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Nguyen, Tuong-Van; Junior, Silvio de Oliveira

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Thermodynamic analysis of oil and gas platforms over various production profiles and feed compositions

Tuong-Van Nguyen^a and Silvio de Oliveira Júnior^b

^a Department of Mechanical Engineering, Polytechnic School of the University of São Paulo, Avenida
Professor Luciano Gualberto 380 – Butantã, São Paulo, Brazil

e-mail: tungu@mek.dtu.dk

^b Department of Mechanical Engineering, Polytechnic School of the University of São Paulo, Avenida
Professor Luciano Gualberto 380 – Butantã, São Paulo, Brazil

e-mail: soj@usp.br

Abstract:

Oil and gas platforms present similar structural designs but process fluids with different thermo-physical and chemical properties. In addition, the field properties, such as the gas-to-oil and water-to-oil ratios, change significantly over time. It is therefore not possible to suggest a standard flow diagram of these facilities. Different processes and operating modes may be implemented to maximise the petroleum production and improve the overall system performance. The present work evaluates, in a first step, the variations of the heating, cooling and power demands over time, in terms of energy and exergy. Feed compositions and production profiles, which correspond to data from actual fields, are used for calibrating the simulations. In a second step, the minimum energy and exergy losses of the platform are assessed by performing thermodynamic analyses, assuming an ideal scenario in which all processes are run at their design points. This approach proves to be useful for evaluating consistently different options for oil and gas production, and for determining, in a further step, the most promising solutions for minimising the energy use over a field lifetime.

Keywords:

Oil and gas; Energy; Exergy; Optimisation; Process integration

1. Introduction

Offshore platforms across the various petroleum regions worldwide include similar operations: oil, gas and water separation, oil stabilisation, gas compression and purification and produced water treatment [3]. The exact system layout depends on whether the petroleum and gas are to be exported in ready-for-sale conditions or will undergo additional onshore processing, as well as on other factors specific to each field.

Hydrocarbon processing may be energy-intensive – the power consumption can range from a few to several hundred MW, depending on the gas production and required pressures [6]. The heating demand can be negligible if the feed is volatile enough, or amount to several tens, which is the case for viscous feeds or low-temperature ones. The cooling needs are usually much greater, as a consequence of all the compression operations on-site. These dissimilarities in energy demands across fields result from differences in the (i) feed conditions (e.g. properties of the petroleum and water mixture, from the composition to the temperatures); (ii) implemented processes (e.g. choice of the CO₂ and H₂O-treatment technologies, if relevant [7]); (iii) operating strategies and modes (e.g. gas injection, import or export); (iv) operating conditions (e.g. temperatures and pressures).

At present, floating production, storage and offloading (FPSO) facilities have gained more interest in countries such as Brazil [14]. They may be operated on remote fields where an extensive pipeline infrastructure is not available for gas export, and the gas should either be injected or liquefied. They may be placed on fields where the produced petroleum contains large quantities of CO₂, as high as 25% on a volume basis, and the produced gas must be treated accordingly with an absorption unit or a membrane process. They may be operating on fields with temperatures as low as 20°C, which

creates additional challenges in the hydrocarbon processing. In this case, an extensive network of oil heaters is required to reach the desired vapour pressure and to enhance the three-phase separation process. Such issues may be specific to Brazilian pre-salt fields – the petroleum extracted in the North and Norwegian Seas feeds is generally at greater temperatures and has negligible contents of carbon dioxide [18].

The priority of the oil and gas operators is to maximise the oil throughout, as well as the gas liquids, if relevant. A major challenge when designing such systems is that the petroleum production curves, water- and gas-to-oil ratios, and feed properties change through the field lifetime [16]. Usually, the production of crude oil ramps up in the first years, reaches a peak quickly, and then declines over time until the platform is shut down [9]. It may be stimulated by gas injection or new wells may be built to extend the field lifetime. Gas extraction follows a similar trend, but the gas production peak does not coincide with the oil production one. Water extraction usually increases over time steadily. Gas is seen as a by-product that can be injected into the reservoir through dedicated wells or through the production ones to ease the extraction process. Part of the produced gas is treated and used in gas turbines for power and heat generation purposes. Usually, the reduction of the energy use is considered secondary compared to the need for a stable and continuous operation. The literature has shown that there exist numerous possibilities for energy efficiency improvements [11]. For instance, energy integration on offshore platforms is minimal, with possibly a couple of internal oil/oil or oil/water heat exchangers. The use of waste heat from the gas turbine exhausts to generate additional power through Rankine cycles is not common, because of weight and space issues on offshore facilities [12]. Centrifugal compressors are operating far from their nominal design points – gas is recirculated to prevent surge, which results in additional power consumption and cooling demand.

Previous works deal with the energy performance of these offshore facilities, with a focus on those present in the Gulf of Mexico, North and Norwegian Seas as well as the Brazilian pre-salt ones. Bothamley [3] compares the differences in processes between different facilities in various petroleum regions, and underlines that those depend on whether oil is to be exported for sales or for further treatment. Svalheim [15] emphasises the high power demand of the gas compression and water injection modules over the whole field lifetime. In a subsequent work, it is pinpointed that the facility may be operated in severe part-load conditions because of the large flowrate variations.

This is also confirmed by the later researches of Voldsund et al. [17] and of Nguyen et al. [10]. Their works demonstrate that, for platforms processing high-temperature feeds, the heating demand is generally negligible. However, the compression operations represent the lion's share of the power consumption and exergy destruction. Similar results are found for ones with low-temperature feeds, with the difference that large amounts of exergy are also destroyed in the petroleum heating steps. Finally, Sánchez et al. [14] compare the thermodynamic performance of three FPSO operating modes and concludes that the energy requirements increase with the crude oil content in the feed.

These studies show the dependency of the process performance on the feed conditions and properties, as well as on the operating modes. They pinpoint how the power demand and total exergy destruction on-site are related to the gas production. However, none actually investigates how different production profiles, together with different operating modes and feed compositions, actually impact the energy requirements of oil and gas platforms.

The aim of the present work is therefore the following. We assess the variations of the power, heating and cooling demands of oil and gas platforms over time, considering different feed properties, field conditions and operating modes. Based on a typical platform layout suggested by the industrial partners, we analyse the performance losses over the life cycle of the plant and suggest possible improvements.

2. Methods

2.1. System description

Oil and gas processing plants can be classified into two categories, depending on the degree of processing performed offshore and onshore, as stressed by Bothamley [3]. The plant can either produce a fully stabilised crude oil ready for sales, or an unstabilised which requires further treatment onshore. This decision impacts the plant design, for example, the number of pressure levels of the separation train, the addition of an oil desalting process, the implementation of a gas treatment system, etc. However, despite these differences, several processes, listed below, are found on all platforms, with differences in operating conditions (Figure 1):

- the production manifolds, in which the streams extracted from the wells are mixed and depressurised;
- the separation train, in which oil, gas and water are separated in two to four stages operating at different pressures and possibly different temperatures, throttling valves and heaters/internal heat exchangers are generally implemented;

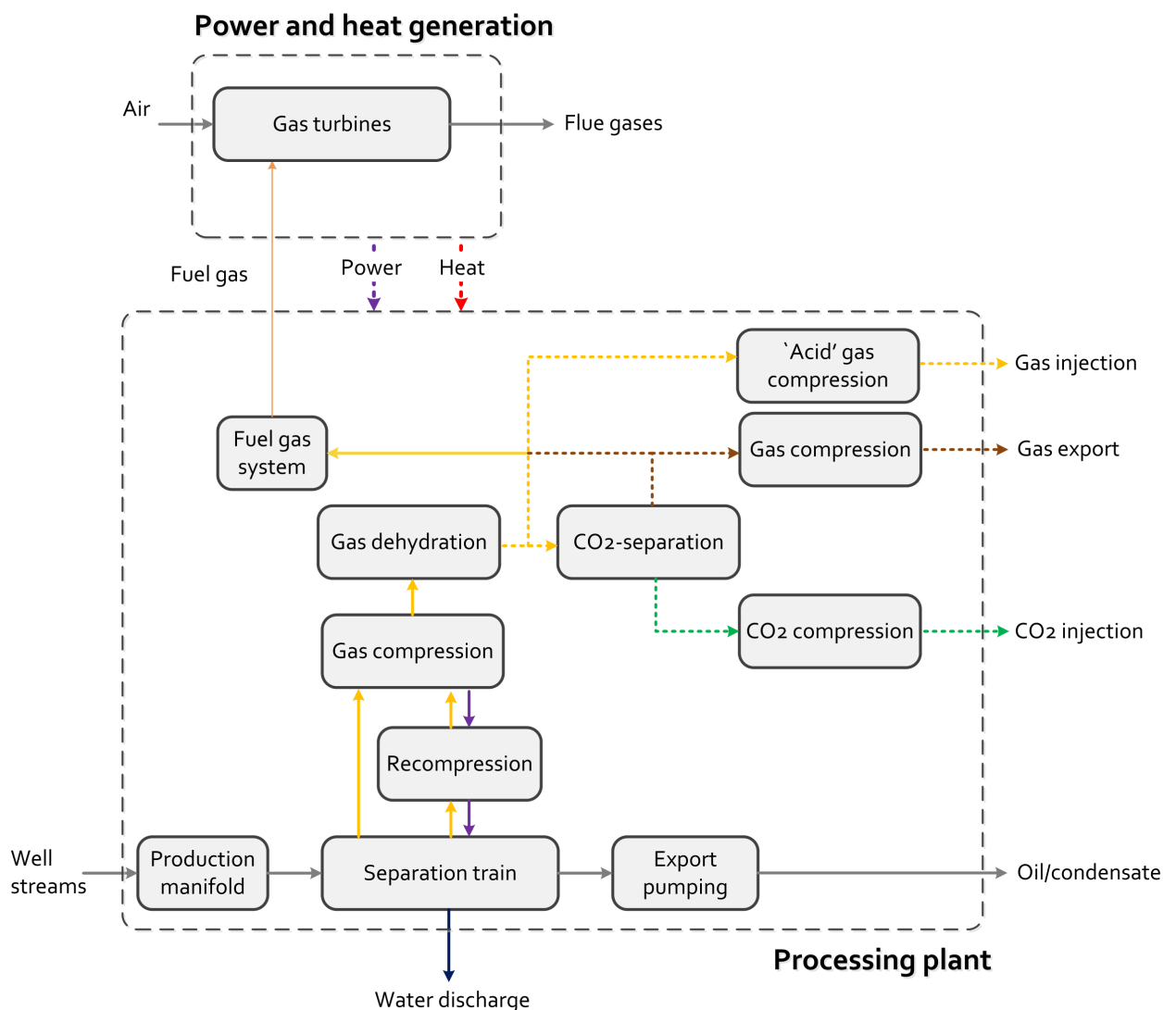


Fig. 1. Block diagram of a typical Brazilian floating production storage offloading (FPSO) platform. The grey arrows denote the petroleum and oil streams, the yellow ones the associated gas before purification, the indigo ones the condensate recovered from the gas scrubbing, the brown ones the cleaned gas after dehydration and CO₂-cleaning, and the green ones for the CO₂-rich gas streams.

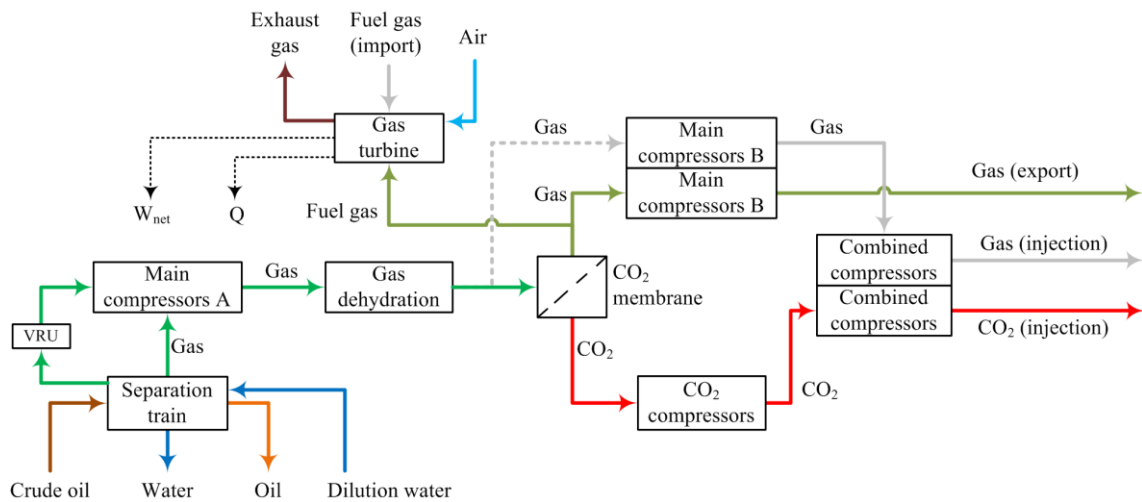


Fig. 2. Simplified scheme of the operational mode 1 (maximum oil/gas) – start of exploitation

- the oil treatment process, in which the oil is purified (desalting and further dehydration, if required), stabilised (vapour pressure requirements), pumped and cooled to the desired storage/export pressure and temperature;
- the produced water treatment process, where water extracted along with oil and gas is cleaned from oil droplets through degassers and cyclones before being injected back into the reservoir or released into the environment;
- the gas recompression train or vapour recovery unit, where the gas recovered from the separators is compressed to the initial feed pressure before further treatment;
- the gas compression and treatment process, where the produced gas is compressed in several steps to the final desired pressure, for example for injection or export – it may include purification steps to remove water, carbon dioxide and other impurities such as hydrogen sulphide;
- the carbon dioxide compression process, where the gas recovered from the treatment process is compressed to the discharge pressure for injection into the reservoir;
- the fuel gas system, where a fraction of the recovered gas is heated and dehydrated by scrubbing for further use in the gas turbines.

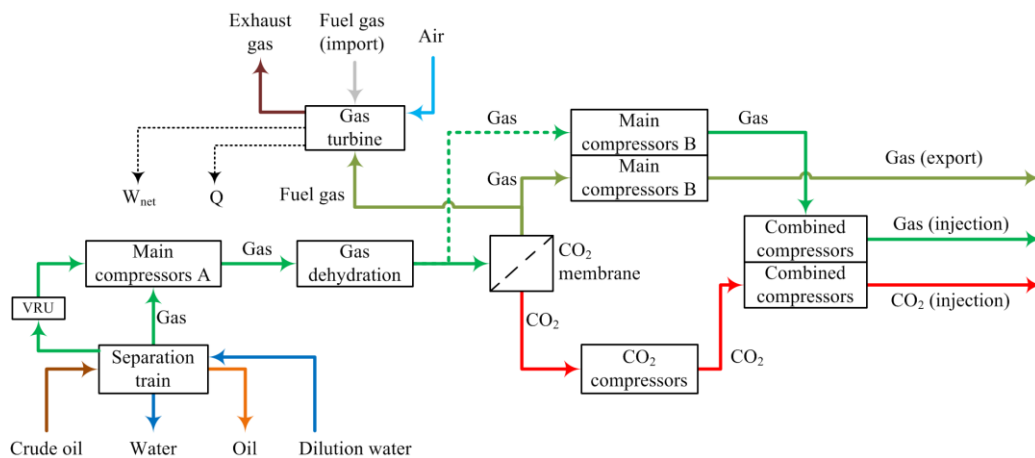


Fig. 3. Simplified scheme of the operational mode 2 (50% BSW) – mid-life conditions

The processing plant is run in different operational modes depending on the production of oil, gas and water. At the beginning of the exploitation, and until the peaks of production of oil and gas are passed, the aim is to maximize the export of hydrocarbons (mode 1 – Figure 2): all gas is exported to the shore. In parallel, water production continuously increases, and gas may be partly injected and partly exported (mode 2 – Figure 3). The assumption presented in Sánchez et al. [14] is that this mode is activated as the water flow represents half of the liquid production. Finally, the gas production decreases until it is not enough for power production – it is then fully injected, and gas or diesel are imported and consumed (mode 3 – Figure 4).

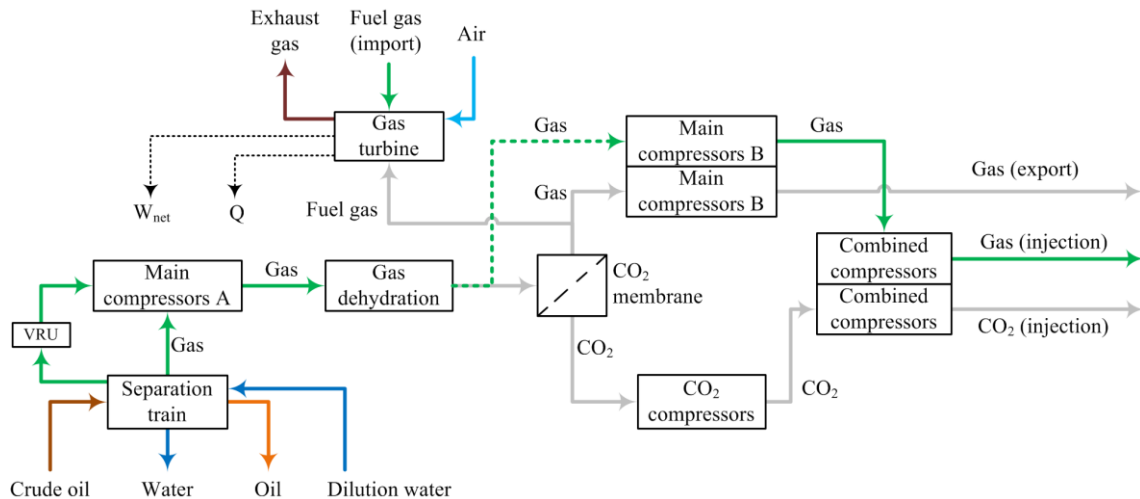


Fig. 4. Simplified scheme of the operational mode 3 (maximum water/CO₂) – end of life conditions

Power and heat are required on-site to drive the abovementioned processes, and are generally generated by burning a fraction of the associated gas in gas turbines. In some cases, an additional furnace is implemented on-site for additional heating purposes, if the heat from the exhaust gases is not sufficient. It is thus possible to add in the analysis the two following processes:

- the gas turbines, where the actual power requirements are satisfied by burning the fuel gas;
- the waste heat recovery process, where a hot medium is used to recover heat from the exhaust gases for satisfying the heating demand in the petroleum separation.

In the rest of this work, we refer to the first category of processes as the oil and gas processing plant, and the second category as the utility one.

2.2. System modelling and simulation

The process models were developed with Aspen PLUS ® version 7.2 [1] based on the Peng-Robinson [13] equation of state. The simulations build on the same assumptions, directly extracted and discussed with the industrial partners:

- The processing plant is designed to handle a crude oil production of 150,000 barrels per day, as well as a gas production of 3,000,000 Sm³/day.
- The feed properties are taken to be 2,300 kPa and 40°C after gathering and depressurising the well-streams in the production manifold.
- The following processes, dew point control with desiccants and oil desalting are not modelled in details, and are represented by a black-box model which output is set based on available measurements.
- Separation of carbon dioxide with membranes is modelled as a black-box with the initial CO₂-concentration, feed and retentate pressures as inputs, and the flowrates and composition of each outflow as outputs. The model is calibrated and developed based both on the available data and the approach of Gassner et al. [4].

2.3. System performance

The performance of the oil and gas processing configurations is assessed by applying energy and exergy analyses. The aim is first to derive the variations of the heating, cooling and electricity demands as a function of the oil, gas and water profiles and of the design point of the platform. It is then to assess the corresponding exergy destruction and irreversibilities in the plant, for suggesting possible improvements.

As underlined by the first law of thermodynamics [2], energy cannot be created or destroyed, but is only transformed from one form to another. An energy mapping shows where energy is converted (for example from heat to electricity) and dissipated (for instance when discharging water into the sea), but cannot be used consistently to assess the system performance.

For an open control volume, in steady-state conditions and steady-flow processes, the energy balance is written as:

$$\dot{Q} - \dot{W} = \sum \dot{m}_{out} h_{out} - \sum \dot{m}_{in} h_{in}$$

Where \dot{Q} and \dot{W} stand for the energy rates in the form of heat and power, \dot{m} for the flow rate of a given material stream (inflowing or outflowing) and h the specific enthalpy. In the rest of this work, we neglect the changes in potential and kinetic energies, which are negligible in comparison to the chemical energy of the oil and gas flows.

Exergy may be defined as ‘the maximum theoretical useful work (shaft work or electrical work) as the system is brought into complete thermodynamic equilibrium with the thermodynamic environment while the system interacts with it only’. Unlike energy, exergy is not conserved but is destroyed in real systems because of the irreversible phenomena taking place, such as heat transfer across finite temperature differences and pressure drops. This concept can be therefore used to pinpoint, identify and quantify the performance losses and possible improvements of a given system. The exergy balance of an open control volume in steady-state and steady-flow processes can be expressed as [5]:

$$\dot{E}_d = \sum \dot{m}_{out} e_{out} - \sum \dot{m}_{in} e_{in} + \sum \dot{E}^Q - \dot{W}$$

where \dot{E}_d is the destroyed exergy, $\sum \dot{m}_{out} e_{out}$ and $\sum \dot{m}_{in} e_{in}$ are the exergy flows associated with material streams, and $\sum \dot{E}^Q$ the exergy flow associated with heat transfer. The exergy flows associated with streams of matter are related to their physical (temperature and pressure) and chemical properties (chemical composition), while the exergy associated with a heat flow is related to the temperature at which the heat transfer process takes place. The concept of exergy is intrinsically linked to a dead state, which is defined here as 1.013 bar, 28°C, and with the chemical composition of the environment defined by Morris and Szargut [8]. This reference temperature is taken considering the sea temperature used for cooling purposes on Brazilian oil and gas platforms.

2.4. Case studies

The present work builds on three feed compositions, three production profiles and three operating modes. The feed compositions taken for the analysis are the following:

- a gas condensate/near-critical oil (Composition 1), typical of Norwegian fields, with a negligible carbon dioxide content (less than 1%), and about 81% methane, 6.5% ethane, 3.6% propane, 6% butanes, on a molar basis;
- a CO₂-lean and volatile petroleum (Composition 2), from a Brazilian field, with a negligible carbon dioxide content (less than 1%), and about 62% methane, 7% ethane, 5% propane and 3% butanes;

- a CO₂-rich and volatile petroleum (Composition 3), from a Brazilian field, with a content of 26% carbon dioxide, 41% methane, 5% ethane and 3% propane.

It is worth noticing that these compositions are taken as a basis for the nominal operating point of the oil and gas facility, which corresponds to the peak production of oil. In other words, the feed contains a higher fraction of light hydrocarbons and carbon dioxide as the gas-to-oil ratio increases; and the oil treatment process is then operated in off-design conditions.

The production profiles selected for the simulations (Figures 5 and 6) are taken from the measurement database of the Norwegian Petroleum Directorate – they correspond to actual fields operating in the last 30 years. The production profiles are selected for the simulations based on the similarities in terms of gas-to-oil ratios. For example, volatile oils are most often associated with high gas-to-oil ratios, at the opposite of heavy ones.

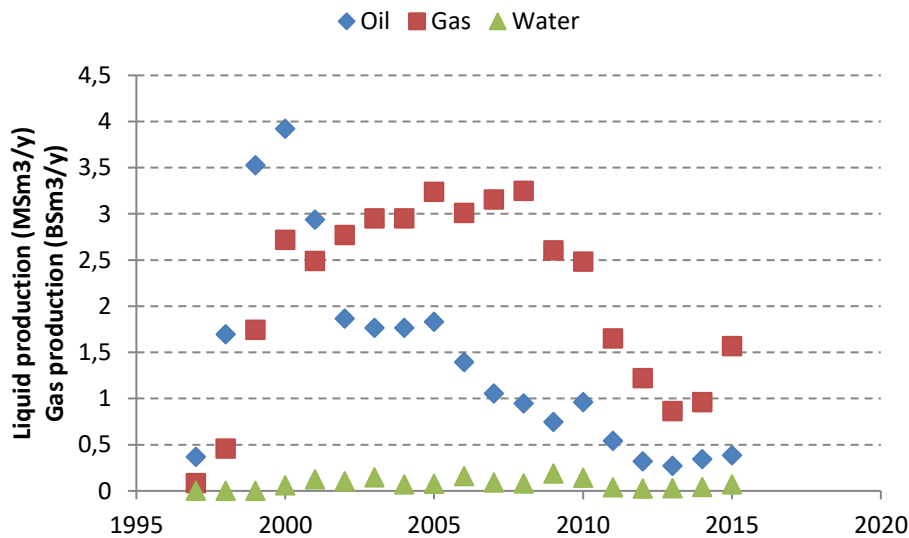


Fig. 5. Production profile of the Njord facility, used for calibrating the water- and gas-to-oil ratios of the simulations with near-critical oils/gas condensates (initial dissolved GOR > 600)

Representative points for each important period of the field life are simulated. They correspond to (i) the beginning of the extraction process, with a sharp increase of the oil production, (ii) the peak production of oil, (iii) the peak production of gas, (iv) the inflexion points of the oil and gas production, when new wells are operated, or when additional gas injection is implemented, (v) end-life conditions, when the water production increases.

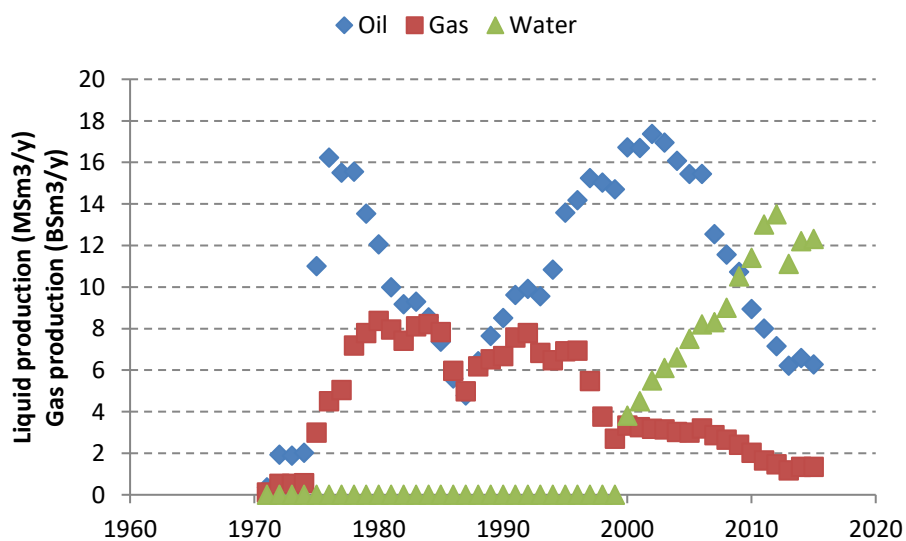


Fig. 6. Production profile of the Ekofisk facility, used for calibrating the water- and gas-to-oil ratios of the simulations with volatile oils (initial dissolved GOR < 600)

3. Results and discussion

3.1. Energy assessment

Although the feed compositions investigated in the present work present significant differences in carbon dioxide, methane and heavy hydrocarbons, several general trends can be drawn. For readability, only the gas condensate case is presented here (Figures 7 and 8). The energy demands for the last two feed compositions are presented in Appendixes A – B.

First, the heating demand is associated with two main processes, namely the oil and gas separation, and the fuel gas heating. The first process is the most energy-intensive, as oil, gas and water are heated between the first and second stage to enhance phase separation. The heating demand reaches a maximum at the oil peak production – the variations of the gas and water flows have little impact, as most gas and water are recovered upstream. The heat requirements of the second process increase together with the gas production, since more fuel gas needs to be preheated with greater power demand. The heat demands of the other processes, such as the dew point control or gas dehydration, are negligible in comparison.

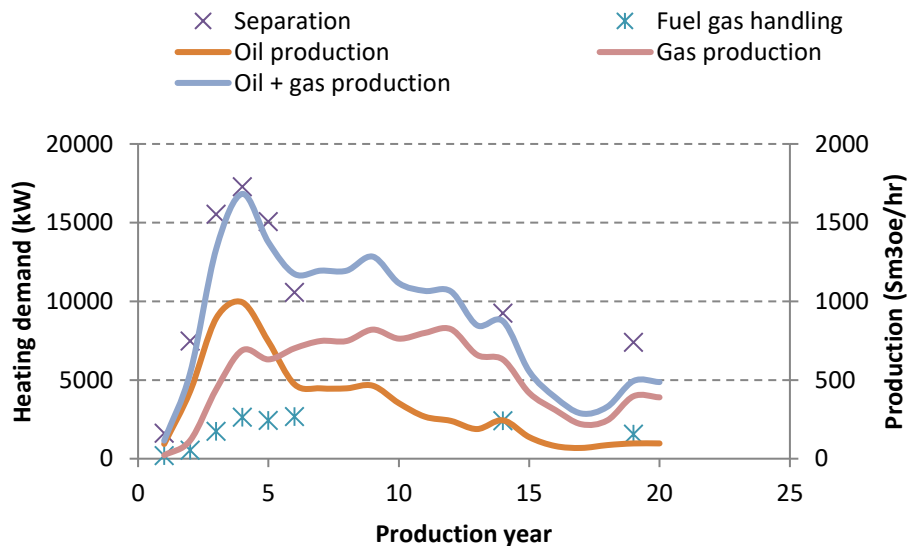


Fig. 7. Heating demand, sorted by sub-system, for the Norwegian petroleum case, on an energy basis

Secondly, the cooling demand is greater than the heating requirements, except for cases with very low gas-to-oil ratios (heavy oils). It usually corresponds to compressor after-cooling, with heat discharged at an initial temperature of 100 – 200°C, or to condensate scrubbing, with heat released at around 80°C. The peak demand is reached when the gas production attains its maximum.

Finally, the net power consumption is highly dependent on the gas production rate, whether the gas has a high or low CO₂-content, but is moderately sensitive to the oil production. The gas compression and treatment processes represent the lion's share of the total power demand (>80%),

The maximum power consumption is therefore expected around the gas production peak, and may be negligible otherwise. However, in practice, the differences in power demands are not as marked, because the compressors are run in severe off-design conditions when the gas flowrate is low, and gas is recirculated and expanded (anti-surge) to maintain the compressor.

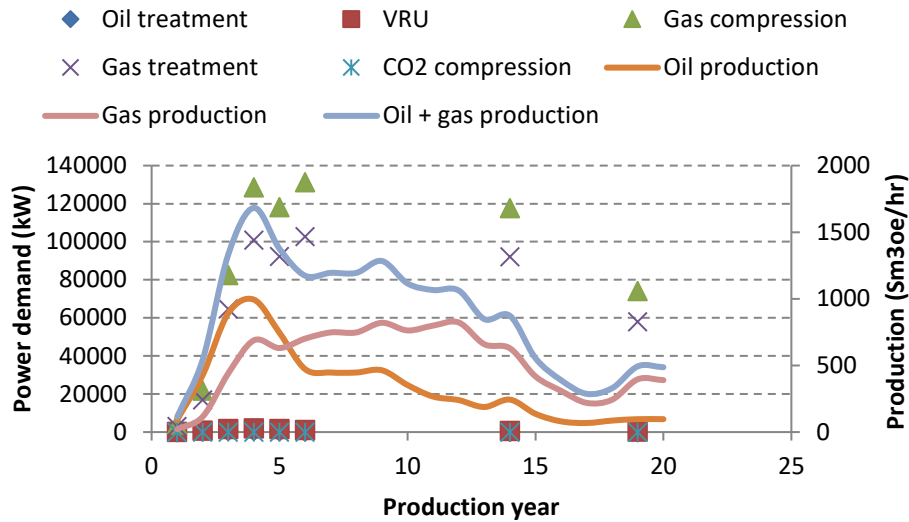


Fig. 8. Power demand, sorted by sub-system, for the Norwegian gas condensate case

For petroleum with high CO₂-content, the use of membranes to purify the incoming gas stream has a significant impact on the total power demand, since the permeate is recovered at 3 bar, and must be recompressed up to 55 bar. In that case, the total power demand can be roughly divided into 1/3 for the gas compression, 1/3 for the gas treatment, 1/3 for the CO₂-compression and injection.

The switch from one mode of operation to another – from the gas export to the gas injection mode – results in lower power consumption on-site for the two following reasons. First, carbon dioxide is not separated from methane and is thus directly compressed from 55 bar instead of 3 bar. Secondly, the injection pressure is lower for acid gas mixtures than for nearly-pure carbon dioxide.

3.2. Exergy analysis

The exergetic assessment shows that the exergy flow associated with the heat exchanges represents only up to 15-20% of the associated energy flow, because of the low temperature of the petroleum heating operations (Figure 9). In other words, than large amounts of exergy are destroyed when transferring heat from the exhaust gases at 400-600°C to the petroleum at a temperature of 40 – 75°C. Moreover, large quantities of exergy are discharged into the environment with the exhaust gases, which suggests that the waste heat could be used more adequately to match the system heat demand.

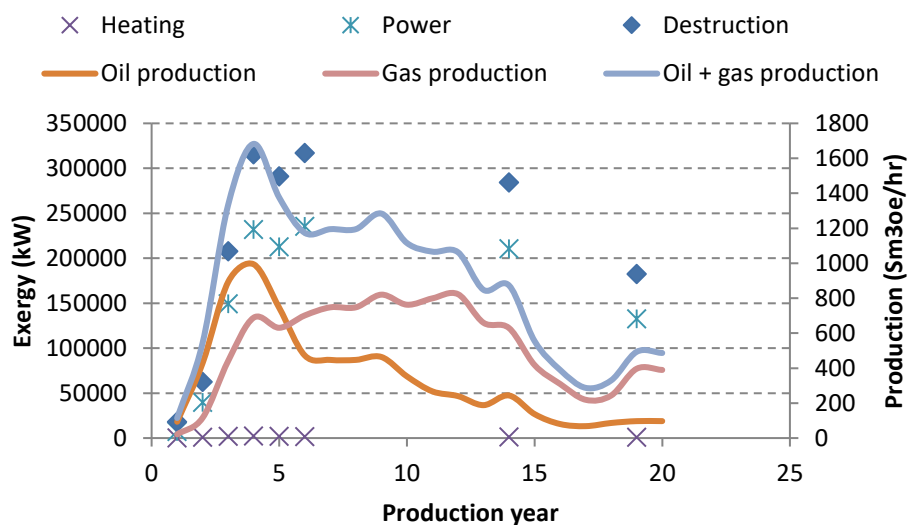


Fig. 9. Exergy demands and destruction for the gas condensate case with negligible CO₂-content

A more detailed analysis of the exergy destruction on-site (Figure 10) shows that the gas turbines represent the main share of the total irreversibilities on-site, because of the combustion process. They represent up to 60 – 65% over time. The processes in the processing plant that display the largest exergy destruction are the gas compression and treatment processes, which are also the greatest power consumers. The membranes and vapour recovery unit follow in case that carbon dioxide must be recovered, because of the large pressure drop across the membrane in the first process and the high pressure ratio in the second.

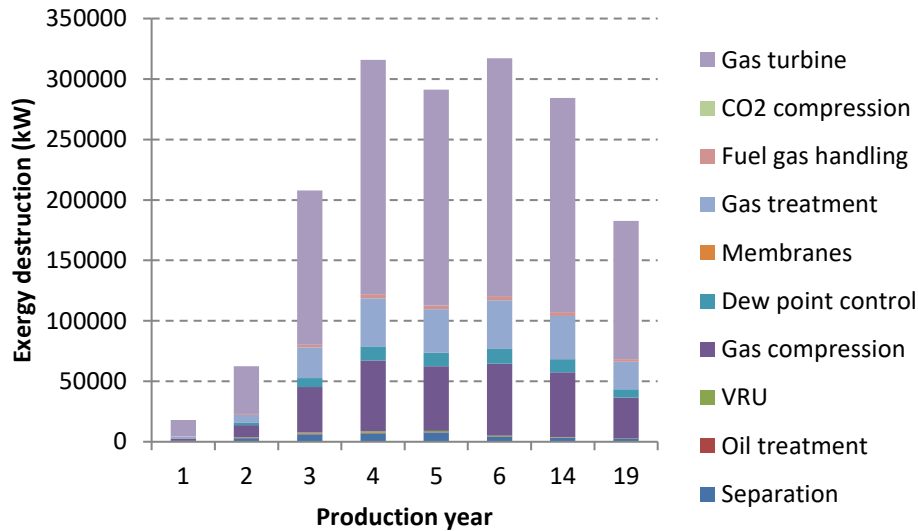


Fig. 10. Exergy destruction on-site for the gas condensate case with negligible CO₂-content

A comparison with the other case studies (Figures 11 to 14) shows that the exergy demands are well-correlated with the gas production profiles (power) and oil (heat), which suggests that these trends can be generalised to all feed compositions. However, it is not possible to derive a direct relation between the total oil and gas production (on an oil equivalent basis) and the energy demands.

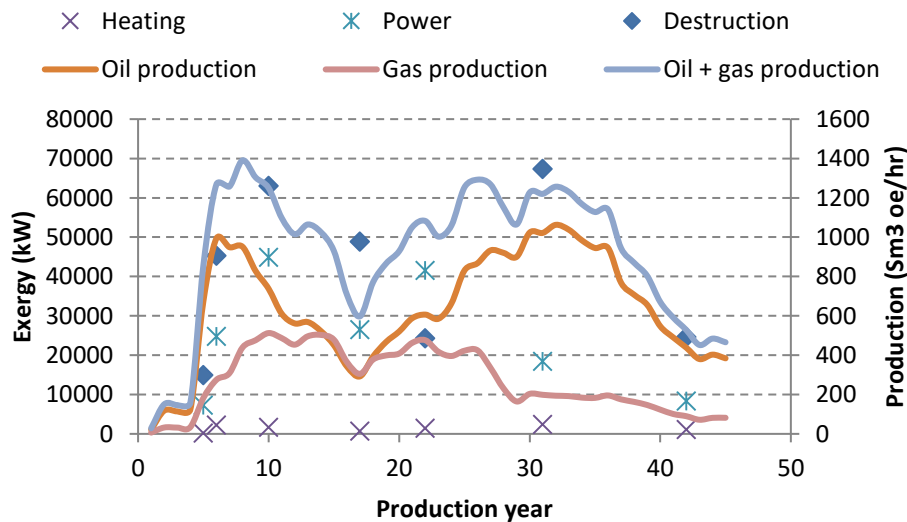


Fig. 11. Exergy demands and destruction for the volatile petroleum case with negligible CO₂-content

These results show the importance of focusing improvement efforts on the compression processes, as they represent the greatest share of exergy destruction and power consumption in all cases, at all life stages. Any reduction in power consumption will result in smaller gas consumption and thus in lower exergy destruction in the power generation system as well.

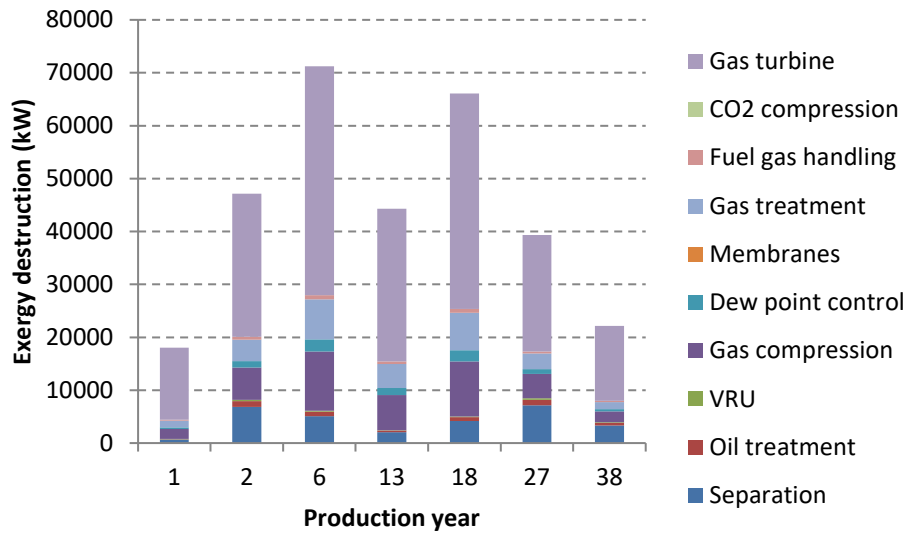


Fig. 12. Exergy destruction on-site for the volatile Brazilian oil case with negligible CO₂-content

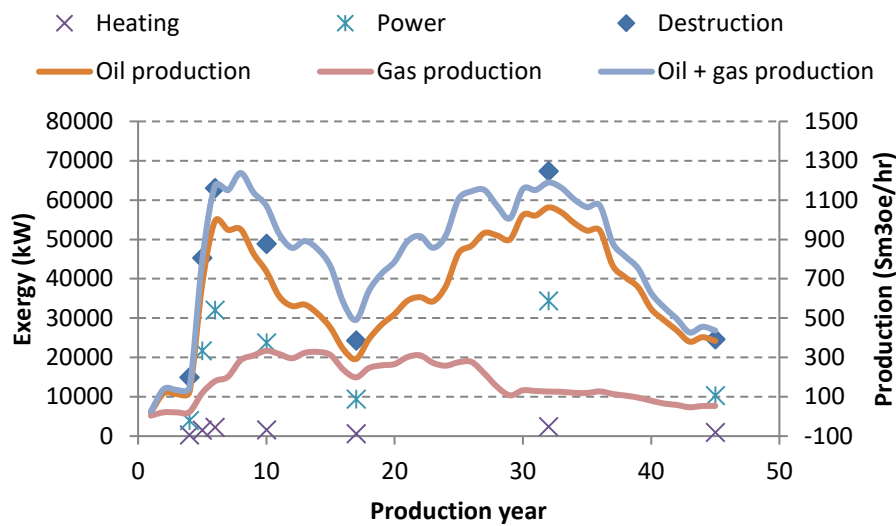


Fig. 13. Exergy demands and destruction for the volatile petroleum case with high CO₂-content

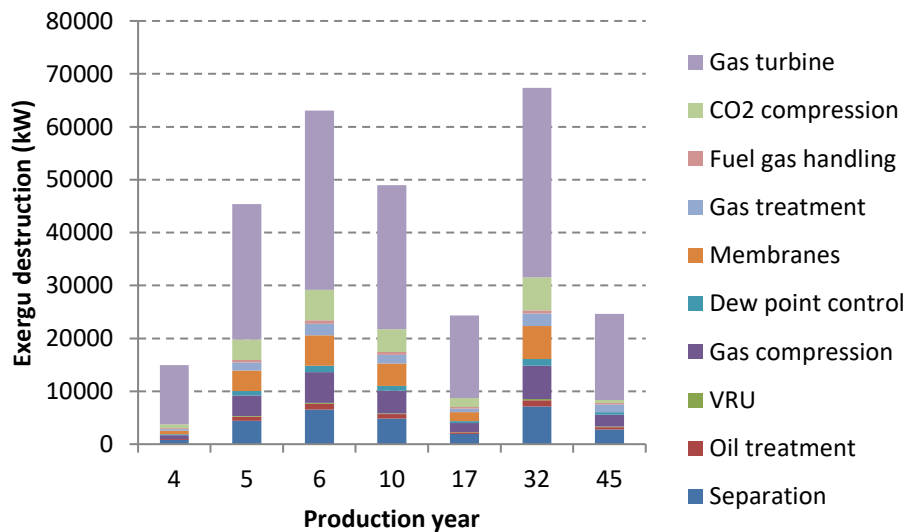


Fig. 14. Exergy destruction on-site for the volatile petroleum case with high CO₂-content

4. Conclusion

The life performance of oil and gas facilities was assessed by modelling these plants with the software Aspen Plus, considering three feed compositions that differ by their methane, carbon dioxide and heavy hydrocarbons content. In addition, two production profiles and three operation modes are considered to assess the impact of different water- and gas-to-oil ratios on the overall system performance. The energy and exergy analysis highlight that the power demand is strongly correlated to the gas production, while the heating demand is related to the oil one. The compression processes represent the lion's share of the total power consumption and cooling demand, as well as irreversibilities in the processing plant. A high content of carbon dioxide in the feed changes slightly the overall picture, as large quantities of exergy are destroyed in the membrane when recovering and recompressing the permeate. The gas turbines represent a large share of exergy destruction and losses as well because of the combustion process, which is highly inefficient and nature, and the large quantities of exergy dumped into the environment with the exhausts. These findings are valid for all cases at all life stages, and suggest focusing improvement efforts on the compression operations and waste heat recovery possibilities. In practice, the exergy destruction expected in those processes is likely greater, as gas turbines and compressors operating in off-design conditions face severe drops in thermal and isentropic efficiency.

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Appendix A

The present appendix presents complementary results of the energy and exergy assessments for the Brazilian volatile petroleum with negligible CO₂-composition.

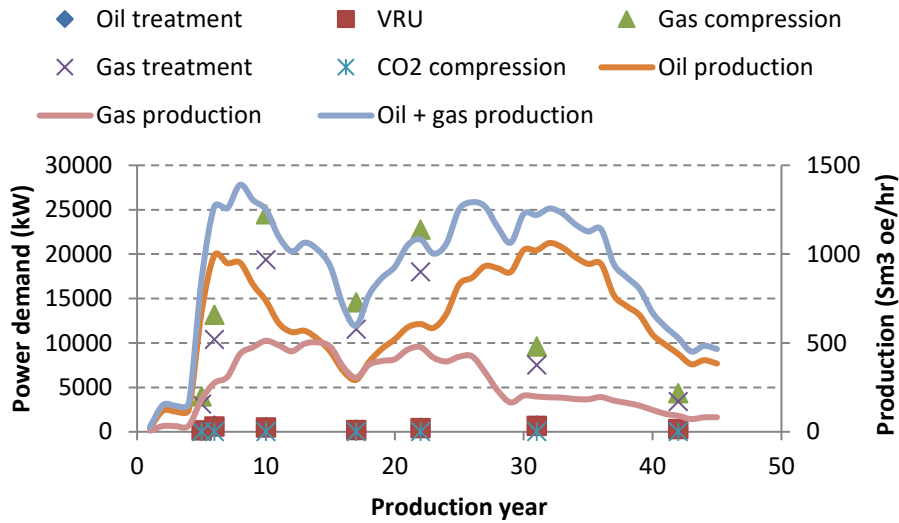


Fig. A.1. Power demand, sorted by sub-system, for the Brazilian volatile petroleum

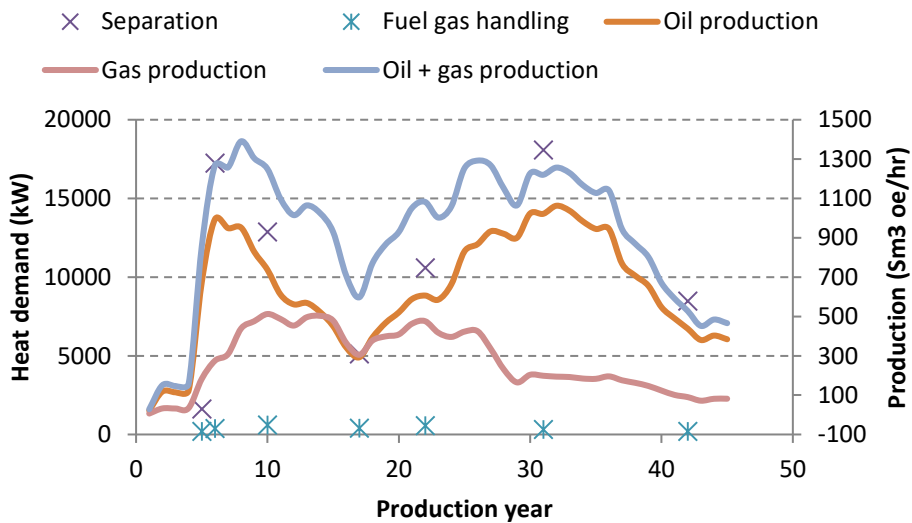


Fig. A.2. Heating demand, sorted by sub-system, for the Brazilian petroleum case with negligible CO₂-composition, on an energy basis

Appendix B

The present appendix presents complementary results of the energy and exergy assessments for the Brazilian petroleum with high CO₂-composition.

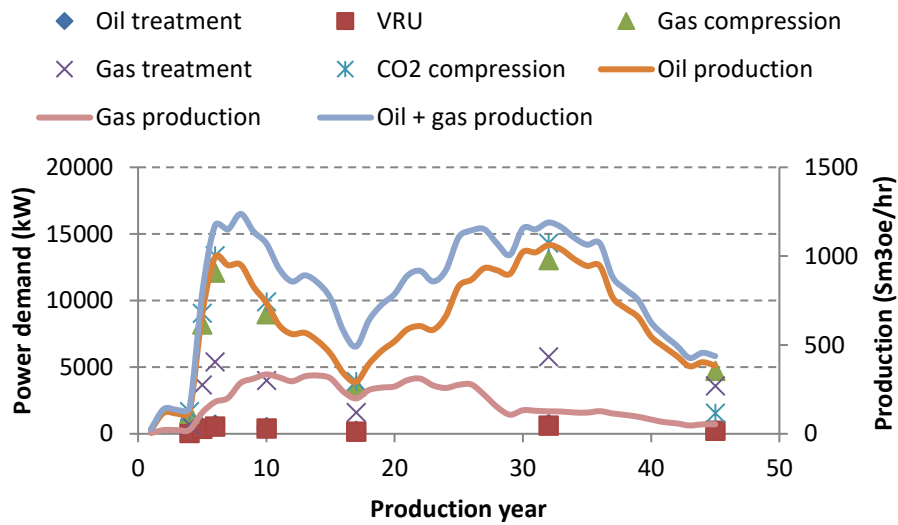


Fig. B.1. Power demand, sorted by sub-system, for the Brazilian petroleum case with high CO₂-composition

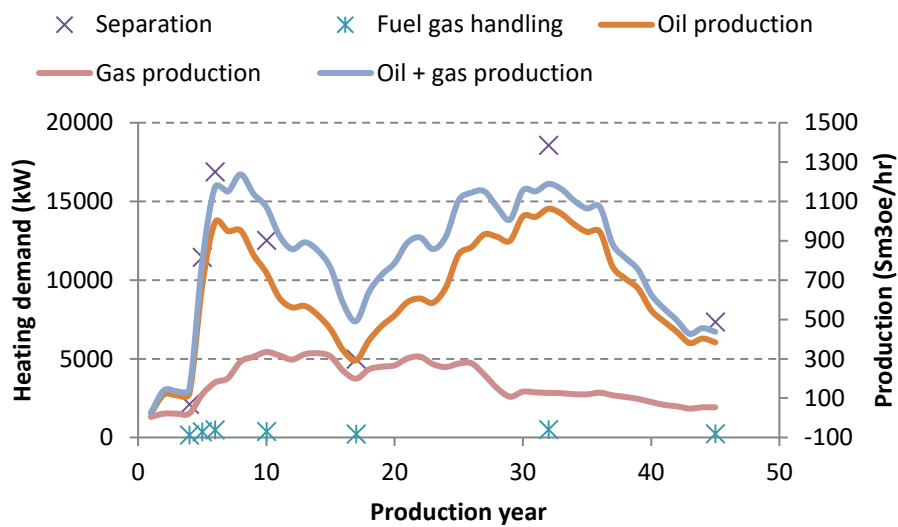


Fig. B.2. Heating demand, sorted by sub-system, for the Brazilian petroleum case with high CO₂-composition, on an energy basis

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