UNDERGROUND MINING ENGINEERING 48(2026) 19-38 UDK 62
UNIVERSITY OF BELGRADE - FACULTY OF MINING AND GEOLOGY ISSN 03542904

Original scientific paper

UPGRADE OF A CONVENTIONAL PUMPING UNIT WITH A COMPRESSOR FOR PRESSURE REDUCTION IN THE CASING, AIMED AT INCREASING OIL AND GAS PRODUCTION AND REDUCING CO2 EMISSIONS

Stevica Jankov[1], Eleonora Desnica[2], Borivoj Novaković, Luka Djordjević

Received: January 11, 2026 **Accepted:** February 17, 2026

Abstract: In the paper, the authors are conducing research into designing and upgrading the conventional system of oil production using a compressor for pressure reduction in the casing, aimed at increasing oil and gas production and reducing CO2 emissions. As oil exploitation progresses, the natural pressure of a reservoir decreases, which results in reduced production from the wells. Therefore, compressor design becomes essential for production optimization. The paper analyses the methodology of designing a compressor which is integrated into the existing sucker rod pump systems, bearing in mind specific pumping unit dimensions, the annular pressure and the quantity of produced gas. The proposed approach includes precise flow dynamics measurement and analysis, as well as optimization of the geometry of compressor installation in order to achieve maximum efficiency. Pilot projects at nine wells have shown a significant increase in fluid production and decrease in CO2 emissions by using a closed casing and directing gas into the production line. The research provides an insight into possible benefits of integrating a compressor with production systems, thus ensuring a more sustainable approach to oil and gas exploitation

Keywords: Beam Gas Compressor, Oil, Wells

1 INTRODUCTION

At the initial stage of production, the natural reservoir energy enables the majority of wells to produce in self-flowing conditions. However, as exploitation progresses, the natural energy gradually becomes used up, leading to a continuous fall in the reservoir pressure, which results in a rapid drop in production in self-flowing wells. An ever-growing number of oil wells at a single oil field is faced with discontinued production, which seriously threatens an efficient and stable oil field production. Consequently,

[1] NAFTAGAS – Oil Services LLC, Novi Sad, Serbia

[2] University of Novi Sad, Technical Faculty "Mihajlo Pupin", Zrenjanin, Serbia

E-mails: stevica.jankov@nis.rs ORCID: https://orcid.org/0009-0000-6503-8200; eleonora.desnica@tfzr.rs ORCID: https://orcid.org/0000-0002-4724-5764; borivoj.novakovic@uns.ac.rs ORCID: https://orcid.org/0000-0003-2816-3584; luka.djordjevic@tfzr.rs ORCID: https://orcid.org/0000-0003-4578-9060

accurate forecasts of natural flow suspension and of key parameters (such as reservoir pressure, bottom-hole flowing pressure and production rate) are essential for designing a diagram of a mechanical exploitation mode, ensuring stable production and establishing production capacities (Gao et al., 2025). When a well is flowing, we analyse pressure drop trends at the wellhead to calculate pressure reduction speeds and determine the time when the pressure will reach its minimum - the time when the well will stop flowing.

By applying the nodal analysis method, we calculate Inflow Performance Relationship (IPR) and fluid production curves under different pressure conditions in the reservoir (Camargo et al., 2008). As Figure 1 shows, the shut-in pressure corresponds to the reservoir pressure at which the Inflow Performance Relationship (IPR) curves do not intersect the Tubing Performance Curve (TPC) under shut-in conditions.

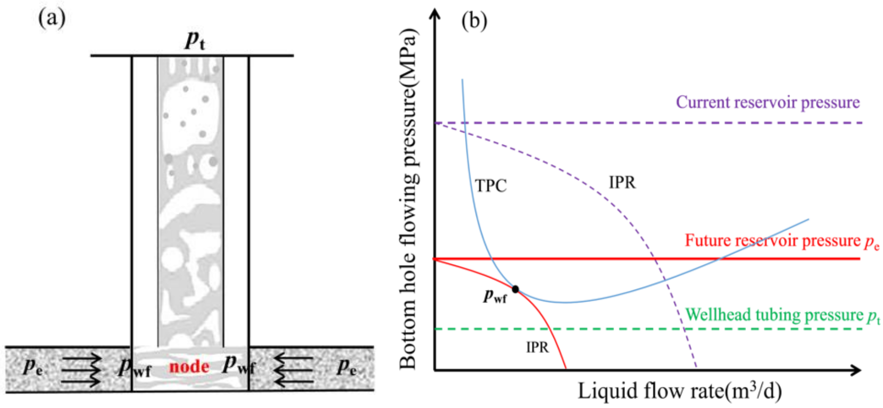


Figure 1 Schematic of fluid inflow into the wellbore (a) and a diagram showing the relationship between fluid production and bottom-hole pressure with inflow (IPR) curve and production (TPC) curve (Gao et al., 2025)

1.1 Sucker rod pumping system basics

After a well stops flowing, we proceed to the selection of a mechanical oil exploitation method to ensure maximum recovery from the oil reservoir. The paper presents the conventional system of oil recovery using sucker rod pumps. We can only speculate on the number of wells using this oil production method globally and these account for 21%, while their share in oil production is 7% (Kis, 2021). Given such large share in oil production, the basic goal of engineers is to safely manage well production with minimum operating expenses, downtime and equipment failures (Kis, 2021). Figure 2 shows the sucker rod pumping system

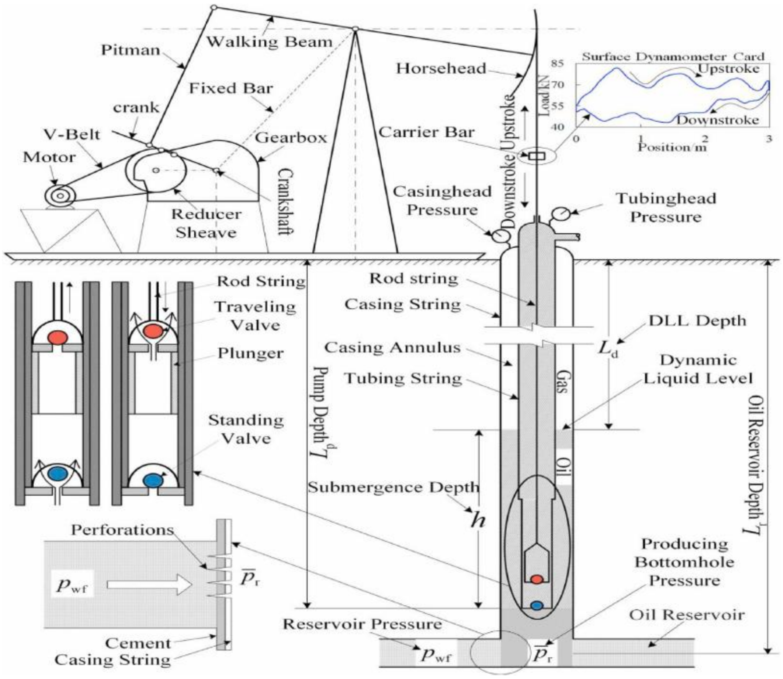


Figure 2 Schematic of the sucker rod pumping system (Chen et al., 2021)

The systems are simple to use owing to their design. However, there are several deficiencies, including loss of efficiency in wells containing gas, sucker rod friction in deviated wells and small installation depth (Bode, 2019).

The sucker rod pumping system and the intelligent three level management system (Aliev et al., 2018):

- Pumping unit level
- RMS level consisting of a controller for collecting data from the sensor and a frequency regulator for the actuator (electric motor) speed control. Furthermore, this level includes a modem equipped with an antenna for data exchange between RMS and the central control station via MODBUS-RTU protocol.
- Oil field centralised control station level consisting of an industrial computer and a wireless modem with an antenna.

During monitoring, it is possible to select an observation interval including all historical data accumulated through the application of the SCADA system.

Each of the parameters shown may be regarded and analysed individually. Given the large number of operation parameters, it is possible to detect a problem and forecast the time of system failure with high precision. The intelligent management system itself gives reports on operation anomalies which the specialist detects and issues requests for the system servicing before it stops working (S. M. Jankov et al., 2025).

One of the preconditions for monitoring the operation of sucker rod pumps is the availability of dynamometer cards. The cards are generated using load and stroke sensors. The shape on the dynamometer card is that of a parallelogram. Technologists, based on the shape of the parallelogram, can identify more than 20 parallelogram types indicating different conditions in a well, and also problems in the operation (Aliev et al., 2018).

The data for examining the impact of the dynamic level were obtained by way of an automatic recorder which measures the depth of the dynamic fluid level in an oil well by applying the acoustic waves method. This principle uses the acoustic waves method based on the concept of acoustic distance measurement. The acoustic waves generator at the wellhead produces a signal and the wave spreads downwards along the annulus. When it reaches the tubing joint, a small part of the wave generates reflection received by a receiver at the wellhead. The largest part of the acoustic wave continues to spread downwards, with its energy gradually dissipating and the strength of the signal progressively reducing. Finally, a part of the wave reaches the liquid level, while the resulting wave (liquid level wave) is received by the receiver. (Jia et al., 2014; Davies et al., 2014; S. Jankov et al., 2025).

2 METHODOLOGY

Over time, oil production systems which use sucker rod pumps face problems due to gas backpressure which accumulates in the annular space (casing), preventing greater production of oil since it reduces the dynamic level which is often at the pump level (Escobar-Remolina et al., 2015). The gas problem is resolved by taking gas away from the well and burning it on the flare or releasing it into atmosphere, which poses great environmental problems and high operational risks (Sandler et al., 2012).

The gas released from a formation frequently creates problems in the operation of the sucker rod pump itself, which may result in oil production disruption due to the impact of gas, while the pressure the exerts on the reservoir may lead to the absence of fluid flow from the reservoir (Al-Khatib, 1984).

In 1971, Charlie McCoy found a solution to eliminate gas from annular space, after which the compressors he designed started being used globally (Al-Khatib, 1984).

2.1 Principle of compressor operation

The main advantage of compressors is in their use of the energy of the pumping unit without requiring any additional source of energy. When the polished rod moves upward, gas is taken and transported from the annulus over the check valve to the lower compressor chamber, while it is simultaneously compressed at the top of the compressor and released into the discharge line through the discharge valve. Figure 3(a) shows blue gas absorbed from a well. When the piston moves, it is pressed (now red) and sent to the discharge line. The process of suction and compression is carried out alternatively in the upper and lower section. If it is suctioned from the lower pipe, the gas at the top of the piston is compressed, and if it is suctioned at the top of the compressor, then the bottom compresses and releases the gas (Figure 3(b)). The process repeats continuously.

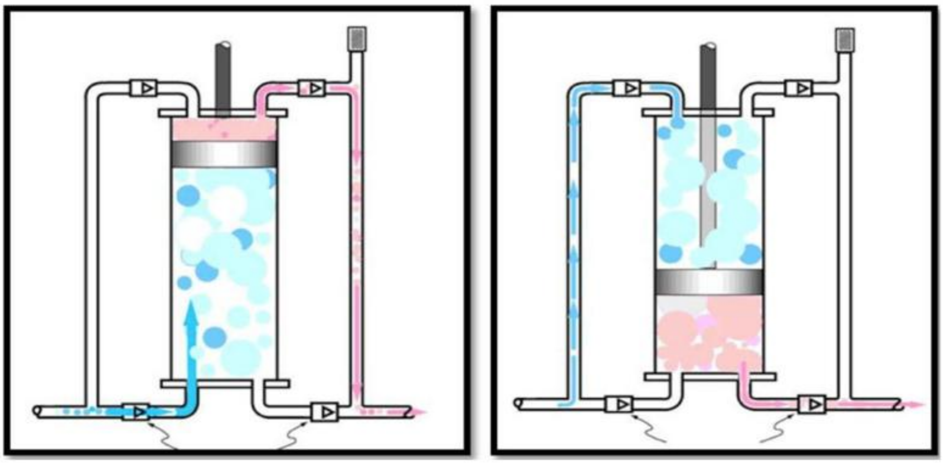


Figure 3 Lower suction (a) and upper suction (b) (Sandler et al., 2012)

It should be noted that the operating principle described here is based on double-acting operation. In case the quantity of gas that should be compressed is reduced, it is possible to use a simple combination of valve closing and opening to change the principle to a single-acting operation (Engl, 2009).

2.2 Compressor design

In his paper (Engl, 2009) describes in detail the Beam Gas Compressor (BGC) design. Several factors affect compressor design and the user should, therefore, provide the manufacturer with a comprehensive information sheet containing the type of the pumping unit with dimensions, quantity of produced gas sent to the production line, i.e. gas production measurements in conditions under which the compressor is to operate, gas content and the number of pumping unit strokes.

In order to design a compressor, it is necessary to have exact information about the quantity of gas that is compressed. System dimensions must be designed so as to enable compression 10 to 20% above the actual gas volume in order to ensure adequate working capacity in situations when gas production changes. Gas measurement, therefore, represents the key parameter in compressor design which must be carried out in conditions similar to the ones under which a well will operate, after compressor installation. Additionally, there is a direct relationship between the calculation of compressor dimensions and the compression flow rate, which is proportional to the pump operating speed, as shown in the equation (1) (Escobar-Remolina et al., 2015).

$$Q = \frac{P * N * S * L}{K} \tag{1}$$

Where:

P – suction pressure (Pa),

Q – gas volume (Sm^3),

K = 0.07531 (for a single-acting compressor),

K= 0.03777 (for a double-acting compressor),

N – number of strokes min^{-1},

S – compressor piston area (m^2),

L – length of piston stroke (m).

Suction pressure for compressor selection is calculated according to the following formula (2):

$$P = \frac{Q * K}{N * S * L} \tag{2}$$

The basic compressor selection formula refers to the piston area calculated by the formula (3).

$$S = \frac{Q * K}{N * P * L} \tag{3}$$

NOTE: Coefficient K for a single-acting compressor is K = 0.07531, and for a double-acting compressor it is K=0.03777.

2.3 Compressor installation geometry

To ensure stable operation and the required length of the compressor piston movement, it is necessary to carry out the installation at the appropriate point of the pumping unit so as to meet the conditions for compressing the calculated gas volume and obtaining the target pressure in the casing.

The formula for the calculation of the point where the compressor is to be installed (4):

$$C = \frac{Y * A}{2 * B} \quad (4)$$

Where:

A – The distance of the walking beam bearing from the suspension point of Pitmen (mm)

B – The height from the Pitman suspension from the Crank to the point of compressor installation (mm)

C – The distance of the point of compressor installation on the Walking Beam to the Walking Beam bearing (the support point on the beam base) (mm)

Y – The length of compressor piston movement (mm)

Figure 4 shows the schematic of the pumping unit with marked A, B, C and Y values that will be used to calculate the point of compressor installation

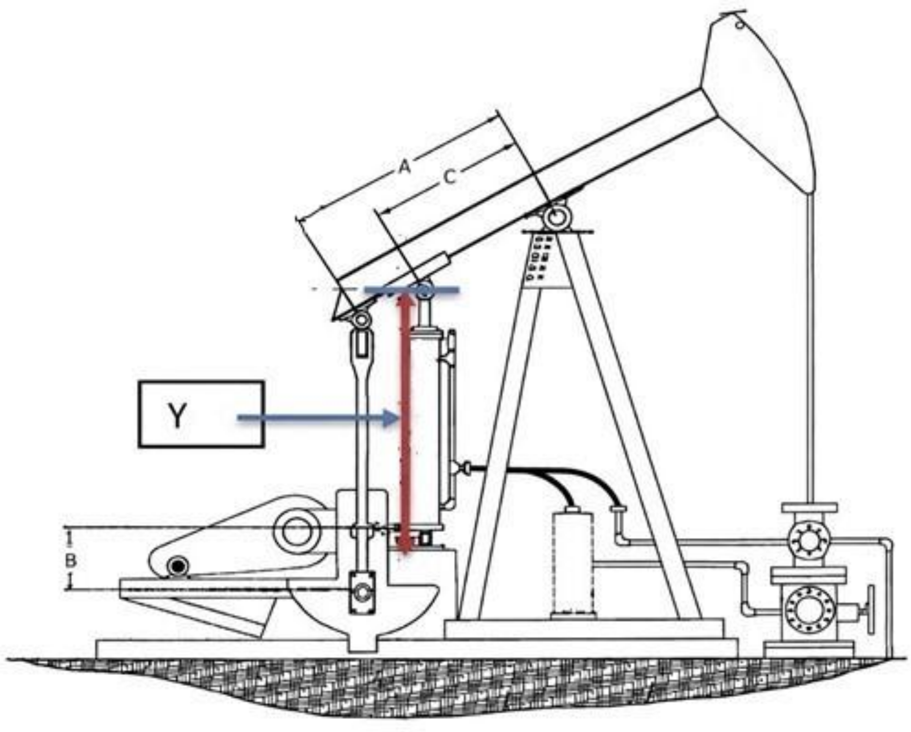


Figure 4 Schematic of the pumping unit with presented A, B, C and Y values that will be used in the calculation of the compressor unit point

3 EXPLORATION METHODOLOGY

3.1 Measurement flow chart

The study was conducted on nine producing oil wells equipped with sucker rod pumping units. Continuous monitoring of operational parameters was performed using a SCADA-based system integrated with stationary sensors. Dynamic fluid level and annular pressure were measured using a stationary acoustic level meter (sonolog), installed at the wellhead. Measurements were recorded four times per day, while gas production was measured at surface separators under reference conditions (101.325 kPa, 15 °C). Pumping unit operating parameters (stroke length, strokes per minute, load) were obtained from dynamometer cards generated by load and displacement sensors.

3.2 Filtering and validation of data

Raw sensor data were filtered to remove outliers caused by transient operating conditions, such as pump start-up or shutdown events and short-term pressure oscillations during compressor commissioning. Dynamic level measurements recorded at annular pressures below 80 kPa were flagged as potentially unreliable and excluded from quantitative analysis. Only stabilized operating periods of at least 24 h duration were considered for before/after comparison.

3.3 Calculation procedure

Gas volume rates were converted to standard conditions and used as input for compressor sizing. Compressor piston area and stroke length were calculated using Equations (1)–(3), based on measured suction pressure, gas volume, and pumping unit stroke frequency. The installation geometry of the compressor on the walking beam was determined using the kinematic relationship given in Equation (4), ensuring compatibility between pumping unit stroke and compressor piston travel. Fluid production before and after compressor installation was calculated from effective pump stroke length derived from dynamometer cards. CO_2 emissions were calculated based on measured gas volumes flared and standard emission factors, as described in Section CO_2 emission calculation

4 RESULTS AND DISCUSSION

In order to increase oil production and reduce CO2 emissions in unprofitable wells, a pilot project was carried out at nine wells. Gas extraction at five wells (E-001, E-002, E-003, E-004 and E-005) was resolved by a closed casing and by directing gas to the production line, thus preventing its emission into the atmosphere. However, in these wells, a pressure rise in the casing resulted in a fluid level drop in the well to the pump level, which led to reduced oil production.

At wells E-006, E-007, E-008 and E-009, oil was produced by taking gas away from the casing and burning it on the flare. In this case, oil production was satisfactory, though a large quantity of gas was burnt on the flare, leading to CO2 emissions contrary to the legal regulations, and also to reduced well profitability due to the loss of gas produced from the reservoir. Table 1 shows the basic properties of wells operating with a closed casing where gas is not burnt on the flare but directed to the production line.

Table 1 Characteristics of Wells with Closed Casing Valve

Well	Sucker rod pump	Pump depth (m)	Well Level (m)	Pump Speed (o/min)	Stroke duration (mm)	Daily fluid production Qf (m^3)	Daily gas production Sm^3/day
E-001	25-175-RHAM-13-4-1-0	1499	1502	5.6	1710	12.6	555
E-002	25-175-RHAM-16-4-0-0	1095	1098	4.7	2021	6.8	222
E-003	25-175-RHAM-13-4-1-0	1480	1483	4.7	1874	10.3	477
E-004	25-175-RHAM-13-4-1-0	1320	1325	4.6	1660	9.7	222
E-005	25-175-RHAM-13-4-1-0	1603	1605	6	1479	11.3	413

Table 2 shows properties of the wells where gas is directed to the flare where it is subsequently burnt.

Table 2 Characteristics of Wells with Open Casing Valve

Well	Sucker rod pump	Pump depth (m)	Well Level (m)	Pump Speed (o/min)	Stroke duration (mm)	Daily fluid production Qf (m^3)	Daily gas production Sm^3/day
E-006	25-175-RHAM-13-4-1-0	1300	1223	4.8	2105	14.1	158
E-007	25-175-RHAM-12-4-2-0	1402	1328	5.6	2188	12.2	588
E-008	25-175-RHAM-13-4-1-0	1439	1356	4.3	2167	9.9	797
E-009	25-175-RHAM-12-4-2-0	1461	1392	6	1882	10.7	1300

The tables lead to the conclusion that wells with a closed casing have a much lower dynamic level. This is a consequence of pressure buildup (approximately 1000 kPa) in the annular space between the casing string and the tubing. Experiments showed that the pressure of 100 kPa reduces the dynamic level by 10 m. Due to the low dynamic level (at the pump level), these wells were determined to have an incomplete filling of the sucker rod pump cylinder as a reduced effective piston stroke length and thus reduced fluid production, as well. The gas produced becomes utilised and together with oil and formation water goes to the production line to the gathering station.

The wells with an open casing were found to have the level around 80m above the pump, the cylinder was full, the effective length of the piston stroke was at the maximum, and production was greater. In this case the problem is in burning of the gas and CO2 emission resulting from burning natural gas from the well.

The data provided in the table were obtained from the sensors installed at the wells. They are transferred to the user by SCADA system and may be visually monitored on the AVEVA platform.

To record the dynamic level in this study, stationary sonolog was used, which measures the level four times a day, with the option to adjust the system for a higher number of measurements. The solonog also has the option of measuring and sending data about the annular pressure. The sonolog MGT APDU-1 is produced by Magmatek, Figure 5.

Figure 5 Sonolog MGT APDU-1 – stationary level meter in the annular space of a well (Приборы контроля параметров скважин https://www.mgtcontrol.ru/catalog/pribory-kontrolia-parametrov-skvazin

Technical characteristics of the device:

1. Measured level range	20 ÷ 6000 m
2. Level resolution	≤1 m
3. Measured pressure range	0 ÷ 10000 kPa
4. Pressure resolution	10 kPa
5. Operating pressure range	80 ÷ 5000kPa
6. Continuous operating time under normal conditions, without battery recharging	≥ 4000 level measurements
7. Installed battery recharging time	≤3 h
8. Sensor communication channel	Bluetooth LE
9. Communication channel range	≥30 m
10. Method of establishing communication	NFC
11. Operating temperature range	-40 ÷ +50 °C
12. Service life	≥5 years
13. Product weight	≤6 kg

Owing to the cutting-edge technologies applied, it is capable of operating in a stationary manner, in a fully automatic mode, for a very long time. When performing level measurement, 1-2 measurements per day may be done for over a year in one charging. Operating together with the information collection and transfer block BSPs, it may be connected to different automation and telemechanical systems over the RS-485 interface and also transfer data through GSM and LoRa WAN channels.

Tasks that are performed:

- Control of the static and dynamic fluid level in producing oil wells in the automatic and manual mode
- Creation of level change curves
- Long-term control of level change during well commissioning
- Operational level control in transfer mode
- Operational data transfer via different connection channels and into telemechanical systems

Produced gas volume is measured by the separator at atmospheric conditions, and the volumes are presented according to Reference conditions: 101,325kPa and 15°C.
Table 3 presents gas composition for the well E-002. Given the fact that all other wells are also situated in the same reservoir, gas composition is almost identical

Table 3 Composition of the gas produced from E-002 well

No	Characteristic	Unit	Method	Value
1	C_1	mol %	SRPS EN ISO 6974-5:2014	66,411
2	C_2	mol %	SRPS EN ISO 6974-5:2014	5,890
3	C_3	mol %	SRPS EN ISO 6974-5:2014	6.027
4	i-C_4	mol %	SRPS EN ISO 6974-5:2014	1,375
5	n-C_4	mol %	SRPS EN ISO 6974-5:2014	3.788
6	i-C_5	mol %	SRPS EN ISO 6974-5:2014	1.201
7	n-C_5	mol %	SRPS EN ISO 6974-5:2014	1.891
8	C_{6+}	mol %	SRPS EN ISO 6974-5:2014	3.709
9	N_2	mol %	SRPS EN ISO 6974-5:2014	2,417
10	CO_2	mol %	SRPS EN ISO 6974-5:2014	7,291
11	Av. molecular weight	g/mol	SRPS EN ISO 6976:2017	27.40
12	Density relative to air	/	SRPS EN ISO 6976:2017	0.9512
13	Density	kg/m^3	SRPS EN ISO 6976:2017	1.1656
14	Vobes index (bottom)	MJ/m^3	SRPS EN ISO 6976:2017	48.98
15	Lower heating value	MJ/m^3	SRPS EN ISO 6976:2017	47.77
16	H_2S	mg/ms^3	SRPS H.F8.507:1992	0.23

As specified in the previous section, the point of compressor installation is determined based on individual pumping unit dimensions so as to make the compressor operation optimal for the calculated gas volume and to simultaneously avoid additional load on the pumping unit operation and also prevent piston breakdown due to a pumping unit stroke larger than the compressor piston stroke. Tables 4 present the required pumping unit dimensions for the calculation of the installation point according to the previously given formula (5):

$$C = \frac{Y * A}{2 * B} \tag{5}$$

Table 4. Dimensions of pumping unit components

Well	Beam	A (in)	B (in)	C (in)	A (mm)	B (mm)	C (mm)
E-001	A 70	70.5	25.5	49.5	1791	648	1258
E-002	API 7.8	70	30	42.6	1778	762	1082
E-003	API 7.8	70.5	25.5	49.5	1791	648	1258
E-004	API 7.8	71	22.5	56.8	1803	572	1442
E-005	API 7.8	71	26	49.2	1803	660	1248
E-006	API 7.8	71	26.5	48.2	1803	673	1225
E-007	API 7.8	70.5	30	42.3	1790	762	1074
E-008	UL 90	82	32	46.1	2082	813	1171
E-009	A 90	82.5	31.5	47.1	2095	800	1197

Compressor selection

According to the parameters described and the compressor designing method, an appropriate compressor was determined for each well, and the point of compressor installation was identified for each pumping unit. The result of this selection is in Table 5.

Table 5 Installed compressor characteristics and dimensions

Well	Beam	Y (in)	Y (mm)	Piston diameter (in)	Piston diameter (mm)	Compressor Type
E-001	A 70	48	1219.2	6	239.2	Single Active
E-002	API 7.8	36	914.4	6	239.2	Single Active
E-003	API 7.8	36	914.4	6	239.2	Single Active
E-004	API 7.8	36	914.4	6	239.2	Single Active
E-005	API 7.8	36	914.4	6	239.2	Double Active
E-006	API 7.8	36	914.4	6	239.2	Single Active
E-007	API 7.8	36	914.4	6	239.2	Double Active
E-008	UL 90	48	1219.2	6	239.2	Double Active

E-009	A 90	48	1219.2	6	239.2	Double Active

At all nine wells, compressors were installed according to the schematic given in Figure 6:

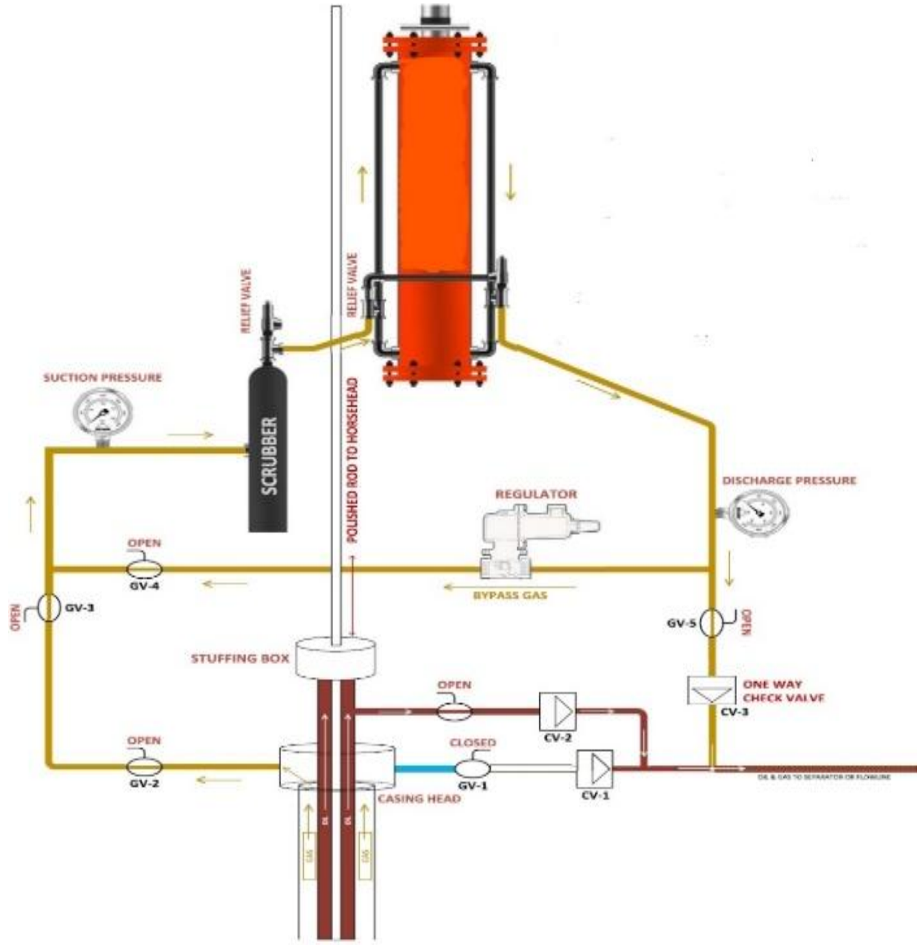


Figure 6 Schematic of the installed compressor with the supporting elements (https://www.creamco.ca/m3-casing-gas-compressor/technical-info/#tab-id-2)

Fluid production increase and CO_2 emission reduction

Gas extraction at five wells (E-001, E-002, E-003, E-004 and E-005) was resolved by a closed casing and by directing gas to the production line, thus preventing its emission into the atmosphere. However, in these wells, a pressure rise in the casing resulted in a fluid level drop in the well to the pump level, which led to reduced oil production. Compressor installation resulted in annular pressure reduction down to the target 170 kPa and fluid level increase in the well by about 80 m above the pump, which led to the increase in the effective length of the piston stroke, cylinder filling and fluid production. Table 6 shows the dynamic level and fluid production before and after compressor installation at wells E-001, E-002, E-003, E-004 and E-005.

Table 6. Dynamic level and fluid production before and after compressor installation at wells

Well	Pump depth (m)	Well Level (m) Before BGC	Well Level (m) After BGC	Pressure (kPa) Before BGC	Pressure (kPa) After BGC	Daily fluid product. Qf (m^3) Before BGC	Daily fluid product. Qf (m3) After BGC	Product. increase Qf (m^3)	Product increas e Qf (%)
E-001	1499	1502	1417	1001	160	12.6	18.3	5.7	45%
E-002	1095	1098	1013	980	170	6.8	12.7	5.9	87%
E-003	1480	1483	1398	960	190	10.3	14.9	4.6	45%
E-004	1320	1325	1240	1050	150	9.7	13.5	3.8	39%
E-005	1603	1605	1520	1100	170	11.3	15.9	4.6	41%

Figure 7 shows fluid production increase after compressor installation at the well E-002. It can be seen that the compressor was installed on 24 December 2025. After the pumping unit was commissioned and the annular pressure reduced from p=980 kPa to p=170 kPa, fluid production rose from Qf=6,8 m^3 to Qf=12,7 m^3. The level in the well rose by 80 m which was enough for the pump to operate with the maximum cylinder filling.

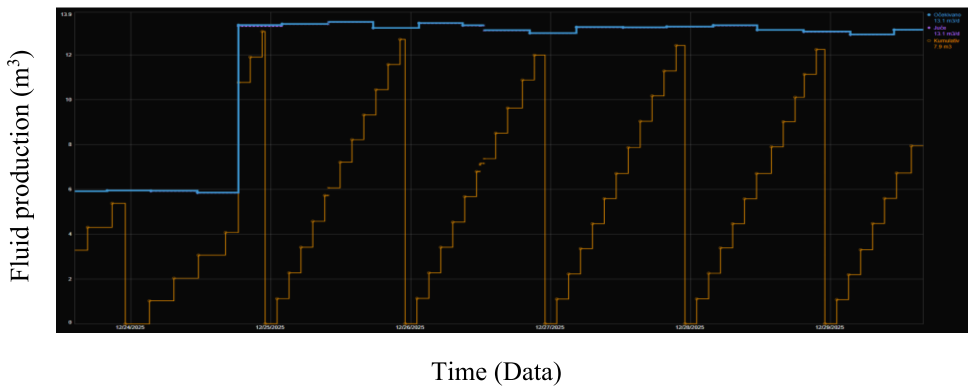
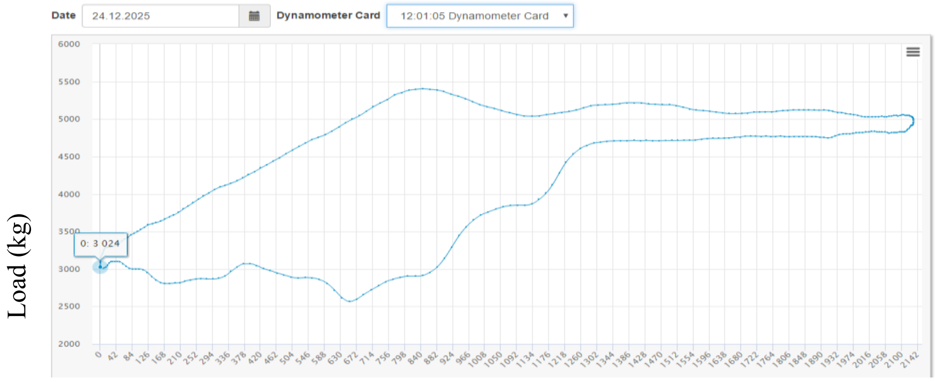


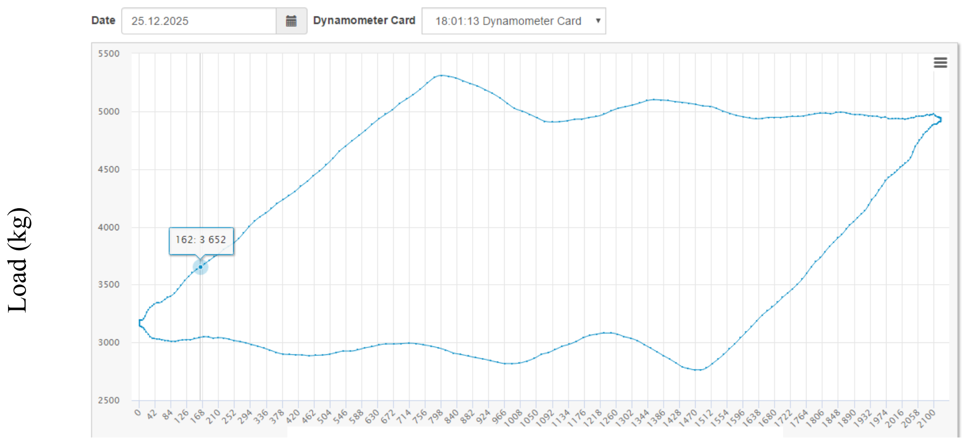
Figure 7 Fluid production increase after compressor installation

For production calculation purposes, the dynamometer cards recorded before and after compressor installation were used. Figure 8 shows the effective pump piston stoke length to be 630 mm. The dynamometer card was recorded on 24 December 2025 before compressor installation, while Figure 9 shows the effective pump piston stroke length to be 1500 mm. This dynamometer card was recorded after compressor installation on 25 December 2025. It also shows complete pump cylinder filling. Furthermore, the maximum and minimum load in the diagrams indicate that compressor installation did not put any additional load on the oil production system using sucker rod pumps.



Piston stroke length (mm)

Figure 8 Dynamometer card recorder before compressor installation



Piston stroke length (mm)

Figure 9 Dynamometer card recorder after compressor installation

4.1 CO_2 emission reduction

At wells E-006, E-007, E-008 and E-009, oil was produced by taking gas away from the casing and burning it on the flare. In this case, oil production was satisfactory, though a large quantity of gas was burned on the flare, leading to CO_2 emissions contrary to the legal regulations, and also to reduced well profitability due to the loss of gas produced from the reservoir. In these wells, due to the pressure of 100 kPa in the annular space, there was no fluid inflow from the reservoir into the wellbore, and the problem was resolved by opening the casing valve and taking the gas away to the flare where it was burnt.

Compressor installation and annular pressure reduction enabled the gas to be transported to the production line and used further. The preserved gas volumes as profit are shown in Table 2 and they represent evident revenues of oil production from the well after compressor installation. Table 7 shows the quantity of released CO_2 when gas is burnt on the flare.

Table 7 Quantity of released CO_2 when gas is burnt on the flare

Well	Daily gas production Sm^3/day	Daily CO2 Production (kg)	Daily CO2 Production (t)
E-006	158	300.2	0.30
E-007	588	1117.2	1.11
E-008	797	1514.3	1.51
E-009	1300	2470.0	2.47

CO_2 emissions from gas flaring were calculated using the standard emission factor for natural gas combustion recommended by the IPCC Guidelines for National Greenhouse Gas Inventories and adopted by the Energy Agency of the Republic of Serbia (AERS).

This value corresponds to complete combustion of natural gas with an average composition consistent with the measured gas composition presented in Table 3.

Sample calculation (Well E-006):

$CO_2 = 158\ Sm^3 * 1.9 = 300.2$ kg/day

Where: 1,9 - Standard emission factor for natural gas combustion

The same calculation procedure was applied to all wells listed in Table 7.

AERS (2025) Energy Agency of the Republic of Serbia - Website, Available online https://www.aers.rs,

Accessed on [20 September 2025] IPCC (2025) The Intergovernmental Panel on Climate Change
https://www.ipccnggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf , Accessed on 20 September 2025

4.2 Limitations and future works

There are several limitations to the design of upgrading conventional pumping units with BGC compressors.

- Level measurement in wells – A stationary sonolog which measures the level in a well operates optimally at an annular pressure of 80-5000 kPa. Although it was stressed that the annular pressure was 170 kPa, it actually varies during compressor operation and frequently reduces below 80 kPa which is inadequate for measuring the actual fluid level in a well. Since errors occur in measurements, an operator must be engaged to control the validity of the data transferred by the sonolog on a daily basis, which entails operator engagement for the purposes of control recording and increases costs, reducing the economic effect of the designed system.

- The produced gas composition is presented in Table 3 where the presence of higher fractions may be noticed which, under normal conditions, would be in a liquid state. In the compressor design, it was necessary to use a scrubber which collects liquid fraction to prevent its entry into the compressor and thus avoid problems in its operation. Given that the scrubber capacity for liquid phase collection is limited, the operator is required to visit the well on a daily basis to empty the scrubber. Scrubber design within the compressor system increases costs, as does operator engagement to empty the scrubber. All of the above reduces the system design efficiency.

Future research should include condition changing to ensure high-quality operation of the sonolog with regard to annular pressure variation, as well as valve opening automation without operator engagement

5 CONCLUSION

This paper studies upgrade of a conventional pumping unit with a compressor for pressure reduction in the casing, aimed at increasing oil and gas production and reducing CO_2 emissions. The analysis of the existing oil production systems showed that gas backpressure problems occur over time, significantly affecting production efficiency. In that context, compressor designing represents a key step towards optimisation of the existing systems.

Compressor designing requires careful analysis of several factors, including pumping unit type, dimensions, the volume of gas sent to the production line, as well as operating conditions under which the compressor is to work. This study used accurate formulas to calculate the compressor piston area and suction pressure, which enabled the optimal compressor size and type to be determined for each individual well. The data obtained helped select the compressors which proved to be the most efficient for each individual well, taking into account specific characteristics and requirements.

Compressor installation enabled annular pressure reduction, which led to an increase in the fluid level in the wells. This change resulted in an increased effective piston stroke length and, consequently, increased fluid production. In cases when gas is directed towards a production line, instead of being burnt on the flare, significant CO_2 emission reduction is achieved, which corresponds with environmental standards and regulations.

Furthermore, it should be noted that compressor designing within the existing system upgrade required integration of modern technologies, such as automatic fluid level and pressure measurement sensors, which ensure continuous monitoring and work optimisation. The sensors, together with the SCADA system, enable operators to carry out real-time monitoring of system performances and to urgently respond to any possible problems.

Future research is recommended to be focused on improving the automation system, and also developing new technologies which would enable even more efficient pressure and fluid level control. Additionally, it is important to study options for reducing maintenance and operating costs in order to ensure sustainability and profitability of the upgraded systems.

In summary, an upgrade of the existing systems with a pressure reducing compressor represents an important step towards oil and gas production increase, simultaneously reducing adverse environmental effects. This approach may become standard in the industry, helping achieve a more sustainable development and a more efficient use of natural resources

REFERENCES

ALIEV, T., RZAYEV, A., GULUYEV, G., ALIZADA, T., & RZAYEVA, N. (2018). Robust technology and system for management of sucker rod pumping units in oil wells. Mechanical Systems and Signal Processing, 99, 47–56.

AL-KHATIB, A. M. (1984). Improving oil and gas production with the beam-mounted gas compressor. Journal of Petroleum Technology, 36(02), 276–280.

BODE, C. (2019). Measurement and Hardware Simulation on Torque, Speed & Load of a Prime Mover for optimization of a Sucker Rod Pumping System.

CAMARGO, E., AGUILAR, J., RÍOS, A., RIVAS, F., & AGUILAR-MARTIN, J. (2008). Production improving in gas lift wells using nodal analysis. Signal Processing, Robotics and Automation, 99–102.

CHEN, L., GAO, X., & LI, X. (2021). Using the motor power and XGBoost to diagnose working states of a sucker rod pump. Journal of Petroleum Science and Engineering, 199, 108329.

ENGL, N. (2009). Ascertainment of potential increase in production of RAG oil wells due to casing pressure drop.

ESCOBAR-REMOLINA, J., BARRIOS-ORTIZ, W., FRANCO-SANDOVAL, L., SACHICA-AVILA, J., MCCOY, C., & RIOS-RECUERO, R. (2015). Reduced Emissions and Increased Production Through gas Compressors: Pilot Case in Colombia. SPE-173601.

GAO, L., LIU, Y., LUO, C., LI, S., & PENG, Z. (2025). Wellbore Flow Behavior and Natural Flow Cessation Prediction in Ultra-Deep Wells: A Case Study of Shunbei Oilfield. Energy Science & Engineering, 13(11), 5385–5400.

JANKOV, S. M., STANISAVLJEV, S. M., NOVAKOVIĆ, B. Z., & ĐORĐEVIĆ, L. R. (2025). Visualization of operation parameters and remote management of oil production through the implementation of SCADA system. Tehnika, 80(5), 501–506.

JANKOV, S., NOVAKOVIĆ, B., IVANOV, G., & ĐORĐEVIĆ, L. (2025). Optimization of oil production using reciprocating pumps through corrective adjustment of operating parameters. Mining and Metallurgy Engineering Bor, 2, 21–34.

KIS, L. (2021). Torque Optimization of Sucker-Rod Pumping Units.

SANDLER, J., FOWLER, G., CHENG, K., & KOVSCEK, A. (2012). Solar-generated steam for oil recovery: Reservoir simulation, economic analysis, and life cycle assessment. SPE-153806.

Cream energy group https://www.creamco.ca/m3-casing-gas-compressor/technical-info/#tab-id-2

Приборы контроля параметров скважин https://www.mgtcontrol.ru/catalog/pribory-kontrolia-parametrov-skvazin

AERS (2025) Energy Agency of the Republic of Serbia - Website, Available online https://www.aers.rs, Accessed on [20.09.2025.] IPCC (2025) The Intergovernmental Panel on Climate Change - https://www.ipccnggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf , Accessed on 20.09.2025.