Upscale Methodology for Gas Huff-n-Puff Process in Shale Oil Reservoirs

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Abstract

Results of recent laboratory experiment studies suggest that huff-n-puff gas injection holds great potential to increase oil recovery from shale oil cores. However, our current knowledge of the field-scale performance of this process is very limited. Reservoir simulation is required to properly upscale this process from laboratory to field conditions in order to predict oil recovery and reduce the risk of failure in field projects.

After examining the literature, the purpose of all upscale methods is to generate a single curve which can describe the relationship of oil recovery versus dimensionless time for different scales. For a gas huff-n-puff process applied in a shale oil reservoir, it is also necessary to generate one single type curve to upscale a lab experiment to field-scale production. In this paper a new expression of dimensionless pressure was generated to describe the huff-n-puff efficiency, and a new version of dimensionless time was also derived that includes dimensionless pressure, permeability, porosity, viscosity, and core length. A compositional numerical model with dynamic gridding was built and validated by matching the experimental data, and the model was then used to test the upscale methodology. Several validation tests were conducted for different fluid and rock parameters, well constraints, and operation schedules. To this end, a type curve was developed for different scales which demonstrates that all sizes yield a similar relationship between oil recovery and dimensionless operation time. It proves that the cumulative oil recovery of gas huff-n-puff EOR in shale oil reservoirs can be predicted. In a case of high-permeability, the curve between oil recovery and dimensionless time deviates from the type curve (moves to the right side). This indicates huff and puff times are too long, and the process is inefficient. In this case, the huff and puff times can be reduced so that the curve follows the generated type curve.

[1] Introduction

Huff-n-puff gas injection to enhance oil recovery in conventional reservoirs has been studied in laboratory and tested in field (Sheng, 2015). The main mechanisms are the miscibility of injected gas with in situ oil so that oil viscosity is reduced and oil may swell, and pressure drive resulting from gas injection. In recent years, the gas huff-n-puff method has been demonstrated to improve oil recovery in shale oil and condensate reservoirs, and it has also been proven effective in our experimental studies (Gamadi et al., 2013, 2014; Yu and Sheng, 2015; Meng et al., 2015; Li et al., 2015; Wan et al., 2015; Meng and Sheng, 2016a) and simulation studies (Wan et al., 2013; Sheng, 2015; Wan and Sheng, 2015a, 2015b; Sheng et al., 2016; Meng and Sheng, 2016b; Wan et al., 2016). Sheng and Chen (2015) show that owing to ultra-low permeability in shale reservoirs, it is very difficult for gas and pressure propagate from an injector to a producer, therefore, gas huff-n-puff is superior to gas flooding. In terms of field application, huff-n-puff gas injection was not widely used in conventional reservoirs. In shale and tight reservoirs, huff-n-puff gas injection has been tried several fields. However, the detailed results were not reported in the literature. CO₂ huff-n-puff injection was conducted in the Bakken formation in the areas of North Dakota (Hoffman and Evans, 2016) and Montana (Sorensen and Hamling, 2016). However, the tests did showed significant oil increase.

In our previous work (Li et al., 2015), we conducted a series of experiments to test the core diameter size effect on oil recovery in laboratory conditions. The core diameters varied from 1 to 4 inches. The results illustrated that cores with bigger diameters yield a lower oil recovery in the same huff-n-puff cycle under the same operation conditions. That means we need to modify the operation conditions, such as by enlarging the huff and puff time to obtain cost-effective oil recovery in a field-scale operation. Previous work of upscaling from lab-scale to field-scale focused upon conventional reservoir studies. Geertsma et al. (1956) derived dimensionless variable groups which govern the displacement of oil in reservoirs by liquids using dimensionless analysis and inspectional analysis. They provided a complete list of dimensionless groups which are useful to design experiments in laboratory. But the list is so long that it is very difficult to use these groups in a practical design. Similarly, Thomas et al. (1997) derived scaling criteria for micellar flooding. Their derivations were based upon six three-phase components which flow in a porous medium.

Li and Lake (1995) developed scaling dimensionless groups for fluid flow through heterogeneous porous media. Wood et al. (2006) first presented the scaling groups to describe CO₂ flooding for a typical line-drive pattern, and then used these groups in a Box-Behnken experimental design to create a screening model most applicable to a Gulf Coast reservoirs. Handy (1960) derived an equation to predict water imbibition behavior so that the recovery increases with the square root of imbibition time under the assumption that water displaces air in a piston-like manner. Mattax and Kyte (1962) proposed an upscale equation of oil recovery vs. dimensionless time for spontaneous imbibition under the condition of using the same core sample shapes, relative permeability functions, and boundary conditions. The fluid viscosity ratios and initial fluid distributions are duplicated. And the gravity effect is neglected. They derived the following equation of dimensionless time to upscale the oil recovery behavior.

$$t = \sqrt{\frac{k}{\emptyset}} \frac{\sigma}{\mu_w L^2} \quad (1)$$

$$t_{\text{matrix block}} = t_{\text{model}} \frac{(\sqrt{\frac{k}{\emptyset}} \frac{\sigma}{\mu_w L^2})_{\text{model}}}{(\sqrt{\frac{k}{\emptyset}} \frac{\sigma}{\mu_w L^2})_{\text{matrix block}}} \quad (2)$$

where t is dimensionless time; k is rock permeability; $\emptyset$ is porosity; σ is interfacial tension; μ_w is water viscosity; and L is the characteristic liner dimension of the block.

Ma et al. (1995) improved Mattax and Kyte's equation by suggesting a new definition of dimensionless time [equation (3)], and they claimed this improved equation fit with different porous media, core dimensions, boundary conditions, and oil and water viscosity. Their equation is also applied to spontaneous imbibition. Basically they modified the characteristic length and viscosity term based on Mattax and Kyte's equation.

$$t_D = t \sqrt{\frac{k}{\emptyset}} \frac{\sigma}{\sqrt{\mu_w \mu_o} L_c^2}, \quad L_c = \sqrt{\frac{V}{\sum_{i=1}^n \frac{A_i}{X_{Ai}}}} \quad (3)$$

where t_D is dimensionless time; t is time; k is rock permeability; $\emptyset$ is porosity; σ is interfacial tension; μ_w and μ_o are water and oil viscosities; θ is the contact angle; L_c is the characteristic length; V is the bulk volume; X is the distance from imbibition surface to no-flow boundary; and A_i is the i^{th} surface.

A classical type curve is the Gringarten type curve for well testing in fractured wells proposed by Gringarten et al. (1979). They defined two dimensionless parameters written as shown in equations (4) and (5).

$$P_D = \frac{kh}{141.2quB} (P_i - P_{wf}) \quad (4)$$

$$t_D = \frac{0.000264kt}{\phi\mu c_t L_f^2} \quad (5)$$

where t_D is dimensionless time; t is time; k is rock permeability; ϕ is porosity; μ is fluid viscosity; B is the oil volume factor; q is the oil production rate; c_t is coefficient of volume compressibility; P_D is the dimensionless pressure; P_i is the initial reservoir pressure; P_{wf} is the well bottom hole pressure; L_f is the half fracture length. Their type curve is used to analyze the well pressure behavior under a constant well rate.

Zhou et al. (2001) used X-ray computed tomography to investigate counter-current imbibition in low permeability porous media and developed a modified scaling group incorporating the mobility ratio. Li and Horne (2002) generated another dimensionless time with almost all the parameters considered based upon theoretical analysis of the fluid-flow mechanisms that govern spontaneous imbibition. Li and Horne (2006) introduced a more general dimensionless time by replacing the original viscosity and permeability with effective viscosity and permeability of the two phases.

$$t_D = c^2 \frac{k}{\phi \mu_w} \frac{P_c}{L_a^2} \frac{S_{wf} - S_{wi}}{t} \quad (6)$$

$$t_D = c^2 \frac{k_e^* P_e^*}{\phi \mu_e} \frac{S_{wf} - S_{wi}}{L_a^2} t \quad (7)$$

where c is the ratio of the gravity force to the capillary force; t_D is the dimensionless time with gravity and capillary forces included; S_{wf} is the water (or wetting phase) saturation behind the imbibition front; S_{wi} is the initial water saturation in the core sample; P_c is the capillary pressure at S_{wf} ; μ_e is the effective viscosity of oil and water phases; L_a is the characteristic length, equal to core length. They also derived a normalized oil recovery equation which is only a function of the defined dimensionless time [equation (8)]. This equation shows that spontaneous water imbibition from experimental data with different sizes, porosities, permeabilities, initial water saturations, interfacial tensions, and wettabilities can be scaled to a single curve of R^* vs. t_D . Their equations apply to co-current and counter-current imbibition.

$$(1 - R^*)e^{R^*} = e^{-t_D} \quad (8)$$

where R^* is the normalized oil recovery.

Delshad et al. (2009) upscaled the oil recovery results of the static imbibition experiment using a reference time based upon gravity which was used earlier by Cuiec et al. (1994). They used a chemical compositional reservoir simulator with the capability to model oil recovery from mixed-wet carbonate rocks in both static imbibition and dynamic fractured block experiments. In their model, because of low IFT, the gravity is dominant effect over capillary force. Pujol and Boberg (1972) discussed the scaling accuracy caused by upscaled capillary pressures for laboratory steam flooding models. Leung and Sanjay (2011) analyzed the uncertainty caused by the upscale of reservoir attributes and the flow response in heterogeneous reservoirs.

Wan et al. (2013) were the first to conduct simulation modeling of gas huff-n-puff in shale oil reservoirs. They claimed total oil recovery can be increased up to 29% by gas huff-n-puff in a hydraulically fractured

shale reservoir, compared with the initial 6.5% recovery from the primary depletion. Yu et al. (2014a, 2014b) built a numerical fracture model to simulate CO₂ huff-n-puff in Bakken tight oil reservoirs. They compared CO₂ flooding in two horizontal wells with CO₂ huff-n-puff in one horizontal well, and analyzed parameters such as injection rate, soak time, number of huff-n-puff cycles, and CO₂ diffusivity. However, the relationship between core scale and oil recovery is still ambiguous. There is no theory to explain the effect of size or dimensionless time upon the gas huff-n-puff EOR process.

In this paper, we derived a new version of dimensionless pressure and dimensionless time. We built and validated a Cartesian model using experimental data, and used it to study the effect of upscale. Subsequently we conducted validation tests for different fluid and rock parameters, well constraints, different huff-n-puff schedules, and using a field performance case. We developed a type curve which can be used to predict oil recovery and design the huff and puff times in case the curve between oil recovery vs. dimensionless time deviates from the type curve.

[2] Theory

A general scaling approach for gas huff-n-puff was developed based upon assumptions that the matrix is homogeneous and isotropic, and that the fracture and matrix permeabilities are constant.

As shown in **Fig. 1**, the oil recovery is dependent upon pressure change during the huff-n-puff cycle. A high matrix average pressure in the huff process and a lower matrix average pressure in the puff process will yield a higher oil incremental oil recovery. Based on our understanding and other studies, the pressure drive is the dominant mechanism in the huff-n-puff gas injection process. Therefore, we started with the Gringarten et al.'s equations which address viscous drive (pressure drive) mechanism, instead of the other equations reviewed above that address imbibition processes. But the huff-n-puff process is not a simple viscous drive process. We need to modify the Gringarten et al.'s equations.

(b). Oil recovery factor & Matrix average pressure vs. operation time in the first cycle
Fig. 1. Oil recovery factor, average pressure change during huff-n-puff cycle

After analyzing **Fig. 1 (b)** which shows the oil recovery and average pressure changes with time, the time dependent term P_{huff} (Eq. 9) is a reasonable choice to describe the efficiency of the huff process. It describes the pressure build up efficiency of huff period. The higher the P_{huff} value is, the faster the reservoir is re-pressurized.

$$P_{\text{huff}} = \frac{S1}{S2} = \frac{\int_0^{t_{\text{huff}}} P_{\text{avg}} dt}{S_{\text{huff}}} = \frac{\int_0^{t_{\text{huff}}} P_{\text{avg}} dt}{P_{\text{max}} \times t_{\text{huff}}} \quad (9)$$

where S1 is the blue area shown in **Fig. 1 (b)**, the integral of injection pressure based on huff time, psi·day; S2 is the yellow area shown in **Fig. 1 (b)**, maximum injection pressure times huff time, psi·day; t_{huff} is the total huff time, day; P_{max} is the maximum average pressure, psi.

Similarly, we use the term P_{puff} (Eq. 10) to describe the efficiency of the puff process. The lower the P_{puff} value, the faster the reservoir is depressurized, which means that the reservoir driving force (pressure gradient) is larger. The puff period is more effective for oil production.

$$P_{\text{puff}} = \frac{S3}{S4} = \frac{\int_0^{t_{\text{puff}}} P_{\text{avg}} dt}{S_{\text{puff}}} = \frac{\int_0^{t_{\text{puff}}} P_{\text{avg}} dt}{P_{\text{max}} \times t_{\text{puff}}} \quad (10)$$

where S3 is the green area shown in **Fig. 1 (b)**, the integral of production pressure based on puff time, psi·day; S4 is the pink area shown in **Fig. 1 (b)**, maximum production pressure times puff time, psi·day; t_{puff} is total puff time, day.

The dimensionless pressure is defined as the huff efficiency subtracted by puff efficiency and represents the efficiency in one huff-n-puff cycle, shown in equation (11). This term describes the performance of huff-n-puff cycle. The higher value of P_D means the huff-n-puff performance is more effective. Thus, more oil will be produced during a specific operation time.

$$P_D = P_{\text{huff}} - P_{\text{puff}} = \frac{\int_0^{t_{\text{huff}}} P_{\text{avg}} dt}{S_{\text{huff}}} - \frac{\int_0^{t_{\text{puff}}} P_{\text{avg}} dt}{S_{\text{puff}}} \quad (11)$$

Furthermore, we analyzed the recovery factor equations for linear flow, spherical flow, and radial flow to justify that we can use a dimensionless time similar to that by Gringarten et al.

For linear flow:

$$RF = \frac{qt}{OOIP} = \frac{\frac{kA \Delta P}{\mu L} t}{AL\phi} = \frac{k\Delta P t}{\phi \mu L^2} \quad (12)$$

For spherical flow:

$$RF = \frac{qt}{OOIP} \sim \frac{\frac{k4\pi r_w}{\mu} \Delta P t}{\phi \frac{4}{3} \pi r_e^3} \sim \frac{3k\Delta P t}{\phi \mu r_e^2} \quad (13)$$

For radial flow:

$$RF = \frac{qt}{OOIP} = \frac{\frac{k}{\mu} 2\pi h \frac{\Delta P}{\ln \frac{r_e}{r_w}} t}{\phi \pi r_e^2 h} \sim \frac{2k\Delta P t}{\phi \mu r_e^2} \quad (14)$$

To obtain the same RF, the operation time t should be proportional to L^2 or r_e^2 , if the other conditions are the same, especially when ΔP is the same. Here r_e is the outer drainage radius representing the dimension. We developed our dimensionless time based upon equation (5) by adding the dimensionless pressure term to the denominator after examining the simulation results discussed later. The dimensionless time with response to the dimensionless pressure and other factors such as permeability, porosity, viscosity, and core length is expressed in equation (15):

$$t_D = \frac{Ckt}{\phi \mu c_t (L^2) (P_D^2)} \quad (15)$$

where, C is constant, 2.64×10^{-4} ; t_D is dimensionless time; k is permeability, md; t is operation time, hours; ϕ is matrix porosity; μ is oil viscosity, cp; c_t is coefficient of volume compressibility, 1/psi; L is characteristic length, ft; P_D is dimensionless pressure.

Note that dimensionless pressure is included in this new equation. Almost all the parameters which govern the mechanism of the gas huff-n-puff process are included in the definition of dimensionless time (Eq. 15). It is expected that experimental data from gas huff-n-puff with different size, porosity, permeability, and operation time can be scaled to a single curve of R^* vs. t_D . We will verify the expectation later with data from gas huff-n-puff experiments and upscaled models.

[3] Validation Tests

[3.1] Model Setup and Validation

A 3D multicomponent simulator, CMG-GEM, was used. A new compositional numerical simulation model with grid blocks of $18 \times 1 \times 1$ was built as shown in **Fig. 2 (a)** to simulate our laboratory experiment (we use shale core plug with 0.125-ft in diameter and 0.167-ft in height). In order to separate the output of

shale matrix and the surrounding fractures, we divided the simulation domain into two sectors. The shale matrix was set as sector S1 covering grid blocks from 2 to 17 in I direction with the permeability of 500 nano-Darcy. Fracture space was set as sector S2, which included the I direction layers 1 and 18 with a permeability of 1000 milli-Darcy. Two injection wells and two production wells are located in the fracture part as shown in **Fig. 2 (a)**. During the huff process, the two injection wells were open and injected gas at a bottom-hole pressure of 2000 psi, and the two production wells were shut in. During the puff process, injection wells were shut in and the two production wells were open with a minimum bottom-hole pressure constraint of 14.7 psi. The distribution of porosity, absolute permeability, and oil saturation were assumed to be homogeneous in the shale matrix. The parameters used in the simulation model are shown in **Table 1**. To maintain accuracy when upscaling the lab experiment, we first tested an upscaled model with 1.25-ft in diameter and 1.67-ft in height. The grid size for the 1.25-ft model was same as that for the 0.125-ft model. Thus, the number of grids was increased from 18 to 180 in I direction as shown in **Fig. 2 (b)**. In this study, we examined the impact of grid refinement on oil recovery by performing a series of numerical sensitivity calculations. **Fig. 3 (a)** illustrates that the grid size in I direction did have an impact on oil recovery results, while grid size in J direction had no influence on oil recovery. So, it is important to keep the grid size in I direction the same when doing the upscale. However, a huge grid number will result in a long simulation time. Dynamic gridding (amalgamation) was applied to the simulation model. It helps to save computing time during a simulation by reducing the number of grid blocks used in the model. The amalgamation process was developed by Sammon (2003) for a compositional simulator. The process was also used in the thermal simulator (Perez-Perez, et al., 2014). The amalgamation process consists of creating a group of fine cells when identified property gradients (pressure and component saturation in this study) in the amalgamation domain are smaller than threshold values (10 psi and 0.0005 set for pressure and saturation changes, respectively, in this study). If the specified property gradient is larger than the defined threshold in the domain, the calculation proceeds with fine grid blocks. Otherwise, course grid blocks will be used. For all the simulation in this study, the initial grid starts with fine grid blocks with the same grid size as the laboratory model. The dynamic gridding procedure is applied during the run processes. Fine grid blocks were used in the zones with large property variations, while zones with small property gradients are amalgamated in blocks of 10 times coarsening. **Fig. 3 (b)** reveals that the cases with / without dynamic gridding yield the same oil recovery factor results. Thus, dynamic gridding can be used in this study.

Fig. 2. Simulation model for (a) 0.125-ft scale and (b) 1.25-ft scale (red area represents shale matrix and green area represents fracture, the color legend corresponds to initial oil saturation)

Table 1. Reservoir and fluid properties used in the simulation model.

Parameter	Value	Unit
Matrix Permeability	0.0005	md
Fracture Permeability	2000	md
Porosity	5	%
Total compressibility	1×10^{-6}	psi-1
Initial core pressure	14.7	psi
Methane Injection Pressure (for core-scale model)	2000	psi
Oil density	47.3	lb./ft ³
Temperature	95	°F

Fig. 3. Effect of numerical dispersion on oil recovery factor vs. time

Fig. 4 presents the pressure and oil saturation distribution when the huff-n-puff process was implemented. In this case, two properties are specified to trigger dynamic gridding at the gas-oil exchange front. As larger pressure and oil saturation changes occur at the matrix-fracture contact surface due to the huff or puff process, a fine model is kept to catch principal phenomena in this region while a coarse model is automatically generated in the model center zone.

Fig. 4. Pressure and oil saturation with dynamic gridding in the model (during the huff period of first cycle)

In order to historically match the experimental data in our previous work with different diameter (1.5, 2, 3, 4 inches) core plugs (Li et al., 2015), the model input parameters including fracture permeability, shale

matrix permeability, relative permeability, and diffusivity of the oil and gas phases were tuned within a reasonable range. **Table 2** presents the pseudocomponent description and inputs for the Peng-Robinson equation of state calculations. The tuned water-oil and gas-oil system relative permeability curves that were used in these simulation models are presented in **Fig. 5**. The Corey parameters for water-oil relative permeability curve are $S_{wc} = 0.1$, $S_{or} = 0.1$, $k_{rw}^e = 0.8$, $k_{ro}^e = 0.7$, $n_o = 2$, $n_w = 2$. The Corey parameters for gas-oil relative permeability curves are $S_{gr} = 0$, $S_{or} = 0.2$, $k_{rg}^e = 0.88$, $k_{ro}^e = 0.7$, $n_o = 4$, $n_g = 2$. The historically matching parameters and their ranges used in the simulation model are shown in Table 3 and the results are presented in **Fig. 6**. Although mismatches exist between some of the simulation results and experimental data, it is acceptable because the experimental data could have some errors, and the properties of four cores were not accurately available. From this point of view, simulation data could be more convincing as we know exactly the models, as discussed below.

Table 2. Peng-Robinson EOS fluid description of Wolfcamp crude oil.

Components	Initial Comp. %	Pc(atm)	Tc(K)	Acentric Fac.	MW	Vc(l/mol)	Vol.Shift
C ₃₋₄	0.018	39.269	394.7228	0.1687	51.1105	0.230214	-0.07924
C ₅₋₈	2.64	29.8467	556.4605	0.3331	101.7772	0.402268	0.027859
C ₉₋₁₉	36.66	19.9401	692.5801	0.5833	185.1622	0.698281	0.128336
C ₂₀₋₄₀	45.32	11.4471	844.253	0.9918	352.9444	1.269132	0.225044
C ₄₁₊	15.36	7.8659	950.8726	1.2629	513.5156	1.797165	0.276248

Fig. 5. Water-oil and Gas-oil system relative permeability curves used in the simulation model

Table 3. History matching parameters and their ranges used in the simulation model.

Parameter	Ranges	Unit
Matrix Permeability	0.0002 to 0.0006	md
Fracture Permeability	500 to 5000	md
Porosity	4.5 to 9	%
Relative Permeability Curve	15 % tolerance	-
Bin number of injection gas with hydrocarbon	5 % tolerance	-

(a) History matching for oil recovery

(b) History matching for pressure profile

Fig. 6. History matched results for different diameter core sizes

[3.2] Type Curve for Upscale Cases

In order to test the field-scale oil recovery, the lab-scale model was upscaled to three different scales, 10^3 , 10^6 and 10^9 times, respectively. The parameters of different scales are shown in **Table 4**. The fluid and rock properties and the well constraints are assumed to be the same for both lab and field scales. The only variable is the scale size as shown in **Table 4**. For a smaller scale, shorter injection and production time can achieve the designed pressure. However, a larger scale needs longer time to reach the same average matrix pressure in the model, as it takes a long time for the gas to diffuse and to disperse into the extremely low permeability matrix from the fracture space. For cases 2 to 4, the huff time and puff time were enlarged to L^2 times than the lab-scale model based on the relationship of the new dimensionless time (shown in equation (15)). The results of oil recovery in different cycles for upscaled cases are

described in **Fig. 7** and **Fig. 8**. **Fig. 7** is the semi-log plot of oil recovery vs. operation time. It illustrates that a larger size needs a longer operation time to yield the same oil recovery than that of a smaller size.

Fig. 8 illustrates that all different scales can reach the same oil recovery if they have enough huff-n-puff time. After converting the operation time to dimensionless time, the oil recovery results of all the scales follow one single curve shown in **Fig. 9**. This curve is the newly generated type curve for gas huff-n-puff in shale oil reservoir production. In the following section, the fluid and rock properties including permeability, porosity, and viscosity are changed to validate the type curve. From **Table 4**, the dimensionless pressures are the same for the four different scales, and the final oil recoveries for the four cases are also the same. This reveals that the dimensionless pressure is an indicator of the final oil recovery.

Table 4. Parameters of different cases.

Case No.	1	2	3	4
Scale	1	10^3	10^6	10^9
Core Sizes (L*H)	0.125*0.167	1.25*1.67	12.5*16.7	125*167
Grid blocks number	18	180	1800	18000
huff time, days	0.005	0.5	50	5000
puff time, days	0.035	3.5	350	35000
P_D	0.8	0.8	0.8	0.8
Injection Pressure	2000 psi

Fig. 7. Oil R.F. vs. operation time for different scales

Fig. 8. Oil R.F. vs. injection cycles of different scales.

Fig. 9. Oil R.F. vs. dimensionless time of different scales.

[3.3] Fluid & Rock Property Validation Tests

Permeability. Take scale diameter with 12.5 ft and height with 16.7 ft as the base case. The huff and puff times are 50 and 100 days, respectively. The permeability changed from 25 nano-Darcy to 25,000 nano-Darcy. The results are shown in **Table 5** and **Fig. 10**.

Table 5. Permeability validation tests for scale 12.5ft * 16.7ft before and after modification.

Case No.	5	6	7	8	9	10	11	12
Permeability, nano-Darcy	25	50	250	500	2500	5000	10,000	25,000
Dimensionless Pressure	0.244	0.298	0.469	0.63	0.91	0.95	0.98	0.99
Injection time, days	50							
Production time, days	100							
After Modification								
Injection time, days	50				10	5	2.5	1
Production time, days	100				20	10	5	2
Dimensionless Pressure	0.244	0.298	0.469	0.63	0.62	0.61	0.59	0.57

Fig. 10. Oil R.F. vs. dimensionless time for permeability validation test.

The results show that as the permeability increases, the dimensionless pressure increases, and the oil recovery factor increases. This confirms that the dimensionless pressure can reflect huff-n-puff efficiency. It also reveals that when the permeability is low, the dimensionless time is small, and the results follow on the early stage (low oil recovery range) of the type curve. However, when the permeability is large, the curves of oil recovery vs. dimensionless time do not match the type curve (move to the right as shown in **Fig. 10**). This result requires further discussion.

In the cases in Table 3, the generated type curve has the dimensionless pressure of 0.8. The ideal maximum dimensionless pressure which can be reached is 1. However, it sacrifices considerable operation time to reach 100% of the maximum dimensionless pressure, resulting in lower oil recovery in a fixed operation time. As discussed in our previous work (Li et al., 2016), there exists optimum huff and puff times. Before reaching the set injection pressure or production pressure, the oil recovery in one huff-n-puff cycle increases, as the injection and production times are increased. After reaching the set injection pressure and production pressure, increasing the huff or puff time will not lead to significantly greater oil recovery. After trying various operation times, the time to reach a value of 0.8 for dimensionless pressure is an optimum operation time for these cases. In the high permeability cases, the dimensionless pressures are beyond 0.9. Compared to the low permeability case, in the high permeability case the pressure propagation is faster from the fracture to the matrix or among matrix blocks. 50 days' huff period plus 100 days' puff period is greater than the necessary time for the high permeability case. Thus, they yield a higher oil recovery at the sacrifice of operation time (move to the right as shown in **Fig. 10**). By using the derived dimensionless time equation, we decreased the huff and puff time for the latter four cases based upon the operation time of 500 nano-Darcy case as presented in **Table 5** (below the row "after modification"). The cumulative oil recovery results are presented in **Fig. 11**, which illustrates that all the results follow the type curve. The effect of permeability has been confirmed for the proposed theory of dimensionless pressure and dimensionless time. The results also indicate that for a larger dimensionless pressure (over 0.8) and a larger dimensionless time (move to the right of the type curve), the huff time or puff time defined by this theory exceeds its requirement. The extra time is not necessary and is not effective for field production. It is necessary to modify the operation time based upon the type curve when the calculated dimensionless pressure is more than 0.8.

The random data for reservoir permeability and porosity were also used in the model to test the effect of heterogeneity on the applicability of the proposed type curve. The variation range is about 20% off the mean value of 300 nD. Then we compared the heterogeneous case with the others in **Fig. 11**. The results show that the heterogeneous case also follows the type curve, which means the dimensionless pressure and dimensionless time method can be applied to heterogeneous cases.

Fig. 11. Oil R.F. vs. dimensionless time for modified permeability validation test and heterogenous test.

Porosity. Validation tests for other parameters such as porosity and viscosity were conducted. The parameters for the tests are shown in **Table 6**. The porosity validation test contains base case No. 8 and cases from 13 to 16, and the results are shown in **Fig. 12**. The results reveal the same trend as the permeability validation test. When the porosity is smaller, it follows the type curve. While when the porosity is greater than 10%, the results shift to the right of the curve, which means the huff and puff times are greater than necessary. However, something is different here than in the permeability cases. It's not realistic for a higher porosity (such as 15% or 25%) case to have such a lower permeability of 500 nano-Darcy. Thus, in a reasonable range of porosity of less than 10%, the results follow the generated type curve.

Table 6. Validation tests with porosity and viscosity for scale 12.5 ft * 16.7 ft.

Case No.	porosity, %	viscosity, cp	permeability, nano-Darcy	huff time, days	puff time, days	P_D
8	5	3	500	50	100	0.63
13	2.5	3	500	50	100	0.75
14	10	3	500	50	100	0.52
15	15	3	500	50	100	0.39
16	25	3	500	50	100	0.3
17	5	1	500	50	100	0.86
18	5	5	500	50	100	0.6
19	5	20	500	50	100	0.34
20	5	1	500	17	33	0.62

Fig. 12. Oil R.F. vs. dimensionless time for porosity validation test.

Viscosity. **Fig. 13** shows the results of the viscosity validation tests. Four different viscosities (1, 3, 5, and 20 cp) were tested for the model, respectively. **Fig. 13** illustrates that a higher viscosity will result in a lower oil recovery, located on the early stage of the curve. The oil recovery for a lower oil viscosity moves to the right of the type curve, which proves that less huff and puff time is necessary for this case. After reducing the operation times as case 20 shows in **Table 6**, the oil recovery result follows the type curve described in **Fig. 13**.

These validation tests illustrate that the type curve can be used to predict the oil recovery for different scales with the given field parameters. Also, the huff and puff times can be modified based upon the comparison of the calculated oil recovery vs. dimensionless time with the type curve. If the resulting curve is located at the right side of the type curve, the huff and puff times should be decreased. If the resulting curve is located on the early stage of the type curve (the left side), it is necessary to increase the huff and puff times to obtain a higher oil recovery.

Fig. 13. Oil R.F. vs. dimensionless time of different scales for viscosity validation test.

[3.4] Operation Schedule Validation Test

In the above discussion, the field-scale model with a diameter of 125 ft and a height of 167 ft required dramatically longer huff and puff times to reach the same final cumulative oil recovery of the lab-scale model. In this section, more feasible huff and puff periods were used in the process as shown in **Table 7** and **Fig. 14**.

Table 7. Huff and puff times validation tests for scale 125 ft * 167 ft.

Schedule	1	2	3	4	5	6
Scale (diameter* length)	125 ft * 167 ft					
huff time, days	5000	5000	200	200	300	500
puff time, days	15000	35000	500	1000	2000	3500
Dimensionless Pressure	0.63	0.8	0.23	0.28	0.33	0.43

Fig. 14. Oil R.F. vs. dimensionless time for huff-n-puff time validation test.

By comparing schedule 1 with schedule 2, we see the final cumulative oil recovery of schedule 2 is 40%, while schedule 1 is only 30%. A longer production time is converted to a larger dimensionless time, which contributes to a higher oil recovery. The same phenomenon is obtained when comparing schedules 3 and 4. **Fig. 14** illustrates that shorter huff and puff times yield a smaller dimensionless time, resulting in a lower cumulative oil recovery. The value of dimensionless pressure increases as the huff and puff periods increase, which reflects the final cumulative oil recovery differences for different cases. The larger the dimensionless pressure is, the higher the final cumulative oil recovery achieved.

[3.5] Validation Test of Well Constraints

In the previous cases, we adopted the same well constraints (well bottom hole pressure 2000 psi during huff process and 14.7 psi during the puff process) with the one in lab-scale which is not realistic in the field production. The field operation conditions were used in the following cases as shown in **Table 8**. The results in **Fig. 15** show that oil recovery for realistic field cases follow the type curve which proves the type curve can represent cases during the gas huff-n-puff process in shale oil reservoir production. Although the initial pressure of the three cases are different, the differences between the dimensionless pressures are minute, which leads to a similar cumulative oil recovery.

Table 8. Well constraints validation tests for 125 ft * 167 ft, Injection time 500 days, production 3500 days

Schedule	7	8	9
huff BHP, psi	7000	6000	5000
puff BHP, psi	1000	1000	1000
huff time, days	500		
puff time, days	3500		
P_D	0.47	0.44	0.42

Fig. 15. Oil R.F. vs. dimensionless time for well constraints validation test.

We have shown a method to predict oil production in shale oil reservoirs when using gas huff-n-puff EOR. If we know the parameters, like porosity, permeability, viscosity, length, we can simulate the huff-n-puff process and design an operation schedule to predict oil recovery.

[4] A Case Study

As there are no field huff-n-puff cases implemented on shale reservoirs, we use a primary depletion case as the first cycle of huff-n-puff to validate the type curve theory. This case is the field production data of a hydraulically fractured horizontal well from the Middle Bakken in North Dakota. **Table 9** presents the reservoir properties which are based on the published data in Middle Bakken shale (Kurtoglu and Kazemi, 2012). The field model was run using the control of actual oil rate history as shown in **Fig. 16 (a)**, and the bottom hole flowing pressure is predicted as shown in **Fig. 16 (b)**. Before the primary depletion, the initial reservoir pressure was 7800 psi. Huff efficiency can be considered 1. The production time of 450 days can be treated as the puff process. The puff efficiency can be calculated by the ratio of the area below the red line to the total area below the initial reservoir pressure before 450 days as shown in **Fig. 16 (b)**. The estimate P_{puff} equals 0.45. As all the other parameters in the dimensionless time equation are known, the dimensionless time can be calculated as 17.87. According to the generated type curve, the cumulative oil recovery is 1.76% when dimensionless time equals 17.87. Thus, for this case, the cumulative oil recovery for 450 days' primary depletion is 2.06%. The historically matching result for water cut is shown in **Fig. 16 (c)**, and the result for bottom hole pressure in 5 years' production is shown in **Fig. 16 (d)**. History matching results for oil recovery in the first 450 production days is shown in Fig. 17. 12 different production times were randomly selected to check the difference between the predicted oil recovery by the theory and simulation results in the subsequent 4 years' production time. The perfect

match shows that the dimensionless time method can properly predict the oil recovery. At the end of 5 years, P_{puff} equals 0.27, and t_D is calculated as 45.45. The oil recovery according to the type curve is 6.28%. This result is in good agreement with the simulation result (6.30%) for the field data as shown in **Fig. 17**.

(a) History matching process with oil rates control

(b) Predicted bottom hole pressure

(c) Water cut in the simulation model

(d) Simulation prediction for 5 years

Fig. 16. History matching for production data in Middle Bakken shale

Fig. 17. Simulation results for cumulative oil recovery after 5 years' primary depletion production

Table 9. Reservoir properties of Bakken formation

Parameter	Value	Parameter	Value
permeability, md	0.005	Thickness, ft	40
porosity, %	5.6	bubble point pressure, psi	1850
oil gravity, API	40	fracture spacing, ft	300
total compressibility, psi ⁻¹	0.000001	initial oil saturation	0.6
reservoir pressure, psi	7800	top of reservoir, ft	8800
reservoir temperature, °F	240	C	0.000264

[5] Conclusion

This paper focuses on the upscale study of the gas huff-n-puff process in shale oil reservoirs. Dynamic gridding in simulation was used in this study. The following conclusions may be drawn from this study.

1. A model of a larger size yields a smaller oil recovery under the same operating conditions. However, the field-scale can reach the same oil recovery when huff and puff times are modified using Eq. 15.
2. A new term, dimensionless pressure, is defined in Eq. 11 as one parameter representing the difference in the huff-n-puff efficiency.
3. A new form of dimensionless time (Eq. 15) for gas huff-n-puff is developed and applied to cases with different sizes. After converting to dimensionless time, a single type curve of oil recovery factor vs. dimensionless time can be generated.
4. The type curve provides a new method to scale and predict oil recovery in shale oil reservoirs during the gas huff-n-puff process. The type curve can also be used to optimize the huff and puff times.

Nomenclature

c	=	constant, the ratio of the gravity force to the capillary force
C	=	constant in dimensionless time in this study, 0.000264
c_t	=	the coefficient of volume compressibility, 1/psi
k	=	absolute permeability, mD
k_e^*	=	effective permeability of the two phases at S_{wf} , mD
L	=	the characteristic length in Eq. 1 and Eq. 15, ft
L_a	=	the characteristic length in Eq. 6 and Eq. 7, ft
L_c	=	the characteristic length in Eq. 3, ft
L_f	=	half fracture length in Eq. 5, ft
P_c	=	capillary pressure, psi
P_e^*	=	capillary pressure at S_{wf} , psi
P_D	=	dimensionless pressure
P_{max}	=	the maximum matrix average pressure in one cycle, psi
P_{avg}	=	the matrix average pressure at any time, psi
P_{huff}	=	huff process efficiency
P_{puff}	=	puff process efficiency
R	=	recovery by spontaneous water imbibition

R^*	=	normalized oil recovery
RF	=	Oil recovery factor in equations (12), (13), and (14)
S_{wf}	=	water saturation behind imbibition front
S_{wi}	=	initial water saturation
t	=	time, hours
t_{Huff}	=	huff time, days
t_{Puff}	=	puff time, days
t_D	=	dimensionless time
μ_e	=	the effective viscosity of the two phases (but considered as one phase), cp
μ_o	=	viscosity of oil, cp
μ_w	=	viscosity of water, cp
$\emptyset$	=	porosity
σ	=	interfacial tension, psi·ft
θ	=	contact angle, °

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