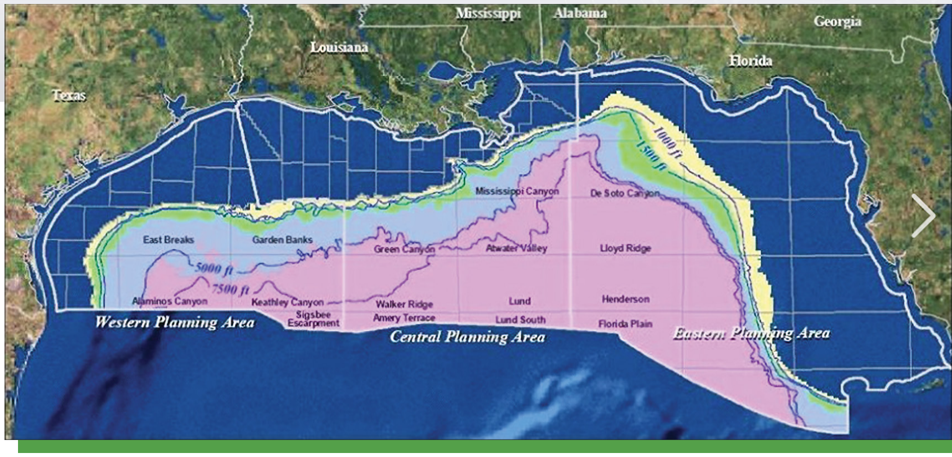
Case Study

Acid Stimulation Evaluation & Recommendation to Improve Well Productivity in Deep Well Completed at the GOM



Gulf of Mexico (GOM) General Map

Overview

Production evaluation using StimPro software confirms the damaged condition of a previously stimulated well. Evaluation results shows that a new improved acid stimulation could increase well productivity in 400% .

Challenge

A deep production well completed in a sandstone formation in the Gulf of Mexico (GOM) was frac-packed and acid-stimulated twice to restore or enhance its production potential. While each stimulation initially improved productivity, the well's performance declined drastically over time, jeopardizing its economic viability and reducing hydrocarbon recovery factors.

Solution & Benefits

An analysis of the well's production and stimulation history, combined with sequential rate-pressure matching of previous acid stimulation treatments, was conducted. Based on the results—validated by the Productivity Index (PI) and reservoir properties—the study suggests that a new, modified stimulation treatment incorporating a larger acid volume, and an additional diversion stage could enhance well productivity and maximize hydrocarbon recovery.

Analysis Results

Pressure and PI Matching:

- Analysis of two stimulation treatments revealed a significant formation damage with a SKIN value of 27 and an initial PI of 2.10 Bbls/psi post-stimulation.
- Despite treatment, PI dropped to 0.6 Bbls/psi over time, significantly reducing productivity.

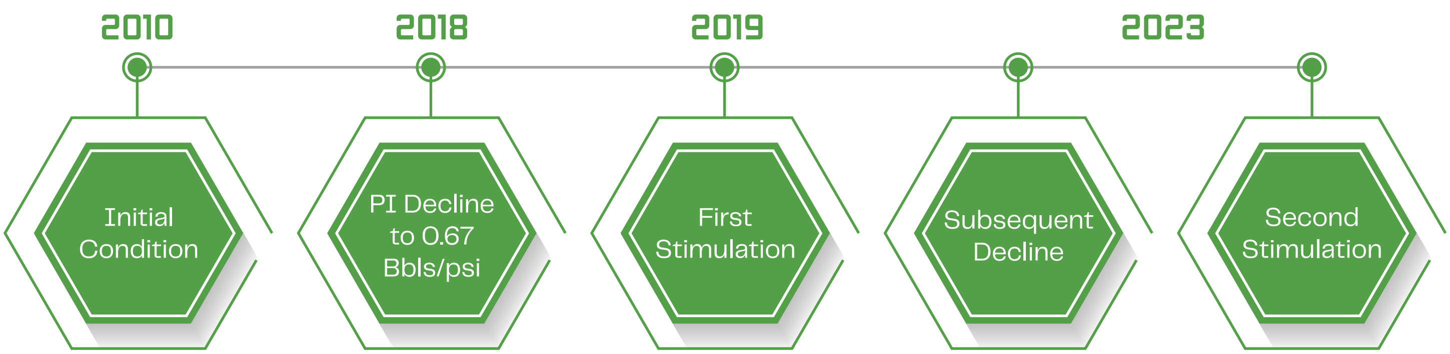
Restimulation Potential:

- StimPro analysis predicts that a restimulation treatment could increase the PI from 0.6 to 3.17 Bbls/psi, significantly improving productivity and hydrocarbon recovery.

Well History and Problem Description

An operator's well, completed in the deeper M-15 sandstone formation at the GOM and producing medium-gravity oil, experienced severe productivity declines due to formation damage caused by the frac-pack completion strategy, fines migration, and asphaltene deposition.

Timeline of Interventions:



The well reported an average PI of 6 Bbls/psi after frac-packing.

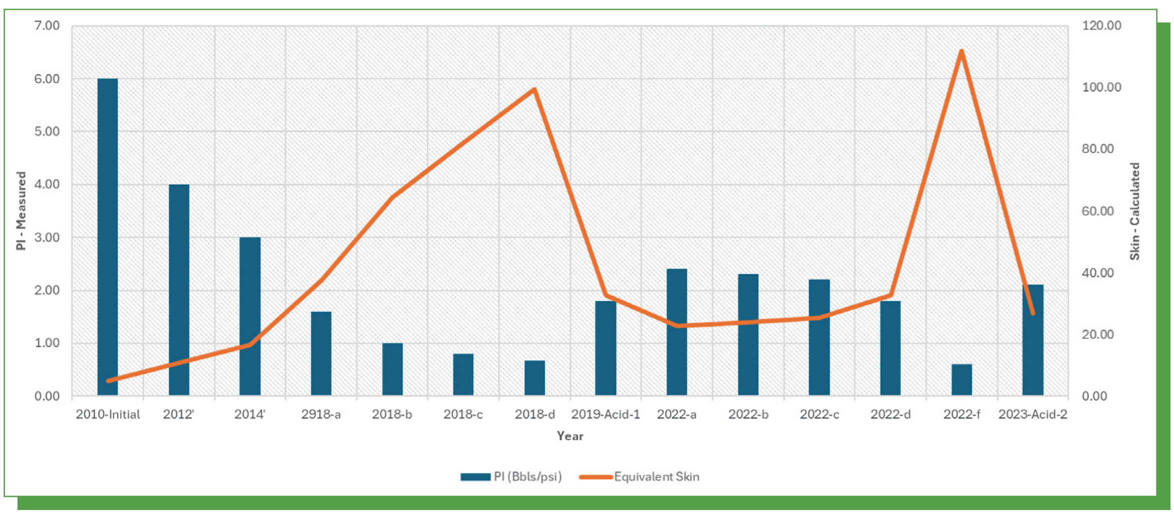
PI dropped due to combined formation damage effects.

A matrix acidizing treatment using bullheading acid blends increased the PI to 2.1 Bbls/psi.

PI dropped back to 0.6 Bbls/psi despite interventions.

A coiled tubing acid stimulation raised the PI to 2.0 Bbls/psi but later decreased again to 0.6 Bbls/psi.

The complete history of the skin and PI change during the life of the well is shown here.



Productivity Index (PI) and Skin History

Proposed Solution:

A modified third matrix acidizing treatment was evaluated using StimPro. This treatment considers deploying a larger acid volume to address deeper formation damage caused by prior stimulations. The new treatment results as shown in the evaluation section of this report enhance long-term productivity of the well.

Well Condition and Stimulation Evaluation Process and Results

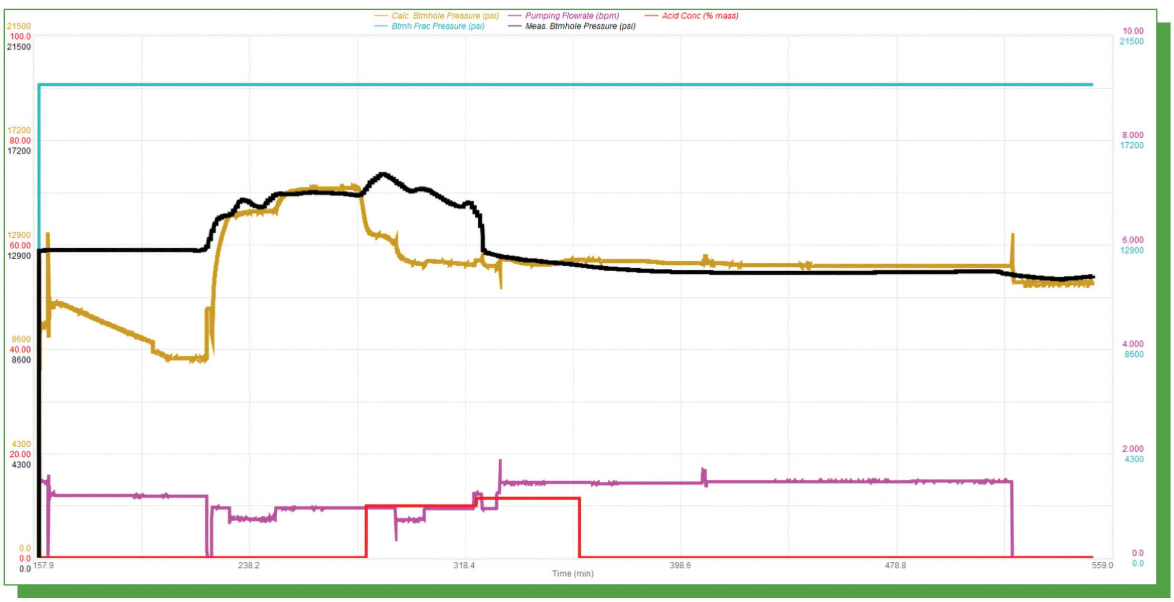
1 First Matrix Stimulation–2019

The first matrix acid stimulation treatment was performed in 2019 using Coiled Tubing (CTU). This treatment involved an aromatic solvent and a formation conditioning water-based brine or organic acid-HCl acid blend. A primary fluid blend of 10% Acetic Acid – 1.5% HF acid was used to stimulate the sandstone formation, as detailed below. No diversion stages were implemented to enhance acid distribution during the treatment.

Stage Type	Treatment Rate (BPM)	Fluid Volume (gals)	Fluid Type
Circulation	1.22	2,168	Water-Based Brine Conditioner
Circulation	1.09	1,009	Aromatic Solvent
Main Acid	0.90	2,170	Water-Based Brine Conditioner & Spacer
Main Acid	0.90	1,553	10% Acetic Acid-10% HCI Blend
Main Acid	1.36	2,194	10% HCI + 1.5% Acid Blend
Flush	1.45	3,301	Water-Based Brine
Overflush	1.47	6,594	Water-Based Brine

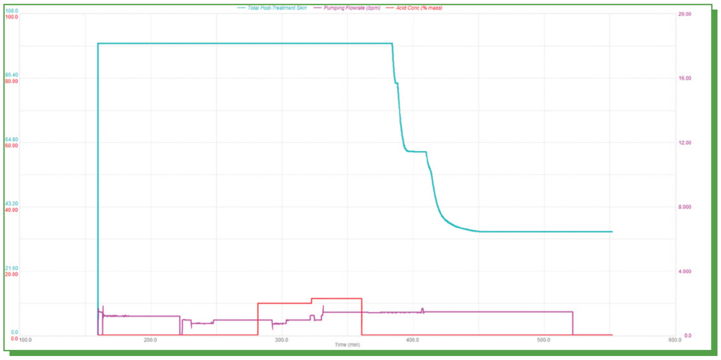
Table 1: 10% Acetic Acid – 1.5% HF Acid via Coiled Tubing (CTU), no diversion stages

To enable CTU operations in a high-pressure environment, a weighted Calcium Chloride brine was used as a bulkhead. However, this brine infiltrated the formation, causing additional and deeper formation damage. The acid treatment rate and downhole pressure history plots, along with the corresponding matches, confirmed the reservoir properties and damage conditions before and after the stimulation. However, the initial part of the treatment history was not matched due to the circulation mode used to fill the CTU and minimize additional control brine placement into the formation. The match primarily focused on the stimulation fluid squeezing into the formation and subsequent pressure fall-off (Early part of the treatment is not matched because stimulation fluid was placed in circulation mode).

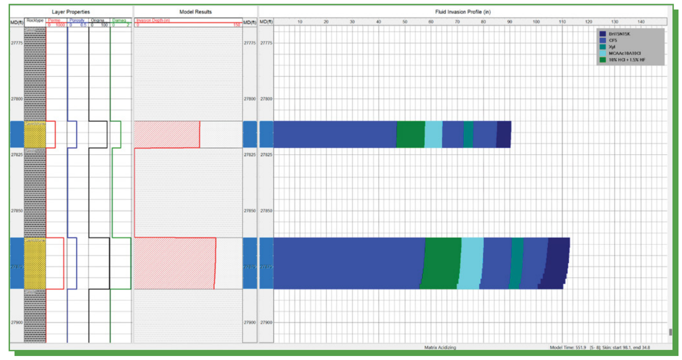


First Pressure Match

The matrix acidizing pressure match indicated a skin reduction from 95 to 35, corresponding to an improvement in productivity index (PI) from 0.7 to 2.1 Bbls/psi. While the treatment initially enhanced productivity, the benefit was temporary, with PI eventually dropping back to 0.6 Bbls/psi. The transient skin values and fluid distribution for the pressure match are shown below.



First Transient Skin



First Fluid Invasion Profile

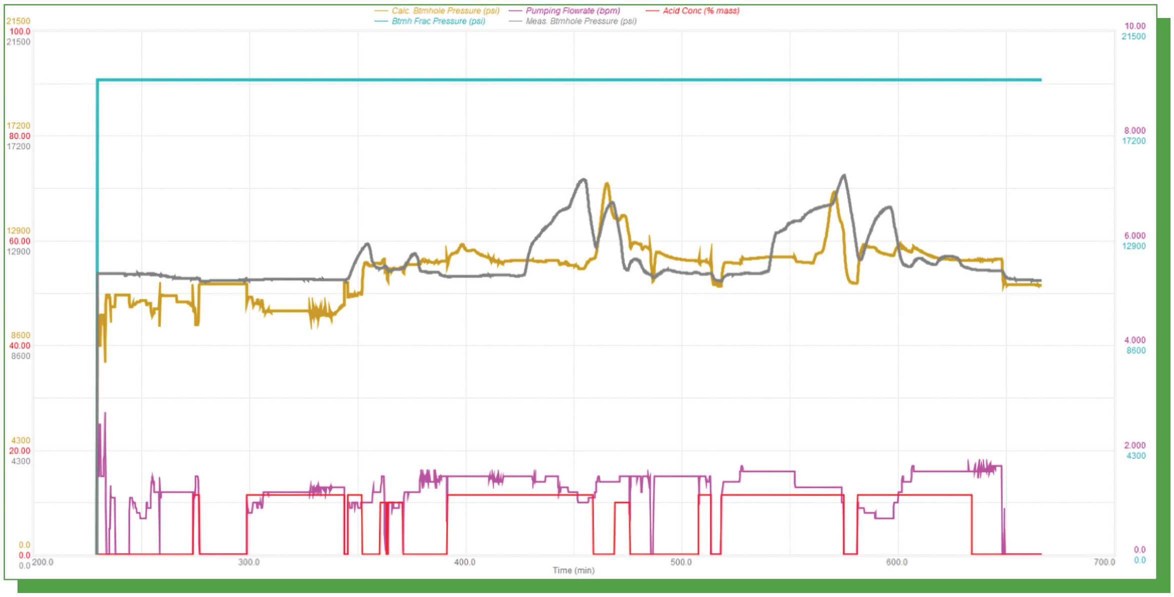
2 Second Matrix Stimulation–2023

The second matrix acid stimulation treatment, also conducted using CTU, followed a similar process with aromatic solvents and formation conditioning water-based brines or organic acid-HCl acid blends. However, this time, a primary fluid blend of 10% HCl Acid – 1.5% HF acid was used to stimulate the sandstone formation. To improve acid distribution, two diversion stages with VDA fluid were added.

Stage Type	Treatment Rate (BPM)	Fluid Volume (gals)	Fluid Type
Preflush	0.82	1,007	Water-Based Brine Conditioner
Solvent	1.19	384	Aromatic Solvent
Conditioner	1.19	381	Mutual Solven Blend
Main Acid	0.46	747	10% Acetic Acid-10% HCl Blend
Main Acid	1.22	1,145	10% HCl + 1.5% HF Acid Blend
Main Acid	1.05	760	10% Acetic Acid-10% HCl Blend
Spacer	1.08	378	Water-Based Brine
Diverter	0.95	420	Diverter
Solvent	1.24	579	Aromatic Solvent
Conditioner	1.45	567	Mutual Solven Blend
Main Acid	1.49	1,132	10% Acetic Acid-10% HCl Blend
Main Acid	1.47	1,701	10% HCl + 1.5% HF Acid Blend
Main Acid	1.24	1,144	10% Acetic Acid-10% HCl Blend
Spacer	1.37	572	Water-Based Brine
Diverter	1.46	424	Diverter
Solvent	1.35	959	Aromatic Solvent
Conditioner	1.5	946	Mutual Solven Blend
Main Acid	1.31	1,904	10% Acetic Acid-10% HCl Blend
Main Acid	1.07	2,841	10% HCl + 1.5% HF Acid Blend
Main Acid	1.6	1,901	10% Acetic Acid-10% HCl Blend
Displacement	1.65	966	Water-Based Brine

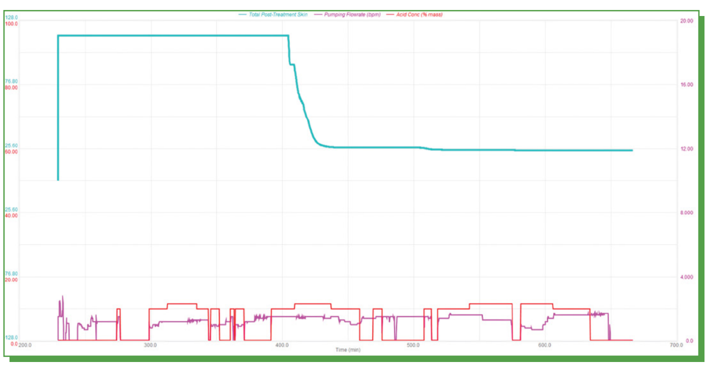
Table 2: 10% HCl Acid – 1.5% HF Acid, two diversion stages with VDA fluid

The stimulation treatment was performed again using CTU but it was not used heavy brine as control fluid on this intervention. The acid treatment Rate-Downhole Pressure history plot and the corresponding match corroborating the reservoir properties and damage conditions before & after the stimulation is shown here. The pressure match for the entire treatment and fall-off period is shown below (Early part of the treatment is not matched because stimulation fluid was placed in circulation mode).

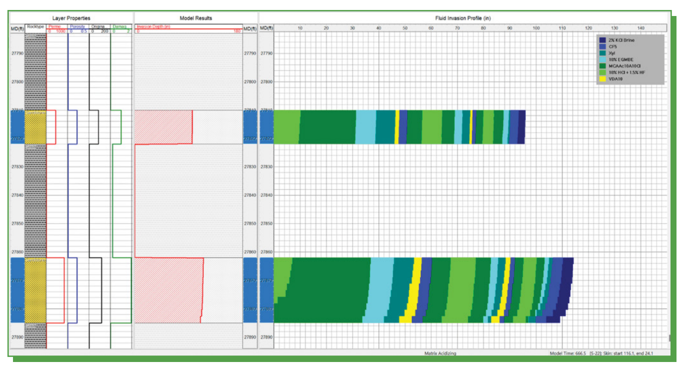


Second Pressure Match

The second matrix acidizing pressure match showed a skin reduction from 116 to 24, equivalent to an improvement in PI from 0.6 to 2.3 Bbls/psi. This second stimulation effectively restored the productivity conditions observed after the first acid stimulation. However, the productivity benefit was again short-lived, with PI eventually dropping back to 0.6 Bbls/psi. The transient skin values and fluid distribution for the pressure match are displayed below.



Second Transient Skin



Second Fluid Invasion Profile

New Matrix Acid Stimulation Design, Considerations and Benefits

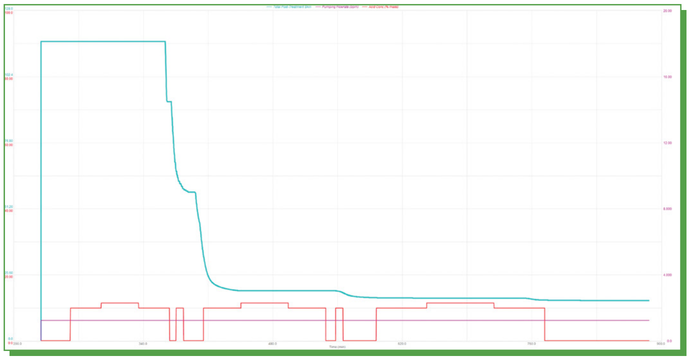
To enhance well productivity, three additional matrix stimulation options were evaluated using . All scenarios focused on increasing preflush and main acid volumes or incorporating an additional diversion stage to improve acid distribution along the completed interval. Below is a summary of the evaluated designs:

1. **Matrix Stimulation Design-1**: Increased pre-flush and main acid volumes by 1,000 gallons.
2. **Matrix Stimulation Design-2**: Increased pre-flush and main acid volumes by 2,000 gallons.
3. **Matrix Stimulation Design-3**: Added one additional diversion stage and increased acid volume. The designed treatment schedule for Design-3 is shown below.

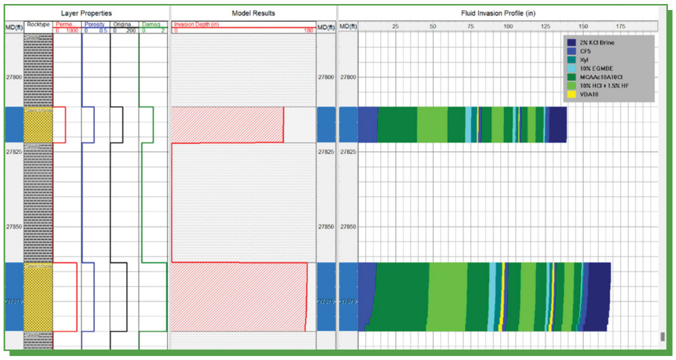
Stage Type	Treatment Rate (BPM)	Fluid Volume (gals)	Fluid Type
Preflush	1.25	1,008	Water-Based Brine Conditioner
Solvent	1.25	378	Aromatic Solvent
Conditioner	1.25	274	Mutual Solven Blend
Main Acid	1.25	752	10% Acetic Acid-10% HCl Blend
Main Acid	1.25	1,126	10% HCl + 1.5% HF Acid Blend
Main Acid	1.25	752	10% Acetic Acid-10% HCl Blend
Spacer	1.25	374	Water-Based Brine
Diverter	1.25	420	Diverter
Solvent	1.25	563	Aromatic Solvent
Conditioner	1.25	567	Mutual Solven Blend
Main Acid	1.25	1,126	10% Acetic Acid-10% HCl Blend
Main Acid	1.25	1,688	10% HCl + 1.5% HF Acid Blend
Main Acid	1.25	1,125	10% Acetic Acid-10% HCl Blend
Spacer	1.25	563	Water-Based Brine
Diverter	1.25	424	Diverter
Solvent	1.25	937	Aromatic Solvent
Conditioner	1.25	937	Mutual Solven Blend
Main Acid	1.25	1,873	10% Acetic Acid-10% HCl Blend
Main Acid	1.25	2,814	10% HCl + 1.5% HF Acid Blend
Main Acid	1.25	1,882	10% Acetic Acid-10% HCl Blend
Spacer	1.25	945	Water-Based Brine
Diverter	1.25	424	Diverter
Solvent	1.25	937	Aromatic Solvent
Conditioner	1.25	937	Mutual Solven Blend
Main Acid	1.25	1,873	10% Acetic Acid-10% HCl Blend
Main Acid	1.25	2,814	10% HCl + 1.5% HF Acid Blend
Main Acid	1.25	1,882	10% Acetic Acid-10% HCl Blend
Displacement	1.25	945	Water-Based Brine
Overflush	1.25	5,000	Water-Based Brine

Table 3: 10% HCl Acid – 1.5% HF Acid, three diversion stages with increased acid volume

The transient skin and invasion profile for the third evaluated option is shown below .



Third Transient Skin



Third Fluid Invasion Profile

The modified acid stimulation treatment (Design-3) demonstrates a significant improvement, increasing the PI from 0.6 to 3.14 Bbls/psi. This enhancement translates to better well productivity and improved fluid recovery.

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