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Research paper

Insights on blowdown gas recovery in natural gas compression stations: A techno-economic assessment considering methane emission charges

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ABSTRACT

Blowdown operations in natural gas compressor stations, required during maintenance, emergencies, or demand reductions, release significant volumes of methane into the atmosphere. These emissions not only contribute to climate change but also represent a loss of valuable energy resources. This study proposes a guideline-based framework for selecting optimal blowdown gas utilization strategies and applies it to a representative case of a small, remote compressor station. The proposed solution involves reinjecting blowdown gas into nearby transmission lines using a three-stage reciprocating compressor. A dynamic model was developed to design the evacuation package, achieving >95 % gas recovery. Techno-economic analysis shows that for an annual blowdown volume of 89,000 Nm^3, incorporating the recently introduced Waste Emissions Charge (WEC) of $1500 per ton of methane results in a 15.04 % return on investment (ROI) and a payback period of 6.65 years. These findings highlight that the proposed solution enhances environmental sustainability by reducing methane emissions, while also improving financial viability under evolving regulatory pressures.

1. Introduction

Methane (CH_4) is a highly potent greenhouse gas (GHG) with a global warming potential (GWP) 86 times greater than carbon dioxide (CO_2) over a 20-year period, resulting in about 30 % of net global warming since the Industrial Revolution [1,2]. The urgent need to mitigate methane emissions has been emphasized in recent global agreements. Notably, at the COP26 summit, the major methane-emitting nations, comprising 158 countries, pledged a 30 % reduction in methane emissions by 2030 [3–5]. Aside from environmental concerns, methane emissions pose safety and economic challenges, especially in the energy sector [6,7]. Meanwhile, methane emissions from this sector can be reduced by 75 %, with approximately 40 % of this reduction being achievable at net-zero cost using known technologies [8,9]. All these aspects emphasize the need to adopt and implement effective methane emissions management techniques.

Annually, about 596 million tons of methane are released into the atmosphere from various sources, both natural and anthropogenic [2,10]. As illustrated in Fig. 1, the energy sector, particularly the natural gas value chain, is one of the prominent contributors to anthropogenic methane emissions. Moreover, when considering factors such as geographic distribution, emission volume, and purity, methane emissions from the energy sector are potentially more accessible for utilization compared to other sources [11].

Within the natural gas value chain, there are three types of methane emissions, i.e., fugitive, vented, and combustion. Vented emissions, commonly called blowdown emissions, involve the controlled discharge of gas from equipment or pipeline systems for maintenance, repair, or emergency purposes, and stand out as a significant source of methane release [12,14–17]. In contrast to the low-volume emissions resulting from incomplete combustion or fugitive emissions from leaks that are dispersed over large areas, blowdown operations release large amounts of high-quality natural gas at specific locations, which makes it easier to capture and repurpose [18–20]. In the broader context of the natural gas value chain, the transmission segment with $\sim 1.7 \times 10^7$ tone or $\sim 2.5 \times 10^{10}$ Nm^3 methane emitted per year offers the greatest potential for blowdown gas utilization. This is because, in the production segment, blowdown gas is often redirected to operational equipment, such as boilers and furnaces, which are already in place to use these emissions. Conversely, the distribution segment typically handles smaller volumes of blowdown gas due to lower pressure and reduced facility scales. The transmission segment comprises extensive pressurized pipelines and compressor stations that are responsible for delivering natural gas to

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Nomenclature

Acronyms

PBP	payback period
ROI	return on investment
SCM	social cost of methane
WEC	waste emission charge

Symbols

C_p	gas heat capacity
M	molecular mass of the gas
m	mass of the gas within the station's equipment
$\dot{m}$	discharge mass flow rate
n	polytropic exponent
$\dot{n}$	discharge mole flow rate
P_0	station pressure
P_1	pressure at discharge of first stage of evacuation package
P_2	pressure at discharge of second stage of evacuation package
P_3	pressure at discharge of third stage of evacuation package
P_{in}	intake pressure of compression stage
P_{out}	discharge pressure of compression stage
q	rate of heat removal
R	universal gas constant
ρ	gas density
T_0	station temperature
T_1	temperature at discharge of first stage of evacuation package
T_2	temperature at discharge of second stage of evacuation package
T_3	temperature at discharge of third stage of evacuation package
T_c	inter/after cooler outlet temperature
T_{in}	intake temperature of compression stage
T_{out}	discharge temperature of compression stage
t	time
V_0	total volume of the station's equipment
$\dot{V}_{in}$	volumetric discharge rate
z	gas compressibility factor

industrial users, distribution facilities, and storage infrastructures [21, 22]. Given the centralized nature of compressor stations, blowdown gases can be more easily captured and repurposed compared to those emissions from distributed pipelines. As a result, it is reasonable to assert that the blowdown gases from compressor stations throughout the natural gas value chain represent a more viable opportunity for capture and utilization compared to other emissions, providing an effective source for mitigating methane emissions.

While existing literature (EPA, PHMSA, industry white papers) describe range of practical approaches for reducing blowdown emissions—such as routing blowdown gas to fuel systems or low-pressure mains, using ejectors, or deploying portable compressors —this information remains dispersed across technical notes and industry reports rather than consolidated into a unified decision framework. Furthermore, most published cost–benefit and mitigation studies focus on large pipeline blowdowns or production-sector facilities, while limited attention has been given to the numerous small, remote compressor stations where economic feasibility poses greater challenges. This study addresses these gaps by (1) integrating existing technical practices into a guideline-based framework for selecting optimal blowdown gas utilization solutions, and (2) performing a detailed techno-economic assessment for a small-scale remote compressor station, explicitly incorporating the Waste Emissions Charge (WEC) and natural gas price volatility to derive actionable ROI and payback thresholds. The principal limitations are: the case study focuses on a specific station configuration and set of operational assumptions (gas composition, station volume, and dispatch patterns), labor and depreciation costs are simplified, and the WEC remains subject to regulatory and political uncertainty. Accordingly, results are presented with sensitivity ranges, and the proposed framework is intended as a practical decision-support tool rather than a universal prescription. Ultimately, this study provides a practical pathway for improving methane management in compressor stations through an integrated technical, economic, and policy-aware framework, contributing to cleaner and more efficient gas transmission operations.

2. Insights on blowdown gas management solutions

In this section, the various types of blowdown events occurring in compressor stations are first described, followed by an overview of existing approaches for managing these events, and state-of-the-art blowdown management solutions. The related works are critically

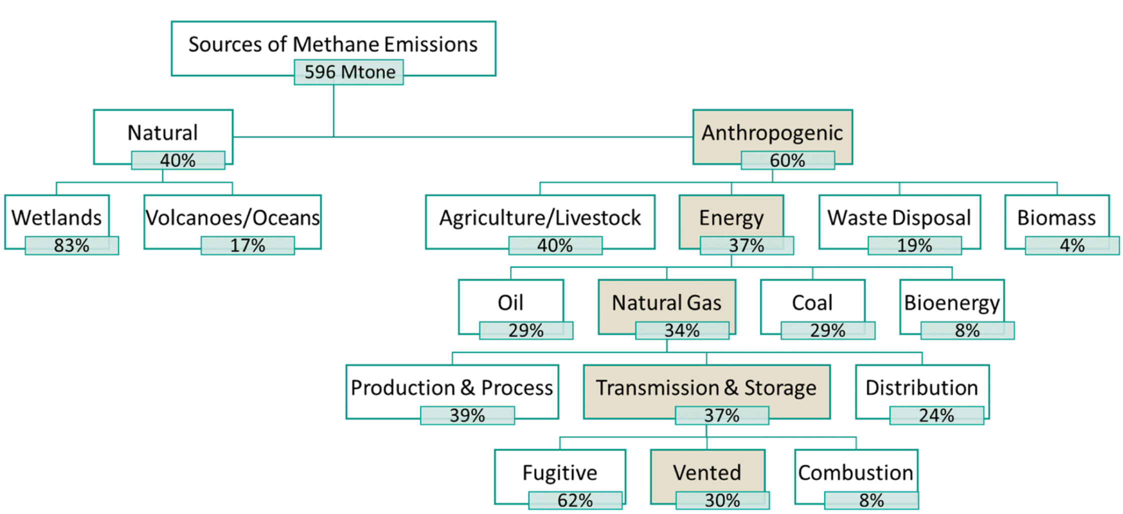

Fig. 1. Annual methane emissions sources together with their relative share in each sector [2,10,12–14].

reviewed and compared, highlighting their operational principles, applicability, and limitations based on insights from previous studies and industrial practices.

2.1. Types of blowdown event in the stations

The selection of a suitable management solution depends on the blowdown operation type and the station's specific conditions, considering both technical feasibility and cost-effectiveness. The frequency of blowdown operations varies depending on the type of event. Demand reduction blowdowns occur most frequently, happening once or more each month as gas flow is adjusted to meet fluctuating demand. These events release significant amounts of gas, creating prime opportunities for recovery and utilization. Maintenance-related blowdowns, which typically occur every one to two years, involve planned operations that facilitate improved planning and recovery strategies due to their scheduled nature. Lastly, emergency shutdowns (ESDs) are infrequent and typically necessitate a prompt return to service in the case of ESD system faults, thereby eliminating the need for blowdown operations. Critical ESDs often limit the ability to capture and utilize the blowdown gas. Nevertheless, when circumstances permit, even emergency blowdown events can be leveraged for gas recovery.

2.2. Approaches and solutions for blowdown gas management

Managing blowdown gases from compressor stations involves a hierarchy of preventive and responsive strategies designed to minimize atmospheric releases and meanwhile maximize resource recovery. Preventive measures aim to reduce the frequency and magnitude of blowdowns through optimized station design and operational practice. When blowdown is unavoidable, the next priority is internal utilization—directing the gas to fuel gas systems, low-pressure lines, or the inlet of active compressors. If internal use is not feasible, the gas can be routed externally to a nearby high-pressure transmission line via a booster compressor. As a final option, blowdown gas may be captured and stored for later utilization or conversion into valuable products such as electricity, CNG, or LNG. The following subsections review these approaches in detail, and Table 1 summarizes their principles, advantages, and limitations.

Table 1
Comparison of blowdown gas management and utilization solutions, their advantages, and limitations [1,9,22–28].

Solution	Implementation considerations	Key advantages	Key limitations
Designing the station based on base and peak load	Station redesign, capacity planning, incorporated during the station design phase	Reduces cycling blowdowns; low marginal operational cost once implemented	Requires network analysis; high retrofit cost for existing stations; suitable just for demand reduction blowdown
Keeping compressors pressurized while offline	No modifications; just improved sealing systems and regular maintenance for safety	Low capital cost; reduces venting vs full blowdown; effective for short periods, typically lasting a few days; eliminates the need for purging and re-pressurization operations before restarting	Risk of continual leakage via packings/valves; not for long Shutdowns; auxiliary power/purging; suitable just for demand reduction blowdown
Injection into fuel gas systems or other low-pressure users	Piping and valve work to fuel header or LP lines	Low CAPEX; simple; high recovery if sink available; suitable for all blowdown types	Requires available sink and minimum fuel demand; manual coordination
Injection into active compressors intake using an ejector	Venturi ejector using motive gas	Low CAPEX; no moving parts; quick deployment; suitable for all blowdown types	Needs active compressor/motive stream; limited when station fully offline
Injection into transmission lines using a booster compressor	Portable/fixed multi-stage compressor to inject to pipeline	Very high recovery (>90 %); portable option; suitable for all blowdown types	Moderate–high CAPEX; requires power, space; operational complexity
Storage for later utilization or conversion to valuable commodities	Compressors, storage vessels, CNG/LNG systems	Decouples discharge/use; flexible end-uses; suitable for all blowdown types	High CAPEX/OPEX; safety/regulatory constraints; uneconomic for small volumes

2.2.1. Station design based on base and peak loads

Designing stations with a clear separation of base-load and peaking compressors reduces the need to take large compressors offline frequently. Base-load units remain in continuous service with low cycling, while smaller peaking units meet variable demand. This strategy reduces the cumulative volume of blowdown events driven by demand cycling, and can reduce capital and operational losses associated with repeated depressurization. However, this solution typically requires network-level planning (pipeline modeling and potential resizing) and may incur substantial retrofit costs where existing stations are not easily reconfigured. It is therefore most effective when incorporated during initial design or major network upgrades [23].

2.2.2. Keeping compressors pressurized while offline

Maintaining an offline compressor under pressure (rather than fully depressurizing) reduces venting and the large transient emissions associated with full blowdown. Studies and field reports show that keeping the unit pressurized can reduce total leakage compared with fully evacuated units because leakage paths to atmosphere are minimized once pressure is equalized with a fuel or low-pressure line; pressurized idling can often reduce aggregate leakage by a substantial fraction compared with depressurization. Limitations include increased risk of internal leaks through rod packings and control valves if left pressurized long-term, the potential need for small continuous purge streams, and electric power consumption for auxiliary systems (e.g., instrument or purge compressors). Regular inspection and suitable sealing technologies (e.g., static seals for rod packing) are recommended to control packings' leakage when this strategy is used [23,24].

2.2.3. Injection into fuel gas systems or other low-pressure users

Routing blowdown gas into a station's fuel gas header or nearby low-pressure users is a low-cost method to recover much of the discharge without large additional equipment. This approach typically requires piping modifications, valves, and operational procedures to equalize pressures and route gas safely to burners or low-pressure networks. It is widely reported in industry practice as one of the simplest and most cost-effective measures when a suitable low-pressure sink exists. Limitations are obvious when no low-pressure consumer is available or when fuel demand is insufficient to accept the blowdown flow; in these cases, the method cannot recover gas and will not prevent emissions [23,25,26].

2.2.4. Injection into active compressors intake using an ejector

Ejectors (venturi devices) use a high-pressure motive gas to entrain and compress lower-pressure blowdown or leakage gas into an intermediate pressure stream that can be directed to a compressor intake or fuel system. Ejectors are inexpensive, have no moving parts, and can be effective where a nearby high-pressure motive source exists and an active compressor inlet is available to accept the mixed stream. However, an ejector requires an active driving stream (hence an active compressor) and its effectiveness depends on available motive pressure and flow; it is not suitable when the station is fully offline or when no active compressor can accept the flow. Ejectors also introduce a thermodynamic penalty and may require careful pressure-matching and operational coordination [23,24].

2.2.5. Injection into transmission lines using a booster compressor (recommended solution in this study)

Using a portable or fixed booster compressor to pressurize and inject blowdown gas into the downstream transmission line recovers a large fraction of the gas inventory and is applicable across planned and many unplanned blowdowns. Multi-stage reciprocating compressors are often selected where high compression ratios and variable suction conditions are required; this arrangement allows progressive pressure reduction of station volumes while delivering gas at pipeline pressure, typically achieving very high recovery (>90–95 %) in well-designed systems. The approach is operationally flexible (can be portable) and recovers high-quality gas with minimal treatment. Drawbacks include higher capital cost than simple piping changes, the need for space and auxiliary services (power), and increased operational complexity. The techno-economic trade-off depends strongly on blowdown frequency, volume, local gas prices, and regulatory incentives (e.g., WEC). Recent field implementations documented in industry reports and Natural Gas STAR case studies report substantial emission reductions where booster compressors are applied, particularly when packages are designed for multi-station use [25,27].

2.2.6. Storage for later utilization or conversion to valuable commodities

Storage approaches (compressing to CNG, liquefying to LNG, or temporary storage in vessels) enable valuation of blowdown gas through sale or onsite use (electricity generation, heating). Storage is flexible and allows decoupling of discharge timing from end-use, and is particularly appealing where downstream sinks are absent. However, storage requires significant capital investment, complex equipment (CNG/LNG handling), safety systems, and is generally only economical for larger or frequent blowdowns. For many small, remote compressor stations the lower blowdown volumes make storage economically marginal unless shared across multiple sites or placed into a broader network of utilization options [1].

3. Material and methods

3.1. Process description

As illustrated in Fig. 2, the studied compressor station consists of two turbo-compressor units arranged in parallel, with one unit typically operating while the other remains on standby to ensure operational reliability. At the suction side of each unit, inlet scrubbers and strainers remove entrained liquids and particulates to protect the compressors and maintain gas quality. The compressed gas is then routed through air coolers to reduce its temperature, followed by discharge scrubbers that remove condensed liquids before the gas is reinjected into the high-pressure transmission pipeline. In this station, approximately 90 % of blowdowns are due to demand fluctuations and the remaining occur due to routine maintenance. Each compressor blowdown event releases approximately 4000 Nm^3 of gas, while a complete evacuation of the station discharges up to 30,000 Nm^3 every two years, depending on the temperature and pressure of the gas. Monthly, the station releases an average of 7300 Nm^3 of gas during blowdown operations, which is equivalent to the evacuation of two compressor units. The station's industrial fuel gas consumption per unit ranges from 80,000 to 100,000 Nm^3 daily, which drops to zero when the compressors are offline. Non-industrial fuel gas consumption ranges from 5 Nm^3 per day during warmer months to 500 Nm^3 per day in colder months.

3.2. Optimal blowdown management solution

According to the guideline outlined in section 2, and considering the specific operational context of the studied station—namely, the absence of nearby non-industrial fuel consumers or low-pressure distribution lines capable of receiving blowdown gas, as well as the relatively small blowdown volumes averaging around 4000 Nm^3 per event— the injection of blowdown gas into the nearby transmission line using a booster compressor represents the most technically solution for this station. This approach can recover over 90 % of the blowdown gas and is versatile enough to be applied to various types of blowdowns. It effectively handles different discharge volumes and involves only moderate investment costs. Furthermore, designing the evacuation package as a portable unit allows shared use among neighboring stations, significantly improving cost-effectiveness through economies of scale.

However, several practical limitations should be acknowledged. The

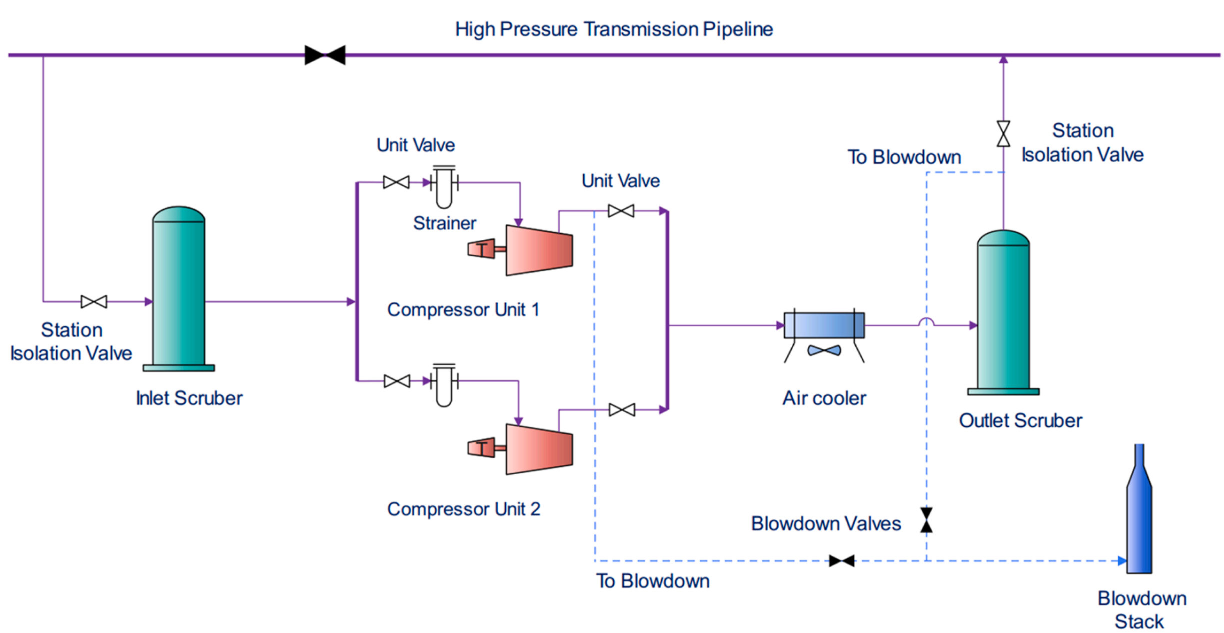

Fig. 2. Process flow diagram of the considered compression station.

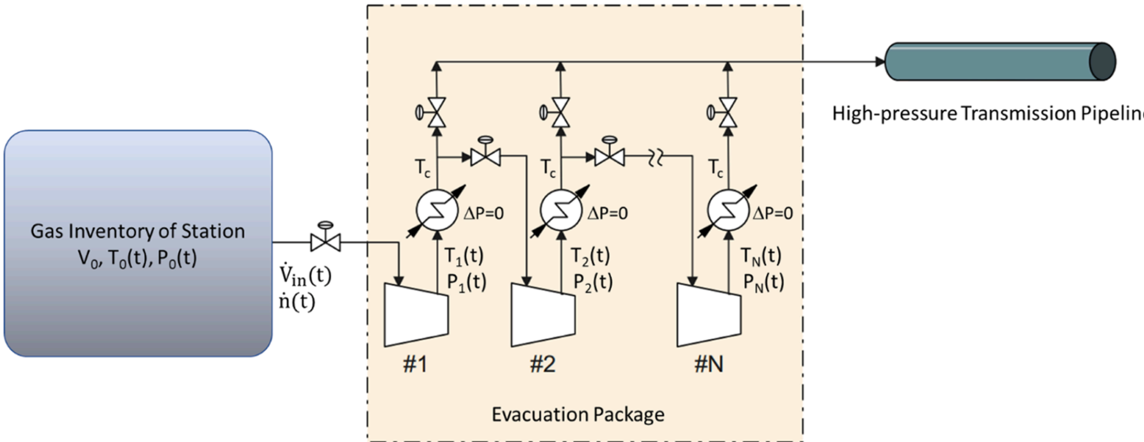

Fig. 3. Simplified process flow diagram of the station evacuation process.

implementation of this system requires sufficient space for temporary installation, reliable power availability, and coordination with existing station control and safety systems. Additionally, the evacuation package may introduce logistical considerations such as transport scheduling (in case of portable ones), setup time, and maintenance planning. Despite these constraints, the proposed approach remains one of the most practical and flexible options for minimizing methane emissions from compressor station blowdowns in remote locations.

3.3. Techno-economic assessment details

The compressor responsible for evacuating gas within the station's facilities must be capable of managing the gradual decrease in its suction pressure during the evacuation process, which can drop from 70 up to 4 bar. Simultaneously, it is necessary to deliver a constant discharge pressure of about 70 bar to match the transmission pipeline pressure. Achieving this requires a compression ratio of about 17.5, making a multi-stage reciprocating compressor the most suitable choice. Such compressors are specifically designed to handle high compression ratios and varying suction pressure while delivering consistent pressure across a broad range of suction pressures [29]. Among various options, compressors driven by gas engines have the highest cost, followed by those with electric motors, and lastly, compressors powered by steam turbines [30]. Given the lack of steam production infrastructure at pressure boosting stations and the availability of electric power, an electrically driven compressor is the preferred choice. Due to the transient nature of the evacuation process, the following unsteady-state mathematical modeling aids in determining the proper compressor capacity and power consumption for further economic evaluation.

A schematic diagram of the evacuation process is presented in Fig. 3, illustrating the gas flow path during a blowdown event and the configuration of the proposed evacuation package. In this setup, the blowdown gas is routed from the blowdown lines to a multi-stage reciprocating compressor, equipped with intercoolers at the outlet of each stage to manage compression temperature. The gas is then progressively compressed and discharged into a nearby high-pressure transmission line. The figure also depicts the key valves that control the flow direction under both normal operating and evacuation modes. By applying a mass balance around the station and assuming a constant gas temperature during the evacuation process, i.e., the evacuation process is done in a long enough time that the gas content of the station has time to equilibrate with the ambient temperature [31], the following equation could be obtained [32,33]:

$$\frac{dm}{dt} = -\dot{m}(t) \rightarrow \frac{d(\rho V_0)}{dt} = -\rho \dot{V}_{in}(t) \rightarrow \frac{d\left(\frac{P_0(t)M}{zRT_0}V_0\right)}{dt} = -\frac{P_0(t)M}{zRT_0}\dot{V}_{in}(t) \rightarrow V_0\frac{d\left(\frac{P_0(t)}{z}\right)}{dt} = -\frac{P_0(t)}{z}\dot{V}_{in}(t) \tag{1}$$

where m represents the mass of the gas within the station's equipment (kg), $\dot{m}(t)$ denotes the discharge mass flow rate (kg s^{-1}), ρ stands for the gas density (kg m^{-3}), R is the universal gas constant (8.314 J mol^{-1} K^{-1}), M signifies the molecular mass of the gas (kg mol^{-1}), $\dot{V}_{in}(t)$ represents the discharge rate (m^3 s^{-1}), which corresponds to the capacity of the first stage of the compressor, $P_0(t)$ denotes the pressure within the station during the discharge (Pa), T_0 designates the temperature within the station during the discharge (K), V_0 is the total volume of the station's equipment (m^3), and z is the gas compressibility factor at pressure $P_0(t)$ and temperature T_0. Eq. (1) is solved using the finite difference method in conjunction with the Peng-Robinson equation of state (EOS), a model well-suited for hydrocarbon mixtures, to determine the compressibility factor, z [34,35]. It should also be noted that any deviation from perfect isothermal conditions (i.e., a decrease in gas temperature) would slightly increase gas density and accelerate pressure decay, rendering the model conservative in predicting evacuation duration and compressor size.

The outlet temperature for each stage of compression is determined using the following equation [29]:

$$T_{out} = T_{in}\left(\frac{P_{out}}{P_{in}}\right)^{\frac{n-1}{n}} \tag{2}$$

where T_{in} and T_{out} represent the inlet and outlet temperatures at each compression stage (K), respectively, while P_{in} and P_{out} denote the inlet and outlet pressures for each stage (Pa). The variable n refers to the polytropic exponent, which is experimentally determined for each specific compressor and is typically less than k, the ratio of specific heat capacities, in reciprocating compressors [36]. For the gas composition of the station under consideration (Table 2), $k = 1.273$, and with a conservative estimate, the polytropic exponent $n = 1.2$ is used, consistent with those reported previously [37].

Table 2
Composition of gas inventory in the station.

Comp.	C_1	C_2	C_3	i-C_4	n-C_4	i-C_5	n-C_5	C_6^+	CO_2	N_2
Mole %	91.060	2.770	0.686	0.090	0.124	0.027	0.018	0.005	0.840	4.380

The required heat removal from the outlet stream of each compression stage is evaluated using the following equation:

$$q(t) = \dot{n}(t)C_p[T_{out}(t) - T_c] \tag{3}$$

where $q(t)$ denotes the rate of heat removal (J s^{-1}), $\dot{n}(t)$ is the molar flow rate of the gas (mol s^{-1}), C_p represents the molar heat capacity of the gas (J mol^{-1} K^{-1}), and T_c is the outlet temperature of inter/after coolers (K).

The power consumption (J s^{-1}) for each compression stage is calculated using the following equation [29]:

$$Power(t) = \frac{nRT_{in}(t)z\dot{n}(t)}{n-1}\left[\left(\frac{P_{out}}{P_{in}}\right)^{\frac{n-1}{n}} - 1\right] \tag{4}$$

Two key economic indicators, i.e., the annual rate of return on investment (ROI) and the payback period (PBP), are calculated to investigate the financial profitability of the proposed solution. The ROI expresses the percentage of the initial investment earned each year and is determined using the following formula [30]:

$$ROI\left(\frac{\%}{yr}\right) = \frac{Annual\ profit\ \left(\frac{\$}{yr}\right)}{Capital\ investment\ (\$)} \times 100 \tag{5}$$

Similarly, the PBP, representing the number of years required to recover the initial investment, is calculated using the following equation [30]:

$$PBP\ (yr) = \frac{Capital\ investment\ (\$)}{Annual\ profit\ \left(\frac{\$}{yr}\right)} \tag{6}$$

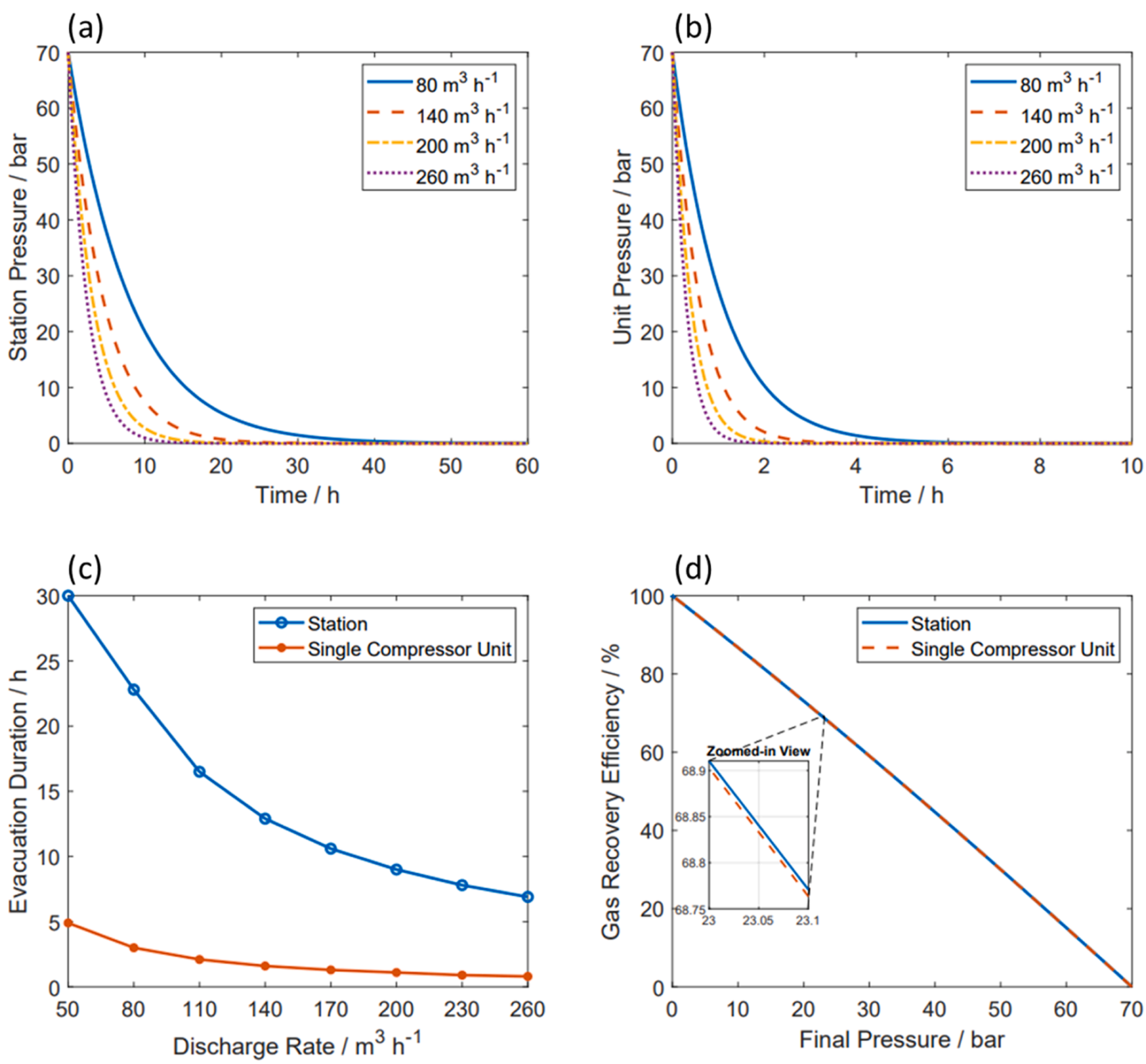

Fig. 4. (a) Station pressure variation during the evacuation process at different discharge rates, (b) Single compressor unit pressure variation during the evacuation process at different discharge rates, (c) Effect of discharge rate on station evacuation duration until reaching 4 bar, and (d) Effect of final station pressure on gas recovery efficiency.

The required capital investment is estimated by the percentage of delivered-equipment cost method. In this method, all components of capital investment are calculated based on proper fractions of the main delivered-equipment cost. As the evacuation package mainly includes a compressor and air cooler, its capital cost could be determined by the compressor's duty, i.e., its power consumption, and the air cooler's heat transfer area [30].

4. Results and discussion

4.1. Discharge rate

The discharge rate is a critical operational parameter that directly influences the size and cost of the compressor, as well as the duration of the discharge operation. Due to safety constraints, local operation management considers the maximum allowable duration for discharging the station and each compressor unit to be <24 and 2 h, respectively. Whole Station evacuation with a total equipment volume of 654 m^3, mainly performed for maintenance, occurs every two years, while routine evacuations in response to demand reduction, involving the active compressor and its accessories with a total volume of approximately 90 m^3, take place two times per month. The evacuation package was designed to accommodate total station evacuation, ensuring its adaptability across all operational scenarios. Fig. 4(a) and (b) display the change in station and unit compressor pressure over time for various discharge rates derived by Eq. (1) simultaneously with Peng-Robinson EOS. Fig. 4(c) illustrates how the duration of the station and unit compressor evacuation to the pressure of 4 bar varies with different discharge rates. As depicted, evacuating the entire station at a discharge rate of 140 m^3/h takes approximately 12.9 h, while evacuating a unit compressor at the same rate requires only about 1.6 h. Consequently, a discharge rate of 140 m^3/h, which satisfies the permissible evacuation duration for both the entire station and the unit compressor and allows additional time for package preparation, is selected as the basis for the evacuation package design and subsequent calculations. Notably, as shown in Fig. 4(d), the gas recovery efficiency for both the station and unit compressor approaches 95 % when the compressor package evacuates the system to a pressure of 4 bar.

4.2. Number of compression stages

The number of compression stages and the compression ratio are determined based on the temperature limits within the compressor. According to the API 618 standard, the maximum allowable discharge gas temperature is 150 °C, but it is recommended to keep the gas discharge temperature below 120 °C to extend the lifespan of the wearing part [38,39]. The outlet temperature of each stage during the evacuation process is calculated by Eq. (2). As can be seen in Fig. 5(a), for a three-stage compressor with intermediate cooling to 40 °C, the gas temperature rises to 76 °C after the first stage and 94 °C after the second and third stage, remaining within permissible limits. In contrast, one- and two-stage compression systems would result in higher outlet temperatures of 207 °C and 124 °C, respectively, exceeding critical thresholds. Thus, the maximum compression ratio at each stage would be 2.6, calculated by $(70/4)^{1/3}$. The sequence of activation of each stage is performed via package output pressure control, when it decreases from 70 bar, the next stage comes into service by manipulation of embedded outlet valves (Fig. 3). As illustrated in Fig. 5(b), the second stage activates around 4.5 h after the first stage and the third stage engages after approximately 8.8 h. Additionally, Fig. 5(c) shows the molar flow rate, which is the same across all stages, calculated using the Peng-Robinson EOS based on the station's temperature, pressure, and discharge rate.

As previously mentioned, the air cooler is used to reduce the temperature of the gas leaving each compression stage to 40 °C. The heat load absorbed at each stage is calculated based on Eq. (3) and is represented in Fig. 6(a). The required air cooler is designed based on maximum heat duty, i.e., 68.9 kW, which requires a 0.37 kW electrical motor and 22.4 m^2 of surface area [40,41].

Fig. 6(b) demonstrates the volumetric flow rate at the outlet of each compression stage following the cooling process, calculated using the Peng-Robinson EOS. Accordingly, the discharge rate of 140 m^3/h (82 CFM) corresponds to the intake capacity of the first compression stage. The intake capacity for the second stage is determined to be 57 m^3/h (33 CFM), while the third stage has an intake capacity of 22 m^3/h (13 CFM).

4.3. Power consumption

The power consumption for each compression stage during the blowdown operation is calculated using Eq. (4), with the results depicted in Fig. 6(c). As illustrated, the maximum power consumption reaches 108 kW during the evacuation process. Considering a mechanical efficiency of 75 %, the maximum required compression power is estimated to be 144 kW. Although this peak power demand occurs only for a brief period, the compressor driver is selected based on this maximum requirement to ensure reliable operation under all conditions.

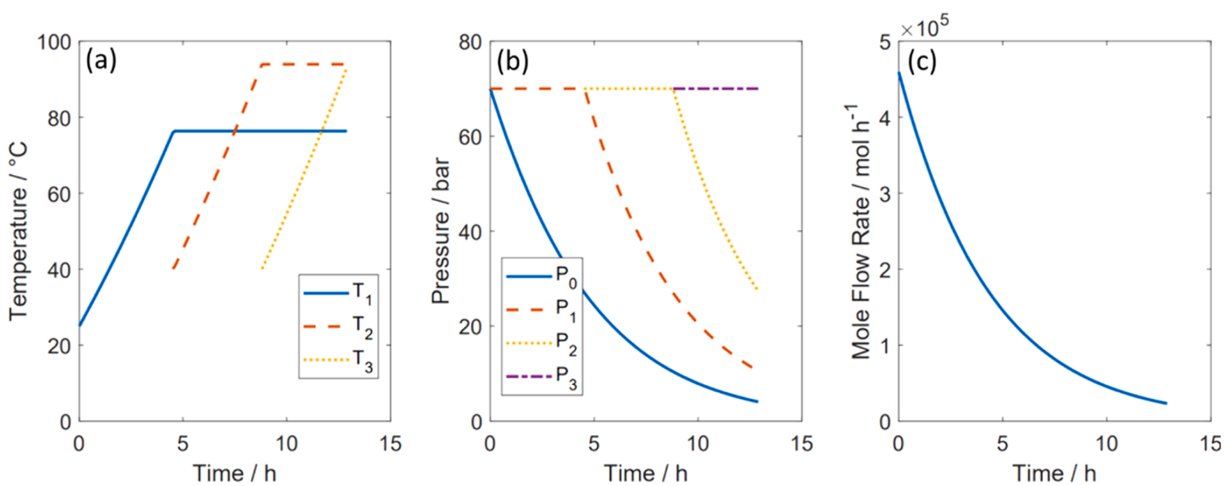

Fig. 5. (a) Temperature variation at the outlet of compression stages (T_1, T_2, and T_3) during the evacuation process, (b) Pressure variation at the station (P_0) and outlet of compression stages (P_1, P_2, and P_3) during the evacuation process, and (c) Gas molar flow rate variation through the compressor stages during the evacuation process.

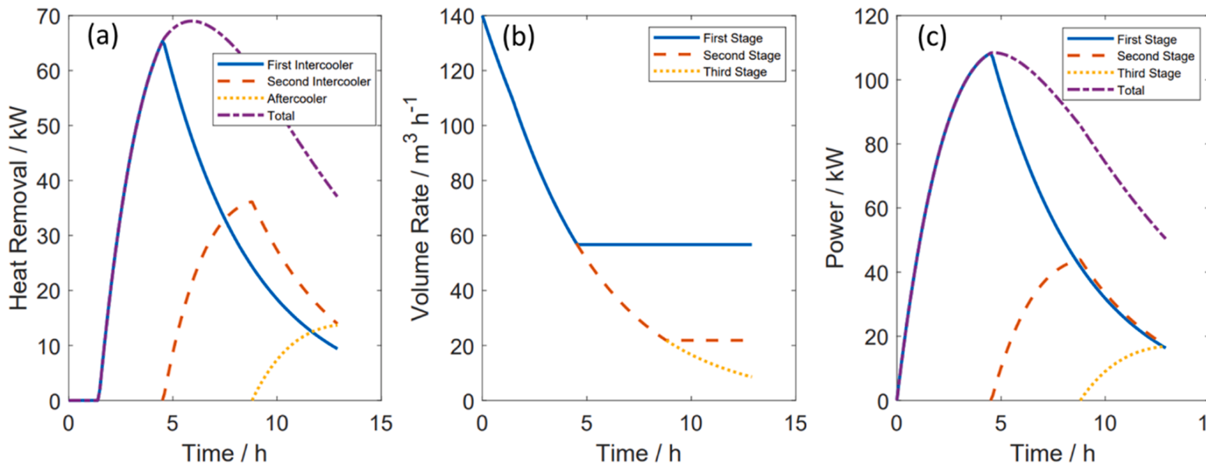

Fig. 6. (a) Rate of heat removal from the outlet stream of each compression stage during the evacuation process, (b) Volume rate variation at the intake of each compression stage during the evacuation process, and (c) Power consumption of each compression stage during the evacuation process.

4.4. Economic evaluation

The purchase costs of a 144 kW electric compressor and an air cooler with a surface area of 22.4 m^2 were estimated at \$136,000 and \$15,000, respectively, in January 2002 [30]. Using the Chemical Engineering Plant Cost Index (CEPCI) values for January 2002 (395.6) and April 2024 (799.1), the total equipment costs are updated accordingly [42]. Delivery, installation, instrumentation and control, piping, and electrical system costs are estimated to be 48.5 % of the equipment purchase price [30], resulting in a \$452,950 fixed capital investment (FCI) estimate for the entire evacuation package. Annual operational costs primarily consist of maintenance and energy costs. Maintenance is considered 6 % of the FCI each year [30]. Energy consumption is determined by the power requirements of the electric compressor and air cooler fans. The compressor driver and air cooler fan use 0.0221 kWh and 0.0001 kWh per cubic meter of the evacuated gas, respectively. Based on average industrial electricity prices of \$0.0844 per kWh (as of June 2024 in the US) and natural gas prices of \$0.07 per cubic meter (Henry Hub, August 2024), annual costs, income, and profit are calculated as follows:

$$\begin{aligned} \textit{Annual costs}\left(\frac{\$}{yr}\right) &= \textit{Energy costs} + \textit{Maintaince costs} \\ &= (0.0221 + 0.0001)\ \frac{kWh}{Nm^3} \times\ 0.0844\ \frac{\$}{kWh} \\ &\quad \times \textit{Evacuated Gas}\left(\frac{Nm^3}{yr}\right) +\ FCI \times\ 0.06\left(\frac{\$}{yr}\right) \end{aligned} \tag{7}$$

$$\textit{Annual income}\left(\frac{\$}{yr}\right) = \textit{Evacuated Gas}\left(\frac{Nm^3}{yr}\right) \times\ 0.07\ \frac{\$}{Nm^3} \tag{8}$$

$$\textit{Annual profit}\left(\frac{\$}{yr}\right) = \textit{Annual income}\left(\frac{\$}{yr}\right) - \textit{Annual costs}\left(\frac{\$}{yr}\right) \tag{9}$$

Fig. 7(a) illustrates the annual income, costs, and profit as a function of the annual evacuated gas volume. The break-even point, where income equals costs, occurs at an annual discharge of 401,500 Nm^3, while the station's average annual evacuation volume is 89,000 Nm^3. Fig. 7(b) outlines the ROI and PBP against the annual evacuated gas volume, which are unfavorable at the typical annual blowdown gas volume of the station, i.e., 89,000 Nm^3.

The profitability of the proposed solution is significantly influenced

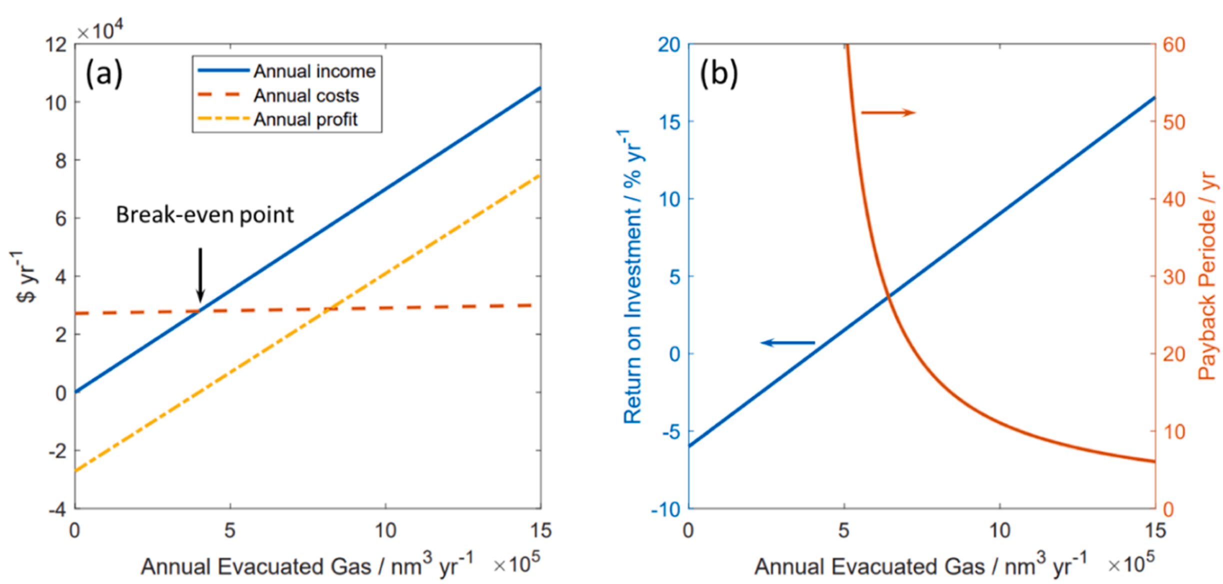

Fig. 7. (a) Annual income, costs, and profit as a function of the annual evacuated gas, and (b) Return on investment and payback period as a function of the annual evacuated gas.

by natural gas prices, annual blowdown gas volume, and potential environmental costs related to emissions. Addressing these environmental costs, Social Cost of Methane (SCM) estimates the broad economic impact of methane emissions, factoring in effects on health, agriculture, and climate change, with an average SCM often exceeding \$4000 per metric ton. In the United States, the recently established Waste Emissions Charge (WEC) under the Inflation Reduction Act (IRA) specifically targets methane, imposing financial penalties on facilities that exceed certain methane emission thresholds. This methane-specific charge is set at \$900 per metric ton in 2024, increasing to \$1200 in 2025, and \$1500 in 2026 and beyond [43,44]. While WEC is lower than SCM estimates, it represents a foundational regulatory approach aimed at reducing emissions. Given the current critical state of global warming, it is increasingly likely that similar emission charges may be implemented by international bodies, applying methane emission costs worldwide. Under current conditions, with a natural gas price of \$0.07 per Nm^3 and an annual discharge volume of 89,000 Nm^3, the break-even point, ROI, and PBP have been determined across various implied methane charges, as shown in Fig. 8. For instance, at a methane fee of \$1500 per metric ton, the ROI and PBP for an annual evacuation volume of 89,000 Nm^3 are 15.04 % and 6.65 years, respectively. To broaden the scope of economic viability assessments across diverse conditions, the ROI calculations were conducted in three scenarios to reflect the impacts of the annual blowdown volume, natural gas price, and the methane WEC.

4.4.1. Scenario #1: methane WEC = 0 \$ ton^{-1}

Given that a methane WEC has yet to be widely implemented internationally, the ROI analysis was extended to account for variations in the annual volume of captured blowdown gas and fluctuating natural gas prices, assuming a methane WEC of \$0 per ton. The total volume of blowdown gas captured can be increased by designing the evacuation package for portability, enabling its use across multiple nearby stations. This approach not only reduces capital costs by eliminating the need for individual evacuation setups at each station but also maximizes resource utilization. As shown in Fig. 9(a), an ROI of 15 % is reached at an annual discharge volume of 1396,200 Nm^3 at the current natural gas price of \$0.07 per Nm^3. In comparison, at the mid-2022 natural gas price peak of \$0.25 per Nm^3, the same ROI of 15 % is achieved with a significantly lower annual discharge volume of 386,500 Nm^3.

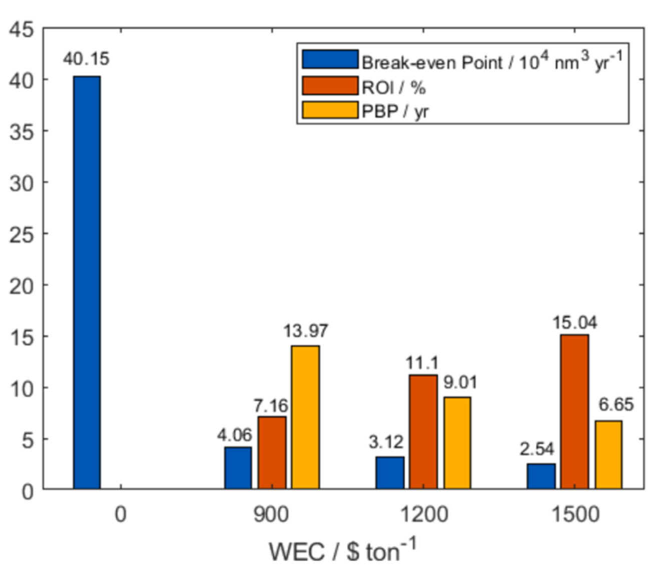

Fig. 8. The break-even point, ROI, and PBP for annual evacuation of 8.9×10^4 Nm^3 yr^{-1} and gas price of 0.07 \$ Nm^{-3} at different methane fee scenarios.

4.4.2. Scenario #2: annual blowdown gas = 89,000 nm^3 yr^{-1}

When deploying the evacuation package across nearby stations is not feasible and the annual captured blowdown gas is limited to the considered station, profitability can still be achieved by leveraging natural gas prices and the methane WEC. As depicted in Fig. 9(b), with a natural gas price of \$0.07 per Nm^3, a methane WEC of \$1493 per metric ton is required to reach a 15 % ROI. At the higher price of \$0.25 per Nm^3, similar to the mid-2022 peak, the same ROI is attainable with a reduced methane WEC of \$1230 per metric ton.

4.4.3. Scenario #3: natural gas price = 0.07 \$ nm^{-3}

In this scenario, the natural gas price is fixed at \$0.07 per Nm^3, reflecting a baseline aligned with current market conditions. With this rate set, the profitability of the solution depends primarily on the annual blowdown volume and methane WEC. As illustrated in Fig. 9(c), if the evacuation package is designed for portability and deployed across two additional nearby stations with similar annual discharge volumes, the combined annual discharge volume would increase to 267,000 Nm^3. Under these conditions, a methane WEC of \$431 per metric ton would be sufficient to achieve a 15 % ROI.

4.5. Environmental benefits and policy implications

The proposed blowdown gas recovery system provides significant environmental benefits in addition to its economic advantages. By capturing and re-injecting vented methane into the transmission network, the system prevents the release of approximately 4000 Nm^3 of methane per event, corresponding to an annual recovery of about 89,000 Nm^3. Assuming a methane density of 0.7831 $kg \cdot m^{-3}$ under normal conditions and a global warming potential (GWP_{20}) of 86 [1], this recovery equates to the avoidance of roughly 269 tons and 5993 tons of CO_2-equivalent emissions per event and per year, respectively. Although the compressor package consumes around 1975.8 kWh of electricity for evacuation of about 89,000 Nm^3 annually (as stated in section 3.4). Based on the emission factor reported by [45], where 1 kWh of grid electricity generated from a natural gas–fired turbine produces up to 750 g CO_2-equivalent, the resulting indirect emissions amount to only 1.48 tons CO_2-equivalent per year. This value is negligible compared to the avoided methane emissions, confirming that the proposed system offers a net-positive environmental impact and aligns strongly with global methane mitigation and climate sustainability goals.

Furthermore, the integration of environmental policies—such as the WEC in the United States and emerging carbon pricing mechanisms globally—could further enhance the profitability of such recovery systems. As demonstrated in the techno-economic assessment, incorporating a methane charge of \$1500 per ton increases the project's ROI to 15.04 % with a payback period of 6.65 years. This strong correlation between emission pricing and project performance highlights the pivotal role of policy-driven incentives in accelerating the deployment of methane recovery technologies. Consequently, the proposed solution not only contributes to national emission reduction targets under the Global Methane Pledge but also represents a practical pathway toward a more sustainable and cleaner gas transmission infrastructure.

5. Conclusion

This study developed and assessed a practical techno-economic framework for recovering and utilizing blowdown gas from natural gas compressor stations, emphasizing small and remote facilities that are often overlooked in emission reduction strategies. The proposed solution—re-injecting blowdown gas into nearby transmission lines through a multi-stage reciprocating compressor—demonstrated significant potential for both environmental and economic benefits, particularly under evolving regulatory frameworks targeting methane emissions. Even in regions without emission fee policies, alternative

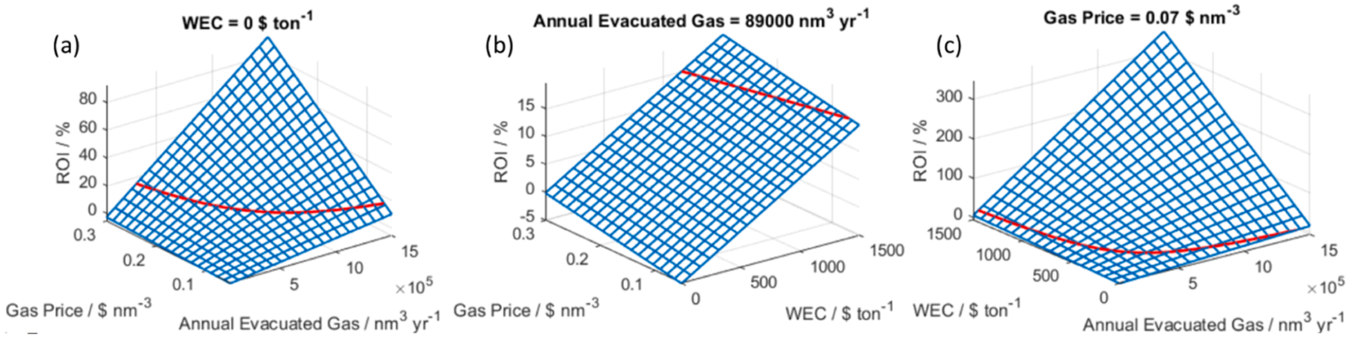

Fig. 9. (a) ROI as a function of gas price and annual evacuated gas volume at WEC = 0 $ ton^{-1}, (b) ROI as a function of gas price and WEC at annual evacuated gas volume = 89,000 Nm^3 yr^{-1}, and (c) ROI as a function of annual evacuated gas volume and WEC at natural gas price = 0.07 $ Nm^{-3}. The red lines indicate locus points where the ROI is 15 %.

incentive measures—including voluntary carbon credit programs, government-supported low-interest financing, and corporate sustainability reporting—can serve as effective drivers for adoption. Additionally, integrating blowdown gas recovery with energy efficiency programs or renewable energy systems can further enhance its attractiveness.

Key findings include:

- The designed evacuation system, operating at a discharge rate of 140 m^3/h, can recover over **95 % of blowdown gas**, equivalent to approximately **89,000 Nm^3 annually**.
- The proposed approach achieves a **15.04 % ROI** with a **6.65-year payback period** under a methane WEC of **$1500 per ton**, confirming its economic feasibility.
- Methane recovery prevents roughly **5993 tons CO_2-equivalent** emissions per year, significantly improving the station's carbon footprint.

Limitations:

The case study is based on a specific station configuration and operational assumptions (gas composition, station volume, and dispatch patterns). Labor and depreciation costs were simplified, and the Waste Emissions Charge (WEC) remains subject to regulatory evolution. The model assumes near-isothermal evacuation, a valid approximation for slow depressurization processes. These simplifications were intentionally adopted to maintain a transparent and generalizable framework that can be readily adapted to other stations.

Future work

Future research could focus on pilot-scale validation under real operational conditions, dynamic model coupling with real-time process data, and integration of this framework into broader methane mitigation and process optimization strategies across transmission systems.

Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work, the authors used ChatGPT (OpenAI) and Grammarly in order to improve the readability, clarity, and grammatical accuracy of the manuscript. After using these tools, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

CRediT authorship contribution statement

Ali Farzaneh: Writing – original draft, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Mostafa Pourali:** Writing – review & editing, Validation, Investigation. **Seyed Morteza Ashrafi Shahri:** Writing – review & editing, Methodology, Investigation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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