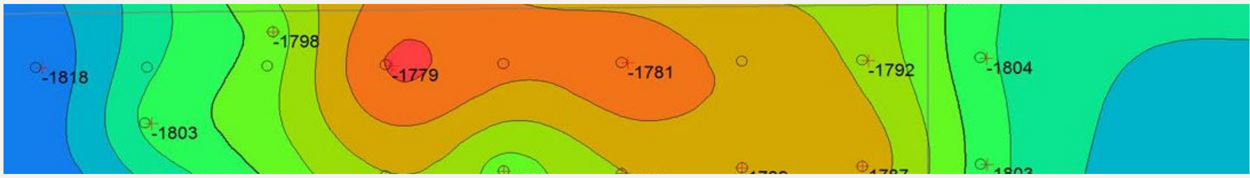

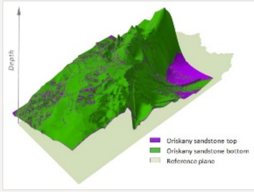

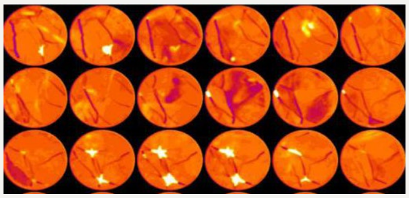

Reservoir Simulation of Enhanced Tight Oil Recovery: Bakken Shale

June 26, 2019
DOE/NETL-YYYY/####

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Author List:

Advanced Resources International (ARI)

Vello A. Kuuskraa
President

Anne Oudinot
Project Manager

George J. Koperna, Jr.
Vice President

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ARI	Advanced Resources International
bbl	Barrel
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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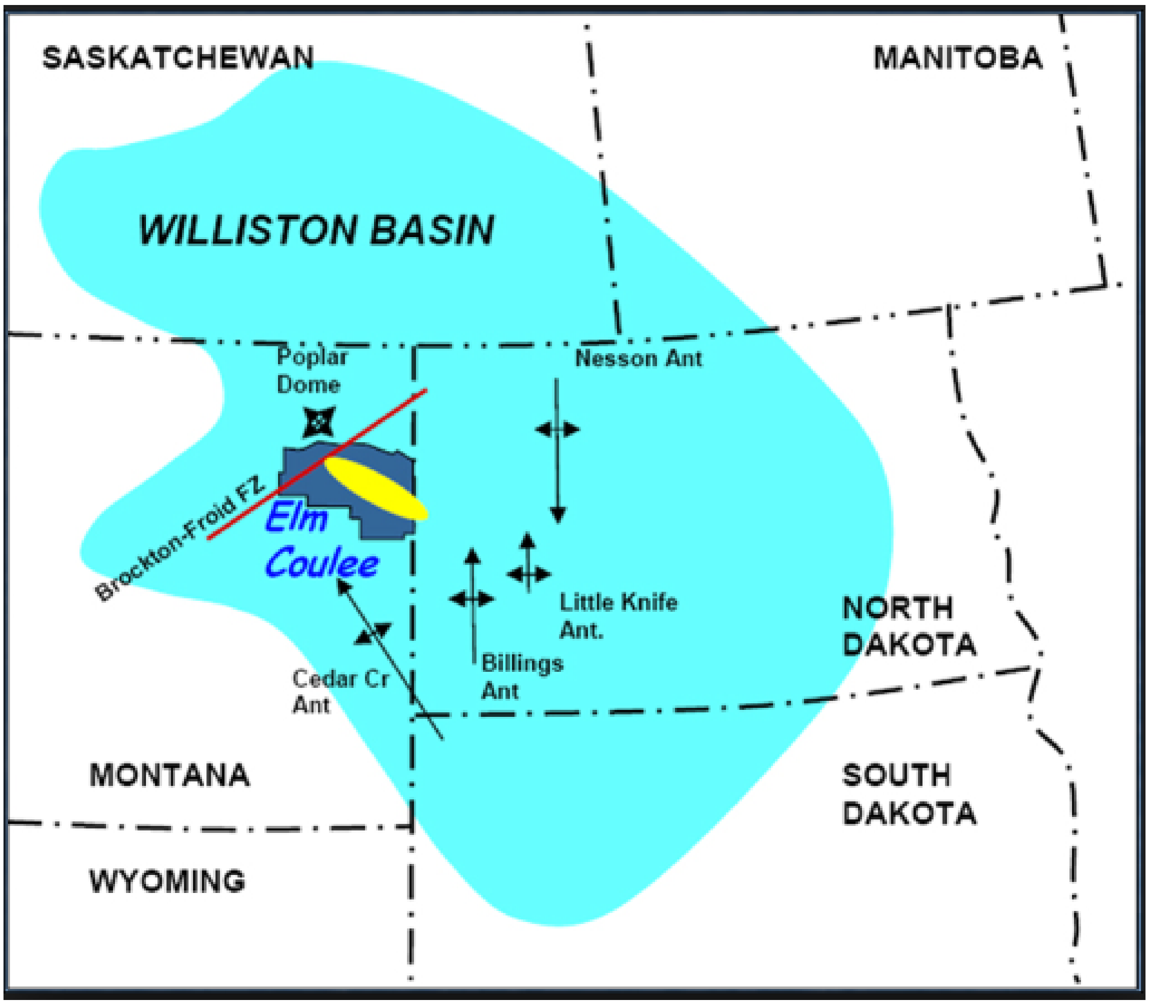
1 Geologic Setting

The Bakken Shale extends across an 18,400 square mile (mi^2) area in the United States (U.S.) portion of the Williston Basin in North Dakota and Montana, plus considerable additional area in the Canadian portion of the Williston Basin in Saskatchewan and Manitoba, as shown in Exhibit 1-1. The pinch-out of the Bakken Shale interval defines the areal extent of this shale deposit.

Exhibit 1-1 Williston Basin Location Map

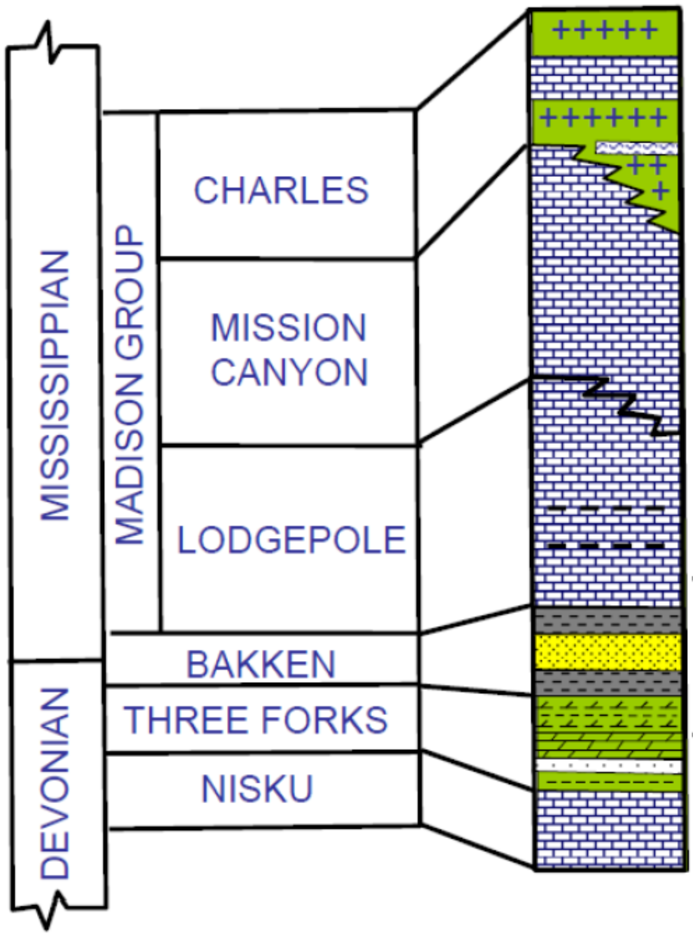


Source: Heck et al., 2004

The majority of Bakken Shale oil production has been from a four-county area of western North Dakota – Dunn, McKenzie, Mountrail, and Williams. This area is often called "the kitchen of the Bakken," due to its higher thermal maturity and its role as the shale oil generation center. The study has selected the Mountrail County portion of this area for its reservoir modeling study.

The Mississippian Bakken Shale lies above the Devonian Three Forks Shale and is overlain by the Lodgepole Formation of the Madison Group, as shown on Exhibit 1-2.

Exhibit 1-2 Bakken Shale Stratigraphic Column

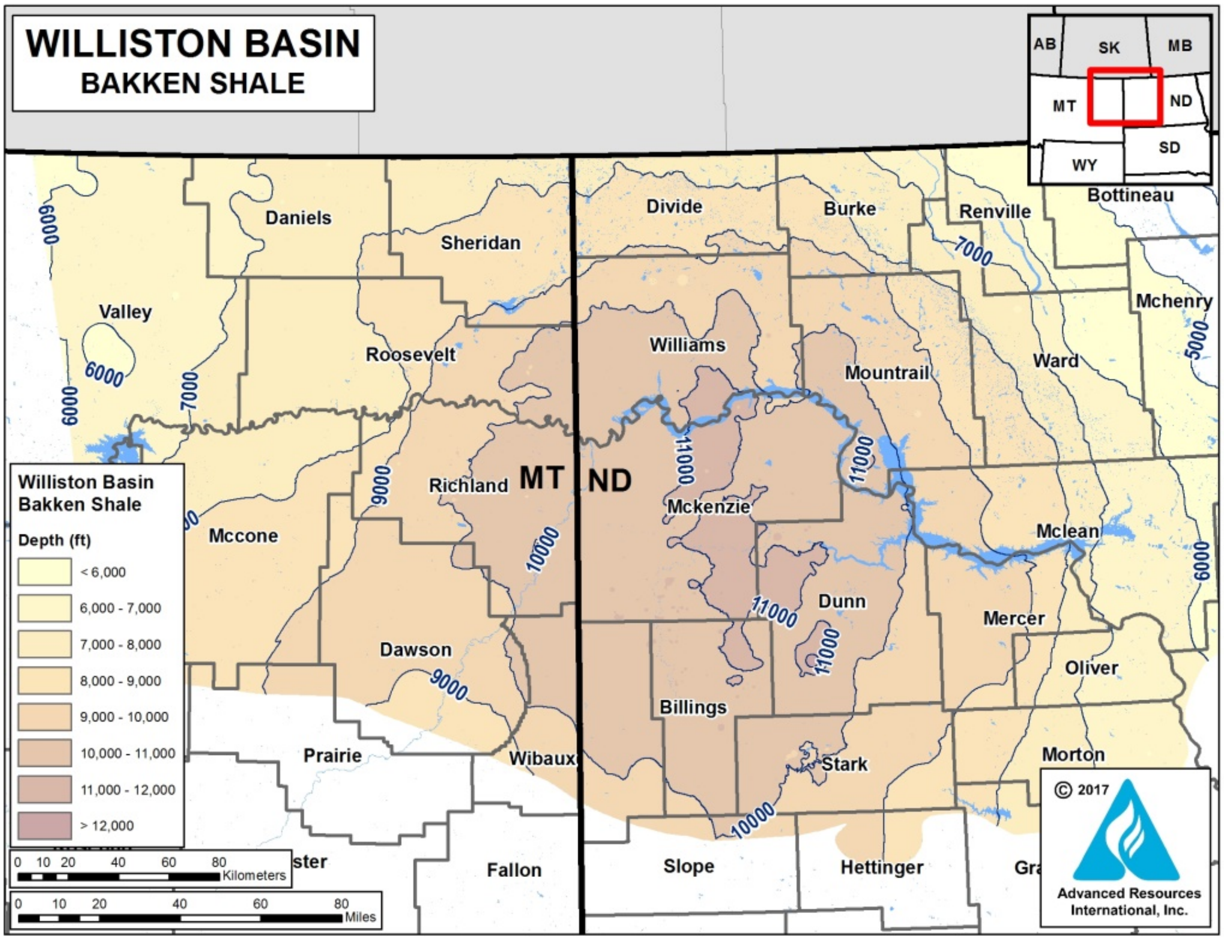


Source: Jin and Sonnenberg, 2013

Below the Bakken Shale is an equally attractive shale formation called the Three Forks Shale (not addressed in this Bakken Shale study) that has become notably active in the recent years. Along with increasing production of tight oil, the Bakken Shale also produces substantial volumes of associated wet gas and natural gas liquids.

The Bakken Shale ranges from a deep (10,000 feet (ft) to 12,000 ft) setting in the center of the Williston Basin, to a moderately deep (7,000 ft to 10,000 ft) setting along the basin margins. It is at a depth of about 9,000 ft in the structurally dominant area in Richland County, Montana and its Elm Coulee Field, as shown in Exhibit 1-3.

Exhibit 1-3 Bakken Shale (Middle Member) Shale Depth

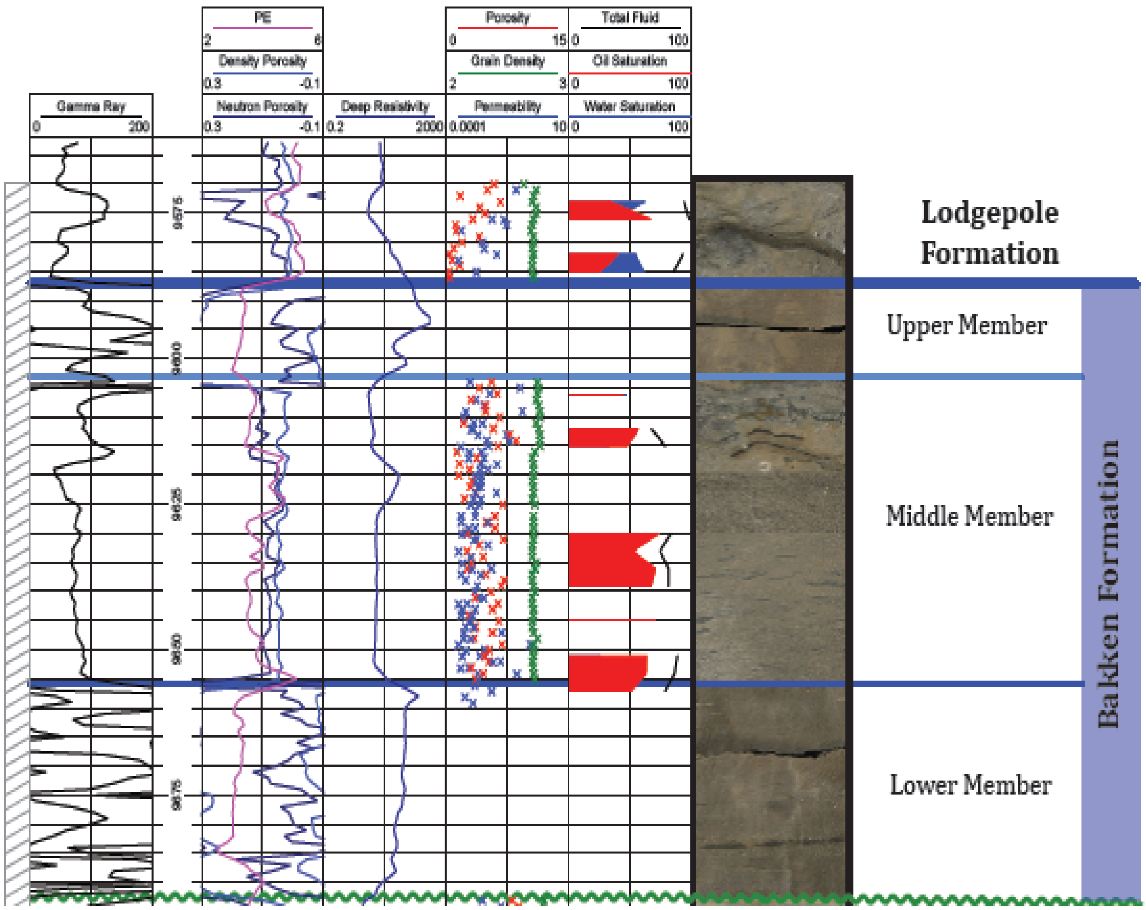


Source: Advanced Resources International, 2018

2 STUDY AREA

The area selected for the reservoir simulation study is located in Mountrail County, one of the four counties comprising the Basin Center Bakken Shale. The Bakken Shale in this area has an Upper and a Lower organic-rich shale interval (Member), with a thick silty dolostone and fine-grained sandstone deposition as the Middle Member, as shown in Exhibit 2-1.

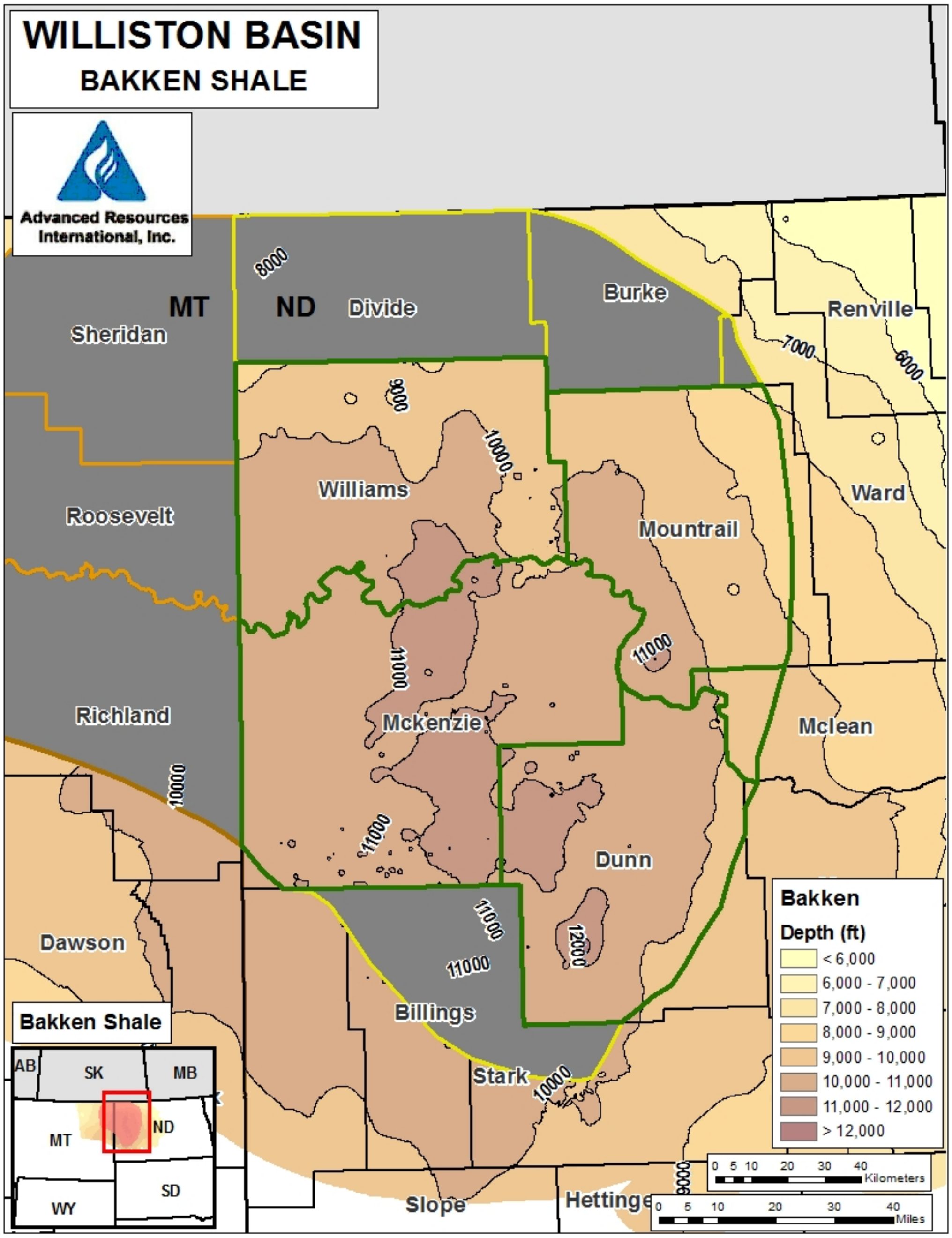
Exhibit 2-1 Typical Bakken Well Log



Source: LeFever, et al. 2013

The Bakken Shale Reservoir Simulation Study Area (Study Area), at a depth of 10,000 ft, is located in Mountrail County south of the Nesson Anticline, as shown in Exhibit 1-3. The Bakken Shale in Mountrail County extends across 1,890 mi^2 or 1,200,000-acre total area and has seen considerable horizontal (Hz) well development. The reservoir simulation study targets a 313-acre area within the larger Mountrail County portion of the Bakken Shale.

Exhibit 2-2 Depth of Basin Center Bakken Shale Area

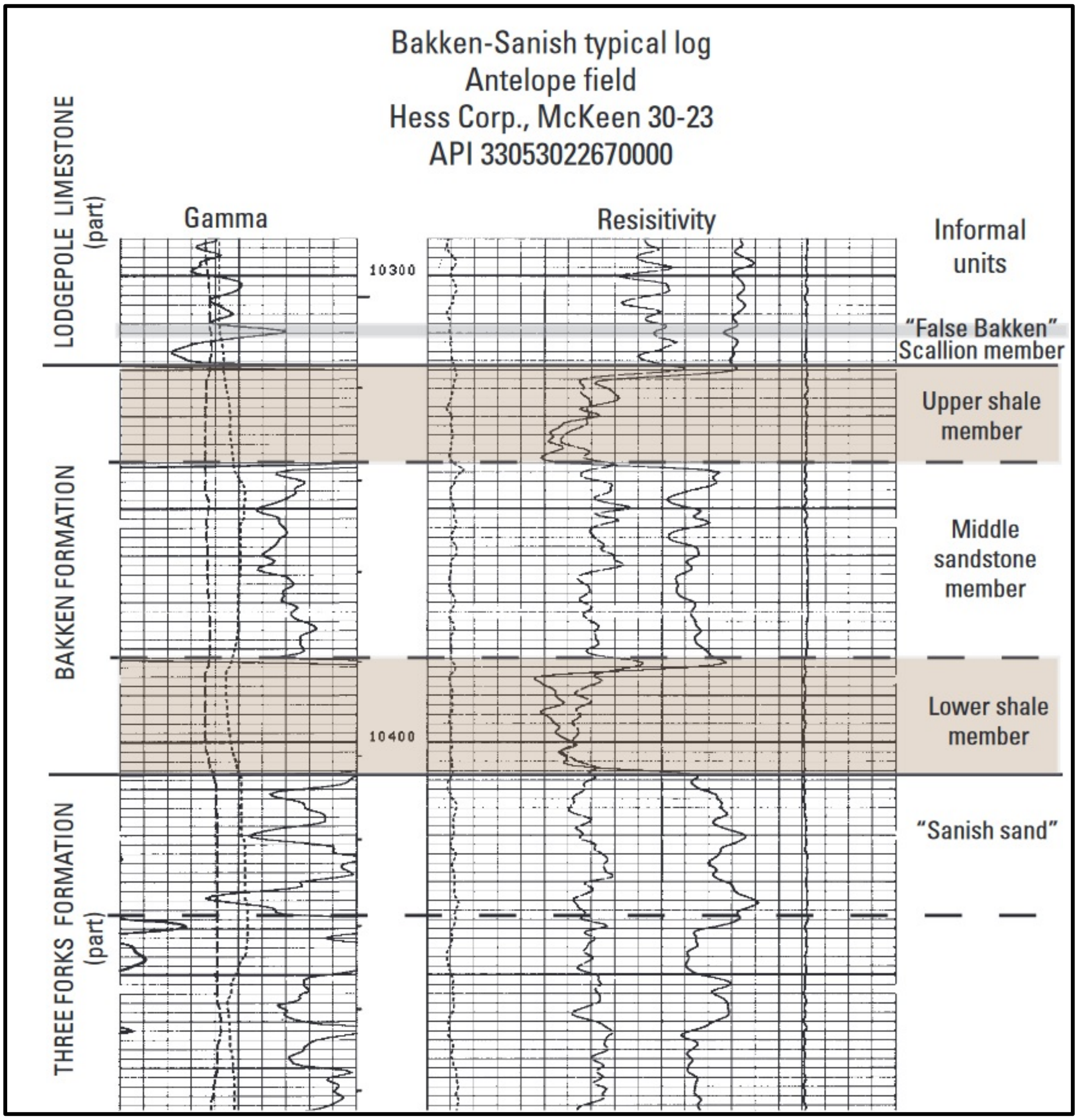


Source: Advanced Resources International, 2019.

3 Sources of Data for Reservoir Properties

The reservoir properties used for the Study Area have been assembled from a variety of sources, including log and core information from the McKeen 30-23 well in Mountrail County, as shown in Exhibit 3-1. Valuable information on Bakken Shale reservoir properties was provided by the Energy & Environmental Research Center (EERC) at the University of North Dakota.

Exhibit 3-1 Mountrail County Well Log, Basin Center Shale Area



Source: EERC, 2019a

4 Reservoir Properties and Oil Composition for Reservoir Simulation in the Bakken Shale

4.1 Representative Reservoir Properties

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

Exhibit 4-1 Bakken Shale Study Area Reservoir Properties

Reservoir Properties	Units
Pattern Area	313 acres
Well Pattern Dimensions	
▪ Length	10,500 ft
▪ Width	1,300 ft
Depth (to top)	10,000 ft
Net Pay	90 ft
▪ Upper (Shale)	10 ft
▪ Middle (Carbonaceous Sands)	50 ft
▪ Lower (Shale)	30 ft
Porosity	
▪ Matrix*	5.8%
▪ Fracture	0.1%
Initial Oil Saturation	
▪ Matrix/Fracture	71.5%
Saturation Gas/Oil Ratio	1.37 Mcf/B
Formation Volume Factor	1.73 RB/STB
Initial Pressure	6,700 psia
Temperature	220 °F
Bubble Point	2,500 psia
Formation Compressibility	1.5 * e $^{-5}$/psi
Oil Gravity	41° API

*Average for three Bakken Shale Units

Source: EERC, 2019a; Advanced Resources International, 2019.

4.2 OIL COMPOSITION

The oil composition data and its additional pressure volume temperature (PVT) data and binary interaction coefficients, representative of a saturation gas/oil ratio of 1,367 standard cubic foot/barrel (scf/Bbl), is provided below for the Middle Bakken Shale in the Study Area from information obtained from EERC in 2019 and the technical literature (Sanaei et al., 2018), as displayed on Exhibit 4-2.

Exhibit 4-2 Bakken Shale PVT and Oil Composition Data

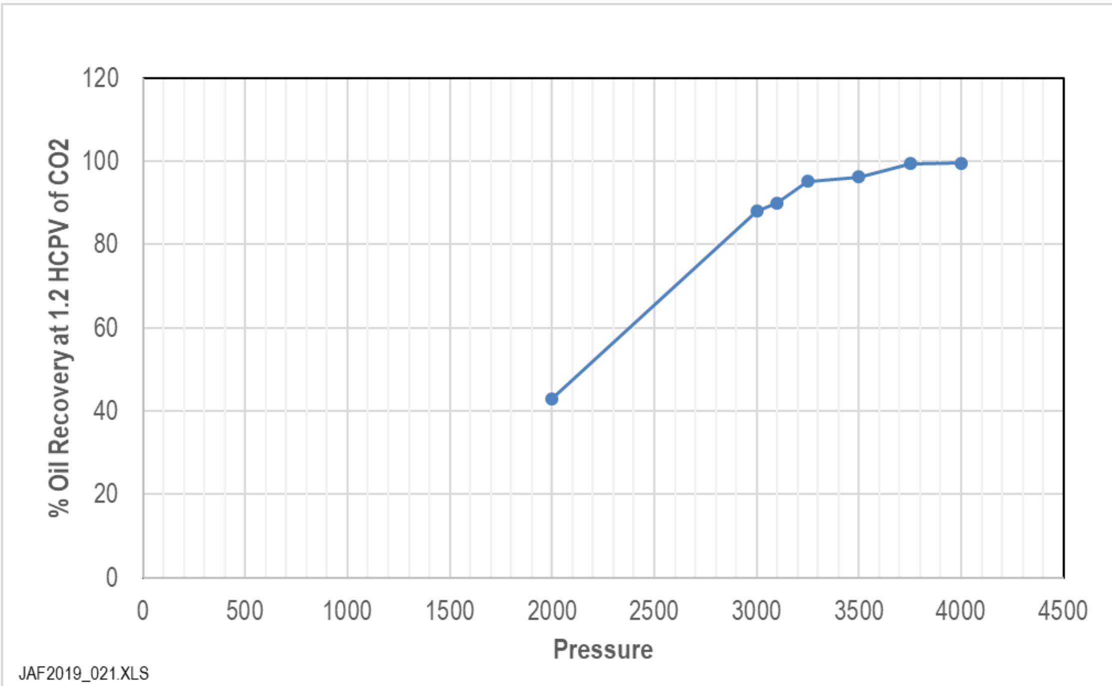
GOR (scf/Bbl)	1,367
Oil Composition	**Percent**
CO_2	0.5
N_2	1.5
C1	33.6
C2	15.8
C3	9.6
C4	6.2
C5	4.0
C6	2.8
C7 – C10	11.9
C11 – C14	5.1
C15 – C19	4.4
C20+	4.5

Source: EERC, 2019a and Sanaei et al., 2018.

4.3 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 Bakken Shale reservoir, Advanced Resources International (ARI) conducted a suite of slimtube simulations (using GEM) to establish a MMP of about 3,500 psi, as displayed on Exhibit 4-3.

Exhibit 4-3 MMP for CO_2 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, shown previously on Exhibit 4-1, the 313-acre Study Area well contains 5.2 million barrels of original oil in-place (OOIP) and 7.2 Bcf of original gas in-place (OGIP), as calculated below.

- OOIP = (313A * 90 ft) * 7758 B/AF (0.058 * 0.715/1.73)
- OOIP = 28,170 AF * 186 B/AF = 5.24 MMB
- OGIP = (5.24 * MMB) * (1,367 Mcf/B) = 7.16 Bcf

4.5 MATRIX PERMEABILITY

Matrix permeability in the Bakken Shale is highly variable, ranging from 0.0003 mD to 15 mD, depending on the lithofacies of the formations (EERC, 2019a). The value for permeability of 450 $* 10^{-6}$ mD used for the Study Area is based on history matching oil and water production for the Bakken Shale in Mountrail County. Other authors have discussed the relationships between Bakken Shale matrix permeability and Bakken Shale clay content, size of pore throats, and stress settings (Alexandre et al, 2011).

4.6 RESERVOIR TEMPERATURE

The bottom-hole reservoir temperature of the Bakken Shale varies considerably across the Williston Basin, generally ranging from 175ºF to 270ºF, with lateral variations in the thermal gradient consistent with thermal maturity (Hester and Schmoker, 1985).

4.7 RESERVOIR PRESSURE

Similar to temperature, there is significant variability in the reservoir pressure of the Bakken Shale, with highest pressures observed in the thermally mature areas in the basin center. The reported pressure gradients for the Bakken Shale range from (0.5 psi/ft) along the northern, less thermally mature portions of the basin margin to highly overpressured (0.7 psi/ft) in the more thermally mature basin center (Schmidt, D. 2011).

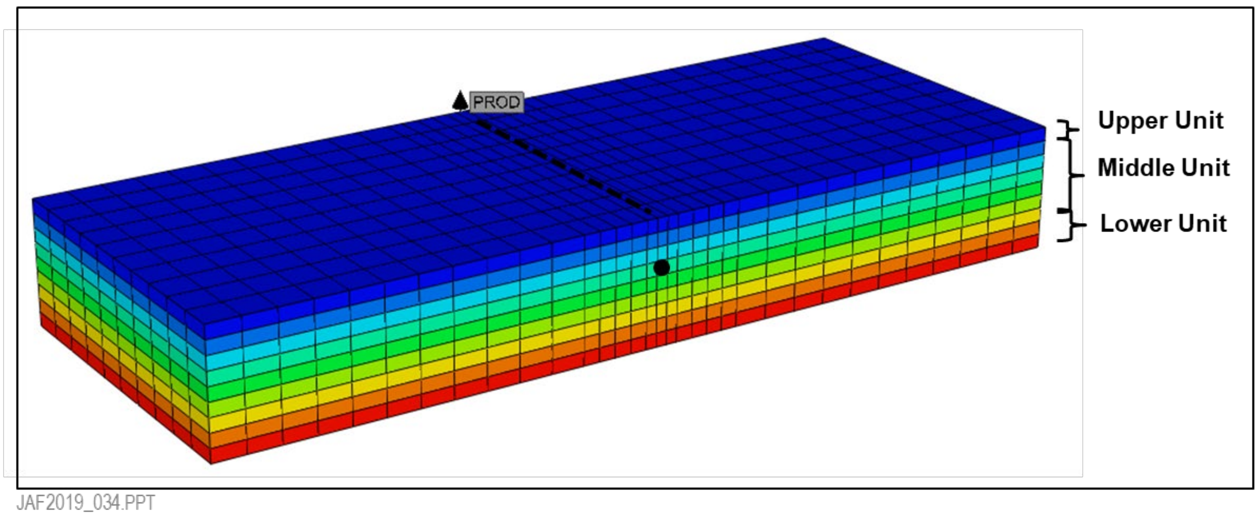
5 RESERVOIR MODEL

5.1 MODEL DIMENSIONS, LAYERS AND GRID BLOCKS

The reservoir model and grid blocks constructed to replicate the Bakken Shale geologic and reservoir setting for the Study Area well are illustrated on Exhibit 5-1:

- The model is 500 ft parallel with the Hz well (1/21st of the 10,500 ft Hz type well) and 1,300 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 (1/21st of the 10,500 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 1,300 ft perpendicular to the Hz well.
- Based on available isopach maps from the Bakken Shale in southwestern Mountrail County, an overall Bakken Shale thickness of 90 ft was deemed representative of the shale in the Study Area, with the net pay of the Middle Bakken Shale set at 50 ft. The total shale thickness was subdivided into 9 vertical layers; 1 layer of 10 ft to represent the Upper Bakken Shale Unit; 5 layers of 10 feet each to represent the Middle Bakken Shale Unit; and 3 layers of 10 ft each to represent the Lower Bakken Shale Unit. Transmissibility barriers were implemented above the Upper Bakken Shale Unit and below the Lower Bakken Shale Unit.
- The Hz well was completed in the Middle Bakken Unit, in vertical layer 4, in the center of the pattern area.

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



Source: Advanced Resources International, 2019.

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 2,880 grid blocks.

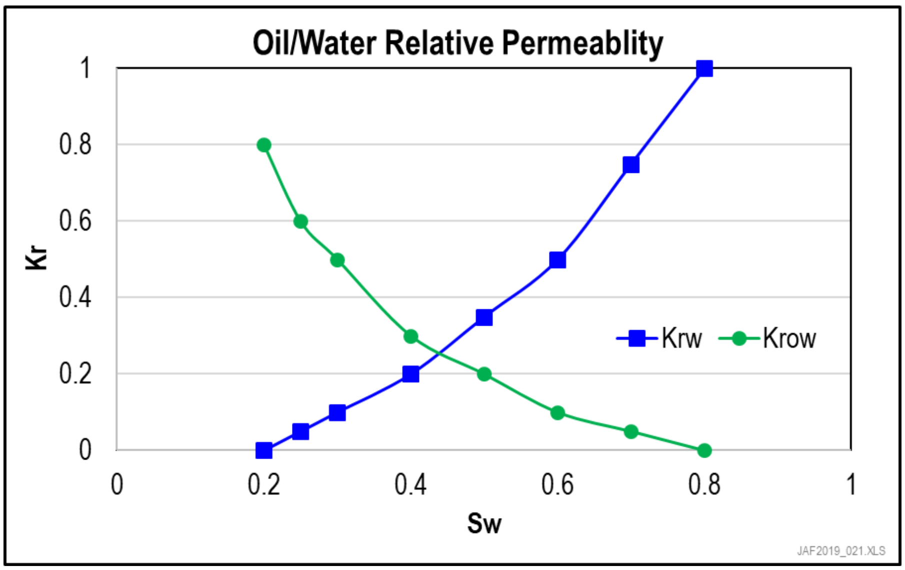
5.2 Reservoir Simulator

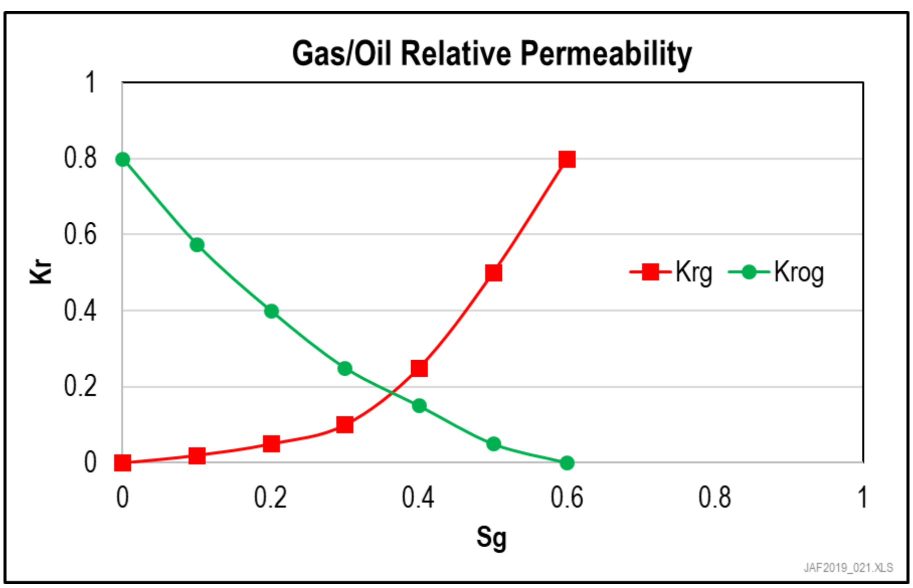
The GEM reservoir simulator from the Computer Modeling Group was utilized for the study. GEM is a robust, fully compositional, Equation of State reservoir simulator used widely by industry for modeling the flow of three-phase, multi-component fluids through porous media.

5.3 Relative Permeability

Information from the technical literature and history matching of oil, water and gas production were used to establish the relative permeability shapes and end points for oil, water, and gas saturation for the Bakken Shale, as displayed on Exhibit 5-2.

Exhibit 5-2 Bakken Shale Relative Permeability





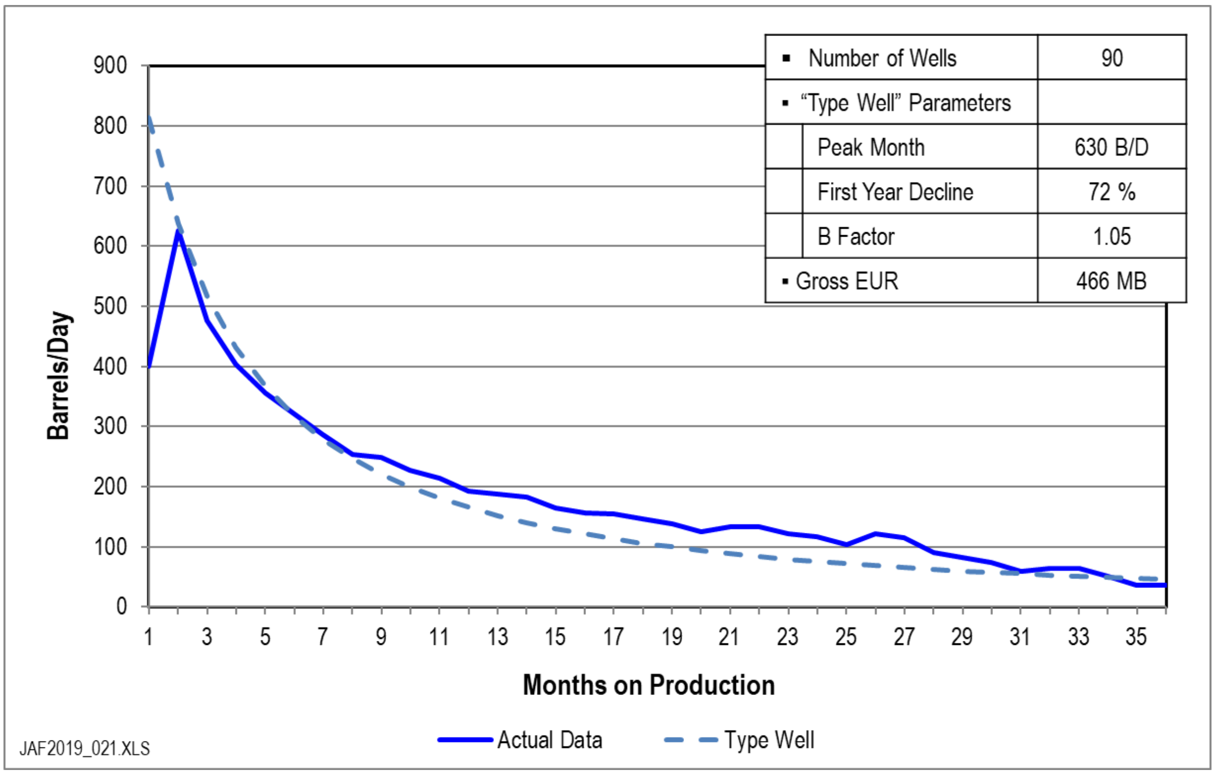
Source: Advanced Resources International, 2019 and Sanaei et al., 2018.

6 TYPE WELL FOR STUDY AREA

The Study Area well chosen for the history match is the "type well" for the Bakken Shale in Mountrail County assembled by Advanced Resources International using production data from the Texas Railroad Commission. The "type well" represents the composite performance of 90 Hz wells drilled in 2016 and has 36 months of oil and gas production, as displayed on Exhibit 6-1.

The well's longer term, 30-year performance was estimated using a peak month production of 630 barrels per day (B/D), a first year production decline of 72 percent, and a "b" of 1.05 for the longer-term production decline.

Exhibit 6-1 Study Area Type Well Oil Production



Source: Advanced Resources International, 2019.

The "type well" in the Study Area has a spacing of 313 acres (4 wells per 1,280 acres) and a Hz lateral of 10,500 ft. It has an estimated 30-year oil recovery of 466,000 barrels.

The reservoir simulation model uses 1/21st of these values for the 500-ft Hz segment representative of the 10,500-ft total Hz well, giving a 30-year oil recovery of 22,200 barrels for the Hz segment of the modeled "type well".

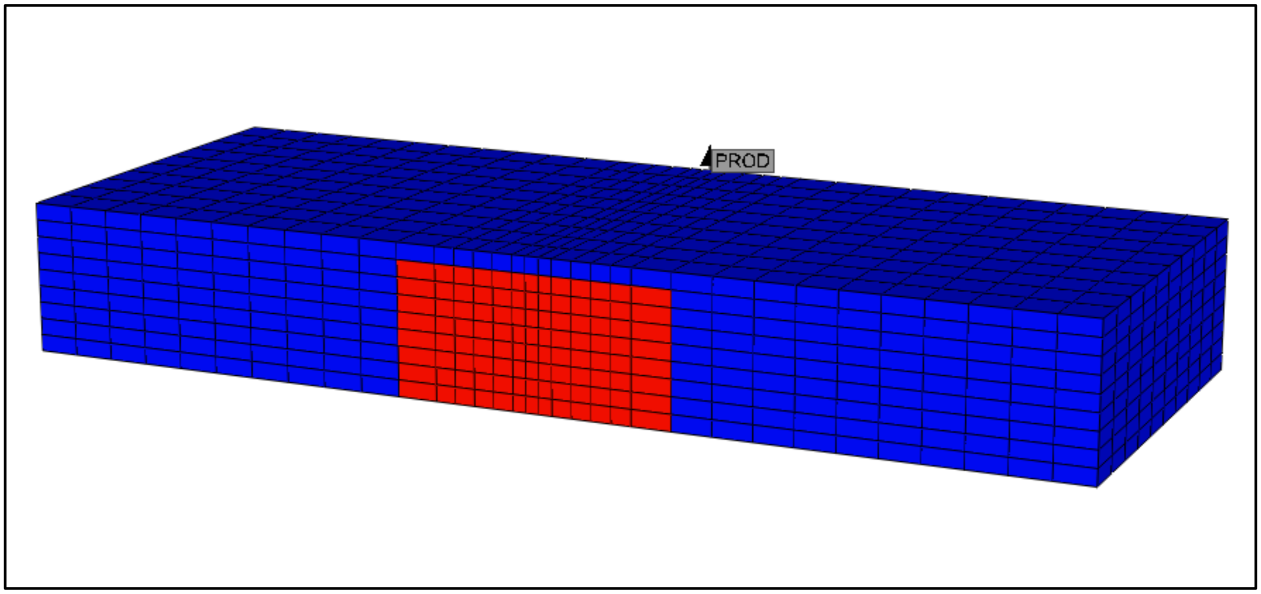
7 REPRESENTING THE IMPACT OF HYDRAULIC STIMULATION

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.

The "segment" well was assumed to be stimulated for 80 percent of its full length (400 ft) with the fracture half-length (length of the fracture on each side perpendicular to the well) used as a variable during the history-matching process. Vertically, the fracture height, also used as a variable during the history-match process, was limited to the Lower and Middle Shale Units, as illustrated on Exhibit 7-1.

Exhibit 7-1 Representative SRV for "Segment" Well



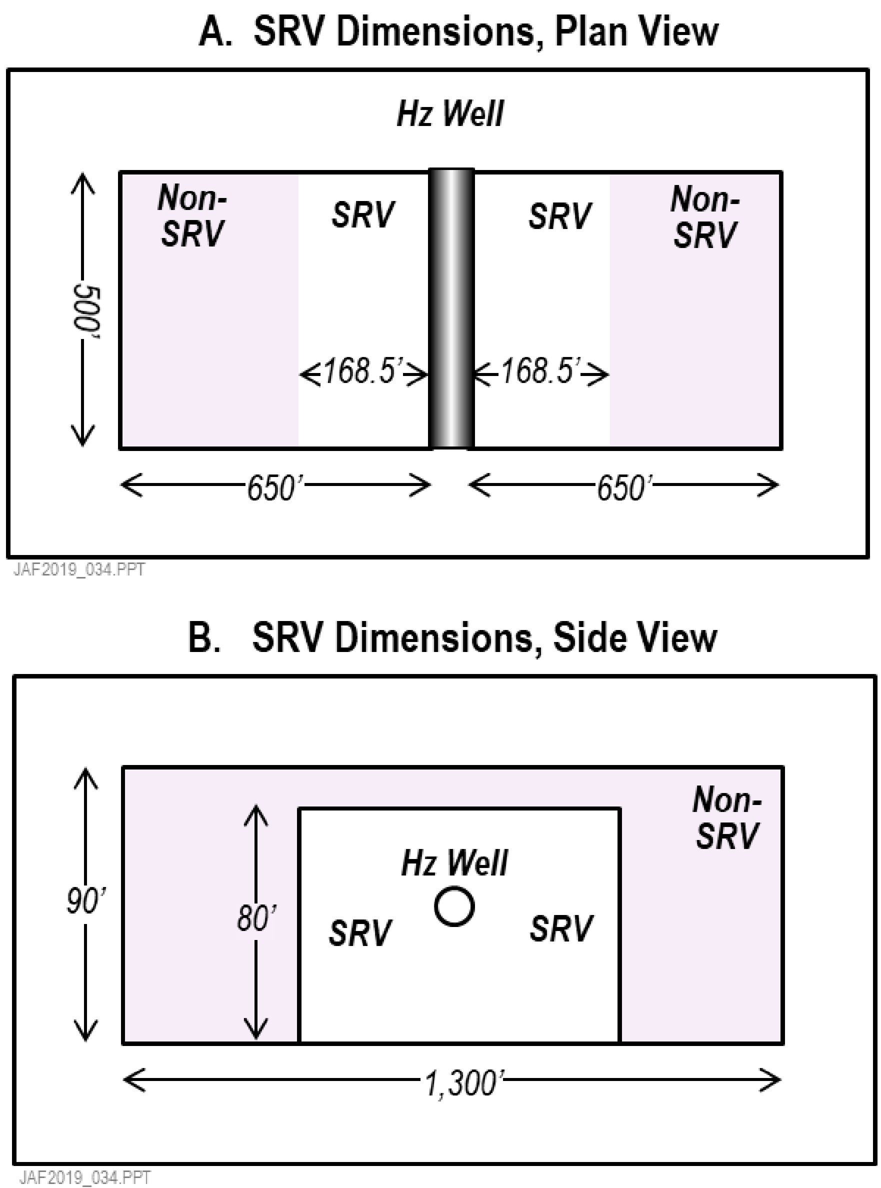
Source: Advanced Resources International, 2019.

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 337 ft wide, consistent with a propped fracture half-length of 168.5 ft.
- The SRV is 80 ft high, encompassing nearly 90 percent of the vertical interval.
- The SRV length extends along 80 percent of the Hz wellbore, equal to 400 ft for the "segment" well (1/21st 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 (Exhibit 7-3) along with the relative permeability curves and the SRV dimensions discussed previously, were used for the history match of the Bakken Shale "type well" in the Study Area of Mountrail County.

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

	Matrix
Non-SRV	
Horizontal	$450 * 10^{-6}$ mD
Vertical	$45 * 10^{-6}$ mD
SRV*	0.065 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, reservoir simulation achieved an excellent history match with the "type well" for the Study Area. With an OOIP of 250,000 barrels (140,000 barrels in the Middle Bakken) for the Hz "segment" well (1/21st of total Hz well) and a 30-year recovery of 22,200 barrels, the oil recovery efficiency is about 9 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 closely 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	13,120	13,150
30 years	22,500	22,200

*For 1/21st 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 natural gas production.

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

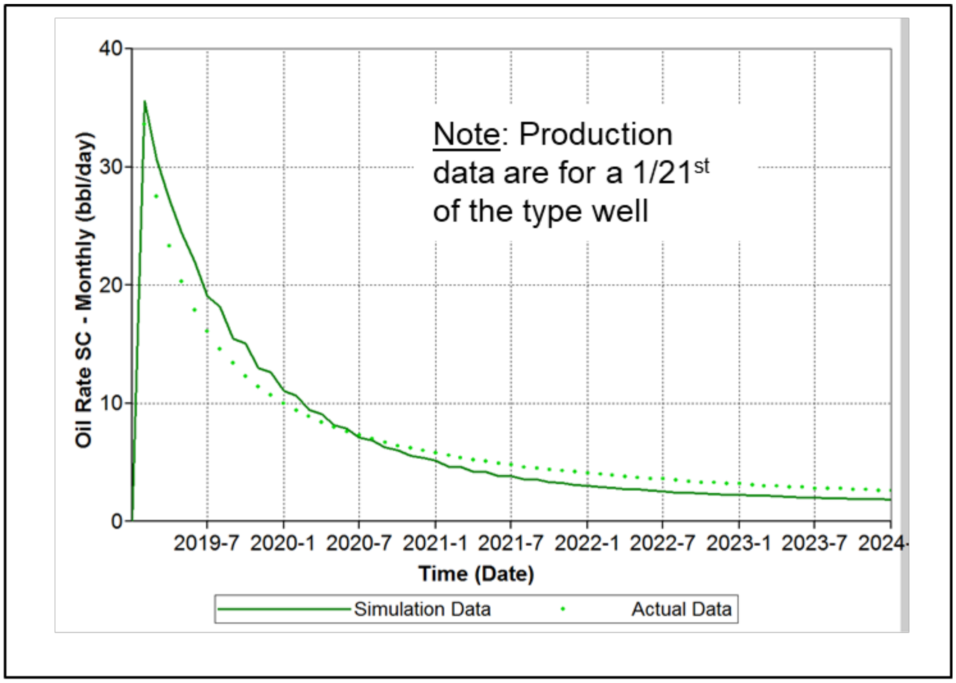
Gas Production Time Period	Type Well* (MMcf)	History Matched Well (MMcf)
5 years	17.9	18.4
30 years	30.7	31.7

*For 1/21st 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 reservoir simulation-based history match of oil production for the Bakken Shale Study Area well in comparison with oil production from the Bakken Shale "type well" for Mountrail County.

Exhibit 8-3 History Match of Monthly Oil Production



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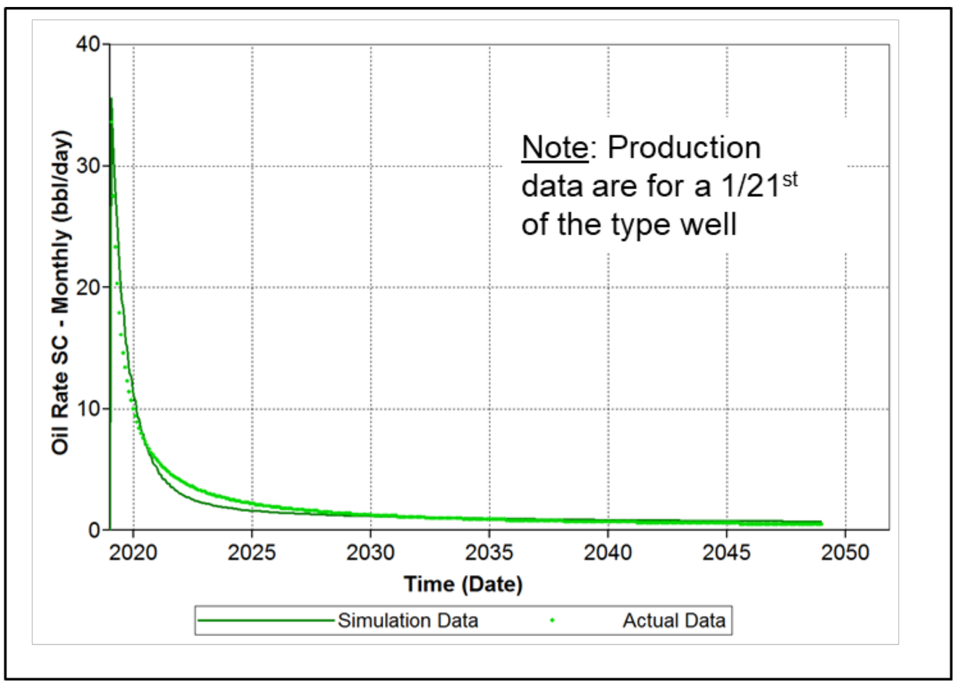
Source: Advanced Resources International, 2019.

Exhibit 8-4 Projection of 30 Years of Primary Production



JAF2019_034.PPT

Source: Advanced Resources International, 2019.

8.2 Modeling of Cyclic CO_2 Injection

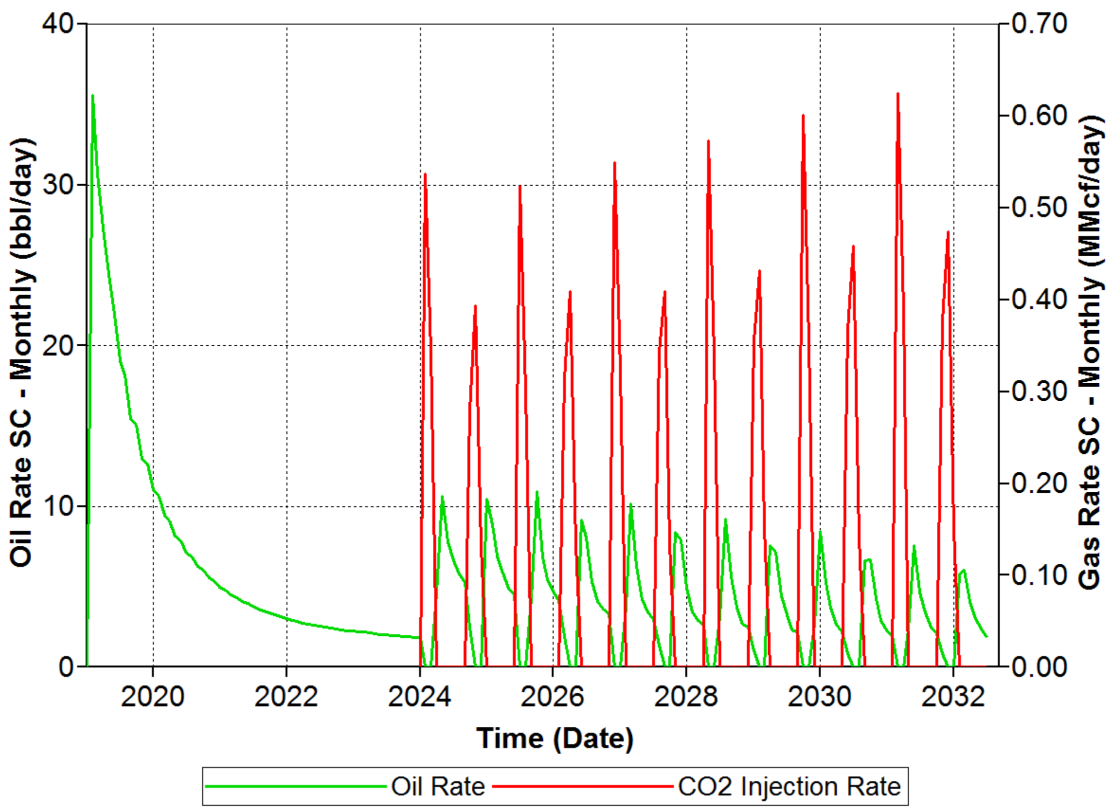
8.2.1 Cyclic CO_2 Injection

Cyclic CO_2 injection was initiated using the GEM compositional simulator in the Study Area well after five years of primary production. At this time, the segment Hz well (1/21st of the overall Hz well) had produced 13,100 barrels, equal to about 60 percent of its estimated ultimate oil recovery.

- In cycle one, CO_2 was injected at a constant rate of 700 thousand cubic feet per day (Mcfd) for 2 months (BHP limit of 7,000 pounds per square inch absolute (psia)) to refill reservoir voidage, with a total of 27,000 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 from the subsequent 12 cycles (8.5 years) of cyclic CO_2 injection, soak, and production from the Hz well segment (1/21st 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 11,300 barrels of oil production for the reduced (1/21st) Hz well segment. With primary oil recovery of 13,100 barrels at the start of cyclic CO_2 injection, total oil recovery reached 24,400 barrels at the end of cyclic CO_2 injection. Continuation of primary recovery for 8.5 years would have provided 4,200 barrels of oil production during this time in addition to the 13,100 barrels at the start of cyclic CO_2 injection. As such, 7,100 barrels of incremental oil recovery (11,300 barrels less 4,200 barrels) is attributable to injection of CO_2, as shown on Exhibit 8-6.

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

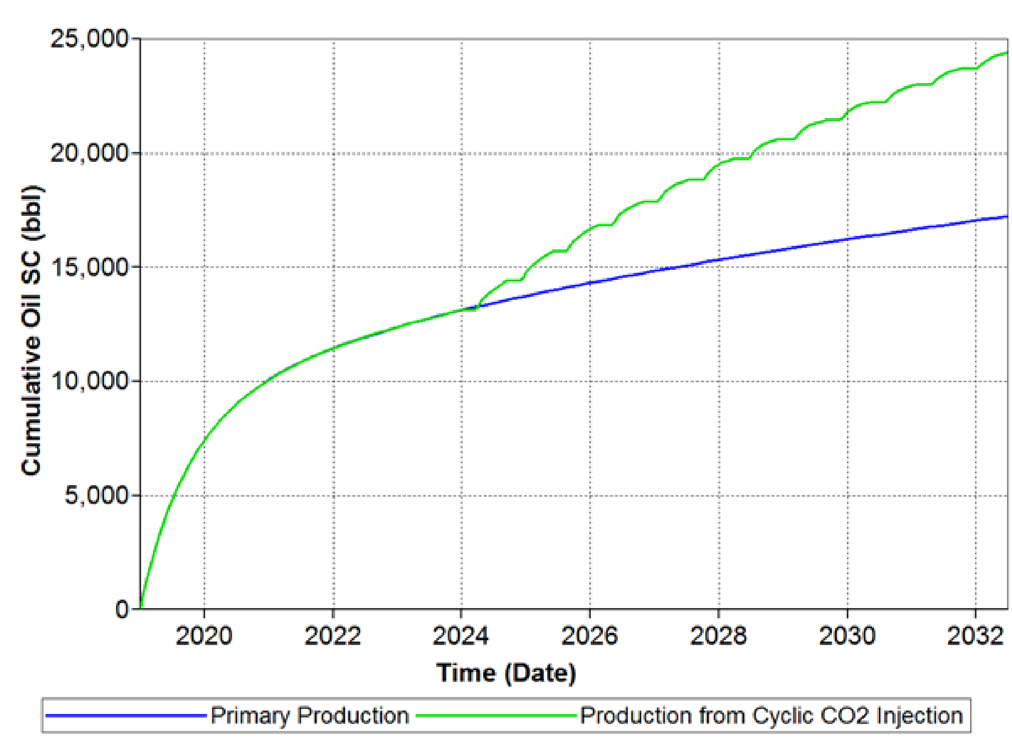
	Cumulative Oil Production			Cumulative CO_2		Estimated CO_2 Storage (MMscf)
	Total (Barrels)	**Primary Production** (Barrels)	**Incremental EOR** (Barrels)	**Injection** (MMscf)	**Production** (MMscf)	
End of 5-year primary	13,100	13,100	-	-	-	-
End of 1st cycle	14,400	13,700	700	27	15	12
End of 6th cycle	19,800	15,500	4,300	155	123	32
End of 12th cycle	24,400	17,300	7,100	330	283	47

Source: Advanced Resources International, 2019.

A significant portion of the CO_2, equal to 14 percent (47 million cubic feet (MMcf)) of the 330 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 1.41x 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



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 237,000 barrels of oil production for the full Hz well, in addition to 275,000 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 512,000 barrels. Continuation of primary recovery for 8.5 years would have provided 88,000 barrels of oil recovery. As such, 149,000 barrels of incremental oil recovery (237,000 barrels less 88,000 barrels) is attributable to injection of CO_2.

Assuming no further cyclic injection of CO_2, this 12 cycle CO_2 injection project provided a 1.41x uplift to oil production for the full Study Area Hz well, as displayed 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	275	275	-	-	-	-
End of first cycle	302	288	14	570	320	250
End of 6th cycle	416	326	90	3,250	2,580	670
End of 12th cycle	512	363	149	6,930	5,940	990

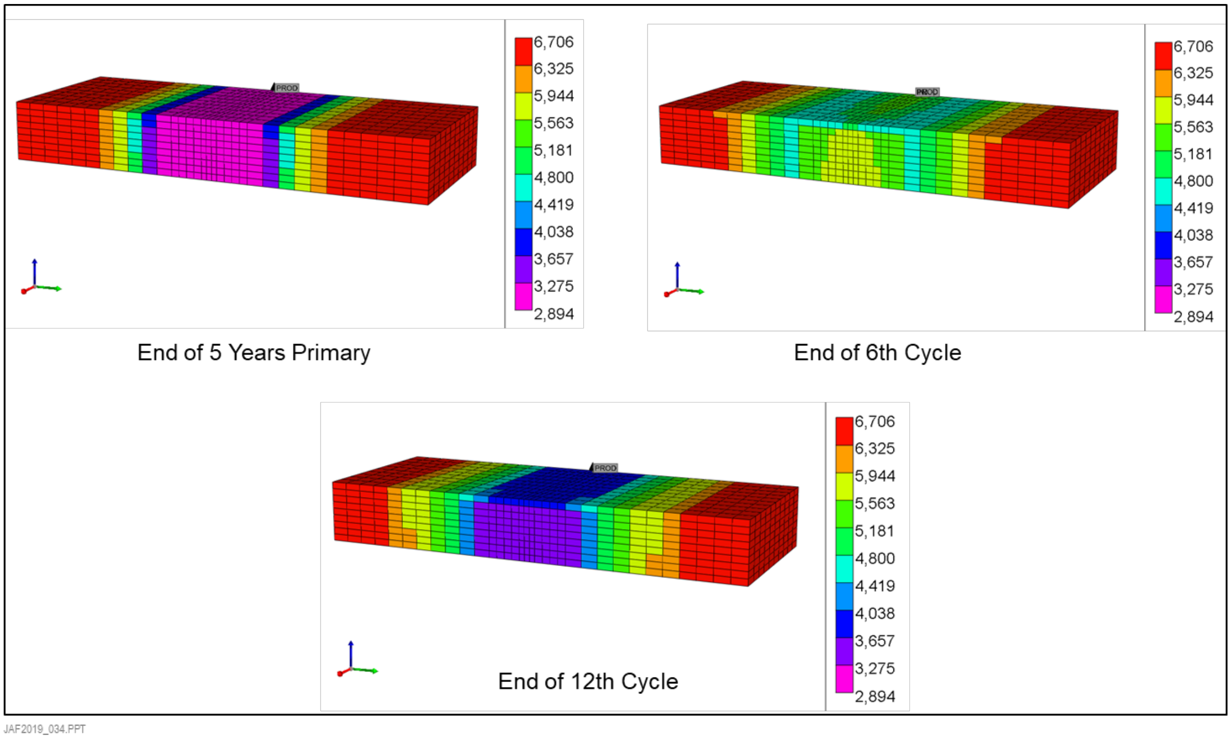
Source: Advanced Resources International, 2019.

Approximately 14 percent (990 Mcf) of the 6,930 MMcf of CO_2 injected remained stored in the reservoir at the end of 12 cycles of CO_2 injection, as displayed 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.

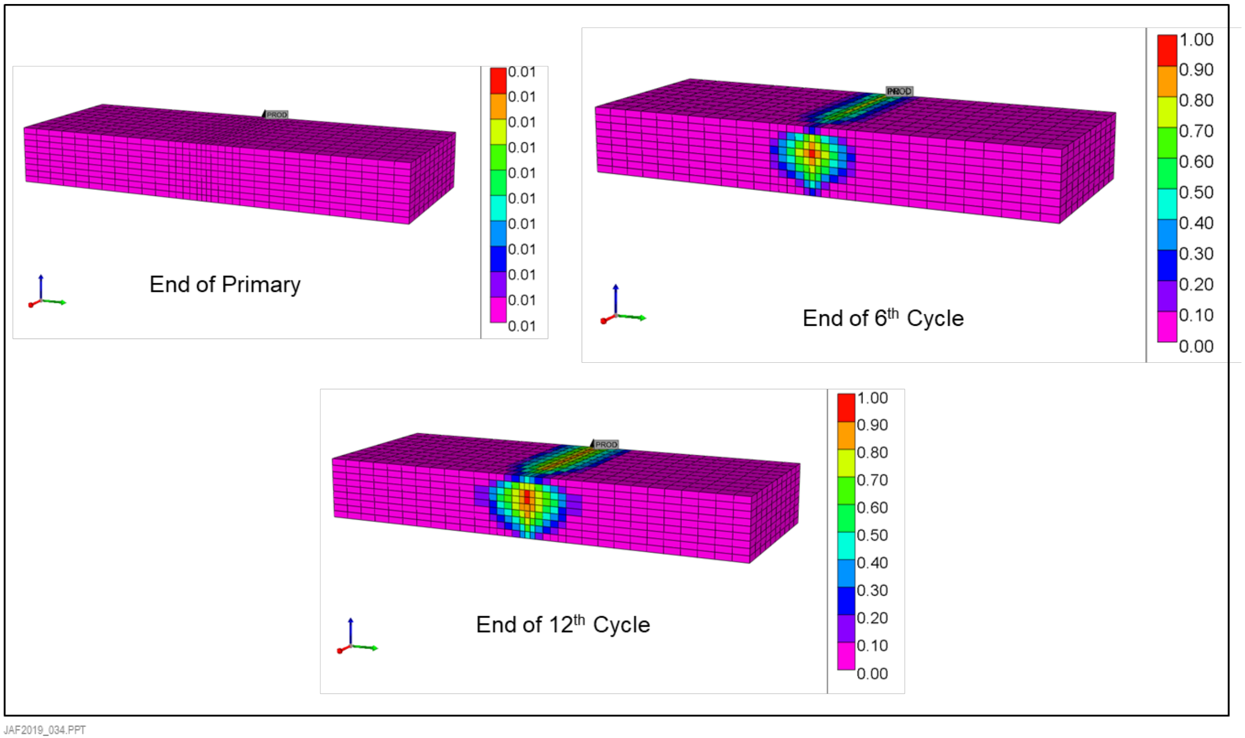
Even more noticeable pressure declines in the non-SRV matrix blocks are evident at the end of 12 cycles of CO_2 injection, as shown in Exhibit 8-9.

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 Bakken 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 70 percent to 80 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 40 percent at the edges of the SRV.

Exhibit 8-10 CO_2 Saturation Profiles Following Cyclic CO_2 Injection



Source: Advanced Resources International, 2019.

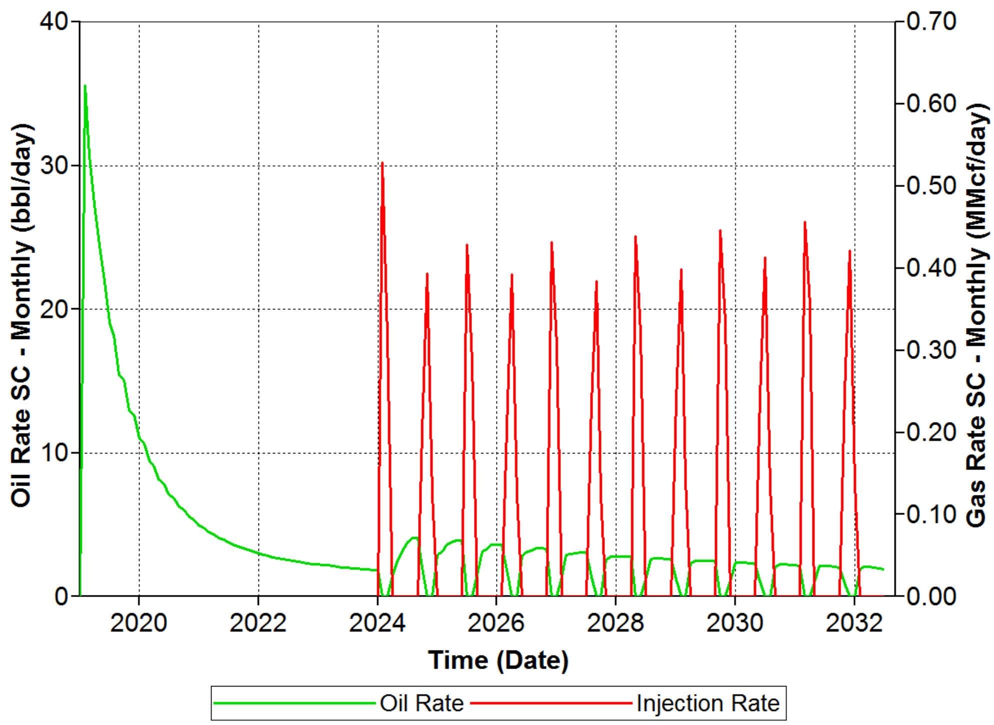
8.3 Performance of Cyclic CO_2 Versus Cyclic Natural Gas Injection

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 shown on Exhibit 8-12, comparing use of CO_2 injection with use of dry gas injection. Even so, injection of 12 cycles of dry gas provided an uplift of 1.11x 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)

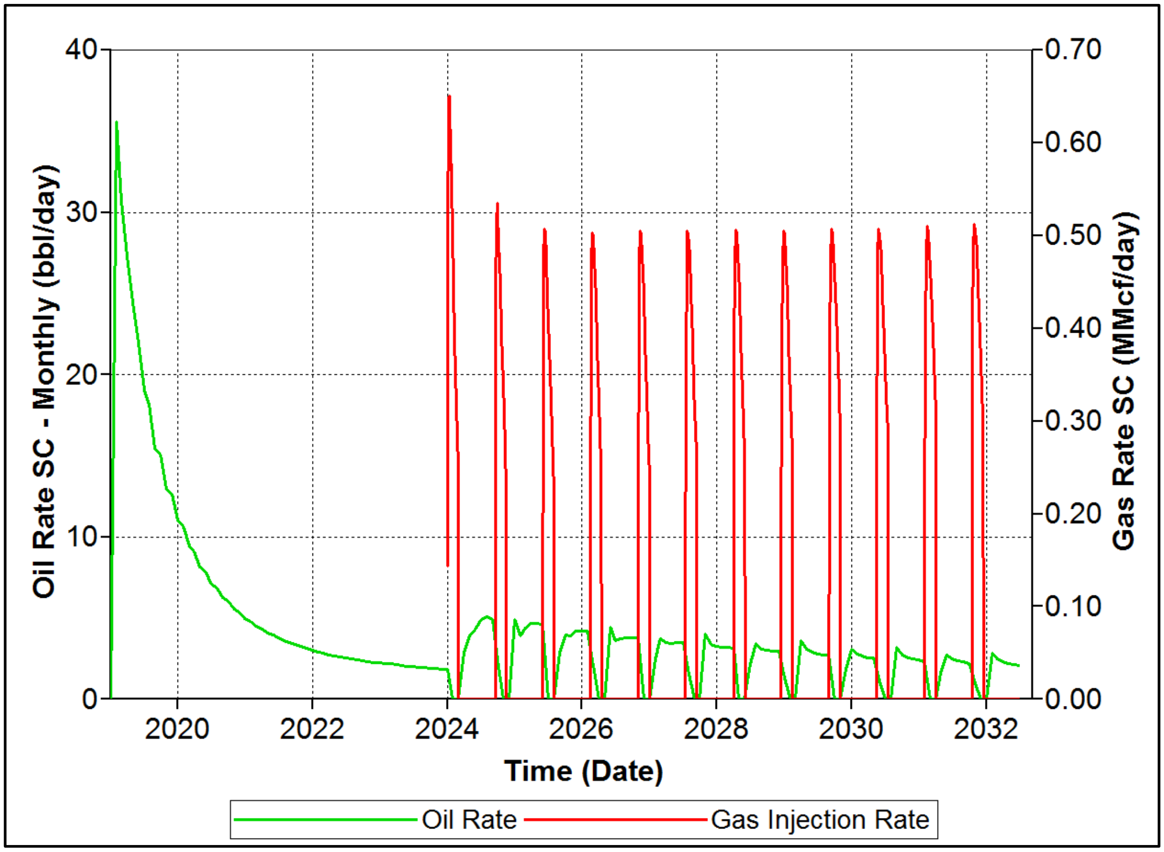
	Cumulative Oil Production Using CO_2			Cumulative Oil Production Using Dry Gas		
	Total (Barrels)	**Primary** (Barrels)	**Incremental** (Barrels)	**Total** (Barrels)	**Primary** (Barrels)	**Incremental** (Barrels)
End of 5-year primary	13,100	13,100	-	13,100	13,100	-
End of 1st cycle	14,400	13,700	700	13,800	13,700	100
End of 6th cycle	19,800	15,500	4,300	16,700	15,500	1,200
End of 12th cycle	24,400	17,300	7,100	19,200	17,300	1,900

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 shown on Exhibit 8-14. Injection of 12 cycles of wet gas provided an uplift of 1.19x 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	13,100	13,100	-	13,100	13,100	-
End of 1st cycle	14,400	13,700	700	14,000	13,700	300
End of 6th cycle	19,800	15,500	4,300	17,600	15,500	2,100
End of 12th cycle	24,400	17,300	7,100	20,600	17,300	3,300

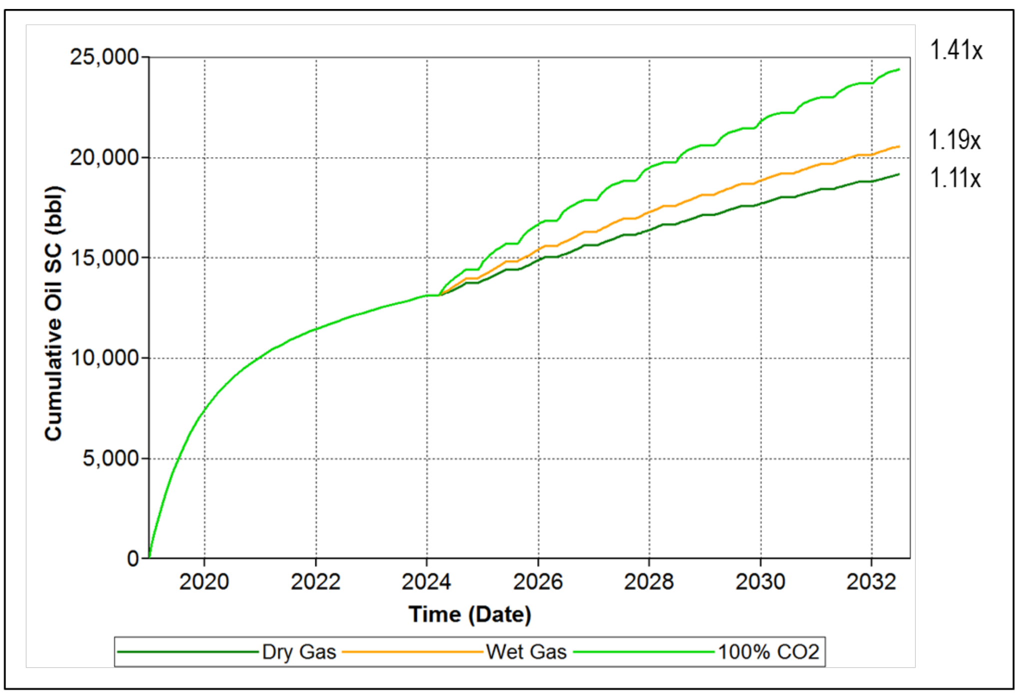
Source: Advanced Resources International, 2019.

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 1.41x in oil production over continuation of primary recovery, compared to uplifts of 1.11x for cyclic dry gas injection and 1.19 for cyclic wet gas injection, as displayed on Exhibit 8-15

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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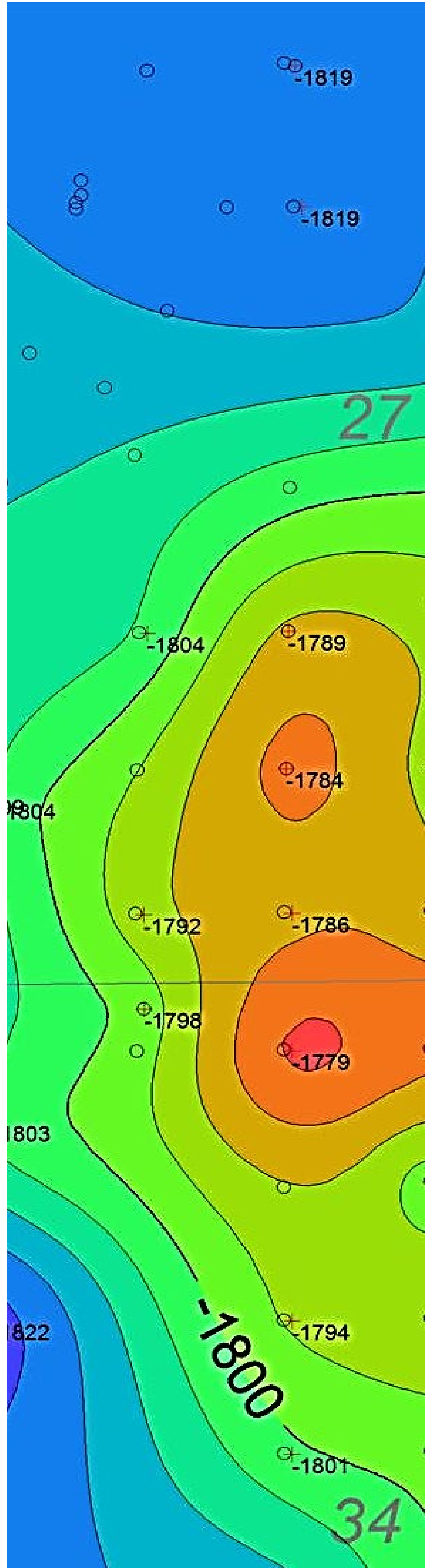

Jared Ciferno
Jared.ciferno@netl.doe.gov

Michael Tennyson
michael.tennyson@netl.doe.gov

NATIONAL ENERGY TECHNOLOGY LABORATORY

www.netl.doe.gov

Albany, OR • Anchorage, AK • Morgantown, WV • Pittsburgh, PA • Sugar Land, TX

(800) 553-7681