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Abstract

Oil and gas platforms in the North Sea region are associated with high power consumption and large CO_2 emissions, as the processing and utility plants suffer from significant changes in production rates and performance losses over the field lifespan. In this paper, a generic model of the overall offshore system is described: its thermodynamic performance is assessed by performing an exergy accounting and rules of thumb for oil and gas platforms are derived. Simulations are built and conducted with the tools Aspen Plus®, Dynamic Network Analysis and Aspen HYSYS®. 62-65% of the total exergy destruction of an offshore platform is attributable to the power generation and waste heat recovery system, and 35-38% to the oil and gas processing. The variability of the feed composition has little effect on the split of the thermodynamic irreversibilities between both plants. The rejection of high-temperature gases from the utility and flaring systems is the major contributor to the exergy losses. These findings suggest to focus efforts on a better use of the waste heat contained in the exhaust gases and on the ways in which the gas compression performance can be improved.

Keywords: Energy systems, Exergy analysis, Oil and gas platforms

1. Introduction

The oil and gas extraction sector was responsible for nearly 26% of the total greenhouse gas emissions of Norway in 2011 [1], since the combustion of natural gas or diesel oil for power generation on offshore installations produces significant amounts of carbon dioxide. The environmental impact and the energy intensity of these facilities are expected to increase in the coming years, as a direct consequence of greater onsite energy use to separate and transport oil and gas to the shore and to inject gas or water into the reservoirs for enhanced oil recovery [2–4]. As environmental awareness has increased in recent decades, more attention has been paid to the ways in which the greenhouse gas emissions and the energy demand of industrial activities can be reduced, by for instance promoting efficiency measures.

However, oil and gas platforms are usually designed for the early life of a petroleum field. The onsite processes suffer from significant changes in production flows and operating conditions over time. They become inevitably less performant, besides the normal process of efficiency reduction due to aging. The performance of this type of facilities is generally expressed in terms of environmental impact, such as the amount of carbon dioxide produced per unit of oil equivalent, or with energy metrics, such as the specific power consumption per unit of oil produced [4,5].

Nomenclature

P	Power, MW		ϵ	relative error
$\bar{e}$	specific exergy (molar), J/mol		η	efficiency
$\dot{E}$	Exergy rate, MW		λ	irreversibility ratio
$\dot{I}$	Irreversibilities rate, MW		*Superscripts*	
$\dot{S}$	Entropy rate, MW/K		$*$	relative
$\dot{V}$	Standard volume flow, Sm^3/hr		ch	chemical
e	specific exergy (mass), J/kg		kn	kinetic
h	specific enthalpy (mass), J/kg		ph	physical
p	pressure, MPa		pt	potential
s	specific entropy (mass), J/(kg·K)		*Subscripts*	
y	component/sub-system exergy ratio		0	dead state
z	pollutant mass fraction		c	chemical specie
Abbreviations			comp	compressor
API	American Petroleum Institute		cv	control volume
ASPEN	Advanced System for Process Engineering		d	destruction
DNA	Dynamic Network Analysis		dr	driver
EOS	Equation of State		exh	exhaust
GOR	Gas-to-Oil ratio		f	fuel
HVAC	Heating, ventilation and air conditioning		gen	generation
NC	Near-Critical		i	inlet
NHV	Net Heating Value, kJ/kg		k	component
NRTL	Non-Random Two Liquid		l	loss
PR	Peng-Robinson		m	metal
TBP	True Boiling Point		mec	mechanical
TEG	Triethylene glycol		min	minimum
TIT	Turbine Inlet Temperature, °C		o	outlet
WOR	Water-to-Oil ratio		p	product
Greek letters			pp	pump
β	chemical exergy correction factor		rf	reservoir fluid
ΔT	temperature approach, K		th	thermal

Svalheim and King [4] stressed the large energy demand of the compression, pumping and injection (gas or seawater) processes and pointed out the benefits that resulted from applying energy-efficiency measures (e.g. operating gas turbines at high load and reducing flaring practices). Their study mentioned that the performance of an offshore platform can be defined as the ratio of the gas consumed onsite to the quantity of oil and gas exported onshore. It was emphasised that the interest of this indicator is limited, as each oil field has different natural characteristics (e.g. gas-to-oil ratio, well-fluid composition, field size): comparing different facilities based on this metric could therefore be misleading.

The other indicators discussed by Svalheim and King [4] are also based either on environmental impact studies or on conventional energy assessments. The latter illustrate the changes from one form of energy to another within a given system and derives from the 1st principle of thermodynamics. This approach has limitations as it does not allow the quantification of the irreversibilities of a system, since energy cannot be destroyed. This shortcoming can be addressed by conducting an exergy analysis, which is based on both the 1st and 2nd principles of thermodynamics.

Unlike energy, exergy can and to a certain extent is destroyed in real processes. An exergy analysis reveals the locations and extents of the thermodynamic irreversibilities present in a system, and exergy

destruction accounts for fuel use throughout successive processes. This method is described in Bejan *et al.* [6,7] and has been applied extensively to evaluate the performance of various industrial processes [5,8–15].

However, there are only a few studies on exergy and offshore processes and relatively little information exists regarding the thermodynamic inefficiencies of the *complete* offshore plant. Examples of exergy analyses on oil platforms are the studies by Oliveira and Van Hombeeck [10] and by Voldsund *et al.* [5,11]. Oliveira and Van Hombeeck carried out an exergy analysis of a Brazilian petroleum plant and focused exclusively on the separation, compression and pumping modules. Their study indicated that the most exergy-consuming processes were the petroleum heating and the gas compression steps, whereas the separation step had the lowest exergetic efficiency.

Voldsund *et al.* [5,11] used a similar approach and simulated the oil and gas processing plant of a Norwegian offshore platform. The sub-systems investigated in their research comprised the separation, recompression and reinjection trains, as well as the fuel gas and oil export processes. Their work demonstrated that the largest exergy destruction took place in the gas reinjection and recompression trains.

The literature seems to contain neither generic analyses considering both the processing and utility systems, nor investigations of the effects of different reservoir fluid compositions on the platform performance.

The goal of this study is to help address these gaps: this paper aims therefore at deriving generic conclusions on the thermodynamic performance of oil and gas platforms in the North Sea region. This research work is originally part of a larger project dealing with the optimisation of electrical energy production on offshore platforms and builds on previous work conducted by the same authors [16]. Three main steps were followed in this study:

- development and validation of a generic model of North Sea oil and gas offshore platforms to generate realistic and reliable production profiles;

- simulation of various operating conditions and well-fluid flows to investigate the overall system behaviour and evaluate the material and energy flows;

- analysis of the energy and exergy consumption patterns with fluctuations of the reservoir fluid composition.

The methodology and the model developed are described and documented in *Section 2*. *Section 3* reports the results obtained for different simulation cases, which are discussed and criticised in *Section 4*. Concluding remarks are outlined in *Section 5*.

2. Methodology

2.1. System description

Reservoir fluids are complex multiphase mixtures with a large variety of chemical components. They contain (i) petroleum, also named crude oil, which exhibits a high content of heavy hydrocarbons, (ii) natural gas, which is mostly methane and light hydrocarbons, and (iii) water. Efficient offshore separation of the oil, gas and water phases is required to maximise the oil production and to minimise its contents of water and gas.

Crude oil is transported to the shore, via pipelines or shuffle tanks, while produced water is cleaned and either discharged overboard or injected into the reservoir for pressure maintenance. Gas may (i) be exported to the coast via a specific pipeline network to be treated onshore, (ii) reinjected into the reservoir via dedicated wells to enhance the oil production or (iii) injected into the oil wells to ease the reservoir fluid lift. Variations and differences across oil and gas platforms may be related to:

- reservoir characteristics (e.g. temperature and pressure, gas-to-oil (GOR) and water-to-oil (WOR) ratios);

- reservoir fluid properties (e.g. chemical composition, thermophysical properties, critical point);

- technical requirements (e.g. crude oil content of gas and water, export temperature and pressure);

- technological choices (e.g. number of trains, gas export, gas lift, system consideration).

However, the conceptual design of these offshore facilities stays similar: although design differences exist from one platform to another, gas purification and exportation, wastewater treatment and seawater injection are the most common gas and water processing technologies in the North Sea region. Moreover, as North Sea crude oil and natural gas have a low content of carbon dioxide, hydrogen sulphide and salt, neither desalting nor sweetening units are necessary onsite. According to [2,17,18], a typical offshore oil and gas platform of this region consists of the following sub-systems:

- Production manifold

- Crude oil separation

- Oil pumping and export

- Gas recompression and purification

- Gas compression and exportation

- Wastewater treatment

- Seawater injection

- Power generation and heat recovery

- Heating, ventilation and air conditioning (HVAC)

- Miscellaneous utilities (e.g. sewage)

The model of the generic offshore platform developed within this study includes the aforementioned processes, excluding the HVAC system and the connected utilities (*Figure 1* and *Figure 2*), which may differ significantly from one platform to another. It was built based on the system configurations presented in the open literature: [2,19–21] for the crude oil processing, [20,21] for the gas treatment process and [22,23] for the water processing. Gas lift and injection were not considered within this study.

The approach of this work assumes an oil and gas processing plant designed for each simulation case investigated, as one of the goals of this study is to provide a basis for comparison between various reservoir fluid compositions. Therefore, the off-design behaviour of the processing plant was not investigated whereas the part-load behaviour of the gas turbines was considered. The design conditions for each component and sub-system modelled in this work are presented further (*Table 1*).

2.2. System model

2.2.1. Fluid modelling

Crude oil contains hydrocarbons ranging from light alkanes to heavy aromatics, naphtenes and paraffins and various impurities such as nickel, nitrogen and sulphur compounds. Complete compositional analyses of this mixture are rarely carried out, which means that the exact chemical composition is unknown. In general, petroleum is characterised by carrying out a true boiling point (TBP) analysis, which gives an approximation of its physical and chemical properties. Molecular weight, viscosity, specific density and gravity are measured, while thermal properties such as heating value and thermal conductivity are estimated by empirical correlations. Petroleum is modelled as a group of known and hypothetical (also called *pseudo-components*) whose properties are derived from the true boiling curve [19,22].

In this study, crude oil was modelled as a mixture of 83 chemical compounds: CO_2, H_2O, O_2, N_2, Ar, H_2S, 47 hydrocarbons and 29 pseudo-components. It had the following bulk properties: an American Petroleum Institute (API) gravity of 39.9, a specific gravity of 0.826, a density of 825.5 kg/m^3 and a content of light hydrocarbons of 27.2 vol%. It was assumed that it is extracted along with associated free gas, with
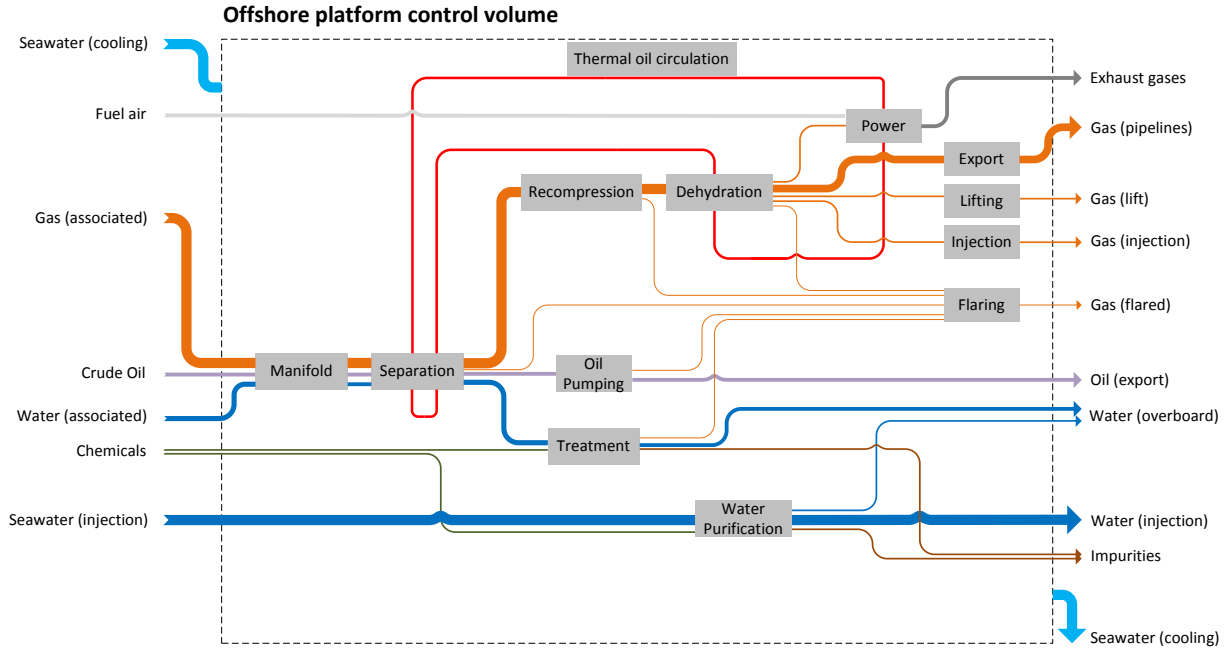
Figure 1: Conceptual layout of processes on North Sea oil and gas platforms

this molar composition: 4.37% N_2, 1.34% CO_2, 75.7% CH_4, 7.22% C_2H_6, 6.70% C_3H_8, 3.89% n-C_4H_{10} and 3.70% n-C_5H_{12}. Standard air, with a molar composition of 77.29% N_2, 20.75% O_2, 1.01% H_2O, 0.92% Ar and 0.03% CO_2, and standard seawater, with a molar concentration, in mol/L, of 0.002 HCO_3^-, 0.525 Cl^-, 0.024 SO_4^{2-}, 0.045 Mg^{2+}, 0.013 Ca^{2+}, 0.450 Na^+ and 0.01 K^+, were considered. The reservoir fluid compositions are presented further in this work (*Table 2*).

2.2.2. Processing plant model

The reservoir fluid is transferred to the platform complex via a network of pipelines and a system of production manifolds **(1)**. The individual streams pass through choke boxes, which consist of valves and chokes, in which they are mixed and depressurised to ease further gas and liquid separation in the separation train **(2)**.

Oil, gas and water are separated by gravity in three stages. Since low pressures and high temperatures ease the separation of these three phases, the pressure of the well-fluid is decreased by throttling valves and its temperature is increased by preheating with a heat medium at the inlet of each stage. The two first stages consist of three-phase separators, the third one consists of a two-phase separator and an electrostatic coalescer. It was assumed that the gravity separators are continuously operated, that physical equilibrium is reached and that no solids are entrained in the gas vapour phase. The power needed to sustain the electric field in the coalescer is ignored, because its contribution to the total power consumption is negligible.

The oil from the separation train enters the export pumping system **(3)**, after having been mixed with oil and condensate that is removed in other parts of the processing plant. It is then pumped and stored in a tank, where the last traces of gas and water are removed by flashing, and finally exported onshore **(4)**.

The gas leaving the separation and oil pumping steps is cooled by heat exchange with seawater, is sent to a scrubber where condensate and water droplets are partly removed and is recompressed to the pressure of the previous separation stage **(5)**. Wet gas enters at the bottom of a packed contactor, in which water is captured by physical absorption with liquid triethylene glycol (TEG).

The water content of the gas after this dehydration **(6)** is usually below 0.01 mol%, which prevents severe corrosion issues in gas pipelines. The wet glycol is depressurised to nearly atmospheric pressure and cleaned of water vapour in a desorption column. A small fraction of dry natural gas is sent for stripping in
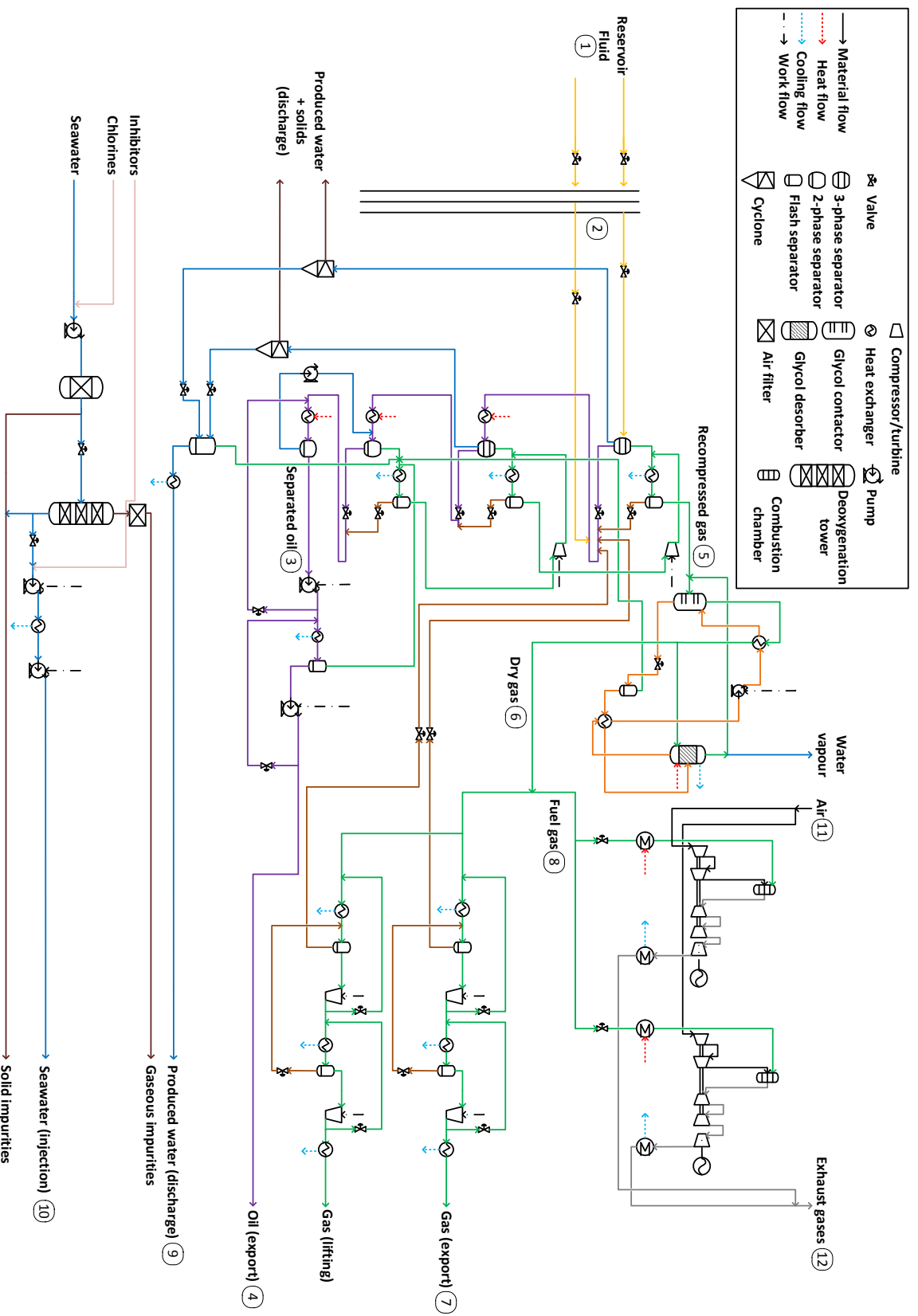
Figure 2: Simplified flow diagram of the offshore platform model

this unit in order to increase the glycol purity to at least 98.5 mol%. Regenerated glycol is pumped to its initial pressure and preheated before re-entering the absorber.

Most of the dry gas is sent to the compression train (7) where it is cooled and scrubbed to further remove heavy hydrocarbons, and compressed for storage and export to the shore. A certain fraction of the dry gas is usually recycled to control the volume of gas entering the compressors and to prevent surge issues. The remaining gas that is not processed is used for power generation directly onsite (8). It is expanded through a succession of valves and combusted with air in gas turbine engines.

The water from the separation and purification trains, also denoted produced water, enters hydrocyclones in which suspended particulates and dissolved hydrocarbons are removed. It then passes through valves and flows through degassers where the last oil and gas traces are recovered before disposal to the sea (9).

In parallel with the oil and gas processing, seawater is treated on the platform for further injection into the reservoir, in order to sustain high pressure conditions and to enhance oil production. The injection fluid must meet strict quality requirements to prevent corrosion and reservoir degradation: it is thus cleaned before being pumped into the reservoir (10). The seawater injection train includes a succession of filters to remove solid impurities such as sand particles and algae, deoxygenation towers to reduce the oxygen content, booster and high pressure pumps.

2.2.3. Utility plant model

The electrical power required onsite is produced by gas turbines, fuelled with a fraction of the natural gas extracted along with oil, and atmospheric air (11). These engines are typically selected on the basis of the maximum expected power demand. They must also, because of the specific features of an offshore plant, satisfy those major requirements:

- high compactness (e.g. small weight and footprint, to lower the capital costs of the oil and gas platform);

- high reliability and availability (e.g. robust gas turbine operation, since the production flows may vary significantly);

- high fuel flexibility (e.g. adaptability to different types of fuels while maintaining an acceptable efficiency).

Hence, the selection of a gas turbine for offshore applications may be a compromise between these three criteria and the engine thermal efficiency. In general, the electrical demand of an offshore platform is supported by multiple and redundant gas turbines running in part-load conditions, which gives additional benefits in terms of plant flexibility and reliability. In this study, the utility system was modelled as two twin-spool gas turbines complemented by power turbines sharing equally the electrical power supply. They are based on the performance characteristics of the SGT-500 engines developed by SIEMENS [24], which are claimed to be highly suitable for offshore and marine applications.

The compressor off-design characteristics are derived by applying a stage-stacking analysis [25–27]. The calculations of the isentropic efficiency of each stage are based on the assumption, presented in Templalexis et al. [28], that total pressure drop can be distinguished in three different components, namely profile (primary) losses, secondary losses and shock losses. Calculations of the primary losses are based on the approach developed in Lieblein [29] and additional losses due to annulus drag, tip clearance and trailing vortices are included based on Saravanamuttoo et al. [30]. The turbine off-design performance is derived by applying the method introduced in Stodola [31] and in Traupel [32].

The waste heat from the exhaust gases is partly used to increase the temperature of a heating medium, such as glycol-water or hot oils, and the remaining is released to the atmosphere via the stack (12). The heating medium circulates in a closed-loop system and provides the heat required on the platform. The highest temperature level of the different process modules is generally found at the reboiler of the desorption column, where triethylene glycol and water are separated. Seawater is processed on the platform as a cooling media, to decrease the amount of heavy hydrocarbons entrained with natural gas in the recompression process, and to prevent foaming and low loads in the separation system.

2.3. System simulation and validation

2.3.1. Simulation basis

The process simulations (*Figure 2*) were carried out with Aspen Plus® version 7.2 [33], with the exception of the power generation and the glycol dehydration systems. Simulations of the production manifolds, petroleum separation, oil pumping, gas recompression and flaring were based on the Peng-Robinson (PR) equation of state (EOS) [34], while simulations of the water purification and injection processes were based on the Non-Random Two Liquid (NRTL) model [35], which is more suited for electrolyte system modelling. Glycol dehydration was simulated with Aspen HYSYS® [36], using the glycol property package, claimed to predict more accurately the behaviour of the triethylene glycol-water mixture [37]. Power generation was simulated by using the in-house tool Dynamic Network Analysis (DNA), which is a program developed at the Technical University of Denmark [38]. The assumptions and parameters are based on the compilation of various data from literature ([4,17,19–21,39–41]) (*Table 1*).

Table 1: Process design assumptions

Reservoir fluid	71°C and 16.5 MPa
Production manifold	Pressure levels: 12 MPa and 7 MPa
Separation train	Pressure levels: 7 MPa, 2.9 MPa, 0.72 MPa and 0.18 MPa
	Temperature levels: feed temperature (1st stage), between 65 and 85°C (others)
	Pressure drops: 0.5-0.3-0.05 bar (3-phase separators), 0.05-0.02 bar (mixers),
	0.25-0.1-0.025 bar (heat exchangers), 0.5-0.3-0.05 bar (flash separators)
Crude oil/glycol heat exchangers	Temperature increase (cold side): 5 K, $\Delta T_{min} = 10$ K
Compression train	Intermediate pressure level: 11.4 MPa
	Recycling: 75 m^3/hr
Gas/seawater heat exchangers	Temperature outlet (hot side): 30-20°C, $\Delta T_{min} = 10$ K
Centrifugal compressors	$\eta_{is} = 63$-67%, $\eta_{mec} = 93\%$ (recompression train),
	$\eta_{is} = 65\%$, $\eta_{mec} = 95\%$ (compression train)
Centrifugal oil pumps	$\eta_{pp} = 62\%$, $\eta_{dr} = 98\%$ (export train)
Centrifugal water pumps	$\eta_{pp} = 81\%$, $\eta_{dr} = 98\%$ (injection train)
Produced water/seawater heat exchangers	Temperature outlet (hot side) = 25°C, $\Delta T_{min} = 10$ K
Skim vessel/degasser	Operating pressure: 1.2 bar
Glycol contactor	Packed column, operating pressure: 7 MPa
Glycol regenerator	1.2 bar, 5 stages, kettle reboiler: 204.4°C, overhead condenser: 98.5°C
Glycol/glycol heat exchangers	Pressure drops: 0.2-0.025 bar
Waste-heat recovery system	Temperature outlet (cold side): 210-220°C
Seawater injection	Standard volume flow rate: 1300 Sm^3/hr
Seawater quality	Oxygen level: 10 ppb, solids content: 5 ppm
Cooling water	Standard volume flow rate: 2400 Sm^3/hr
Flaring-to-fuel gas ratio	12.4 vol% (based on statistical data from the Danish Energy Agency [17])
Export and injection pressures	12.5 MPa (seawater), 14.5 MPa (oil) and 18.5 MPa (gas)

2.3.2. Case studies

Six cases were investigated within this study, corresponding to the same processes and operating conditions – but with different reservoir fluid compositions and loads (*Table 2*). As emphasised by Svalheim and King [4], production flows are strongly time-dependent: it is thus unlikely to find, for one platform, six distinct situations with sensibly similar flow rates and sensibly different gas-to-oil (GOR) and water-to-oil (WOR) ratios. In practice, the operating pressures and temperatures of the separation train are adapted to the reservoir fluid composition. Each simulation case was defined on the same well-fluid molar flow rate, fixed at 18450 kmol/hr, as well as identical design conditions (*Table 1*).

Case 1, referred as the baseline case in the rest of this study, was intended to represent a reservoir fluid containing oil, associated free gas and water with a cut of 15 mol%. Gas- and water-to-oil ratios were chosen based on the production data of different oil platforms operating in the North Sea region in order to simulate a volatile oil. *Case 2* and *Case 3* differ from *Case 1* by the content of water, which was increased by 10 mol% points and decreased by 5 mol% points, respectively.

Cases 4,5 and *6* were intended to represent three different types of oils, respectively black, near-critical (NC) and condensate, which differ in their content of heavy hydrocarbons [40]. Black oil has a low API gravity, a large fraction of heavy hydrocarbons, and a relatively low content of methane, whereas near-critical and condensate oils are characterised by a high API gravity (≥40°) and light hydrocarbons content.

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The latter are generally located at greater depths, which results in higher reservoir pressures [40,42]. These differences in physical properties across petroleum reservoirs were not considered in the process modelling, and the impact of this assumption is briefly discussed further (*Section 4*).

Table 2: Simulation specifications – reservoir fluid properties

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Flow						
Mass (t/hr)	738	757	963	1783	649	543
Volume (m^3/hr)	2044	1750	2153	2567	2093	2147
Mole fraction						
CH_4	49.2	42.9	49.0	29.5	59.0	62.2
C_2H_6	4.70	4.10	6.30	3.60	6.72	6.64
C_3H_8	4.70	4.10	4.03	2.00	3.82	3.18
n-C_4H_{10}	3.40	3.00	3.53	3.90	3.09	2.26
n-C_5H_{12}	1.40	1.20	2.35	3.30	2.21	1.52
n-C_6H_{14}	0.60	0.50	2.36	2.80	1.55	1.12
CO_2	0.90	0.80	0.02	0.02	1.11	0.26
N_2	2.80	2.50	1.55	0.30	0.47	2.01
C_7+ and others	12.3	10.7	15.9	39.6	7.01	5.81
H_2O	20.0	30.2	15.0	15.0	15.0	15.0
Exergy						
$\bar{e}_{ch}$ (GJ/kmol)	1.88	1.64	2.31	4.32	1.54	1.37
$\bar{e}_{ph}$ (MJ/kmol)	7.87	6.90	7.81	6.26	8.66	9.04
$\dot{E}$ (GW)	9.62	8.40	11.9	22.2	7.91	7.04

2.3.3. Error analysis

Simulation results and calibrated values presented in the open literature, in [5,10,11,20,24,39], were used to validate the models and tools developed within this work. Eight model variables were tested (*Table 3*) and the relative errors were calculated based on the following definition:

$$\epsilon = \left| \frac{v_{simulation} - v_{expected}}{v_{expected}} \right| \tag{1}$$

Table 3: Error analysis parameters

Parameter	Unit	Description
$\dot{V}_{water}$	Sm^3/hr	Produced water flow
$\dot{V}_{gas}$	Sm^3/hr	Export gas flow
$\dot{V}_{oil}$	Sm^3/hr	Export oil flow
P	MW	Power consumption
$\dot{m}_{exh}$	kg/s	Exhaust gas flow
η_{th}	%	Gas turbine – thermal efficiency
T_{exh}	°C	Gas turbine – exhaust gas temperature
TIT	°C	Gas turbine – turbine inlet temperature

2.3.4. Sensitivity analysis

Operating parameters, such as gas and oil export pressures, seawater injection flow rate, and pressure differ from one platform to another, depending on the physical properties of the oil field and on the pipeline network requirements. Moreover, different technological choices such as the selection of the gas compressors (e.g. centrifugal, radial or axial, depending on the volume flow and pressure ratio per stage) and of the oil pumps (e.g. centrifugal or positive displacement) apply for each platform. The effects of these different machine characteristics were investigated in a parametric study (*Table 4*), based on the values discussed in [5,10,11,43,44]

Table 4: Sensitivity analysis parameters

Parameter	Description	Base value	Lower	Upper
η_{pp} (%)	Centrifugal oil pump efficiency	62	55	78
η_{is} (%)	Isentropic efficiency (compression)	65	45	80
η_{is} (%)	Isentropic efficiency (recompression)	63-67	45	80

2.4. Exergy analysis

An exergy analysis was performed on the offshore platform system to identify the process units with the greatest internal irreversibilities, based on the following assumptions. The dead state conditions are taken to be $T_0 = 5°C$, $p_0 = 1$ atm and a chemical composition of X_0, as defined in the model of Szargut [45]. The system works in steady-state and no exergy is accumulated.

2.4.1. Flow exergy

As enthalpy and entropy, exergy is a property which can be defined for every stream of matter [6]. The specific exergy of a material stream e is a function of its physical e^{ph}, chemical e^{ch}, kinetic e^{kn} and potential e^{pt} components and is defined as:

$$e = e^{ph} + e^{ch} + e^{kn} + e^{pt} \qquad (2)$$

Kinetic and potential contributions on the flow exergies were assumed to be negligible toward physical and chemical exergies. Physical exergy is related to temperature and pressure differences from the dead state, and the values were computed from the process simulations by applying the Peng-Robinson and Non-Random-Two-Liquid thermodynamic equations of states:

$$e^{ph} = (h - h_0) - T_0(s - s_0) \qquad (3)$$

where h and s are the specific enthalpy and entropy of a stream of matter per unit-of-mass, respectively. Chemical exergy is related to deviations in chemical composition from reference substances present in the environment, and was calculated based on the model of Szargut [45,46] for pure substances, and on the heuristic correlations of Rivero [47] for hypothetical components:

$$e^{ch,c} = \beta NHV_c + \sum z_m e_{ch,m} \qquad (4)$$

where NHV_i stands for the Net Heating Value, z_j the mass fraction of metal impurities, $e^{ch,c}$ the corresponding chemical exergy and β the chemical exergy correction factor.

2.4.2. Exergy destruction and losses

The internal irreversibilities of a given system result in exergy destruction, which can be calculated from the global exergy balance [6]:

$$\begin{aligned} \dot{E}_d &= \sum \dot{E}_i - \sum \dot{E}_o \\ &= \sum \left(1 - \frac{T_0}{T_k}\right) \dot{Q}_k - \dot{W}_{cv} + \sum \dot{m}_i e_i - \sum \dot{m}_o e_o \end{aligned} \qquad (5)$$

where $\dot{E}_d$, $\dot{E}_i$ and $\dot{E}_o$ are the destroyed, input and output exergy rates, respectively, $\dot{m}$ is the mass flow rate of a stream of matter, and $\dot{Q}_k$ and $\dot{W}_{cv}$ the time rates of energy transfer by heat and work ($\dot{Q} \geq 0$ indicates heat transfer to the system, $\dot{W} \geq 0$ work done by the system). The subscripts i and o denote inlet and outlet and the subscript k the boundary of the component of interest.

Alternatively, the exergy destruction rate can be determined from the Gouy-Stodola theorem [7]:

$$\dot{E}_d = T_0 \dot{S}_{gen} \qquad (6)$$

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where $\dot{S}_{gen}$ is the entropy generation rate.

The exergy losses, unlike the exergy destruction, do not result from internal irreversibilities of a system, but rather from the rejection of exergy to the environment without any practical use. They are also denoted external irreversibilities and are for instance associated with waste streams [6,48]. The lost exergy is destroyed by reaching equilibrium when being mixed into the environment and the exergy loss rate $\dot{E}_l$ is defined as:

$$\dot{E}_l = \sum \dot{E}_{rejected} \tag{7}$$

2.4.3. Exergy efficiency and irreversibility ratio

The exergy destruction rate $\dot{E}_{d,k}$ within a specific process component k can then be related to the exergy destruction rate within the whole system $\dot{E}_d$ by calculating the exergy destruction ratio y_d^*, defined as:

$$y_d^* = \frac{\dot{E}_{d,k}}{\dot{E}_d} \tag{8}$$

Similarly, the exergy loss rate $\dot{E}_{l,k}$ within a specific process component k can be related to the exergy loss rate of the whole system $\dot{E}_d$ by calculating the exergy loss ratio y_l^*, defined as:

$$y_l^* = \frac{\dot{E}_{l,k}}{\dot{E}_l} \tag{9}$$

The thermodynamic performance of a given component k can be expressed by defining its exergetic efficiency η_k and by identifying the fuel and product of interest. It should be emphasised that fuel and product exergies $\dot{E}_{f,k}$ and $\dot{E}_{p,k}$ of the component k are not necessarily equal to its input $\dot{E}_{i,k}$ and output $\dot{E}_{o,k}$ exergies.

$$\eta_k = \frac{\dot{E}_{p,k}}{\dot{E}_{f,k}} = 1 - \frac{\dot{E}_{d,k} + \dot{E}_{l,k}}{\dot{E}_{f,k}} \tag{10}$$

The definitions of exergetic fuels and products for the components and sub-systems investigated within this study are extensively discussed in Bejan *et al.* [6] and in Kotas [12–14].

Alternatively, for systems such as physical separation plants or that include dissipative devices, the relationship between the irreversibilities of a system and its total exergy input can be expressed with the exergy loss ratio λ, as defined in Kotas [13,14]. It derives from the exergetic efficiency definition proposed by Grassmann [49] and represents the proportion of the total exergy flowing into the control volume that is lost through irreversibilities. The criteria λ is denoted irreversibility ratio in the rest of the study to avoid confusion with the exergy loss ratio y_l^* defined in Bejan *et al.* [6].

$$\lambda = \frac{\dot{I}}{\dot{E}_i} \tag{11}$$

where $\dot{I}$ is the rate of irreversibilities of the investigated system.

3. Results

3.1. System simulation and analysis

3.1.1. Process simulation

The offshore platform model was used to investigate the six case studies in order to obtain the net oil, gas and water production flows (*Table 5*) and the electrical energy demand of each module (*Table 6*). The power consumption of the offshore platform ranges from 22.6 MW to 31.1 MW and the maximum value is obtained with black oil as input (*Case 4*), as the power demand of the oil pumping section increases sharply.

Results indicate that the major electricity consumer is generally the compression train, which is responsible for 42% to 56% of the total power demand in the remaining cases.

The seawater injection process ranks second with a share of 17% to 23% and a power demand of about 5.3 MW. Seawater pumped to a pressure of 12.5 MPa for further injection into the reservoir is not extracted through the oil and natural gas wells and does not enter the separation train. As the water purification and injection processes are not integrated within the other onsite systems, crude oil, produced oil, gas and water do not flow through this section of the platform. The electrical energy demand of this process is therefore independent of the composition and flow rate of the reservoir fluid. It depends exclusively on the flow rate of the seawater required for pressure maintenance and on the pressure level requirements.

The third greatest power demand of the offshore facility is either the gas recompression process or the oil pumping, depending on the amount of gas extracted along with oil. The power consumption of these compressors is smaller in the cases with a high gas-to-oil ratio (*Cases 5 and 6*): this suggests that most of the associated gas, rich in light hydrocarbons such as methane and ethane, exits the separation train at the first stage and bypasses the booster compressors.

Case 4 is characterised by a different power consumption profile: the oil pumping section has the greatest demand, accounting for about 41% of the total plant consumption. The results suggest that the additional power needed to pump the surplus of oil overcomes the decrease of power required in the gas compression section. The duty of the recompression train also increases in this specific case, because hydrocarbons of intermediate molecular weight (e.g. butane, pentanes, hexanes and heptanes) are not flashed at the first separation stage but at the second and third ones. This results in larger recycle flows between the separation and recompression modules and thus in a significant increase of the power and cooling demands of this section.

In contrast, a greater water fraction has a negative feedback on the electrical energy demand of the processing plant, since water is directly removed in the three-phase separators and only small amounts are carried through the plant. The effect of a higher water fraction in the wet gas leaving the recompression train is limited: the power demand of the dehydration process slightly increases because of the larger glycol flow in the absorption-desorption loop to reduce the water content of gas to the required specification.

Table 5: Net oil, gas and water production flow rates of the offshore platform system

| | Simulation cases | | | | | |
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Oil (export)						
Molar (Mmol/hr)	3.2	3.0	4.5	9.9	2.3	1.7
Volume (Sm^3/hr)	614	548	843	1962	407	316
Mass (t/hr)	508	451	686	1628	325	255
Gas (export)						
Molar (Mmol/hr)	11.1	9.7	10.8	5.9	12.9	13.6
Volume (kSm^3/hr)	262	228	255	139	305	319
Mass (t/hr)	234	203	223	118	267	273
Produced water						
Molar (Mmol/hr)	3.4	4.7	2.1	1.7	2.3	2.3
Volume (Sm^3/hr)	60.9	85.2	38.0	30.2	41.4	41.6
Mass (t/hr)	61.0	85.3	38.0	30.2	41.5	41.6

3.1.2. Error analysis

The separation, gas recompression and injection process models were verified against literature [5,10, 11,20,24,39] and the error analysis showed an average deviation smaller than 7-8% for all tested variables (*Figure 3*). The maximum difference was found in the prediction of the power consumption of the processing plant. For loads above 50%, which is the region of interest, the maximum relative error was found in the prediction of the gas turbine thermal efficiency and was around 3.7%.

Table 6: Power consumption (values expressed in (MW)) of the processing plant

| | Simulation cases | | | | | |
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Compression	10.8	9.5	10.4	6.0	12.3	13.1
Recompression	2.8	4.1	4.7	6.9	3.5	3.0
Oil pumping	4.0	3.6	5.5	12.9	2.7	2.1
Seawater injection	5.3	5.3	5.3	5.3	5.3	5.3
Total (MW)	22.9	22.6	26.0	31.1	23.8	23.5
Total (MJ/Sm$^3_{oil}$)	134	148	111	57.1	211	268
Total (MJ/t$_{rf}$)	112	107	97	63	132	156
Total (MJ/m$^3_{rf}$)	40	46	43	44	41	39
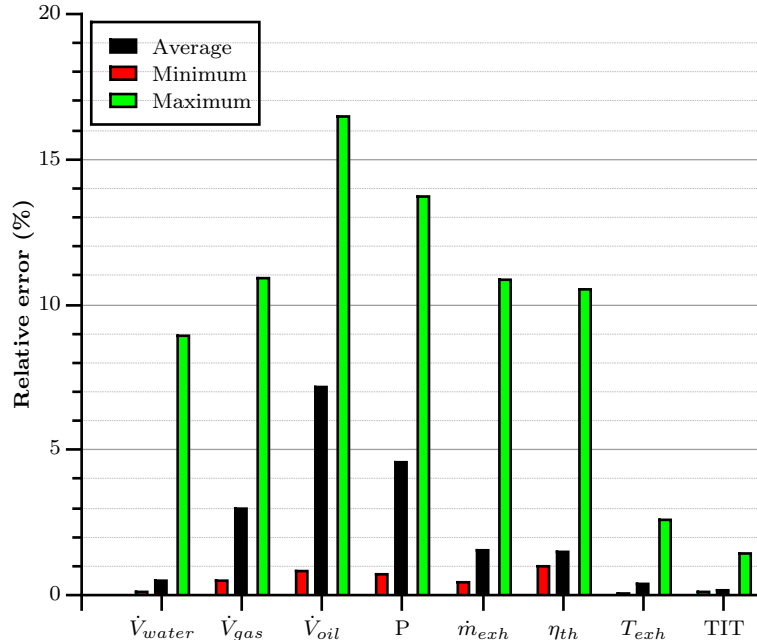
Figure 3: Minimum, average and maximum relative error ϵ (%) for the tested model variables (*Table 3*)

3.1.3. Sensitivity analysis

A sensitivity analysis on three parameters (*Table 4*) was conducted to illustrate the trends of the power consumption profile as a function of the efficiencies of the gas compressors and of the oil export pumps. The results suggest that the total power demand is mostly sensitive to the efficiency of the gas compressors in the compression train (*Figure 4*). The power demand between a state-of-the-art centrifugal compressor operated near its design point and a poorly designed one, or operated at part-load, can vary from 3 to 9 MW. This difference is significant in all cases but is particularly marked in *Case 5* and *Case 6*, where near-critical and condensate oils are processed. The variations in power demand with the efficiencies of the oil pumps are comparatively small, with the exception of the black oil case where the electrical power demand of the export train is much more significant (*Figure 5*). Similar trends are found with the variations of efficiencies of the gas recompressors, although they are less marked than with the gas compressors (*Figure 6*).

3.2. Exergy analysis

3.2.1. Exergy flows

The results of the combined process simulations and exergy accountings (*Table 7*) indicate that the produced water and exhaust gases from the power generation system have a small specific exergy content. Operations such as compression and pumping, which aim at increasing the physical exergy of the gas and

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Figure 4: Effect of the isentropic compressors efficiency η_{is} (45-80%) on the compression train *(left)* and total *(right)* power demands

Figure 5: Effect of the centrifugal oil pumps efficiency η_{pp} (55-78%) on the oil export *(left)* and total *(right)* power demands
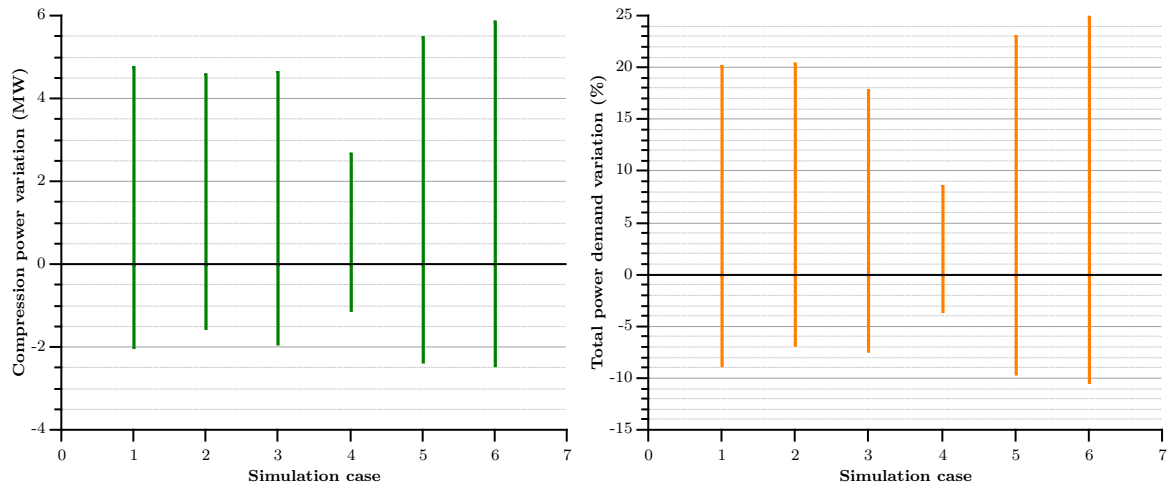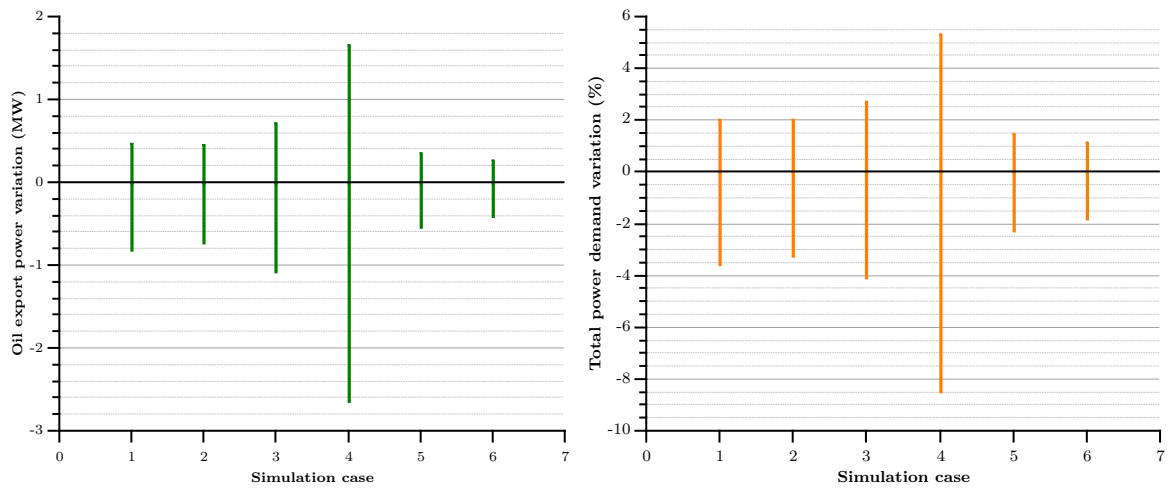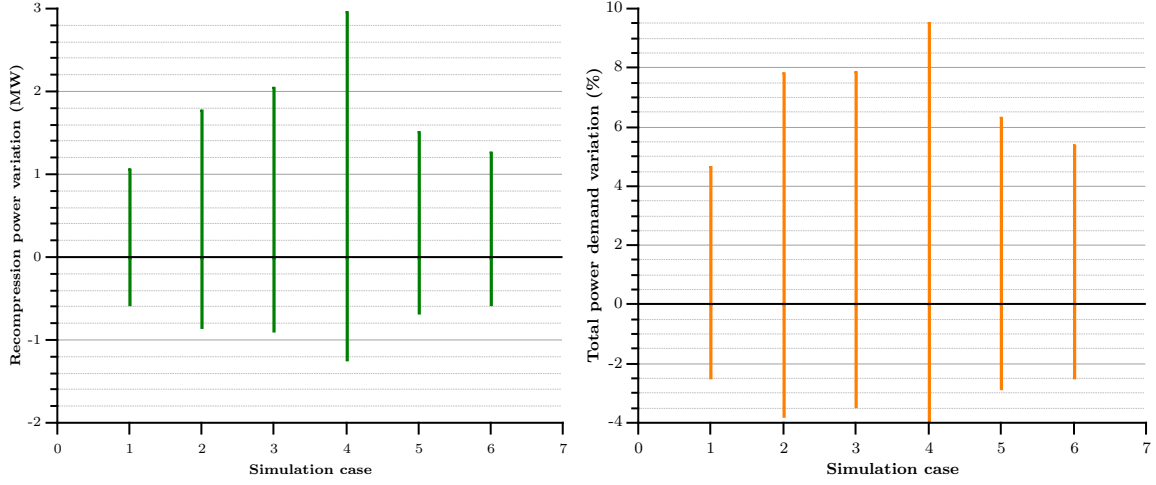
Figure 6: Effect of the isentropic compressors efficiency η_{is} (45-80%) on the recompression train *(left)* and total *(right)* power demands

oil flows, have a minor impact on the total specific exergy of these streams. The input and output exergies of the offshore platform system are dominated by the chemical exergy content of the oil and gas streams, which ranges from 43 to 48 MJ/kg and is at least 100 times as great as their physical exergy (*Table 2*). Most of the exergy found at the outlet of the offshore platform system is thus carried by these two streams, independently of the case considered.

Table 7: Flow rates and associated specific exergies (values given in (Mmol/hr) and (GJ/kmol), respectively) – stream numbers refer to *Figure 2*

| | Simulation cases | | | | | | | | | | | |
| Stream number (type) | Case 1 | | Case 2 | | Case 3 | | Case 4 | | Case 5 | | Case 6 | |
	$\dot{n}$	$\bar{e}$	$\dot{n}$	$\bar{e}$	$\dot{n}$	$\bar{e}$	$\dot{n}$	$\bar{e}$	$\dot{n}$	$\bar{e}$	$\dot{n}$	$\bar{e}$
1 (Reservoir fluid)	18.5	1.88	18.5	1.64	18.5	2.31	18.5	4.32	18.5	1.54	18.5	1.37
2 (Reservoir fluid)	18.5	1.87	18.5	1.63	18.5	2.30	18.5	4.31	18.5	1.53	18.5	1.36
3 (Separated oil)	3.7	6.42	3.2	6.48	4.8	6.52	10.2	7.18	2.5	6.07	1.8	6.36
4 (Pumped oil)	3.2	7.17	3.0	6.77	4.5	6.80	9.9	7.37	2.3	6.40	1.7	6.63
5 (Recompressed gas)	11.7	0.96	11.6	0.96	11.9	1.04	6.4	0.99	13.6	1.00	14.9	1.02
6 (Dry gas)	11.4	0.97	9.9	0.97	11.0	1.00	6.1	1.00	13.1	1.00	13.8	0.98
7 (Compressed gas)	11.1	0.99	9.7	0.99	10.8	1.02	5.9	1.02	12.9	1.02	13.6	1.00
8 (Fuel gas)	0.18	0.97	0.17	0.97	0.19	1.00	0.22	1.00	0.18	1.00	0.18	0.98
9 (Produced water)	3.4	<0.001	4.7	<0.001	2.1	<0.001	1.7	<0.001	2.3	<0.001	2.3	<0.001
10 (Injected water)	71.1	<0.003	71.1	<0.003	71.1	<0.003	71.1	<0.003	71.1	<0.003	71.1	<0.003
11 (Air)	20.5	<0.001	20.3	<0.001	21.4	<0.001	22.8	<0.001	20.9	<0.001	20.7	<0.001
12 (Exhaust gases)	20.5	0.003	20.4	0.003	21.4	0.003	22.9	0.004	21.0	0.003	20.8	0.003
Flared and vented gases	0.02	0.96	0.02	0.96	0.02	0.99	0.03	0.99	0.02	0.99	0.02	0.97

3.2.2. Exergy destruction, losses and efficiencies

The total destroyed exergy on the overall offshore platform, i.e. including both the processing and the utility plant, is between 68 and 84 MW, with 62-65% of this being attributable to the gas turbines and waste heat recovery and 35-38% to the oil, gas and seawater processing plant (*Table 8*). The largest exergy destruction of the *complete* system lies, in *any case*, in the combustion chambers of the gas turbines and amounts to almost 50% of the total exergy destruction of the platform. It can be split into thermodynamic irreversibilities due to mixing of natural gas and compressed air and to the combustion process by itself. This exergetic analysis demonstrates that the variability of the well-fluid composition has a moderate effect on this result, but, on the opposite, has a significant impact on the share of exergy destruction across the processing plant.

The total exergy destruction of the processing plant exclusively is between 24 and 32 MW. The maximum

Table 8: Exergy destruction (values expressed in (MW)) of the offshore platform

Sub-system, component	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
			Simulation cases			
Production manifold	6.01	5.25	6.10	6.07	6.32	6.75
Separation	3.49	3.60	4.36	8.41	2.37	1.82
Heaters	0.85	0.73	1.16	2.32	0.63	0.47
Throttles	1.87	1.62	2.56	5.40	1.19	0.92
Mixers & others	0.77	1.25	0.64	0.69	0.55	0.43
Recompression	2.88	4.85	3.54	3.32	3.61	3.30
Coolers	1.92	3.00	1.80	1.23	2.10	2.07
Throttles	0.15	0.20	0.13	0.07	0.18	0.11
Compressors	0.62	0.82	1.04	1.58	0.74	0.60
Mixers & others	0.19	0.82	0.57	0.44	0.58	0.52
Glycol dehydration	3.18	3.23	2.75	1.76	3.24	3.68
Fuel gas and flaring	1.23	1.39	1.48	1.42	1.52	1.53
Gas compression	4.78	4.20	4.62	2.61	5.48	5.80
Coolers	1.57	1.35	1.50	0.69	1.86	1.95
Compressors	2.92	2.57	2.83	1.63	3.33	3.56
Mixers	0.02	0.02	0.02	0.02	0.02	0.02
Throttles	0.27	0.27	0.27	0.27	0.27	0.27
Oil pumping	2.29	2.29	2.94	7.69	1.06	1.12
Pumps	1.14	1.02	1.60	3.64	0.73	0.60
Coolers	1.03	1.27	1.34	4.05	0.33	0.52
Throttles & others	0.12	0.10	0.12	0.21	0.07	0.05
Wastewater treatment	0.11	0.20	0.07	0.06	0.07	0.07
Seawater injection	0.23	0.23	0.23	0.23	0.23	0.23
Processing plant	24.2	25.2	26.1	31.6	23.9	24.3
Power generation	40.8	40.2	43.4	47.8	41.5	41.3
Compressors	2.87	2.82	3.12	3.61	2.92	2.92
Turbines	4.55	4.51	4.74	5.00	4.59	4.59
Combustion chamber	33.0	32.6	35.1	38.7	33.4	33.2
Others	0.40	0.40	0.43	0.47	0.41	0.41
Heat carrier circulation	3.41	3.37	3.55	3.79	3.43	3.42
Utility system	44.2	43.6	47.0	51.6	44.9	44.7
Platform	68.4	68.8	73.1	83.2	68.8	69.0

exergy destruction is found in *Case 4* (31.6 MW), which is characterised by a crude oil poor in light hydrocarbons, while the minimum is found in *Case 6* (23.9 MW), featured by a crude oil with a high gas content. A comparison of the specific exergy destruction per unit of mass, actual volume and exergy input is presented further (*Table 12*).

The results also indicate that the largest thermodynamic irreversibilities of the processing plant occur in the production manifold and in the gas compression systems, followed by the recompression and separation modules (*Table 9*). In contrast, the contributions from the wastewater treatment and the seawater injection processes are negligible, and the exergy destruction taking place in the oil pumping step is moderate in most cases. The latter is significant only when black crude oil enters the platform (*Case 4*) because of the higher content of heavy hydrocarbons and larger oil flow at the inlet of the export pumping section.

The exergy destruction within the production manifold is caused by the well-fluid depressurisation from 16.5 to 7 MPa without generation of any useful product. The second greatest irreversibilities are found at the gas compression section: they are mainly due to the poor performances of the gas compressors and to the recycling around these components to prevent surging. Significant exergy destruction also takes place in the recompression step because the streams flowing out of the separation train are mixed at different temperatures and compositions before scrubbing and throttling.

Table 9: Exergy destruction ratio of the offshore platform (excl. utility system) y_d^* (%)

Sub-system	Simulation cases					
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Production manifold	24.8	20.8	23.4	19.2	26.4	27.8
Separation	14.4	14.3	16.7	26.6	9.9	7.5
Recompression	11.9	19.2	13.6	10.5	15.1	13.6
Dehydration	13.1	12.8	10.5	5.6	13.6	15.1
Fuel gas and flaring	5.1	5.5	5.7	4.5	6.4	6.3
Gas compression	19.8	16.6	17.7	8.3	22.9	23.9
Oil pumping	9.5	9.1	11.3	24.4	4.4	4.6
Wastewater treatment	0.5	0.8	0.3	0.2	0.3	0.3
Seawater injection	1.0	0.9	0.9	0.7	1.0	0.9

The exergy losses of the offshore platform are nearly constant in all cases: they are related to effluent streams rejected into the environment without being valorised, such as flared gases, discharged seawater, wastewater and exhaust gases from the gas turbine systems (*Table 10*). Approximatively 60% of the total exergy losses is due to the direct rejection of high-temperature exhaust gases to the environment, while about 30% is associated with the flaring and ventilation of natural gas throughout its processing. The remaining 10% is related to the exergy content of cooling and wastewater discharged overboard: these exergy losses are comparatively small, as the discharged streams are rejected at nearly environmental conditions (*Table 11*). The exergy losses associated with exhaust gases are higher in *Case 3* and *Case 4*, as the mass flow rate of exhaust gases increases with the power demand of the processing plant.

Table 10: Exergy losses (values expressed in (MW)) of the offshore platform

Waste stream	Simulation cases					
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Exhaust gases	18.5	18.3	20.4	23.4	19.1	18.9
Cooling water	2.46	2.81	2.80	5.17	2.21	2.09
Flared gases	10.5	10.4	11.4	13.0	10.8	10.7
Wastewater	0.85	1.21	0.33	0.28	0.36	0.37
Platform	32.3	32.7	34.9	41.9	32.5	32.1

A comparison based on the irreversibility ratio λ suggests that the offshore processing becomes less performant with increasing gas-to-oil and water-to-oil ratios (*Table 12*). It also indicates that the total exergy destruction and losses within the offshore platform represent only 0.5-1.5% of the total exergy flowing into the system.

In the baseline case, the gas turbine system, the gas compression and the oil pumping processes have a low exergetic efficiency, of about 27%, 42% and 37% respectively, as a result of large thermodynamic

Table 11: Exergy loss ratio of the offshore platform y_l^* (%)

| Waste stream | Simulation cases | | | | | |
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Exhaust gases	57.3	56.0	58.5	55.8	58.8	58.9
Cooling water	7.62	8.59	8.02	12.3	6.80	6.51
Flared gases	32.5	31.8	32.7	31.0	33.2	33.3
Wastewater	2.63	3.70	0.95	0.67	1.11	1.15

Table 12: Specific exergy destruction, losses and irreversibility ratios

| Irreversibilities | Simulation cases | | | | | |
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
$\dot{E}_d$ (MW)	68	69	73	83	69	69
e_d (MJ/t$_{rf}$)	334	327	273	168	382	457
e_d (MJ/m$^3_{rf}$)	120	142	122	117	118	116
$\dot{E}_l$ (MW)	32	33	35	42	33	32
e_l (MJ/t$_{rf}$)	158	156	130	85	180	213
e_l (MJ/m$^3_{rf}$)	57	67	58	59	56	54
Total (MW)	101	102	108	125	101	101
Total (MJ/t$_{rf}$)	491	483	404	253	562	670
Total (MJ/m$^3_{rf}$)	177	209	181	175	174	170
λ (%, internal)	0.71	0.82	0.61	0.37	0.87	0.98
λ (%, total)	1.05	1.21	0.91	0.56	1.28	1.43

irreversibilities associated with chemical reaction and heat transfer in the first process, and with mixing and friction in the second and third ones. No meaningful exergetic efficiency could be defined for the production manifold and the gas flaring modules. They mainly consist of arrangements of mixers and throttling valves, which are dissipative by design: they destroy exergy without generating any useful product. Alternatively, as the exergetic product is null, it may be argued that the exergetic efficiency is 0.

This exergetic analysis shows that exergy is introduced onsite in the form of raw materials (crude oil, fuel air, seawater and chemicals) and exits in the form of valuable products (oil and gas sent onshore) and waste streams (produced water, exhaust and flare gases) (*Figure 7*). The chemical exergy of the reservoir fluid flows through the offshore platform system and is separated into the oil and gas chemical exergies with only minor destruction in the processing plant, as no chemical reactions take place. On the opposite, chemical exergy is consumed to a great extent in the utility plant, as a fraction of the produced natural gas is used and combusted in the gas turbines.

3.2.3. Possibilities for improvement

Generic recommendations for improvement of the platform performance can be derived from the exergy analysis. The overall goal is to reduce or eliminate the exergy destruction and losses of the plant and the main ones are ranked as follows:

1. Combustion chambers of the gas turbines (chemical reaction, mixing, friction, heat transfer)
2. Exhaust gases from the waste heat recovery system (high temperature and large physical exergy)
3. Flared and vented gases from the processing plant (large chemical and physical exergy contents)
4. Production manifold (mainly due to depressurisation)
5. Compressors in the gas compression train

The largest thermodynamic irreversibilities are found at the combustors. In theory, the exergy destruction taking place in the combustion chambers could be reduced by decreasing the overall air-to-fuel ratio [6]. However, it implies that the combustion temperature increases toward the adiabatic flame temperature, which causes significant thermal stress and impacts the lifetime of the components.

The exhaust gases leaving the waste heat recovery system are rejected at high temperature to the atmosphere, which represents a substantial loss of physical exergy. The excess heat contained in the flue gases
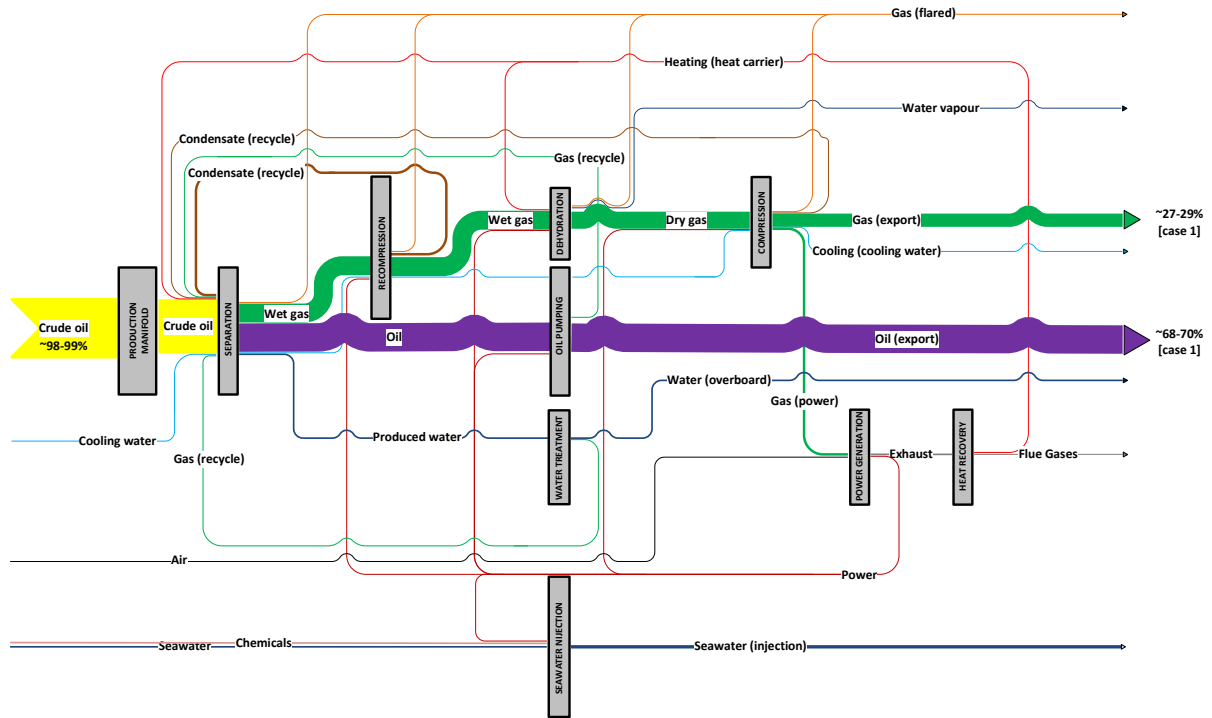
Figure 7: Grassmann diagram of the offshore platform system

could be partly recovered for producing electricity, by using a bottoming cycle such as an organic Rankine cycle. The stack temperature and the exergy loss of the platform system would decrease in consequence. The waste heat recovery system could in theory be further improved: the heat carrier is heated from 200°C to 220°C, suffers severe pressure drops in the closed-loop system, and the large temperature gaps with the exhaust gases of the gas turbine are responsible for a significant exergy destruction associated with heat transfer. However, as the highest temperature requirement of the processing plant is found at the kettle reboiler of the glycol desorber (about 200-205°C), integrating a direct heat exchange between the glycol/water mixture and the flue gases would have a limited positive impact.

The third main source of exergy destruction/losses is associated with flared gas from the processing plant: continuous flaring should therefore, if possible, be limited. The gases sent for flaring could be recovered in the processing plant: this presents the combined benefits of decreasing the exergy losses, reducing the environmental impact of the offshore facility and recovering more gas for sale.

The irreversibilities taking place in the production manifold could *a priori* hardly be reduced with the current set-up of offshore processing since a lower pressure of the well-fluid is required at the inlet of the separation train. Higher pressure levels in the separation train would lead to smaller exergy destruction rates in the production manifold train, although this might result in lower gas recovery and conflict with the process constraints of other system sections. The integration of multiphase flow expanders would allow energy recovery from the throttling steps and would lead to smaller exergy destruction rates. However, it is a challenge to design such devices which could stand the processing of multiphase mixtures (oil, water, gas and sand) on the long term. Implementing them in the separation train might be easier, as most of the water-sand mixture is removed in the first-stage separator.

Substantial exergy destruction is associated with the gas compression train, as the compressors typically used on oil offshore platforms are featured by a relatively low isentropic efficiency and gas recirculation, since flow variations are expected and surge must be prevented. The sensitivity of the total power consumption of the processing plant to the compressors efficiency emphasises the importance of this system section:

its performance could be increased by re-wheeling (removal and replacement of the compressor internals), implementing variable speed drive systems, using alternative control methods and adjusting the stagger angle of vanes. Another possibility is to integrate compressors of different sizes in parallel so that the majority of them is operated near their optimal operating point.

4. Discussion

4.1. Comparison with literature

The process simulation results are in accordance with the findings of Svalheim and King [4], who stated that the gas compression, oil pumping and seawater injection steps are the most energy-consuming steps. It was suggested to use the produced water extracted along with oil and gas instead of treated seawater [50], but it was also emphasised that the hydrocarbon content of the wastewater emulsion might result in plugging issues. Further research and quality control of the treated water are thus necessary before this option becomes viable [22].

The present results on the thermodynamic performance of oil and gas platforms can be compared to the results of Voldsund *et al.* [5,11], which were introduced in *Section 1*. They considered a real-case offshore facility located in the North Sea region, processing a crude oil rich in methane (78%) and producing about 370 kSm^3/hr of natural gas, 135 Sm^3/hr of oil and 67 Sm^3/hr of water. In this regard, the most similar case investigated within this work was *Case 6*. The power demand was about 18.5 MW without seawater injection, which is about 20% smaller than the value calculated and presented in their paper. This difference is mainly imputable to the assumptions on the isentropic efficiency of the gas compressors in the present study, which was at first set to 65% and varied by conducting a sensitivity analysis. In their work, the isentropic efficiency was between 47% and 69% in the recompression train and between 54% and 69% in the compression section. Other differences are the total volume of gas processed in the gas compression section, which is about 15% larger, and the final pressure level, which is 23.5 MPa.

Furthermore, the comparison between these two research works also suggests that the gas compression-treatment process is one of the most exergy-destructive steps of a typical oil offshore processing. Similarly, the recompression and separation steps rank next, while the exergy destruction taking place in the oil export pumping is generally negligible. The main discrepancy lies in the accounting of the exergy associated with overboard discharge of cooling water. It is in the present work accounted as an exergy loss whereas it is considered as exergy destruction in their study, because of a different choice of the system boundaries. They suggested to focus on the gas compression and injection train, by for instance eliminating anti-surge recycling. One of the main emphases was on the performance improvement of this system section, since a more efficient gas process would induce a reduction of the power consumption and a lower exergy destruction in both the oil processing and power generation plants. There was on overall a good correspondence between the findings of both works.

Oliveira and Van Hombeeck [10], who investigated a real-case Brazilian oil platform, also stressed the great power demand and the significant exergy destruction associated with the gas compression step. However, the authors pointed out the importance of the crude oil heating operations taking place within the separation module. The considerable exergy consumption in the feed preheating is responsible for a furnace demand of about 25 MW exergy for a feed of 450 t/hr, which differs strongly from the findings of Voldsund *et al.* [11] and the present results. These discrepancies are mainly due to the temperature differences between the North Sea and the Brazilian feeds flowing out of the oil reservoir. The feed characteristics at the inlet of the separation train were 7.4°C and 10.78 bar in their work and the well-fluid should therefore be heated before oil, gas and water separation. On the opposite, it was about 65-75°C at the inlet of the first-stage separator in the present work and in the study of Voldsund *et al.* [5,11]. These differences in results and conclusions suggest that offshore platforms located in different oil regions (e.g. North Sea, Gulf of Mexico, Brazilian Basin) may, with respect to process and exergy considerations, present highly different characteristics.

Finally, energy conservation measures on offshore installations, such as waste heat recovery, are discussed in the works of Kloster [51,52]. It was also argued that the replacement of simple cycle gas turbines by

combined cycle ones would be the most significant energy efficiency measure for oil and gas platforms, as this would greatly reduce their fuel consumption and CO_2-emissions. Moreover, the addition of a bottoming steam cycle, as suggested, could improve the performance of the overall platform in both design and part-load conditions, while maintaining a high flexibility of the power generation units.

4.2. Significance and limitations of the study

The results of this paper may be used as guidelines to predict the major sources of thermodynamic irreversibilities of a North Sea oil and gas platform. However, caution should be exercised in drawing conclusions for cases presenting different design setups. Although gas export is the preferred gas processing technology in the North Sea oil region [2], processing routes such as gas injection are practiced on several platforms [17] to support the reservoir pressure and enhance oil recovery. It is for instance the case of the oil platform investigated in Voldsund *et al.* [5,11]. It may be difficult to estimate the exergy destruction profile for these cases, since it depends on factors such as the injection pressure, the compression train efficiency and the gas recirculation. The power demand and the exergy destruction are nonetheless expected to increase because the injected gas must be compressed to a higher pressure than in the reservoir to induce oil flowing [5,53]. Similar reasoning applies to the gas lift process: the difference being that the gas is injected into the well flow in the wellhead to decrease the specific gravity of the reservoir fluid.

Another possible difference across offshore platforms is the inventory of gas turbine units. The study on which this work builds on, conducted by the same authors [16], considers two twin-spool and a single one-spool gas turbines. It is shown that the utility system accounts for about 67.3% of the total exergy destruction, which is similar to the results presented in this paper. This indicates that the exergy destruction share between the processing and the utility plants is moderately affected by the number and type of the power generation units. However, if no waste heat recovery system is integrated after the gas turbines, the exergy losses are expected to be greater, because the flue gases would be released to the environment at a higher stack temperature.

The present findings may also be used for making qualitative estimates on the magnitude of exergy destruction for different compositions and operating conditions. The investigations carried out in this work were made at specific temperatures and pressures of the reservoir and processing systems, which may not be encountered in actual cases. In practice, temperatures and pressures of the separation train are adjusted to control the oil and gas flows in each stage to prevent foaming, to ensure a minimum circulating flow and to enhance the recovery of light hydrocarbons. One of the main aims is to reduce the power consumption of the recompression system while reaching the desired crude oil vapour pressure at the outlet of the export pumping train. Pressure levels are generally lower and temperature levels in the reservoir as the API gravity of oils increases (heavy oils) [39,40]. This suggests that the exergy destruction in the production manifold, the separation train and the recompression system may be slightly underestimated in this study.

Finally, a conventional exergy analysis, as conducted in this work, does not allow:

- the evaluation of interactions and cost flows among the system components and processes, as it does not consider their mutual interdependencies [15];

- the assessment of the environmental impact of this facility, as the exergy losses associated with the emissions of pollutants are neither proportional to their toxicity, nor to the exergy costs related to their treatments [54].

Several methods have been proposed over the last decades to increase the level of details and accuracy of an exergy analysis, with the examples of the extended exergy accounting method [54,55], the exergoeconomic [56,57] and the advanced exergy-based analyses [15,58]. The readers are referred to these references for more extensive explanations of these concepts. Future work will address the limitations of the exergy analysis method by applying these approaches to the specific case of an oil and gas platform.

5. Conclusion

A generic North Sea offshore platform was modelled in order to establish rules of thumbs for oil and gas platforms of that region. The material outflows and energy requirements under different sets of production

flows were predicted and validated. This overall model includes power generation, oil and gas processing, gas purification and seawater injection sub-models. The first sub-model was calibrated by use of published data from SIEMENS while the others were verified by comparison with open literature.

Six simulation cases were investigated to analyse the effects of different gas-to-oil and water-to-oil ratios on the thermodynamic performance of this integrated system, based on the exergy analysis method. Exergy is destroyed with a split of about 65%/35% for the utility system (power generation and waste heat recovery) and the oil, gas and water processing, respectively. Exergy losses are mostly due to the rejection of high-temperature exhaust gases from the cogeneration plant to the environment and on flaring practices. However, the exergy destruction and loss rates represent only 0.5 to 1.5% of the total input exergy because of the inherently large chemical exergy content of oil and natural gas.

At identical design conditions, the irreversibility ratio of an offshore platform is higher with increasing gas-to-oil and water-to-oil ratios, suggesting that the thermodynamic performance of this overall system is optimal with low well-fluid contents of gas and water.

Although the exact values of exergy destruction would differ from one platform to another, it is suggested that significant inefficiencies and possibilities for performance improvement of the system exist. Recovering more thermal exergy from the exhaust gases, limiting or eliminating flaring practices and monitoring the gas compression trains could increase the thermodynamic performance of conventional oil and gas offshore platforms.

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