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Black-Oil and Compositional Reservoir Simulation of Gas-Based EOR in Tight Unconventionals

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Abstract

High pressure gas-based enhanced oil recovery (EOR) may involve miscible processes with nearcritical phase behavior. This is often the case for unconventionals, in which the injection pressure may be much higher than the minimum miscibility pressure. Despite the existence of near-critical phase behavior, black-oil PVT (BOPVT) are still used in reservoir simulation, often without validating the results with compositional (COMP) reservoir simulation. Long simulation runtimes associated with the COMP model, and sometimes the lack of an appropriate equation-of-state (EOS), are both reasons for using BOPVT tables instead.

This paper compares the performance of the BOPVT and COMP models in reservoir simulation for two gas-based EOR processes in tight unconventional reservoirs, namely Huff-n-Puff (HnP) and Fracture-to-Fracture (F2F). We also give considerable attention to an important related topic to this fluid-model comparison; the creation of appropriate BOPVT tables using a valid EOS model.

In our study, we use a tuned, basin-wide EOS model of Eagle Ford fluids, both for the compositional reservoir simulations and for creating BOPVT tables. We study a wide range of reservoir fluids (black oil, volatile oil, near-critical oil, near-critical gas condensate, and medium-rich gas condensate), along with a range of relevant hydrocarbon injection gases (lean processed gas with 91 mol% C_1 , primary separator gas with 71 mol% C_1 , and an ethane-rich gas with 53 mol% C_1). Furthermore, we assess various in-situ fluid conditions including a two-layer model with one layer containing oil and the other layer containing gas condensate, and another single-layer system that is initially two phases with equal gas and oil saturations throughout.

We find that reservoir simulation of the HnP process requires a COMP model because of complex two-phase behavior that is a strong function of composition and pressure—with both composition

and pressure showing large variations within the target EOR volume during the HnP cycles. A conventional BOPVT table does not describe this complex fluid behavior with sufficient accuracy; reservoir simulation with the BOPVT model consistently overestimate oil recovery for the HnP process.

For a displacement-based process involving injection in some fractures and production from neighboring fractures (F2F), high injection pressures lead to a displacement front that will usually develop and maintain miscibility. We find that use of the BOPVT model in reservoir simulation of the F2F process is valid for oil reservoirs, but less so for gas reservoirs.

A key finding of this study is that any gas-based recovery process relying on vaporization cannot be modeled with a conventional, nor extrapolated, BOPVT model. This is simply because the solution oil-gas ratio (OGR | r_s) remains constant (at a given pressure) throughout the EOR process for the BOPVT model, where in reality the solution OGR should decrease as the vaporized oil becomes heavier. Modifications of the BOPVT model that allow for change in the $r_s(p)$ curve over time (i.e. capturing the effect of changing oil properties) can improve the ability to model accurately such vaporization-dominant processes. We illustrate one such method.

Introduction

Reservoir simulation is a useful tool to understand the mechanisms, and to predict the performance, of gas-based enhanced oil recovery (EOR) in tight unconventionals. It allows engineers to quantitatively evaluate a particular EOR method through a simple "if this, what then" type study, and/or through more intricate optimization algorithms. Models of tight unconventional reservoirs are often focusing on capturing the fracture complexity in the reservoir caused by the intensive hydraulic-fracturing process. This can lead to large field models with complex numerical gridding, which may force the engineer to compromise on other aspects of the reservoir model, for example the fluid model, due to excessive runtimes.

The BOPVT and EOS-based¹ COMP models have been the standard fluid models in reservoirsimulation packages since the early 1980's. The BOPVT model is based on table values of the volumetric behavior (B_o , B_{gd} , R_s , r_s , etc.) for the oil and gas phases as a function of pressure (p). The COMP model uses the phase molar composition(s) provided by the flash calculation (z_i or x_i and y_i), along with pressure (p) and temperature (T), to get the volumetric behavior.

The flow equations in most reservoir simulators are posed the same way for the two fluid models, with the main difference being the number of components. The BOPVT model has two "components", oil and gas, whereas the COMP model has a number of components (typically 8-12) defined by the component slate of the EOS. The mathematical description of how the fluid properties are included in reservoir simulation are well described elsewhere (Coats 1980, Coats et al. 1998).

Reservoir simulation of EOR may involve more complex phase behavior compared to primary recovery (pressure depletion). Thus, using the BOPVT model should not be assumed sufficient, but rather validated against results from using the COMP model. Studies on BOPVT versus COMP for EOR processes in conventionals (Coats 1985, Fevang and Whitson 1996, El-Banbi et al. 2000, Fevang et al. 2000) show that the COMP model is always preferred, but for some cases can be

¹ We write "EOS-based" here to distinguish it from the less-commonly used compositional treatment based on K-value tables.

replaced by the BOPVT model, like for example gas cycling above the dewpoint, miscible displacement when the average reservoir pressure is much greater than the first-contact minimum miscibility pressure, and constant-pressure miscible displacement (e.g. slimtube modeling). The authors are not aware of any such comparison-study for gas-based EOR in unconventionals, hence this paper.

A quantitative study on the relative impact of different recovery mechanisms for the HnP process has been performed by Hoffman and Reichhardt (2019). They argue that the BOPVT model is more versatile than the COMP model in reservoir simulation when studying the relative impact of vaporization, swelling, and viscosity reduction. Unfortunately, the authors do not mention, nor show, a quantitative comparison of the BOPVT and COMP models.

Phase Behavior for Gas-Based Enhanced Oil Recovery

The phase behavior of, and mechanisms associated with, gas-based EOR for unconventionals are studied in the detail by Carlsen, Whitson, Dahouk, et al. (2019), and Mydland et al. (2020). We will only revisit the main points here.

The Huff-n-Puff EOR Process

This cyclic EOR process relies on mixing of the injection gas (IG) and reservoir fluid (oil and/or gas) in the near-fracture part of the reservoir. The incremental recovery from HnP is a strong function of the following:

- 1. <u>Shattering/rubblization of the fractured region:</u> The hydraulic-fracturing process is thought to shatter/rubblize the matrix in some areal extent around the hydraulic fracture. This may result in pieces of rock that have a sufficiently small minimum dimension such that the injection gas is able to permeate the rock and extensively mix with the reservoir fluid during the injection (and sometimes shut-in/soak) period(s), a process driven mainly by molecular diffusion (component dispersion).
- 2. <u>The phase behavior of mixing the injection gas and reservoir fluid:</u> The HnP recovery efficiency in each production period (puff) can be expressed by the efficiency function defined as:

$$\eta(t) = \min\left\{1, \ \frac{p_{m,SV}(t_{ep}) - p_s(t_{eh})}{p_{m,SV}(t_{ep}) - p_{m,SV}(t)}\right\},\dots(1)$$

A value of 1 indicates first-contact miscible mixing during injection, and subsequently constant-compositional removal during production (most efficient). A value of 0 indicates two phases at all times, resulting in production of oil by pure vaporization (least efficient). A value between 0 and 1 indicates a combination of the two. The cycle efficiency at the end of a production period ($t = t_{ep}$) can be estimated by performing a constant-volume-injection/constant-volume-depletion experiment (CVI/CVD).

3. <u>Gas containment (conformance)</u>: To achieve pressure buildup during the injection period, the injection gas cannot leak off in large quantities. The reasons for gas leakoff can be numerous, but fractures that short circuit the gas flow to neighboring wells is probably the most common.

The Fracture-to-Fracture EOR Process

This cyclic EOR process relies on miscible displacement of the reservoir oil by the injection gas, a recovery process well-known to be highly efficient from projects in conventionals [the most famous example is the Prudhoe Bay Miscible Gas Project (McGuire et al. 1999)]. The target volume for the F2F is potentially much larger than that of the HnP process (depending on the extent of shattering). However, the F2F process has yet to show any success in unconventionals.

The performance of the F2F process is mainly controlled by the fracture spacing (i.e. the displacement distance), and the matrix permeability (i.e. the resistance to flow through the matrix). A large fracture spacing (>50ft), and a low matrix permeability (<100nd), would result in a long period of time with cyclic gas injection without any uplift in oil production. Smaller fracture spacing and higher matrix permeability will both yield faster recovery and a shorter period of cyclic gas injection (assuming everything else the same) before EOR "uplift" is observed.

Reservoir Simulation Using Black-Oil PVT and Compositional Models

The reservoir simulation of the EOR processes will be performed in two parts. First, we model the HnP process on a single dual-porosity (DP) cell pair (i.e. one matrix and one fracture cell), using both fluid models, to understand the details of the phase behavior in the target volume for the HnP process. Second, we model the HnP and F2F processes on well scale for a variety of fluid systems to show how the two fluid models compare in their predictions of the relevant phase behavior.

Reservoir-Model Gridding and Properties

The well-scale model used in this study is a planar-fracture, symmetry-element, 1D model. The reason for such a simple model is to isolate the fluid effects of the EOR modeling. Including reservoir heterogeneity (i.e. 2D and 3D gridding) will normally require a large number of grid blocks to eliminate the numerical dispersion when modeling miscible gas processes (Jessen et al. 2004, Coats et al. 2009). We found it impractical to do modeling with that level of detail as we study a number of different cases. Also, if the two fluid models differ much in their predictions for such a simple reservoir model, then there is no reason to believe otherwise for more-complex reservoir models.

Fig. 1 shows the full well model at the top, and the corresponding symmetry-element model at the bottom. The blue region represents the shattered volume (SV) of rock (DP region), and the light grey represents the matrix (SP region). The numerical gridding of the bottom model in Fig. 1 is shown in **Fig. 2.** The reservoir-model properties are given in **Table 1**.

The scheduling for the two EOR process is using the constraints found in Table 1 for rates and pressures, but the duration of injection and production periods in each cycle are determined differently. For the HnP process, we determine the duration of the periods by injecting and producing at a constant rate until reaching the maximum or minimum bottomhole pressure (BHP) constraint, respectively. When a BHP constraint is reached, we revert to production or injection immediately (i.e. no shut-in periods between huff and puffs). For the F2F process, we determine the period durations by a more-delicate approach that considers for the frontal pressure (p_{fr}) and its relation to the minimum miscibility pressure (MMP). The details of this will be explained later.

The "single-cell" model in this study is a single dual-porosity block consisting of matrix blocks and surrounding fractures [i.e. the "sugar-cube" model by Warren and Root (1963)]. Numerically, this "sugar-cube" model is represented by a pair of grid blocks, one for the matrix blocks and one for the surrounding fractures. The well is connected to the fracture grid block. In Fig. 2, the "single-cell" model would represent the first matrix-fracture pair from either the left or right side. The cases presented for the single-cell model were not performed using the scheduling data in Table 1. Instead, it was put on BHP control for the entire simulation (pressure depletion and HnP). The BHP profile for these simulations is given in **Fig. 3**.

All reservoir-simulation results presented in this paper were obtained using Sensor (Coats Engineering), with the fully-implicit formulation activated.



Fig. 1—Well model (top) and corresponding symmetry-element model (bottom)

| Property | Value | Unit |
|------------------------------------------------------------------------------|-----------|---------------------|
| Model Dimensions and Gridding: | | |
| Number of Cells in x-Direction in DP Region, $N_{x,DP}$ | 10 | |
| Number of Cells in x-Direction in SP Region, $N_{x,SP}$ | 8000 | |
| Number of Cells in y-direction, N_y | 1 | |
| Number of Cells in z-direction (Numerical Layers), N_z | 2 | |
| Fracture Half Length, x_f | 300 | ft |
| Reservoir-Half-Length/Fracture-Half-Length Ratio, x_e/x_f | 1 | |
| Fracture Spacing, $2y_e$ | 50 | ft |
| Shattered Volume Extent, y_{SV} | 5 | ft |
| Fracture (=Reservoir) Height, <i>h</i> | 150 | ft G |
| Depth to 10p of Reservoir, D_R | 10000 | Π main |
| lintial Reservoir Pressure, p_R | 9000 | psia |
| Matrix: | | |
| Permeability, k_m | 0.1 | μd |
| Porosity, φ_m | 0.0005 | |
| Initial Water Saturation, S _{wi} | 0.2 | |
| Connate Water Saturation, S_{wc} | 0.2 | |
| Residual Oil Saturation to Water, Sorw | 0.3 | |
| Residual Oil Saturation to Gas, Sorg | 0.4 | |
| Critical Gas Saturation, S_{gc} | 0.05 | |
| Water End-Point Relative Permeability at Residual Oil Saturation, k_{rwro} | 1.0 | |
| Gas End-Point Relative Permeability at Residual Oil Saturation, k_{rgro} | 1.0 | |
| Oil End-Point Relative Permeability at Connate Water Saturation, k_{rocw} | 1.0 | |
| Water Corey Exponent, n_w | 4.0 | |
| Oil Corey Exponent in Oil-Water System, n_{ow} | 3.0 | |
| Oil Corey Exponent in Oil-Gas System, <i>n</i> _{og} | 3.0 | |
| Gas Corey Exponent, n_g | 4.0 | |
| Fracture: | | |
| Permeability, k_f | 100 | ud |
| Porosity, φ_f | 0.05 | • |
| Initial Water Saturation | 1.0 | |
| Connate Water Saturation, S_{wc} | 0.0 | |
| Residual Oil Saturation to Water, Sorw | 0.0 | |
| Residual Oil Saturation to Gas, Sorg | 0.0 | |
| Critical Gas Saturation, S_{gc} | 0.0 | |
| Water End-Point Relative Permeability at Residual Oil Saturation, k_{rwro} | 1.0 | |
| Gas End-Point Relative Permeability at Residual Oil Saturation, k_{rgro} | 1.0 | |
| Oil End-Point Relative Permeability at Connate Water Saturation, k_{rocw} | 1.0 | |
| Water Corey Exponent, n_w | 1.0 | |
| Oil Corey Exponent in Oil-Water System, n_{ow} | 1.0 | |
| Oil Corey Exponent in Oil-Gas System, n_{og} | 1.0 | |
| Gas Corey Exponent, n_g | 1.0 | |
| Other: | | |
| Matrix-Block Size in x-Direction in DP Matrix Cell, L_x | 1 | ft |
| Matrix-Block Size in y-Direction in DP Matrix Cell, L_y | 5 | ft |
| Matrix-Block Size in z-Direction in DP Matrix Cell, L_z | 150 | ft |
| Water Compressibility, c_w | 3e-6 | 1/psi |
| Water Density, ρ_w | 62.4 | lbm/ft ³ |
| Water Viscosity, μ_w | 0.5 | ср |
| Rock Compressibility, <i>c</i> _r | 4e-6 | 1/psi |
| Scheduling | | |
| No. of Fractures per Well | 200 | |
| Maximum Oil Production Rate <i>a</i> | 3000 | STB/D |
| Maximum Gas Production Rate a | 20 | MMscf/D |
| Minimum Flowing Bottomhole Pressure p | 1500 | nsia |
| Maximum Gas Injection Rate. q_{ajmax} | 20 | MMscf/D |
| Maximum Flowing Bottomhole Pressure. nime | 10000 | psia |
| Well Productivity Index, PI | 10.15 | rb-cp/(D-psi) |
| Pressure Depletion Time Period, t_{dp} | 730 | days |
| Total Simulation Time (Case Dependent), t _{end} | 3000-3600 | days |

Table 1—Properties used in reservoir simulation



Fig. 2-Numerical gridding/structure of the symmetry-element model



Fig. 3—Bottomhole pressure profile used to control the well for the single-cell modeling

Fluid Model and Method of Generating Black-Oil Tables

An 11-pseudo-component EOS (EOS11) has been developed by lumping a field-wide Eagle-Ford EOS (Alavian et al. 2014, Younus et al. 2019), along with five different fluid compositions, a black oil (BO), a volatile oil (VO), a near-critical oil (NCO), a near-critical gas condensate (NCGC), and a gas condensate (GC). Three injection gases have also been made, a lean processed gas (Lean Processed), a primary separator gas (Separator), and an ethane-rich processed gas (C2-Enriched). The EOS11 and fluid compositions are given in **Tables 2 and 3.** The C2-enriched injection gas in Table 3 is used by default unless stated otherwise. The PVT-simulation package PhazeComp (Zick Technologies) was used to do all fluid calculations.

To achieve an "apple-to-apple" comparison of the BOPVT and COMP models for a specific fluid system, we need to ensure that the fluid models are consistent, and that the simulations are initialized with identical fluid properties. Thus, we use the EOS11 for both the COMP model, and to create the BOPVT tables.

The BOPVT tables consist of two parts, hereby referred to as the lower and upper parts, that are generated separately. The two parts are subsequently "spliced" together, in which all undersaturated properties are calculated for the set of pressures to complete the BOPVT table. The

short-version of obtaining the saturated properties are as follows (detailed explanation in Appendix A):

- 1. <u>Lower BOPVT Table</u>: Perform a constant-composition-expansion (CCE) experiment on the initial reservoir fluid composition $[(z_i)_{Ri}]$; starting at a maximum pressure going down to some lower pressure in increments, in which the initial saturation pressure (p_{si}) is one of the pressure steps. At each pressure, store either the total composition (if single phase), or the equilibrium vapor (EQV) and equilibrium liquid (EQL) compositions (if two phases), and process these through the separator train to get the BOPVT properties [The definitions of the BOPVT properties can be found in Whitson and Brulé (2000)]
- 2. <u>Upper BOPVT Table:</u> Perform a saturation pressure calculation of the initial fluid and store the resulting EQL. Swell the EQL $[(x_i)_{Ri}]$ by mixing it with an injection-gas composition $[(y_i)_{IG}]$ in increments until reaching a critical mixture ($K_i = 1$). At each injection increment, perform a CCE experiment that starts at the same maximum pressure as in 1 and ends at the saturation pressure of the initial fluid, where the saturation pressure of the current cell mixture is one of the pressure steps.

The common procedure for generating BOPVT tables is to only generate the lower part. However, this may leave out a large range of gas/oil ratios (GORs) that can cause instability when modeling gas-based EOR processes. **Fig. 4** shows the plot of the solution GOR (R_s) and inverse solution OGR ($1/r_s$) as a function of the saturation pressure (p_s) for the BO. The solid lines with circles indicate the lower part of the BOPVT table, and the dashed lines with circles indicate the upper part. We see that the lower part of the BOPVT table is missing the range from 500 to ~36350 scf/STB. The grid cells in the reservoir model will likely experience GORs within the missing range during a gas-injection process. Therefore, we "close" the GOR range by swelling the initial reservoir fluid to a critical mixture (critical GOR), in this case by using the injection-gas composition, to get a stable model behavior and supposedly better fluid description during the EOR period.



Fig. 4—Solution gas/oil ratio and inverse solution oil/gas ratio versus saturation pressure for the BO fluid system

| Componer | nt Molecu | ılar Cri | tical | Critical | Critical Z- | | · Acentric | | ic Volume | | Parachor | $\Omega_{\mathrm{a}}{}^{0}$ | $\Omega_{ m b}{}^0$ |
|-------------------------------------------------------------------------------------------------------|-----------------|----------|----------|-----------|-------------|---------|------------|------------------|-------------|---------|----------|-----------------------------|---------------------|
| | Weig | ht Pres | ssure Te | mperature | factor for | | · F | Factor | | Shift | | | |
| | Visc. Corr. | | | | | | | | | | | | |
| (-) | (-) (psia) (°R) | | (-) | (-) (-) | | | (-) | (-) | (-) | (-) | | | |
| N2 | 28.01 | 4 492 | 2.84 | 227.16 | | 0.29178 | 0.03700 | |) -0 | .16758 | 59.10 | 0.457236 | 0.0777961 |
| CO2 | 44.01 | 106 | 9.51 | 547.42 | | 0.27433 | 0. | 0.22500 | | 00191 | 80.00 | 0.457236 | 0.0777961 |
| H2S | 34.08 | 32 129 | 9.97 | 672.12 | | 0.28292 | 0. | 0.09000 | | .04470 | 80.10 | 0.457236 | 0.0777961 |
| C1 | 16.04 | 13 667 | 7.03 | 343.01 | | 0.28620 | 0. | 0.01100 | | .14996 | 71.00 | 0.457236 | 0.0777961 |
| C2 | 30.07 | 70 706 | 5.62 | 549.58 | | 0.27924 | 0. | 0.09900 -0.06280 | | .06280 | 111.00 | 0.457236 | 0.0777961 |
| C3N-C5 | 54.08 | 39 560 |).75 | 730.95 | | 0.27465 | 0. | 18452 | 2 -0 | .05535 | 178.97 | 0.457236 | 0.0777961 |
| C6C8 | 96.72 | 21 464 | 4.54 | 993.39 | | 0.26498 | 0. | 27372 | 2 -0 | .00741 | 267.31 | 0.457236 | 0.0777961 |
| C9C12 | 138.1 | 60 359 | 9.66 | 1137.99 | | 0.25397 | 0. | 40076 | 6 0. | 05238 | 365.85 | 0.457236 | 0.0777961 |
| C13C17 | 207.2 | 15 260 |).83 | 1300.44 | | 0.24558 | 0. | 57898 | B 0. | 11079 | 532.32 | 0.457236 | 0.0777961 |
| C18C29 | 313.6 | 94 192 | 2.71 | 1473.62 | | 0.24563 | 0. | 81861 | 0. | 14922 | 787.86 | 0.457236 | 0.0777961 |
| C30+ | 493.8 | 36 145 | 5.31 | 1658.37 | | 0.26023 | 1. | 13360 |) 0. | 13239 | 1220.21 | 0.457236 | 0.0777961 |
| BIPS | N2 | CO2 | H2S | C1 | | C2 | C3N-C | 5 | C6C8 | C9C12 | C13C17 | C18C29 | C30+ |
| N2 | 0.00000 | 0.00000 | 0.13000 | 0.02500 | 0 | 01000 | 0.09530 |) 0 | .10979 | 0.10966 | 0.10991 | 0.10985 | 0.11000 |
| CO2 | 0.00000 | 0.00000 | 0.13500 | 0.10500 | 0 | 13000 | 0.11921 | 1 0 | .11479 | 0.11466 | 0.11491 | 0.11485 | 0.11500 |
| H2S | 0.13000 | 0.13500 | 0.00000 | 0.07000 | 0 | .08500 | 0.07536 | 5 0 | .05088 | 0.04964 | 0.04990 | 0.04984 | 0.05000 |
| C1 | 0.02500 | 0.10500 | 0.07000 | 0.00000 | 0 | .00092 | 0.00463 | 3 0 | .01071 | 0.01664 | 0.02507 | 0.03352 | 0.10933 |
| C2 | 0.01000 | 0.13000 | 0.08500 | 0.00092 | 0 | .00000 | 0.00365 | 5 0 | .01274 | 0.02327 | 0.03876 | 0.05547 | 0.07108 |
| C3N-C5 | 0.09530 | 0.11921 | 0.07536 | 0.00463 | 0 | .00365 | 0.00000 |) 0 | .00278 | 0.00866 | 0.01913 | 0.03170 | 0.04416 |
| C6C8 | 0.10979 | 0.11479 | 0.05088 | 0.01071 | 0 | 01274 | 0.00278 | 3 0 | .00000 | 0.00165 | 0.00746 | 0.01608 | 0.02547 |
| C9C12 | 0.10966 | 0.11466 | 0.04964 | 0.01664 | 0 | .02327 | 0.00866 | 50 | .00165 | 0.00000 | 0.00211 | 0.00752 | 0.01438 |
| C13C17 | 0.10991 | 0.11491 | 0.04990 | 0.02507 | 0 | .03876 | 0.01913 | 3 0 | .00746 | 0.00211 | 0.00000 | 0.00168 | 0.00555 |
| C18C29 | 0.10985 | 0.11485 | 0.04984 | 0.03352 | 0 | .05547 | 0.03170 |) 0 | .01608 | 0.00752 | 0.00168 | 0.00000 | 0.00113 |
| C30+ | 0.11000 | 0.11500 | 0.05000 | 0.10933 | 0 | .07108 | 0.04416 | 50 | .02547 | 0.01438 | 0.00555 | 0.00113 | 0.00000 |
| Equation of state type Peng-Robinson Separator Stage 1, Temperature | | | | | | | 100 °F | | | | | | |
| Reservoir Temperature, T_R 250 °F Separator Stage 1, Pressure 30 | | | | | | | 300 psia | | | | | | |
| | - | | | | | Separat | or Stage | 2, Tei | mperatu | re | | | 60 °F |
| | | | | | | Separat | or Stage | 2, Pre | ssure | | | | 14.7 psia |
| LBC Viscosity Coefficients $a0 = 0.1023, a1 = 0.023364, a2 = 0.058544, a3 = -0.040758, a4 = 0.009332$ | | | | | | | | | | | | | |

Table 2—Equation of state, binary interaction parameters, and general fluid information.

| | | | | | | C2- | | Lean |
|-----------------------------------------|-----------|-----------|-----------|-----------|-----------|-----------|------------|-----------|
| Component | BO | VO | NCO | NCGC | GC | Enriched | Separator | Processed |
| N2 | 5.300E-04 | 1.177E-03 | 1.307E-03 | 1.381E-03 | 1.531E-03 | 4.420E-04 | 1.521E-03 | 7.580E-04 |
| CO2 | 3.914E-03 | 6.640E-03 | 7.190E-03 | 7.500E-03 | 8.131E-03 | 6.210E-03 | 8.548E-03 | 1.066E-02 |
| H2S | 0.000E+00 | 0.000E+00 |
| C1 | 2.723E-01 | 5.493E-01 | 6.052E-01 | 6.367E-01 | 7.008E-01 | 5.298E-01 | 7.097E-01 | 9.091E-01 |
| C2 | 8.810E-02 | 1.269E-01 | 1.347E-01 | 1.392E-01 | 1.481E-01 | 4.635E-01 | 1.620E-01 | 7.953E-02 |
| C3N-C5 | 1.677E-01 | 1.179E-01 | 1.079E-01 | 1.023E-01 | 9.075E-02 | 0.000E+00 | 1.141E-01 | 0.000E+00 |
| C6C8 | 1.397E-01 | 6.035E-02 | 4.433E-02 | 3.530E-02 | 1.695E-02 | 0.000E+00 | 4.051E-03 | 0.000E+00 |
| C9C12 | 1.159E-01 | 4.875E-02 | 3.520E-02 | 2.755E-02 | 1.201E-02 | 0.000E+00 | 1.625E-04 | 0.000E+00 |
| C13C17 | 7.403E-02 | 3.109E-02 | 2.242E-02 | 1.753E-02 | 7.594E-03 | 0.000E+00 | 1.21a0E-06 | 0.000E+00 |
| C18C29 | 8.569E-02 | 3.598E-02 | 2.594E-02 | 2.029E-02 | 8.788E-03 | 0.000E+00 | 2.474E-09 | 0.000E+00 |
| C30+ | 5.213E-02 | 2.189E-02 | 1.578E-02 | 1.234E-02 | 5.346E-03 | 0.000E+00 | 2.548E-09 | 0.000E+00 |
| GOR | 500 | 2000 | 3000 | 4000 | 10000 | Inf | Inf | Inf |
| (scf/STB) | | | | | | | | |
| OGR | 2000 | 400 | 333.3 | 250 | 100 | 0 | 0 | 0 |
| (STB/MMscf) | | | | | | | | |
| p_s at T_R | 1825 | 5054 | 6305 | 7203 | 8982 | - | - | - |
| (psia) | | | | | | | | |
| MMP _{MC} (C2- enriched gas) | 2943 | 3179 | 3318 | 3452 | 4423 | - | - | - |

Table 3—Initial-fluid and injection-gas (IG) compositions with some associated properties. All MMP_{MC} values were predicted to be by the condensing/vaporizing mechanism.

Results and Discussion

Single-Cell Modeling of the Huff-n-Puff Process

The target volume for the HnP process is the shattered volume (DP region). The single-cell model is used to study the details of the HnP process on each "piece of rock" found in the shattered volume surrounding a hydraulic fracture. We use the dual porosity "approximation" to control injected gas into the rock volume during the injection period (huff), and the produced gas and oil leaving the rock volume during the produced period (puff). Inherent to the DP model is the assumption of full mixing and equilibrium within the rock pore volume at all times.

The results below show four comparable properties as function of time for the BOPVT and COMP models, matrix-cell oil saturation, matrix-cell gas saturation, producing OGR, and oil recovery factor.



Fig. 5-BO, single-cell model, initially undersaturated, C2-enriched injection gas



Fig. 6—VO, single-cell model, initially undersaturated, C2-enriched injection gas



Fig. 7-NCO, single-cell model, initially undersaturated, C2-enriched injection gas



Fig. 8—NCGC, single-cell model, initially undersaturated, C2-enriched injection gas



Fig. 9-GC, single-cell model, initially undersaturated, C2-enriched injection gas

The comparison of the BOPVT and COMP models for the HnP process in **Figs. 5 through 9** show similar results for all cases—reservoir simulation with the BOPVT model consistently overestimates the oil recovery performance.

The difference between the BOPVT and COMP models are based on, at each time step, (1) whether the pore-volume mixture is single-phase or two-phase and, if two-phase; (2a) the relative volumes of each phase and (2b) the distribution of heavier ["stock-tank oil (STO)"] components in the gas and oil phases; and (3) phase viscosities.

The PVT properties are particularly important during the production period (puff). When the rock pore-volume mixture remains single phase (gas or oil), maximum STO recovery is achieved during production. When the mixture is two-phase (i.e. cell pressure less than the saturation pressure of the total mixture), the PVT properties will determine relative mobility of each phase (from phase volume—i.e. phase saturation, and viscosity), together with the amount of STO carried in each phase.

By nature of large injected gas volumes, most time steps with two-phase conditions will have high gas mobility. Consequently, much of the oil recovery comes directly from the STO held in solution in the gas phase (solution oil-gas ratio, r_s , for the BOPVT model, or heavier components in the equilibrium gas composition, y_{n+} , for the COMP model). The oil phase will often have little or no mobility, contributing little to the HnP oil recovery process.

In summary, the two PVT properties dominating the HnP oil recovery efficiency is saturation pressure and STO-carrying capacity of the gas phase. The excessive oil recovery predicted by the BOPVT model is caused by the model underpredicting the saturation pressures and overpredicting the solution OGR compared with the COMP model—both resulting in overprediction of STO recovery during the HnP process. **Table 4** and **Figs. 10 and 11** quantify these differences for the BO fluid system.

Fig. 10 shows the variation in the SV-matrix-pore-volume (i.e. the matrix grid block in the DP model) saturation pressure as a function of time for COMP (pink) and BOPVT (blue) results. The saturation pressure is calculated for the cell/total composition (z_i) if the cell is single-phase, whereas it is set equal to the cell pressure if the cell is two-phase [i.e. equal to the saturation pressure of the phase compositions (x_i and y_i)]. The time period where the line is flat indicates that the pore space is undersaturated and producing a constant composition with maximum STO recovery efficiency ($\eta(t)=1$). When pore space $p_s(t)$ decreases, this tells us that two phases exist and the STO recovery efficiency is decreasing ($0 \le \eta(t) < 1$) as pressure decreases. Fig. 10 clearly shows that the BOPVT-model saturation pressure is much lower than the COMP-model saturation pressure. This results in the BOPVT model yielding higher STO recoveries than the COMP model, where the difference in $p_s(t_{eh})$, and consequently STO recovery efficiency $\eta(t_{ep})$, increase with HnP cycles. Table 4 computes the HnP cycle efficiency $\eta(t_{ep})$ from the results shown in Fig. 10. Only the first HnP cycle shows similar results between the BOPVT and COMP models.

Fig. 11 gives another quantification of the difference in both p_s and STO solubility in the reservoir gas phase (r_s) for the BOPVT and COMP models. The thick solid lines represent the BOPVT saturation pressure and phase solution gas/oil ratios R_s (oil phase) and $1/r_s$ (gas phase). These

BOPVT properties are invariant during the entire HnP process. The thin solid lines are based on COMP-model results during the entire HnP process. At each time step where the pore space has two phases, we extract phase compositions and compute solution GORs. During the injection period (huff) the pressure is increasing, while during the production period (puff) the pressure is decreasing. The important and severe hysteresis of r_s for increasing HnP cycles, combined with an increasing saturation pressure for each cycle, leads to lower STO recoveries in the COMP model. The BOPVT model does not capture the dynamically-changing $p_d(r_s)$ and $p_b(R_s)$ relationships. Instead, it uses invariant functions (the thick solid lines) that result in overly optimistic STO recovery.

Because the oil is mainly recovered as a condensate (i.e. in solution in the gas phase) for the HnP process, we express the recovered oil volume for each HnP cycle through the producing OGR (r_p)

$$\Delta \mathbf{N}_{\mathbf{p}} = \int_{t_{ch}}^{t_{cp}} r_p(t) q_{\overline{g}}(t) dt \qquad (2)$$

The $r_p(t)$ results in Figs. 5 through 9 are all similar, so we only look at the details for the BO fluid system in Fig. 5 (bottom left). The same $r_p(t)$ curve is plotted on a linear scale in **Fig. 12** for the 2nd to 4th production periods. The area under the $r_p(t)$ curve for BOPVT (dashed line) and COMP (solid line) models is proportional to the production volume ΔN_p (cycle "uplift") in each puff period predicted by the two fluid models. The oil production is expressed as an oil recovery factor ($N_p(t)/N$) in Fig. 5, and one can see a clear and increasing separation of the HnP recovery between the BOPVT and COMP models.



Fig. 10-Saturation pressure in the DP matrix cell









| | | BOPVT | COMP | BOPVT | COMP |
|-----------|----------|---------------|---------------|----------------------|----------------------|
| Cycle No. | t_{ep} | $p_s(t_{eh})$ | $p_s(t_{eh})$ | Eff., $\eta(t_{ep})$ | Eff., $\eta(t_{ep})$ |
| (-) | (D) | (psia) | (psia) | (-) | (-) |
| 1 | 910 | 3305 | 3411 | 0.79 | 0.77 |
| 2 | 1090 | 4778 | 5001 | 0.61 | 0.59 |
| 3 | 1270 | 5306 | 6663 | 0.55 | 0.39 |
| 4 | 1450 | 4410 | 8505 | 0.66 | 0.17 |
| 5 | 1630 | 3496 | 9945 | 0.76 | < 0.01 |
| 6 | 1810 | 2282 | 9937 | 0.91 | < 0.01 |
| 7 | 1990 | 1500 | 9931 | 1.00 | < 0.01 |
| 8 | 2170 | 1500 | 9928 | 1.00 | < 0.01 |
| 9 | 2350 | 1500 | 9925 | 1.00 | < 0.01 |

Table 4—HnP recovery efficiency computed for the black-oil PVT and compositional models to show the difference in predicted recovery.

Well-Scale Modeling of the Huff-n-Puff Process

A symmetry-element model was used to study the impacts of the HnP process on well-scale for the two fluid models. The model is described by Figs. 1 and 2, and Table 1. Again, the entire range of fluid systems in Table 3 was used.

The key features of this well-scale model are a "shattered volume" (SV) of rock (represented by the dual-porosity model) adjacent to the hydraulic fracture, and a single-porosity rock volume outside the SV. Results given in the previous section for a single matrix grid block pieces of rock) in a DP cell pair show the expected performance within the SV region where rock rubble is of a sufficiently small size to allow for complete mixing of the injection gas and reservoir fluid within the duration of the injection period.

The single-porosity region (intra-fracture region beyond the SV, i.e. the middle part of the model in Fig. 2) will lead to *no* incremental oil recovery for the HnP process, as described by Mydland et al. (2020). They show that the injection gas entering a single-porosity region will push oil away from the fractured region during the injection period (miscibly or nearly so), and that the oil reverts back to its initial position in the single-porosity region during the production period (analogous to a piston moving back and forth)

Consequently, the uplift seen from the HnP process in the well-scale model is only recovery of oil in the SV region (as described above), but now for a large collection of individual matrix blocks (rock rubble).

All models have an initial two-year period of depletion, prior to starting the HnP process, lasting for about eight to ten years with variable injection and production periods in each cycle (case dependent). A summary of the cases studied are as follows:

- 1. Single geologic layer, initially undersaturated, all five reservoir fluid systems, using the C2-enriched injection gas.
- 2. Two geologic layers, initially undersaturated, with different fluids in each layer (gas condensate and volatile oil), using the C2-enriched injection gas.
- 3. Single geologic layer, saturated VO with initial gas saturation equal to initial oil saturation, using the C2-enriched injection gas.

- 4. Single geologic layer, initially undersaturated VO, using the lean processed injection gas.
- 5. Single geologic layer, initially undersaturated VO, using the separator injection gas.





Fig. 13—Case 1: BO, single geologic layer, initially undersaturated, C2-enriched injection gas















Fig 17—Case 1: GC, single geologic layer, initially undersaturated, C2-enriched injection gas

The well-scale results of the HnP process in **Figs. 13 through 17** are all indicating that the BOPVT model overpredicts oil recovery. The difference between the BOPVT and COMP models are increasing going from oil to gas, reflecting the increasing variation with cycle for the $r_s(p)$ curve, and how the BOPVT model fails to capture this.

The oil cases (Figs. 13 to 15) might appear to have a negligible difference in oil recovery. However, it is important to note that the difference in recovery between the two fluid models is a strong function of the SV extent (i.e. size of the DP region), which in this case is 25% of the reservoir model. As the SV becomes larger, so will the difference in predicted oil recovery by the two fluid models. This is because all mixing contributing to oil recovery for the HnP process happens in the SV region. A larger SV (>25% of the intra-fracture volume) might be more realistic for modern wells in unconventionals. A detailed study of a fractured rock volume in the Eagle Ford (Raterman et al. 2018, Raterman et al. 2019) indicate closely-spaced planar fractures (i.e. slabs of rock with a small minimum dimension=fracture spacing) between the conductive hydraulic fractures.

Case 2:

This case has two physical layers instead of one, in which the thickness of each physical layer is half of the layer thickness given in Table 1 (i.e. 75 ft each). The upper and lower layers are initialized with the VO and GC, respectively. The well perforates the upper layer only, but there is vertical communication in the fracture network allowing for flow to and from both layers.

The concept of having an oil above gas would violate the gravitational distribution in conventional reservoirs. However, we know that this can be the case for tilted basins (e.g. the Montney and Eagle Ford) in unconventionals, in which gravitational effects are negligible because of the very-low permeability, making the phase of the fluid controlled by the increasing temperature with depth (i.e. oil at shallow depths with a critical transition to a gas at deeper depths) (Whitson et al. 2018, Alqahtani et al. 2020).

The initialization of the model is done by using two initialization regions. For the COMP model we assign the two different compositions to the two different initialization regions, using the same EOS11 for both regions. For the BOPVT case we assign the two different BOPVT tables to two different PVT regions corresponding to the initialization regions, and then initialize the model by providing the two initial GORs (2000 and 10000 scf/STB) to each of the initialization regions.



Fig. 18-Case 2: VO (layer 1) and GC (layer 2), two physical layers, initially undersaturated, C2-enriched injection gas

We see from **Fig. 18** that the BOPVT model overpredicts the oil recovery from the multi-layer model. Surprisingly to us, it seems that the BOPVT model predicts the depletion recovery quite accurately, despite the fact that we are using two completely different BOPVT-tables for each of the layers, and the produced fluids are mixed together in the fractures.

Case 3:

This case has the same model properties as for the case in Fig. 14, except that the model is initially two-phase saturated [i.e. $p_{Ri} = (p_{si})_{VO} = 5054.3$ psia] with the oil and gas saturations set equal ($S_{oi} = S_{gi} = 0.4$). This case is intended to show a simple case of some parts of the Montney basin where gas from the deeper part has migrated to the shallower oil part, resulting in zones that are two-phase saturated (Kuppe et al. 2012).



Fig. 19—Case 3: VO, single physical layer, initially two-phase saturated, C2-enriched injection gas

We see from **Fig. 19** that the BOPVT model overpredicts the oil recovery. The difference in recovery is larger for this case compared with the undersaturated VO case in Fig. 14. This indicates that this case has a phase behavior that is less accurately captured by the BOPVT model, considering that both cases use the exact same BOPVT table.

Case 4:

The injection-gas composition in this case is changed to a leaner² type ("Lean Processed" in Table 3). This injection gas has also been used to create a new set of BOPVT tables (i.e. changing the properties of the upper part).



Fig. 20—Case 4: VO, single physical layer, initially undersaturated, lean processed injection gas

We see in **Fig. 20** that the BOPVT model overpredicts oil recovery. The difference in this case is also larger compared with the case in Fig. 14, despite both models being initialized equally. We see that the difference is mainly caused by the COMP model recovering less, which is explained by the injection gas being leaner in this case, resulting in a less efficient recovery process (more vaporization driven).

Case 5:

In this case, the injection-gas composition is set to the default calculated by Sensor if no injectiongas composition is provided, i.e. a separator gas ("Separator" in Table 3). This composition should resemble the phase behavior of the injection gas for the BOPVT model, which is always the surface

² A lean gas typically consists >90% of the lightest components, i.e. C1 and N2.

gas ($r_s = 0$ STB/MMscf). Thus, it is reasonable to expect an improved match between the BOPVT and COMP models for this case.



We see from Fig. 21 that the oil recovery in this case shows the closest match yet between the BOPVT and COMP models. This can also be seen in the producing GOR plot, in which the two fluid models appear to have a better match for the three first cycles compare with the other VO cases above.

Well-Scale Modeling of the Fracture-to-Fracture Process

The F2F process is a cyclic displacement-type EOR process rather than a cyclic mixing-type EOR process (HnP). Thus, the F2F process relies on completely different mechanisms of recovery compared to the HnP process. Displacement of oil by gas is known to have a high recovery efficiency (>90%) in the swept volume³, *if* miscible conditions are achieved—i.e. the pressure at the displacement front is greater than the minimum miscibility pressure by multi contact (p_{fr} > MMP_{MC}).

The comparison of the BOPVT and COMP models are done for all fluid systems in Table 3, with the reservoir properties as summarized in Table 1. The C2-enriched injection gas has been used in all cases.

The scheduling of the F2F process is different compared with the HnP process in that the duration of injection and production periods are chosen on a different basis (constraints in Table 3 are still used). For all cases, the scheduling is determined as follows using the BOPVT model for all fluid systems (meaning that any differing predictions for the BOPVT and COMP models will cause a difference in the pressure for the COMP model): The injection periods (now injecting at a constant rate into one fracture only) last until reaching the maximum BHP constraint. For the first production period, we produce (from the fracture on the opposite side) until the pressure at the injection fracture reaches 4500 psia. This number is chosen based on the MMP_{MC} values in Table 3 to ensure miscible conditions at the displacement front initially. The duration of the first production period is then fixed for all consecutive production periods.

³ We emphasize *swept volume* here to ensure that the reader does not confuse this with a *recovery factor* (N_p/N) of >90% for a reservoir undergoing a displacement-type process. The total recovery efficiency for a displacement process is commonly expressed as $\eta_t = E_A E_V E_D$, i.e. the product of the areal-, vertical-, and displacement efficiency, respectively, where our statement is that $E_D > 0.9$.

The choice of durations for the injection and production periods is not the optimum. However, it is based on attempting to maintain the following relationship during the F2F process

As the front moves away from the injection fracture (high pressure) towards the producing fracture (low pressure), the frontal pressure decreases. Therefore, we use a minimum pressure constraint (in this case 4500 psia) for the injection fracture while producing to find a production-period duration that maintains the frontal pressure greater than the MMP_{MC}, ensuring miscible displacement for as long as possible. Because the producing fracture has a minimum BHP that is less than the MMP_{MC}, the frontal pressure will ultimately become less than the MMP_{MC} as it nears the producing fracture. However, there are three contributing factors of maintaining a high frontal pressure for most of the F2F duration: (1) the pressure drop between the injection and production fractures happens mainly in the oil phase (i.e. ahead of the front, meaning the pressure in the injection fracture is near-equal to the frontal pressure, hence the pressure constraint for the injection fracture during production), (2) the displacement efficiency achieved by multi-contact miscibility is not acting as a switch, but more as a dimmer; near-miscible conditions (i.e. the frontal pressure is near-equal to, but less than the MMP_{MC}) will also be highly efficient, and (3) the choice of a constant duration for all the production periods will cause the minimum pressure in the injection fracture to increase with cycle, which in turn "adds" pressure to the displacement front each cycle.



Fig. 22—BO, single physical layer, initially undersaturated, C2-enriched injection gas



Fig. 23—VO, single physical layer, initially undersaturated, C2-enriched injection gas



Fig. 24—NCO, single physical layer, initially undersaturated, C2-enriched injection gas



Fig. 25—NCGC, single physical layer, initially undersaturated, C2-enriched injection gas





The well-scale results for the F2F process show a good match between the BOPVT and COMP models for the BO and VO cases in **Figs. 22 and 23**, a reasonable match for the NCO case in **Fig. 24**, and an increasing mismatch for the NCGC and GC cases in **Fig. 26**.

For the oil cases (Figs. 22 through 24), the BOPVT model is able to develop and maintain the multi-contact miscible front. One reason for this is the low level of mixing of injection gas and reservoir fluid in the single-porosity region (except at the front), which keeps the compositions, and consequently the BOPVT properties, within the range of the BOPVT table. Another factor

contributing is the frontal pressure in relation to the MMP_{MC} for the oil cases. As most of the pressure drop happens in the oil phase ahead of the front, we maintain miscibility for a longer period of time with these cases, and thereby minimize the differential flow of gas and oil caused by mobility differences (i.e. we keep the zone of mixing narrow around the displacement front).

For the gas cases (Figs. 25 and 26), the ongoing phase behavior is more complex due to the cyclic variation in pressure, which causes the frontal pressure to oscillate around the MMP_{MC}, allowing for gas to cyclically move "ahead" of the front and mix with oil. This in turn, causes dispersion of the miscible front (i.e. mixing in a wider range around the front) that results in a displacement efficiency lying somewhere in between the efficiency of immiscible displacement (Buckley-Leverett type displacement) and the near-100% efficiency of fully miscible displacement. This is not captured correctly by the BOPVT model. The effect of the cyclic pressure on the displacement is quite severe for the NCGC case where we see the time of breakthrough is much later for the BOVT model. For the GC case, miscibility is only maintained for a very short period of time (pressure drop approximately equal on both sides of the front), causing the whole process to be driven mainly by vaporization; a mechanism we already know that the BOPVT table cannot predict accurately.

Black-Oil PVT Versus Compositional for Recurrently Changing BOPVT Tables

All cases presented above have relied on a single BOPVT table for each fluid system. These tables were all extrapolated to a critical GOR (i.e. closing the GOR gap) in an attempt to adapt them for gas-based EOR modeling. However, this has proven insufficient for all cases with the HnP process. As we have already explained, the variation in BOPVT properties with each HnP cycle, particularly for the $r_s(p)$, is not captured correctly by a single table.

Sensor has the ability to recurrently change the BOPVT tables for parts of, or the entire reservoir model (tables are assigned to the grid cells through the use of PVT regions). We will use this option to change the BOPVT tables that govern the DP region of the model for each cycle. To do this, we need to have knowledge about the compositions in the DP matrix grid blocks over time, such that the BOPVT tables can be generated from these compositions.

The correct way of obtaining the DP-matrix-grid-block compositions would be to run the full HnP simulation with the COMP model and extract the compositions. An alternative procedure of estimating the compositions is by the HnP-emulating CVI/CVD experiment suggested by Carlsen, Whitson, Dahouk, et al. (2019). The CVI/CVD experiment can be simulated with a PVT-simulation package using a tuned EOS, providing a fast method of estimating the compositional changes in the SV matrix pore volume during the HnP process. The initial composition for the CVI/CVD experiment is the total composition (z_i) in the DP matrix grid blocks at the end of the depletion period. This composition must also be estimated, which can be done in one of the two following ways:

1. Performing a standard depletion experiment (CCE or CVD) on the initial composition will provide a fair estimate of the *equilibrium* compositions $(x_i \text{ and } y_i)$ at the end of the depletion. The *total* composition (z_i) is then estimated by recombining the equilibrium compositions at a proportion that matches the matrix-cell saturations $(S_o \text{ and } S_g)$ at end of depletion, where the saturations are obtained from a simulation with the BOPVT model.

Using the BOPVT model to estimate saturations should yield reasonable results as the BOPVT and COMP models are expected to give similar results for the depletion period.

2. Perform a simulation of the depletion period using the COMP model, and then extract the matrix-cell compositions at the end of the simulation.

The compositions of interest from the CVI/CVD experiment are the compositions at the end of the injection periods (huffs). The BOPVT tables are generated with these compositions in the same manner as described above, with the exception that we have swelled the EQL at initial saturation pressure with its corresponding EQV, not the injection gas.

Fig. 27 shows the producing OGR and oil recovery factor for the use of recurrently changing BOPVT tables (CVI/CVD compositions). The VO and C2-enriched injection gas are used in this case. For comparison, we have added; (1) the single-BOPVT-table results from Fig 14, and; (2) the results from recurrently changing the BOPVT tables, in which extracted cell compositions from a run with the COMP model have been used instead of the CVI/CVD compositions.

Although the results from using multiple tables show a clear improvement from using a single table, there is still some mismatch between the BOPVT and COMP models. The difference is larger for the compositions estimated by the CVI/CVD method. Still, using multiple BOPVT tables (or some other method of correcting the $r_s(p)$ variation over time for the BOPVT model) may be an acceptable alternative to running the simulations with the COMP model, especially if multiple runs are needed in a short period of time (e.g. history matching). The runtimes for the cases in Fig. 27 are given in **Table 5**.



Fig. 27—VO, single physical layer, initially undersaturated, C2-enriched injection gas. One case shows the use of a single blackoil PVT table, two of the cases show the results of using recurrently changing black-oil PVT tables (generated from two different estimates of the matrix composition in the SV region), and one case shows the "true" results from a compositional simulation.

| Case | Runtime (min) |
|------------------------|---------------|
| BOPVT (Single Table) | 10.6 |
| BOPVT (CVI/CVD z_i) | 10.6 |
| BOPVT (COMP z_i) | 11.2 |
| COMP | 382.1 |

Table 5-Runtimes for black-oil PVT modeling in Fig. 27, compared with compositional model.

Conclusions

- 1. Gas-based enhanced oil recovery in tight unconventionals requires a compositional fluid treatment in reservoir simulation to properly capture the key phase behavior controlling EOR recovery.
- 2. The black-oil PVT model will in all cases overpredict the oil recovery for the huff-n-puff method. This is because a single black-oil PVT table does not capture properly the change in matrix pore volume composition over time, i.e. that the oil in the reservoir becomes heavier, and thus harder to vaporize, with each huff-n-puff cycle.
- 3. Extrapolating the black-oil PVT table to the critical point using the injection-gas composition will remove instabilities in the simulation, but the predicted oil recovery for most of the cases involving the HnP process will overestimate the "true" recovery.
- 4. The black-oil PVT formulation can yield reasonable results for modeling of the fractureto-fracture process, at least for low- to medium-high-GOR oils (<2000 scf/STB).
- 5. Recurrently changing the black-oil PVT tables when modeling the huff-n-puff process will improve the oil recovery predictions. This correction of the black-oil PVT properties, particularly the dynamically changing solution OGR, may serve as a simplified alternative to modeling with a compositional fluid model, especially when large run times are problematic.

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Nomenclature

| B_{gd} | = | Dry-gas formation volume factor | Т | = | Temperature |
|------------|---|-----------------------------------------|----------------|---|--------------------------------------------------------------|
| B_o | = | Oil formation volume factor | t | = | Time |
| K_i | = | Phase equilibrium ratio | tak | = | Time at end huff |
| р | = | Pressure | ten | = | Time at end puff |
| p_b | = | Bubblepoint pressure | T_R | = | Reservoir temperature |
| p_d | = | Dewpoint pressure | x _i | = | Liquid mole fraction |
| p_{fr} | = | Frontal pressure | $(x_i)_{Ri}$ | = | Liquid mole fraction for initial reservoir fluid at p_{si} |
| p_{iwf} | = | Bottomhole flowing injection pressure | Vi | = | Vapor mole fraction |
| $p_{m,SV}$ | = | Matrix pressure in the shattered volume | (Vi)IG | = | Vapor mole fraction for injection gas |
| p_{Ri} | = | Initial reservoir pressure | () 1) 10 Zi | = | Total mole fraction |
| p_s | = | Saturation pressure | $(7_i)_{R_i}$ | = | Total mole fraction for initial reservoir fluid |
| p_{si} | = | Initial saturation pressure | η | = | HnP recovery efficiency |
| $p_{w\!f}$ | = | Bottomhole flowing pressure | | | |
| r_p | = | Producing oil/gas ratio | | | |
| r_s | = | Solution oil/gas ratio | | | |
| R_s | = | Solution gas/oil ratio | | | |

- S_g = Gas saturation
- S_{gi} = Initial gas saturation
- S_o = Oil saturation
- S_{oi} = Initial oil saturation

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Appendix A: Black-Oil-PVT-Table Generation for Gas-Based EOR Modeling

A conventional BOPVT table is always generated using some depletion test (CCE/CVD) on the initial reservoir-fluid composition, along with the specified set of separator conditions. Methods of estimating the initial reservoir fluid composition are well explained by Fevang and Whitson (1994), and Carlsen, Whitson, Alavian, et al. (2019). The resulting BOPVT table is what we refer to here as the "lower part".

For all reservoir fluids that are not at its critical point initially, there will be a missing range of GORs when generating the lower part of the BOPVT table (i.e. as shown in Fig. 4 for the BO composition in Table 3). For pressure-depletion modeling, this is normally not a problem, although some special cases like e.g. gas-coning studies can yield cell GORs outside the BOPVT-table range. For gas-injection processes, the GOR in the grid cells are likely to vary in the whole range of the BOPVT table (and likely outside as well for very high GORs), meaning the missing GOR range needs to be "closed".

Three methods of extrapolating the BOPVT table to a critical point have been tested, and they are the following (ranked by "complexity"):

- 1. Single-stage swell to a critical mixture of the EQL composition at the saturation pressure of the initial reservoir fluid, using either the corresponding EQV at the saturation pressure, or a specified injection-gas composition.
- 2. Incremental swelling to a critical mixture of the EQL composition at the saturation pressure of the initial reservoir fluid, using either the corresponding EQV at the saturation pressure, or a specified injection-gas composition.
- 3. Estimating the convergence pressure of the initial reservoir fluid, and then compute the negative-flash compositions ($x_i = y_i = z_i$) at this pressure.

Methods 1 and 2 will yield the same critical mixture (for the same initial reservoir fluid extrapolation gas), but the resulting BOPVT tables (i.e. the upper BOPVT table) will be different. We use a CCE experiment to obtain the BOPVT properties, and for method 1, this gives a constant

composition in the cell for all pressures between the initial saturation pressure and the critical pressure. For method 2, the composition changes with each injection increment. This means that the K-value behavior for methods 1 and 2 are different, hence resulting in different BOPVT tables for the pressure between the saturation pressure of the initial fluid and the critical pressure.

Method 3 is based on a built-in logic in PhazeComp that locates the convergence pressure (and the corresponding negative-flash compositions) for any fluid (if it exists) upon user request.

Figs. A-1 and A-2 show the solution GOR and inverse solution OGR as a function of the saturation pressure, calculated with the three methods above, for the BO and VO compositions in Table 3, respectively. Methods 1 and 2 have been tried for both the EQV and the C2-enriched injection gas in Table 3.

We see in Fig. A-2 that method 1 can result in two saturation pressures for a single GOR value (i.e. the solid line "swelling" out and joining the solid line with circles at the initial saturation pressure), which will cause instabilities in the modeling. This seems to be a problem only when using the injection-gas composition in this case, but it may cause similar behavior for the EQV as well in other cases. The effect of this seems to be less important for the BO in this case.

We see in Fig. A-1 that method 3 causes a non-smooth transition between the upper and lower BOPVT tables. Although every GOR in the upper table has a unique saturation pressure, we would prefer to see a smooth transition between the tables to ensure stability in the modeling.

On the basis of the findings above, we have decided to use method 2 for the BOPVT-table extrapolation in this paper. We have developed an automated solution for the BOPVT-generation procedure, using PhazeComp for the PVT calculations. A note of caution when generating BOPVT tables that includes a critical point is to ensure sufficient pressure points around the critical pressure to avoid negative compressibilities. This is discussed in detail by Singh et al. (2007).



Fig. A-1—Solution gas/oil ratio and inverse solution oil/gas ratio for the BO fluid system. The extrapolated parts show the three suggested methods. (SST = single-stage swell, Incr. = incremental, Conv. Pr. = Convergence pressure)



Fig. A-2— Solution gas/oil ratio and inverse solution oil/gas ratio for the BO fluid system. The extrapolated parts show the three suggested methods. (SST = single-stage swell, Incr. = incremental, Conv. Pr. = Convergence pressure)