

Evaluation, Diagnostics, and Optimization of the Lagomar Exploitation Unit's Gas Collection and Distribution Network

Summary

Currently, the Lagomar Exploitation Unit's gas distribution and collection network is facing a series of operational problems due to changes in the normal behavior of both the pressure and the volume handled by the system, mainly as a result of shutdowns of the gas compression plants supplying the lift gas. Deferred production due to well shut-ins during the contingency and liquids buildup in the tubing constitute an important operational problem that requires a solution in the least possible time in order to minimize the impact whenever any of these scenarios may occur.

This research's objective is to evaluate the behavior of the gas collection and distribution network of flow stations 15-1, 16-1, 1-2, 1-12, 2-12, belonging to the Block I, II and XIII of the Lagomar Exploitation Unit in the Maracaibo District of PDVSA using the commercial application ReODGO in order to optimize the gas injected to the gas manifolds of each station and use the remaining gas for export to third parties, and at the same time avoid over-injection on the wells thus achieving hydrocarbons production gains. Likewise, it is expected to detect bottlenecks reducing the gas transfer capacity on the network due to the presence of liquids on the system's lines. The possibility to count on an integrated platform able to dynamically simulate the different scenarios that may show up in the system networks allows us to minimize deferred production in case of contingencies and, in normal conditions, diagnose and optimize lift gas injection to increase wells production and maximize natural gas usage.

Overview

Nowadays, the Gas Lift method of Artificial Lift is one of the most commonly used oil well production methods worldwide. The Continuous Gas Lift Method is similar to the natural flow production method with the difference residing in the fact that the gas-liquid ratio in the fluid leg is altered by the injection of compressed gas. The gas reduces the leg's weight in such a way that the reservoir's energy will turn out enough to lift the production up to the surface. It is necessary to inject the gas steadily as deep as possible to sufficiently reduce the leg's weight and inject the adequate gas rate for the friction of the multiphase flow not to defeat the weight reduction. Additionally, in order to

optimize the gas distribution between wells associated to this system it is necessary to use algorithms that would allow us to lift as much oil as possible, since the presence of water would reduce the method's profitability.

Problems with continuous gas lifted wells are mainly focused in three areas: in the lift gas supply system (gas injection choke too open or almost closed, low or high injection pressure); in the produced fluids collection system (valves restrictions, high wellhead backpressure); or in the well itself (hole on tubing, valves out of calibration, dry gas circulation, etc.). This Artificial Lift method features valves which represent one of the most important components of the Gas Lift approach. Continuous gas injection is made through these valves from the annulus to the ejector.

In the practice, these valves end up replaced for two reasons: change of Artificial Lift method due to production decline in the first place and, as second reason, failure in some of the valves, generating a faulty operation and causing production deferment due to production decline.

Attaining an efficient use of the lift gas in any particular well or area is deemed as a complex task given the number of technical, operational and financial aspects that must be taken into account and integrated to obtain the best solution.

This is the reason why the Lagomar Exploitation Unit, belonging to the PDVSA West Division's Maracaibo District, looks forward to obtain the maximum fluids recovery through the efficient use of the injection gas per oil barrel, as part of its production optimization area projects.

The Unit's infrastructure is comprised of 332 wells, 98% of which are gas lifted, using approximately 180 MMCFD of gas. The gas is distributed through 10 Manifolds and the wells production is collected on 18 Flow Stations where the liquid-gas phases are separated. The gas is then transported to the LAMA compression facility while the fluids are taken to the Punta de Palma tank farm. Segregation wells are located on Blocks I, II, XII and UD-1 of the Lake of Maracaibo and currently feature a 60 MBPD production with 50% water-cut.

This thesis intends to detail the procedure employed to dynamically simulate and optimize the gas distribution network associated to Flow Stations 15-1, 16-1, 1-12 and 2-12 belonging to Blocks I, II and XII of the Lagomar Exploitation

Unit, supported by an integral simulation from the middle interval of the perforations up to the gas collection and compression networks. This is achieved using the WellFlo, FieldFlo and Reo-DGO software packages.

Experimental Part

Diagnostics Methodology for the Artificial Lift System in Continuous Gas Lift Wells

The LAG diagnostic system allows detection of any fails that may occur during the production process of a well in order to detect such fail on time and offer a quick solution to the problem so that the production results affected in a minimum.

Following is a series of steps recommended at the moment of performing diagnostics:

A. Compiling and analyzing production variables, production measurement, gas pressures and consumption, porosity, permeability and reservoir pressure, using tools such as:

- Multiple nibs pressure recorders
- Acoustic logs
- Downhole and fluid level checkup with wireline equipment
- Pressure and flowing temperature logs
- Production test including lift gas disk

B. Comparing well behavior:

B.1. Well produces the expected rate (with its potential)

- Well produces without injection (natural flow): It is recommended to simulate the well with reducers, which control production and are located between the wellhead and the flow line, in order to control reservoir pressure and keep it from declining according to its production.
- Well produces its potential and receives injection gas: Its optimum operation point must be determined in order to look for improvement opportunities.
- Well communicated without production decline: if a production change was observed, the instruments' calibration must be checked out; if everything is okay and the problems persist (low pressure), then there possibly is tubing-annulus communication or the operator valve is out of calibration.

B.2. Well does not produce the expected rate

- Well does not produce its potential and receives injection gas: A test must be done for the deepest point of injection in order to determine if the gas injection

is being made by a higher valve other than the operator valve. Besides, the well must be simulated to study improvement alternatives via gas adjustment. If the problem persists:

- Elaborate a gas valve change design
- Study the possibility of tubing-annulus communication
- Study the possibility of a downhole checkup or tubing obstruction
- Well does not produce its potential and does not receive injection gas: This may be due to a gas line obstruction or faulty lift valves. In this case it is recommendable to compare the system's or gas manifold's pressure with the casing injection pressure (CHP).
- Communicated wells: If a low casing pressure is observed, then it is recommended to check for the following:
 - The well does not feature an orifice valve design as operator valve
 - It does not feature an unloading valve design, where the operator valve is calibrated to operate at low pressure

Wells Simulation through FloSystem's WellFlo

FloSystem is comprised of a series of programs developed by Edinburgh Petroleum Services Ltd. This tool allows the Petroleum Engineer design, optimize and diagnose oil wells and production systems. The software is comprised of 5 applications: WellFlo (including an optional lift gas section), WellFlo ESP, PSP2 (Pseudo-Pressures Folder Generator by WellFlo), Well Data Manager and FieldFlo.

WellFlo is a nodal analysis program, which models naturally flowing wells, injection wells and continuous gas lift wells. It has been designed to analyze oil wells behaviors, starting from the well model in terms of fluids pressure and temperature as a function of the flow rate and fluids properties.

FieldFlo Simulation

This system works together with WellFlo and operates as a folder where each well's nodal analysis results are loaded in order to simulate the behavior of the multiphase flow network or the set of wells associated to a flow station.

FieldFlo may be used for optimizing several gas, light oil and oil and gas fields, etc.

ReO-DGO Simulation

DGO is ReO-based commercial package from Edinburgh Petroleum Services (EPS). This

application allows optimizing the distribution of injection gas to wells, high pressure gas and gas for other uses (exporting or secondary recovery), by means of determining the optimal operational conditions of the gas system that would generate the highest financial return for the Corporation.

This simultaneous simulation and optimization system uses the Sequential Linear Programming (SLP) technique as a programming model, with 100% configurable constraints and objects. The tool's execution interacts directly with WellFlo and FieldFlo.

Regarding the simulation model, the application allows determining network pressures, temperature and flows, while on the optimization side it allows determining the production economical strategy subject to financial and engineering constraints.

Starting from the optimization concept, DGO intends to find the cash flow for each resource (q_i) so that it maximizes the accumulated cash flow of the Objective Function (Q): ...{Sales (oil, gas) – Operational Costs}.

All of this subject to a series of field constraints such as:

- Well Production Models
- Available infrastructure constraints (infrastructure model: facilities, lines, etc.)
- Constraints in the reception/supply to third parties (configurable)

Based on the above, DGO also allows to determine the following elements:

- Optimum gas lift rate for each GL well
- Optimum load of compressor units
- Optimum pressures on the lift gas distribution manifolds
- Optimum balance between the use of lift gas or other uses such as secondary recovery (reservoir injection) or export.

Benefits that could be gained through the DGO tool

Optimization:

- Production increase by injection gas distribution optimization
- Savings in royalties payments by fuel gas optimization

Operational:

- Gas metering validation
- Development of contingency plans for several plant events

- Larger operational flexibility on compressor plants
- Decrease in the handling of effluents

Design, Simulation and Planning:

- Design, evaluation and selection of equipment
- Detection / diagnostics of bottlenecks and quantification of gas system impacts
- Integral planning and development of the wells, facilities and gas compression system infrastructure

Environmental:

- Decrease in flow stations' gas vents

Conclusions and Recommendations

- It could be observed that most of the studied wells on the Flow Station (FS) 15-1 show an IP of less than 0.5 BPD/LPC, which indicates depletion of the reservoirs where the wells are located.
- It was determined that for FS 15-1 there is no predominating vertical multiphase flow correlation in the studied areas – Gray, Duns and Ros STD applied almost in the same proportion, while Orkiszewski, Fancher and Brown applied to a lesser extent.
- Different scenarios were carried out for lift gas distribution on FS 15-1 whenever operational problems arise and we have a determinate injection gas volume available.
- In overall, FS 16-1 is optimized regarding injection gas, with only a single well showing over-injection, VLA-0145, and one with sub-injection, VLA-0164.
- Regarding multiphase flow correlations distribution on Flow Station 16-1, no correlation was found to fit most of the wells, with the most currently used being Duns and Ros STD, Orkiszewski, Fancher, Brown and Gray.
- Most of the wells featuring calibrated valves in their mechanical configuration show problems in their lift system.
- It could be observed that by reducing the separation pressure of Flow Station 16-1 from 75lpc to 50lpc, a gain of 160BPD / 80BPD would be obtained.
- Different scenarios were carried out for lift gas distribution on FS 15-1 whenever operational problems arise and we have a determinate injection gas volume available.
- Adjusting the gas injection on wells belonging to Flow Stations 15-1 and 16-1 to well VLA-0145 in order to obtain the calculated gas savings.

SEP. PRESS. (LPC)	INJ. Q. (MMCFD)	LIQ. Q.	OIL Q.	FORM. G (MMCFD)	TOTAL G. (MMCFD)
50	6,09	3330	1512	1,513	7,603
55	6,09	3295	1500	1,51	7,597
60	6,09	3280	1485	1,501	7,591
65	6,09	3265	1470	1,495	7,585
70	6,09	3250	1455	1,489	7,579
75	6,09	3235	1440	1,483	7,573
80	6,09	3220	1425	1,474	7,564
90	6,09	3205	1410	1,471	7,551

- Automation of the Flow Stations 15-1 and 16-1 gas manifolds is recommended in order to include them into the injection gas distribution scenarios.
- Carry out an infrastructure project to adequate FS 16-1 and reduce the separation pressure.
- The Lagunillas-Lago INF-Duns, modified Ross and Gray vertical flow correlations are the ones that simulate most of the 1-2, 1-12 and 2-12 Flow Stations wells, respectively.
- According to the simulation made, FS 1-2 has an over-injection of 1.170 MMCFD, as a consequence the flow station has a deferred production of 93 net barrels of the station's production.
- FS 1-12 has an over-injection of 164 MCFD with an associated production of 62NB.
- Wells of FS 2-12 have an optimum gas injection rate.
- 1North-1South Scenario: Lift gas redistribution performed on well of the studied Flow Stations allows reducing the production deferment in 1747 gross barrels, 573 net barrels, 540 MCFD of formation gas and a lift gas saving of 540 MCFD.
- 0North-2South Scenario: Application of an optimized shut-in redistributing lift gas in this scenario allows reducing the production deferment in 623 gross barrels, 198 net barrels and 320 MCFD of formation gas.
- 2North-0South Scenario: Performing an optimized shut-in allows reducing the production deferment in 4205 gross barrels, 2367 net barrels, 6580 MCFD of formation gas and a lift gas saving of 50 MCFD.
- Current production losses due to separation pressure increases starting from 90lpc on Flow Station 1-2 are of 276 net barrels and 333 MCFD. Carrying out cleanups on the lift gas collecting lines implies an additional deferment of 45 net barrels.
- Theoretically, in order to transport 51 MMCFD through the 16" line from FS 1-2, to LGV/VI it is necessary to have a pressure of 204lpc on Flow Station 1-2, which demonstrates the existing bottleneck in the area.
- According to the current optimum operation scenario there must be currently a separation pressure of 63lpc on Flow Station 1-12 and 85 on Flow Station 2-12, indication of presence of liquids on lines going from these flow stations to Llanogas and from Llanogas to Flow Station 1-2.
- Gas vented from flow stations when trying to flow in its entirety through the 16" pipe is of 30.4 MMCFD, equivalent to a production of 5724 gross barrels and 2220 net barrels.
- The optimum operation scenario covers a 8.1Km, 24" pipeline from Llanogas to LGV/VI with separation pressures on the Flow Stations of 46lpc, 49lpc and 52.5lpc for 1-2, 1-12 and 2-12, respectively.
- Installing a high pressure 12" pipe from PE-15-1 to PE-19-1 improves the north-south gas transfer reducing production deferment with the two (2) north plants and zero (0) south plants scheme.
- Applying lift gas redistribution to wells belonging to Flow Stations 1-2, 1-12 and 2-12 during scheduled and non-scheduled plant shutdowns in order to minimize production deferment on those stations.
- Performing a gas collection pipeline cleaning from FS 1-12 to the Llanogas manifold, from FS 2-12 to Llanogas and from Llanogas to FS 1-2 in order to reduce separation pressures on Flow Stations 1-12 and 2-12.
- Automating the valve that controls the low pressure gas delivery from FS 1-2 to FS LL-75 in order to reduce the response time to low intake pressure problems on the plants, non-scheduled plant shutdowns or Tía Juana plants chain shutdowns.
- Carry out an 8.1Km, 24" pipeline run from the Llanogas manifold to LGV/VI.
- Carry out a high pressure gas pipeline run from PE-15-1 to PE-19-1 in order to increase the north-south gas transfer and eliminate deferred production with the 2 north – 0 south scenarios.