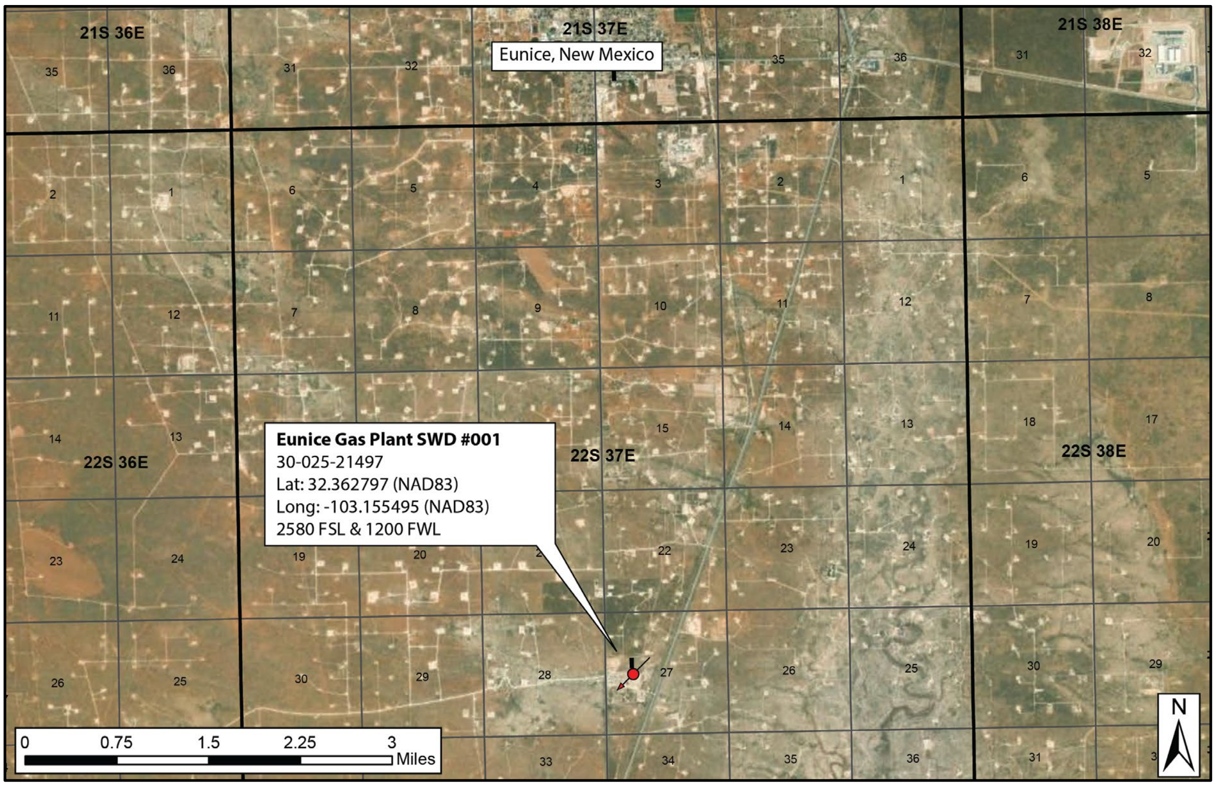
ANALYSIS OF INJECTION RESERVOIR CONDITIONS AND MOTION TO CONTINUE OPERATIONS UNDER THE CURRENT NMOCC ORDER R-12809-D

MILESTONE REPORT (10-YEAR)

Targa Midstream Services, LLC
Eunice Gas Plant SWD No. 1
(API: 30-025-21497)



Surface Location: 2,580 FSL & 1,200 FWL (S27, T22S, R37E)
NAD83 Coordinates: 32.362797, -103.155495

June 2023

Prepared for:

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TARGA

GEOLEX INCORPORATED

ANALYSIS OF INJECTION RESERVOIR CONDITIONS AND MOTION TO CONTINUE OPERATIONS UNDER THE CURRENT NMOCC ORDER R-12809-D

TARGA MIDSTREAM SERVICES, LLC
Eunice Gas Plant SWD #1 (API: 30-025-21497)
NMOCC Order R-12809-D

This document presents the results from the analysis of injection testing operations and subsequent reservoir pressure fall-off and temperature decay monitoring for the Eunice Gas Plant SWD #1 well. The well has been designed and permitted for service as a wet acid gas injection (AGI) well to dispose of waste carbon dioxide, hydrogen sulfide, and cooling tower water resulting from gas-processing operations at the Targa Eunice North Gas Processing Facility. The analysis, included herein, has been completed in accordance with the requirements of New Mexico Oil Conservation Commission (NMOCC) Order No. R-12809-D (Condition No. 2), which requires Targa Midstream Services, LLC (Targa) provide “the results of a temperature fallback, temperature decay, or other equivalent test”. This test was performed in April 2023, the results and subsequent analysis of which are presented in this report in fulfillment of the above-referenced requirement of NMOCC Order R-12809-D.

In this submittal, we are providing the results of the required temperature fallback test, which consisted of down-hole temperature monitoring during and after a period following a water injection test, as well as down-hole pressure monitoring. The results of these analyses demonstrate that the Eunice Gas Plant SWD #1 well, and San Andres Formation injection reservoir, continues to adequately accommodate the acid gas injection needs of the Targa Eunice Gas Plant Facility. Furthermore, analysis of reservoir equilibration trends (temperature and pressure) suggest reservoir performance has improved throughout the period of AGI operation, as evidenced through comparison to prior injection test operations. This is the result of minor dissolution and the resultant enhancement of permeability along existing fluid pathways. Over the period of AGI operations (since 2011), the well has continually operated within all permit-approved operating conditions and shows no signs of reservoir performance degradation or mechanical well integrity issues. The well, as completed, is fully suitable for continued AGI service.

GENERAL LOCATION AND OPERATIONS SUMMARY

The Eunice Gas Plant SWD #1 well (the “Eunice AGI”) is located approximately five (5) miles south-southwest of Eunice, New Mexico, in Section 27 of Township 22 South, Range 37 East (Figure 1). Following NMOCC authorization, in calendar year 2011, Targa has operated the Eunice Gas Plant SWD #1 as an AGI well disposing of gas-processing facility wastes, including carbon dioxide (CO_2), hydrogen sulfide (H_2S), and produced and facility wastewater. The well is constructed using a three-string design to inject via an open hole completion and is authorized for disposal into the San Andres Formation along a depth interval from 4,250 to 4,850 feet TVD. An as-built well schematic is shown in Figure 2. Injection operations, via the Eunice AGI well, are limited to a maximum allowable surface injection pressure of 1,600 psig and the well is limited to a maximum injection rate of 4,075 barrels per day of oilfield produced water, gas processing plant wastewater, and compressed acid gas (CO_2 and H_2S).

Prior to the commencement of AGI operations, in 2011, the well was utilized for the disposal of only oilfield produced water and facility wastewater. Table 1 below generally summarizes injection volume records for the Eunice AGI well, as documented by the New Mexico Oil Conservation Division.

Table 1. Summary of produced water and acid gas injected via the Eunice Gas Plant SWD #1 well

Operating Period	Injected Water (bbls)	Daily Avg. – Water (bbls/day)	Injected Acid Gas (MMSCF)	Daily Avg. – Acid Gas (MSCFD)
1994-2011	4,233,565	706	0	0
2011-2023	2,224,032	504	10,135	2.35

RESERVOIR TESTING AND MONITORING PROCEDURE

In meeting the requirements of NMOCC Order R-12809-D (Condition No. 2), Targa and Geolex developed and completed a water injection test on April 18, 2023, followed by post-injection pressure fall-off and temperature decay testing. Down-hole pressure and temperature conditions were monitored during and after the injection test utilizing real-time, bottom-hole sensors deployed via wireline. The primary objective of the testing was to pump freshwater and establish down-hole conditions characteristic of normal operations at the Eunice facility, shut in the AGI well, and monitor and record the reservoir response following the period of injection.

As the Eunice AGI well operates daily (since 2011) with minimal interruptions of service, a prolonged injection test was not necessary to re-establish reservoir pressure conditions typical of normal operations and suitable to conduct fall-off and warm-back testing. As such, injection operations consisted of pumping approximately 500 barrels of freshwater at a relatively constant injection rate and injection pressure. The general testing procedure completed is summarized below:

1. Review recent AGI well operating data with Targa operators prior to date of testing to ensure no abnormal conditions have been observed in the days preceding testing operations.

2. Conduct inspection of well site with Targa personnel and relevant subcontractors.

3. Complete pre-job safety meeting and review testing procedure, site safety equipment, and evacuation procedures with all service providers, safety personnel, and Targa representatives.

4. Rig up pumping equipment (Cudd Energy) and wireline (Renegade) logging equipment, including real-time, down-hole pressure and temperature sensors and wireline lubricator to ensure pressure control.

5. Secure job site and begin pressure testing flow lines and pumping equipment.

6. Isolate subsurface safety valve (SSSV) from plant control system to assure component will remain open (sleeved) during wireline operations.

7. Once SSSV is isolated, utilize manual pump to apply hydraulic pressure and lock out.

8. Displace current wellbore fluid with freshwater to purge well of H_2S-laden fluids and protect wireline equipment.

9. Run in well with wireline equipment while recording the pressure and temperature gradient, to an approximate depth of 4,220 ft., assuring that tools stay within tubing to minimize equipment risk and additional exposure to H_2S.

10. Monitor and record initial reservoir pressure and temperature conditions.

11. Pump approximately 500 barrels of freshwater, maintaining a constant injection rate of approximately 5 barrels per minute and ensuring maximum allowable operating pressure (1,600 psig) is not exceeded.

12. Discontinue pumping operations, shut in well, and continue to monitor down-hole pressure and temperature conditions.

13. Continue monitoring down-hole conditions until sufficient data have been collected to characterize re-equilibration of the reservoir following injection operations.

Prior to the commencement of injection testing, wireline pressure and temperature equipment were utilized to identify pressure and temperature conditions with depth (Figure 3, Table 2) and initial bottom-hole conditions. Initial pressure and temperature conditions, at a wireline tool depth of 4,220 ft., were 1,667 psig and 97.76 °F, respectively. The average pressure gradient observed was approximately 0.4683 psi/ft.

Table 2. Initial pressure, temperature, and pressure gradient prior to the initiation of testing operations

Depth (ft)	Pressure (psig)	Temperature (°F)	Gradient (psi/ft)
1000	159.04	74.98	0.00
1500	373.75	78.67	0.4294
2000	590.14	80.03	0.4328
2500	805.05	83.40	0.4298
3000	1020.41	87.51	0.4307
3500	1236.12	91.47	0.4314
4000	1451.53	94.65	0.4308
4220	1667.11	97.76	0.9799

As described on page 2, approximately 500 barrels of freshwater were utilized to complete injection testing for the Eunice AGI well. Pumping rates were maintained at approximately five (5) barrels per minute, corresponding to surface injection pressures ranging from approximately 989 to 1,058 psig over the duration of the injection test. These parameters were maintained to assure that well testing operations did not subject the Eunice AGI well to conditions exceeding normal operating conditions.

During injection testing, a maximum surface injection pressure of approximately 1,058 psig, and corresponding bottom-hole pressure of approximately 1,816 psig were recorded. Note that values correspond to a wireline tool placement depth of 4,220 ft.

Following the injection test, the Eunice AGI well was shut in and down-hole pressure and temperature conditions continued to be monitored and recorded. Monitoring equipment remained in the well for approximately 41 hours, after which, it was observed that pressure differential had declined significantly to less than approximately 0.4 psi/hour and temperature differential had declined to less than 0.03 F°/hour. Following consultation with the Geolex team, down-hole temperature and pressure monitoring equipment were retrieved, and the well was placed back in AGI service. Figure 4 includes all recorded pressure and temperature trends during the injection test and extended period of pressure/temperature fall off.

RESERVOIR PERFORMANCE AND PRESSURE TRANSIENT ANALYSIS RESULTS

Results of the Eunice AGI injection test demonstrate the San Andres Formation's excellent capability to continue to meet the injection and disposal needs of the Targa Eunice facility. Within a period of two hours following the 500-barrel water injection test, pressure differential reduced significantly to less than 1 psi/hour. Within approximately 16 hours, temperature differential was observed to have decreased to approximately 0.1 F°/hour. The final measured shut-in bottom hole pressure and temperature, after a period of 41 hours, was 1,736 psig and 117.58 °F, respectively. Conditions of the injection test and observed pressure and temperature conditions are summarized in Table 3 below.

Table 3. Summary of injection testing conditions and observed bottom-hole pressure and temperature

Initial Bottom Hole Pressure/Temperature (pre-test)	1,667.11 psi / 97.75 °F
Water Injection Rate (500 bbls injected)	7,344 bbls/day
Initial Bottom-Hole Shut-In Pressure/Temperature (after pumping ceased)	1,816 psi / 79.11 °F
Final Bottom-Hole Shut-In Pressure/Temperature (when test was terminated)	1,736 psi / 117.58 °F

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In addition to assessing the raw pressure and temperature conditions recorded during and after the injection test period, Geolex collaborated with Sproule Incorporated to complete a pressure transient analysis. The complete results of these analyses are included in Appendix A.

In completing this model and analysis, a reservoir area of one-square mile was assumed for the model area. Utilizing known reservoir and typical injection stream characteristics, a pressure type curve and injection pressure derivative was generated to identify flow regimes affecting pressure fall-off behavior (Figure 5). In evaluating the Eunice AGI well test, linear flow dominates the pressure behavior during the fall-off period. This behavior is commonly observed in acid stimulated or hydraulically fractured reservoirs, as well as naturally fractured carbonate reservoirs. While an initial acid stimulation was completed (in 2011), the NMOCD-approved disposal fluids, consisting of compressed CO_2, H_2S, and produced water would, in effect, also be similar to a long-term acid stimulation. This effect is further enhanced due to the San Andres reservoir being comprised of carbonate rocks, which has resulted in the enhancement of porosity and permeability as natural fluid pathways become slightly enlarged, owing to minor dissolution of carbonate minerals in contact with the injected acid gas/water stream.

Results of the analysis of pressure fall-off data (i.e., pressure transient analysis) indicate that the average reservoir pressure, after 12 years of acid gas injection is approximately 1,768 psia (corrected to reflect pressure at the midpoint of the open-hole interval). Additionally, pressure fall-off data indicate an average reservoir permeability, to water, of 2.5 millidarcies (mD). When compared to a similar pressure-transient analysis conducted in calendar year 2011, which determined an average reservoir permeability of 0.745 mD, it is clear that permeability along natural fluid pathways has been enhanced over the Eunice AGI period of operation. Furthermore, comparison to a step-rate injection test completed in 1983, which shows an initial bottom-hole pressure of 1,707 psig, indicates that operation of the Eunice Gas Plant SWD #1 well has not resulted in a significant increase in reservoir pressure, after the period of operation spanning several decades.

To conclude, no significant performance degradation of the reservoir or the well has been observed over the life of well operations, and trends in down-hole pressure and temperature conditions following injection testing clearly demonstrate that the San Andres Formation injection reservoir is fully capable of continuing to accommodate the injection needs of Targa at the Eunice Gas Plant, and furthermore, could accommodate additional disposal capacity, if necessary.

SUMMARY AND MOTION TO CONTINUE AGI OPERATIONS

In meeting the requirements of NMOCC Order R-12809-D, Targa and Geolex have completed water injection testing, and completed pressure fall-off and temperature decay testing. Testing operations consisted of a brief injection period, using approximately 500 barrels of freshwater, to re-establish reservoir conditions similar to those during typical AGI well operation. During this test, real-time, down-hole pressure and temperature sensors were deployed to record conditions during and after injection testing. Down-hole gauges remained in the Eunice AGI well for a period of 41 hours, at which time, sufficient reservoir data had been collected to conduct an analysis of the reservoir's response to injection.

Results of the analysis of recorded bottom-hole pressure data (i.e., pressure transient analysis) indicate that, based on observed pressure fall-off trends, the average San Andres injection reservoir pressure is approximately 1,768 psia. Additionally, average reservoir permeability was determined to be approximately 2.5 mD. In general, pressure fall-off behavior is indicative of an acid-stimulated, or naturally fractured injection reservoir. These results are expected, as the Eunice AGI well has operated for approximately 12 years, injecting a mixed stream of produced water and acid gas, which has resulted in the enhancement of porosity and permeability over the period of AGI operation. When compared to a prior pressure transient analysis, a minor increase in average reservoir permeability is observed, owing to the expected enhancement of permeability and porosity while sequestering acid gas in a carbonate-dominated reservoir.

Based on the results of injection testing and analysis of down-hole pressure and temperature data, it is clear that the San Andres Formation injection reservoir is clearly capable of accommodating the current and future disposal needs of the Targa Eunice Gas Plant. After several years of operation, disposing of produced water and acid gas, the Eunice Gas Plant SWD #1 well continues to operate with little impact to ambient pressure conditions within the reservoir, and injection operations are successfully maintained without exceeding maximum allowable operating conditions.

Targa proposes to continue to utilize the Eunice Gas Plant SWD #1 well, as the primary disposal method for gas processing wastes consisting of compressed CO_2, H_2S, produced water, and facility wastewater, as approved by NMOCC Order R-12809-D.

FIGURES

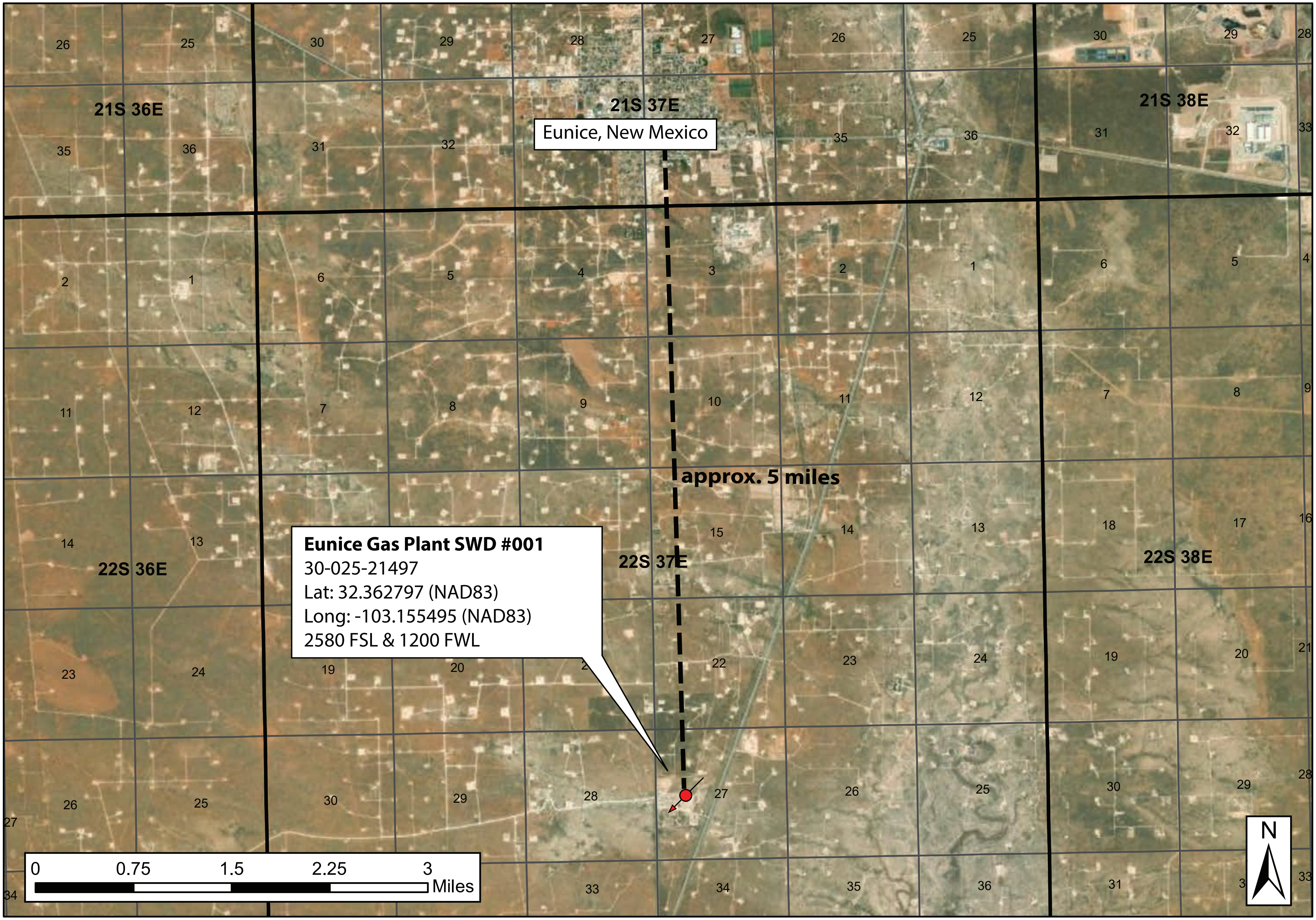

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Figure 1. General location map showing the Eunice Gas Plant SWD #1 well, approximately 5 miles south of the City of Eunice in Section 27 (T22S, R37E)

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AS-BUILT AGI WELL SCHEMATIC
Eunice Gas Plant SWD #1
30-025-21497
Section 27, T22S, R37E

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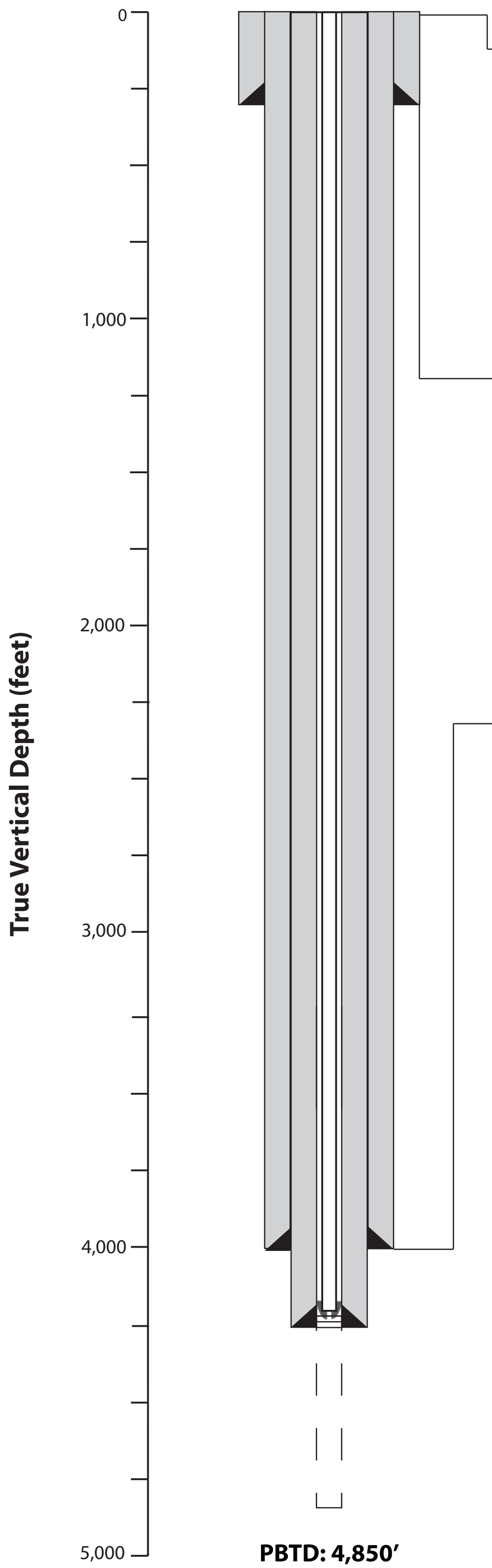


Conductor Casing

10-3/4" SURFACE CASING to 300 ft. 15.00" OH

10-3/4", 32.7#/ft., Surface Casing from 0' to 300'

300 sacks - Class C Cement, 14.8 ppg, 1.33 ft3/sack
Circulated Cement to Surface

Halliburton SSSV @ 277'

7" INTERMEDIATE CASING to 4,010 ft. 8.75" OH

7", 20 #/ft., J-55, BTC from 0' to 4,010'

1750 sacks - Class C Cement
Circulated Cement to Surface

5-1/2" PRODUCTION CASING to 4,258 ft. 6.25" OH

5-1/2", 17#/ft., J-55, BTC from 1,059 to 4,258'

310 sacks - Class C Cement
Top of Cement @ approx. 1,059' (Determined by CBL)

Stage Tool @ 3,902'

Halliburton packer @ 4,190'

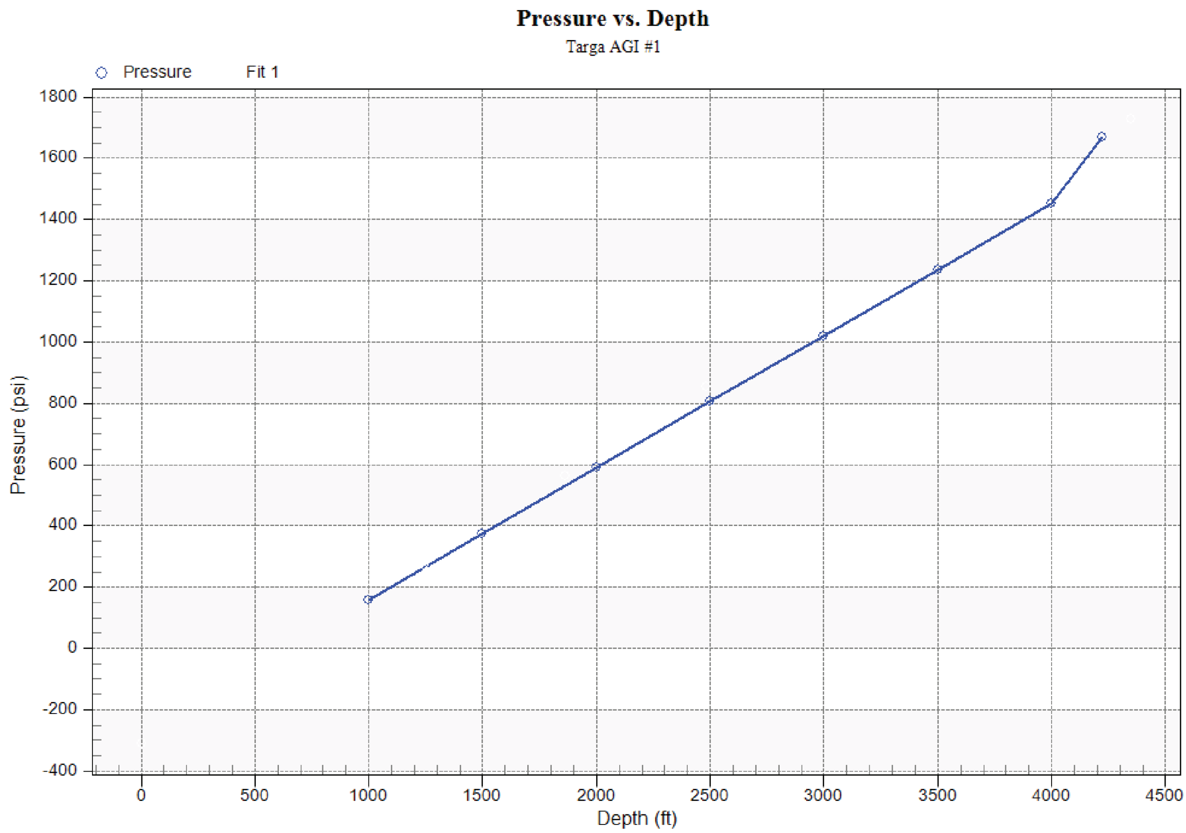
5-1/2" alloy csg @ 4,182' to 4,199'

TUBING AND EQUIPMENT

2-7/8", 65 #/ft., J-55 EUE from 0' to 4,258'

OPEN-HOLE INJECTION INTERVAL FROM 4,258' TO 4,850'

Figure 2. Eunice Gas Plant SWD #1 as-built well schematic



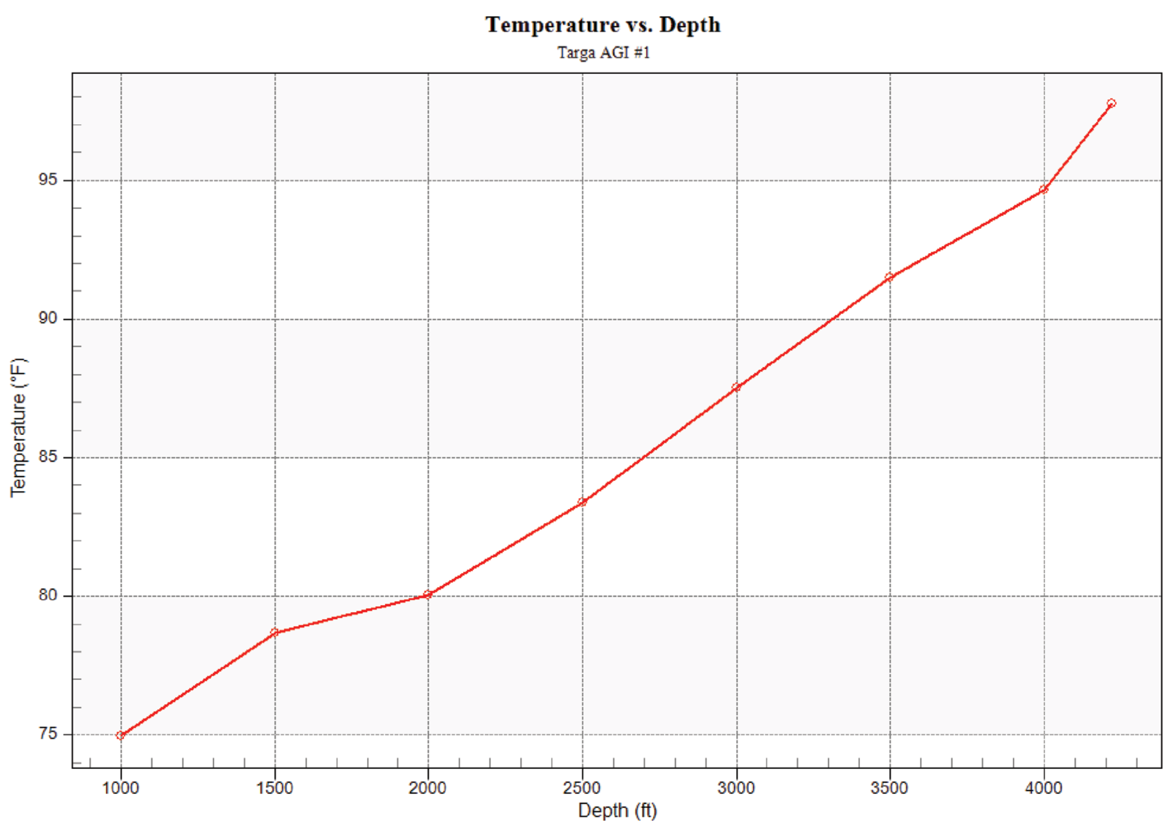


Figure 3. Initial pressure and temperature gradients measured prior to fluid injection test operations on April 18, 2023. Observed gradients for pressure and temperature are 0.4383 psi/ft. and 0.0071 F°/ft, respectively

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DOWN-HOLE PRESSURE AND TEMPERATURE V. TIME (RECORDED AT WIRELINE DEPTH OF 4,220')

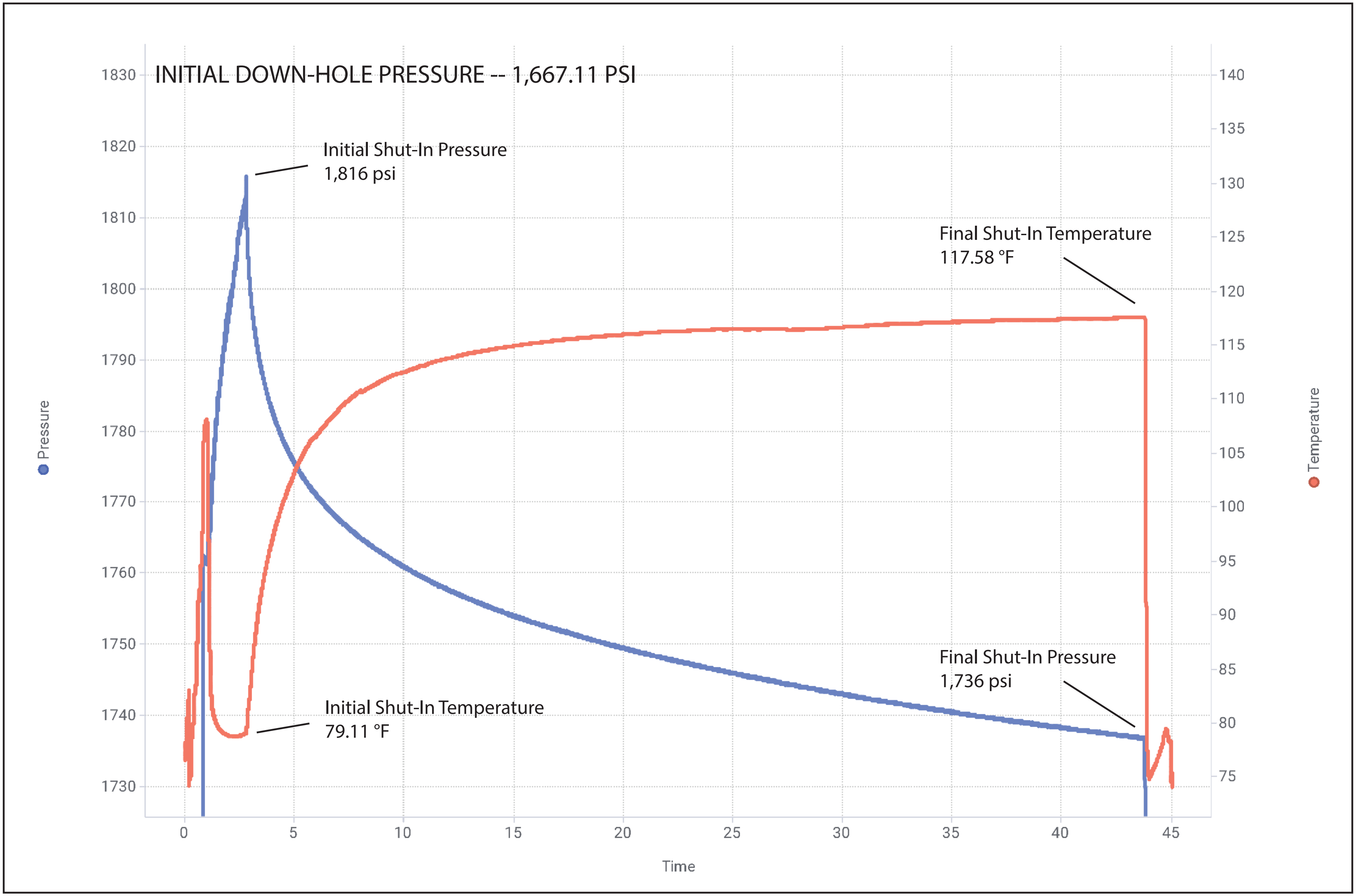

Figure 4. Recorded down-hole pressure and temperature trends during injection operations, and post-injection monitoring period (approximately 41 hours)

APPENDIX A

PRESSURE TRANSIENT ANALYSIS REPORT
Eunice Gas Plant SWD #1
(API: 30-025-21497)

Completed by: Geolex, Inc. and Sproule Inc.

Welltest Analysis of Targa AGI #1, New Mexico, USA

May 24, 2023

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Sproule

Digital Report Notification

This report has been prepared in a fully digital, auditable, and legally compliant format using a PDF/A standard (ISO 19005-1, 2 or 3).

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Prepared for:	**Geolex Incorporated**	
Project No.:	10562.115314.	
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Sproule

Ref.: 10562.115314.

May 24, 2023

Mr. David A. White, M.S.
Geolex Incorporated
500 Marquette Avenue, NW
Suite 1350
Albuquerque, NM 87102

Re: Welltest Analysis of Targa AGI #1, New Mexico, USA

Dear Sir:

This report was prepared by Sproule Incorporated ("Sproule") at the request of Mr. David A. White, M.S, Geolex Incorporated (hereinafter referred to as "the Company") to summarize the results of a pressure transient analysis of the injection and fall-off test conducted over the open hole interval (4,258 – 4,850ft MD) in the Targa AGI #1 well in New Mexico.

Standards & Context

This report was prepared by Sproule using current geological and engineering knowledge, techniques and computer software and was prepared within the Code of Ethics of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA").

Analysis Software

For this analysis, Sproule used the WellTest software by IHS Markit. The functionality of the program is not the responsibility of Sproule, and results were accepted as calculated by the software. Sproule's responsibility is limited to the quality of the data input and reasonableness of the outcoming results.

Background

The Targa AGI #1 well was drilled to a depth of 4,850 ft MD and is cased down to 4,258 ft MD. As such, the open-hole interval from 4,258 – 4,850 ft MD is the subject of this test. The well has been used for water disposal since January 1994, and water was injected into the formation at an average rate of about 1,500 bbl/d until August 2011. Since then, a combination of water and carbon dioxide has been injected into the formation. Through to the end of March 2023, 6,441,502 bbls of water and 9,987,561 Mcf of carbon dioxide have been injected into this well. Assuming almost 9,000 days of injection, this translates to an equivalent water injection rate of 716 bbl/d and carbon dioxide injection rate of 1,110 Mcf/d.

On April 18, 2023, an injection and fall-off test was initiated, and a subsurface pressure and temperature gauge was set in the wellbore at a recorder run depth of 4,220 ft MD. Shortly thereafter, water injection was resumed. Water was injected at an initial average rate of about 2 bbls/minute for less than 2 minutes. This rate was subsequently increased to 3 bbl/minute for less than 2 minutes, to 3.9 bbl/minute for 1½ minutes then to 5.1 bbl/minute which equates to 7,344 bbl/d. This rate was maintained for 100 minutes, until the well was shut-in for fall-off. Thereafter, the bottomhole fall-off pressures were monitored for 41 hours, and the test was terminated on April 20.

The measured bottomhole pressures have been adjusted from a recorder run depth of 4,220 ft MD to the mid-point of the open-hole interval (4,554 ft MD) using a water gradient of 0.442 psi/ft. This equates to a pressure adjustment of 147.6 psi. Figure 1 shows the adjusted bottomhole pressures and water rates measured during the test.

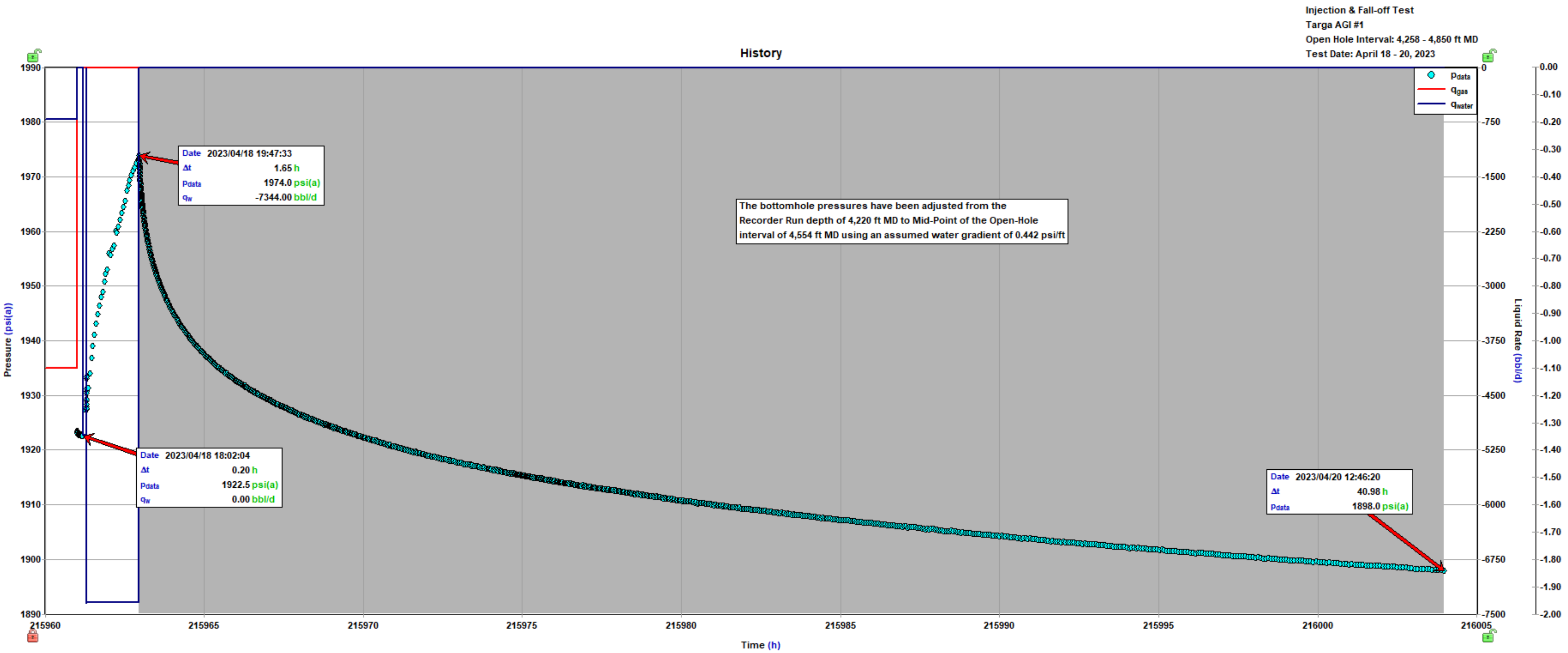


Figure 1: Bottomhole Pressure and Injected Fluid Rate History

Diagnostics

Figure 2 shows a plot of the raw gauge pressures and temperatures measured during the test. This shows that the bottomhole temperature had reduced to 79ºF by the end of the injection period, and then increased to 118ºF by the end of the fall-off.

Figure 3 shows the depth-corrected sandface pressures and injection rates measured during the first 6 minutes of injection while ramping up to the final injection rate of 5.1 bbls/minute. From this data it is apparent that the duration of each step rate was too short for the pressure to stabilize. Furthermore, the oscillating nature of the pressure data during the second rate (3 bbls/minute) makes it challenging to determine the representative pressure for this step. Additionally, the pressure fluctuated drastically when the rate was increased to 5.1 bbls/minute. Although the sudden drop in pressure when the rate was increased to 5.1 bbls/minute suggests the fracture gradient may have been exceeded, these issues with the data may be attributed to fluctuations in the injection rate.

The Company provided estimates of gross pay (769 ft), a net to gross ratio of 90 percent, a range of porosity (8.2 – 15 percent) and irreducible water saturation of 20 percent. Since the water saturation prior to injection of carbon dioxide was 100 percent, the analysis assumes current gas and water saturations of 70 and 30 percent, respectively. Based on these, as shown in Figure 4, a plot of the type curve and pressure derivative was generated to identify the flow regimes affecting the pressure fall-off behaviour.

Wellbore storage dissipated very quickly, and linear flow (which is characteristic of a stimulated reservoir) dominates almost the entire pressure fall-off response. This pressure response can manifest in wells that have been acid stimulated or hydraulically fractured and is occasionally seen in wells producing from naturally fractured carbonate reservoirs. It should be noted that since radial flow was not developed during the test, the permeability can not be determined with confidence. However, from this plot it can be determined that the permeability is less than 3.8 md. It should also be noted that the relatively small gap between the type curve (blue data) and pressure derivative (orange data) suggests very low skin.

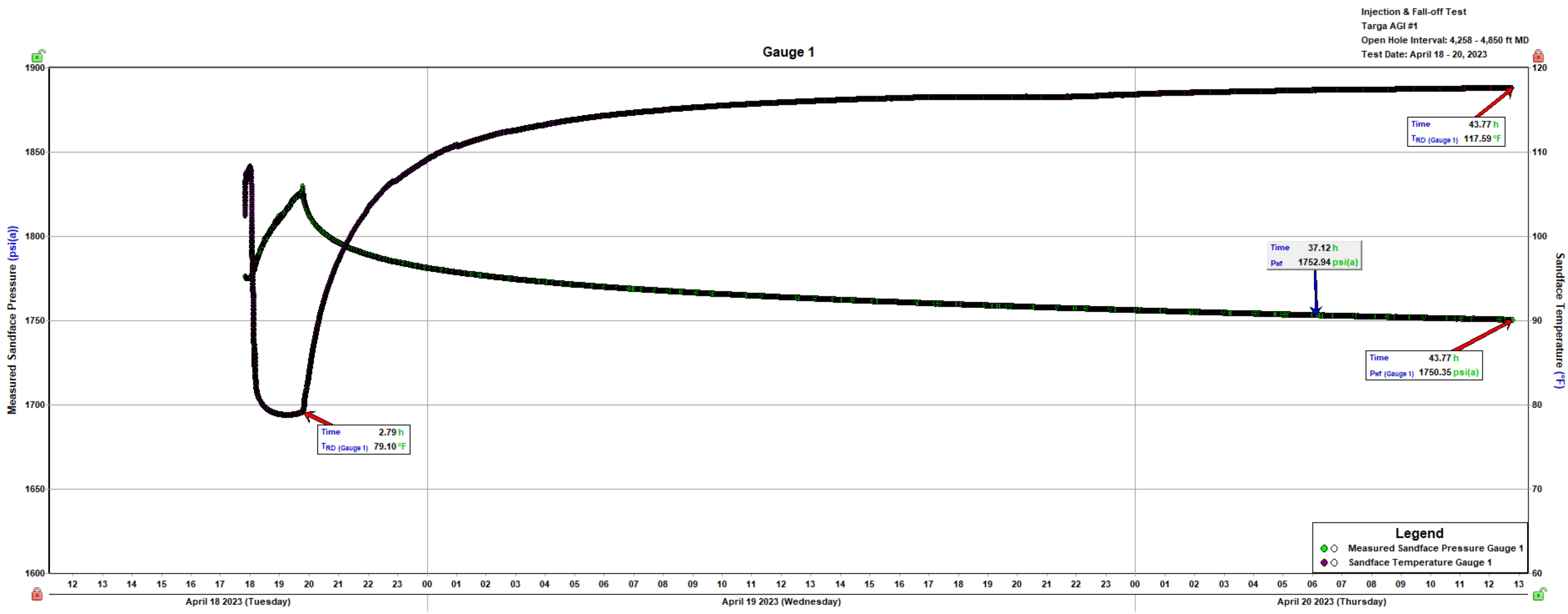


Figure 2: Raw Gauge Pressures & Temperatures

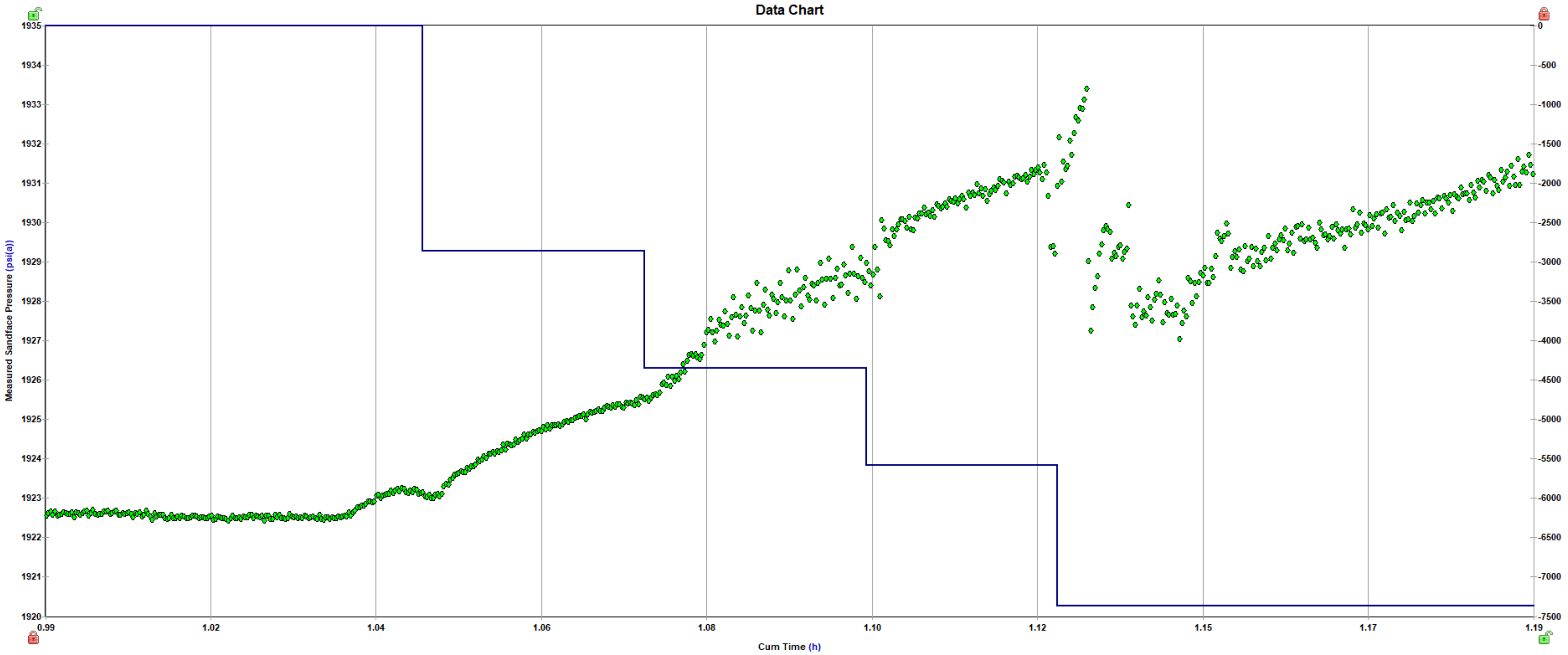


Figure 3: Depth-Corrected Sandface Pressures and Injection Rate Ramp-Up

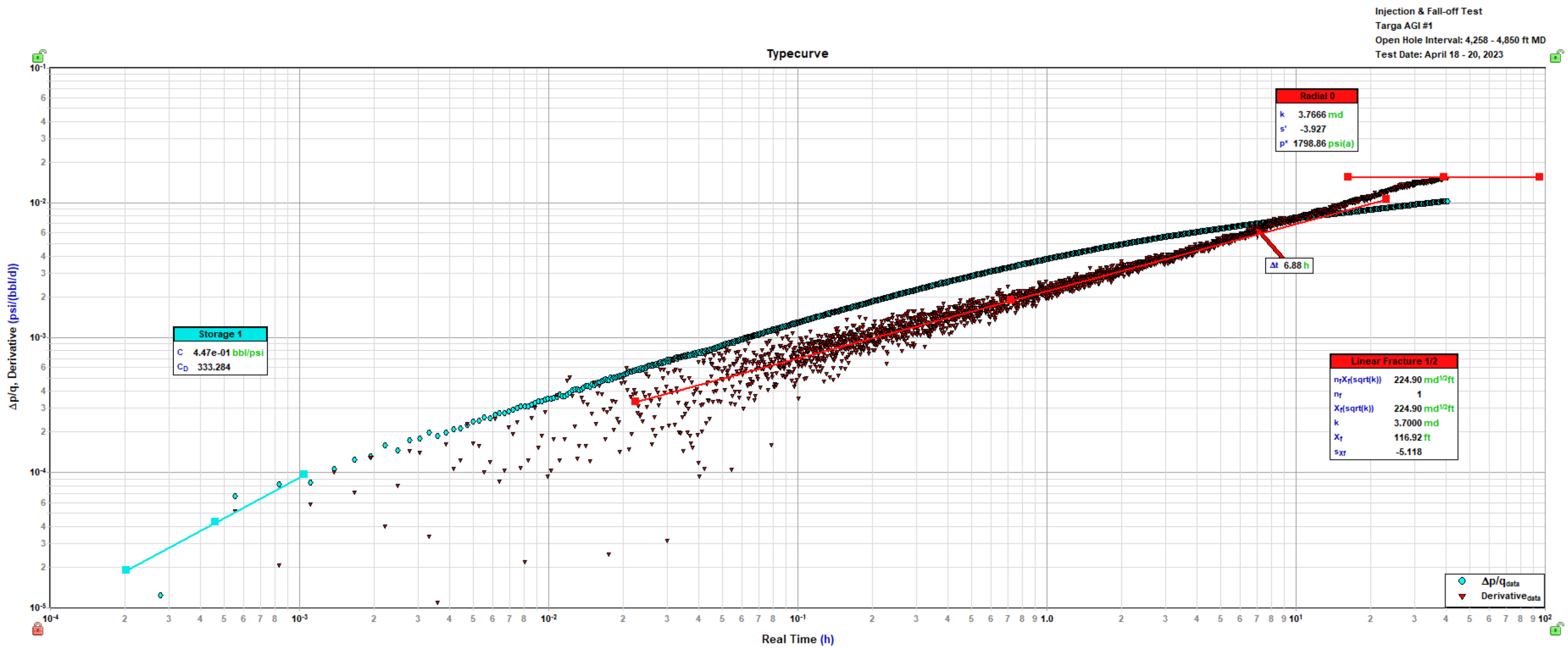


Figure 4: Plot of Type Curve & Pressure Derivative

Result Summary

A reasonable match with the pressure fall-off is achieved using an infinite conductivity fracture model. Since the permeability cannot be determined with confidence, history matching cannot provide a unique solution, and these results should be used with caution. Assuming net pay of 692 ft, the match is obtained with permeability of 2.5 md, a fracture half-length of 118 ft, and total skin of -5.1.

Figure 5 shows the match achieved with the pressure derivative during the fall-off period.

Prior to resuming injection, the measured sandface pressure was 1,923 psia. At the end of the injection period the pressure had increased to 1,974 psia. After 41 hours of the subsequent shut-in, the final measured bottomhole pressure had decreased to 1,898 psia. Assuming a one square mile drainage area, the infinite conductivity fracture model extrapolates the pressure fall-off to 1,768 psia. Please once again note, that this pressure should be used with caution.
Table 1 summarizes the test results.

Table 1: Summary of Test Results

Measured Bottomhole Pressure Prior to Injection (April 18, 2023)	1,923 psia
Final Measured Injection Bottomhole Pressure (April 18, 2023)	1,974 psia
Final Measured Water Injection Rate (April 18, 2023)	7,344 bbls/d
Final Measured Shut-in Bottomhole Pressure (April 20, 2023)	1,898 psia
History Matching: Infinite Conductivity Fracture Model	
Average Reservoir Pressure *	1,768 psia
Fracture Half-Length	118 ft
Skin	-5.1
Effective Permeability To Water **	2.5 md
Assumed Reservoir Width (X_e)	5,280 ft
Assumed Reservoir Length (Y_e)	5,280 ft

* The extrapolation of the reservoir pressure is dependent on permeability and the assumed drainage area and this value should be used with caution.
** Since radial flow was not developed, this estimate of permeability should be used with caution.

A wellbore schematic is provided in Appendix A. Additional information and plots pertaining to the Infinite Conductivity Fracture Model are provided in Appendix B. The abbreviations, units and conversion factors used in this analysis are provided in Appendix C. The raw pressure data that were provided in a wireline report from Renegade Wireline Services are provided in Appendix D.

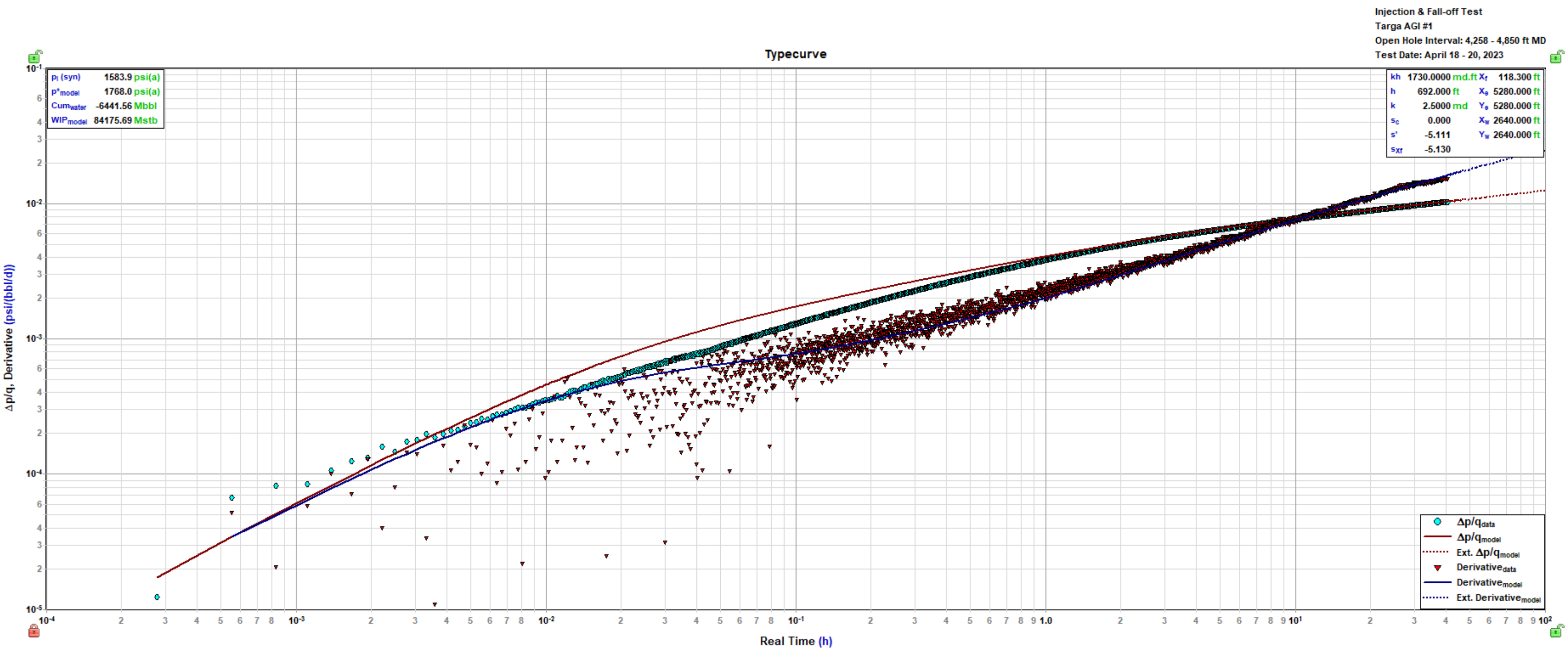


Figure 5: History Match of Type Curve and Pressure Derivative

Please do not hesitate to contact us if we can be of assistance to you regarding this or any other matter.

Authentication

This welltest analysis is authenticated by the licenced professional(s) preparing it as follows:

Responsible Member Validation

The following Responsible Member of Sproule Incorporated certify that our internal quality control process has been followed in accordance with our Professional Practice Management Plan.

Meghan Klein, P.Eng.
Senior Manager, Engineering

Appendix A — Wellbore Schematic

Attachement #1

Eunice Gas Plant SWD #1

	Location:
Footage	2500 FSL & 1200 FWL
Section	27
Survey	T22S R37E
County	Lea
Elevations:	
GR	3345
TD	4550
PBTD	

History	

	Tubing Detail (top to bottom)
Joints	**Description**
1	X-over
1	2 7/8" 6 5# J-55 EUE Duoline sub
8	jts 2 7/8" 6 5# J-55 EUE Duoline
1	X-over
1	Halliburton SSSV @ 277'
1	X-over
124	jts 2 7/8" 6 5# J-55 EUE Duoline
1	Halliburton seal assembly stung in Halliburton
	pkr @ 4190'
1	2 7/8" 6 5# J-55 EUE Duoline sub
1	X nipple (1 875 ID)
1	2 7/8" 6 5# J-55 EUE Duoline sub, EOT @ 4219'

API No:	**30-025-21497**

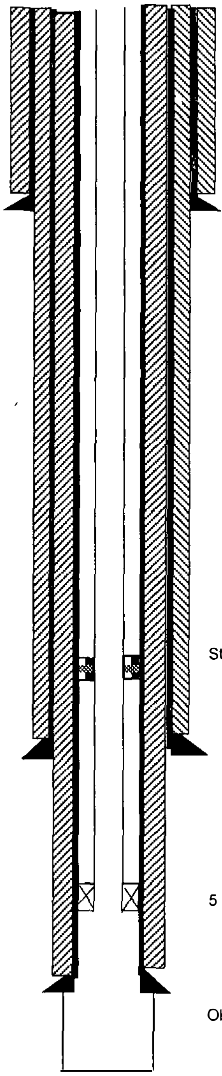


Figure A-1: Wellbore Schematic

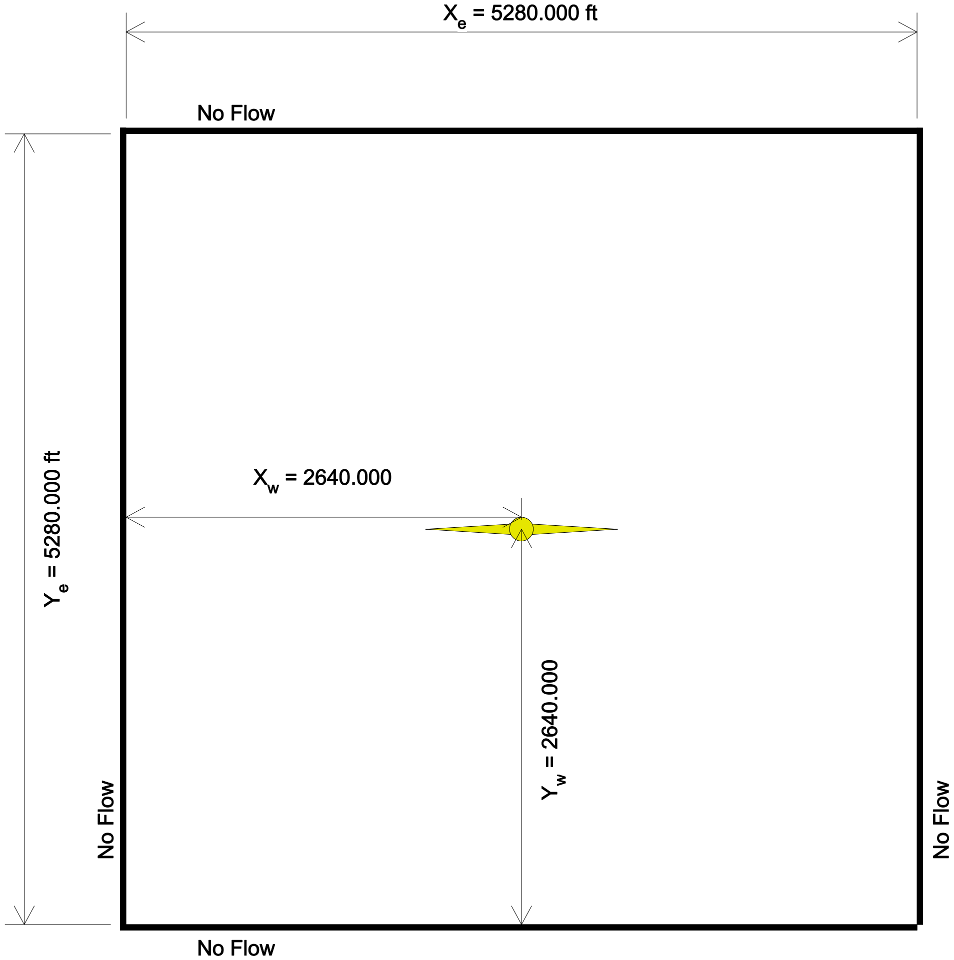
Appendix B — Infinite Conductivity Fracture Model

Frac. Bound. 1

k = 2.5000 md
s_c = 0.000
X_f = 118.300 ft
WIP_{model} = 84175.69 Mstb

Plan View

(Not to scale)



Side View

(Not to scale)

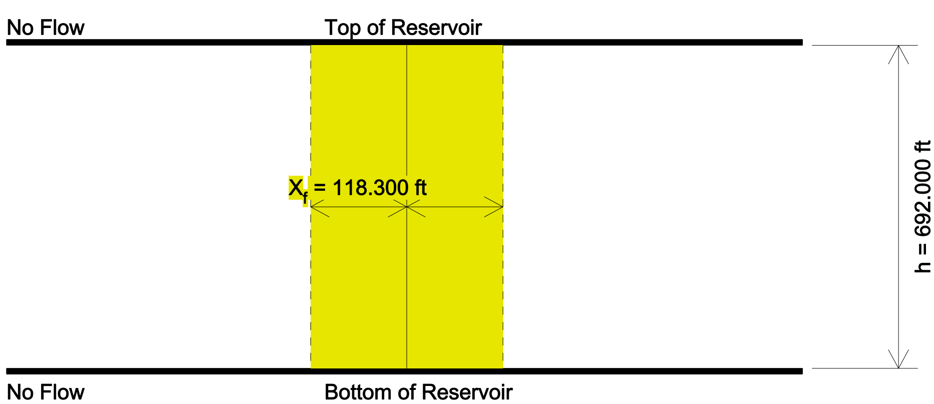


Figure B-1: Reservoir Dimensions & Properties

Water Model - Frac. Bound. 1

Analysis Results

Effective Water Permeability (k_w)	2.5000 md
Total Mobility ($(k/\mu)_t$)	4.39 md/cP
Total Transmissivity ($(kh/\mu)_t$)	3037.52 mdft/cP
Total Skin (s')	-5.111
Choked Fracture Skin (s_c)	0.000
Skin Equivalent to X_f ($_{sXf}$)	-5.130
Wellbore Volume (V_w)	213992 bbl
Dim. Wellbore Storage Constant (C_D)	330.000
Fracture Half-Length (X_f)	118.300 ft
Reservoir Length (X_e)	5280.000 ft
Reservoir Width (Y_e)	5280.000 ft
Well Location X-Direction (X_w)	2640.000 ft
Well Location Y-Direction (Y_w)	2640.000 ft

Reservoir Parameters

Net Pay (h)	692.000 ft
Total Porosity (ϕ_t)	8.20 %
Gas Saturation (S_g)	70.00 %
Oil Saturation (S_o)	0.00 %
Water Saturation (S_w)	30.00 %
Formation Compressibility (c_f)	5.2797e-06 1/psi
Total Compressibility (c_t)	2.5037e-04 1/psi
Wellbore Radius (r_w)	0.350 ft

Production and Pressures

Total Fluid Rate (in situ) ($(q\beta)_t$)	-7374.6 rbbl/d
Final Gas Rate ($q_{g\ final}$)	0.000 MMscfd
Final Water Rate ($q_{w\ final}$)	-7344.0 bbl/d
Total Cumulative Production Water (Cum_{water})	-6441.56 Mbbl
Final Flowing Pressure (p_{wfo})	1974.0 psi(a)
Final Measured Pressure (p_{last})	1898.0 psi(a)

Fluid Properties

Reservoir Temperature (T_{resv})	117.0 °F
Reservoir Pressure (p_{resv})	1750.0 psi(a)
Water Specific Gravity (γ_w)	1.000
Water Viscosity (μ_w)	0.5695 cP
Water Compressibility (c_w)	3.00e-06 1/psi
Water Formation Volume Factor (B_w)	1.004 bbl/stb
Solution Gas Ratio (R_{sw})	0.0 scf/bbl

Synthesis Results

Average Error (E_{avg})	0.08 %
Synthetic Initial Pressure (p_i (syn))	1583.9 psi(a)
Extrapolated Model Pressure (p^*_{model})	1768.0 psi(a)
Pressure Drop Due to Total Skin (Δp_{skin})	0.0 psi(a)
Flow Efficiency (FE)	1.000
Damage Ratio (DR)	1.000

Forecasts

Forecast Flowing Pressure (Report) (p_{flow})	1974.0 psi(a)
Forecast Rate at 3 Months and Current Skin ($q_{@\ 3\ Months}$)	-1989.9 bbl/d
Forecast Rate at 6 Months and Current Skin ($q_{@\ 6\ Months}$)	-1724.8 bbl/d
Constant Rate Forecast Flow Time (Report) (t_{flow})	12.00 month
Forecast Rate at Specified Time and Current Skin ($q_{@\ Current\ Skin}$)	-1519.9 bbl/d
Stabilized Injectivity Index @ Current Skin (II_{Actual})	8.403 (bbl/d)/psi
Forecast Rate at Specified Time and Skin = 0 ($q_{@\ 0\ Skin}$)	-1519.9 bbl/d
Stabilized Injectivity Index @ Skin = 0 (II_{Ideal})	8.403 (bbl/d)/psi
Forecast Rate at Specified Time and Skin = -4 ($q_{@\ -4\ Skin}$)	-1531.4 bbl/d

Figure B-2: Analysis Details

Injection & Fall-off Test
Targa AGI #1
Open Hole Interval: 4,258 - 4,850 ft MD
Test Date: April 18 - 20, 2023

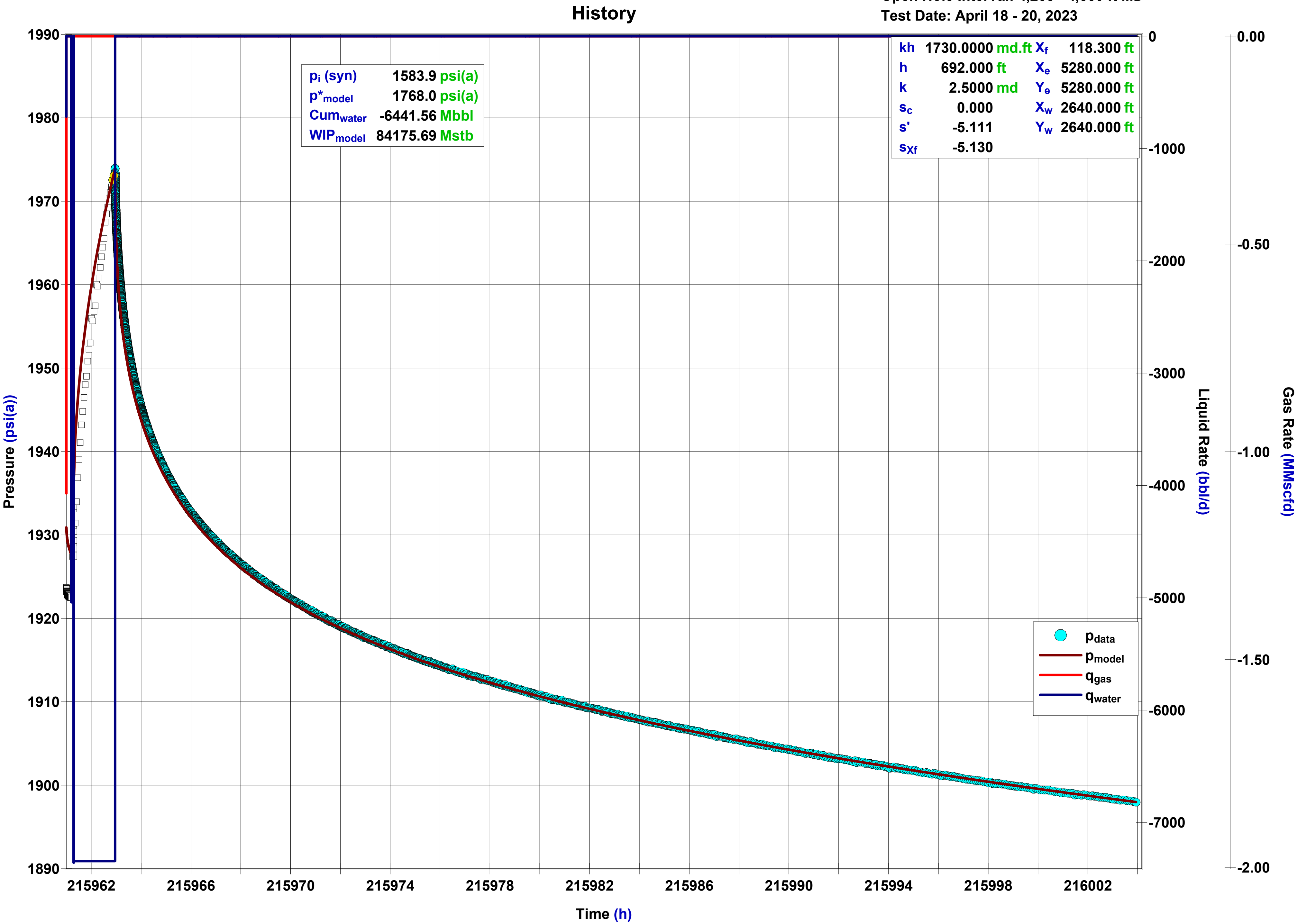


Figure B-3: History Match of Pressure Fall-off

WellTest 2019.1™ Ver 19.1.2.181
P:\Geolex 115314 Targa 2023\Engineering Worknotes\LMO Worknotes\FAST Welltest Files\Targq AGI#1.fkt 17-May-23

Injection & Fall-off Test
Targa AGI #1
Open Hole Interval: 4,258 - 4,850 ft MD
Test Date: April 18 - 20, 2023

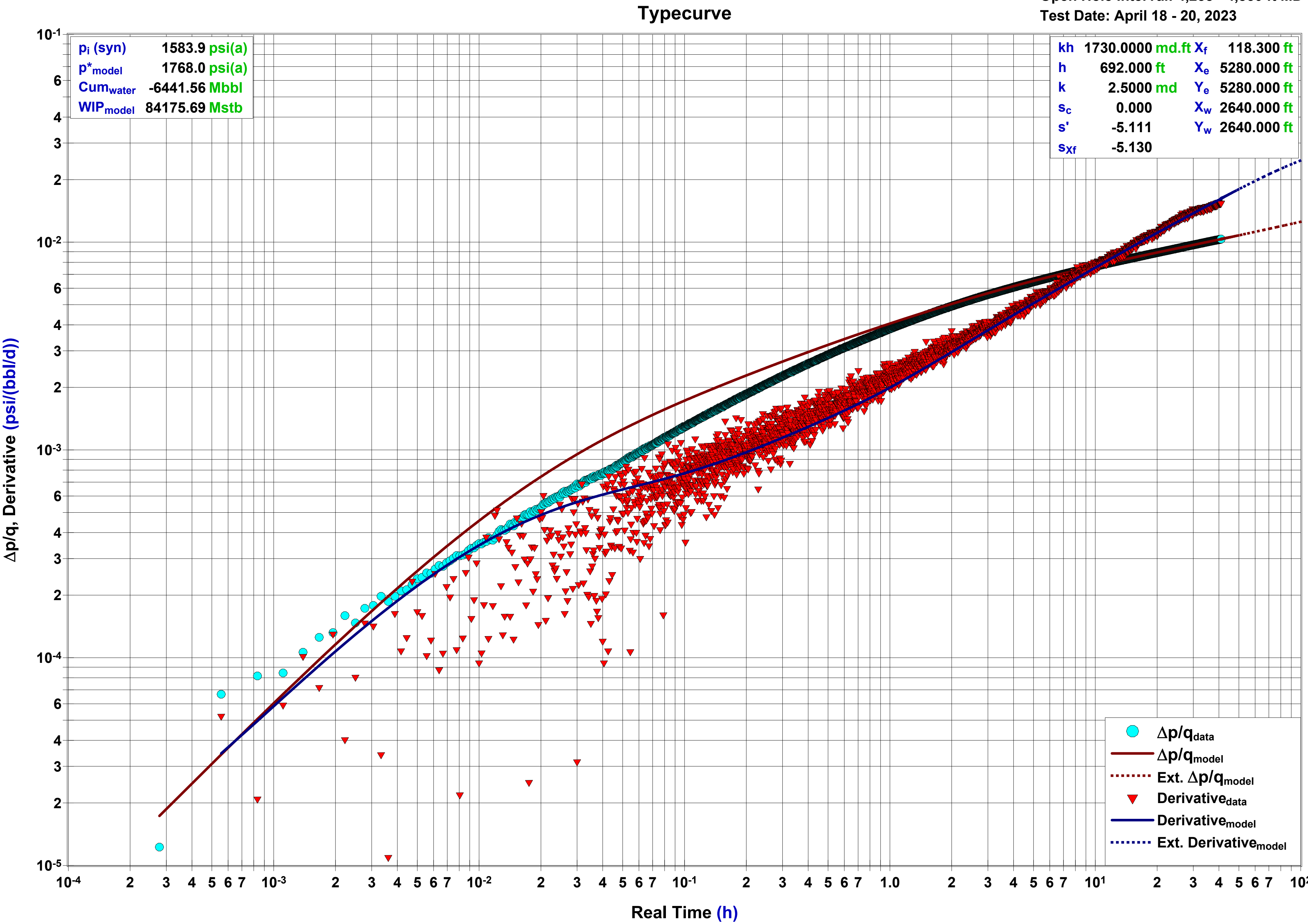


Figure B-4: History Match of Type Curve & Pressure Derivative

Appendix C — Abbreviations, Units and Conversion Factors

This appendix contains a list of abbreviations found in Sproule reports, a table comparing Imperial and Metric units, and conversion tables used to prepare this report.

Abbreviations

ADR	abandonment, decommissioning and reclamation
AFE	authority for expenditure
AOF	absolute open flow
APO	after pay out
B_g	gas formation volume factor
B_o	oil formation volume factor
BOE	barrels of oil equivalent
bpd	barrels per day
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
bfpd	barrels of fluid per day
BPO	before pay out
BS&W	basic sediment and water
BTU	British thermal unit
bwpd	barrels of water per day
CF	casing flange
CGR	condensate-gas ratio
D&A	dry and abandoned
DCQ	daily contract quantity
DPIIP	discovered petroleum initially-in-place
DSU	drilling spacing unit
DST	drill stem test
EOR	enhanced oil recovery
EPSA	exploration and production sharing agreement
FPSO	floating production, storage and off-loading vessel
FVF	formation volume factor
g/cc	gram per cubic centimeter
GIIP	gas initially-in-place
GOR	gas-oil ratio
GORR	gross overriding royalty
GRV	gross rock volume
GWC	gas-water contact
HCPV	hydrocarbon pore volume

ID	inside diameter
IOR	improved oil recovery
IPR	inflow performance relationship
IRR	internal rate of return
k	permeability
KB	kelly bushing
LKH	lowest known hydrocarbons
LKO	lowest known oil
LNG	liquefied natural gas
LPG	liquefied petroleum gas
McfGE	thousands of cubic feet of gas equivalent
Mcfpd	thousands of cubic feet per day
md	millidarcies
MDT	modular formation dynamics tester
MPR	maximum permissive rate
MRL	maximum rate limitation
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
NRA	no reserves assigned
NRI	net revenue interest
NPV	net present value
NRV	net rock volume
NTG	net-to-gross
OD	outside diameter
OGIP	original gas in place
OIIP	oil initially-in-place
OOIP	original oil in place
ORRI	overriding royalty interest
OWC	oil-water contact
P1	proved
P2	probable
P3	possible
P&NG	petroleum and natural gas
PI	productivity index
ppm	parts per million
PSU	production spacing unit
PSA	production sharing agreement
PSC	production sharing contract
PVT	pressure-volume-temperature

RFT	repeat formation tester
RT	rotary table
SCAL	special core analysis
SS	subsea
TPIIP	total petroleum initially-in-place
TVD	true vertical depth
UPIIP	undiscovered petroleum initially-in-place
WGR	water-gas ratio
WI	working interest
WOR	water-oil ratio
2D	two-dimensional
3D	three-dimensional
4D	four-dimensional
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
°API	degrees API (American Petroleum Institute)

Sproule

Imperial and Metric Units

Imperial Units			Metric Units	
M (10^3)	thousand	**Prefixes**	k (10^3)	kilo
MM (10^6)	million		M (10^6)	mega
B (10^9)	billion		G (10^9)	giga
T (10^{12})	trillion		T (10^{12})	tera
Q (10^{15})	quadrillion		P (10^{15})	peta
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	miles		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
MMcf	million cubic feet			
Bcf	billion cubic feet		e^6m^3	million cubic metres
bbl	barrels		m^3	cubic metres
Mbbl	thousand barrels		e^3m^3	thousand cubic metres
stb	stock tank barrels		stm^3	stock tank cubic metres
bbl/d	barrels per day	**Rate**	m^3/d	cubic metre per day
Mbbl/d	thousand barrels per day		e^3m^3/d	thousand cubic metres
Mcf/d	thousand cubic feet per day		e^3m^3/d	thousand cubic metres
MMcf/d	million cubic feet per day		e^6m^3/d	million cubic metres
Btu	British thermal units	**Energy**	J	joules
oz	ounces	**Mass**	g	grams
lb	pounds		kg	kilograms
ton	tons		t	tonnes
lt	long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	degrees Kelvin
M$	thousand dollars	**Dollars**	k$	1 kilodollar

Sproule

Imperial and Metric Units (Cont'd)

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
d	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Sproule

Conversion Tables

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf)
(@ 101.325 kPaa, 15°C)		(@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise
density (kg/m3), ρ	ρ÷1000x141.5-131.5	= °API

Sproule

Conversion Tables (Cont'd)

Conversion Factors — Imperial to Metric

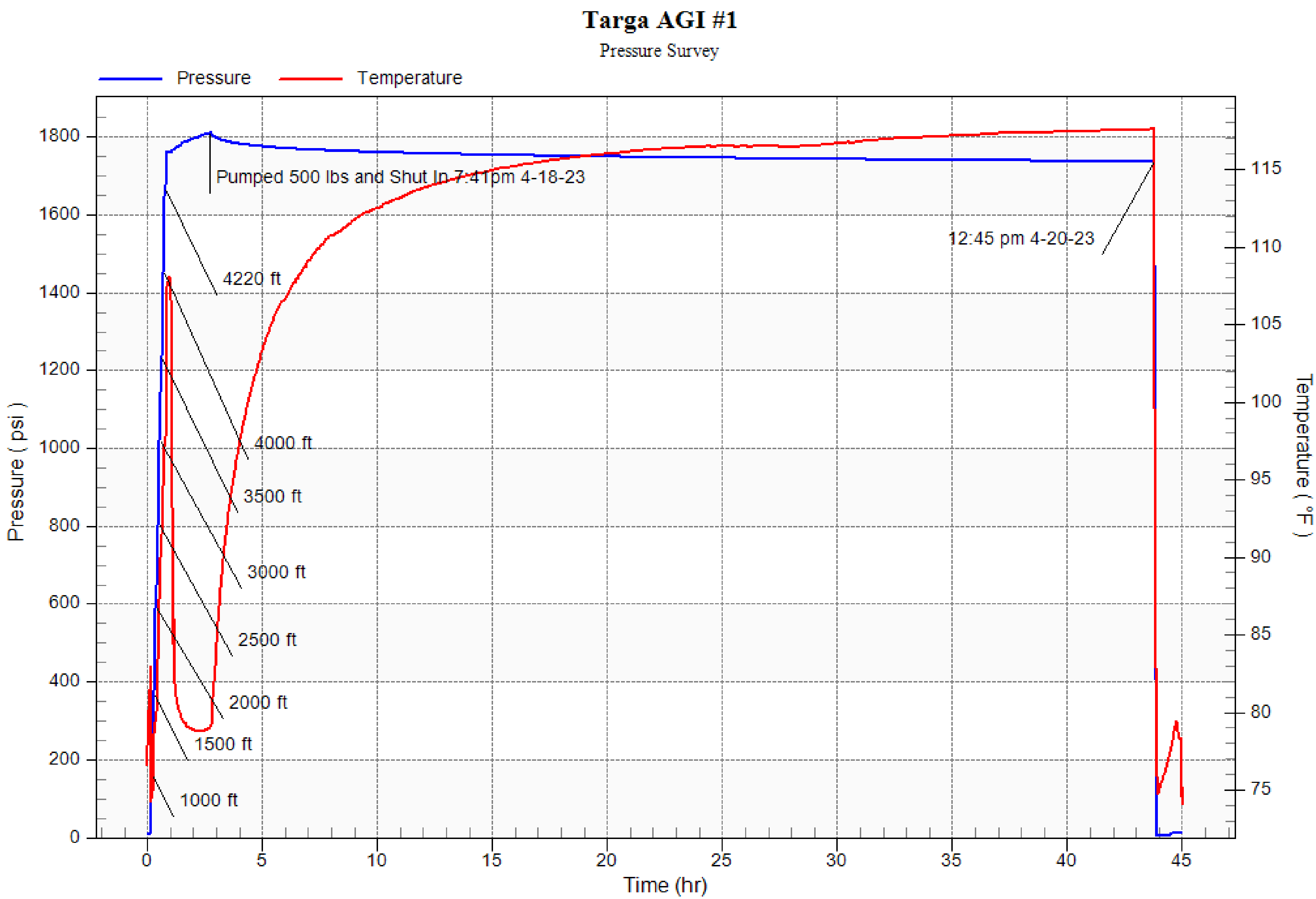
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf)	x 0.03743222	= megajoules per cubic metre (MJ/m^3)
(@ 14.65 psia, 60°F)		(@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
dollars per barrel ($/bbl)	x 6.29287	= dollars per cubic metre ($\$/m^3$)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
Horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)
°API	(°APIx131.5)x	= density (kg/m3)
	1000/141.5	

Appendix D — Raw Pressure Data

Targa AGI #1
April 18, 2023

JOB INFORMATION SHEET

Company Information		
Company Name:	Targa	
Well Information		
Well Name:	Targa AGI #1	
Location:	Lea County, NM	
Field – Pool:	Targa AGI	
Status:	Disposal Well	
Test Information		
Type of Test:	Pressure Survey	
Gauge Depth:	4220 ft	
Temperature @ Run Depth	117.59 degF	
Surface Temperature:	74.11 degF	
Gauge Information		
	Top Recorder	Bottom Recorder
Serial Number:	81276	
Calibration Date:	3/21/22	
Pressure Range:	10000 psi	
Comments		
Pressure Survey 3 min stops every 500ft from surface to 4220ft Set tools and pumped 500lbs water Shut in 2 days		


Targa AGI #1
Pressure Survey
Pressure
Temperature
Pumped 500 lbs and Shut In 7:41pm 4-18-23
12:45 pm 4-20-23
4220 ft
4000 ft
3500 ft
3000 ft
2500 ft
2000 ft
1500 ft
1000 ft
Pressure (psi)
Temperature (°F)
Time (hr)
0
200
400
600
800
1000
1200
1400
1600
1800
75
80
85
90
95
100
105
110
115
0
5
10
15
20
25
30
35
40
45

Gradient Data Report

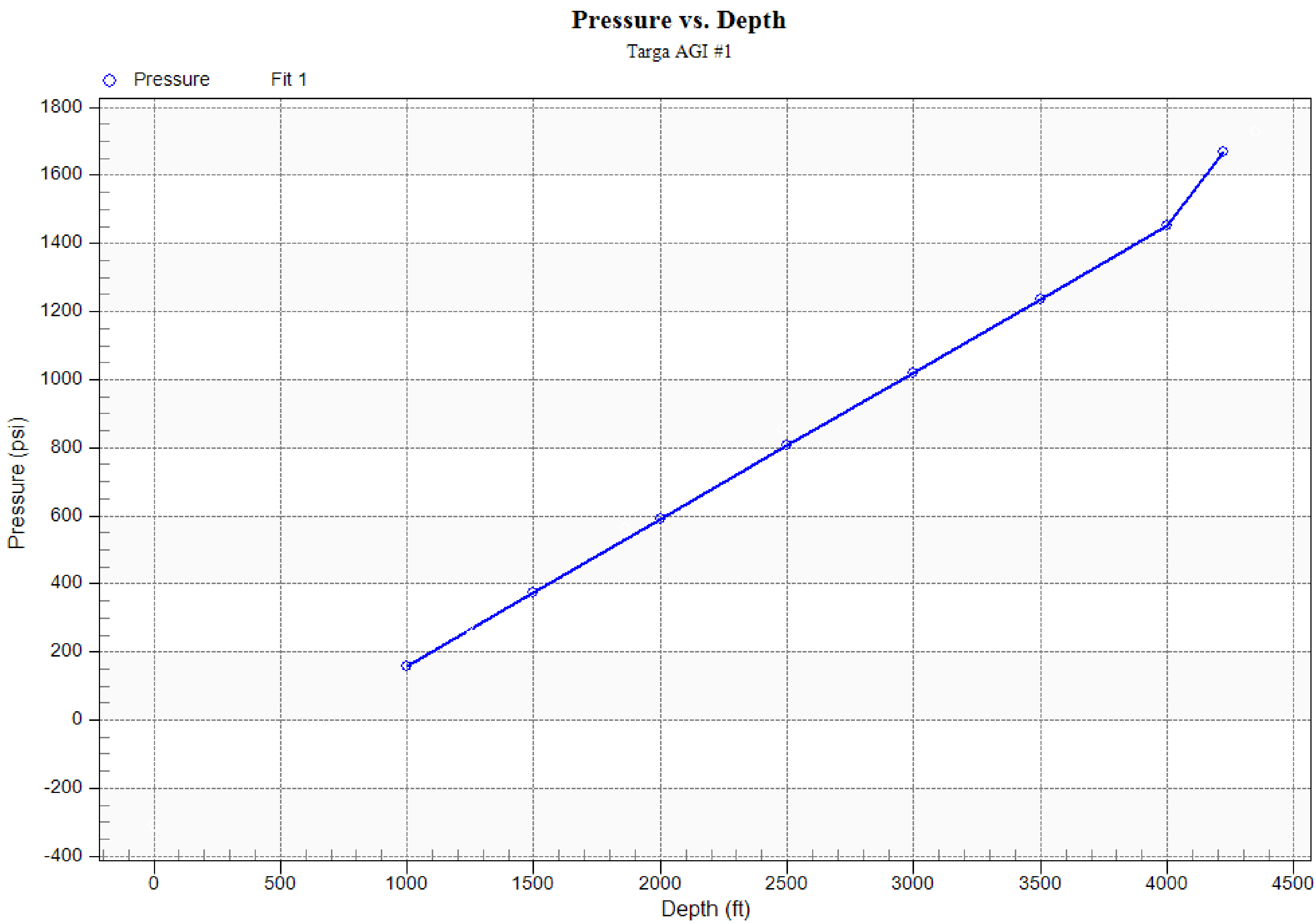
Targa AGI #1

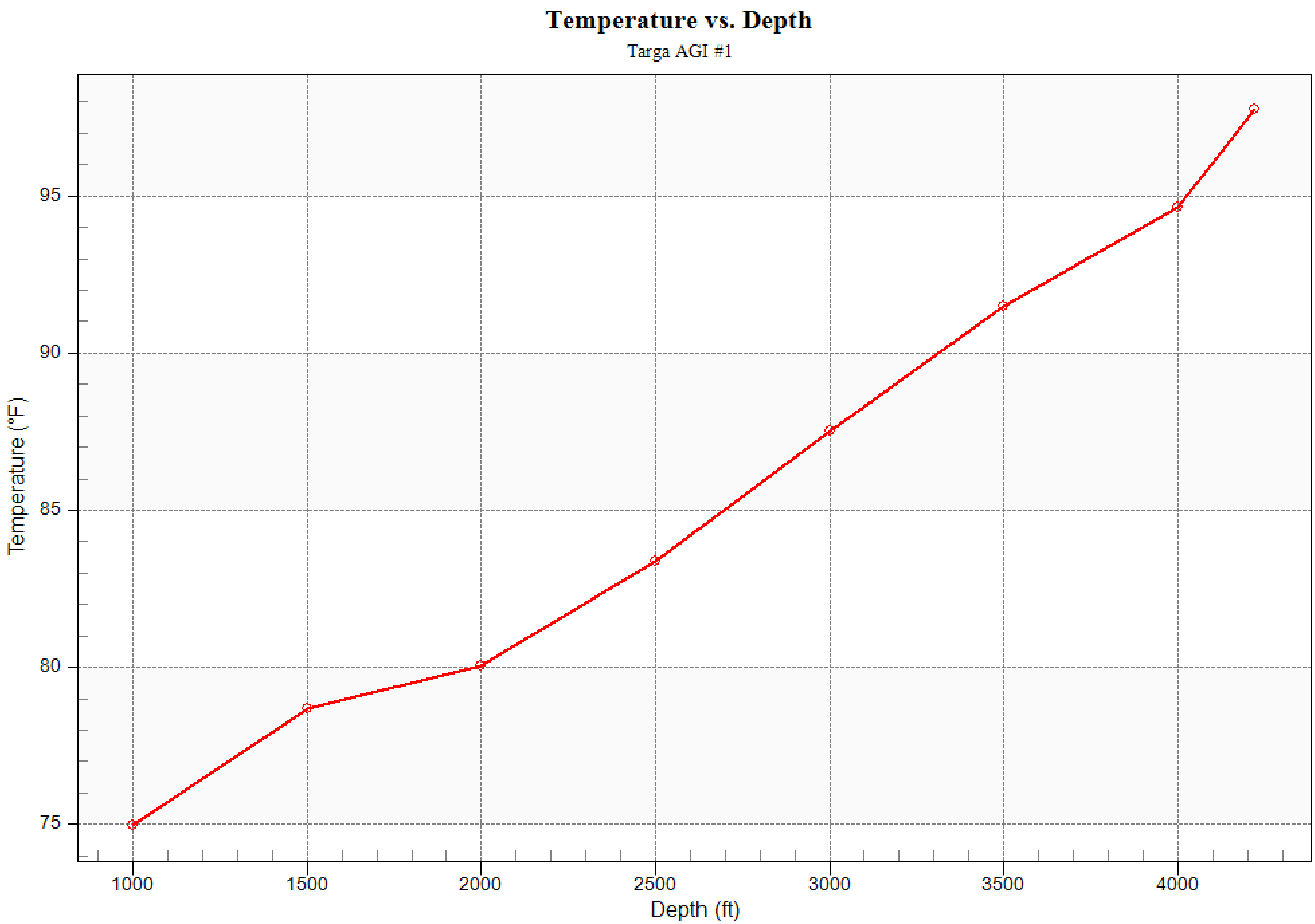
Gradient Data Table

Depth ft	Pressure psi	Temperature degF	Gradient psi/ft
1000.00	159.04	74.98	0.0000
1500.00	373.75	78.67	0.4294
2000.00	590.14	80.03	0.4328
2500.00	805.05	83.40	0.4298
3000.00	1020.41	87.51	0.4307
3500.00	1236.12	91.47	0.4314
4000.00	1451.53	94.65	0.4308
4220.00	1667.11	97.76	0.9799

Analysis Summary

Depth ft	Gradient psi/ft
0.00	
	0.4683
4220.00	


Pressure vs. Depth
Targa AGI #1
Pressure
Fit 1
Pressure (psi)
1800
1600
1400
1200
1000
800
600
400
200
0
-200
-400
0
500
1000
1500
2000
2500
3000
3500
4000
4500
Depth (ft)


Temperature vs. Depth
Targa AGI #1
Temperature (°F)
95
90
85
80
75
1000
1500
2000
2500
3000
3500
4000
Depth (ft)

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 235965

CONDITIONS

Operator:	
TARGA MIDSTREAM SERVICES LLC 811 Louisiana Street Houston, TX 77002	OGRID: 24650
	Action Number: 235965
	Action Type: [C-103] Sub. General Sundry (C-103Z)

CONDITIONS

Created By	Condition	Condition Date
mgebremichael	The reservoir analysis for the 10 year milestone report has been approved and OCD is expecting a comprehensive milestone report in a format that was communicated via email	10/11/2023