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REVIEW OVER RECENT NORWEGIAN STUDIES REGARDING COST OF LOW CO2-EMISSION POWER PLANT TECHNOLOGY

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ABSTRACT

Several Norwegian companies have conducted "engineering cost evaluations" for capture of carbon dioxide (CO2) from thermal power plant emissions. Some of these studies have also combined capture with enhanced oil recovery (EOR)—thus investigating a possible commercial application for CO2-sequestration. The work to date has included assessments of:

i) Pre-combustion decarbonisation (PCD) in conjunction with a natural gas (NG) fuelled Integrated Reformer Combined-Cycle (IRCC) plant.
ii) Post-combustion decarbonisation using different solvents and also membranes for flue gas cleaning on both offshore and land-based Combined-Cycle Power Plant (CCPP).
iii) Flue gas stoichiometric combustion to generate an inert gas mixture (predominantly of nitrogen and carbon dioxide) suitable for EOR.
iv) Zero-emission power plant using either oxygen-based boiler combustion or a modified gas turbine cycle in conjunction with an air separation unit (ASU); also employing both the CO2 and nitrogen for EOR.
v) Evaluation of oxygen combustion with direct steam generation as proposed by Anderson *et al*. (1999).

On-going studies are also focussing attention on economic removal of CO2 in conjunction with reservoir EOR and aquifer storage, including investigation into the socio-economic benefits of long-term sequestration through development of a CO2-infrastructure (Hustad and Bjønnes, 2000).

INTRODUCTION

"Engineering cost evaluations" distinguish themselves from more general "studies" by the fact that they include not only contingency and return on investment, but also cost factors based on engineering experience and regional differences. The oil industry for example can easily operate with a 15% increase in overall capital investment (CAPEX) between "North Sea" estimates compared with US "Gulf Coast" estimates. Furthermore, when considering thermal power plant installations, we observe that even larger differences may appear regarding the presumed cost for combined-cycle turbines in terms of dollars per kilowatt installed.

Variation in cost for "CO2-capture" often arise through differing definition of plant battery limits, degree of fuel-gas pre-conditioning, and extent of final CO2 conditioning before transportation and long-term storage. Overall cost for "CO2-sequestration" includes this last phase, but here costs will obviously also depend upon length of pipeline, local permanent storage conditions, and potential commercial use of the CO2 for EOR. Eventually it is comparison of cost for "CO2-avoidance"[1] that should determine if one approach is environmentally preferable.

[1] That is the CO2 sequestered (permanently stored) less the CO2 expended to the atmosphere in getting it there. All these terms (including also "CO2-removal" and "CO2-storage") are often used in the literature and care must be exercised regarding their specific use.

The present review paper applies available thermo-economic data from several engineering companies, and recompiles this information using similar assertions based upon average OECD conditions[2]. A comparative study has also been conducted by the IEA-GHG (1999). We use a standard cash flow analysis over 25 years with 10% discount rate to determine the real cost of electricity using net present value (NPV) equal to zero. Fuel cost of 2 US$/GJ (around 56 øre/Nm^3 in Norwegian currency) is slightly high by current Norwegian standards but nonetheless realistic for European conditions.

Comparisons are made with a baseline NG-fired CCPP with overall plant efficiency of 58%, and fully installed CAPEX of 650 US$/kW. The resulting cost of electricity (COE) without CO2-capture is 24 mills/kWh (that is 20 øre/kWh) and probably realistic for Norwegian coastal conditions. We note that a 10% change in CAPEX or the price of fuel gas results in 5% on the COE.

The cost of capture includes CO2-conditioning to 150 bar at battery limit, but does not include projected transportation and final injection. These will usually increase sequestration costs by between US$ 10 to 15 per tonne of CO2 (tCO2) for distances from 100 to 200 kilometre and volumes between 1 to 4 million tCO2 per year (Wildenborg, 2000), and add +5 to +7 mills/kWh on the COE. Estimates also suggest that with oil at US$ 20 per barrel then an oil reservoir may typically be willing to pay 14 to 18 US$/tCO2 if it is feasible to use CO2 instead of natural gas for EOR (Hustad and Bjønnes, 2000).

REVIEW OF WORK WITH PRE-COMBUSTION DECARBONISATION (PCD)

Both Integrated Gasification Combined-Cycle (IGCC) and IRCC installations are examples of complex plants that can be adapted to PCD of fossil fuels. The IRCC process differs slightly in that the combustible component of the gas turbine fuel-gas is hydrogen, as compared with a gasification synthesis gas that usually includes some carbon monoxide and CO2. This requires minor modifications of established IGCC gas turbine combusters as demonstrated by *General Electric* (Todd and Batista, 2000).

Foster Wheeler conducted IRCC studies for both steam-reforming and partial oxidation on behalf of the IEA-GHG & Statoil (1998) and subsequently Statoil (1998). Furthermore, in April 1998 *Norsk Hydro* initiated a major project evaluation of an IRCC plant for a proposed 1200 MW installation on the west coast of Norway. The plant sketched in Fig.1, comprised an auto-thermal reformer (ATR), with CO-shift and absorption of CO2 using an established cleaning process such as "Selexol". The power plant included a triple-train combined cycle unit with both gas turbine and heat recovery steam generator (HRSG) integrated with the reforming section.

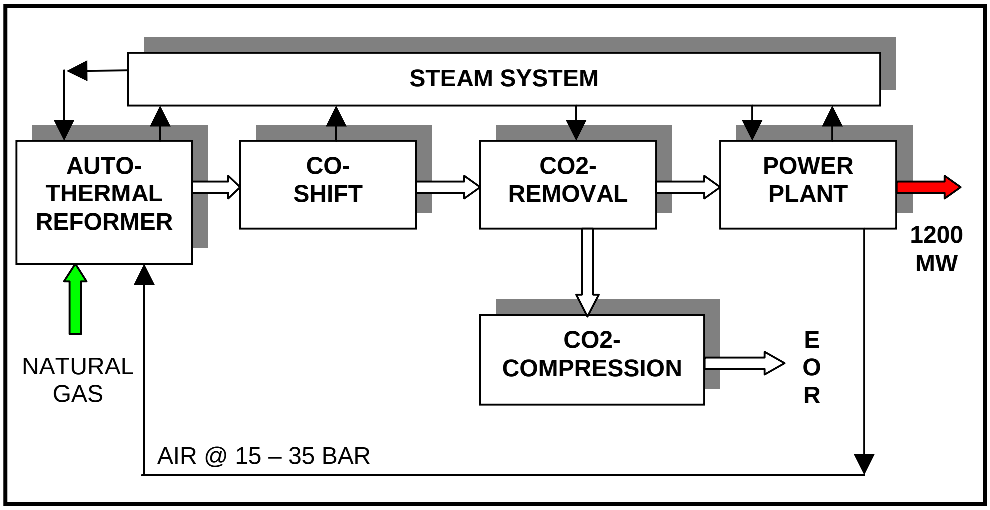

Figure 1: Schematic diagram of the proposed Norsk Hydro IRCC plant.

[2] This would appear to be about half way between "Gulf Coast" and Norwegian "North Sea" estimates and probably appropriate for typically the Dutch or UK coast in Northern Europe.

The plant size was determined by a desire to supply 60 million tCO2 over 15 years for EOR to the *Grane* oil field. The proposal was eventually deemed too risky because of being tightly linked with scheduled development of *Grane* that is due to come on-line with 215,000 barrels of oil per day in 2003. However the company helped to focus attention towards the potential for EOR using CO2.

Overall estimates for CAPEX have varied depending upon the degree of integration, but is typically around 1200 US$/kW with 87% reduction of CO2-emissions and 47% plant efficiency. This results in a capture cost of 36 US$/tCO2 and an additional +13 mills/kWh on the COE. The ATR constituted about 35% of total equipment costs, while the power plant is 42% of total equipment costs. The CO2-compression unit is 7% of costs and reduces plant efficiency by about 2%-point.

There is probably some scope for optimising plant integration—notably by varying the operating pressure of the ATR as indicated in Fig.1. Work by Andersen *et al*. (2000) suggests integrated operations around 15 bar may be preferable to higher pressures that have also been considered[3]. Experience from IGCC plants shows that operations and control can also be challenging (Ploeg, 2000). However the gasification industry has managed to reduce costs during the past decade from above 1400 to possibly below 1000 US$/kW (Brkic and Cooperberg, 1999). If we tentatively assume that an advanced IRCC plant could in 5 to 8 years cost 1050 US$/kW having 50% efficiency, then this would result in 25 US$/tCO2 and +10 mills/kWh on the COE.

REVIEW OF WORK COVERING POST-COMBUSTION DECARBONISATION

In 1996 *Kværner* completed a study on behalf of *Statoil* regarding removal of 2,2 million tCO2 per year from the *Kårstø* industrial complex on the west coast of Norway. Decarbonisation with flue gas cleaning is here the most practicable option because capture may then include emissions from a variety of sources including a proposed 400 MW CCPP.

In 1997 *Statoil* also initiated a development programme into using improved MDEA and hybrid solvents to reduce costs by 40% compared with the Kværner study, whilst removing 87% of the CO2 from the flue gas of a conventional 400 MW power plant as sketched in Fig.2. Three major suppliers have in collaboration with *Statoil* contributed to recent engineering cost estimating exercises (Undrum *et al.*, 2000). The results vary slightly depending upon plant integration and choice of solvents. However, plant efficiency is consistent between the three at 49 – 51%, with CO2 compression typically accounting for 12 – 14 MW.

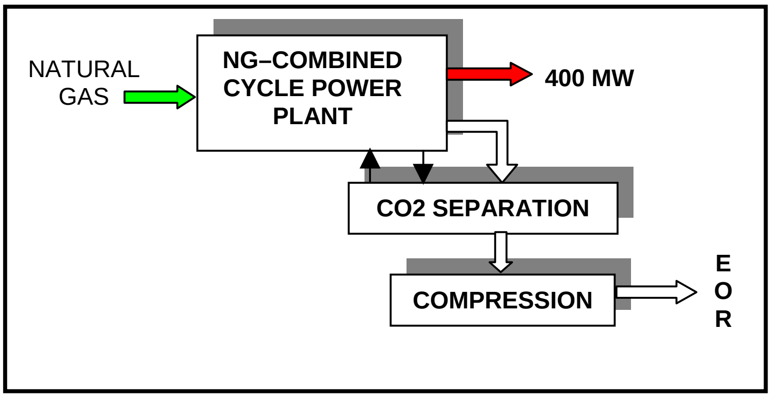

Figure 2: Schematic diagram for flue gas cleaning.

Applying <u>current</u> technology on a 400 MW plant the CAPEX is above 1500 US$/kW resulting in at least 50 US$/tCO2 and +17 mills/kWh on the COE. Realistic RD&D goals for the next 5 years are inferred to be a 30% cost reduction within the absorber section and 20% improvement on power losses. This could, in combination with economies of scale for a 1200 MW plant, reduce CAPEX to around 1100 US$/kW and 27 US$/tCO2 with +10 mills/kWh on the COE.

Statoil is also co-ordinating SACS (2000), and participating in the "CO2 Capture Project" organised by *BP-Amoco*.

[3] Alternatively, implementation of ATR-technology in conjunction with large-scale methanol production suggest that ATR's have improved economic performance when operating between 70 to 100 bar (Olsvik and Hansen, 1998).

Kværner have also developed their own proprietary membrane technology for flue-gas cleaning, with specific emphasis towards offshore installations (Falk-Pedersen *et al.*, 2000). This technology is currently available for initial commercial implementation. The company has succeeded in reducing both weight and footprint by over 40% compared with the more conventional amine techniques, and they have improved O&M costs by around 30%.

Naturkraft (a small IPP owned jointly by *Statoil, Norsk Hydro* and *Statkraft*), investigated briefly part stoichiometric flue-gas combustion as sketched in Fig.3. The resulting "inert gas" comprises 87 vol% nitrogen and 12 vol% CO2, and is suitable for injection into an oil reservoir. The study was initiated to consider alternative schemes for EOR in conjunction with the *Grane* oilfield, and also possible retrofits given future tightening of CO2-emissions legislation.

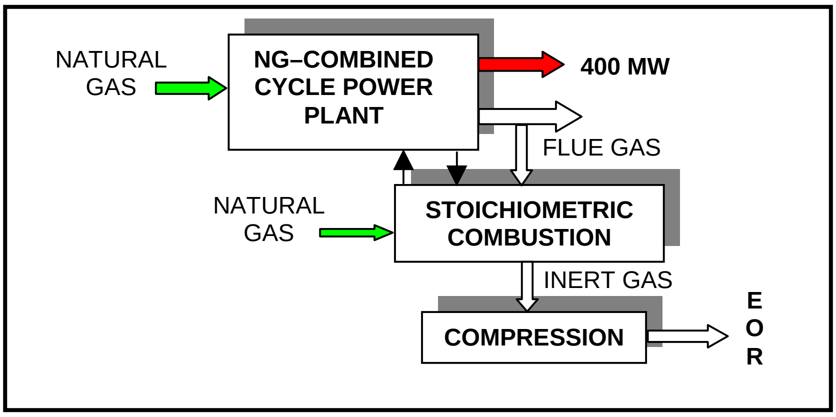

Figure 3: Schematic diagram for "inert gas" concept.

The plant CAPEX increased from the baseline 650 to 1150 US$/kW, with inclusion of the afterburner and compression unit. Thermal power output rose 46 MW but net output remained the same due to increased compression work. Overall plant efficiency reduced to 53%. The CO2-avoidance cost is not truly comparable with the other schemes in view of the fact that the plant is still emitting 75% of its original CO2-emissions. For EOR the concept was commercially attractive when the price of natural gas rose above 1.2 US$/GJ, but the concept has not been pursued any further by the company.

OXYGEN COMBUSTION

Combustion of hydrocarbon fuel in the presence of oxygen results in steam and comparatively easily separated CO2. The concept is well established, but with evolving new oxygen technology (Allam *et al.*, 2000) is being re-evaluated by several companies including *Aker Maritime*.

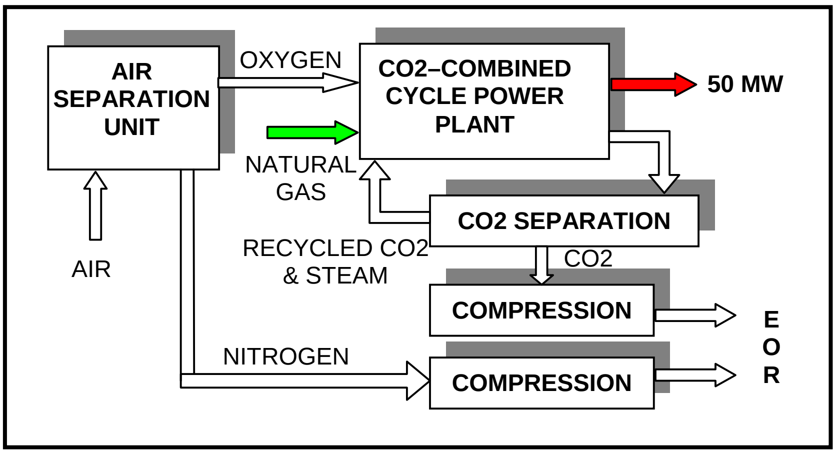

Figure 4: Schematic diagram for a 50 MW CO2-closed cycle plant (HiOx) that could be appropriate for EOR.

Project evaluations are also currently being undertaken for a 250 MW North Sea installation using a conventional boiler and steam turbine configuration having efficiency of 37%. Alternatively (as sketched in Fig.4), in conjunction with a 50 MW CO2 "closed-cycle" gas turbine which re-circulates a large portion of the CO2 gas in the combustion process. Commercial development for new turbine technology is potentially feasible (Jackson *et al.*, 2000) and has been estimated by one turbine manufacturer to be in the region of US$ 60 million (private communication *Aker Maritime*). A 50 MW plant would typically generate injection gas sufficient for an oil field producing an average of 150,000 barrels per day. Over a 15-year life such an oil reservoir may pay between US$ 400 – 600 million on EOR using conventional hydrocarbon gas, thus there would appear to be some economic incentive for continued project evaluations.

Finally we note that Anderson *et al*. (1999) have proposed an alternative oxygen combustion scheme (Fig.5) being developed in the USA by *Clean Energy Systems (CES)*. This "Internal Rankine Cycle" (ICR) is based upon a stoichiometric gas generator that directly produces high-temperature, high-pressure turbine drive gas, and re-circulates the steam as opposed to the CO2 gas. Bilger (1999) confirms the thermodynamic assessment presented by *CES*, and points out that the cycle exhibits a specific work output of 2MJ/kg which is three times that achieved in a conventional CCPP. Anderson *et al*. (2000) have proposed a 100 MW "near-term" CES-plant with 53% efficiency and CAPEX of 730 US$/kW resulting in less than 5 US$/tCO2. Our own "engineering estimates" require slightly higher CAPEX of 850 US$/kW, but still yields CO2-capture at 15 US$/tCO2 and +5 mills/kWh COE (when compared against our 400 MW baseline NG-CCPP). Development of a 10 MW gas generator at *Livermore Laboratories* is currently being funded by the *US-DOE* and *State of California*, (Surles *et al.*, 2000).

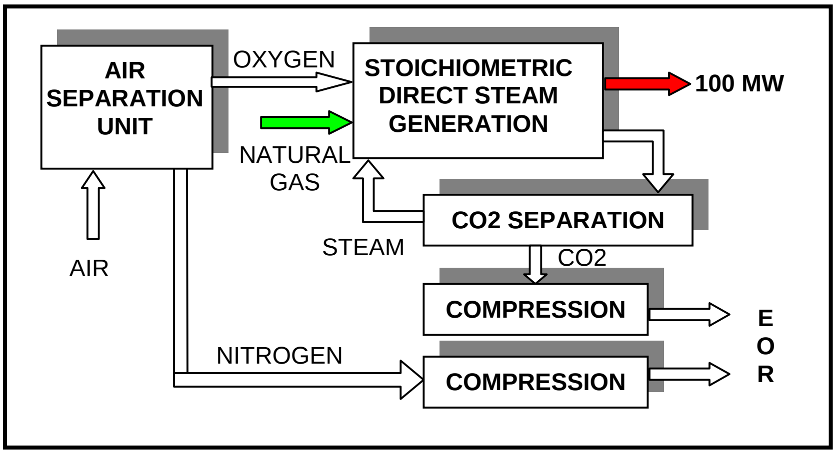

Figure 5: Schematic Diagram of the CES Power Plant.

CONCLUSIONS

Results are summarised in the Table 1 using both "near-term" technology and an indication of trends we might anticipate in the next decade. We presume that both PCD and flue-gas scrubbing can reduce costs to below 1100 US$/kW with 3 – 4% improvement on current efficiency. Also investment costs reduce 15% when moving from a 400 to a 1200 MW plant. Typically this yields capture cost around 25 US$/tCO2 and +10 mills/kWh on the COE. However both these technologies will continue to have part emissions of CO2, NOx, and chemical solvent waste.

Table 1: Summary of possible costs for CO2-capture achievable in 5 and in 10 years.

Concept	Power (MW)		Efficiency (%)		CAPEX (US$/kW)		COE (mills/kWh)		Emission (mill. tCO2)		Cost (US$/tCO2)	
Baseline NG-CCPP	400		58	61	650	650	25	24	1,17	1,11	–	–
PCD / IRCC	1200		47	50	1200	1050	38	34	0,55	0,52	36	25
Flue gas cleaning	400	1200	50	54	1500	1100	42	34	0,20	0,37	50	27
HiOx–CO2-Recirc.	400	50	37	42	1500	1200	47	40	0	0	40	34
CES–Steam Recirc.	100		53	(65)	850	(??)	30	(??)	0	0	15	(??)

The commercial incentive for flue-gas cleaning may lie in conjunction with removing emissions from existing industrial complexes by using a central cleaning plant with a local flue-gas infrastructure for collection. The incentive for PCD could be in combination with large-scale production of alternative energy carriers such as methanol, ammonia, or hydrogen. The technology also provides considerable scope for reducing CO2-emissions within the refinery and gasification industry. However, the only current possibility for commercial implementation would seem to be in combination with EOR, where CO2 may compete with the conventional role of hydrocarbon gases.

The commercial competitiveness of oxygen combustion is that it is a "zero-emission" option, and is more amenable to extended EOR and less dependent on economies of scale. There is also here considered to be some anticipation regarding introduction of new technology in the next 10 years.

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