Closed Loop Gas Capture

Pilot Test Summary

Introduction to Closed Loop Gas Capture

Closed Loop Gas Capture ("CLGC") is a process that provides an alternative to flaring or shutting in wells when third party purchasers temporarily reduce their capacity to purchase gas from EOG Resources, Inc.'s ("EOG's") compressor stations. Currently, third-party market interruptions are a leading source of flaring for EOG's operations in the Permian Basin.

CLGC further reduces dependency on third-party market runtime by providing additional optionality, and has multiple environmental and operational benefits, including:

- Reduced greenhouse gas emissions due to flaring. CLGC provides a real-time response to reduced market takeaway.
- Improved economic development of mineral resources. CLGC enables the continued production of oil that otherwise might be shut in to prevent flaring of associated gas. It also enables the potential recovery of gas that otherwise might be flared. Both benefit mineral and royalty interest owners.
- Limited surface disturbance. CLGC uses existing infrastructure - compressor stations, production wells, and production facilities – and requires minimal additional pipeline infrastructure.

During periods of third-party market interruptions, gas from a compressor station can be diverted through a pipeline, metered, and injected into a nearby well. The well is shut in during the injection period. After the injection period, the well is produced using existing production and measurement equipment.

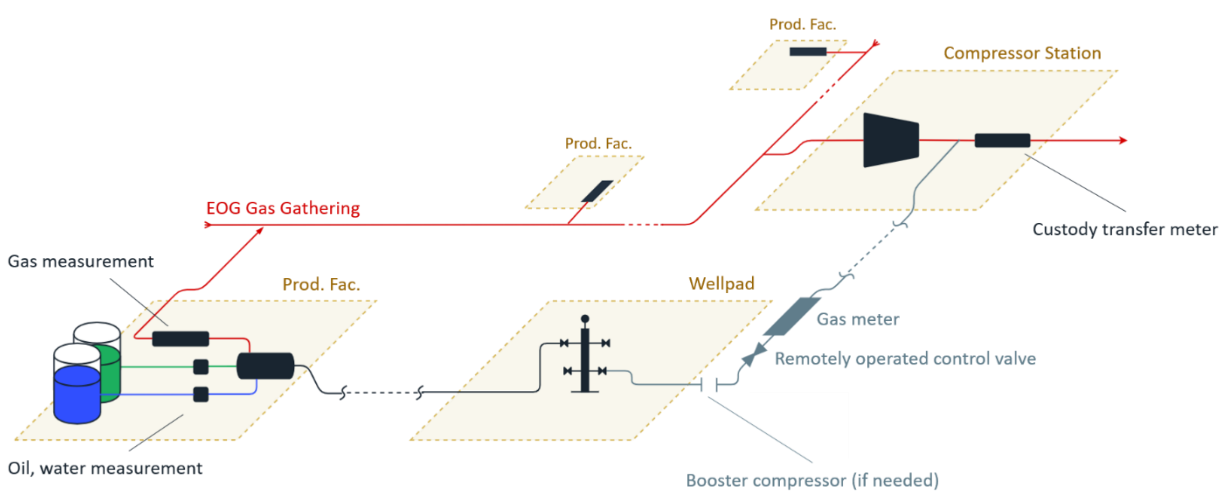


Figure 1 - Closed Loop Gas Capture Schematic

Geologic and Reservoir Considerations

Candidate injection wells for CLGC are chosen based on the following geologic and reservoir criteria: (1) structurally benign with no faulting, (2) enough storage space for the injected gas, (3) low matrix and fracture permeability to contain the gas near the wellbore, (4) low/drawn-down pore pressure to allow for low-pressure injection, (5) approximately static relative permeability, and (6) no negative effect on future development or existing production in nearby leases/ formations.

Infrastructure Considerations

Candidate injection wells are chosen based on the following infrastructure criteria: (1) proximity to compressor stations, which minimizes pipeline length to such well, and (2) proximity to core development areas where production and flaring potential are highest.

Production Considerations

Candidate injection wells are chosen for low, stable production and low bottom-hole pressure. Low, stable production ensures that short periods of injection will not significantly affect field production and that the well's native production is easily determined for allocation. Low bottom-hole pressure allows standard compression equipment to be used for injection.

Candidate injection wells must also have adequate mechanical integrity to ensure safe operations during injection cycles. The production casing string must be capable of withstanding proposed injection pressures and have adequate cement in place to isolate the injection zone.

Pilot Test Parameters

The Caballo 23 Fed #2H (the "Pilot Well") was selected as the pilot test injection well based on the well selection criteria discussed above. Pertinent well details are as follows:

- Well Name: Caballo 23 Fed #2H
- Completion Date: Feb 2012
- Target: Avalon Shale
- Current Production: 15 BOPD, 80 BWPD, 350 MCFD

Wellbore mechanical integrity for the Pilot Well was confirmed by successfully pressure testing casing to 1,650 psig with a full hydrostatic column of fluid from 9,000' to surface. A cement bond log confirmed adequate isolation of the injection zone. See Appendix 2 for the Pilot Well well diagram.

The Pilot Well is gas lifted for normal production operations with open ended tubing set at 9,450'. This packer-less design allows for the well to be produced up tubing during production operations and enables gas injection down casing for CLGC operations. The following schematics illustrate production operation versus CLGC operation:

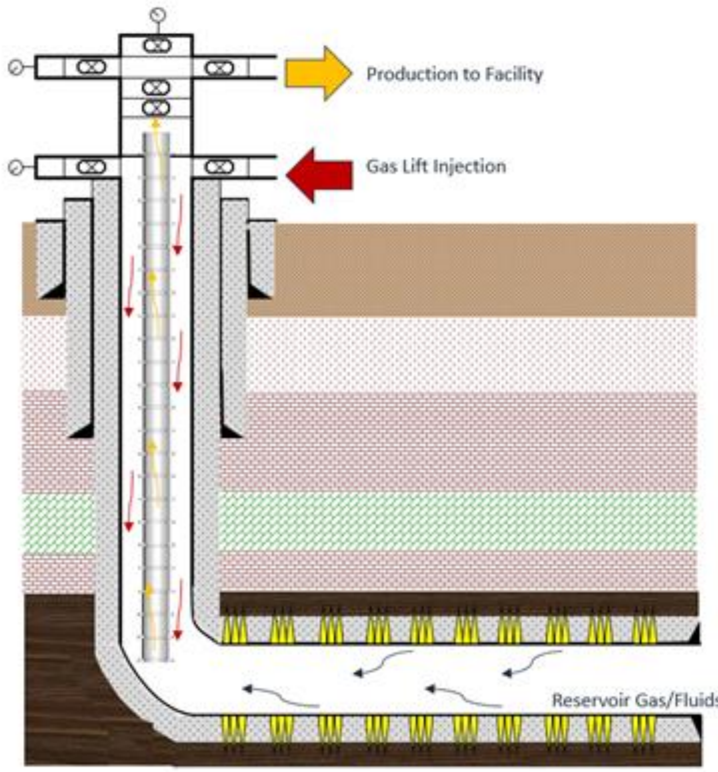


Figure 2 - Production Operation

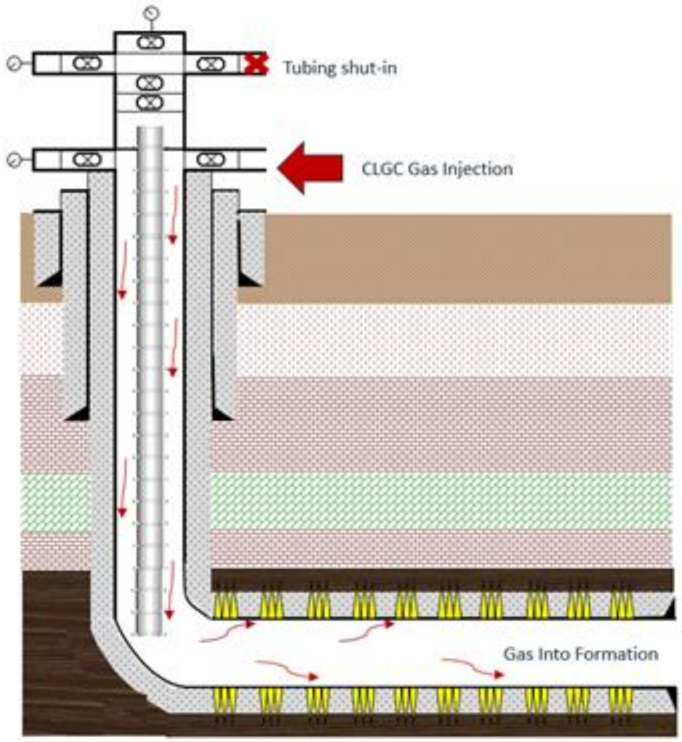


Figure 3 - CLGC Operation

The Pilot Well is located in Lea County, New Mexico, 25S 33E.

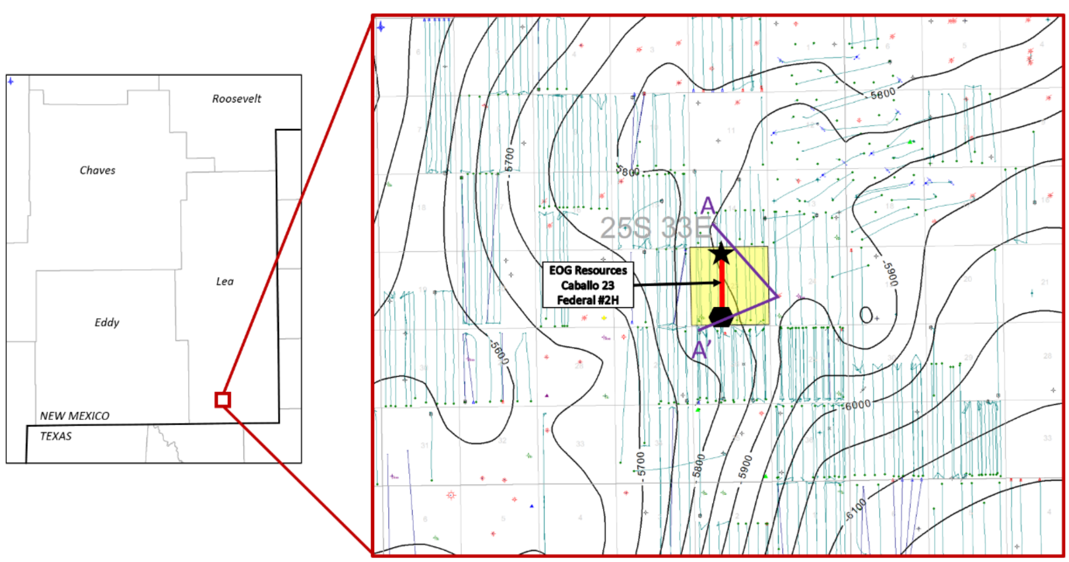


Figure 4 - Caballo 23 Fed #2H Location

Cross section A to A’ is shown below.

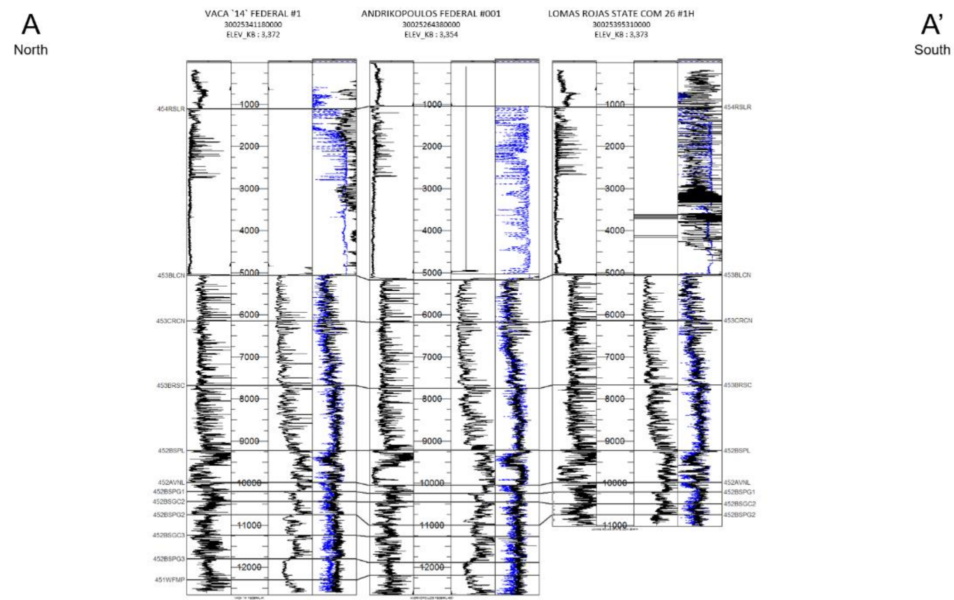


Figure 5 - Cross Section A to A' through Caballo Lease, from Rustler to Wolfcamp

As stated, the Pilot Well is targeted in the Avalon Shale. In the Delaware Basin, the Avalon Shale sits stratigraphically above the First Bone Spring Sand and below the Bone Spring Lime. Above the Bone Spring Lime is the Delaware Sands series, capped by the Rustler. The Avalon target is a quartz rich mudrock with low permeability. The Lower Avalon has a high percent of carbonate and serves as a flow barrier between the Upper Avalon and the First Bone Spring Sand. The Bone Spring Lime carbonate acts as a flow barrier between the Avalon and the Brushy Canyon Sand.

The Pilot Well did not intersect any visible faults during drilling, suggesting the location for the test is structurally benign throughout the Avalon Shale. This is further confirmed with consistent dip in structure and consistent thickness of the Avalon unit.

These geologic parameters help keep injected gas near the wellbore, preventing both horizontal and vertical migration.

The Pilot Well had produced 147 mbo, 1890 mmscf, 254 mbw prior to testing. It had a bottom hole pressure (“BHP”) of ~450 psig. Conversion of cumulative production to reservoir volume indicated that maximum test volumes would not exceed 1.5% of removed volume. This ratio of injected gas to produced gas, combined with Computer Modeling Group, Ltd. (“CMG”) reservoir models, led to confidence that CLGC would not significantly build BHP or appreciably recharge the reservoir. CMG models simulating repeated cycles of injection and production predicted gradual recovery of injected gas and no to negligible long-term productivity enhancement.

Surface Equipment

Injection gas was delivered from a nearby localized gas lift (LGL) compressor station:

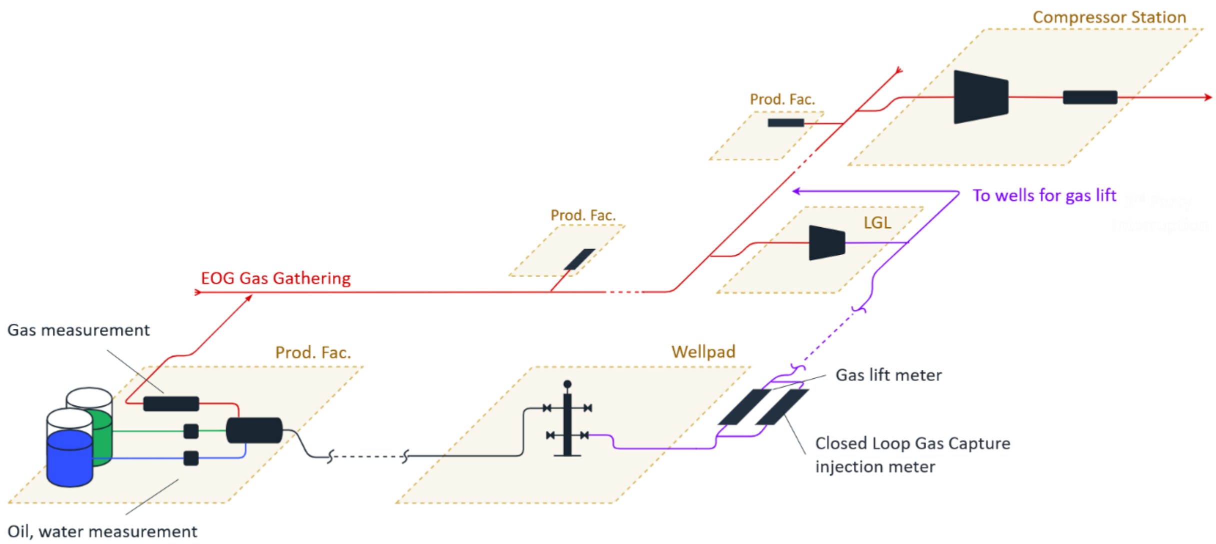


Figure 6 - Pilot Test Infrastructure

Injection rates were controlled with automated control valves.

The following data were collected before, during, and after injection, and monitored by EOG's 24-hour control room:

From Pilot Well:

- Injection rate
- Injection pressure
- Cumulative injection volume
- Injection gas composition
- Casing pressure
- Tubing pressure
- Oil, gas, and water production
- Produced gas composition
- Recovery percentage

From wells offset to Pilot Well:

- Gas lift injection rates
- Gas lift injection pressures
- Gas lift injection composition
- Casing pressures
- Tubing pressures
- Produced gas composition

To safeguard injection pressure below acceptable limits of 3,500 psig, a casing pressure safety high alarm was set at 1,275 psig and a casing pressure safety high shutdown was set at 1,350 psig.

Allocation

Gas produced after a period of injection was measured with the Pilot Well gas meter and allocated on a daily basis between gas lift, native production, and recovered injection. The equation used was:

$$Total\ wellhead\ volume - gas\ lift\ injection - native\ production = injection\ recovered$$

This method follows conventional production accounting in that it removes gas lift injection "off the top" of daily production values. Gas lift injection volumes are determined by a gas lift injection meter.

This method then prioritizes native production, ensuring that appropriate native production is allocated to the well. Appropriate native production is determined by decline curve analysis and gas-liquid-ratio analysis. If on a given day the well makes less than these methods predict, all production is allocated as native production.

After accounting for gas lift injection and native production, if surplus gas remains, it is allocated as recovered injection.

Pilot Test Results

A series of four tests confirmed the safety and effectiveness of CLGC.

Test 1: High Rate Test

The first CLGC test was designed to simulate a short third-party sales market outage and achieve a high injection rate (greater than 10 mmscfd).

Injection rate was increased to a peak injection rate of nearly 15 mmscfd while the casing pressure rose from 665 psig to approximately 1,100 psig. The injection rate fell steadily as casing pressure approached 1,200 psig. For the remainder of this 5-hour test, casing pressure steadied near 1,250 psig with a sustained injection rate of 10.5 mmscfd. A total of 2.5 mmscf was injected. Figure 7 shows rates and pressures during the test.

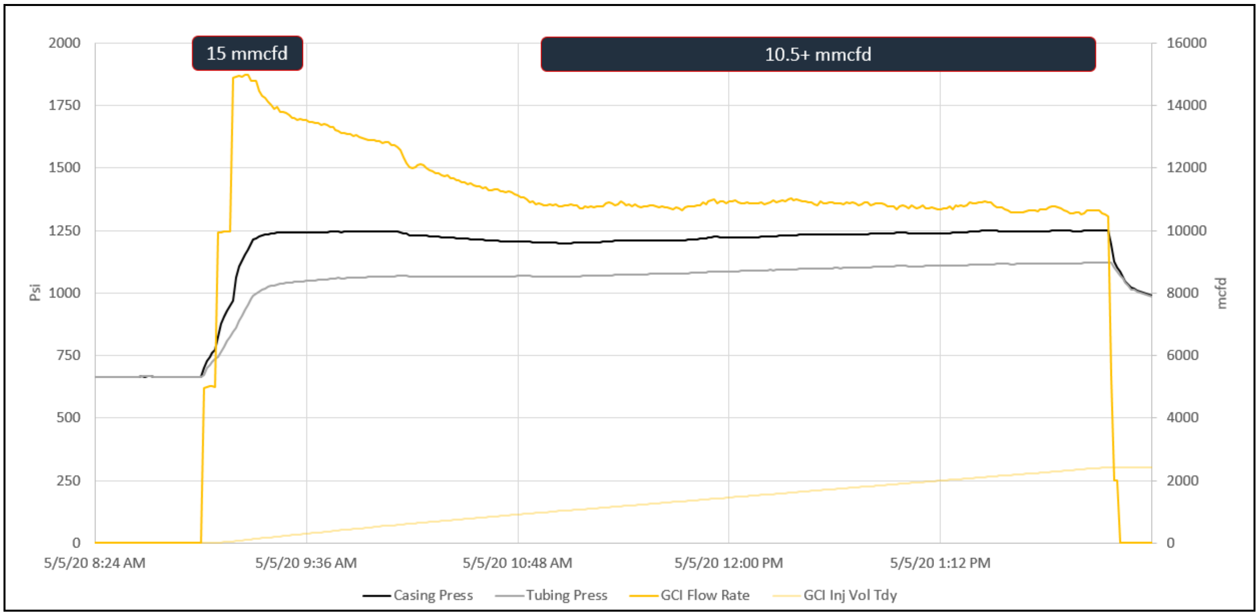


Figure 7 - Test 1

CLGC Test 1 showed that injection rates over 10 mmscfd are achievable and sustainable during brief third-party market outages.

After completion of the test, the Pilot Well was reopened in order to resume normal production operations and flow back injected gas. Figure 8 below shows the gas recovery profile. One hundred percent of injected gas was recovered within a ten-day period.

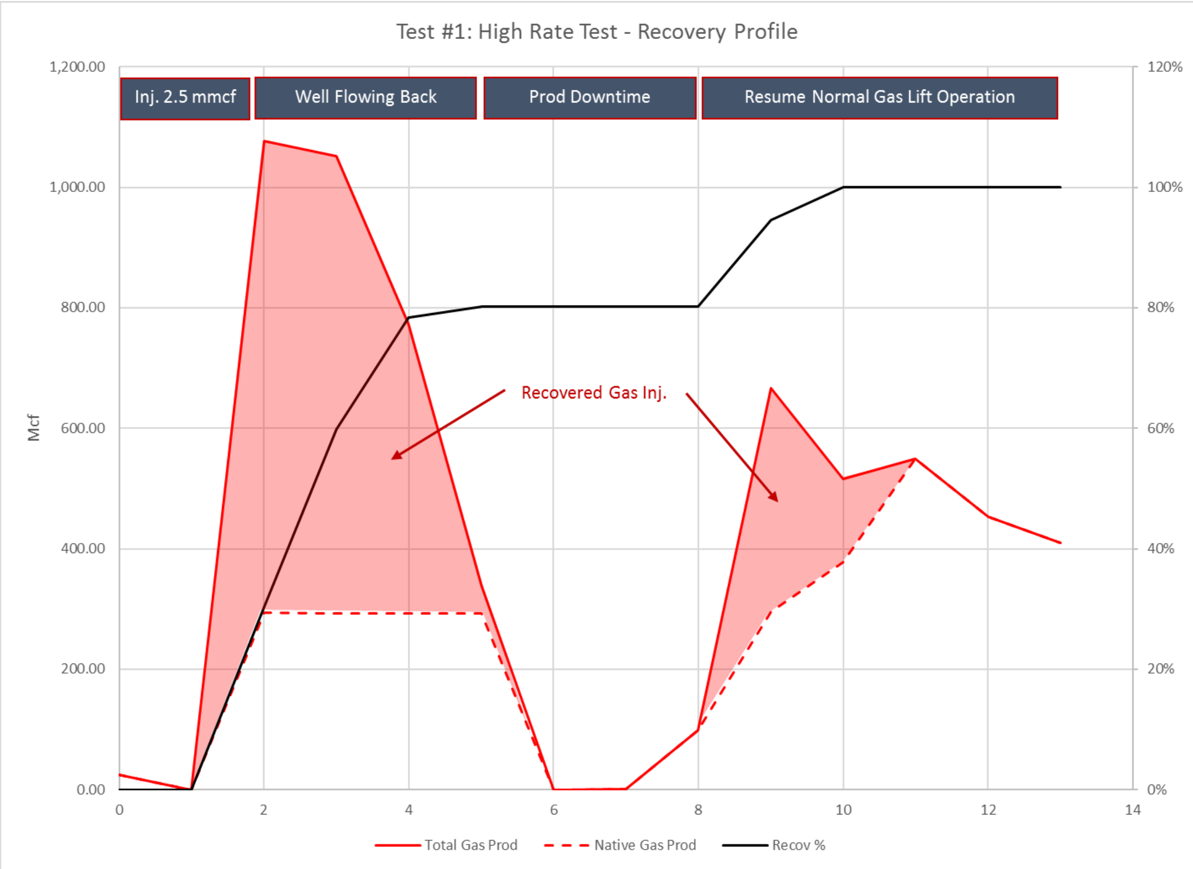


Figure 8 - Test 1 Recovery

Test 2: High Volume Test

The second CLGC test was designed to simulate a third-party sales market interruption lasting several days.

Gas was injected at a rate of 5.5 mmscfd for four days. Casing pressure climbed from 550 psig to 1,000 psig after approximately 12 hours, and then rose slowly for the remainder of the test, peaking at 1,120 psig and only gaining 20 psig in the final 24 hours. The test was concluded after injecting 21.2 mmscfd. The gradual rise in casing pressure indicated the well is capable of accepting an even larger volume of gas, proving the well has sufficient volume for most third-party sales market interruptions.

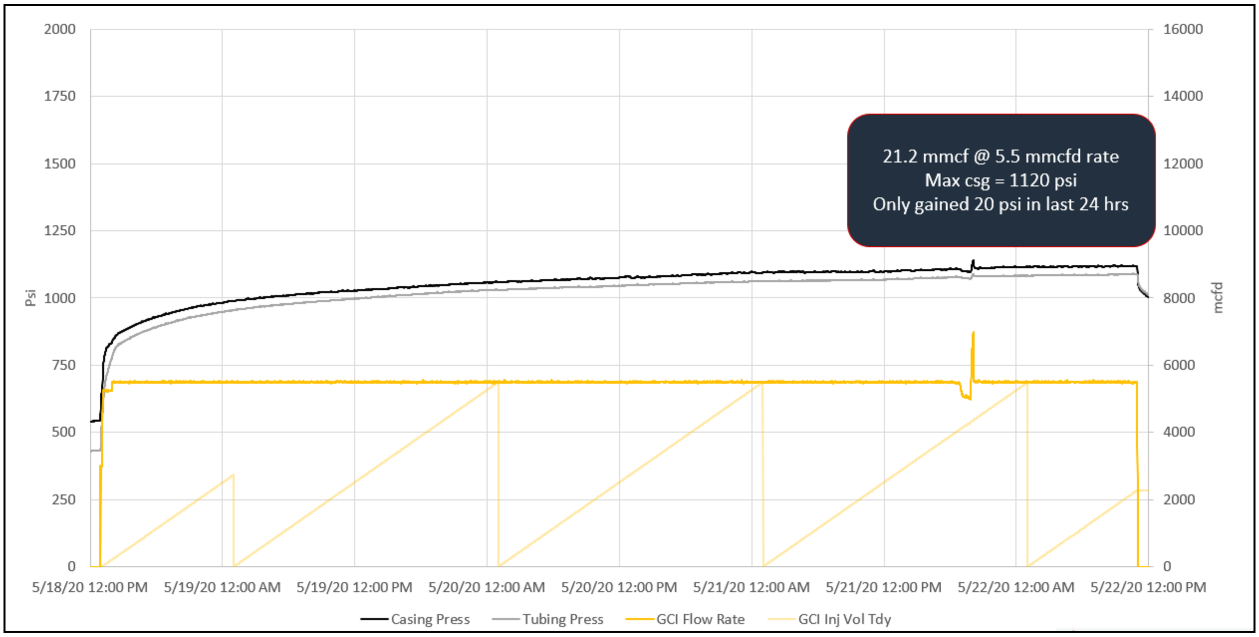


Figure 9 - Test 2

After completion of the test, the Pilot Well was returned to production. Figure 10 shows the recovery profile.

Figure 10 - Test 2 Recovery

Approximately 50% of the injected gas was recovered within 15 days and approximately 65% was recovered within 30 days. This recovery, although slower than that of Test 1, indicated defined, near-wellbore boundaries with minimal or no leak-off, and showed that large-volume recoveries are achievable.

Test 3: 24-hour High Rate Test

The third CLGC test was designed to simulate a 24-hour third-party sales market interruption that requires a high injection rate (10 mmscfd).

Injection was quickly increased to 9-10 mmscfd and monitored for 24 hours. As seen in Figure 11 below, the casing pressure leveled out at 1,250-1,275 psig.

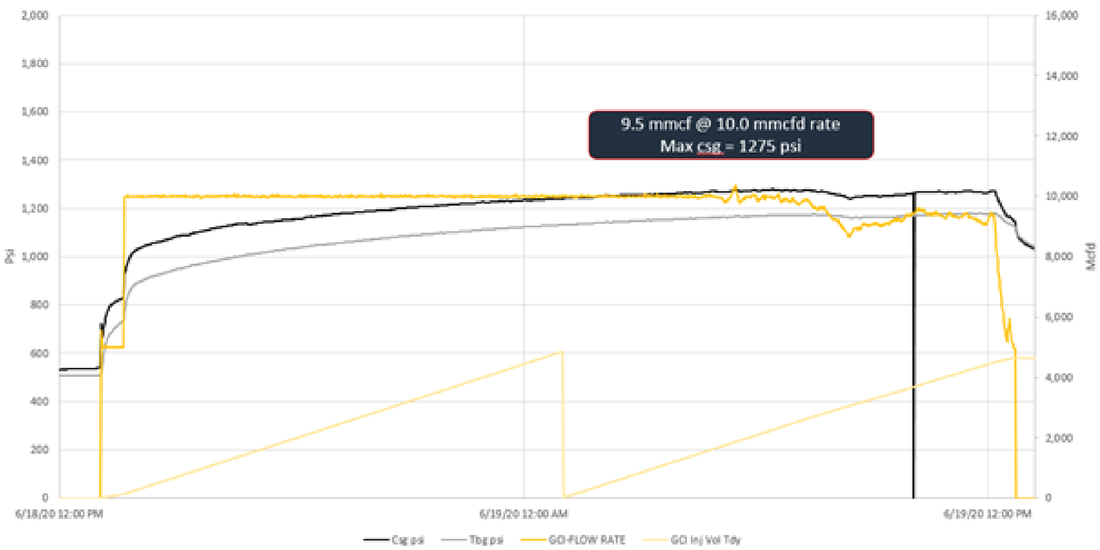


Figure 11 - Test 3

This test achieved sufficient rates and volumes at acceptable pressures and demonstrated the ability to quickly increase injection to accommodate real time needs.

The recovery profile in Figure 12 below again shows that high recovery rates are achievable, with 100% of injected gas being recovered within 25 days. After recovering the injected gas volume from Test 3, the well continued producing above expected normal gas rates. This indicates that unrecovered gas from previous injection cycles is still recoverable.

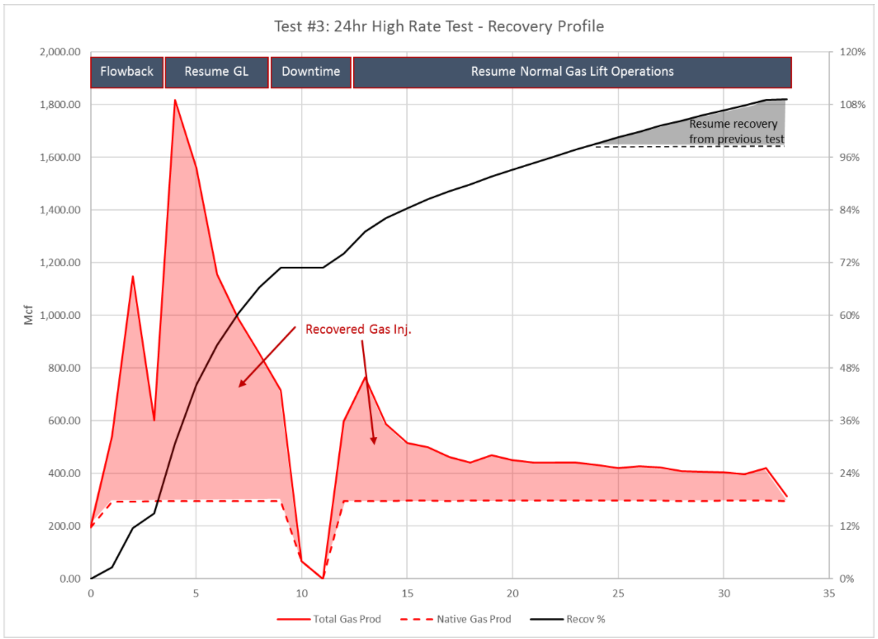


Figure 12 - Test 3 Recovery

Test 4: 24-hour Medium Rate Test

The fourth CLGC test was designed to determine the injection and recovery characteristics of a 24-hour injection at a rate lower than that of previous tests.

Injection was quickly increased to 7 mmscfd and monitored for 24 hours. As seen in Figure 13 below, the casing pressure leveled out at 1,220-1,240 psig.

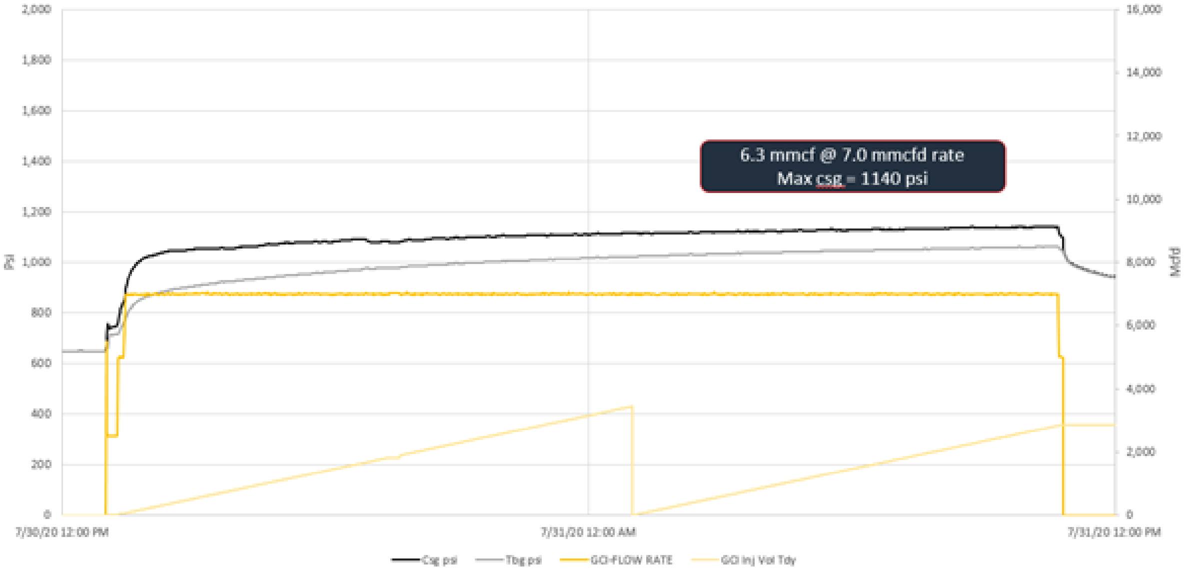


Figure 13 - Test 4

This test further demonstrated that CLGC provides real time control to react to changing field conditions with sufficient injection rates and volumes to reduce flaring.

The recovery profile in Figure 14 below again shows that high recovery rates are achievable within a couple of weeks.

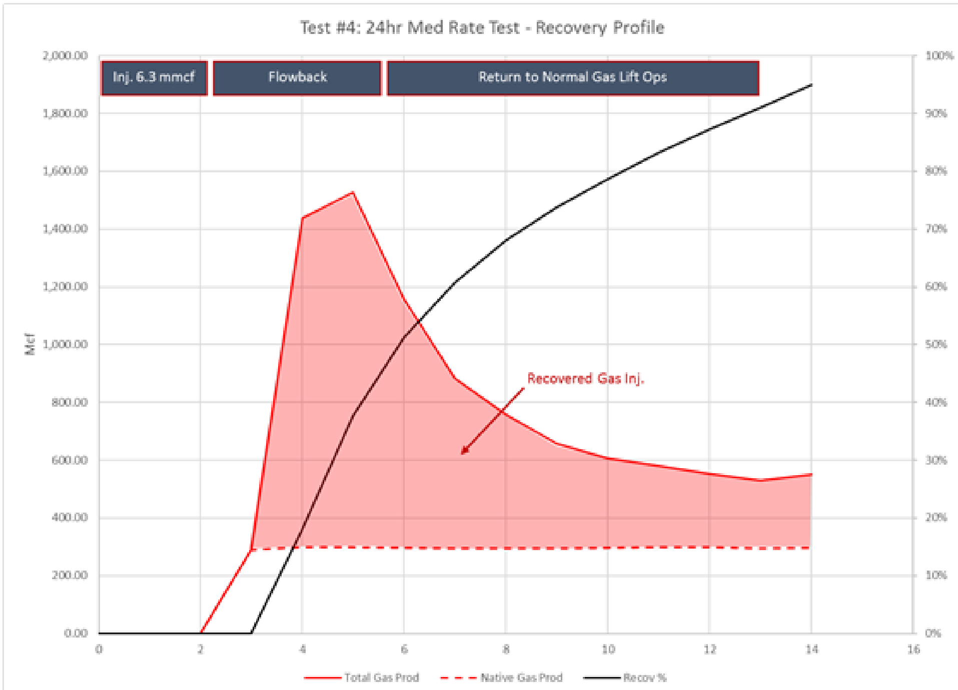


Figure 14 - Test 4 Recovery

Fluid Level Shots

An Echometer Acoustic Liquid Level Instrument was used to observe fluid levels and determine BHP before testing and at various points during testing. Prior to any tests, an initial static fluid level was observed at 9,018' and BHP was calculated to be approximately 1,172 psig. The highest fluid level observed throughout the CLGC testing was immediately after Test 3 at 8,783' with a calculated BHP of 1,775 psig. Fluid level shots taken after flowing the well for a couple of days show that BHP quickly trends back towards normal levels. These fluid level shots indicate that gas injection from CLGC has no significant or sustained impact on BHP. This conclusion confirms CMG modeling conducted prior to testing. As the reservoir is expansive compared to injection volumes, intermittent injection and production cycles do not meaningfully increase reservoir pressure. For full details of fluid level shots during testing please refer to the Appendix.

Intermediate Casing Pressure

The intermediate casing pressure was monitored continuously throughout testing to ensure mechanical integrity of the production casing. Variances in the intermediate casing pressure observed during injection cycles were determined to be due to the temperature effects from injecting warm gas at high rates and ballooning effects of increased production casing pressure. No loss of mechanical integrity in the production casing was observed. Figure 15 below shows the intermediate casing pressure during Test 2. Detailed information and conclusions are as follows:

Information

- Prior to injection: 150 psig on intermediate casing
- Bled down, recovered ~2 gallons water
- Built 15 psig in 3-1/2 hrs
- Began injection test: Intermediate casing built to 130 psig in 2 hrs.
- Bled down to collect sample, recovered ~1 gallon fluid fresh water (0 mg/L chlorides)
    - Production water is 80,000+ mg/L chlorides
- During injection test: Intermediate casing cycled from peaks of 500-700 psig to lows of 200-400 psig
    - Cycles correlate with injection gas temperature cycles
- After injection test: Intermediate casing back to range of 75-150 psig

Conclusions

- Injecting warm gas at high rates likely causes intermediate casing pressure to increase due to temperature effect.
- Increased production casing pressure likely causes intermediate casing pressure to increase due to ballooning effect.
- No observed mechanical integrity issue.

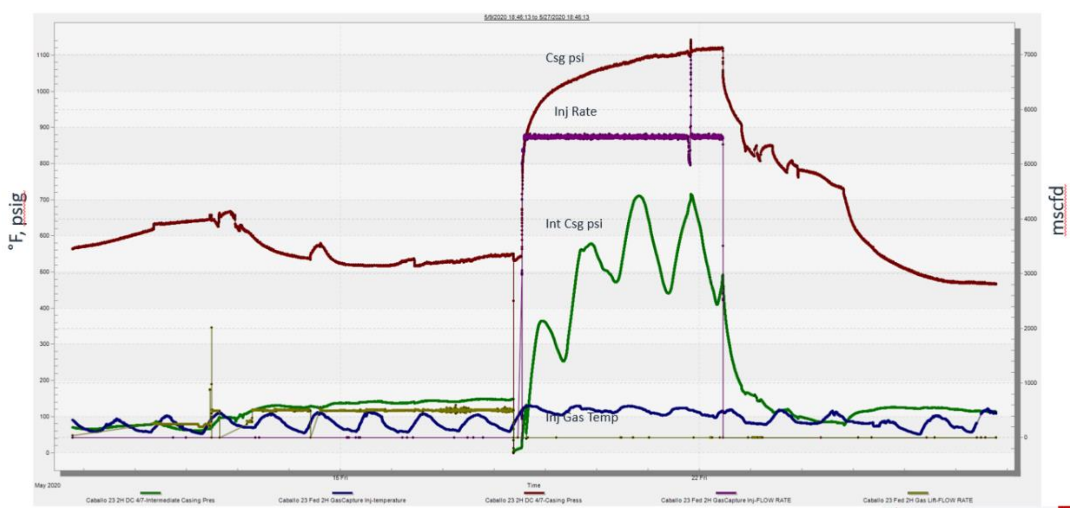


Figure 15 - Intermediate Casing Pressure During Test 2

Offset Well Monitoring

During the high volume test (Test 2), a gas production increase of 200-500 mscfd was observed in the two closest offset wells, the Caballo 23 Fed #3H and Caballo 23 Fed #5H. Since both offset wells are within 1,000 ft. of the Pilot Well, direct fractal hydraulic connectivity was initially suspected. However, further investigation led to the conclusion that offset well response appears limited to pressure transient changes associated with changing flow boundaries. Pressure waves can move through reservoir space more quickly than the actual fluids that convey the pressure. These poroelastic effects are more gradual and predictable than hydraulically-connected pressure impacts, and can be observed from simply shutting in a well without injection. (See Figure 17.)

Several observations led to the conclusion that direct fractal hydraulic connectivity is not occurring:

1) There is no pressure response in the offset wells when they are shut-in while the Pilot Well is injecting.
2) There is no pressure response or change in production in the offset wells when the Pilot Well begins flowing back.
3) The gas being injected into the Pilot Well had lower CO2 content than that of the produced gas in the offset wells, so if direct fractal connectivity was occurring, the CO2 content in the offset wells would be expected to decrease. Gas analyses collected during Test 2 show no apparent change in gas composition in the offset wells. See gas analyses in the Appendix.
4) Offset wells typically see a small increase in production (40-100 mcfd) when the Pilot Well is shut-in. This seems to point to the interactions between the three wells being more related to reservoir characteristics rather than direct fractal connectivity. (See Figure 17.)

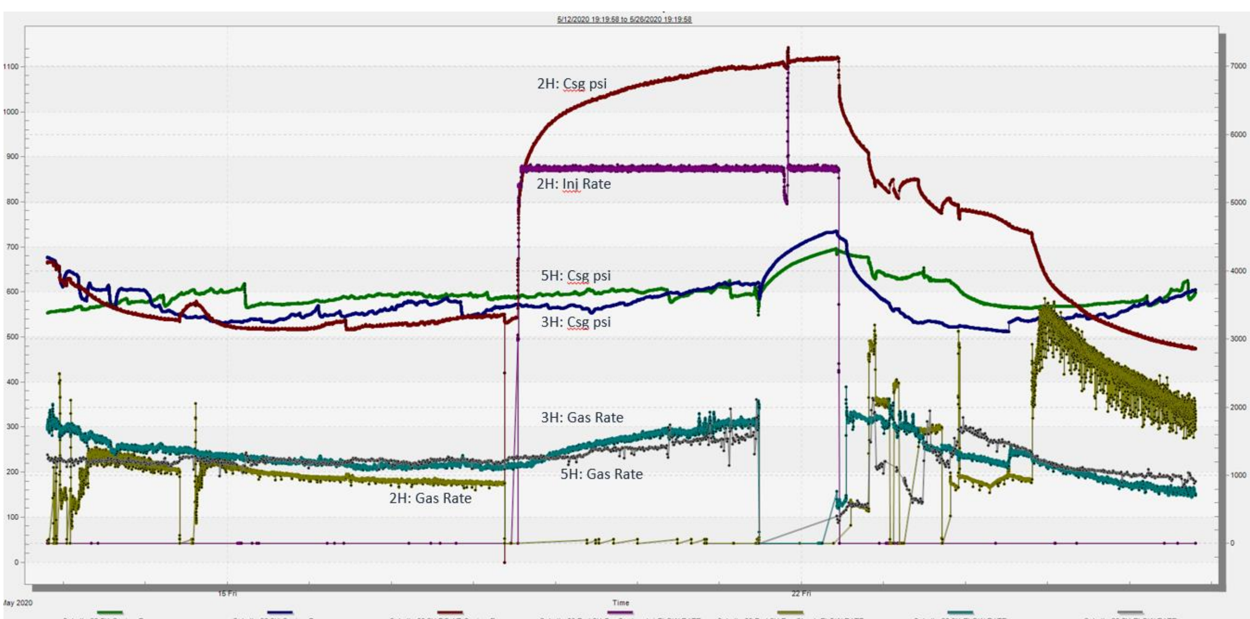


Figure 16 - Offset Well Monitoring During Test 2

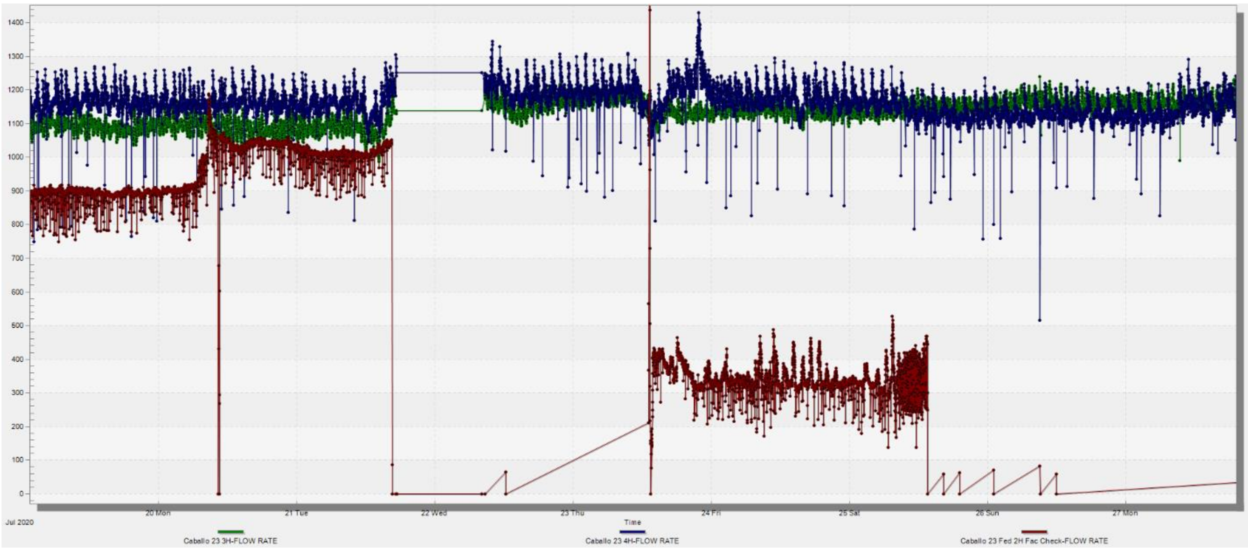


Figure 17 - Offset Response when Caballo 23 Fed #2H is Shut-In

Pilot Test Conclusion

This pilot test demonstrated the feasibility of CLGC as an alternative to shutting in wells or flaring in response to third-party market disruptions. Highlights of the pilot test include:

- Sufficient rates and volumes to respond to most third-party market interruptions.
    - Injection rates of up to 15 mmscfd
    - Injection volumes of up to 21 mmscf
- Injection pressures below 1,275 psig: low enough for standard compression equipment, with potential to increase rate and volume if needed.
- Recovery profiles that exceeded EOG's conservative predictions.
- Negligible effect on Pilot Well production.
- Negligible effect on offset wells.
- Successful demonstration of equipment operation, data collection and monitoring, and production accounting.

The pilot test results indicate that the reservoir can easily accept volumes that exceed the expected requirements for CLGC. Quick recovery of injected gas is beneficial economically and suggests there is minimal risk of permanent leak-off or reservoir damage.

EOG looks forward to further implementation of Closed Loop Gas Capture to help reduce greenhouse gas emissions associated with third-party market interruptions, as part of a commitment to innovation and environmental stewardship.

Appendices (need to finalize)

1) FL Shots
2) Wellbore diagram
3) Big versions of every diagram

Appendix 1: Fluid Level Shots

Summary:

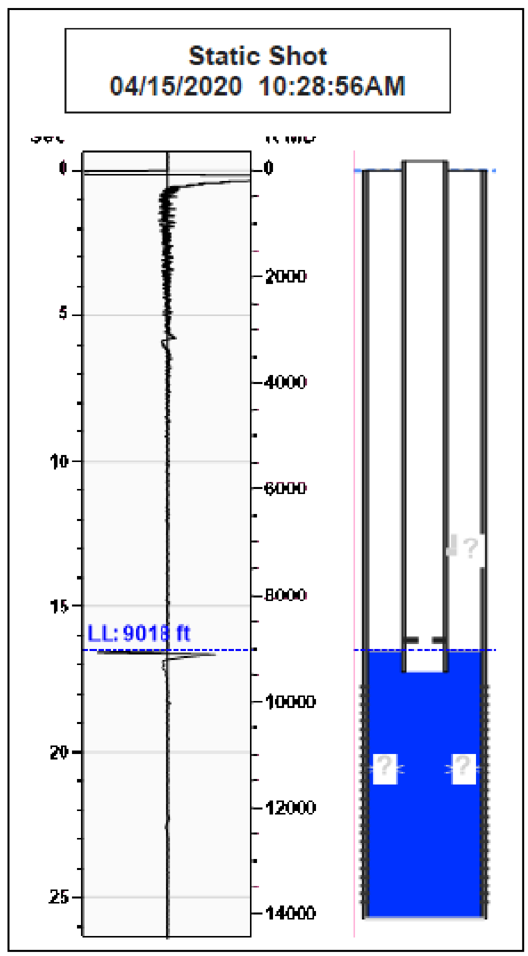
On 4/15/20 five static fluid level shots were taken over a one-hour period from an Echometer Acoustic Liquid Level Instrument. The final static fluid level shot indicates that the liquid level was at 9,018’ with 532 psig casing pressure, and the calculated static BHP was 1,172 psig. Fluid level shots were recorded throughout the testing process to evaluate BHP, which fluctuated from 1,150 psig to 1,775 psig.

Well Information

TD: 14,110’ **TVD:** 9,455’ **PBTD:** 14,097’ **GR:** 3,350’ **KB:** 3,380’

Surface Casing: 11¾” 42# H-40 at 1,190’. Cemented with 650 sx. Cement circulated.
Intermediate Casing: 8⅝” 32# J-55 & HCK-55 at 5,005’. Cemented with 1,200 sx. Cement circulated.
Production Casing: 5½” 20# HCP-110 at 14,097’. Cemented with 1,450 sx. TOC at 4,806’ by CBL.
Perforated Interval: 9,729’-14,060’ (9,455’ TVD)

Fluid Level Shots



Fluid gradient (f_g) = 0.433 psi/ft
Gas gradient (g_g) = 0.05 psi/ft

1. 9:23am – Well was shut-in and 1st fluid level shot taken.
FL = 9,080’ Csg = 528 psig
BHP = (TVD - FL)*f_g + Csg + (FL*g_g)
BHP = (9,455’ - 9,080’)*0.433 + 528 + (9,080’*0.05)
BHP = 1,144 psig

2. 9:39am – 2nd fluid level shot.
FL = 9,060’ Csg = 530 psig
BHP = (9,455’- 9,060)*0.433 + 530 + (9,060’*0.05)
BHP = 1,154 psig

3. 9:56am – 3rd fluid level shot.
FL = 9,038’ Csg = 530 psig
BHP = 1,162 psig

4. 10:12am – 4th fluid level shot.
FL = 9,028’ Csg = 531 psig
BHP = 1,167 psig

5. 10:28am – 5th fluid level shot.
FL = 9,018’ Csg = 532 psig
BHP = 1,172 psig

6. 5/6/20 – FL after high rate test (Test #1)
FL = 9,019’ Csg = 755 psig
BHP = 1,395 psig

7. 5/18/20 – FL prior to high volume test (Test #2)
FL = 9,086’ Csg = 540 psig
BHP = 1,154 psig

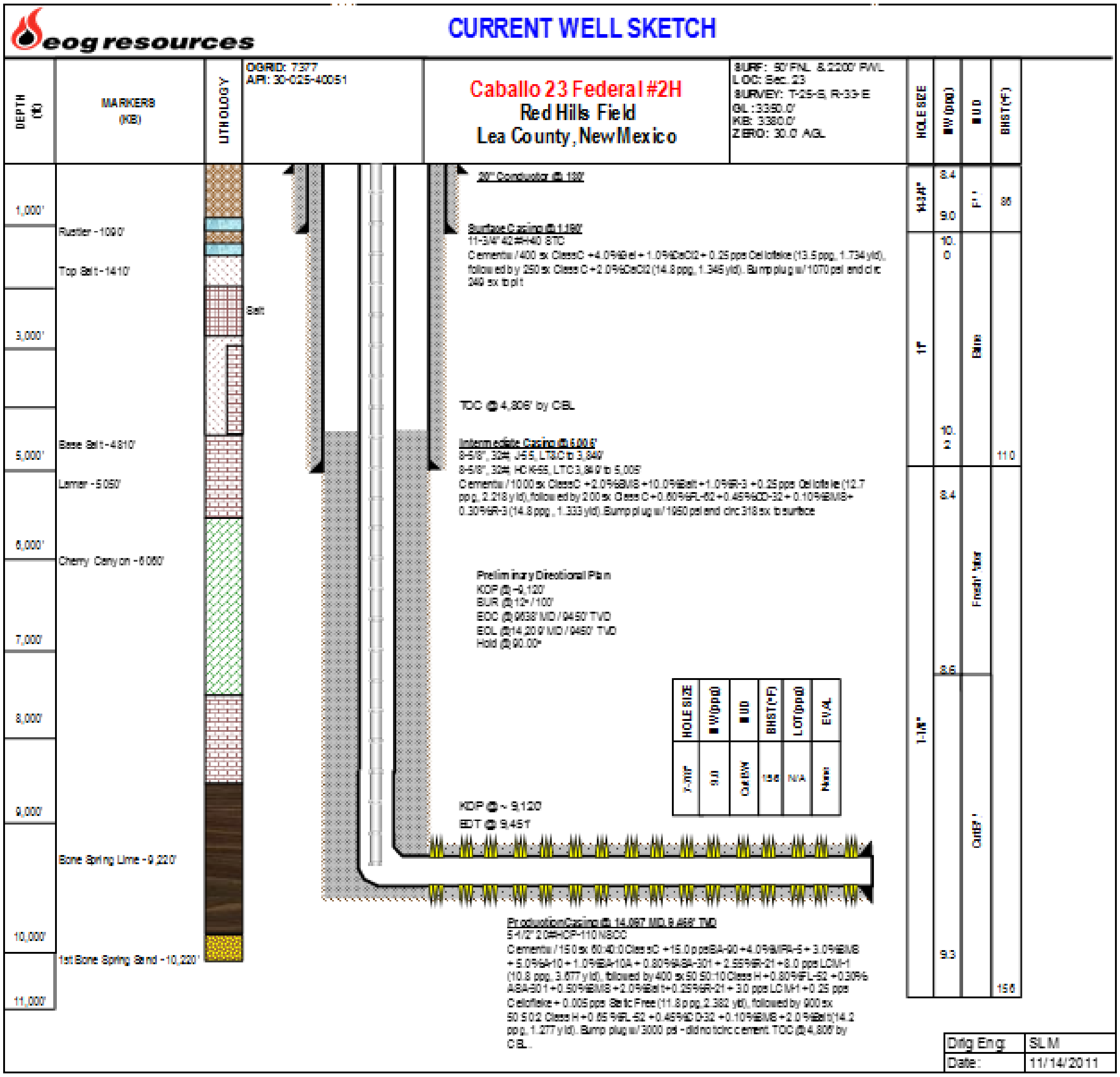
8. 6/18/20 – FL prior to 24-hr high rate test (Test #3)
FL = 9,058’ Csg = 523 psig
BHP = 1,147 psig

9. 6/19/20 – FL immediately after 24-hr high rate test (Test #3)
FL = 8,783’ Csg = 1045 psig
BHP = 1,775 psig

10. 6/19/20 – FL 1-hr after beginning flowback after 24-hr high rate test (Test #3)
FL = 8,833’ Csg = 990 psig
BHP = 1,681 psig

11. 6/22/20 – FL after a few days flowing back after 24-hr high rate test (Test #3)
FL = 9,220’ Csg = 634 psig
BHP = 1,196 psig

Appendix 2: Wellbore Diagram



Appendix 3: To be added after diagrams are finalized: big versions of every diagram