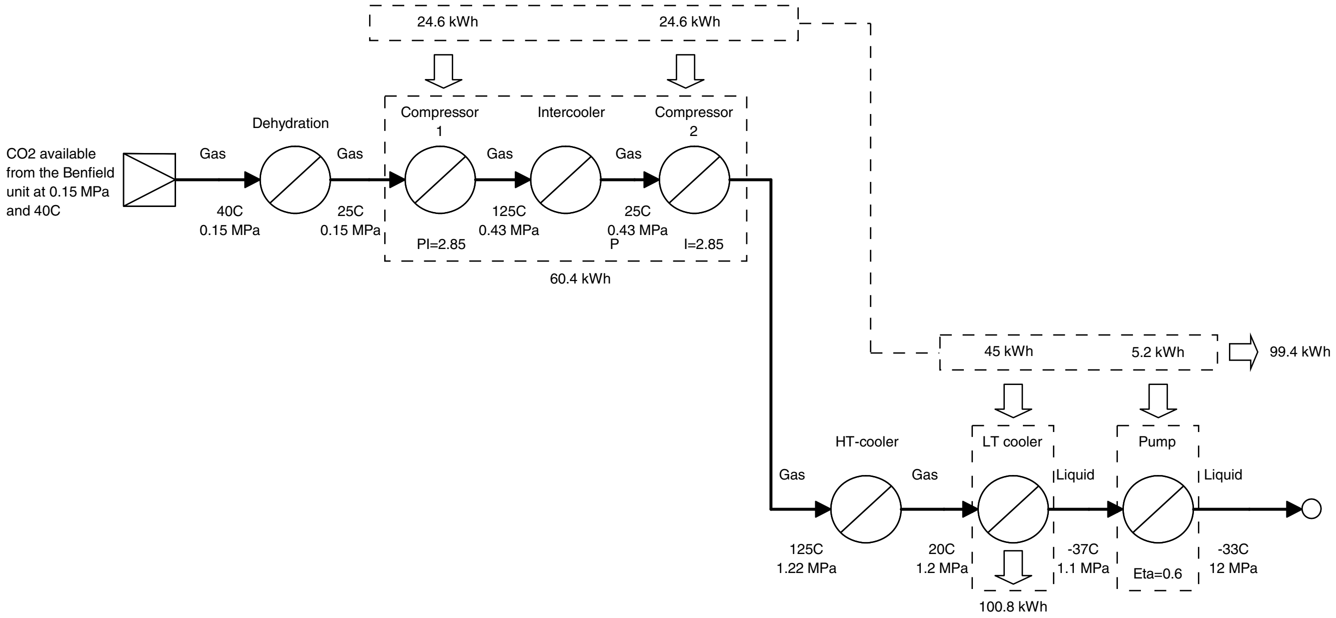

Fig. 3. Conditioning of the CO_2 by liquefaction prior to storage. This scheme goes via condensation at a pressure between the triple point and the critical point and includes refrigeration and further pressurisation (pumping) of the liquid CO_2. Eta is a denotion for pump efficiency, and PI denotes the pressure ratio.

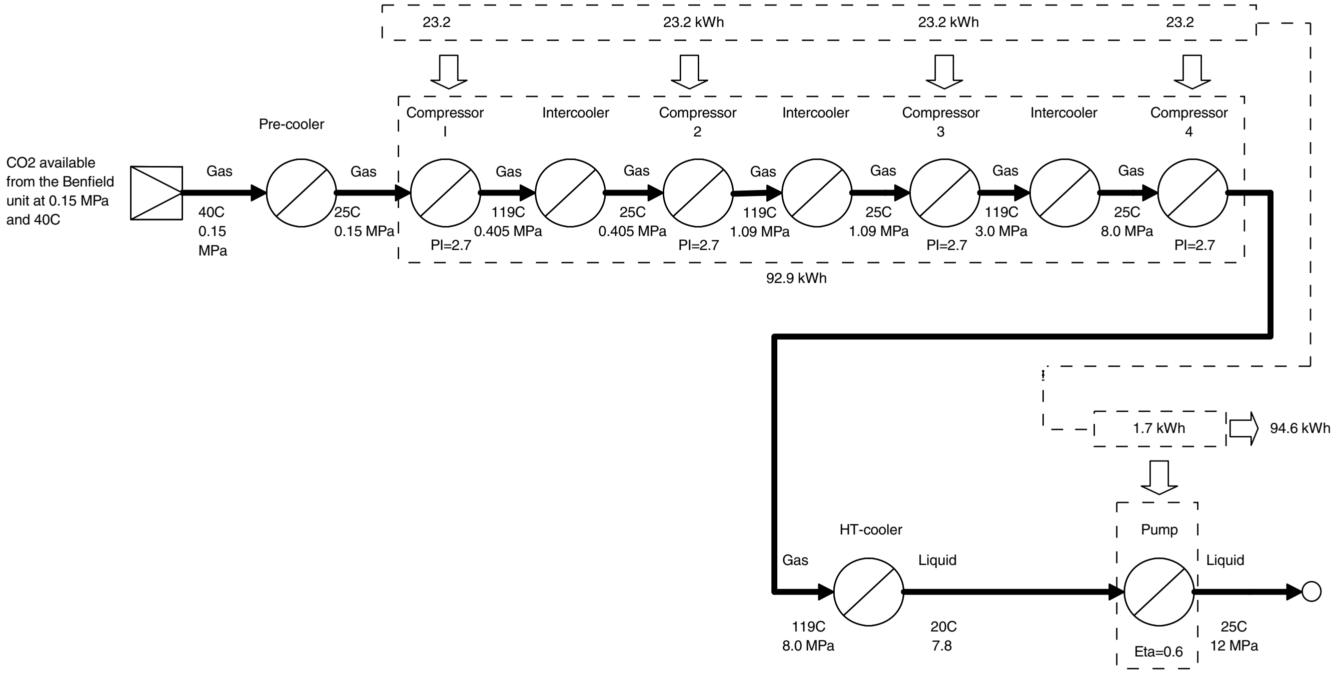

Fig. 4. Conditioning of the CO_2 by compression to super-critical pressure and pumping in dense phase. In this chart PI denotes pressure ratio, and Eta means pump efficiency.

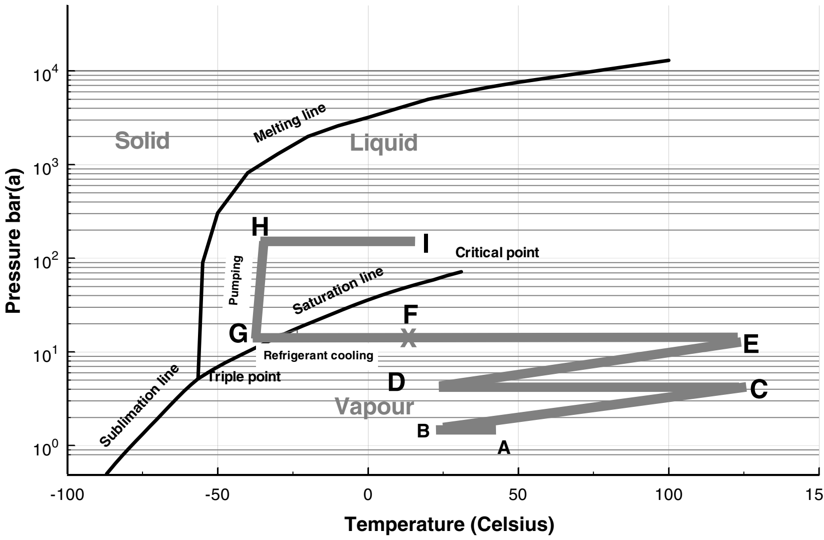

Fig. 5. Phase diagram of carbon dioxide (CO_2) indicating the trajectory for the CO_2 pre-treatment as it appears for the Sargas concept following the refrigeration approach at actual pressure (1.16 MPa, 11,6 bar).

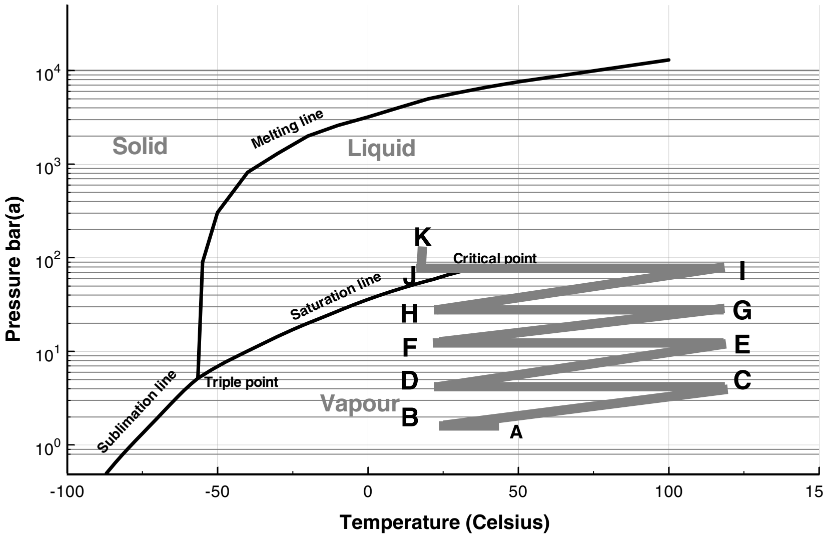

Fig. 6. Phase diagram of carbon dioxide (CO_2) indicating the path for the CO_2 pre-treatment as it appears for the Sargas concept with densification resulting from continued compression and cooling to atmospheric temperature level.

As no refrigerator unit is required in this case, power input will be required only by the compressors and the pump that affect the pressure of the stream of captured CO_2. Calculations show that per tonne CO_2 each compressor stage requires 23.2 kWh whereas the pump calls for just 1.7 kWh. In total this scheme requires an aggregated power at 94.6 kWh per tonne CO_2, which is about 5% lower than the previous alternative sub-critical condensation scheme.

5. Sargas technology metrics

Table 2 summarises some main characteristics of the *Sargas* technology in plain numbers that may serve as input data for a technology assessment to be conducted under the EU-based EMINENT project.

From this summary and the presentation of the technology above, it becomes evident that *Sargas* responds appropriately to the main drivers for the European CCS project portfolio in terms of [13,14]:

- Environmental issues;
  - (i) Emphasising near zero emission (including also other gases than CO_2).
- Economics;
  - (i) Cost-effectiveness – both capital cost and operational expenses - including maintenance;
  - (ii) Competitive conversion and performance cost;
  - (iii) Capture cost (typical reduction expected from 50 to 60 Euro per tonne to some 20–30 Euro per tonne CO_2 captured).
- Techno/operational aspects;
  - (i) Primary energy demand (i.e. overall chain efficiency – source to sink);
  - (ii) Fuel flexibility: natural gas, coal and lignite, co-firing, etc.;
  - (iii) Reliability and availability;

Table 2
Current Sargas plant metrics

Feature (100 MW unit block)	Value	Comments
Gross power generated (MW)	105	
Fuel input (MW)	267	
Overall plant efficiency (HHV) – %	39.3	Not accounting for CO_2 pressurisation
Overall net plant efficiency – %	36.3	CO_2 pressurisation taken into consideration
Fuel supply kg/s	7.5	Dry coal. HHV equals 33.927 MJ/kg
Unit power – MW_e	100	Full plant 400 MW_e requiring 4 unit blocks
CO_2 generated – kg/s	26.47	
CO_2 captured – kg/s	23.92	Thus emitting 2.5518 kg/s CO_2
Power for CO_2 pre-treatment (MW)	8.15	Based on 94.5 kWh per tonne CO_2
CO_2 capture rate – %	90.36	
Investment – Million USD	215.	Coal-based plant Norway
Power output per annum – GWh	750	Based on 7500 h operation per year
CO_2 for storage – ktpa[a]	715	400 MW plant: 2.86 Mtpa CO_2
CO_2 emission – ktpa	70	400 MW plant: 280 ktpa CO_2
Fuel Cost assumptions – USD/tonne	65	EC 2006 (Dons, 2007, [10])
Cost of electricity – USD/MWh	6	Mature 400 MW 20–25% lower COE. (These costs need, however, to be verified by a full-scale demonstration unit)
Investment, OPEX etc. – USD/MWh	*4*	
Fuel element – USD/MWh	*2*	
Technology maturity level (TML)[b]	4	Ready to bid 2007

The technical data are mainly collected from the HYSYS calculations, and the commercial data are supplied by Sargas AS.

[a] ktpa denotes kilo-tonne per annum (or 1000 tonne per year). Mtpa is mega tonne per annum.

[b] According to EMINENT denotion: TML-1: Paper idea, TML-2: Laboratory tests performed, TML-3: Pilot testing performed, TML-4: Demonstrator tests performed, TML-5: Commercial stage.

(iv) Optimum integration of components and overall system, including the CO_2 chain.

5.1. Advanced coal technologies without CCS

In Fig. 7 the state of the art in power generation technology – basically from coal – is indicated, however, without CCS [15]. This compares with the data given by Eurelectric, as shown in Table 3 [16].

5.2. Fuel penalty comparison

When CCS is applied to coal-based power generation plants these plants will require some 20–40% more fuel in order to deliver the same amount of electric energy. This is known as fuel penalty, and may depend on technology and level of technology maturity, as shown in Table 4.

This suggests that in consideration of coal-based power generation the state of the art would be 47% without CCS and at least 9% less if CCS is employed. This suggests that the efficiency of the best pulverised coal plant (as referred to in the table) would drop from 47% to 38% (at best), which means a fuel penalty of 19%.[10] The reason for the high fuel penalty is (1) the vast amount of medium-pressure steam that is required to regenerate the solvent in the absorption process, which usually requires 3–4 GJ/tonne CO_2 delivered as steam at approximately 4 bar pressure, and (2) the compression work of the CO_2.

A similar reasoning as above applies to the other candidate technologies. On this basis one may make easy comparisons by using the state of technologies from Fig. 7 and applying the typical penalties from Table 4, and thereby forming the best case references of these technologies – however, with the inclusion of CCS – in terms of efficiency level as indicated by the dotted line in Fig. 8.

By making this comparison one may consider *Sargas* with some 36–37% efficiency, as a fairly efficient concept – almost on par with the currently best large-scale technology options for coal.

6. Conclusion

Sargas constitutes a new energy technology aimed at power generation from fossil fuels – especially coal. It employs a complete CCS scheme characterised by pressurised post-combustion capture, and is a complete system that can only be used in connection with a PFBC. This means that direct employment of the CO_2 capture unit is only possible on a limited number of plants (<20 on the global scale) because the technology can neither be used in (most) existing plants, nor in coal-fired plants that are currently being planned, unless a full replacement of the boiler system is made and a gas turbine bottom cycle is added to the plant.[11] Nevertheless, the PFBC concept has some very desirable properties such as the ability to fire waste coal. Such coal is currently stored and considered a pollutant. This possibility opens several new niche markets. Modifications of the process may furthermore be used for compact gas or heavy oil-fired processes, suitable for marine and offshore use.

The *Sargas* technology is deemed capable of obtaining a capture rate that exceeds 90%. Its net electric conversion is around 36% based on a 100 MW_e unit block including the CCS unit delivering pressurised CO_2 in dense phase. This net efficiency level is comparable with large-scale coal-based power generation plants provided CCS would be included.

Sargas makes use of compact equipment of proved design that offers low extra investment cost in CO_2 capture, and the penalty in terms of pressure loss is somewhat lower than in other coal-based power cycle concepts that employ post-combustion capture [11]. However, despite the somewhat higher fuel penalty, the present *Sargas* cycle may offer cost-advantages over other comparable capture concepts, although this remains to be verified by large-scale demonstration. Furthermore, owing to the relatively low turbine inlet temperature of the gas turbine *Sargas* claims to be robust and reliable with a fairly long turbine life and low down time.

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[10] In order to compensate for this reduction, 19% more fuel is required, which again may require additional CCS and thereby additional fuel along the supply chain, although this would be outside the control volume of the actual plant.

[11] Such replacement is, however, technically possible. And, depending on the age and state of the plant that is subjected to retrofit, a potential of 3–5% points has been envisaged.

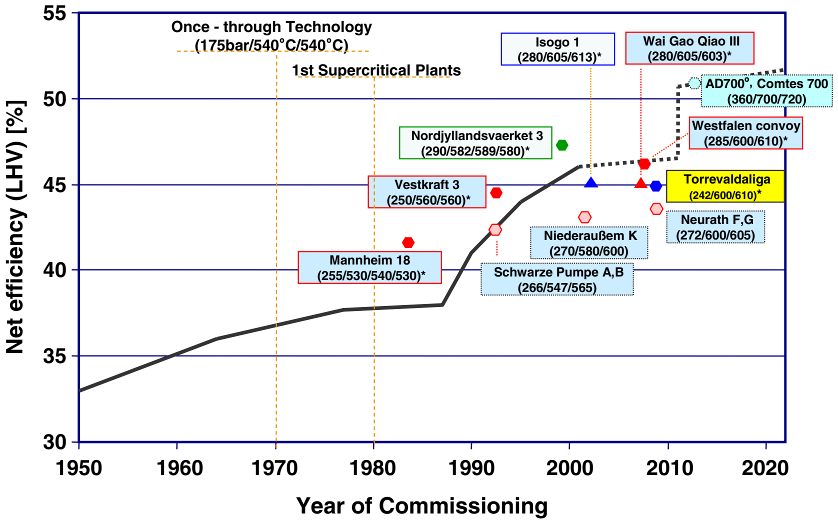

Fig. 7. Efficiency of coal-fired power plants versus time, including state of the art ov technologies (Source: Alstom Power).

Table 3
State of the art by technology showing the efficiency level and examples of plants

Fuel	Technology	Efficiency level (%)
Coal	Pulverised coal, boilers with ultra-critical steam parameters (State of the art; Refer Nord-Jyllandsverket, Denmark, with sea-water cooling, 47%)	Up to 47%
	Atmospheric circulating fluidised bed combustion (Refer Gardanne power plant, France)	>40%
	Pressurised fluidised be combustion (PFBC) (Refer Cottbus, 74 $\mathrm{MW_e}$/220 $\mathrm{MW_{th}}$, Germany)	>40%
	Coal-fired integrated gasification combined cycle (IGCC) (Refer Buggenum: 43% the Netherlands, Puertollano: 45%, Spain)	>43%
Natural gas	Large gas turbine (Refer Gas turbine World Handbook, 2000/2001)	Up to 39%
	Large gas-fired combined cycle gas turbine power plant (NG-CCGT) (Refer Mainz-Wiesbaden, GuD plant (by Siemens), Germany)	>58%

(Source: Efficiency in electricity generation, eurelectric July 2003).

Table 4
Fuel penalty by technology and capture concept and assumed state-of-the-art efficiency

Technology	Capture concepts	% – points efficiency drop	Efficiency with CCS (%)
Pulverised hard coal	Chemical MEA	9	38
Pulverised hard coal	Oxy combustion	11	36
Pulverised lignite	Chemical MEA	12	33[a]
IGCC, hard coal	Rectisol/selexol	8	31–33
IGCC, lignite	Rectisol/selexol (80% capture rate)		35–38
NGCC	Chemical MEA	9	49

Additional improvements may take place in the coming 15–20 years.

[a] The efficiency of pulverised lignite is usually 2–3% lower than that of pulverised hard coal.

The capture part is made up by the proved hot potassium carbonate processes, such as the Benfield process, that makes use of an inorganic solvent. In contrast to MEA or other amine-based or organic solvents, potassium carbonate is stable and does not degrade in the presence of oxygen. It also seems evident that *Sargas* may respond to the main drivers for the European CCS project portfolio in terms of environmental, economic and techno/operational aspects, according to the way that the project is stated.

There is, however, one component that is identified as being crucial to the concept, which is the recuperating heat exchanger. In order to overcome uncertainties demonstration tests were being performed throughout 2007 aimed at verification and optimisation of core elements of the technology. Further testing is scheduled for 2008. On this basis it is anticipated that the *Sargas* technology will be deemed ready for going into commercially bids in late 2008 (at the earliest).

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It should be mentioned hereunder that the Commission support does not affect the Sargas technology – neither directly nor indirectly – in any other way than via this independent particular paper study.

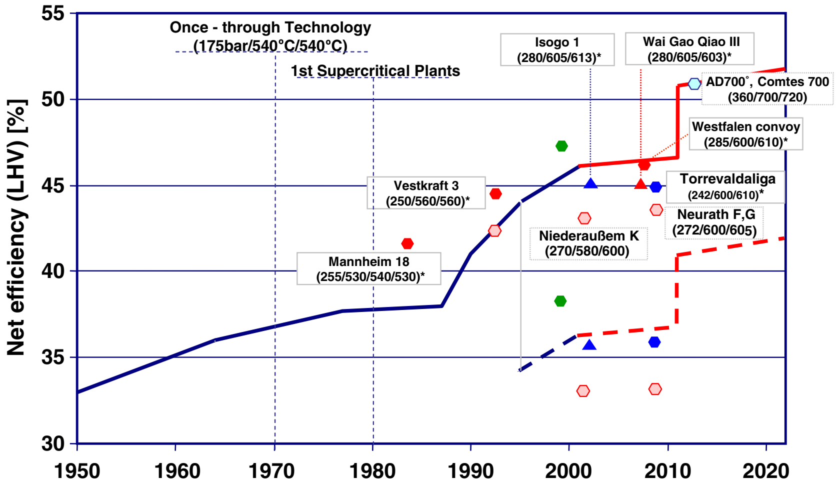

Fig. 8. State of the art in technology for power generation from coal (refer previous figure) with indication of efficiency level (dotted lines) taking typical fuel penalty into account.

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