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Energy efficiency and greenhouse gas emission abatement opportunities for an existing gas treatment plant: a comprehensive technical and economic analysis

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Abstract

This research paper examined the operational performance and greenhouse gas (GHG) emissions of an existing gas treatment plant. Extensive data collection and analysis were undertaken to assess energy consumption and emissions and identify major emitter units. A GHG emission inventory was developed, and a benchmarking analysis was conducted. The gap analysis revealed excessive emissions, leading to the identification of potential GHG abatement alternatives for the turbo compressor and stabilizer heater. Technical feasibility assessments and economic evaluations were performed for the implementation of waste heat recovery systems, specifically an absorption chiller and a hot oil-driven re-boiler. The results demonstrated significant energy savings, emission reduction, and positive financial returns. The economic evaluation of the abatement opportunities revealed an estimated annual savings of $229,287 US with a simple payback period (SPBP) of 2.96 years and an internal rate of return (IRR) of 32%/year for the absorption chiller. The re-boiler heat system showed an estimated annual savings of $209,456 US with an SPBP of 5.14 years and an IRR of 14%/year. The total investment for both opportunities amounted to $1,755,773 US, with a total annual savings of $438,743 US. The combined SPBP for the opportunities was 4 years, with an IRR of 21%/year. Sensitivity analyses demonstrated the absorption chiller's financial viability, while the hot oil-driven re-boiler opportunity proved more sensitive to variations in investment costs and savings. Therefore, it is recommended to implement both opportunities together.

Keywords: Greenhouse gas emissions, Gas treatment plants, Turbo compressor, Stabilizer heater, Abatement alternatives, Waste heat recovery, Absorption chiller

Introduction

The gas sector plays a pivotal role in meeting the escalating energy demand worldwide, driven by population growth and improved living standards [1]. However, these advancements have placed considerable pressure on the global energy market. Over the past decade, there has been a notable surge in gas consumption, accompanied by an increase in fuel costs, thereby straining energy markets. Consequently, certain countries are grappling with the challenge of meeting rising demands while experiencing stagnant or diminishing power supply, leading to a widening energy shortage gap [2, 3]. Additionally, traditional gas supply and delivery face constraints, intensified by factors such as global competition, concerns regarding climate change, deteriorating grid infrastructure, and security issues [4–6]. These circumstances further exacerbate the energy situation, resulting in adverse environmental, human health, and financial consequences. Hence, it becomes imperative to optimize energy usage by enhancing the efficiency of gas plants, improving facility designs and equipment, conserving energy, and promoting sustainable and renewable energy sources [7].

Gas treatment plants, responsible for processing raw natural gas from the wellhead, are crucial components of the natural gas supply chain [8]. These plants remove impurities and contaminants, ensuring the final product meets the stringent quality standards required for consumption and industrial use [9]. Nevertheless, these gas treatment plants are notorious for their substantial energy consumption and subsequent carbon emissions, particularly due to the operation of gas turbines and fired heaters, which are among the major GHG emitters in such facilities [10].

Energy efficiency stands at the forefront of the global drive for sustainability [11]. In the oil and gas sector, improving energy efficiency not only reduces operational costs but also minimizes the environmental footprint [12]. The quest for energy optimization and emissions reduction in gas treatment plants represents a multifaceted challenge that requires innovative solutions [13]. Through a comprehensive assessment of the energy consumption patterns and emissions sources within a gas treatment plant, opportunities for optimization can be identified and harnessed [14]. One of the most promising avenues in this regard is the utilization of waste heat recovery techniques [15].

The definition of industrial waste heat has been described in various ways. According to Viklund and Johansson [16] waste heat refers to the heat produced as a by-product during industrial processes, without considering the potential for heat recovery within or between processes. On the other hand, Ammar et al. [17] define waste heat as heat that is not economically viable for recovery. Meanwhile, Bendig et al. [18] define waste heat as the exergy available in a process after heat recovery and utility integration. While both Ammar et al. [17] and Bendig et al. [18] acknowledge the possibility of heat recovery within a process, they fail to account for the heat rejected from a site utility system designed to fulfill the process energy demand.

Various methods can be employed for waste heat recovery. Heat exchangers are commonly used to transfer heat from hot waste streams to colder fluids or gases, which can be utilized for preheating, steam generation, or electricity production. Organic Rankine cycles (ORCs) utilize organic fluids with lower boiling points to convert waste heat into electricity efficiently. Combined heat and power (CHP) systems simultaneously generate heat and electricity from industrial waste heat. Other methods include thermoelectric generators and absorption refrigeration systems, which directly convert waste heat into electricity or use it for cooling applications, respectively [19, 20].

Under ISO ambient conditions, gas turbine energy efficiencies are typically around 30% [21]. However, high ambient temperature and relative humidity have a negative impact on turbine energy efficiency. Gas turbines operate at a constant volume, so power output decreases as air density and mass flow rate decrease in elevated temperatures. Additionally, high humidity conditions increase the heat consumption of the gas turbine combustion chamber due to water's high specific heat [22–24]. On average, for every 1°C increase in ambient temperature, gas turbine output power decreases by approximately 0.5 to 0.9% [24]. To improve NG turbine performance and overall plant energy efficiency, a promising approach is to utilize waste heat for powering an absorption chiller to produce chilled water for cooling and generate a thermal load within the plant. This study explores these approaches.

In the past, the utilization of waste heat for enhancing the efficiency of gas plants has been relatively insignificant. This lack of progress can be attributed to various factors, including the absence of financial incentives, limitations imposed by licensed process technologies that impede energy efficiency improvements, and concerns surrounding the safety of specific waste heat sources. However, with increasing environmental concerns and the global energy shortage, there is mounting pressure on plants to embrace waste heat recovery technologies. Furthermore, as most natural gas plants have already achieved a notable level of process heat integration, the next significant step towards enhancing energy efficiency lies predominantly in the utilization of waste heat [25].

Absorption chillers offer various benefits such as reduced energy usage, eco-friendliness, and silent operation [26]. They can seamlessly integrate into pre-existing natural gas treatment plants. This research focuses on utilizing waste heat from gas turbine exhaust gases to provide the required heat, enabling cooling of the gas turbine compressor inlet air while also delivering extra cooling capacity for controlling room buildings.

Previous studies have shown the benefits of absorption chillers. Mohanty and Paloso Jr. [27] found that absorption chillers can increase a gas turbine's power output by up to 13%. Al-Ibrahim and Varnham [28] compared different cooling technologies and concluded that absorption refrigeration is the most effective but expensive option. Popli, Rodgers, and Eveloy [29] focused on waste heat-powered absorption chillers, which can enhance power output and reduce fuel consumption in the oil and gas industry. Ameri and Hejazi [30] reported a power output increase of up to 9.99% with absorption chillers. Other studies have explored the impact of inlet air cooling (IAC) on gas turbines, with improvements in performance observed [31, 32]. Caresana et al. [33] noted the effects of ambient temperature on power output and system efficiency. Singh [34] investigated the use of absorption refrigeration for inlet air cooling and observed an increase in net power output. Radchenko et al. [35] proposed a design methodology for efficient turbine intake air cooling. Al Moussawi et al. [36] reviewed trigeneration technologies, emphasizing their energy and economic savings potential. Baudat and Fan [37] proposed a power recovery system, and Popli, Rodgers, and Eveloy [38] presented a trigeneration scheme using waste heat.

Methods

The process of developing a GHG abatement plan for the gas treatment plant involves the following steps:

Plant identification and process description

This study focuses on an existing upstream gas treatment plant designed to utilize high-pressure associated gases from nearby gas wells. The plant has a processing capacity of 85 MMSCFD of high-pressure gas and approximately 3000 barrels per day of condensate. It produces two main products: residue gas, which is transported 58 km through a gas transmission line to another processing plant, and recovered stabilized condensate, which is stored in two tanks and subsequently pumped into the company's crude oil pipeline. The plant comprises six vessel-type slug catchers, a dew-pointing control unit, a condensate recovery stabilization unit, and a gas compression unit. In addition, it includes auxiliary facilities such as wastewater treatment, flare, and venting, as well as utility systems like water supply and drainage, fuel gas, power supply, instrumentation, and utility air. Figure 1 provides a simplified block diagram of the selected plant.

Data collection

Extensive data collection was conducted for one year prior to the study to comprehensively analyze the plant's operational performance. Performance variables, including flow rate data for sales gas and condensate, were captured (Fig. 2), and monthly fuel gas consumption was examined (Fig. 3).

Preliminary analysis of the data

Preliminary data analysis will provide a better understanding of the operational regime, the nature and quantity of energy consumption, and their associated emissions. It will also facilitate the identification of major emitter units that need to be closely examined during the study. The preliminary analysis was carried out based on the available data, following the approach outlined below:

Specifying the types and quantities of energy sources and their associated emissions

The selected gas plant relied solely on an internal fuel gas source as the primary energy source, driving all systems either directly for thermal loads or indirectly through electricity generation units for electrically driven equipment. The annual fuel gas consumption amounted to approximately 839.10 MMSCF, resulting in approximately 60.13 K tons of carbon dioxide (CO_2) equivalent emissions.

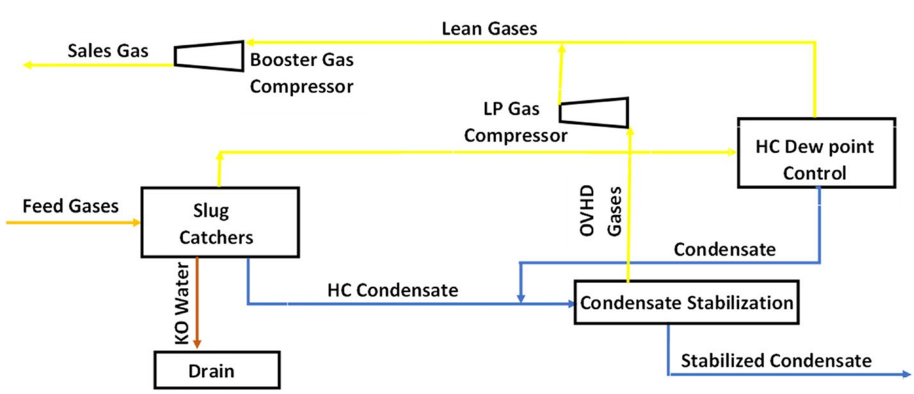

Fig. 1 Block diagram of the selected gas plant

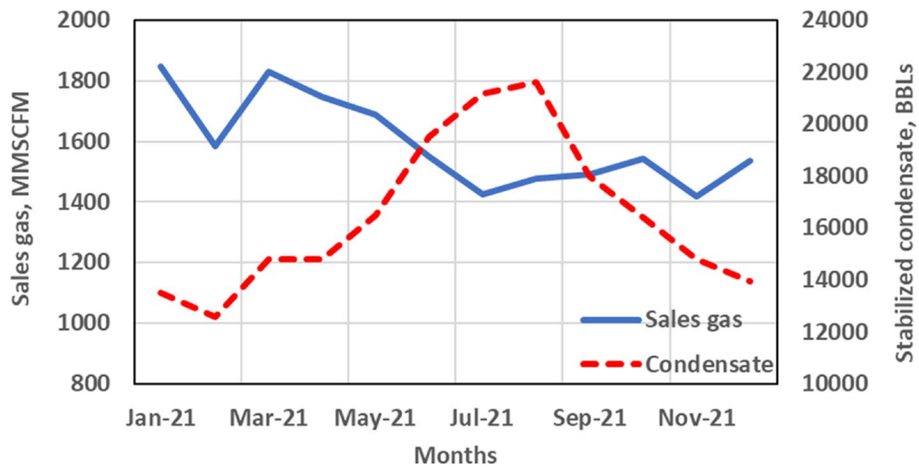

Fig. 2 Monthly plant products flow rates

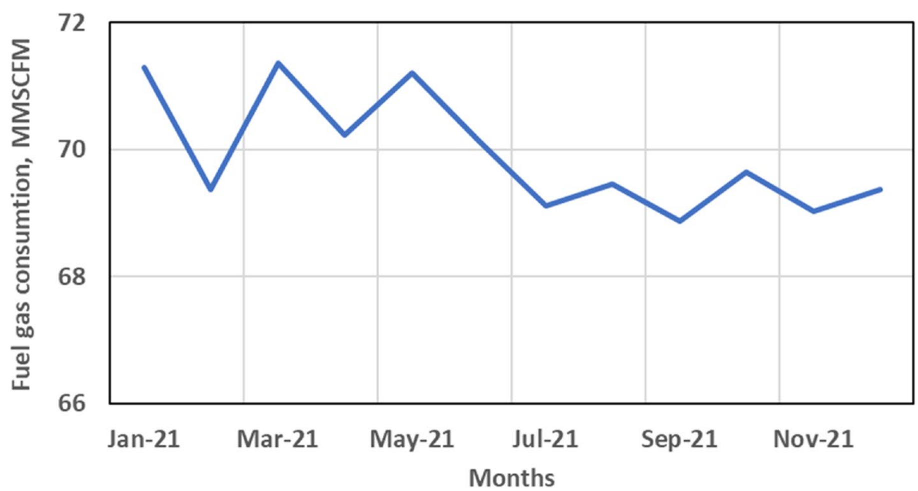

Fig. 3 Monthly fuel gas consumption

Figure 4 presents the monthly GHG emissions associated with the plant's energy consumption during 2021. Furthermore, Fig. 5 illustrates the plant's monthly carbon intensities (CIs), which reflect the level of GHG emissions adjusted by the total barrels of oil equivalent produced.

It is clear that there was a significant increase in the CI from March to July, with another peak in October. These spikes were associated with decreased production levels, while energy consumption and flaring remained relatively high.

Developing plant GHG emission inventory

The total plant's GHG emissions amount to approximately 113,039 tons of CO_2-eq and arise from a variety of sources, including energy consumption, non-routine flaring, and methane emissions. A detailed breakdown of the plant's annual GHG emissions by source category is provided in Fig. 6. Additionally, Table 1 identifies the

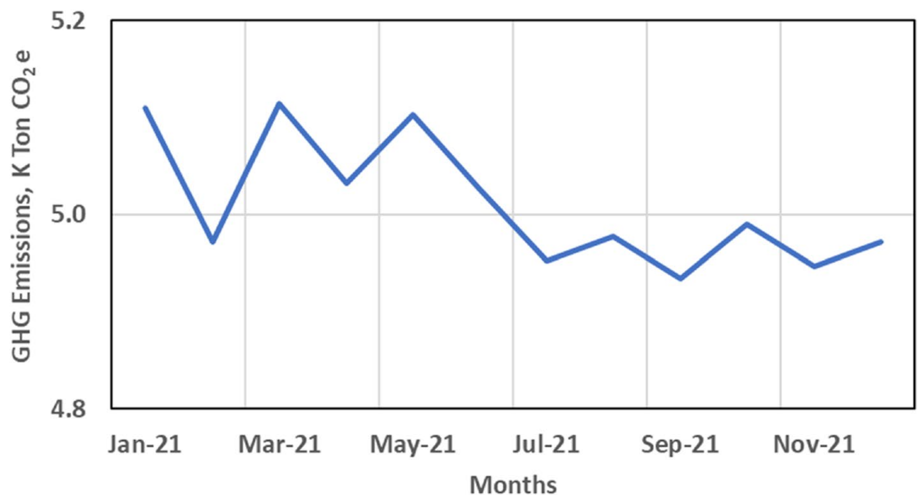

Fig. 4 Monthly plant GHG emissions

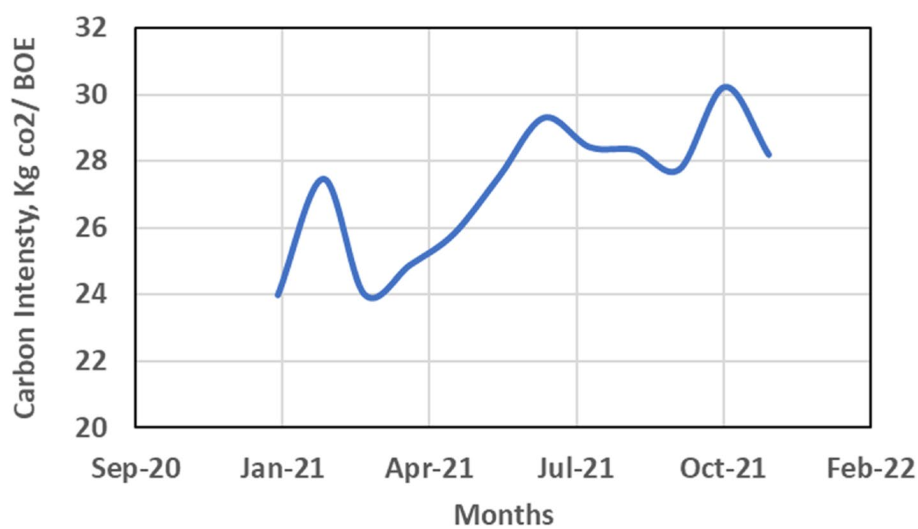

Fig. 5 Plant monthly carbon intensities

major emitters within the plant that necessitate further investigation. Remarkably, these major units collectively contribute to around 82% of the total GHG emissions.

Plant emission benchmarking

The benchmarking analysis was conducted to evaluate the CI of the plant in comparison to similar facilities. Furthermore, the analysis extended to making comparisons across diverse sectors, notably the upstream sector encompassing oil and gas production, the midstream sector linked to transportation, and the downstream segment involving crude refining. Data from the National Inventory Reports (NIR) of various countries, compiled under the United Nations Framework Convention on Climate Change (UNFCCC), were utilized for this purpose. Figure 7 displays the CIs of the

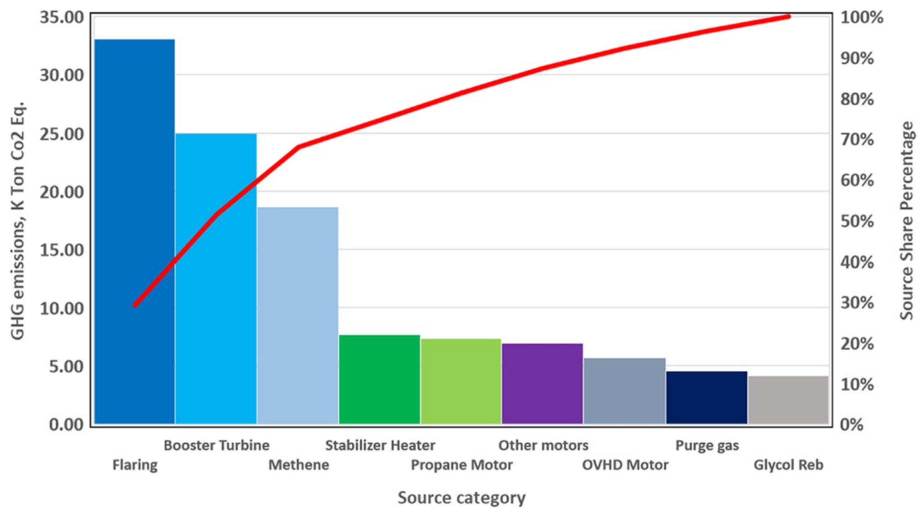

Fig. 6 Plant emissions by source category

Table 1 List of the major emitter units

Equipment	Energy used MMBTU/Y	Emissions (K Ton CO_2 e)	% from total emissions
Non-routine flaring	558,450	33.05	29%
Turbo compressor	421,601	24.95	22%
Methene fugitives	315,426	18.67	17%
Stabilizer heater	129,678	7.68	7%
Refrigeration comp. motor	124,349	7.36	7%
Total from SEUs	**1,549,504**	**91.71**	**82.00%**
Plant total	1,909,780	113.039	100%

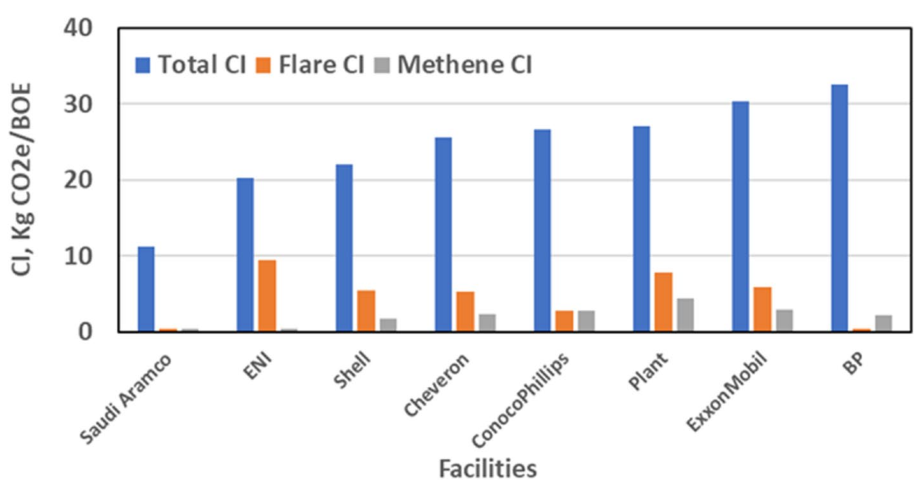

Fig. 7 Facilities carbon intensities [39]

plant and global oil and gas peers, focusing on total emissions (blue bar), flaring emissions (orange bar), and methane emissions (silver bar).

Upon comparing the plant's CI in 2021 with that of global oil and gas peers, it becomes apparent that the plant's CI exceeds the observed average. The total CI of the plant was measured at 27.0 kg CO_2-eq/boe, surpassing the overall average of 24.07 kg CO_2-eq/boe. Additionally, the plant's CI associated with flaring, measuring 7.89 kg CO_2-eq/boe, surpasses the presented average of 5.5 kg CO_2-eq/boe. However, the plant's CI related to methane, recorded at 4.46 kg CO_2-eq/boe, was nearly identical to the presented average of 4.40 kg CO_2-eq/boe.

In parallel, Fig. 8 delves into the carbon intensity (CI) of the plant by comparing it to the context of upstream, midstream, and downstream activities within the local environment. It is evident that the plant's CI values are notably competitive when compared to both upstream and downstream sectors.

Gap analysis

A comprehensive assessment was conducted to compare actual emissions with benchmark emissions. Figure 9 displays the cumulative sum of the difference (CUSUM) between these two values. The graph reveals that over the course of 1 year, there was an excess emission of approximately 37,000 tons of CO_2 equivalent.

Further investigation identified several factors contributing to the elevated CI observed in the plant. These factors include non-routine flaring, methane fugitives, and emissions related to the energy consumption of significant energy users, specifically the turbo compressor and stabilizer heater. It is worth noting that the study did not specifically focus on flaring and methane emissions, as separate studies have extensively addressed abatement techniques in those areas. Consequently, the study primarily concentrated on assessing the performance of significant energy users.

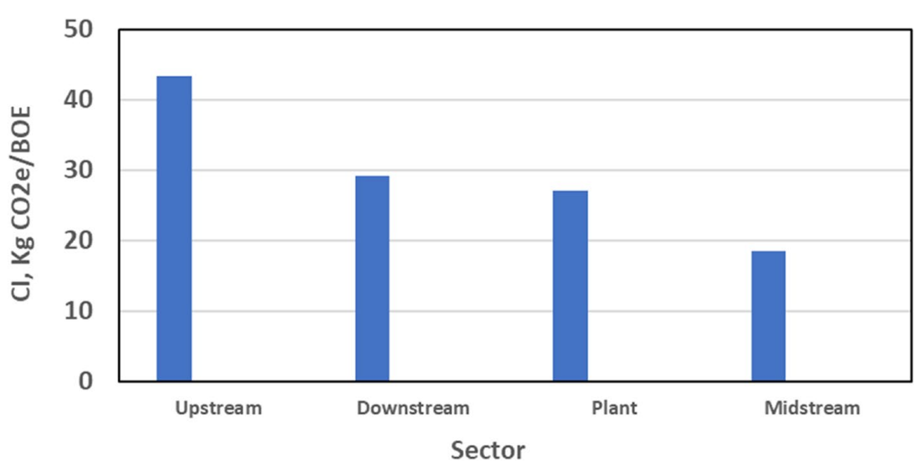

Fig. 8 Local sector carbon intensities [39]

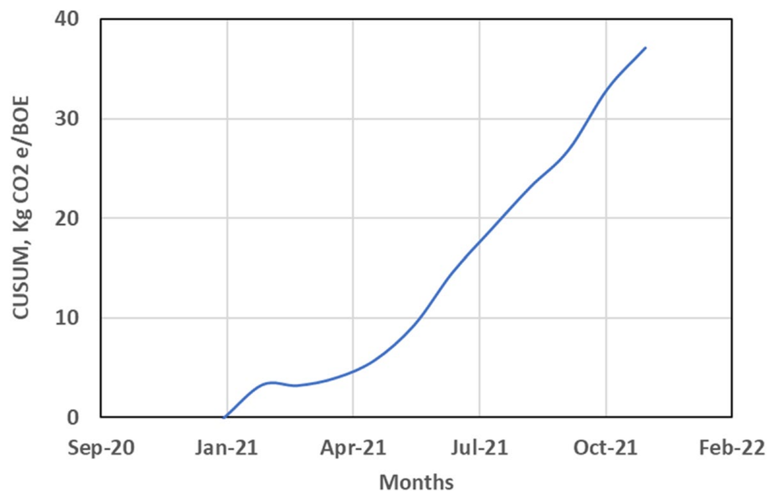

Fig. 9 Emission cumulative sum of difference

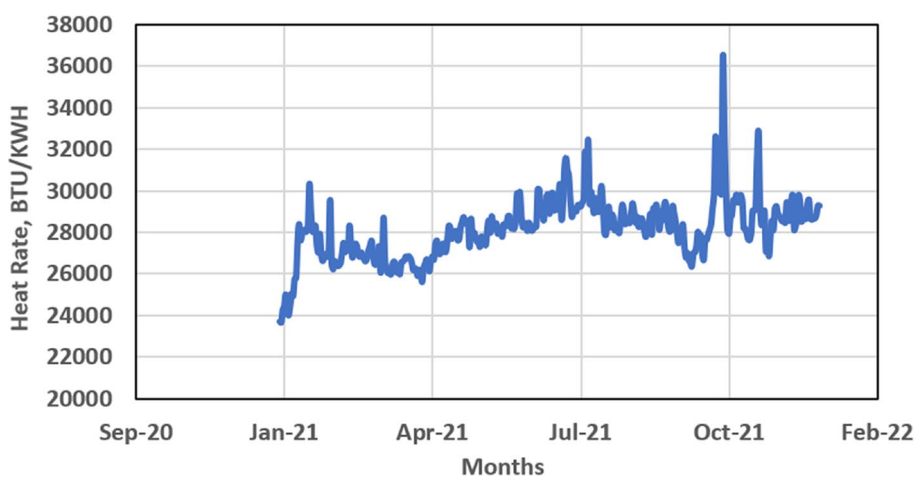

Fig. 10 Turbo compressor performance during 2021

Turbo compressor gap analysis

Turbo compressor process description

The plant is equipped with two dual-shaft open-cycle gas turbine-driven centrifugal compressors, both of which were commissioned in 1990. One of these compressors is currently operational, while the other serves as a standby unit. The gas turbine has a design efficiency rating of 25.7% and a total power capacity of 3.2 MW. The compressor is designed to operate with an efficiency of 72%, and the corresponding cycle design efficiency is 18.5%.

Turbo compressor performance analysis

It is worth noting that the operating efficiency of the cycle typically ranges from 10 to 13%. Furthermore, in this open cycle system, the turbine exhaust, which reaches temperatures as high as 450 to 550°C, goes unused, resulting in significant

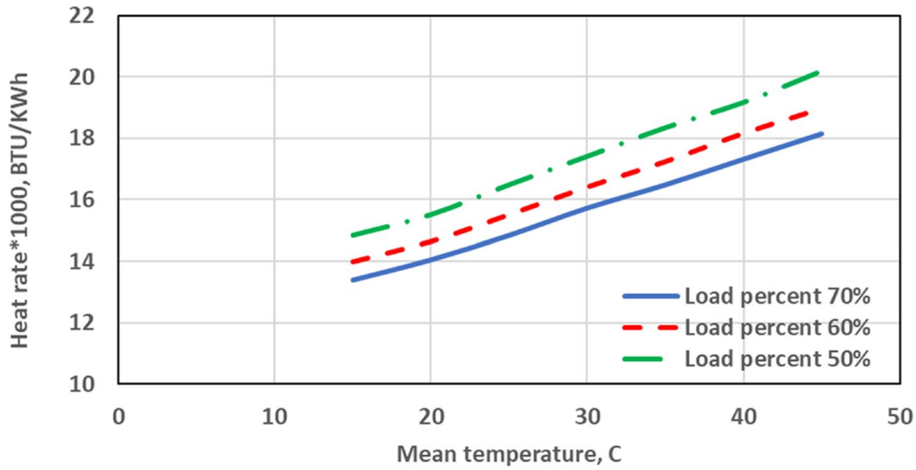

Fig. 11 Effect of ambient temperature and load factor on cycle performance

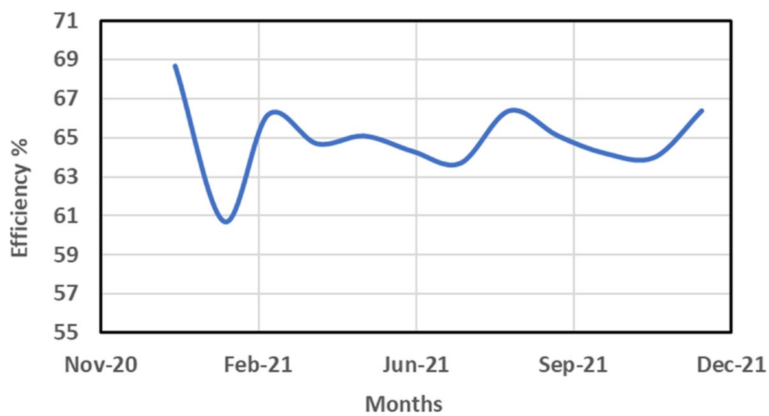

Fig. 12 Monthly heater performance

heat wastage. Figure 10 presents the actual cycle performance throughout the year 2021. It is evident from the graph that there is a notable peak in heat rate during the month of October. Further analysis revealed that this increase in heat rate coincided with a decrease in production rate, while the fuel consumption did not decrease by the same proportion.

Figure 11 provides insights into the impact of ambient temperature and load factors on the cycle performance. It is evident that ambient temperature has a significant influence on cycle performance.

Stabilizer heater gap analysis

Stabilizer heater process description

The stabilizer heater serves as a re-boiler for the condensate stabilizer tower. The heater is a vertical cylindrical, natural draft with fuel gas firing, and it is equipped with three burners complete with their pilots and electrical igniters. The heater design efficiency is 82.68%, based on a design stack temperature of 335 °C and a design excess air of 10%.

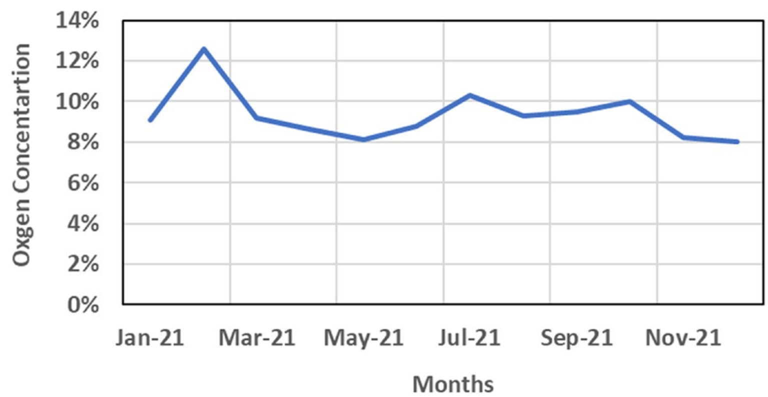

Fig. 13 Monthly oxygen concentration

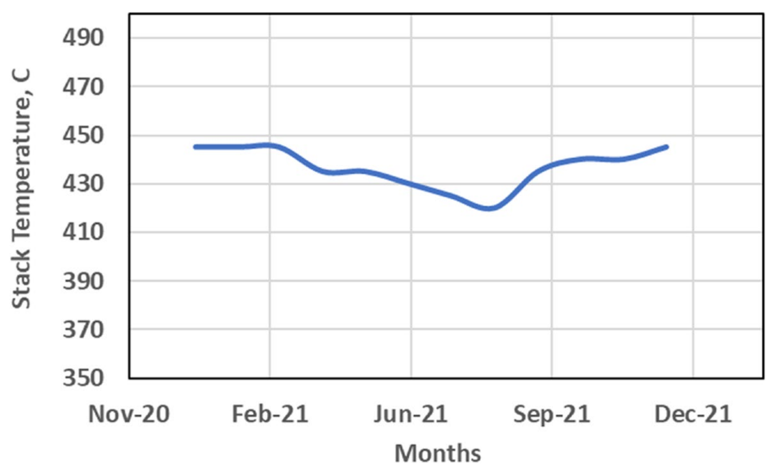

Fig. 14 Monthly heater stack temperature

Stabilizer heater performance analysis

The heater exhibited an average operating efficiency of approximately 65%. Figure 12 provides a monthly performance overview of the heater throughout the year 2021.

Figure 13 provides an illustration of the average monthly oxygen concentration in the flue gases. It is evident from the graph that the oxygen concentration is relatively high throughout the year, exceeding the recommended oxygen concentration of 2%. This indicates the presence of excess air in the combustion process, which in turn has led to decreased combustion efficiency.

Figure 14 presents an illustration of the average monthly heater stack temperature. It is evident from the graph that the stack temperature remains consistently high throughout the year, exceeding the design stack temperature of 335°C. The elevated stack temperature suggests that a significant amount of heat was being lost through the flue gases without effectively transferring it to the desired process.

Identification of potential GHG abatement alternatives

Based on the results of the plant's GHG emissions inventory and the conducted gap analysis, a concise list of potentially applicable alternatives for reducing GHG emissions was developed.

Abatement measures for the turbo compressor

Based on the performance analysis, it is evident that the exhaust gases contain recoverable heat that can be utilized. Approximately 5.0 MW $_{thermal}$ of net heat could be recovered from a single-gas turbine (GT). This recovered thermal energy can be employed in the following ways:

- Powering an absorption chiller to produce chilled water for cooling purposes. This includes cooling the intake air for the gas turbine compressor.
- Additionally, the recovered thermal energy can meet the cooling requirements of the main control building.
- Generating thermal load for use within the plant.

Abatement measures for the stabilizer heater

Based on the performance analysis, it was found that the heater had significantly low operating efficiency, accompanied by high stack temperature and oxygen concentration. Utilizing the available recovered thermal energy from the turbine exhaust, it is feasible to replace the current heater with a more efficient oil heating system.

Regarding the pre-defined abatement opportunities, Fig. 15 illustrates the system setup that showcases the proposed approaches.

Results and discussion

Technical feasibility

The different proposed opportunities for harnessing the recovered heat were evaluated in terms of their sizing, taking into consideration the availability of the heat and the relevant operating parameters.

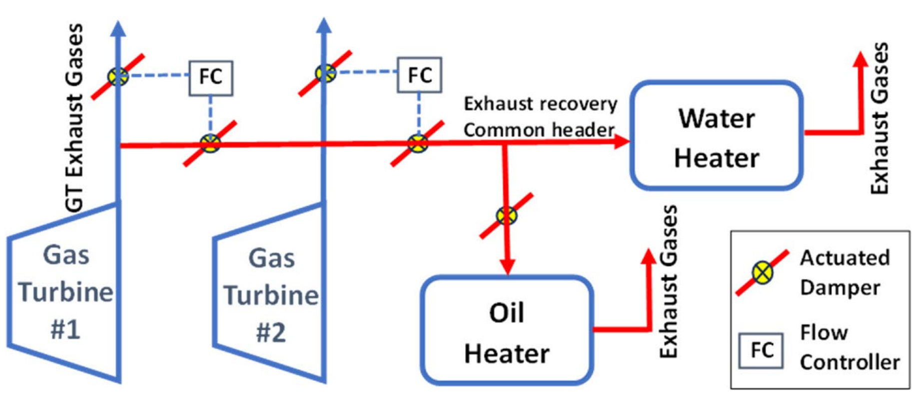

Fig. 15 Proposed abatement opportunities

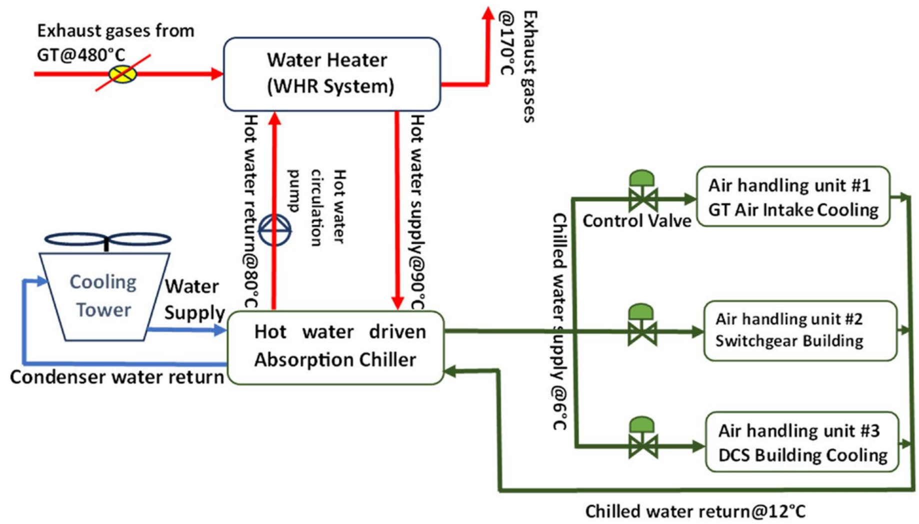

Fig. 16 WHR—hot water absorption chiller

Generation of thermal cooling through an absorption chiller

The absorption chiller was sized based on the cooling demand for cooling the combustion air intake to the GT compressor, as well as the cooling demand for the DCS building and the Switchgear Power Generation Building.

Absorption chiller process description

Figure 16 provides an illustration of the proposed absorption chiller system utilizing water and lithium bromide (LiBr) as the refrigerant and absorbent pair. The system utilizes the exhaust gas from a gas turbine, with a temperature of 480°C, as the heat source in the water heater (generator). This generator increases the temperature of the LiBr solution, causing water to evaporate and leaving behind a concentrated LiBr solution. The high-pressure and high-temperature vapor generated enters the condenser, where it releases heat to a cooling medium (cooled water) and condenses into a high-pressure liquid. The high-pressure liquid then flows through an expansion valve, reducing its pressure and temperature, resulting in partial evaporation and transformation into a low-pressure vapor. This low-pressure vapor is directed to three separate evaporators: one absorbs heat from the combustion air intake to the gas turbine compressor, another caters to the cooling demand of the distributed control system (DCS) building, and the third cools the switchgear power generation building. These absorption processes cause further evaporation of the vapor, converting it back to a gaseous state. The vapor subsequently returns to the absorber, where it is absorbed by the LiBr solution, forming a dilute LiBr solution. To restart the cycle, a pump is employed to increase the pressure of the dilute LiBr solution from the absorber, sending it back to the generator.

The cooling load for each specific application within the demonstrated setup was estimated based on the existing operating parameters at the plant.

Table 2 Cooling load calculation for combustion air intake

Item	Value	Unit
Combustion air quantity	16.93	kg/s
Temperature difference to cool air	15.00	°C
Air-specific heat Cp	1.00	kJ/kg. °C
Required heat	253.94	kW
Required heat to cool air intake	72.20	TOR

Table 3 The air handling unit #1 sizing and specs

Item	Capacity (TOR)	Chilled water supply temp. °C	Chilled water return temp. °C	Air flow rate (CFM)
AHU #1 to GT air intake	150	6	12	61,000

Table 4 The AHUs #2&3 sizing and specs

Item	Capacity (TOR)	Chilled water supply temp. °C	Chilled water return temp. °C	Air flow rate (CFM)
AHU #2 to switchgear building	40	6	12	14,000
AHU #3 to DCS building	24	6	12	8,400

Assessment of combustion air intake cooling for the gas turbine

The cooling load for the GT is presented in Table 2, considering the GT air intake of 16.93 kg/s based on the exhaust gases at ISO condition with a flow rate of 17.2 kg/s for the exhausted flue gases. Additionally, an assumed air temperature drop of 15 °C in the air intake was considered.

According to plant representatives, both turbo compressors will run simultaneously to meet increased production demands. This results in an estimated cooling load of 150 ton of refrigeration (TOR) for the two turbines. To address this requirement, the sizing and specifications of air handling unit (AHU) #1, as presented in Table 3, need to be considered.

Assessment of cooling load for the DCS and switchgear buildings

In the switchgear building, two direct expansion (DX) packaged units are installed to provide central air conditioning. Each unit has a capacity of 233,000 Btu/h (19.4 TOR) with a coefficient of performance (COP) of 2.22 at ISO Condition. Consequently, the AHU #2 will be sized at 40 TOR to meet the cooling requirements of this building.

Similarly, the DCS building is equipped with two DX-packaged units for its central air conditioning system. Each unit has a capacity of 144,000 Btu/h (12 TOR) with a COP of 2.22 at ISO condition. As a result, the AHU #3 will be sized at 24 TOR to adequately serve the cooling needs of the DCS building. The sizing and specifications for AHU#2 and AHU#3 are presented in Table 4.

Table 5 Absorption chiller sizing

Item	Value	Unit
Absorption chiller capacity	220	TOR
Cooling tower capacity	410	TOR
CoP of hot water driven absorption chiller	8	%
Condenser water temperature difference	10	°C
Chilled water temperature difference	6	°C
Condenser circuit flow rate	34.33	LPS
Chilled water flow rate	30.70	LPS
Condenser water pump capacity @ 40 m head	69.29	KW
Chilled water pump capacity @ 40 m head	61.96	KW
Cooling tower makeup	44.50	m3/day
Waste heat recovery—effectiveness	85	%
Recovered exhaust heat	1.14	$MW_{\mathbf{thermal}}$

Sizing of absorption chiller and the associated components

The sizing of the absorption chiller is designed to fulfill the cooling requirements of three AHUs responsible for supplying chilled air to the gas turbines' air intake, the switchgear building, and the DCS building. To meet these demands, the total capacity of the absorption chiller will be sized at 220 TOR, while the cooling tower capacity will be sized at 410 TOR. The capacities for the chilled water pump, condenser water pump, and makeup water for the cooling tower, along with their respective specifications, can be found in Table 5.

Table 6 Summary of avoided energy and ghg emission reduction due to absorption chiller

Item	Value	Unit
AHU #1 to cool the air intake to GT	69,473	MMBtu/year
AHU #2 to serve cooling load of the switchgear building	4883	MMBtu/year
AHU #3 to serve cooling load of the DCS building	2930	MMBtu/year
Total avoided energy	77,286	MMBtu/year
Fuel gas cost	4.75	US$/MMBtu
Total avoided energy costs	367,000	US$/year
GHG emission reduction	4100	Ton CO_2-eq/year
Energy reduction to total energy input	15.3	%

Table 7 Operating cost for absorption chiller cooling system

Item	Value	Unit
AHU #1 fan energy consumption	222,807	kWh/year
AHU #2 fan energy consumption	21,628	kWh/year
AHU #3 fan energy consumption	12,977	kWh/year
Chilled water pump	526,680	kWh/year
Condenser water pump	588,924	kWh/year
Total additional energy consumption	1,373,016	kWh/year
Equivalent input energy for energy production	29,014	MMBtu/year
Total cost for extra energy required	138,000	US$/year
Additional GHG emissions	1540	Ton CO_2-eq/year

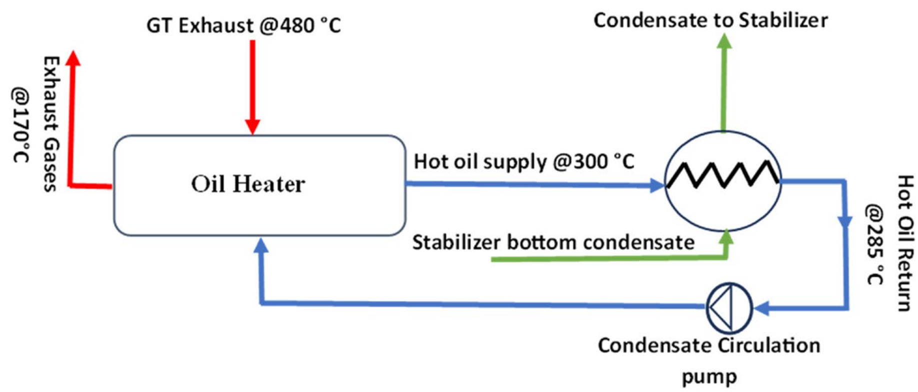

Fig. 17 Waste heat recovery system to drive a re-boiler

Table 8 Existing operating parameters for the re-boiler at 100% duty

Item	Useful heat re-boiler (Btu/h)	Heat exchanger effectiveness of heated oil-driven re-boiler	Input energy to re-boiler (Btu/h)	GT exhaust gases to be recovered through a waste heat recovery system (Btu/h)
Recovered heat to heated oil	9,523,900	0.95	10,025,158	11,139,064

According to this analysis, it has been determined that the waste heat recovery (WHR) system's capacity to produce hot water, which drives the absorption chiller, is sized at 1.14 MW $_{\text{thermal}}$.

Avoided energy through waste heat recovery (WHR) system

Table 6 presents a summary of the achieved energy savings and reduction in GHG emissions resulting from the implementation of the absorption chiller to serve the assumed cooling load.

Table 7 presents a summary of the calculations for the additional energy consumption, GHG emissions, and associated costs resulting from the implementation of the WHR system to generate thermal cooling energy. The WHR system requires energy consumption for the operation of pumps related to the cooling towers (condenser water cooling) and chilled water distribution.

The implementation of the absorption chiller system results in a net avoided energy cost of approximately $229,000 US/year, a reduction of 2560 tons of CO_2-eq emissions/year. Additionally, it achieves a net energy reduction of 9.53% in the total energy input.

Installing hot oil-driven re-boiler using WHR

Hot oil-driven re-boiler process description

This opportunity involves utilizing recovered waste heat to generate a thermal load. The process involves passing the waste heat through a gas-to-fluid heat exchanger, which then allows for the design of a hot oil-driven re-boiler, as illustrated in Fig. 17.

The assessment of the assumed system has been carried out considering the 100% duty of the re-boiler from a sizing perspective. However, the calculation of

Table 9 Avoided energy due to re-boiler replacement

Item	Value	Unit
Avoided energy to replace the re-boiler by waste heat recovery system	12.584	MMBtu/h
The existing re-boiler loading condition (duty)	40%	%
The equivalent full load hours of the re-boiler	3504	HRs
Avoided energy due to existing operations of the re-boiler	44,096	MMBtu/year
Fuel gas cost	4.75	US$/MMBtu
Anticipated energy cost savings	210,000	US$/year
GHG emission reduction	2340	Ton CO_2-eq/year

Table 10 Estimated investment cost—WHR system

Description	USD
Exhaust gases main manifold for 2 GTs furnished by 5 modulated exhaust dampers—the manifold is sized for 33.8 kg/s flue gases	313,000
Waste heat recovery hot water generator—capacity of 1 $MW_{thermal}$	95,000
Waste heat recovery hot oil generator—capacity of 3.25 $MW_{thermal}$	277,000
Re-boiler of hot oil driven type—capacity 2.8 $MW_{thermal}$	357,000
Absorption chiller of 220 TOR capacity	138,000
Cooling tower of 410 tor capacity	68,000
Chilled water pumps at 110 m^3/h, 40 m head	30,000
Condenser water pump at 125 m^3/h, 40 m head	33,000
AHU#1 for cooling air intake to gas turbine (150 TOR)	42,000
AHU#2 for cooling switchgear building (40 TOR)	21,000
AHU#3 for cooling DCS building (24 TOR)	15,000
Sub-total investment cost	**1,389,000**
Balance of the system	97,000
Engineering and overhead costs	67,000
Extra installation work cost	208,000
Total investment cost	**1,761,000**

anticipated energy savings was performed based on the actual operating duty. The existing operating parameters for the re-boiler at 100% performance duty are illustrated in Table 8.

Avoided energy for replacement of the existing re-boiler

The existing re-boiler was operated at approximately 40% loading, which served as the basis for calculating the avoided energy. Table 9 presents the avoided energy and the corresponding reduction in GHG emissions resulting from the replacement of the existing re-boiler and the corresponding reduction in energy consumption.

The study demonstrated that the recovered gases amounted to 4.4 MW $_{thermal}$. Out of this, 1.13 MW $_{thermal}$ was utilized to drive the absorption chiller, and 3.26 MW $_{thermal}$ was allocated for hot oil generation. Furthermore, the available exhaust gases to be recovered from the single-gas turbine were estimated to be approximately 5 MW $_{thermal}$. Based on these findings, the study was deemed feasible from a technical point of view.

Financial and economical evaluation

Investment cost estimation for emission abatement opportunities

The total investment cost for each abatement opportunity was estimated to assess the financial feasibility of each option. The cost estimates were presented as an order of magnitude, indicating a broad range of values, with an approximate accuracy of ±15%.

Waste heat recovery to generate hot water and hot oil

The total investment cost for both WHR systems, including the generation of cooling load and the heated oil, is illustrated in Table 10.

The total investment cost is $1,761,000 US. Out of this amount, $1,081,000 US is allocated for the installation of a hot oil driven re-boiler, while $680,000 US is dedicated to the generation of thermal cooling through an absorption chiller.

Economical and financial evaluation

The abatement cost for the identified opportunities, expressed in $/ton CO_2-eq, can be derived using the subsequent formula:

Marginal abatement cost ($/ton CO_2-eq) = net present value/total GHG emissions abated over project life

Table 11 Cost-effectiveness evaluation of opportunities: abatement cost analysis

Opportunities	Net present value USD	Total emission abated Ton CO_2-eq	Abatement cost $/Ton CO_2-eq
WHR—absorption Chiller	$ −730,000	25,600	−28
WHR—re-boiler Heat	$ −211,000	23,400	−9
Opportunities 1&2	$ −941,000	49,000	−19

Table 12 Emission abatement opportunity economic evaluation by SPBP

Opportunities	Estimated investment	Estimated annual savings	SPBP
	USD	USD	Years
WHR—absorption chiller	680,000	229,000	2.96
WHR—re-boiler heat	1,081,000	210,000	5.14
Total	**1,761,000**	**439,000**	**4.00**

Table 13 Emission abatement opportunities economic evaluation by IRR

Opportunity	IRR %/year	Investment	Annual savings—K.USD/year									
		K.USD	Year	Year	Year	Year	Year	Year	Year	Year	Year	Year
		0	1	2	3	4	5	6	7	8	9	10
Absorption chiller	32	(680)	229	229	229	229	229	229	229	229	229	229
Re-boiler heat	14	(1076)	209	209	209	209	209	209	209	209	209	209
Total	21	(1760)	440	440	440	440	440	440	440	440	440	440

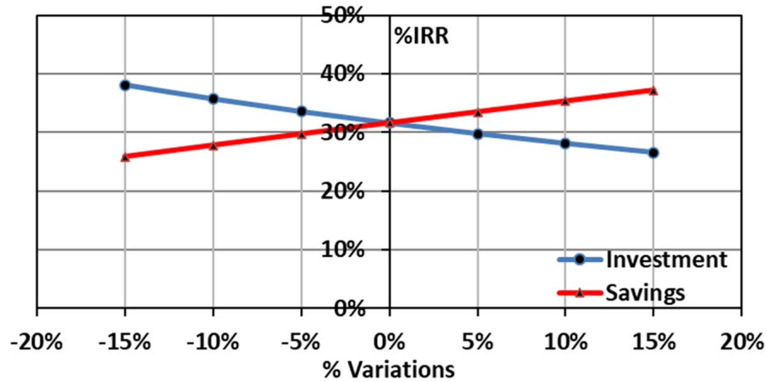

Fig. 18 Sensitivity analysis outputs for WHR—absorption chiller

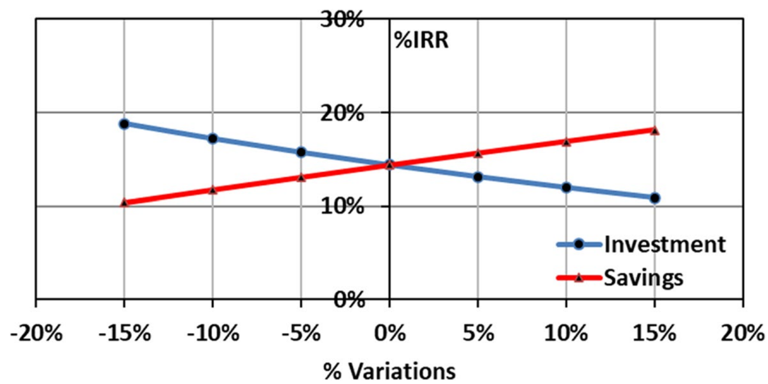

Fig. 19 Sensitivity analysis outputs for WHR—re-boiler heat

$$\text{Net present value} = \sum_{\text{Project life}} \frac{\text{Net cash flow}_t}{((1+d)*(1+i))^t}$$

where *d* signifies the discount rate, set at 10% for this analysis, *i* denotes the interest rate, which is also 10% in this instance, and *t* represents the time of cash flow, specifically spanning 10 years.

Table 11 offers a comprehensive economic assessment of the identified opportunities through the lens of abatement costs.

Table 12 provides an economical evaluation of the abatement opportunities using the simple payback period (SPBP) as an economic indicator.

It is evident that the evaluated abatement opportunities are long-term projects. Consequently, the internal rate of return (IRR) was employed as an economic evaluation tool, considering the time value of money. Table 13 presents the calculated IRR for each opportunity.

Sensitivity analysis

The economic indicators mentioned above were calculated using two main inputs. Firstly, the investment cost was estimated using the order of magnitude technique, which involved considering data from similar projects and utilizing engineering expertise. Secondly, the annual cost savings were determined through a combination of engineering calculations, historical data analysis, anticipated data, and an assumed cost of $4.75 US per MMBTU.

The sensitivity analysis outputs in Fig. 18 illustrate the variations in economic indicators for the generation of thermal cooling through an absorption chiller, considering a range of − 15 to + 15%. It is evident from the analysis that the opportunity maintains its economic feasibility even in scenarios where the investment cost increases by 15% resulting in a 5% decrease in IRR or a 15% decrease in savings leading to a 6% decrease in IRR.

Figure 19 presents the sensitivity analysis outputs for the installation of a hot oil driven re-boiler. This opportunity exhibits a moderate IRR of approximately 14%. It is noteworthy that the project is sensitive to variations in both the estimated investment cost and the calculated savings. If the investment cost increases by 15%, the IRR is projected to decrease to 11%. Similarly, a 15% decrease in savings would result in an IRR of 10%.

Recommendation

It is recommended to implement both opportunities in conjunction with each other. The combination of these opportunities yields improved economic indicators, as demonstrated in Fig. 20.

Conclusions

This research paper provided a comprehensive analysis of the operational performance, energy consumption, and greenhouse gas emissions of an existing gas treatment plant. Major emitter units were identified, and their contributions to the overall emissions profile were quantified. Potential GHG abatement alternatives for the turbo compressor and stabilizer heater were proposed, involving the recovery and utilization of waste heat. Technical feasibility assessments confirmed the viability of implementing waste heat recovery systems, while economic evaluations demonstrated positive financial returns over time.

The research findings indicated that the adoption of an absorption chiller and a hot oil-driven re-boiler could result in substantial energy savings, emission reduction, and

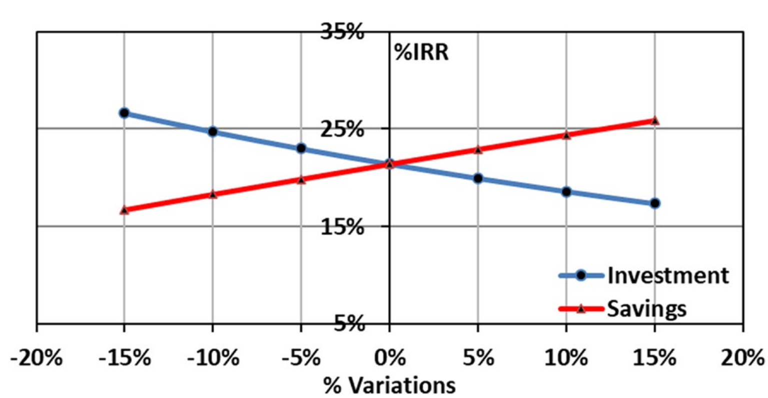

Fig. 20 Sensitivity analysis outputs for both opportunities

improved operational efficiency. Moreover, sensitivity analyses have underscored the financial viability of the absorption chiller, while shedding light on the hot oil-driven reboiler's sensitivity to variations in investment costs and savings. To ensure maximum feasibility and profitability, it is strongly recommended to implement both opportunities together.

These findings contribute to the field of energy optimization and emissions reduction in gas treatment plants, providing valuable insights for the industry. The research underscores the importance of implementing sustainable practices and technologies to mitigate environmental impact while realizing economic benefits.

Abbreviations

GHG	Greenhouse gas
SPBP	Simple payback period
IRR	Internal rate of return
WHR	Waste heat recovery
MMSCFD	Million standard cubic feet
BBLs	Barrels
K Ton	Thousand ton
CI	Carbon intensity
CUSUM	Cumulative sum of the difference
TOR	Ton of refrigerant
AHU	Air handling unit
LiBr	Lithium bromide
DCS	Distributed control system
GT	Gas turbine
DX	Direct expansion
CoP	Coefficient of performance

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Authors' contributions
MM designed the research study, conducted data collection and analysis, and drafted the manuscript. GM and TM contributed by providing valuable feedback, revising the manuscript, and approving the final version for submission.

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Availability of data and materials
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Declarations

Competing interests
The authors declare that they have no competing interests.

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