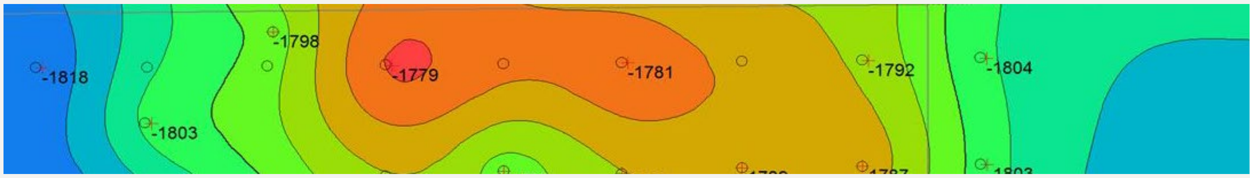

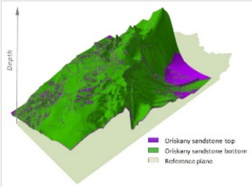

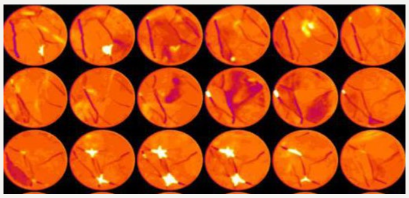

Reservoir Simulation of Enhanced Tight Oil Recovery: Wolfcamp Shale/Midland Basin

August 7, 2019

DOE/NETL-YYYY/####

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DOE Contract Number DE-FE0025912

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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ARI	Advanced Resources International
bbl	Barrel
Bcf	Billion cubic feet
B/D	Barrels per day
CO_2	Carbon dioxide
DOE	Department of Energy
EERC	Energy & Environmental Research Center
ft	Foot, Feet
GOR	Gas-oil ratio
Hz	Horizontal
MBbl	Thousand barrels
MBOED	Thousand Barrels Oil Equivalent per Day
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MESA	Mission Execution and Strategic Analysis
mi^2	Square mile
MM	Million
MMB/D	Million barrels per day
MMB/mi^2	Million barrels per day per square mile
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMP	Minimum miscibility pressure
N_2	Nitrogen
NETL	National Energy Technology Laboratory
OGIP	Original gas in-place
OOIP	Original oil in-place
psi	Pounds per square inch
psia	Pounds per square inch absolute
psi/ft	Pounds per square inch per foot
PVT	Pressure volume temperature
RB/STB	Reservoir barrels/stock tank barrels
Scf/Bbl	Standard cubic foot/barrel
SRV	Stimulated Reservoir Volume
U.S.	United States
°F	Degrees Fahrenheit

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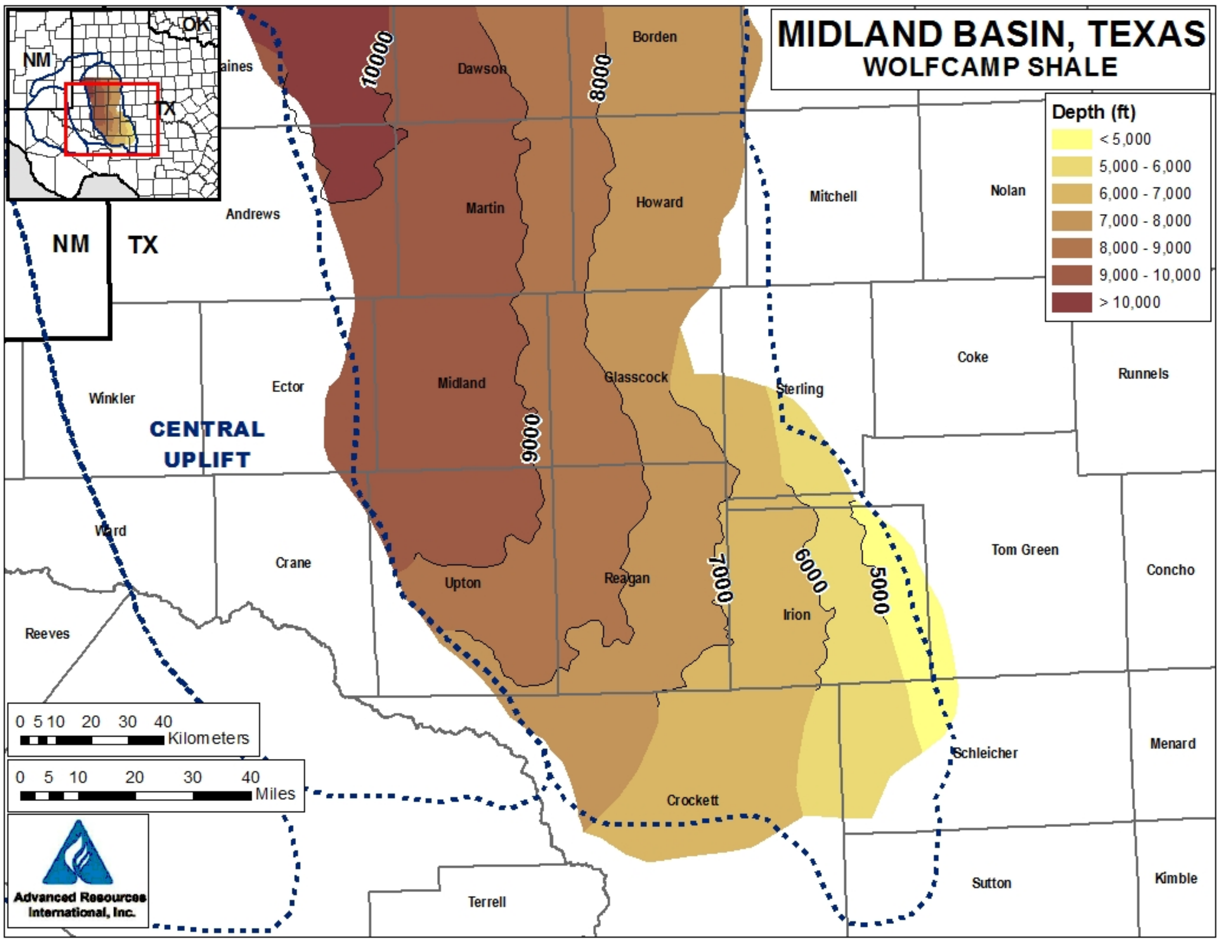
1 GEOLOGIC SETTING

The Midland Basin encompasses a 13,000 square mile area of West Texas. It contains all or parts of 20 counties in West Texas, ranging from Terry and Lynn on the north to Crockett and Schleicher on the south. Much of the tight oil development in the Midland Basin has occurred in the center of the basin, primarily in Martin, Midland, Upton, Howard, Glasscock, and Reagan counties at depths of 7,000 feet (ft) to 10,000 ft, displayed in Exhibit 1-1.

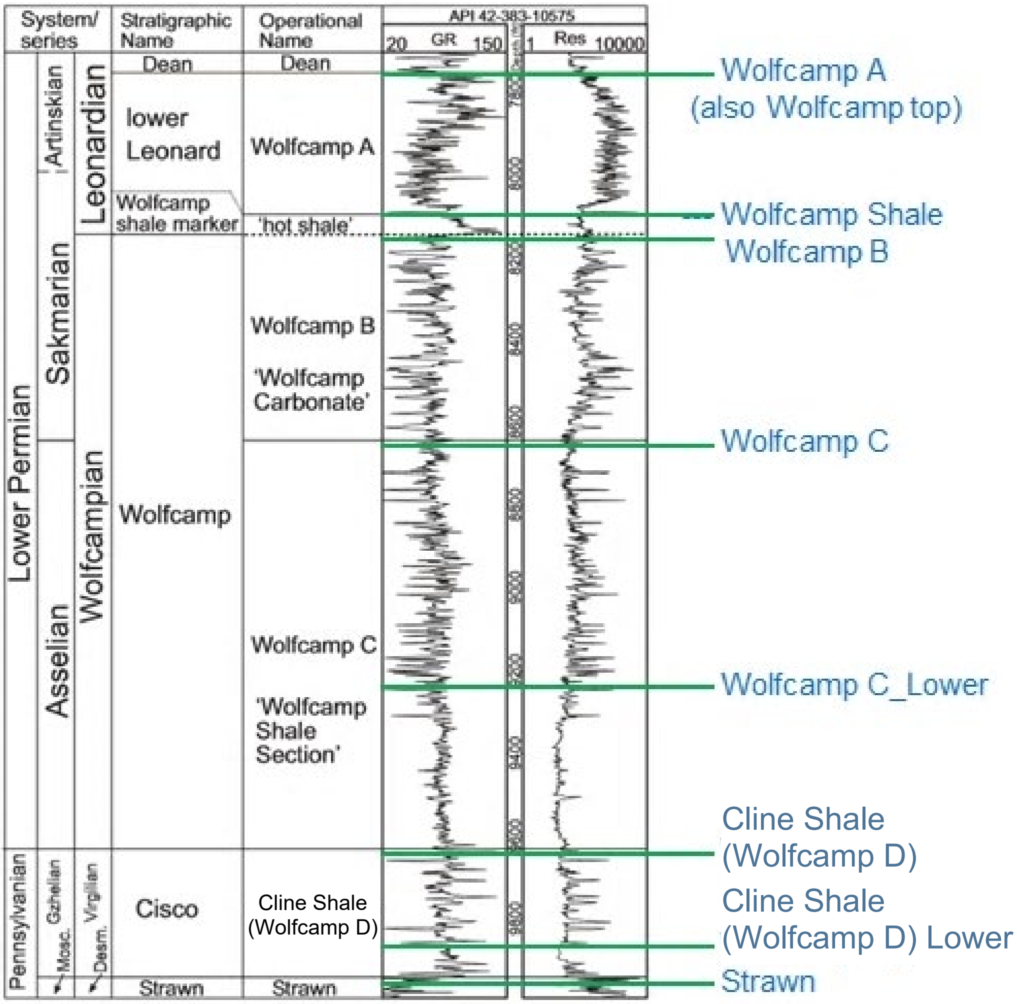
Exhibit 1-1 Midland Basin Wolfcamp Shale Location and Depth Map (Top of Wolfcamp Bench B)



Source: Advanced Resources International, 2019.

The Midland Basin's large tight oil resources exist in three major Permian-age formations, the Spraberry tight sand, the Wolfcamp Shale (Benches A, B, and C), and the Cline Shale (also called Bench D of the Wolfcamp Shale), shown in Exhibit 1-2.

Exhibit 1-2 Midland Basin Stratigraphic Column

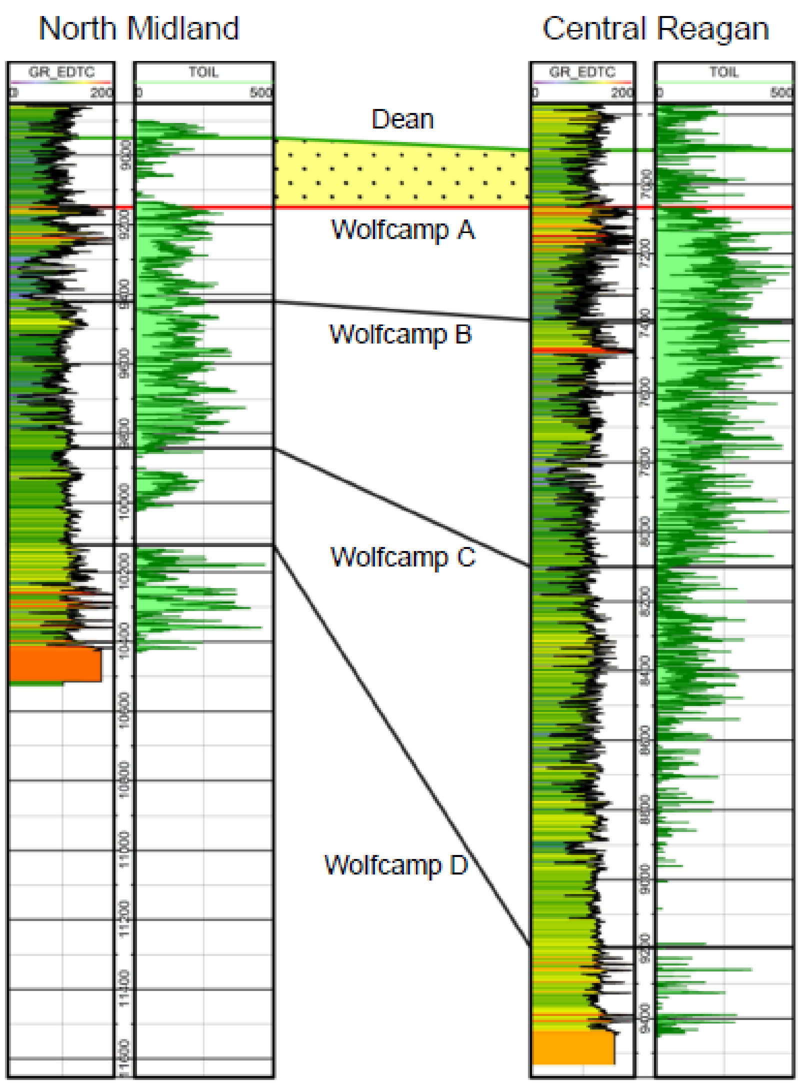


Source: Modified from Moreland, R., 2017.

2 STUDY AREA

The area selected for the reservoir simulation study is located in Reagan County, one of the three counties comprising the Eastern Basin Extension Wolfcamp Shale Area. The Wolfcamp Shale in this area contains three benches (A, B, and C), shown in Exhibit 2-1. The three Wolfcamp benches contain organic-rich shale, limestone and a mixture of other rock types. The Wolfcamp Bench B, the primary shale target in the Midland Basin, at a depth of 8,000 ft, was selected for the Reservoir Simulation Study.

Exhibit 2-1 Typical Wolfcamp Shale Logs



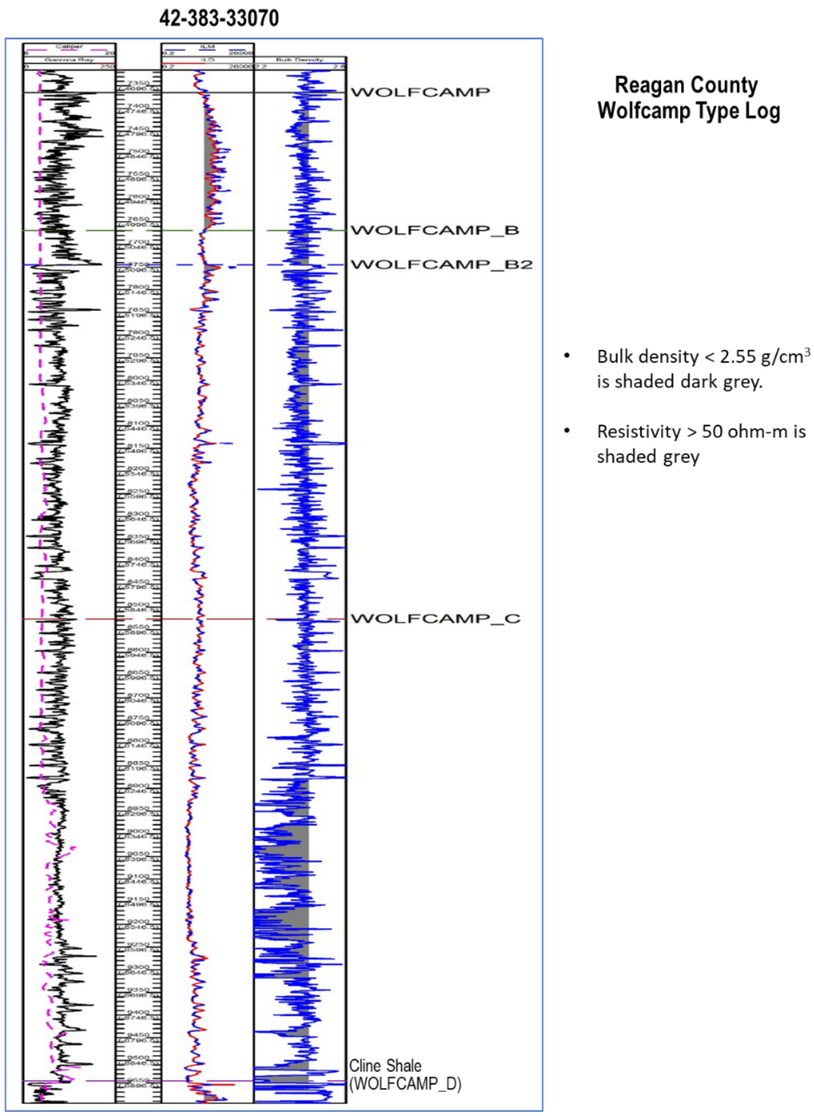
Source: Earthstone Energy, Inc, 2019

The Wolfcamp Shale in Reagan County extends across a 1,180 mi^2 area. The reservoir simulation targets a 180-acre area within the larger Reagan County Wolfcamp Shale tight oil resource area.

3 SOURCES OF DATA FOR RESERVOIR PROPERTIES

The reservoir properties used for the Study Area have been assembled from a variety of sources, including the Wolfcamp Shale Type Log, Well 42-383-33070, located in Reagan County, shown on Exhibit 3-1.

Exhibit 3-1 Reagan County Well Log, Eastern Basin Extension Area, Wolfcamp Shale



Source: Advanced Resources International, 2019.

The data from this well was used to establish the net pay, porosity, and oil saturations for the Wolfcamp Shale Bench B in the Study Area. In addition, Advanced Resources International (ARI) was provided data on reservoir properties from the U.S. DOE/NETL Permian/Midland Basin Hydraulic Fracturing Test Site operated by GTI (Ciezobka, J., 2017).

4 Reservoir Properties and Oil Composition for Reservoir Simulation in the Wolfcamp Shale (Bench B)

4.1 Representative Reservoir Properties

Exhibit 4-1 provides a comprehensive listing of the reservoir properties for the Wolfcamp Shale Bench B that were used in performing the reservoir simulation for the Study Area.

Exhibit 4-1 Wolfcamp Shale Study Area Reservoir Properties

Reservoir Properties	Units
Pattern Area	180 acres
Well Pattern Dimensions	
▪ Length	9,000 ft
▪ Width	880 ft
Depth (to top)	8,000 ft
Net Pay (All units)*	290 ft
Porosity	
▪ Matrix (Avg)*	4.7%
▪ Fracture	0.1%
Initial Oil Saturation (Avg)*	
▪ Matrix/Fracture	57% / 1%
Saturation Gas/Oil Ratio	0.85 Mcf/B
Formation Volume Factor	1.42 RB/STB
Initial Pressure	4,265 psia
Temperature	159 º F
Bubble Point	2,800 psia
Formation Compressibility	2.2 * e^{-5}/psi
Oil Gravity	39º API

*Rock Units	Net Pay	Porosity	Oil** Saturation
Organic Shale	130	4.4%	75%
Mixed Lithology	160	5.0%	44%
Total	290	4.7%	57%

**Oil and water saturation are based on history matching of production.

Source: GTI, 2019; Advanced Resources International, 2019.

4.2 OIL COMPOSITION

The oil composition data and the binary correlation coefficients, representative of a saturation gas/oil ratio of 850 standard cubic foot/barrel (scf/Bbl), are provided below for the Wolfcamp Shale (Bench B) in the Study Area, Exhibit 4-2 and Exhibit 4-3.

Exhibit 4-2 Wolfcamp Shale PVT and Oil Composition Data

GOR (scf/Bbl)	
Oil Composition	**Percent**
CO2	0.35%
N2	1.16%
C1	33.32%
C2	8.66%
C3	9.55%
IC4	1.06%
NC4	4.86%
C5 - 6	8.66%
C7 – C12	18.70%
C13 – C21	7.50%
C22 – C80	6.23%

Source: Li, 2017.

Exhibit 4-3 Binary Interaction Coefficients for Wolfcamp Live Oil

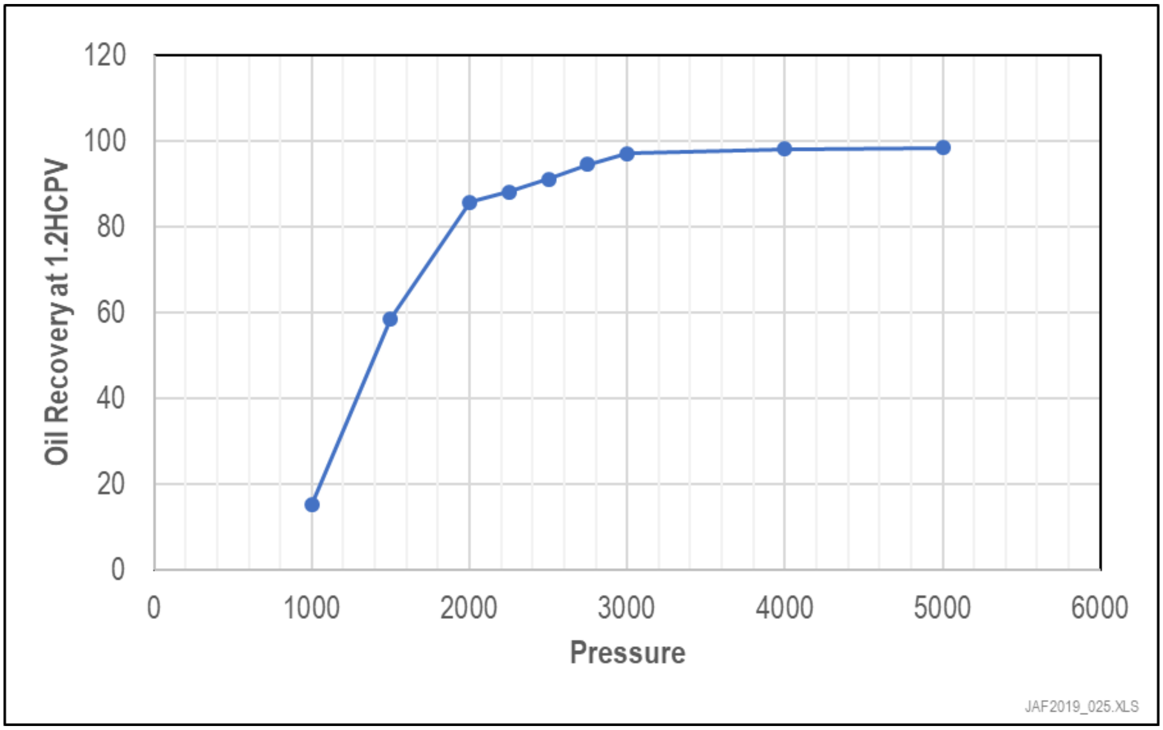
Component	**Binary Interaction Coefficients**							
	CO2	N2	C1	C2	C3	IC4	NC4	C5 - 6
C1	0.105	0.025	0					
C2	0 .13	0.01	0.0027	0				
C3	0.125	0.09	0.0085	0.0017	0			
IC4	0.12	0.095	0.0157	0.0055	0.0011	0		
NC4	0.115	0.095	0.0147	0.0049	0.0009	0.0000	0	
C5 – 6	0.115	0.1	0.0319	0.0165	0.0017	0.0030	0.0035	0
C7 - 12	0.086	0.11	0.0470	0.0279	0.0162	0.0089	0.0097	0.0016
C13 – 21	0.075	0.11	0.1003	0.0728	0.0539	0.0402	0.0417	0.0218
C22 - 80	0.050	0.11	0.1266	0.0964	0.0750	0.0590	0.0608	0.0365

Source: Li, 2017.

4.3 Estimating Minimum Miscibility Pressure for CO_2 and the Reservoir's Oil

To estimate the minimum miscibility pressure (MMP) between carbon dioxide (CO_2) and the oil composition for the Study Area Wolfcamp Shale Bench B reservoir, ARI conducted a suite of slimtube simulations (using GEM) to establish a MMP of about 2,600 psi, displayed in Exhibit 4-4.

Exhibit 4-4 Minimum Miscibility Processes (MMP) for CO2 for Study Area Oil Composition



Source: Advanced Resources International, 2019

4.4 Estimated Original Oil and Gas In-Place

Given the geologic and reservoir properties on Exhibit 4-1, the Study Area well pattern area contains 7.6 million barrels of original oil in-place (OOIP) and 6.5 billion cubic feet (Bcf) of original gas in-place (OGIP).

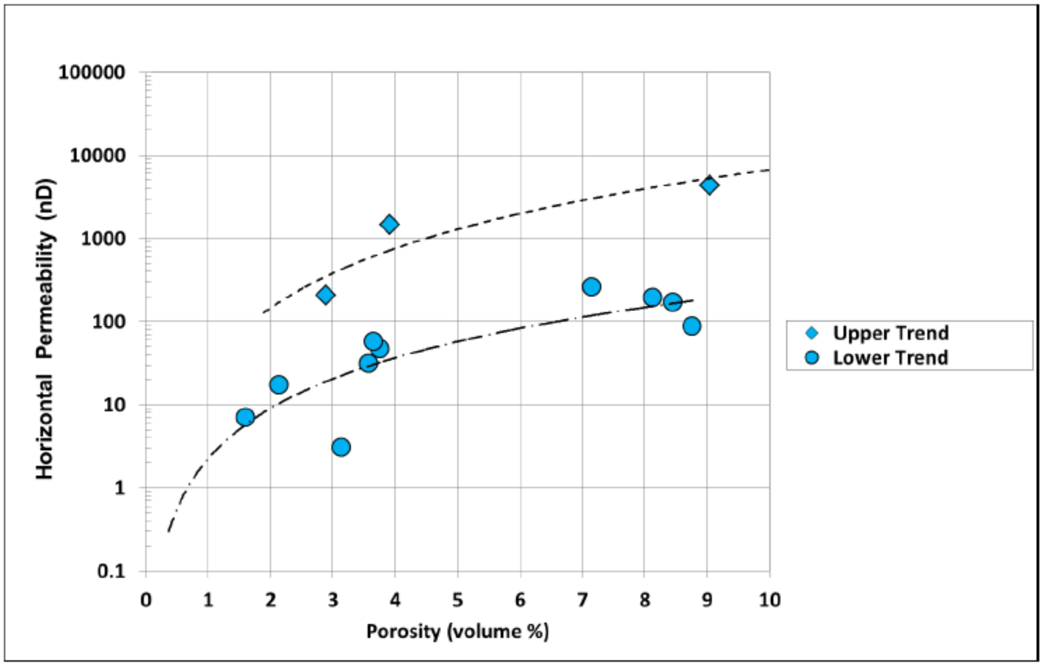
- OOIP = (180A * 290 ft) * 7758 B/AF (0.047 * 0.57/1.42)
- OOIP = 52,200 AF * 146 B/AF = 7.63 MMB
- OGIP (7.62 * MMB) * (0.85 Mcf/B) = 6.48 Bcf

4.5 MATRIX PERMEABILITY

Data from the literature for Wolfcamp Shale permeability is plotted versus porosity on Exhibit 4-5. A wide range of permeability values exist among these samples, characteristic of the variable mineralogy, pore sizes, and pore types in the shale. Three samples shown as Upper Trend have connected porosity associated with the organic material (Walls, 2017).

History matching of oil and water production was used to establish permeability values for the shale matrix and SRV.

Exhibit 4-5 Porosity versus Permeability for Wolfcamp Shale, Midland Basin



Source: Walls, 2017.

4.6 RESERVOIR TEMPERATURE

The bottom-hole reservoir temperature of the Wolfcamp Shale varies considerably across the Midland Basin, generally ranging from 130 ºF to 180 ºF, with lateral variations in the thermal gradient consistent with thermal maturity.

4.7 RESERVOIR PRESSURE

Similar to temperature, there is significant variability in the reservoir pressure of the Wolfcamp Shale, with highest pressures observed in the thermally mature areas in the basin center. The reported pressure gradients for the Wolfcamp Shale range from (0.4 pounds per square inch per foot (psi/ft)) along the southern, less thermally mature portions of the basin margin to overpressured (0.6 psi/ft) in the more thermally mature basin center.

5 RESERVOIR MODEL

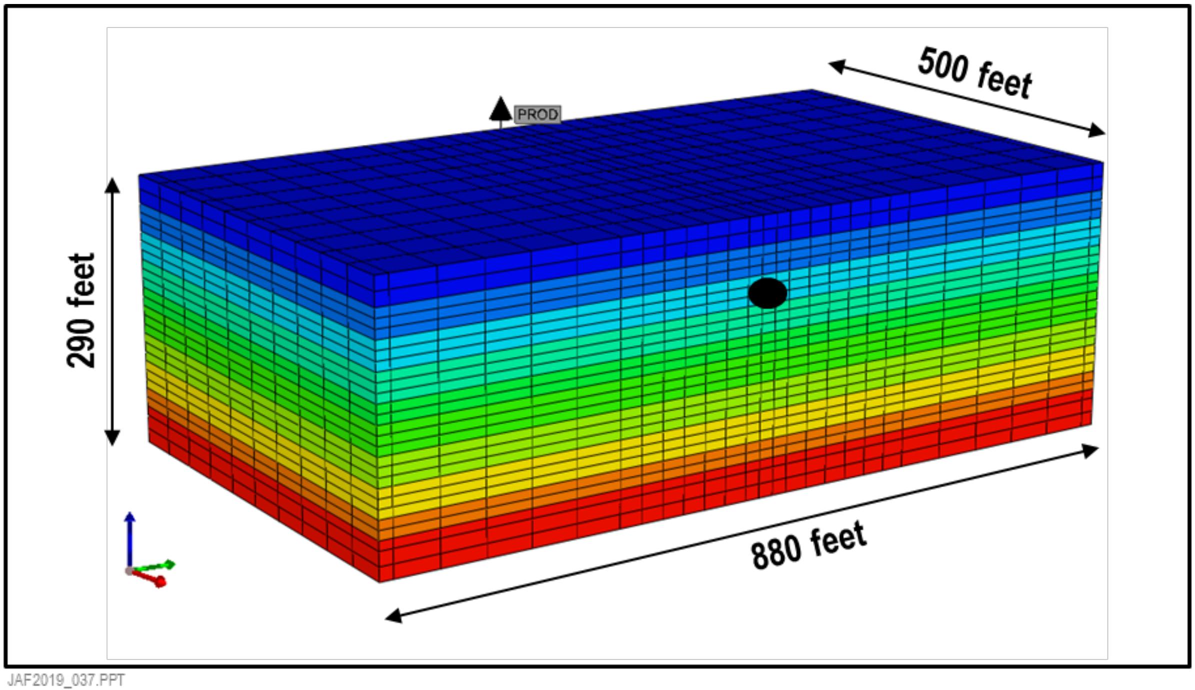
5.1 MODEL DIMENSIONS, LAYERS AND GRID BLOCKS

The reservoir model and grid blocks for the Wolfcamp Shale Bench B geologic and reservoir setting for the Study Area well are illustrated on Exhibit 5-1 and Exhibit 5-2:

- The model is 500 ft parallel with the horizontal (Hz) well (1/18th of the 9,000 ft Hz type well) and 880 ft perpendicular to the well (typical well spacing in the Study Area). The reservoir model uses 10 grid blocks, each 50 ft in length, to capture the 500 ft (1/18st of the 9,000 ft Hz type well) of reservoir parallel with the Hz well and 32 grid blocks, ranging from about 6.7 ft near the Hz well to about 48 ft beyond the Hz well to capture the 880 ft perpendicular to the Hz well.
- Based on an available type log from the Wolfcamp Shale in central Reagan County, the overall Wolfcamp Shale Bench B was assigned a thickness of 290 ft. The total shale thickness was subdivided into 27 vertical layers – 2 layers of 15 ft each to represent the 30 ft of organic shale at the top; 8 layers of 10 ft each to represent the first 80 ft of mixed lithology; 7 layers of 10 ft each to represent the 70 ft of shale in the middle; 8 layers of 10 ft each to represent the second 80 ft of mixed lithology; and 2 layers of 15 ft each to represent the remaining 30 ft of organic shale. The Hz well was completed in vertical layer 8, in the center of the pattern area.

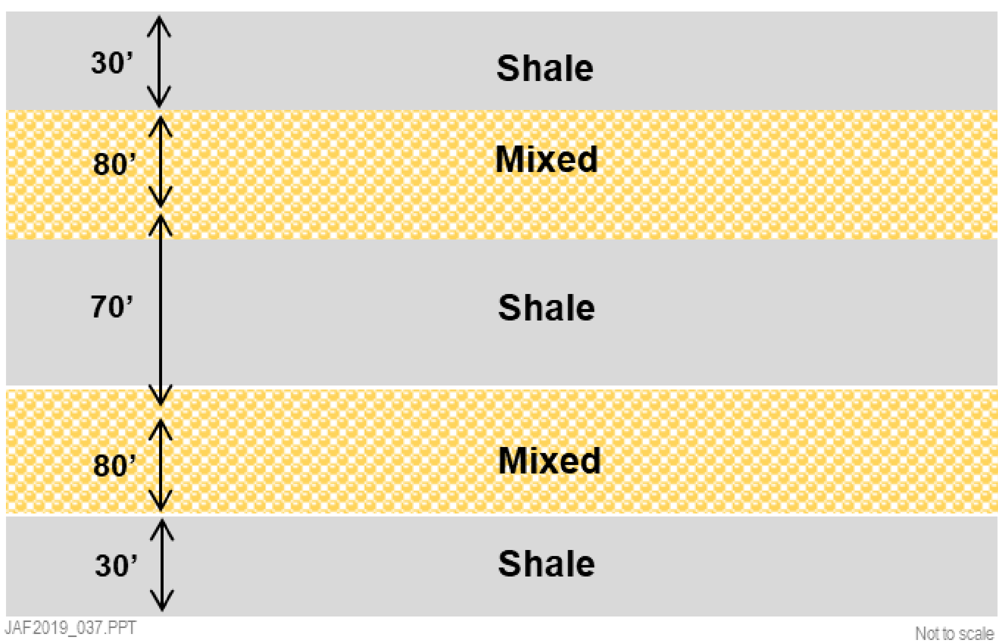
The reservoir property values previously provided on Exhibit 4-1 and the oil composition and GOR values previously provided on Exhibit 4-2 were used to populate the reservoir model and its 7,290 grid blocks.

Exhibit 5-1 Reservoir Model and Grid Blocks Used for Wolfcamp Shale Study



Source: Advanced Resources International, 2019.

Exhibit 5-2 Reservoir Model Layers to Represent Distributed Lithology



Source: Advanced Resources International, 2019.

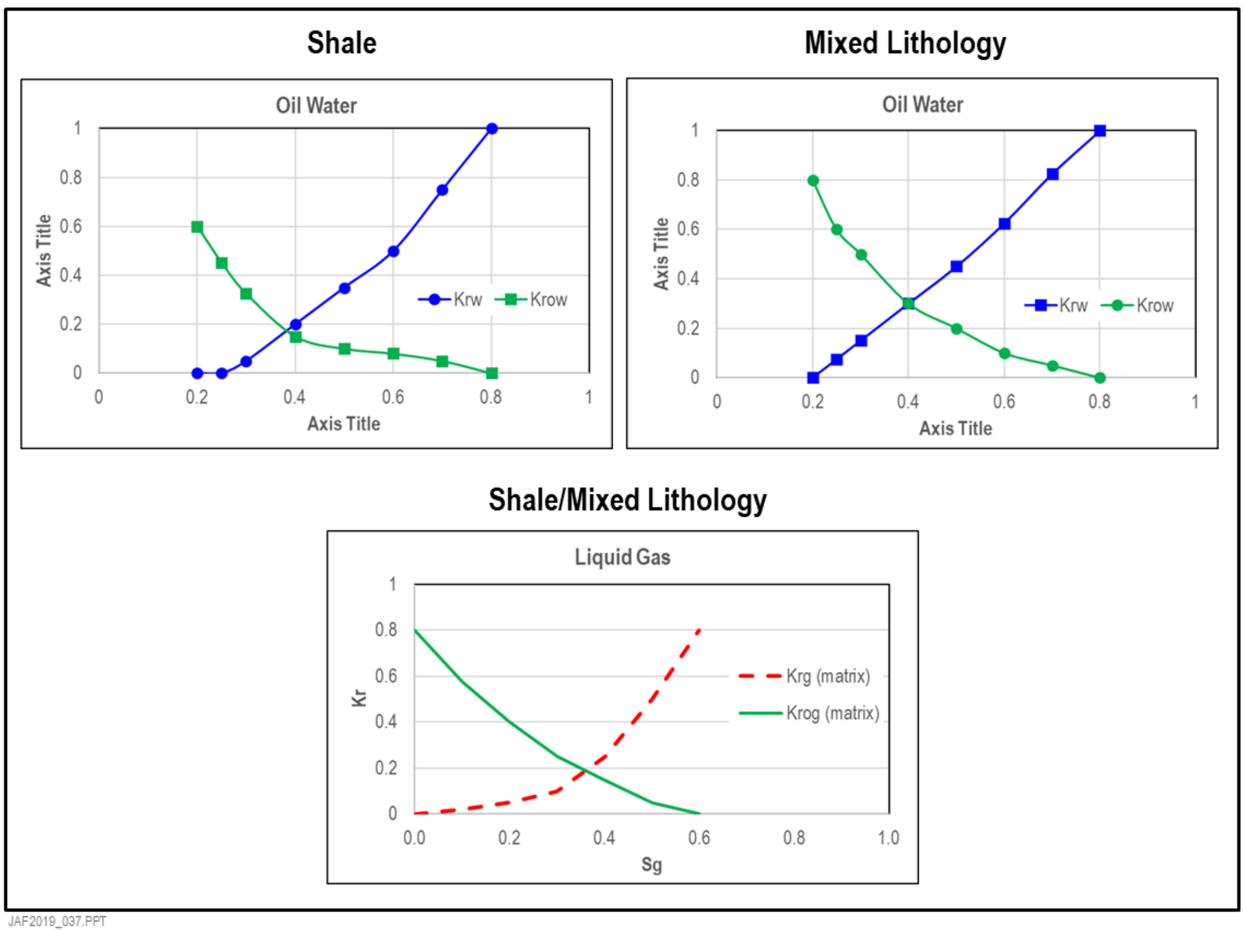
5.2 Reservoir Simulator

The GEM reservoir simulator from the Computer Modeling Group was utilized for the study. GEM is a robust, fully compositional, Equation of State reservoir simulator used widely by industry for modeling the flow of three-phase, multi-component fluids through porous media.

5.3 Relative Permeability

Laboratory information derived from the technical literature along with history matching of oil and water production were used to establish the relative permeability shapes and end points for oil and water in the matrix, displayed in Exhibit 5-3.

Exhibit 5-3 Wolfcamp Shale Bench B Relative Permeability Curves



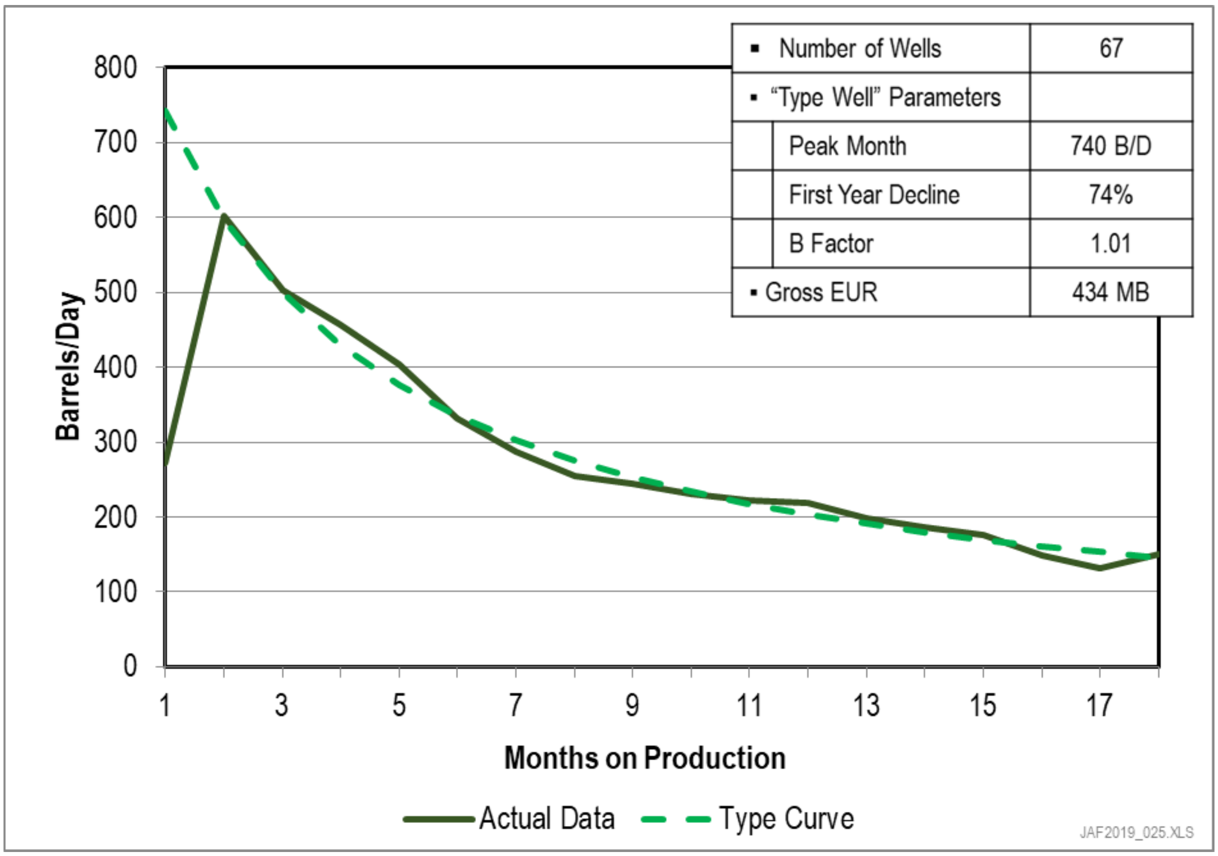
Source: Advanced Resources International, 2019.

6 TYPE WELL FOR STUDY AREA

The Study Area well chosen for the history match is the "type oil well" for the Wolfcamp Shale in Reagan County assembled by ARI using production data from the Texas Railroad Commission. The "type oil well" represents the composite performance of 67 Hz wells drilled in 2016 and has 19 months of oil and water production, displayed in Exhibit 6-1.

The well's longer term, 30-year performance was estimated using a peak month production of 740 barrels per day (B/D), a first-year production decline of 74 percent, and a "b" of 1.01 for the longer-term production decline.

Exhibit 6-1 Study Area Type Well Oil Production

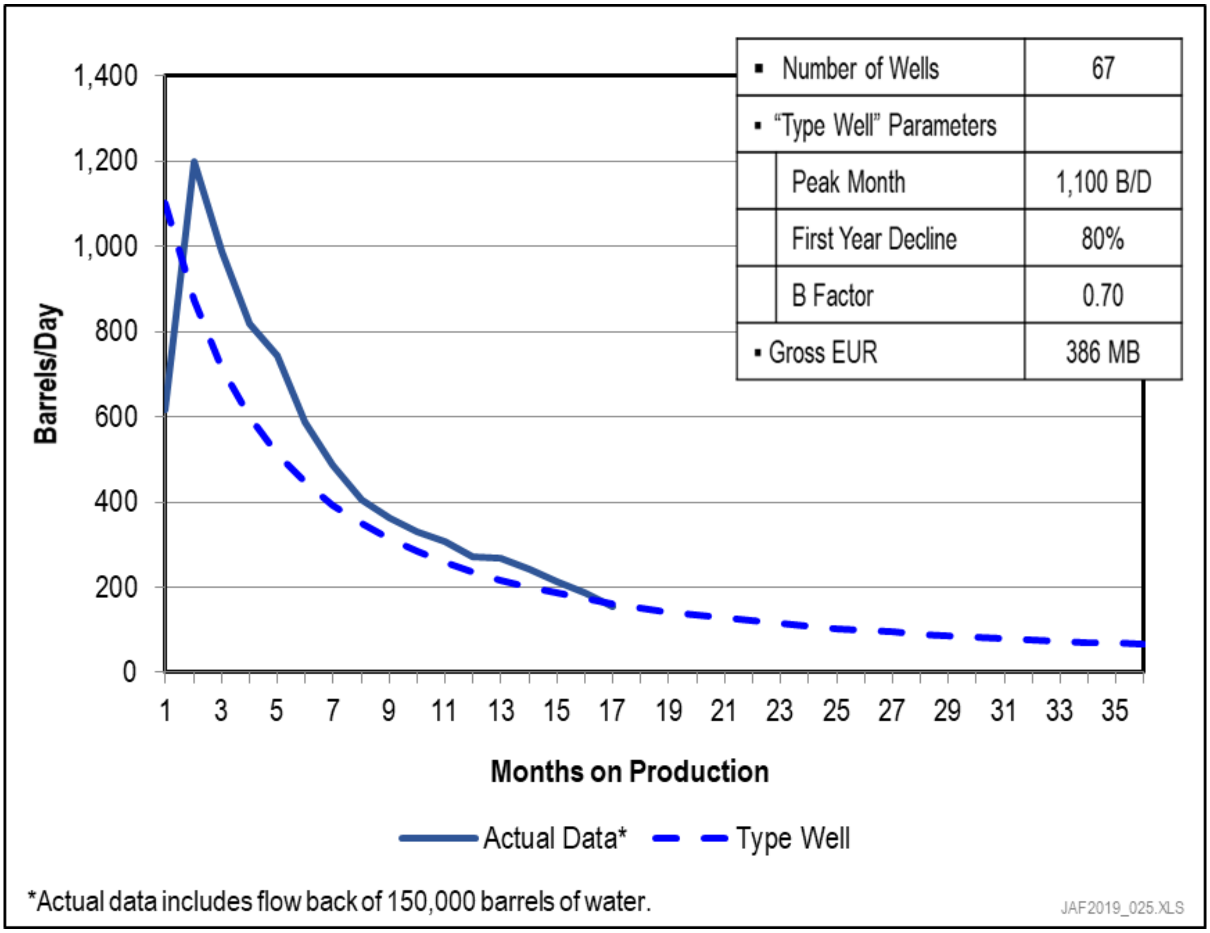


Source: Advanced Resources International, 2019.

The "type oil well" in the Study Area has a spacing of 180 acres and a Hz lateral of 9,000 ft. It has an estimated 30-year oil recovery of 434,000 barrels. The reservoir simulation model uses 1/18th of these values for the 500-ft Hz segment representative of the 9,000-ft total Hz well, giving a 30-year oil recovery of 24,100 barrels for the Hz segment of the modeled "type well".

Exhibit 6-2 illustrates the water production associated with the "type oil well" in Reagan County. The reported actual water production includes the flow back of water injected as part of the hydraulic stimulation. Removing the flow back water, the "typical oil well" has 30-year water production of 386,000 barrels.

Exhibit 6-2 Study Area Type Well Water Production



▪ Number of Wells		67
▪ "Type Well" Parameters		
	Peak Month	1,100 B/D
	First Year Decline	80%
	B Factor	0.70
▪ Gross EUR		386 MB

Source: Advanced Resources International, 2019.

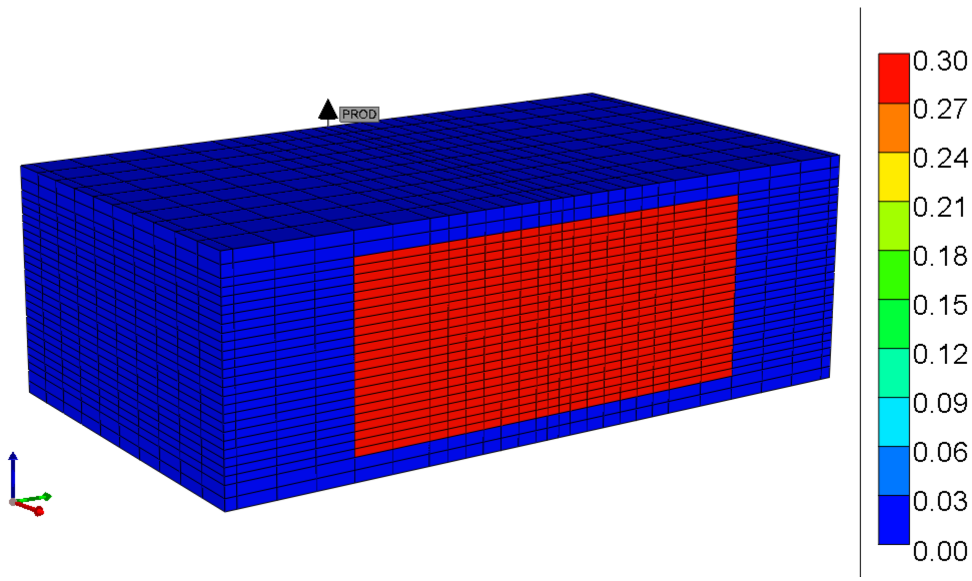
7 Representing the Impact of Hydraulic Stimulation

7.1 Stimulated Reservoir Volume

To capture the impact of the hydraulic stimulation on the horizontal well, a Stimulated Reservoir Volume (SRV) was established in the model, assuming an enhanced permeability in the SRV for both the fractures and the matrix, displayed in Exhibit 7-1.

The “segment” well was assumed to be stimulated for its full length (500 ft). The fracture half-length (length of the fracture on each side perpendicular to the well) and the vertical fracture height were used as variables during the history-matching process.

Exhibit 7-1 Representative SRV for “Segment” Well



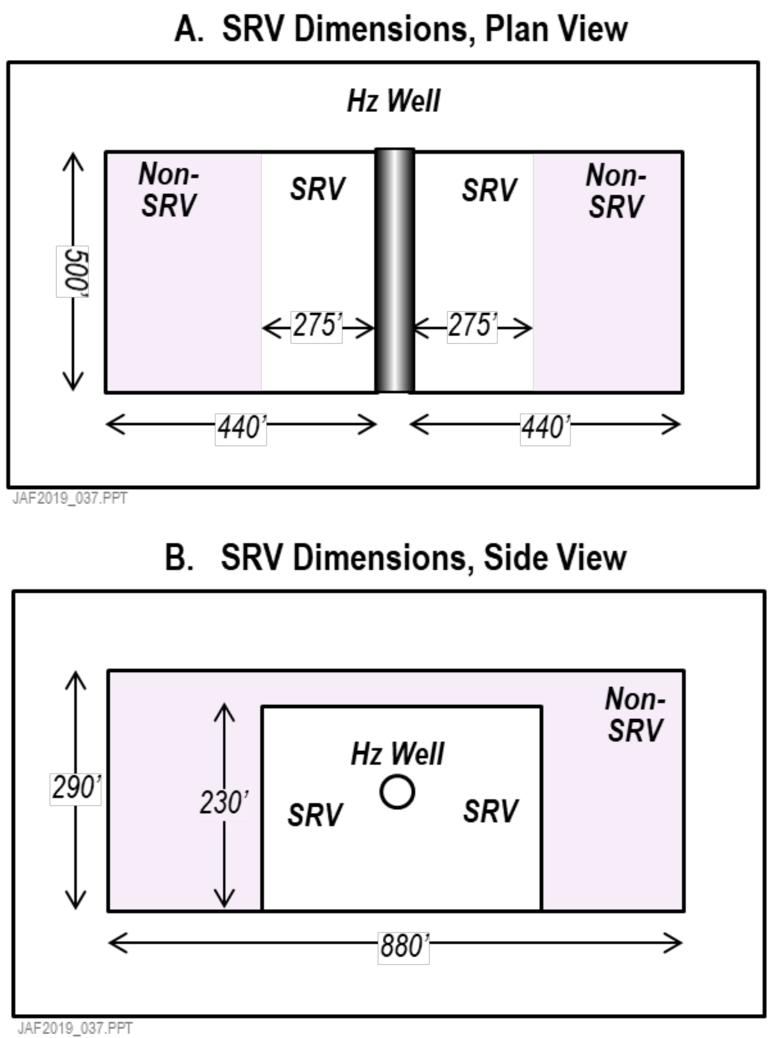
Source: Advanced Resources International, 2019.

7.2 SRV DIMENSIONS FROM HISTORY MATCH

The SRV dimensions for the Study Area well, using guidance from the technical literature and on well performance history matching, are discussed below and illustrated on Exhibit 7-2.

- The SRV is 550 ft wide, consistent with a propped fracture half-length of 275 ft.
- The SRV is 230 ft high, encompassing nearly 80 percent of the vertical interval.
- The SRV length extends along the Hz wellbore, equal to 500 ft for the "segment" well (1/18th of the total Hz lateral).

Exhibit 7-2 Estimated SRV Dimensions from History Match of Well Performance



Source: Advanced Resources International, 2019.

7.3 Permeability Values from History Match

The matrix and fracture permeability values along with the relative permeability curves and the SRV dimensions discussed previously, were used for the history match of the Wolfcamp Shale Bench B "type well" in the Study Area of Reagan County, shown in Exhibit 7-3.

Exhibit 7-3 Permeability Values Used for History Match (mD)

	Matrix
Non-SRV	
Horizontal	$500 * 10^{-6}$ mD
Vertical	$50 * 10^{-6}$ mD
SRV*	0.3 mD

Source: Advanced Resources International, 2019.

8 HISTORY-MATCHING OIL AND NATURAL GAS PRODUCTION

8.1 HISTORY MATCH

Using the key history matching parameters of SRV dimension and permeability, the reservoir simulation task achieved an excellent history match with the "type well" for the Study Area. With an OOIP of 424,000 barrels for the Hz "segment" well (1/18th of total Hz well) and a 30-year history matched oil recovery of 22,300 barrels, the oil recovery efficiency is about 5 percent of OOIP.

Exhibit 8-1 provides a tabular comparison of the "type well" and the history matched Study Area well for two selected years of oil production. The history match for the 5-year and 30-year time periods are reasonably in-line with actual oil production.

Exhibit 8-1 Comparison of Oil Production for Type Well and History Matched Study Area Well

Oil Production Time Period	Type Well* (Bbls)	History Matched Well (Bbls)
5 years	14,900	15,100
30 years	24,100	22,300

*For 1/18th of actual data for the type well in the Study Area.

Source: Advanced Resources International, 2019.

Exhibit 8-2 provides similar data for the "type well" and the history matched Study Area well for water production.

Exhibit 8-2 Comparison of Water Production for Actual and History Matched Study Well

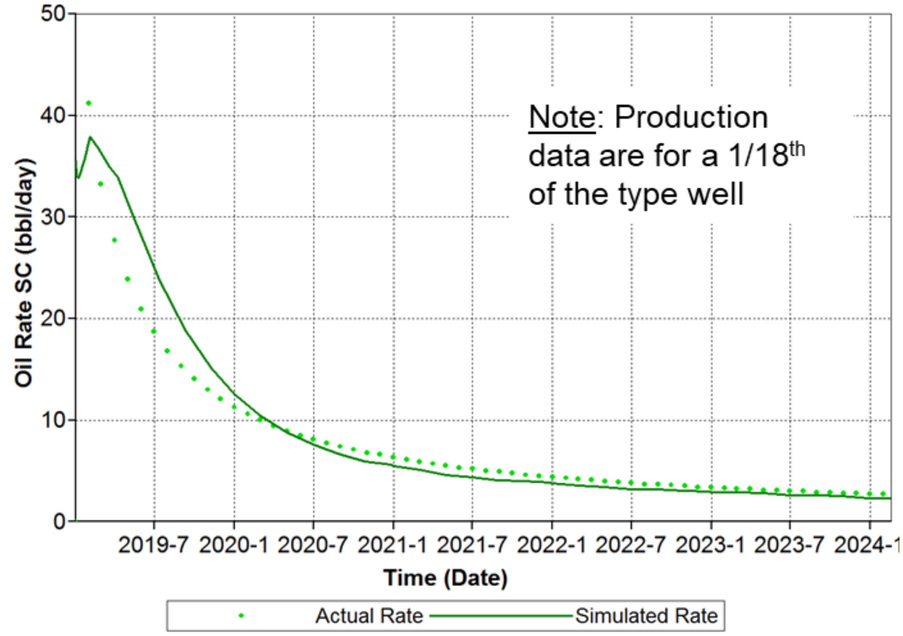
Water Production Time Period	Type Well* (Bbls)	History Matched Well (Bbls)
5 years	16,900	17,100
30 years	21,400	20,900

*For 1/18th of actual data for the type well in the Study Area.

Source: Advanced Resources International, 2019.

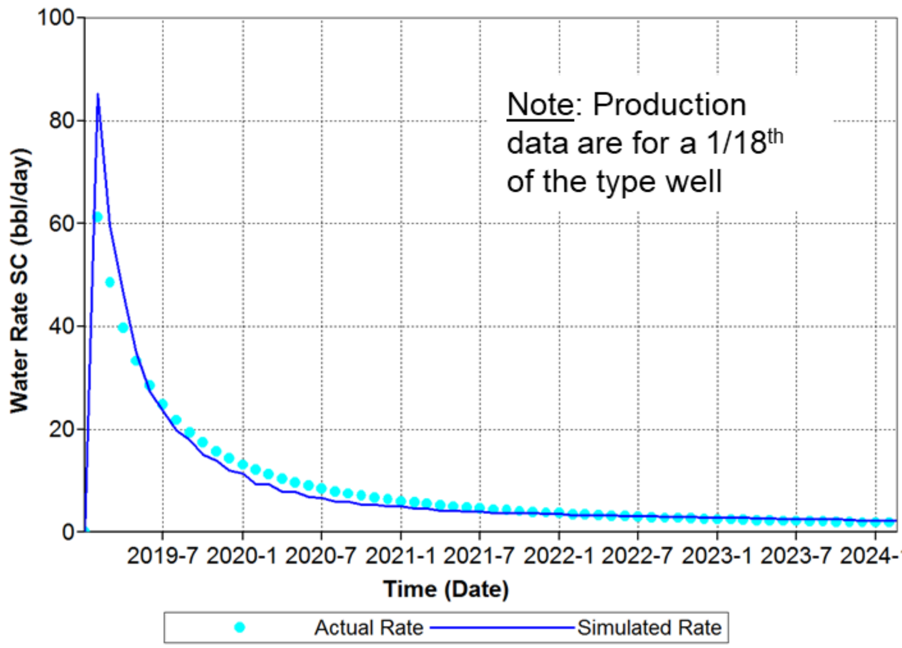
Exhibit 8-3 and Exhibit 8-4 show the near-term monthly and longer-term annual history matched oil production for the Wolfcamp Shale Bench B Study Area well in comparison with oil production from the Wolfcamp Shale Bench B "type well" for Reagan County.

Exhibit 8-3 History Match of Monthly Oil Production (5 Years)



Source: Advanced Resources International, 2019.

Exhibit 8-4 History Match of Annual Oil Production (30 Years)



Source: Advanced Resources International, 2019.

8.2 Modeling of Cyclic CO_2 Injection

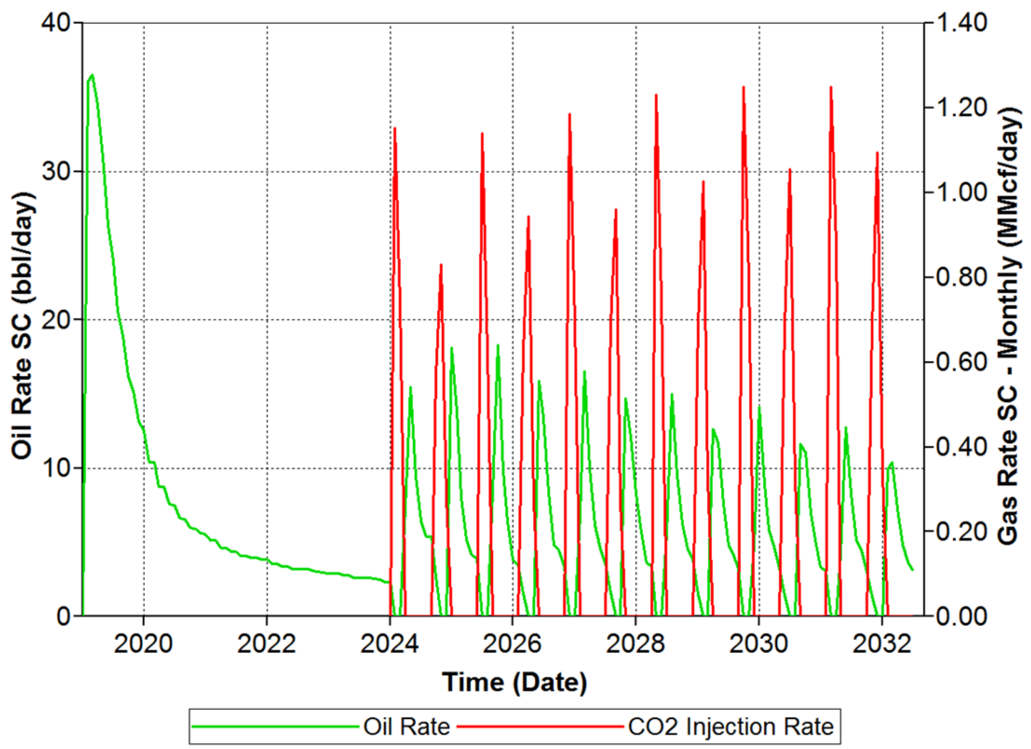
8.2.1 Cyclic CO_2 Injection

Cyclic CO_2 injection was initiated using the GEM compositional simulator in the Study Area well after five years of primary production from the Study Area well. At this time, the segment Hz well (1/18th of the overall Hz well) had produced 15,100 barrels, equal to nearly 80 percent of its estimated ultimate oil recovery.

- In cycle one, CO_2 was injected at a constant rate of 1,250 thousand cubic feet per day (Mcfd) for 2 months (BHP limit of 4,800 pounds per square inch absolute (psia)) to refill reservoir voidage, with a total of 33,000 Mcf of CO_2 injected.
- CO_2 injection was followed by a two-week soak time and then followed by six months of production.
- Eleven additional cycles of CO_2 injection, soak, and production followed.

Exhibit 8-5 illustrates the oil production data for the first 5 years of primary oil production and for the subsequent 12 cycles (8.5 years) of cyclic CO_2 injection, soak, and production from the Hz well segment (1/18th of total Hz well).

Exhibit 8-5 Primary Production and Enhanced Oil Recovery from Cyclic CO_2 Injection



Source: Advanced Resources International, 2019.

8.2.2 Performance of Cyclic CO_2 Injection: Reduced Hz Well Segment (500 ft)

The 12 cycles of CO_2 injection over 8.5 years provided 17,000 barrels of oil production for the reduced (1/18th) Hz well segment. With primary oil recovery of 15,100 barrels at the start of cyclic CO_2 injection, total oil recovery reached 32,100 barrels at the end of cyclic CO_2 injection. Continuation of primary recovery for 8.5 years would have provided 4,600 barrels of oil production during this time. As such, 12,400 barrels of incremental oil recovery (17,000 barrels less 4,600 barrels) are attributable to injection of CO_2, as shown in Exhibit 8-6.

Exhibit 8-6 Cumulative Oil Production, CO_2 Injection and CO_2 Production (Hz Well Segment)

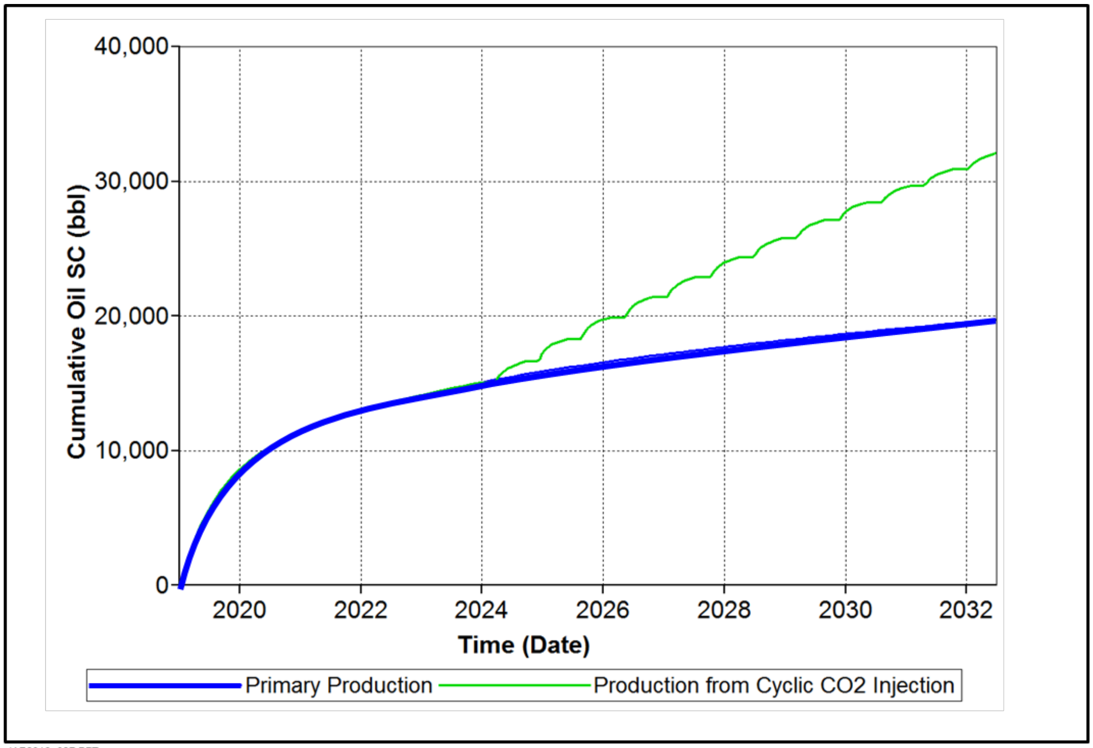
	Cumulative Oil Production			Cumulative CO_2		Estimated CO_2 Storage (MMscf)
	Total (Barrels)	Primary Production (Barrels)	Incremental EOR (Barrels)	Injection (MMscf)	Production (MMscf)	
End of 5-year primary	15,100	15,100	-	-	-	-
End of 1st cycle	16,700	15,900	800	57	33	24
End of 6th cycle	24,400	18,000	6,400	333	265	68
End of 12th cycle	32,100	19,700	12,400	707	600	107

Source: Advanced Resources International, 2019.

A significant portion of the CO_2, equal to 15 percent (107 million cubic feet (MMcf)) of the 707 MMcf of CO_2 injected, remained in the reservoir after the end of the 12th cycle, with higher incremental CO_2 storage during the initial CO_2 injection and production cycles and declining incremental CO_2 storage values during the later CO_2 injection and production cycles, as shown on Exhibit 8-6.

Assuming no further injection of CO_2, this 12 cycle CO_2 injection project provided an uplift of 1.63x to primary oil production from the Study Area segment well, as displayed on Exhibit 8-7. Continuation of cyclic CO_2 injection for additional cycles as well as optimization of the CO_2 injection project would increase this uplift value.

Exhibit 8-7 Cumulative Oil Production from Primary and Cyclic CO_2 Injection



JAF2019_037.PPT

Source: Advanced Resources International, 2019.

8.2.3 Performance of Cyclic CO_2 Injection: Full Hz Well (10,500 ft)

The 12 cycles of CO_2 injection over 8.5 years provided 306,000 barrels of oil production for the full Hz well, in addition to 272,000 barrels from primary oil recovery at the start of CO_2 injection. This provides an overall oil recovery, including primary and cyclic CO_2 injection, of 578,000 barrels. Continuation of primary recovery for 8.5 years would have provided 83,000 barrels of oil recovery. As such, 223,000 barrels of incremental oil recovery (306,000 barrels less 83,000 barrels) are attributable to injection of CO_2.

Assuming no further cyclic injection of CO_2, this 12 cycle CO_2 injection project provided a 1.63x uplift to oil production for the full Study Area Hz well, as tabulated on Exhibit 8-8.

Exhibit 8-8 Cumulative Oil Production, CO_2 Injection and CO_2 Production: Full Hz Well

	Cumulative Oil Production			Cumulative CO_2		Estimated CO_2 Storage (MMscf)
	Total (M Barrels)	**Primary** (M Barrels)	**Incremental EOR** (M Barrels)	**Injection** (MMscf)	**Production** (MMscf)	
End of 5-year primary	272	272	-	-	-	-
End of first cycle	302	288	14	1,030	590	440
End of 6^{th} cycle	416	326	90	5,990	4,700	1,220
End of 12^{th} cycle	578	355	223	12,730	10,800	1,930

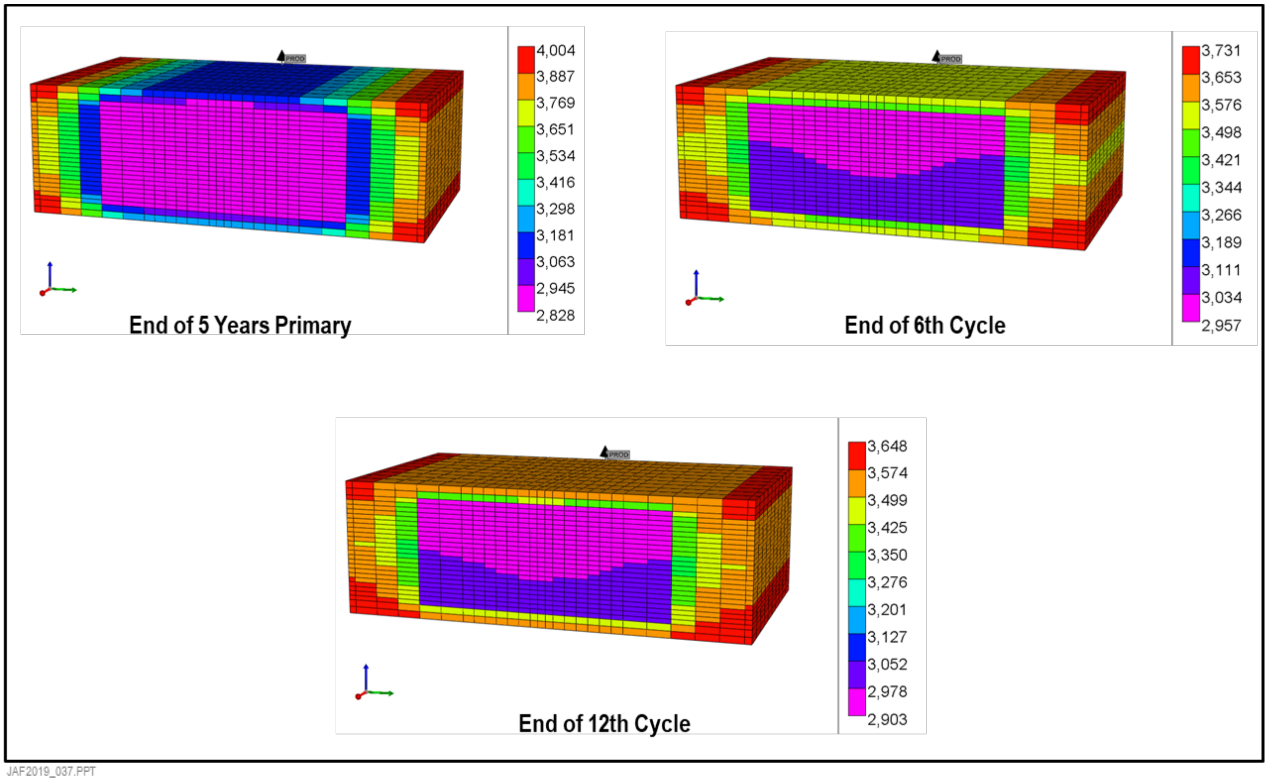
Source: Advanced Resources International, 2019.

Approximately 15 percent (1,930 Mcf) of the 12,730 MMcf of CO_2 injected remained stored in the reservoir at the end of 12 cycles of CO_2 injection, as tabulated on Exhibit 8-8.

8.2.4 Pressure Distribution

An in-depth look at the reservoir pressure profiles at the end of primary production reveals a substantial decline in reservoir pressure for the SRV matrix as well as pressure declines in the non-SRV matrix blocks closer to the SRV matrix, as shown in Exhibit 8-9.

Exhibit 8-9 Pressure Profiles Following Primary Recovery and Cyclic CO_2 Injection (psig)



Source: Advanced Resources International, 2019.

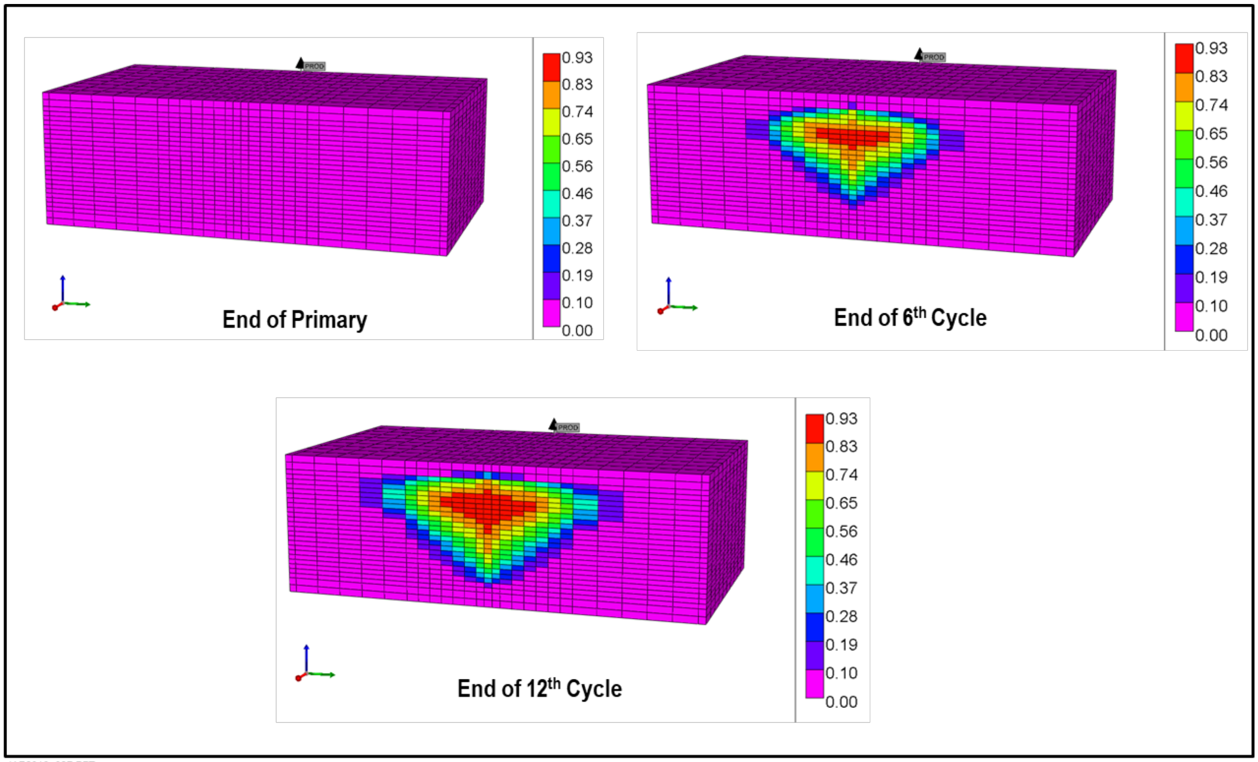
Even more noticeable pressure declines in the non-SRV matrix blocks are evident at the end of 12 cycles of CO_2 injection, as shown in Exhibit 8-9.

8.2.5 CO_2 Distribution and Storage

Examining the CO_2 saturation in the reservoir – at the end of 6 and 12 cycles of CO_2 injection and fluid production – provides valuable information on the efficiency of CO_2 distribution in the SRV matrix as well as information on the volumes of potential CO_2 storage in the Wolfcamp Shale, as shown on Exhibit 8-10.

- At the end of 6 cycles of CO_2 injection and fluid production, CO_2 saturation in the SRV matrix reached 80 percent to 90 percent near the Hz well declining to 10 percent to 20 percent at the edges of the SRV.
- At the end of 12 cycles of CO_2 injection and fluid production, CO_2 saturation in the SRV matrix reached 80 percent to 90 percent near the Hz well, declining to 20 percent to 30 percent at the edges of the SRV.

Exhibit 8-10 CO_2 Saturation Profiles Following Cyclic CO_2 Injection



Source: Advanced Resources International, 2019.

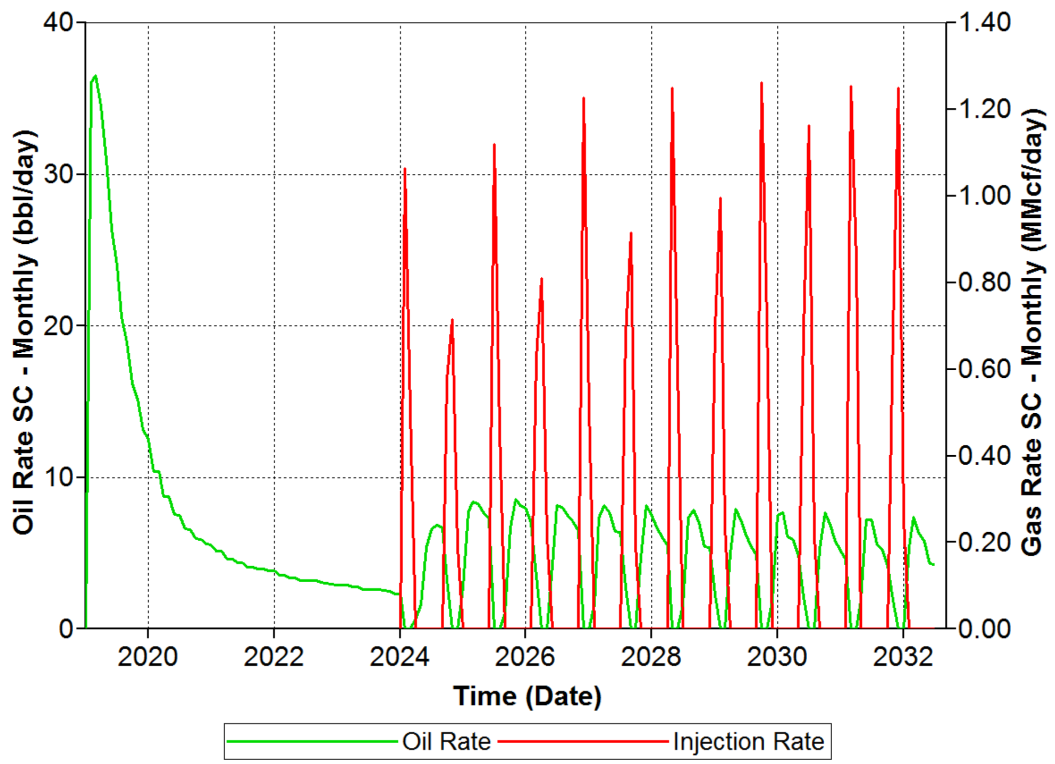
8.3 Performance of Cyclic CO_2 Versus Cyclic Natural Gas Injection

The reservoir simulation study next examined the expected performance of using cyclic natural gas injection for enhanced recovery. The first run involved cyclic injection of dry gas (100 percent C_1), representative of cyclic gas injection in some of industry's reported field EOR projects. The second run involved cyclic injection of wet gas (80 percent C_1, 14 percent C_2, 4 percent C_3, and 2 percent C_4), typical of the wet gas produced from the Study Area.

8.3.1 Dry Gas Injection

Similar to injection of CO_2, cyclic dry gas was injected into the Study Area well after five years of primary production. Exhibit 8-11 shows the 12 cycles of dry gas injection and oil production.

Exhibit 8-11 Primary Production and Enhanced Oil Recovery from Cyclic Dry Gas Injection



Source: Advanced Resources International, 2019.

The cyclic injection of dry gas provided notably lower incremental oil recovery than the cyclic injection of CO_2, as tabulated on Exhibit 8-12. Even so, injection of 12 cycles of dry gas provided an uplift of 1.42x in oil production compared to continuation of primary recovery.

Exhibit 8-12 Cumulative Oil Production: CO_2 Injection versus Dry Gas Injection (Hz Well Segment)

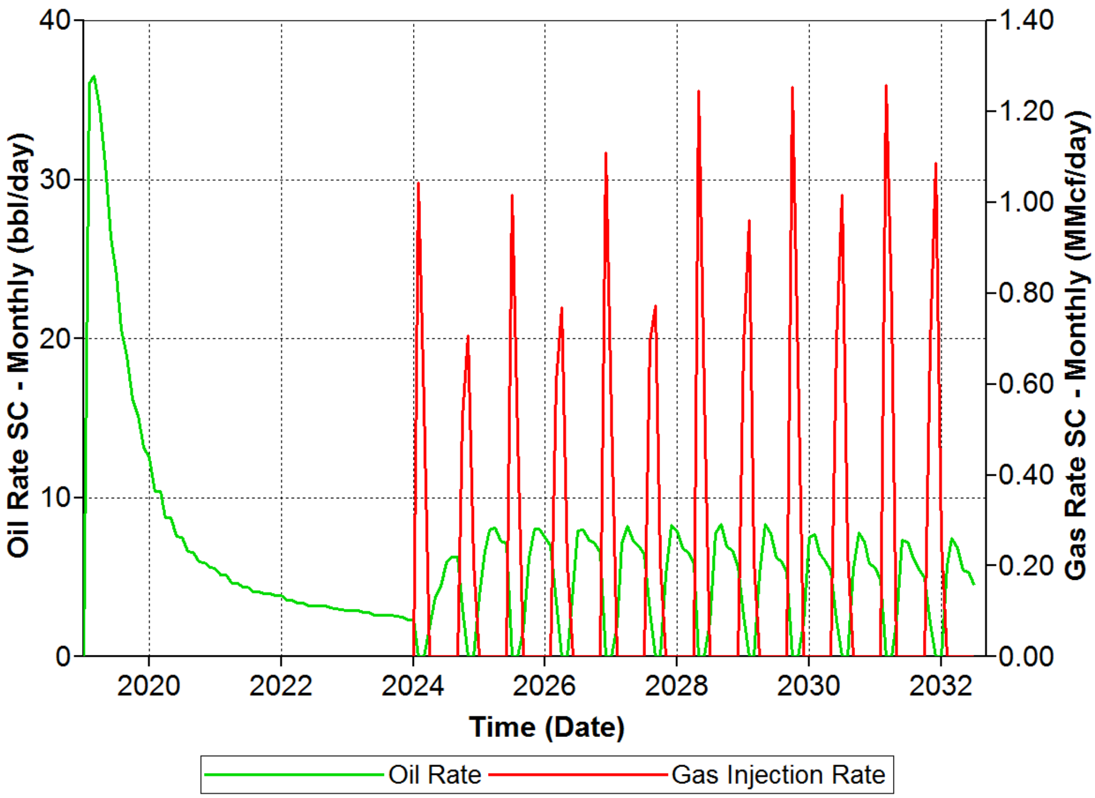
	Cumulative Oil Production Using CO_2			Cumulative Oil Production Using Dry Gas		
	Total (Barrels)	**Primary** (Barrels)	**Incremental** (Barrels)	**Total** (Barrels)	**Primary** (Barrels)	**Incremental** (Barrels)
End of 5-year primary	15,100	15,100	-	15,100	15,100	-
End of 1st cycle	16,700	15,900	800	16,000	15,900	100
End of 6th cycle	24,400	18,000	6,400	22,300	18,000	4,300
End of 12th cycle	32,100	19,700	12,400	28,000	19,700	8,300

Source: Advanced Resources International, 2019.

8.3.2 Wet Gas Injection

Next, wet gas was cyclically injected into the Study Area well after five years of primary production. Exhibit 8-13 illustrates the 12 cycles of wet gas injection and oil production.

Exhibit 8-13 Primary Production and Enhanced Oil Recovery from Cyclic Wet Gas Injection



Source: Advanced Resources International, 2019.

The cyclic injection of wet gas provides somewhat more incremental oil recovery than use of dry gas, but still less incremental oil recovery than use of CO_2, as tabulated on Exhibit 8-14. Injection of 12 cycles of wet gas provided an uplift of 1.47x in oil production compared to continuation of primary recovery.

Exhibit 8-14 Cumulative Oil Production: CO_2 Injection versus Wet Gas Injection (Hz Well Segment)

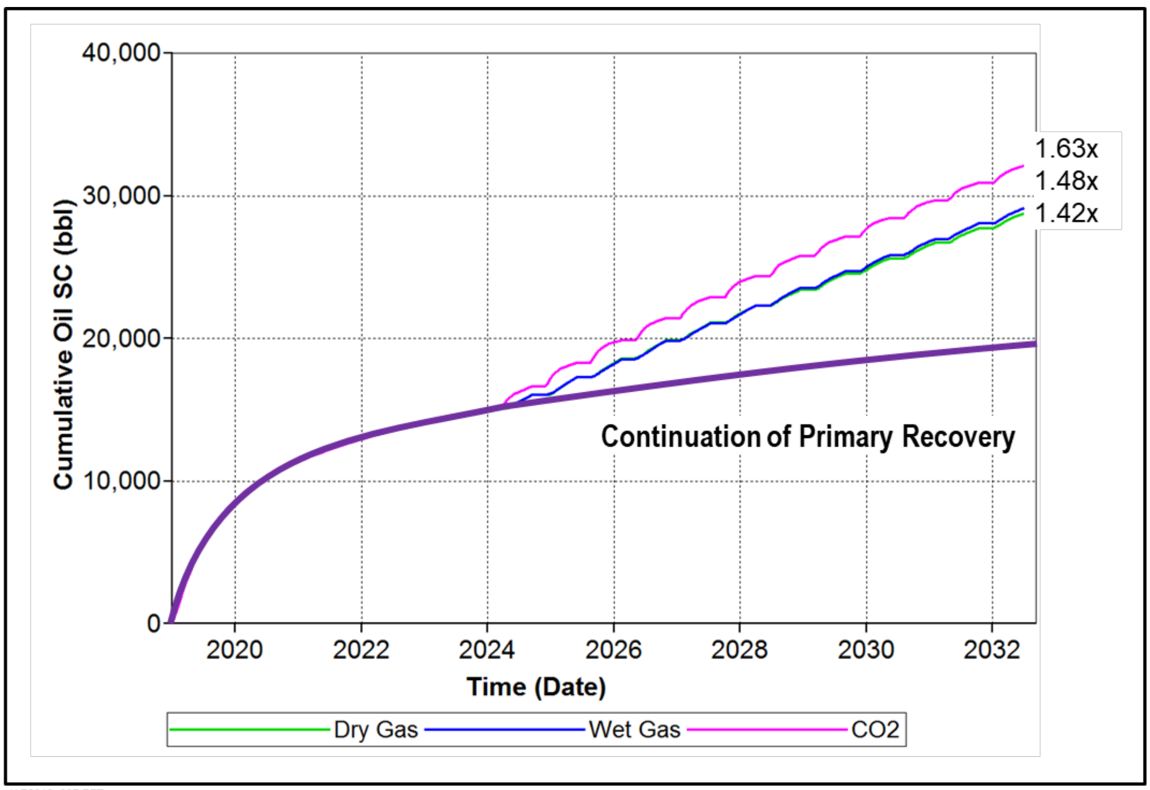
	Cumulative Oil Production Using CO_2			Cumulative Oil Production Using Wet Gas		
	Total (Barrels)	Primary (Barrels)	Incremental (Barrels)	Total (Barrels)	Primary (Barrels)	Incremental (Barrels)
End of 5-year primary	15,100	15,100	-	15,100	15,100	-
End of 1st cycle	16,700	15,900	800	16,100	15,900	200
End of 6th cycle	24,400	18,000	6,400	22,300	18,000	4,300
End of 12th cycle	32,100	19,700	12,400	29,100	19,700	9,400

Source: Advanced Resources International, 2019.

8.3.3 Comparison of Cyclic CO_2, Dry Gas, and Wet Gas Injection

Reservoir simulation for the Study Area well shows that cyclic injection of CO_2 provides an uplift of 1.63x in oil production over continuation of primary recovery, compared to uplifts of 1.42x for cyclic dry gas injection and 1.48 for cyclic wet gas injection, as displayed on Exhibit 8-15.

Exhibit 8-15 Comparison of Cyclic CO_2, Dry Gas and Wet Gas Injection (Hz Well Segment)



Source: Advanced Resources International, 2019.

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