From:	Engineer, OCD, EMNRD
To:	Ramona Hovey
Cc:	McClure, Dean, EMNRD; Kautz, Paul, EMNRD; Goetze, Phillip, EMNRD; Rose-Coss, Dylan H, EMNRD; Wrinkle, Justin, EMNRD; Powell, Brandon, EMNRD; lisa@rwbyram.com; McMillan, Michael A.; Lamkin, Baylen L.
Subject:	Approved Administrative Order IPI-536
Date:	Wednesday, September 14, 2022 12:32:11 PM
Attachments:	IPI536 Order.pdf

NMOCD has issued Administrative Order IPI-536 which authorizes Milestone Environmental Services, LLC to increase the max allowable surface pressure of the Beaza SWD #1 (30-025-49600) to 2000 psi while the down hole configuration stays consistent with that portrayed by the application.

The administrative order is attached to this email and can also be found online at OCD Imaging.

Please review the content of the order to ensure you are familiar with the authorities granted and any conditions of approval. If you have any questions regarding this matter, please contact me.

Dean McClure
Petroleum Engineer, Oil Conservation Division
New Mexico Energy, Minerals and Natural Resources Department
(505) 469-8211

Revised March 23, 2017

RECEIVED:	REVIEWER:	TYPE:	APP NO:

ABOVE THIS TABLE FOR OCD DIVISION USE ONLY

NEW MEXICO OIL CONSERVATION DIVISION
- Geological & Engineering Bureau –
1220 South St. Francis Drive, Santa Fe, NM 87505

ADMINISTRATIVE APPLICATION CHECKLIST

THIS CHECKLIST IS MANDATORY FOR ALL ADMINISTRATIVE APPLICATIONS FOR EXCEPTIONS TO DIVISION RULES AND REGULATIONS WHICH REQUIRE PROCESSING AT THE DIVISION LEVEL IN SANTA FE

Applicant:________________________________ **OGRID Number:** ____________
Well Name: ________________________________ **API:**____________
Pool: ________________________________ **Pool Code:** ____________

SUBMIT ACCURATE AND COMPLETE INFORMATION REQUIRED TO PROCESS THE TYPE OF APPLICATION INDICATED BELOW

1) **TYPE OF APPLICATION:** Check those which apply for [A]

A. Location – Spacing Unit – Simultaneous Dedication

☐ NSL ☐ NSP(PROJECT AREA) ☐ NSP(PRORATION UNIT) ☐ SD

B. Check one only for [I] or [II]

[I] Commingling – Storage – Measurement

☐ DHC ☐ CTB ☐ PLC ☐ PC ☐ OLS ☐ OLM

[II] Injection – Disposal – Pressure Increase – Enhanced Oil Recovery

☐ WFX ☐ PMX ☐ SWD ☐ IPI ☐ EOR ☐ PPR

FOR OCD ONLY

☐ Notice Complete

☐ Application Content Complete

2) **NOTIFICATION REQUIRED TO:** Check those which apply.

A. ☐ Offset operators or lease holders
B. ☐ Royalty, overriding royalty owners, revenue owners
C. ☐ Application requires published notice
D. ☐ Notification and/or concurrent approval by SLO
E. ☐ Notification and/or concurrent approval by BLM
F. ☐ Surface owner
G. ☐ For all of the above, proof of notification or publication is attached, and/or,
H. ☐ No notice required

3) **CERTIFICATION:** I hereby certify that the information submitted with this application for administrative approval is **accurate** and **complete** to the best of my knowledge. I also understand that **no action** will be taken on this application until the required information and notifications are submitted to the Division.

Note: Statement must be completed by an individual with managerial and/or supervisory capacity.

____
Date

____
Print or Type Name

____
Phone Number

____
Signature

____
e-mail Address

LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS

June 16, 2022

Mr. Philip Goetze
State of New Mexico Energy, Minerals and Natural Resources department
Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, NM 87505

RE: Increase Surface Injection Pressure Request
Milestone Environmental Services LLC
Beaza SWD #1 (API #30-025-49600)
Order No. R-21441

Mr. Goetze,

Milestone Environmental Services LLC is requesting an increase of the Maximum Surface Injection Pressure (MASIP) for the Beaza SWD #1 well to 2000 psig and increase of the Maximum rate of injection from 10,000 bpd to 20,000 bpd. Per Order R-21441, Milestone performed a step-rate test to determine the fracture pressure of the injection formation. As discussed in the attached step-rate test report, a formation parting pressure was not identified at surface injection pressures up to 2,077 psig and injection rates up to 37,872 bbl/day, the maximum safe fluid velocity for injection through the 4-1/2" diameter tubing.

	REQUESTED	MAXIMUM TEST VALUE
MAX VOLUME	2,000	2,077
MASIP	20,000	37,872

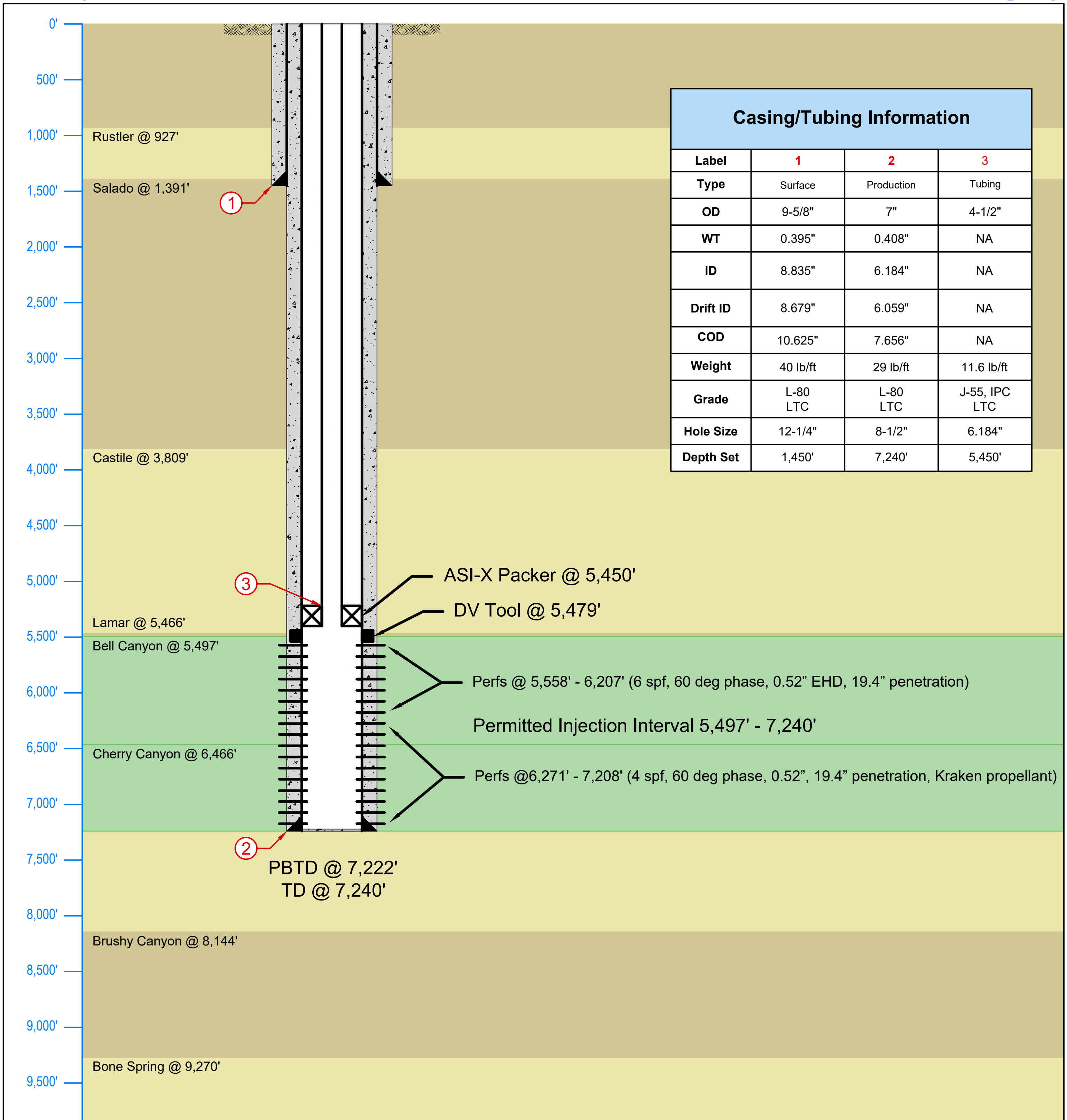
Please find the attached supporting documents for this request:

- As-built wellbore schematic
- Structure map of the top of the Bell Canyon formation
- Structure map of the top of the Cherry Canyon formation
- N-S Cross section
- Step-rate test report, dated May 23, 2020
- Description of injectate used for the step-rate tests
- Volume, pressure and time data from the step-rate tests (Excel File)

Should you require any additional information or have any questions regarding this application, please do not hesitate to contact me at (512) 600-1777.

Sincerely,

Ramona Hovey
Sr. Petroleum Engineer
(512) 600-1777 (o)
(512) 585-0654 (c)
ramona@lonquist.com



Casing/Tubing Information

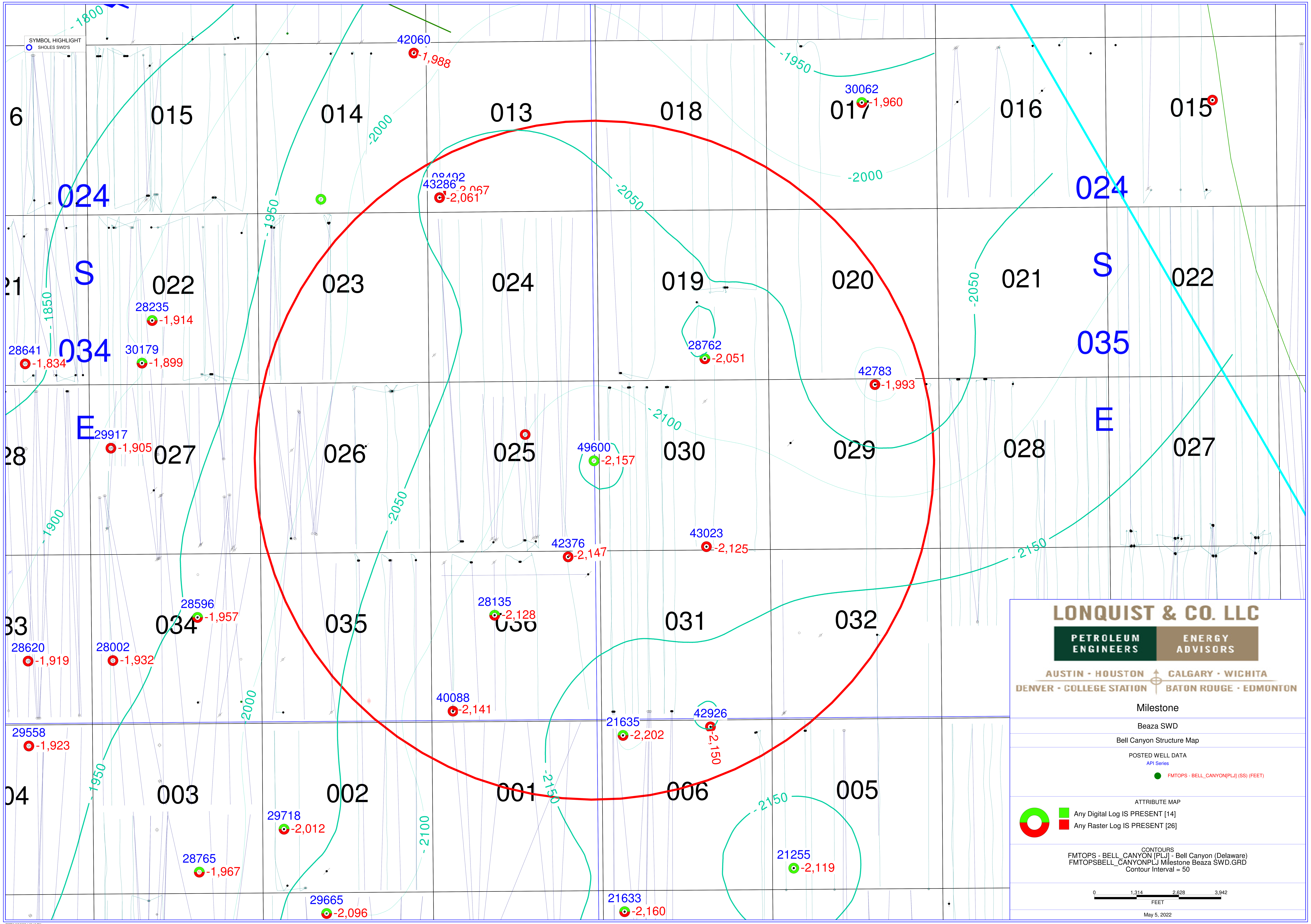
Label	1	2	3
Type	Surface	Production	Tubing
OD	9-5/8"	7"	4-1/2"
WT	0.395"	0.408"	NA
ID	8.835"	6.184"	NA
Drift ID	8.679"	6.059"	NA
COD	10.625"	7.656"	NA
Weight	40 lb/ft	29 lb/ft	11.6 lb/ft
Grade	L-80 LTC	L-80 LTC	J-55, IPC LTC
Hole Size	12-1/4"	8-1/2"	6.184"
Depth Set	1,450'	7,240'	5,450'

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
Texas License F-9147
12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Milestone Environmental

Beaza SWD No. 1

Country: USA	**State/Province:** New Mexico	**County/Parish:** Lea
Location: 160' FEL & 2,480' FNL of Unit H, Section 25, Township 24S, Range 34E		**District:** 1 (Hobbs)
API No: 30-025-49600	**Field:**	**Well Type/Status:** Disposal / New Drill
State ID No:	**Project No:** 1761	**Date:** 03/16/2022
Drawn: WHG	**Reviewed:** RH	**Approved:** RSC
Rev No: 3	**Notes:**	


SYMBOL HIGHLIGHT
SHOLES SWD'S
LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
AUSTIN - HOUSTON
CALGARY - WICHITA
DENVER - COLLEGE STATION
BATON ROUGE - EDMONTON
Milestone
Beaza SWD
Bell Canyon Structure Map
POSTED WELL DATA
API Series
FMTOPS - BELL_CANYON[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT [14]
Any Raster Log IS PRESENT [26]
CONTOURS
FMTOPS - BELL_CANYON [PLJ] - Bell Canyon (Delaware)
FMTOPSBELL_CANYONPLJ Milestone Beaza SWD.GRD
Contour Interval = 50
0
1,314
2,628
3,942
FEET
May 5, 2022
024 S 034 E
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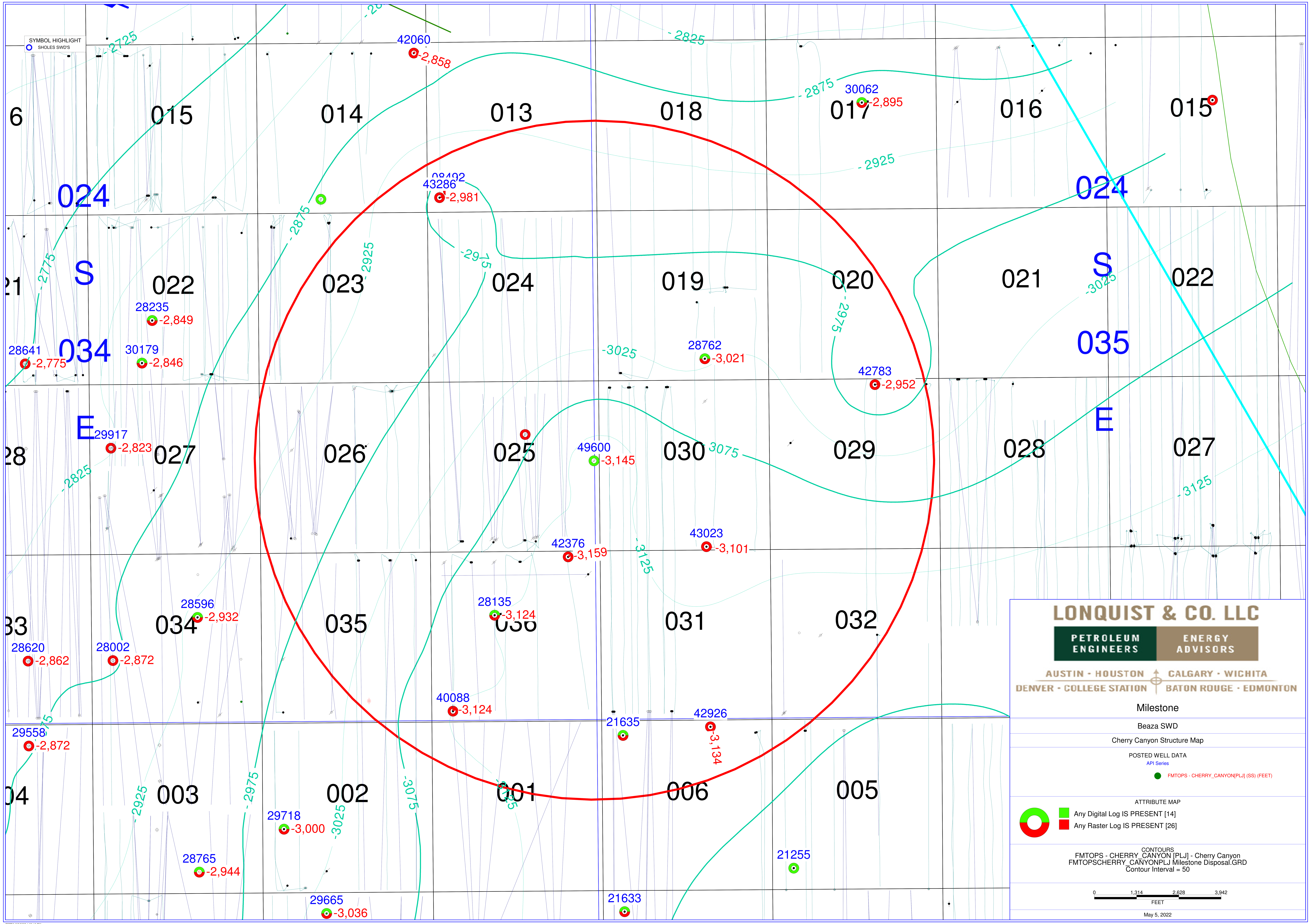
005
42060 -1,988
30062 -1,960
43286 -2,061
28235 -1,914
28641 -1,834
30179 -1,899
28762 -2,051
42783 -1,993
29917 -1,905
49600 -2,157
42376 -2,147
43023 -2,125
28596 -1,957
28135 -2,128
28620 -1,919
28002 -1,932
40088 -2,141
21635 -2,202
42926 -2,150
29558 -1,923
29718 -2,012
28765 -1,967
21255 -2,119
29665 -2,096
21633 -2,160
-1800
-1850
-1900
-1950
-2000
-2050
-2100
-2150


SYMBOL HIGHLIGHT
SHOLES SWD'S
42060 -2,858
30062 -2,895
43286 -2,981
28235 -2,849
28641 -2,775
30179 -2,846
28762 -3,021
42783 -2,952
29917 -2,823
49600 -3,145
42376 -3,159
43023 -3,101
28596 -2,932
28135 -3,124
28620 -2,862
28002 -2,872
40088 -3,124
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42926 -3,134
29558 -2,872
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29665 -3,036
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LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
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BATON ROUGE - EDMONTON
Milestone
Beaza SWD
Cherry Canyon Structure Map
POSTED WELL DATA
API Series
FMTOPS - CHERRY_CANYON[PLJ] (SS) (FEET)
ATTRIBUTE MAP
Any Digital Log IS PRESENT [14]
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CONTOURS
FMTOPS - CHERRY_CANYON [PLJ] - Cherry Canyon
FMTOPSCHERRY_CANYONPLJ Milestone Disposal.GRD
Contour Interval = 50
0 1,314 2,628 3,942
FEET
May 5, 2022

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS
AUSTIN • HOUSTON • CALGARY • WICHITA
DENVER • COLLEGE STATION • BATON ROUGE • EDMONTON

Milestone Environmental

Beaza SWD

N-S Structural Cross Section

Horizontal Scale = 400.7
Vertical Scale = 50.0
Vertical Exaggeration = 8.0x

UWI
Well Name
WELL - TD
WELL - ELEV_KB

Light Blue shade in depth track indiactes propesed perf intervals
Dark blue line with light blue shade indicates rock with <.35 vshale and > 18% crossplot porosity

May 5,2022 4:34 PM

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS

May 23, 2022

Phillip Goetze
Hearing Examiner
Oil Conservation Division of New Mexico
1220 S. St. Francis Drive
Santa Fe, New Mexico 87505

RE: Step Rate Test Analysis
Milestone Environmental Services LLC
Beaza SWD No. 1 (30-025-49600)
Order No. R-21441

Dear Mr. Goetze:

Lonquist & Co. LLC ("Lonquist") is submitting an analysis of two step rate tests performed on the above referenced Beaza SWD No. 1 Disposal Well ("Beaza") in Lea County. This testing required by the Oil Conservation Division of New Mexico ("OCD") is pursuant to Order No. R-21441. This order requires that a step rate test ("SRT") be performed prior to commencing the second year of injection.

The maximum sustained injection rate for the first test was 37,872 bbl/day. This was estimated to be the maximum safe fluid velocity for injection through the 4-1/2" diameter tubing. The second test reached a maximum sustained injection rate of 23,380 bbl/day, and was performed to verify reservoir behavior at lower injection rates. The pressure vs. rate chart (Figure 3) showed a gradual decrease in slope for the first several stages of each test. As discussed below, this behavior is known as rate-dependent skin. After a thorough analysis, the determination was made that it is highly unlikely that the formation parting pressure was reached during the tests and the results were inconclusive in the identification of the formation parting pressure gradient for this well. Additionally, it is believed that a repeat SRT would yield equally inconclusive results within the maximum safe fluid velocity for this well. Available SRT data from offset wells has been provided in this report and demonstrates for the currently permitted injection range that formation parting pressure was not reached in Beaza SWD No. 1.

1415 Louisiana St., Suite 3800 | Houston, Texas 77002 USA | Tel 713.559.9950 | Fax 713.559.9959

This letter documents the analysis and conclusions of the tests. The next sections of the report detail the test procedures, data analysis and results, followed by the evaluation of offset SRTs and conclusions. The attached set of figures provides graphic depictions of the analysis and findings.

Test Procedure

The initial test was performed prior to initial injection, on April 4, 2022. This was done to ensure that the bottom hole pressure would be at or near the native reservoir pressure. Surface pressure was monitored in the tubing throughout the test and bottom-hole pressure readings were captured by a pressure gauge set at 6,400 feet. Surface pressure, bottom-hole pressure, and flow rate readings were captured and recorded at one-second intervals. Fourteen stages of continuous-rate injection were performed at incrementally increasing volumes. Injection at each stage was performed at equal time intervals of 30 minutes throughout the test. Injection began at very low rates in order to ensure that formation behavior would be adequately observed prior to the formation parting pressure were it to occur earlier than anticipated. At the completion of the final injection stage, pumping was ceased and the well was shut-in, allowing pressure to bleed-off into the injection zone. Figure 1 in the attached analysis provides an overview of the pressures and flow rate data captured during the first test.

Anomalous pressure behavior in the low-rate steps led to speculation that fluid movement was being constrained to a limited portion of the perforated intervals early in the test. A revised test procedure to counter this behavior was proposed and a second test was performed.

The second test was performed on May 4, 2022. The well remained shut-in between the first and second test. Similar to the initial test, surface pressure was monitored in the tubing and bottom-hole pressure readings were captured by a pressure gauge set at 6,400 feet. Surface pressure, bottom-hole pressure, and flow rate readings were captured and recorded at one-second intervals. Seventeen injection stages were performed, ten at increasing rates, followed by seven at decreasing rates. The decreasing rate stages were included in the second test to confirm reservoir behavior and ensure that all perforations were accepting fluid during low injection rate stages. Additionally, the duration of each stage was increased from 30 minutes in the initial test to 60 minutes to ensure pressure stabilization. Figure 2 in the attached analysis provides an overview of the pressures and flow rate data captured during the second test.

Data Analysis and Results

Bottom-hole pressure and flow rate measurements at the end of each injection stage were isolated to generate Table 1 and Table 2 below for each test.

First SRT (4/4/2022)			
Step	Flow Rate (bbl/min)	Flow Rate (bbl/day)	Bottom-hole Pressure (psi)
1	0.7	936	3,523
2	0.8	1,210	3,569
3	1.2	1,656	3,596
4	1.5	2,160	3,622
5	2.1	3,024	3,654
6	3.2	4,536	3,692
7	5.0	7,128	3,700
8	8.0	11,520	3,705
9	11.2	16,056	3,722
10	14.0	20,160	3,742
11	17.1	24,624	3,748
12	20.2	29,016	3,763
13	22.9	32,976	3,775
14	26.3	37,872	3,789

Table 1 – Summary of First SRT

Second SRT (5/4/2022)			
Step	Flow Rate (bbl/min)	Flow Rate (bbl/day)	Bottom-hole Pressure (psi)
1	0.6	814	3391
2	0.7	1068	3451
3	0.9	1284	3511
4	1.4	2077	3577
5	2.0	2905	3613
6	3.1	4458	3661
7	5.0	7243	3694
8	8.0	11457	3718
9	11.1	15997	3748
10	14.2	20380	3766
11	11.0	15807	3759
12	8.0	11533	3744
13	5.0	7223	3722
14	3.0	4357	3694
15	2.0	2880	3664
16	1.5	2160	3635
17	1.2	1728	3614

Table 2 – Summary of Second SRT

<u>Bottom-hole Pressure vs. Injection Rate</u>

Bottom-hole pressures from each table were plotted against the associated injection rates to illustrate their relationship. This is provided as Figure 3 in the attached analysis. The plot resulted in a continuous gradual decrease in slope throughout the low-rate stages of both tests followed by a linear trend at higher rates in the first test.

Typically, SRT data plotted in this way reveals one or more discrete changes in slope preceded and followed by linear trends. The distinct changes in slope are used to identify formation parting pressure, or their absence, in the case of a continuous straight line, indicates that the parting pressure was not reached.

During each change in injection rate, the data from these tests depicts a continuous and consistent transition in the effective permeability encountered in the formation for the first eight steps in both tests and for the entire step-down portion of the second test. This pressure response is indicative of a near-wellbore permeability (or skin) that varies with the injection rate. This behavior is known as rate-dependent skin. To verify this observation, the magnitude and shape of the pressure rises in each step were modeled in PanSystem™, a well testing analysis software. The skin value was adjusted for each step to achieve a match between pressure change and injection rate. The modeled skin value from each step was plotted against the associated injection rate. This plot has been provided as Figure 4. The plot depicts the strongly dependent relationship between skin and injection rate, particularly during the lower-rate steps. This is indicative of a rate-dependent skin as identified in studies of injection wells that exhibit this behavior. This phenomenon is explained by a gradual increase in the width of preexisting near-wellbore fractures as pressures rise due to injection. The increasing near-wellbore fracture width results in a decreasing skin value.

Given these findings, it is likely that near-wellbore fractures were created during the well completion and existed prior to commencement of these tests. The well was perforated with propellant enhanced perforating charges which are designed to create near-wellbore fractures for improved injectivity in disposal wells. Similar pressure behavior was observed in the SRT of another disposal well analyzed by Lonquist which utilized the same perforating technology for a completion in the Delaware Mountain Group ("DMG") in Loving County, TX. In the case of Beaza, a considerable quantity of these charges were deployed over a broad portion of the injection interval. In total, 1,600 of the specialty charges were detonated at a spacing of 4 shots per foot in the lower 400 feet of the 786 feet perforated interval. 2,316 standard 0.52" EHD charges were detonated at spacing of 6 shots per foot on the upper 386 feet of the perforated interval. A product brochure outlining the specific properties of this specialty perforating technology has been provided as an attachment to this report.

Parting Pressure of Confining Layers

Given the magnitude of the pressure gradients reached during these injection tests and the associated injection depths, it is unlikely that damage would have been caused to the upper or lower confining formations. The highest formation pressure gradient recorded during these tests was 0.592 psi/ft at an injection rate of 37,872 bbl/day. This gradient is significantly lower than the parting pressure gradients estimated from published literature for the upper confining layer, the Castile anhydrite, and the lower confining layer, the Bone Spring. These confining layers have been noted to exhibit parting pressure gradients of roughly of 0.66 psi/ft and 0.75 psi/ft, respectively.

Analog Well Discussion and Conclusions

Step Rate Test data from analog injection wells suggests that the formation parting pressure gradient was not reached during testing at Beaza. Data from the nearest four DMG disposal wells with publicly available SRT reports was considered. Following step rate testing on each of these four wells, MASIP values were issued to reflect the findings of these tests. These wells and their respective MASIPs are listed in the Table 3 below for reference.

Well	MASIP	
	(psi)	(psi/ft)
Beaza SWD No. 1	1,099	0.200
Antelope Ridge Unit No. 4	1,350	0.261
Antelope Ridge No. 5	1,228	0.238
Curry Federal No. 2	1,360	0.260
North Bell Lake Unit 4 No .15	1,870	0.370

Table 3 – MASIP Summary

Figure 5 shows the MASIPs assigned for each of these four offset wells overlaid with surface pressure vs injection rate for the Beaza SRTs. All anomalous pressure behavior in the Beaza tests can be seen to lie beneath a surface injection pressure of 300 psi and below a rate of 5,000 bbl/day. Aside from a slight upward curve due to friction in the tubing, a linear relationship in the Beaza data can be seen for pressures and rates above 300 psi and 5,000 bbl/day. The currently assigned MASIP for Beaza is not reached until an injection rate of about 25,000 bbl/day, significantly surpassing the permitted maximum of 10,000 bbl/day. The MASIPs from the four closest DMG offset injection wells with SRT data are not reached until higher rates, and the linear pressure vs. rate trend remains consistent until the highest step is reached at a rate of 37,872 bbl/day and an injection pressure of 2,077 psi.

The nearest of the offset wells reviewed was the Antelope Ridge Unit No. 4 which is located 5.5 miles northwest of Beaza. While the other three offset SRTs begin at higher bottomhole pressure gradients, the Antelope Ridge Unit No. 4 covers the range of pressure gradients over which the anomalous pressure behavior occurs in the Beaza SRT. The changing slope on the BHP vs rate chart for Beaza occurs continuously from approximately 0.55 to 0.58 psi/ft. The SRT at the Antelope Ridge Unit No. 4 shows a linear BHP vs rate trend over this gradient range from 0.561 psi/ft to the parting pressure gradient seen at 0.588 psi/ft.

Beaza was able to inject at a rate of 29,000 bbl/day before reaching the parting pressure gradient witnessed in the Antelope Ridge No. 4 of 0.588 psi/ft. Furthermore, no indication of slope change was observed in the Beaza data from 0.588 psi/ft to the final measured gradient of 0.592 psi/ft at an injection rate of 37,872 bbl/day. This indicates that Beaza is able to inject at rates in excess of the permitted rate of 10,000 bbl/day without approaching the parting pressure gradient of the injection zone. This is further supported by the parting pressure gradients seen at the other three offset wells which are significantly higher than the maximum gradient seen during testing at Beaza. The table below lists the initial and final bottom-hole pressure gradients ("BHG") seen during each step rate test as well as the parting pressure gradient, if identified during testing.

Step Rate Test Bottom-Hole Gradient Summary			
Well	**SRT Initial BHG (psi/ft)**	**SRT Parting Pressure BHG (psi/ft)**	**SRT Final BHG (psi/ft)**
Beaza SWD No. 1 (First SRT)	0.551	Not Identified	0.592
Beaza SWD No. 1 (Second SRT)	0.530	Not Identified	0.589
Antelope Ridge Unit No. 4	0.561	**0.588**	0.598
Antelope Ridge No. 5	0.620	**0.660**	0.674
North Bell Lake Unit No. 15	0.593	**> 0.647**	0.647
Curry Federal No. 2	BHG unknown (BH gauge depth not specified)		

Table 4 – Step Rate Test Bottom-Hole Gradient Summary

As requested in Order No. R-21441, this test and analysis has been performed in an effort to determine the parting pressure gradient of the injection formation in accordance with current OCD guidelines. We respectfully request a MASIP for the Beaza SWD No. 1 of 2,000 psi. Please call if you require additional information or clarification. Contact information is below:

Ben H. Bergman P.E.
1415 Louisiana St., Suite 3800
Houston, Texas 77002
Phone: 713-559-9990; ben@lonquist.com

Respectfully submitted:

Certified By:
Lonquist & Co., LLC

Ben H. Bergman 5/23/2022 P.E.

Ben H. Bergman, P.E.
Sr. Engineer
New Mexico License No. 23122

Date Signed: May 23rd
2022 Houston, Texas

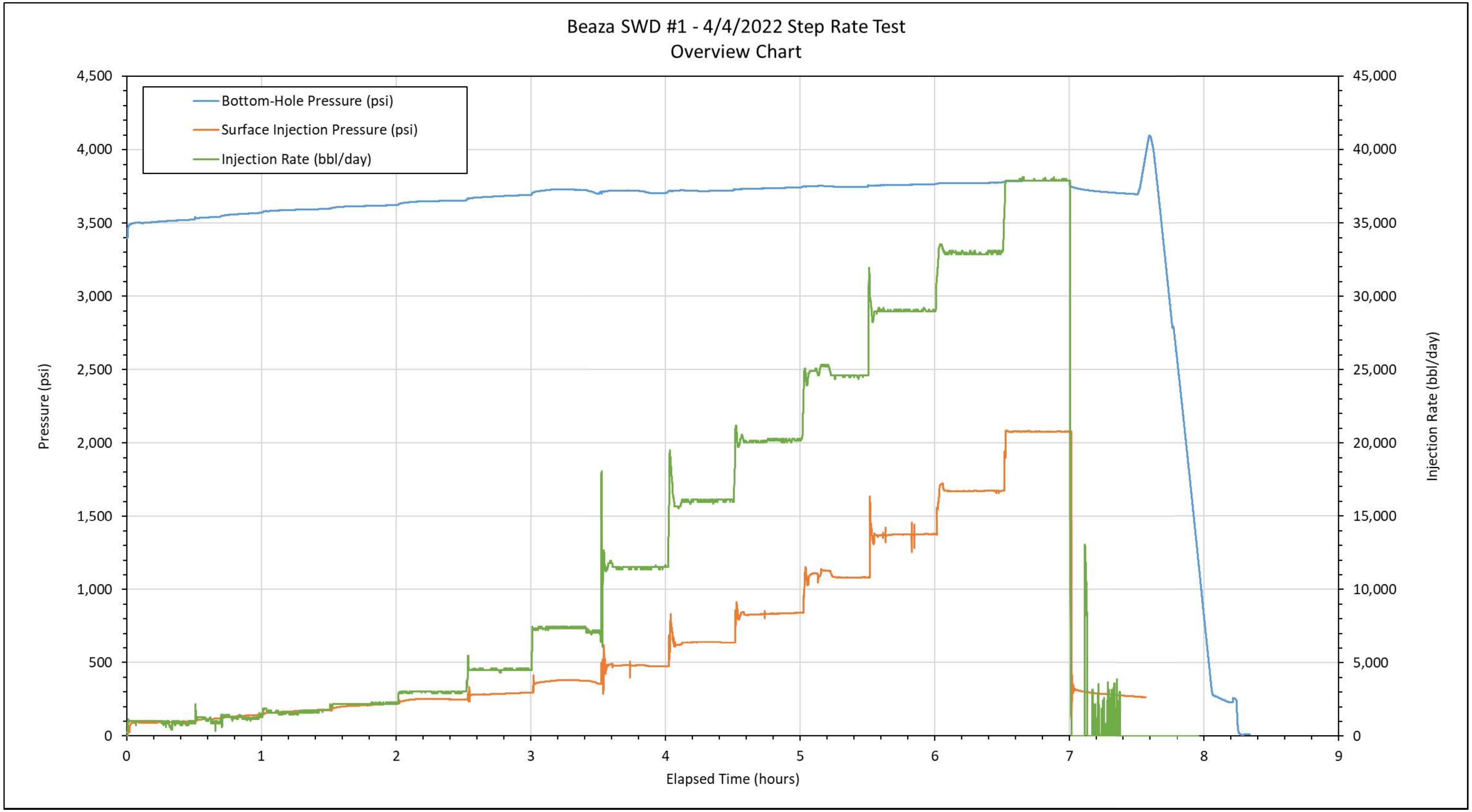


Figure 1 – First Step Rate Test Overview Chart

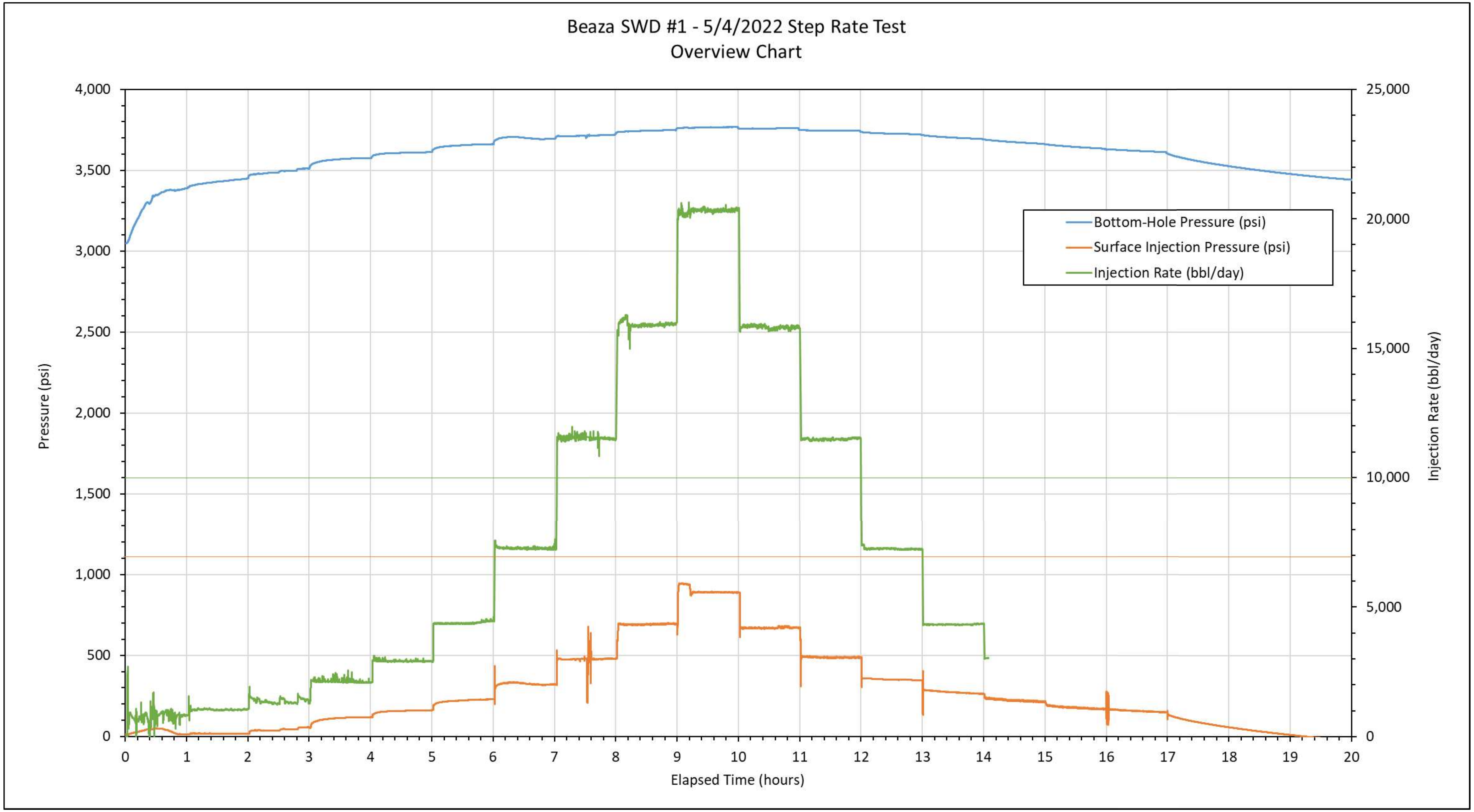


Figure 2 – Second Step Rate Test Overview Chart

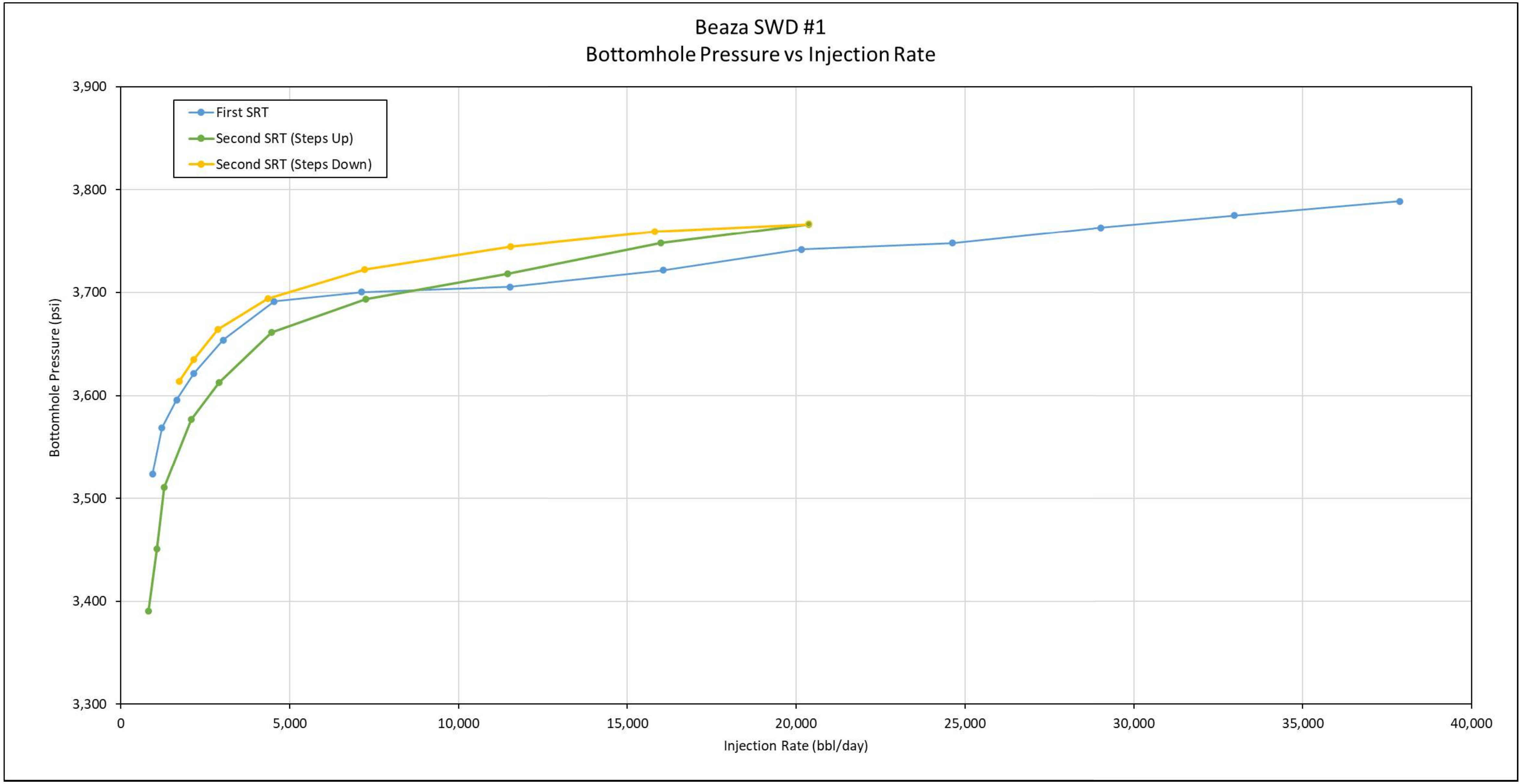


Figure 3 – Bottom-Hole Pressure vs Injection Rate Chart

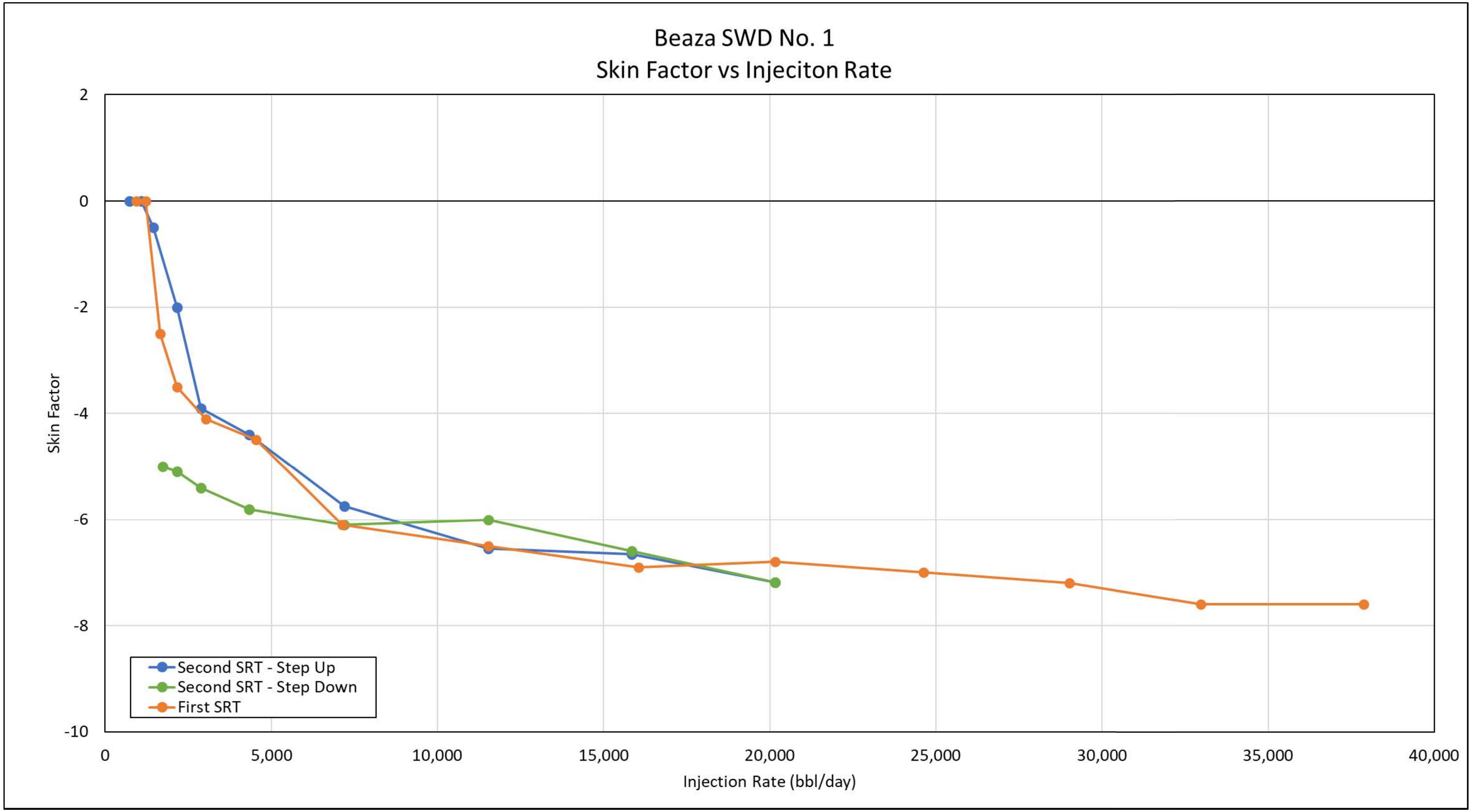


Figure 4 – Modeled Skin vs Injection Rate Chart

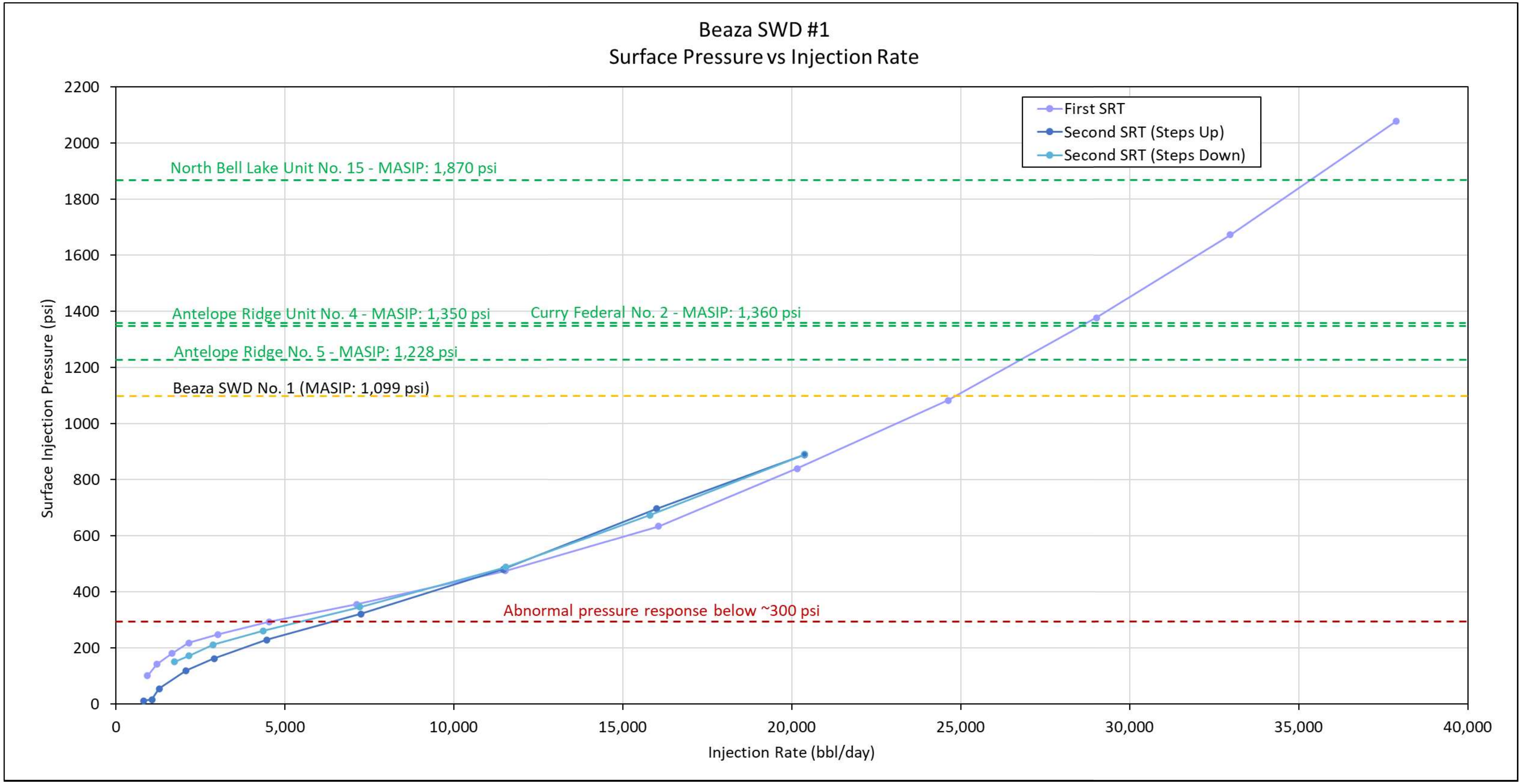


Figure 5 – Modeled Skin vs Injection Rate Chart

Maximize SWD Injection

ENHANCED ENERGETICS

Fracture past perf tunnel damage

- Create ideal flow paths for injection
- Extend useful life of SWD wells

Replace or enhance acid jobs

- Less time, cost and NPT than an acid job
- Allows acid to penetrate deeper into formation

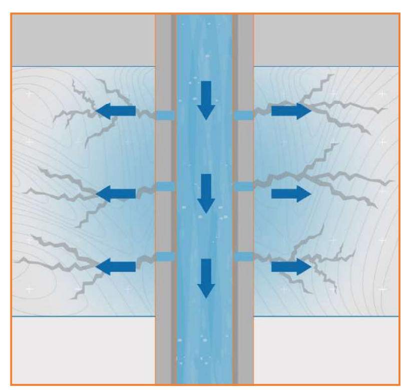
Lower pumping pressures

- Increase injection rates and volumes
- Reduce power consumption

Break down all perforations for injection

- Improve injectivity index and profile

Saltwater disposal and waterflood injection well efficiency is significantly improved with Kraken® propellant boosters. The efficiency gained by penetrating deeply beyond perforation tunnel damage lowers surface pressure, increases injection rates and achieves measurably lower injection cost per barrel. Kraken has allowed some operators to eliminate acid jobs or to decrease workover acid job frequency.



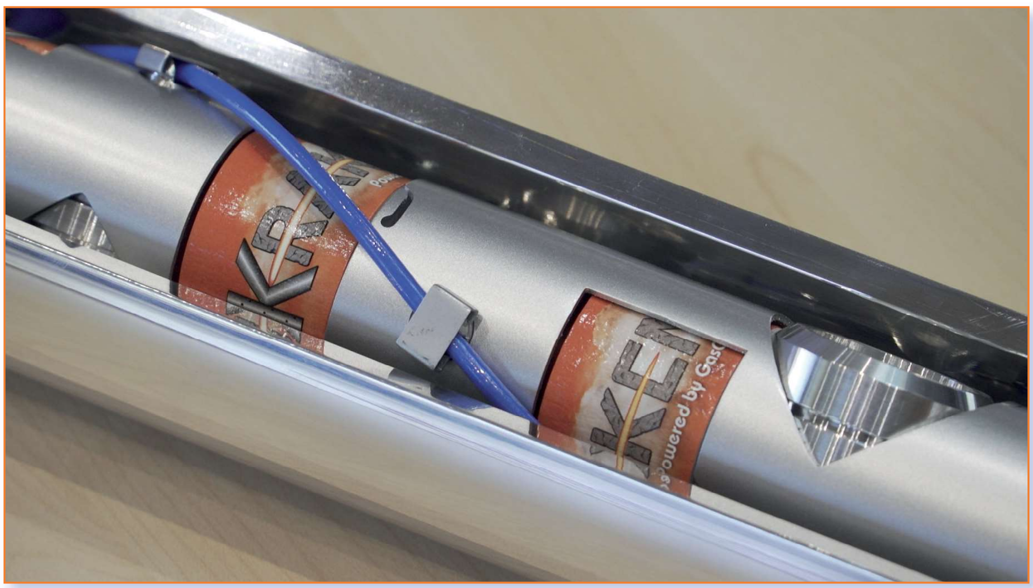
Hundreds of thousands of dollars can be saved by applying Kraken technology to new injection well completions and recompletions.

Kraken Enhanced Perforating Technology

Kraken technology is a progressively burning, solid propellant designed to increase penetration, eliminate clogged perforations and overcome near-wellbore damage from compaction caused by traditional perforators. Progressively burning Kraken propellant boosters generate high-pressure gas in the perforation tunnels, which creates fractures that improve well connectivity. Engineers who analyze Kraken results by breakdown pressure, initial production or injection increase (IP/II), operating time and safety will observe that the return on incremental investment in enhanced perforating performance routinely exceeds their expectations.

Enhanced Energetics offers a proven propellant-enhanced perforating technology (U.S. Patent 10,024,145 B1) designed to lower total cost of operations and improve profitability of vertical and horizontal producing and injection wells. Kraken® enhanced perforating is significantly more effective than standard perforating at improving completion and recompletion performance in conventional, unconventional and saltwater disposal wells. Standard gun systems and shaped charges can easily be enhanced with Kraken technology to

- Perforate and stimulate in one trip
- Create fractures in every perforation tunnel prior to hydraulic fracturing
- Bypass skin to enhance productivity or injectivity index
- Break down the formation to lower treating pressures and improve rates.



Gun size	2.75, 3.125, 4.0 in. [70, 79, 102 mm]
Typical gun swell	0.22 in. [5.6 mm]
Maximum shot density	6 spf [19 spm]
Maximum pressure	20,000 psi [138 MPa]
1-hr temperature rating*	280°F [138°C]
10-hr temperature rating*	260°F [127°C]

*Exceeding maximum temperature ratings can result in unintentional detonation.

Beaza SWD No. 1
Step Rate Test Injection Fluid Description

First Step Rate Test – 4/4/2022

Fluid Density:	10.3 ppg
Fluid Source:	Malaga 2 Brine Facility operated by Mesquite SWD, INC
Fluid Composition:	Brine containing dissolved NaCl and KCl

Second Step Rate Test – 5/4/2022

Fluid Density:	10.4 ppg
Fluid Source:	Malaga 2 Brine Facility operated by Mesquite SWD, INC
Fluid Composition:	Brine containing dissolved NaCl and KCl

State of New Mexico
Energy, Minerals and Natural Resources Department

Michelle Lujan Grisham
Governor

Sarah Cottrell Propst
Cabinet Secretary

Todd E. Leahy, JD, PhD
Deputy Secretary

Adrienne Sandoval, Director
Oil Conservation Division

Ramona Hovey
Milestone Environmental Services, LLC
E-mail: ramona@lonquist.com

RE: **Injection Pressure Increase; Order IPI-536**
Beaza SWD No. 1 (30-025-49600)
Injection Authority: Order No. R-21441
SWD;BELL CANYON-CHERRY CANYON (pool code: 96802)
UIC Class II Disposal Well

Dear Ramona Hovey:

Reference is made to your request on behalf of Milestone Environmental Services, LLC (OGRID 328435; the "Operator") for the application received June 16, 2022, to increase the maximum surface injection pressure ("MSIP"):

Well No.	API Number	UL-S-T-R	Injection Authority	Existing MSIP Limit (psi)	Existing Tubing OD (in)
Beaza SWD #1	30-025-49600	H-25-24S-34E	R-21441 SWD-2034	1100	4.5

It is the Oil Conservation Division's ("OCD") understanding that the requested pressure increase is needed to maintain the rate of injection and this pressure increase will not result in:

1. the fracturing of the permitted disposal interval;
2. the fracturing of either the upper or lower confining strata; or
3. induced-seismic events as a consequence of the higher injection pressure.

Based on the results of the submitted step rate injection test, the following shall be the new pressure limit while equipped with injection tubing:

Well No.	Step Rate Test Date	New MSIP Limit (psi)	While Injecting	Injection Interval (ft)	Pressure Gradient (psi/ft)
Beaza SWD #1	4/4/2022	**2000**	Slurry	5558-7208	0.36

This approval is based on the provision that the tubing size, packer setting depth and completion interval for the well does not change. Any future requested pressure increase will require resubmission of additional data and/or a new step-rate test. The Director retains the right to require, at any time, wireline verification of completion and packer setting depths in the well. This approval is subject to the Operator being in compliance with all other OCD rules including, but not limited to, Rule 19.15.5.9 NMAC.

The MSIP for the Beaza SWD No. 1 shall not exceed 2,000 pounds per square inch ("psi") for the operation following the issuance of this Order. After twelve (12) months of injection, the Operator shall submit a Form C-103 notice of intent ("NOI") to conduct a step-rate test and injection profile log on the Beaza SWD No. 1. No later than ninety (90) days after the NOI has been approved by the OCD, the Operator shall conduct the test and run the log. No later than ninety (90) days after the step-rate test has been conducted and the injection profile log has been run, the Operator shall submit a subsequent report summarizing the results (including field measurements) to the OCD. The OCD shall review the MSIP of this Order and the results to confirm that the injectate is being confined to the injection interval and that fracturing of the permitted disposal interval or confining strata is not occurring. The Director shall retain the authority to amend this Order should the results suggest that the injectate is not being confined, or that fracturing of the permitted disposal interval or confining strata is occurring.

Further, as stipulated in Order R-21441, the limitation of injection into the Beaza SWD No. 1 of not exceeding 10,000 barrels per day remains in full force and effect.

Further, the Director may rescind any injection pressure increase permit if it becomes apparent that the injectate is not being confined to the permitted disposal interval, impacts correlative rights, is endangering any freshwater aquifer or endangers public health and safety.

Sincerely,

[signature]

DATE: 9/14/2022

ADRIENNE SANDOVAL
Director

cc: Case File 20657
Order SWD-2034
Well file 30-025-49600
New Mexico State Land Office, OGML

LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS

May 23, 2022

Phillip Goetze
Hearing Examiner
Oil Conservation Division of New Mexico
1220 S. St. Francis Drive
Santa Fe, New Mexico 87505

RE: Step Rate Test Analysis
Milestone Environmental Services LLC
Beaza SWD No. 1 (30-025-49600)
Order No. R-21441

Dear Mr. Goetze:

Lonquist & Co. LLC ("Lonquist") is submitting an analysis of two step rate tests performed on the above referenced Beaza SWD No. 1 Disposal Well ("Beaza") in Lea County. This testing required by the Oil Conservation Division of New Mexico ("OCD") is pursuant to Order No. R-21441. This order requires that a step rate test ("SRT") be performed prior to commencing the second year of injection.

The maximum sustained injection rate for the first test was 37,872 bbl/day. This was estimated to be the maximum safe fluid velocity for injection through the 4-1/2" diameter tubing. The second test reached a maximum sustained injection rate of 23,380 bbl/day, and was performed to verify reservoir behavior at lower injection rates. The pressure vs. rate chart (Figure 3) showed a gradual decrease in slope for the first several stages of each test. As discussed below, this behavior is known as rate-dependent skin. After a thorough analysis, the determination was made that it is highly unlikely that the formation parting pressure was reached during the tests and the results were inconclusive in the identification of the formation parting pressure gradient for this well. Additionally, it is believed that a repeat SRT would yield equally inconclusive results within the maximum safe fluid velocity for this well. Available SRT data from offset wells has been provided in this report and demonstrates for the currently permitted injection range that formation parting pressure was not reached in Beaza SWD No. 1.

This letter documents the analysis and conclusions of the tests. The next sections of the report detail the test procedures, data analysis and results, followed by the evaluation of offset SRTs and conclusions. The attached set of figures provides graphic depictions of the analysis and findings.

Test Procedure

The initial test was performed prior to initial injection, on April 4, 2022. This was done to ensure that the bottom hole pressure would be at or near the native reservoir pressure. Surface pressure was monitored in the tubing throughout the test and bottom-hole pressure readings were captured by a pressure gauge set at 6,400 feet. Surface pressure, bottom-hole pressure, and flow rate readings were captured and recorded at one-second intervals. Fourteen stages of continuous-rate injection were performed at incrementally increasing volumes. Injection at each stage was performed at equal time intervals of 30 minutes throughout the test. Injection began at very low rates in order to ensure that formation behavior would be adequately observed prior to the formation parting pressure were it to occur earlier than anticipated. At the completion of the final injection stage, pumping was ceased and the well was shut-in, allowing pressure to bleed-off into the injection zone. Figure 1 in the attached analysis provides an overview of the pressures and flow rate data captured during the first test.

Anomalous pressure behavior in the low-rate steps led to speculation that fluid movement was being constrained to a limited portion of the perforated intervals early in the test. A revised test procedure to counter this behavior was proposed and a second test was performed.

The second test was performed on May 4, 2022. The well remained shut-in between the first and second test. Similar to the initial test, surface pressure was monitored in the tubing and bottom-hole pressure readings were captured by a pressure gauge set at 6,400 feet. Surface pressure, bottom-hole pressure, and flow rate readings were captured and recorded at one-second intervals. Seventeen injection stages were performed, ten at increasing rates, followed by seven at decreasing rates. The decreasing rate stages were included in the second test to confirm reservoir behavior and ensure that all perforations were accepting fluid during low injection rate stages. Additionally, the duration of each stage was increased from 30 minutes in the initial test to 60 minutes to ensure pressure stabilization. Figure 2 in the attached analysis provides an overview of the pressures and flow rate data captured during the second test.

Data Analysis and Results

Bottom-hole pressure and flow rate measurements at the end of each injection stage were isolated to generate Table 1 and Table 2 below for each test.

First SRT (4/4/2022)			
Step	Flow Rate (bbl/min)	Flow Rate (bbl/day)	Bottom-hole Pressure (psi)
1	0.7	936	3,523
2	0.8	1,210	3,569
3	1.2	1,656	3,596
4	1.5	2,160	3,622
5	2.1	3,024	3,654
6	3.2	4,536	3,692
7	5.0	7,128	3,700
8	8.0	11,520	3,705
9	11.2	16,056	3,722
10	14.0	20,160	3,742
11	17.1	24,624	3,748
12	20.2	29,016	3,763
13	22.9	32,976	3,775
14	26.3	37,872	3,789

Table 1 – Summary of First SRT

Second SRT (5/4/2022)			
Step	Flow Rate (bbl/min)	Flow Rate (bbl/day)	Bottom-hole Pressure (psi)
1	0.6	814	3391
2	0.7	1068	3451
3	0.9	1284	3511
4	1.4	2077	3577
5	2.0	2905	3613
6	3.1	4458	3661
7	5.0	7243	3694
8	8.0	11457	3718
9	11.1	15997	3748
10	14.2	20380	3766
11	11.0	15807	3759
12	8.0	11533	3744
13	5.0	7223	3722
14	3.0	4357	3694
15	2.0	2880	3664
16	1.5	2160	3635
17	1.2	1728	3614

Table 2 – Summary of Second SRT

Bottom-hole Pressure vs. Injection Rate

Bottom-hole pressures from each table were plotted against the associated injection rates to illustrate their relationship. This is provided as Figure 3 in the attached analysis. The plot resulted in a continuous gradual decrease in slope throughout the low-rate stages of both tests followed by a linear trend at higher rates in the first test.

Typically, SRT data plotted in this way reveals one or more discrete changes in slope preceded and followed by linear trends. The distinct changes in slope are used to identify formation parting pressure, or their absence, in the case of a continuous straight line, indicates that the parting pressure was not reached.

During each change in injection rate, the data from these tests depicts a continuous and consistent transition in the effective permeability encountered in the formation for the first eight steps in both tests and for the entire step-down portion of the second test. This pressure response is indicative of a near-wellbore permeability (or skin) that varies with the injection rate. This behavior is known as rate-dependent skin. To verify this observation, the magnitude and shape of the pressure rises in each step were modeled in PanSystem™, a well testing analysis software. The skin value was adjusted for each step to achieve a match between pressure change and injection rate. The modeled skin value from each step was plotted against the associated injection rate. This plot has been provided as Figure 4. The plot depicts the strongly dependent relationship between skin and injection rate, particularly during the lower-rate steps. This is indicative of a rate-dependent skin as identified in studies of injection wells that exhibit this behavior. This phenomenon is explained by a gradual increase in the width of preexisting near-wellbore fractures as pressures rise due to injection. The increasing near-wellbore fracture width results in a decreasing skin value.

Given these findings, it is likely that near-wellbore fractures were created during the well completion and existed prior to commencement of these tests. The well was perforated with propellant enhanced perforating charges which are designed to create near-wellbore fractures for improved injectivity in disposal wells. Similar pressure behavior was observed in the SRT of another disposal well analyzed by Lonquist which utilized the same perforating technology for a completion in the Delaware Mountain Group ("DMG") in Loving County, TX. In the case of Beaza, a considerable quantity of these charges were deployed over a broad portion of the injection interval. In total, 1,600 of the specialty charges were detonated at a spacing of 4 shots per foot in the lower 400 feet of the 786 feet perforated interval. 2,316 standard 0.52" EHD charges were detonated at spacing of 6 shots per foot on the upper 386 feet of the perforated interval. A product brochure outlining the specific properties of this specialty perforating technology has been provided as an attachment to this report.

<u>Parting Pressure of Confining Layers</u>

Given the magnitude of the pressure gradients reached during these injection tests and the associated injection depths, it is unlikely that damage would have been caused to the upper or lower confining formations. The highest formation pressure gradient recorded during these tests was 0.592 psi/ft at an injection rate of 37,872 bbl/day. This gradient is significantly lower than the parting pressure gradients estimated from published literature for the upper confining layer, the Castile anhydrite, and the lower confining layer, the Bone Spring. These confining layers have been noted to exhibit parting pressure gradients of roughly of 0.66 psi/ft and 0.75 psi/ft, respectively.

Analog Well Discussion and Conclusions

Step Rate Test data from analog injection wells suggests that the formation parting pressure gradient was not reached during testing at Beaza. Data from the nearest four DMG disposal wells with publicly available SRT reports was considered. Following step rate testing on each of these four wells, MASIP values were issued to reflect the findings of these tests. These wells and their respective MASIPs are listed in the Table 3 below for reference.

Well	MASIP (psi)	MASIP (psi/ft)
Beaza SWD No. 1	1,099	0.200
Antelope Ridge Unit No. 4	1,350	0.261
Antelope Ridge No. 5	1,228	0.238
Curry Federal No. 2	1,360	0.260
North Bell Lake Unit 4 No .15	1,870	0.370

Table 3 – MASIP Summary

Figure 5 shows the MASIPs assigned for each of these four offset wells overlaid with surface pressure vs injection rate for the Beaza SRTs. All anomalous pressure behavior in the Beaza tests can be seen to lie beneath a surface injection pressure of 300 psi and below a rate of 5,000 bbl/day. Aside from a slight upward curve due to friction in the tubing, a linear relationship in the Beaza data can be seen for pressures and rates above 300 psi and 5,000 bbl/day. The currently assigned MASIP for Beaza is not reached until an injection rate of about 25,000 bbl/day, significantly surpassing the permitted maximum of 10,000 bbl/day. The MASIPs from the four closest DMG offset injection wells with SRT data are not reached until higher rates, and the linear pressure vs. rate trend remains consistent until the highest step is reached at a rate of 37,872 bbl/day and an injection pressure of 2,077 psi.

The nearest of the offset wells reviewed was the Antelope Ridge Unit No. 4 which is located 5.5 miles northwest of Beaza. While the other three offset SRTs begin at higher bottomhole pressure gradients, the Antelope Ridge Unit No. 4 covers the range of pressure gradients over which the anomalous pressure behavior occurs in the Beaza SRT. The changing slope on the BHP vs rate chart for Beaza occurs continuously from approximately 0.55 to 0.58 psi/ft. The SRT at the Antelope Ridge Unit No. 4 shows a linear BHP vs rate trend over this gradient range from 0.561 psi/ft to the parting pressure gradient seen at 0.588 psi/ft.

Beaza was able to inject at a rate of 29,000 bbl/day before reaching the parting pressure gradient witnessed in the Antelope Ridge No. 4 of 0.588 psi/ft. Furthermore, no indication of slope change was observed in the Beaza data from 0.588 psi/ft to the final measured gradient of 0.592 psi/ft at an injection rate of 37,872 bbl/day. This indicates that Beaza is able to inject at rates in excess of the permitted rate of 10,000 bbl/day without approaching the parting pressure gradient of the injection zone. This is further supported by the parting pressure gradients seen at the other three offset wells which are significantly higher than the maximum gradient seen during testing at Beaza. The table below lists the initial and final bottom-hole pressure gradients ("BHG") seen during each step rate test as well as the parting pressure gradient, if identified during testing.

Step Rate Test Bottom-Hole Gradient Summary			
Well	**SRT Initial BHG (psi/ft)**	**SRT Parting Pressure BHG (psi/ft)**	**SRT Final BHG (psi/ft)**
Beaza SWD No. 1 (First SRT)	0.551	Not Identified	0.592
Beaza SWD No. 1 (Second SRT)	0.530	Not Identified	0.589
Antelope Ridge Unit No. 4	0.561	**0.588**	0.598
Antelope Ridge No. 5	0.620	**0.660**	0.674
North Bell Lake Unit No. 15	0.593	**> 0.647**	0.647
Curry Federal No. 2	BHG unknown (BH gauge depth not specified)		

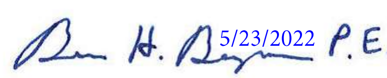
Table 4 – Step Rate Test Bottom-Hole Gradient Summary

As requested in Order No. R-21441, this test and analysis has been performed in an effort to determine the parting pressure gradient of the injection formation in accordance with current OCD guidelines. We respectfully request a MASIP for the Beaza SWD No. 1 of 2,000 psi. Please call if you require additional information or clarification. Contact information is below:

Ben H. Bergman P.E.
1415 Louisiana St., Suite 3800
Houston, Texas 77002
Phone: 713-559-9990; ben@lonquist.com

Respectfully submitted:

Certified By:
Lonquist & Co., LLC



Ben H. Bergman, P.E.
Sr. Engineer
New Mexico License No. 23122

Date Signed: May 23rd
2022 Houston, Texas

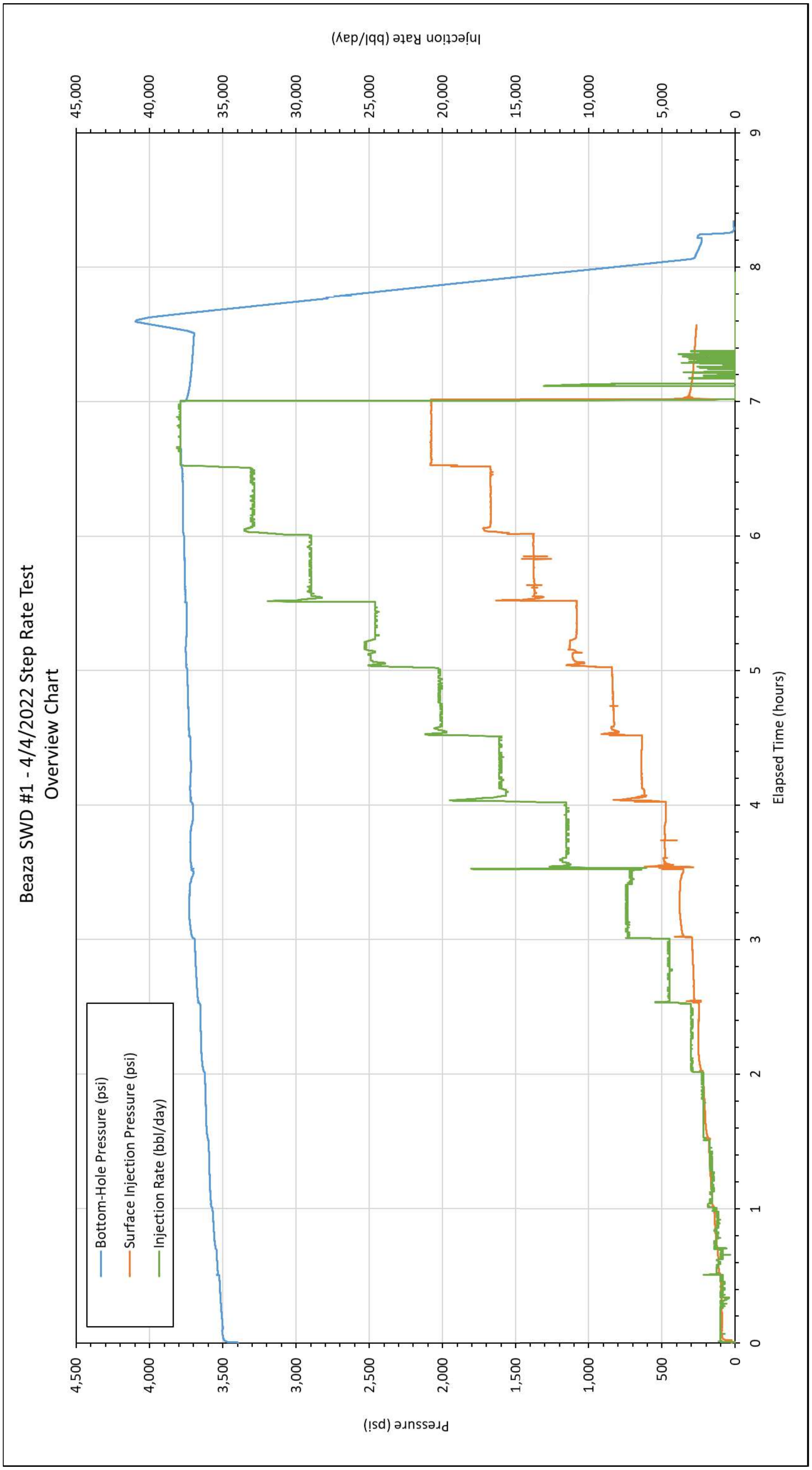


Figure 1 – First Step Rate Test Overview Chart

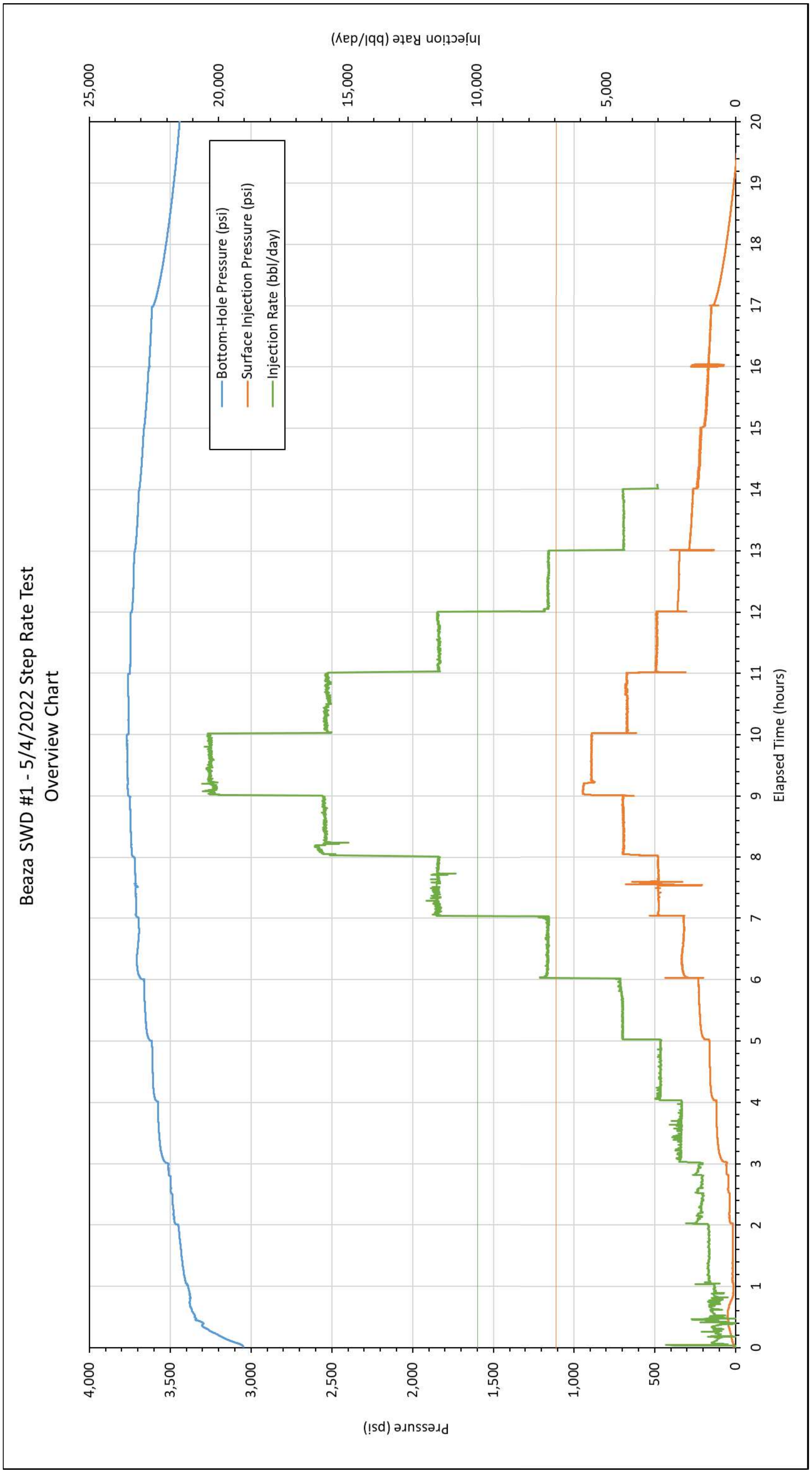


Figure 2 – Second Step Rate Test Overview Chart

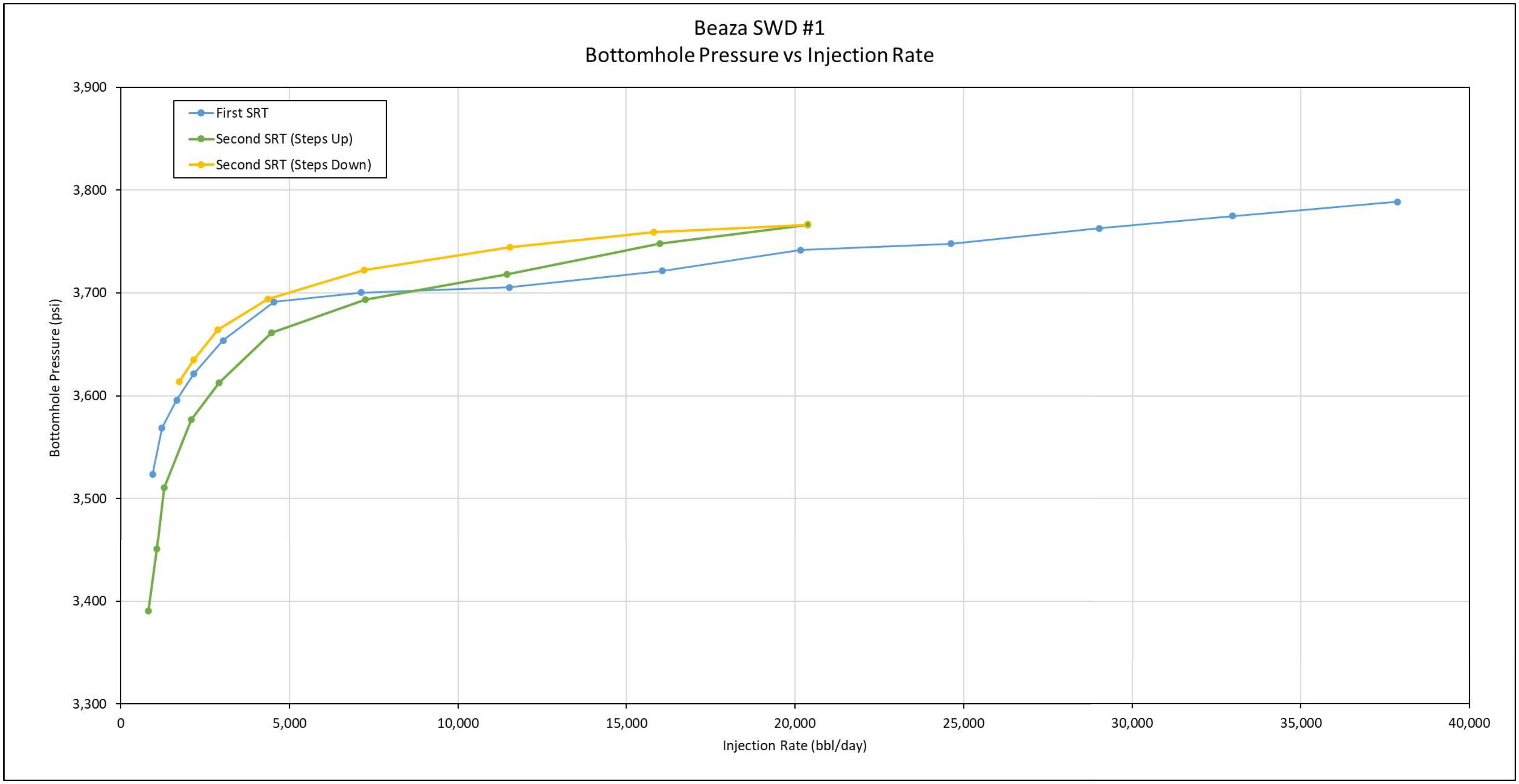


Figure 3 – Bottom-Hole Pressure vs Injection Rate Chart

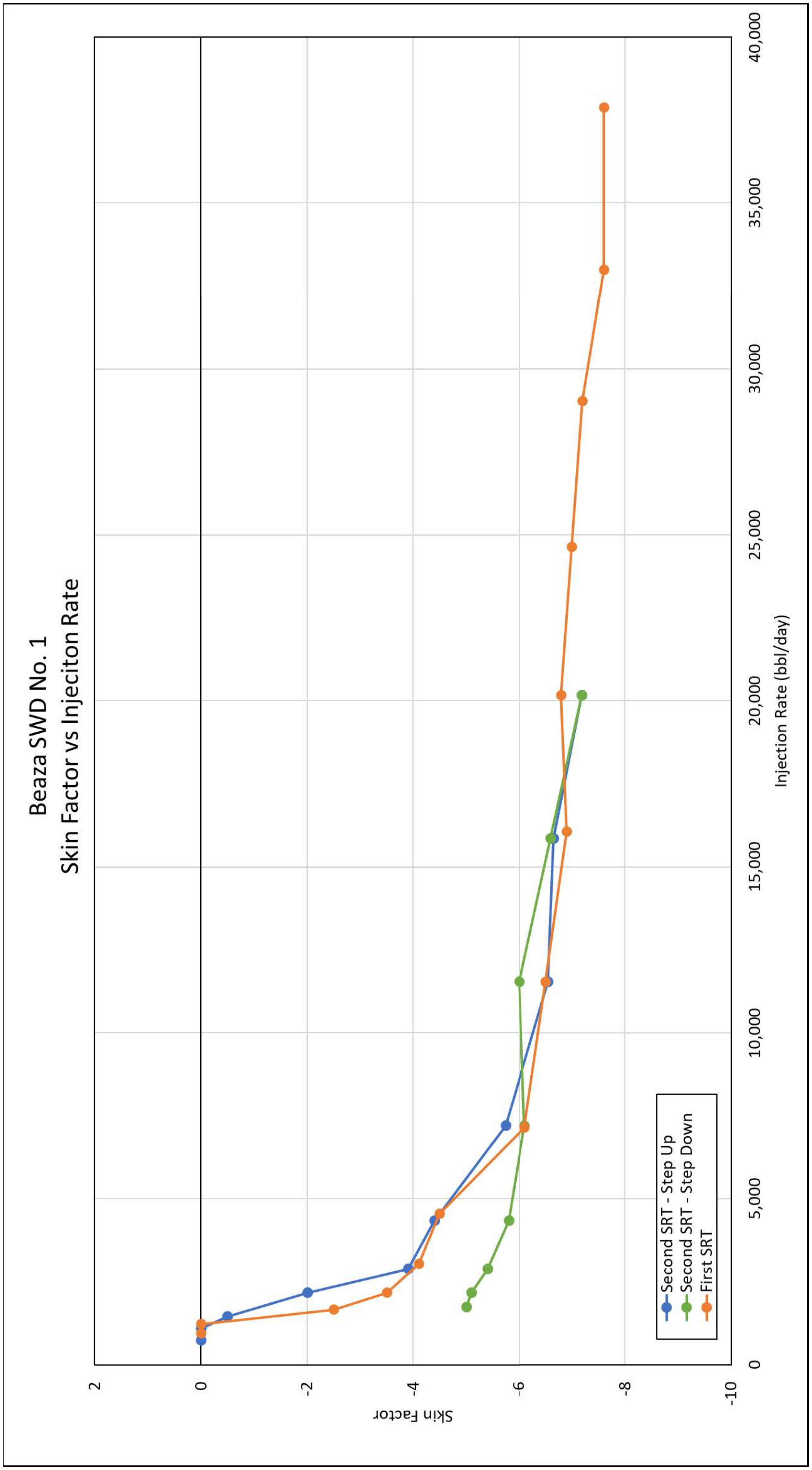


Figure 4 – Modeled Skin vs Injection Rate Chart

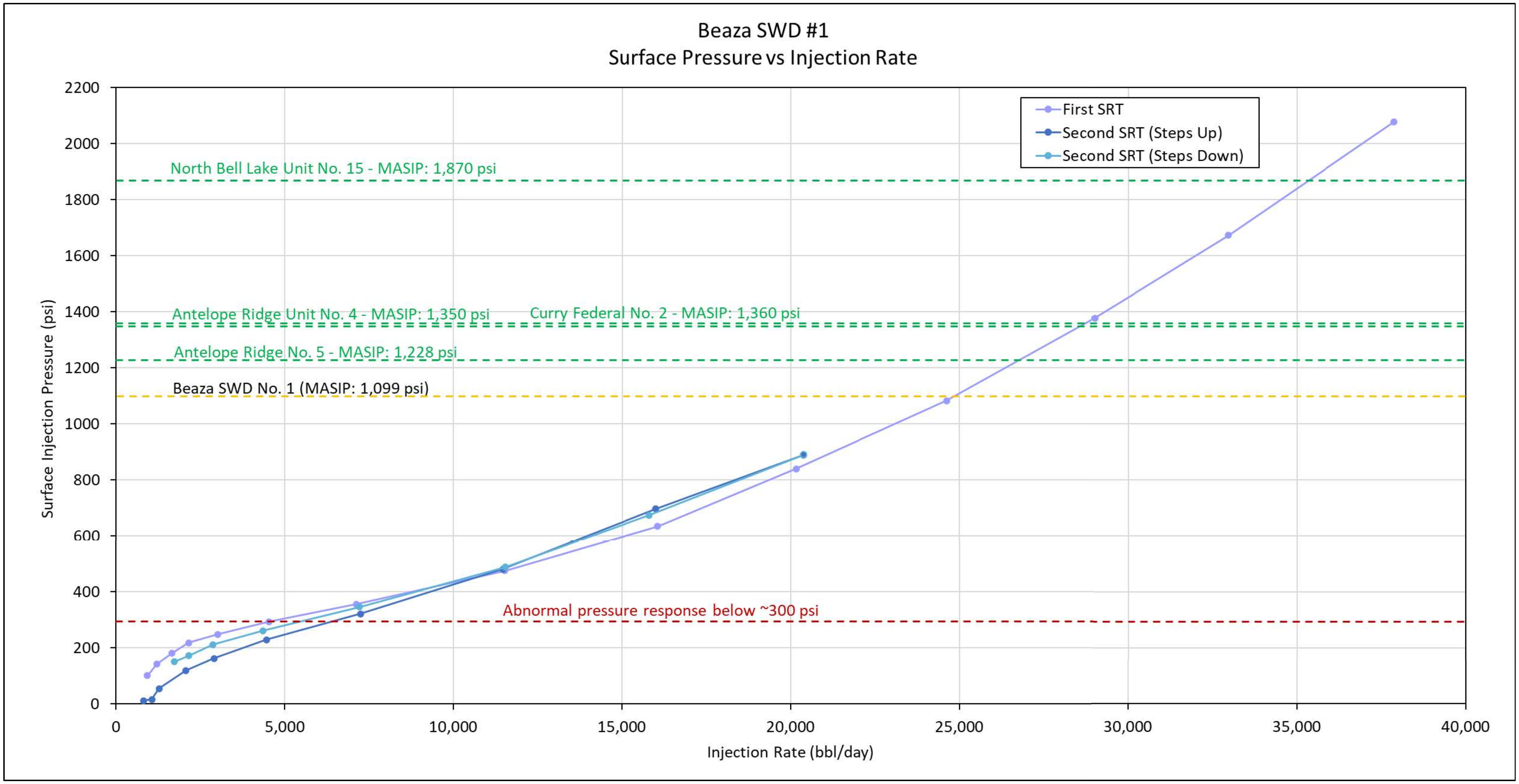


Figure 5 – Modeled Skin vs Injection Rate Chart

Maximize SWD Injection

ENHANCED ENERGETICS

Fracture past perf tunnel damage

- Create ideal flow paths for injection
- Extend useful life of SWD wells

Replace or enhance acid jobs

- Less time, cost and NPT than an acid job
- Allows acid to penetrate deeper into formation

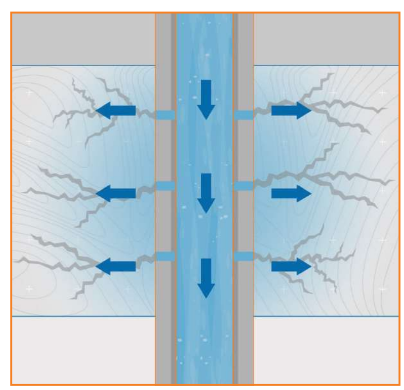
Lower pumping pressures

- Increase injection rates and volumes
- Reduce power consumption

Break down all perforations for injection

- Improve injectivity index and profile

Saltwater disposal and waterflood injection well efficiency is significantly improved with Kraken® propellant boosters. The efficiency gained by penetrating deeply beyond perforation tunnel damage lowers surface pressure, increases injection rates and achieves measurably lower injection cost per barrel. Kraken has allowed some operators to eliminate acid jobs or to decrease workover acid job frequency.



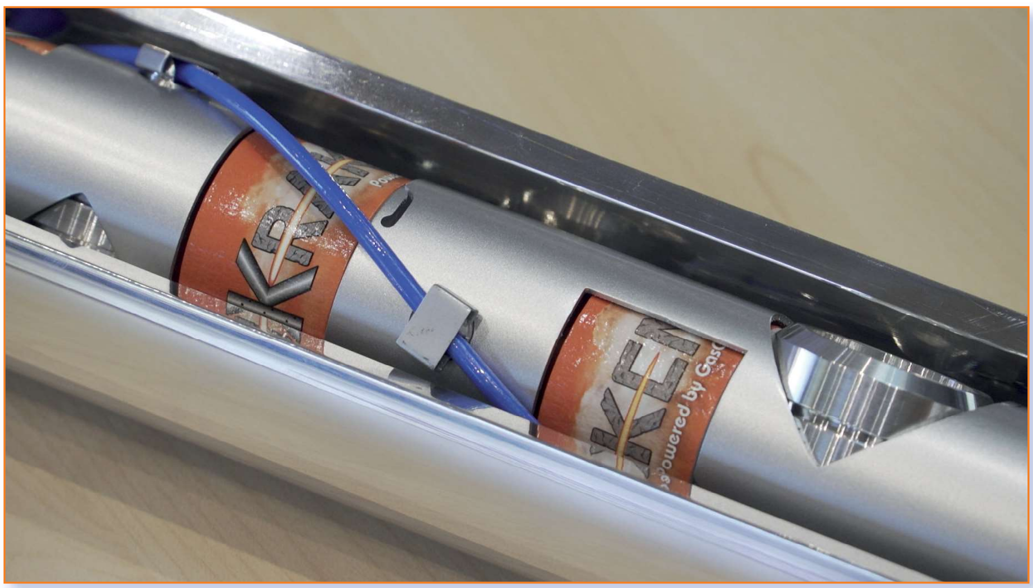
Hundreds of thousands of dollars can be saved by applying Kraken technology to new injection well completions and recompletions.

Kraken Enhanced Perforating Technology

Kraken technology is a progressively burning, solid propellant designed to increase penetration, eliminate clogged perforations and overcome near-wellbore damage from compaction caused by traditional perforators. Progressively burning Kraken propellant boosters generate high-pressure gas in the perforation tunnels, which creates fractures that improve well connectivity. Engineers who analyze Kraken results by breakdown pressure, initial production or injection increase (IP/II), operating time and safety will observe that the return on incremental investment in enhanced perforating performance routinely exceeds their expectations.

Enhanced Energetics offers a proven propellant-enhanced perforating technology (U.S. Patent 10,024,145 B1) designed to lower total cost of operations and improve profitability of vertical and horizontal producing and injection wells. Kraken® enhanced perforating is significantly more effective than standard perforating at improving completion and recompletion performance in conventional, unconventional and saltwater disposal wells. Standard gun systems and shaped charges can easily be enhanced with Kraken technology to

- Perforate and stimulate in one trip
- Create fractures in every perforation tunnel prior to hydraulic fracturing
- Bypass skin to enhance productivity or injectivity index
- Break down the formation to lower treating pressures and improve rates.



Gun size	2.75, 3.125, 4.0 in. [70, 79, 102 mm]
Typical gun swell	0.22 in. [5.6 mm]
Maximum shot density	6 spf [19 spm]
Maximum pressure	20,000 psi [138 MPa]
1-hr temperature rating*	280°F [138°C]
10-hr temperature rating*	260°F [127°C]

*Exceeding maximum temperature ratings can result in unintentional detonation.

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Step Rate Test Procedure			**Project No.:** 2375
	Milestone Environmental Services LLC			**Date:** April 25, 2022
				Page: 1 **of** 6
Well: Beaza SWD No. 1	**State:** NM	**County:** Lea	**API:** 30-025-49600	**District:** 1 (Hobbs)

INTRODUCTION:

Milestone Environmental Services LLC ("Milestone") has requested Lonquist & Co, LLC ("LCO") prepare procedures for a Step Rate Test ("SRT") on Beaza SWD No. 1. This test is being performed to support an application for injection pressure increase at the subject well. This procedure will follow the draft guidance document for the Application Process for Injection Pressure Increases provided by the Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department ("OCD").

The general scope of the work is as follows:

- If required by the District, a bradenhead test and mechanical integrity test (MIT) will be performed. The well must pass both tests before a SRT can be performed.
- Prior to testing, shut in the well long enough, but not less than 48 hours to ensure that the bottom hole pressure is at or near the shut-in formation pressure.
- Procure a minimum of nine (11) 500-bbl frac tanks
- Fill tanks with clean brine water from a client facility or third-party source
- MIRU pumps and iron
- MIRU WL unit and Perform gauge ring run
- TIH with BHP gauge to the mid-perf depth
- If wellbore is not full, fill with brine at 0.5 BPM
- Allow pressure to stabilize
- Step up rates as detailed in the Rate Schedule table
- Shut in well completely and record pressure fall-off
- Conclude test and RDMO pumps and WL unit

OBJECTIVES

Perform a step-rate test that:

1. Adheres precisely to the flow rates and durations included in the Rate Schedule below
2. Confirms well behavior witnessed in previous step rate test
3. Record fall-off pressure for an extended duration

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	

LONQUIST & CO. LLC — PETROLEUM ENGINEERS / ENERGY ADVISORS	Step Rate Test Procedure	Project No.: 2375
	Milestone Environmental Services LLC	Date: April 25, 2022
		Page: 2 of 6

Well: Beaza SWD No. 1	State: NM	County: Lea	API: 30-025-49600	District: 1 (Hobbs)

REGULATORY INFORMATION:

The Beaza SWD No. 1 is regulated by the New Mexico OCD. The operator must submit Division Form C-103 to the OCD District office with the description of the procedure for the SRT prior to the test. Once the operator has an approved Sundry Notice, the operator shall notify the appropriate OCD District office at least 72 hours prior to the scheduled SRT so that OCD personnel may be present to witness the test. A bradenhead test (if required by the District) and mechanical integrity test (MIT) will be performed before the SRT. If the subject well fails either test, then the SRT will be suspended until the mechanical integrity issue(s) has been remediated. The mechanical integrity testing may be modified at the discretion of the District Supervisor.

The completed SRT results are to be submitted to the Engineering Bureau in Santa Fe and should include the following information:

- Administrative application checklist (available on OCD website under Unnumbered Forms on Form webpage).
- Cover letter with contact information, general description of test and pressure increase being proposed.
- Complete data summary including injection rates, duration of each step, pressure measurements (surface and bottom hole) and the ISIP.
- SRT-specific information: location of pressure gauges (depth); initial bottomhole pressure; injection fluid type and specific gravity.
- Graph summary of pressure versus injection rate with interpretation.
- Current well completion diagram.
- Copy of the order authorizing the injection into the well.

If a pressure increase is granted, it shall be limited for use in the well with the same tubing, size, length, and type of interior coating as present for the SRT. If these components are changed, the operator must ask the Engineering Bureau to recalculate the surface pressure limit, which may require another SRT.

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Step Rate Test Procedure	Project No.: 2375
	Milestone Environmental Services LLC	Date: April 25, 2022 Page: 3 of 6

Well: Beaza SWD No. 1	State: NM	County: Lea	API: 30-025-49600	District: 1 (Hobbs)

STEP-RATE TEST DETAILED PROCEDURE:

1. Once the operator has an approved Sundry Notice, notify appropriate OCD District office at least 72 hours prior to the scheduled SRT so that OCD personnel may be present to witness the test.
2. If required by the District, a bradenhead test and mechanical integrity test (MIT) will be performed. The well must pass both tests before an SRT can begin.
3. Prior to testing, shut in the well long enough, but not less than 48 hours to ensure that the bottom hole pressure is at or near the shut-in formation pressure
   a. Pressure should be recorded for the duration of the shut in to confirm stabilization
4. Set a minimum of eleven (11) 500-bbl frac tanks (Enough to complete the planned test with contingency brine)
   a. Fill with a minimum of 5,500 bbls of clean brine water from a client facility or third-party source
5. RU pumps and iron
   a. MIRU kill trucks/frac pumps and lay iron
   b. Pumps, iron and flow control should be sized so that steps in rate will not create pressure or rate transients, other than those caused by the intended steps
6. If not already present, install flow meter(s) and surface pressure gauge capable of digitally recording injection rates and pressures
   a. Recording frequency of one second or less is ideal
   b. Pressure gauges and flow meters should have continuous readout for observation throughout test
   c. Ensure pressure gauges are recently calibrated and able to accommodate the full range of expected rates and pressures
7. MIRU WL
8. Perform gauge ring run
9. PU BHP gauge and RIH to the mid-perf depth, ensure the gauge is calibrated
10. Ensure the wellbore is full of brine before initiating the test
    a. If necessary, fill hole with brine at a constant rate of 0.5 BPM
    b. Once the well is full, stop pumping and allow the pressure to stabilize
11. Begin test at an injection rate of 0.5 BPM for 30 minutes
    a. **Surface injection pressure, bottomhole pressure, and injection rate must be digitally recorded for the duration of the test**
12. Step up rates per the table included below
    a. Surface pressure should not exceed 80% of the maximum pressure rating of the wellhead at any time
    b. Changes in flow rate must occur over as short of intervals as possible
    c. Injection rates should be controlled with a constant flow regulator
    d. All injection flow rates, including hole conditioning treatments prior to the test, must be documented on service company forms
    e. Haul additional brine as needed
    f. A minimum of three fluid samples should be caught throughout the test, at the beginning, middle and end
       i. The density of the samples will be read by an in-house method
       ii. Fluid density will be reported to the OCD with SRT results

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Step Rate Test Procedure			Project No.: 2375
	Milestone Environmental Services LLC			Date: April 25, 2022 Page: 4 of 6
Well: Beaza SWD No. 1	**State:** NM	**County:** Lea	**API:** 30-025-49600	**District:** 1 (Hobbs)

13. Upon completion of the final injection stage, the line valve must be closed to stop injection immediately. This will allow the pressure to bleed off into the formation.
    a. Ensure that pressure values are recorded at the highest obtainable frequency during shut-in
    b. Continue to capture falloff pressure data for an extended duration
    c. Monitor for fracture closure and/or original reservoir pressure
14. Conclude test
    a. POOH with BHP gauge
    b. RDMO WL
15. The completed SRT results are to be submitted to the Engineering Bureau in Santa Fe and should include the following information:
    a. Administrative application checklist (available on OCD website under Unnumbered Forms on Form webpage).
    b. Cover letter with contact information, general description of test and pressure increase being proposed.
    c. Complete data summary including injection rates, duration of each step, pressure measurements (surface and bottom hole) and the ISIP.
    d. SRT-specific information: location of pressure gauges (depth) initial bottomhole pressure; injection fluid type and specific gravity.
    e. Graph summary of pressure versus injection rate with interpretation.
    f. Current well completion diagram.
    g. Copy of the order authorizing the injection into the well.

EQUIPMENT DESCRIPTION

- Surface Pressure Gauge with continuous readout and digital data recording
- Bottomhole Pressure Gauge with live surface readout and digital data recording
- In-line Flow Meter with a rate range that includes 0.5 BPM to 14 BPM

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Step Rate Test Procedure			Project No.: 2375
	Milestone Environmental Services LLC			Date: April 25, 2022 Page: 5 of 6
Well: Beaza SWD No. 1	**State:** NM	**County:** Lea	**API:** 30-025-49600	**District:** 1 (Hobbs)

RATE SCHEDULE

- Schedule is subject to change. Durations may increase to accommodate pressure stabilization and rates may change based on pressure behavior indicative of formation fracture.

Step No.	Injection Rate			Duration (minutes)	Stage Volume (BBL)	Cumulative Volume (BBL)
	BPM	GPM	BPD			
1	0.5	21	720	60	30	30
2	0.75	31.5	1080	60	45	75
3	1	42	1440	60	60	135
4	1.5	63	2160	60	90	225
5	2	84	2880	60	120	345
6	3	126	4320	60	180	525
7	5	210	7200	60	300	825
8	8	336	11520	60	480	1305
9	11	462	15840	60	660	1965
10	14	588	20160	60	840	2805
11	11	462	15840	60	660	3465
12	8	336	11520	60	480	3945
13	5	210	7200	60	300	4245
14	3	126	4320	60	180	4425
15	2	84	2880	60	120	4545
16	1.5	63	2160	60	90	4635
17	1	42	1440	60	60	4695
18	0.75	31.5	1080	60	45	4740
19	0.5	21	720	60	30	4770

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS	Step Rate Test Procedure			Project No.: 2375
	Milestone Environmental Services LLC			Date: April 25, 2022
				Page: 6 of 6
Well: Beaza SWD No. 1	**State:** NM	**County:** Lea	**API:** 30-025-49600	**District:** 1 (Hobbs)

INJECTION HISTORY

This is a new well that has not yet commenced injection

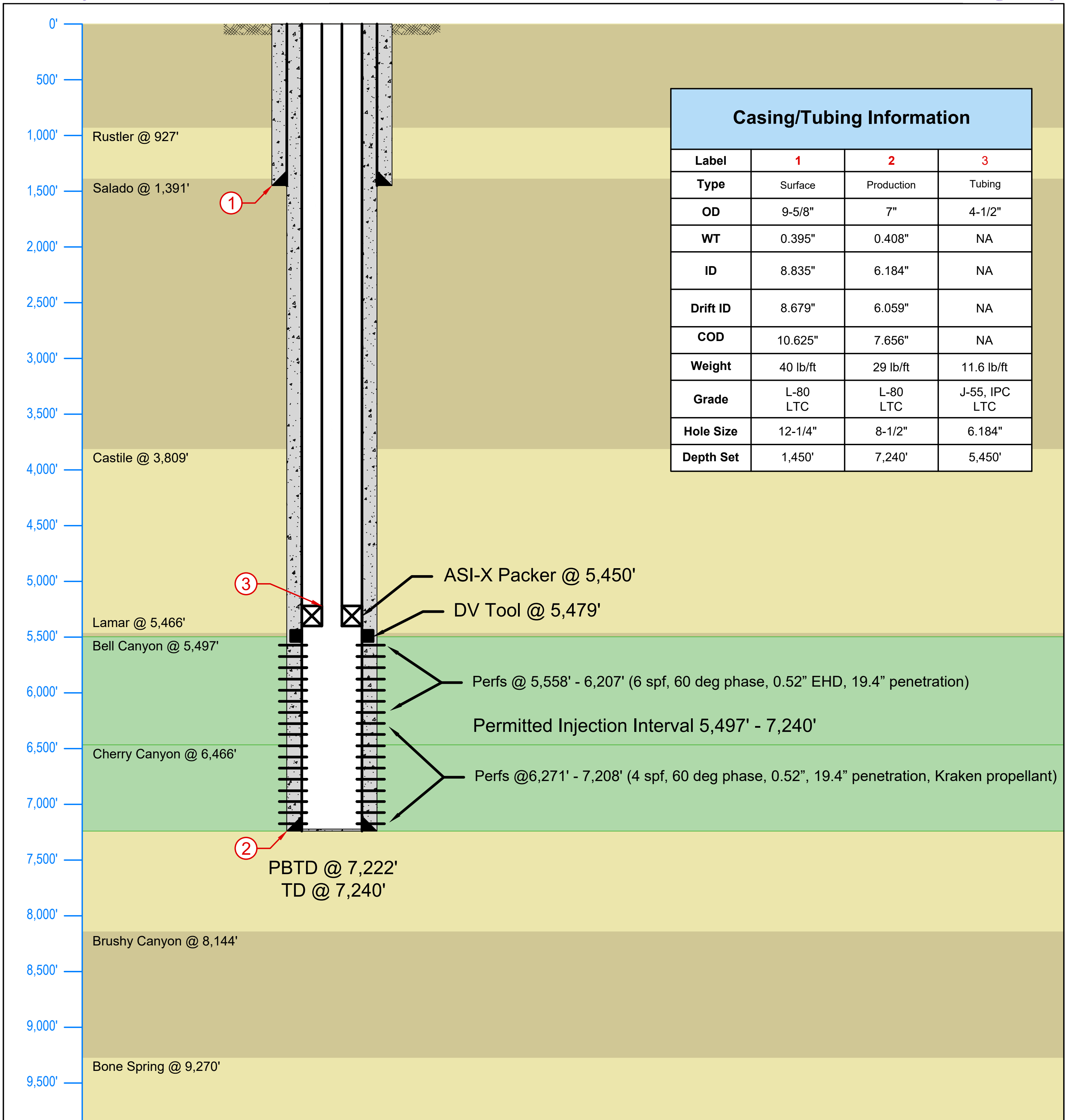
WELL TREATMENT HISTORY

- The lower 400' of perforations were acidized in February 2022 with approximately 700 bbls of 15% HCL at a maximum pressure of 1,100 psi.
- The upper 386' of perforations were acidized in March 2022 with approximately 250 bbls of 15% HCL at a maximum pressure of 1,115 psi.
- A step rate test was performed on April 4th, 2022. A summary is attached.

ATTACHMENTS

1. Wellbore Diagram
2. April 4th, 2022 Step Rate Test Summary

PREPARED BY	DATE	REVIEWED BY	DATE	APPROVED BY	DATE	Client Signature
JAM	04/21/2022	NLB	04/22/2022	WHG	04/25/2022	



Casing/Tubing Information

Label	1	2	3
Type	Surface	Production	Tubing
OD	9-5/8"	7"	4-1/2"
WT	0.395"	0.408"	NA
ID	8.835"	6.184"	NA
Drift ID	8.679"	6.059"	NA
COD	10.625"	7.656"	NA
Weight	40 lb/ft	29 lb/ft	11.6 lb/ft
Grade	L-80 LTC	L-80 LTC	J-55, IPC LTC
Hole Size	12-1/4"	8-1/2"	6.184"
Depth Set	1,450'	7,240'	5,450'

LONQUIST & CO. LLC
PETROLEUM ENGINEERS | ENERGY ADVISORS

Milestone Environmental

Beaza SWD No. 1

Country: USA	**State/Province:** New Mexico	**County/Parish:** Lea
Location: 160' FEL & 2,480' FNL of Unit H, Section 25, Township 24S, Range 34E		**District:** 1 (Hobbs)
API No: 30-025-49600	**Field:**	**Well Type/Status:** Disposal / New Drill
State ID No:	**Project No:** 1761	**Date:** 03/16/2022
Drawn: WHG	**Reviewed:** RH	**Approved:** RSC
Rev No: 3	**Notes:**	

Texas License F-9147

12912 Hill Country Blvd. Ste F-200
Austin, Texas 78738
Tel: 512.732.9812
Fax: 512.732.9816

Received by OCD: 9/14/2022 1:03:05 PM

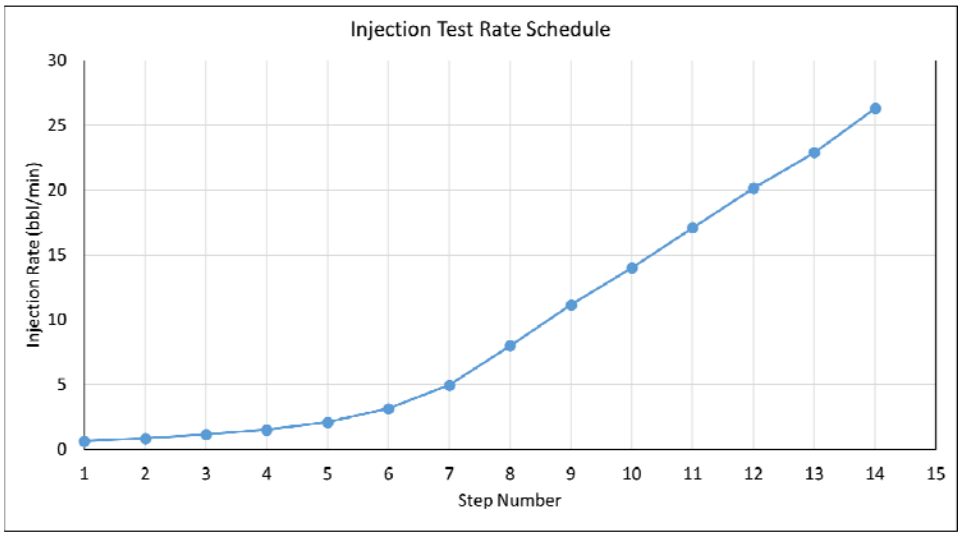
Beaza SWD No. 1
Step Rate Test Evaluation
Milestone Environmental Services LLC

April 2022

PRIVILEGED AND CONFIDENTIAL INFORMATION

Step Rate Test Overview

- Step Rate Test was performed 4/4/2022 on the Beaza SWD No. 1 in Lea County, NM
- Current Injection Permit:
  - Slurry Injection into Bell Canyon & Cherry Canyon
  - MASIP = 1,099 psi (0.2 psi/ft at 5,497 ft)
  - Max Rate = 10,000 bbl/day
  - Requires SRT within first 12 months of injection



Step No.	Injection Rate	
	bbl/min	bbl/day
1	0.7	936
2	0.8	1,210
3	1.2	1,656
4	1.5	2,160
5	2.1	3,024
6	3.2	4,536
7	5.0	7,128
8	8.0	11,520
9	11.2	16,056
10	14.0	20,160
11	17.1	24,624
12	20.2	29,016
13	22.9	32,976
14	26.3	37,872

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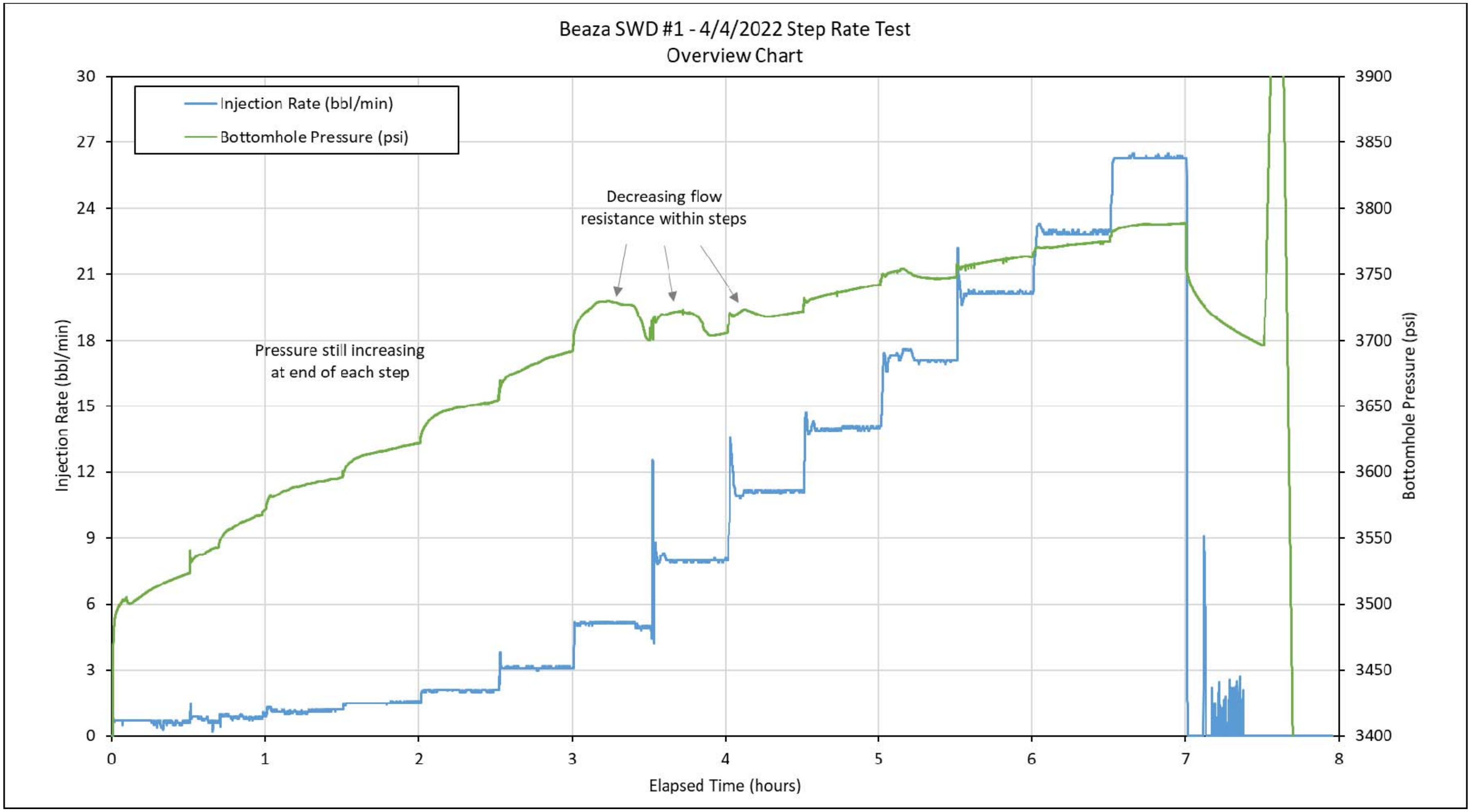
Step Rate Test Overview



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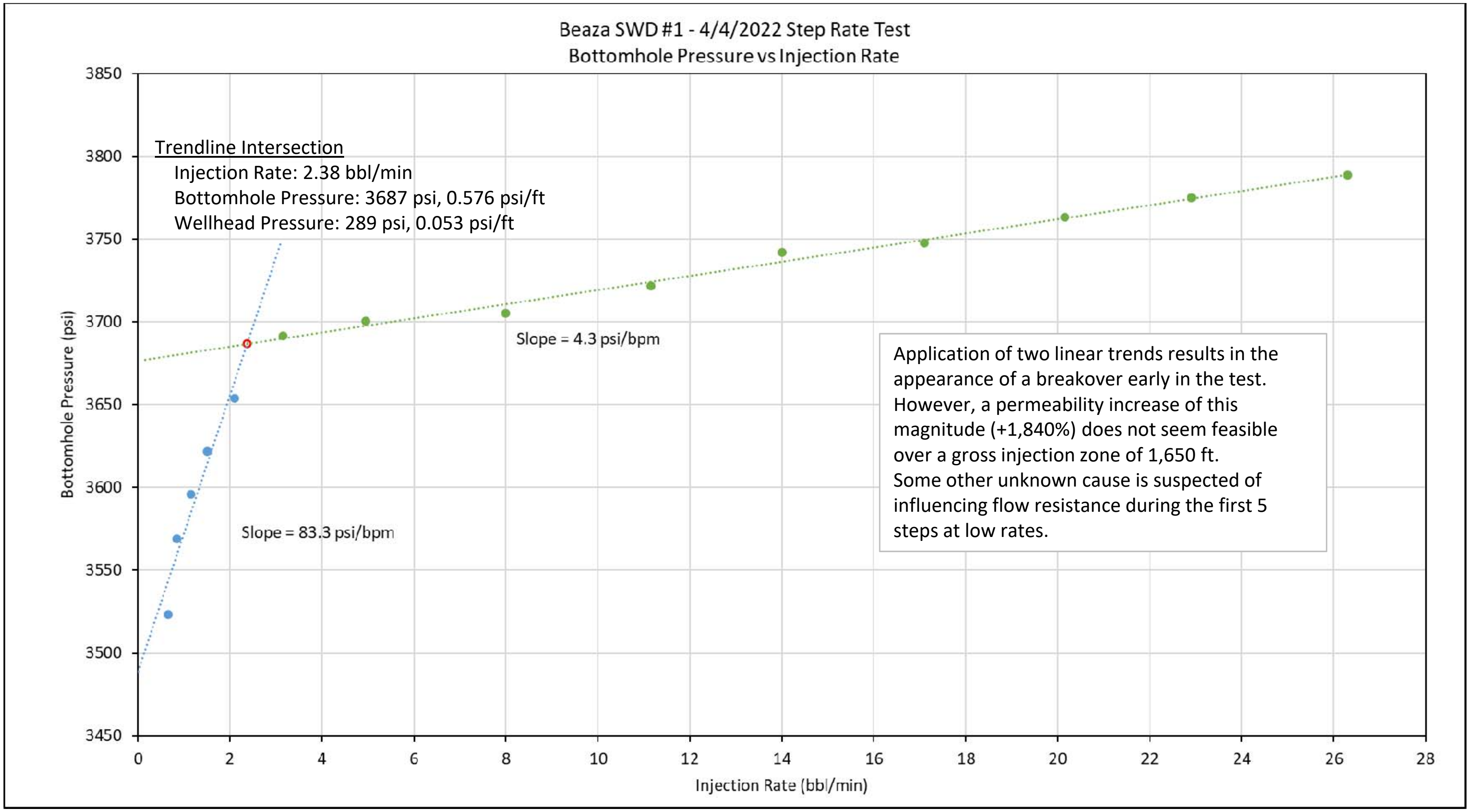
Bottomhole Pressure vs Rate



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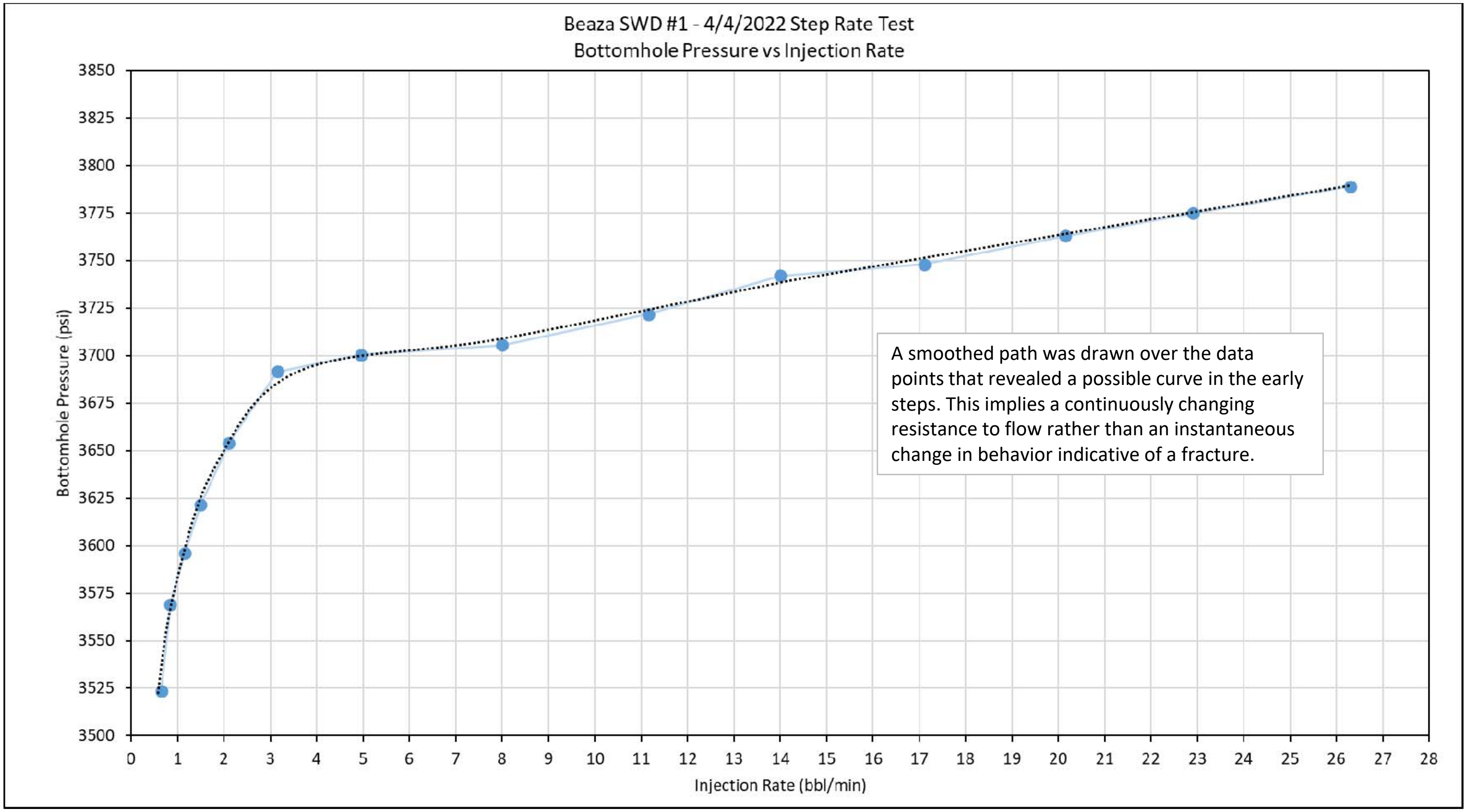
Bottomhole Pressure vs Rate



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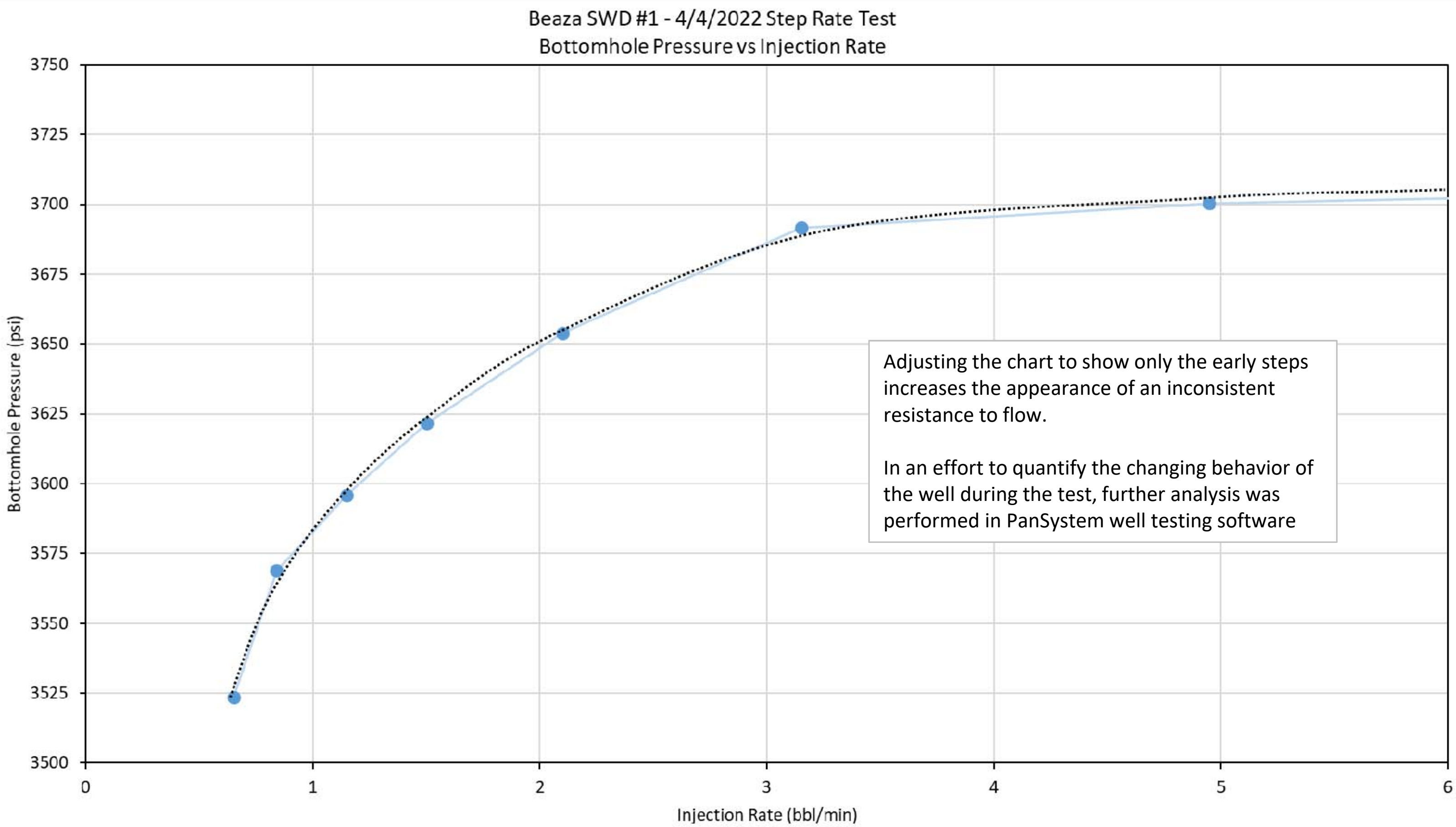
Bottomhole Pressure vs Rate – Zoomed in



Adjusting the chart to show only the early steps increases the appearance of an inconsistent resistance to flow.

In an effort to quantify the changing behavior of the well during the test, further analysis was performed in PanSystem well testing software

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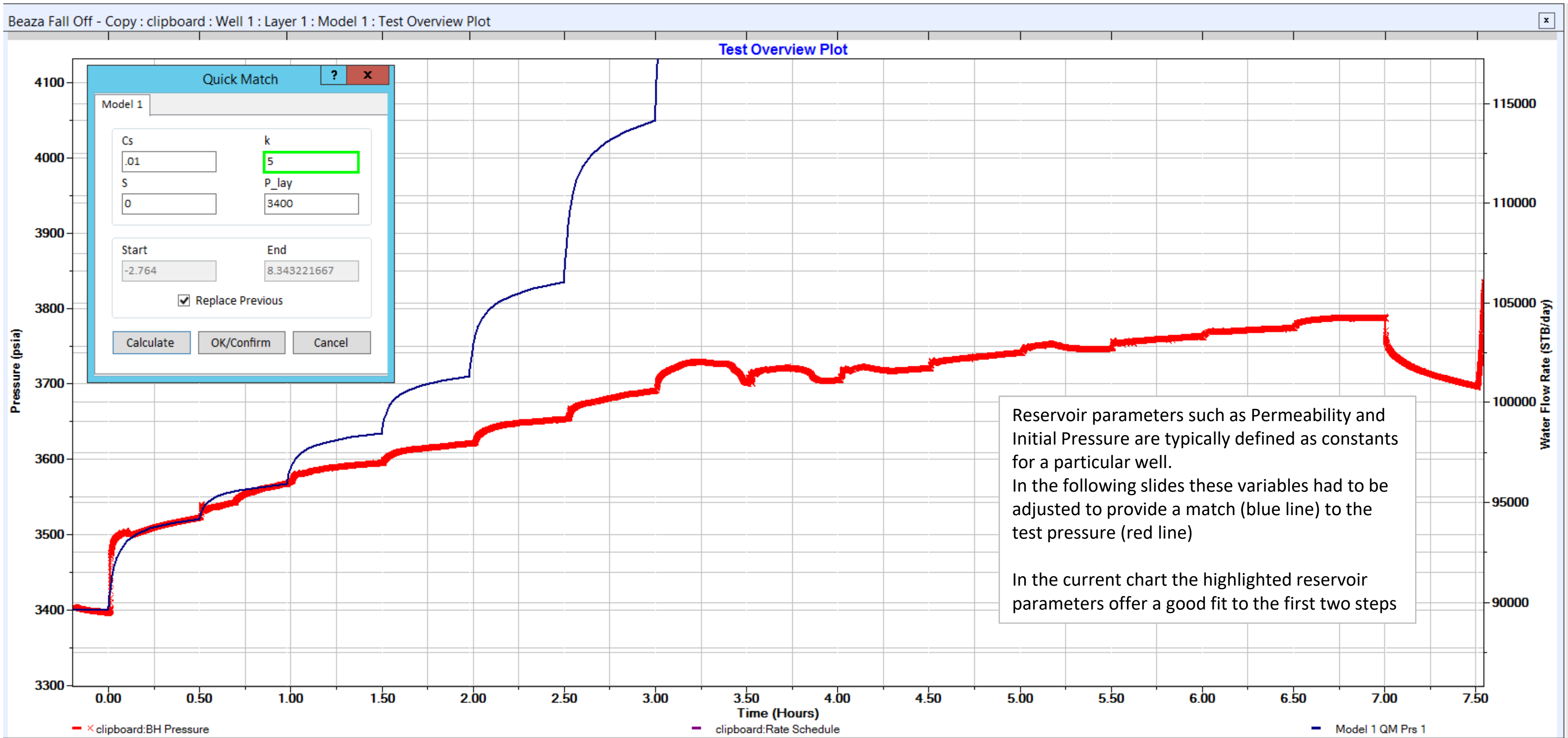
PanSystem Analysis – Simulation fit to First Step



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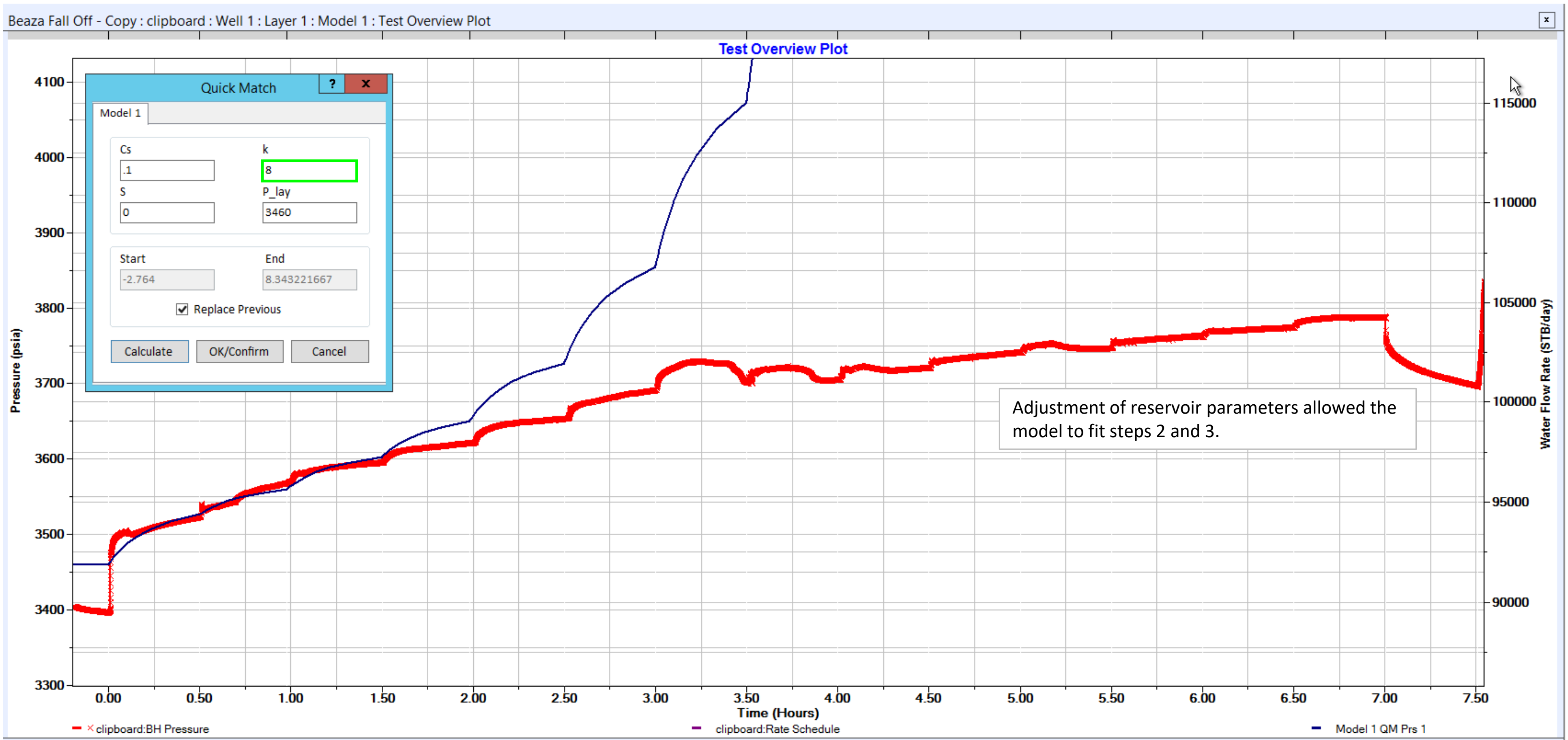
PanSystem Analysis – Simulation Fit to Early Steps



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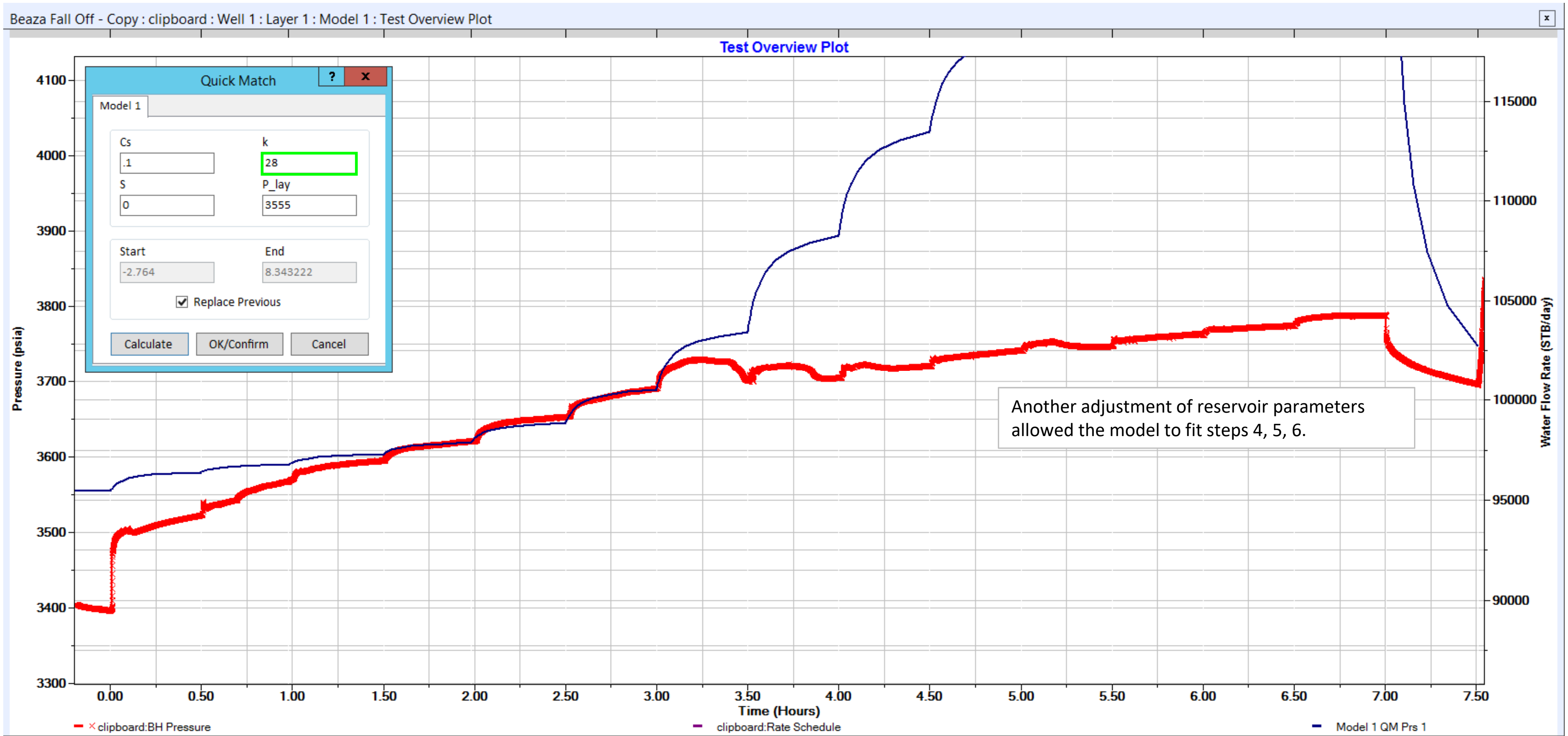
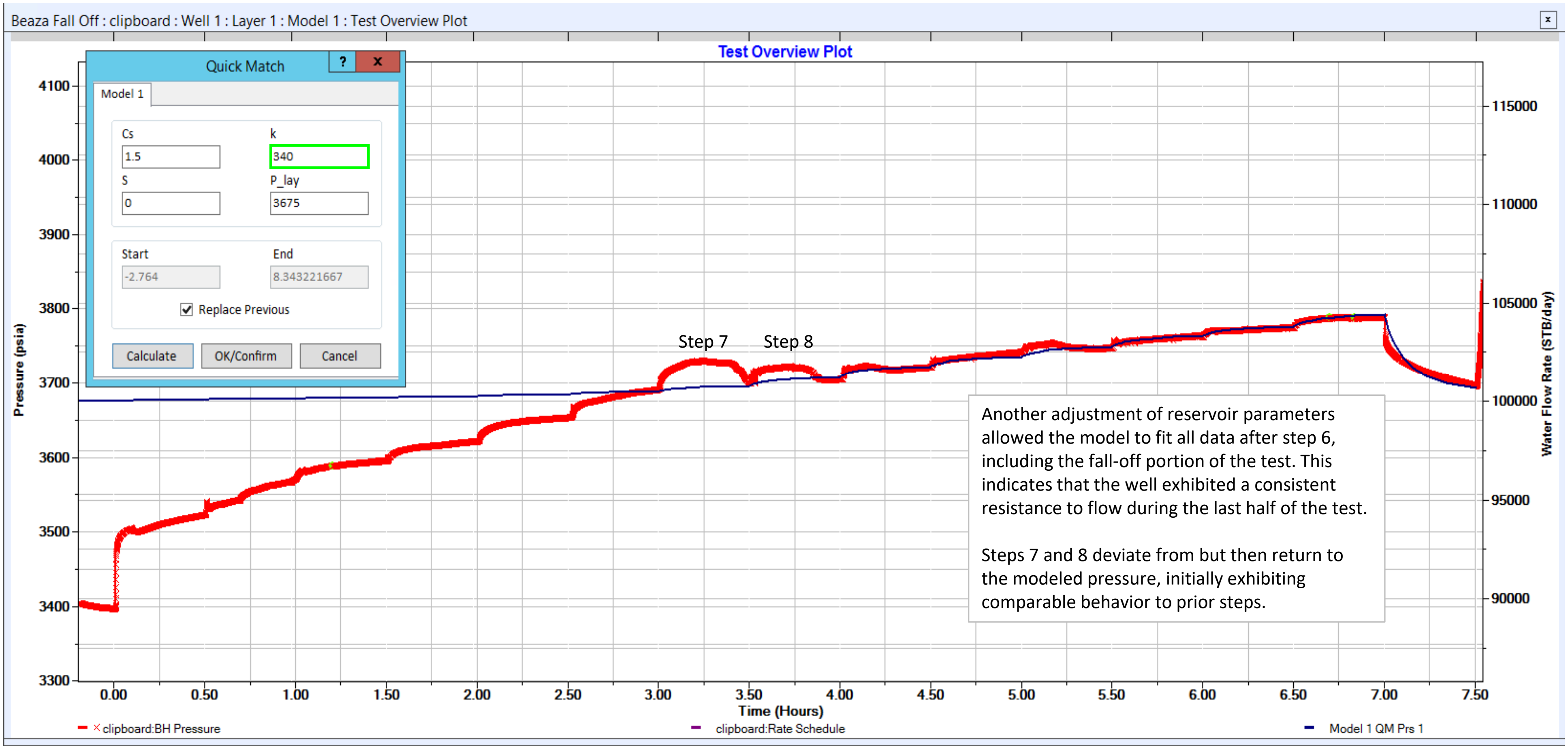
PanSystem Analysis – Simulation Fit to Middle Steps



PanSystem Analysis – Simulation Fit to Late Steps



Another adjustment of reservoir parameters allowed the model to fit all data after step 6, including the fall-off portion of the test. This indicates that the well exhibited a consistent resistance to flow during the last half of the test.

Steps 7 and 8 deviate from but then return to the modeled pressure, initially exhibiting comparable behavior to prior steps.

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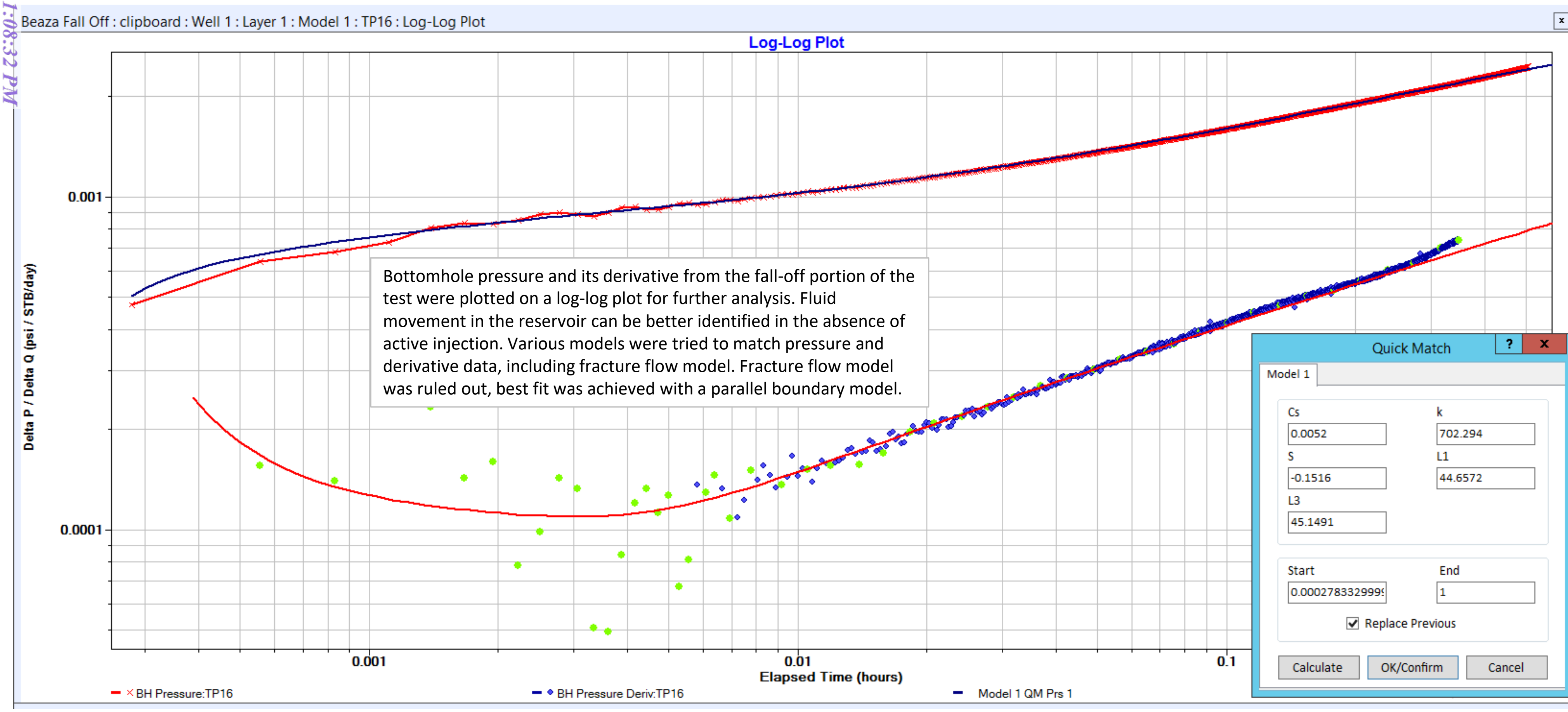
PanSystem Analysis – Log-Log Plot of Fall-Off Data



Bottomhole pressure and its derivative from the fall-off portion of the test were plotted on a log-log plot for further analysis. Fluid movement in the reservoir can be better identified in the absence of active injection. Various models were tried to match pressure and derivative data, including fracture flow model. Fracture flow model was ruled out, best fit was achieved with a parallel boundary model.

Summary

- Continually changing resistance to flow during the first part of the test is likely caused by anomalous fluid dynamics within the large perforated interval including:
  - 786’ of perforations across a 1,650’ interval
  - Lack of fluid movement deeper in the well
  - Lack of fluid movement in zones of lower permeability
  - Inconsistent fluid density within the wellbore
- Consistent resistance to flow during the second half of the test.
- No evidence of fracture closure during the fall-off portion of the test.
- Max flow rate and pressures during test
  - Injection Rate: 26.3 bpm
  - Bottomhole Pressure: 3,789 psi, 0.59 psi/ft
  - Wellhead Pressure: 2,077 psi, 0.38 psi/ft

Path Forward

- An additional test will be run to confirm well behavior
  - Proposed rate schedule starts at low rates, steps up to 14 bbl/min, and steps back down to ensure all perforations are accepting fluid during the second half of the test
  - 45 to 60 minute steps are suggested to achieve pressure stabilization at each injection rate
  - Record fall-off pressures for an extended duration

Step No.	Injection Rate	
	bbl/min	bbl/day
1	0.5	720
2	0.75	1,080
3	1	1,440
4	1.5	2,160
5	2	2,880
6	3	4,320
7	5	7,200
8	8	11,520
9	11	15,840
10	14	20,160
11	11	15,840
12	8	11,520
13	5	7,200
14	3	4,320
15	2	2,880
16	1.5	2,160
17	1	1,440
18	0.75	1,080
19	0.5	720

From: Nathaniel Byars
To: Ramona Hovey; Rose-Coss, Dylan H, EMNRD; Will George; Thompson, Joseph, EMNRD; Goetze, Phillip, EMNRD; jasonlarchar@milestone-es.com; shaungee@milestone-es.com; John Moltz; Cordero, Gilbert, EMNRD; McClure, Dean, EMNRD; Steve Pattee; Powell, Brandon, EMNRD
Subject: RE: [EXTERNAL] RE: NMOCD - Milestone Beaza SWD No.1 SRT Discussion
Date: Wednesday, May 25, 2022 8:53:47 AM
Attachments: Rate-dependent skin in SWD well.pdf

All,

Most of the papers on rate-dependent skin are from studies of production wells, but the attached was the best regarding a disposal well in south Texas. The BHP/rate relationship in the Beaza shows the same rate-dependent skin behavior but a similar completion design is not directly studied in any papers we found.

Note, that the mechanism for fracture creation discussed in this paper is hydraulic rather than an even distribution of propellant charges across a broad interval. The well in this paper is injecting through 60 feet of perfs into a tight formation. All of the injection was performed in significant excess of the 0.76 psi/ft fracture gradient they identified, in order to observe the rate-dependent skin behavior beyond that gradient.

The magnitude of the effect and number of perforating charges in the Beaza is significant enough to cause a rapid drop to a near baseline skin value at a low rate and bottom-hole gradient.

Thanks,

Nathaniel Byars, P.E.
Principal Engineer

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AUSTIN · HOUSTON · CALGARY · WICHITA · BATON ROUGE · DENVER · COLLEGE STATION

From: Ramona Hovey <ramona@lonquist.com>
Sent: Monday, May 23, 2022 3:32 PM
To: Rose-Coss, Dylan H, EMNRD <DylanH.Rose-Coss@state.nm.us>; Will George <will@lonquist.com>; Thompson, Joseph, EMNRD <Joseph.Thompson@state.nm.us>; Nathaniel Byars <nathaniel@lonquist.com>; Goetze, Phillip, EMNRD <Phillip.Goetze@state.nm.us>; jasonlarchar@milestone-es.com; shaungee@milestone-es.com; John Moltz <John.Moltz@lonquist.com>; Cordero, Gilbert, EMNRD <Gilbert.Cordero@state.nm.us>; McClure, Dean, EMNRD <Dean.McClure@state.nm.us>; Steve Pattee <steve@lonquist.com>; Powell, Brandon, EMNRD <Brandon.Powell@state.nm.us>
Subject: RE: [EXTERNAL] RE: NMOCD - Milestone Beaza SWD No.1 SRT Discussion

Please find the attached step-rate test report for our discussion tomorrow afternoon.

Regards,

Ramona Hovey
Principal Engineer

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-----Original Appointment-----
From: Ramona Hovey
Sent: Thursday, May 19, 2022 8:08 AM
To: Rose-Coss, Dylan H, EMNRD; Will George; Thompson, Joseph, EMNRD; Nathaniel Byars; Goetze, Phillip, EMNRD; jasonlarchar@milestone-es.com; shaungee@milestone-es.com; John Moltz; Cordero, Gilbert, EMNRD; McClure, Dean, EMNRD; Steve Pattee; Powell, Brandon, EMNRD
Subject: [EXTERNAL] RE: NMOCD - Milestone Beaza SWD No.1 SRT Discussion
When: Tuesday, May 24, 2022 3:00 PM-4:00 PM (UTC-06:00) Central Time (US & Canada).
Where: Microsoft Teams Meeting

Microsoft Teams meeting

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Flow Rate-Dependent Skin in Water Disposal Injection Well

Reinjection is one of the most important methods to dispose fluid associated with oil and natural gas production. Disposed fluids include produced water, hydraulic fracture flow back fluids, and drilling mud fluids. Several formation damage mechanisms are associated with the injection including damage due to filter cake formed at the formation face, bacteria activity, fluid incompatibility, free gas content, and clay activation. Fractured injection is typically preferred over matrix injection because a hydraulic fracture will enhance the well injectivity and extend the well life. In a given formation, the fracture dimensions change with different injection flow rates due to the change in injection pressures. Also, for a given flow rate, the skin factor varies with time due to the fracture propagation. In this study, well test and injection history data of a class II disposal well in south Texas were used to develop an equation that correlates the skin factor to the injection flow rate and injection time. The results show that the skin factor decreases with time logarithmically as the fracture propagates. At higher injection flow rates, the skin factor achieved is lower due to the larger fracture dimensions that are developed at higher injection flow rates. The equations developed in this study can be applied for any water injector after calibrating the required coefficients using injection step rate test (SRT) data. [DOI: 10.1115/1.4033400]

1 Introduction

Produced water is a by-product of oil and gas production. The produced water can include formation water, injected water, condensed water, and trace amounts of treatment chemicals [1–2]. It is the largest volume by-product or waste stream associated with oil and gas exploration and production, estimated at 21×10^9 barrels per year (57.4×10^6 bbl/day) in the United States in 2007 [3]. The estimated water oil ratio worldwide is 2:1 to 3:1. In the U.S., this ratio reached as high as 8:1 because many U.S. fields were mature and past their peak production. The ratio may be even higher, as many older U.S. wells have ratios >50:1 [4].

In the U.S., 98% of the water produced from onshore wells is injected into underground formations. Fifty-nine percent is used in waterflooding to support the oil reservoir pressure and increase oil production, and 40% is disposed into nonproducing formations. The remaining 2% was managed through surface disposal including evaporation ponds, offsite commercial disposal, beneficial reuse, and other management methods. While more than 91% of the water produced from the offshore wells is discharged to the ocean, most of the remaining volume is injected for enhanced oil recovery (EOR) purposes [4].

Underground water injection and disposal are performed through class II wells. Class II wells are the wells that inject fluids for EOR, dispose of fluids associated with oil and gas production, and inject liquid hydrocarbon for storage. (Of approximately 144,000 class II wells in the U.S., salt water disposal represents 20%.) [5]

Besides produced water, oil field waste waters are a mixture of many different streams, including cooling tower blowdown, boiler water blowdown, ion exchange bed regeneration stream, filter backwash, cleaning solutions (acids, caustic, and detergents), and corrosion inhibitors and biocides.

1.1 Formation Damage During Water Injection.

Water quality is the most important factor that affects the formation during water injection. Water quality refers to the chemical, physical, and biological characteristics of water [6]. Five components in water detrimental to water injection include microorganisms, dispersed oil, suspended solids, dissolved gases, and dissolved solids [7].

A formation can be subjected to several mechanisms by the injection of low quality water, which cause damage (i.e., reduction of the formation permeability) including mechanical damage due to injection of solids or fines migration [8]; interaction between the formation minerals and injected water that might cause clay activation (swelling and/or deflocculation) [9], formation dissolution, chemical adsorption and wettability alternation, relative permeability alterations due to multiphase flow, biological damage due to the presence of bacteria [10]; interaction between formation brine and incompatible injected water that can produce insoluble scales, emulsions, wax, and asphaltene deposition [11]; and non-Darcy flow effects [12]. Oily water waste may also become adsorbed inside the formation and block the pore throats, although this effect is more pronounced in water-wet than in oil-wet formations [13]. Modeling fracture damage can help in predicting more accurately the decline in the production flow rate from a propped fracture well [14].

The mitigation technique to avoid loss of the formation injectivity depends on the formation damage mechanism. Water filtration is essential to avoid mechanical damage by removing solid particles larger than 10% of the pore diameter. Using clay inhibitor is a must in clay-rich formations to prohibit clay swelling

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Contributed by the Petroleum Division of ASME for publication in the Journal of Energy Resources Technology. Manuscript received May 28, 2015; final manuscript received April 5, 2016; published online May 5, 2016. Assoc. Editor: Gunnar Tamm.

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and/or deflocculation. Oil skimming and gas removal from the waste water will help in minimizing the relative permeability damage effect. Biocides are usually used to stop the bacteria growth and keep the near wellbore area free of bacteria biomasses that severely affect the well injectivity. Also, other inhibitors and chemicals can be used to prevent scale formation, emulsification, precipitation of insoluble solids, and wax asphaltene deposition [9].

Based on field observation, it was concluded that a continuous loss of injectivity is obtained with matrix produced water reinjection [15], and successful PWRI is likely to require fracturing [16]. It is a commonly held belief within petroleum engineering that most successful water-injection wells have been fractured. When dealing with low permeability formations or with injection water of poor quality, fractures are usually induced intentionally in order to obtain a higher injectivity. Unintentional fracturing can also occur, for instance, when cold water is injected into a relatively hot reservoir. The cooling of the reservoir rock can reduce the rock stress to the point where the injection pressure exceeded the tensile strength of the rock and fracturing occurs [17,18].

1.2 Skin Factor. When the near wellbore region has a permeability that is higher or lower than the virgin rock permeability, the actual bottom-hole pressure will be different than the ideal bottom-hole pressure that would have been observed if the near wellbore region were untouched with the same properties as the virgin rock. This effect of having different permeabilities in the near wellbore and far wellbore region is called the skin effect. Skin factor is a dimensionless parameter that is used to quantify the magnitude of skin effect [19]. A positive skin factor is obtained when the near wellbore region has permeability lower than the native formation permeability (formation damage), while negative skin factor means the permeability of the near wellbore region has been increased (stimulation) [20].

Hawkins presented the following model to calculate the skin factor using the permeability and radius of the skin zone [21]

$$s = \left(\frac{k}{k_s} - 1\right)\ln\left(\frac{r_s}{r_w}\right) \tag{1}$$

where k is the native formation permeability, k_s is the skin zone permeability, r_s is the skin zone radius, r_w is the wellbore radius, and s is the skin factor.

Injection of low quality water will damage the near wellbore region reducing its permeability and creating a positive skin factor. Hydraulic fracturing will enhance the well injectivity/productivity and will result in a negative skin factor.

The skin factor due to the presence of a hydraulic fracture can be calculated using the following equation [22]:

$$s = \ln\left[\frac{r_w\left(\frac{\pi}{C_{fD}} + 2\right)}{x_f}\right] \tag{2}$$

For a hydraulic fracture with infinite conductivity, Eq. (2) will take the following form:

$$s = \ln\left[\frac{2r_w}{x_f}\right] \tag{3}$$

Equation (2) neglects the damage formed on the fracture faces. Mather et al. [23] developed a model to calculate the fracture skin taking in consideration the damage around the wellbore and fracture faces

$$s = \frac{\pi k}{2}\left[\frac{r_s k_s k_{sd}}{(r_s - d)k_{sd} + dk_s} + \frac{(x_f - r_s)kk_d}{(r_s - d)k_d + dk_s}\right]^{-1} - \frac{\pi r_s}{2x_f} \tag{4}$$

Here, C_{fD} is the dimensionless fracture conductivity, d is the depth of the fracture face damage, k_d is the fracture face damage permeability, k_{sd} is the permeability in the region with near wellbore damage and fracture face damage, and x_f is the fracture half-length.

To apply Eq. (4) in actual field cases, fracture simulator will be needed to predict the fracture propagation rate with time at different injection flow rates. Also, lab work is needed to determine the damage parameters d, k_d, and k_{sd}; these parameters are strongly dependent on the properties of the solid content in the water (solid loading and particle size distribution) and on the pore throat size. For water disposal wells (especially commercial ones), water properties cannot be controlled since water comes from several sources. It is not practical to run for each water truck a complete water analysis to measure the solid contents, core analysis to define the damage parameters, and fracture simulator to predict the fracture propagation with time and flow rate.

Based on these facts, the development of a simple equation to predict the evolution of the skin factor with time is important in order to better predict the well behavior over long-term water injection. The developed equation idea is similar to the equation used for gas producer that states that the skin factor is linearly depend on the production flow rate. However, the problem that occurs during water injection is different than that observed during gas production since the skin factor in water injectors is time dependent as well as gas dependent. That said, running an SRT is all that is needed in order to develop and calibrate the new skin factor equation.

1.3 Rate-Dependent Skin. The term rate-dependent skin was originally used in association with high rate gas producing wells to describe the increase in skin factor at higher flow rates due to turbulent flow [24]

$$s' = s + Dq_g \tag{5}$$

Here, D is the non-Darcy coefficient, s' is the flow rate-dependent skin, and q_g is the gas flow rate.

In water-injection wells when injection is conducted through an unpropped hydraulic fracture, the fracture dimensions are different at different injection flow rates. A larger fracture will be developed at a higher flow rate to handle the lager water volume injected, and smaller fracture will be formed at lower injection flow rates. Based on Eqs. (3) and (4), the skin factor decreases with an increasing injection flow rate because of the longer fracture formed at higher injection rates.

Beside the injection flow rate effect, the fracture dimensions are function of time as well. At a constant injection flow rate, the fracture propagation continues with time until reaching a point where the fracture leak-off volume equals to the injection flow rate. After this point, the fracture will not propagate further unless the injected water damages the fracture faces which reduces leak-off and causes the fracture to propagate to handle the injected volumes. Usually, fracture propagation can be predicted by using a fracture simulation package [25,26]. However, geomechanical analysis is always needed to prepare the input data for the fracture simulators, which might consume time to prepare it.

The objective of this paper is to use injection test data to develop a simple equation to estimate the skin factor as a function of time and injection flow rate for a water injector well. A general form of the relationship is presented as well as a specific equation for a well in the Eagle Ford Shale basin in Texas, U.S.

2 Well Details

Data from a salt water disposal well located in Texas and used to dispose of produced water, flow back water, and drilling fluid water were analyzed in order to develop the targeted equation. The well is perforated through Escondido sands formation (Fig. 1).

The permeability of this formation was estimated to be very low (around 5 mD). Also, from the geomechanical analysis run using Advantek's @LOG software, the formation fracture pressure ranges between 2100 and 2450 psi (Fig. 2). Based on the permeability and fracture pressure value, successful injection requires the presence of a hydraulic fracture in this tight formation. The maximum allowable surface injection pressure (MASIP) for this well is between 1500 and 1600 psi.

Figure 3 shows the inflow and well performance curves. The curves show that under matrix injection and assuming no damage around the wellbore (skin = 0), the maximum injection rate that could be achieved at MASIP is less than 0.5 bpm. To achieve injection flow rate higher than 4 bpm at MASIP, the formation should have a skin factor less than −6.5. From Eq. (3), the formation should have a hydraulic fracture with half-length more than 460 ft.

The well was treated using 120 bbls of 20% HCl at injection flow rate ranges from 2 bpm to 8 bpm. The well performance during the acid job is shown in Fig. 4. This figure shows the rate-dependent skin phenomenon due to the hydraulic fracture propagation: the skin factor at injection rate of 2 bpm was around −4, and at 8 bpm was less than −6.8. This reduction in the skin factor conforms to the interpretation of the development of increasing fracture length at higher injection flow rates.

3 Well Testing

Two injection tests (an SRT and pressure fall-off test (PFOT)) were conducted to evaluate the well performance and the fracture geometry. Figure 5 shows the pressure and rate data for the injection tests, while the injection schedule is given in Table 1.

Analyzing the SRT showed that for the three injection rates used in the test, the injection was always conducted under a hydraulic fracture flow regime. The three points on the pressure–rate plot lay on the same straight line (no change in the slope), and the pressure was always higher than the minimum horizontal stress (MHS) value (Fig. 6) that has been calculated by using @LOG software as shown in Fig. 2.

Pressure fall-off data were analyzed to calculate the formation permeability and fracture dimensions. From the log–log diagnostic plot (Fig. 7), the different flow regimes were clearly identified: the early unity slope region identifies the wellbore storage interval; the fracture linear flow was identified by the half-slope line; the 3/2 slope line identifies the fracture closure; and finally, the pseudoradial flow region was identified by the zero slope line [27].

G-function is a time function that mainly used to estimate the closure time of fracture. This technique is dependent on fluid leak-off rate, and hence, it is considered as a preclosure analysis. The form of G-function used in this paper assumes high fluid efficiency in low permeability formation (which is true for water), and this validates the assumption of linear variation of fracture surface area with time during fracture propagation [28].

From the plot of G-function versus bottom-hole pressure and G-function versus its derivative (Fig. 8), the fracture closure pressure was identified to be 2480 psi. This value agrees with the value of MHS calculated from the well log using Advantek's @LOG software, which was 2450 psi. This result was expected as the closure pressure is equivalent to the MHS [29]. Summary of the fall-off test analysis is given in Table 2.

4 Development of the Rate-Dependent Skin Equation

The injection tests data were used to develop the new equation assuming that pseudoradial flow has been established. The skin factor for each flow rate was calculated using the following equation [30]:

$$\mathrm{BHP} - P_i = \left[\frac{70.6 q \mu B}{kh}\right]\left[\mathrm{Ei}\left(\frac{-948 \phi \mu c_t r_w^2}{kt}\right) + 2s\right] \qquad (6)$$

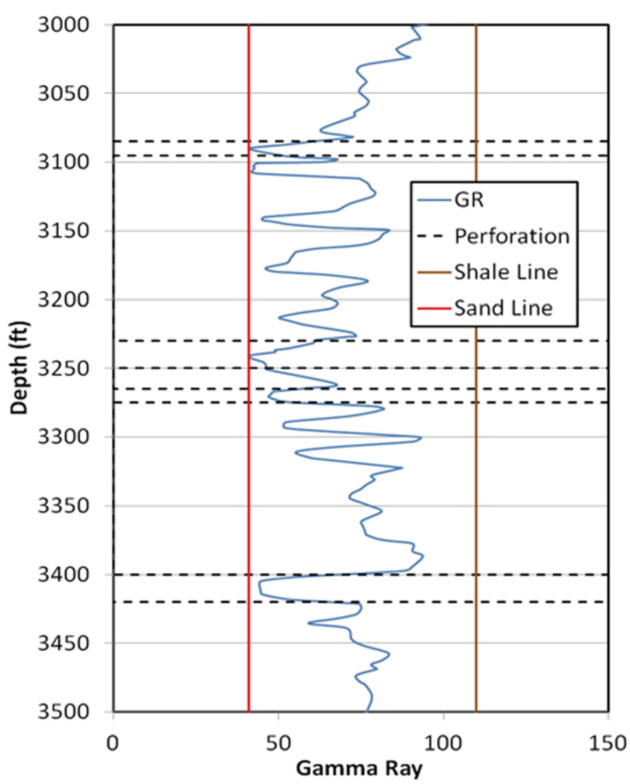

Fig. 1 The disposal well has four perforation intervals through Escondido formation (60 ft net perforations)

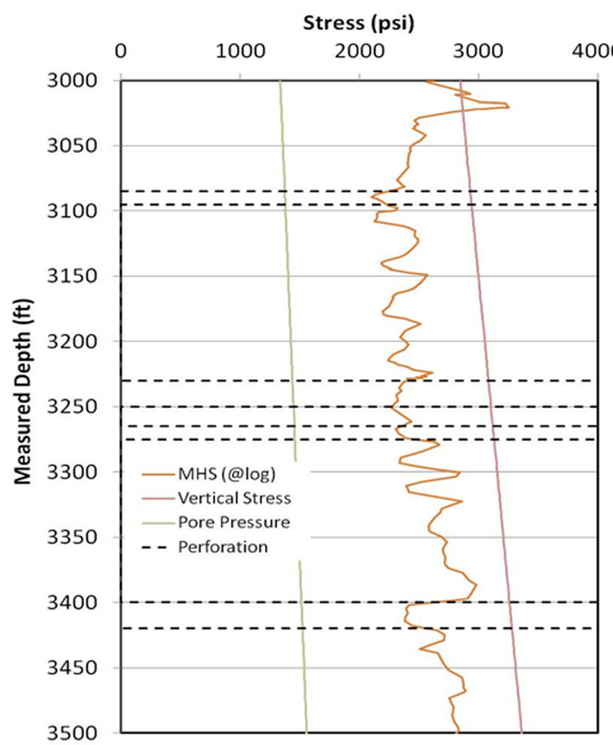

Fig. 2 Stress analysis of the Escondido formation

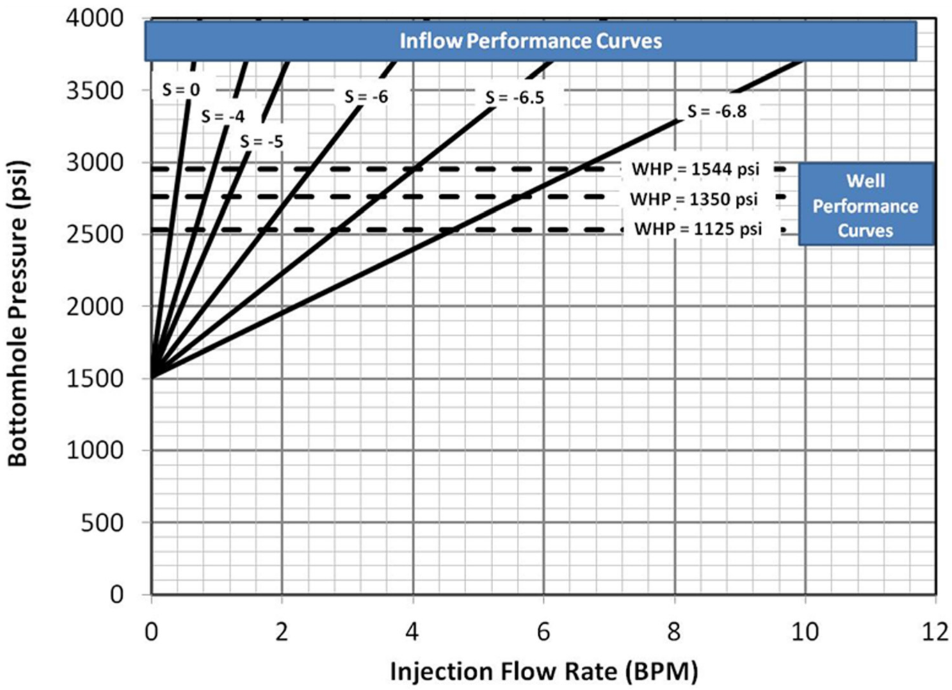

Fig. 3 Inflow and well performance curves

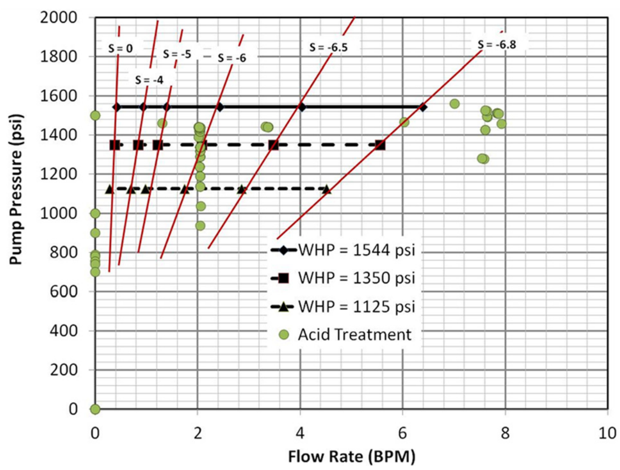

Fig. 4 Well performance during the well acidizing

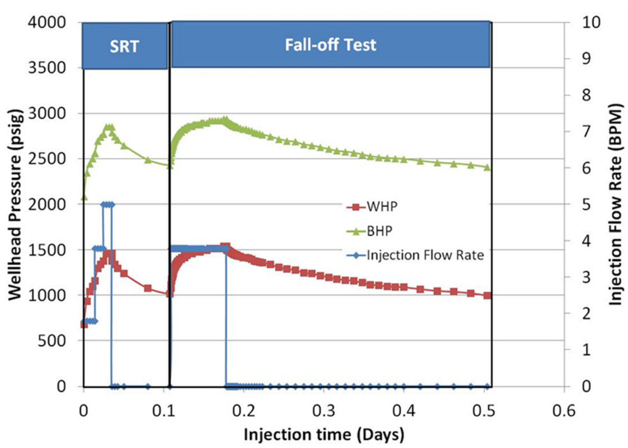

Fig. 5 Pressure and rate data for the SRT and PFOT

Solving Eq. (6) for skin factor yields

$$s = \frac{1}{2}\left(\frac{\text{BHP} - P_i}{\left[\frac{70.6 q \mu B}{kh}\right]} - \text{Ei}\left(\frac{-948 \phi \mu c_t r_w^2}{kt}\right)\right) \tag{7}$$

Here, B is the formation volume factor, BHP is the bottom-hole pressure, c_t is the total compressibility, q is the injection flow rate, h is the formation thickness, P_i is the formation pressure (pore pressure), t is the injection duration, ϕ is the formation porosity, and μ is the fluid viscosity.

The skin factor was calculated at the end of each injection step, and the results obtained showed that the skin value decreased with increasing injection flow rate (Fig. 9). The following equation governs the change in the skin factor at different flow rates:

$$s = -0.3406\left(\frac{q}{1440}\right) - 4.2999 \tag{8}$$

This equation can be generalized to be

$$s = a\left(\frac{q}{1440}\right) + b \tag{9}$$

where a and b are constants which depend on the well and fluid properties, s is the skin factor, and q is the injection flow rate in BPD.

The time factor is not considered in Eq. (9). This equation assumes that the fracture is developed to its maximum length at the time we start injecting, and it does not propagate after that. However, we know that the hydraulic fracture is propagating with time due to damage induced by the injection.

In order to include the injection time effect in the developed equation, the skin factor was calculated every 5 min of injection for each flow rate. Different skin development trends were noted for each flow rate as shown in Fig. 10. In general, a logarithmic relationship between the skin factor and injection time was captured and covered by the following equation:

$$s = -A \ln\left(\frac{t}{60}\right) - B \tag{10}$$

Table 1 Injection tests schedule

Injection duration (min)	Injection flow rate (BPM)	Volume injected (bbl)	Test
20	1.8	36	SRT
15	3.8	57	
15	5	75	
106	0	0	
100	3.8	380	PFOT
500	0	0	
Cumulative volume (bbl)		548	

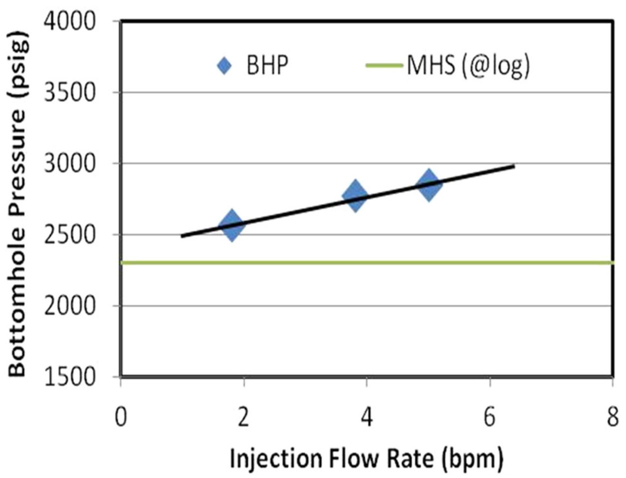

Fig. 6 Pressure–rate plot (SRT analysis). MHS is the formation minimum horizontal stress.

Table 2 Fall-off test analysis results

Parameter	Value
Permeability (k), mD	8.4
Transmissibility (kh/μ), mD ft/cP	508
Closure pressure (P_c), psi	2480
Closure time (t_c), hr	3.6

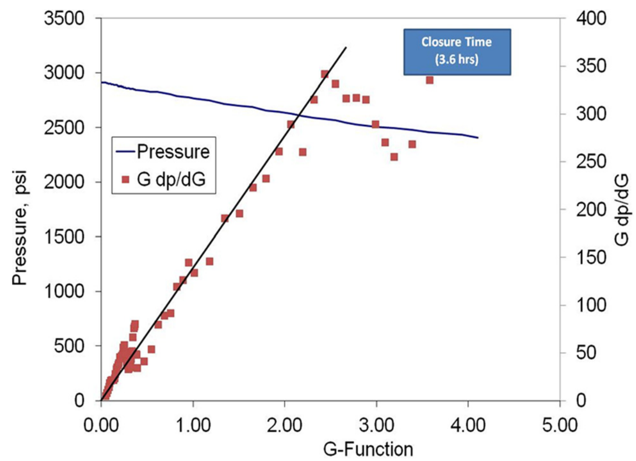

Fig. 8 G-function analysis of the pressure fall-off data

In the above equation, A and B are the fitting parameters and were controlled by the injection flow rate (Fig. 11) and can be calculated using the following equations:

$$A = Ce^{D\left(\frac{q}{1440}\right)} \tag{11}$$

$$B = E\,e^{F\left(\frac{q}{1440}\right)} \tag{12}$$

where C, D, E, and F are the fitting parameters on the A and B versus q plots. They depend on the damage building rate, which is a function of the formation and fluid properties. The values of these constants for the current case are listed in Table 3.

The general rate-dependent skin equation for an unpropped hydraulically fractured injection well is as follows:

$$s = -Ce^{D\left(\frac{q}{1440}\right)}\ln\left(\frac{t}{60}\right) - Ee^{F\left(\frac{q}{1440}\right)} \tag{13}$$

The above equation can be developed for any injector by using the following steps:

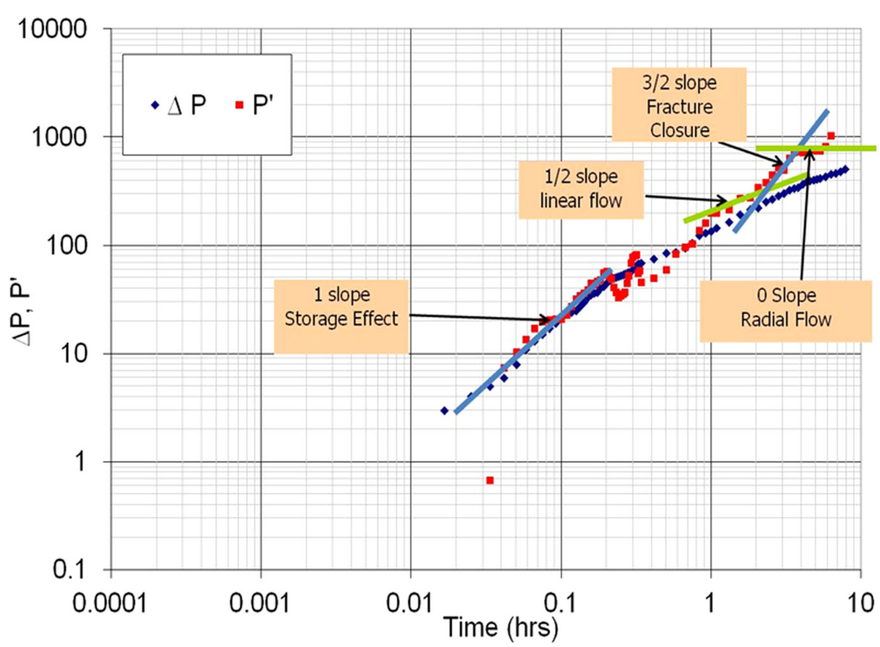

Fig. 7 Log–log diagnostic plot for the water disposal well

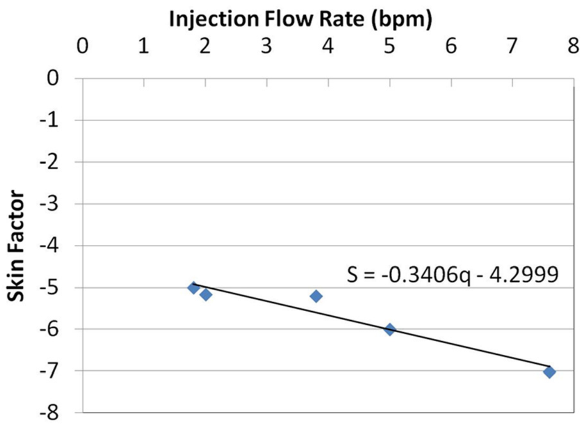

Fig. 9 The relationship between the skin factor and injection flow rate

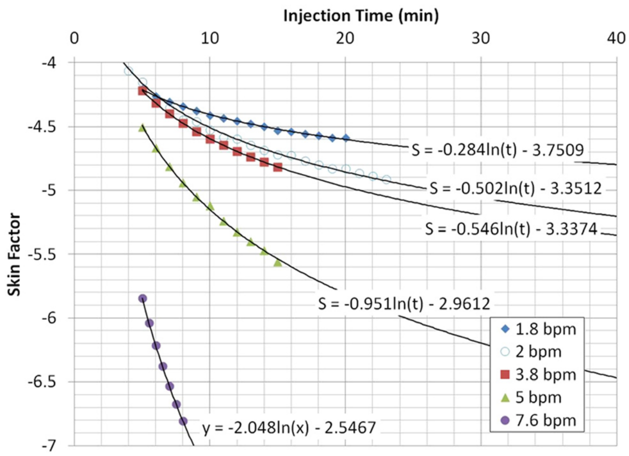

Fig. 10 The relationship between the skin factor and injection time

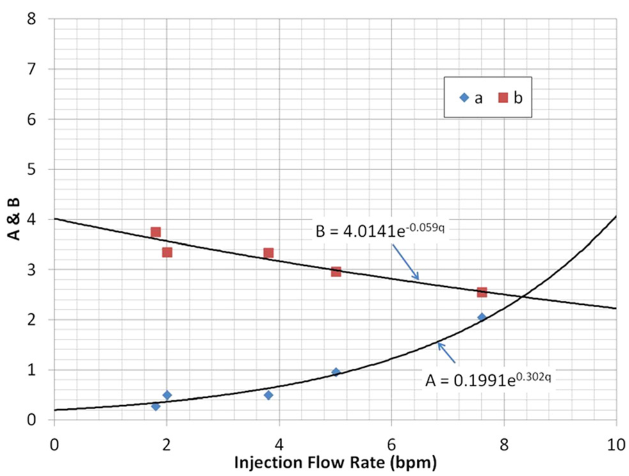

Fig. 11 The calculations of the *C*, *D*, *E*, and *F* constants

Table 3 Summary of the developed equation constants

Constant	C	D	E	F
Value	0.1991	0.302	4.0141	−0.059

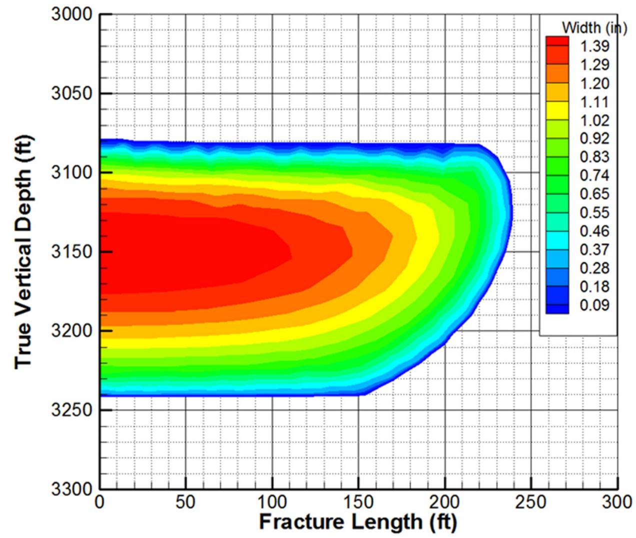

Fig. 12 Hydraulic fracture dimensions calculated by @FRAC3D

(1) SRT should be conducted using the same fluid that will be used in the ongoing injection operations.
(2) For each step, the skin factor to be calculated using Eq. (7) at multiple time steps.
(3) For each flow, plot of skin factor versus injection time should be fitted to obtain the constants *A* and *B* in Eq. (10).
(4) A relationship between *A*'s and *B*'s and the injection flow rate can be obtained as shown in Fig. 11.
(5) *C* and *D* are the fitting parameters in the exponential relationship between *A* and *q* as shown in Fig. 11 and Eq. (11).
(6) *E* and *F* are the fitting parameters in the exponential relationship between *A* and *q* as shown in Fig. 11 and Eq. (12).
(7) Substitute *A* and *B* in Eq. (10) by Eqs. (11) and (12) to get the general skin expression (Eq. (13)).

5 Validations and Case Study

The PFOT data were used to check the validity of Eq. (13). The PFOT was conducted by injecting water at 3.8 bpm for 100 min. A 3D fracture simulation was conducted using Advantek's @FRAC3D simulator to monitor the fracture propagation. The simulator estimated fracture length of 239 ft at the end of the PFOT (Fig. 12). Using Eq. (3), the skin factor equivalent to this

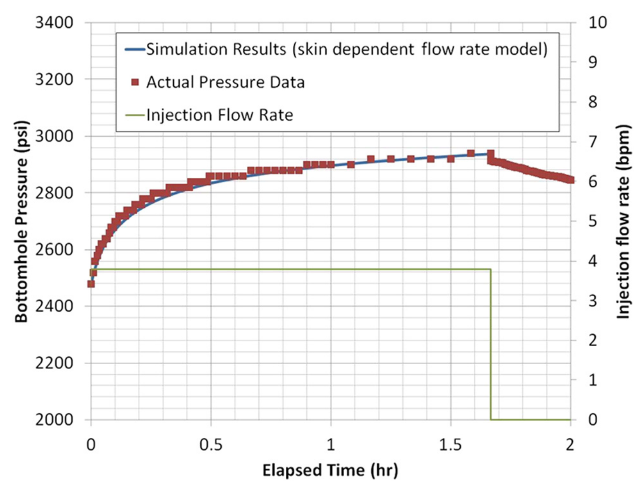

Fig. 13 A good match between the actual and calculated BHP was obtained for the PFOT

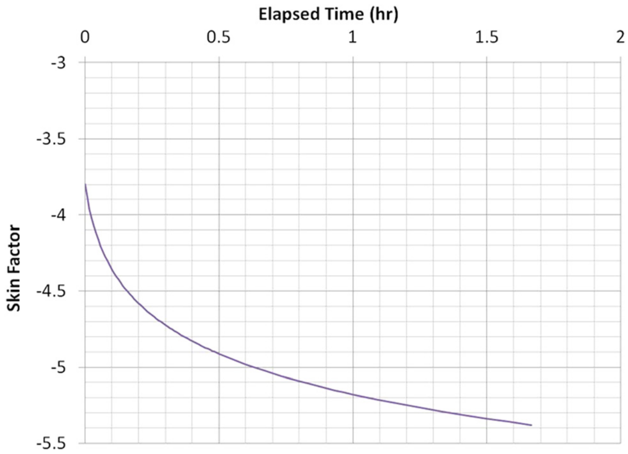

Fig. 14 Skin factor calculated using Eq. (13)

simulated fracture length is −5.82. The skin factor calculated from the field data at the end of the PFOT using the rate-dependent skin equation Eq. (13) is −5.9, which agrees very closely to the skin calculated from fracture simulator results.

The skin factor was calculated at several time steps, and using Eq. (6), the BHP was also calculated. A good match between the calculated and actual BHP during the PFOT was obtained as shown in Fig. 13. Using Eq. (13), the initial skin factor calculated to be −3.8, which indicates that the fracture opens up as soon as the injection initiated. As the fracture is propagating with time, the calculated skin is decreasing to reach −5.4 after 1.8 hrs of injection as shown in Fig. 14.

The pressure is calculated assuming constant skin factor to highlight the significance of using the new model to predict the skin development and its impact on pressure calculations. Figure 15 shows that at high value skin factor (higher than −4) which is

Table 4 Injection time and volume to reach MASIP

Injection flow rate (BPM)	Injection duration to reach MASIP (min)	Volume to be injected (bbl)
1	554	554
2	116	232
4	95	380
5	89	445
6	86	518

used in the calculations, the injection pressure was overestimated, and at low skin factor (less than −6), the pressure was underestimated. However, when the average skin factor was used (−5), the calculated pressure was initially less than the actual pressure, and after some time, the calculated pressure increased to be higher than the actual pressure. The match was only obtained when change in skin factor with time has been taken into consideration as shown in Fig. 14.

For the ongoing injection operations, the injection time before the pressure reaches the MASIP at each injection flow rate is shown in Table 4. The actual injection operation was conducted at 5 bpm, and the injection lasted for 87 min before the MASIP was reached, while the calculations showed that 89 min of injection would be accommodated at rate of 5 bpm before reaching the MASIP. This difference between the calculated time to reach MASIP and the actual time to reach MASIP of less than 2 min represents an error of less than 3%.

6 Conclusions

In this paper, a flow rate-dependent skin correlation was developed based on the data of and injection test from a water-injection well located in Texas, U.S. Based on the results of this study, the following conclusions can be drawn:

(1) Using the developed equation can save the time and effort needed to use other complex formula and lab analysis that

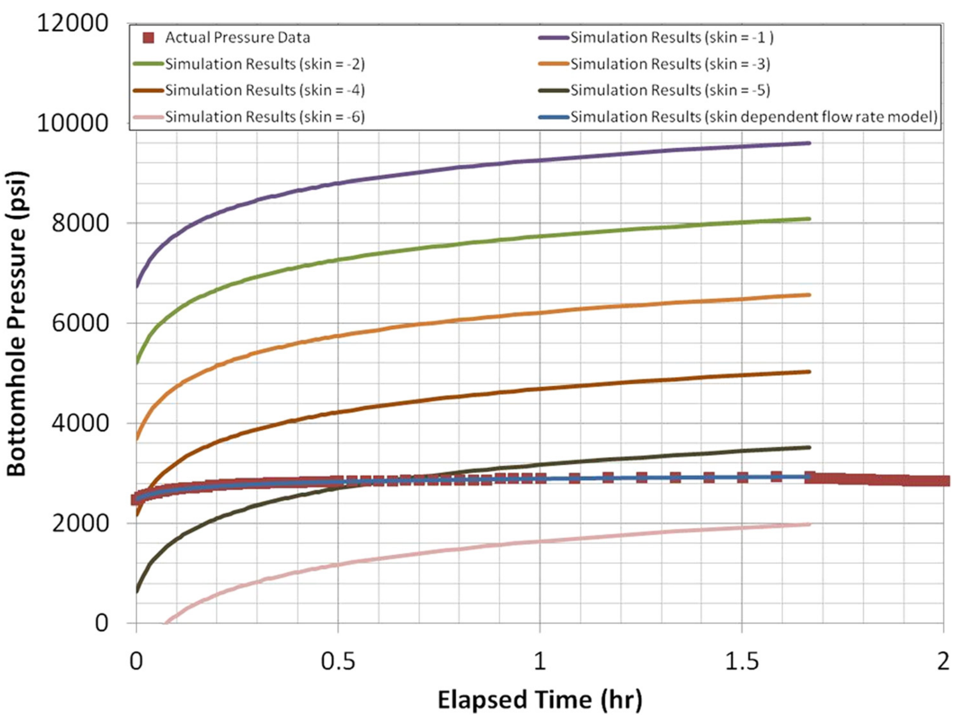

Fig. 15 Comparison between the injection pressures calculated using the skin-dependent flow rate model and constant skin values

is needed to obtain the damage parameters. To use the developed equation, all that is needed is an SRT using the water that will be used for ongoing injection.

(2) A good match was obtained between the field data and the results obtained from the developed correlation. The development equation helped in predicting the ongoing injection operations with an error of less than 3%.

(3) The constants shown in this paper are only valid to the injector well shown in this paper. To apply Eq. (13) generally, an injection test should be conducted first to calculate the constants E, C, D, and F as Illustrated in this paper.

(4) For water injection in an unpropped fracture, the skin factor depends on two factors: the injection flow rate and injection time.

(5) The skin factor development rate is higher at higher injection rates (due to fracture propagation).

Nomenclature

a and b = flow rate-dependent skin constants
B = formation volume factor
BHP = bottom-hole pressure (psi)
C, D, E, and F = time and Flow rate-dependent skin constants
c_t = total compressibility $(\text{psi})^{-1}$
C_{fD} = dimensionless fracture conductivity
d = depth of the fracture face damage (ft)
D = the non-Darcy coefficient $(\text{MSCF/d})^{-1}$
h = formation thickness (ft)
k = native formation permeability (mD)
k_d = fracture face damage permeability (mD)
k_s = skin zone permeability (mD)
k_{sd} = permeability in the region with near wellbore damage and fracture face damage (mD)
P_i = formation pressure (psi)
q = injection flow rate (BPD)
q_g = gas flow rate (MSCF/d)
r_s = skin zone radius (ft)
r_w = wellbore radius (ft)
s = skin factor
s' = flow rate-dependent skin
t = injection time (hr)
x_f = fracture half-length (ft)
μ = fluid viscosity (cP)
ϕ = formation porosity

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State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
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CONDITIONS

Action 143357

CONDITIONS

Operator:	
Milestone Environmental Services, LLC 15721 Park Row Houston, TX 77084	OGRID: 328435
	Action Number: 143357
	Action Type: [IM-SD] Admin Order Support Doc (ENG) (IM-AAO)

CONDITIONS

Created By	Condition	Condition Date
dmcclure	None	9/14/2022