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Thermo-Economic Modelling and Process Integration of CO_2-Mitigation Options on Oil and Gas Platforms

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The offshore extraction of oil and gas is an energy-intensive process associated with large CO_2 and CH_4 emissions to the atmosphere and chemicals to the sea. The taxation of these emissions has encouraged the development of more energy-efficient and environmental-friendly solutions, of which three are assessed in this paper. The integration of steam bottoming cycles on the gas turbines or of low-temperature power cycles on the export gas compression can result either in an additional power output, or in a greater export of natural gas. Another possibility is to implement a CO_2-capture unit, which allows recovering CO_2 that can be used for enhanced oil recovery. In this paper, a North Sea platform is considered as case study, and the site-scale retrofit integration of these three options is analysed, considering thermodynamic, economic and environmental performance indicators. The results illustrate the benefits of valorising the waste heat recovered from the exhaust gases, as the total CO_2-emissions can be reduced by more than 15 %. Exploiting low-temperature heat seems feasible, although more challenging in retrofit situations. Integrating CO_2-capture appears promising with a CO_2-avoidance cost between 23 and 29 \$/tCO_2 for the chosen economic assumptions.

1. Introduction

The extraction and processing of oil and gas on offshore fields is an energy-intensive sector that represented up to 26 % of the total CO_2-emissions of Norway in 2011. These emissions are caused by the combustion of diesel, gas or oil for on-site power generation and are subject to a hydrocarbon fuel tax that has increased the last years, from 210 (\$ 35) to 410 NOK (\$ 67) per ton of CO_2 (Norwegian Ministry of Petroleum, 2012). In this context, reducing the CO_2 emissions has become more and more interesting from both an environmental and an economic prospective. This goal can be achieved (i) by improving the performance of the oil processing plant with a low-temperature waste heat recovery cycle (Rohde, 2013), (ii) by increasing the efficiency of the power generation plant with a steam network (Kloster, 1999), by (iii) implementing a carbon capture unit, or by (iv) connecting offshore platforms to the mainland through electrical cables. Several studies dealing with the design of these processes can be found in the literature. However, at the knowledge of the authors, these technologies are generally optimised individually, and the literature lacks a systematic analysis of the site-scale integration of these processes. The different synergies should therefore be assessed thoroughly to enhance the performance of the overall plant. The objectives of the present work are to (i) evaluate the prospects for integrating steam bottoming cycles, low-temperature cycles and CO_2-capture processes on an existing oil and gas platform, (ii) assess the thermo-environomic (i.e. thermodynamic, economic and environmental) performance, (iii) and identify the possible trade-off between competing objectives, by performing multi-objective optimisations.

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2. Methodology

2.1 System description

Oil and gas platforms present similar structural designs but process petroleum with different characteristics (e.g. viscosity) and operate on fields with different properties (e.g. temperature, pressure, water- and gas-to-oil ratios) (Manning, 1991). An oil and gas facility can be divided into two main sub-systems: the processing plant, where oil, gas and water are separated and treated, before being exported to the shore or rejected to the environment; and a utility plant, where the power and heat required for driving the separation and compression processes are produced.

The different technological options, which can be implemented to reduce the CO_2-emissions of the oil and gas plant, are investigated and included a process superstructure displayed in Figure 1. There are five gas turbines, of which three provide the power required in the processing plant, and the remaining two are run in case of water injection. The steam cycle is considered as a bottoming cycle to the main gas turbines (Kloster, 1999). The low-temperature cycles that are investigated in this work are based on carbon dioxide (trans-critical), propane (subcritical) and ethane-propane (trans-critical) mixtures as working fluids, following the study of Rohde et al. (Rohde, 2013). Since the turbine exhausts are rejected at low pressure (near-atmospheric) and have a low CO_2-concentration, the CO_2-removal step is achieved by chemical absorption with monoethanolamine (Tock, 2012). For a grass-root case, the integration of pre-combustion carbon capture and storage may be better, since the resulting equipment and the compression work would be smaller. Flue gases enter an absorption column in which an aqueous solution with alkanolamines, at a mass concentration of 30 - 35 %, flows counter-currently. The carbon dioxide is captured by scrubbing and chemical recombination into bicarbonate ions. The captured CO_2 is then dehydrated and compressed to 180 bar, as this is the required pressure for enhanced oil recovery when using gas.

2.2 Thermo-economic modelling

The methodology followed in this work has been extensively described in Bolliger et al. (2009), and has been extended to the design of other systems such as hydrogen production (see e.g. Tock et al. (2012)). The approach (Figure 2) relies on the combination of flow-sheeting techniques, energy integration models, economic evaluations using the correlations of Turton et al. (2012) and a multi-objective optimisation routine (Molyneaux, 2002), based on a genetic algorithm.

The models of the oil and gas platform and of the CO_2-capture by monoethanolamine are developed using the commercial flow-sheeting software Aspen Plus (Aspen Technology, 1999), and the modelling and

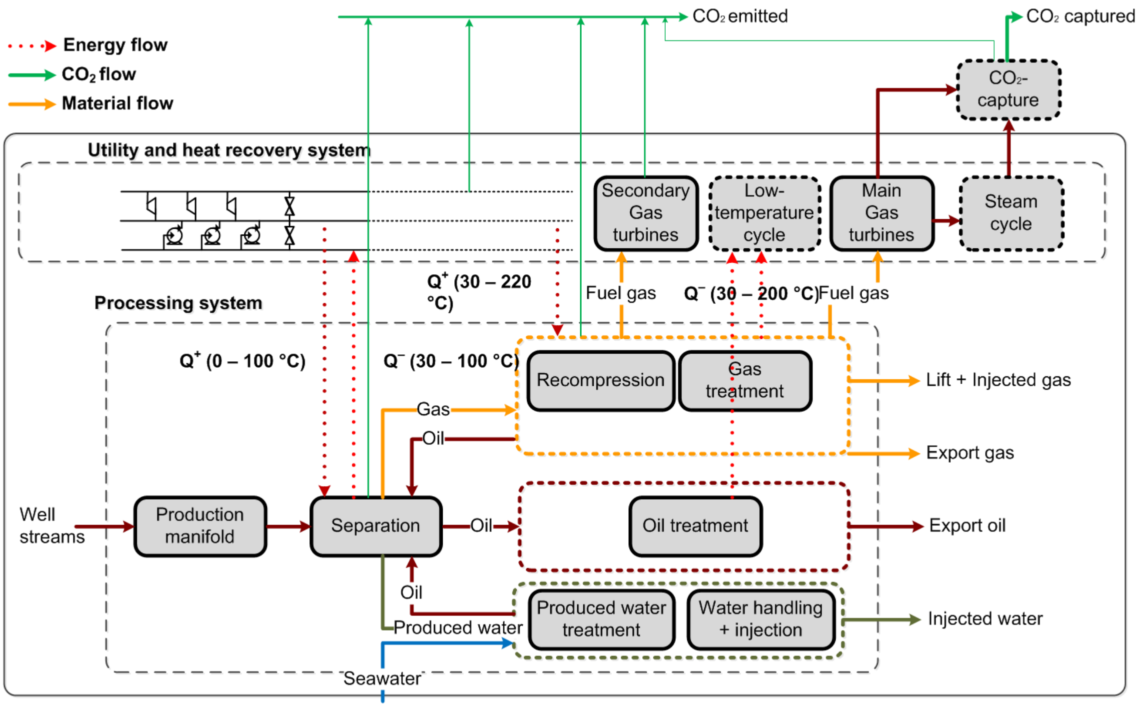

Figure 1: Process superstructure of CO_2-mitigation options for oil and gas platforms

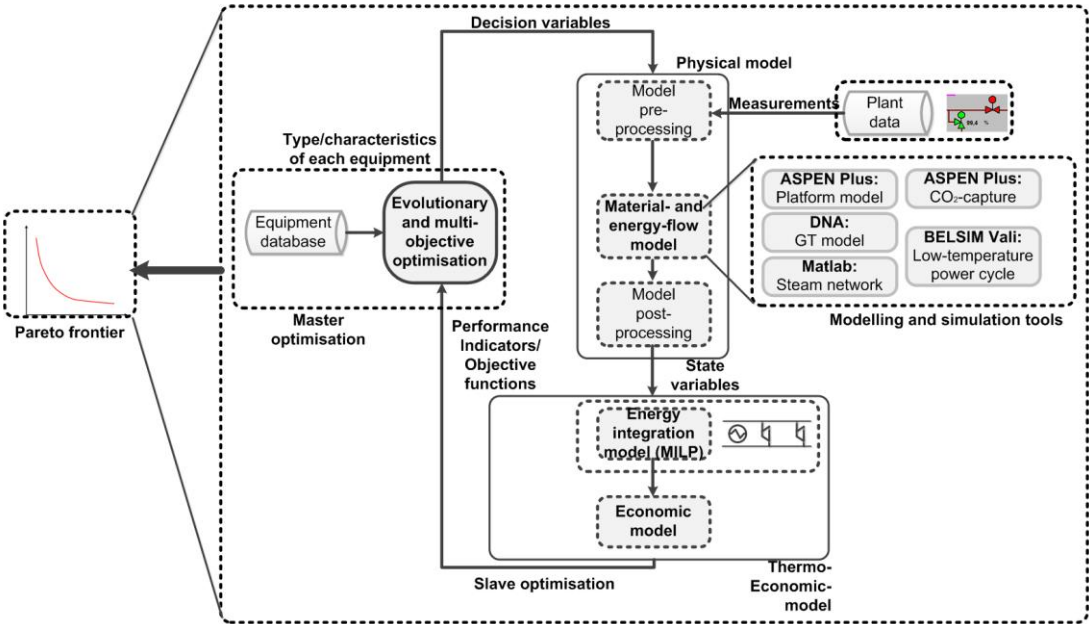

Figure 2: Framework methodology for the modelling and optimisation of the CO_2-mitigation options

assumption details are presented in Nguyen et al. (2014) and Tock et al. (2012). The steam network is simulated, based on the work of Maréchal and Kalitventzeff (1997).

The low-temperature power cycles are modelled with Belsim VALI (BELSIM Vali, 2010), using a piecewise linear parameterisation for the temperature-enthalpy profiles. The energy-integration model builds on the use of the pinch analysis technique (Linnhoff, 1989), considering individual temperature differences ($\Delta T_{min}/2$) of 2 K, 4 K and 8 K for phase-changing, liquid and gas streams. This heat cascade problem is formulated as a Mixed Integer Linear Programming (MILP) problem, assessing precisely the heating and cooling requirements of the oil platform, and optimising the selection and use of the utilities (e.g. process water and seawater). The heating demand is satisfied by waste heat recovery from the turbine exhausts, while the cooling demand is met by processing seawater or recovering cooling water from the processing plant. The economic model builds on the resulting state variables and system operating conditions, calculating the costs with the capacity-based correlations of Turton et al. (Turton, 2012), which have an uncertainty of about 30 %. An operation of 95 %, a lifetime of 15 y and an interest rate of 10 % are considered.

2.3 Performance indicators

The overall performance can be evaluated by a large variety of thermodynamic and economic indicators, and this study focuses on:

(i) The energy intensity of the facility σ, defined as the ratio of the energy used on-site in form of fuel gas, to the energy exported to the shore with oil and gas;

(ii) The energy efficiency of the cogeneration plant η, defined as the ratio of the energy transfers with heat and power (steam network and gas turbines), to the energy used as fuel gas;

(iii) The additional investment costs C_{inv}, which are associated with the implementation of a steam cycle, a low-temperature power cycle and a CO_2-capture unit;

(iv) The increase of natural gas δ_{NG} exported to the shore;

(v) The reduction of CO_2-emissions δ_{CO2} caused by the decrease of fuel gas consumption and the possible integration of a CO_2-mitigation plant;

(vi) The changes in operating costs C_{op}, due to the replacement of monoethanolamine because of degradation issues;

(vii) The CO_2-avoidance cost *CAC*, defined as the ratio of the increase in investment costs over the decrease of CO_2-emissions;

(viii) The power capacity of the additional systems *P*.

2.4 Multi-objective optimisation

Several objectives can be considered, based on the numerous performance indicators: they illustrate that decision-makers need to evaluate the trade-offs between two or more competing objectives (e.g. limitation of the investment costs versus reduction of CO_2-emissions). The objectives considered in the optimisation procedure are the maximisation of the power capacity *P*, the minimisation of the investment costs C_{inv} and the maximisation of the reduction of the local CO_2-emissions δ_{CO2}. The optimal system configurations are computed by performing a multi-objective optimisation and displaying the solutions under the form of a Pareto optimal frontier. The master decision variables amount to 48, of which 18 are related to the operation of the steam cycle (e.g. pressures, temperatures, vapour fraction), 5 to the selection of the cooling utility (e.g. process water and temperatures), 12 to the selection and design of the low-temperature power cycle (e.g. superheating approach), and 13 to the configuration of the CO_2-capture unit (e.g, equipment sizes and operating conditions).

3. Results and discussion

3.1 Baseline case

The current system is characterised by a power demand of about 19 MW, a heating demand smaller than 5 MW and a cooling demand greater than 30 MW, which is met by processing more than 2,000 m^3/h of seawater at about 8 °C and lifted onsite. The pinch point of the overall facility is located at about 150 °C, illustrating that most heat discharged to the environment is at low (under 100 °C) temperatures. The heating demand, between 150 and 230 °C, is satisfied by recovering heat from the exhaust gases at about 330 °C. The thermal efficiency of the gas turbines varies between 23 % (current operating point) to 34 % (nominal design point), and the energy intensity σ amounts to 4.6 %. The total daily CO_2-emissions produced locally reach about 450 t, of which more than 90 % are emitted from the gas turbines.

3.2 Optimal configurations

The optimal solutions recovered from the multi-objective optimisation routine can be grouped into three clusters: *Cluster 1*, where only a steam network is integrated, *Cluster 2*, where a steam network and a low-temperature cycle are integrated, and *Cluster 3*, where a steam network and a CO_2-capture unit with monoethanolamine are implemented. The following trends can be observed.

In general, the integration of a steam network allows for a greater power production *P*, ranging from 3 to 8 MW at design conditions for a total investment cost C_{inv} from 6 to 14 M$. There are no further increases in operating costs, as no additional fuel is required, and the number of operators is assumed to be constant. The efficiency η increases to about 35-40 % when the steam cycle is run at full-load conditions, and between 28 and 33 % when run for the normal operating conditions. All the optimal steam cycles consist of a single production level at a pressure between 8 and 13 bar and a condensation level below 0.5 bar. The cooling utility used in the steam condenser is the process water, i.e. the cooling water from the processing plant at about 16.5 °C. The export of natural gas to the shore δ_{NG} increases by up to 14 %, and this goes along with a reduction of the CO_2-emissions of up to 16 %. The CO_2-avoidance cost *CAC* reaches about 27-33 \$/tCO_2, which should be compared against the CO_2-tax of about 67 \$/tCO_2.

The integration of a low-temperature power cycle results in an additional power generation of up to 3.5 MW, if heat can be recovered from all the coolers located in the gas recompression and compression sections. Although the heat exchangers are already installed, such solutions may be problematic as further retrofit of the pipeline connections and of the heat exchangers may be necessary. Setting the low-temperature power cycle only on the after-cooler placed at the outlets of the gas treatment process may not be viable, because the gas flow through this heat exchanger is already small (lower than 2 kg/s) and is expected to decrease with time. The total investment cost C_{inv} ranges between 5 and 7 M$, and the preferred low-temperature cycle for these applications is the ethane-propane cycle, as suggested previously in the work of Rohde et al. (2013). As expected, the economic and environmental benefits related to the decrease of the fuel gas consumption are smaller, with δ_{NG} and δ_{CO2} smaller than 8 % in all cases. The CO_2-avoidance cost is higher than for the integration of a steam cycle, reaching about 31-36 \$/tCO_2.

Finally, integrating a CO_2-capture plant seems more appropriate when it is performed in conjunction with a steam cycle. However, the energy penalty that is related to the thermal regeneration of the chemical sorbent, and which is pointed out in other studies, is not as significant in the present case. The heat required in the desorption column is provided by the cooling of the exhaust gases after the gas turbines and steam cycle, illustrating the positive synergy between the bottoming cycle and the CO_2-capture plant. The power demand at normal operating conditions increases by about 12 %, as a consequence of the power demand for compressing the CO_2 and pumping the monoethanolamine. The purity of the CO_2-rich stream exceeds 97 % on a molar basis and the CO_2-capture rate varies between 87 % and 93 %. The investment costs vary between 7 and 11 M$ for the CO_2-plant solely. The CO_2-avoidance cost varies thus between 23 and 29 \$/tCO_2, considering that the steam cycle is integrated with the CO_2 capture plant.

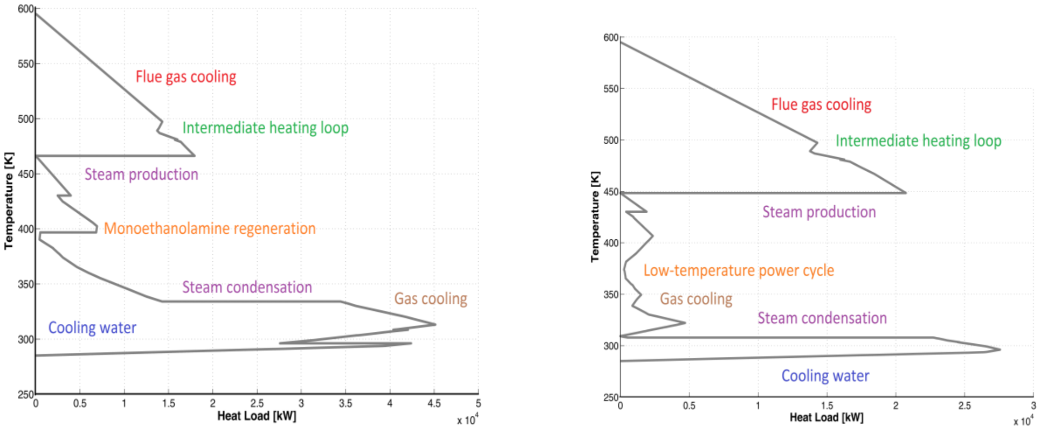

Figure 3: Balanced Grand Composite Curves for a steam network and monoethanolamine CO_2-capture unit (left) and a combined steam cycle + low-temperature C_2H_6-C_3H_8 power cycle (right)

The area between the Grand Composite Curve and the temperature axis (Figure 3) illustrates the exergy destruction taking place in the heat exchanger network. The integration of a steam cycle and a low-temperature power cycle reduces the exergy destruction at both high and low temperatures. This illustrates the high thermodynamic performance of such an integrated system, combined with a total increase of gas export of about 22 % and a reduction of the CO_2-emissions of 25 %. On the contrary, the integration of a steam cycle and a CO_2-plant only reduces the exergy losses with the exhaust gases, taking place at a temperature of 100 to 330 °C. The total CO_2-emissions of the platform can be reduced by up to 70 % when combining a steam cycle with an ethanolamine plant, the remaining emissions being caused by flaring and emissions from the secondary gas turbines on-site.
The Pareto fronts (Figure 4) illustrate the trade-off between the maximum power capacity, the CO_2-capture and the investment costs. A system where a CO_2-capture plant is installed along with a steam cycle presents the greatest potential for CO_2-reduction. However, this is performed at the expense of significant investment costs, of about 14-18 M$, which are compensated by the significant reductions in CO_2-taxes, which amount to about 0.02 M$ per day. These investment costs vary with the facility on which the CO_2-capture plant is implemented. They do not include site-specific investment costs, which can vary in a range as wide as 10—96 M$ (Torp & Brown, 2005).

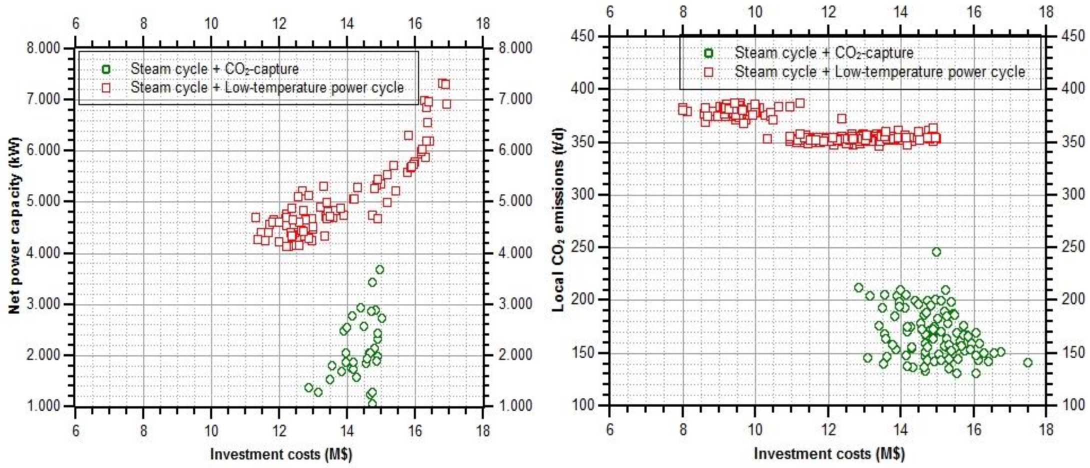

Figure 4: Thermo-economic and thermo-environomic Pareto frontiers comparing the maximum power capacity (left) and the CO_2-reduction potential (right) against the total investment cost

The need for an additional power capacity on this platform needs to be investigated carefully: the total power demand may increase with time, as more water may be injected into the reservoir for an enhanced oil recovery. The combination of a steam cycle and a low-temperature waste heat recovery may not be interesting in practice, as it requires consequent retrofitting. On the contrary, the implementation of a steam network with a CO_2-capture unit allows for greater power generation, if needed, as well as a smaller fuel gas consumption and higher thermal efficiency at part-load conditions. Considering the expected lifetime of this facility, this alternative may be interesting, and the operating constraints of the mono-ethanolamine system should be evaluated carefully.

4. Conclusions

The site-scale integrations of steam bottoming cycles, low-temperature power cycles and CO_2-capture processes are compared. All possible configurations are embedded in a superstructure process model, which are further optimised by process integration. Their competitiveness is evaluated, using performance criteria assessing thermodynamic, economic and environmental aspects. In all cases, the integration of a steam network is revealed to be profitable, with an increase of the power generation capacity of up to 8 MW, a greater gas export of up to 16 % and a CO_2-avoidance cost of 31 - 36 \$/tCO_2. The integration of low-temperature power cycles is more challenging, as it requires a more extensive retrofitting of the facility, while presenting a higher CO_2-avoidance cost for a smaller power capacity. The present analysis suggests that CO_2-capture from the exhaust gases is competitive, given the current CO_2-tax (67 \$/tCO_2) on hydrocarbon fuels and the potential for sequestrating up to 70 % of the total CO_2 emitted on the platform.

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