Compressor Downtime Mitigation in Gas Lift Operations Utilizing an Automated Compression Optimization System: A Field Study

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1. Abstract

Compressor downtime remains one of the primary causes of lost production, unstable injection performance, and fugitive methane emissions in gas lift operations. This paper reviews a zero-methane emission compression optimization system designed to stabilize gas lift performance by mitigating gas lift compressor issues, reducing shutdown frequency, and capturing methane emissions. The closed loop system incorporates autonomous recirculation, real-time pressure control, and high-resolution monitoring to maintain steady gas-injection conditions and prevent scrubber-related malfunctions that commonly lead to compressor failures.

A large-scale field study was conducted across 77 gas compressors supporting 281 gas-lifted wells in the Permian Basin to evaluate the impact of deploying this optimization technology. The study compares compressor performance with and without the optimization skid in operation. Key performance indicators included shutdown frequency, downtime duration, under-injection events, scrubber liquid-level freeze-up incidents, methanol consumption associated with freeze-up mitigation, and methane emissions generated during disruption periods.

Results show that deploying the optimization system reduces compressor downtime by over 90% compared with traditional mitigation methods by improving liquid handling and preventing liquid-level and dump-valve freeze-ups caused by the Joule–Thomson cooling effect under high differential pressure. These improvements result in a more stable and consistent gas-injection process. Participating operators reported a substantial decline in shutdown events and improved production consistency, leading to increased oil output and higher cash flow. Field data also confirmed complete methane

capture during gas compression, including emissions from rod-packing vents and blowdowns, providing a clear environmental advantage in gas-lift operations.

Overall, the compression optimization system offers a practical and scalable solution for operators seeking to reduce downtime, lower operational costs, maximize oil production, improve gas-lift stability, and meet evolving environmental expectations. This field study provides a framework for integrating an automated optimization skid into field development strategies as operators target both operational reliability and environmental compliance.

2. Introduction

Gas lift is one of the most common artificial lift methods in unconventional oil fields across the United States, driven by the extensive shale development and the wide range of operating conditions encountered in these regions. Its flexibility and adaptability put it as a key component of modern oil production operations (Latif, 2018). In large shale oil producing regions such as the Permian Basin, gas lift systems are commonly supported by centralized compression facilities that supply lift gas to multiple wells. As a result, gas compression reliability is critical in such high producing facilities to maintain stable gas injection and consistent optimal production (Redden, 1974). Even short duration compressor shutdowns can disrupt gas injection, reduce oil production, and increase operational complexity in gas lift operations.

Compressor downtime in gas lift operations is typically caused by a combination of mechanical and production related factors rather than a single failure mechanism. Common mechanical shutdowns include low engine oil pressure conditions and engine panel faults initiated by safety protection systems. Production related issues often involve liquid handling challenges, such as scrubber liquid level and dump line freeze-ups due to the Joule–Thomson cooling effect under high differential-pressure conditions (Elmer, 2017). In some cases, these production related disturbances also result in under-injection events due to stuck or malfunctioning liquid dump valves, where insufficient lift gas is injected downhole, reducing well unloading efficiency and leading to significant oil production losses.

Beyond the operational impacts of their downtime, gas compressors are increasingly recognized as a significant source of methane emissions. Compressor emissions commonly originate from scrubber discharges, dump-valve leakage, rod-packing and blowdown vents (Bylin, 2010). As environmental regulations and emissions reporting requirements continue to evolve, operators face increasing pressure to reduce these emissions while maintaining reliable gas lift performance.

Traditional mitigation methods, such as methanol injection and manual control adjustments, remain widely used but are largely reactive rather than proactive and do not address the root causes of compressor shutdowns. In conventional gas lift compression facilities, liquids discharged from compressor scrubbers are usually dumped into a low-pressure flow line or an atmospheric accumulation tank, where the rapid pressure loss promotes Joule–Thomson cooling and causes the discharge lines and scrubber liquid-level to freeze up. These conventional approaches often increase operating costs, field intervention, and safety exposure without efficiently preventing the causes of compressor shutdowns. Although recent advances in automation and real-time monitoring have improved visibility into compression performance and enabled partial mitigation of compressor shutdowns (McCormick, 2007), many solutions remain focused on monitoring and post-event correction rather than addressing shutdown causes at their source. As a result, compressor downtime, under-injection, and associated methane emissions continue to persist in gas lift operations.

This paper presents a large-scale field evaluation of an automated compression optimization system developed to address some of the primary causes of compressor shutdowns at their source. The system enhances liquid handling, stabilizes pressure conditions, and ensures consistent gas injection by mitigating compressor shutdown triggers, including scrubber liquid-level freeze-ups, eliminating the need for methanol and reducing operational expenses, as well as reducing engine panel and low engine oil pressure shutdowns commonly associated with wet fuel gas (Kurz et al., 2014). It also mitigates compressor under-injection resulting from dump-valve malfunctions and eliminates associated methane emissions. The study evaluates the system's impact on compression reliability, production efficiency, economic outcomes, and environmental performance using data collected from gas-lift facilities in the Permian Basin.

3. System Overview: Automated Compression Optimization System

3.1. Objectives

3.1.1. Avoid compressor shutdown and under-injection

The main objective of the automated compression optimization system is to enhance the reliability of gas lift facilities by preventing some of the compressor shutdown triggers and under-injection events impacting oil production. The system stabilizes gas lift operations by preventing compressor shutdowns associated with scrubber liquid-level and dump-line freeze-ups, low engine oil pressure, and engine panel faults, while maintaining consistent gas injection. Through proactive control of transient operating conditions, the system reduces downtime frequency, improves injection stability, and supports efficient well unloading and sustained production performance.

3.1.2. Eliminate methane emissions

Another goal of the system is the total capture of routine methane emissions associated with gas compression, including scrubber discharges, dump-valve leakage, blowdown, and rod packing vents. Through closed-loop gas management within the compression network, the system captures gas released during transient operating conditions and abnormal dump behavior rather than traditionally venting it to the atmosphere. This continuous recovery approach improves the environmental performance of the gas lift facility while maintaining efficient compression performance.

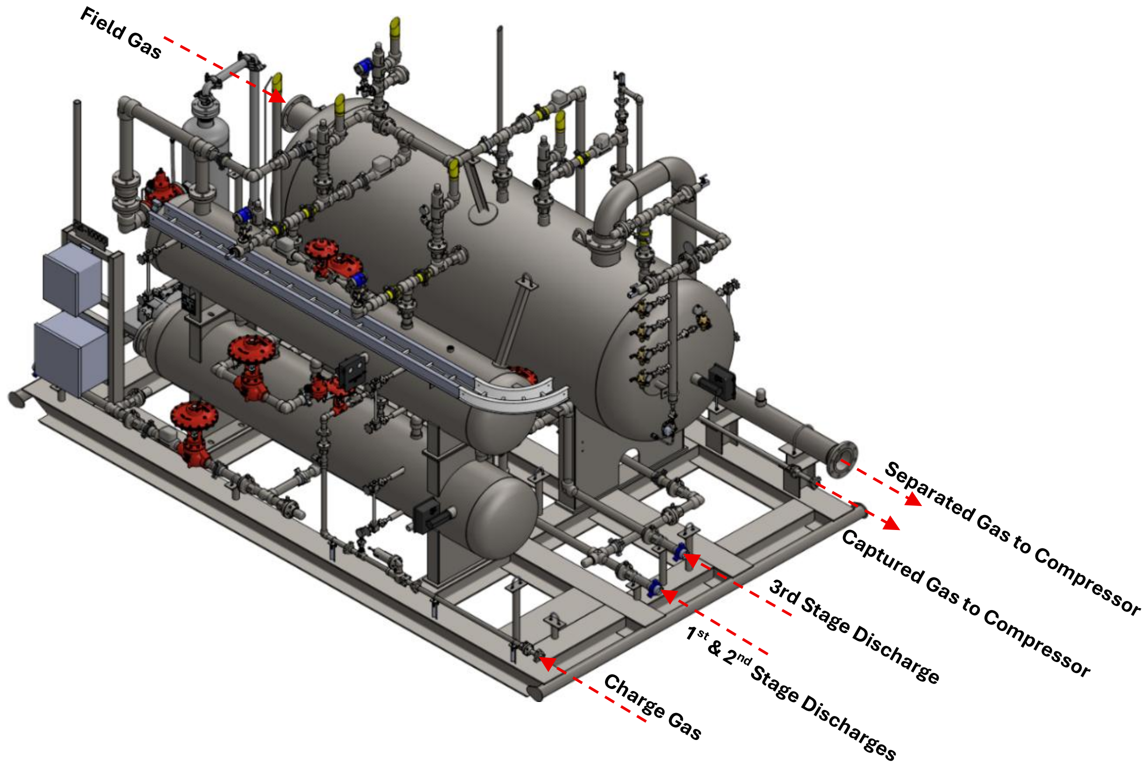
3.1.3. Reduce operational expenses

Beyond reliability and emissions control, the optimization system is designed to reduce operating costs and field intervention by minimizing reliance on methanol injections for freeze-up mitigation and decreasing the need for manual operational adjustments. Through automated liquid management, pressure stabilization, and real-time monitoring of gas compression, the system increases facility uptime, improves oil production consistency, and enhances the economic performance of gas-lift operations.

3.2. System Structure

The compression optimization system, shown in **Fig. 1,** is structured as an integrated closed-loop gas recovery and liquid control unit (U.S. Patent #s 10,519,983; 11,255,349; 11,466,703; and 12,228,020) installed upstream of the gas compressors and connected to the scrubber discharge circuits, vent capture lines, compressor suction inlet or fuel line (B.J. Ellis, 2019). The system consists of a 48 in. diameter inlet separation unit, 24 in. diameter high and low-pressure charge vessels, a 24 in diameter low-pressure sump vessel, along with a suction scrubber, a screw compressor to reinject recovered gas, automated pressure control components, and thermal mass flow meters.

The inlet separation unit comes with 10 in. inlet and outlet nozzles and is designed to handle a gas flow rate capacity up to 11 MMscf/d. The low-pressure charge vessel is directly open to the centralized sump vessel, and both operate at 16 oz of pressure. The high-pressure charge vessel operates at 200 psi and is connected to the inlet separator through a back-pressure control valve. Both pressure charge vessels feed into the centralized sump vessel, which contains internal heated oil tubing supplied from the screw compressor lubrication system, at an operating temperature of 200 °F. The low-pressure charge vessel is connected to a suction scrubber maintained below 16 oz and installed upstream of the skid's screw compressor. Recovered gas is compressed by the screw compressor and discharged through a thermal mass flow meter into the gas compressor suction inlet or fuel line.



US Patent #s

10519983;
11255349;
11466703;
12228020

Figure 1 - 3D model of the compression optimization system

3.3. System Mechanism

The compression optimization system operates by integrating gas–liquid separation, pressure management, liquid handling, closed loop gas recovery, and automated real-time telemetry to ensure gas compression stability. At the front end of the system, an inlet separator performs the primary separation of the gas–liquid mixture in the incoming gas stream. The separator contains an inlet deflector plate and a mist pad to enhance separation efficiency. Separated gas exits the vessel through the outlet line directed to the gas compressor suction inlet, while separated liquids are routed to the sump vessel.

Liquid and gas discharges and leaks from the compressor are directed to the optimization skid through segregated piping circuits based on discharge pressure. Scrubber liquid and gas discharges from the suction and intermediate compression stages are directed to the low-pressure charge vessel, while third-stage scrubber discharges are directed to the high-pressure charge vessel. This pressure-managed configuration, as shown in the field setup in **Fig. 2**, replaces conventional atmospheric liquid accumulation tanks typically installed adjacent to gas compressors. Thereby, minimizing rapid depressurization within scrubber discharge lines and associated freeze-up behavior due to Joule Thompson cooling effect as illustrated in (**Eq. 1)**. As a result, thermal stability is maintained within scrubber discharge lines.

$$\Delta T = \mu JT \Delta P \tag{1}$$

$$\Delta T \propto \Delta P$$

The temperature response of the gas stream to pressure changes during gas expansion is represented by the Joule –Thomson coefficient, μ_{JT}. ΔP describes the pressure drop occurring across the discharge lines, while ΔT quantifies the resulting temperature drop (Çengel, 2002). Together, these parameters describe the cooling effect associated with rapid depressurization within scrubber discharge lines, which directly influences freeze-up behavior causing the compressor to shut down.

Liquids present in both pressure charge vessels feed into the centralized low-pressure sump vessel, which serves as the primary liquid accumulation and processing unit. The sump incorporates a heated oil tubing supplied from the screw compressor lubrication system, operating at 200°F, where heat transfer from the tubing vaporizes hydrocarbons from the accumulated liquids, leaving primarily condensed water, which is eventually discharged to the facility flowline. When the sump liquid level reaches dump conditions, a controlled discharge sequence is initiated using regulated high-pressure charge gas supplied from the compressor’s first or second-stage discharge, depending on the required pressure on the liquid dump line, to overcome downstream flowline pressure and efficiently evacuate the accumulated liquid in the sump.

The liquid handling process enables the system to generate a recovered lean, dry gas stream suitable to fuel the compressor. This dry fuel enhances engine operating stability and reduces engine panel and low engine oil pressure shutdowns commonly associated with combustion instability and poor fuel quality.

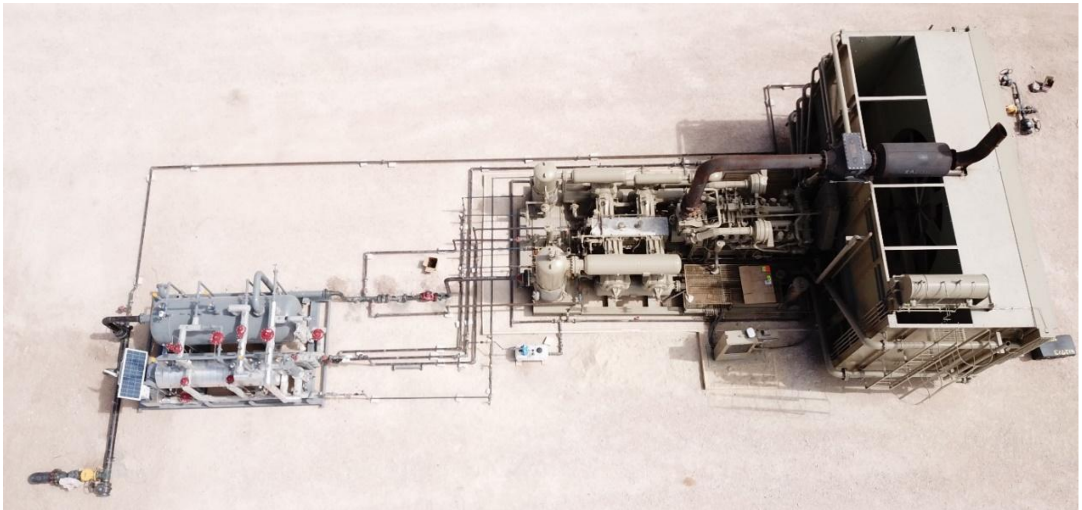


Figure 2 – Onsite view of the optimization system connected to a gas compressor

Gas recovered from flashed liquid within the sump, as well as gas captured from the first and second-stage scrubber discharge lines, is routed through the low-pressure charge vessel to a suction scrubber maintained at a pressure below 16 oz, low enough to take in compressor rod packing and blowdown vents. Captured low-pressure gas is then directed from the suction scrubber to the screw compressor, where it is compressed and discharged back into the gas compressor suction inlet or fuel line. Gas associated with abnormal high-pressure discharge behavior, such as a stuck third-stage dump valve, is routed to the high-pressure charge vessel. Once the discharge pressure exceeds 200 psi, the back-pressure control valve opens and redirects the stored gas from the high-pressure charge vessel to the inlet separator and back to the compressor suction inlet, where circulation continues until normal dump valve operation is restored.

Concurrently, the system's real-time telemetry platform automatically identifies abnormal dump valve conditions and alerts the operator for quick intervention. Therefore, this closed-loop configuration minimizes gas losses during compressor transient conditions, sustains continuous gas injection and production stability, and eliminates routine methane emissions from compression operations.

4. Field Study Description

A large-scale field study was conducted throughout 2024 to evaluate the operational, environmental, and economic performance of gas compressors with and without implementing an automated compression optimization system. The study covered several gas lift facilities operated by multiple oil and gas producers in the Permian Basin, representing a wide range of production rates, compression configurations, and operating conditions typical of unconventional shale development.

The study dataset consists of 154 gas compressors, including 77 compressors operating at 36 centralized compression facilities equipped with the compression optimization system supporting 281 gas lifted wells, with one optimization system installed per facility. The remaining 77 compressors operated under conventional configurations without the optimization system and served as the reference group. Facilities in both groups were selected to ensure comparable operating environments, gas injection volumes, and production characteristics to limit the influence of operational variability on performance comparisons. All facilities remained in normal production operations throughout the study period.

For the optimized compression facilities, the optimization system was connected to each compressor to capture scrubber discharges, gas vent streams, and reinject the recovered gas into the compressor suction inlet or fuel line. No modifications were made to standard operating procedures for the reference group facilities beyond routine maintenance and monitoring. Operational data were collected continuously throughout the year, including compressor runtime, shutdown events, injection volumes, liquid/gas discharge handling behavior, methanol usage, and vented gas activity. Data sources included compressor control panels, telemetry systems, and automated measurement units installed on the optimization system.

5. Key Performance Metrics

Compression performance of both groups was evaluated using operational and economic parameters and assumptions derived from field measurements and market pricing data. These parameters were regularly monitored and collected during the field study period representing average operating conditions across the evaluated gas lift facilities. Key production metrics included average gas injection volumes, oil production rates, compressor downtime, and under-injection events. Economic evaluation included crude oil market pricing, royalty and standard revenue deductions, recovered methane valuation based on natural gas market prices, and cost of methanol usage.

Production performance was evaluated using an average oil production rate of 150 BPD per gas-lifted well at a corresponding average gas injection rate of 0.650 MMSCFD. Economic valuation was performed using an assumed market oil price of $60 per barrel and a net price of $45 per barrel after accounting for 25% royalty interests and standard revenue deductions observed across participating operators. Compressor shutdown and under-injection events were quantified using compression data from both gas compression groups. An average month length of 30.5 days (732 operating hours) was used to consistently convert downtime and under-injection duration into oil production losses and quantify their negative impact on production revenue.

The recovered gas value was calculated using the three-month average Henry Hub natural gas price, resulting in a unit value of $3.35 per MCF. This value reflects the average measured heating value of the recovered gas, which was approximately 1,400 Btu/scf. Chemical operating costs for traditional freeze-up mitigation were evaluated using methanol consumption field data, reflecting an average usage rate of 10 gallons/day per 1.0 MMSCFD of injected gas. An average unit cost of $3.50 per gallon was applied to quantify methanol expenses for traditional mitigation.

Production losses resulting from compressor downtime and under-injection events, together with recovered methane value and methanol costs for freeze up mitigation, were integrated to assess the overall economic performance of both conventional and optimized gas lift facility groups under real operating conditions.

Table 1 presents the key operational inputs and economic assumptions derived from field measurements and market pricing data that were applied in the performance evaluation of the gas lift facilities during the study period.

Table 1 - Field study inputs & economic assumptions

Total gas lift compressors per evaluated group	77
Total optimized gas lift facilities	36
Total number of optimization systems (one system per optimized facility)	36
Total gas lifted wells in optimized facilities	281
Average oil production per well (Bpd) (per average injection rate)	150
Average injection rate (MMSCFD) (per average well production rate)	0.650
Assumed WTI oil price ($/Bbl.)	60
Assumed WTI oil price ($/Bbl.) (less 25% royalty interest & deductions)	45
Methane capture value ($/MCF)	$3.35
Methanol injected (Gallons/day) (per 1.0 MMSCFD of gas injected)	10

Methanol cost ($/Gallon)	$3.50
Days per month	30.5
Hours per month	732

In addition to these operational inputs and economic assumptions, field measurements indicated a total gas lift injection throughput of 183 MMSCFD and a cumulative recovered methane volume of 476,806 MCF across the optimized gas lift facilities during the study period. Together, these values formed the basis to derive and calculate the production and economic performance metrics presented in **Table 2**.

Table 2 - Derived production & economic performance metrics

Total injection volume for optimized facilities (MMSCFD)	183
Total methane captured utilizing optimization systems (MCF)	476,806
Average injection volume per compressor (MMSCFD)	2.4
Average injection volume per facility/optimization system (MMSCFD)	5.1
Hourly oil production value per well ($)	281
Average oil production potential per facility (Bbl./Month)	35,779
Average hourly production potential per compressor (Bbl.)	23
Hourly production revenue potential per compressor ($)	1,028

6. Results & Discussion

Study results have shown that gas lift facilities equipped with the compression optimization system achieved substantial operational and economic improvements relative to the non-optimized reference group. Throughout 2024, optimized gas lift compressors exhibited notable reductions in shutdown events related to scrubber liquid level, engine panel, and low engine oil pressure, resulting in a significant decrease in associated compressor downtime. In addition, compressor under-injection duration was greatly reduced due to the system's rapid detection of malfunctioning dump valves, enabling immediate corrective action to restore normal operating conditions. This significantly enhanced injection stability, and minimized production losses.

Furthermore, optimized facilities achieved complete methane recovery and eliminated the need for traditional methanol injection for freeze-up mitigation, thereby improving economic and environmental performance relative to conventional gas lift facilities where methane emissions and methanol injection are typical.

6.1. Reduction in Compressor Shutdowns

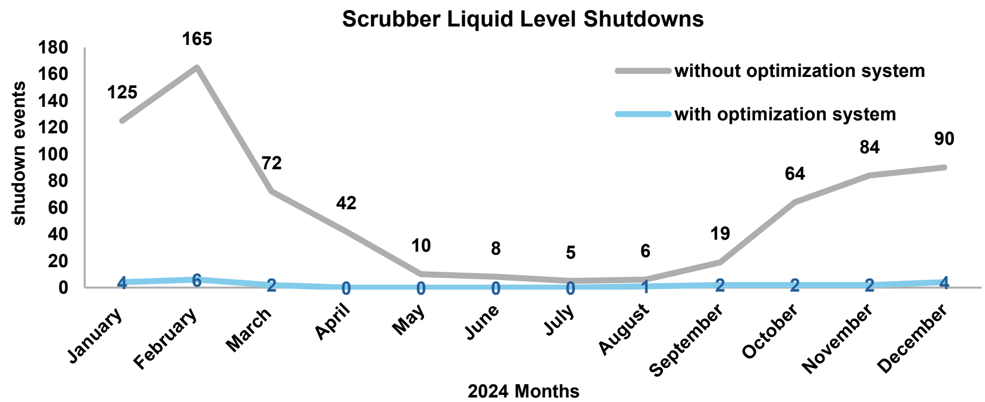


Figure 3 - Impact of optimization system on scrubber liquid level shutdowns during 2024

Fig. 3 compares monthly scrubber liquid level shutdown events across the two facility groups operating with and without the compression optimization system throughout 2024. Non-optimized facilities experienced frequent compressor shutdowns, particularly during winter months when associated low ambient temperatures increased scrubber liquid accumulation and dump line freeze-ups. On the other hand, optimized facilities showed a substantial reduction in compressor shutdown frequency throughout the year, including winter months, demonstrating improved compressor liquid handling and gas injection stability.

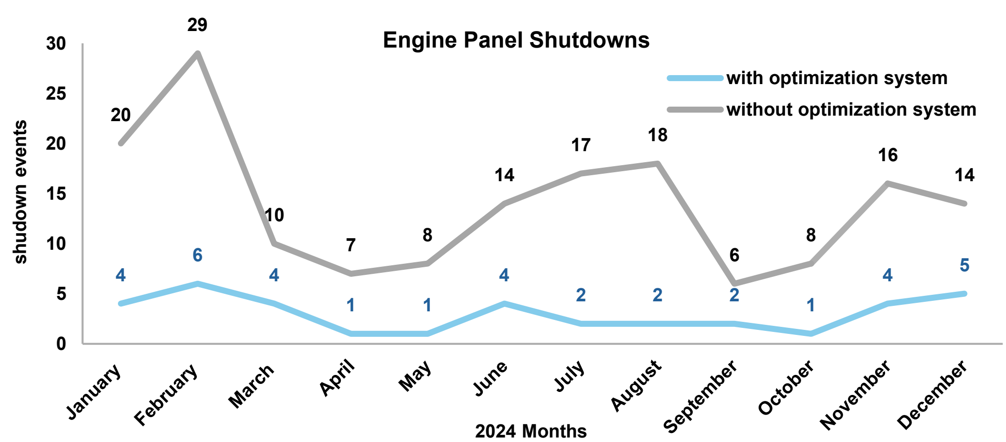


Figure 4 - Impact of optimization system on engine panel shutdowns during 2024

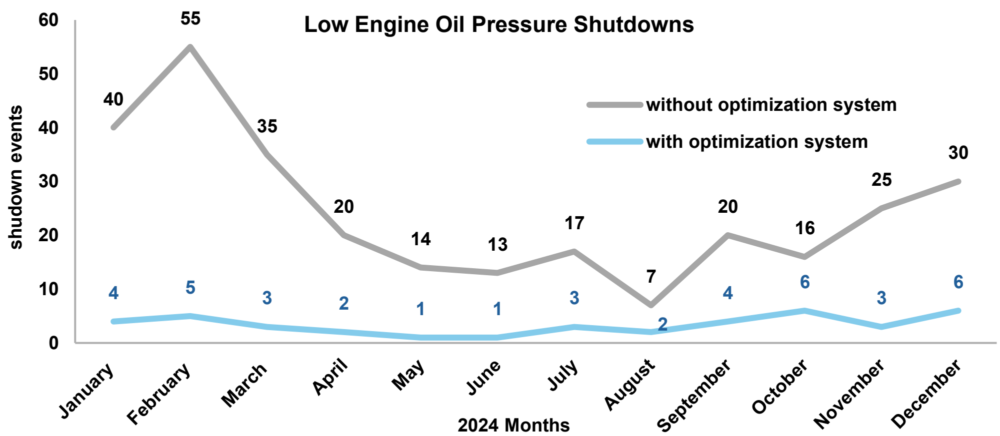


Figure 5 - Impact of optimization system on low engine oil pressure shutdowns during 2024

In addition to mitigating scrubber liquid level shutdowns, the optimization system also improved compressor engine performance. As shown in **Figs. 4 and 5**, optimized compressors experienced substantially less engine panel and low oil pressure shutdown events throughout 2024, including winter months when liquid accumulation in is most frequent. This improvement results from the ability of the optimization system to generate a lean, dry recovered gas stream by removing entrained liquids prior to directing it back to the compressor fuel line. The resulting dry fuel gas reduced combustion instability and engine performance issues that commonly triggered engine panel faults and low oil pressure shutdowns at non-optimized facilities.

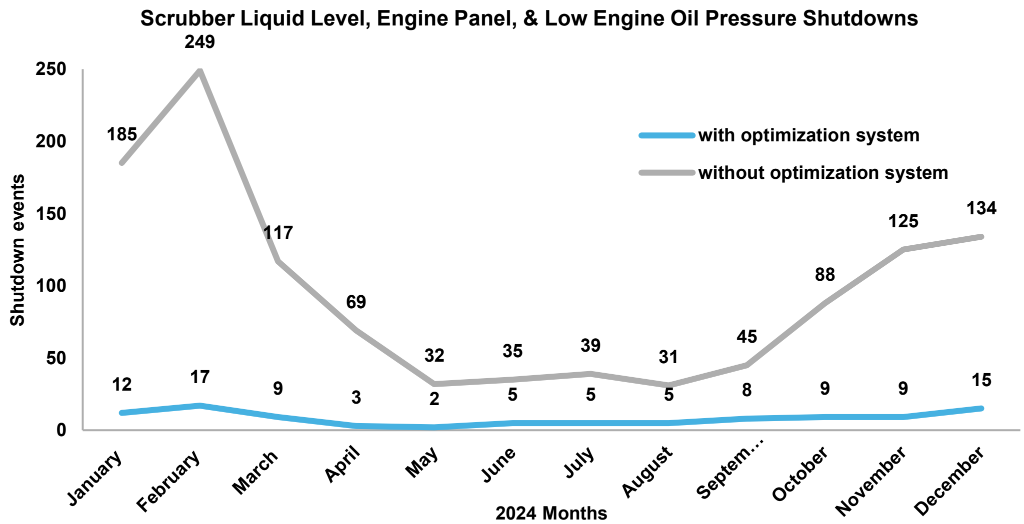


Figure 6 - Impact of optimization system on total compressor shutdowns related to (scrubber liquid level, engine panel, and low oil pressure) during 2024

Fig. 6 compares total monthly compressor shutdown events related to scrubber liquid level, engine panel, and low engine oil pressure at optimized and non-optimized facilities during 2024. Non-optimized compressors experienced high shutdown frequencies, particularly during winter months, while optimized compressors showed substantially less shutdowns throughout the year.

Table 3 - Summary of compressor shutdown events, and resulting production losses

2024 Gas Lift Compressors Downtime Analysis	Non-optimized Facilities			Optimized Facilities		
Frequency/Duration analysis	Events	Hours	Hrs./Event	Events	Hours	Hrs./Event
Compressor scrubber liquid level shutdowns	690	2996	4.7	23	81	2.9
Engine panel shutdowns	167	652	4.2	36	110	2.5
Low engine oil pressure shutdowns	292	1048	3.9	40	88	1.8
Total compressor shutdowns	1149	4696	4.1	99	279	2.8
Average per compressor annually	14.9	61.0	4.1	1.3	3.6	2.8
Average hourly production potential (per compressor)	23 Bbl.			23 Bbl.		
Average annual negative impact on oil production (per compressor)	1,394 Bbl.			83 Bbl.		
Average annual negative impact on oil production (all compressors)	107,314 Bbl.			6,376 Bbl.		

Compressor downtime and associated oil production losses varied significantly between optimized and non-optimized facilities throughout 2024. As summarized in **Table 3**, non-optimized facilities encountered a total of 1149 compressor shutdown events, yielding 4,696 hours of downtime, and resulting in an annual oil production loss of 107,314 barrels. On the other hand, optimized facilities recorded only 99 compressor shutdown events, yielding 279 downtime hours and a substantially lower oil production loss of 6,376 barrels. These results demonstrate the significant gas lift operational improvements achieved utilizing the compression optimization system.

6.2. Reduction in Under-injection

Optimized and non-optimized gas lift facilities exhibited significant differences in under-injection duration and corresponding oil production losses throughout 2024. As illustrated in **Table 4**, non-optimized facilities experienced an average under-injection duration of 72 hours per event prior to resolution, while optimized facilities reduced the average duration to 4.2 hours. This reduction in response time resulted in a substantial decrease in oil production losses, from 74,191 barrels of annual oil production losses at non-optimized facilities to 4,638 barrels at optimized facilities. These results describe the critical role of the system’s rapid malfunction detection in minimizing under-injection impacts on oil production by maintaining injection stability and well unloading efficiency.

Table 4 - Oil production losses associated with compressor under-injection

2024 Under-Injection Impact on Oil Production	Non-Optimized Facilities	Optimized Facilities
Monthly average frequency of under-injection events	2.5 times	2.5 times
Average duration of each under-injection event until resolved	72 hrs.	4.2 hrs.
Monthly average duration of under-injecting	180 hrs.	10.5 hrs.
% of month under-injecting	24.6%	1.4%
Average rate of lift gas losses during under-injection	0.100 MMSCFD	0.100 MMSCFD
% of under-injection gas losses (relative to daily gas injection target: 5.1 MMSCFD)	2.0%	2.0%
% of under-injection	0.48%	0.03%
Average oil production potential (per facility monthly)	35,779 Bbl.	35,779 Bbl.
Average negative impact on oil production (per facility monthly)	172 Bbl.	11 Bbl.
Average negative impact on oil production (per facility annually)	2060 Bbl.	129 Bbl.
Average negative impact on oil production (per field annually)	74,191 Bbl.	4,638 Bbl.

The positive impact of reduced compressor downtime and improved injection stability was more significant under higher gas injection rates and pressure conditions, such as those encountered in centralized gas compression and high-pressure gas lift (HPGL) applications, particularly during early-stage well development when oil production rates are higher. Under such conditions, production performance exhibits increased sensitivity to compression reliability, aligning with prior studies that identify the strong connection between optimizing gas lift and achieving optimal production (Abdelkerim, 2024).

6.3. Total Methane Capture

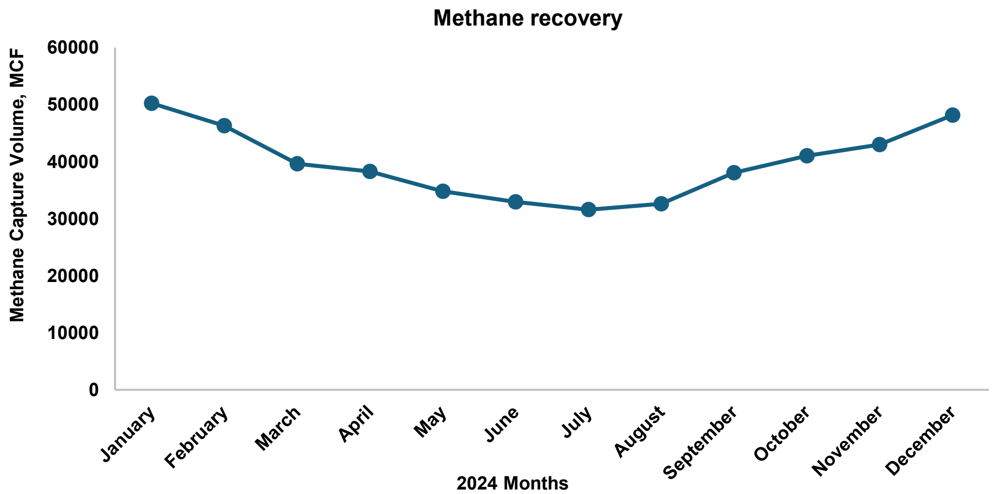


Figure 7 - Monthly methane recovery at optimized facilities utilizing the compression optimization system during 2024

Methane recovery remained relatively consistent throughout 2024 at optimized facilities using the compression optimization system, as shown in **Fig. 7**. Total methane capture reached 476,806 MCF, with slightly higher recovery during colder months when scrubber discharge leaks, dump valve malfunctions are more common. Overall, the sustained recovery performance demonstrates the system's effectiveness in capturing and repurposing lift gas, contributing to both environmental and economic benefits.

Table 5 - Oil production revenue losses associated with compressor downtime

2024 Gas Lift Compressors Downtime Analysis	**Non-optimized Facilities**			**Optimized Facilities**		
Frequency/Duration analysis	Events	Hours	Hrs./Event	Events	Hours	Hrs./Event
Total compressor shutdowns (all 77 compressors)	1149	4696	4.1	99	279	2.8
Average number of shutdowns per compressor annually	14.9	61.0	4.1	1.3	3.6	2.8
Average hourly production potential per compressor	23 Bbl.			23 Bbl.		
Annual oil production losses (per compressor)	1,394 Bbl.			83 Bbl.		
Annual negative impact on oil production (all 77 compressors)	107,314 Bbl.			6,376 Bbl.		
Annual negative impact on oil production revenue (all 77 compressors)	$4,829,116			$286,909		

Throughout 2024, Compressor downtime resulted in significant oil production revenue losses at non-optimized facilities. As shown in **Table 5**, non-optimized compressors encountered 4,696 downtime hours, leading to an annual production revenue loss of about $4.83 million. In contrast, optimized compressors recorded only 279 downtime hours, resulting in a much lower annual revenue impact of about $0.29 million.

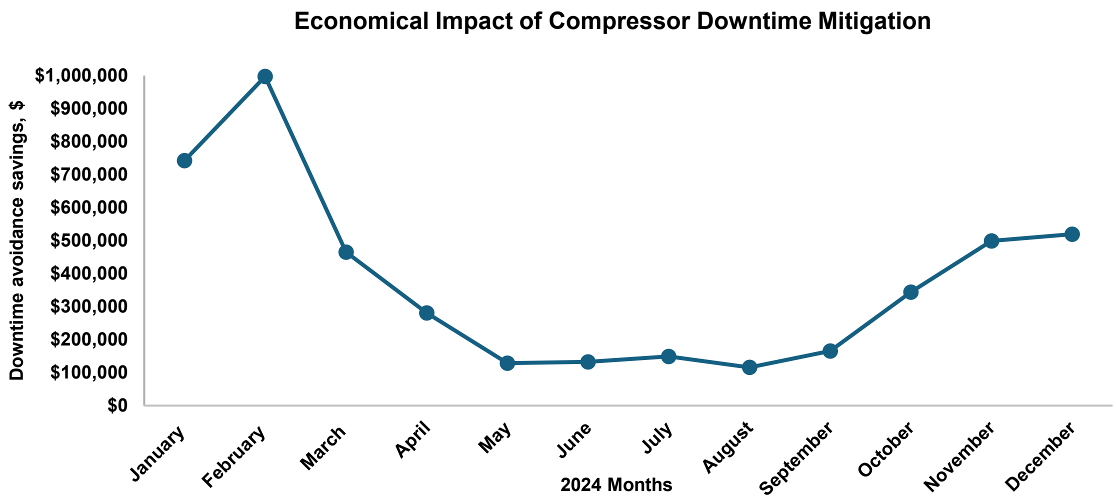


Figure 8 - Economic benefit of the optimization system in 2024 by reducing shutdowns related to (scrubber liquid level, engine panel faults, and low engine oil pressure).

Fig. 8 shows the monthly economic savings achieved by reducing compressor shutdowns at the optimized facilities during 2024. The highest savings occurred during the winter months, when shutdown triggers such as scrubber liquid level freeze-ups and fuel gas quality issues were most frequent at non-optimized facilities. Savings started to decrease during the warmer mid-year months and increased back again toward the end of the year as colder conditions returned.

Table 6 - Oil production revenue losses associated with compressor under-injection

2024 Under-Injection Impact on Oil Production Revenue	Non-Optimized Facilities	Optimized Facilities
Negative impact on oil production (per facility monthly)	172 Bbl.	11 Bbl.
Negative impact on oil production revenue (per facility monthly)	$7,728	$483
Negative impact on oil production revenue (per facility annually)	$92,739	$5,796
Negative impact on oil production revenue (per field annually)	$3,338,610	$208,663

Beyond the economic benefits from reduced compressor downtime, the optimization system also significantly reduced production revenue losses associated with compressor under-injection. As shown in **Table 6**, annual production losses decreased from approximately $3.34 million at non-optimized facilities to about $0.21 million at optimized facilities. The system also generated economic value through methane recovery while eliminating the need for methanol injection. At a total gas lift injection throughput of 183 MMSCFD, optimized facilities recovered 476,806 MCF of methane, corresponding to estimated savings of $1,597,300 during 2024. Additionally, by avoiding traditional methanol usage for freeze-up mitigation, estimated at 10 gallons/day per MMSCFD over five winter months, optimized facilities avoided about $976,763 in annual operating expenses incurred at non-optimized facilities.

Table 7 - Summary of the potential annual savings utilizing the optimization system

2024 Potential Annual Savings Utilizing Compression Optimization Systems	Per Field	Per Facility
Compressor downtime mitigation	$4,542,207	$126,172
Under-injection duration reduction	$3,129,947	$86,943
Methane recovery savings	$1,597,300	$44,369
Methanol injection avoidance	$976,763	$27,132
Total savings	$10,246,217	$284,617

Collectively, the compression optimization system delivered substantial financial benefits by reducing compressor downtime, minimizing under-injection losses, recovering methane, and avoiding methanol injection costs. As summarized in **Table 7**, the optimized gas lift facilities achieved a potential annual economic benefit exceeding $10.2 million, averaging about $284 thousand per facility during 2024.

7. System Limitations

Despite the benefits demonstrated and discussed, the compression optimization system does have economic and operational limitations. At very low gas injection rates, the economic return may not justify system installation costs. In addition, the system only mitigates compressor scrubber liquid level, engine panel, and low engine oil pressure shutdowns, but does not address other mechanical shutdown triggers such as engine wear, lubrication failure, excessive vibration, electrical or control system faults. Also, although the system generates lean, dry recovered gas, it does not provide advanced gas conditioning beyond proper phase separation. Therefore, applications requiring specific gas fuel quality may require additional gas conditioning equipment.

8. Conclusion

In conclusion, this field study demonstrates that gas-lift facilities equipped with the compression optimization system achieved significant operational improvements compared with non-optimized facilities. Throughout 2024, optimized compressors recorded reductions of 96% in scrubber liquid level shutdowns, 78% in engine panel shutdowns, and 86% in low engine oil pressure shutdowns, resulting in an overall 94% reduction in compressor downtime. In addition, compressor under-injection duration was reduced by 93%, improving gas-injection stability and well unloading efficiency.

The system also delivered meaningful environmental benefits by capturing methane emissions. Through complete methane capture during gas compression operations, the system recovered 476,806 MCF of methane, reducing greenhouse gas emissions and improving the environmental performance of gas-lift facilities.

These improvements also translated into significant economic benefits. The annual oil production losses associated with compressor downtime decreased from 107,314 barrels to 6,376 barrels, while losses related to compressor under-injection declined from 74,191 barrels to 4,638 barrels. Collectively, reduced downtime and under-injection, recovered gas, and eliminated methanol usage generated a total potential economic benefit exceeding $10 million annually across the 36 optimized facilities.

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