URTeC: 2869

Compositional Tracking of a Huff-n-Puff Project in the Eagle Ford: A Second Take

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Abstract

This is a follow-up paper to URTeC 539, “Compositional Tracking of a Huff-n-Puff Project in the Eagle Ford” (the “original paper”). That paper documented compositional tracking analysis of a gas Huff-n-Puff (HnP) field project in the *black oil area* of the Eagle Ford. It also detailed the gas HnP process in general from many different perspectives, including important considerations for reservoir simulation and key phase behavior related concepts.

In this paper we present compositional tracking results and interpretations for a field project in the *gas condensate area* of the Eagle Ford. The objective of this paper is to help understand the mechanisms behind gas-based enhanced oil recovery (EOR) seen in actual field performance. This is accomplished by computing and interpreting daily wellstream compositions obtained from production data during the production period(s) of a HnP project in the Eagle Ford.

Wellstream compositions are determined from readily available production data using an equation of state (EOS) model and measured oil and gas properties obtained from sampling at the wellhead. The wellstream composition is estimated daily in one of the following two ways: (1) if measured properties from field sampling are available, then regress to find a wellstream composition that matches all the measured oil and gas properties (e.g. stock-tank oil API, gas specific gravity, gas/oil ratio (GOR), and separator fluid compositions). (2) if measured properties from field sampling are not available, then flash the most-recent wellstream composition estimated from (1) and recombine the resulting oil and gas streams to match the producing GOR.

Multiple lab-scale HnP EOR experiments and associated results have been published earlier, but only limited amounts of compositional data have been presented. The results presented in this paper will help to improve the understanding of the ongoing mechanisms for the HnP EOR process. In turn, one can better optimize the injection and production strategies, ultimately leading to larger recoveries. The data and observations from the field project are presented in detail. The wellstream compositions before and after HnP implementation are shown and interpreted.

Introduction

In 2019 we reported (Carlsen et al. 2019) compositional tracking results for a gas HnP project in the *black oil area* of the Eagle Ford. This paper, hereby referred to as the original paper, studied the gas HnP process from three different perspectives: (i) fundamental phase behavior, (ii) compositional reservoir simulation, and (iii) field-scale performance monitoring. Notable conclusions and observations from that study were:

- The premise for uplift in a HnP process is a shattered volume (SV) containing rubble (small pieces of rock) that experience substantial mixing of the injection gas and reservoir fluid during a typical injection/soaking period (~15-45 days).
- The recovery efficiency from the SV is related directly with:
    a. Size distribution of the rubble, with smaller pieces yielding larger HnP incremental recoveries.
    b. The difference between *the pressure within the rubble* and *the saturation pressure of the fluid mixture within the rubble*, at the end of each injection/soaking cycle. The greater this pressure difference, the higher the efficiency.
- Multi-contact miscibility, and its associated MMPs, are *not* relevant for the gas HnP process.
- Reservoir simulation of a field HnP process requires a multi-stage modeling procedure that incorporates small-scale rubble-fracture phenomena that must be upscaled to well models.
- Compositional tracking of a HnP field project yields a wellstream "signature" reflecting different EOR recovery mechanisms. These different signatures can improve our understanding of recovery efficiency and uplift for a particular HnP project.

These conclusions have later been supported by Hawthorne et al. (2020), and Mydland et al. (2020). Hawthorne et al. presented experimental evidence for the importance of "rubble size" on recovery, using CO_2 as an injectant. The experiments showed that smaller pieces of rock resulted in the highest recovery efficiency, while the larger pieces resulted in the lowest recovery efficiency for the HnP process. Mydland et al., conducted a comprehensive reservoir simulation assessment of the gas HnP process, which on a general basis confirmed the observations made by Hawthorne et al. The simulation assessment incorporated all the gas HnP relevant physics, i.e. Darcy flow, molecular diffusion, and phase behavior.

In this paper, we will focus on a gas HnP field project in the *gas condensate area* (R_{si} ~3,000-5,000 scf/STB) of the Eagle Ford, i.e. a *leaner* in-situ reservoir fluid than the field example presented in the original paper (Carlsen et al. 2019). Throughout this paper we will refer to the two different project areas as the "black oil area" and the "gas condensate area". The gas condensate area contains mixtures close to the critical point, resulting in some parts of the area being defined as near-critical fluids.

Based on field observations, associated analyses, and interpretations, we will attempt to answer and discuss the following:

1. What are the (operational) characteristics of a successful gas HnP project?
2. How can field observations be used to enhance our understanding of the HnP process?
3. What do field observations tell us about the way the gas HnP process should be modeled? (reservoir simulation)?
4. What impact does different in-situ reservoir fluids have on the gas HnP recovery response?
5. How does the *gas condensate area* presented in this paper compare with the *black oil area* presented in the original paper?

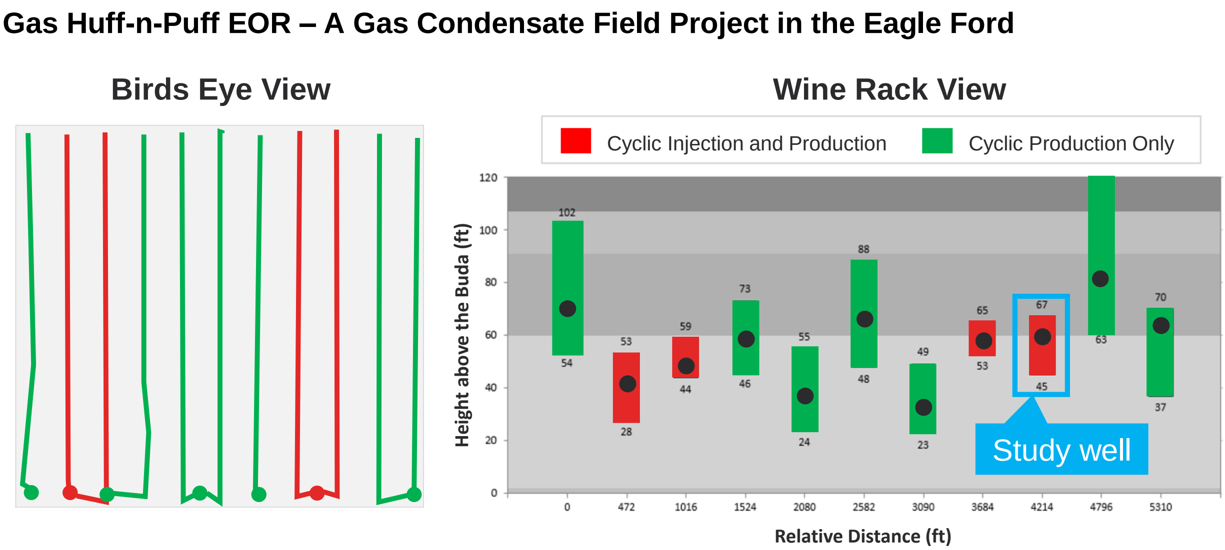

Fig. 1. Birds-eye view (left) and wine-rack view (right) of the gas HnP field project studied in this paper. Red color indicates wells that were subjected to cyclic injection and production (HnP), while green color indicates wells that were subjected to cyclic production (puff) only.

Project Area.

The HnP project studied in this paper involves a group of 11 wells configured such that four of the wells were subjected to cyclic injection and production (i.e. HnP), while the remaining seven wells were subjected to cyclic production (i.e. shut in during injection periods). The configuration is shown in **Fig. 1**.

Most of the wells came online in early 2015, and the HnP process started in late 2018 (i.e. a 3.5-year primary depletion period prior to HnP implementation). The first 15 injection periods lasted for 15-45 days, and average injection rates were 14-16 MMscf/D. Cumulative injected volume per cycle ranged from 200 to 600 MMscf. A "representative" injection-gas composition for this project is 75 mol% C_1, 13 mol% C_2, 5 mol% C_3, and 7 mol% C_{4+}, with some variation in time.

During the injection (huff) periods, gas was injected in one or two wells depending on the cycle. Because gas was observed in the neighboring producers during injection (well spacing approximately 500 ft), it was decided to shut in these wells while injecting to mitigate gas circulation within connected fractures and allow for pressure buildup. When the wells were put back on production (puff), increased oil production rates were observed (compared to the baseline forecast) in the four HnP wells and neighboring producers.

Study Well

As there is much data acquired from this project, we will focus our analysis on one of the HnP wells, i.e. the well highlighted in blue in Fig. 1 (the "Study well"). **Fig. 2** summarizes some key operational timeseries data from the study well during the gas HnP project. The data include production rates, pressures, and temperatures.

The measured cumulative oil production (top figure) shows incremental oil recovery compared with the forecasted depletion production, indicating that the HnP process yields additional oil recovery. The seemingly successful HnP implementation is further supported by the calculated EOR efficiency, $E_v = (N_p(t) - N_{p,f}(t))/G_i(t)$ which is ~15 STB/MMscf on average.

As seen in the second-to-top figure, the oil rate during the HnP process is substantially larger than pre implementation, with a near five-fold difference at the start of the production period. Interestingly, even though the water rate also increases compared with pre implementation, it does not increase as much as the oil rate.

Separator conditions change considerably through time. The separator pressure is kept at ~1100 psia, but it varies in the range from 200 to 1200 psia over shorter periods of time. Separator temperature ranges from 40 to 120 °F. During the injection period, the bottomhole-pressure response is rapid, indicating very good conformance. Maximum BHP is ~8000 psia, while minimum BHP is ~1000 psia. The maximum BHP seen in the study well during injection in its closest neighbor is ~4000 psia. The bottomhole temperature profile is mirroring the injection periods of the study well; lower bottomhole temperatures (T ~ 160-180 °F) during injection and higher bottomhole temperatures (T ~ 240 °F) during production.

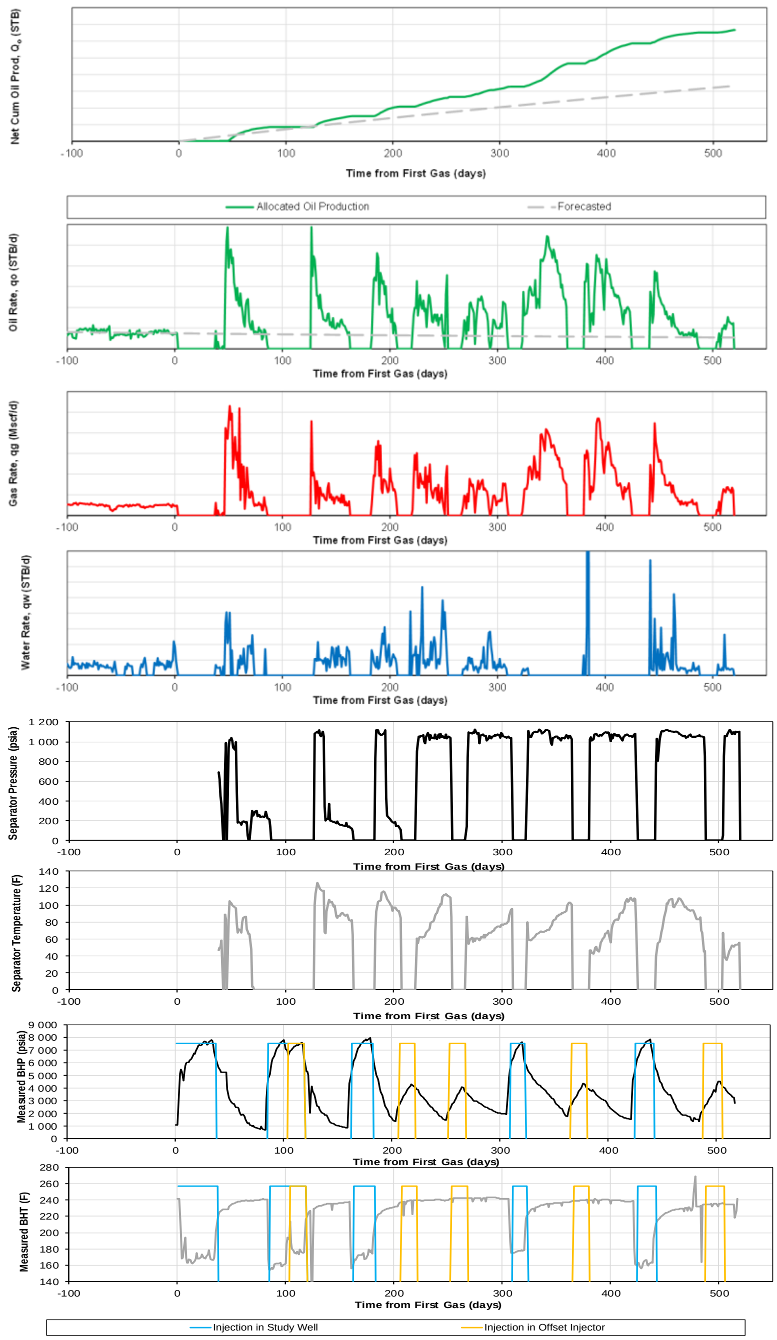

Fig. 2. Allocated oil, gas and water rates for the study well, together with temperature and pressure profiles at the separator and bottomhole. In the bottomhole pressure and temperature plots, it is also shown when the offset well was injecting.

Gas Huff-n-Puff EOR Field Observations—Analysis and Key Takeaways

Compositional Tracking

In this paper, *compositional tracking* refers to monitoring the produced wellstream compositions (z_i), separator compositions (x_i and y_i), and stock-tank liquid API over time. This can be achieved in two ways. The first option is to collect daily separator samples, send them to the lab, and *physically* recombine them to a wellstream composition with associated analyses (this is expensive, time-consuming, and impractical). The second option is to use a tuned EOS model, together with readily available production and sampling data, to *compute* daily wellstream compositions. The second option is used in this study.

Methodology

A basin-wide EOS model tuned to a large set of PVT experiments covering the whole spectrum of fluids produced in the Eagle Ford (GORs from 300 to 200,000 scf/sep.bbl) has been used. The different methodologies of predicting daily wellstream compositions are summarized by Carlsen et al. (2020). In short, the wellstream composition is estimated in either of the following ways, for a given day, depending on the data available for that day:

1. **Fluid Sampling Data is Available (Whitson & Sunjerga, 2012):** Regress to find a wellstream composition that matches all the measured oil and gas properties, e.g. stock-tank oil API, gas specific gravity, GOR, and separator-fluid compositions. The regression is performed by adjusting; (i) the molar gas fraction of the wellstream, f_g; (ii) the wellstream composition of lighter components (C_1-C_6, H_2S, CO_2 and N_2); and (iii) the average molecular weight of heavier components, i.e. the C_{7+} fraction. The EOS-model component properties and binary interaction parameters (BIPs) remain unchanged through this regression.
2. **Only Production Data is Available (Hoda & Whitson, 2013):** Flash the most-recent wellstream ("feed stream") composition estimated from (1), and recombine the resulting oil and gas streams to match the producing GOR.

This will result in wellstream compositions that honor all daily measured production data.

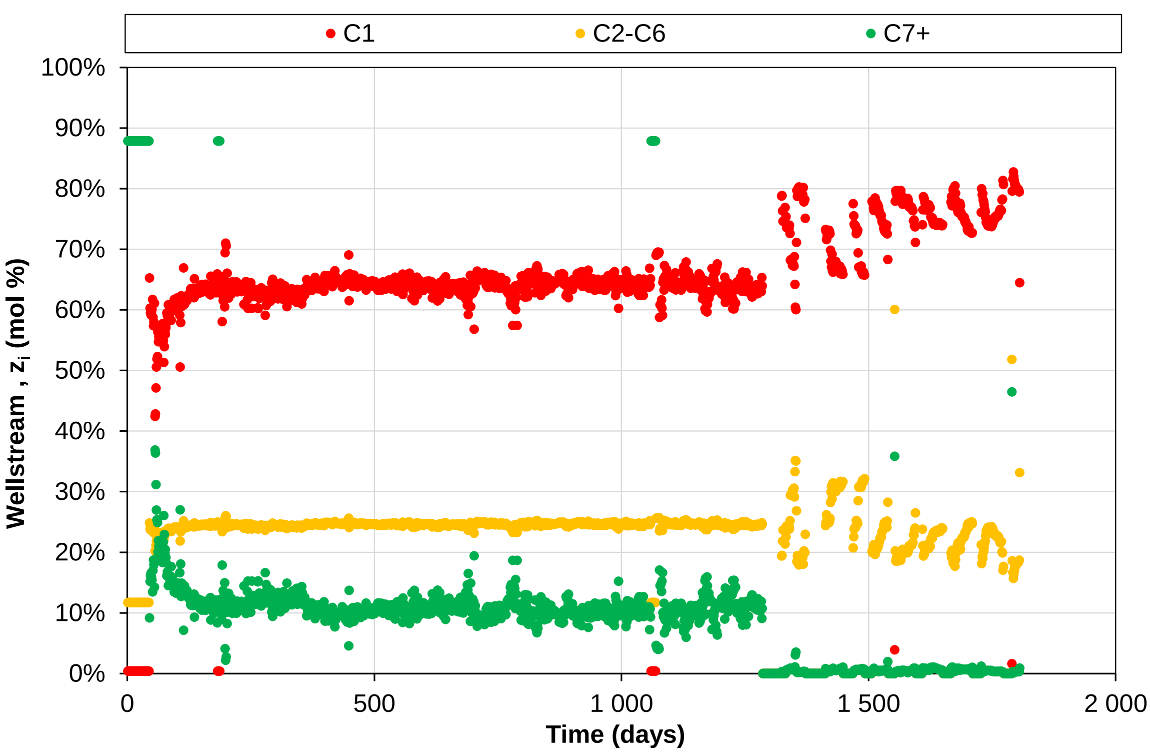

Fig. 3: Wellstream compositions versus time for the "Study Well" both pre and post gas HnP implementation

Characteristics of HnP Produced Wellstreams—Field Observations

The production and fluid sampling data were successfully used to predict daily wellstream compositions for the study well that was subjected to cyclic gas injection. **Fig. 3** shows the variation over time for C_1, C_2-C_6 (grouped together), and C_{7+} in the measured wellstream composition. One can clearly see the compositional differences before and after gas HnP was implemented. Before implementation, the C_1 content of the wellstream was ~65 mol%, the C_2-C_6 content was ~25 mol%, while C_{7+} amounted to ~10 mol%. After implementation, the C_1 content of the wellstream varied between 65-80 mol%, the C_2-C_6 content varied between 15-30 mol% and the C_{7+} content varied between 0.25-1 mol%. The large time-variations observed for the producing wellstream composition underlines the compositional sensitivity of the gas HnP process. It is worth noting that the compositional changes observed in a single HnP production period are larger than the compositional changes observed over the entire primary-depletion period. The general trends over time for the wellstream composition show *increasing* C_1 amount, *decreasing* C_2-C_6 amount, and an inconclusive trend for the C_{7+} amount.

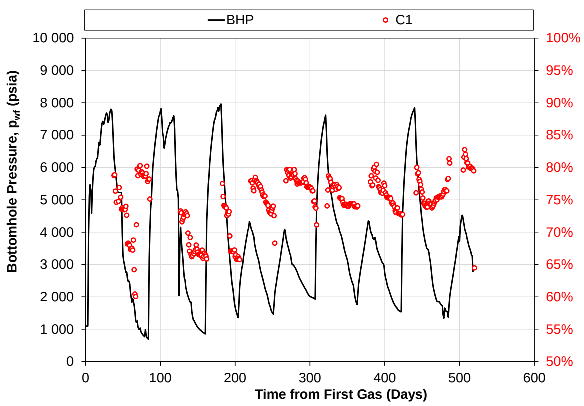

Fig. 4a. Wellstream C_1 versus time.

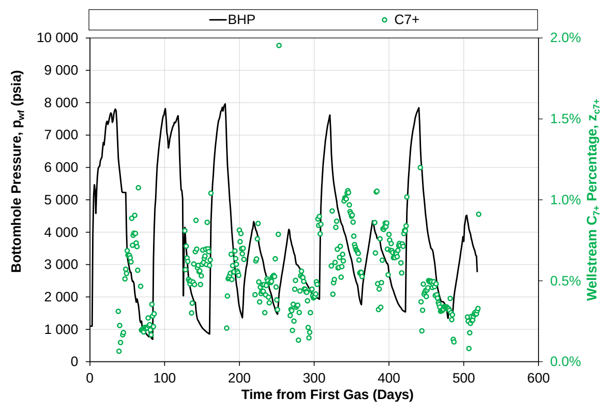

Fig. 4b. Wellstream C_{7+} versus time.

A Mix of Injected Gas & Reservoir Fluid

Fig. 4 shows a "zoomed-in" view of the predicted C_1 and C_{7+} wellstream composition versus time for the gas HnP well. One key observation from this figure is that the produced gas at the very early part of the production period is not just the injected gas, which contains less than 0.2 mol% C_{7+}, but a mix of the injected gas and reservoir fluid, resulting in a wellstream C_{7+} content of ~0.5-1 mol%. Attaining an increased amount of C_{7+} components in the returning wellstream (i.e. enrichment of the injection-gas composition) is *the* main premise for increased oil recovery by the HnP process, as these heavier components turn into stock-tank oil when the wellstream is processed at the surface.

Gas Condensate Area Versus Black Oil Area

For comparison, the *black oil area* presented in the original paper yielded a wellstream C_{7+} content of ~2% during the production cycles. The fact that the C_{7+} content from the production period in this *gas condensate area* is lower than the *black oil area* is not an indication of a less efficient recovery process; it is an expected result. An area with a low initial oil formation volume factor (B_{oi}<2) [i.e. low solution GOR (R_{si}<1000)] has a larger target for EOR, and consequently a higher EOR efficiency, than an area with a high initial oil formation volume factor. On a general basis, for the same hydrocarbon pore volume (HCPV), the recovery efficiency (E_v) varies from highest to lowest going from an oil reservoir to a gas reservoir (which intuitively makes sense as you would not perform enhanced *oil* recovery in a (dry) *gas* reservoir). The variation in E_v is exemplified in **Fig. 5**, which shows the simulation of the gas HnP PVT experiment presented by Carlsen et al. (2019) for different reservoir fluids, keeping everything else the same. This result is supported by the difference in C_{7+} amount in the producing wellstream composition when comparing the *black oil area* and the *gas condensate area.*

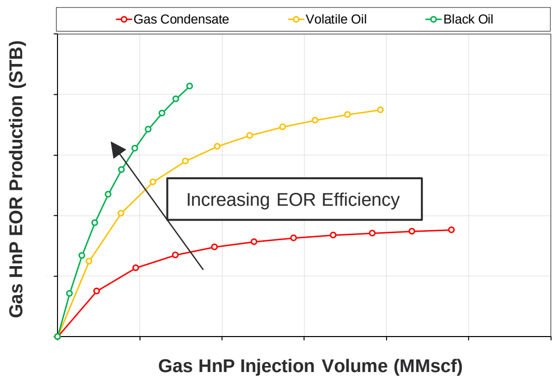

Fig. 5. Impact of In-situ Reservoir Fluids on the gas HnP recovery. Results from simulating the Gas HnP PVT experiment (Carlsen et al. 2019) for different in-situ reservoir fluids, from black oil to gas condensate. The Gas HnP recovery efficiency.

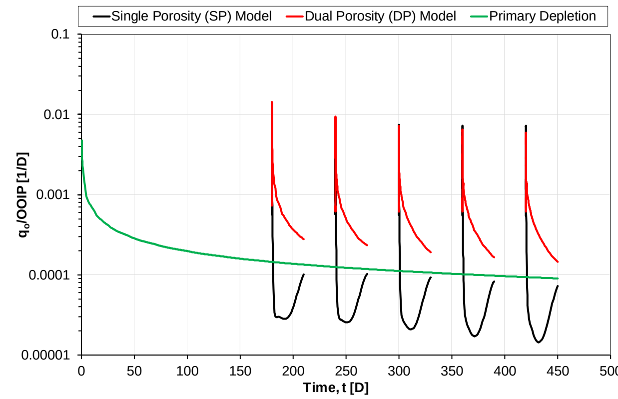

Fig. 6. Gas HnP performance (*q_o/OOIP)* comparison of a dual porosity (DP) simulation model and a single porosity (SP) simulation model. Note how the SP model yields no additional recovery, while the DP model yields significant uplift (Carlsen et al. 2019)

Signature of an *Efficient* Gas HnP Process

Most of the production periods observed in this field exhibits decreasing wellstream C_{7+} behavior in tandem with decreasing bottomhole pressure, indicating an efficient gas HnP scheme. The EOR recovery efficiency is at its highest in the beginning of each production period and decreases throughout the period with decreasing C_{7+}. Such behavior for the efficiency is comparable to what is observed in the HnP PVT experiment presented in the original paper. It is also consistent with the production period response obtained from reservoir simulation of the HnP using a dual porosity (DP) model, as shown in **Fig. 6**. The dual-porosity model has an inherent assumption of full mixing in the matrix block. This is equivalent to assuming the rock pieces in the shattered volume sufficiently small such that the mixing process of injection gas and reservoir fluid, a process mainly driven by diffusion, results in full/complete mixing in the duration of the injection and/or soak period(s) (Mydland et al. 2020).

Signature of an *Inefficient* Gas HnP Process

Interestingly, the gas HnP signature of a process that yields no incremental recovery exhibits the exact opposite of what is observed in this project; wellstream C_{7+} increasing throughout the puff period starting with C_{7+} content equal to injection-gas composition, and increasing to approximately the same C_{7+} amount of the pre implementation wellstream. This is the signature of a "piston-like" displacement process. From a reservoir simulation perspective, this is achieved by the classical "planar fracture model"[1] using a single porosity (SP) model. The flowback from such a response is exemplified in Fig. 6. Mydland et al. (2020) provide a more comprehensive comparison of the dual-porosity- and single-porosity-modeling approaches.

Reality Versus Reservoir Simulation

By comparing the production period response from an actual field project, as given in Fig. 2, with the simulated flowback responses given in Fig. 6, it is observed that the dual porosity representation is clearly the most consistent with field observations. This suggest that substantial amounts of surface area ("shattering") has been generated as a result of completion, which is key for uplift from the gas HnP scheme. These conclusions are largely supported by the field observations made by ConocoPhillips in the Eagle Ford (Raterman et al. 2017, 2019) and the Hydraulic Fracture Test Site data (Gale et al. 2018) acquired from the Wolfcamp Formation in the Midland Basin.

[1] Planar fracture model: a highly conductive fracture surrounded by a "slab of rock" (single porosity matrix)

Incorporation of the Dual Porosity Model

It is important to note that if a DP region is used in a reservoir simulation model, it should, in its most rigorous implementation, match the behavior of an equivalent SP model to ensure physically consistent results (Coats, 1989). To achieve such a match for the DP model, one can follow the procedure outlined by Mydland et al. (2020): Perform simulations of the HnP process on rubble pieces in the SV using a SP model in which molecular diffusion is included. The results of this modeling should be used to tune the performance of the DP region in full-field model.

Gas HnP & Reservoir Temperature

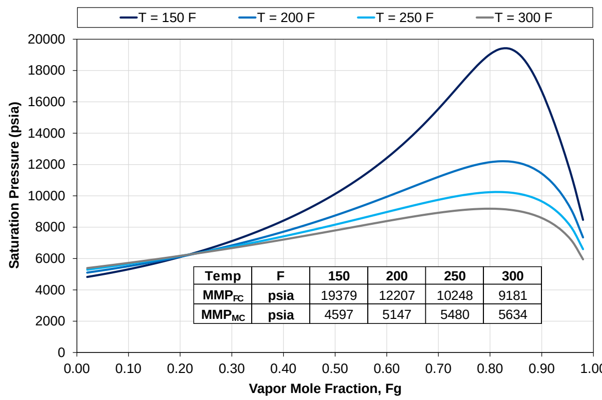

Fig. 7a. *Hydrocarbon injection gas* - Example of how temperature effects minimum miscibility pressure by first contact (i.e. max pressure on the swell test curve) for a Eagle Ford reservoir fluid and a hydrocarbon injection gas.

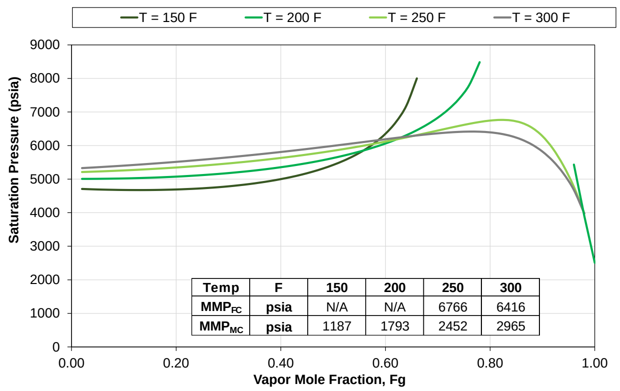

Fig. 7b. *CO_2 injection gas* - Example of how temperature effects minimum miscibility pressure by first contact (i.e. max pressure on the swell test curve) for a Eagle Ford reservoir fluid and a CO_2 injectant.

Higher temperature is generally positive for the gas HnP process. In a conventional displacement process, in which *multi-contact miscibility* is relevant, the multi-contact MMP (MMP_{MC}) is *proportional* to temperature. In other words, higher temperature yields higher MMP by *multi-contact*. For the gas HnP process, on the other hand, in which *first-contact miscibility* is relevant, the first-contact MMP (MMP_{FC}) is *inversely proportional* to temperature. In other words, higher temperature, yields lower MMP by *first-contact*. **Fig. 7** shows multiple computed swell tests at different temperatures for an Eagle Ford reservoir fluid using either an HC (Fig. 7a), or CO_2 (Fig. 7b) as injection gas. The MMP_{FC} and MMP_{MC} are presented as table values in the figures for comparison purposes. By definition, the MMP by first contact is the maximum pressure on a swell test curve, and as seen from Fig. 7, the MMP by first contact decreases with increasing temperature. The reservoir-fluid and injection-gas compositions are kept the same in all the simulated experiments. Fig. 7b also highlights another interesting phenomenon in which the swell test does not close when performing the experiment at T = 150 °F and T = 200 °F. This implies that there does not exist a first-contact MMP for the fluid system at that temperature. Examples of this phenomenon for swell tests conducted in the lab can be found in Whitson and Brulé (2000). Increasing the temperature can, to some extent, have a positive effect on the main process that causes mixing for the HnP process, namely molecular diffusion.

Operational Learnings[2]

If there are geological, petrophysical, and/or geomechanical aspects that suggest better gas containment for a certain area before HnP implementation then this information should be given considerable weight when deciding on a field project area. Subsurface communication between wells during injection should be expected, but it is not necessarily a negative thing, as the communication will also have a positive production impact in wells that are not subjected to gas injection. Higher fracture gradients are good in general, as this allows for higher bottomhole pressures, which in turn increases the probability of the reservoir fluid mixture being single phase for a larger duration of the production period (higher recovery efficiency). Infill drilling in the proximity of the project field should be avoided as such operations (especially the hydraulic fracturing part) can have a negative impact on the quality of the final project assessment. Continuous acreage around the project area (i.e. own the neighboring land) is beneficial as "leak-off" gas is then produced back within the company's acreage. In our opinion, the operational characteristics of a successful gas HnP project, as the example presented in this paper, are

1. large injection volumes,
2. rapid and large pressure buildup (good conformance),
3. wells with modern completions (large, complex surface area created during completion).

Summary

1. **Field Observations:** The wellstreams produced during the HnP flowback (production period) suggest that the produced fluids are a mix of the injected gas and the reservoir oil. Attaining an increased amount of C_{7+} components in the returning wellstream (i.e. enrichment of the injection-gas composition) is *the* main premise for increased oil recovery by the HnP process, as these heavier components turn into stock-tank oil when the wellstream is processed at the surface.
2. **Reservoir Simulation:** HnP-production-period results observed in the field suggest that a dual porosity region, or an equivalent single porosity representation with large surface area incorporation diffusion, must be included in the reservoir simulation model to replicate field production responses.
3. **Gas HnP and In-Situ Reservoir Fluids:** In general, gas HnP in a *black oil area* yields larger oil recovery in absolute numbers than in a *gas condensate area*. For the same HCPV, *black oil areas* have a larger EOR target, and consequently a higher recovery efficiency (assuming the same injection gas, and maximum and minimum pressures).
4. **Gas HnP & Reservoir Temperature:** In general, a higher reservoir temperature is positive for the gas HnP process as it i) *decreases* the MMP by first-contact, and ii) *increases* the rate of diffusion. This is the opposite effect of temperature on a conventional displacement process, in which higher reservoir temperature results in a higher multi-contact MMP.

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[2] This section covers opinions and recommendations from the authors based on field experience, some of which are not supported by arguments or evidence in this paper. We encourage the reader to digest this information accordingly.

Nomenclature

B_o	= oil formation volume factor (FVF), res.bbl/STB
API	= stock-tank liquid API
GOR	= gas/oil ratio, scf/STB
MMP	= minimum miscibility pressure, psia
MMP_{FC}	= first-contact minimum miscibility pressure, psia
r_s	= solution CGR, STB/MMscf
R_s	= solution GOR, scf/STB
x_i	= separator oil composition, mol%
y_i	= separator gas composition, mol%
z_i	= wellstream composition, mol%
E_v	= EOR efficiency (incremental produced STB / MMscf of gas injected), STB/MMscf

Acknowledgments

The authors want to thank the management at EP Energy for permission to publish this paper. We would also like to thank Innovation Norway for providing funding to develop this technology.

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