A novel approach to gas cycling enhanced oil recovery (GCEOR) evaluation in unconventional porous media.

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Abstract. Unconventional production suffers from three specific weaknesses: rapid production decline, infill well interference and poor recovery. Gas-Cycling Enhanced Oil Recovery (GCEOR) has the potential to improve all three of these limitations. Many authors use reservoir simulation to evaluate the benefits of GCEOR. These forecasts are often uncalibrated and lack fundamental experimental data. Traditional, axial core testing, is not practical for unconventional rock. The Darcy equation ($Q = k\ A\ \Delta P/\ \mu\ L$) describes why axial core testing is impractical. For a permeability of 100 nD and a viscosity of 0.5 mPa-s, with typical ΔP, the time required to inject one hydrocarbon pore volume (HCPV) of fluid is 22 weeks. Using radial flow with the same conditions, approximately three hours would be required to inject one HCPV. Patented equipment design allowed GCEOR experimentation at full reservoir conditions in porous media ranging from 10 nD up to 2400 nD (Duvernay and Montney) using fluids ranging from gas condensate gas to 40 API oil. Some of the conclusions, based upon more than 70 primary depletions followed by multiple cycles of GCEOR Huff and Puff, were: 1. Geological heterogeneities play a major role in GCEOR performance. 2. Well-designed GCEOR performs like gas storage; injection gas volumes were less than 5 Mscf per incremental barrel of hydrocarbon liquid recovered by GCEOR. 3. Acid gases may also be sequestered using GCEOR in unconventionals. 4. GCEOR for hydrocarbon liquids recovery applied to gas condensate fluids performs well compared to primary depletion hydrocarbon liquid recovery. This paper describes laboratory-scale testing that can help to optimize GCEOR in unconventional porous media.

1 Introduction

Horizontal drilling combined with hydraulic fracturing (frac) can be represented schematically according to Figure 1. Many authors have simulated the associated phenomena. Depending on the well spacing (Figure 1A), when the wells are completed there may be unstimulated rock between the end of the fracs from one well and the end of the fracs from an adjacent well. If the half length of the fracs is long then the wells interfere (frac driven interference (FDI) or frac hits) and so there is no outer reservoir – all the rock in between the wells is SRV. Figure 1B represents one well and the half lengths orthogonal from one side of one well. Ahmadi [13] suggests that as Huff and Puff (HP) cycles (Injection and Production cycles) proceed, the gas-residual oil interaction continues five centimeters away from the frac into the matrix every HP cycle; because the frac-matrix area is so large a few centimeters invasion may yield hundreds of thousands of barrels of EOR.

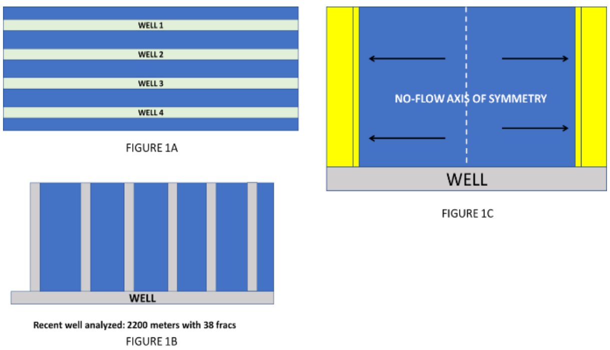

Fig. 1. Schematic of Stimulated Rock Volume (SRV) structure with well(s) and fractures.

This incremental gas invasion with concomitant oil recovery adjacent to the frac-matrix interface occurs where the differential pressure gradients are the highest. Margaret SPE model [14] provides an analytical single-phase solution in which pressure gradients are available. The pressure gradients are orders of magnitude higher than in conventional porous media (hundreds of thousands of kPa/m or tens of thousands of psi/ft).

2 Materials and Method

In the field, the dominant flow regimes are flow from the matrix into the frac and then flow in the frac into the well. Matrix-frac flow is reproduced under differential pressure gradient in the experiment and flow in the frac; the frac permeability is on the order of Darcy whereas the matrix permeability is on the order of nano-Darcy or hundreds of nano-Darcy. The only production that is not included in the experiment is matrix draining directly into the well, which would correspond to well production rates of an un-fracked well – which is negligible as proven by personal communication with associates who have tried to produce un-fracked unconventional Montney wells. It must be emphasized that with the radial-flow design, hydrocarbon pore volume (HCPV) can be maximized independent of the induced differential pressure gradients. In order to minimize material balance errors, effort was made to maintain HCPV ten times larger than the dead volumes (valves and lines) associated with the equipment. These large HCPV facilitated resolution of oil recoveries and gas utilization, cycle by cycle, along with produced fluid compositional analyses, densities and enabled material balances that exhibited errors less than 5% typically.

3 Results

Table 1 presents a summary of the properties of the rock, fluids, pressure and temperature of the different unconventional systems that were analyzed in this work. The least permeable rock that was tested was approximately 5 nD. The maximum permeability tested was a naturally fractured core with an average radial-flow oil permeability of 2400 nD. API gravity of the oils tested ranged from 41 to 48 degrees and the solution gas oil ratios (GOR) were a minimum of 840 scf/BBL up to 3520 scf/BBL. In addition, two gas condensate systems were also tested: one possessing a condensate-gas ratio of 115 BBL/MMscf and another a CGR of 200 BBL/MMscf.

Table 1. Range of Rock and Fluid Properties.

PROJECT #	Permeability (nD)	Fluid GOR (scf/BBL)	STO API	Viscosity (cP)	T (F)	Pres (PSI)	Pb (PSI)	Peclet*
MONTNEY 1	2400	1460	43	0.247	189	3800	3750	5.4
MONTNEY 2	1770	1404	43	0.522	197	4410	4400	0.54
MONTNEY 3	1697	1581	44	0.202	172	3640	3600	0.71
MONTNEY 4	832	870	41	0.458	140	3100	3000	1.53
MONTENY 5	319	2650	47	0.205	161	4450	4300	0.34
MONTNEY 6	211	1182	45	0.588	156	4000	3900	
MONTNEY 7	138	2664	42	0.137	203	5800	4700	
DUVERNAY 1	14	840	40	0.277	192	5250	2000	0.06
DUVERNAY 2	5	3520	48	0.151	239	9718	3875	
DUVERNAY 3	LAMINATED	1117	43	0.21	226	6835	2762	

* Peclet Number defined as velocity x distance/ Diffusivity

Example results of the experiments are shown next. Figure 2 presents the pressure history from a primary depletion followed by GCEOR cycles using 40% Ethanes-plus in the 13 nD project. The frac pressures and peripheral pressures of the matrix are shown for each cycle of the experiment.

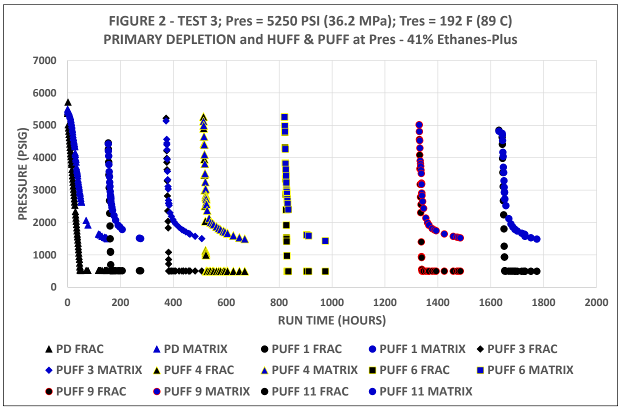

Fig. 2. Pressure history from 13 nD project – cycle by cycle.

Figure 3 presents corresponding recovery data from the same test. With the large HCPV, recoveries are resolved, cycle by cycle, showing that GCEOR recovers more than twice as much as primary depletion.

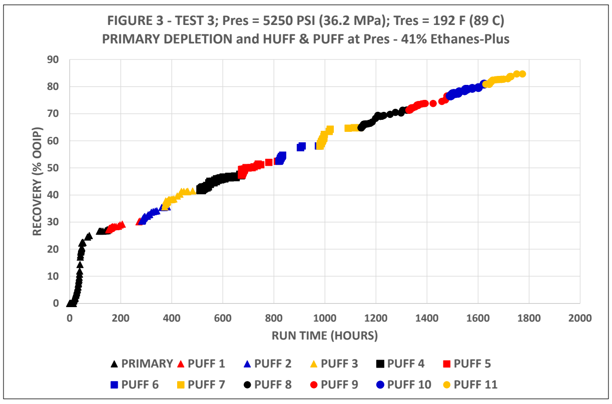

Fig. 3. Recovery data from 13 nD – cycle by cycle.

Figure 4 presents the compositional analyses of the produced flashed oil from the different cycles. The degree of extraction of intermediates during the GCEOR cycles is obvious by comparison to the composition of the produced, flashed oil from the primary depletion. Specifically, propanes through normal octane were extracted from the residual oil. As these intermediates are extracted into the gas phase, produced and condensed, one

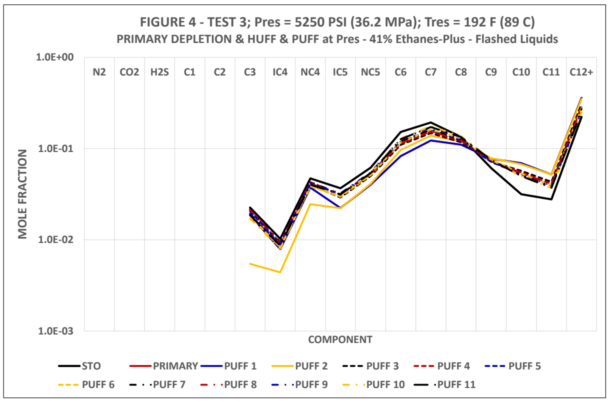

Fig. 4. Compositional analysis of flashed oil.

observes the corresponding increase in produced liquid API. The gas phase enrichment is shown in Figure 5 and the API change is presented in Figure 6.

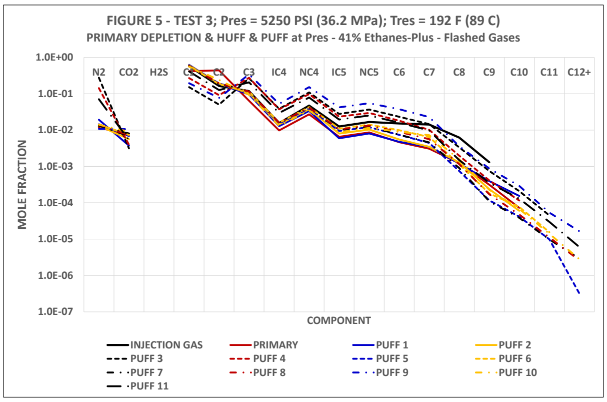

Fig. 5. Gas phase enrichment.

The black line in Figure 5, corresponding to the injection gas, shows that Puff cycle produced gases contain more of the same intermediates that were extracted from the oil phase in Figure 4. As these components are produced along with the intermediates that are contained in the injected gas the produced liquid API steadily increases.

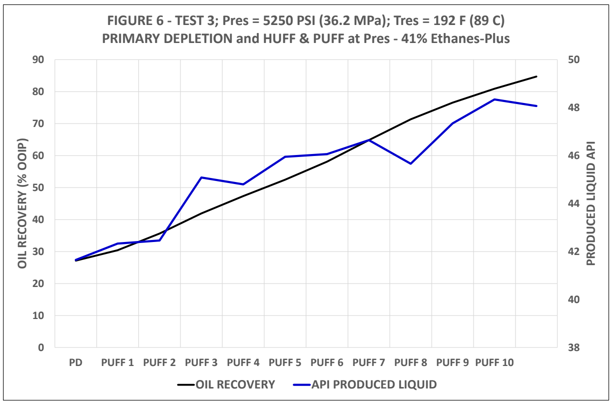

Fig. 6. Changes in API.

Along with the dataset presented to this point, differential pressure gradients were measured as well as oil flux. The oil flux measured is then multiplied by the area of the hydraulic fracs in contact with the matrix in the field scenario, thus providing peak oil rates on a field basis. Figure 8 presents these data. With GCEOR the terminal rates remain higher than would be expected with continued primary production and overall recovery factor approached 85% with primary recovery at approximately 27% (Figure 3).

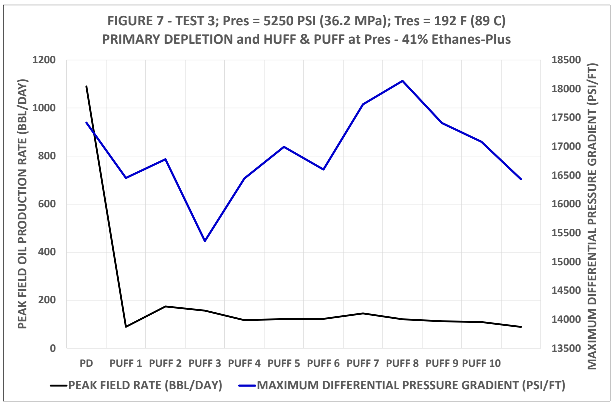

Fig. 7. Peak oil rates on a field basis.

This technology and procedures were applied repeatedly to many other unconventional systems, summarized in Table 1, providing a significant GCEOR dataset of over 70 primary depletions and multiple GCEOR Huff and Puff cycles.

Additional techniques were used to resolve hydrocarbon liquid recovery, component by component, in gas condensate systems. Figure 8 presents the result of using n-pentane to flush out residual hydrocarbons after GCEOR, while leaving any immature hydrocarbons in the rock (kerogen, pyro bitumen, bitumen), had been prosecuted on unconventional full-diameter rock saturated with gas condensate fluids. Integration of the best-fit of each of the components provides the mass of residual components after primary depletion and subsequent GCEOR. Figure 9 provides the recovery factor comparison between recovery based on produced components, total hydrocarbons produced and resolved component by component and the residual components determined by the pentane flush technique; reasonable accuracy was achieved.

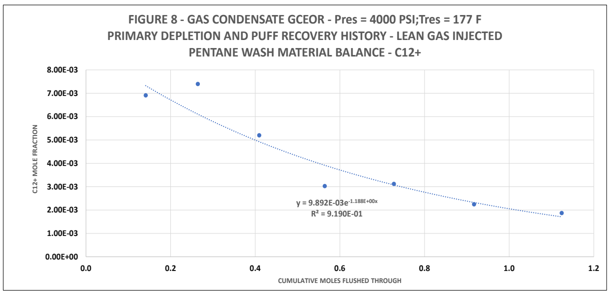

Fig. 8. N-Pentane injection results.

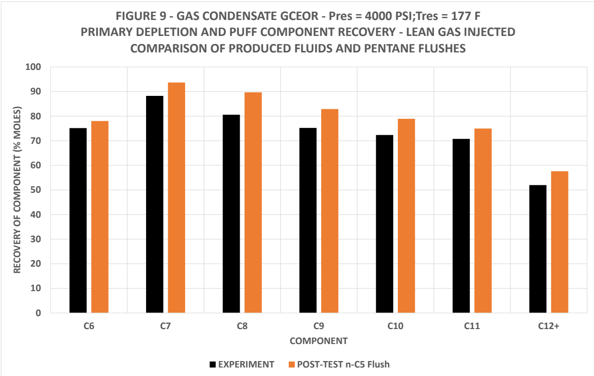

Fig. 9. Recovery factor comparison.

Analysis of the complete dataset allowed insight into the performance of GCEOR. General insights are discussed next.

4 Discussion

Some specific questions were illuminated through this testing:

1. Does geology play an important role in GCEOR?

Figure 10 shows the relationship between GCEOR response and the degree of geological heterogeneity. The geological heterogeneity includes micro-scale and macro-scale heterogeneity and is discussed in some detail in Thomas et al. [11].

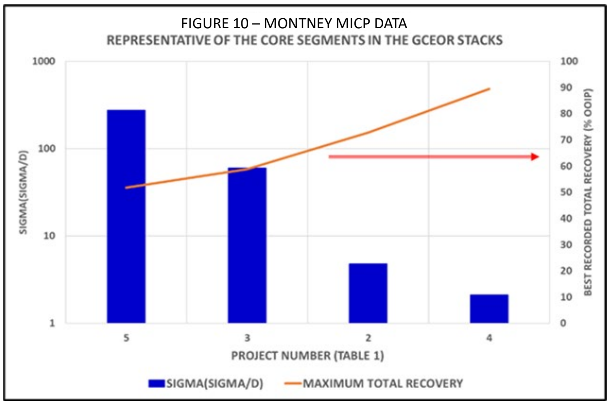

Fig. 10. Geological heterogeneity and GCEOR response.

Figure 11 shows what was done subsequently to study the role of porous media character on GCEOR response. Project 5 is run number 3 from Table 6 above. Project 4 (MONTNEY 4) Run 1 is shown as Project 4 in Figure 12 (Second from the right). The MONTNEY 4 fluids were then used, with the same temperature and pressure conditions for Project 4 (MONTNEY 4) but in the MONTNEY 5 porous media. The results were virtually the same as the MONTNEY 5 results; this indicates that the geology determined the Primary and GCEOR response. MONTNEY 1 fluids were then used, at MONTNEY 1 run conditions, but in the MONTNEY 5 porous media. Again, the results with MONTNEY 1 fluids were almost identical to the MONTNEY 4 fluids and the MONTNEY 5 fluids. Although in the MONTNEY 4 core the MONTNEY 4 fluids resulted in excellent GCEOR response, the same fluids in the MONTNEY 5 core performed poorly. Thus, the conclusion that the geology was limiting. The same argument is true for the MONTNEY 1 fluid system. Indeed, geology does matter in GCEOR.

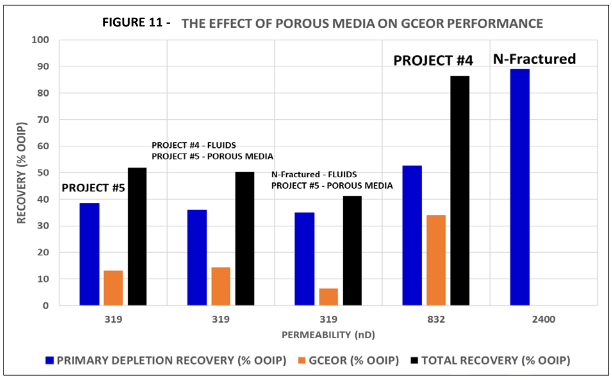

Fig. 11. GCEOR response interchanging core fluids.

2. Are Gas Condensate reservoirs amenable to GCEOR?

Figure 12 shows the experimental primary depletion and GCEOR response from a 215 BBL/MMscf gas condensate reservoir. Approximately the same recovery of liquids was achieved with GCEOR as during the primary depletion.

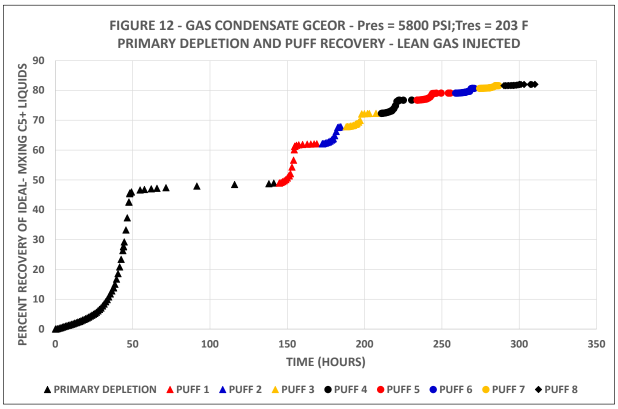

Fig. 12. Experimental primary depletion and GCEOR response.

The analogous response for a volatile oil in the same porous media using the same injection gas and operating conditions. The primary depletion recovery of oil was superior to that of the gas condensate fluid but the GCEOR response with the oil was inferior compared to the condensate.

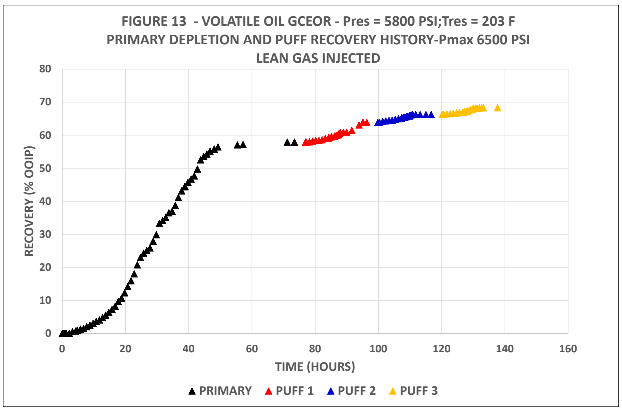

Fig. 13. Volatile oil GCEOR.

Although the First Contact Miscible pressures for the two systems are very close (6600 and 6750 psi) the Gas Condensate performed much better. The Multi-Contact Miscible pressures were 4925 and 5825 psi; if in situ, dynamic, multi-contact phenomena were to occur this may be responsible for the superiority of GCEOR in the Gas Condensate system. It is expected that the primary depletion recovery is worse for the Condensate system due to the value of maximum liquid dropout compared to the critical condensate saturation (Scc). For porous media of this quality (630 nD) it is anticipated that the Scc would be much higher than the maximum liquid dropout (Monger McClure - ?). Therefore, thermodynamics is one of the few methods that would be able to access and recover the hydrocarbon liquid trapped in the rock. Another system was also run using the same techniques: same porous media, same injection gas, same reservoir conditions but one primary depletion and GCEOR with gas condensate fluid and another with volatile oil. Indeed, Gas Condensate reservoirs are amenable to GCEOR. With respect to field applications, it may be that those SRV's that produce less hydrocarbon on primary depletion may be better candidates for GCEOR.

3. Is GCEOR efficient from a Gas Utilization perspective?

Figure 14 shows total oil recovery versus gas volume injected during a series of Huff and Puff gas injection cycles. This Montney system proved very responsive to GCEOR. The gas utilization values, factoring in injection gas recovered during the production/ Puff cycles were 0.48, 0.85, 1.96, 0.02 and 1.14 Mscf/BBL of incremental oil recovered.

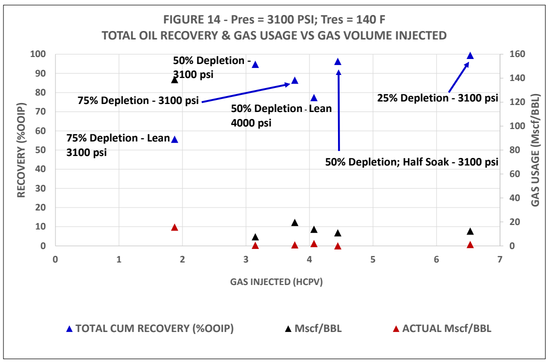

Fig. 14. Total oil recovery and gas usage vs. gas volume injected.

Figure 15 shows another system that performed well on GCEOR. The best runs utilized 0.4, 0.9, 4.4 and 4.6 Mscf/BBL incremental oil recovered by GCEOR. In light of the value of energy as a gas compared to the value of energy as a liquid, these values would provide significant margin to make GCEOR a viable field EOR application.

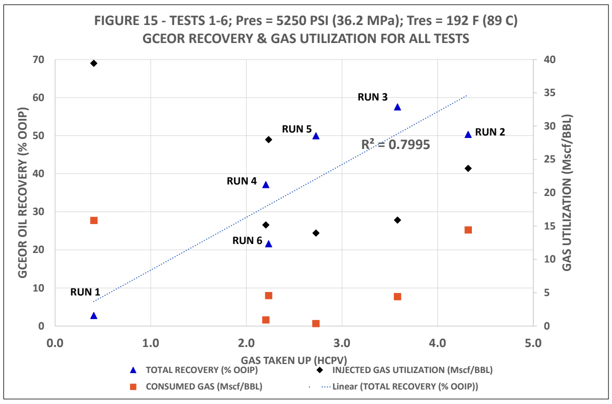

Fig. 15. GCEOR recovery and gas utilization for all tests.

That is, if gas cost is on the order of 4$/ Mscf, then with the maximum gas utilization of 4.6 Mscf/BBL from Figure 15, the cost would be 18.4 $/ BBL incremental oil recovered. With 80 $ oil, including compression and transportation cost, there is still a significant margin for a financially viable project. Indeed, the best performance of GCEOR projects tested approached the behavior of a gas storage operation. Gas is injected to recover oil with very little gas lost; almost all of the gas is produced during the production cycles. Of course, if CO2 were available, and was injected, the higher the oil recovery the more CO2 could be sequestered. The portion of the HCPV that is recovered would be made available for sequestration; after the last production cycle, one more injection cycle (Huff) would be executed, pressurizing the SRV followed by shut in so that the CO2 would remain in situ. Indeed, GCEOR can be efficient for gas utilization in a properly designed application.

5 Conclusions

Multiple porous media and reservoir fluids were analyzed for GCEOR upside using a novel, patented experimental design (Serial No.: 16/834,383, Filed: March 30, 2020, System and Device for Analyzing Fluid Flow in Unconventional Hydraulically-Fractured Porous Media, Thomas, Piwowar and Gibb) and protocol.

In light of more than seventy primary depletions and multiple subsequent GCEOR cycles, the following was concluded:

1. Geological character, including micro- and macro-scale heterogeneities impacts directly and significantly the performance of GCEOR in low permeability porous media.
2. GCEOR was more effective in retrograde gas condensate systems than GCEOR applied to oils in the same porous media. GCEOR in a gas condensate system recovered more than three times more hydrocarbon liquid than the oil system.
3. Well designed GCEOR approaches a gas storage operation wherein very low gas requirements (1 to 2 Mscf/BBL) recover incremental oil; if the operator delays gas sales, that gas can be used to recover residual oil after primary depletion. The gas in situ, after the last Huff cycle can then be left in situ or can be produced and sold.

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