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ORIGINAL ARTICLE

# Energy efficiency to increase production and quality of products in industrial processes: case study oil and gas processing center

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**Abstract** The emphasis of this paper is to show the existence of some non-energy benefits that can be taken into account in an energy efficiency investment aimed to reduce energy consumption and increase production and product quality in an oil and gas processing center (OGPC) in México. The function of OGPC is to separate crude oil, gas, and saltwater coming from marine and terrestrial oil fields. Traditionally, application of process energy integration techniques has been aimed to reduce energy consumption associated with heating and cooling services. In this paper, the process energy integration (standard pinch analysis) of an OGPC shows the possibility of reducing natural gas and electricity consumption by 75 % and 98 %, respectively. However, the novel aspect of this work is the identifications and use of some waste heat streams available in processes to reduce energy consumption, and more importantly couple them with some non-energy-related benefits to produce massive economical savings. For example, by allowing an improvement in the quality of heavy crude oil for exportation (reduction in salt content), an increased sale price of 0.6 USD/barrel is achieved, rising profit to 156.88 MMUSD/year. Additional economic benefits came from the restauration of the production of 3,711 barrel of naphtha per day (33.86 MMUSD/year), by solving security issues related to the use of direct-fire heaters in the condensate stabilization plant.

**Highlights**
• Non-energy benefits have been analyzed to improve the financial attractiveness of energy efficiency investments
• Energy analysis can be aimed not only to reduce energy consumption but also to increase product quality and production
• Waste heat recovery potentials are exploited in the context of full thermal integration of an oil and gas processing center.

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**Keywords** Non-energy benefits · Energy efficiency · Heat recovery · Oil and gas processing

## Introduction

Until recently, measures to improve the energy efficiency of oil and gas plants have generally been limited to the enhancement of cooling/heating process, electrical/mechanical power generation, and steam production, rather than waste heat recovery in main plant process operations (Sahil et al. 2012). However, growing environmental concerns and global energy shortages have placed increased pressure on plants to integrate waste heat recovery technologies. Valerie and Peter (2012) presented a detailed energy audit for a major natural gas (NG) processing facility in the Middle East and identified sources of waste heat to evaluate their potential for on-site recovery. Li et al. (2007) analyzed the entire upstream supply chain for a mature oil field in an integrated manner, comparing individual elements, and achieving, by integrated network analysis, a production closer to the technical potential of the wellhead platforms. Labeyrie and Rocher (2010) improved energy efficiency by reducing the flaring and venting. Popli et al. (2011) explored the use of waste heat-powered absorption cooling to boost the efficiency of natural gas processing, enhance hydrocarbon recovery, and reduce utility cost. Michele et al. (2011) analyzed the revamping options of existing surface oil and gas treatment facilities due to the natural depletion of their reservoirs. Colley and Young (2009) found opportunities to reduce operating costs, increase revenues, and address greenhouse gas emissions by optimizing the energy consumption of upstream oil and gas (UOG) facilities, all with cost-effective actions. Five oil and gas production facilities in California identified projects to improve energy efficiency, whose implementation would reduce greenhouse gas (GHG) emissions by nearly 25% (California Air Resources Board, 2014). Campana et al. (2013) considered Organic Rankine cycle (ORC) as a technology that offers important opportunities in heat recovery, and presented a number of existing plants of oil and gas industry, located in the 27 countries of the European Union, and a comprehensive estimate of ORC potential power output. Mohammed A. Khatita et al. (2014) utilizes the ORC, as a case study, in an existing gas treatment plant in Egypt to recover the waste heat and convert it into electricity. In summary, previous findings suggest that there is a strong consensus within the oil and gas industry on the importance of saving energy by improving the efficiency of operations along the supply chain, and eliminating unnecessary waste by taking advantage of energy efficiency improvements (IPIECA 2013). However, non-energy benefits should have more attention. Quantifying non-energy benefits can help to show the financial possibilities of energy-efficient technologies and increase the probability of adopting these investments. An International Energy Agency (IEA) analysis shows that while industrial energy efficiency is improving, a large benefit potential remains untapped. The IEA review (2014) of existing studies shows that energy efficiency measures in industry can provide a number of additional direct benefits for businesses; hence, investments in industrial energy efficiency are essential to meet future energy needs. Lilly and Pearson (1999) evaluated benefits based on five energy efficiency case studies and found additional benefits to account for 24% of overall benefits. Pye and McKane (2000) include in their publication the terms increased productivity, reduced production costs, higher product quality, and improved worker safety. A systematic review on the benefit terms of energy efficiency investments establishes non-energy benefits as the most relevant term for such investments. Finman and Laitner (2002) analyzed 77 case studies to get an indication of the value of the additional benefits attributable to energy efficiency in a manufacturing setting. Worrell et al. (2003) identified and described productivity benefits associated with a given energy efficiency measure and demonstrated that non-energy benefits can amount to more than the energy benefits and stated that non-energy benefits can contribute to a shorter payback time. Lung et al. (2005) have also demonstrated the fact when non-energy benefits are incorporated into payback models. Sauter and Volker (2013) analyzed additional benefits attributable to energy efficiency by reducing operation and maintenance costs, safer working conditions, productivity gains, and a reduced resource use and pollution. Including non-energy benefits in the investment process can make energy efficiency investments more attractive and increase their priority against other investments (Josefine Rasmussens 2017). Therese Nehler and J. Rasmussen (2016) mentioned the lack of knowledge in industry regarding experiences in non-energy benefits. Given this preamble, this paper will show the non-energy benefits of energy efficiency investment, applied to oil and gas production facility, and the analysis is aimed to reduce energy consumption and increase production and product quality. The study case focus on an oil and gas processing center (OGPC) in México, whose function is to separate crude oil, associated gas, and saltwater coming from marine and terrestrial oil fields. The OGPC receives heavy crude oil from Mexican marine fields and light crude oil from terrestrial fields separates oil, sour gas (containing sulfur), and brine, and delivers oil for refining or exportation and compressed gas for petrochemical or gas processing plants. The main operations of the OGPC include separation of oil and gas from crude oil, pumping, gas compression (with turbo compressors), light oil dehydration, gas sweetening (sulfur-free fuel gas), light hydrocarbon production as well as electrical power generation (with turbo generators). In the study, streams were identified by their requirement of heating or cooling facilities currently used, and also identified combustion gas streams (waste heat) dissipated to the atmosphere.

## Heat recovery potentials

The thermal assessment of OGPC was divided into five stages:

(a) Selection of processes to be considered in OGPC.
(b) Identification and data collection (inlet and outlet temperatures and thermal loads) of "hot streams" (needing cooling) and "cold streams" (needing heating). Also, fuel and electricity consumption of facilities currently used to heat and cool the process streams.
(c) Thermal integration analysis by drawing the "cold and hot composite curves" of OGPC processes in a temperature vs. enthalpy diagram. These curves show the minimum heating and cooling services required in the process (Linnhoff et al. 1982).
(d) Identification of energy efficiency options and non-energy benefits considering: (1) process thermal integration, (2) waste heat recovery to improve quality of product, and (3) waste heat recovery to save production supplies.
(e) Economic evaluation of projects, considering energy savings and non-energy benefits, from (1) process thermal integration, (2) waste heat recovery to improve product quality and recovering production.

## Process selection

Seven main processes of the OGPC are analyzed in the following sections:

### Reception and separation

Figure 1 shows the reception and separation diagrams in which heavy and light crude oils from offshore and inland fields are stabilized (separation of crude oil and gas mixture) and pumped by two groups of pumps, CB-1 and CB-2 (driven by combustion engines operated with natural gas) to a dehydration system, and then routed to storage tanks.

As shown in Fig. 1, a heat source is available from CB-1 (H1) and CB-2 (H2) exhaust gases, with a combined thermal potential of 3.43 MWt.

### Compression station

The sour gas obtained from the separation process goes through three stages of compression. First and second stages use compressors driven by electric motors while the third stage use a compressor driven by gas turbine, exhausting combustion gases to atmosphere. It should be mentioned that there is an inter-cooling systems that use electric fans after first and second stages of compression; however, the inter coolers are not included in the analysis considered as part of the compressor package. On the other hand, a cooling system, using electric fans and a chiller after the third stage, and exhaust gases from turbo compressors are indeed considered in the analysis. Figure 2 shows the gas compression process.

Heat sources are available in the exhaust gas of the second (H3) and third (H4) compression stages, and at the exhaust gas of the third stage turbo compressor (H5). A total power of 16.41 MWt is available at the whole compression station.

### Light oil heating system

The light oil heating system raises the temperature of the light oil stream and thereby improves the water-oil separation in the dehydration process. As shown in Fig. 3, the light oil stream (C2) is heated before the dehydration process, by using a thermal oil circuit (C1) heated by three furnaces. The total thermal demand of the system is 42.6 MWt.

### Gas sweetening (desulfurization) plant

The OGPC has a sweetening plant, which eliminates sulfur components from the sour gas. Sulfur-free gas is distributed as fuel gas in the following systems: light oil heating plant, moto-compressors for light and heavy oil pumping, turbo compressors for gas compression, and turbo generators installed in the power plant. Figure 4 shows the process scheme. Heat is available in the feed sour gas stream (H7). On the other hand, stream (C3) of amine regeneration tower requires heating.

In summary, heat available in the sweetening gas plant is 0.21 MWt, whereas the thermal demand is 1.47 MWt.

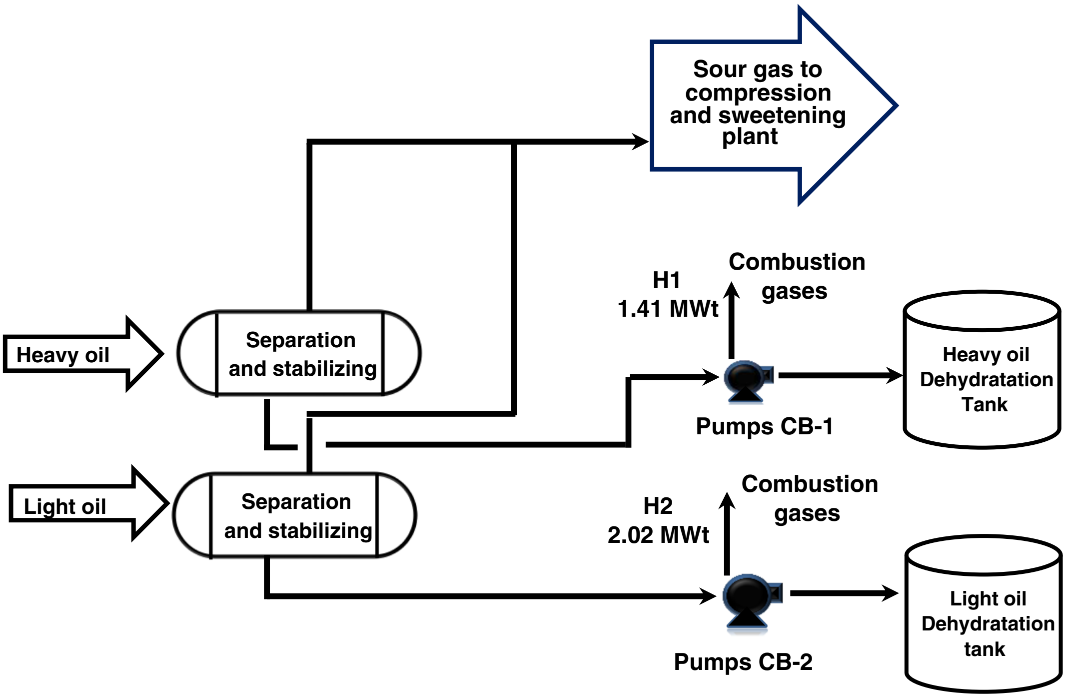


**Fig. 1** Oil pumping process

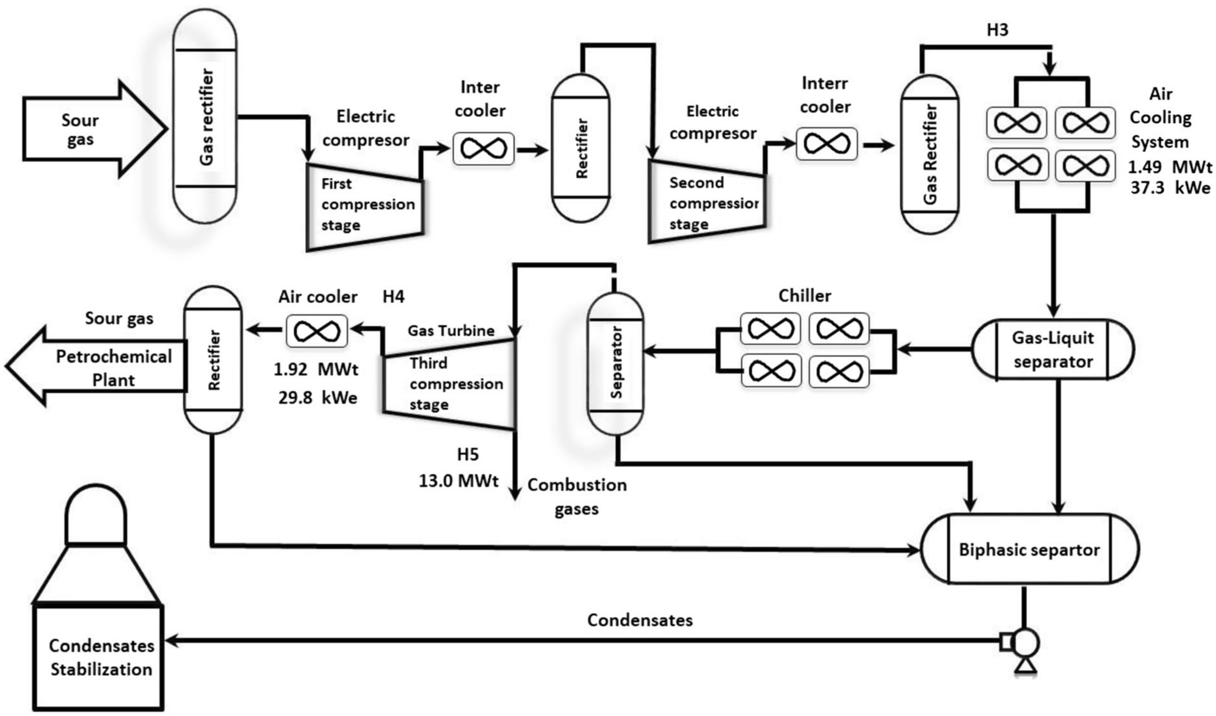


**Fig. 2** General scheme of the gas compression station

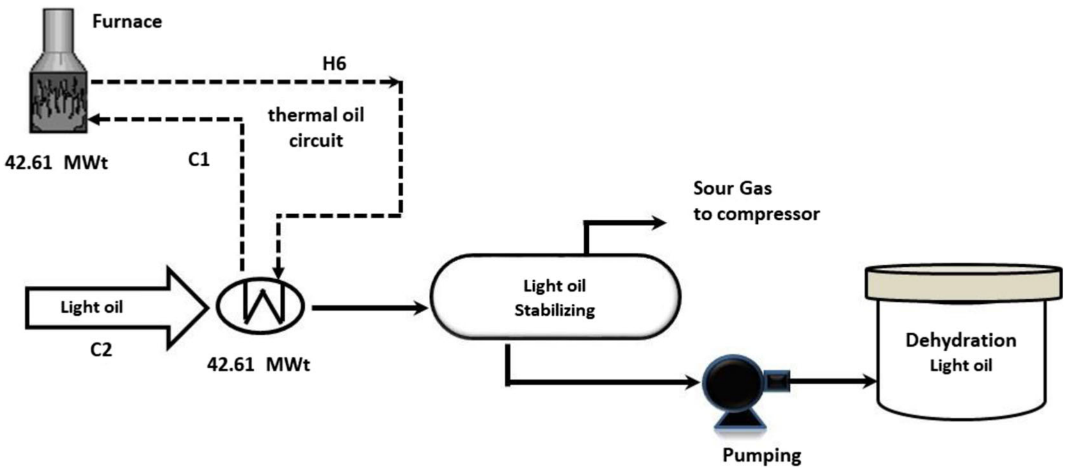


**Fig. 3** Light oil heating process

## Condensate stabilization plant

From the biphasic separator, in the compression plant, a stream of condensed product is sent to the condensate stabilization plant, where naphtha is separated from sour gas, and gas is sent for exportation. Figure 5 shows the stabilized condensate scheme. Heat is available (0.92 MWt) in hot light hydrocarbon (naphtha) stream (H8), whereas heat (3.40 MWt) is needed at the cold stream (C4) at the bottom of the stabilizing tower.

It is important to note that, for security reasons, this plant is out of operation due to the risk that imposes the heating of light hydrocarbon (naphtha) by a direct-fire heater. Due to this insecure operation, an estimate of 3711 BPD (barrel per day) of naphtha are not produced. Considering an average sale price of 25 USD/barrel, this could represent an additional income of 92,775 USD/day, which represents a non-energy benefit.

## Power plant

The electric power demand in the OGPC is supplied by the power plant, through a self-generation system, which consist of four turbo generators. Usually, only two turbo generators (total 48 MWe) are used with no thermal utilization of combustion gases (thermal potential 58.6 MWt). Overall, the power plant feeds turbo compressors, air

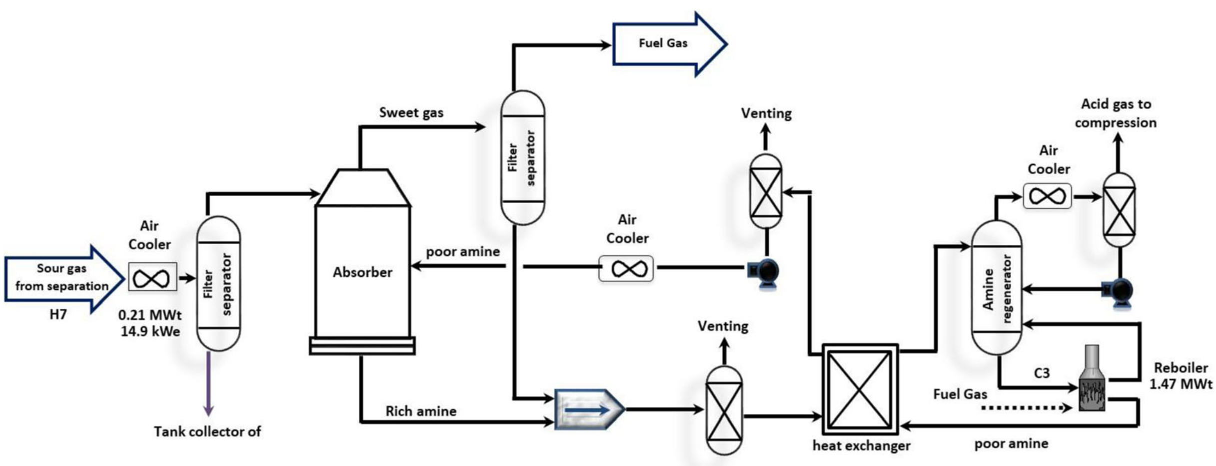


**Fig. 4** General scheme of sour gas sweetening

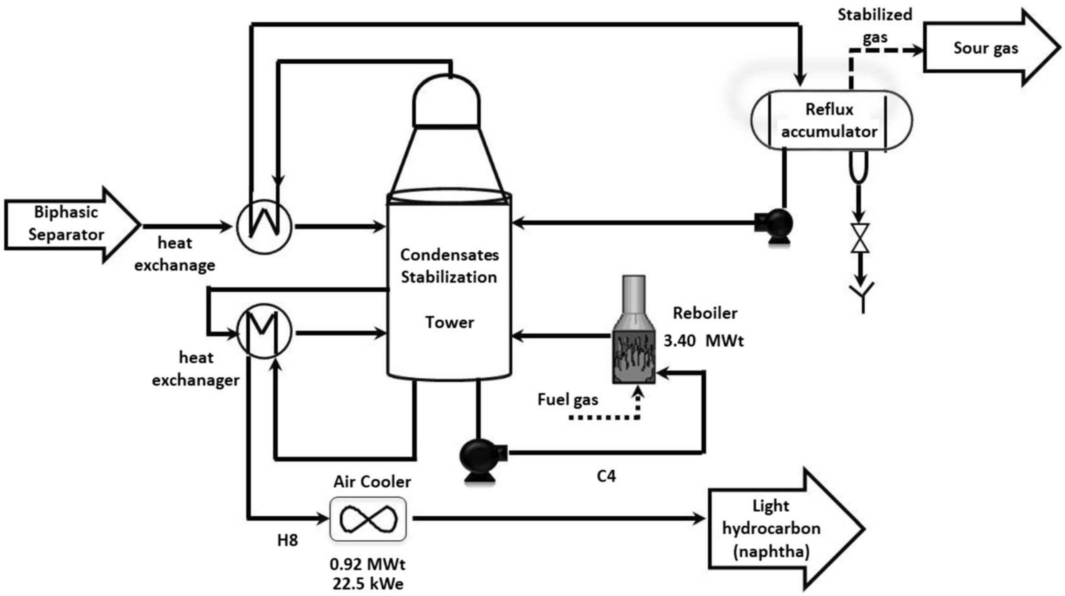


**Fig. 5** General scheme of the condensate stabilizing plant

coolers, pumping systems driven by electric motor for oil handling, and other services.

Heavy oil heating system

Given the impact of the saltwater content on the oil, heavy crude oil dehydration and desalination processes are very important for handling, conditioning, and transporting of crude oil. Specifications for crude oil exports limit the water content to a maximum of 0.5% (by volume) and a salt content (sodium chloride) to a maximum of 50 PTB (Pounds per Thousand Barrels) of equivalent sodium chloride per 1000 barrels of clean crude oil. Higher saltwater content results in a decrease of the sale price, due to penalties in its commercialization.

The dehydration and desalination processes generally begin with a chemical treatment that breaks the emulsions and subsequently allows water to separate and decant. To facilitate heavy oil water separation, heat

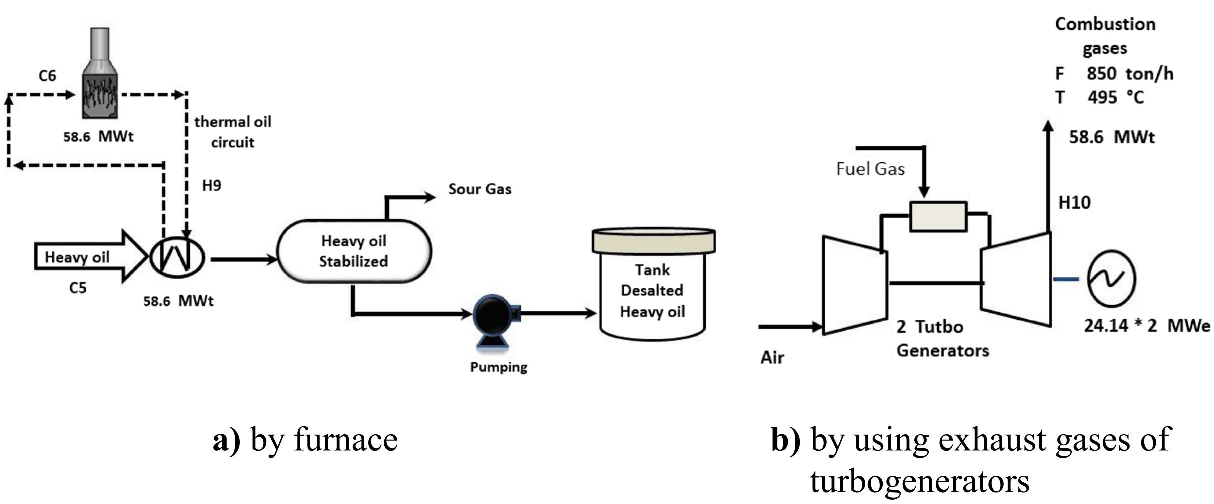


**Fig. 6** Options of heavy oil heating. **a** By furnace. **b** By using exhaust gases of turbo generators

must be applied in a second stage to keep heavy oil at 60 °C. If the temperature is lower, the increase in viscosity reduces the desalination efficiency. In our case, the heavy oil (C5) should increase its temperature from 39 to 60 °C, to obtain the required specifications (0.5% water volume and 50 PTB).

An incremental price (estimation by OGPC) of 0.6 USD/barrel of heavy oil with better quality (reduced in saltwater) is considered. To achieve that, heat is required to reach a heavy oil production of 716,336 BPD (Barrels per Day). The heat could be supplied in two ways: (a) by using a gas furnace as illustrated in Fig. 6 a or (b) by taking advantage of waste energy (combustion gases) from turbo generators as illustrated in Fig. 6 b. The latter possibility is analyzed later, in "Energy-saving options and non-energy benefits" section.

## Identification of streams and data collection

Tables 1 and 2 show the hot streams (which need cooling) and cold streams (which need heating) selected for the current assessment. Table 3 shows heating and cooling services required and waste heat available sources at the OGPC.

## Thermal integration analysis

The thermal integration analysis considers two cases:

Case 1 includes heating and cooling needs of current OGPC operation plants: gas compression, light oil heating, and gas sweetening.

Case 2 considers thermal needs from current (case 1) OGPC operation plants, and it includes condensate stabilization plant, heating of heavy oil, and recovering waste heat from pumps, turbo generators, and turbo compressors.

### Composite curves

The process streams considered in case 1 and case 2 are represented by hot and cold composite curves in a temperature vs. thermal load diagram, as shown in Figs. 7 and 8.

In the thermal integration analysis, the composite curves allow to determine the minimum requirements for heating (gas heaters) and cooling (air coolers), need-

**Table 1** Hot streams selected for assessment

| Hot streams | Figure | Process | Equipment | Energy available | Thermal load MWt | Temperature In °C | Temperature Out °C |
|---|---|---|---|---|---|---|---|
| H1 | 1 | Reception and separation | CB-1 pumps | Hot exhaust gases (to atmosphere) | 1.41 | 469 | 100 |
| H2 | 1 | Reception and separation | CB-2 pumps | Hot exhaust gases (to atmosphere) | 2.02 | 469 | 100 |
| H3 | 2 | Compressor station | Air cooler second stage | Hot gas | 1.49 | 124 | 60 |
| H4 | 2 | Compressor station | Air cooler third stage | Hot gas | 1.92 | 128 | 75 |
| H5 | 2 | Compressor station | Turbo compressor | Hot exhaust gases (to atmosphere) | 13 | 447 | 125 |
| H6 | 3 | Light oil heating system | Heat exchanger thermal oil–light oil | Hot thermal oil | 42.61 | 150 | 40 |
| H7 | 4 | Gas sweetening | Air cooler feed sour gas | Hot sour gas | 0.21 | 70 | 37 |
| H8 | 5 | Stabilized condensate | Air cooler condensate products | Hot condensates | 0.92 | 122 | 52 |
| H9 | 6a | Heavy oil heating system | Heat exchanger thermal oil–heavy oil | Hot thermal oil | 58.60 | 200 | 158 |
| H10 | 6b | Heavy oil heating system | Turbo generators | Hot exhaust gases (to atmosphere) | 58.60 | 450 | 225 |
| H11 | 9 | Light oil heating system | Heat exchanger thermal oil–light oil | Hot thermal oil | 46.01 | 174 | 55.5 |

Table 2 Cold streams selected for assessment

| Cold streams | Figure | Process | Equipment | Energy required | Thermal load MWt | Temperature In °C | Temperature Out °C |
|---|---|---|---|---|---|---|---|
| C1 | 3 | Light oil heating system | Furnace alone thermal oil | Heating cold thermal oil | 42.61 | 40 | 150 |
| C2 | 3 | Light oil heating system | Heat exchanger thermal oil–light oil | Heating cold light oil | 42.61 | 30 | 52 |
| C3 | 4 | Gas sweetening | Reboiler regenerator tower | Heating cold amine | 1.47 | 112 | 121 |
| C4 | 5 | Stabilized condensate | Reboiler stabilizing tower | Heating cold gas | 3.40 | 155 | 162 |
| C5 | 6a | Heavy oil heating system | Heat exchanger thermal oil–heavy oil | Heating cold heavy oil | 58.60 | 39 | 60 |
| C6 | 6a | Heavy oil heating system | Heat exchanger thermal oil–generator exhaust gases | Heating cold thermal oil | 58.60 | 157 | 202 |
| C7 | 9 | Light oil heating system | Furnace plus compressors exhaust gases | Heating cold thermal oil | 33.0 | 94 | 174 |
| C8 | 9 | Light oil heating system | Compressors exhaust gases (plus furnace) | Heating cold thermal oil | 13 | 55.5 | 94 |

ed to meet the thermal requirements of all plants considered. Composite curves show potential savings of thermal energy in the OGPC.

In case 1, the thermal integration analysis of OGPC (see Fig. 7) shows the possibility of reducing 8% of fuel gas consumption in heaters and 98% reduction of electrical demand in air coolers.

Taking advantage of waste heat potentials identified in OGPC processes, case 2 shows that the thermal integration would reduce 75% the fuel gas consumption in direct-fired heaters and 98% of electrical demand in air coolers (see Fig. 8).

Finally, Table 4 shows the summary of the integration cases.

Table 3 Heating and cooling services required and available waste heat sources

| Plant | Figure | Heating services: Thermal load MWt | Heating services: Natural Gas Ton/h | Cooling services: Thermal load MWt | Cooling services: Electrical Power kWe | Exhaust gases: Thermal load MW |
|---|---|---|---|---|---|---|
| Reception and separation | 1 | 0.0 | 0.0 | 0.0 | 0.0 | H1, H2 1.41 + 2.02 = 3.43 |
| Compression | 2 | 0.0 | | H3, H4<br>1.49 + 1.92 = 3.41 | H3, H4<br>29.8 + 37.3 = 67.1 | H5<br>13.0 |
| Light oil Heating furnace | 3 | C1<br>42.61 | C1<br>3.34 | 0.0 | 0.0 | |
| Gas sweetening | 4 | C3<br>1.47 | C3<br>0.11 | H7<br>0.21 | H7<br>14.9 | |
| Condensate stabilizing | 5 | C4<br>3.40 | C4<br>0.26 | H8<br>0.92 | H8<br>22.5 | |
| Heavy oil heating furnace | 6a | C6<br>58.6 | C6<br>4.52 | 0.0 | 0.0 | |
| Turbo generator combustion gases | 6b | 0.0 | 0.0 | 0.0 | 0.0 | H10<br>58.6 |
| Total | | 106.08 | 8.23 | 4.54 | 104.5 | 75.03 |

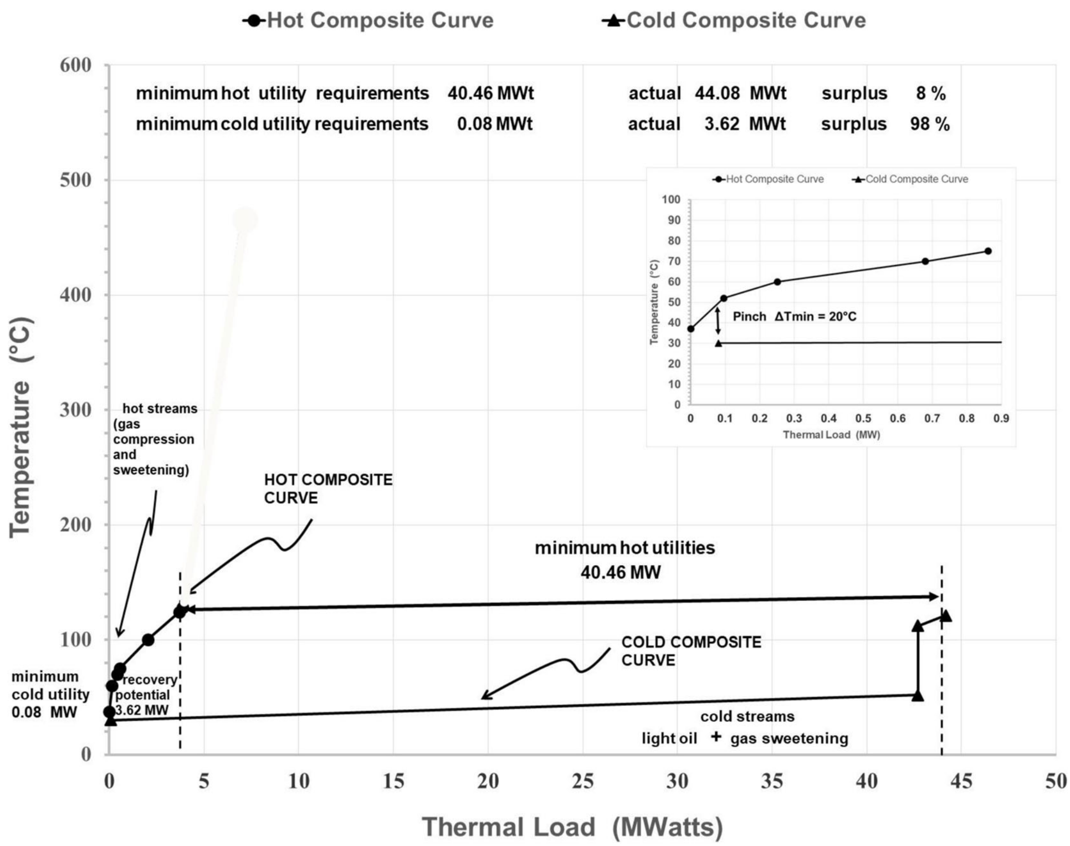


**Fig. 7** Case 1: Composite curves OGPC current plants in operation (compression, light oil heating, gas sweetening)

## Energy-saving options and non-energy benefits

Two projects (projects I and II) involving energy-saving and non-energy benefits are proposed for case 2, and are aimed to recovering waste heat to (1) reactivation of condensate stabilization production in order to sell light hydrocarbon (naphtha), and reduce fuel consumption of heating light oil, and (2) increase quality of heavy oil to export, improving their desalination process.

Project I considers the installation of a thermal oil (Dowtherm) circuit, for waste heat recovery from the exhaust gases of turbo compressors, and used for condensate stabilization and light oil heating (see Figs. 3 and 5). In this case, a reduction of 13 MWt in the thermal load supplied by the furnace is achieved. It should be noted that the furnace still requires around 33 MWt, as shown in Fig. 9.

## Economic evaluation

The waste heat recovered from turbo compressors and turbo generators allows (1) to reduction of fuel gas consumption in the light oil heating furnace; (2) to reactivate production of light hydrocarbon (naphtha) in the condensate stabilization process, by replacing the direct-fire heater, using instead thermal oil heated with the exhaust gases of turbo compressors; (3) to improve the quality of heavy crude oil to export, using exhaust gases from turbo generators to increase the temperature in desalination process.

Table 5 shows waste heat recovered and energy and non-energy benefits for project I and project II.

The premises considered for Table 5 were estimated with data provided by OGPC (2017), and are as follows:

• Fuel gas low heating value of 45,660 MJ/ton, (INECC 2014).

• Fuel gas priced at 3.3 USD/kJ, (OGPC 2017).

• Electricity price of 0.32 USD/kWh, (OGPC 2017).

• Average price of 25.0 USD/barrel of light hydrocarbon (naphtha), recovered in stabilized condensate plant (OGPC 2017).

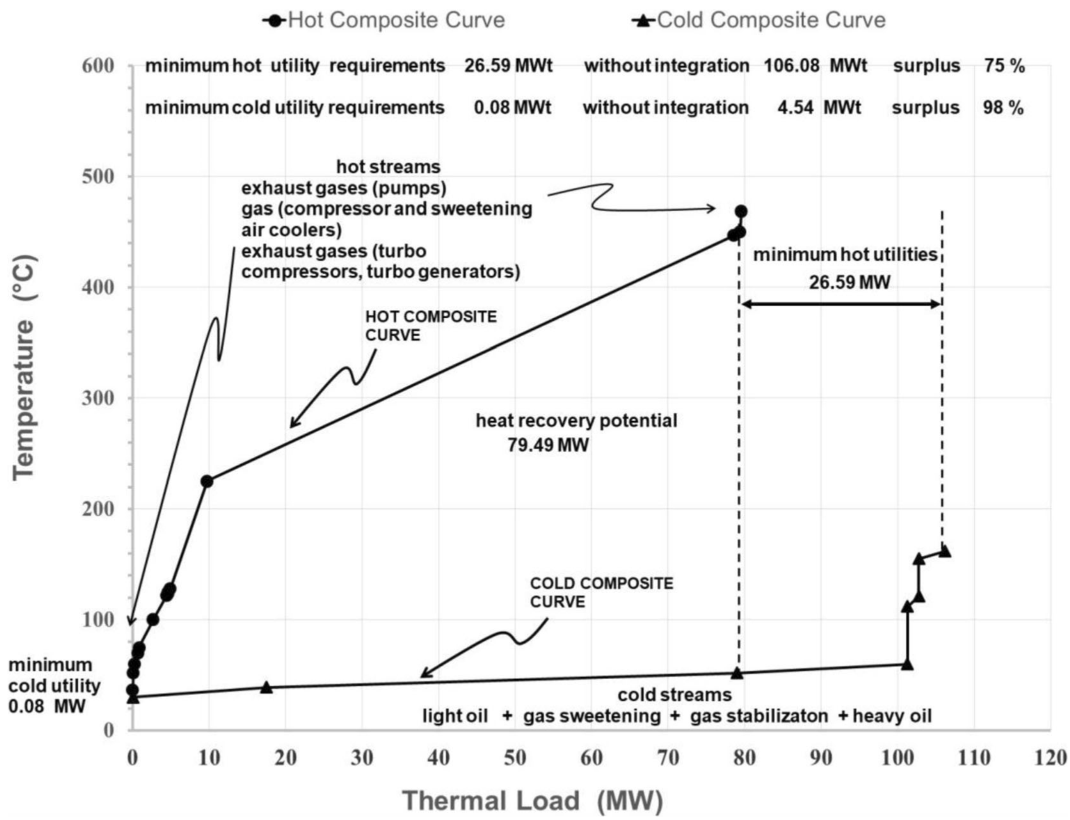


**Fig. 8** Case 2: Composite curves OGPC (current plants in operation plus stabilization plant, heavy oil heating, and use of waste heat streams)

• Fuel oil savings obtained considering the fuel consumption for heating light and heavy oil only by furnaces (see heating services Table 3), and reduction in those services considering waste heat recovery (see Figs. 9 and 10).

• An emission factor of 2.66 $kgCO_2$/kg of fuel gas for calculation of $CO_2$ production in combustion engines (INECC 2014).

• Reduction of $CO_2$ emissions obtained by multiplying emission factor and fuel gas saving.

• The Oil and Gas Processing Center (OGPC) provided investment estimates and operation costs of heat exchangers and equipment of thermal oil circuits, considering quotations from suppliers (OGPC 2017).

• The payback period (PP) was calculated using the formula:

$$PP = [\text{Investment}]/[\text{Economic Benefits–Operation\&Maintenance costs}].$$

• Thermal oils Dowtherm and Therminol were selected by their thermal properties similar to light and heavy crude oil, respectively.

## Results and discussion

In Mexico, the standard business approach for energy projects in oil and gas plants is basically aimed to improve energy efficiency of individual components that means optimization of combustion in furnaces and boilers, fuel gas preheating using electrical resistances, and preheating of combustion air using exhaust gases of the same combustion engine. On the other hand, cogeneration projects, for self-sufficiency of electric power, take advantage of gas turbine exhaust gases for additional generation of electricity. In only few projects, thermal integration studies, applying the standard pinch technology, are used. In the case of the OGPC, the generation of additional electricity is not

**Table 4** Thermal integration cases

| Cases | Heating required | | | Cooling required | | |
|---|---|---|---|---|---|---|
| | Actual without integration (MWt) | Minimum with integration (MWt) | Savings | Actual without integration(MWt) | Minimum with integration(MWt) | Savings |
| Case 1: Current operating plants<br>Plant (streams):<br>Compression (H3, H4)<br>Light oil heating (H6, C1)<br>Sweetening (H7, C3) | 44.08 | 40.46 | Thermal energy (MWt)<br>3.62 (8%)<br>Fuel gas (ton/h)<br>0.28<br>Fuel gas cost<br>0.37 MMUSD/year | 3.62 | 0.08 | Energy (MWt)<br>3.54 (98%)<br>Electric power<br>70.8 kWe<br>Electricity cost<br>0.20 MMUSD/year |
| Case 2: Current operating plants + condensate stabilization plant + heavy oil heating<br>+ pumps, turbo generators, and turbo compressor exhaust gases<br>Plant (streams):<br>Separation (H1, H2)<br>Compression (H3, H4)<br>Compressor exhaust gases (H5)<br>Light oil heating (H6, C1)<br>Sweetening (H7, C3)<br>Condensate stabilization (H8, C4)<br>Heavy oil heating (C6, H9)<br>Generator exhaust gases (H10) | 106.08 | 26.59 | Thermal energy (MWt)<br>79.49 (75%)<br>Fuel gas (ton/h)<br>6.14<br>Fuel gas cost<br>8.21 MMUSD/year | 4.54 | 0.08 | Energy (MWt)<br>4.46 (98%)<br>Electric power<br>89.2 kWe<br>Electricity cost<br>0.25 MMUSD/year |

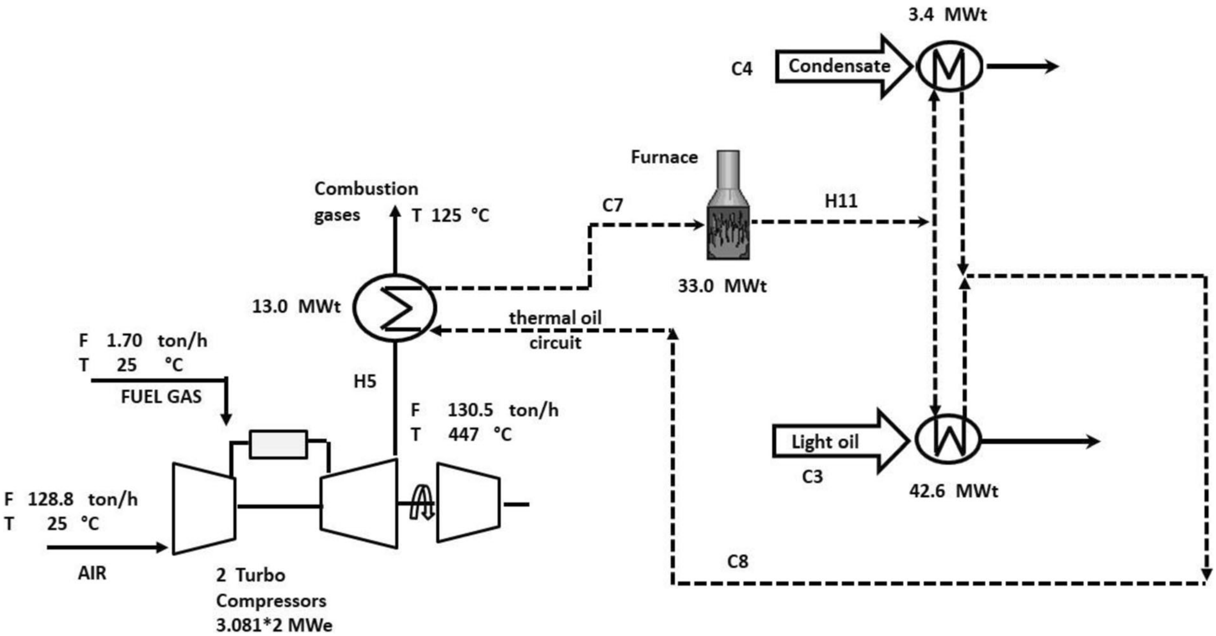


**Fig. 9** Condensate stabilizing plant and light oil heating scheme. Project II contemplates the installation of an additional thermal oil (Therminol) circuit, for waste heat recovery from the turbo generator exhaust gases, and used for heavy oil heating to improve the desalination process, avoiding the use of fuel gas furnaces (Fig. 10)

required; hence, the cogeneration systems with combined cycles do not apply as they do in ORC (Organic Rankine Cycle) systems. However, in this first study, an analysis of waste heat recovery in oil and gas processing center was made to achieve, not only energy savings, but a handful of non-energy benefits: improvement of product quality, recovery of production, and a reduction of carbon emissions.

By taking advantage of waste heat available in oil and gas processing plants, the proposed projects I and II produced the following energy and non-energy benefits:

(1) An energy benefit of 0.64 MMUSD/year, associated with a saving of 4205 ton/year of fuel gas consumption. This was made possible by recover waste heat in turbo compressor exhaust gases, and reducing 13 MWt of the thermal load supplied by the light oil heating furnace. It should be noted for this case that there are 33 MWt still required in the furnace.
(2) An energy benefit of 6.05 MMUSD/year associated with savings of 39,595 ton/year of fuel gas due to the recovery waste heat in the turbo generator exhaust gases, avoiding the use of heavy oil heating furnaces.
(3) A non-energy benefit of 33.86 MMUSD/year by restoring production of 3711 BPD of naphtha in the condensate stabilization plant (currently out of operation due to security problems in the use of direct-fire heaters). This was calculated considering a naphtha average sale price of 25.0 USD/B.
(4) A non-energy benefit of 156.88 MMUSD/year by reducing the salt content of the heavy oil and improve its quality. A total of 716,336 BPD of heavy crude oil are considered for sale in export markets, with an increment of 0.6 USD/barrel in the sale price.
(5) A non-energy benefit by reducing an estimate of 116,507 ton/year of $CO_2$ emissions, derived from 43,800 ton/year of fuel gas savings.
(6) Another additional non-energy benefit derived from the waste heat recovery was the reduction of turbo compressors and turbo generator exhaust gas temperature to atmosphere.

In order to implement all energy savings and non-energy benefits, the following investments are required:

Project I

(a) A new set of heat exchangers at the recovery system of turbo compressor exhaust gases, with an estimate of 5.07 MMUSD.
(b) A set of components (pumps, tanks, pipes, etc.) of thermal oil (Dowtherm) circuit, with an amount of 34.2 MMUSD.

**Table 5** Energy and non-energy benefits project I and project II

| Project | Equipment considered | Waste heat recovered | | | Benefits | | | Economy |
|---|---|---|---|---|---|---|---|---|
| | | Thermal oil circuit | Heat source | Heat load MWt | Fuel gas savings (Ton/h) MMUSD/year | Production increase (BPD) MMUSD/year | $CO_2$ reduction Ton/year | Investment and operation MMUSD |
| Project I<br>Light oil heating and reactivation of condensate stabilization production | Turbo compressor exhaust gases | Dowtherm | H5 dissipated to atmosphere | 13.0 | (0.48)<br>0.64 | 3711 BPD × 25.0 USD/B = 33.86 MMUSD/year | 11,184 | Project I<br>Dowtherm circuit<br>34.2<br>Heat exchangers<br>5.07<br>Operation<br>0.732/year |
| Project II<br>Heavy oil heating | Turbo generator exhaust gases | Therminol | H10 dissipated to atmosphere | 58.60 | (4.52)<br>6.05 | 716,336 BPD × 0.6 USD/B = 156.88 MMUSD/year | 105,323 | Project II<br>Therminol circuit<br>34.20<br>Heat exchangers<br>11.45<br>Operation<br>0.732/year |
| | | | Total | 79.59 | (43,800) ton/year<br>6.69 MMUSD/year | 190.74 MMUSD/year | 116,507 ton $CO_2$/year | Investments 84.92<br>Operation<br>1.45/year |
| | | | | | Payback period (months) | | | Project I 14.2<br>Project II 3.5 |

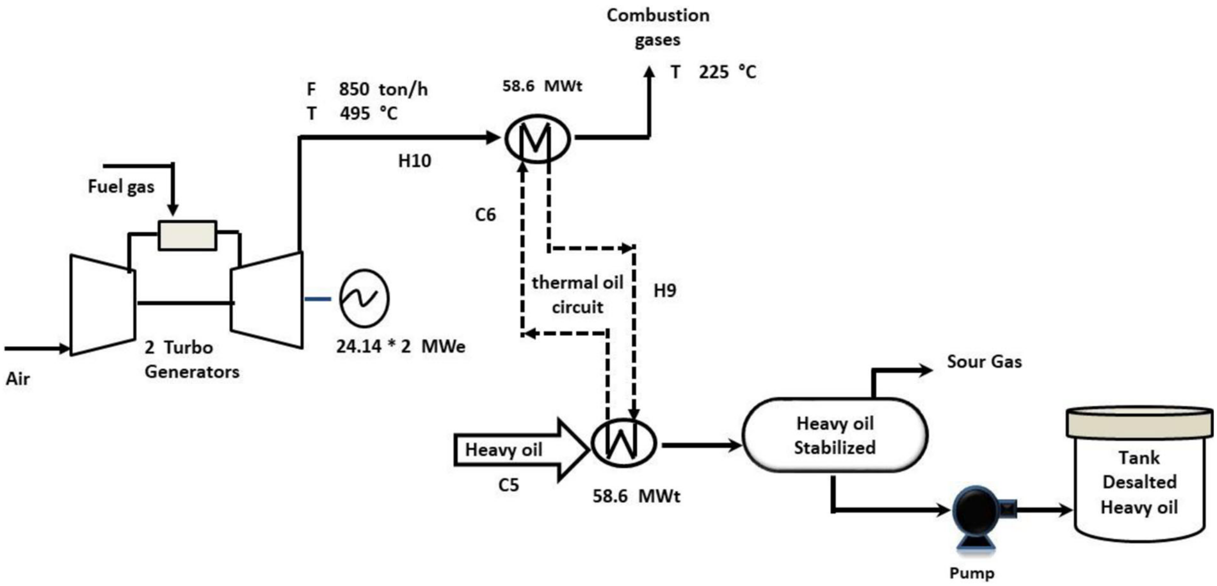


**Fig. 10** Heavy oil heated by turbo generator exhaust gases

(c) Operation costs associated with required annual replacement of components of the thermal oil circuit, estimated in 0.732 MMUSD/year.

Taking in account all this numbers, the payback period was estimated in 14.2 months.

Project II

Investment for project II considers the following components:

(a) Heat exchangers for turbo generator waste heat recovery system and heavy oil heating.
(b) Components (pumps, tanks, pipes, etc.) of thermal oil circuit.
(c) Operation costs associated with required annual change of components of thermal oil circuit, estimated at 0.732 MMUSD/year.

In this case, the payback period was estimated in 3.5 months.

The results of economic evaluation show profitable revenues in projects I and II.

## Conclusions

The technical literature shows that there is a strong consensus within the oil and gas industry on the importance of saving energy, by improving the efficiency of operations along the supply chain and eliminating unnecessary waste. The primary strategies include implementation of energy management systems, identifying and introducing best management practices, driving energy efficiency and greenhouse gas (GHG) emission reduction projects, and developing new technologies. However, there is a lack of understanding as far as non-energetic benefits can be integrated in the analysis.

The following general recommendations, which go beyond the case study, can be drawn.

•Optimum energy efficiency of individual components does not necessarily lead to an optimum integral process in industrial plants. A much better approach comes from considering a thermal integration between components.

•In the context of viewing and analyzing each plant individually, it is difficult to identify and exploit the thermal potentials. However, when considering the plants as a whole, new possibility can be identified and taken into advantage to optimize heating and cooling needs.

•When industrial plants have scattered heat sources, which cannot be used directly in the context of the same processes, the installation of thermal oil circuits allow their recovery and their use anywhere in the plant.

•The energy analysis, traditionally applied to reduce energy consumption and associated with heating (fuel) and cooling (electricity, water) services, can expand these goals to include options to increase production and quality of products.

•By including non-energy benefits in the overall technical and economic analysis, the investment project becomes more attractive. Non-energy benefits can be greater than energy benefits, and contribute to a shorter payback time.

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**Compliance with ethical standards**

**Conflict of interest** The authors declare that they have no conflict of interest.

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