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Gas Lift Optimization: Solution to Non-Linear Field Network Problem using Sequential Quadratic Programming Technique

[1]Okafor Chukwudi Victor; [2]Loyibo Emmanuel

Abstract:- The future of global energy production is quite unknown; various agencies and international entities have led talks and publications claiming that the oil production has peaked in conjunction with a significant increase in energy consumption. Companies will have to rethink and reassess their current and future production strategies even more. The purpose of this paper is to show how gaslift can be used to boost oil production output. The petroleum sector has undergone significant changes in its operations, and in order to maximize profits by increasing production, adequate process optimization of all procedures, including artificial lift, is required. A well-executed gaslift technique could bring about a sustainable decrease in operating cost over time of a project and as such give a high profit output. Gaslift is a widely used technique for enhancing oil recovery from reservoirs in the oil and gas industry, Gaslift Optimization is the process of maximizingoil production through injecting gas into the wellbore to diminish hydrostatic pressure and augment the fluid flow rate. Gaslift Optimization is an important area of research aimed at improving the productivity and efficiency of oil and gas fields. In this study, I investigated the use of Sequential Quadratic Programming (SQP) technique for Gaslift Field Optimization technique that has been applied to various fields including economics, engineering and finance. The SQP algorithm is well-suited for Gaslift Optimization because it can handle non-linear constraints and efficiently solve large-scale optimization problems. It can also handle multiple objective functions and constraints simultaneously. In addition, the algorithm can be modified to include different types of constraints such as production constraints, gas injection constraints and pressure constraints.

The main objective of this research is to develop an optimization model that maximizes the oil production rate while minimizing the operational cost of Gaslift. The study involves the development of a non-linear mathematical model that represents the Gaslifts field network, which is then optimized using the SQP technique. The model is then validated using field data from a selected oil and gas field. The research also investigates the real impact of several parameters such as wellhead pressure, gas injection rate and chokes size on the performance of the Gaslift field network. The findings of this research will provide valuable insights into the use of SQP technique for Gaslift field optimization, which can then be applied to improve the productivity of oil and gas fields.

I. INTRODUCTION

The production of oil from oil wells gradually decreases with time as production continues. This reduction is a consequence of the declining reservoir pressure which results in rising water-cuts, GOR, leading to increased operational costs of production from the well against marginal recovery (abdalsadig et al. 2016). Continuous production decline may cause the oil rate to fall to a level that economic profitability is no longer attained. At this condition, of the options available to the operator is to include external operational enhancements/assistances to the well to bring the well back to life and increase profitability by increasing daily production rates (saepudin et al. 2010). There are many methods available to the production engineer to increase the daily production from non-producing or low-producing wells. This includes nodal analysis techniques, artificial lift methods, etc (noorbakhsh and khamehchi, 2020).

Artificial lift methods are particularly used to increase production from wells when there is insufficient reservoir energy to lift the fluids to the surface or when the production rates have considerably fallen below the desired rate (noorbakhsh and khamehchi, 2020). Various methods for artificial lift" are at your disposal, including progressive cavity pumps, gaslifts, esp, sucker rod pumps, and plunger lifts, as highlighted by okorocha in 2020. Among these techniques, gaslift stands out as one of the most commonly employed artificial lift methods, especially where there is the availability of liftgas for injection.Elevating fluids from the well's bottomhole to the surface is achieved through the injection of high-pressure gas into the tubing or casing. The gas injected lightens the well fluids reducing the pressure at the bottomhole and increasing drawdown thereby facilitating the movement of fluids up to surface. Gaslift has been successfully applied to several fields and has increased the total production from oil fields increasing the profitability of the field (ghassemzadeh and pourafshary, 2015).

The engineer usually encountersthe difficulty of decision-making that would translate to the optimization of petroleum assets. In most cases, constraints are imposed; the best decisions are those that would achieve maximum oil recovery, lowest operational cost, and highest profits while honoring the constraints imposed on the system (díeza et al. 2005). Effective production optimization strategy hinges on well-structured modeling and simulations using commercially available simulation software. This software utilizing their 'model methodologies' employ controlled optimization techniques to compute the optimal decision variables based on a complete representation of the framework (Krishnamoorthy et al. 2017). Efficient optimization strategies have recorded increased production rates in the range of 1 to 4% (Suwartadi et al. 2018). Even slight enhancements in production rates have the potential to generate significant revenue for the asset owner, as indicated by Suwartadi in 2017.

The injection of gas normally increases the production of oil from wells. Nevertheless, an excessive amount of gas injection could amplify the decline in frictional pressure and diminish oil production. Increased frictional pressure drops occur as a resultof gas slippage which leads to accelerated gas movement compared to oil, resulting in a higher proportion of gas returning to the surface than oil. (krishnamoorthy et al. 2018). Each well individually has its optimum rate of gas injection that would yield maximum production of oil from that well. The optimization strategy in this respect must to be able to take into account back-pressure imposed by the interconnected wells within the network system in the field. Wells are interconnected within the operational area because they share certain surface facilities such as separators, manifolds, compressors, pumps, storage facilities, etc (krishnamoorthy et al. 2018).

Gaslift provides a highly versatile method for artificially lifting oil from wells with inadequate reservoir pressures when injection gas, sourced from either associated or non-associated gas reservoirs and supported by a surface compression plant, is available. Gaslift involves the process of injecting high-pressured gas into the producing fluid column from the surface through one or more subsurface valves set at certain predetermined depths. There are basically two types of gaslift approach employed in the industry; these are the continuous flow gaslift and the intermittent flow gaslift (halliburton, 2008).

In continuous flow gaslift, within the well's tubing,a continuous flow of gas is introduced aerating the liquid and lowering overall fluid column density, according to eikrem (2008), this diminishes the hydrostatic element of the flowing bottomhole pressure.

In intermittent flow gaslift, gas is injected at intervals into the pipe whenever a significant volume of liquid has moved into the wellbore. Comparatively, an elevatedquantity of injected gas is flowed beneath thecolumn of liquid thus, the column of liquid is propelled to the top. The introduction of gas is then halted until a fresh slug with the appropriate quantity reaccumulates. Liquids production is done in cycles.

A. *Gaslift Optimization Techniques*

Optimization is utilized in many areas of production engineering. An area that demands considerable attention is gaslift.In this, various issues emerge at both the field and well levels.Due to these issues and limitations, there is a necessity to optimize the gaslift system, aiming to either maximize total oil production or enhance profits derived from the field.In the optimization of gaslift, the focus may involve the analysis of individual wells or the analysis of multiple wells simultaneously.

B. *Well-Based Gaslift Optimization*

Production optimization can be done at the well-based level or at the field level. Investigations on the well mostly rely on physical well tests conducted on the site. Other test such as fluid composition test, PVT test etc. Provide information of the well condition and its productivity. Furthermore, step-rate gas injection test is used when gaslift provides accurate description of the fluctuation of the production fluid with changes in liftgas injection. Single well production optimization is concerned with strategies deployed to model the behavior of single-well with regards to well-defined parameters like completions, the fluid composition, pressure, temperature, both at the reservoir and at the wellhead. Nodal analysis techniques are particularly effective in optimization of production of single-well.

C. *Field-Based Gaslift Optimization*

The method of optimization shall be more complex than that of single well methods when considering the entire field, optimization of field gaslift, due to multiple wells interconnected in such a way as to create an integrated problem and more sophisticated optimization techniques need to be applied for this issue which arises from shared well allocations (Rashid, 2012).

The challenges evident in the optimization of multi-well fields include;

- Challenge of allocating gas to wells due to restricted gas availability
- The impact of retrograde pressure arising from the interconnection of wells in terms of injection and production.
- Constraints related to surface equipment and handling facilities.
- Production difficulty of some wells.
- Challenges that may emerge from well shut-ins and workovers.

Among these challenges, the allocation of liftgas to wells represents the most prominent optimization area that has garnered attention from researchers. The majority of parameters cannot be changed for optimization of the gas allocation on account of the initial design. Because of this, the controllable parameter is the gas injection rate. Optimizing the injection rate of gas to wells to maximize total field oil production and/or profits becomes the focus of allocation optimization in gaslift.Therefore, generally,optimizing the allocation of gas aims to determine the most effective distribution, resulting in the highest profit. Gas is allocated primarily to individual wells with

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greater production potential while adhering to field constraints related to the simultaneous interconnected production of other wells (Wang, 2013; Ghassemzadeh, 2005).

Liftgas is mainly allocated to wells according to its gaslift performance curve.The gaslift performance curve is a graphical representation illustrating the relationship between the production rate of oil and the gaslift rate of the well.If there are no limitations on the availability of gas, the optimum rate at which the gas is injected matchesthe gas allocation that results in the maximum rate of oil production from the field.In scenarios where gas availability is restricted and there are interconnections among wells, the optimization algorithm can only ascertain the gas injection rate for each well.

Dependent on the followingconditions

$G_i(x) \leq 0 \quad i = 1, 2, 3, \text{-------} m_1$ (1)

$G_i(x) \leq 0 \quad i = m_1, m_1 + 1, \text{------} m$ (2)

$X \in R^n$

D. Non-Linear Programming

In a non-linear optimization problem, either the objective function or one of the constraints is non-linear. These problems can manifest in various dimensions. Gaslift optimization methods involve solving intricate non-linear mathematical problems.

E. Sequential Quadratic Programming (SQP)

This a procedure used in solving nonlinear programming problems. SQP has been extensively used as a technique for optimization in different areas of engineering with recorded success (Díeza et al. 2005). Much research efforts have been dedicated to using SQP technique to solve large-scale problems especially in the petroleum industry. Nocedal &Wright (1999) has conducted an extensive explanation of the theory of SQP and its functionalities. SQP uses an iterative method for optimization method that's constrained. SQP performance relies on the standard of the gradient and the hessian information. In cases where there are discontinuities in either the function or the constraints in respect with the optimization variable, there can be no calculation of the gradient information. This results in poor SQP solvers in the region that is proximal to the discontinuities. The objective function often is aimed at optimizing the overall oil output or revenue. In gas allocation problems, the optimization variable borders on injection gas, how the injection gas would be optimally allocated to the wells in a way that the maximum total oil production for the field would be achieve. Usually, this involves constraints integrated into the system, including the separator capacity that is the volume of water the separator can handle, the storage capacity, the quantity of oil or gas that can be stored especially when the facility is offshore. These are specified in SQP solvers in commercial software like GAP (Díeza et al. 2005).

Davidson and beckner (2003) utilized Sequential Quadratic Programming Technique for well-rate allocation using a reservoir simulator. They discovered that SQP techniques performed optimally in gas allocation challenge in field optimization bases.

F. Statement of Problem

The Otuk field in the Niger Delta faces restricted access to gas resources. Gas competition emerges as a result of increasing gas prices and restrictions imposed by surface facilities. Therefore, it is essential to ensure appropriate gas allocation across the gaslift wells to maximize the overall oil production from the field. Additional constraints include surface facility limitations, such as compression capacity, pressure drop between wells and compressor station, and the handling capacity of fluids. Among these constraints, the objective is to maximize the total rate of field oil production while adhering to the constraints and ensuring optimal economic recovery from the field. This is achieved by integrating the gaslift and production systems of the field into a unified network. The model incorporates both a gaslift and production system, enabling the examination of the impacts arising from a single component on the entire system.

G. Objective Of the Study

The primary goal in Gaslift field optimization is to enhance the overall rate of oil production from the field by addressing complex non-linear mathematical problems arising from the integration of multiple constraints.

Additional objectives include;

- To conduct field network optimization of gaslifted wells by a specific allocation of different rate of gas injection to individual wells.
- To calculate and design the mathematical optimization model for SQP-based optimization technique in gap.
- To compare optimization gaslift optimization with and without field network solution solvers.

H. Scope Of the Research

This study centers on the application of non-linear mathematical modeling and optimization techniques to determine the maximum rate of oil production in a field comprising multiple wells. Wells sharing the same surface gathering network impose limitations on each other, such as pressure drop.Optimization is conducted with the consideration of limited gas availability, ensuring that the gas injected into individual wells is necessary to achieve the maximum field production rate. In this work, focus is made on adjusting the rate pertaining to the injection of gas and the pressure of the compressor to maximize total rate of field production of oil.The constraints involve surface facility limitations, including compressor capacity, separator capacity, and produced fluid storage capacity, collectively impacting the availability of injected gas and compressor pressure.This work will involve the utilization of softwares such as Prosper and GAP. Prosper is used for the well-based gaslift performance. Gap is used for modeling the constrained field network optimization with and without network solvers.

I. Significance Of the Study

This study provides effective methods for resolving challenges encountered in multi-well field optimizations through gaslift injection. The approach and methodology presented in this study will be valuable for operators seeking to optimize their assets and enhance longevity through the implementation of gas lift strategies.The approach and methodology presented in this study will be valuable for operators seeking to optimize their assets and enhance longevity through the implementation of gas lift strategies.

II. METHODOLOGY

A. Formulation of the Model for Gaslift Optimization

In formulating the model for gaslift and its optimization, two aspects are taken into consideration: well optimization and field gaslift optimization.

B. Single Well Gaslift

On the individual well level, the movement of fluid from the reservoir upwards is regulated by the relationship between Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) of wells. The intersection point of these two curves provides the production flow rate under the prevailing conditions of pressure, tubing diameter, and Watercut. etc.

The equation at the reservoir level is gotten from the IPR as for under-saturated reservoir

$$q_o = j(\bar{p} - p_{wf}) \quad (3)$$

$\bar{p} = Reservoir\ static\ pressure, psi p_{wf}$
$= Well\ flowing\ pressure, psi$

$$j = \frac{2\pi kh}{\mu\beta \ln(r_e - r_w) + S} \quad (4)$$

$S = skin$
$\beta = formation\ volume\ factor, stb/scf$
$\mu = Viscosity, cp$
r_e and r_w are reservoir and well radius, ft
For saturated reservoir

$$q_o = q_{max}\left[1 - 0.2\frac{p_{wf}}{\bar{p}} - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right] \quad (4)$$

The oil rate and the liquid rate is related by the water-cut given as

$$q_o = (1 - WC)q_l \quad (5)$$

Where WC is the water cut
$q_l = Liquid\ rate, bbl/d$
$q_o = oil\ rate, bbl/d$

The gas rate and the oil rate are related by the gas-oil-ratio (GOR)

$$q_g = GOR q_o \quad (6)$$

The liquid rate for undersaturated reservoir is formulated as:

$$q_l = \frac{q_b}{\bar{p} - p_b}(\bar{p} - p_{wf}) \qquad if\ p_{wf} \geq p_b \quad (7)$$

$$q_l = q_b + (q_{max} - q_b)\left[1 - 0.2\frac{p_{wf}}{\overline{p_b}} - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right] \quad if\ p_{wf} < p_b \quad (8)$$

$p_b = Bubble\ point\ pressure, psi$
$q_b = fluid\ flowrate\ at\ bubble\ point\ pressure, stb/d$

The liquid flowrate for the tubing is governed by hydrostatic and friction heads

The hh is given as;

$$\frac{dP}{dl} = \rho_l g \cos\theta - (\rho_l - \rho_g) E_g g \cos\theta \quad (9)$$

$\rho_l = liquid\ density$
$\rho_g = Gas\ density$

The liquid density is given as

$$\rho_l = \rho_o + (\rho_w - \rho_o)WC \quad (10)$$

The vertical tubing flow equation can be represented by the equation

$$\frac{dP}{dh} = \bar{\rho}\,\mathrm{Cos}\,\theta + \frac{fpv^2}{2d} + pv\frac{dv}{dh} \quad (11)$$

Where;
H = length of tubing
D=diameter
F=friction factor
V= velocity of fluid

$\theta = Inclination\ of\ the\ tubing$
$\bar{\rho}$
$= Average\ density\ of\ fluid\ inside\ the\ tubing\ which\ consist\ of\ liquids\ and\ gas$

$$\bar{\rho} = \gamma_g\rho_g + (1 - \gamma_g)\rho_l \quad (12)$$

The gas density relies on pressure p given by;

$$\rho_g = \gamma p \quad (13)$$

$$\gamma = \frac{28.97\gamma_g}{ZRT} \quad (14)$$

$$\gamma_g = \frac{u_{sg}}{C_o(u_{sg} + u_{sl}) + U_d} \quad (15)$$

C_o represents the effects of theuneven distribution of velocity and concentration profiles. Drift flux velocity(U_d)signifies the mean relative velocity between the two phases. Many correlations exist to solveC_o andU_d.

The sum of the superficial gas and liquid velocities yields the mixture velocity.

$$u_m = u_{sg} + u_{sl} \quad (16)$$

$$u_{sl} = \frac{q_l}{A} \quad (17)$$

$$u_{sg} = \frac{ZTP_{sc}}{T_{sc}P}\frac{q_g}{A} \quad (18)$$

$$A = \pi\frac{D^2}{4} \quad (19)$$

Note: d is the tubing internal diameter

The friction factor (f) is determined based on the flow regime. In laminar flow, where fluid flow is not complex, the friction factor is a simple function of the Reynolds number, given as:

$$f = \frac{16}{R_e} \quad (20)$$

However, in turbulent flow, where the flow becomes more complex, the friction factor can be determined by the Colebrook-White equation, expressed as;

$$\frac{1}{\sqrt{f}} = -4\log\left(\frac{\frac{e}{D}}{3.7} + \frac{1.255}{R_e\sqrt{f}}\right) \quad (21)$$

The tubing head pressure is calculated using the correlation provided below;

$$P_{th} = \frac{AR^B Q}{S^C} \quad (22)$$

Where;
R= Gas-liquid-ratio (GLR)
Q= Gross liquid rate
S=bean diameter

A, B, and C are constants dependent on the fluid properties and the type of choke employed.

C. Field Gaslift Optimization

In a Field-wide Gaslift optimization, the complexity increases due to the interdependence of multiple wells. Let's consider a field where gaslift is to be implemented for a cluster of *n* wells. The wells share common surface equipment such as compressors, separators, and flowlines, all interconnected. If the separator is so close ensuring a minimal pressure disparity between the separator and the manifold, the flowlines are horizontal,inthis case, we can assume that the separator is in proximity to the manifold. The overall production rate of the oil in the field Q_o from all the *n*wells is the sum of all the individual well's production q_{oi} of oil and it is a function of the liftgas injection rates for the individual well q_{gi}.

Mathematically;

$$Q_o = \sum_{i=1}^{N} q_{oi} = f(Q_g) = f(q_{g1}, q_{g2}, \dots q_{gN}) \quad (23)$$

$$Q_g = (q_{g1}, q_{g2}, \dots q_{gN}) \quad (24)$$

D. Optimization Problem in Gaslift

Oil production maximization (the objective function)

$$Q_o = max \sum_{i=1}^{N} q_{oi} \quad (25)$$

Subject to the constraints:

- *Gas availability constraint*

$$\sum_{i=1}^{N} q_{gi} \le Q_{gmax} \quad (26)$$

$$q_{gi} \ge 0, \quad for \ i = 1,2, \dots . . N \quad (27)$$

Equation 3.26 expresses the constraint that gas injection must be greater than zero for the wells

$$q_{gi} = q_{gi}^{f} + q_{gi}^{inj} \quad (28)$$

- *water production constraints*

$$\sum_{i=1}^{N} q_{wi} = Q_w \le Q_{wmax} \quad (29)$$

- *Liquid production constraints*

$$\sum_{i=1}^{N} q_{li} \le Q_{lmax} \quad (30)$$

$$Q_{lmax} = Q_w + Q_o \quad (31)$$

E. The Boundary Conditions

- The liquid flowrate should not exceed 50,000 stb, to be able to be handled by the separator. $Q_{lmax} \le 50000 \frac{stb}{d}$
- The production Watercut must not be greater than 80%. This is to avoid too much production of water that would lead to uneconomical operation.
- $(Water\ cut\ (WC) \le 0.8)$
- The separator pressure must not surpass 250 psig.
- The node pressure must not exceed the reservoir pressure.

F. Materials Utilized

The software utilized for this project are Prosper and GAP. The modeling tool Prosper was utilized to simulate well natural flow and individual well gaslift design and GAP was utilized in modeling the field gaslift optimization.

G. Data used for modelling

Table 1: Reservoir Data

Parameter	Value
Initial reservoir pressure (psi)	5160
Reservoir temperature (f)	234
Reservoir permeability (md)	50
Reservoir thickness (ft)	200
Drainage area (acres)	500
Wellbore radius (ft)	0.354
Average porosity	0.23
Reservoir pressure at time of gaslift (psi)	4000

Table 2: PVT Input Data

Parameter	Value
Pressure Of Bubble Point (Psi)	2470
Oil Gravity (Api)	40
Gas Gravity	0.7
Gas Gravity for Injection	0.8
Oil Formation Volume Factor	1.404
Oil Viscosity (Cp)	0.435
Gas-Oil-Ratio (Scf/Stb)	650
Water Salinity (Ppm)	140,000

Table 3: Well Data

Parameter	Well One	Well Two	Well Three	Well Four
Watercut	15%	15%	15%	15%
Watercut During Gaslift	80%	80%	80%	80%
WellheadFlowing Temp (^{O}f)	80	115	88	95
Skin (Well Test)	4	3	3.5	4
Tubing Size, Inch	3.958	3.875	3.958	3.875
Geothermal Gradient (Btu/Hr/Ft^2/^{O}f	10.9609	10.3516	11.1016	13.9141
Well Depth (Ft)	11,400	11,900	10,680	9890

Table 4: Well-Test Data

Parameter	Tubing Head Pressure (Psi)	Tubing Head Temp (F)	Watercut (%)	Liquid Rate (Bbls)	Gauge Depth (Ft)	Gauge Pressure Reservoir Pres (Psi)	Sure (Psi)	GOR (Scf/Stb)
Value	930	134	15	8300	11,100	4012	5260	650

The model simulation workflow sequence is in figure 3.1 below;

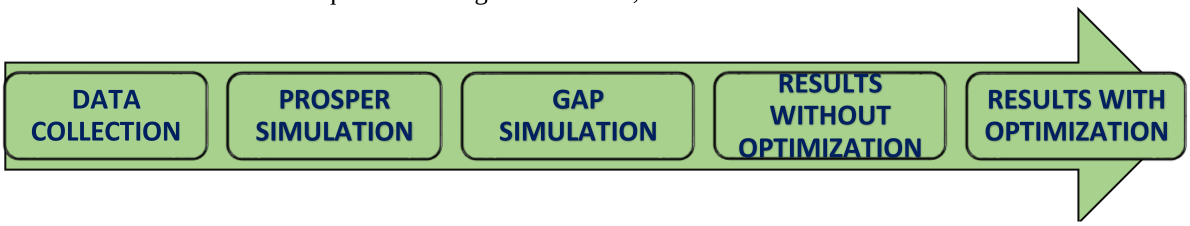

Fig. 1: Methodology Workflow

H. Utilizing Sequential Quadratic Programming within the Framework of GAP.

The wells' response to the well's production rate can be depicted through nodal analyses. For each node, the following relationship can be observed:

$$\sum_{i=1}^{n} \dot{m} = 0 \quad (32)$$

$$P_{ups} - P_{down} - \Delta P = 0 \quad (33)$$

$$\Delta P = f(\dot{m}, p, T, L, \dots \dots) \quad (34)$$

$$P_{sep} = Constant \quad (35)$$

The solution obtained by the solver for the natural response of the network is often not optimal in most cases.Higher production rates are achievable for the field network by modifying specific conditions.

The optimization problem formulated for this work is provided below:

$$Maximize\ Q_o$$
$$subject\ to\ Q_{inj} \leq Q_A \quad (36)$$

Where;

$$Q_o = \sum_{i=1}^{4} q_{oi} \quad (37)$$

$$Q_{inj} = \sum_{i=1}^{4} q_{inji} \quad (38)$$

$$q_{inji} \geq 0\ for\ n = 1,2,3,4$$

Where;

Q_o = total field production rate
Q_{oi} = oil production rate for well 1, bbls
Q_{inj} = total field gas injected
Q_{inji} = liftgas injection rate for well 1, mmscfd
Q_a = total gas available for injection in the field, mmscfd

GAP addresses the non-linear gaslift optimization problem by assigning the appropriate injection of gas to wells, ensuring the optimal production rate of oil for the entire field is achieved.

I. Analysis of the Field Case

Otuk field is an onshore field with four wells. Production from these wells has been ongoing, but a significant reduction in production rate was experienced. Given that gaslift systems were initially pre-fitted, each of these wells was opened for gaslift in the early 2000’s.These wells share common surface facilities such as compressors, the surface lines, the manifold, and separators. Due tothe distinctiveness of the present wells in its completion and its geometry, gaslifting each well, results to different maximum capabilities of injection and production wells. Every well possesses unique optimal production with injection potentials when treated as individual unit. This is accomplished in well optimization, with a specific focus on the optimization at the well level.

The well network imposes additional constraints on the gaslift system when optimization is necessary within the field.As the wells are interconnected within the field's network system, injection and production activities in one well influence the others.

All the wells produce through liftgas injection, with the gas produced being injected at designed rates.All the wells are equipped with pre-fitted gaslift mandrels and gaslift valves, each having an orifice installed at the injection point.

In the course of this study,Gaslift is performed using two distinct optimization approaches;

- There exists a constraint on the amount of field injection gas available and the wells are given equal specified amount of liftgas.In this approach, the GAP model is executed without applying optimization, and the total amount of oil produced is determined based on the process using the specified gas available for injection.
- When there is a constraint on the available field gas for injection, the optimization software examines the amount of gas allocated for injection into each well within the network to achieve optimum oil production, considering the separator conditions. In this model, the gap software is executed with optimization and tends to check the amount of gas required for injection by every well within the network which is further optimized to attain the best production for the field.

J. Developing The Well Model

Each well was individually modeled using prosper. The PVT data for each well were inputted and regressed to align with standard correlations. The data for each well includes average heat capacity, geothermal gradient, downhole completion and deviation surveys. Gaslift properties for the wells in well-by-well liftgas injection include liftgas properties, valves positions, liftgas rates and casing pressures.

In the prosper modelling, the gradient of the downhole equipment, the IPR and gaslift designs were modelled for individual well. Vertical Lift Performance (VLP) curves were generated for varyingGOR, watercuts, skin, liftgas injection rates and pressure, which are then transferred to GAP.

K. Establishing The Surface Network for The Well.

The modeling of the surface network system was conducted using the gap software. The network system in the surface comprises the gaslift system for production and the liftgas injection system. The gaslift production system consists of wells (4 wells), wellheads, flowlines, separators and manifolds. Two types of flowlines are implicated: the first involves the flowlines from wellheads to the manifolds, while the second pertains to the flowlines from the manifolds to the low-pressure single-stage separator. The liftgas injection system comprises of the separator, compressor, the flowlines, the manifolds, the wellheads and the wells.The integration of wells into the interconnected system (comprising production and injection systems) involved importing the previously generated IPR and VLP curves. The pipelines were meticulously defined, incorporating details such as lengths, inner diameters, roughness, and multiphase correlations for calculating pressure drops. Subsequently, the pipelines were aligned with selected standard pipeline correlations.

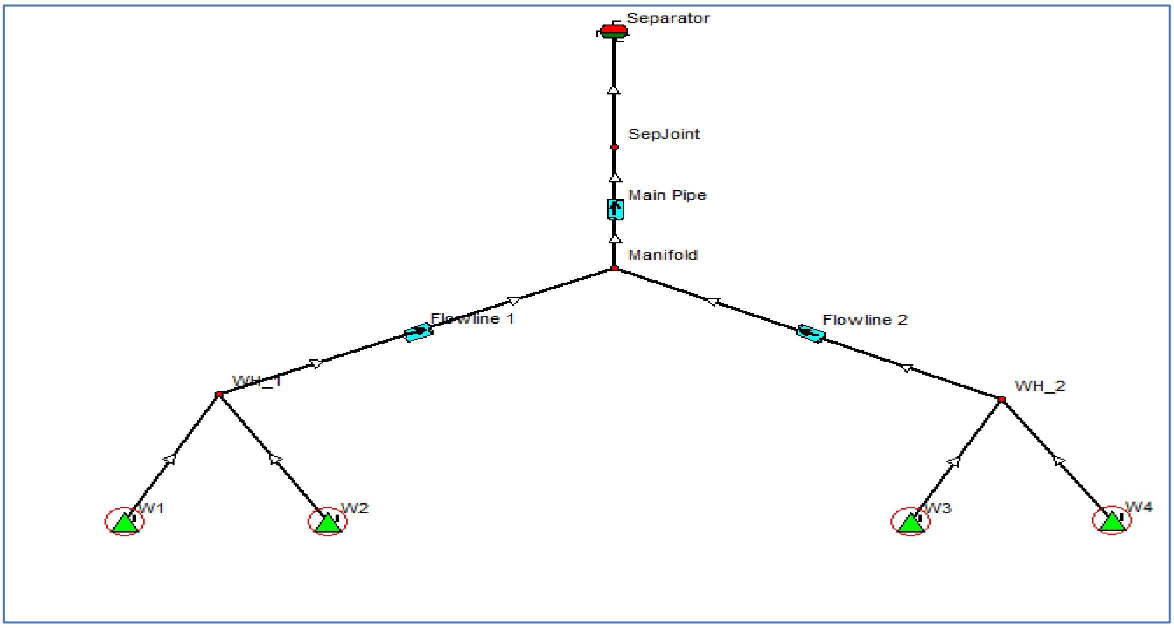

Fig. 2: The Gaslift System Production Network in Gap

Figure 2 illustrates the surface production network diagram in GAP. Notice that the arrows a pointing upwards to the separator. In the figure, wells W1 and W2 are connected to wellhead WH_1, whereas wells W3 and W4 are connected to wellheads WH_2. The two wellheads are then linked to the manifold through flowlines 1 and 2.

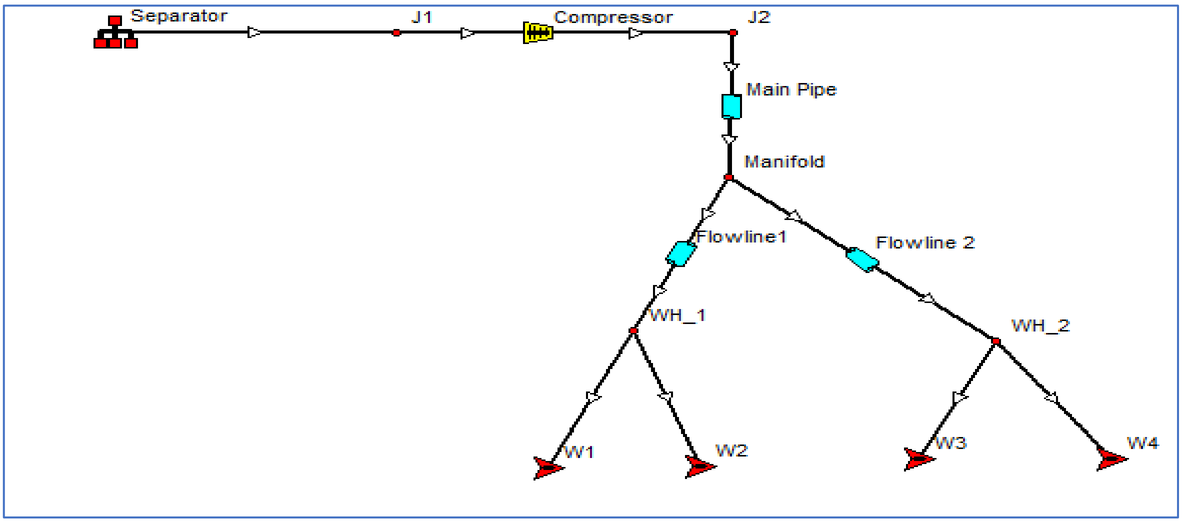

Fig. 3: The Gaslift System Injection Network in Gap

Figure 3 depicts the gas lift injection system, with the construction drawings starting from the pressure separators and extending to the wells.The compressor compresses the gas, which is then injected into the wells. The injection network checks if there is sufficient pressure to inject the required volume of gas at the casing head. The liftgas is compressed at the compressor and injected into the wells through the injection manifolds.

Figure 2 and **3** shows a field production network that was bunkered, and with it comes a higher constraint for the quantity of fluids produced. To maximize field production, it is required to redesign the production network so that each well has its own flowline through the wellhead to the manifold. It creates a lower constraint, thereby showing a high increase in oil production.

L. Redesign Of Gaslift Field Network For Production And Injection Network

The field gaslift field production system network and injection system network were redesigned such that each well was attached with a seprate flowline which transported the well fluids to the central manifold. This is unlike the earlier construction in which well one and well two shared one flowline (flowline 1) while well three and well four shared one flowline (flowline 2). The redesigned field production system network is referred to as ‘new’ while the old gaslift field production system network is referred to as ‘old’ for the purpose of comparison.

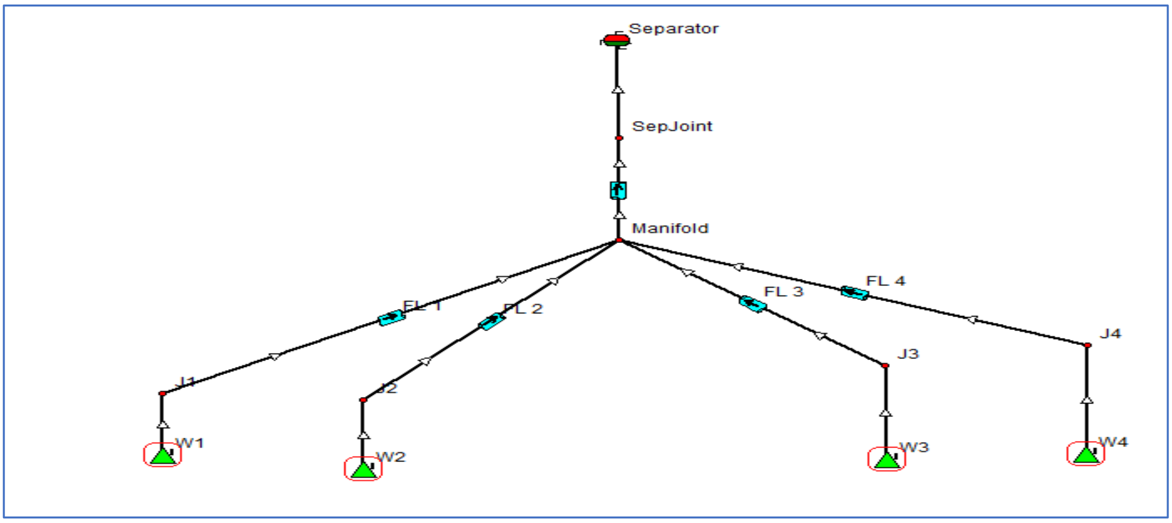

Fig. 4: Redesigned (New) Gaslift Field Production System Network

Figure 4 shows the redesigned gaslift field production system network. It is seen that the wells were associated with a flowline designated fl1, fl2, fl3, and fl4 for the four individual wells in the field. The optimization process was applied to resolve field network, and the results derived from this optimized field network solution were compared with the old field network architecture in terms of oil rates, liquid rates and gaslift injection rates.

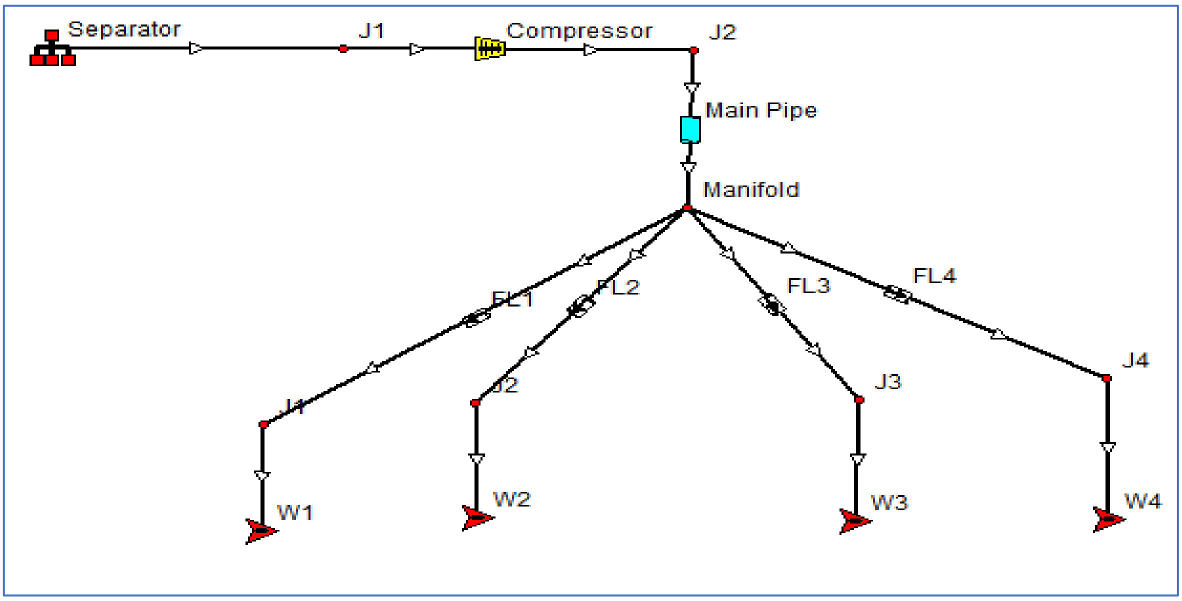

Fig. 5: Redesigned (new) gaslift field injection system network

Figure 5 shows the redesigned gaslift field injection system network. The system network was redesigned by associating each injection well to a single flowline. Wells W1, W2, W3 and W4 were associated with well was associated with a flowlines fl1, fl2, fl3, and fl4. The field network was resolved with optimization and the results obtained from the field network solution were compared with the old field network architecture in terms of liftgas injected to each well.

Using this system, the production of fluids was maximized by a cumulative of over 12%, however several considerations were utilized for its optimization.

These considerations are:

- Well placement
- Wellbore management using techniques such as testing, fluid levels monitoring, pressure monitoring, optimizing gaslift and managing flowrate.
- Pipeline design.
- Manifold and separator optimization.
- Flow assurance.
- Control system checks.

By utilizing the capabilities of gap and prosper software, the gaslift field optimization solved as a solution to non-linear field network problem using sequential quadratic programming can effectively analyze, optimize and monitor production of oil from multiple wells through flowlines to the manifold. These tools provide insights into the behavior of the gaslift system, facilitate various scenario comparisons and assist in making data driven decisions to maximize oil production efficiency.

M. Network Solution Process

The network was solved for both the production and injection systems, as well as the coupled network system. In solving the network, GAP utilizes the solve network without optimization and the solve network with optimization.

A. Solve network without the application of optimization

In solving the network without the application of optimization, the total field gas available was evenly distributed to the wells at fixed pressures. The resulting liquid and oil production rates were determined using GAP software. Various field gas availability scenarios were examined to assess the impact of field gas allocation on oil production in the field. The following gas allocations were employed as constraints: 10 mmscfd, 12 mmscfd, 15 mmscfd, and 20 mmscfd, with pressure constraints of 200 psig and 250 psig.

B. Solve network with the application of optimization

Solving network with the application optimization, GAP runs a non-linear optimization process on the wells to determine the optimal production rate of the field and the liftgas injection rates for the wells that will translate to this optimum field production rate. GAP follows this trend.

- GAP optimizes the production model to maximize the oil production while adhering to the specified constraints (i.e., gas allocation and separation pressure).
- GAP determines the liftgas injection rate for the first step, and this rate is passed as a fixed rate to the wells in the liftgas injection system. GAP then solves the injection system, and the pressures at the wells are determined. If the required pressure exceeds the calculated pressure in the production system, the calculation is halted. Otherwise, step two is initiated, and calculations for the production system are performed again. New casing pressures are determined, and new injection rates are estimated and passed on to the injection network. The loop continues until the required constraints are met.

III. RESULTS AND DISCUSSIONS

A. Well Gaslift Design Results in Prosper

The four wells were designed for Gaslift in Prosper to find the production capacity of the wells based on well parameters,The results for the Prosper simulation for Gaslift design of individual wells are given in table;

Table 5: Prosper Simulation for Individual Wells

S/N	Parameter	Well One	Well Two	Well Three	Well Four
1	Oil production, stb/d	2466.7	2429.1	2399.4	2455.6
2	Liftgasdesign rate, mmscfd	7.424	7.798	7.226	6.481
3	IPR pressure, psig	2979	2979	2979	2979
4	VLP pressure, psig	3341.98	3392.93	3444.45	3302.36
5	Oil rate, stb/d	2670.6	2670.6	2670.6	2670.6
6	Liquid rate, stb/d	8901.9	8901.9	8901.9	8901.9
7	GLR injected,mmscfd	1393.89	1463.58	1393.89	1054.44
8	Orifice depth, ft	5976.07	6051.91	5610.02	4910.82
9	Casing pressure, psig	1400	1362.86	1336.83	4910.82
10	Injected rate, mmscfd	4.86	4.364	5.122	4.11

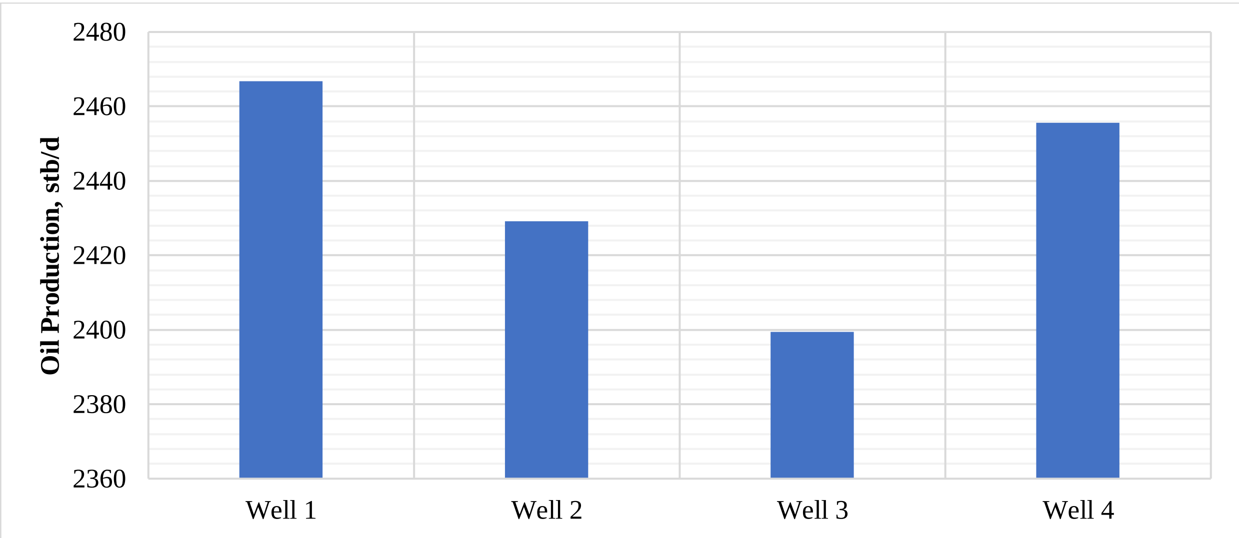

Fig. 6: Prosper Design Rates of Individual Wells Without Surface Linking

From **figure 6**, well 1 has quite the highest oil production with gaslift while well 3 has the least oil production with gaslift.

B. Results For Network Simulation of The Field in Gap

Table 6: Solver Run For 10 Mmscfd Gas Allocation

Parameter	Solved with optimization			Solved without optimization		
	Gas injected, mmscfd	**Oil rate, stb/d**	**Liquid rate, stb/d**	**Gas injected, mmscfd**	**Oil rate, stb/d**	**Liquid rate, stb/d**
Well 1	2.8	7907	9302	2.5	7903	9298
Well 2	3.7	7920	9318	2.5	7827	9209
Well 3	2.7	7746	9113	2.5	7719	9081
Well 4	0.9	7844	9228	2.5	7874	9263
Total	10	31417	36961	10	31323	36851

Table 7: Solver Run For 12 Mmscfd Gas Allocation

Parameter	Solved with optimization			Solved without optimization		
	Gas injected, mmscfd	**Oil rate, stb/d**	**Liquid rate, stb/d**	**Gas injected, mmscfd**	**Oil rate, stb/d**	**Liquid rate, stb/d**
Well 1	3.7	7953	9356	3	7919	9316
Well 2	3.7	7914	9310	3	7876	9266
Well 3	2.8	7739	9105	3	7730	9094
Well 4	1.8	7868	9257	3	7862	9249
Total	12	31474	37028	12	31387	36925

Table 8: Solver Run For 15 Mmscfd Gas Allocation

Parameter	Solved With Optimization			Solved Without Optimization		
	Gas Injected, Mmscfd	**Oil Rate, Stb /D**	**Liquid Rate, Stb/D**	**Gas Injected, Mmscf/D**	**Oil Rate, Stb /D**	**Liquid Rate, Stb /D**
Well 1	3.7	7952	9355	3.75	7952	9355
Well 2	3.7	7913	9309	3.75	7910	9306
Well 3	3.6	7739	9104	3.75	7729	9093
Well 4	2.2	7862	9249	3.75	7841	9225
Total	13.2	31465	37018	15	31432	36979

Table 9: Solver Run For 20 Mmscfd Gas Allocation

Parameter	Solved with optimization			Solved without optimization		
	Gas injected, mmscfd	**Oil rate, stb/d**	**Liquid rate, stb/d**	**Gas injected, mmscfd**	**Oil rate, stb/d**	**Liquid rate, stb/d**
Well 1	3.7	7952	9355	5	7897	9290
Well 2	3.7	7912	9309	5	7882	9272
Well 3	3.6	7739	9104	5	7681	9036
Well 4	2.4	7862	9249	5	7782	9156
Total	13.4	31465	37017	20	31242	36755

C. Liquid Rates Vs Injection Rates for Each Well (Solved with Optimization)

- *Well 1*

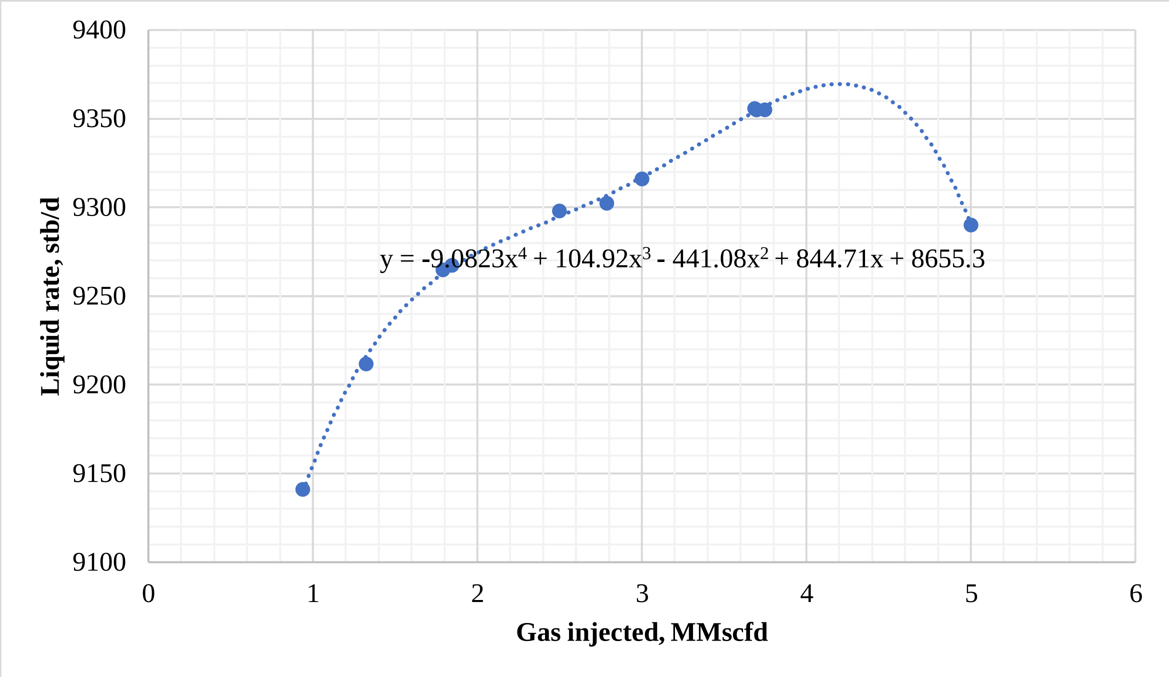

Fig. 7: Liquid Rate Vs Liftgas Injection Rate for Well 1

- *Well 2*

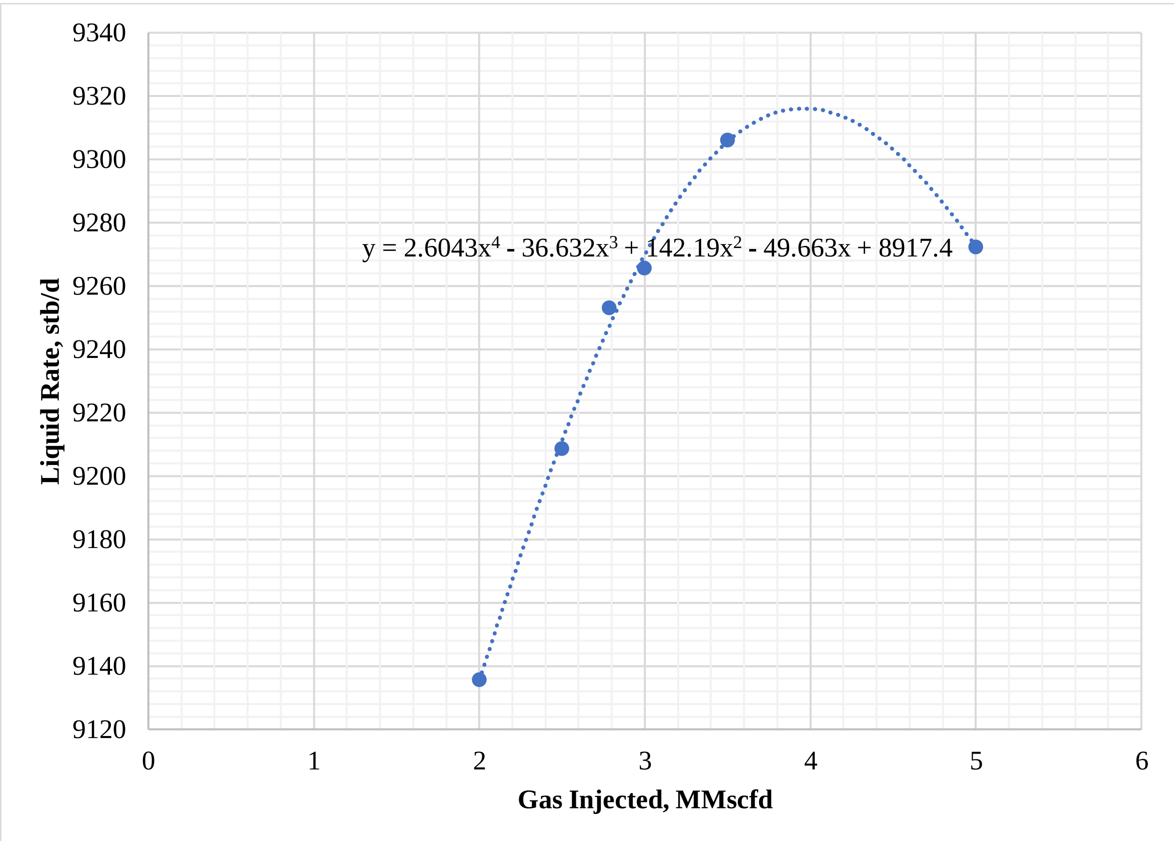

Fig. 8: Liquid Rate Vs Liftgas Injection Rate for Well 2

➢ *Well 3*

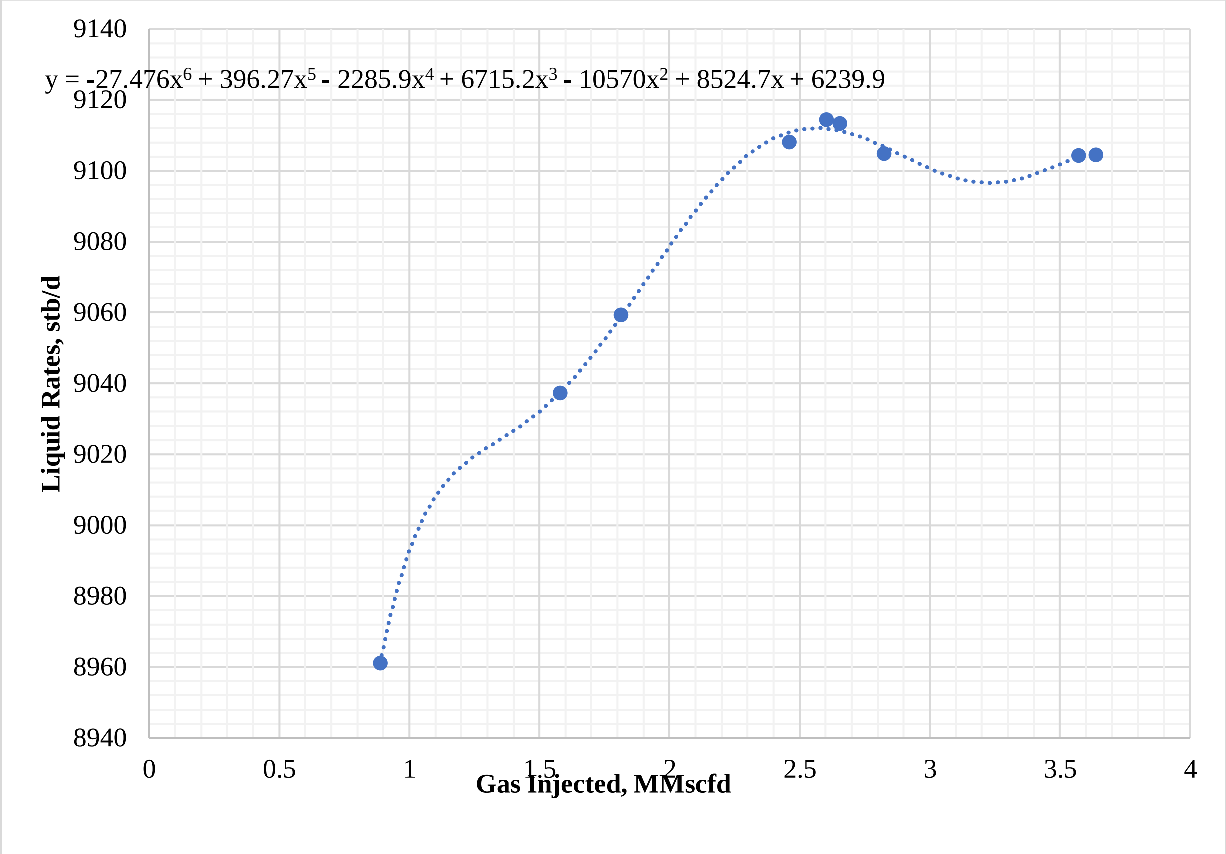

Figure 9: Liquid Rate Vs Liftgas Injection Rate for Well 3

➢ *Well 4*

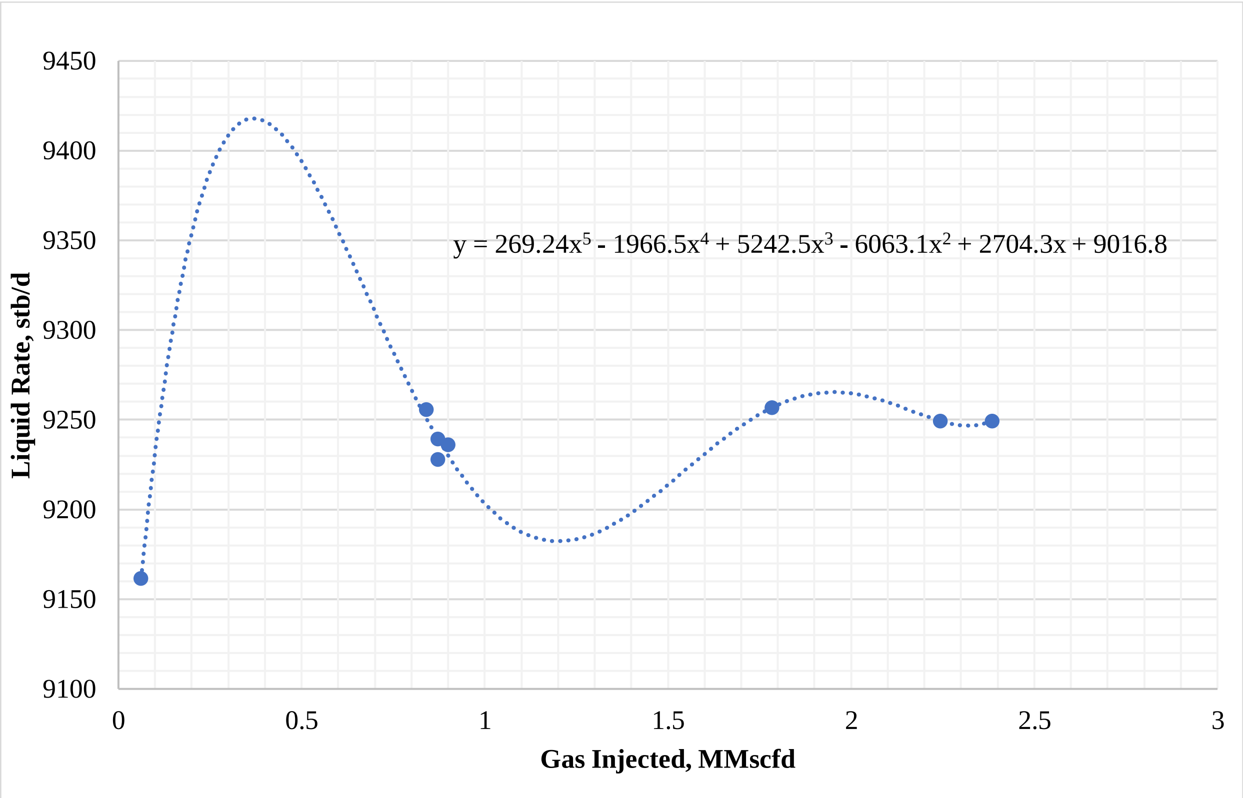

Fig. 10: Liquid Rate Vs Liftgas Injection Rate for Well 4

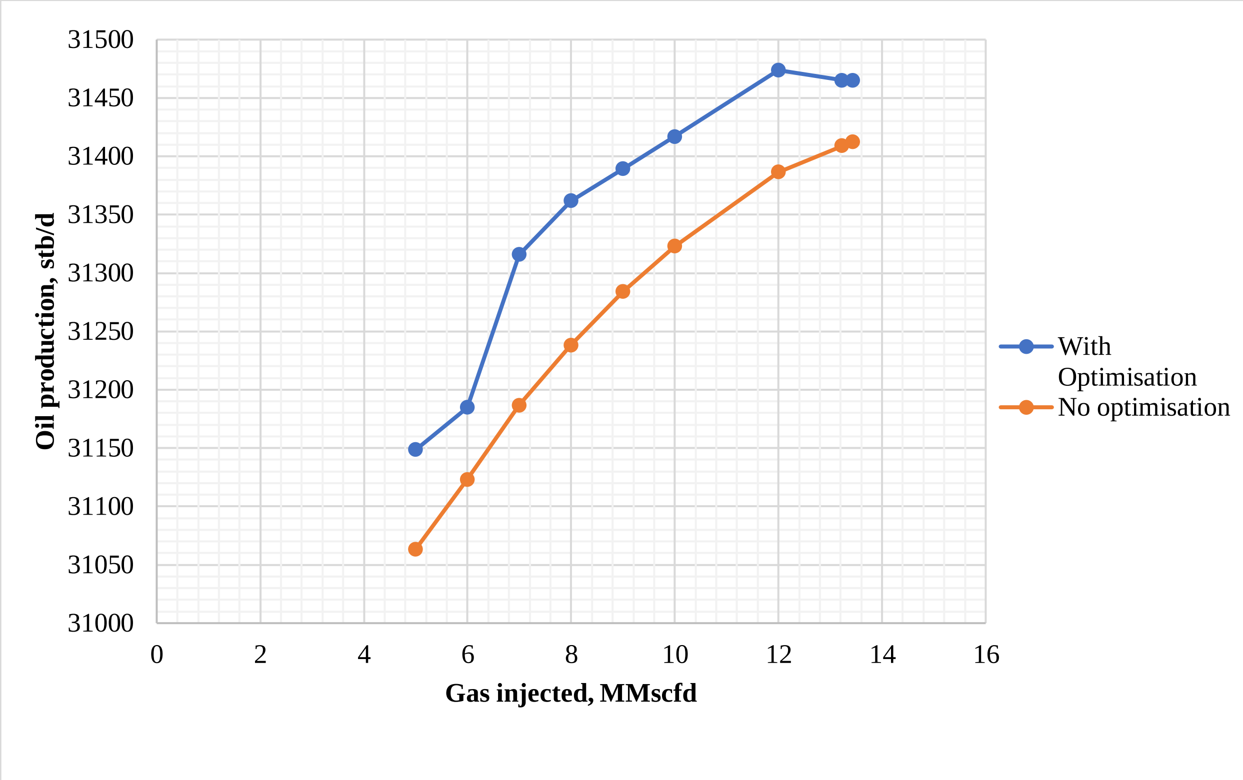

Fig. 11: Comparison Of Field Network Solved With And Without Optimization In Gap

From Figure 11, it can be observed that solving the field network system with optimization results in higher oil production compared to the scenario without optimization.This discrepancy arises because, without optimization, individual wells may have been subjected to gaslift injection rates either below or above their optimum values, thereby impacting the overall field production.Additionally, the impact of one well's activity, whether injection or production, influences the other wells as they are linked to common surface network facilities.The pressure drop in the surface lines generates back pressures in individual wells, and this must be taken into consideration when optimizing the field network.

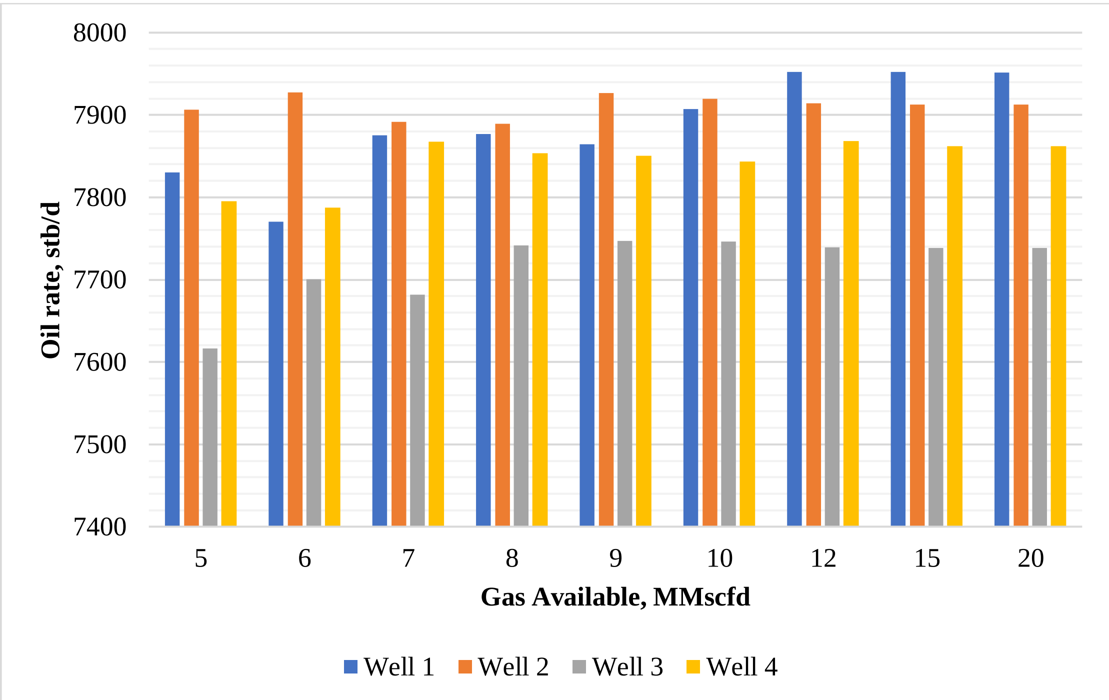

Fig. 12: Oil Rate Vs Liftgas Available (With Optimization)

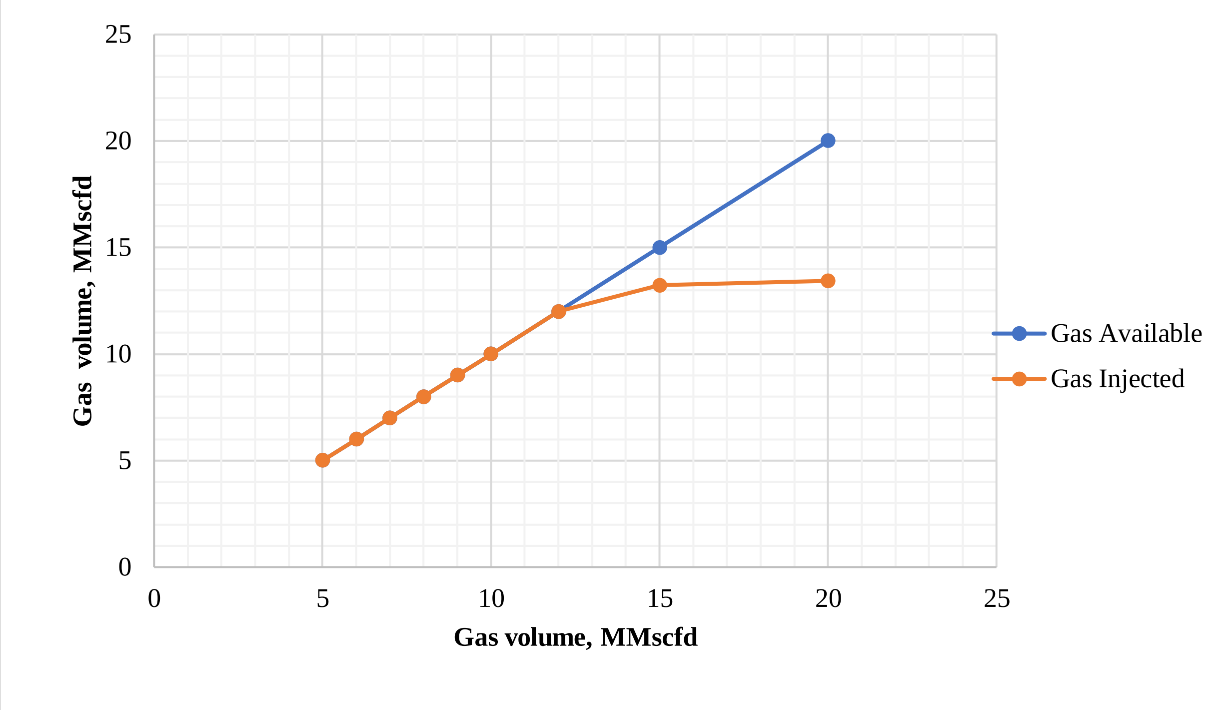

Fig. 13: Comparison Of Gas Available and Gas Utilized for Injection in The Network System Optimization in Gap.

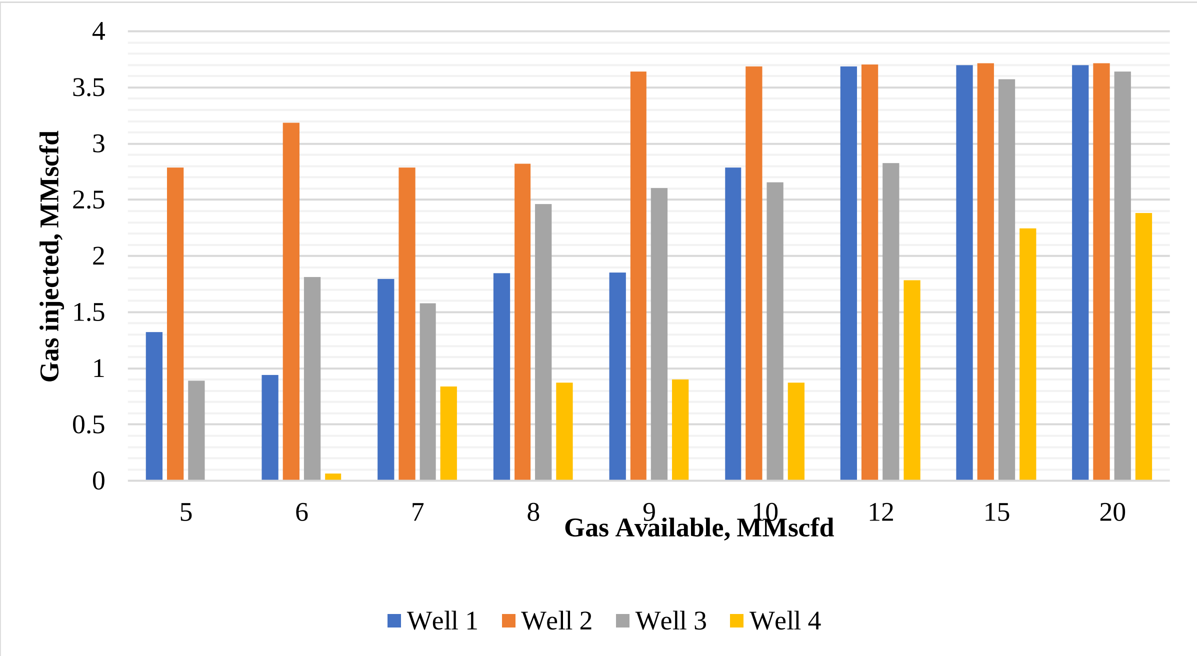

Fig. 14: Gas Injected Vs. Liftgas Available (With Optimization)

Table 10: Oil Produce and Injected Gas Ratio for Various Liftgas Availability

Liftgas Available, mmscfd	With Optimization (qo/qg, stb/mscf)	Without Optimization (qo/qg, stb/mscf)
5	6.2	6.2
6	5.2	5.2
7	4.5	4.5
8	3.9	3.9
9	3.5	3.5
10	3.1	3.1
12	2.6	2.6
15	2.4	2.1
20	2.3	1.6

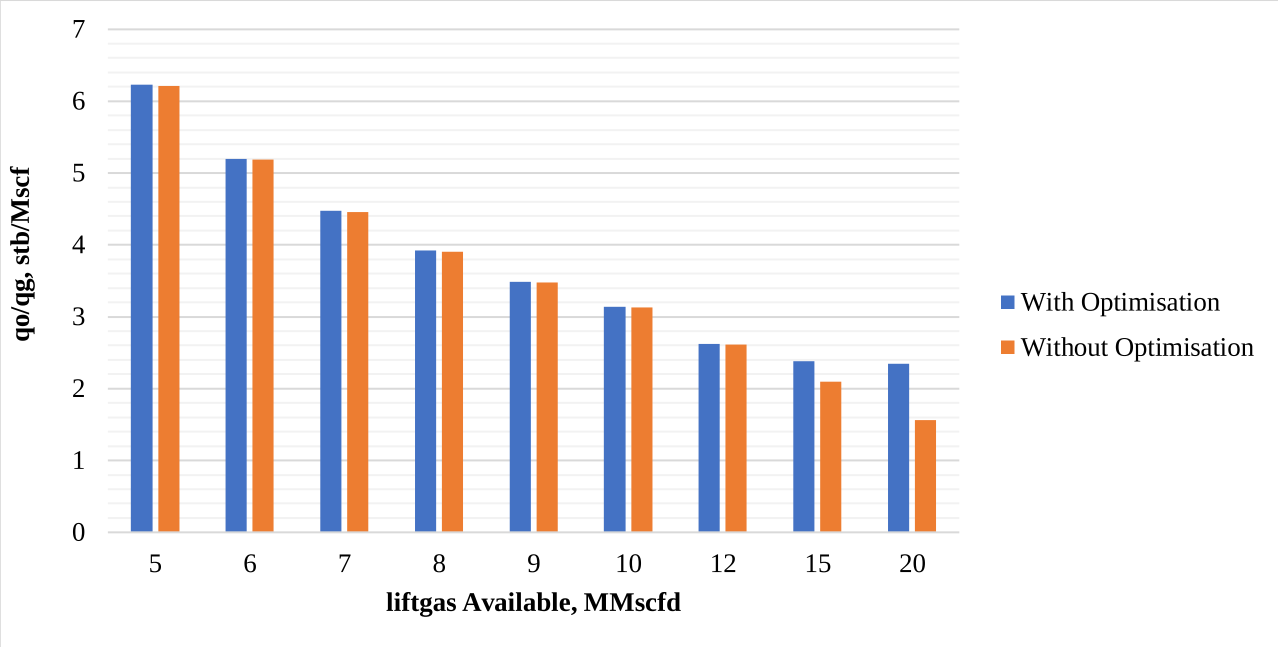

Fig. 15: Chart Showing Oil Produce and Injected Gas Ratio for Various Liftgas Availability

D. Results For Redesign of Gaslift Field Network Systems

The network architecture for the gaslifted field production and injection system networks were redesigned such that one well was associated with one flowline. As a result, there were a total of four flow lines for the four wells. The network solution was re-run with the new architecture and the result was compared with that of the old architecture already simulated.

E. Oil Rate Results

The oil production rate results for the network solution of the old and new architectures of the Gaslift field production system are presented and discussed in this section.

Table 11: Results Of Oil Rate for Old and New Field Production System Network Architecture.

Liftgas available	**10mmscfd**		**12mmscfd**		**15mmscfd**		**20mmscfd**	
Architecture	**Old**	**New**	**Old**	**New**	**Old**	**New**	**Old**	**New**
Well 1, stb/d	7907	8029	7953	8055	7952	8064	7952	8063
Well 2, stb/d	7920	8052	7914	8054	7913	8053	7912	8052
Well 3, stb/d	7746	7865	7739	7864	7739	7866	7739	7866
Well 4, stb/d	7844	7955	7868	7968	7862	7968	7862	7969
Total produced, stb/d	31417	31901	31474	31941	31465	31950	31465	31951

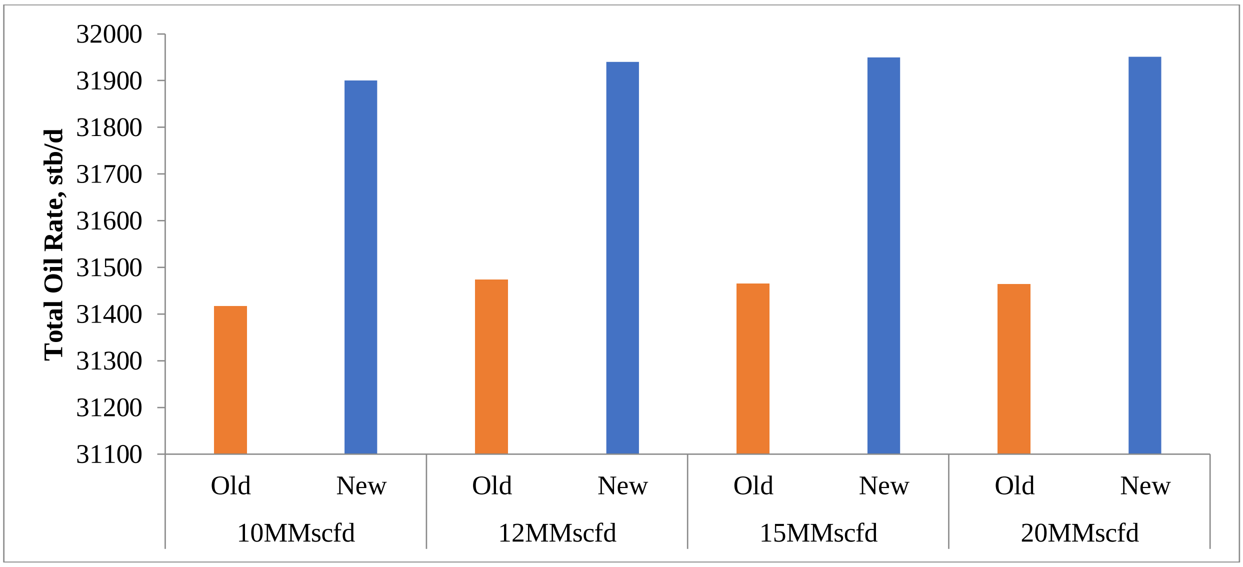

Fig. 16: Comparison Of Total Oil Rate of Old and New Architectures For The Gaslift Field Production System Network

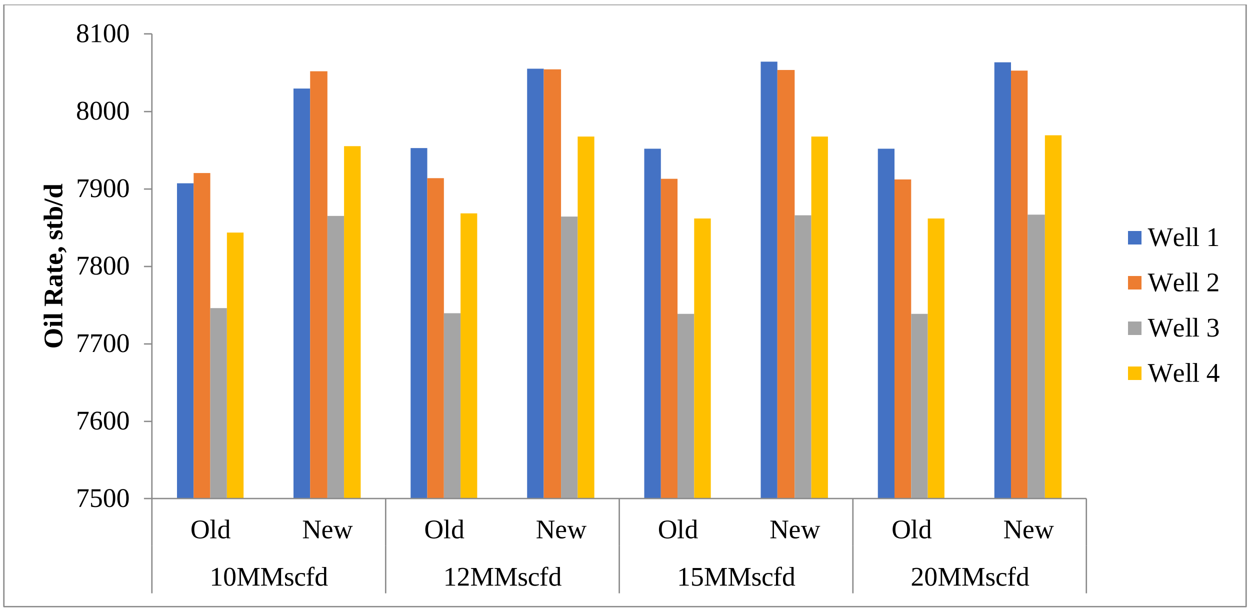

Fig. 17: Comparison of Individual Well Oil Rates Between Old and New Network Architectures

F. Liquid Rate Result

Table 12: Liquid Rates for Old and New Field Production System Network Architecture

Gas available	**10mmscfd**		**12mmscfd**		**15mmscfd**		**20mmscfd**	
Architecture	**Old**	**New**	**Old**	**New**	**Old**	**New**	**Old**	**New**
Well 1, stb/d	9302	9446	9356	9477	9355	9487	9355	9486
Well 2, stb/d	9318	9473	9310	9475	9309	9474	9309	9473
Well 3, stb/d	9113	9253	9105	9252	9104	9254	9104	9254
Well 4, stb/d	9228	9359	9257	9374	9249	9374	9249	9375
Total produced, stb/d	36961	37531	37028	37577	37018	37588	37017	37589

The gas available considered in table 4.7 include 10 mmscfd, 12 mmscfd, 15 mmscfd and 20 mmscfd. The network solver optimally allocated to each well the required optimum gas injection rate necessary for optimal oil production from the field based on the available gas.

Figure 18 shows the total liquid rate from the field due to different liftgas available

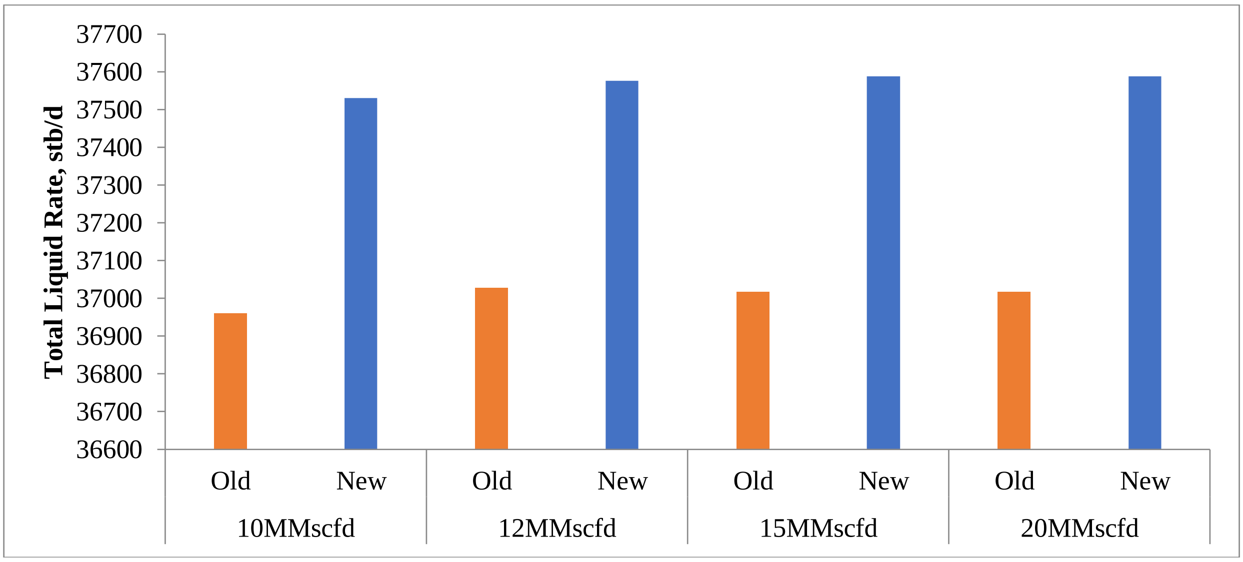

Fig. 18: Comparison Of Total Liquid Rate for Old and New Architectures for The Gaslift Field Production System Network

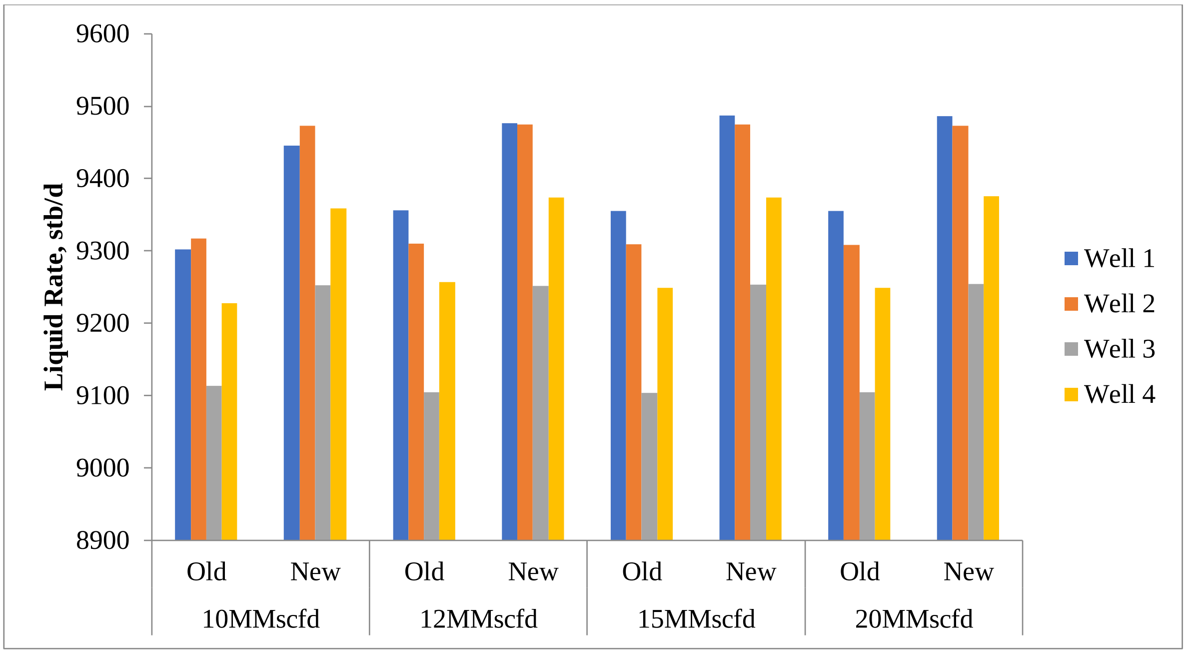

Fig. 19: Comparison Of Individual Well Liquid Rates Between Old and New Network Architectures

G. Gaslift Injection Rate Results

Table 13: Liftgas Injection Rates Results Calculated by Network Solver for The Old and New Network Architectures.

Liftgas available	10mmscfd		12mmscfd		15mmscfd		20mmscfd	
Architecture	**Old**	**New**	**Old**	**New**	**Old**	**New**	**Old**	**New**
Well 1, mmscfd	2.8	2.6	3.7	3.5	3.7	3.8	3.7	3.7
Well 2, mmscfd	3.7	3.7	3.7	3.8	3.7	3.8	3.7	3.8
Well 3, mmscfd	2.7	2.8	2.8	3.1	3.6	3.5	3.6	3.6
Well 4, mmscfd	0.9	0.9	1.8	1.7	2.2	1.7	2.4	1.8
Total gl injection rate, mmscfd	10.0	10.0	12.0	12.0	13.2	12.8	13.4	13.0

Figure 20 shows the graphical representation of the total liftgas injection rates as was given in table above:

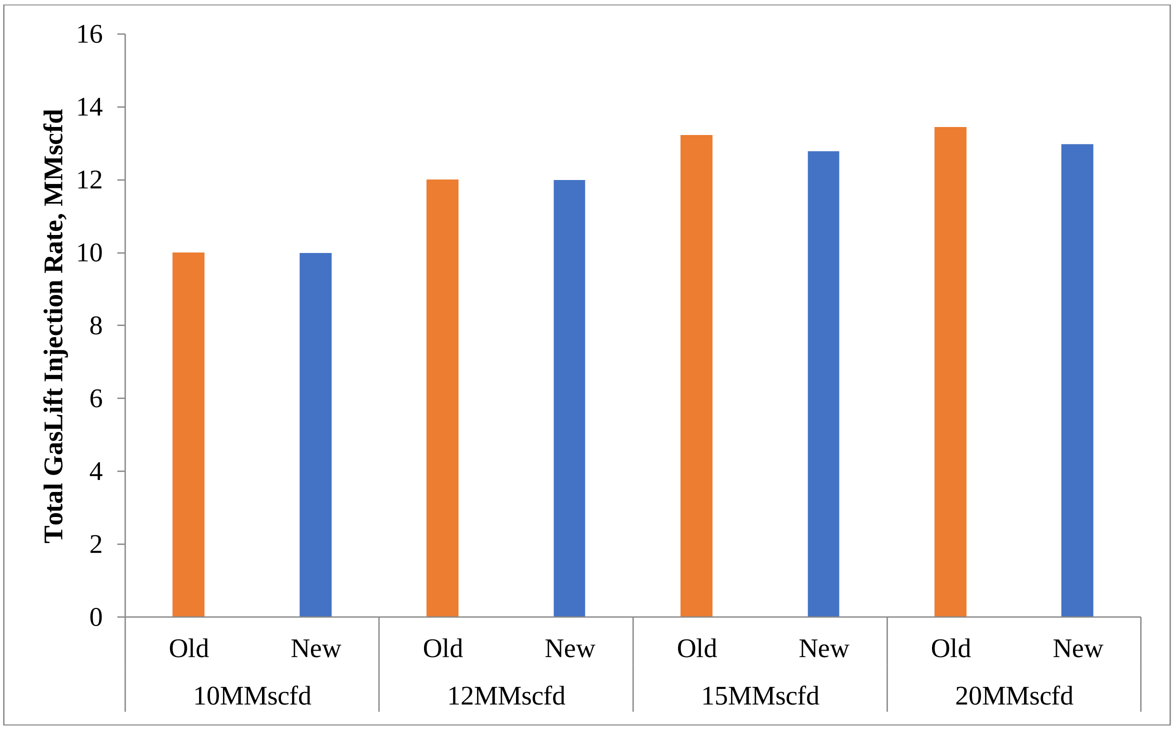

Fig. 20: Field Total Liftgas Injection Rates for The Old and New Architectures

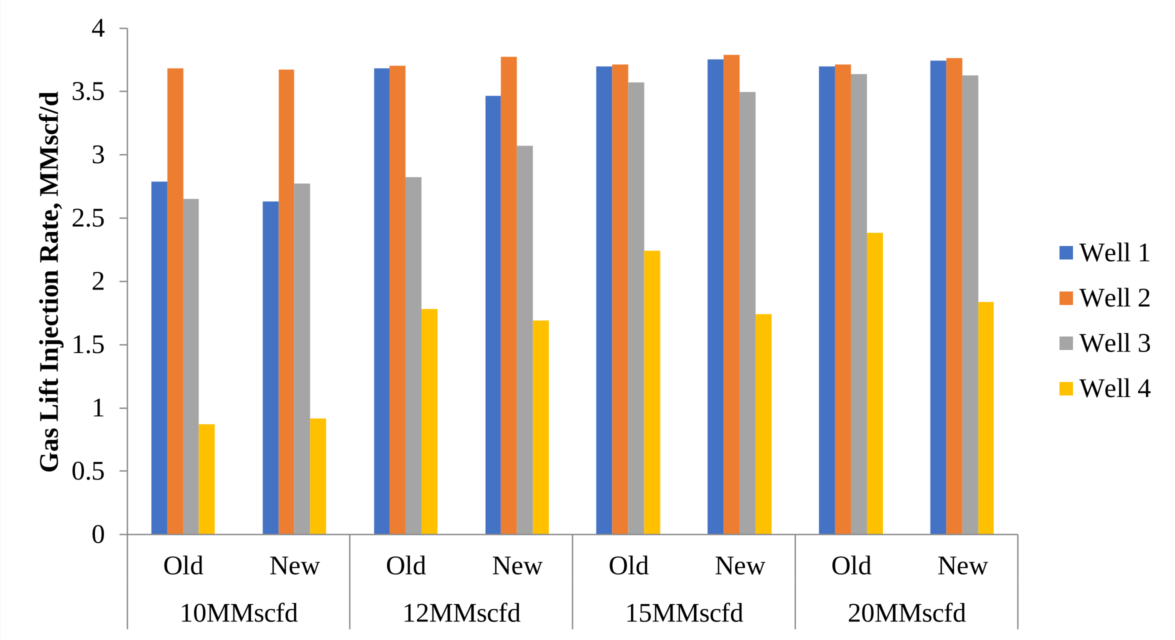

Fig. 21: Comparison Of Liftgas Injection Rate of Individual Wells for The Old and New

H. Field Project Economics

Table14: Rates For Field Network Solution with Gaslift Optimization

Gas available	Gas injected, mmscfd	Oil produced, stb/d	Gas produced, mmscfd	Water produced, stb/d	Liquid produced	Incremental oil rate, stb/d
Natural flow		5263	3.5	21053	26316	0
5	5.0	31149	20.3	5497	36645	25886
6	6.0	31185	20.3	5503	36688	25922
7	7.0	31316	20.4	5526	36842	26053
8	8.0	31362	20.4	5534	36896	26099
9	9.0	31389	20.4	5539	36928	26126
10	10.0	31417	20.4	5544	36961	26154
12	12.0	31474	20.5	5554	37028	2621
15	13.23	31465	20.5	5553	37018	26202
20	13.4	31464	20.5	5553	37017	26202

Similarly, **table 15** givesthe network of the field solution without gaslift optimization

Table 15: Rates For the Network of The Field Without Gaslift Optimization

Gas available	Gas injected, mmscfd	Oil produced, stb/d	Gas produced, mmscfd	Water produced, stb/d	Liquid produced, stb/d	Incremental rate
Natural flow		5263	3.45	21053	26316	0
5.00	5.00	31063	20.19	5482	36545	25800
6.00	6.00	31123	20.23	5492	36615	25860
7.00	7.00	31187	20.27	5504	36690	25924
8.00	8.00	31238	20.30	5513	36751	25975
9.00	9.00	31284	20.33	5521	36805	26021
10.00	10.00	31323	20.36	5528	36851	26060
12.00	12.00	31387	20.40	5539	36925	26123
15.00	15.00	31432	20.43	5547	36979	26169
20.00	20.00	31242	20.31	5513	36755	25978

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I. *Economic Parameters*

The economic parameters for evaluating the project economics of the Otuk field are provided below. The capital costs and operating costs of the Gaslift project are further analyzed.

The capital cost of the Otuk field is outlined in the table below. The total capital cost is estimated to be 4,350,000 USD, covering the initial installation of all equipment required to commence Gaslift operations in the field.

$$NPV = \sum_{i=0}^{n} \frac{R_i - CAPEX_i - OPEX_i}{(1+r)^n} \quad 3.38$$

Where;
$CAPEX_i$= total capital investment incurred in the project at year zero
$OPEX_i$= total operating expenses incurred from the project at year n
R_i=total revenues realized from the project a year, which can come from sales of oil
R= the discount rate
N= plant life
I=the current time

Table 16: Estimated Capital Costs for Otuk Gaslift Project

Item	Amount US$
Gaslift equipment (valves, mandrels)	150000
Compressor	2400000
Gaslift surface pipeline system	1000000
Miscellaneous	800000
Total capex	4350000

Note: there are three compressor units and the cost of one unit is USD 800,000

The operational necessities for the Gaslift operation are outlined in the provided table;

Table 17: Estimated Operating Costs for Otuk Gaslift Project

Item	Amount
Lift energy cost	0.056kw/bbl/day
Water treatment	Us$1500/day
Maintenance cost	Us$40000/month
Injection gas cost	Us$1.5/mscfd
Electricity cost	Us$0.08/kwh
Miscellaneous	Us$2000/day
Operating days	365 days

J. *Net Present Value of Otuk Field*

The NPV of Otuk Field is given below. NPV is evaluated for Gaslift operation for a 1-year period using $NPV = \sum_{i=0}^{n} \frac{R_i - CAPEX_i - OPEX_i}{(1+r)^n}$.

Where the OPEX is 1,758,076 USD and the CAPEX is 4,350,000 USD. Assuming the total revenue realized from the Gaslift project in a year is 11,596,332 USD, where the discount rate is 15% and the duration of the Gaslift project is 10 years.

Utilizing Microsoft Excel to compute the Net Present Value (NPV) for both scenarios is succinctly presented in the table below.

Table 18: Summary of the Production Results for Otuk Gaslift Project for Different Gas Availability

Gas available, mmscfd	Gas used without optimization, mmscfd	Gas used with optimization, mmscfd	Npv without optimizations, us$	Npv with optimization, us$	Incremental npv, us$	% incremental npv
0	0	0	76840968	76840968	0	0
5.00	5.00	5.00	444301922	445541406	1239484	0.28
6.00	6.00	6.00	445082041	445982522	900481	0.20
7.00	7.00	7.00	445920345	447801493	1881148	0.42
8.00	8.00	8.00	446584313	448382959	1798646	0.40
9.00	9.00	9.00	447163086	448693596	1530510	0.34
10.00	10.00	10.00	447642322	449008499	1366177	0.31
12.00	12.00	12.00	448392924	449663728	1270804	0.28
15.00	15.00	13.23	448796861	449429976	633115	0.14
20.00	20.00	13.44	445580931	449406078	3825147	0.86

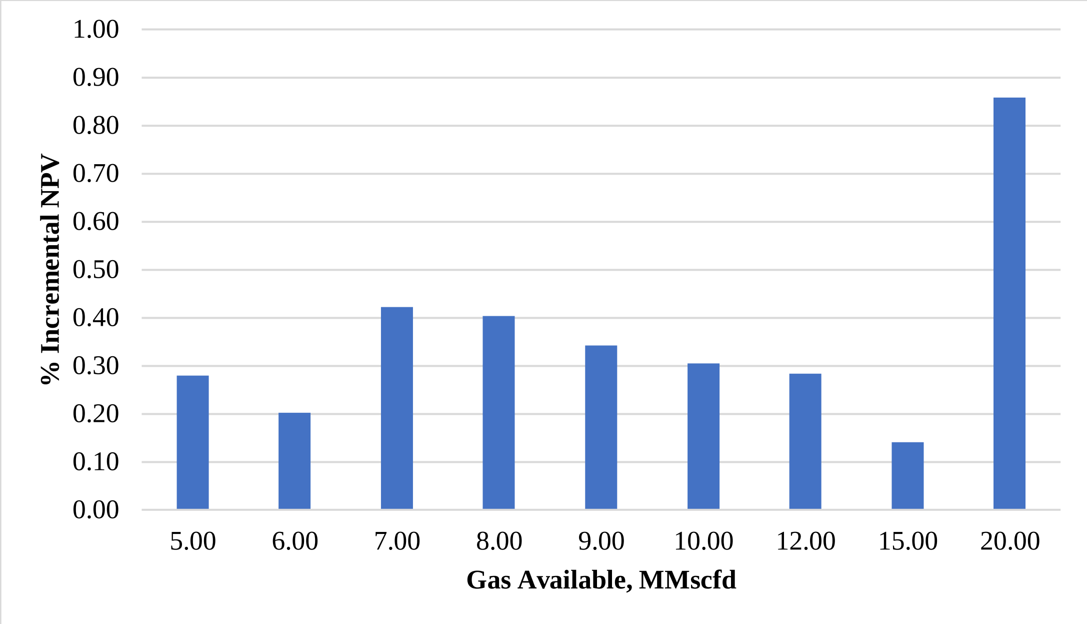

Fig. 23: Percentage Increase in NPV for Otuk Field Gas lift Using Optimization and Without Using Optimization.

IV. CONCLUSION AND RECOMMENDATION

A. Summary

Gaslift Optimization: A solution to non-linear field network problem using Sequential Quadratic Programming Technique, focuses on the application of the SQP technique using GAP and Prosper to optimize Gaslift operations. This research delves into the key findings and results obtained Through the application of SQP, demonstrating its effectiveness in improving gaslift efficiency.

B. Conclusions

Field Gaslift Optimization has been conducted in the Otuk field, which includes four wells. The network solver has been executed using GAP software to determine the liftgas injection rate needed to achieve the optimal liquid production rate in the field. GAP utilized a sequential quadratic programming technique to address the optimization problem, with oil production as the objective function and gas allocation constraints.

This work investigated field Gaslift systemas a resolution for a non-linear optimization problem. The subsequent findings are derived from this work:

- The field total oil produced without optimization for total liftgas available corresponding to 10 mmscfd, 12 mmscfd, 15 mmscfd and 20 mmscfd are for 31323 stb/d, 31387 stb/d, 31432 stb/d and 31242 stb/d respectively.
- The optimized field total oil produced for total liftgas available corresponding to 10 mmscfd, 12 mmscfd, 15 mmscfd and 20 mmscfd are for 31417 stb/d, 31474 stb/d, 31465 stb/d and 31465 stb/d respectively.
- 10mmscfd, 12 mmscfd, 15 mmscfd and 20 mmscfd of total liftgas available, the optimized field gaslift injection rates achieved are 10 mmscfd, 12 mmscfd, 13.23 mmscfd and 13.44 mmscfd respectively.
- When the network system was redesigned by assigning one well to one flowline, oil produced for total liftgas available corresponding to 10 mmscfd, 12 mmscfd, 15 mmscfd and 20 mmscfd were for 31901 stb/d, 31465 stb/d, 31950 stb/d and 31951 stb/d respectively. These represent differences of 484 stb/d (1.54%), 467 stb/d (1.48%), 485 stb/d (1.54%), and 486 stb/d (1.54%) total production increase.
- Maximum production of 31951 stb/d was achieved through the redesignednetwork system within the field for a 20mmscfd gas available with an injection rate of 13mmscfd. The optimal oil production of 31950stb/d was achieved for a 15mmscfd of gas available.
- Modeling field production system networks by associating each individual well with one flowline increases the recovered oil by up to 1.5% and reduce the total field liftgas injection rates by 2%.
- Field-wide gaslift optimization ensures an optimal production rate while simultaneously reducing operational costs through the calculation of liftgas injection rates that are deemed optimum.
- Optimizing production of crude oil from wells through four flowlines to the manifold offered a significant rise in production by 10%, with improved system efficiency of 20% and enhanced operational performance.

The results from the GAP simulation clearly demonstrate that solving the network with optimization leads to a more efficient utilization of liftgas, resulting in higher liquid and oil productions compared to the scenario without optimization.This outcome can be attributed to the interconnected nature of the wells, where each well shares common facilities such as separators, manifolds, and compressors at the top.

The simulation results indicate that the optimal gas allocation for the field is 12 mmscfd, leading to a liquid production of 37,028 stb/d and an oil production of 31,474 stb/d.Therefore, injecting additional gas for gaslift would lead to a decrease in oil production and an increase in operational costs.

When evaluating the optimal gas lift for each well, well one exhibits an optimum lift gas injection rate of 4.2 mmscfd, while wells two, three, and four have optimal rates of 3.45 mmscfd, 2.6 mmscfd, and 0.35 mmscfd, respectively.

Redesign of the Gaslift production system network architecture by associating one well to one flowline increases the oil and field liquid rate, thereby reduces the total liftgas injection rates for the field. This is because using one flowline per well optimizes the pressure change in the lines thus reducing back pressure effects associated with shared surface facilities which then increases the total production of oil. Moreover, it was observed that for the gas, its injection rates were optimized and for the oil, its production rates were optimized by redesigning the production system network of the field.

The economic assessment of the Otuk field project indicates that a higher Net Present Value (NPV) is achieved when the Gaslift system is implemented in the field gathering network with genuine optimization compared to a solution without optimization. It was evident from figure 23The highest increase in NPV for the Otuk field, whether through optimization or in the absence of optimization, is observed when the gas availability is 20 mmscfd.The rationale behind this observation is that, at a gas availability of 20 mmscfd, the field attains its optimum injection gas rate of 13.44 mmscfd when solved with Gaslift Optimization. The remaining gas is not injected, saving the cost of gas or compression. However, in the absence of optimization, the entire 20 mmscfd of gas is introduced into the wells, leading to a reduced marginal rate of production compared to gas injection.

After the optimization of the oil production from the well through a single flowline to the manifold, the outcomes of the optimization process include;

- Increased oil production
- Improved flow assurance
- Enhanced system efficiency
- The optimal gas allocation for the gaslift
- Reliable production plan

C. Recommendation

Gaslift Optimization should be conducted on a field-wide basis to ensure the comprehensive optimization of the network within the field. The approach taken in this research is beneficial for achieving complete system network optimization, addressing the non-linear mathematical challenges encountered in field Gaslift optimization.

This work considered gas allocation as a single constraint.Further research can explore additional constraints like Watercut, Separator Capacity, Gas-Oil Ratio (GOR), Compressor Capacity, etc. Additionally, future investigations can shift the primary focus to Net Present Value (NPV) rather than oil/liquid production as the main objective function.

Production through bunkered flowlines should not be done and as such individual wells should have a single pipeline delivering to the manifold so as to have a rise in production and maximize profit.

D. Contribution To Knowledge

The following contribution to knowledge were made in the study;

- The research work utilizes SQP technique into Gaslift field optimization. When identifying the optimum solution, it involves using constrained non-linear problems in optimization process, while Gaslift Optimization has been studied before, SQP offers an improved convergence and accuracy compared to traditional optimization technique.
- The research further analyzes oil production dynamics within a Gaslift field optimization system, specifically analyzing the current production of crude through two distinct flowline configurations: bunked and debunked flowlines.

E. Future Studies

- **Advanced optimization algorithms**: Investigate the potential of the other optimization algorithms, such as genetic algorithms or particle swarm optimization, to compare their performance with SQP in the context of Gaslift Optimization.
- **Real-time implementation**: Explore the feasibility of implementing the optimized Gaslift strategy in real-time field operations. Consider the challenges and benefits of integrating the SQP technique into existing field management systems.
- **Case studies**: Extend the research by applying SQP technique to different field networks with varying complexities.

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