



Energy efficiency measures for offshore oil and gas platforms

Nguyen, Tuong-Van; Voldsund, Mari; Breuhaus, Peter; Elmegaard, Brian

Published in:
Energy

Link to article, DOI:
[10.1016/j.energy.2016.03.061](https://doi.org/10.1016/j.energy.2016.03.061)

Publication date:
2016

Document Version
Peer reviewed version

[Link back to DTU Orbit](#)

Citation (APA):
Nguyen, T.-V., Voldsund, M., Breuhaus, P., & Elmegaard, B. (2016). Energy efficiency measures for offshore oil and gas platforms. *Energy*, 117(2), 325–340. <https://doi.org/10.1016/j.energy.2016.03.061>

General rights

Copyright and moral rights for the publications made accessible in the public portal are retained by the authors and/or other copyright owners and it is a condition of accessing publications that users recognise and abide by the legal requirements associated with these rights.

- Users may download and print one copy of any publication from the public portal for the purpose of private study or research.
- You may not further distribute the material or use it for any profit-making activity or commercial gain
- You may freely distribute the URL identifying the publication in the public portal

If you believe that this document breaches copyright please contact us providing details, and we will remove access to the work immediately and investigate your claim.

Energy efficiency measures for offshore oil and gas platforms

Tuong-Van Nguyen^{a,*}, Mari Voldsund^b, Peter Breuhaus^c, Brian Elmegaard^a

^a*Section of Thermal Energy, Department of Mechanical Engineering, Technical University of Denmark, Building 403, Nils Koppels Allé, 2800 Kongens Lyngby, Denmark*

^b*Department of Chemistry, Norwegian University of Science and Technology, Høgskoleringen 5, 7491 Trondheim, Norway*

^c*Department of Energy, International Research Institute of Stavanger, Professor Olav Hanssens vei 15, 4021 Stavanger, Norway*

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 CO₂-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 CO₂-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 CO₂-tax on the offshore sector has been levied by the Norwegian government in 1991 and was doubled in 2011 [1] to encourage CO₂-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].

*Principal corresponding author. Tel.: +45 4525 4129
Email address: tungu@mek.dtu.dk (Tuong-Van Nguyen)

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

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

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

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

42 The installation of alternative power systems such as organic Rankine cycles was discussed in subse-
43 quent works. Pierobon et al. [18] conducted a multi-objective optimisation for designing ORCs in offshore
44 conditions, aiming at minimising the weight of the bottoming cycle while maximising the reductions in
45 CO₂-emissions. Mazzetti et al. [19,20] analysed as well alternative working fluids such as carbon dioxide,
46 and they claimed that CO₂-cycles may be much less space-demanding for similar efficiencies and capacities.
47 CO₂-cycles were analysed thoroughly in Walnum et al. [21] where the performance of these cycles was eval-
48 uated at reduced gas turbine loads, and in Skaugen et al. [22], where process optimisations were conducted
49 for designing a compact and light cycle under a set of practical constraints. Barrera et al. [23] analysed the
50 impacts of varying water, gas and oil flows, and their results suggest that the amounts of injected gas and
51 water have a strong impact on the power output of these cycles.

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

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

65 The present paper is part of a larger project dealing with the modelling and analysis of oil and gas
66 producing platforms and is a continuation of the work presented in Nguyen et al. [26]. It builds on previous
67 works conducted by the same authors and is structured as follows. Section 2 describes the system of interest

68 in this work, and on the similarities and differences between the four cases. The improvements investigated
69 in this study are presented further, together with the benefits achieved for each platform, with respect to the
70 processing (Section 3) and power (Section 4) plants, and are followed by concluding remarks in Section 5.

71 2. System description

72 2.1. General design

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

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

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

93 2.2. Case studies

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

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

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

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

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

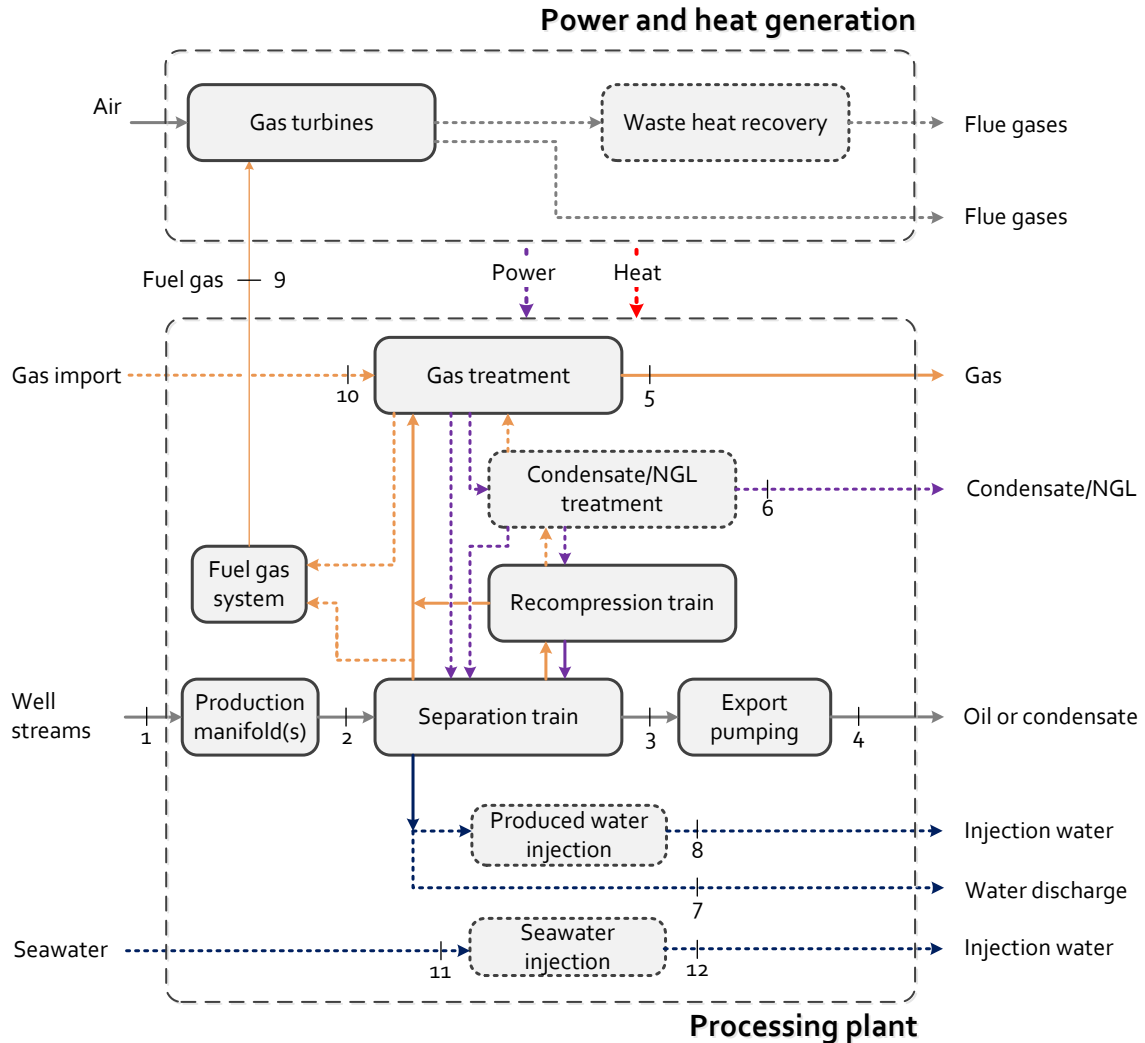


Figure 1: General system overview of an oil and gas platform. Arrows represent one to several streams while block represent different subsystems. Solid lines indicate that the corresponding stream or process is present for all the studied platforms and can generally be found on all typical oil and gas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

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

118 2.3. System modelling

119 The measurements were taken for a ‘normal’ production day and are presented in further details in
 120 Voldsund et al. [28] for Platform A, Voldsund et al. [10] for Platforms B and C, and in Nguyen et al. [9]
 121 for Platform D. The present analysis was built on a compilation of (i) system information received from the
 122 platform databases, given for a single time point, or on a hourly to daily basis, (ii) fiscal declarations to the
 123 Norwegian Petroleum Directorate, (iii) assumptions based on the authors’ experience, discussed with field
 124 experts, and (iv) data compiled from process flowcharts and literature. The models were developed with the
 125 commercial flowsheeting software Aspen Plus [29], version 7.2, based on the Peng-Robinson [30], Redlich-
 126 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 (type)	Platform A		Platform B		Platform C		Platform D	
	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
2 (reservoir fluids)	70	74	120	106	46 ^a 7 ^b 13 ^c	62 ^a 69 ^b 63 ^c	8	49–67 63 ^b
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

^aFrom high pressure manifold

^bFrom low pressure manifold

^cFrom test manifold

127 dehydration) equations of state.

128 2.4. Performance analysis

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

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

147 Hence, the focus of this work is on the evaluation of the following design changes: (i) introduction of an
148 additional pressure level in the production manifolds; (ii) implementation of multiphase expanders instead
149 of expansion valves; (iii) limitation of the gas recirculation around the compressors, by installing parallel
150 trains or rewheeling; (iv) promotion of process and energy integration; (v) exploitation of low-temperature

151 heat ($\leq 100^\circ\text{C}$) from the gas intercooling and aftercooling steps; (vi) downsizing or replacement of the gas
 152 turbines; and (vii) valorisation of the high-temperature waste heat ($\geq 300^\circ\text{C}$) from the turbine exhausts.
 153 These suggestions for process modifications are not relevant for all case studies (Table 2) - the points (i)–(v),
 154 which are related to changes of the processing plant, are presented in Section 3, while the points (vi)–(vii),
 155 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 \checkmark means that the proposed improvement is relevant and investigated, a symbol \blacklozenge means that the proposed improvement is pertinent but not considered in this work because of missing data, and a symbol \times means that the proposed improvement is neither relevant nor studied.

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

156 3. Processing plant

157 3.1. Multi-level production manifold

158 3.1.1. Approach

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

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

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

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

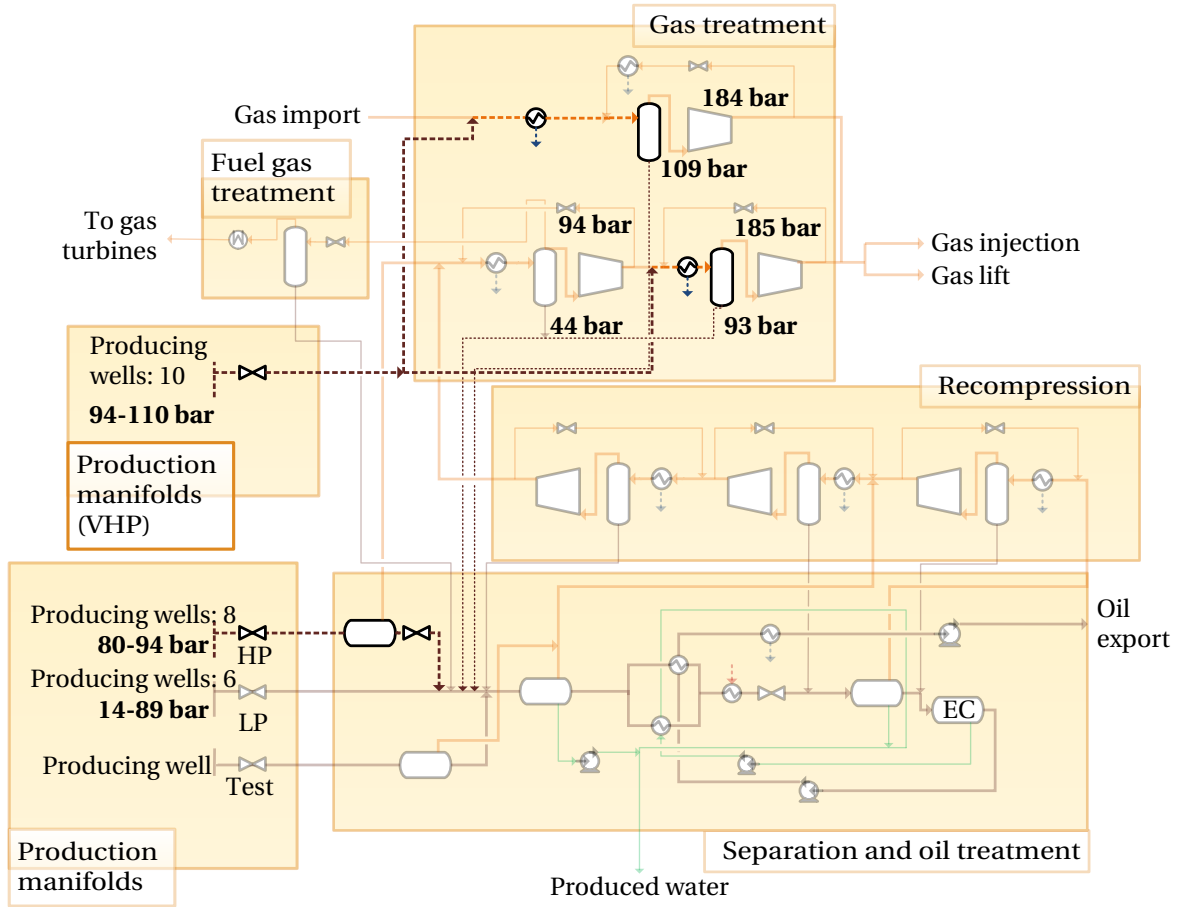


Figure 2: Schematics of the proposed retrofit of Platform C with a very high pressure (VHP) manifold.

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

195 3.1.2. Findings

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

201 *Scenario 2.* Greater power savings can be achieved if the pressure levels of the VHP and HP production
 202 manifolds can be optimised (Figure 3), with a reduction of the power consumption from an original value
 203 of about 30 MW to only 17 if anti-surge recirculation can be limited as well. The Pareto fronts indicate

204 that the optimal gas and oil recoveries vary in a range of 0.5%, while the total power consumption varies
 205 between 17,000 to 26,500 kW.

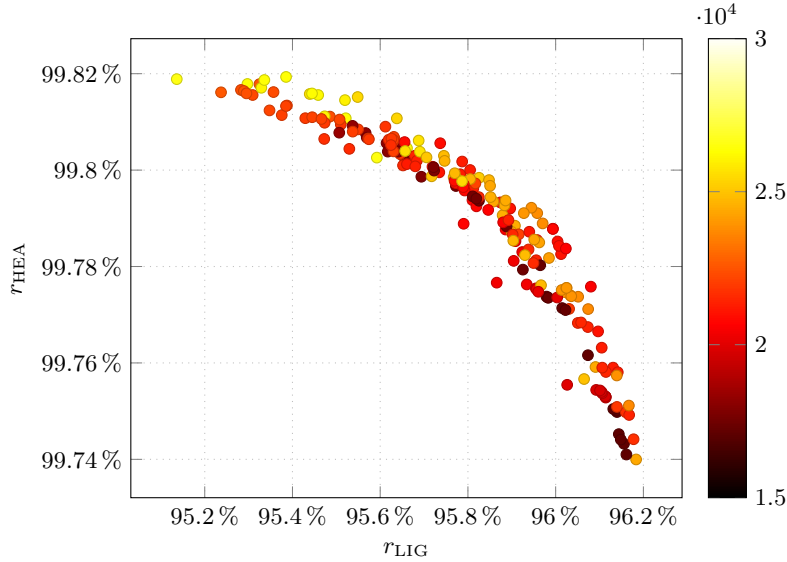


Figure 3: Pareto-optimal solutions for an integrated design of production manifolds with an additional pressure level (VHP) in the case of Platform C. The colour bar illustrates the power consumption of each solution, expressed in kW.

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

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

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

223 3.1.3. Discussion

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

232 it is then important to ensure that an extra pressure level will not result in additional power consumption
233 of the low-pressure compressors due to higher anti-surge gas recirculation.

234 3.2. Multiphase flow expanders

235 3.2.1. Approach

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

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

250 3.2.2. Findings

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

258 As for the production manifold, the introduction of multiphase expanders between each separation stage
259 may be considered, though with smaller benefits. Smaller liquid flows are processed and they generally
260 have lower temperatures and pressures than the reservoir fluid streams entering the separation section. A
261 preliminary analysis indicates that the power recovered at the 1st separation stage represents about 11 and
262 30 % of the power output of the multiphase expanders that could be integrated in the production manifolds
263 of Platforms A and B.

264 3.2.3. Discussion

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

272 3.3. Reduction of anti-surge recirculation

273 3.3.1. Approach

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

279 gas exported to the shore, increasing the operational benefits, reducing the power consumption and exergy
 280 destruction in the expansion processes.

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

292 3.3.2. Findings

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

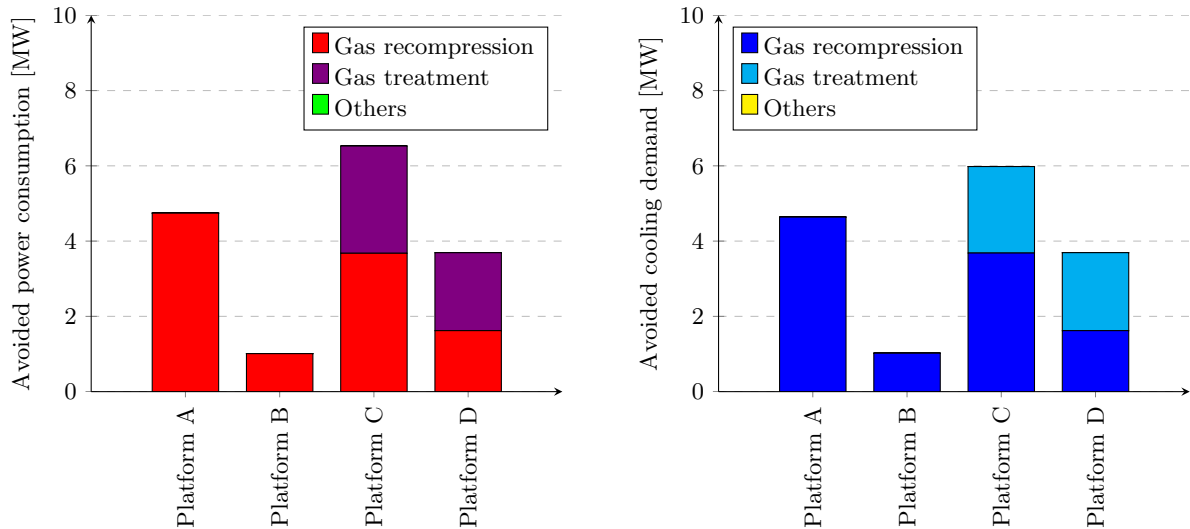


Figure 4: Avoided power and cooling demands if no anti-surge recirculation.

300 In addition, less recycling results in less exergy destruction (Figure 5) because of (i) the elimination of the
 301 pressure losses through the anti-surge control valves, (ii) the smaller exergy destruction by heat transfer in
 302 the coolers, and (iii) the smaller exergy destruction in the compression process. The first reduction amounts
 303 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
 304 four platforms. The sums of the second and third ones are roughly equal to the first ones. The reductions
 305 in exergy destruction due to smaller mixing effects represent less than 50 kW per stage.

306 3.3.3. Discussion

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

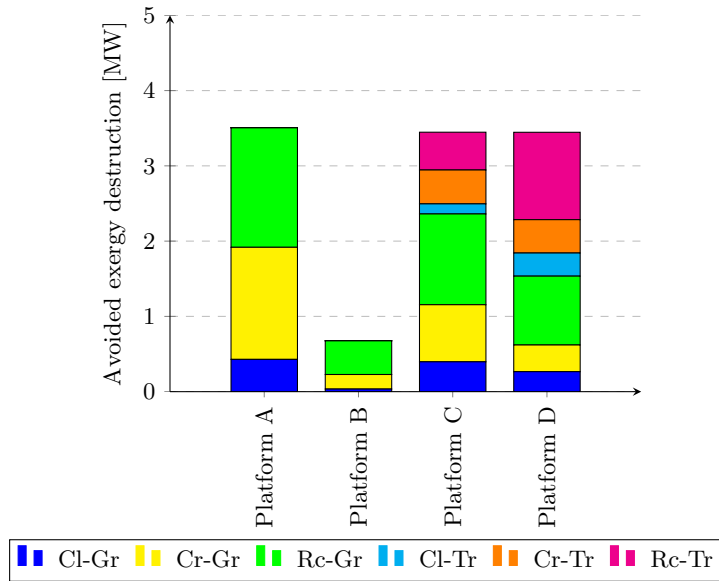


Figure 5: Absolute changes in exergy destruction if no anti-surge recirculation. The acronyms Cl, Cr and Rc stand for coolers, compressors and recycle, while Gr and Tr denote the recompression and treatment processes.

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

313 3.4. Energy integration

314 3.4.1. Approach

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

324 3.4.2. Findings

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

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

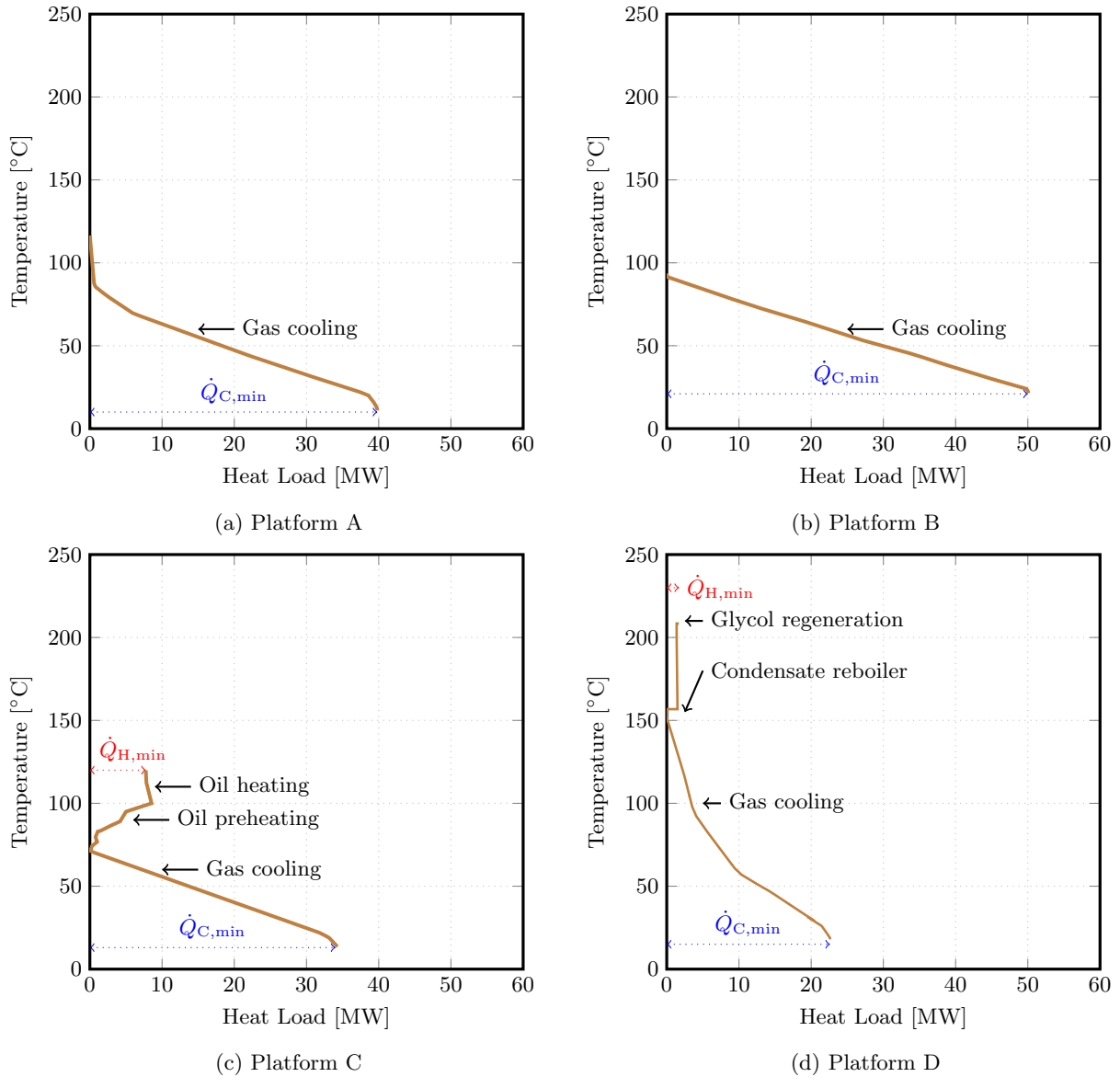


Figure 6: Grand Composite Curves of four North Sea offshore platforms.

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

337 Improving the integration of the current site is particularly relevant for Platforms C and D (Figure 8),
 338 but this may be challenging for geographical and operational reasons. The site profiles show that all the site
 339 cooling demand takes place at temperatures lower than 120 °C, which is the temperature of the oil heating
 340 process. The integration of gas-oil heat exchangers faces two issues. First, all the gas streams should be
 341 cooled down to 20–50 °C, and the oil stream has an initial temperature of 45–55 °C. The gas streams should
 342 therefore be cooled in two steps, by first exchanging heat with the oil, and then with cooling water. Secondly,
 343 the oil stream cannot be heated by only one gas stream, as the heating demand for the oil can reach up to
 344 12 MW, while the cooling demand for each individual gas stream does not exceed 4 MW.

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

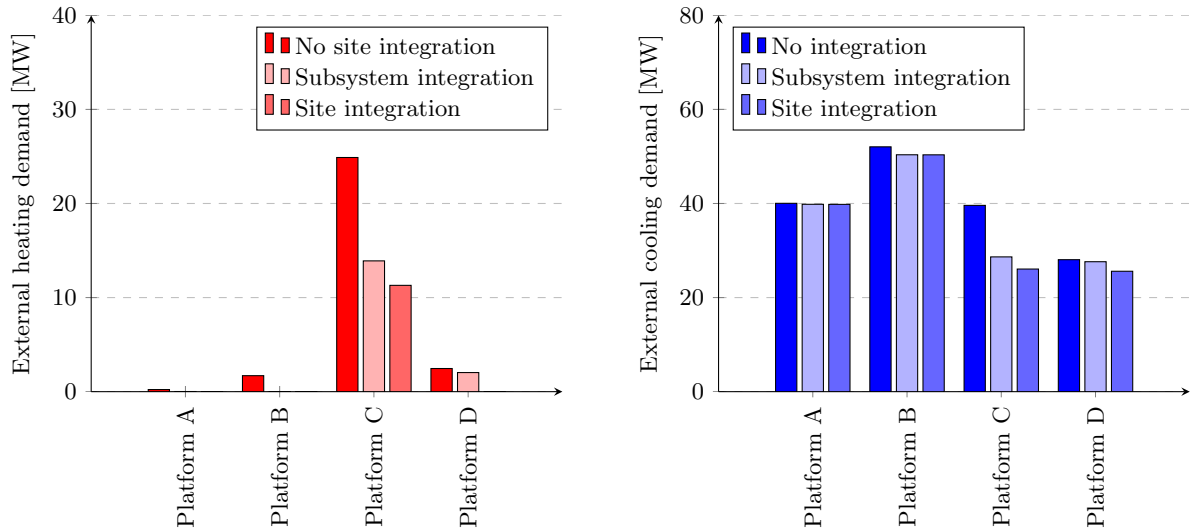


Figure 7: External utility demands without integration, with subsystem integration and with site integration.

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

355 3.4.3. Discussion

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

364 3.5. Waste heat recovery

365 3.5.1. Approach

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

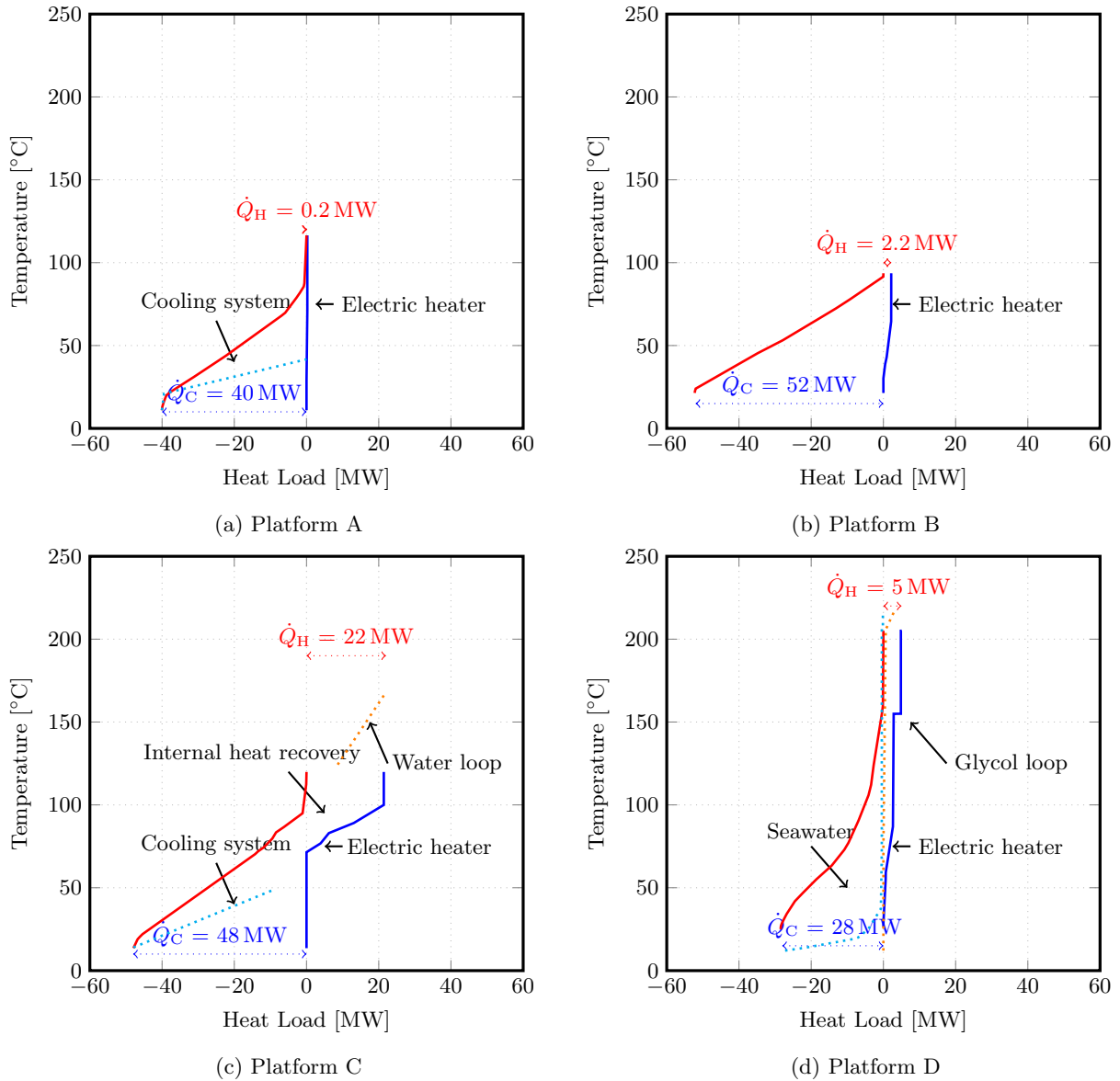


Figure 8: Total site profiles of four North Sea offshore platforms. The solid and dotted lines correspond to the heat-temperature profiles of the process and utility streams, respectively.

375 3.5.2. Findings

376 *Platform B.* The quantity of heat discharged in the gas aftercooler for Platform B currently exceeds
 377 40 MW, and the results suggest that the most efficient solution is to implement a bottoming organic Rankine
 378 cycle with a mixture of ethane and propane operating in transcritical conditions. The performance of the
 379 low-temperature power cycle is directly correlated to a few design parameters, such as the condensation
 380 and production levels, the temperature after superheating and the ethane fraction. More than 2.5 MW of
 381 power can be produced, which represents more than half of the total power consumption (5.5 MW) of the
 382 processing plant. The thermal efficiency of this organic Rankine cycle is particularly low, because the gas
 383 temperature is around 100 °C at the aftercooler inlet and should be reduced to about 32 °C to satisfy the
 384 pipeline export specifications. These requirements restrict severely the evaporation level on the organic fluid

385 side and the maximum power output.

386 *Platform D.* As for Platform B, the most effective solution is the integration of ORCs with a hydrocarbon
387 mixture. Although these cycles display a thermal efficiency as low as 10 %, 1.5 to 3.5 MW can be generated,
388 depending on the rate of the produced gas. The optimal low-temperature power cycles operate between 20 °C
389 and 170 °C and recover heat from the gas streams in the treatment process prior to each compression stage.
390 However, the design of such a cycle is challenging and costly, as the working fluid should be evaporated and
391 superheated in several heat exchangers. A more cost-efficient alternative is to utilise the waste heat from
392 one single hot stream as done for Platform B, using the heat from the gas to be exported in the final heat
393 exchanger. The system would then be relatively compact and light, including only four components. The
394 cycle should then operate between 23 °C (19.5 bar) and 144 °C (56 bar) and can provide a net supplement of
395 power of 590 kW, which corresponds to a thermal efficiency of 8.3 %. However, setting the low-temperature
396 power cycle only on the aftercooler placed at the outlets of the gas treatment process may not be viable,
397 because the gas flow through this heat exchanger is already small (lower than 2 kg/s) and is expected to
398 decrease with time, as the gas production currently decreases on this field.

399 3.5.3. Discussion

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

405 4. Power plant

406 4.1. Gas turbines

407 4.1.1. Approach

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

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

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

425 4.1.2. Findings

426 The three gas turbines installed on Platform D (Siemens SGT-500) are characterised by an exhaust
427 temperature lower than 350 °C and a nominal capacity of 19 MW. Two other gas turbines (Siemens SGT-
428 200) are used for water injection but are usually not operating. At present, these engines are run far
429 from their nominal design point because a common operating strategy on offshore platforms is to share the
430 demands between several gas turbines run in parallel. For example, two of the gas turbines installed on
431 Platform D operate at about 45 % load, while the third one is on standby. Their current electrical efficiency

432 ranges below 25 % while it exceeds 33 % in nominal conditions. For the current power demand of 19 MW,
433 two SGT-500 gas turbines running in parallel consume about 15 MW of additional fuel than a single one
434 operating near its nominal point.

435 A comparison of several gas turbines of the same category (SGT-200 to SGT-800) suggests that three
436 SGT-200 engines could replace the two SGT-500 models. Moreover, the Siemens SGT-200 turbines have
437 an exhaust temperature between 400 and 475 °C in the load range of 90–95 %, which may open more
438 possibilities for implementing a steam bottoming cycle than with the current gas turbines, for which the
439 exhaust temperature falls below 350 °C. These smaller turbines have a capacity of about 7 MW each and
440 are slightly less efficient at their nominal point than the bigger ones. However, they would be operated at
441 a much higher operating load, between 90 and 95 %, and with an electrical efficiency of 32 to 33 %. This
442 scenario would result in a fuel demand smaller by 10 to 15 MW, which corresponds to a rough reduction in
443 the total platform CO₂-emissions of 10 %.

444 4.1.3. Discussion

445 The changes are significant because of the much higher loads and efficiencies of the gas turbines consid-
446 ered in the current and improved scenarios. It is difficult to evaluate the effects over the remaining field
447 lifetime as these depend on the production profile and power demand, and on the part-load performance of
448 each gas turbine. The *installation of smaller turbines* seems promising and may be a viable option both
449 from a thermodynamic, economic and environmental perspective - the energy savings result in greater gas
450 production and smaller CO₂-emissions, which in turn lead to higher gas sales and lower CO₂-taxes. The
451 installation of smaller turbines may not require additional space and volume on-site, but the capital costs
452 of these engines should be evaluated carefully and compared against the operational benefits.

453 4.2. Waste heat recovery

454 4.2.1. Approach

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

460 The integration of waste heat recovery cycles may be beneficial for all platforms, but sufficient data were
461 available only for Platforms C and D, which are taken as case studies. The three gas turbines implemented
462 on Platform C (General Electric LM-2500 engine) are characterised by an exhaust temperature greater than
463 500 °C and have a nominal capacity of 25 MW each. As mentioned previously, three turbines on Platform
464 D provide the main share of the mechanical and electrical loads. The possibility of electrifying Platform D
465 and connecting it to other facilities and to the power grid was discussed by the platform stakeholders, and
466 the production of additional power for export may be beneficial. On the contrary, such studies were not
467 conducted for Platform C, and this work considers that the power produced by a bottoming cycle is used
468 to substitute the power produced by the other engines present on-site.

469 The integration of waste heat recovery cycles is complex in practice because of the large number of oper-
470 ating parameters to consider. The problem is hence formulated as a mixed integer non-linear programming
471 optimisation problem, built on a system superstructure to include all possible system configurations (with or
472 without reheating, with or without extraction, etc.). The objectives are to maximise the power production
473 or thermal efficiency, and to minimise the installation costs and CO₂-emissions. The waste heat recovery
474 operating parameters (e.g. pressure) and strategy (e.g. thermal intermediate loop), as well as the selection
475 of the cold and hot utilities (e.g. seawater), are defined as decision variables which are emulated by a genetic
476 algorithm. The working fluid considered in this work is steam. The complete list of the variables with their
477 optimisation range is presented in Nguyen et al. [17].

478 4.2.2. Findings

479 *Platform C.* The introduction of a steam network for combined heat and power may be of interest, since
480 the external heating demand, at present, is of about 15 MW. The utility plant on that platform consists

481 of two main gas turbines of the LM-2500 type, and the total flow rate of exhaust gases amounts to about
 482 119 kg/s, with a temperature at design point of 566 °C, and at the simulated current conditions of 516 °C.

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

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

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

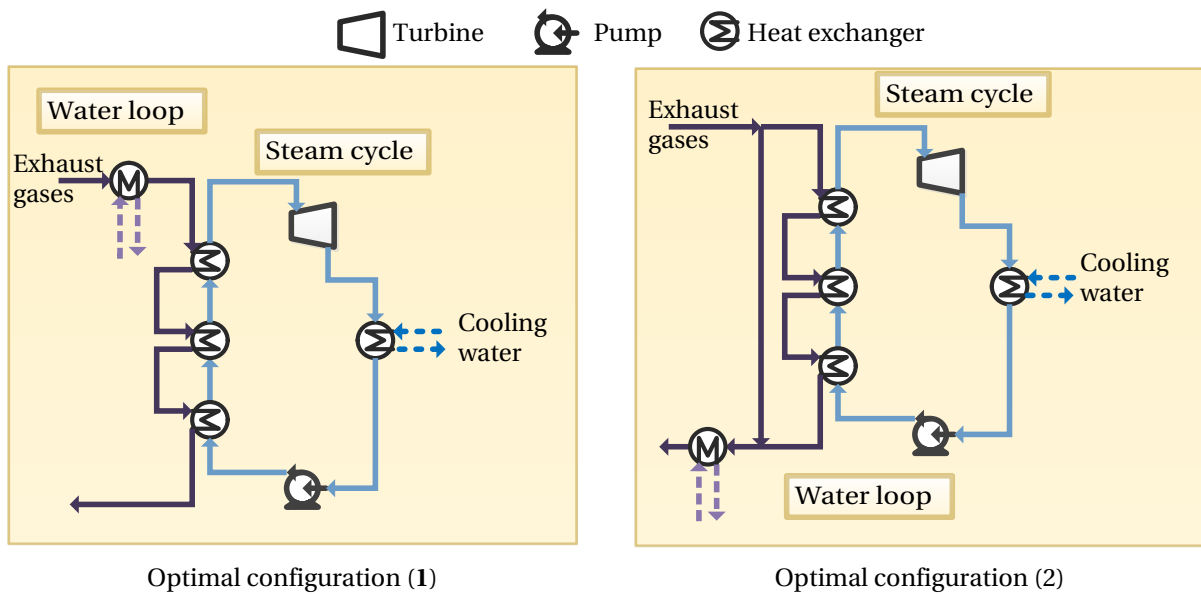


Figure 9: Optimal configurations of the steam cycle integration for Platform C.

496 The maximum power production of the steam turbine reaches about 5.5 and 5.8 MW for the first and
 497 second optimal configurations. The latter may be preferable from an economic perspective, since a smaller
 498 flow of gases is processed through the HRSG, and the costs of the steam cycle are smaller. The reductions
 499 in fuel consumption and CO₂-emissions range between 11 and 14.5%.

500 *Platform D.* At the difference of Platform C, the integration of a combined heat and power plant may not
 501 be relevant, as the current heat demand is smaller than 5 MW, while the power demand exceeds 16 MW in
 502 normal operating conditions. The net power capacity at the platform operating conditions can be increased
 503 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
 504 two sub-systems. Each gas turbine has a nominal capacity of about 19 MW, and one of them can therefore

505 be removed and replaced with a steam bottoming cycle, the third one still being on-site for power backup. In
506 this scenario, the combined cycle efficiency increases from 23.3% (current GT efficiency, at about 40% load)
507 up to 32.4%. The reductions in CO₂-emissions from the gas turbines reach about 9.5%, which corresponds
508 to an absolute decrease from 450 to about 390-400 tons per day.

509 Another possibility is to implement a steam cycle on both gas turbines and to operate them on lower
510 capacity, and this results in a reduction of the fuel consumption by about 20.2%, and this corresponds
511 to an absolute decrease of the CO₂-emissions from 450 to about 360-370 tons per day. The equipment
512 weight will increase on the platform, which may be problematic depending on the plant, and additional
513 space may be required if the bottoming cycle cannot be placed on the top of other equipment, as suggested
514 in Bothamley et al. [3]. None of the optimised design set-ups include reheating or extraction, because the
515 moderate temperature of the heat source does not favour the use of more than one production (evaporation
516 and superheating) and utilisation (condensation) level. The production of steam takes place at pressures
517 between 10 and 20 bar.

518 4.2.3. Discussion

519 Integrating a *waste heat recovery cycle* results in a greater power capacity, if required, or in a lower fuel
520 gas consumption and smaller CO₂-emissions. The introduction of these processes is a complex design task,
521 as many layouts can be suggested, depending on the energy requirements of the platform and on the plant
522 layouts. It may be beneficial, as such cycles present a satisfying behaviour at design and part-load conditions,
523 if they are properly designed and integrated within the offshore system. The heating demand, if any, can
524 be met by recovering the waste heat from the exhaust gases, either by direct or indirect exchange through
525 a heating medium loop. However, despite the additional flexibility and higher efficiency, the integration
526 of waste heat recovery systems results in greater space and weight requirements, unless the Rankine cycle
527 replaces one of the existing gas turbines. This substitution would lead to fuel savings and CO₂-emission
528 reductions in all cases, since the efficiency of the resulting combined cycle would then be higher than the
529 efficiencies of the gas turbines alone.

530 5. Conclusion

531 Several energy saving scenarios were analysed. The proposed measures were of different types. They
532 aim at reducing the electrical or thermal energy use, by re-designing some sections of the processing plant
533 (production manifolds), re-dimensioning the compressors (gas recompression and treatment), promoting
534 energy and process integration (heat exchanger network), implementing expanders and waste heat recovery
535 cycles. The savings potentials differ significantly from one platform to another. The implementation of
536 an additional pressure level is, for instance, irrelevant for facilities where the export pressure is below the
537 feed pressure, and the substitution of throttling valves by multiphase expanders is challenging because of
538 technological limitations. Site-scale integration can result in a significant decrease of the external heating
539 demand if the plants are fully-integrated, but this may be difficult because of additional operational issues.
540 The greatest energy saving improvement is associated with the limitation, if possible, of anti-surge recycling,
541 by, for example, adding parallel trains or re-wheeling them. The installation of smaller gas turbines and
542 waste heat recovery systems would result in a more efficient power generation system, and thus in better
543 use of the fuel energy, higher operational profits and lower CO₂-emissions. All in all, the total power
544 and fuel gas consumptions can be reduced by up to 20%, and this pinpoints the importance of designing
545 and operating adequately each processing section. The findings of this research may be used for screening
546 possible improvements and estimating qualitatively their potential. Caution should be exercised when
547 analysing the feasibility of a given technology, as different design layouts and feed properties would greatly
548 impact its benefits. Each platform should be assessed individually to depict the 'low-hanging fruits', and
549 the most relevant solutions, with respect to aspects such as energy efficiency, economic profitability and
550 environmental impact, should be analysed.

551 **Acknowledgements**

552 The funding from the Norwegian Research Council through the Petromaks programme, within the project
 553 2034/E30 led by Teknova, is acknowledged. The authors thank Audun Røsjorde from Statoil ASA for
 554 his feedback and comments on the process improvements suggested in this work. They are also grateful
 555 to Tomasz Jacyno, Mathies Hjorth Jensen, Tamás Gábor Fülöp and Thor Hardarson from the Technical
 556 University of Denmark, as well as Knut Jøssang and Jonas Reier Kaasa from the Norwegian University of
 557 Science and Technology, since the work performed in the frame of specialisation and master projects has
 558 ultimately led to several of the results presented in this paper.

559 **Appendix A. Process Flowsheets**

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

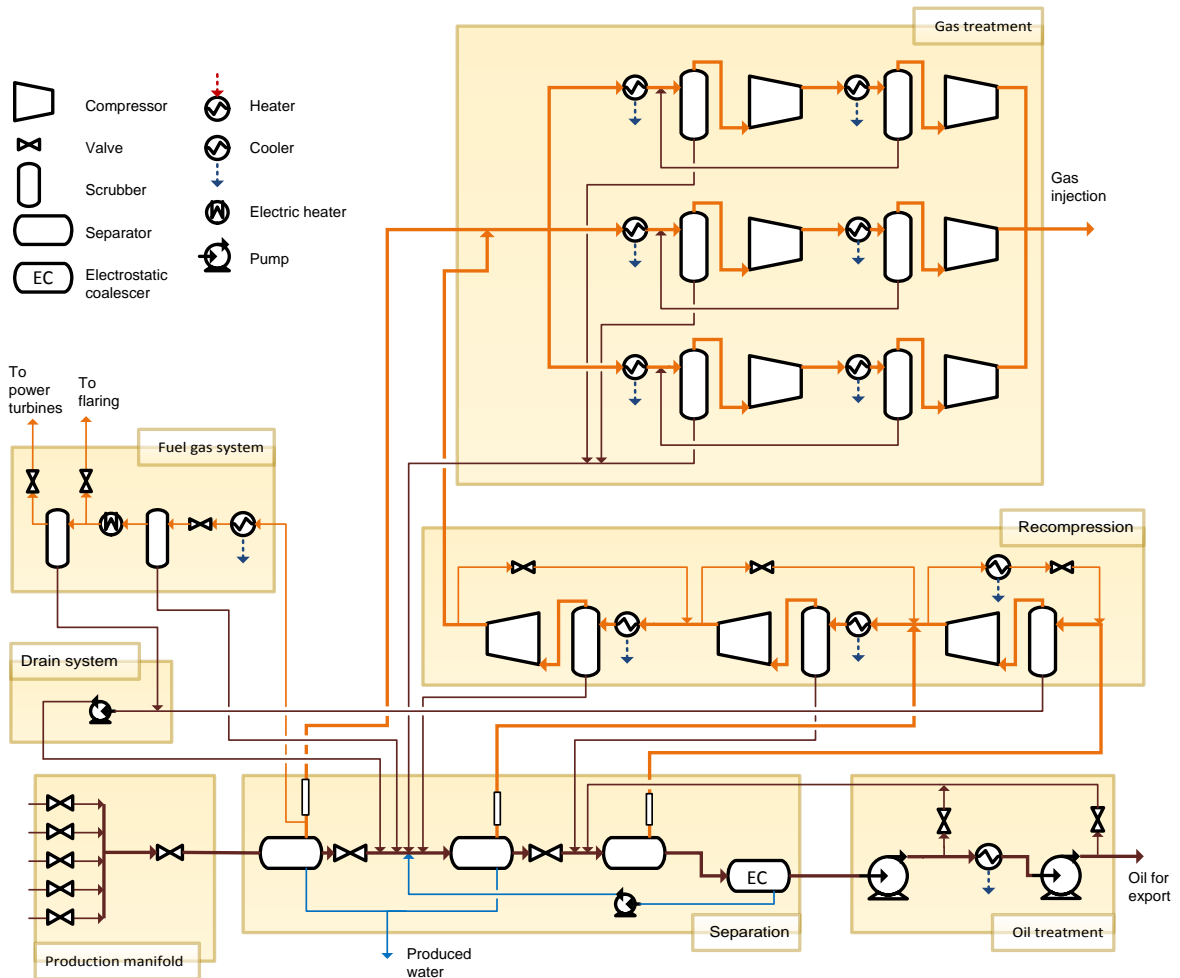


Figure A.10: Process flow diagram of the processing plant of Platform A. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams are shown with brown arrows.

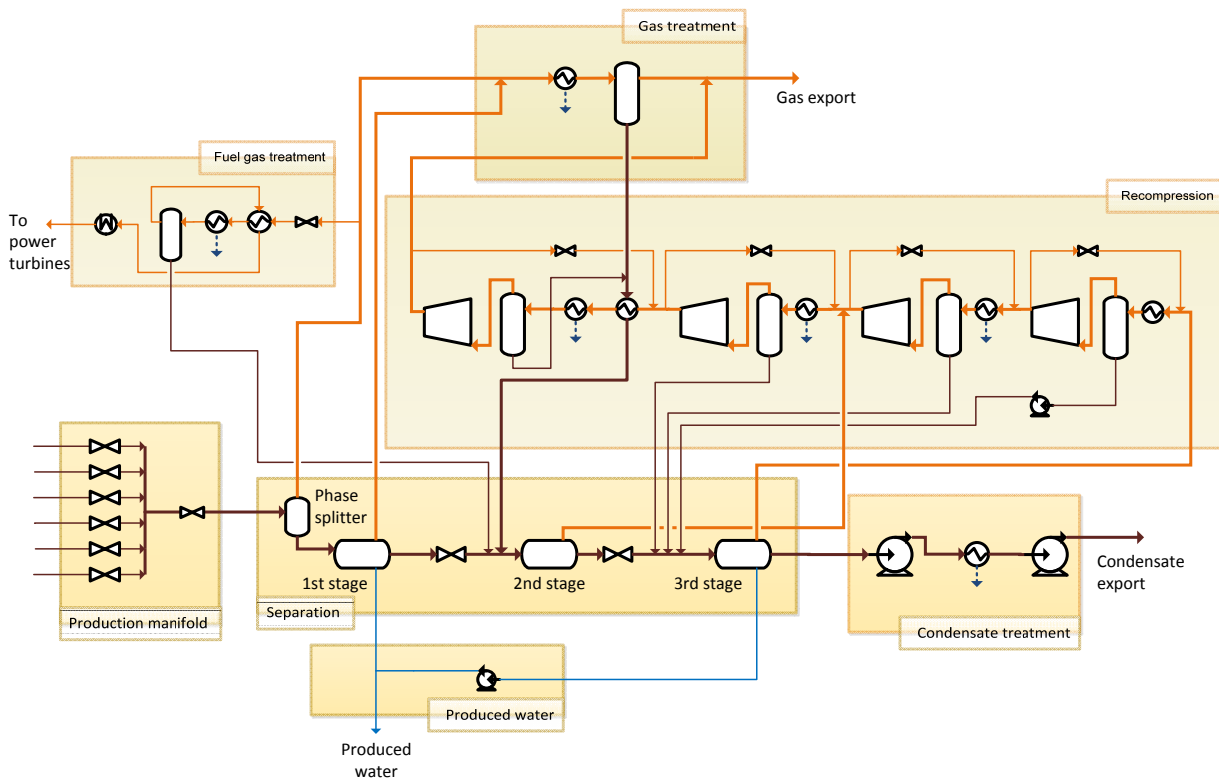


Figure A.11: Process flow diagram of the processing plant of Platform B. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams are shown with brown arrows. Symbol explanations can be found in Fig. A.10.

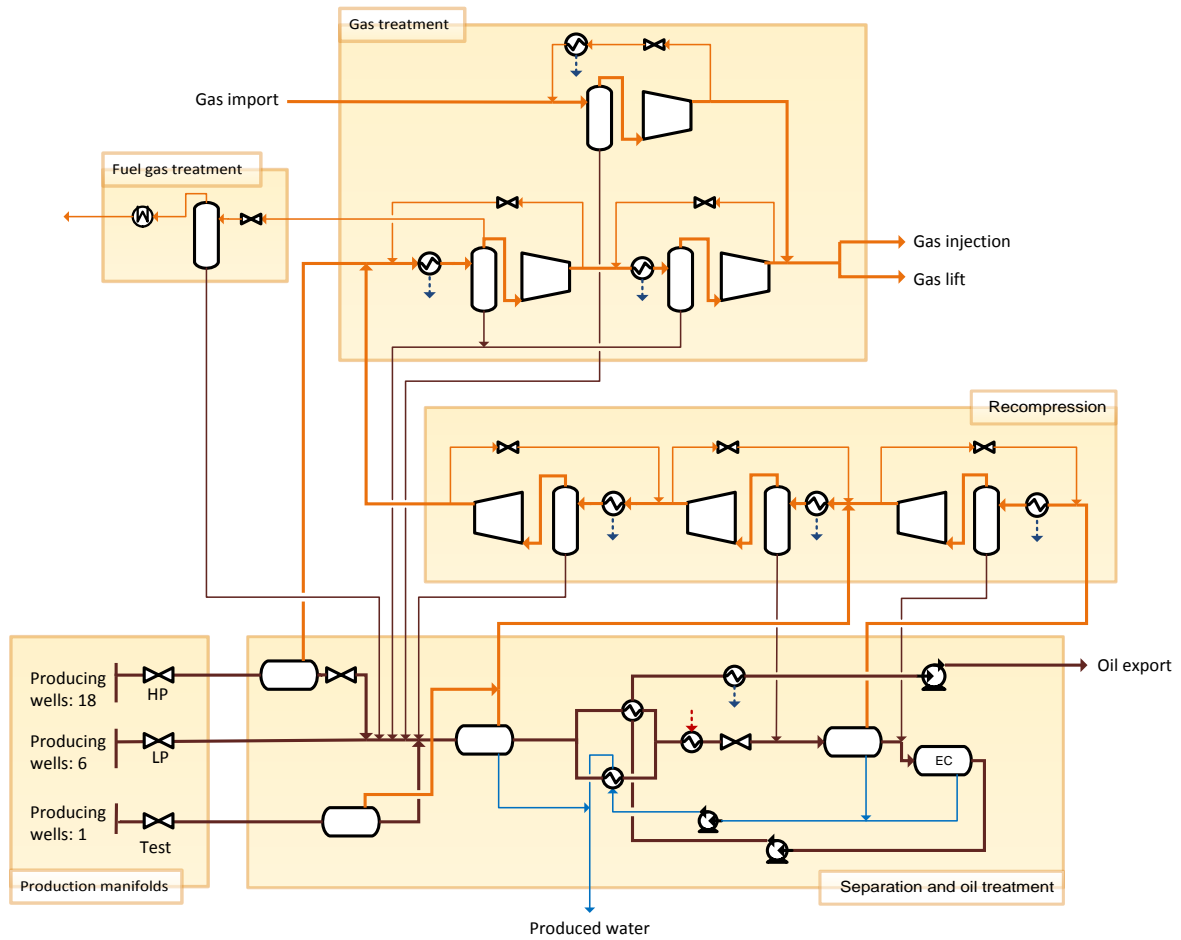


Figure A.12: Process flow diagram of the processing plant of Platform C. Gas streams are shown with orange arrows, water streams with blue arrows, and oil, condensate and mixed streams with brown arrows. Symbol explanations can be found in Fig. A.10.

 Compressor
  Valve
  Pump
  Hydrocyclone
  Separator
  Heat exchanger
  Scrubber
  Degasser
  Column
  Kettle
  Filter

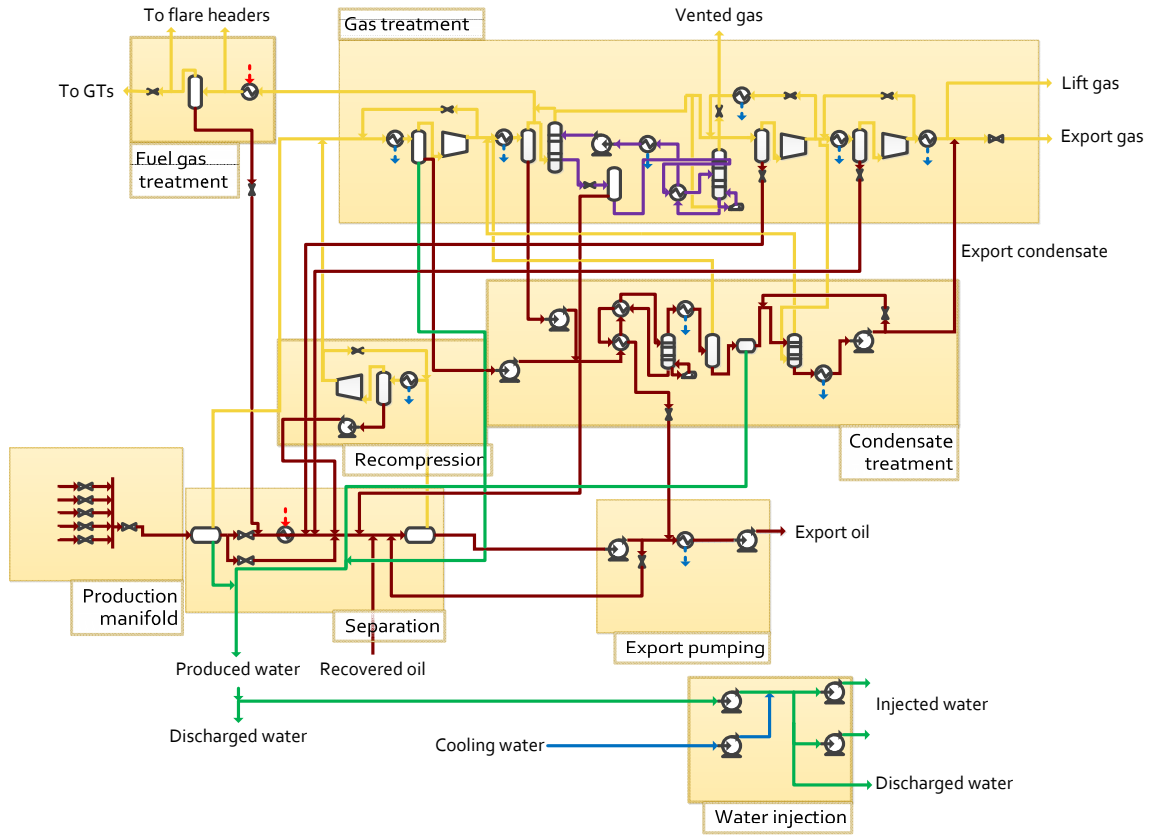


Figure A.13: Process flow diagram of the processing plant of Platform D. Gas streams are shown with orange arrows, water streams with blue arrows, glycol is shown with purple arrows, and oil, condensate and mixed streams are shown with brown arrows.

561 **References**

- 562 [1] Norwegian Ministry of Petroleum and Energy . Facts 2012 – The Norwegian Petroleum Sector. Tech. Rep.; Norwegian
563 Petroleum Directorate; Oslo, Norway; 2012.
- 564 [2] Bækken J, Zenker E. Petrofacts 2007; Faktaheftet 2007. Tech. Rep.; Norwegian Ministry of Petroleum and Energy; 2007.
- 565 [3] Bothamley M. Offshore Processing Options for Oil Platforms. In: Proceedings of the SPE Annual Technical Conference
566 and Exhibition. Houston, USA: Society of Petroleum Engineers; 2004, p. 1–17 (Paper SPE 90325).
- 567 [4] Vanner R. Energy Use in Offshore Oil and Gas Production: Trends and Drivers for Efficiency from 1975 to 2025. PSI
568 Working Paper; Policy Studies Institute; 2005.
- 569 [5] Svalheim SM. Environmental Regulations and Measures on the Norwegian Continental Shelf. In: Proceedings of the SPE
570 International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production. Kuala Lumpur,
571 Malaysia: Society of Petroleum Engineers; 2002, p. 1–10 (Paper SPE 73982).
- 572 [6] Svalheim SM, King DC. Life of Field Energy Performance. In: Proceedings of the SPE Offshore Europe Conference. July;
573 Aberdeen, United Kingdom: Society of Petroleum Engineers; 2003, p. 1–10 (Paper SPE 83993).
- 574 [7] Oliveira Jr. SD, Van Hombbeck M. Exergy Analysis of Petroleum Separation Processes in Offshore Platforms. *Energy
575 Conversion and Management* 1997;38(15-17):1577–84.
- 576 [8] Voldsund M, He W, Røsjorde A, Ertesvåg IS, Kjelstrup S. Evaluation of the Oil and Gas Processing at a Real Production
577 day on a North Sea Oil Platform Using Exergy Analysis. In: Desideri U, Manfrida G, Sciubba E, editors. Proceedings of
578 ECOS 2012 - The 25th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact
579 of Energy Systems; vol. II. Perugia, Italy: Firenze University Press; 2012, p. 153–66.
- 580 [9] Nguyen TV, Jacyno T, Breuhaus P, Voldsund M, Elmegaard B. Thermodynamic analysis of an upstream petroleum plant
581 operated on a mature field. *Energy* 2014;68:454–69.
- 582 [10] Voldsund M, Nguyen TV, Elmegaard B, Ertesvåg I, Røsjorde A, Jøssang K, et al. Exergy destruction and losses on four
583 North Sea offshore platforms: A comparative study of the oil and gas processing plants. *Energy* 2014;74:45–58.
- 584 [11] Nguyen TV, Fülöp T, Breuhaus P, Elmegaard B. Life performance of oil and gas offshore platforms –site-scale integration
585 and exergy-based assessment. *Energy* 2014;73:282–301.
- 586 [12] Casseti G, Colombo E. Thermo-economic analysis of an oil separation process on offshore platform. In: Proceedings of
587 ECOS 2015 - The 28th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact
588 of Energy Systems. Pau, France; 2015, p. 1–17.
- 589 [13] Kloster P. Energy Optimization on Offshore Installations with Emphasis on Offshore and Combined Cycle Plants. In:
590 Proceedings of the Offshore Europe Conference. Aberdeen, United Kingdom: Society of Petroleum Engineers; 1999, p.
591 1–9 (Paper SPE 56964).
- 592 [14] Kloster P. Reduction of Emissions to Air Through Energy Optimisation on Offshore Installations. In: Proceedings of
593 the SPE International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production.
594 Stavanger, Norway: Society of Petroleum Engineers; 2000, p. 1–7 (Paper SPE 61651).
- 595 [15] Nord L, Bolland O. Steam bottoming cycles offshore – challenges and possibilities. *Journal of Power Technologies*
596 2013;92(3):201–7.
- 597 [16] Nord L, Bolland O. Design and off-design simulations of combined cycles for offshore oil and gas installations. *Applied
598 Thermal Engineering* 2013;54:85–91.
- 599 [17] Nguyen TV, Tock L, Maréchal F, Elmegaard B. Oil and gas platforms with steam bottoming cycles: Retrofit integration
600 and thermo-environmental evaluation. *Applied Energy* 2014;131:222–37.
- 601 [18] Pierobon L, Benato A, Scolari E, Haglind F, Stoppato A. Waste heat recovery technologies for offshore platforms. *Applied
602 Energy* 2014;136:228–41.
- 603 [19] Mazzetti M, Nekså P, Walnum H, Hemmingsen A. Novel Energy Efficiency Technologies for Reduction of Offshore CO₂
604 Emissions. In: Offshore Technology Conference. Houston, United States: Offshore Technology Conference; 2013, p. 1–12.
- 605 [20] Mazzetti M, Ladam Y, Walnum H, Hagen B, Skaugen G, Nekså P. Flexible combined heat and power systems for offshore
606 oil and gas facilities with CO₂ bottoming cycles. In: ASME 2014 Power Conference. American Society of Mechanical
607 Engineers; 2014, p. V002T08A003–.
- 608 [21] Walnum H, Nekså P, Nord L, Andresen T. Modelling and simulation of CO₂ (carbon dioxide) bottoming cycles for offshore
609 oil and gas installations at design and off-design conditions. *Energy* 2013;59:513–20.
- 610 [22] Skaugen G, Walnum H, Hagen B, Clos D, Mazzetti M, Nekså P. Design and optimization of waste heat recovery unit
611 using carbon dioxide as cooling fluid. In: ASME 2014 Power Conference. American Society of Mechanical Engineers; 2014,
612 p. V001T03A006–.
- 613 [23] Barrera J, Bazzo E, Kami E. Exergy analysis and energy improvement of a Brazilian floating oil platform using Organic
614 Rankine Cycles. *Energy* 2015;88:67–79.
- 615 [24] Mazzetti M, Nekså P, Walnum H, Hemmingsen A. Energy-Efficient Technologies for Reduction of Offshore CO₂ Emissions.
616 *Oil and Gas Facilities* 2014;3(1):89–96.
- 617 [25] Nguyen TV, Tock L, Breuhaus P, Maréchal F, Elmegaard B. CO₂-mitigation options for the offshore oil and gas sector.
618 *Applied Energy* 2016;161:673–94.
- 619 [26] Nguyen TV, Voldsund M, Breuhaus P, Elmegaard B. Evaluation of energy efficiency efforts of oil and gas offshore pro-
620 cessing. In: Proceedings of ECOS 2015 - The 28th International Conference on Efficiency, Cost, Optimization, Simulation
621 and Environmental Impact of Energy Systems. Pau, France; 2015, p. 1–14.
- 622 [27] Econ Pöyri . CO₂-emissions effect of electrification. Tech. Rep. R-2011-041; Statoil ASA; 2011.
- 623 [28] Voldsund M, Ertesvåg IS, He W, Kjelstrup S. Exergy Analysis of the Oil and Gas Processing a Real Production Day on
624 a North Sea Oil Platform. *Energy* 2013;55:716–27.

- 625 [29] Aspen Technology . Aspen Plus – Modelling Petroleum Processes. Burlington, USA: Aspen Technology; 1999.
- 626 [30] Peng DY, Robinson DB. A New Two-Constant Equation of State. *Industrial & Engineering Chemistry Fundamentals* 1976;15(1):59–64.
- 627
- 628 [31] Soave G. Equilibrium constants from a modified Redlich–Kwong equation of state. *Chemical Engineering Science* 1972;27(6):1197–203.
- 629
- 630 [32] Pénélox A, Rauzy E, Fréze R. A consistent correction for redlich-kwong-soave volumes. *Fluid Phase Equilibria* 1982;8:7–
- 631 23.
- 632 [33] Soave G. 20 years of Redlich–Kwong equation of state. *Fluid Phase Equilibria* 1993;82:345–59.
- 633 [34] Schwartzenruber J, Renon H. Extension of UNIFAC to High Pressures and Temperatures by the Use of a Cubic Equation
- 634 of State. *Industrial & Engineering Chemistry Research* 1989;28(7):1049–55.
- 635 [35] Kotas T.J. *The Exergy Method of Thermal Plant Analysis*. Malabar, USA: Krieger Publishing; 1995.
- 636 [36] Leyland G. Multi-objective optimisation applied to industrial energy problems. Ph.D. thesis; École Polytechnique Fédérale
- 637 de Lausanne; 2002.
- 638 [37] Molyneaux A. A practical evolutionary method for the multi-objective optimisation of complex integrated energy systems
- 639 including vehicle drivetrains. Ph.D. thesis; École Polytechnique Fédérale de Lausanne; 2002.
- 640 [38] Mattson C, Messac A. Pareto Frontier Based Concept Selection under Uncertainty, with Visualization. *OPTE: Optimiza-*
- 641 *tion and Engineering* 2005;6(1):85–115.
- 642 [39] Smith I, Stosic N, Kovacevic A. Power recovery from low cost two-phase expanders. *TRANSACTIONS-GEOTHERMAL*
- 643 *RESOURCES COUNCIL* 2001;:601–6.
- 644 [40] Charron Y, Pagnier P, Marchetta E, Stihlé S. Multiphase Flow Helico-Axial turbine: Applications and Performance. In:
- 645 *Proceedings of the 11th Abu Dhabi International Conference and Exhibition*. Society of Petroleum Engineers; 2004, p.
- 646 1–8 (Paper SPE 88643).
- 647 [41] Falcimaigne J, Decarre S. *Multiphase Production: Pipeline Transport, Pumping and Metering*. Editions OPHRYS; 2008.
- 648 [42] Devold H, Moen TE. *Electrification, Energy Efficiency and Power from Shore*. Tech. Rep.; ABB; 2012. URL:
- 649 [www04.abb.com/global/dkabb/dkabb504.nsf/0/6c0627884bb4ae62c1257a1a0045b877/\\$file/Electrification+Energy+](http://www04.abb.com/global/dkabb/dkabb504.nsf/0/6c0627884bb4ae62c1257a1a0045b877/$file/Electrification+Energy+Efficiency+and+Power.pdf)
- 650 [Efficiency+and+Power.pdf](http://www04.abb.com/global/dkabb/dkabb504.nsf/0/6c0627884bb4ae62c1257a1a0045b877/$file/Electrification+Energy+Efficiency+and+Power.pdf).
- 651 [43] Smith R. *Chemical Process: Design and Integration*; vol. 50. New York, USA: John Wiley & Sons; 2005.
- 652 [44] Linnhoff B, Boland D. *A user guide on process integration for the efficient use of energy*. 1982.
- 653 [45] Rohde D, Walnum H, Andresen T, Nekså P. Heat recovery from export gas compression: Analyzing power cycles with
- 654 detailed heat exchanger models. *Applied Thermal Engineering* 2013;60(1–2):1–6.