Using CO_2 Prophet to Estimate Recovery Factors for Carbon Dioxide Enhanced Oil Recovery

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Chapter B of
Three Approaches for Estimating Recovery Factors in Carbon Dioxide Enhanced Oil Recovery
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Chapter B. Using CO_2 Prophet to Estimate Recovery Factors for Carbon Dioxide Enhanced Oil Recovery

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Introduction

The Oil and Gas Journal's enhanced oil recovery (EOR) survey for 2014 (Koottungal, 2014) showed that gas injection is the most frequently applied method of EOR in the United States and that carbon dioxide (CO_2) is the most commonly used injection fluid for miscible operations. The CO_2-EOR process typically follows primary and secondary (waterflood) phases of oil reservoir development. The common objective of implementing a CO_2-EOR program is to produce oil that remains after the economic limit of waterflood recovery is reached. Under conditions of miscibility or multicontact miscibility, the injected CO_2 partitions between the gas and liquid CO_2 phases, swells the oil, and reduces the viscosity of the residual oil so that the lighter fractions of the oil vaporize and mix with the CO_2 gas phase (Teletzke and others, 2005). Miscibility occurs when the reservoir pressure is at least at the minimum miscibility pressure (MMP). The MMP depends, in turn, on oil composition, impurities of the CO_2 injection stream, and reservoir temperature. At pressures below the MMP, component partitioning, oil swelling, and viscosity reduction occur, but the efficiency is increasingly reduced as the pressure falls farther below the MMP.

CO_2-EOR processes are applied at the reservoir level, where a reservoir is defined as an underground formation containing an individual and separate pool of producible hydrocarbons that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system. A field may consist of a single reservoir or multiple reservoirs that are not in communication but which may be associated with or related to a single structural or stratigraphic feature (U.S. Energy Information Administration [EIA], 2000).

The purpose of modeling the CO_2-EOR process is discussed along with the potential CO_2-EOR predictive models. The data demands of models and the scope of the assessments require tradeoffs between reservoir-specific data that can be assembled and simplifying assumptions that allow assignment of default values for some reservoir parameters. These issues are discussed in the context of the CO_2 Prophet EOR model, and their resolution is demonstrated with the computation of recovery-factor estimates for CO_2-EOR of 143 reservoirs in the Powder River Basin Province in southeastern Montana and northeastern Wyoming.

Modeling CO_2-EOR Production and Assessment of Recovery Potential

The technical performance of an EOR project is measured by the volume of incremental oil that can be produced beyond the oil that would have been produced through the waterflood stage of reservoir development. If the CO_2-EOR recovery factors are sufficiently high, producers will have an incentive to profitably recover the remaining oil after waterflood. From a national or regional prospective, the aggregate volume of oil that remains after waterflood is large,[2] and the percentage that can be commercially recovered is of interest to industry and government decisionmakers. Unlike undiscovered oil accumulations, the candidate reservoirs are already identified, and most have a documented production history. For assessments of potential EOR recovery at the national or regional levels, analysts might have to screen and evaluate thousands of reservoirs. Each reservoir, however, has some production history and possibly other data that may allow the analyst to estimate values of reservoir temperature, pressure, porosity, permeability, net pay, and oil in place. The parameter values assigned to each reservoir are assumed to represent average values for the reservoir. Ideally, the data available for each potential candidate reservoir are sufficient to determine, at the reconnaissance level, amenability to miscible CO_2-EOR (Taber and others, 1997) and to predict reservoir performance.

A numerical reservoir model is a tool to predict reservoir response, in terms of produced oil, natural gas, and CO_2, to the injection of CO_2 and water. In actual EOR project developments, the operator commonly has a sophisticated simulation model prepared that characterizes reservoir and fluid

[1]U.S. Geological Survey.

[2]If 600 billion barrels of original oil in place has been discovered in the United States and primary and waterflood phases of development have recovered only one-third of that, then about 400 billion barrels remain in discovered reservoirs as a target for enhanced oil recovery (Kuuskraa and others, 2013).

composition spatially at individual grid points. The model is used in the design of the EOR project and later for the daily operations and management of reservoir production. Such models are three-dimensional and provide an array of reservoir attributes at each grid point, which is identified with a physical location in the reservoir. Compositional reservoir models also show the changes in the chemical composition of reservoir fluids as injection and production progress. Data required to populate such models include a site-specific geochemical characterization of the crude oil, reservoir rocks, and reservoir parameters that is well beyond what is available from public and commercial data sources. During the last two decades of the 20th century, the Federal Government sponsored development of at least two public domain CO_2-EOR scoping models: CO_2 PM and CO_2 Prophet.

CO_2 PM is a pattern-level[3] analytical model developed by Paul and others (1984) for the National Petroleum Council's (NPC's) 1984 study to model miscible CO_2-EOR project recoveries for a set of candidate oil reservoirs. It was described by Ray and Munoz (1986), and its application to the NPC study was described by Robl and others (1986). CO_2 PM applies sweep efficiency correlations as a means of relating injected fluids to produced oil, natural gas, water, and CO_2.

CO_2 Prophet is another pattern-level reservoir model. It uses computational algorithms that represent later advances in modeling fluid recovery (Willhite, 1986). CO_2 Prophet predicts the reservoir responses by generating fluid flow streamlines between injection and production wells and models the physical displacement and recovery of oil along stream tubes formed when the streamlines are used as boundaries (Green and Willhite, 1998). This model was developed for the U.S. Department of Energy by Texaco Inc. under contract DE–FC22–93BC14960 and was described by Dobitz and Prieditis (1994). When this model is used for national or regional assessments, the predicted oil recovery factor for a pattern is applied to the entire reservoir. In the past, CO_2 Prophet has been applied to regional and national assessments for the U.S. Department of Energy by Advanced Resources International (ARI, 2006a, b, c, d) and by ARI and the U.S. Department of Energy, National Energy Technology Laboratory (Wallace and others, 2013). Industry applications of CO_2 Prophet include its use as a scoping tool to evaluate potential candidate reservoirs (Hsu and others, 1995).

Estimation of Recovery Factors for Miscible CO_2-EOR

CO_2-EOR process modeling provides predictions of the reservoir's production response to a pre-specified regime of CO_2 and water injection. For this analysis, the forecasts are computed on the basis of a single pattern of injector and producer wells that is assumed to be representative of the reservoir.[4] The CO_2-EOR recovery factor as defined here represents the fraction of the pattern's original oil in place (OOIP) that is recovered over the duration of the EOR project and is interpreted to represent technically recoverable[5] oil because no economic screen or cutoff is applied.

A CO_2-EOR process will be miscible if the reservoir pressure is maintained at least as high as the MMP of the oil. The MMP depends on the composition of the oil and reservoir temperature (Mungan, 1981). The formation fracture pressure, which is calculated by using an appropriate pressure gradient and depth, must also be greater than the MMP to assure that miscibility can actually be attained. In the implementation of an actual CO_2-EOR program, the reservoir pressure is commonly increased to the MMP by shutting in producing wells and continuing to inject water after the waterflood program has been discontinued.

Initial Reservoir Conditions and Injection Regime

The application of CO_2 Prophet to the suite of carbonate and clastic reservoirs that are suitable candidates for miscible CO_2-EOR requires a number of simplifying assumptions. The computational program requires the entry of data that represent the nature of the reservoir and associated fluids at the start of the CO_2-EOR process. The simplifying assumptions are the major determinants for the values of these data. An assumed parameter used as the initial oil saturation at the start of the CO_2-EOR evaluation is the residual oil saturation to water (oil saturation after the waterflood). For the clastic reservoirs, this value is assumed to be 0.25, and for carbonate reservoirs, the value is assumed to be 0.305. These values are based on past high-level reconnaissance-type CO_2-EOR oil recovery assessments such as the 1984 NPC study (Robl and others, 1986) and subsequent industry and government adjustments (Donald J. Remson, National Energy Technology Laboratory, written commun., 2015).

The water and CO_2 injection rates and the injection regime also reflect initial conditions. These rates were set so that the reservoir pressure remains at or above the MMP but below fracture pressure less a safety margin of 400 pounds-force per square inch (psi),[6] and the analyst assumed a five-spot injector/producer pattern and pattern area (Lyons, 1996). Holtz (2014) reported that after initial CO_2 injection, water and CO_2 injectivity may increase, decline, or remain the same. However, changes in injectivity are specific to individual reservoirs and even individual patterns and cannot

[3]A pattern is a configuration of injector and production wells.

[4]In commercial applications of CO_2 Prophet where pattern-specific data are available, individual patterns across a reservoir can be modeled and then pattern results can be aggregated to arrive at an average recovery factor.

[5]Technically recoverable resources are the resources in accumulations producible by using current recovery technology and industry practices but without reference to economic profitability.

[6]This safety margin of 400 psi is somewhat arbitrary, and there are reservoirs where it may be desirable to have a greater margin.

be accurately predicted. Holtz (2014) and Wallace and others (2013) discussed a number of treatments that are commercially available to remediate the injectivity losses. Consequently, for the calculation of the technically recoverable oil from miscible CO_2-EOR, it is assumed that any decline in injectivity is remediated.

The total volume of CO_2 injected during the EOR project model runs amounts to 100 percent of the hydrocarbon pore volume (HCPV). The assumed injection regime is accomplished in three phases. In phase 1, the volume of injected CO_2 is equivalent to 25 percent of the current HCPV; in phase 2, the volume of injected CO_2 is equivalent to 35 percent of the HCPV; and in phase 3, the volume of injected CO_2 is equivalent to 40 percent of the HCPV. To achieve a tapered water-alternating-with-gas (WAG) injection, for each phase, a different water:gas ratio is specified. Phase 1 has a 1:3 WAG ratio, phase 2 has a 1:2 WAG ratio, and phase 3 has a 1:1.5 WAG ratio. As the WAG is tapered, water is injected in greater cumulative amounts in each phase relative to the injected CO_2 over time.

Reservoir Heterogeneity and Other Default Reservoir Conditions

The model's calculations also require a value for the Dykstra-Parsons coefficient of permeability variation to characterize reservoir heterogeneity. Producers use measured permeability values from well logs or core samples to calculate the Dykstra-Parsons coefficient. Homogeneous reservoirs have permeability variations near 0, and at the extreme, heterogeneous reservoirs have permeability variations near 1. When permeability variation measurements are available for individual patterns, the Dykstra-Parsons coefficient value may be assigned to individual patterns across the reservoir. However, for reconnaissance-type regional or national studies that must evaluate thousands of reservoirs, reservoir-specific values of the Dykstra-Parsons coefficients based on the actual permeability measures are simply not publicly available.

An alternative approach is to use a constructed coefficient, correlated with actual reservoir heterogeneity, to represent the average value of the Dykstra-Parsons coefficient for the reservoir. Hirasaki and others (1984) developed an algorithm for application in the 1984 NPC EOR study to calculate a pseudo-Dykstra-Parsons coefficient derived from the calculated waterflood sweep efficiency and mobility ratio (between water and oil) for each candidate reservoir. The relations among pseudo-Dykstra-Parsons values, sweep efficiency, and mobility ratios were presented in graphical form by Willhite (1986) and Hirasaki and others (1984). The graphs were digitized so that for any given mobility ratio and sweep efficiency, the pseudo-Dykstra-Parsons coefficient could be numerically computed.

Hirasaki and others (1984, 1989) suggested some adjustments in the values of the pseudo-Dykstra-Parsons coefficient calculated from their sweep efficiency formula to more closely align values with the Dykstra-Parsons coefficient based on measurements of permeability variability. If the calculated coefficient value was positive but less than 0.5, it was set to 0.5. When the coefficient value exceeded 0.98, it was set to a default value of 0.72, and calculated coefficient values that were between 0.72 and 0.98 were left unchanged (Hirasaki and others, 1989). According to J.K. Dobitz (Windy Cove Energy, written commun., 2015), an author of CO_2 Prophet, the program uses a maximum of 10 layers to describe variations in permeability, and that maximum limits the maximum distinguishable value of the pseudo-Dykstra-Parsons coefficient to 0.86. So if the pseudo-Dykstra-Parsons coefficient given by the method of Hirasaki and others (1984) is greater than 0.86, then it is reset to 0.86.

Other assumptions about the initial conditions follow. The connate water or irreducible water saturation values were assumed to be 0.2 for all reservoirs. On the basis of data presented by Lange (1998), a value of 0.08 was selected in this study for all reservoirs suitable for miscible CO_2-EOR to represent the residual oil saturation following multiple passes (contacts) of the CO_2 solvent. The specific gravity for casing-head gas, with respect to air (where the specific gravity of air equals 1.0), was assumed to be 0.7. The values of the endpoints of the relative permeability functions were based on default values for mildly water-wet reservoirs suggested by Michael Stein (BP, retired, written commun., 2014).[7]

Recovery-Factor Determinants

CO_2 Prophet models the physical process occurring in the reservoir when water and CO_2 are injected. It is a simplification of the actual physical processes and does not capture the chemical processes that would be described by a sophisticated compositional model. Nor does the modeling capture the unanticipated operational factors such as fractures or thief zones that affect the actual recovery factors. A number of numerical experiments were carried out with the same reservoir model in order to understand the primary determinants of the EOR recovery factor as computed by the CO_2 Prophet model. The experiments showed that the principal determinants of the recovery factors were the residual oil saturation at the start of the CO_2-EOR program and the measure of reservoir heterogeneity; to a much smaller extent, the injected volume of CO_2 beyond 100 percent of the HCPV, the water:CO_2 gas ratio, and the oil viscosity[8] affect the recovery factors.

[7]In particular, the following parameters are specified: the endpoint relative permeability of oil at connate water saturation is 1, the endpoint relative permeability of water at residual oil saturation is 0.3, the endpoint relative permeability of CO_2 at connate water saturation is 0.4, the endpoint relative permeability of gas-to-connate-water saturation is 0.4, and the exponents on the relative permeability equations are 2.0.

[8]The maximum viscosity allowed for miscible CO_2-EOR is 10 centipoises. Measuring the effect of the oil viscosity is somewhat more complicated. A change in oil viscosity that changes the API gravity of the oil will change the MMP, which will also affect the required reservoir operating pressure and injection rates.

The reservoir heterogeneity, represented by the Dykstra-Parsons coefficient, is used directly by the model to create permeability layers that exhibit the inferred permeability variability and resistance to fluid flow. Figure B1 shows the recovery factor as a surface function of the residual oil saturation, which ranges from 0.13 to 0.33, and the Dykstra-Parsons coefficient, which ranges from 0.50 to 0.85. For figure B1, the volume of injected CO_2 is 100 percent of the HCPV.

Figure B2 shows the effects of increasing the injected volume of CO_2 to 150 percent of the HCPV. The curve labeled 100 percent of HCPV can be visualized as a slice of the recovery-factor model in figure B1 for a reservoir where the assumed residual oil saturation to water is 0.305, which is characteristic of carbonate reservoirs that are candidates for miscible CO_2-EOR. The absolute value of the improvement in the recovery factor ranges from 2.5 to 3.5 percent, and the incremental increases in the recovery factor decline as the residual oil saturation declines.

Along with the recovery-factor estimates, the reservoir simulation provides the volumes of injected CO_2 and produced CO_2 and oil. The net utilization of CO_2 over the life of the EOR program is the arithmetic difference between the volume of injected and produced CO_2 divided by the volume of oil produced. The injected minus the recovered CO_2 is the amount of CO_2 lost during the recovery process. The net utilization of CO_2 over the life of the project can be used to estimate the amount of CO_2 that will naturally be retained in the reservoir when the CO_2-EOR program is completed. Figure B3 shows how the net utilization varies with the residual oil saturation and the Dykstra-Parsons coefficient. For the set of data points generated to the recovery-factor surface shown in figure B1, the correlation coefficient between recovery factor and net utilization was calculated to capture the strength and direction of the relationship. The calculated correlation coefficient is –0.86. This correlation coefficient suggests for an individual reservoir that the greater the recovery factor, the lower the net utilization will be. The estimate of the retained CO_2 is obtained by taking the product of the oil produced and the net utilization factor; the estimate is based on the assumption that the operator will not try to capture and re-sell CO_2 remaining in the reservoir.

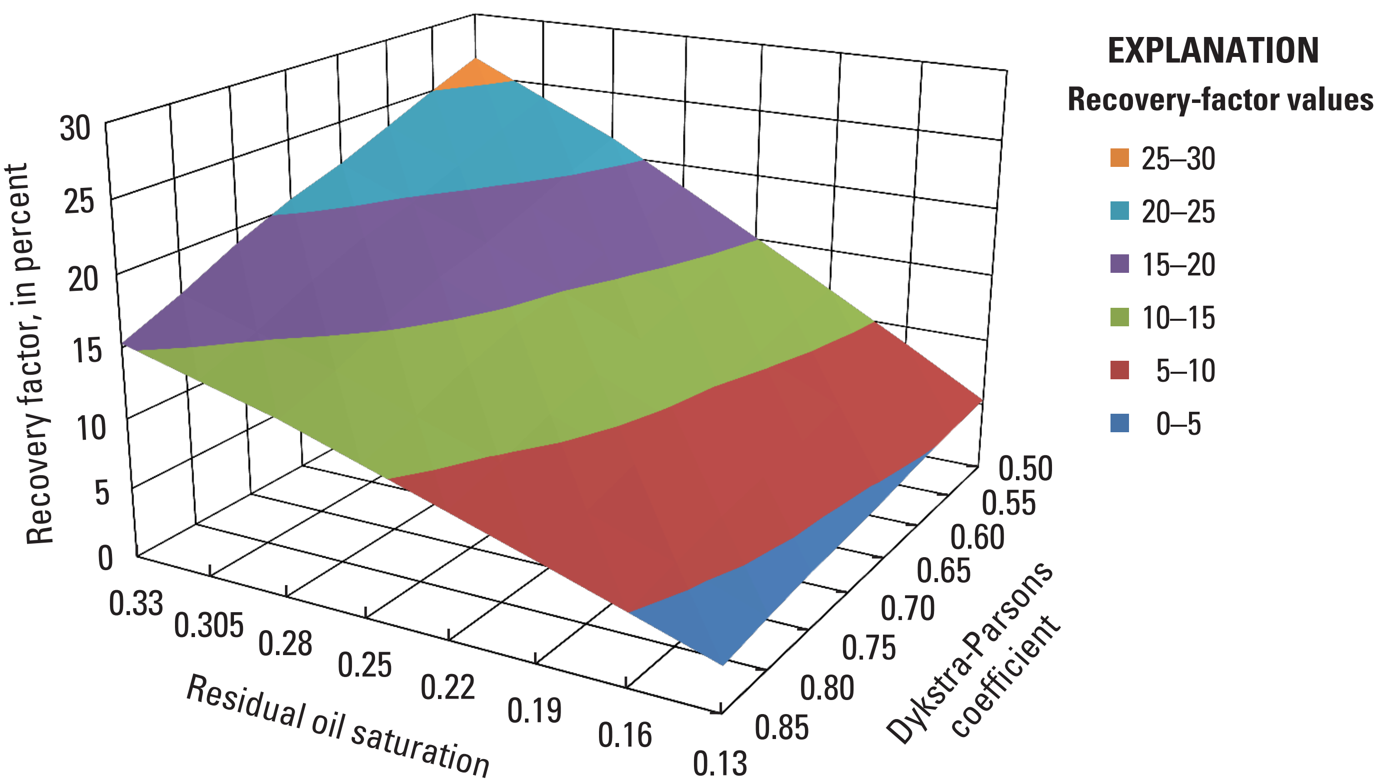

Figure B1. Three-dimensional graph showing estimated recovery factors during miscible carbon dioxide (CO_2) enhanced oil recovery (EOR), in percentage of the original oil in place, shown as a function of reservoir heterogeneity as represented by the Dykstra-Parsons coefficient and the residual oil saturation to water at the start of the EOR program. The residual oil saturation of 0.305 is assumed to be characteristic of carbonate reservoirs that are candidates for miscible CO_2-EOR. The CO_2 Prophet model was used to compute recovery factors for a representative reservoir.

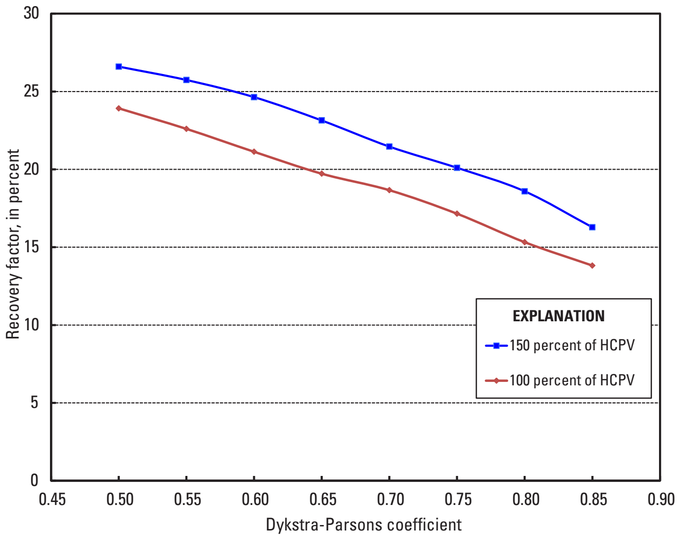

Figure B2. Two-dimensional graph showing estimated recovery factors during miscible carbon dioxide (CO_2) enhanced oil recovery (EOR), in percentage of the original oil in place, shown as a function of reservoir heterogeneity when the residual oil saturation at the start of the EOR program is 0.305. The red line represents a slice of figure B1, at 0.305 residual oil saturation. Figure B1 is based on a volume of CO_2 equivalent to 100 percent of the hydrocarbon pore volume (HCPV). The CO_2 Prophet model was used to compute recovery factors for a representative reservoir.

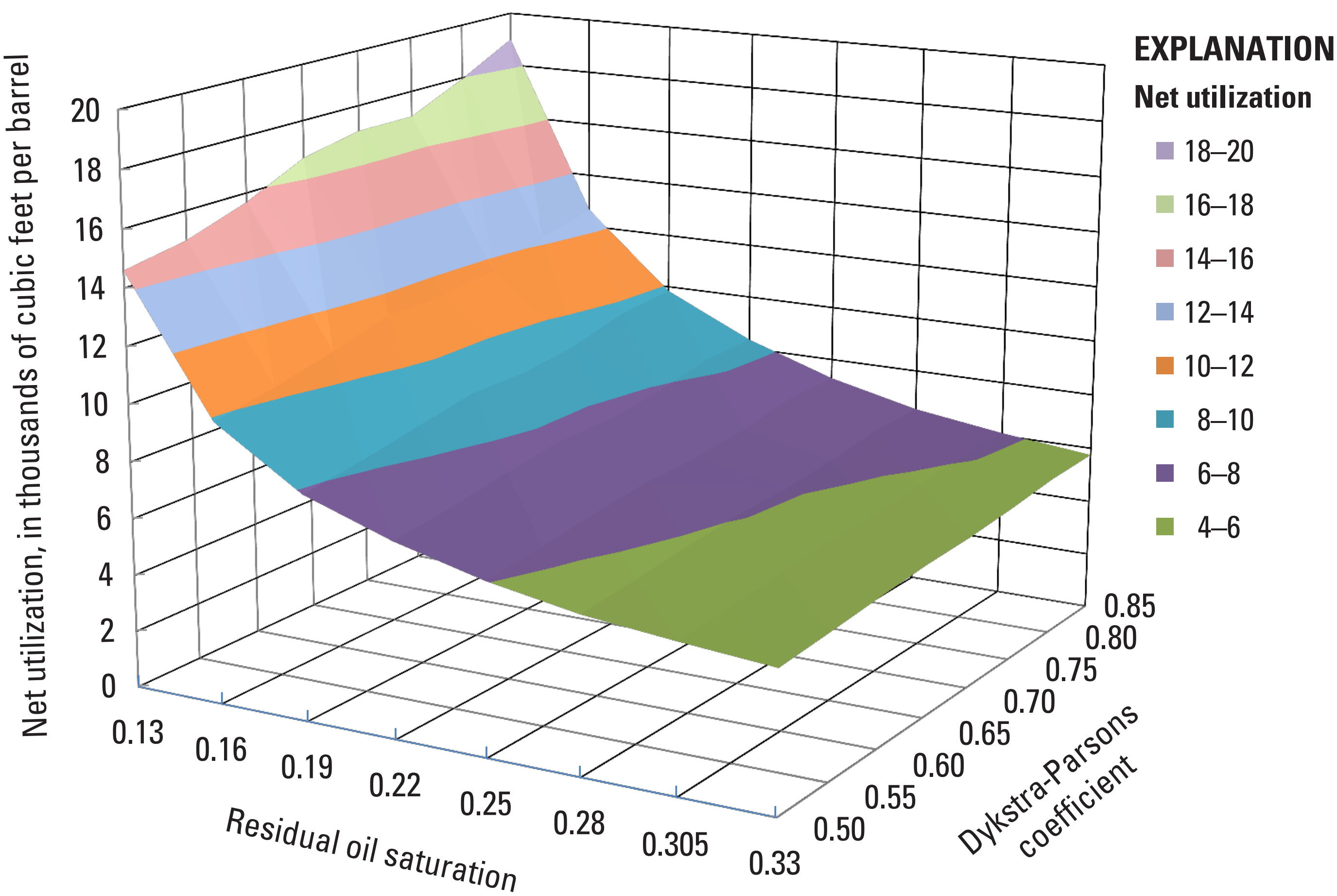

Figure B3. Three-dimensional graph showing estimated net carbon dioxide (CO_2) utilization factors during miscible CO_2 enhanced oil recovery (EOR), in thousands of cubic feet per barrel (both measured at standard surface conditions), shown as a function of reservoir heterogeneity as represented by the Dykstra-Parsons coefficient and the residual oil saturation at the start of the EOR program. The CO_2 Prophet model was used to compute net CO_2 utilization factors for a representative reservoir.

Recovery-Factor Estimates for Reservoirs in the Powder River Basin Province

Selection of Reservoirs for Recovery-Factor Calculations

Several criteria were imposed on the reservoirs selected from the candidates that were considered for miscible CO_2-EOR and that conformed to the requirements set out by Taber and others (1997). Reservoirs that had recovery factors evaluated by using the CO_2 Prophet model had an average permeability of at least 2 millidarcies, a net pay thickness of at least 5 feet, and an estimate of OOIP of at least 5 million barrels. Recovery factors for selected reservoirs in the conterminous United States were presented by Attanasi and Freeman (2016). As a related report from the same study, this chapter uses the Powder River Basin Province, which includes reservoirs in Wyoming and Montana, as an example and provides additional data; recovery factors were estimated for 143 clastic reservoirs in this province.

Distributions of Recovery Factors and Net Utilization Factors

The play and province classification scheme followed here corresponds to the definitions used in the 1995 USGS National Oil and Gas Assessment (NOGA; Gautier and others, 1996). The play names and codes are identified in table B1. There were no miscible carbonate reservoirs identified in the Powder River Basin Province, so the recovery factors are representative of clastic reservoirs. Distributions of the recovery factors and net utilization factors for 143 reservoirs in the 7 conventional plays evaluated for the Powder River Basin are shown in figures B4 and B5, respectively. Boxplots display the distribution of values where the interquartile range is shown between the 25th percentile (bottom of box) and the 75th percentile (top of box). The median value is the thick line, and the minimum and maximum values are shown by the vertical lines outside the box. Table B1 provides characteristics of each play distribution.

For each of the reservoirs evaluated, the residual oil saturation at the initiation of CO_2-EOR recovery was assigned a value of 0.25 because the candidates were classified as clastic reservoirs. Each reservoir was assumed to have 100 percent of the HCPV injected with CO_2 over the duration of the EOR recovery program. The range of calculated recovery factors therefore reflects variations in reservoir heterogeneity as measured by the pseudo-Dykstra-Parsons coefficient, oil viscosity, and other variables that may affect recovery. The play-level recovery-factor distributions, as shown by each boxplot in figure B4, are generally right skewed. A right-skewed distribution is not symmetric and is indicated by the boxplots when the vertical distances between the minimum and first quartile to the median value are much shorter than the vertical distances from the median to the third quartile and maximum value. Across plays, median recovery factors (represented by the heavy line inside the box) range from 9.50 to 13.43 percent of the OOIP (table B1). These values are well within the published records (Christensen and others, 2001) when adjustments are made to the data to account for the percentage of the HCPV injected with CO_2.

Figure B5 shows the play distributions of the net CO_2 utilization factors, represented as boxplots. The net utilization factor indicates the rate at which CO_2 is retained per barrel of oil produced over the entire CO_2-EOR program. On an annual basis, the modeling results show that the net utilization is generally highest during the initial years of EOR production. Higher utilization is consistent with a greater percentage of the injected CO_2 being retained in the reservoir. The retention factor is simply the percentage of injected CO_2 that is retained in the reservoir. Table B1 shows the relevant retention statistics for each evaluated play of the Power River Basin Province. These median play values are consistent with the empirical findings of Olea (2015).

Table B1. Estimated recovery factors, net carbon dioxide utilization factors, and carbon dioxide retention factors during miscible carbon dioxide enhanced oil recovery (CO_2-EOR) for 143 clastic reservoirs in 7 plays in the Powder River Basin Province.

[Play codes and names are from 1995 U.S. Geological Survey National Oil and Gas Assessment (NOGA; Gautier and others, 1996). The recovery factors and median net CO_2 utilization factors from this study were also published in Attanasi and Freeman (2016, table 7). Estimates of recovery factors, net CO_2 utilization factors, and CO_2 retention factors were calculated by the CO_2 Prophet model. Net CO_2 utilization factors are in thousands of cubic feet of CO_2 per barrel of produced oil at standard surface conditions]

Play code	Play name	Number of oil reservoirs eligible for CO_2-EOR	Distribution of data					
			Minimum	Maximum	1st quartile	Median	Mean	3d quartile
			Recovery factor, in percent					
3302	Basin Margin Anticline	21	8.43	17.33	9.25	9.50	9.99	9.83
3304	Upper Minnelusa Sandstone	45	8.90	18.44	9.23	9.65	11.10	11.86
3306	Fall River Sandstone	14	9.16	18.42	9.64	9.79	11.61	12.74
3307	Muddy Sandstone	27	8.37	17.83	9.54	9.91	10.59	10.24
3309	Deep Frontier Sandstone	11	9.74	14.15	10.02	13.43	12.07	13.92
3312	Sussex-Shannon Sandstone	9	9.61	14.29	9.96	10.05	10.63	10.11
3313	Mesaverde-Lewis	16	9.45	13.75	9.61	9.85	10.79	11.46
			Net CO_2 utilization factor, in thousands of cubic feet per barrel of oil produced					
3302	Basin Margin Anticline	21	4.79	6.96	5.09	5.31	5.50	5.89
3304	Upper Minnelusa Sandstone	45	4.29	6.85	5.39	5.73	5.78	6.32
3306	Fall River Sandstone	14	4.98	7.47	5.96	6.44	6.27	6.58
3307	Muddy Sandstone	27	5.13	7.89	6.01	6.48	6.52	7.20
3309	Deep Frontier Sandstone	11	5.13	6.99	5.98	6.27	6.31	6.80
3312	Sussex-Shannon Sandstone	9	6.33	8.34	6.83	7.13	7.13	7.33
3313	Mesaverde-Lewis	16	5.63	6.77	5.89	6.34	6.26	6.53
			CO_2 retention factor, in percent					
3302	Basin Margin Anticline	21	21.42	33.85	22.25	22.63	23.53	23.03
3304	Upper Minnelusa Sandstone	45	21.93	36.55	22.97	24.40	26.24	28.17
3306	Fall River Sandstone	14	21.81	35.03	22.14	22.86	25.38	27.43
3307	Muddy Sandstone	27	21.60	36.59	22.42	23.06	24.32	23.92
3309	Deep Frontier Sandstone	11	24.47	31.99	24.83	30.44	28.22	31.06
3312	Sussex-Shannon Sandstone	9	22.91	30.61	23.66	23.80	24.71	23.90
3313	Mesaverde-Lewis	16	22.62	30.60	23.36	23.41	25.07	25.85

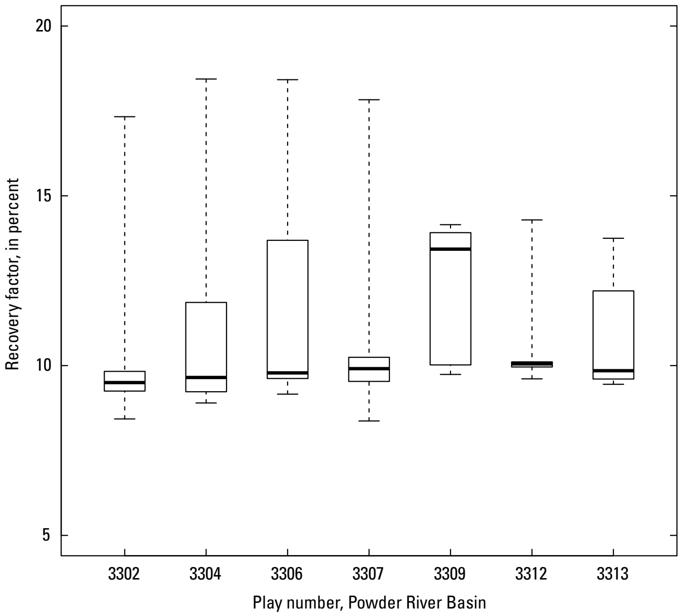

Figure B4. Boxplots showing distributions of the estimated recovery factors for clastic reservoirs by play in the Powder River Basin Province during miscible carbon dioxide enhanced oil recovery. The CO_2 Prophet model was used to compute recovery factors. Play codes and names are provided in table B1. Box extremities represent the first and third quartiles, and extreme values of the linear members are the minimum and maximum values. The darkened horizontal line inside each box is the median value.

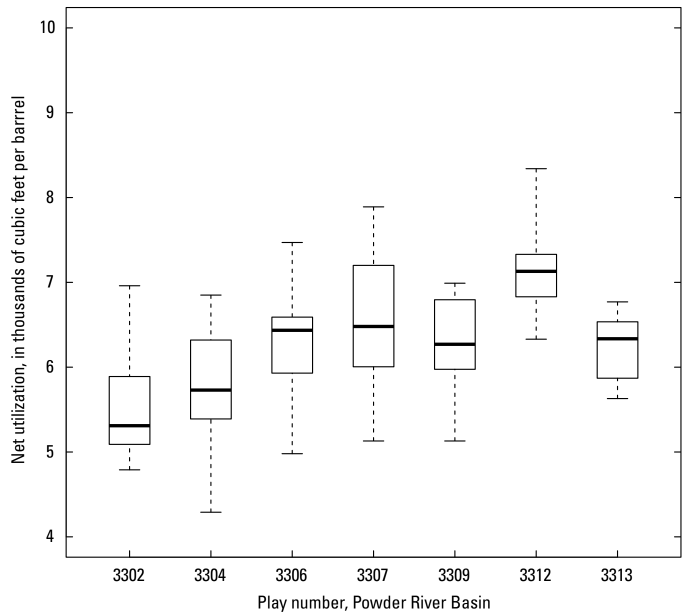

Figure B5. Boxplots showing distributions of the estimated net carbon dioxide (CO_2) utilization factors for clastic reservoirs by play in the Powder River Basin Province during miscible CO_2 enhanced oil recovery. The CO_2 Prophet model was used to compute the net CO_2 utilization factors, which are in thousands of cubic feet of CO_2 per barrel of produced oil (both measured at standard surface conditions). Play codes and names are provided in table B1. Box extremities represent the first and third quartiles, and extreme values of the linear members are the minimum and maximum values. The darkened horizontal line inside each box is the median value.

Summary and Conclusions

This chapter has demonstrated a scheme for calculating reservoir-level estimates of miscible CO_2-EOR recovery factors for application to assessments of potentially recoverable oil from EOR for entire petroleum provinces and regions. The scheme uses the CO_2 Prophet model. The scope of the regional or national assessments may require the evaluation of thousands of candidate reservoirs. Although numerical reservoir modeling requires specific data for individual reservoirs, the modeler will need to formulate a set of reasonable assumptions to provide default parameter values. This modeling approach allows one to clearly identify the oil production attributable to CO_2-EOR. For the modeling presented here, the residual oil saturation to water (that is, the oil that remains at the completion of a waterflood program), was the starting point for evaluation of potential CO_2-EOR production. All models are simplifications of the actual processes and should therefore not be expected to reflect all the subtleties of real-world petroleum operations.

CO_2 Prophet (Dobitz and Prieditis, 1994) was applied to calculate the technically recoverable oil to provide an estimate of the miscible CO_2-EOR recovery factor. The estimated recovery factors were highly sensitive to the reservoir heterogeneity and the assumed values for residual oil saturation to water. Other variables that affect recovery factors to varying degrees are the percentage of HCPV injected with CO_2 and the viscosity of the oil.

An advantage of applying rudimentary reservoir models, such as CO_2 Prophet, for calculating miscible CO_2-EOR recovery factors is that the oil attributed to the EOR program can be clearly delineated from oil produced under secondary recovery. Furthermore, the model provides a production profile for the oil as a function of the injected fluids. This profile allows the analyst to quantify the effects of alternative injection regimes on recovery factors. CO_2 Prophet, by predicting production, also allows the analyst to estimate the commercially recoverable oil from EOR. Estimates of net utilization and CO_2 retention are byproducts of the model's results. A significant challenge to using reservoir models in high-level assessments is the requirement for reservoir-level data.

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