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Energy efficiency measures for offshore oil and gas platforms

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Abstract

Oil and gas platforms are energy-intensive systems – each facility uses from a few to several hundreds MW of energy, depending on the petroleum properties, export specifications and field lifetime. Several technologies for increasing the energy efficiency of these plants are investigated in this work. They include: (i) the installation of multiple pressure levels in production manifolds, (ii) the implementation of multiphase expanders, (iii) the promotion of energy and process integration, (iv) the limitation of gas recirculation around the compressors, (v) the exploitation of low-temperature heat from the gas cooling steps, (vi) the downsizing or replacement of the existing gas turbines, and (vii) the use of the waste heat from the power plant. The present study builds on four actual cases located in the North and Norwegian Seas, which differ by the type of oil processed, operating conditions and strategies. The benefits and practical limitations of each measure are discussed based on thermodynamic, economic and environmental factors. Significant energy savings and reductions in CO_2-emissions are depicted, reaching up to 15–20 %. However, they strongly differ from one facility to another, which suggests that generic improvements can hardly be proposed, and that thorough techno-economic analyses should be conducted for each plant.

Keywords: Energy efficiency, process integration, oil and gas platforms

1. Introduction

The Norwegian oil and gas offshore sector has contributed for about 20 to 30 % to the total Norwegian CO_2-emissions in the last decade, and this number is expected to stay in the same magnitude in the coming years. These emissions are caused in a large share by the combustion of natural gas in gas turbines to produce the power required to drive the compression and pumping operations, and the remaining is associated with gas flaring and diesel combustion. A CO_2-tax on the offshore sector has been levied by the Norwegian government in 1991 and was doubled in 2011 [1] to encourage CO_2-mitigation measures. The emissions per produced oil equivalent decreased by approximately 19 % from 1990 to 2005 [2], as a result of this incentive and global technology improvement. However, the total emissions actually doubled, because of the increased gas production and exploitation activities. The extended exploitation of mature fields results in processing of higher amounts of water and gas, and therefore in greater power consumption per unit oil.

The energy use and emissions associated with oil production differ from one field to another, depending on the field conditions (e.g. crude oil temperature), export specifications (e.g. purity requirements and pressure), and field lifetime (e.g. 'plateau' or 'end-life' production) [3]. Different strategies can be applied to improve the energy performance of oil and gas facilities, which can be classified into two categories [4].

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The first possibility is to reduce the energy requirements of the processing plant, by increasing the efficiency of the most energy-intensive processes, promoting system integration or recovering energy from the feed (after the production manifolds) or product (in the gas treatment section) flows.

Several measures for promoting energy savings were proposed in the works of Svalheim et al. [5,6], such as flaring reduction, energy and process integration, as well as re-wheeling of turbomachinery components. de Oliveira Jr. and van Hombeeck [7] proposed to focus on the plant energy integration, focusing on the separation sub-system. Voldsund et al. [8] and Nguyen et al. [9] suggested to analyse the possibility of reducing anti-surge recirculation, reducing losses in the manifolds and increasing the compressors efficiency, as significant power savings could be achieved. Subsequent work [10] pinpointed the same findings for two other platforms, although the system configurations were highly different. Nguyen et al. [11] extended their studies to include the utility plants, showing that about 55 to 60 % of the performance losses take place in the gas turbines, but that they are unavoidable. On the contrary, those taking place in the oil separation and gas compression operations could be reduced by exploiting high-energy streams, but they require changes in the system set-up, replacement of existing components or addition of other processes. Cassetti and Colombo [12] evaluated the costs associated with each performance loss within the separation process of an oil platform, and they suggested to pay attention to the heat generation and transfer processes.

The second possibility is to improve the energy conversion processes, by converting the existing gas turbines and furnaces into cogeneration plants, importing electricity from the shore, or replacing the existing gas turbines by smaller - and more efficient - ones, if possible.

Combined cycle power plants with steam cycles were installed on the Oseberg, Snorre and Eldfisk fields [13,14]. These few examples illustrate that the integration of such plants is uncommon because of stringent weight and space constraints, although large fuel savings and reductions of environmental pollutants are achieved. Designs with once-through heat recovery steam generators may be of interest for offshore combined cycle, as they present a lower weight than conventional combined cycles, with the benefits of additional flexibility to changes in demand for mechanical and electrical power [15,16]. Proper integration with the processing plant is pointed to be crucial for avoiding improper configurations of the steam cycle [17].

The installation of alternative power systems such as organic Rankine cycles was discussed in subsequent works. Pierobon et al. [18] conducted a multi-objective optimisation for designing ORCs in offshore conditions, aiming at minimising the weight of the bottoming cycle while maximising the reductions in CO_2-emissions. Mazzetti et al. [19,20] analysed as well alternative working fluids such as carbon dioxide, and they claimed that CO_2-cycles may be much less space-demanding for similar efficiencies and capacities. CO_2-cycles were analysed thoroughly in Walnum et al. [21] where the performance of these cycles was evaluated at reduced gas turbine loads, and in Skaugen et al. [22], where process optimisations were conducted for designing a compact and light cycle under a set of practical constraints. Barrera et al. [23] analysed the impacts of varying water, gas and oil flows, and their results suggest that the amounts of injected gas and water have a strong impact on the power output of these cycles.

Downsizing the existing gas turbines or removing the redundant ones, as proposed by Mazzetti et al. [24], may also be relevant, as this would result in a reduction in fuel consumption without additional weight and volume on-site. As mentioned in Nguyen et al. [25], electrifying the platform may be beneficial both from an energy and environmental perspective, since the onshore power plants generally have a higher efficiency than offshore ones, because they are often natural gas combined cycles or renewable plants.

The present work aims to cover and compare all these energy efficiency measures, based on four actual facilities which were investigated as well in Voldsund et al. [10]. This work considers the main components and sub-systems of an offshore plant, from the production manifolds to the gas compression operations, including the power generation system. Utilities such as air conditioning and operations such as drilling are excluded from the analysis. The objectives of this work are to (i) evaluate the prospects and challenges associated with each energy efficiency effort, (ii) assess the differences in terms of energy savings when comparing different facilities, (iii) pinpointing the benefits and limitations of each measure in practice, using thermodynamic, economic and environmental criteria.

The present paper is part of a larger project dealing with the modelling and analysis of oil and gas producing platforms and is a continuation of the work presented in Nguyen et al. [26]. It builds on previous works conducted by the same authors and is structured as follows. Section 2 describes the system of interest in this work, and on the similarities and differences between the four cases. The improvements investigated in this study are presented further, together with the benefits achieved for each platform, with respect to the processing (Section 3) and power (Section 4) plants, and are followed by concluding remarks in Section 5.

2. System description

2.1. General design

Oil and gas offshore platforms present similar structural designs (Figure 1) that include separation, compression and pumping operations, but process fluids with different thermophysical and chemical properties. The field characteristics and export specifications differ from one platform to another, and these singularities result in different system configurations, operating conditions and strategies. For example, the limitations on the maximum water content allowable in the exported gas streams are more stringent in the Gulf of Mexico, which explains why a dehydration process is commonly installed on the platforms located in these areas. These differences are also relevant for the cases investigated in this work.

A typical oil and gas platform consists of two main sub-systems: a processing plant, in which which oil, gas and water are processed, separated, and rejected (water), exported (oil and gas), and possibly injected back into the reservoir (water and gas); a power plant, where a fraction of the gas that is extracted on-site is consumed in gas turbines to produce the power and heat required in the processing plant. In some cases, the power demand is satisfied by importing power from the shore (electrification) [27].

Petroleum is extracted through different wells and processed on-site through production manifolds operating at different pressure levels to ensure optimum production and recovery rates depending on the field conditions. Oil, gas and water are then separated by gravity in a certain number of stages operating at different pressure and temperature levels, in the separation train. The water recovered from the phase separators is then cleaned and discharged/injected, while the oil at low pressure is pumped in an oil treatment section, for further export. Recovered gas is then cooled, scrubbed and compressed in one to several stages to the initial feed pressure, in a recompression section. It is then compressed, if necessary, to the required export or injection pressure, and possibly dehydrated or cleaned in the gas treatment section.

2.2. Case studies

The present work deals with the analysis of four actual platforms located in Norway, operating in the North Sea, with the exception of Platform D, which operates in the Norwegian Sea. The most important flowrates and operating conditions are presented in Table 1 while the process flowsheets are shown in Appendix A.

Platform A has been in operation for about 20 years (Figure A.10), produces oil, injects gas for pressure maintenance, and discharges water into the sea. The field is characterised by a high gas-to-oil ratio (2800), high feed temperatures (80–87 °C) and pressures (88–165 bar). The power demand is about 25 MW, while the heating demand is smaller than 1 MW.

Platform B has been in operation for about 10 years (Figure A.11), produces gas and condensate, and disposes water in another reservoir. The field is characterised by a very high gas-to-oil ratio (3200), high feed temperatures (64–111 °C) and pressures (123–155 bar). The power demand is the smallest of all case studies (5.5 MW), as gas is separated and exported at moderate pressures, while the heating requirements are negligible, as for Platform A.

Platform C has been in production for about 10 years (Figure A.12), processes heavy oil and gas, where the term heavy refers to the high density and viscosity of the crude oil. Gas is injected back into the reservoir and produced water is discharged. At the year of study, gas was also imported for further injection to stimulate the oil production. The power demand reaches approximately 30 MW and the heating needs exceed 10 MW. Heat is recovered from the exhausts of the gas turbines and transferred via means of a hot water loop at high pressure.

Platform D has been in operation for about 20 years (Figure A.13), produces volatile oil and gas, and the produced water is injected for oil recovery. The petroleum has a low content in heavy hydrocarbons but has a propane content of nearly 9 % in volume. The power demand is about 19 MW in normal production days,

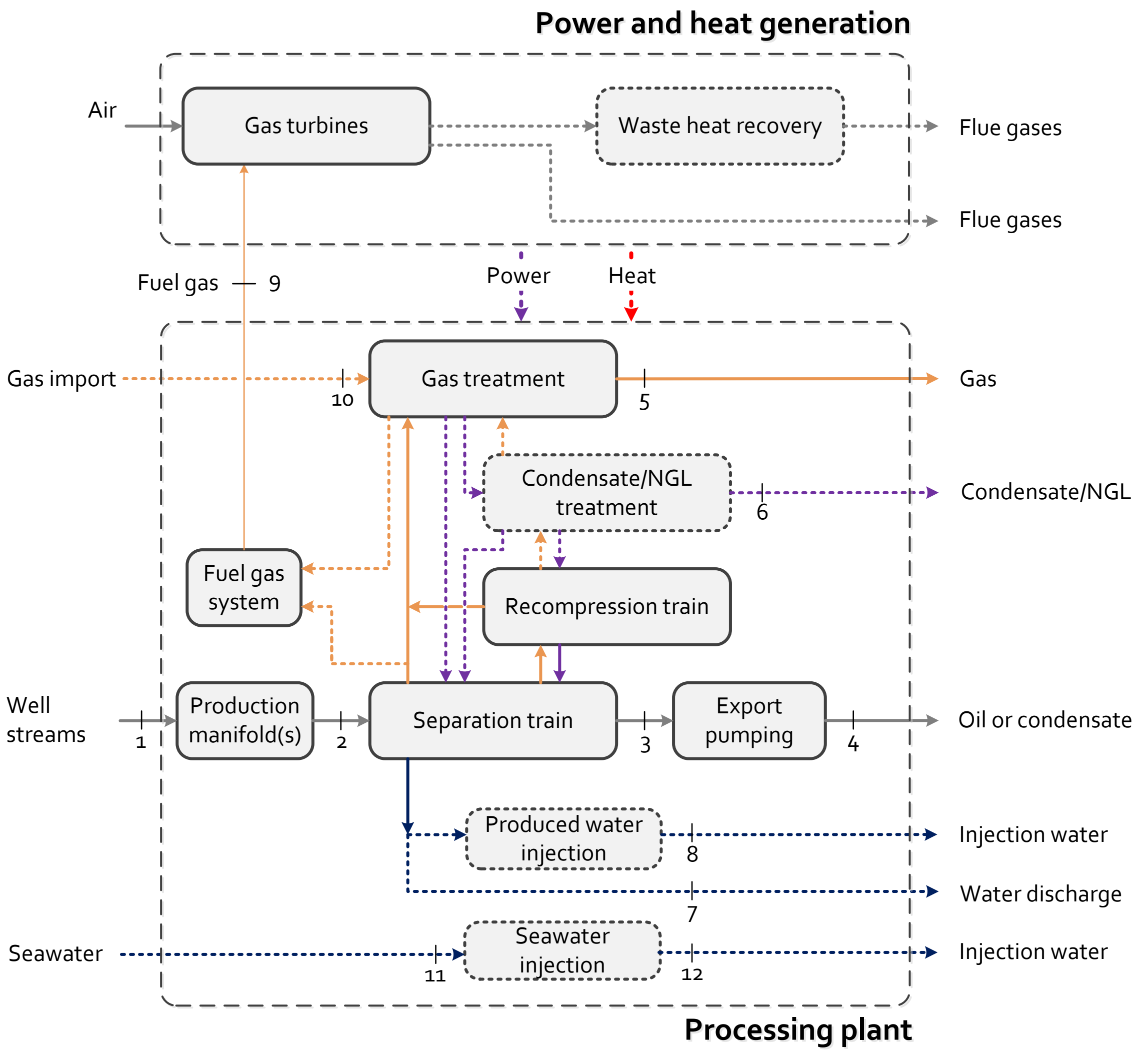


Figure 1: General system overview of an oil and gas platform. Arrows represent one to several streams while block represent different subsystems. Solid lines indicate that the corresponding stream or process is present for all the studied platforms and can generally be found on all typical oil and gas facilities, while dotted ones denote flows or sections that are more uncommon.

while the heating demand is about 5 MW. Heat is also recovered from the turbine exhausts and transferred using a hot glycol loop.

2.3. System modelling

The measurements were taken for a 'normal' production day and are presented in further details in Voldsund et al. [28] for Platform A, Voldsund et al. [10] for Platforms B and C, and in Nguyen et al. [9] for Platform D. The present analysis was built on a compilation of (i) system information received from the platform databases, given for a single time point, or on a hourly to daily basis, (ii) fiscal declarations to the Norwegian Petroleum Directorate, (iii) assumptions based on the authors' experience, discussed with field experts, and (iv) data compiled from process flowcharts and literature. The models were developed with the commercial flowsheeting software Aspen Plus [29], version 7.2, based on the Peng-Robinson [30], Redlich-Kwong with Soave modifications [31–33] (oil and gas processing) and the Schwartzentruber-Renon [34] (gas

Table 1: Pressures and temperatures in the oil- and gas processing of the studied oil and gas platforms. The stream numbers refer to Figure 1.

Stream number	Platform A		Platform B		Platform C		Platform D	
(type)	p [bar]	T [°C]	p [bar]	T [°C]	p [bar]	T [°C]	p [bar]	T [°C]
1 (reservoir fluids)	88–165	80–87	123–155	64–111	13–111	51–72	15–187	55–74
					46[a]	62[a]		49–67
2 (reservoir fluids)	70	74	120	106	7[b]	69[b]	8	63[b]
					13[c]	63[c]		
3 (oil/condensate)	2.8	55	2.4	62	2.7	97	1.7	45–55
4 (oil/condensate)	32	50	107	56	99	76	19	61–68
5 (treated gas)	236	78	118	35	184	75	179	81
6 (condensate)	-	-	-	-	-	-	179	68
7 (discharged water)	9	73	-	-	7.2	71	1.3	55
8 (injection water)	-	-	61	78	-	-	-	-
9 (fuel gas)	18	54	37	50	39	61	21	59
10 (gas import)	-	-	-	-	110	4.4	-	-
11 (inlet seawater)	-	-	-	-	-	-	1	8
12 (injection seawater)	-	-	-	-	-	-	127–147	57

[a]From high pressure manifold
[b]From low pressure manifold
[c]From test manifold

dehydration) equations of state.

2.4. Performance analysis

The performance of each plant is analysed based on thermodynamic assessment tools. The aims are to (i) map the energy flows, (ii) assess the system inefficiencies, by locating and quantifying the potentials for improvements, and (iii) investigate process integration opportunities, by identifying the main energy users, sources and sinks. Thermodynamic analyses were performed previously by the same authors (see e.g. Refs. [10] and [11]), and the reader is referred to the textbook of Kotas [35] for a detailed introduction to these methods. The main findings are recalled as follows:

- most energy and exergy input to an offshore platform corresponds to the petroleum flows extracted through the wells;
- most energy and exergy output is associated with the streams of oil and gas for export and injection;
- the exergy consumption of a platform differs from one facility to another, from as low as 30 MW (Platform B) to 110 MW (Platform A);
- the power demand of the processing plant ranges from 5.5 MW (Platform B) to 30 MW (Platform C);
- the heating needs, on an exergy basis, can be close to null (Platforms A and B) or reach up to 7 MW (Platform C);
- the exergy destroyed in the *processing plant* is comprised between 11 MW (Platform B) to 22 MW (Platform C);
- the exergy destroyed in the *power plant* is generally greater because of the irreversibilities associated with the combustion phenomena, but is as well unavoidable.

Hence, the focus of this work is on the evaluation of the following design changes: (i) introduction of an additional pressure level in the production manifolds; (ii) implementation of multiphase expanders instead of expansion valves; (iii) limitation of the gas recirculation around the compressors, by installing parallel trains or rewheeling; (iv) promotion of process and energy integration; (v) exploitation of low-temperature heat ($\leq 100\,°C$) from the gas intercooling and aftercooling steps; (vi) downsizing or replacement of the gas turbines; and (vii) valorisation of the high-temperature waste heat ($\geq 300\,°C$) from the turbine exhausts. These suggestions for process modifications are not relevant for all case studies (Table 2) - the points (i)–(v), which are related to changes of the processing plant, are presented in Section 3, while the points (vi)–(vii), which are related to modifications of the power plant, are described in Section 4.

Table 2: Investigated improvement scenarios for the four offshore platforms presented in this research. A symbol ✓ means that the proposed improvement is relevant and investigated, a symbol ✦ means that the proposed improvement is pertinent but not considered in this work because of missing data, and a symbol ✗ means that the proposed improvement is neither relevant nor studied.

	Platform A	Platform B	Platform C	Platform D
Multi-level production manifold	✗	✗	✓	✗
Multi-phase flow expanders	✓	✓	✓	✓
Reduction of anti-surge recirculation	✓	✓	✓	✓
Energy integration	✓	✓	✓	✓
Low-temperature waste heat recovery	✦	✓	✦	✓
Downsizing of the gas turbines	✦	✦	✦	✓
High-temperature waste heat recovery	✦	✦	✓	✓

3. Processing plant

3.1. Multi-level production manifold

3.1.1. Approach

The integration of an additional pressure level in the production manifolds can allow for extracting and processing gas at a higher pressure level, which would result in a lower power demand of the gas compression section. A smaller amount of gas would be recovered at lower pressures, and therefore smaller amounts of heavy hydrocarbons would be carried over in the gas streams from the separation section. Such a retrofit is relevant only for platforms with a large number of producing wells, which excludes Platform A, with a high power demand of the gas compression process, which excludes Platform B, and where the reservoir fluid is extracted over a large range of pressures, which excludes Platform D. In the case of Platform C (Figure 2), a large number of processing wells (10) are producing at a pressure higher than the second stage of the gas treatment (94 bar), and the gas fraction of the reservoir fluids extracted through these wells is above 30 %.

However, the introduction of an additional pressure level is relevant only with another control strategy of the compressors on-site, or alternatively with re-wheeling or downsizing of these components. At present, gas is recirculated around the compressors to prevent surge, which implies that the power consumption is nearly constant. An additional pressure level in the production manifold involves smaller gas flows in the gas recompression train, and it is thus necessary to downsize the corresponding compressors, or to evaluate possibilities for avoiding gas recirculation.

The benefits of the scenarios proposed as follows are therefore evaluated against a *baseline* scenario where no gas is recirculated. The first improvement scenario assumes (Scenario 1) that the separation pressures are fixed and cannot be optimised. In this case, the very high pressure manifold should operate at the pressure of the 2nd stage of the gas treatment section, i.e. at least at 93 bar, and 10 wells may be rerouted. The second improvement scenario (Scenario 2) assumes that the separation and production manifold pressures can be adjusted. In that case, all the wells currently connected to the high pressure manifold can be rerouted, and the compressors at the last recompression and first gas treatment stages should be retrofitted. Scenario 2 is reformulated as an optimisation problem, for which the decision variables are the production manifold pressures, and the objectives the minimisation of the total power consumption, and the maximisation of the oil and gas recoveries.

The two last parameters are evaluated by calculating the fractions of the light r_{LIG} and heavy r_{HEA} hydrocarbons contained in the feed that are carried with the produced gas and oil streams, considering that

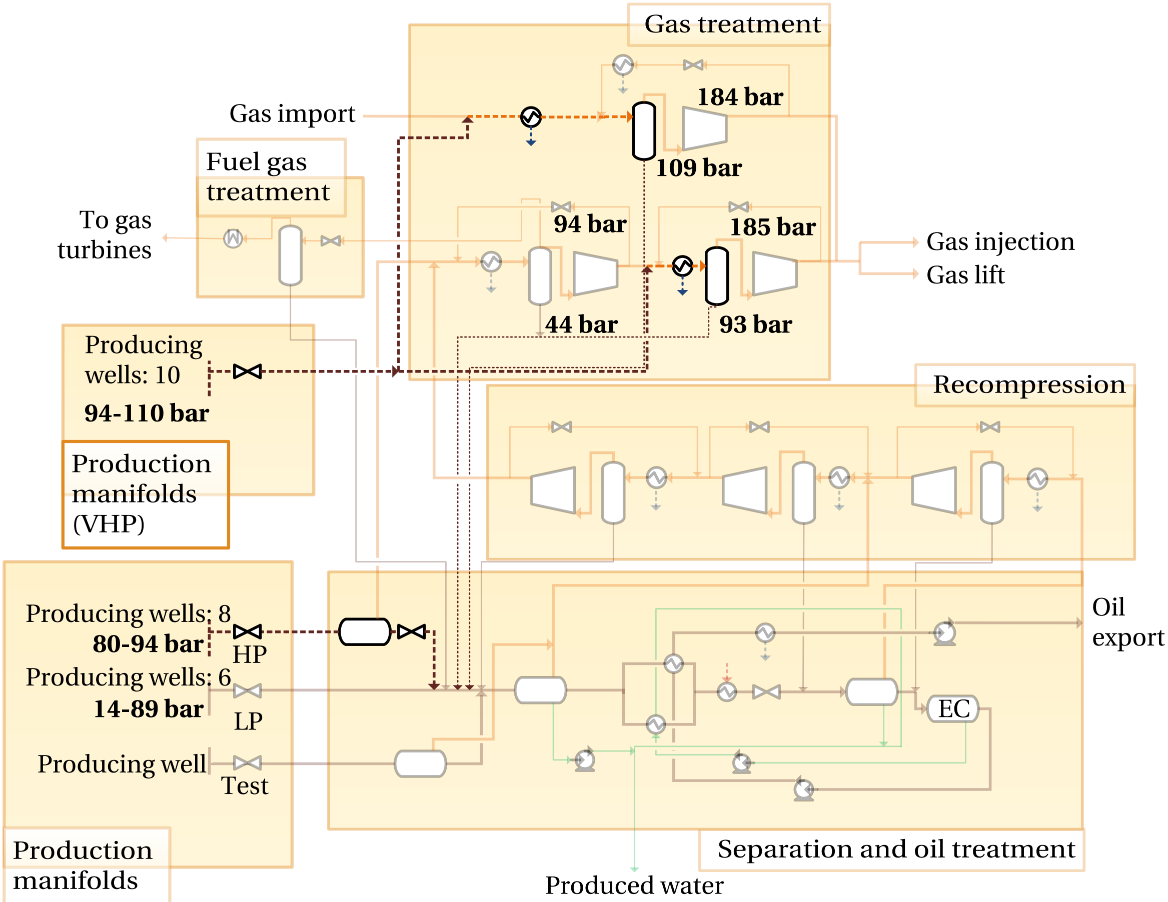


Figure 2: Schematics of the proposed retrofit of Platform C with a very high pressure (VHP) manifold.

propane should rather be placed in the gas flow, and butanes in the liquid throughout. The thermodynamic performance is assessed with the total power consumption $\dot{W}$ of the oil and gas processing plant. The factors presented above are clearly competing, as a greater recovery of light hydrocarbons would result in smaller recovery of heavy ones, and higher power consumption. A multi-objective optimisation is performed applying a a genetic algorithm developed by Leyland [36] and Molyneaux [37]. The results are displayed as a Pareto-frontier [38], which illustrates the trade-offs between the three conflicting objectives: each solution on this front cannot be improved with respect to one objective without a worse-off of another objective. The decision variables correspond to the pressures of each level of the production manifolds, which can vary in a range of 1.7 bar to the highest well pressure.

3.1.2. Findings

Scenario 1. The introduction of a VHP level at a pressure of 93.9 bar results in a net power saving of 1.7 MW. The recovery of medium- and heavy-weight hydrocarbons into the oil stream is nearly identical. However, the recovery of light-hydrocarbons is slightly worse, by 0.2 %-point, because more methane and ethane are entrained with the liquid condensate recovered in the high-pressure scrubber of the last compression stage.

Scenario 2. Greater power savings can be achieved if the pressure levels of the VHP and HP production manifolds can be optimised (Figure 3), with a reduction of the power consumption from an original value of about 30 MW to only 17 if anti-surge recirculation can be limited as well. The Pareto fronts indicate that the optimal gas and oil recoveries vary in a range of 0.5 %, while the total power consumption varies between 17,000 to 26,500 kW.

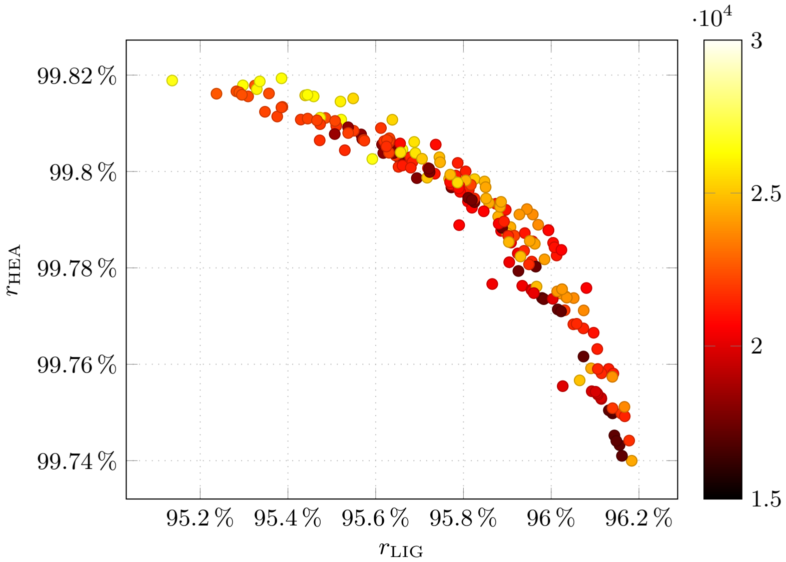


Figure 3: Pareto-optimal solutions for an integrated design of production manifolds with an additional pressure level (VHP) in the case of Platform C. The colour bar illustrates the power consumption of each solution, expressed in kW.

The decision on allocating a given well to the very-high pressure manifolds depends obviously on the well pressure. For example, the 15th well should rather be connected to the HP level because of its low inlet pressure (65.4 bar), whilst the 19th well should preferably be linked to the VHP level because of its high inlet pressure (83.7 bar).

However, the initial oil, gas and water contents of each feed stream have an importance, as suggested with the case of the 26th well. The associated flow has a high pressure, of about 94 bar, but should optimally be placed on the HP level because of the high liquid throughout (oil production of 20.6 Sm^3/h). The resulting flow at the inlet of the 2nd stage compression level in the gas treatment section (which corresponds to the 5th compression level for the whole platform) would then have a higher content of water and heavy hydrocarbons than desired, which would cause greater power consumption.

The optimum pressure levels, with respect to the maximisation of the oil and gas production, as well as the minimisation of the power consumption, range between 15 and 44 bar for the high-pressure level, and between 34 and 78 bar for the VHP one. However, the recoveries of light and heavy hydrocarbons vary only in a range of 0.1 % over the whole optimisation domain, and the results indicate that the optimal pressure levels for minimising the total power consumption to around 17 MW, are of 16 and 40 bar. The suggested VHP level is in the same order of magnitude as the HP level in the current situation (as of 2012), and the proposed HP level is about 8 to 10 bar higher than the LP one.

3.1.3. Discussion

The operation of *multiple operation levels* in the production manifolds may result in significant energy savings if the pressure levels and well allocations are selected adequately to minimise the power consumption of the processing plant, while ensuring high recoveries of light and heavy hydrocarbons in the gas and oil streams, respectively. Processing the feed streams at different levels is commonly done on offshore platforms, and implementing an additional one may not face strong technical issues. A drawback would be the higher loading of the cooler and separator operating on the stage at which the additional pressure manifold would be connected, as well as the greater system complexity. Such an improvement is more easily implemented in grassroot designs, when the field pressures are the highest. It can also be performed in retrofit situations, but it is then important to ensure that an extra pressure level will not result in additional power consumption of the low-pressure compressors due to higher anti-surge gas recirculation.

3.2. Multiphase flow expanders

3.2.1. Approach

Feed streams from the production manifolds may have a high energy content, if the exploited fields are characterised by high temperatures and pressures, and that the feeds have a high gas content. The use of multiphase flow expanders could result in additional power production, while the implementation of multiphase flow ejectors could enhance higher oil recovery in depleted wells, which is of particular interest for mature oil fields. These components may replace the existing multiphase valves installed in the production manifold and separation sections. The cases of Platforms A and B are considered, since they both have increasing gas-to-oil ratios, which exceed 2500 for both, while the gas-to-oil ratios of the Platforms C and D are much lower.

Estimating the efficiency of multiphase flow expanders is challenging, as there are no practical examples of such applications in oil and gas processing. Hydraulic expanders and turbines are well-known technologies with hydraulic efficiencies exceeding 90 %, but the current literature suggests that the performance of multiphase expanders, using two-phase helico-axial ones, is comprised between 30 and 70 %, depending on the initial feed pressure [39–41]. Since the inlet feed pressures range between 70 and 130 bar, the hydraulic efficiency may be, with the current state-of-the-art technologies, closer to the lower bound.

3.2.2. Findings

A preliminary analysis suggests that energy could efficiently be recovered with such technologies. If the valves present in the production manifold are substituted with multiphase expanders, the power production would represent about 6.5 and 16 % of the total power consumption of Platforms A and B, assuming an efficiency of 30 %. The temperature at the expander outlets would be about 3 to 5 °C lower than in the current situation, with a drop of the vapour fraction of less than 5 %. These differences would impact to a minor extent the downstream separation and recompression sections, because more gas would be recovered in the low-pressure stages.

As for the production manifold, the introduction of multiphase expanders between each separation stage may be considered, though with smaller benefits. Smaller liquid flows are processed and they generally have lower temperatures and pressures than the reservoir fluid streams entering the separation section. A preliminary analysis indicates that the power recovered at the 1st separation stage represents about 11 and 30 % of the power output of the multiphase expanders that could be integrated in the production manifolds of Platforms A and B.

3.2.3. Discussion

The implementation of *multiphase flow expanders* can be interesting for power generation purposes, but is relevant only for fields processing high-temperature and high-pressure feeds, with a high gas fraction. However, the production of oil, gas and water varies significantly over a field lifetime. An expander designed for early or plateau production phases, so when the water extraction is at its minimum, may become particularly inefficient when the field enters its end-life conditions, and may therefore be replaced by a smaller one. Another issue is that the reservoir fluids may contain significant amounts of impurities and sand, and the possible erosion issues complicate the designing task.

3.3. Reduction of anti-surge recirculation

3.3.1. Approach

Gas recirculation around the compressors causes additional power and cooling demands, since the gas flows in the compressors and heat exchangers are kept constant to prevent surge. At present, the anti-surge recycling rates represent up to 92, 34, 41 and 75 % for the compressors of the recompression train for Platforms A–D, and up to 22 and 35 % for the compressors in the gas treatment section for Platforms C and D. Avoiding gas recirculation may therefore be an interesting alternative for increasing the amount of gas exported to the shore, increasing the operational benefits, reducing the power consumption and exergy destruction in the expansion processes.

When designing a new offshore compression train, it may be interesting to implement compressors that exhibit an acceptable efficiency when they are operated at their maximum capacity and at part-load conditions, rather than ones that present a high efficiency at their design point only. The possibility of designing smaller but parallel trains, to delay the start of off-design operations, may likewise be considered. All trains would be run close to their maximum capacity in peak production; when the production starts declining, the gas flows would be split to ensure proper loading of each compression line, and a train may be shut down at a later point, when the gas extraction drops sharply. Preliminary simulations are conducted in this work to estimate the potential benefits of such solutions, assuming that the gas compressors display an efficiency equivalent to the current ones. Finally, tuning of the compressor anti-surge controls may be investigated in details if relevant, as previous studies within this topic have shown promising reductions in power and fuel gas consumption for a North Sea field [42].

3.3.2. Findings

The power consumption of the entire processing plant decreases by 15 to 20 % and the greatest reduction is observed for the platforms that operate the furthest from their nominal point, such as Platform D, since more gas is recirculated to prevent surge. The cooling demand of the entire processing plant decreases by more than 10 % for Platforms A, C and D (Figure 4). The potential savings are smaller for Platform B, because the major cooling demand, of about 45 MW, corresponds to the gas aftercooling before export. This demand is not impacted by the gas recirculation rates, since there is no compressor operating in the gas treatment section of this platform, and the power consumption is nearly constant.

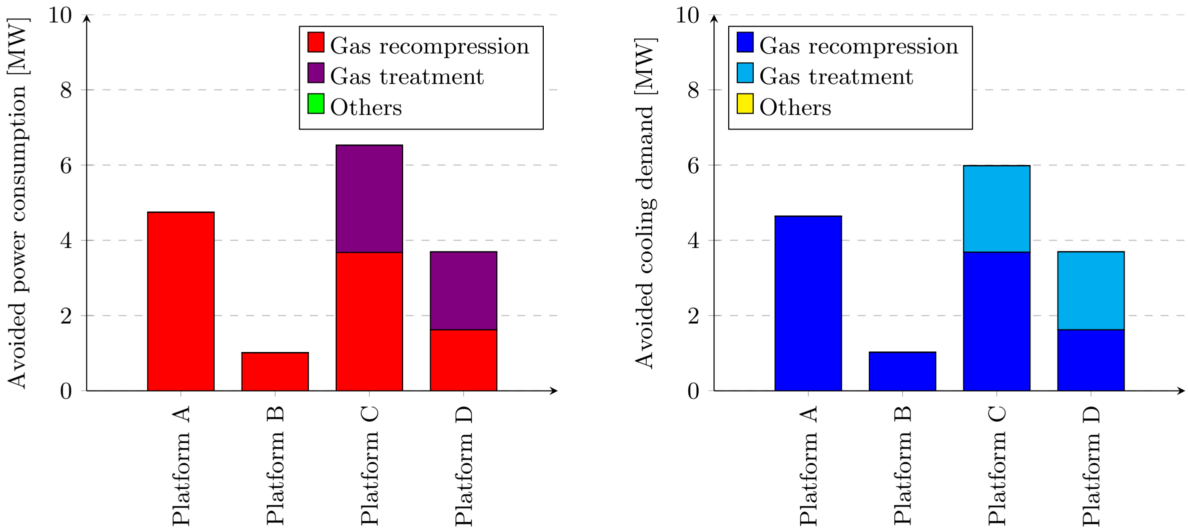


Figure 4: Avoided power and cooling demands if no anti-surge recirculation.

In addition, less recycling results in less exergy destruction (Figure 5) because of (i) the elimination of the pressure losses through the anti-surge control valves, (ii) the smaller exergy destruction by heat transfer in the coolers, and (iii) the smaller exergy destruction in the compression process. The first reduction amounts to about 1600, 450, 1700 and 2000 kW, which corresponds to a decrease of 8.3, 3.8, 7.4 and 14.8 % for the four platforms. The sums of the second and third ones are roughly equal to the first ones. The reductions in exergy destruction due to smaller mixing effects represent less than 50 kW per stage.

3.3.3. Discussion

Limiting *anti-surge recirculation* shows to be beneficial over the field lifetime because of the smaller power demand when the field reaches its end-life. However, this can only be achieved by (i) operating several and

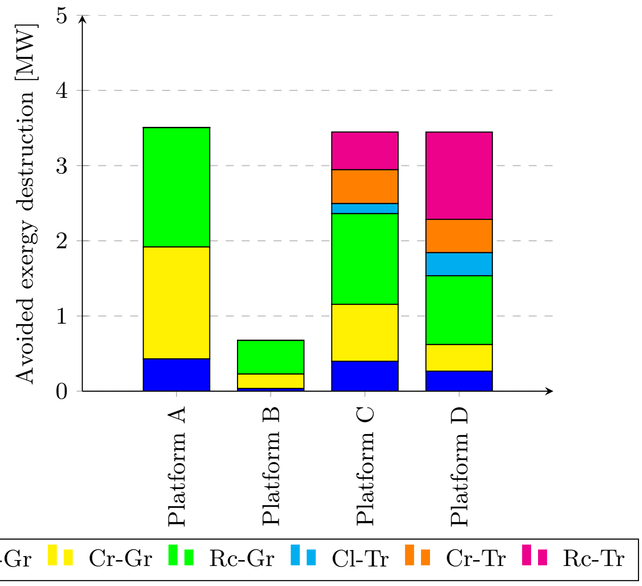


Figure 5: Absolute changes in exergy destruction if no anti-surge recirculation. The acronyms Cl, Cr and Rc stand for coolers, compressors and recycle, while Gr and Tr denote the recompression and treatment processes.

parallel compression trains, which implies that additional space is required on the platform, and that more weight will be present, (ii) re-wheeling the compressors or implementing smaller ones when the production of oil and gas falls under a certain level, which implies additional maintenance operations and extra costs, (iii) tuning the control system, which may not be feasible depending on the plant.

3.4. Energy integration

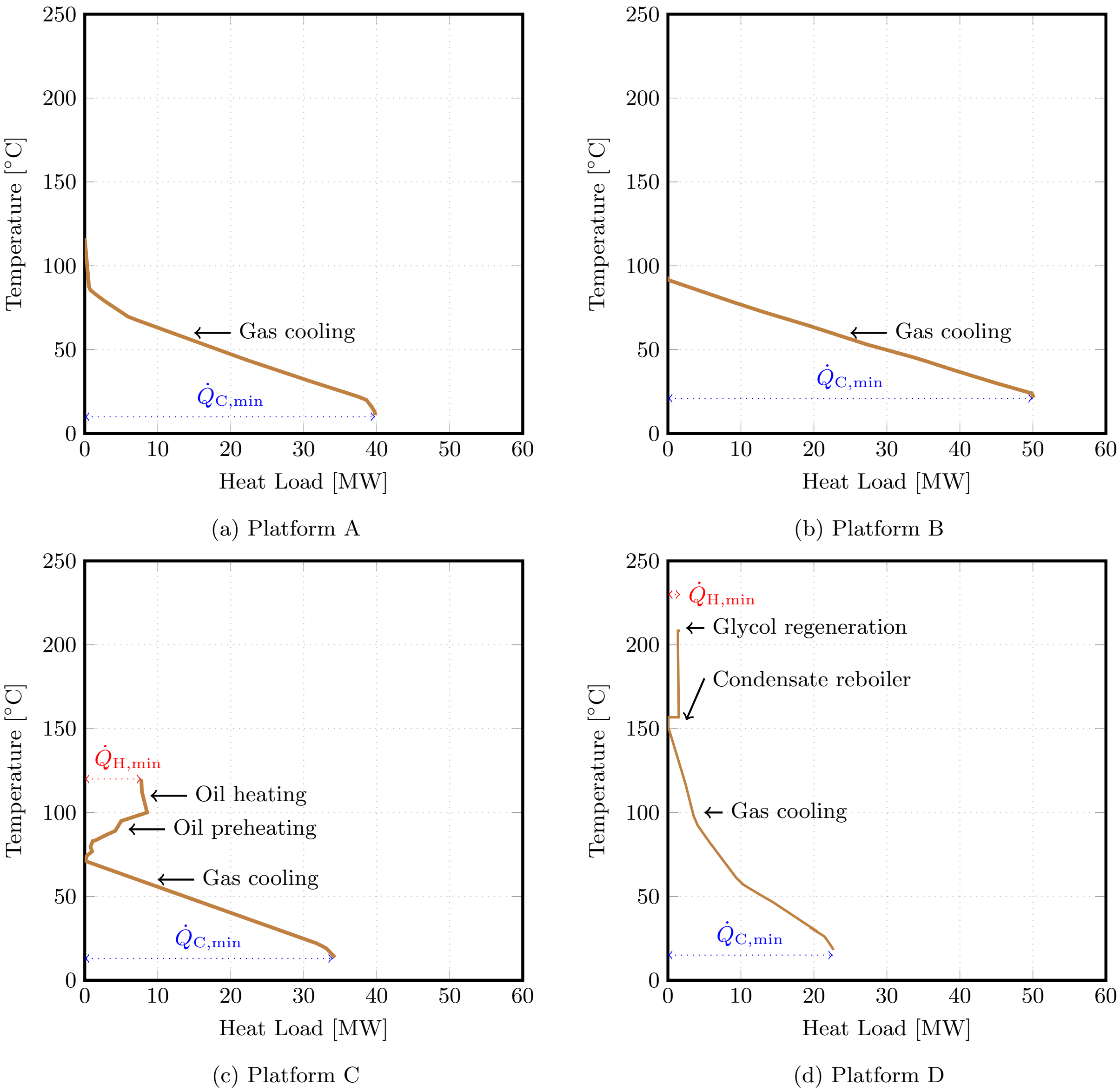
3.4.1. Approach

Process integration techniques aim at minimising the energy use of a given system by promoting internal heat exchanges and improving the integration of each individual process with the hot and cold external utilities. Higher energy recovery could result in a smaller demand for external cooling, therefore decreasing the power consumption associated with the seawater lift operations, while a better match between the temperature profiles of the processing and utility plants could open possibilities for cogeneration. The assessment of the system energy requirements builds on the pinch analysis concept, which is presented in details in Smith [43] and was introduced by Linnhoff [44]. The minimum and individual temperature differences (annotated $\frac{\Delta T}{2}$ in the literature) were taken to 2, 4 and 8 °C for phase-changing, liquid and gaseous streams.

3.4.2. Findings

A pinch analysis of each individual sub-system shows that some processes such as the oil separation or the condensate treatment require heating or cooling, while others such as the gas treatment and oil pumping only have a cooling demand (Figure 6). The interest of the total site integration lies in the matching between the heating demands of a given sub-system with the cooling needs of another one. The heat-temperature profiles of each plant show that most cooling demand takes place at low temperatures and results from the gas cooling processes prior to each compression step. The heating demand is much smaller than the cooling demand for all platforms and is significant for Platform C because of the need for heating the viscous petroleum feed.

The benefits of such improvements can be observed by comparing the external utility demands resulting from the integration of each sub-system individually to an improved scenario, where the overall site is



(a) Platform A

(b) Platform B

(c) Platform C

(d) Platform D

Figure 6: Grand Composite Curves of four North Sea offshore platforms.

integrated (Figure 7). The benefits are minor for Platforms A and B because of the negligible heating demands, which are satisfied by either electrical heating or small energy recovery.

Improving the integration of the current site is particularly relevant for Platforms C and D (Figure 8), but this may be challenging for geographical and operational reasons. The site profiles show that all the site cooling demand takes place at temperatures lower than 120 °C, which is the temperature of the oil heating process. The integration of gas-oil heat exchangers faces two issues. First, all the gas streams should be cooled down to 20–50 °C, and the oil stream has an initial temperature of 45–55 °C. The gas streams should therefore be cooled in two steps, by first exchanging heat with the oil, and then with cooling water. Secondly, the oil stream cannot be heated by only one gas stream, as the heating demand for the oil can reach up to 12 MW, while the cooling demand for each individual gas stream does not exceed 4 MW.

In practice, direct heat exchange between the process streams may not be feasible for operational reasons,

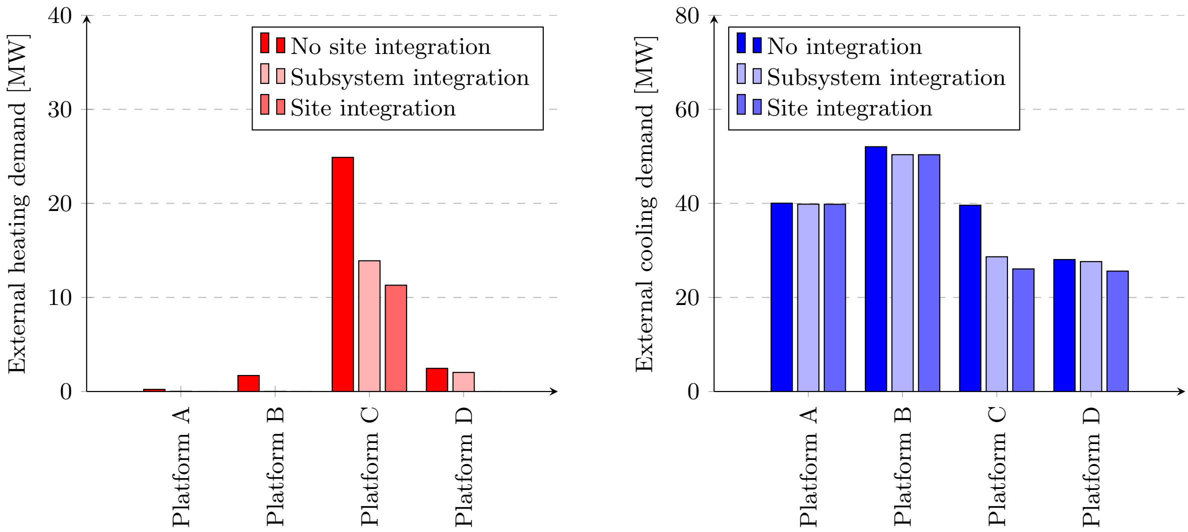


Figure 7: External utility demands without integration, with subsystem integration and with site integration.

and a central utility system may be used, such as a cold water loop. In this case, the potential for heat recovery is limited to less than 2 to 3 MW. However, the use of a central utility system is not beneficial from a process integration perspective, because (i) most heating demands take place at temperatures higher than the temperature of the cooling water utility system; (ii) most cooling demands take place at temperature lower than the temperature of the hot glycol utility system; (iii) two temperature differences should be considered: from the heat source (e.g. hot gas) to the utility stream (e.g. hot water), and from the utility stream to the heat sink (e.g. cold oil). The present findings illustrate therefore that improving the energy integration of these facilities is challenging despite the large temperature gaps between some hot and cold streams because of operational issues.

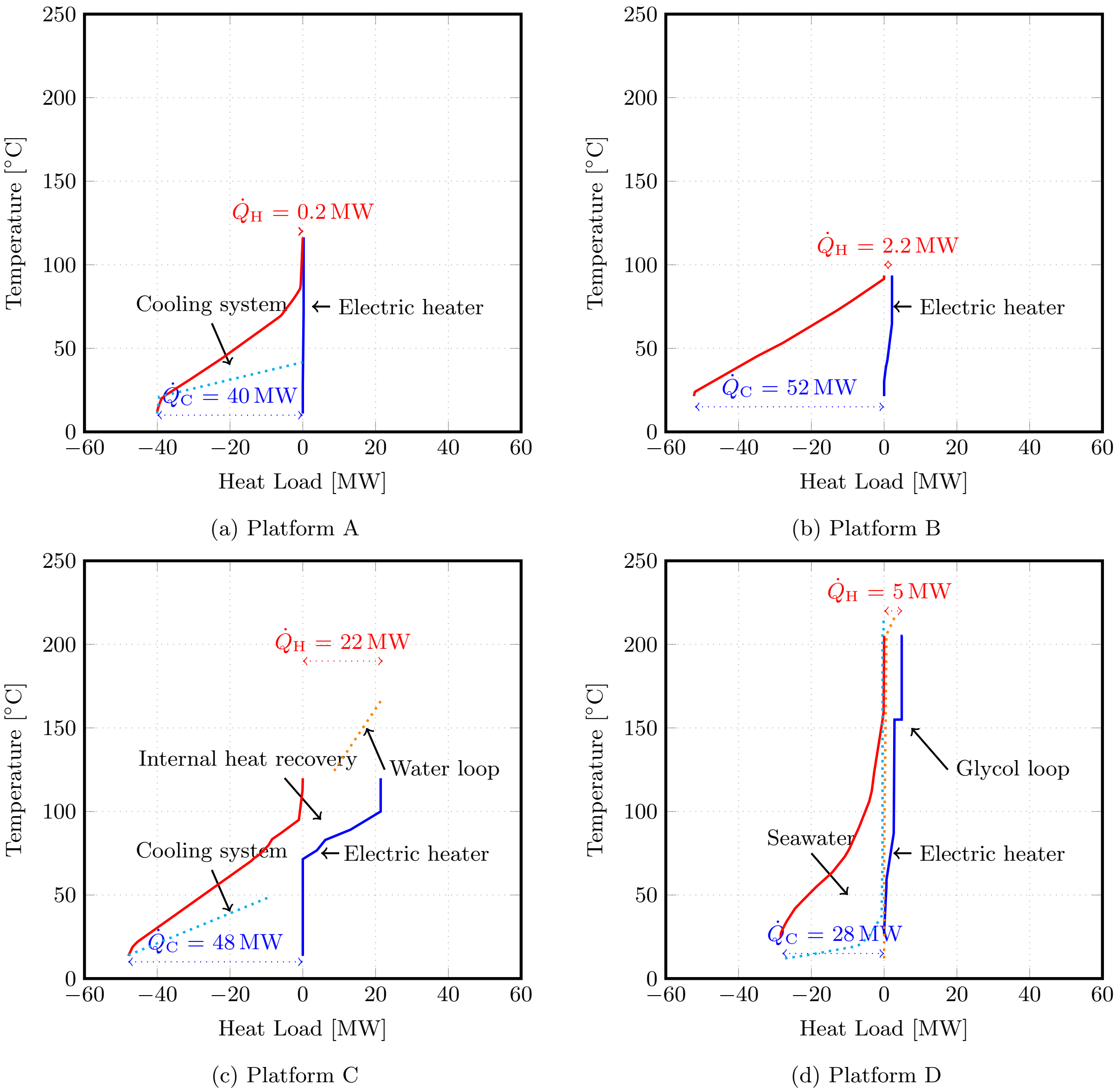
3.4.3. Discussion

Higher degree of *system integration* presents clear benefits with respect to fuel consumption, energy use and environmental impacts, especially if the heating and cooling demands of the process streams can be matched. The implementation of internal heat exchangers is not uncommon, with the examples of oil-oil or oil-condensate heat exchangers in the separation processes. However, a too close integration may be problematic in case of system failure or too large variations of the production flows with respect to the equipment design points. It is therefore necessary, in such cases, to ensure that a backup solution is present on-site or that redundant equipment are installed to accommodate fluctuations of the oil, gas and water flows, temperatures and pressures.

3.5. Waste heat recovery

3.5.1. Approach

Waste heat is available at low temperatures from the gas recompression and treatment sections, because gas is cooled at each compression stage (intercooling) or after the last step before export (aftercooling), to reduce the power demand of the processing plant, to improve the dehydration process, and to avoid too high temperatures at the pipeline inlets. The implementation of low-temperature cycles is discussed only for Platforms B and D, since gas needs to be cooled prior to export, while it is used only for lift and field injection on Platforms A and C. Steam Rankine cycles are not relevant in such cases because heat is available at too low temperatures, and organic Rankine cycles operating with the working fluids presented in the study of Rohde et al. [45] (e.g. propane, carbon dioxide, ethane-propane mixture) are considered instead.



(a) Platform A

(b) Platform B

(c) Platform C

(d) Platform D

Figure 8: Total site profiles of four North Sea offshore platforms. The solid and dotted lines correspond to the heat-temperature profiles of the process and utility streams, respectively.

3.5.2. Findings

Platform B. The quantity of heat discharged in the gas aftercooler for Platform B currently exceeds 40 MW, and the results suggest that the most efficient solution is to implement a bottoming organic Rankine cycle with a mixture of ethane and propane operating in transcritical conditions. The performance of the low-temperature power cycle is directly correlated to a few design parameters, such as the condensation and production levels, the temperature after superheating and the ethane fraction. More than 2.5 MW of power can be produced, which represents more than half of the total power consumption (5.5 MW) of the processing plant. The thermal efficiency of this organic Rankine cycle is particularly low, because the gas temperature is around 100 °C at the aftercooler inlet and should be reduced to about 32 °C to satisfy the pipeline export specifications. These requirements restrict severely the evaporation level on the organic fluid side and the maximum power output.

Platform D. As for Platform B, the most effective solution is the integration of ORCs with a hydrocarbon mixture. Although these cycles display a thermal efficiency as low as 10 %, 1.5 to 3.5 MW can be generated, depending on the rate of the produced gas. The optimal low-temperature power cycles operate between 20 °C and 170 °C and recover heat from the gas streams in the treatment process prior to each compression stage. However, the design of such a cycle is challenging and costly, as the working fluid should be evaporated and superheated in several heat exchangers. A more cost-efficient alternative is to utilise the waste heat from one single hot stream as done for Platform B, using the heat from the gas to be exported in the final heat exchanger. The system would then be relatively compact and light, including only four components. The cycle should then operate between 23 °C (19.5 bar) and 144 °C (56 bar) and can provide a net supplement of power of 590 kW, which corresponds to a thermal efficiency of 8.3 %. However, setting the low-temperature power cycle only on the aftercooler 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, as the gas production currently decreases on this field.

3.5.3. Discussion

At present, the integration of *organic Rankine cycles* has never been proven in an offshore environment and may be particularly challenging for heat recovery from the gas cooling steps. The power savings may reach up to 3.5 MW for the case studies of this work. However, a main issue is the variability of the gas flows over time, and a proper design and control strategy of the bottoming cycle are thus essential to avoid severe off-design conditions.

4. Power plant

4.1. Gas turbines

4.1.1. Approach

At present, the main energy efficiency efforts on offshore platforms are related to the reduction of flaring and installation of steam bottoming cycles, and the latter is discussed later in this work. A possibility for decreasing the fuel consumption, as proposed in Section 3, is to reduce the additional power demand associated with the gas recirculation in the gas compression operations, by having smaller compressors in parallel, and by switching them on/off depending on their loads. The compressors will be operated closer to their maximal efficiency, which contributes to a higher site performance.

The same reasoning can be applied for the gas turbines installed offshore. The total power demand of the platform generally reaches a maximum in ‘plateau’ conditions, which often corresponds to the nominal operating conditions of the gas turbines, and decreases over time, which implies that the gas turbines operate far from their optimal point for a long period of the field lifetime. As mentioned by Mazzetti et al. [24], many offshore gas turbine run in the load range of 60 to 70 % to ensure constant operation.

Three possibilities can then be followed and the same conclusions can be drawn for the present case studies: downsizing the power plant system, by replacing existing gas turbines by smaller ones; removing one gas turbine and adding a bottoming cycle, if no possibility of power export; adding smaller gas turbines completed with bottoming cycles. The first possibility is investigated as follows, considering only the case of Platform D, since detailed gas turbine data and information on the control strategy were not available for the others.

4.1.2. Findings

The three gas turbines installed on Platform D (Siemens SGT-500) are characterised by an exhaust temperature lower than 350 °C and a nominal capacity of 19 MW. Two other gas turbines (Siemens SGT-200) are used for water injection but are usually not operating. At present, these engines are run far from their nominal design point because a common operating strategy on offshore platforms is to share the demands between several gas turbines run in parallel. For example, two of the gas turbines installed on Platform D operate at about 45 % load, while the third one is on standby. Their current electrical efficiency ranges below 25 % while it exceeds 33 % in nominal conditions. For the current power demand of 19 MW, two SGT-500 gas turbines running in parallel consume about 15 MW of additional fuel than a single one operating near its nominal point.

A comparison of several gas turbines of the same category (SGT-200 to SGT-800) suggests that three SGT-200 engines could replace the two SGT-500 models. Moreover, the Siemens SGT-200 turbines have an exhaust temperature between 400 and 475 °C in the load range of 90–95 %, which may open more possibilities for implementing a steam bottoming cycle than with the current gas turbines, for which the exhaust temperature falls below 350 °C. These smaller turbines have a capacity of about 7 MW each and are slightly less efficient at their nominal point than the bigger ones. However, they would be operated at a much higher operating load, between 90 and 95 %, and with an electrical efficiency of 32 to 33 %. This scenario would result in a fuel demand smaller by 10 to 15 MW, which corresponds to a rough reduction in the total platform CO_2-emissions of 10 %.

4.1.3. Discussion

The changes are significant because of the much higher loads and efficiencies of the gas turbines considered in the current and improved scenarios. It is difficult to evaluate the effects over the remaining field lifetime as these depend on the production profile and power demand, and on the part-load performance of each gas turbine. The *installation of smaller turbines* seems promising and may be a viable option both from a thermodynamic, economic and environmental perspective - the energy savings result in greater gas production and smaller CO_2-emissions, which in turn lead to higher gas sales and lower CO_2-taxes. The installation of smaller turbines may not require additional space and volume on-site, but the capital costs of these engines should be evaluated carefully and compared against the operational benefits.

4.2. Waste heat recovery

4.2.1. Approach

The integration of Rankine cycles allows for combined production of heat and electricity, increasing the efficiency of the power system, offering more flexibility, and opening possibilities for power export if the platforms are connected to the onshore grid or to other facilities. These cycles may be integrated to exploit medium- and high-temperature waste heat from the gas turbine (power plant) exhausts. At present, the fumes are directly discharged into the atmosphere at moderate to high temperatures.

The integration of waste heat recovery cycles may be beneficial for all platforms, but sufficient data were available only for Platforms C and D, which are taken as case studies. The three gas turbines implemented on Platform C (General Electric LM-2500 engine) are characterised by an exhaust temperature greater than 500 °C and have a nominal capacity of 25 MW each. As mentioned previously, three turbines on Platform D provide the main share of the mechanical and electrical loads. The possibility of electrifying Platform D and connecting it to other facilities and to the power grid was discussed by the platform stakeholders, and the production of additional power for export may be beneficial. On the contrary, such studies were not conducted for Platform C, and this work considers that the power produced by a bottoming cycle is used to substitute the power produced by the other engines present on-site.

The integration of waste heat recovery cycles is complex in practice because of the large number of operating parameters to consider. The problem is hence formulated as a mixed integer non-linear programming optimisation problem, built on a system superstructure to include all possible system configurations (with or without reheating, with or without extraction, etc.). The objectives are to maximise the power production or thermal efficiency, and to minimise the installation costs and CO_2-emissions. The waste heat recovery operating parameters (e.g. pressure) and strategy (e.g. thermal intermediate loop), as well as the selection of the cold and hot utilities (e.g. seawater), are defined as decision variables which are emulated by a genetic algorithm. The working fluid considered in this work is steam. The complete list of the variables with their optimisation range is presented in Nguyen et al. [17].

4.2.2. Findings

Platform C. The introduction of a steam network for combined heat and power may be of interest, since the external heating demand, at present, is of about 15 MW. The utility plant on that platform consists of two main gas turbines of the LM-2500 type, and the total flow rate of exhaust gases amounts to about 119 kg/s, with a temperature at design point of 566 °C, and at the simulated current conditions of 516 °C.

The optimal and most feasible configurations are the following (Figure 9):

- the flue gases from both gas turbines are mixed and run first through the gas-water loop heat exchanger, followed by the heat recovery steam generator. This layout results in a gas temperature of about 240 °C at the HRSG inlet, which severely limits the steam production pressure;
- part of the exhaust gases is processed through the heat recovery steam generator to satisfy the power demand, and is mixed with the remaining flue gases at high temperature, before entering the gas-water loop heat exchanger. In such a configuration, the splitting ratio at the design point is fixed to avoid water condensation in the flue gases, and the final discharge temperature is set to match a temperature approach of 12 °C.

Other configurations are not feasible or interesting in practice, because the large heating demand of the processing plant (15 MW) at high temperature (above 200°C) constraints both the minimum flow rate of exhaust gases to process through the heating system and the minimum temperature at the inlet of the heat recovery steam generator.

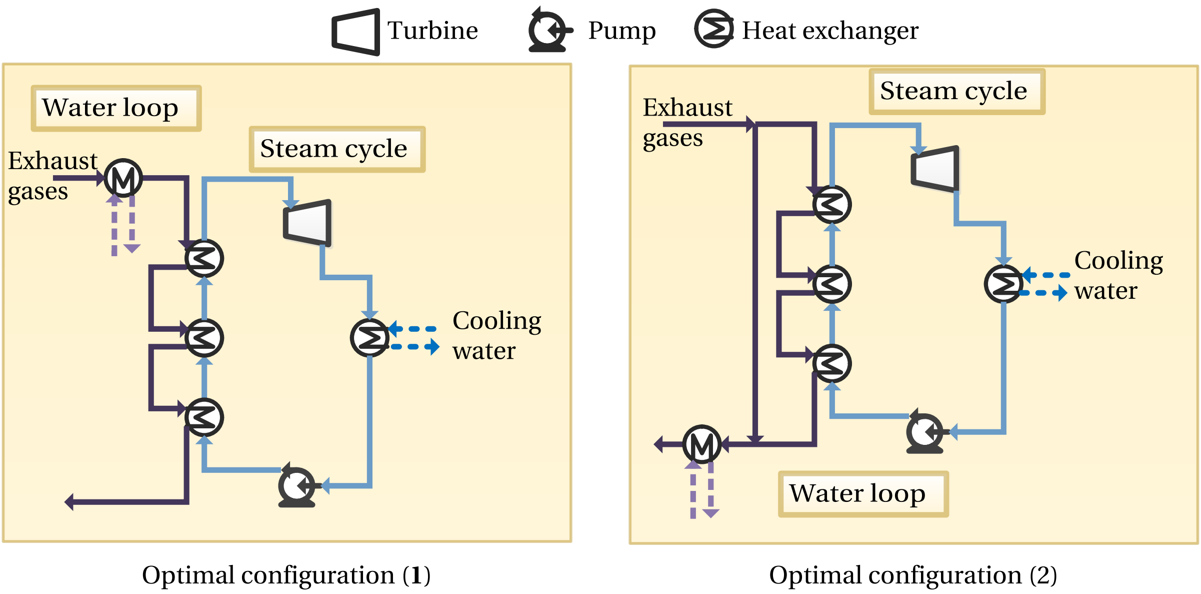


Figure 9: Optimal configurations of the steam cycle integration for Platform C.

The maximum power production of the steam turbine reaches about 5.5 and 5.8 MW for the first and second optimal configurations. The latter may be preferable from an economic perspective, since a smaller flow of gases is processed through the HRSG, and the costs of the steam cycle are smaller. The reductions in fuel consumption and CO_2-emissions range between 11 and 14.5 %.

Platform D. At the difference of Platform C, the integration of a combined heat and power plant may not be relevant, as the current heat demand is smaller than 5 MW, while the power demand exceeds 16 MW in normal operating conditions. The net power capacity at the platform operating conditions can be increased by up to about 4.5 MW if the waste heat from one gas turbine is recovered, and up to 9.2 MW if from the two sub-systems. Each gas turbine has a nominal capacity of about 19 MW, and one of them can therefore be removed and replaced with a steam bottoming cycle, the third one still being on-site for power backup. In this scenario, the combined cycle efficiency increases from 23.3 % (current GT efficiency, at about 40 % load) up to 32.4 %. The reductions in CO_2-emissions from the gas turbines reach about 9.5 %, which corresponds to an absolute decrease from 450 to about 390-400 tons per day.

Another possibility is to implement a steam cycle on both gas turbines and to operate them on lower capacity, and this results in a reduction of the fuel consumption by about 20.2 %, and this corresponds to an absolute decrease of the CO_2-emissions from 450 to about 360-370 tons per day. The equipment weight will increase on the platform, which may be problematic depending on the plant, and additional space may be required if the bottoming cycle cannot be placed on the top of other equipment, as suggested in Bothamley et al. [3]. None of the optimised design set-ups include reheating or extraction, because the moderate temperature of the heat source does not favour the use of more than one production (evaporation and superheating) and utilisation (condensation) level. The production of steam takes place at pressures between 10 and 20 bar.

4.2.3. Discussion

Integrating a *waste heat recovery cycle* results in a greater power capacity, if required, or in a lower fuel gas consumption and smaller CO_2-emissions. The introduction of these processes is a complex design task, as many layouts can be suggested, depending on the energy requirements of the platform and on the plant layouts. It may be beneficial, as such cycles present a satisfying behaviour at design and part-load conditions, if they are properly designed and integrated within the offshore system. The heating demand, if any, can be met by recovering the waste heat from the exhaust gases, either by direct or indirect exchange through a heating medium loop. However, despite the additional flexibility and higher efficiency, the integration of waste heat recovery systems results in greater space and weight requirements, unless the Rankine cycle replaces one of the existing gas turbines. This substitution would lead to fuel savings and CO_2-emission reductions in all cases, since the efficiency of the resulting combined cycle would then be higher than the efficiencies of the gas turbines alone.

5. Conclusion

Several energy saving scenarios were analysed. The proposed measures were of different types. They aim at reducing the electrical or thermal energy use, by re-designing some sections of the processing plant (production manifolds), re-dimensioning the compressors (gas recompression and treatment), promoting energy and process integration (heat exchanger network), implementing expanders and waste heat recovery cycles. The savings potentials differ significantly from one platform to another. The implementation of an additional pressure level is, for instance, irrelevant for facilities where the export pressure is below the feed pressure, and the substitution of throttling valves by multiphase expanders is challenging because of technological limitations. Site-scale integration can result in a significant decrease of the external heating demand if the plants are fully-integrated, but this may be difficult because of additional operational issues. The greatest energy saving improvement is associated with the limitation, if possible, of anti-surge recycling, by, for example, adding parallel trains or re-wheeling them. The installation of smaller gas turbines and waste heat recovery systems would result in a more efficient power generation system, and thus in better use of the fuel energy, higher operational profits and lower CO_2-emissions. All in all, the total power and fuel gas consumptions can be reduced by up to 20 %, and this pinpoints the importance of designing and operating adequately each processing section. The findings of this research may be used for screening possible improvements and estimating qualitatively their potential. Caution should be exercised when analysing the feasibility of a given technology, as different design layouts and feed properties would greatly impact its benefits. Each platform should be assessed individually to depict the 'low-hanging fruits', and the most relevant solutions, with respect to aspects such as energy efficiency, economic profitability and environmental impact, should be analysed.

Acknowledgements

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Appendix A. Process Flowsheets

The process flowsheets of each platform are shown in Figs. A.10 – A.13.

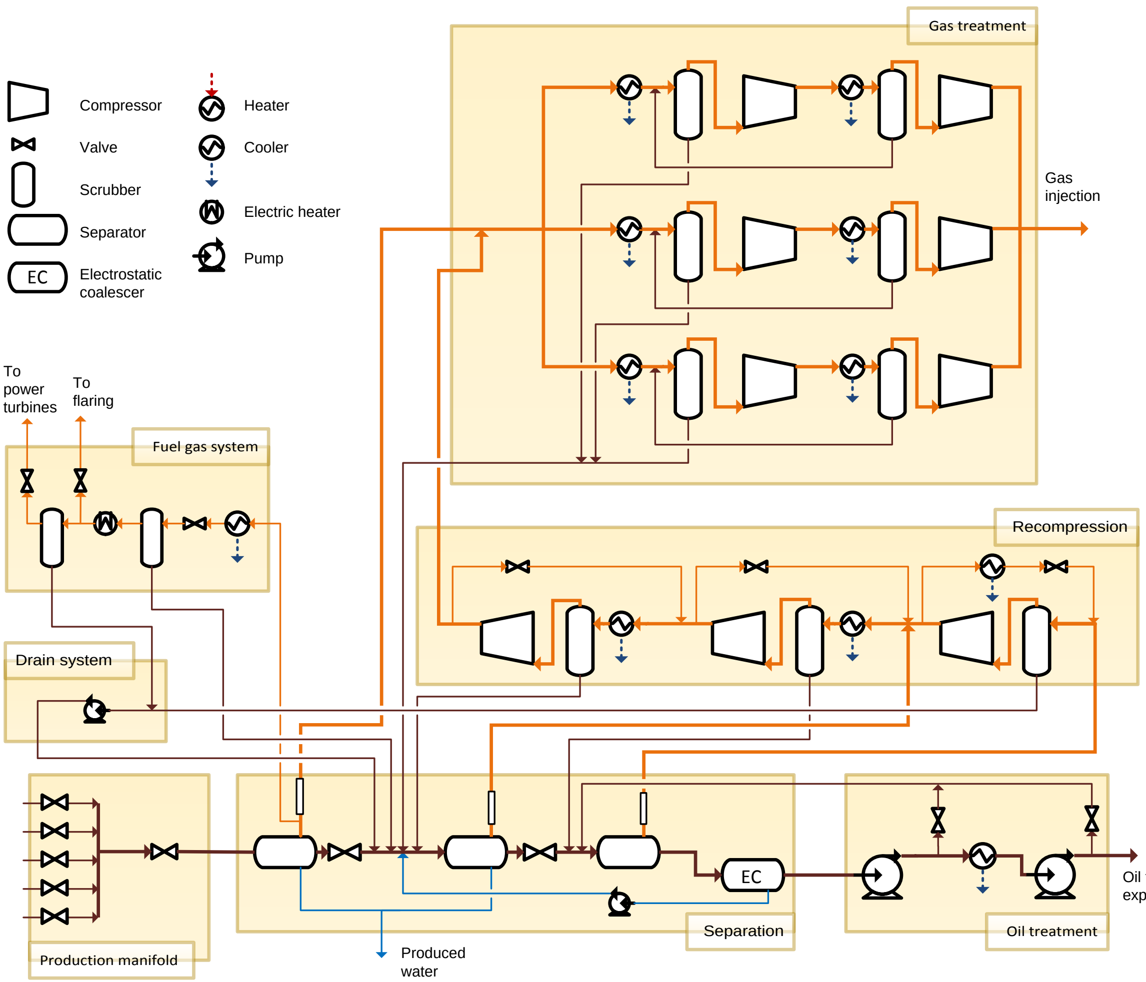

Figure A.10: Process flow diagram of the processing plant of Platform A. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams are shown with brown arrows.

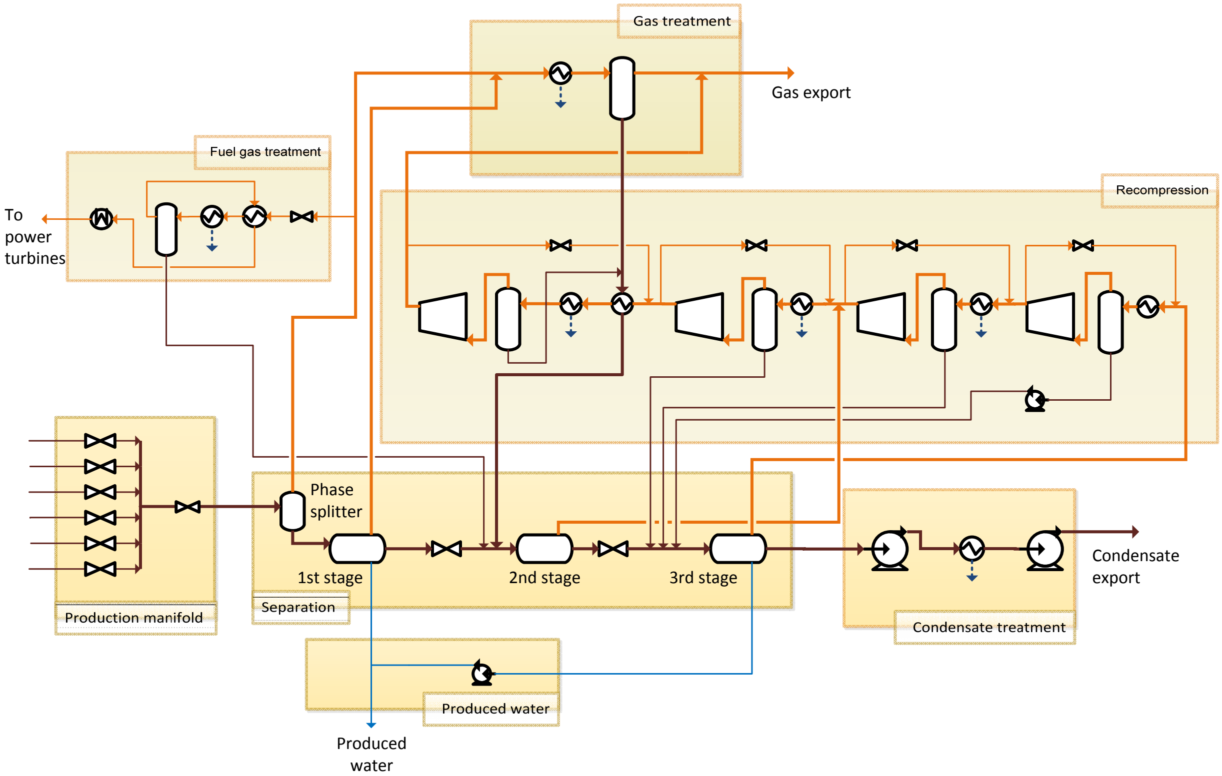

Figure A.11: Process flow diagram of the processing plant of Platform B. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams are shown with brown arrows. Symbol explanations can be found in Fig. A.10.

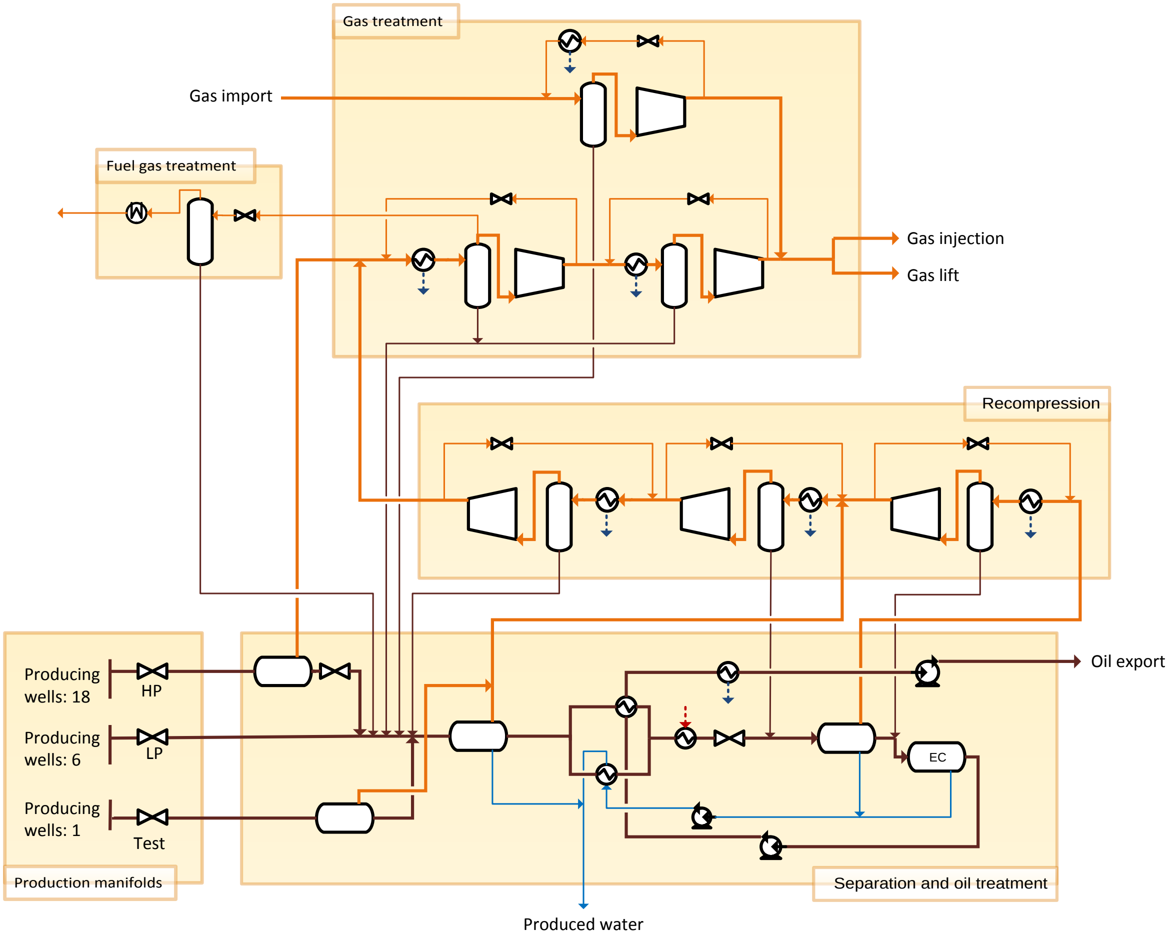

Figure A.12: Process flow diagram of the processing plant of Platform C. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams are shown with brown arrows. Symbol explanations can be found in Fig. A.10.

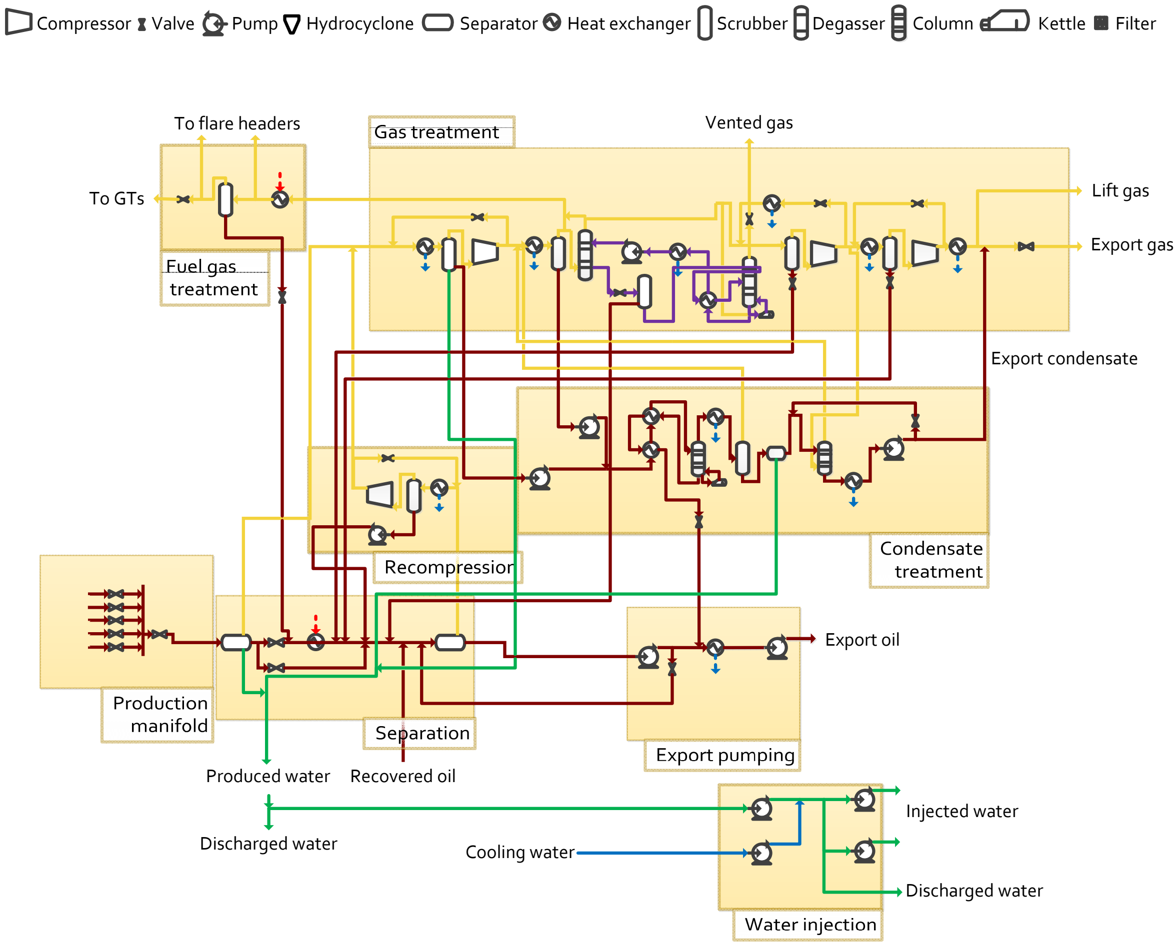

Figure A.13: Process flow diagram of the processing plant of Platform D. Gas streams are shown with orange arrows, water streams with blue arrows, glycol is shown with purple arrows, and oil, condensate and mixed streams are shown with brown arrows.

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