NATIONAL ENERGY TECHNOLOGY LABORATORY

Oil & Gas

DOE Award No.: DE-FE0031782

Data Analysis and Integration Summary Report

Using Natural Gas Liquids to Recover Unconventional Oil and Gas Resources

Project Period (October 1, 2019 through September 30, 2022)

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U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

Office of Fossil Energy

This summary report contains preliminary findings related to project progress and should not be considered final.

1.0 Introduction

This document presents a summary of the analysis and integration of field treatment data for the project *Using Natural Gas Liquids to Recover Unconventional Oil and Gas Resources (FE0031782)*. The project is part of the U.S. Department of Energy Oil and Gas Program to develop and advance technologies that can significantly improve the recovery efficiencies of unconventional oil and gas resources.

The overall objective of this project is to improve the ultimate recovery from unconventional oil and gas (UOG) resources in the United Sates by developing a method for using unrefined natural gas liquids (NGLs) as treatment fluids to improve hydrocarbon production. Horizontal extended-lateral drilling coupled with high volume hydraulic fracturing has significantly increased production from UOG resources in the U.S. However, the recovery efficiency is low compared to the estimated oil and gas in place. Recent data indicate that less than 10% of the oil in the liquid-rich UOG reservoirs is produced. Alternative completion methods using NGLs could increase production (Battelle, 2016; Wan et al., 2013; Wan, 2013); however, field validation tests are needed to develop an approach that is economical, efficient, and compatible in the UOG setting to advance towards commercial deployment.

This project aims to develop, and field test a method to improve recovery of oil resources in UOG shale plays by using Y-Grade NGLs, or a similar combination of NGLs, as treatment fluids. Refined NGLs have been used as a hydraulic treatment fluid in UOG plays for decades and are shown to be particularly effective because their miscibility with oil allows oil to flow more freely; however, the use of Y-Grade (unrefined) NGLs has not been studied. The use of Y-Grade NGLs would be advantageous over refined NGLs because Y-Grade NGLs do not require infrastructure or investment in refining and are already being produced from many UOG reservoirs.

The concept was tested and monitored in the field at a commercial well site owned by an independent operator in Eastern Ohio. The project team, which consists of multiple oil and gas operators, Linde Gas North America LLC (Linde) and the Ohio Division of Geological Survey (ODGS), has extensive experience with oil and gas production in the Appalachian basin and the ability to work together quickly to solve technical issues and research needs. A key part of the proposed work was the use of existing wells for field testing and monitoring. A total of four wells (three vertical and one horizontal) were available for this project. One of the vertical wells was utilized as the test well for the NGL treatment test. A nearby vertical well was used for micro seismic monitoring. The remaining vertical well and the horizontal well provided a baseline for typical UOG production in the oil window of the UPP. Major technical tasks of the project include characterization of the geotechnical properties of the UPP with an emphasis on the field site; design and planning for the NGLs testing; field testing and monitoring; analysis and integration of field data; and economic and resource/reserve assessment.

The microseismic monitoring well and NGL treatment well were successfully plugged back during September-October 2020 in preparation for treatment and monitoring. A nitrogen Diagnostic Fracture Injection Test (DFIT) was completed on the NGL treatment well on July 22, 2021, consisting of 133,000 scf (91 Bbl) of nitrogen. A nitrogen foam frac was completed in the Utica-Point Pleasant interval on 8/17/21 with funding from outside sources. A micro seismic monitoring array was installed in the nearby well and monitored micro seismic activity during the treatment well frac job. Y-Grade NGL injection commenced on 8/26/2021. A total of 215 Bbl was injected but the job was shut down due to a small leak on the suction hose on the pump truck. The Y-Grade treatment resumed on 8/27/2021 and an additional 726 Bbl of Y-Grade NGL was injected at a well head pressure of 3850 psi. Total volume of injected Y-Grade over the two days of injection was 941 Bbl. The well was shut-in for 17 days following injection to allow the Y-Grade NGLs to soak on the formation.

Y-Grade treatment flow back commenced on 9/13/2021. During this report period (January – March, 2022), Y-Grade NGL treatment flow back and monitoring was continued. Production data, including surface pressures, oil, nitrogen, natural gas, and flow times was measured and recorded. Periodic gas samples were collected and analyzed to determine composition of flowback gas. As of March 30, 2021, the well has flowed a total of 159 hours and produced 667 Bbl of oil and 2,576 mcf gas.

The objective of Task 5 is to compile field testing data and evaluate the performance of the NGL treatment test. The task includes reservoir simulations of the treatment process, processing of well testing data, analysis of micro seismic monitoring data, and production data analysis. A summary of these activities is provided in the following sections.

2.0 Reservoir Simulations of the NGL Treatment

Building upon reservoir simulations developed in the NGL treatment design task, numerical reservoir simulations were completed to match the field treatment conditions and activities. A simplified "shoe-box" or "layer-cake" model reflecting the average reservoir conditions around the vertical well and its hydraulic fracture from the nitrogen fracturing treatment was developed for the purposes of evaluating the treatment via dynamic, compositional reservoir simulation. The 3D model domain as constructed is shown below in Figure 2-1. Average porosities and permeabilities (from well-log information) were used for each layer. Porosity and permeability were also homogeneous across each layer.

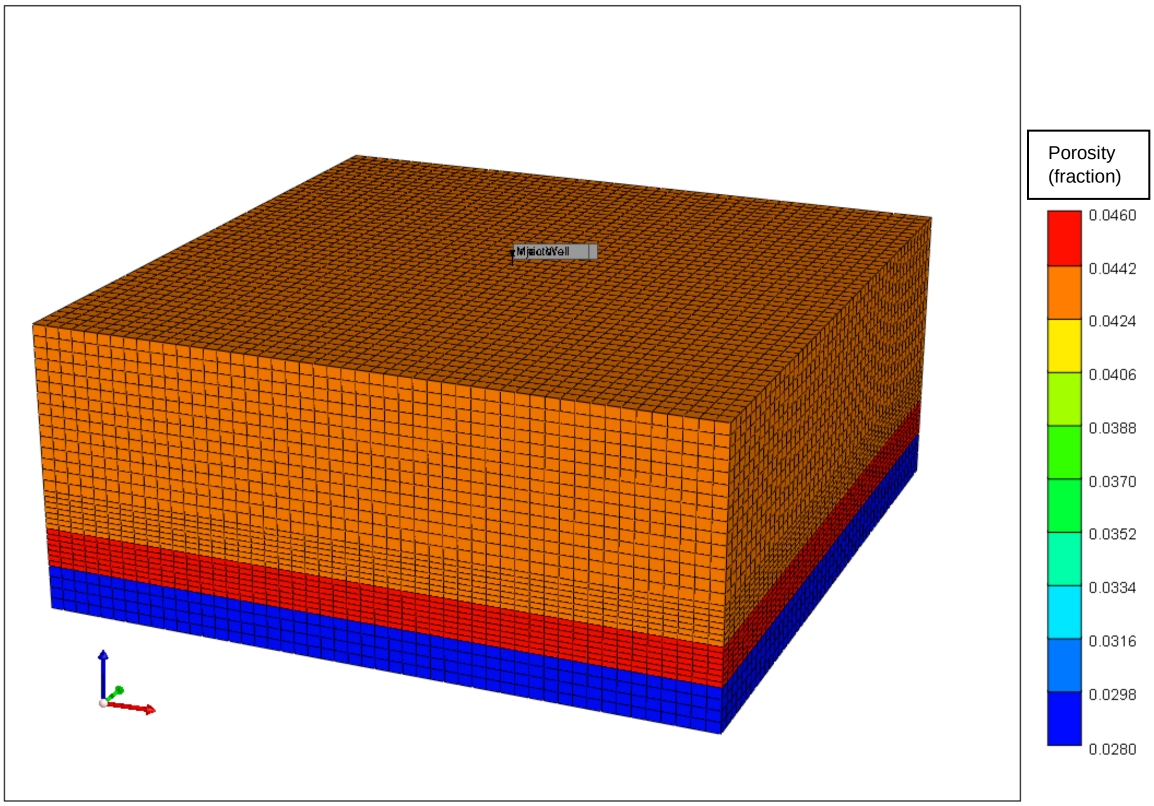

Figure 2-1:3D reservoir model domain for the simulation. The porosity field is shown in this image. Note that average porosities are used, and porosities are homogeneous across each layer.

Figures 2-2 through 2-4 are cross-sections of the permeability field. Notice that permeabilities are very low in the entire reservoir, reflecting the tightness of the shale rock. Grid blocks have been refined around the vertical well in select layers reflecting the fracture half-lengths formed from the nitrogen fracture treatment. The narrowest dimension of each grid block reflects the estimated fracture width. The refined gridblocks with propped fractures have been assigned a much higher, fracture permeability. The permeabilities and fracture dimensions reflected in this analysis came from a separate analysis of the fracture treatment.

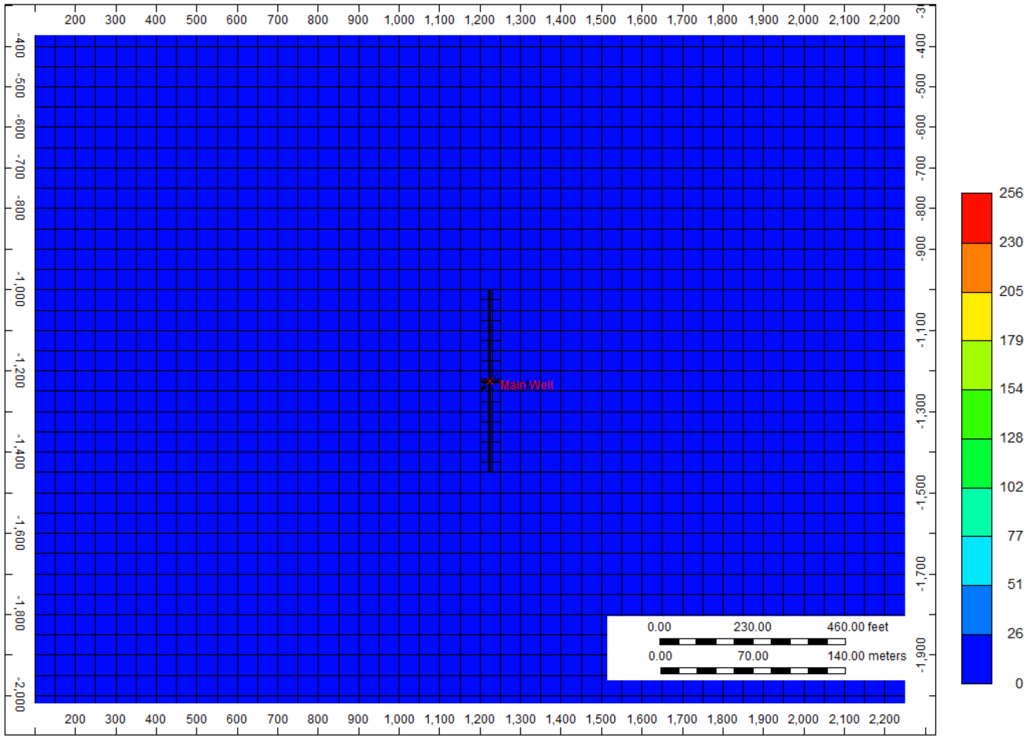

Figure 2-2: Shows an aerial cross-section of the permeability field. Note the grid refinement around the well in the center capturing the extent of the fracture half-length. The dimensions of the refined gridblocks reflect the fracture widths expected from the fracture treatment.

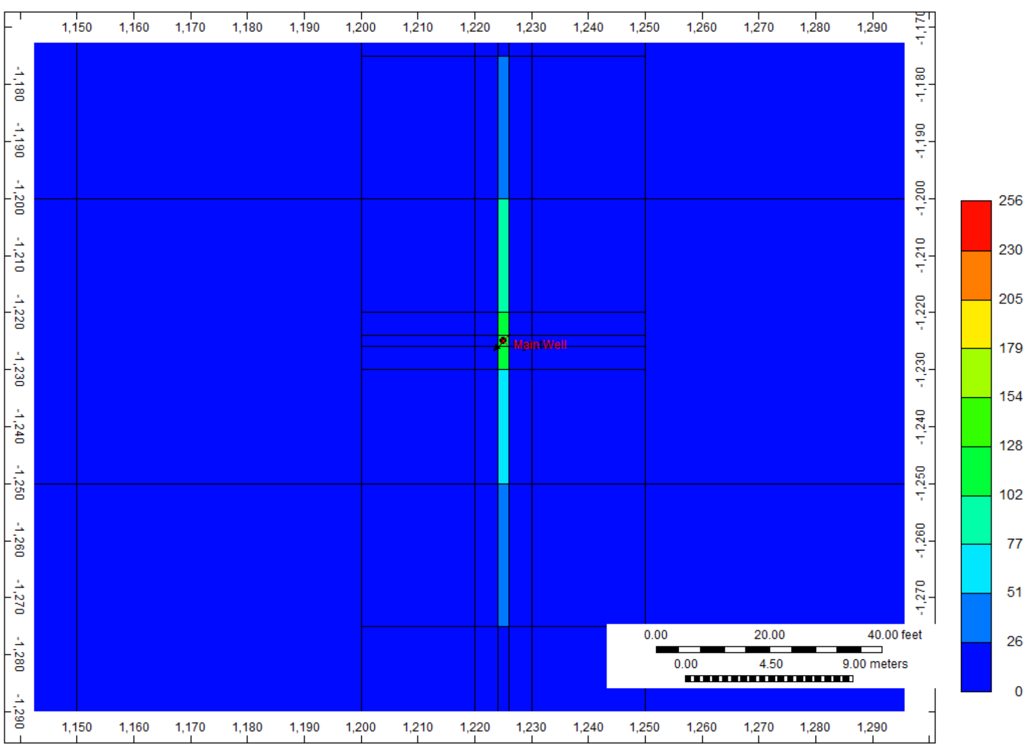

Figure 2-3: Shows a zoomed in view of the same aerial cross-section of the permeability shown in the Figure 2-2. Note that the refined grid blocks has been assigned a much higher permeability.

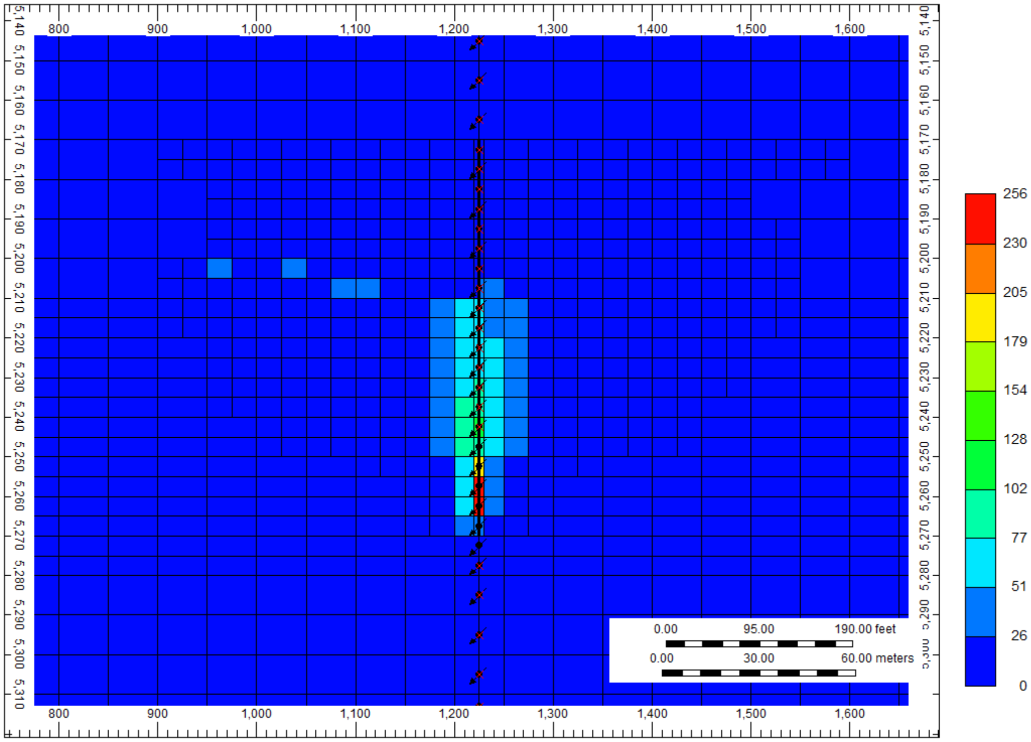

Figure 2-4: shows a vertical cross-section of the permeability field with the grid blocks refined around the vertical well where a propped hydraulic fracture is assumed to be present. These grid blocks are assigned fracture permeabilities that are higher the surrounding shale rock.

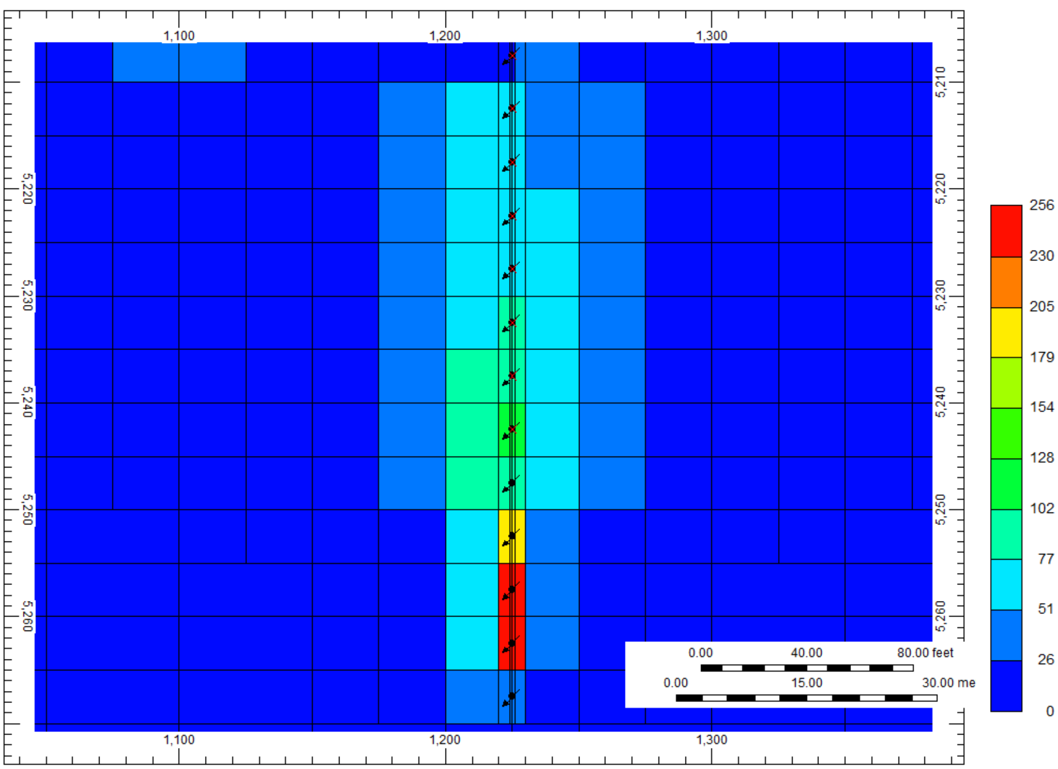

Figure 2-5: Shows a zoomed in view of the vertical permeability cross section shown in the earlier image.

Note that the simulation was performed to analyze / predict the aggregate effects. Only the cumulative volume of NGLs injected into the reservoir was honored, not the timing and injection rates. The composition of the Y-grade NGLs was honored in the injection stream in the simulation. A total of 11230 ft^3 of NGLs were injected (Figure 2-6).

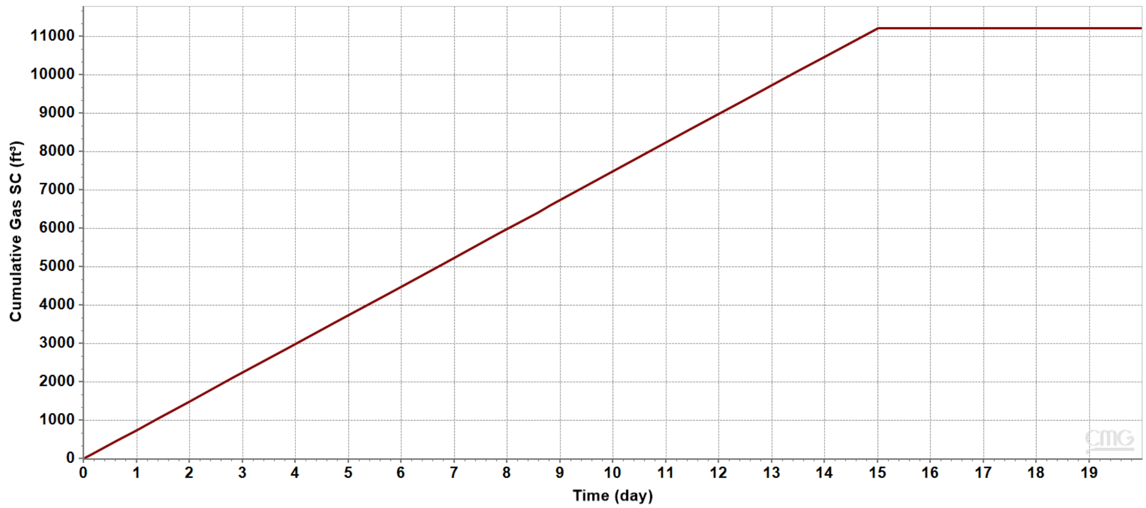

Figure 2-6: Shows the cumulative volume of NGLs that were injected into the reservoir.

The oil rate from the NGL treatment was forecasted from the simulation. Figures 2-7 and 2-8 present the expected oil rates from the stimulation treatment. Note that Figure 2-7 predicted a high flow rate in the beginning, that likely produces back all the injected NGLs in a short duration, followed by a sustained period of low production. The low oil production period is shown in Figure 2-8. Production steadily declining from 10 bbls/day declining to 2 bbl/day is predicted by this simulation.

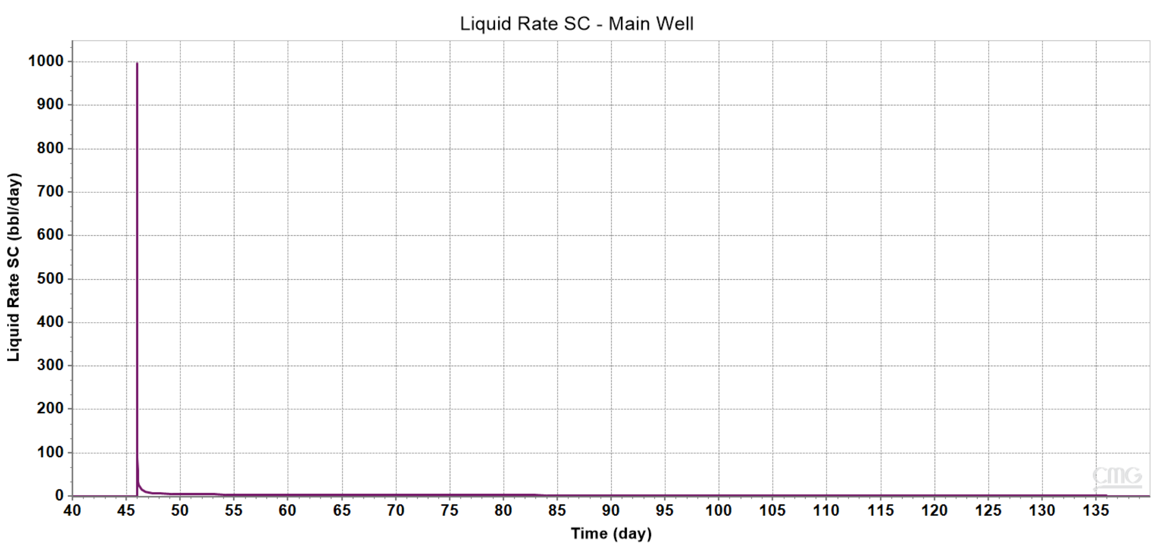

Figure 2-7: A "burst" of production followed by a rapid decline to a steady-state production is predicted. The initial period likely produces back the injected NGLs.

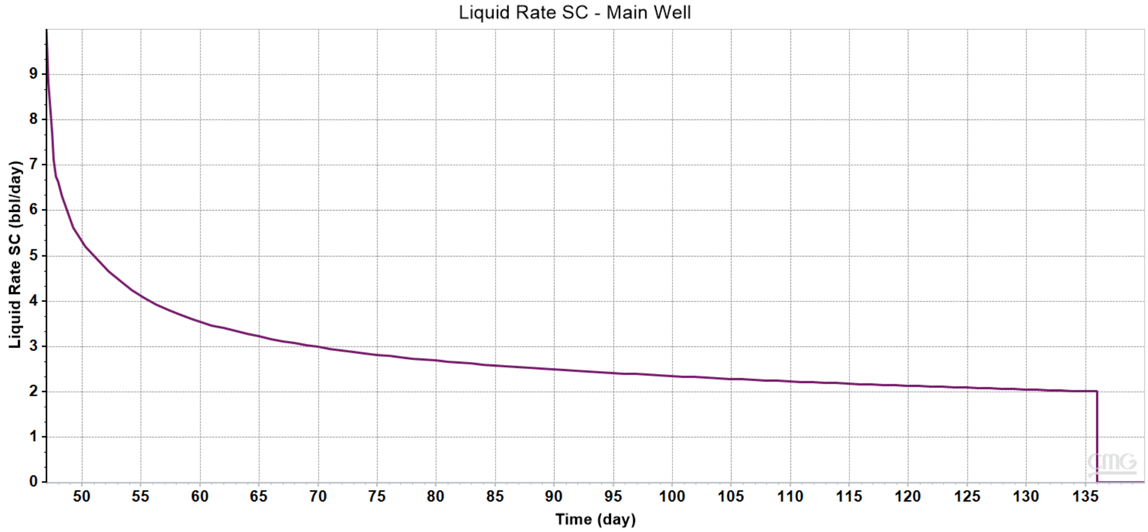

Figure 2-8: A close up of the production profile after the NGL treatment. Note that the simulation was arbitrarily ended on the 135 day mark, and production likely continues to decline further.

3.0 Well Testing Data Analysis

This section presents a review of well testing data during the NGL treatment in the Utica Point-Pleasant test well. These datasets portray the NGL treatment in terms of well stimulation, NGL injection, treatment pressures, and flow rates. A 750 Bbl, 75-quality foam frac was performed on the vertical NGL treatment well on 08/17/2021. The frac was performed on 8/17/2021 through 2 7/8" tubing set on a packer. Bottom hole pressure and temperatures gauges were installed in the well. Proppant consisted of 100 sacks of 80/100 mesh sand and 230 sacks of 20/40 mesh sand. Following the frac job, the well was flowed back for 2 hours. There was a strong hydrocarbon odor noted during the flowback but just a sheen of oil on the recovered water.

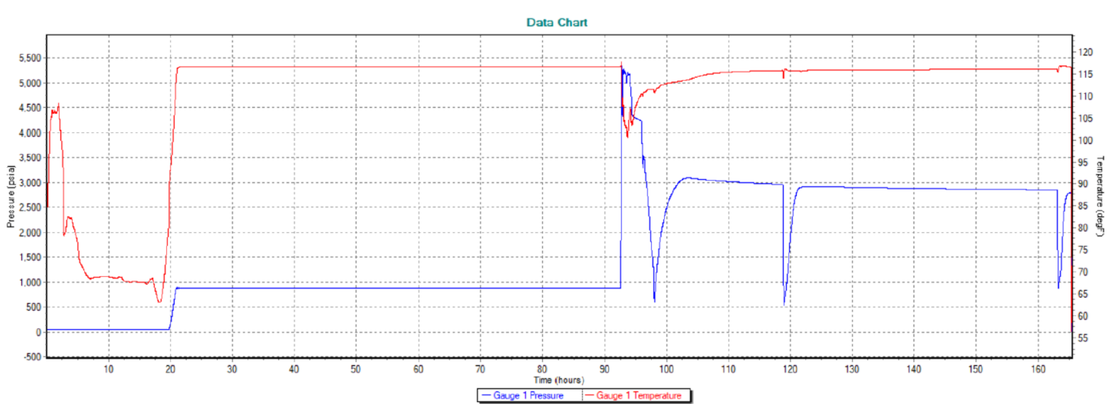

Figure 3-1: NGL treatment well bottomhole temperature/pressure data during nitrogen frac/flowback.

Figure 3-1 shows bottom hole temperature/pressure of the nitrogen frac during:

- Installation of tubing, packer and gauges at 20 hours,
- Nitrogen foam treatment at 92 hours,
- Nitrogen foam treatment instant shut-in at 94 hours,
- Flow back at 96 hours, 119 hours and 163 hours.

Figure 3-2 shows a detailed look at the treatment well bottom hole pressure and temperature gauge data during pumping & flowback:

- Commence pumping nitrogen pad at 92.5 hours
- Shut down to re-prime pump truck at 92.7 hours
- Resume pumping at 92.8 hours
- Shut down at 94.2 hours
- Open well for flow back at 95.9 hours
- Choke freezing off at 96.1 hours
- Increase choke to full open at 97.8 hours
- Shut well in at 97.9 hours

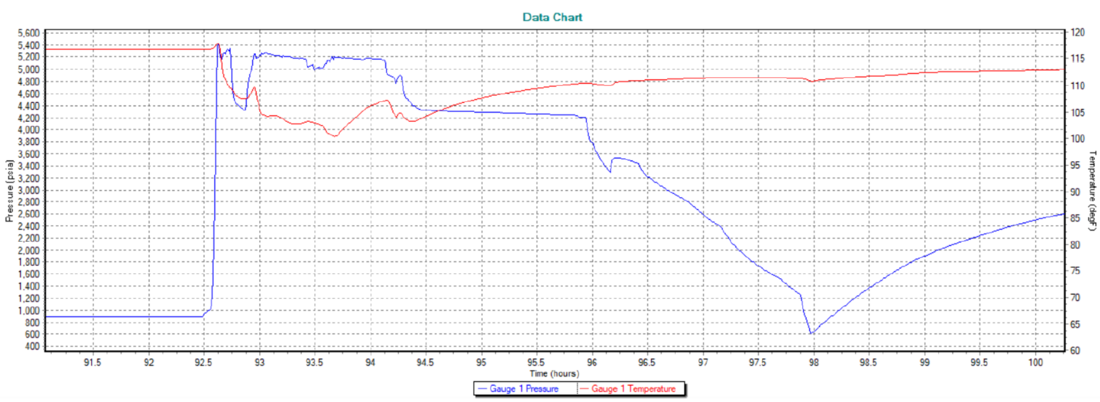

Figure 3-2: Zoom of treatment well nitrogen stimulation pumping/flowback data

The Y-Grade NGL injection was performed over a two-day period from 08/26/2021 to 08/26/2021. Figure 3-3 shows the field setup for the injection. A total of 941 Bbl of Y-Grade NGLs was injected. The well was shut-in for a period of seventeen (17) days following the injection to allow the Y-Grade to soak on the formation.

Aerial Photo of Treatment well Y-Grade Injection, 8/26/2021

1. Nitrogen transport, pump truck and tube trailer
2. Y-Grade storage trailers
3. Y-Grade pump truck
4. Flowback tank, separators and pressurized tank
5. Wellhead
6. Remote-controlled manifold trailer with infrared camera
7. Fire sheds
8. Firefighting/foam generating trailers and 500 Bbl water storage tank
9. Command center trailer
10. Hydraulic remote-control unit
11. Firefighting/foam generator unit and 500 Bbl water storage tank

Figure 3-3: Aerial view of the treatment well Y-grade injection setup

Special flowback equipment was installed to allow safe and efficient flowback of the Y-Grade treatment. The equipment consisted of a nine valve, 5,000 psi manifold with production chokes, two (2) 1440 psi separators, an 80-Bbl pressurized storage tank, a digital orifice gas meter and a flare stack. Bottomhole data over the frac/flowback periods is shown in Figure 3-4.

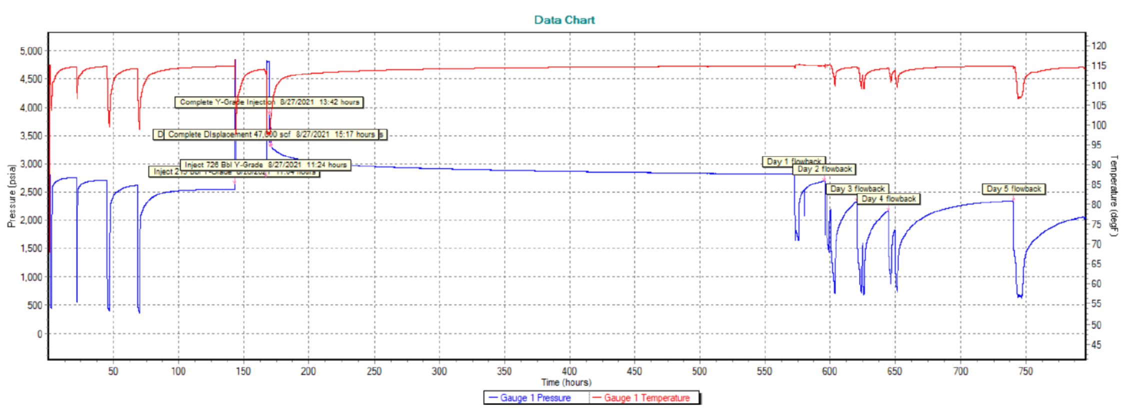

Figure 3-4: Y-Grade injection bottomhole gauge data

4.0 Microseismic Monitoring Analysis

This section presents a review of the microseismic monitoring data analysis for the microseismic work completed during well stimulation. Reservoir Imaging Ltd. from Calgary, Alverta Canada recorded Micro seismic data with a downhole geophone array installed in the microseismic monitoring well prior to, during and after the nitrogen foam stimulation. Once the geophone array was positioned at the proper depth in the well, a vibroseis truck furnished by Precision Geophysical was used to produce seismic source waves from three (3) different locations around the microseismic monitoring well to orient the geophones.

The micro seismic data was analyzed by ESG Solutions in Calgary, Alberta Canada. A summary of ESG solutions final report and interpretations follows. Figures 4-1 through 4-3 shows 404 micro seismic events which were identified during and after the foam frac treatment on the injection test well. The plan view on the left indicates the induced fracture to have a SW-NE trend from the wellhead. The depth view to the right indicates two separate groupings of micro seismic events; one in the target zone of the UPP and a shallower grouping in the Queenston shale.

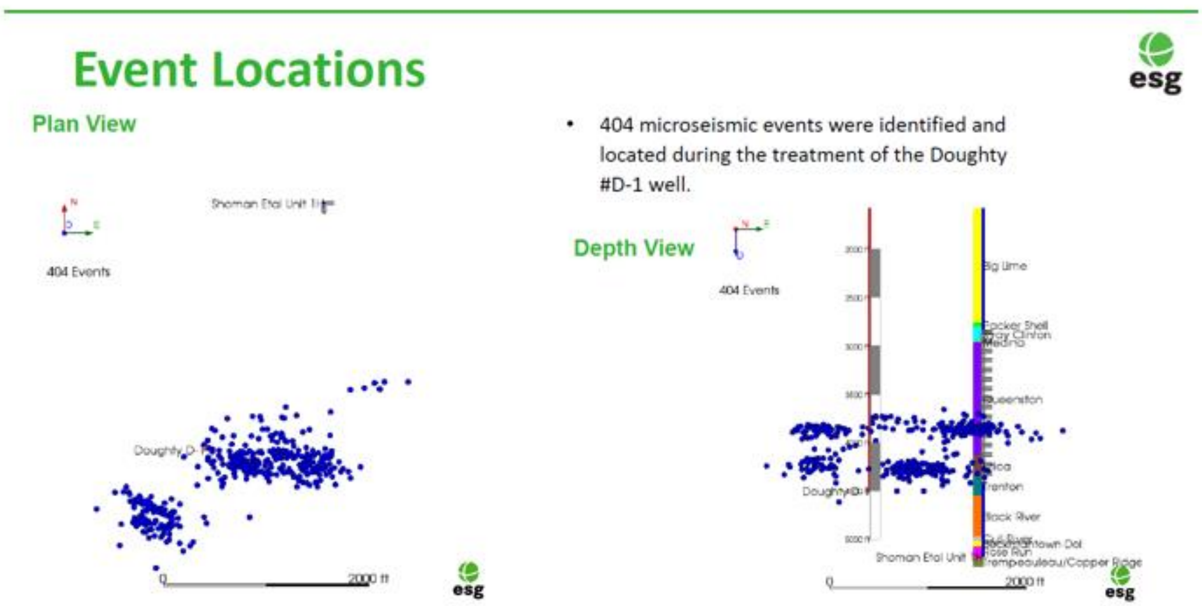

Figure 4-1. Microseismic monitoring events.

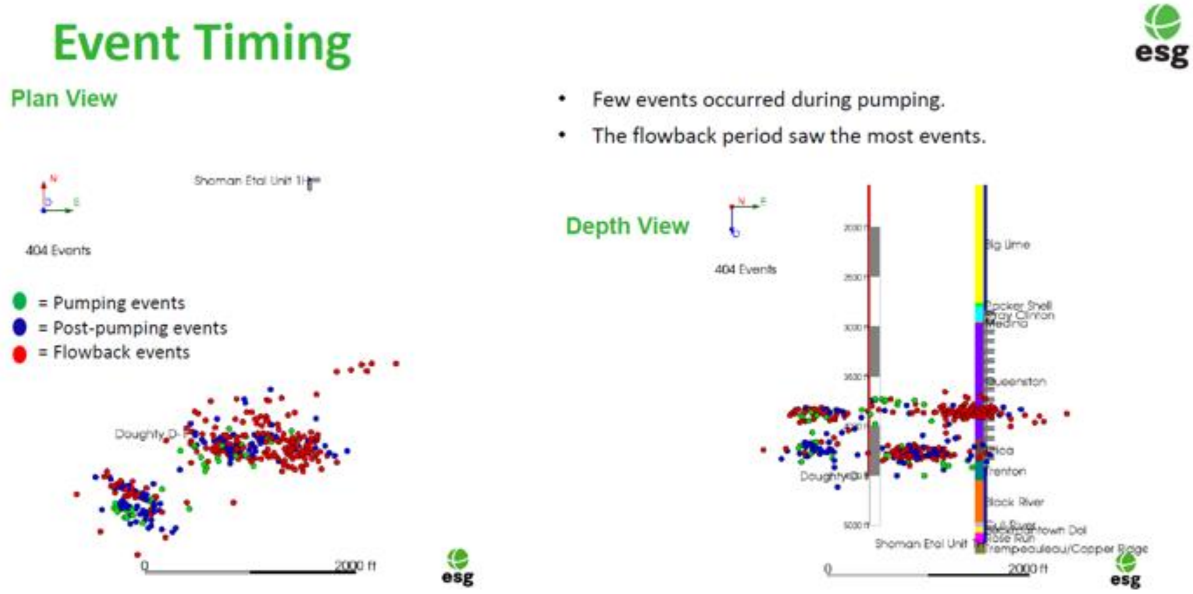

Figure 4-2. Microseismic monitoring events chronologically.

Figure 4-2 above shows the micro seismic events chronologically; during the pumping of the frac job, during post-pumping and during flow back. The interesting point of this data is that the majority of the recorded seismic events occurred during post-pumping and flow back. One theory for this is that the nitrogen foam is a compressible fluid that creates more muffled seismic events than a non-compressible frac fluid. The events recorded during the post-pumping and flow back periods are thought to be a result of the formation adjusting to the change (increase and decrease) in pressure. If only those events which occurred during pumping were charted, it could possibly give an indication of the approximate area of the induced fracture network.

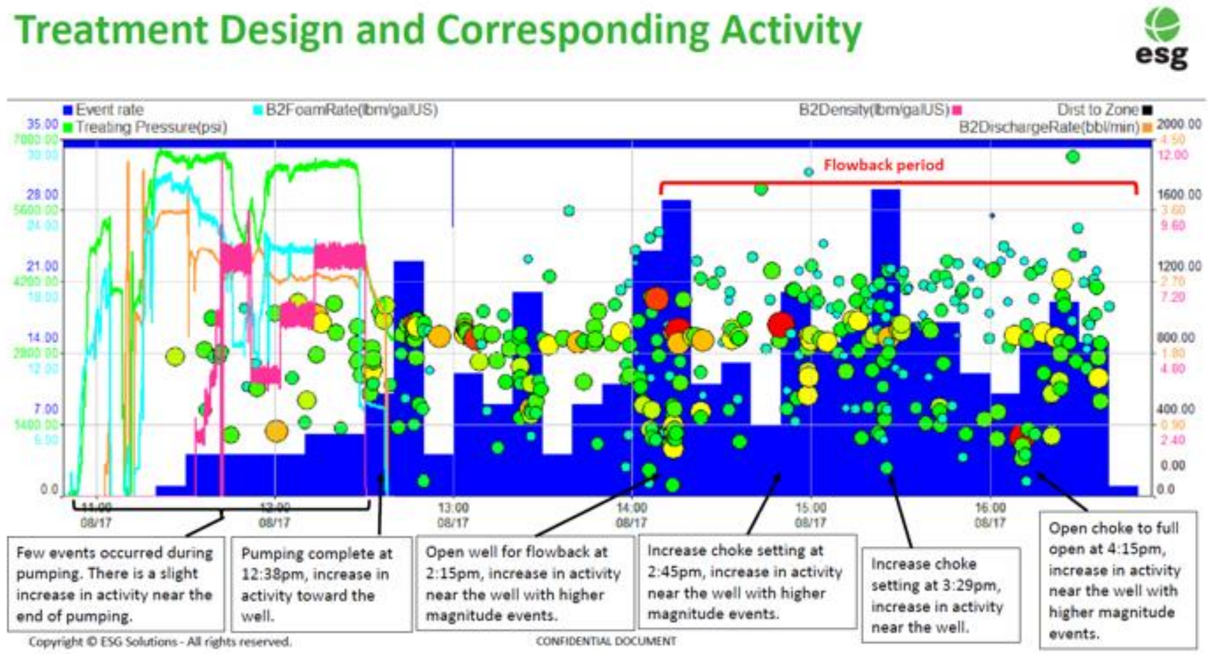

Figure 4-4. Microseismic monitoring events and well treatment events.

Figure 4-4 shows the rate of events with time during pumping, post-pumping and flowback. The larger the diameter of the event, the greater the magnitude. This chart confirms there are more seismic events during post-pumping and flowback than during pumping. An increase in event frequency is evident when the well was opened for flowback and with each increase in the choke setting.

Formation Distribution

- The bottom left image displays all the events in cross-section view colored by formation based on the 3D horizons. The middle graph shows a histogram of event depths. The bottom right pie chart shows the total event distribution percentages by formation. The pie charts omit fractions less than 2%.
- Most events occurred within the Queenston, with slightly fewer events within the Utica.
- Events did not grow above the Queenston but there was limited activity beneath the Utica (primarily in the Trenton).

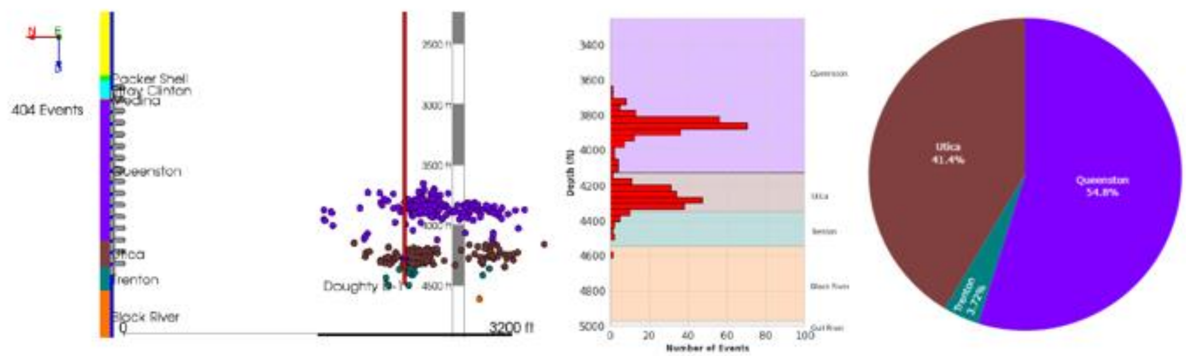

Figure 4-5. Microseismic monitoring events.

Figure 4-5 illustrates the distribution of micro seismic events by formation. Note that more than half of the recorded events occurred in the Queenston formation and most of them occurred during flowback. It is unlikely that the frac was extending into the Queenston formation during flowback, so those events are assumed to be the formation reacting to the decrease in the pressure due to the flowback

5.0 Production Data Analysis

This section presents a review of well testing data after the NGL treatment in the Utica Point-Pleasant test well. These datasets portray the results of the NGL treatment in terms of improved oil recovery, NGL returns, nitrogen flowback, and associated gas production. Y-Grade NGL injection occurred on 8/26/2021 and 8/27/2021, after which the treatment well was shut-in for 17 days to allow the NGLs to soak on the formation. Periodic flow back commenced on 9/13/2021, and the amount of oil and gas produced in each of these periods was recorded. All produced gas was subsequently flared. These flow periods occurred 3-4 days per week through October 2021, at which point the formation was allowed to repressurize for a month. In December 2021, the operator began flowing the well 2 days/week for approximately 2-4 hours each time.

At the beginning of flowback, well bottom hole pressure was at 2800 psi and wellhead pressure was around 2180 psi. The BHP monitoring tool was retracted on 9/22/2021 (when formation pressure was around 2000 psi), but WHP has been tracked throughout the production process. Wellhead shut-in pressure has decreased from the initial 2180 psi to around 500 psi as of June 2022. Produced gas has been sampled several times during production, and the produced oil was sampled once (on 10/15/2021). These samples were sent for lab testing to determine composition. The results of the production field tests are discussed throughout this section.

Fluid Analysis

The oil being produced from the NGL field tests was sampled on 10/15/2021 and analyzed. The molar composition of this oil is shown in Figure 5-1. The oil is relatively light with a specific gravity of 0.6385. A small amount of nitrogen is present in this sample. This is likely a result of the nitrogen foam frac that occurred in the formation.

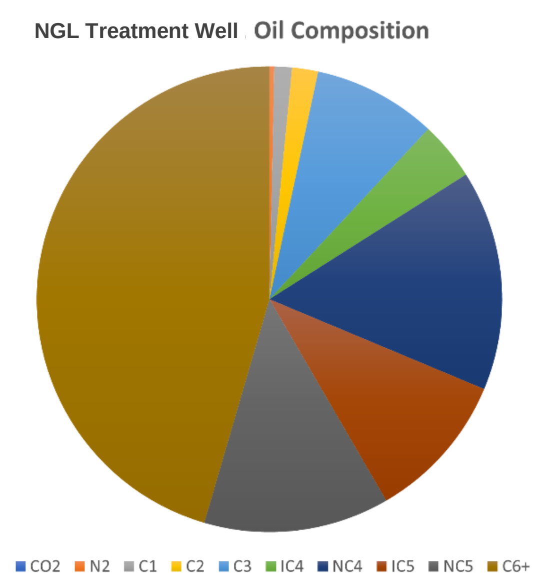

Figure 5-1: Molar composition of the produced oil from the NGL treatment well.

Gas samples were also taken at various times throughout production. The evolution of produced gas composition with time is shown in Figure 5.2. As with the oil in Figure 5.1, this is the molar composition of the fluid. The gas has a significant nitrogen component, as high as 50% in mid-late September 2021. This nitrogen fraction steadily decreases to around 20% on 4/22/2022 when it was last sampled. The use of nitrogen negatively impacts the economic viability of producing gas through this NGL-soaking process.

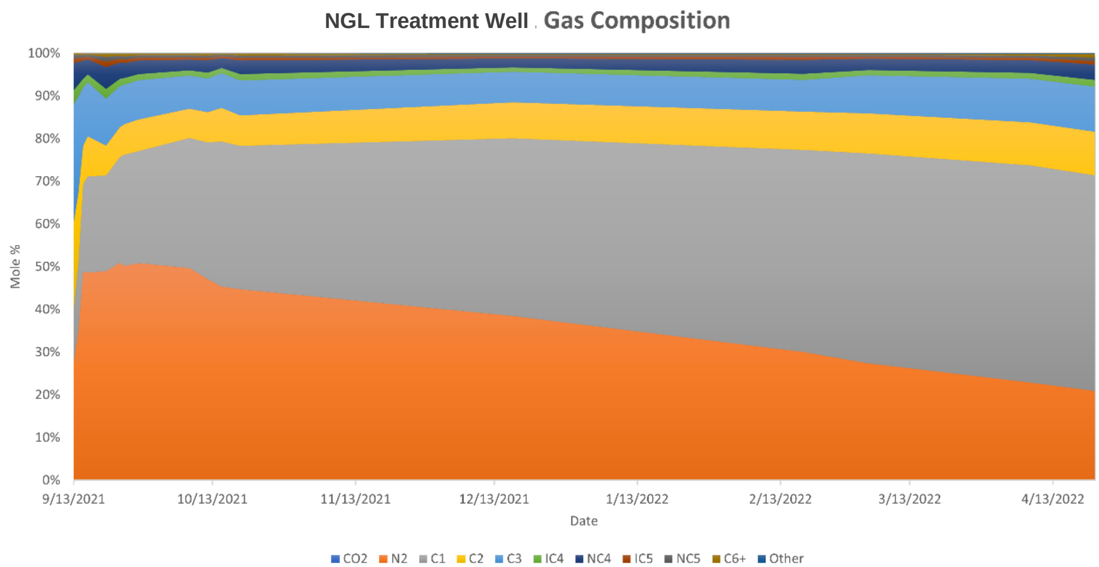

Figure 5-2: Molar composition of the gas sampled at NGL treatment well; varying with time.

Cumulative Production

Table 5-1 below shows the cumulative production values as of 6/17/2022 for both oil and gas from the NGL treatment well. These production numbers are quite high as compared to other Utica/Point Pleasant wells in the region. One nearby well produced from the UPP for around 1 calendar year, yielding approximately 67 bbls of oil and 1200 mcf of gas.

NGL Treatment Well Cumulative Production			
Oil:	726 bbl	**Gas:**	2888 mcf

Table 5-1: Cumulative production from field tests as of 6/17/2022

By combining the production data with our fluid analysis, we can estimate production volume by component. The production volume splits by component for oil and gas are shown below in Figures 5-3 and 5-4, respectively. A significant amount of heavy hydrocarbons (C6+), 386 bbls, have been produced in liquid form. In addition to this, we see 45 bbls of propane and 118 bbls of butane liquid. These components are also present in gaseous form, producing a volume of 354 mcf propane and 163 mcf butane. Perhaps the most striking feature in these figures is the large presence of nitrogen gas. A total of 1166 mcf of nitrogen gas was produced from the NGL treatment well, comprising over 40% of the total volume of gas.

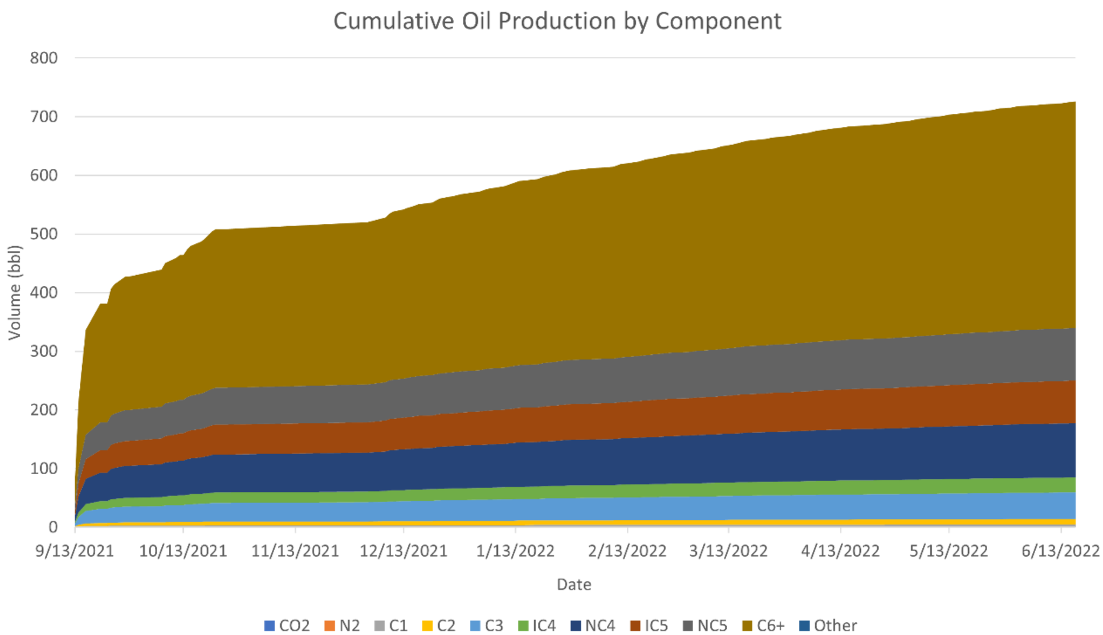

Figure 5-3: Cumulative liquid production volume by component from the NGL treatment well.

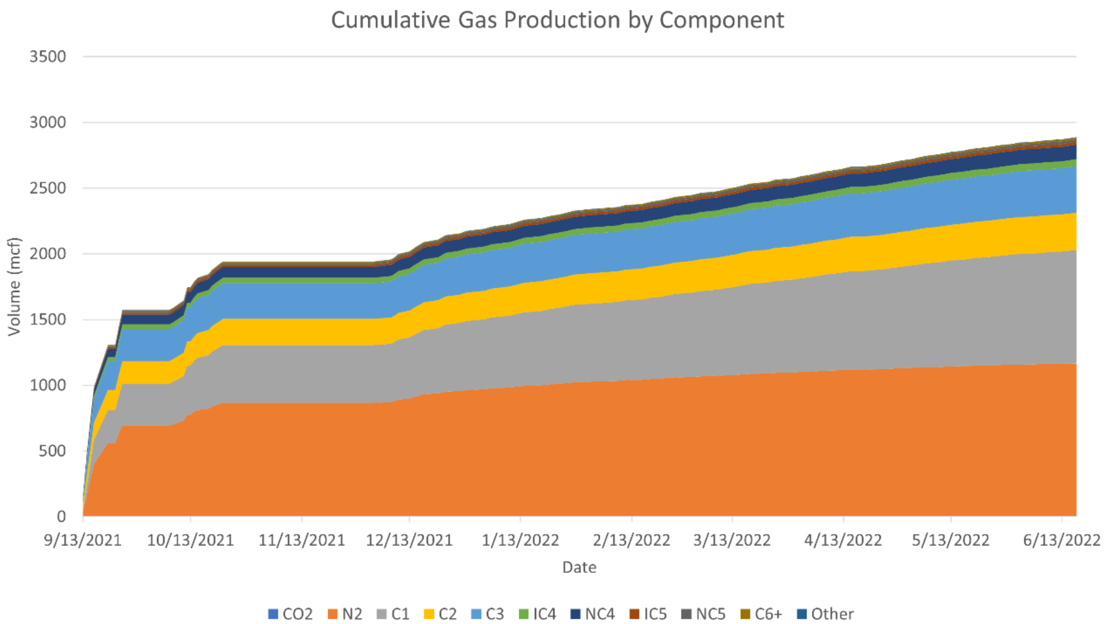

Figure 5-4: Cumulative gas production volume by component from the NGL treatment well.

Component Retention Analysis

In addition to the compositional analysis done on the produced oil and gas, a sample of the injected Y-Grade NGLs was also sent for lab testing. The molar composition of the Y-Grade is shown below in Figure 5-5; it is primarily comprised of propane (light blue) and butane (green/dark blue). The component analysis of both the NGLs and the oil provided us with fluid densities in lbm/bbl. This information, combined with component-wise cumulative production, allows us to compare the amount of material injected to the amount of produced material. A total of 941 bbls of Y-Grade was injected into the formation. The net production of each component in lb-mols is shown in Table 5-2. A significant amount of propane and butane was retained by the formation, while a large net gain of heavy hydrocarbons (C6+) was produced.

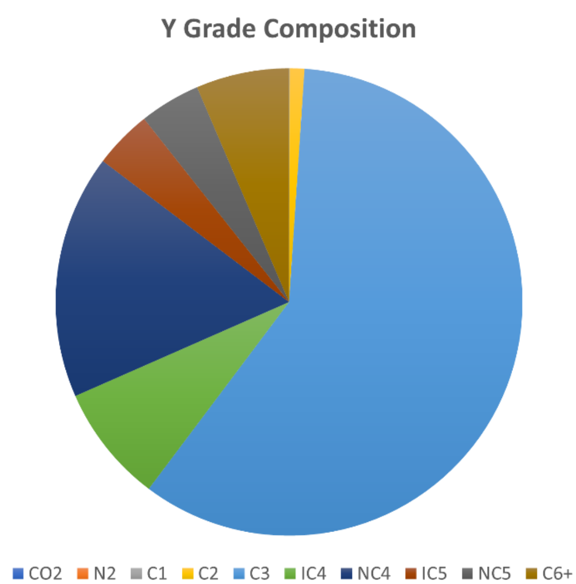

Figure 5-5: Molar composition of the injected Y-Grade NGLs.

Component	Amount injected (lbmols)	Gas produced (lbmols)	Liquid produced (lbmols)	Net (lbmols)
CO2	**0**	2.756307	0	2.756307327
N2	**0**	3072.879	7.000329	3079.879561
C1	**1.591355**	2274.22	26.16958	2298.798099
C2	**34.68879**	749.9327	38.56044	753.8043683
C3	**2036.274**	933.5158	183.0573	-919.700989
IC4	**280.4536**	138.6931	86.53594	-55.2245455
NC4	**580.7984**	291.6628	326.1752	37.03961488
IC5	**138.6821**	58.38977	220.1292	139.8368488
NC5	**144.9249**	50.2302	274.8734	180.1786969

Table 5-2: Net amount of substance produced by component (amount out – amount in) in lb-mols.

Decline Curve Analysis

We fit decline curves to both the oil and gas production data from the NGL treatment well. These fitted functions are shown in Figure 5-6 below. The fits reflect transient pressure conditions in the formation, which is likely given the intermittent periods of production and shut-in. These curves predict a total production of roughly 1485 bbls of oil and 7882 mcf of gas. This is likely an overshot as it assumes constant production. A lower bound on total production is given by a simple exponential fit, which assumes boundary dominated flow within the reservoir – 824 bbls of oil and 5242 mcf of gas. Comparing these numbers with the actual current cumulative production shown in Table 5-1, it is likely that there are more hydrocarbons that will be produced from the NGL treatment well.

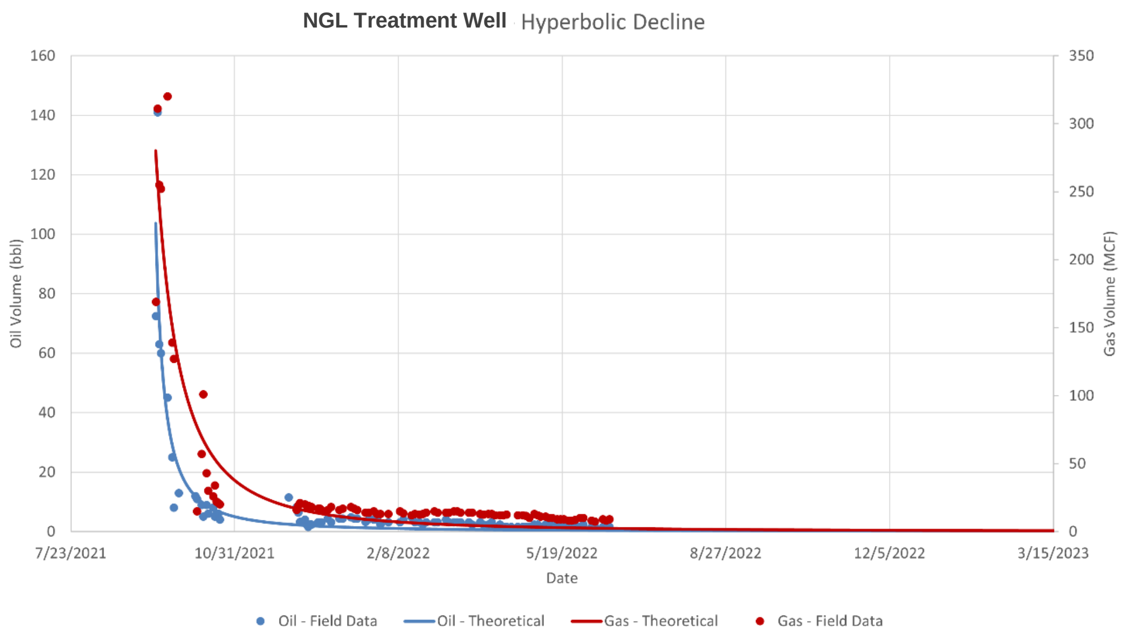

Figure 5-6: Decline curves for oil (blue) and gas (red)

But how much longer can this production continue? To try to answer this question, we looked at production rates for oil and gas as opposed to production volumes. Through a similar fitting procedure, we obtained the fits shown in Figure 5-7. Zooming into the later portions of this fit (Figure 5-8), we see nontrivial production rates as late as 2025. We also compare these fits with the simulation results presented in Figure 2-8 which predict roughly 2 bbl/day oil production rates at the 135 day mark. This corresponds to a date of 1/25/2022, where our fit gives a rate of 1.2 bbl/hr. Given the usual 2 hour flow back periods, this production model is consistent with simulation.

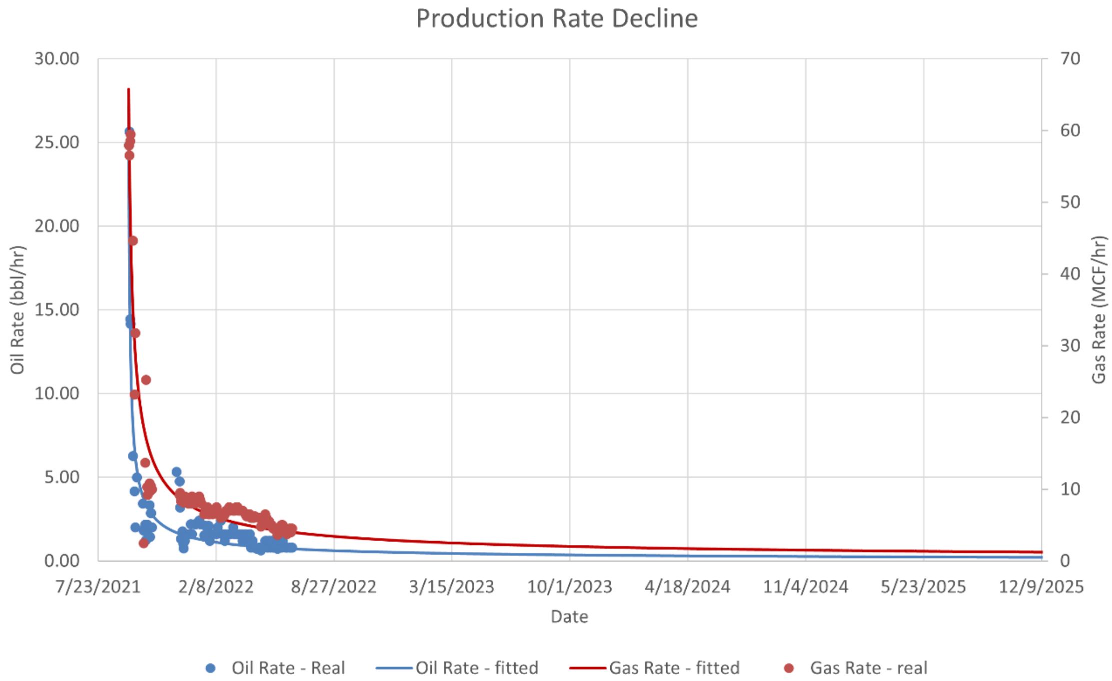

Figure 5-7: Decline curves for the oil and gas production rates at the NGL treatment well.

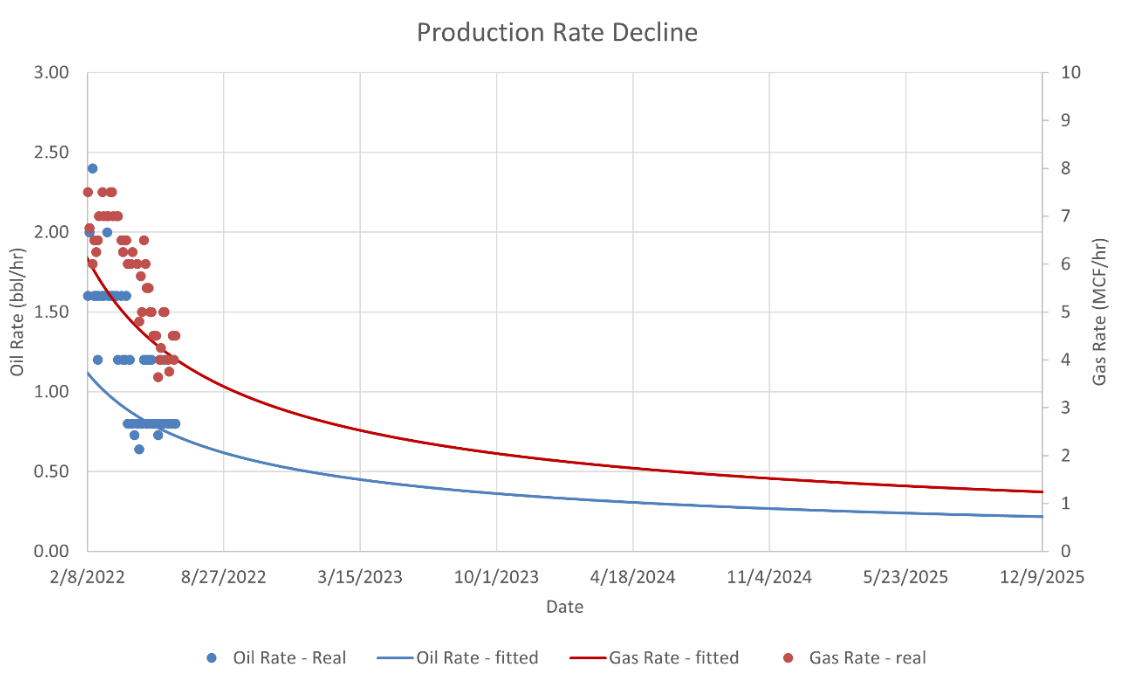

Figure 5-8: Same as Figure 5-7, but only showing the period after 2/8/2022. Nontrivial production rates continue into 2025.

6.0 References

Battelle. 2016. Feasibility of Enhanced Oil Recovery Using Cyclic Gas Injection in Utica – Point Pleasant Shale Oil. Prepared for Utica Shale JIP Members, October 2016.

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