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# The effect of the formation damage on the productivity in Bahi oil field

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***Abstract***
The skin effect is a crucial factor that can significantly impact the productivity of oil and gas wells. The skin effect refers to the additional pressure drop caused by the formation damage or alteration near the wellbore, which can be either positive (increased pressure drop) or negative (decreased pressure drop).
By addressing the skin effect, operators can improve the overall efficiency and economics of their oil and gas operations, maximize hydrocarbon recovery and enhance the profitability of their assets. Continuous research and technological advancements in well construction, completion, and stimulation techniques are crucial for the industry to effectively manage the skin effect and optimize well productivity.
In this research, damage to the study area was studied a well A1 has the highest well flowing pressure (Pwf) of 2100 psi and the highest maximum flow rate (Q max) of 9800 bbl/day without skin effects. Well A2 has the second-highest Pwf of 2450.409 psi, but the lowest Q max of 8050 bbl/day without skin effects. Well A3 has the Pwf 1620 psi and Q Max of 3600, but a significantly lower Q max of 3600 bbl./day without skin effects.

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## 1- Introduction:

Formation damage is defined as the impairment to reservoir (reduced production) caused by wellbore fluids used during drilling/completion and workover operations. It is a zone of reduced permeability within the vicinity of the wellbore (skin) as a result of foreign-fluid invasion into the reservoir rock.[1]

Typically, any unintended impedance to the flow of fluids into or out of a wellbore is referred to as formation damage. This broad definition includes flow restrictions caused by a reduction in permeability in the near-wellbore region, changes in relative permeability to the hydrocarbon phase, and unintended flow restrictions in the completion itself. Flow restrictions in the tubing or those imposed by the well partially penetrating a reservoir or other aspects of the completion geometry are not included in this definition because, although they may impede flow, they either have been put in place by design to serve a specific purpose or do not show up in typical measures of formation damage such as skin.[1]

Formation damage can be caused by factor such as fine particle transportation in porous media, Fines enter the formation as suspensions during drilling and completion operations.

They can also be generated due to fluid-fluid and fluid-rock interactions. When they enter the formation, they get entrapped in the pore openings, fill and plug the pore spaces of the formation.

Sedimentary rocks also contain loosely attached fines. When injection fluids are incompatible with formation fluids, these fines can be released from the rock surface, migrate and plug at pore constrictions. The end result is severe permeability reduction.

**2 -Problem Statement:**

The problem statement for the study on the effect of formation damage on productivity in the Bahi oil field could be framed as follows:

"Formation damage in the Bahi oil field is suspected to have a significant impact on well productivity. However, the extent and nature of formation damage, as well as its specific influence on productivity, remain poorly understood. Therefore, there is a need to comprehensively investigate the effect of formation damage on productivity in order to develop effective mitigation strategies and optimize hydrocarbon recovery."[1]

**3 - Study Importance:**

Investigating the effect of formation damage on productivity in the Bahi oil field is important for several reasons:

1. Production Optimization: Understanding the impact of formation damage is crucial for optimizing production in the Bahi oil field. By identifying and mitigating formation damage issues, operators can potentially increase productivity and enhance overall hydrocarbon recovery.
2. Economic Considerations: Formation damage can lead to reduced well productivity and increased operational costs. By studying the effect of formation damage, operators can make informed decisions regarding well stimulation, reservoir management strategies, and the allocation of resources to improve economic returns.
3. Field Development Planning: The knowledge gained from studying formation damage can be used to design more effective well completion and stimulation strategies in future field development plans. This can help optimize reservoir performance and maximize production potential.[1]

**4 - Objectives of the Study:**

The study on the effect of formation damage on productivity in the Bahi oil field may have the following objectives:

1. Characterize Formation Damage: Assess and characterize the types, mechanisms, and extent of formation damage occurring in the Bahi oil field. This may involve analyzing core samples, conducting laboratory experiments, and studying well performance data.
2. Quantify Productivity Impact: Quantify the impact of formation damage on well productivity by analyzing production data, pressure data, and well performance indicators. This could involve comparing the productivity of damaged and undamaged wells to identify the specific effects of formation damage.
3. Identify Contributing Factors: Investigate the factors contributing to formation damage in the Bahi oil field, such as drilling fluids, completion techniques, reservoir properties, or operational practices. Understanding these factors is crucial for developing effective mitigation strategies.
4. Mitigation Strategies: Propose and evaluate potential mitigation strategies to minimize or prevent formation damage. This may involve identifying suitable drilling fluids, stimulation techniques, or reservoir management practices that can mitigate the negative effects of formation damage on productivity.[3]

**5 - Scope of the Study:**

The scope of the study on the effect of formation damage on productivity in the Bahi oil field may include:

1. Data Collection: Gathering relevant data such as well logs, core samples, production data, and operational records to analyze and understand the formation damage and its impact on productivity.
2. Laboratory Experiments: Conducting laboratory experiments to simulate formation damage mechanisms, evaluate the effectiveness of different mitigation strategies, and validate the findings.
3. Field Case Studies: Analyzing well performance data and conducting field case studies to assess the impact of formation damage on productivity in different areas of the Bahi oil field.
4. Recommendations: Providing recommendations for best practices, mitigation techniques, and operational guidelines to optimize well productivity and mitigate the effects of formation damage in the Bahi oil field.[3]

**6. Basic Causes of Damage: -**

Contact with a foreign fluid is the basic cause of formation damage. This foreign fluid may be a drilling mud, a clean completion or workover fluid, stimulation or well-treating fluid, or even the reservoir fluid itself if the original characteristics are altered.

Most oilfield fluids consist of two phases-liquid and solids. Either can cause significant formation damage through one of several possible mechanisms.

**6.1 Potential Formation Damage Problems During Various Well Operations.**

The problems of potential damage to the formation during various well operations are divided into:

**1** Drilling
2 Casing and Cementing
3 Completion
4 Well Stimulation
5 Production
6 Secondary Recovery Operations – Injection Wells

**6.2 Classification of Damage Mechanisms: -**

The numerous mechanisms that result in formation damage may be generally classified as to the manner by which they decrease production:

- \- Reduced absolute permeability of formation results from plugging of pore channels by induced or inherent particles.
- \- Reduced relative permeability to oil results from an increase in water saturation or oil-wetting of the rock.

**6.3 Skin and Skin Factor**

- Skin: A dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates some damage or influences that are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.
- Skin factor: A numerical value used to analytically model the difference from the pressure drop predicted by Darcy's law due to skin. Typical values for the skin factor range from -6 for an infinite-conductivity massive hydraulic fracture to more than 100 for a poorly executed gravel pack. This value is highly dependent on the value of kh. For example, a 20-psi [138-kPa] total pressure drop

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related to skin effect could produce almost any skin factor, depending on the value of kh. For any given pressure drop from skin effect, the skin factor increases proportionally as kh increases.

- No damage K=Kd and S =0
- Damaged wells Kd<K and S >0
- Stimulated wells K d >K and S <0

Where:-

K = absolute permeability (md).

Kd = damage permeability (md).

The mathematical relationship between skin factor and permeability is :

$$S = \ln\left(\frac{re}{rw}\right) + \frac{q\mu}{2\pi kh}\Delta P - 3.23$$

Where:

re : Radius of investigation

rw : Well radius

q : Flow rate

$\mu$ : Viscosity

K : Permeability

h : thickness of formation

ΔP : pressure difference

The value of the total skin measured from well test has many sources other than formation damage .the total skin factor is the sum of various skin components.

S total = S damage +S geometry+ S completion + S production

**7. Hydraulic Fracturing**

Hydraulic fracturing is the process of pumping fluid into a wellbore at an injection rate that is too high for the formation to accept without breaking. During injection the resistance to flow in the formation increases, the pressure in the wellbore increases to a value called the break-down pressure, that is the sum of the in-situ compressive stress and the strength of the formation. Once the formation “breaks down,” a fracture is formed, and the injected fluid flows through it. From a limited group of active perforations, ideally a single, vertical fracture is created that propagates in two "wings" being 180° apart and identical in shape and size. In naturally fractured or cleated formations, it is possible that multiple fractures are created and/or the two wings evolve in a tree-like pattern with increasing number of branches away from the injection point.

Fluid not containing any solid (called the “pad”) is injected first, until the fracture is wide enough to accept a propping agent. The purpose of the propping agent is to keep apart the fracture surfaces once the pumping operation ceases, the pressure in the fracture decreases below the compressive in-situ stress trying to close the fracture. In deep reservoirs, man-made ceramic beads are used to hold open or “prop” the fracture. In shallow reservoirs, sand is normally used as the propping agent.[1]

**7. 1 The Objective from The Hydraulic Fracturing**

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well. The productivity index defines the rate at which oil or gas can be produced at a given pressure differential between the reservoir and the wellbore, while the injectivity index refers to the rate at which fluid can be injected into a well at a given pressure differential.

There are many applications for hydraulic fracturing. Hydraulic fracturing can:

- Increase the flow rate of oil and/or gas from low-permeability reservoirs
- Increase the flow rate of oil and/or gas from wells that have been damaged
- Connect the natural fractures and/or cleats in a formation to the wellbore
- Decrease the pressure drop around the well to minimize sand production
- Enhance gravel-packing sand placement
- Decrease the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition
- Increase the area of drainage or the amount of formation in contact with the wellbore
- Connect the full vertical extent of a reservoir to a slanted or horizontal well.

There could be other uses, but most of the treatments are pumped for these reasons.
A low-permeability reservoir is one that has a high resistance to fluid flow. In many formations, chemical and/or physical processes alter the reservoir rock over geologic time. Sometimes, these diagenetic processes restrict the openings in the rock and reduce the ability of fluids to flow through the rock. Low-permeability rocks are normally excellent candidates for stimulation by hydraulic fracturing.

Regardless of the permeability, a reservoir rock can be damaged when a well is drilled through the reservoir and when casing is set and cemented in place. Damage occurs, because drilling and/or completion fluids leak into the reservoir and alter the pores and pore throats. When the pores are plugged, the permeability is reduced, and the fluid flow in this damaged portion of the reservoir may be substantially reduced. Damage can be especially severe in naturally fractured reservoirs. To stimulate damaged reservoirs, a short, conductive hydraulic fracture is often the desired solution.
In many cases, especially for low-permeability formations, damaged reservoirs, or horizontal wells in a layered reservoir, the well would be uneconomical unless a successful hydraulic fracture treatment is designed and pumped. The engineer in charge of the economic success of such a well must design the optimal fracture treatment and then go to the field to be certain the optimal treatment is pumped successfully.[1]

## 8 - Methodology

### Introduction

The production capacity of existing fields before they were destroyed was 20,000 barrels of oil per day, determine of the formation damage by using Drill Stem Test (DST).[6]

### 8.1 Available Data

The available data are included for 3 wells well A1, A2 and A3

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**Table (1) Available Data for Wells**

| Data | Value | | | Unit |
|---|---|---|---|---|
| | **Well A1** | **Well A2** | **Well A3** | **Well A1** |
| Choke size: | 64 | 64 | 64 | 1/64 in. |
| Reservoir pressure: | 3000 | 3000 | 3000 | psia |
| Total measured depth: | 5,836 | 5,791 | 5,595 | ft |
| Average inclination angle: | 0 | 0 | 0 | deg |
| Tubing I.D.: | 1.995 | 1.995 | 1.995 | in. |
| Gas production rate: | 920,000 | 300,000 | 300,000 | scfd |
| Gas specific gravity: | 0 | 0 | 0 | air=1 |
| Oil specific gravity: | 0.75 | 0.75 | 0.75 | $H_2O$=1 |
| Water cut: | 38.2 | 38.2 | 57.8 | % |
| Water specific gravity: | 1.05 | 1.05 | 1.05 | $H_2O$=1 |
| Solid production rate: | 0 | 0 | 0 | $ft^3$/d |
| Solid specific gravity: | 0 | 0 | 0 | $H_2O$=1 |
| Tubing head temperature: | 60 | 60 | 60 | °F |
| Bottom hole temperature: | 156 | 156 | 156 | °F |
| Absolute open flo (AOF): | 9592.434754 | 8009.158479 | 3702.759763 | bbl/d |
| Choke flow constant: | 10 | 10 | 10 | |
| Choke GLR exponent: | 0.546 | 0.546 | 0.546 | |
| Choke size exponent: | 1.89 | 1.89 | 1.89 | |

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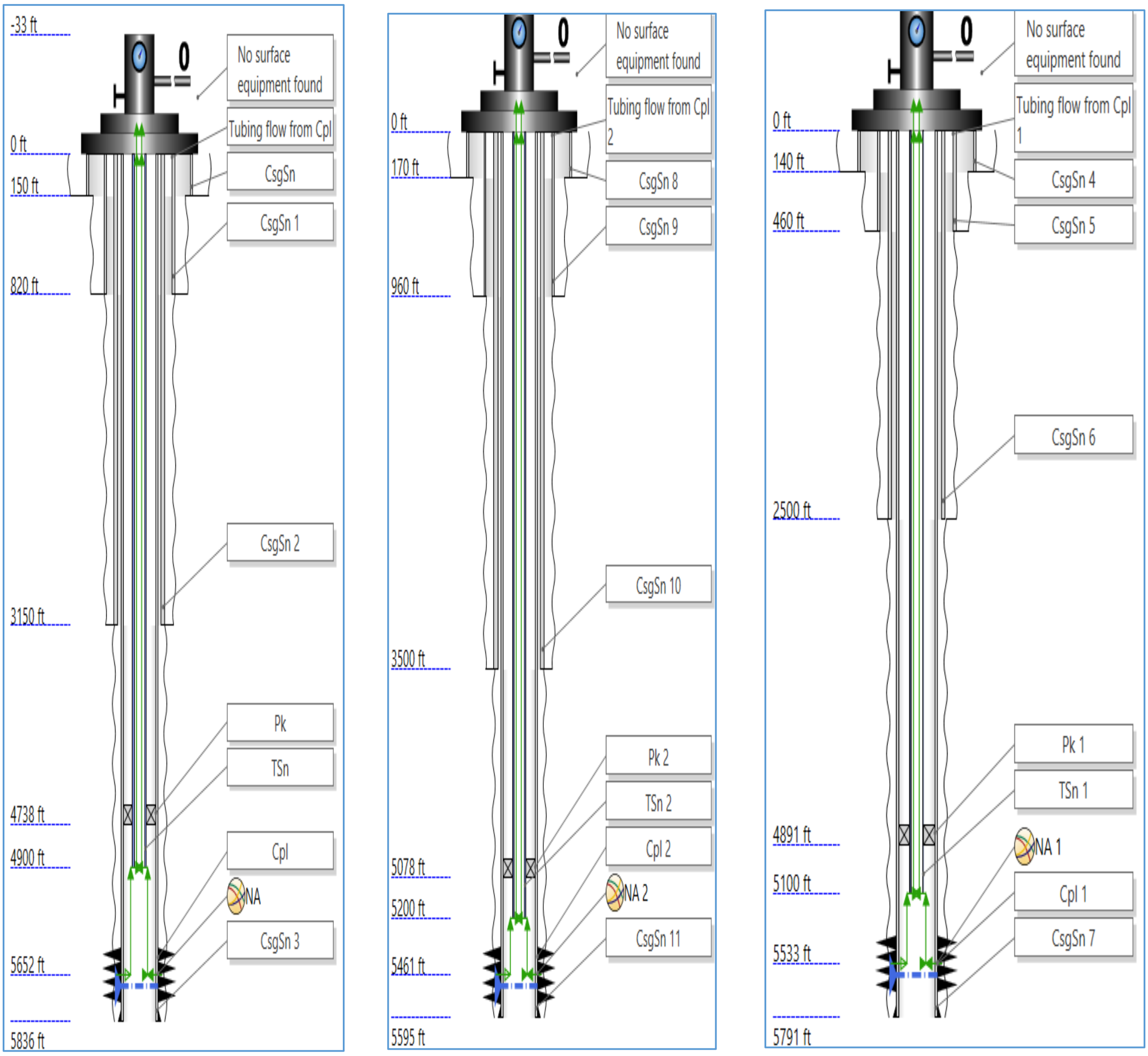


**Well A3** **Well A2** **Well A1**

Figure (1) The design for Wells

The IPR curve, also known as the Inflow Performance Relationship curve, represents the relationship between the wellbore flow rate and the pressure drawdown or bottomhole flowing pressure. It provides information about the flow capacity or productivity of the reservoir.

The IPR curve is typically plotted with the wellbore flow rate (in barrels per day or cubic meters per day) on the horizontal axis and the pressure drawdown (in psi or pascal) on the vertical axis. The curve shows the relationship between these two variables and helps determine the maximum flow rate that can be sustained at a given pressure drawdown.

The IPR curve is derived from reservoir engineering calculations and considers reservoir properties, fluid properties, and wellbore conditions. It provides valuable information for well and reservoir

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management decisions, such as optimizing production rates, selecting artificial lift methods, and evaluating well performance under different operating scenarios.

The intersection point of the IPR curve with the OPR curve represents the operating point or production rate at which the well is currently producing. By analyzing this intersection point, production engineers can assess whether the well is producing efficiently or if there is any potential for optimization.

The Outflow Performance Relationship (OPR) or Tubing Performance Curve represents the relationship between the flowing bottomhole pressure (FBHP) and the flow rate through the production tubing. It illustrates the tubing's ability to deliver fluids from the reservoir to the surface at different pressure drawdown conditions.

Typically, the OPR curve is plotted with the flowing bottomhole pressure on the vertical axis and the flow rate on the horizontal axis. It helps determine the maximum flow rate achievable at various bottomhole pressure conditions.

The OPR curve takes into account factors such as tubing size, wellbore geometry, fluid properties, and production constraints. It is useful for evaluating the performance and limitations of the production tubing and optimizing production rates within the tubing's operating limits.

By analyzing the OPR curve, production engineers can determine the appropriate operating conditions, such as surface flow rate or flowing bottomhole pressure, to achieve the desired production rates while considering tubing performance limitations.[1]

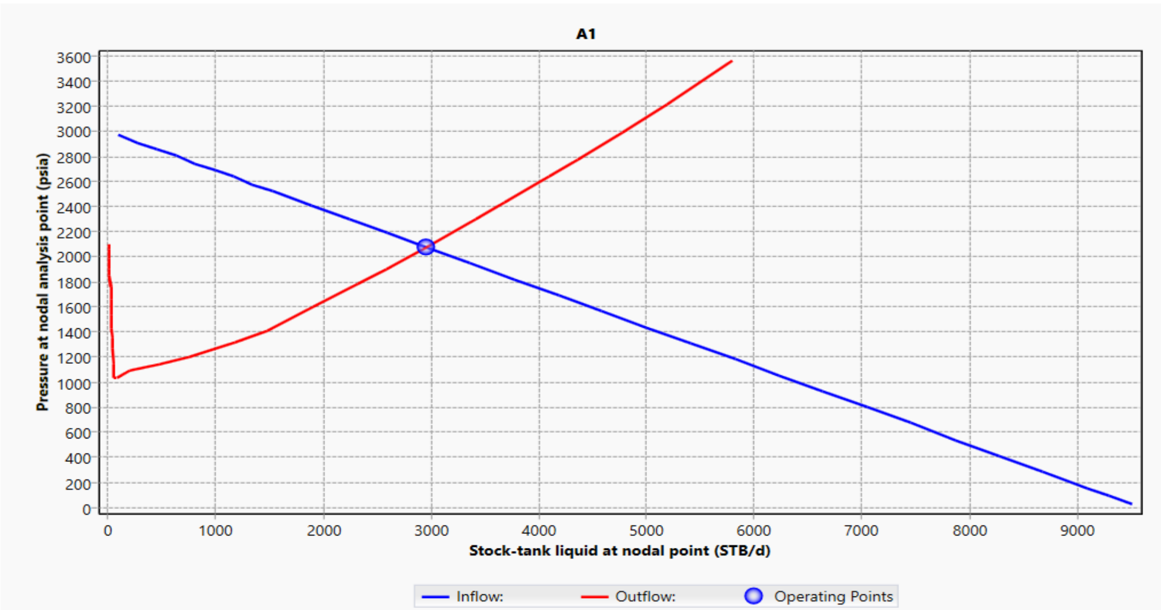


Figure (2) The Operating Point for Well A1

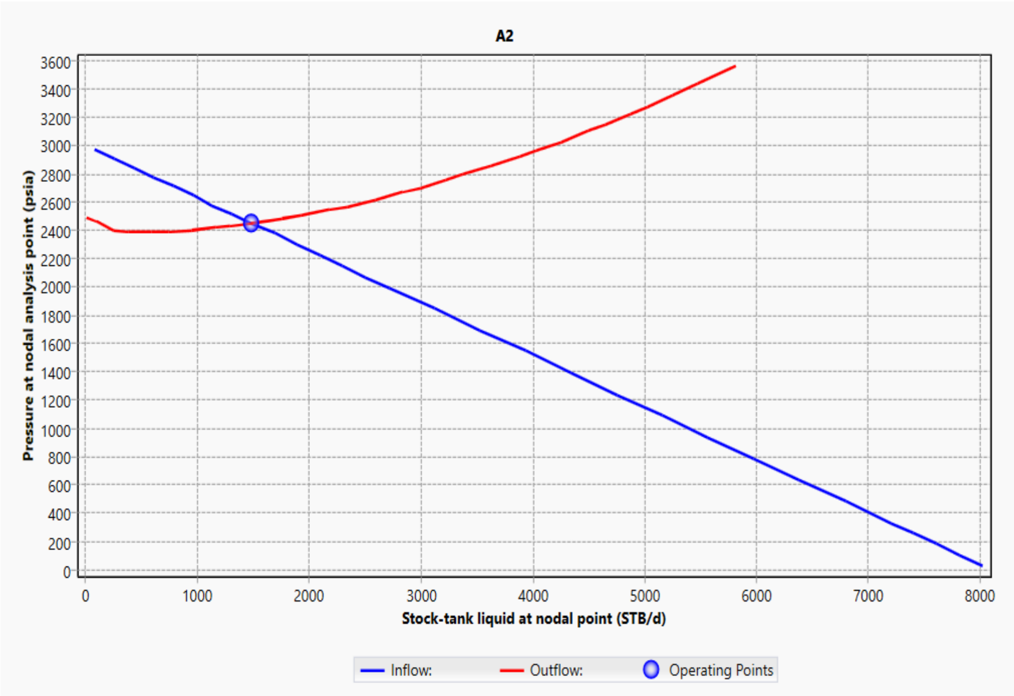


Figure (3) The Operating Point for Well A2

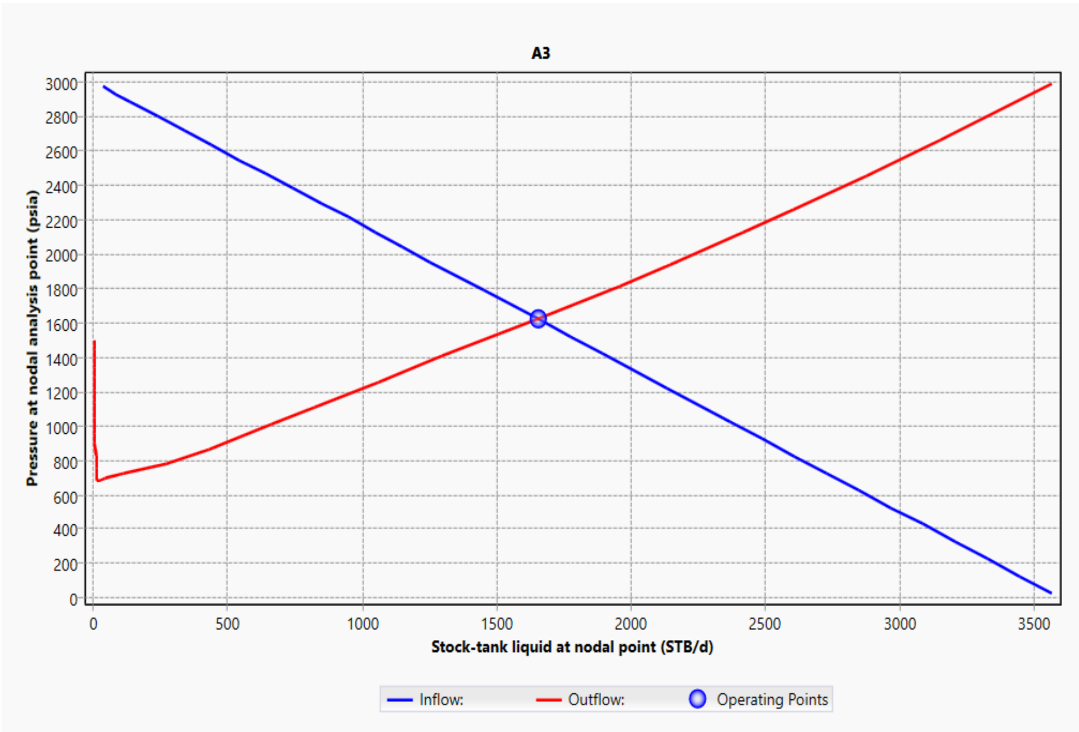


Figure (4 The Operating Point for Well A3

From the above figure the man results are the following:

Based on the data provided, it appears to be a set of well performance data with corresponding values for flowing bottomhole pressure (Pwf) without skin and flow rate (Q) without skin. Let's break down the information for each well:

**Well A1:**
- Pwf (Without Skin): 2100
- Q (Without Skin): 2900

**Well A2:**
- Pwf (Without Skin): 2450.409
- Q (Without Skin): 1483.896

**Well A3:**
- Pwf (Without Skin): 1620.674
- Q (Without Skin): 1655.192

The values provided represent the flowing bottomhole pressure (Pwf) and flow rate (Q) for each well without considering the skin effect. The skin effect refers to any additional pressure drop near the wellbore due to formation damage or other factors, which can impact the flow behavior and productivity of the well.

Without further context or information, it is challenging to provide specific comments or interpretations about the data. However, based on the given values, it is apparent that the flow rates for Wells A1 and A3 are the same, while the Pwf values differ for all three wells.

To gain a more comprehensive understanding of the data and draw meaningful conclusions, it would be helpful to compare these values with additional parameters, such as skin factor, reservoir properties, or operational conditions. Additionally, analyzing trends or changes in the data over time or in relation to other wells in the field could provide further insights into the performance of each well.[6]

**Table (2) The Results of the Operating Point for The Study Wells**

| Well | Pwf (Without Skin) | Q (Without Skin) | Q max (Without Skin) |
|---|---|---|---|
| A1 | 2100 | 2900 | 9800 |
| A2 | 2450.409 | 1483.896 | 8050 |
| A3 | 1620.674 | 1655.192 | 3600 |

### 9. Conclusion

1. The skin effect is a crucial factor that can significantly impact the productivity of oil and gas wells. The skin effect refers to the additional pressure drop caused by the formation damage or alteration near the wellbore, which can be either positive (increased pressure drop) or negative (decreased pressure drop).
2. Well A1 has the highest well flowing pressure (Pwf) of 2100 psi and the highest maximum flow rate (Q max) of 9800 bbl/day without skin effects.
3. Well A2 has the second-highest Pwf of 2450.409 psi, but the lowest Q max of 8050 bbl/day without skin effects.
4. Well A3 has the same Pwf of 1655, but a significantly lower Q max of 3600 bbl/day without skin effects.

## 10 - Recommendations

1.Recommendede of the Conduct a detailed analysis of the reservoir characteristics, well design, and operational factors that may be influencing the well performance to identify opportunities for optimization.

2. Consider implementing well interventions or modifications to improve the productivity of Well A3, such as addressing any potential skin effects or other near-wellbore issues.
3. Recommended, develop a comprehensive production strategy that takes into account the unique characteristics and performance of each well to maximize the overall productivity of the asset.

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