APPENDIX C

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IHS ENERGY

ECONOMIC IMPACT OF CO2 EOR IN NORTH DAKOTA

Interim Report

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2 Conventional Field CO2 EOR

3 Economic Model Assumptions

4 Upstream Economics

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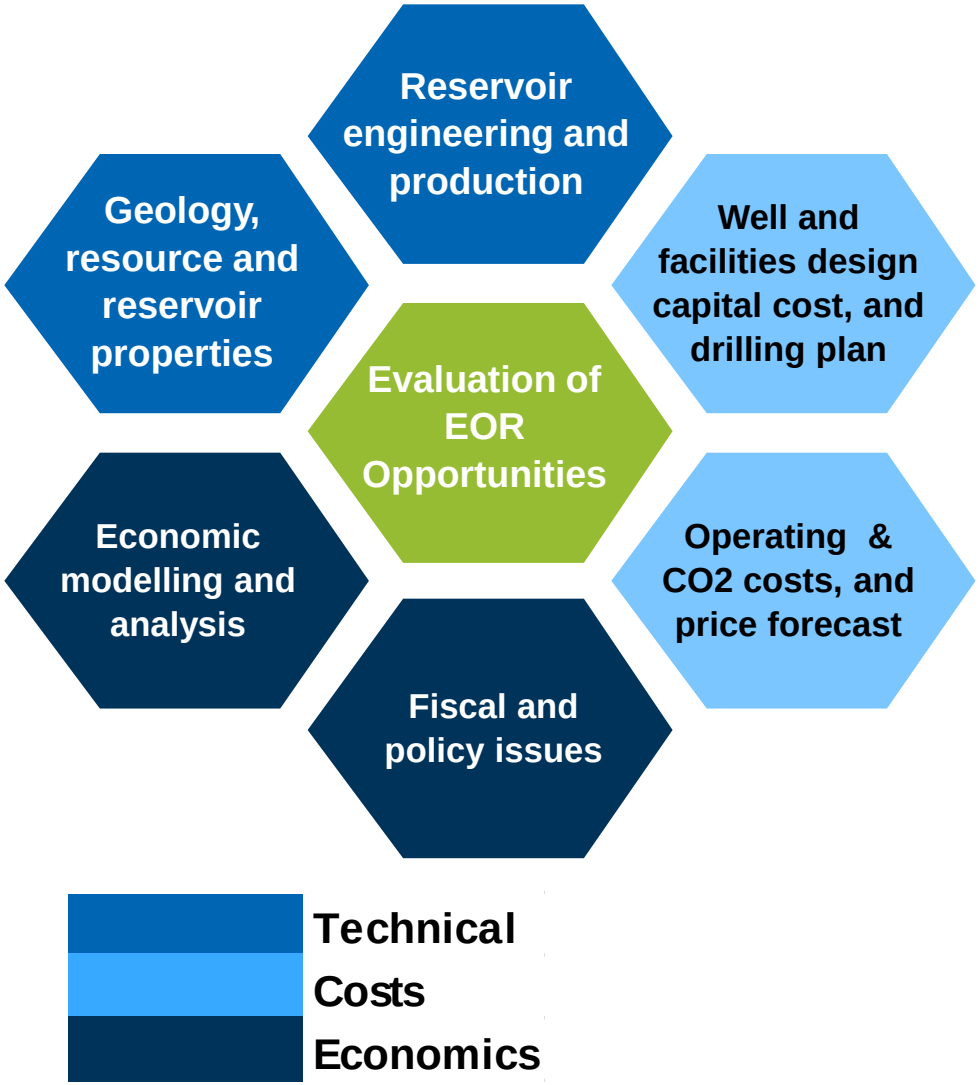
Approach



- Scope: Economics of CO2 EOR application for conventional and unconventional developments in North Dakota
- Process: Research, screening, analysis, validation
- Sources:
  - IHS proprietary databases and research
  - Third party information such as research reports, presentations, etc.
  - Industry models
  - Proprietary cost and economic models

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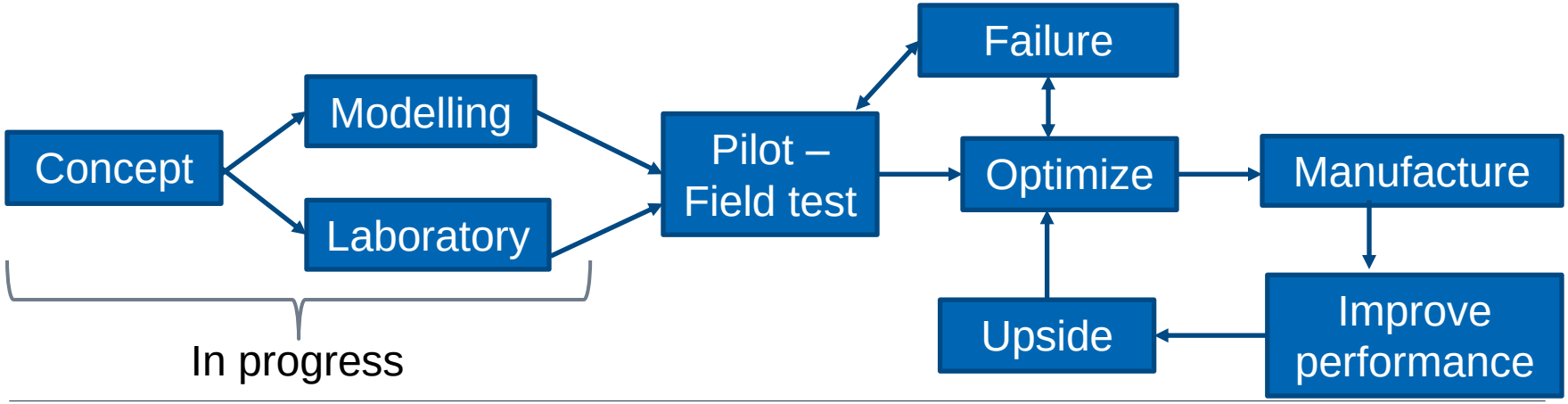
EOR-CO2 analysis – Conventional vs. Unconventional

- Conventional EOR - well established and documented
  - Performed since the mid-1980s
  - Many fields undergoing CO2 EOR in the US
  - Narrow range of uncertainties – more highly predictable
- Unconventional EOR (Bakken / Three Forks)
  - Still in concept / modeling stage
  - No fields / one small pilot (EC 2009) – pilot planned at Sanish field
  - High range of uncertainties – We don't know how will work for sure



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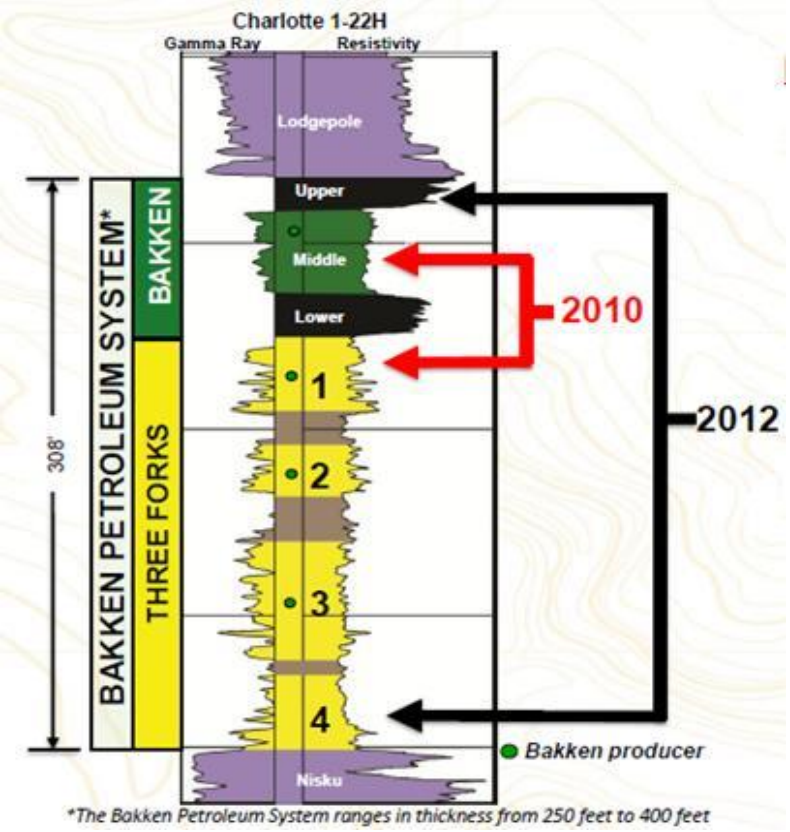
Bakken - attractive candidate for CO2 EOR consideration

1. Wide spread in seven ND counties consisting of 10,300 square miles
2. One – four possible Bakken/Three Fork zones
3. Recent estimates of OOIP 167 - 900 Bbbls; 5% recovery rate would be 8.4 - 45 Bbbls
4. Over-pressured reservoirs - BHP: 6000-7000 psi – more likely to reach MMP
5. CO_2 EOR model has produced some encouraging, yet diverse outcomes
6. Meets all of IHS field screening criteria
7. As Bakken production begins to decline per IHS forecast in about 10 years (2026):
    1. Infrastructure already in place
    2. Oil price increase/recovery underway
    3. Evolution of technology (1) CO2 injection (2) carbon Capture



CLR investor presentation 2012

Recovery perception change

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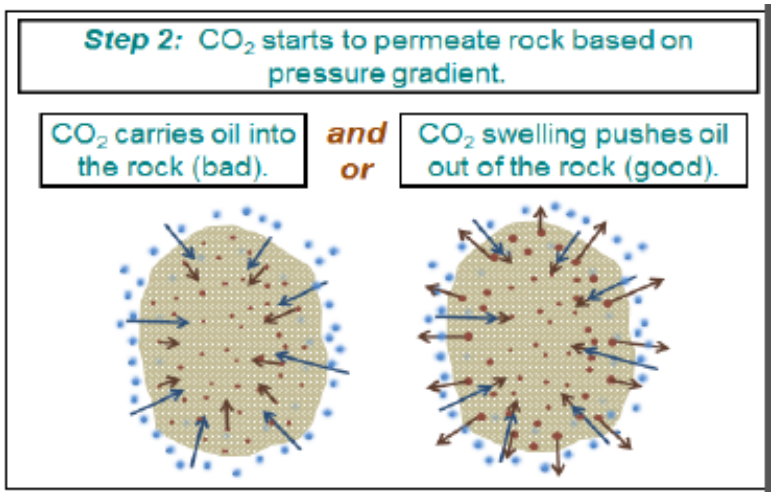
Uncertainties: Lie buried deep within the rock itself

1. Heterogeneity of the Bakken reservoir properties
2. Extent and ability of micro fractures to carry CO_2 into pore spaces for commercial recovery
3. How CO2 will react with oil within the micro-pores
4. MMP and effect of pressure increase and drops (due to hydraulic fracturing)



EERC – Overview of EERC's Bakken CO2 EOR Research Programs 2014

How do we derive inputs for an economic model which is intended to affect public policy?

(1) Review of published work such as CO2-EOR Bakken modelling
(2) Build on knowledge of the Bakken / Three Forks primary production
(3) Apply lessons-learned from conventional CO2 - EOR

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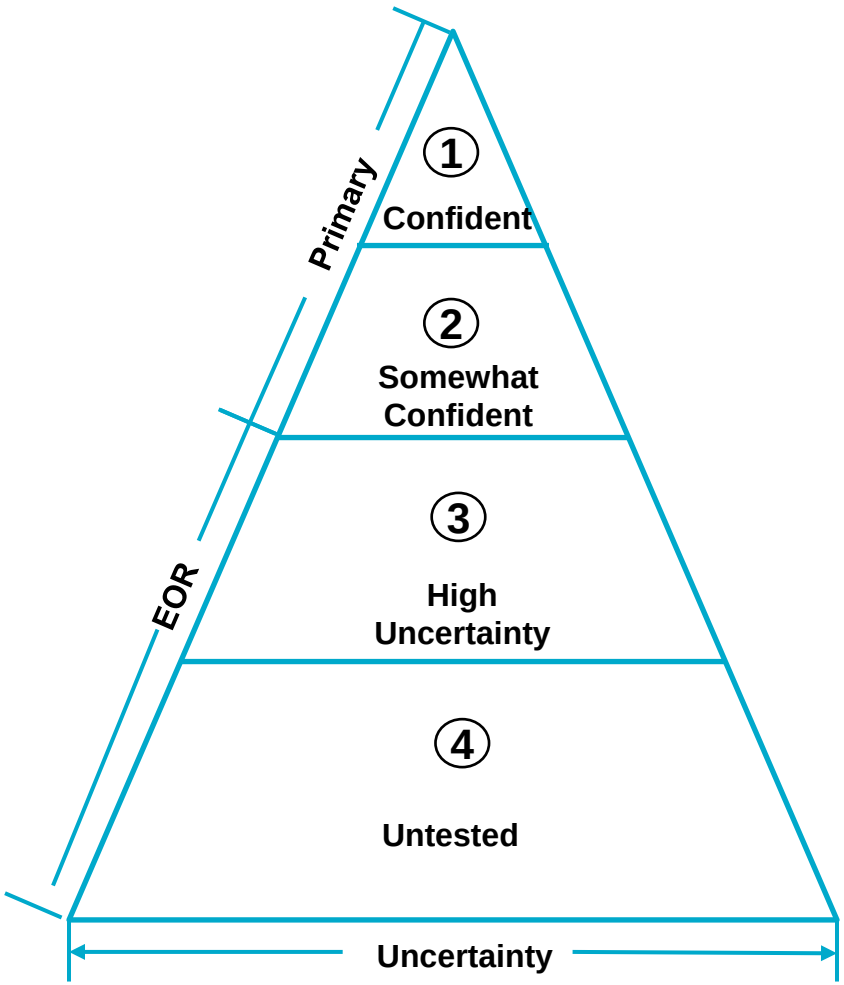
Bakken/Three Forks – what we know and don't know



1
- Play extent & sweet spots
- Production performance ranges
- OOIP & primary recovery
- Well completion designs
- Bakken, Upper Three Forks works

2
- Performance of 0.25 mile spacing
- Timing of oil price recovery
- Second and third Three Forks viability
- Long-term well life and production decline

3
- CO_2 per bbl needed for CO2
- CO2 recovery factors
- MMP
- CO_2 source and availability

4
- Extent of Bakken/Three Forks EOR
- Three Forks benches
- Fractures interferences
- Spacing - CO_2 penetration
- Shape of oil production profile
- CO_2 re-injection percentage

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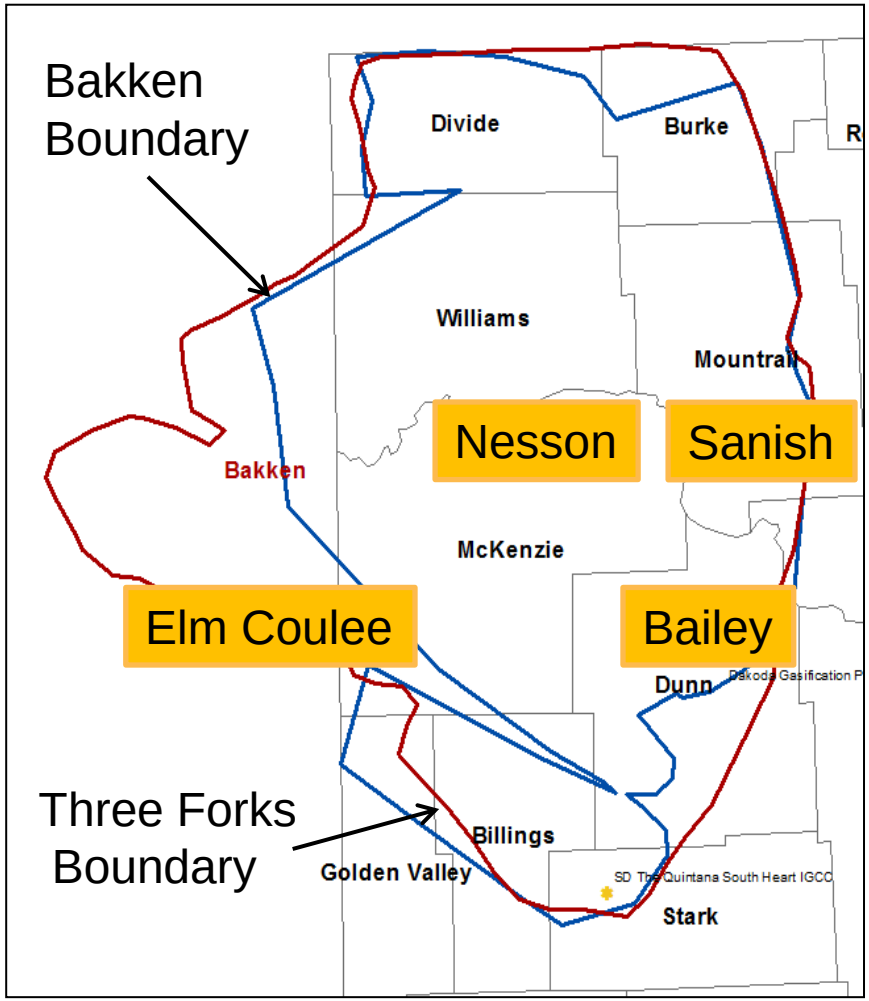
Bakken areas modelled for seven counties

- Primary and EOR properties determined for each of the four areas shown on map
- Counties assigned to an areas
- **Sanish – Sweet spot**
  - *Mountrail County*
- **Nesson – Recently developing highly productive area**
  - *Williams County*
  - *McKenzie County*
- **Bailey – Less potential**
  - *Dunn County*
- **Elm Coulee – considered fringe with lower potential**
  - *Billings County*
  - *Burke County*
  - *Divide County*



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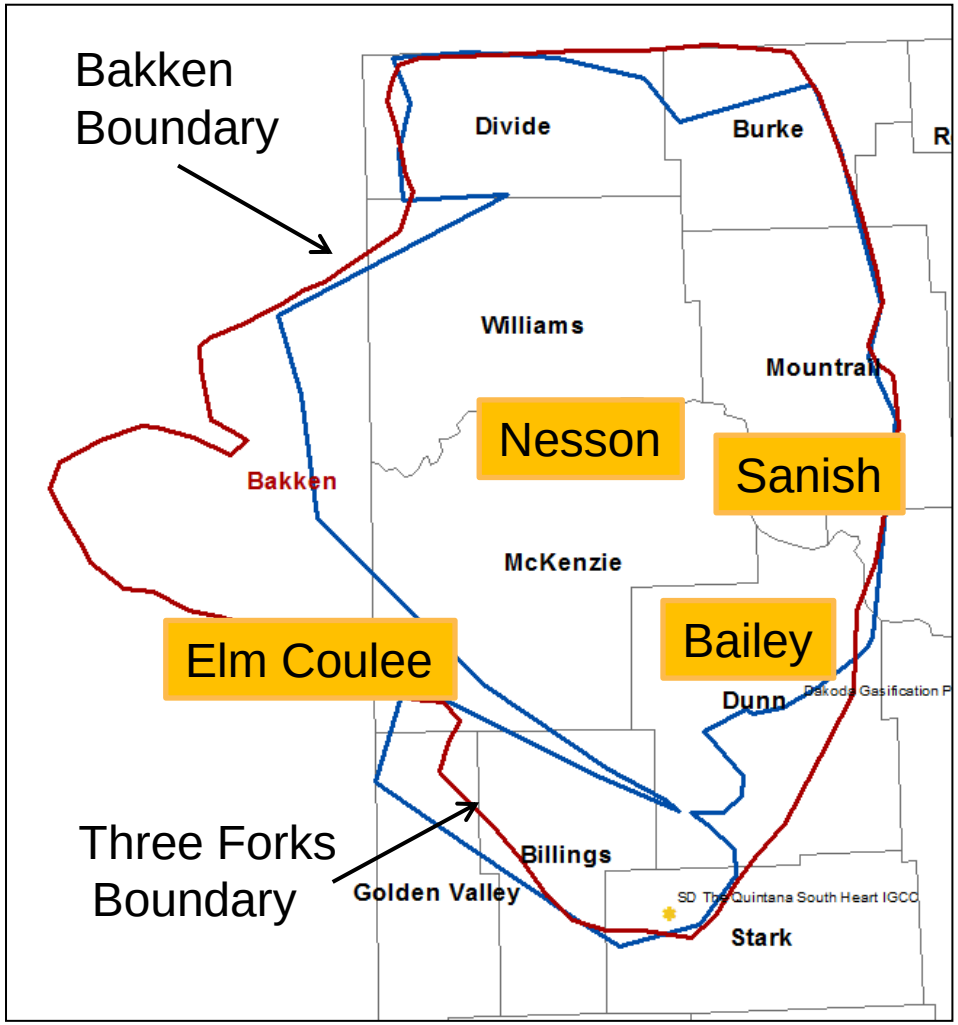
Bakken/Three Forks primary recovery

- **Bailey**
  - OOIP/mi2 - 5270 bbls
  - EUR/well – 374 bbls
  - Prim RF – 7.1% ½ mi sp
  - Prim RF – 14.2% ¼ mi sp
- **Sanish**
  - OOIP/mi2 - 9078 bbls
  - EUR/well – 501 bbls
  - Prim RF – 5.5% ½ mi sp
  - Prim RF – 11.0% ¼ mi sp
- **Nesson**
  - OOIP/mi2 - 6736 bbls
  - EUR/well – 440 bbls
  - Prim RF – 6.5% ½ mi sp
  - Prim RF – 13.1% ¼ mi sp
- **Elm Coulee**
  - OOIP/mi2 - 4815 bbls
  - EUR/well – 189 bbls
  - Prim RF – 3.9% ½ mi sp
  - Prim RF – 7.8% ¼ mi sp



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CO2 EOR Bakken economic model input assumptions

CO2 EOR recovery factor of OOIP (oil in place) - We used

5% (1/2 mi injector well spacing)
7.5% (1/4 mi injector well spacing)

1. Low end of ND conventional RF range 4.6 – 16.8% -
2. EERC suggests 4%
3. Mid range of 0.5%-24% recovery factors obtained from published CO2-EOR modeling *(All results are coming from simulations or analytical calculations).*

1. *CO2 Flooding the Elm Coulee Field;* Shehbaz, Shoaib, et, al; SPE 123176; 2009
2. *Geologic Characterization of a Bakken Reservoir for Potential CO2 EOR*; Basak Kurtoglu, et, al; SPE 168915 / URTex 1619698; 2013
3. *Modeling Gas Injection into Shale Oil Reservoirs in the Sanish Field, North Dakota;* Cuiya Dong, et, al; SPE 168827 / URTeC 1581998; 2013
4. *CO2-Based Enhanced Oil Recovery from Unconventional Reservoirs: A Case Study of the Bakken Formation;* G. Liu, et, al; SPE 168979-MS; 2014
5. *Integrated Reservoir Characterization and Modeling in Support of Enhanced Oil Recovery for Bakken;* Basak Kurtoglu; Williston Basin Petroleum Conf, North Dakota; 2014
6. *The EERC's CO2 Enhanced Bakken Recovery Research Program;* John Harju; ND Legislative Council Energy Development and Transmission Committee Meeting; 2012
7. *Overview of the EERC's Bakken CO2 EOR Research Programs;* John Harju; 8th Annual Wyoming CO2 Conference; 2014

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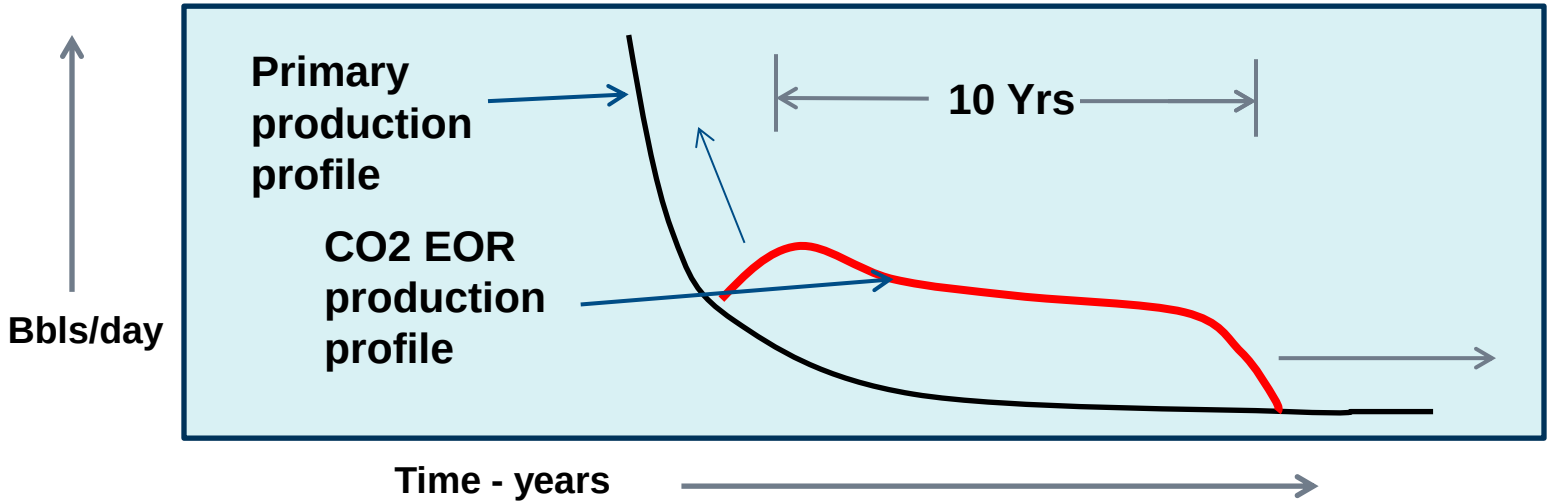
CO2 EOR Bakken economic model input assumptions

Production profile – We used

- Single well model – flat production for a 10 year cycle
- Field production created by applying schedule of drilling or conversion of injector wells
- CO2 EOR production may occur independently of primary production profile



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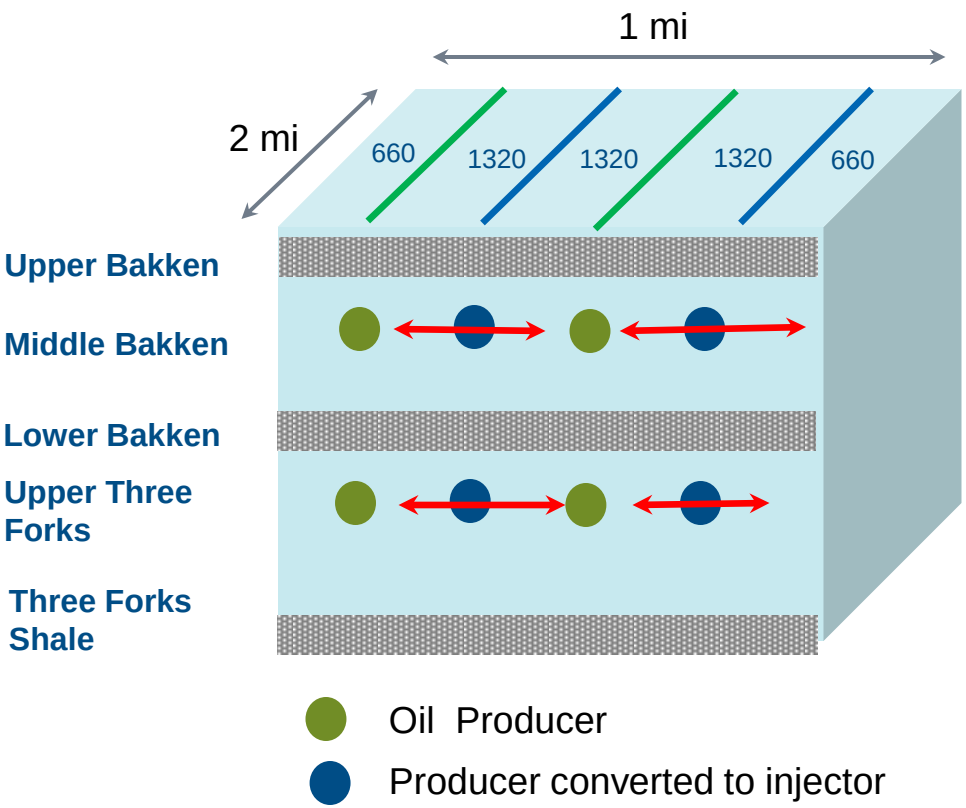
Bakken / Three Forks development unit – Case 1

- No new injectors drilled, alternating producers being converted to injectors
- Two producer – injector pairs for each 2-square mile unit in both the Bakken and Upper Three Forks
- IHS Bakken/Three Forks primary production forecast assumes 9500 ft laterals spaced ¼ mile (1320 feet) apart
- Each alternating injector well to add to each producer:
  - *Nesson – 336 Mbbls*
  - *Sanish – 454 Mbbls*
  - *Bailey – 266 Mbbls*
  - *Elm Coulee – 241 Mbbls*



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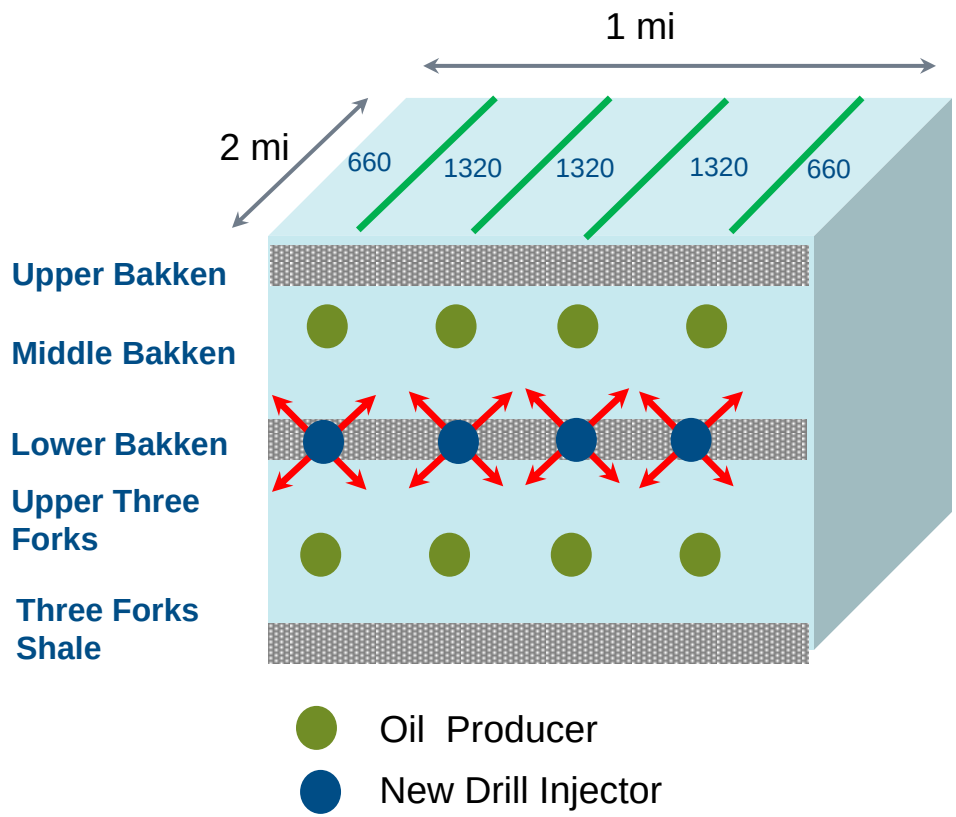
Bakken / Three Forks development unit - Case 2

- Drill new injectors into the lower Bakken to produce both the middle Bakken and the upper Three Forks
- Contingency if closer spacing were needed (660-feet from producer) for effective EOR
- One injector for two producers in combined Bakken and Upper Three Forks
- Due to closer spacing we assume 50% increase in recovery per injector
- Each injector well to add to each producer:
  - *Nesson – 252 Mbbls*
  - *Sanish – 340 Mbbls*
  - *Bailey – 200 Mbbls*
  - *Elm Coulee – 181 Mbbls*



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CO2 EOR Bakken economic model input assumptions

CO_2 Sources:

Due to potential size and scalability much more CO_2 may be required – Up to 2.2 bcf/d for Case 2

We added 2.00 $/mcf long-haul transport fee to CO_2 cost for economic modelling

Amount or Use of CO_2 mcf/bbl:

14.5 mcf/bbl for case 1

11.3 mcf/bbl for case 2 (injection wells closer to producers)

1. Comparable to amounts projected for conventional fields
2. Reasonable mid point between 0.15-33 mcf/bbl obtained from published CO2-EOR modeling

Re-injection of CO_2

20% after two years – this is less than half of conventional re-injection, but the Bakken / Three Forks are less permeable, so we assume less CO_2 recovery

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CO2 EOR Bakken economic model input assumptions

- **Percentage of Bakken/Three Forks area which could be developed or how much of the Bakken is likely to undergo CO2 EOR**
  - 20% in core counties,
  - 13% in fringe counties
    1. Conservative assessment but allows us to apply scalability like we currently have in the Bakken
    2. Risked area
       1. 50% geologic properties will allow this to work
       2. 50% access to large amounts of CO2
       3. 80% price recovery and technology advancement
- **What Three Forks benches to include – Only upper Three Forks**
    1. Similar reservoir properties to the middle Bakken
    2. Established commercial primary production
    3. Unsure if lower benches will be extensively developed – possibly no producing wells in these benches in large areas throughout the play

Conventional production peaked in 1985 at 140 Mbbls/d – Our forecast shows the Bakken / Three Forks peaking in 2026 at 10 times that amount

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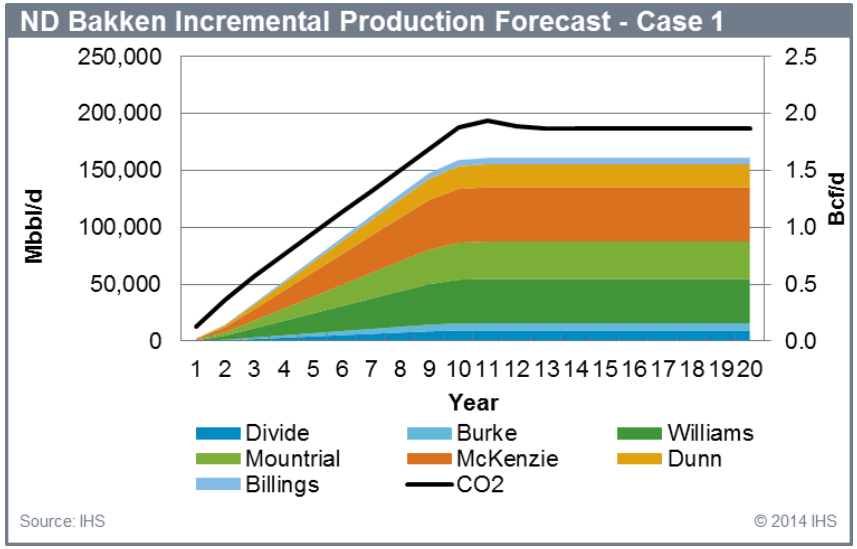
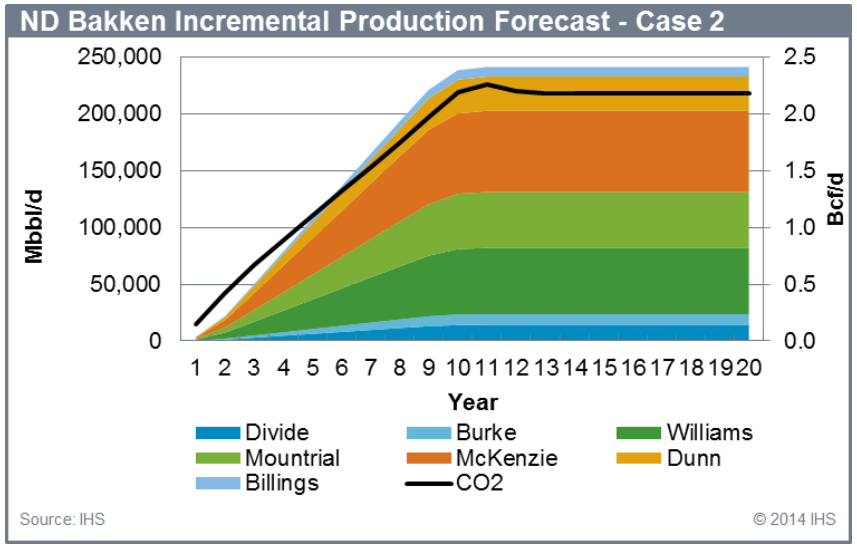
CO2 EOR Bakken summary





- During a 20-year development cycle, over 3600 injector wells would be converted or drilled
- CO2 requirements would be enormous with case 1 requiring 10.6 Tcf and Case 2 requiring 12.4 Tcf over this 20 year cycle
- Much more work is required to realize these types of numbers, however, this analysis provides a view of the potential for CO2 EOR in the Bakken
- We assume for our economic modeling that production will begin in 2021, so only a portion of this production is realized in the 2017 – 2036 forecast time period

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Technical Evaluation – Conventional Fields

Reservoir modelling objectives and results

Purpose

Screen all conventional North Dakota fields for good CO2 – EOR candidates

Simulation

IHS used the numerical simulation methodology to model conventional fields using Eclipse reservoir simulation software

We began with 126 fields that had undergone water flooding and identified 18 candidate fields for economic modelling

Reservoir Modeling

Calculate oil recovery factor as a percentage of OOIP (oil in place) – ultimate recovery

Establish a production profile forecast – cash flow stream

Generate the number and configuration of injector wells – basis for development plan

Calculate the amount of CO2 needed – sourcing and cost

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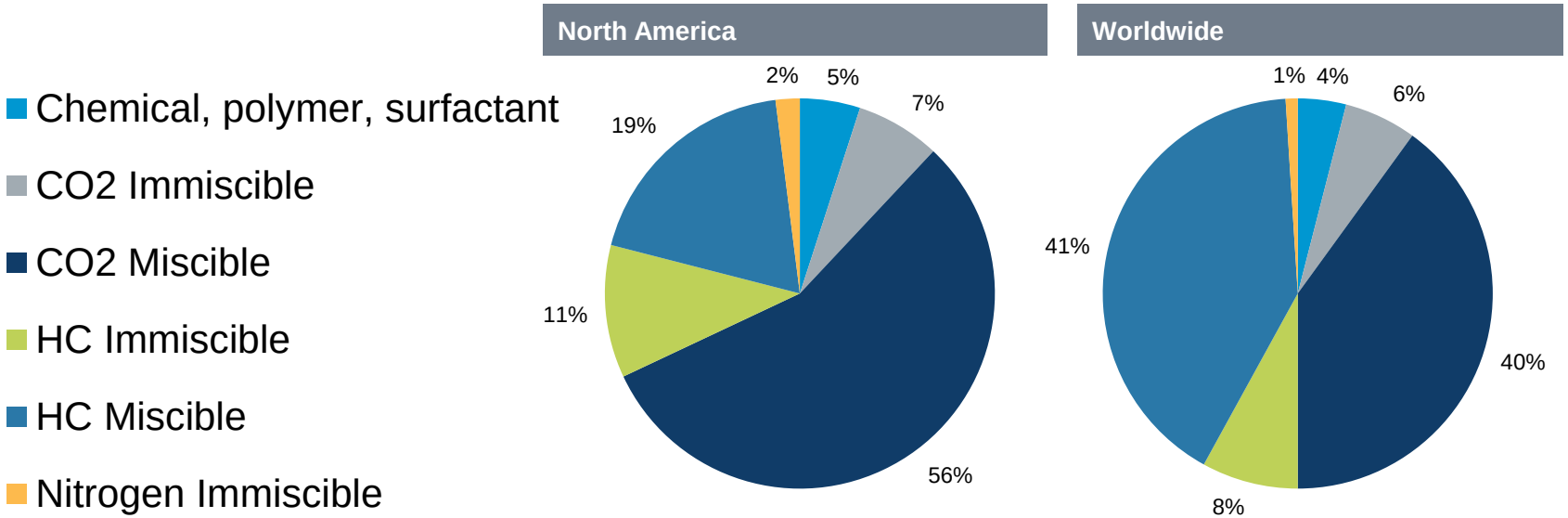
Worldwide EOR conventional project categories



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- In North America, CO_2 miscible, Hydrocarbon (HC) immiscible and miscible mechanisms are the most successful EOR processes.
- Above summary excludes steam based EOR processes.
- Miscibility is the capacity of a solvent, such as CO2, to mix with oil and form one homogenous phase in all properties – oil becomes less viscous and the bonded CO2 expands the oil molecules, forcing some of them to flow toward production wells

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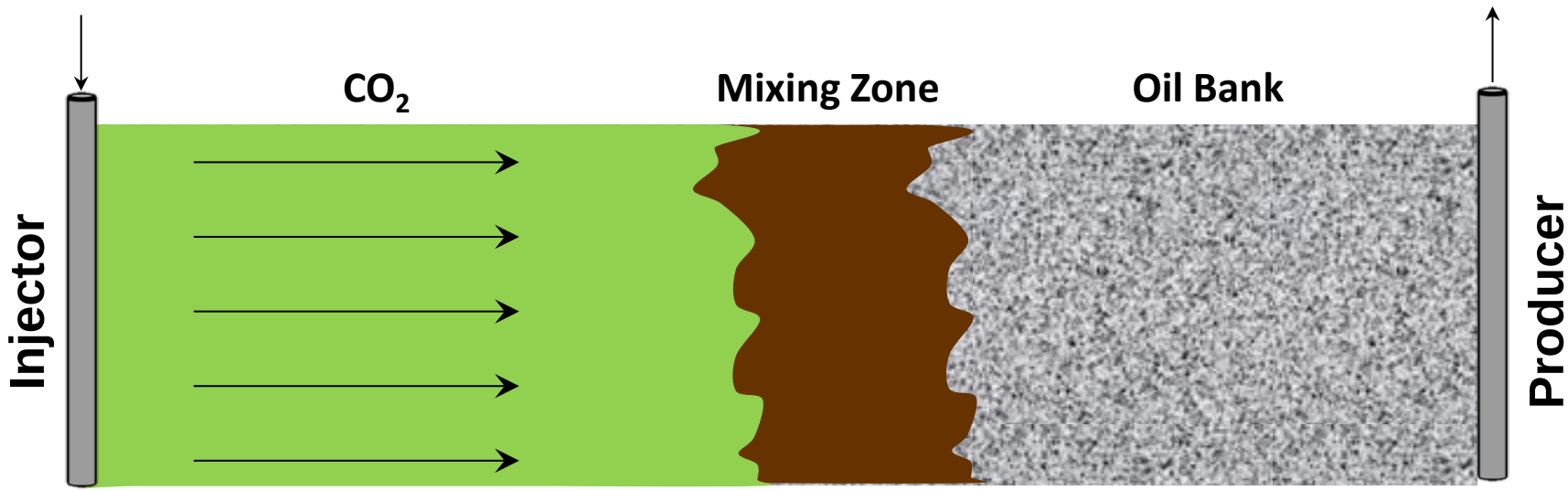
CO_2-EOR Process Mechanism

- The CO_2 miscible process is displayed below:



- There are two categories of miscible floods:
  - **First Contact Miscible (FCM)**
  - **Multiple Contact Miscible (MCM)**
- Due to the lack of Pressure Volume Temperature (PVT) data, the FCM process was utilized in this study using average API gravity and viscosity values which were publically available.

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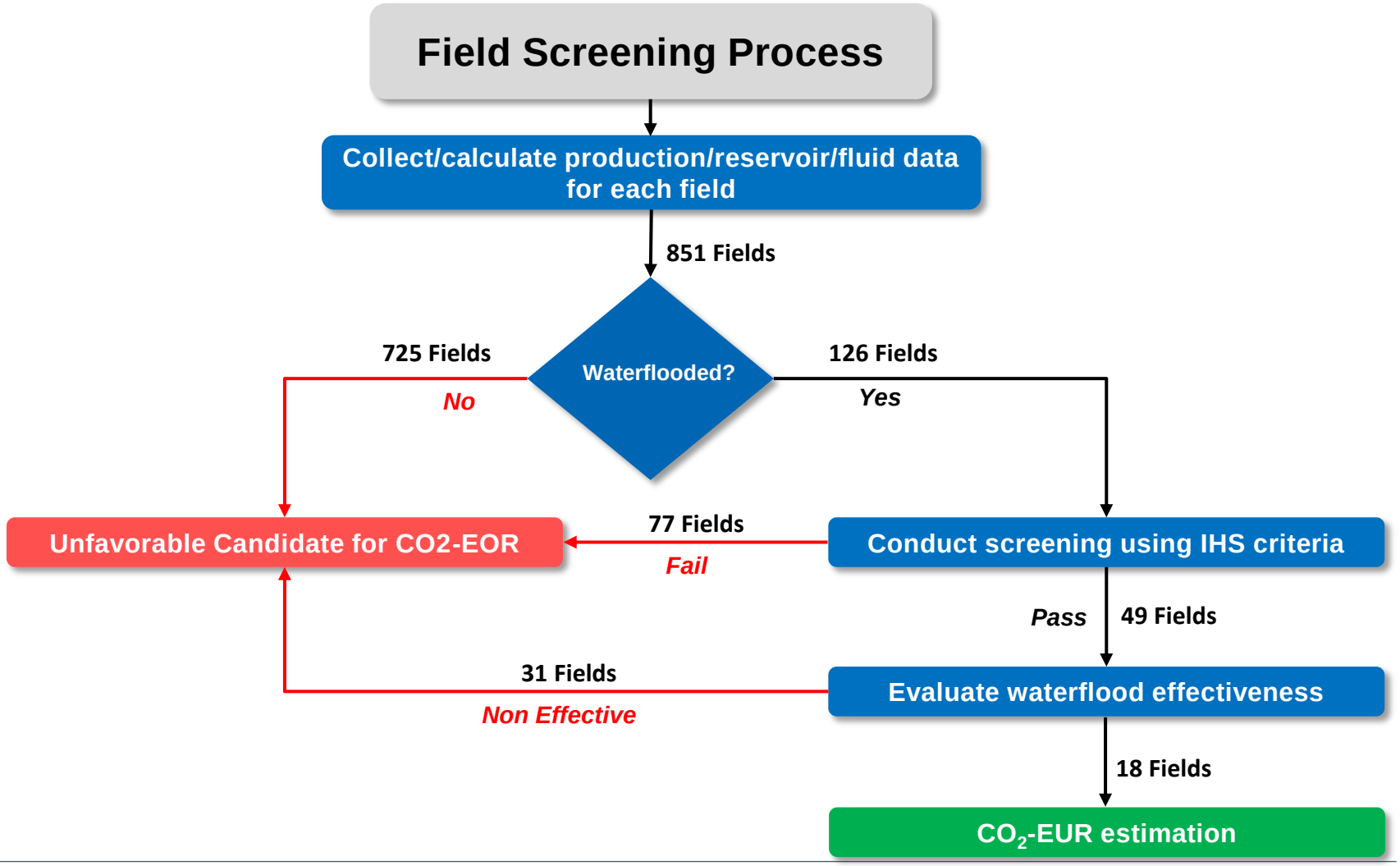
CO_2-EOR Evaluation – conventional fields - flow chart



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IHS screening criteria for potential CO_2-EOR floods

- Extensive literature review was conducted to collect the reservoir/operation parameters of current successful CO_2 miscible floods.
- A data set was set up for 100+ CO_2 projects in the US and Canada.
- In some projects, reservoir parameters were reported as a range instead of a specific value, hence an average value was used for the analysis.
- Reservoir parameters from the successful and promising projects were selected to set up the screening criteria.

Reservoir Parameter	National Petroleum Council 1976	M.A Klins 1984	J.J. Taber 1997	J.L. Dickson 2010	IHS
Depth, ft	>2300	>3000	>2500	>2500	>2500
Oil Gravity, API	>27	>30	>22	>22	>22
Viscosity, cp	<10	<12	<10	<10	<10
Oil Saturation, %	>25	>25	>20	>20	>20
Temperature, F	<250	nc	nc	nc	>86

49 of the 126 ND fields analyzed passed this screening criteria

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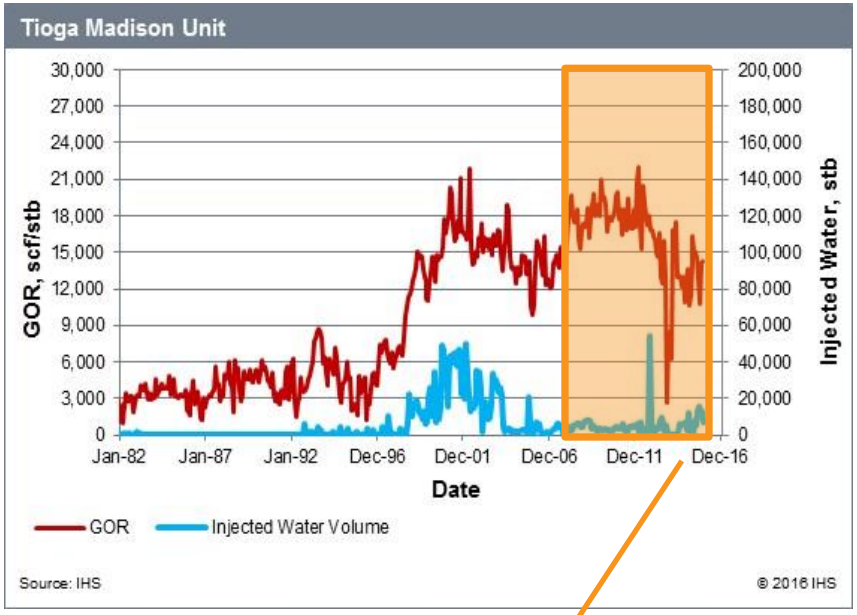
Screening fields for successful waterflood

Examples of fields with poor waterflood performance



Reasons for failing the final screening

- **High current GOR**
- **No current active waterflood.**

Reasons for failing the final screening

- **High current GOR**
- **Poor waterflood performance.**

- Successful waterflood scheme results in constant or decreasing GOR trend vs time.

Only 18 of the 49 ND fields analyzed had successful waterfloods

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List of North Dakota fields with "good" and "poor" results

No.	Field Name	Class
1	Beaver Lodge Devonian Unit	Good
2	Fryburg Heath-Madison Unit	Good
3	Cedar Hills North Red River B Unit	Good
4	Cedar Hills South Red River B Unit	Good
5	Big Stick Madison Unit	Good
6	Charlson North Madison Unit	Good
7	Blue Buttes Madison Unit	Good
8	North Elkhorn Ranch Madison Unit	Good
9	T.R. Madison Unit	Good
10	Newburg Spearfish-Charles Unit	Good
11	Medora Heath-Madison Unit	Good
12	Rough Rider East madison Unit	Good
13	Horse Creek Red River Unit	Good
14	Disckinson Heath Unit	Good
15	West Rough Rider Madison Unit	Good
16	Charlson South Madison Unit	Good
17	Bear Creek Duperow Unit	Good
18	Hufflund Madison Unit	Good

- If the waterflood of a field had poor performance, then this field was categorized as a "Poor" candidate for CO_2-EOR process. Successful waterflood preferentially nominated a field as a "Good" candidate for the CO_2-EOR process.
- These 18 "Good" fields were modelled for CO_2-EOR

No.	Field Name	Class
1	Antelope Madison Unit	Poor
2	Medicine Pole Hills Red River Unit	Poor
3	Medicine Pole Hills West Red River Unit	Poor
4	Medicine Pole Hills South Red River B Unit	Poor
5	Northeast Foothills Madison Unit	Poor
6	Antelope Devonian Unit	Poor
7	North Tioga Madison Unit	Poor
8	Foothills Madison Unit	Poor
9	North Black Slough Midale Unit	Poor
10	South Black Slough Midale-Rival Unit	Poor
11	Hawkeye Madison Unit	Poor
12	West Dickinson Lodgepole Unit	Poor
13	Versippi Lodgepole Unit	Poor
14	Dickinson Lodgepole Unit	Poor
15	Duck Creek Lodgepole Unit	Poor
16	Hiline Lodgepole Unit	Poor
17	Livestock Lodgepole Unit	Poor
18	Subdivision Lodgepole Unit	Poor
19	Tioga Madison Unit	Poor
20	Beaver Lodge Madison Unit	Poor
21	Red Wing Creek Madison Unit	Poor
22	Rival Madison Unit	Poor
23	Capa Madison Unit	Poor
24	Clear Creek Maddison Unit	Poor
25	South Starbuck Madison Unit	Poor
26	Plaza Madison Unit	Poor
27	Little Misouri Redi River Unit	Poor
28	State Line Red River Unit	Poor
29	Little Knife North Madison Unit	Poor
30	South Westhope Spearfish-Charles Unit	Poor
31	Fryburg South River Unit	Poor

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Numerical reservoir modeling assumptions

- **Flooding pattern:** 5 Spot (injector well pattern)
- **Drainage area of numerical model:** 120 acres/(2 wells)
- **CO_2 injection volume:** 40% Hydrocarbon Pore Volume (HCPV)
- **Homogenous properties:** The reservoir properties (permeability and porosity as well as the fluid properties) were assumed to be constant in the horizontal and vertical directions.
- **Continuous CO_2 injection**
- **No free gas at current reservoir pressure**
- **No external water:** The water production is associated with the current water saturation within the drainage area of the well.
- **Injection Constraint:** Maximum injection rate
- **Production Pressure:** Slightly above Minimum Miscibility Pressure (MMP). MMP is the minimum pressure at which CO_2 is miscible in oil (at any proportion of injected CO_2)
- **CO_2 Miscibility:** First contact miscible (FCM) with limited dispersion over the grid block size

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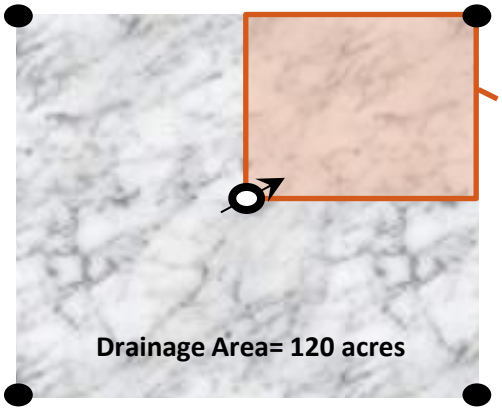
Reservoir Model

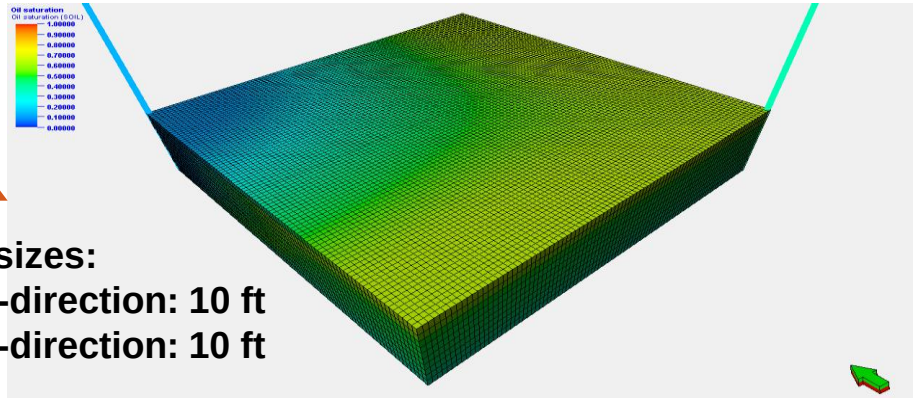
Grid Pattern

- For the purpose of the economic analysis, a 5 spot pattern was selected in the reservoir modeling section. The 5-spot pattern figure displays a 120 acres drainage area in which one injector and one producer is needed.
- For each field, the total number of required injectors and producers was calculated. For example Beaver Lodge Devonian unit requires ~110 injectors and ~110 producers in order to develop the entire field with CO2-EOR scheme (based on the area of the field).
- In this study, areal heterogeneity (variation within the reservoir) was not included due to the lack of detailed petrophysical analysis; hence, an element of symmetry was present for the five spot flood pattern. In order to reduce the numerical run time, a quarter of the five spot pattern was modeled. However, the injection/production profiles were up-scaled to the field level.

5-Spot Pattern:



Simulation Model: Quarter of 5-Spot Pattern



Grid Block sizes:
i-direction: 10 ft
j-direction: 10 ft

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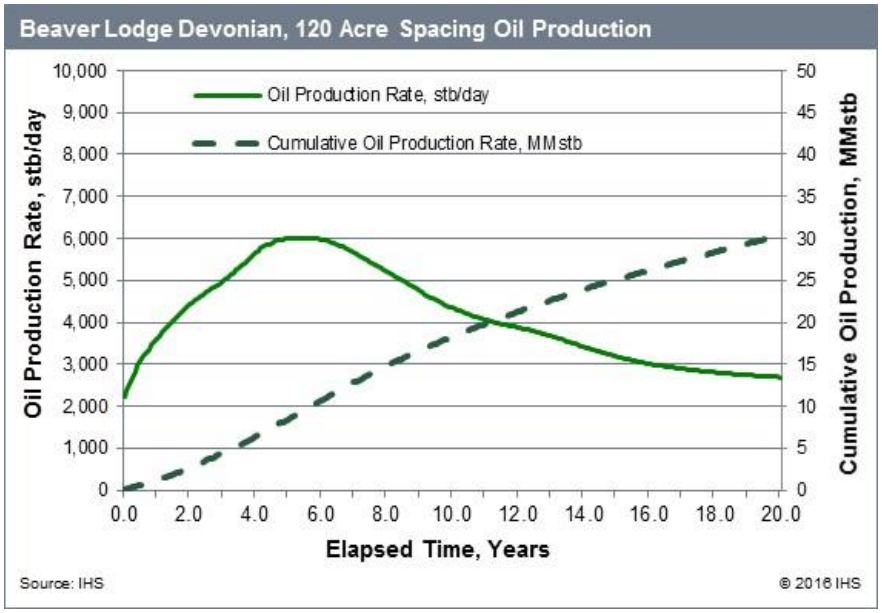
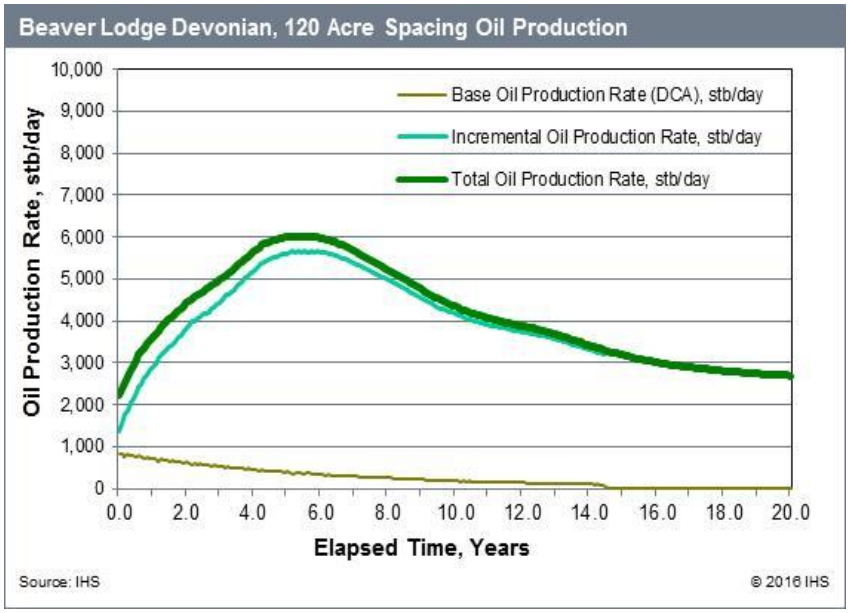
CO_2-EOR Simulation Results

Beaver Lodge Devonian Unit

- The figures below show incremental oil and gas production profiles from the CO_2-EOR process for the Beaver Lodge Devonian unit that was used in the economic model.
- The CO_2-EOR response is very rapid in the current model which is due to the selection of the FCM modeling approach. However, the final incremental recovery is expected to be very close to what is expected from a full field model.
- Producing GOR is constant and equal to initial R_s. Recovery factor for Beaver Lodge Devonian unit is 16.8%
- Incremental recovery 30.5MMbbl





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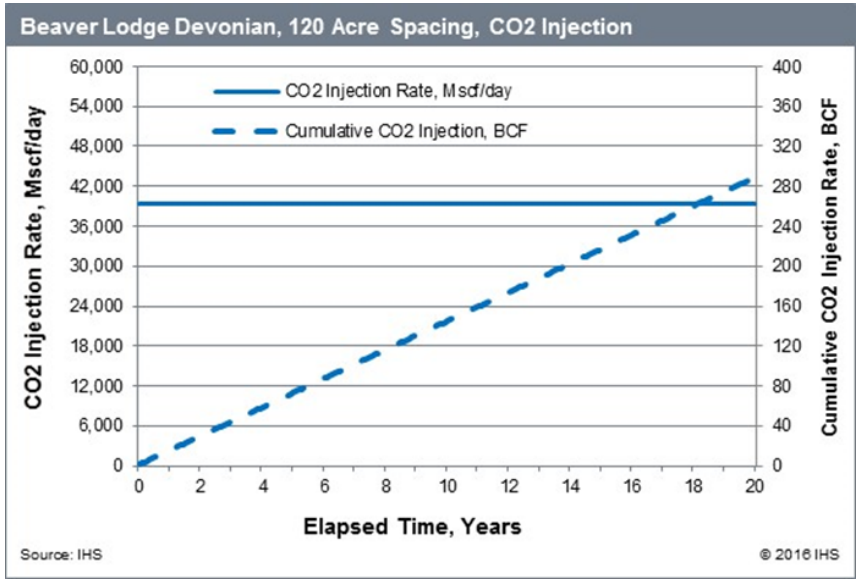
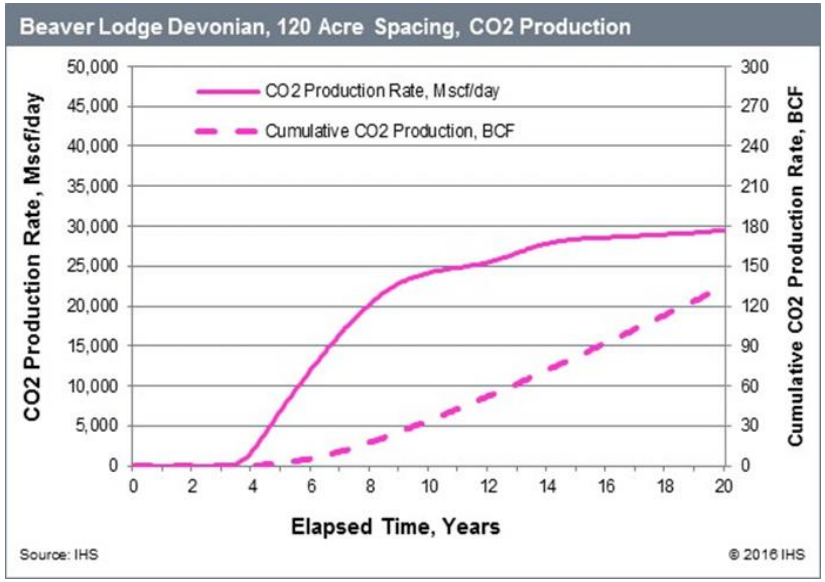
CO_2-EOR Simulation Results

Beaver Lodge Devonian Unit

- CO_2 was injected into Beaver Lodge Devonian at a constant rate. A total of 280 BCF CO_2 was injected over 20 years of injection/production.
- With the current modeling assumptions, it takes ~4 years for the CO_2 to reach out to the location of the producer. As a result, during the first four years of production, the amount of CO_2 production is zero. Over a 20 year forecast, ~130 BCF (46%) of the injected CO_2 is produced (and can be re-injected).





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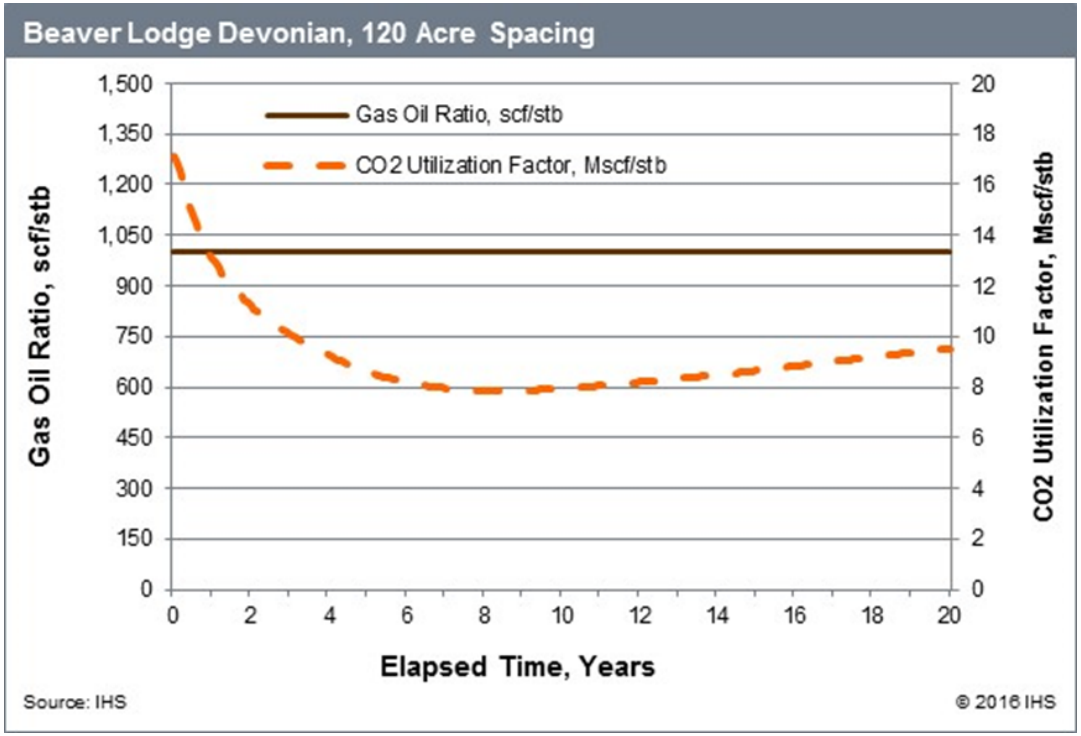
CO_2-EOR Simulation Results

Beaver Lodge Devonian Unit

- CO_2 utilization factor per (mscf/stb for Beaver Lodge Devonian unit varies between 10-18 mscf/stb.



- Initially significant volumes of CO_2 is required to be dissolved into the oil. Near the end of the forecast period, CO_2 breakthrough occurs which causes an increasing trend in the CO_2 utilization factor.

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Numerical results of oil recovery for suitable fields

- Numerical simulation was conducted for 18 fields that passed all screening criteria. For each field average reservoir properties were utilized. Table below summarizes the EUR from CO_2-EOR for each field. The Beaver Lodge Devonian and the Hofflund Madison Units display maximum and minimum recovery among the suitable fields respectively.
- Table below presents a comparison between the results of current study and similar studies that were conducted for North Dakota fields.

Field Name	Rank	Numerical Np Estimate Mstb	Recovery Factor %	Utilization Factor Mscf/bbl	Recovery Factor, %	
					Advanced Resources International	University of North Dakota
BEAVER LODGE DEVONIAN UNIT	1	30,530	16.8	9.0	8.0	8.0
FRYBURG HEATH-MADISON UNIT	2	20,624	13.3	5.0	8.0	
CEDAR HILLS NORTH RED RIVER B UNIT	3	19,110	6.9	12.0		
CEDAR HILLS SOUTH RED RIVER B UNIT	4	18,416	5.1	17.5		
BIG STICK MADISON UNIT	5	15,770	9.5	10.5	8.0	
CHARLSON NORTH MADISON UNIT	6	6,961	8.7	11.1	8.0	
BLUE BUTTES MADISON UNIT	7	5,776	6.2	13.6	8.0	8.0
NORTH ELKHORN RANCH MADISON UNIT	8	4,524	8.2	11.0		
T. R. MADISON UNIT	9	4,242	9.9	9.6		
NEWBURG SPEARFISH-CHARLES UNIT	10	4,157	4.3	18.2	8.0	
MEDORA HEATH-MADISON UNIT	11	3,978	6.9	12.0		
ROUGH RIDER EAST MADISON UNIT	12	3,715	12.0	9.1	8.0	
HORSE CREEK RED RIVER UNIT	13	3,391	7.4	9.0		
DICKINSON HEATH UNIT	14	2,849	4.6	23.5		
WEST ROUGH RIDER MADISON UNIT	15	2,386	8.0	12.2		
CHARLSON SOUTH MADISON UNIT	16	1,267	8.7	11.1	8.0	8.0
BEAR CREEK DUPEROW UNIT	17	931	6.8	16.4		
HOFFLUND MADISON UNIT	18	675	6.5	16.8		

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Comparison of analytical and numerical CO_2-EOR performance results – IHS used the Numerical method

The analytical approach that was developed by *Claridge* is utilized to estimate the incremental oil produced using CO_2 miscible injection. *This utilizes* a complex equation for estimating the fraction of oil produced from a CO_2 miscible flood:

Field Name	Rank	Analytical Np Estimate (Mstb)	Numerical Np Estimate (Mstb)
Beaver Lodge Devonian Unit	1	54,046	30,530
Fryburg Heath-Madison Unit	2	28,597	20,624
Cedar Hills North Red River B Unit	3	32,982	19,110
Cedar Hills South Red River B Unit	4	38,914	18,416
Big Stick Madison Unit	5	35,022	15,770
Charlson North Madison Unit	6	16,531	6,961
Blue Buttes Madison Unit	7	14,990	5,776
North Elkhorn Ranch Madison Unit	8	10,760	4,524
T.R. Madison Unit	9	7,025	4,242
Newburg Spearfish-Charles Unit	10	7,477	4,157
Medora Heath-Madison Unit	11	8,267	3,978
Rough Rider East madison Unit	12	5,976	3,715
Horse Creek Red River Unit	13	6,967	3,391
Disckinson Heath Unit	14	10,495	2,849
West Rough Rider Madison Unit	15	5,238	2,386
Charlson South Madison Unit	16	2,996	1,267
Bear Creek Duperow Unit	17	2,670	931
Hufflund Madison Unit	18	1,915	675

Analytical methods are quick and easy to be utilized for EUR estimation for case studies with minimal available information. However, it suffers from oversimplification of the process and excludes several important parameters/processes which lead to over estimating of recoveries. Numerical results can be used to correct the analytical estimations.

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Co2 EOR Conventional Modeling Summary

- IHS constructed a CO_2-EOR Screening data base for identification of North Dakota fields that are amenable to such process. North Dakota reservoir parameters were obtained from a compilation of IHS' data base and the public domain. These values are not carved in stone and require in-depth analysis and updating. Therefore, results from this study should be considered as a starting point in the screening process and should not be used to replace an in-depth evaluation and study of a CO_2-EOR process for a specific field.
- No optimization scenarios were considered. Also the CO_2-EOR process is premised to be implemented after the waterflood mechanism is exhausted.
- Of the 100+ fields investigated in the present study, only 18 fields passed all the screening criteria. The following fields show potential incremental in reserves:
  - **Beaver Lodge Devonian Unit**
  - **Fryburg Heath Madison Unit**
  - **Cedar Hills River B Unit**
  - **Big Stick Madison Unit**
  - **Charlson North Madison Unit**
- Estimated incremental cumulative oil production of CO_2-EOR for candidate fields in North Dakota ranges between 0.7 and 30.5 MMstb per field (technically recoverable), requiring between 32 and 486 BCF of CO_2.

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1 CO2 EOR in Unconventional Reservoirs

2 Conventional Field CO2 EOR

3 **Economic Model Assumptions**

4 Upstream Economics

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Critical costs for EOR field economic modeling

Modeled Fields

- Reserves
- Production
- # Wells
- CO2

- Well and facilities cost
- Infrastructure
- Scheduling
- Opex and maintenance
- Source and price of CO2
- Oil price forecast
- Fiscal terms and tax incentives
- Multiple scenarios

Field EOR

- Production
- Rate of Return
- State Take
- Economic Impact

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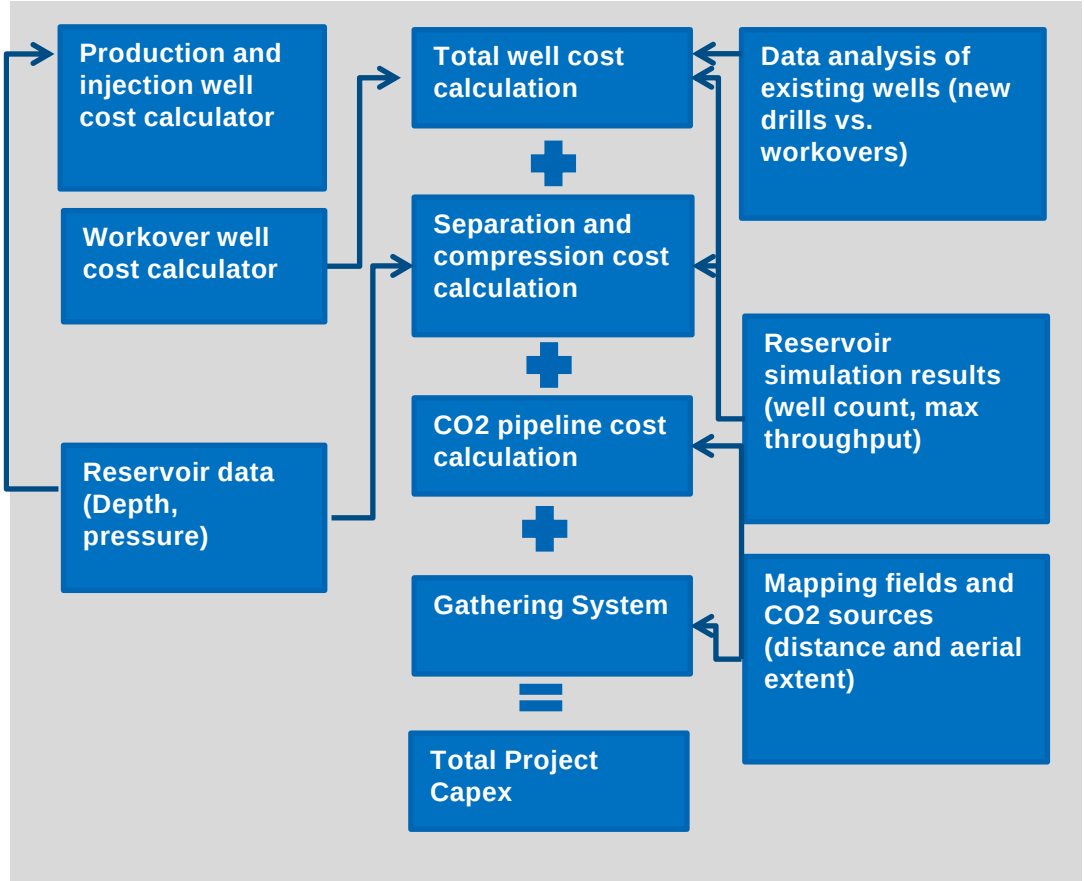
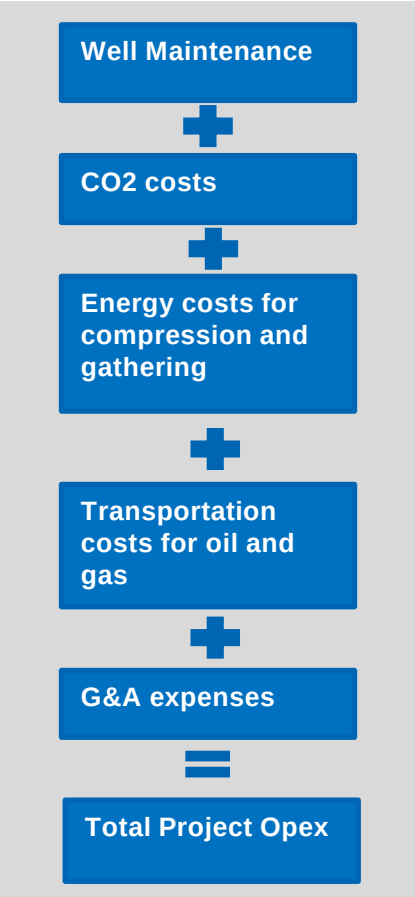
Cost Methodology for EOR CO2 Injection Projects





IHS leveraged in-house expertise along with extensive literature review and projects research to map the capital and operating costs related to CO2 EOR projects

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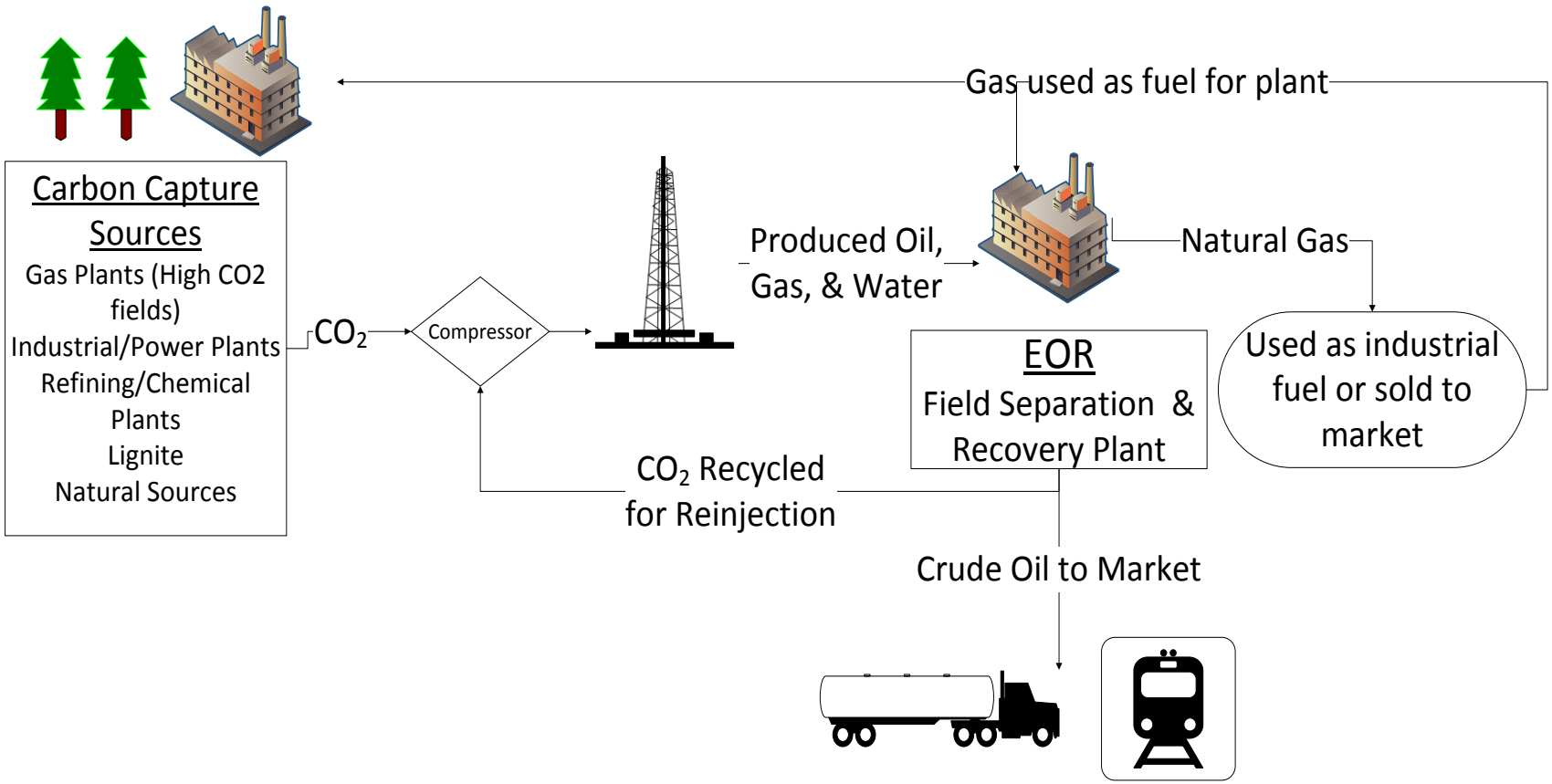
CO2 EOR Development Schematic



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Cost – Facilities: Project Components

Wells

- Production and Injection
- Reuse wells that are currently producing
- Re-drill through temporarily abandoned wells

CO2 Pipeline

- From CO2 source or trunk line
- 4, 6, 8, 12, 16, 20 or 24 inch pipelines depending on throughput

CO2 Separator

- Extracts CO2 for injection from gases produced

CO2 Compression

- Combines imported and separated CO2
- Pressurizes CO2 for injection into the reservoir (miscible pressure)

Gathering system

- For flow between wells and central facilities for oil, gas and CO2

Production Wells

Injection Wells

CO2 Separator

CO2 Pipeline

Compression

Gathering System

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Well Types

The following well types are encountered during a CO2 EOR project

1 Production Well

Drilled to produce oil and gas. Oil and CO2 migrates from the injection well to the production well.

2 Injection Well

Injects CO2 into the reservoir allowing CO2 to mix with, and release, oil from the formation.

3 Production Well Workover

Re-entry and redevelopment of the production tubing string on existing production wells to protect from the highly corrosive nature of the gas.

4 Redrill CO2 Injection Well

Temporarily abandoned wells re-drilled and recommissioned to use as a CO2 injection well.

Assumptions:

- Any currently producing wells will be reused, temporarily abandoned wells will be recommissioned and reused, and tubing will be upgraded for highly corrosive gas.
- Well costs, lease equipment, and operating costs are be based on IHS regional cost databases

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Well Opex Methodology

Fixed monthly opex per well (injectors and producers)

- Opex based on depth
  - Includes scheduled maintenance, road restoration, labor, pumping costs and energy
  - Based on US cost rates from EIA data for Rocky Mountain region
    - Netted down to consider other operating costs already modeled

Variable Costs

- Oil
  - Oil Transportation to market
    - Determine market based on region
    - Determine distance to market
    - Determine combination of transport (pipeline, truck and rail) to get a $/bbl/mile
- Gas
  - Gas transportation and marketing (to Chicago)
    - If gas is marketable, use regional gas transportation rates
    - Gas is assumed to require minimal processing for dehydration

G/A

- General and administrative expenses

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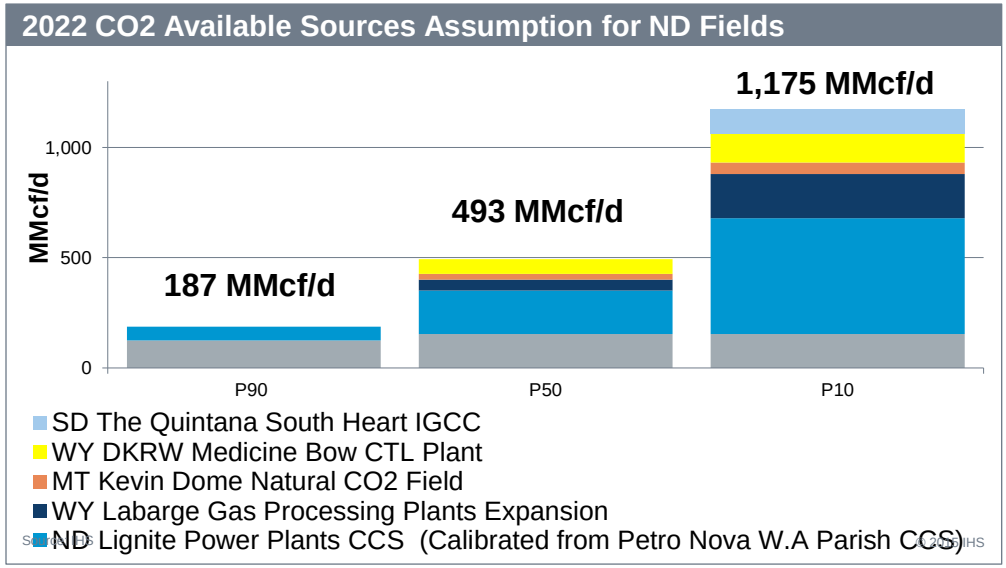
2022 Assumption for ND CO2 Available Sources



Bakken - source and cost of CO2

- Due to the large requirements of CO2 for proposed high volume Bakken projects CO2 requirements as high as 2.3 bcf / day will be required
- Assuming that CO2 may have to be transported long distances – purchase price includes an added $2.00 / mcf transport fee

Conventional - Sources and Cost of CO2 –

- Low case scenario has fewer sources of CO2, with some projects having long distances to a source – limited to 187 MMcf/d – Purchase price $1.56 /mcf
- Base case scenario has more CO2 sources making the distance to source shorter for some projects – limited to 493 MMcf/d – Purchase price $1.61/mcf
- High case scenario has many more sources with most projects benefitting from shorter distances to the CO2 source – Limited to 1,175 MMcf/d – Purchase price $1.71 mcf

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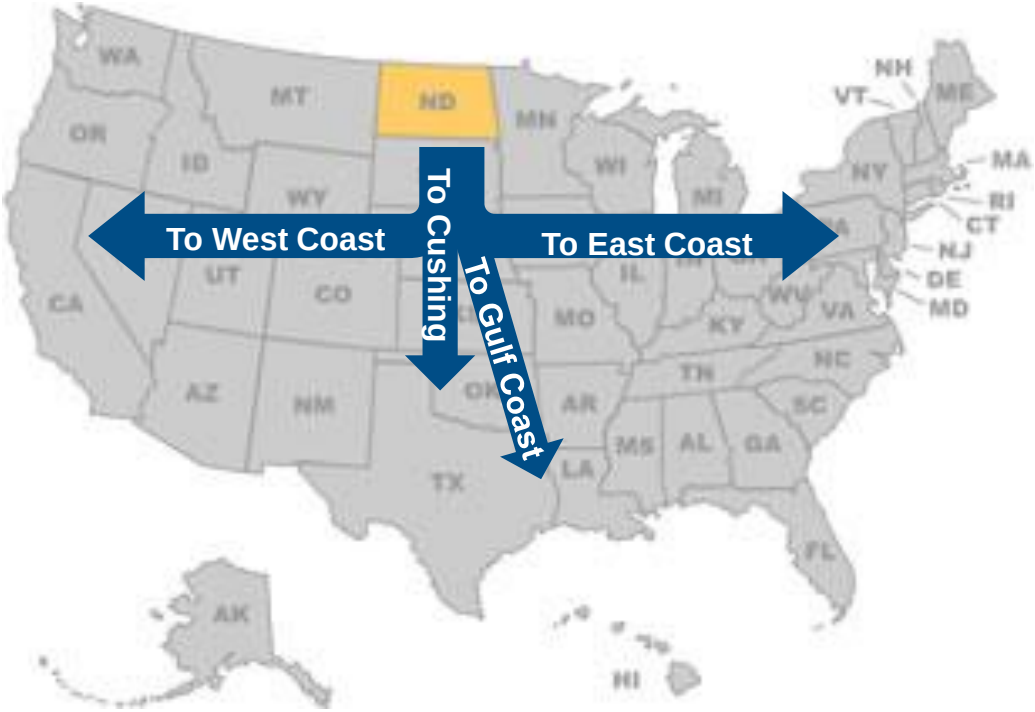
Oil Transit to Markets



Market	Transportation Cost ($/bbl)
East Coast	$13.32-16.03
West Coast	$15.85-16.77
Cushing (OK)	$9.14-11.80
Gulf Coast	$9.33-12.14

IHS aggregated production into broad field designations

For each field, the calculation of transport costs involved decisions:

- whether crude produced in the field would move via truck out of the wellhead to secondary transportation options
- whether crude would move via gathering pipeline or if it could be directly trucked to a trunkline pipeline or rail loading terminal
- whether crude would move via pipeline or rail to its ultimate destination

Transportation Cost includes all costs to get to market --gathering, pipeline, rail, & trucking.

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North Dakota Fiscal Terms

Taxes

Corporate Income Tax

Federal: **35%**

State: **4.31% (max rate modelled)**

- ND depreciation is same as for Federal income tax
- State income tax is deductible for Federal income tax

Depreciation

Tangible (50%)

- Double declining balance

Depreciation

Intangible (50%)

- 30% (5-year straight line); 70% expensed

Production Tax

Oil gross production tax of 5%.

Gas production tax is an annually adjusted flat rate per thousand cubic feet of all nonexempt gas produced in ND.

$0.1106 per mcf (2016 rate), adjusted annually for oil price.

Production tax applied to wellhead income

- CO2 injection operating costs assumed to be deductible post-production costs

Extraction Tax

Oil extraction tax rate of 5%*

*Rate is reduced based on various circumstances. Rate rises to 6% if crude prices average above $90/bbl for 3 consecutive months. Tertiary recovery projects get a 10-year exemption.

Ad Valorem Taxes

No ad valorem production tax for oil and gas production.

However, tax may be levied on separation facilities. Applied to 10% of total capital spent. Assumes CO2 Separation Facility is not exempt from Ad Valorem Tax. Certain oil & gas equipment exempt from property tax.**

** CO2-gas processing unit is not exempt from ad valorem tax.

Lease Terms

Royalty

12.5-22% (18% assumed)

Rental

Typically a nominal amount paid on per-acre basis (i.e. **$1/acre, not modelled**)

Bonus

. **$2,500-$4,000/acre** in Bakken region. (**not modelled**).

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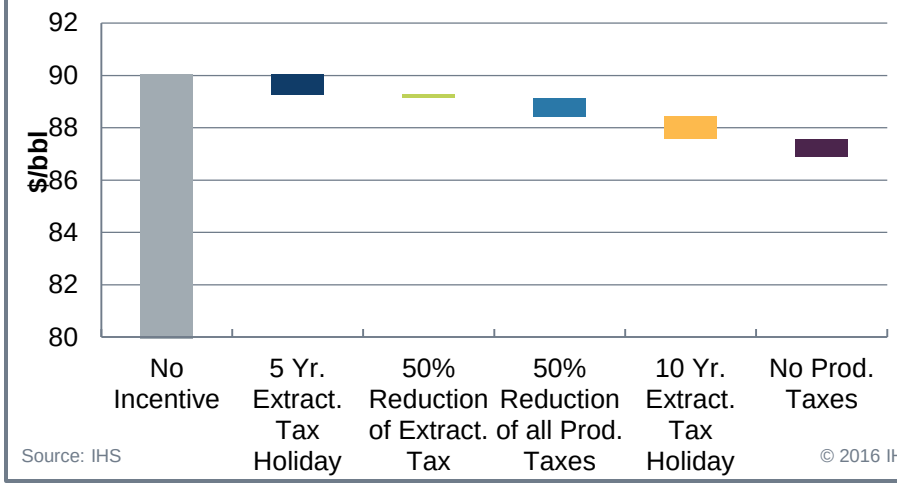
Fiscal Analysis – Bakken in Mountrail County (Sanish)

Montrail County Case 1 Breakeven Fiscal Scnarios



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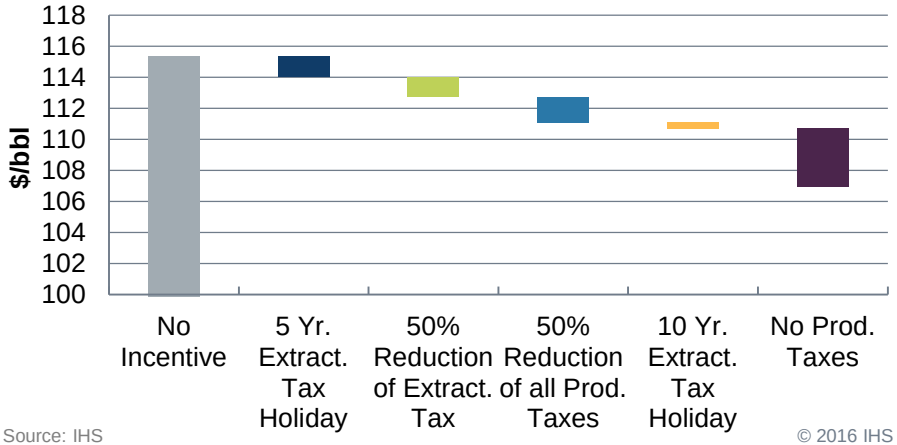
Montrail County Case 2 Breakeven Fiscal Scenarios



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- Case 1 break even at 10% IRR is $90/bbl and Case 2 break even is $115/bbl under current fiscal terms.
- Current fiscal terms are already efficient for more profitable sections of the play under Case 1.
- Fiscal incentives may only be able to improve the break even price by $3.14/bbl for Bakken Case 1.
- For Bakken Case 2, which is much more capital intensive, fiscal incentives may improve the break even price by as much as $8.37/bbl.

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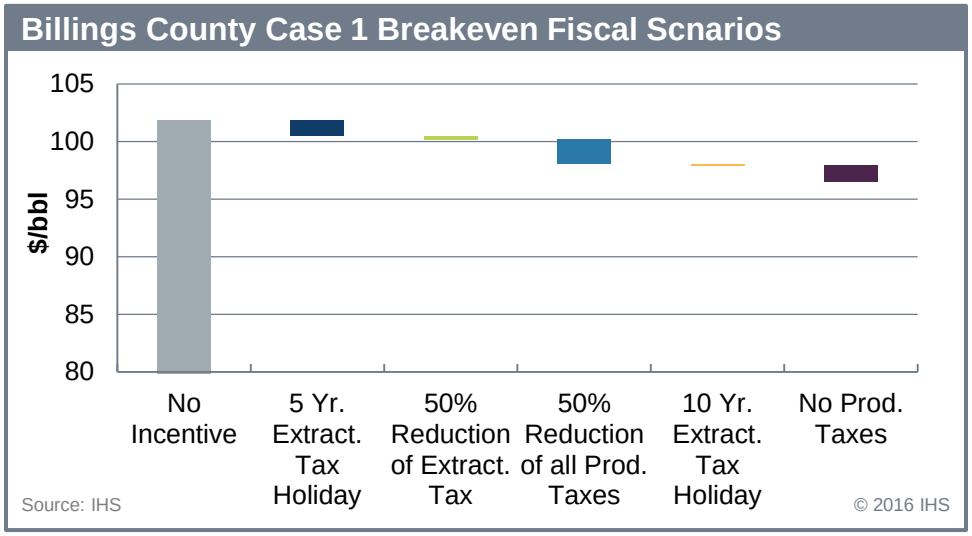
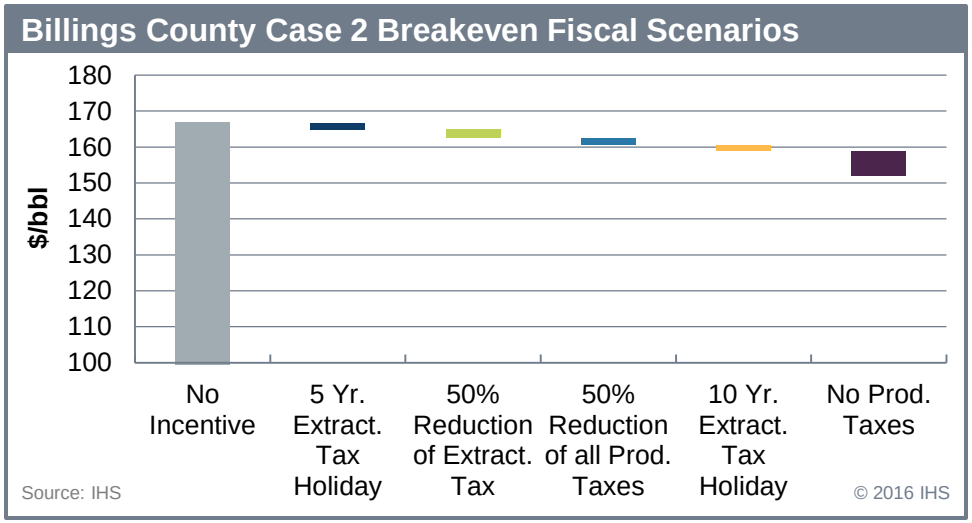
Fiscal Analysis – Bakken in Billings County (Elm Coulee)





- Case 1's break even price at 10% IRR is $102/bbl and Case 2's break even price is $167/bbl under current fiscal terms
- Fiscal incentives may only be able to improve the break even price by $5.40/bbl to develop Bakken Case 1
- For Bakken Case 2, fiscal incentives may improve the break even price by as much as $14.55/bbl.

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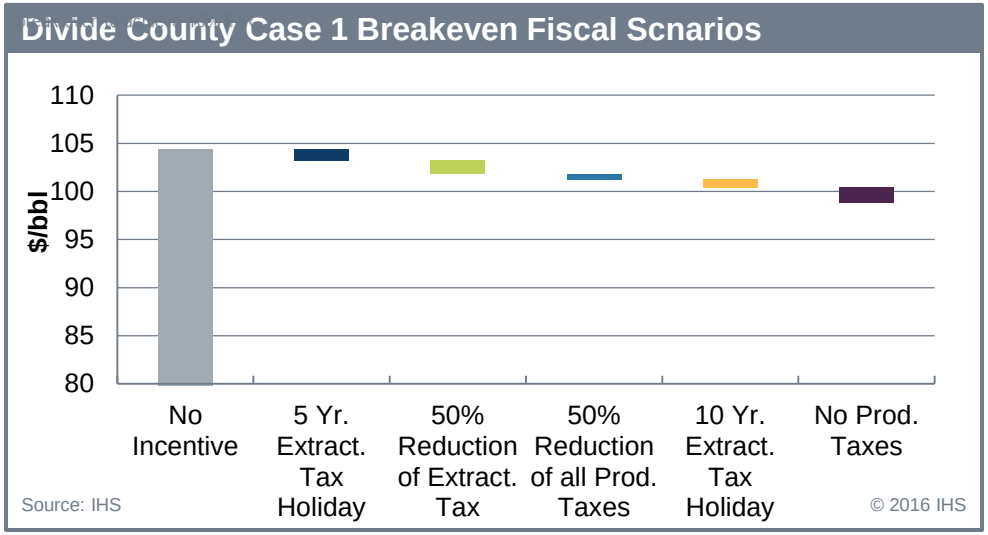
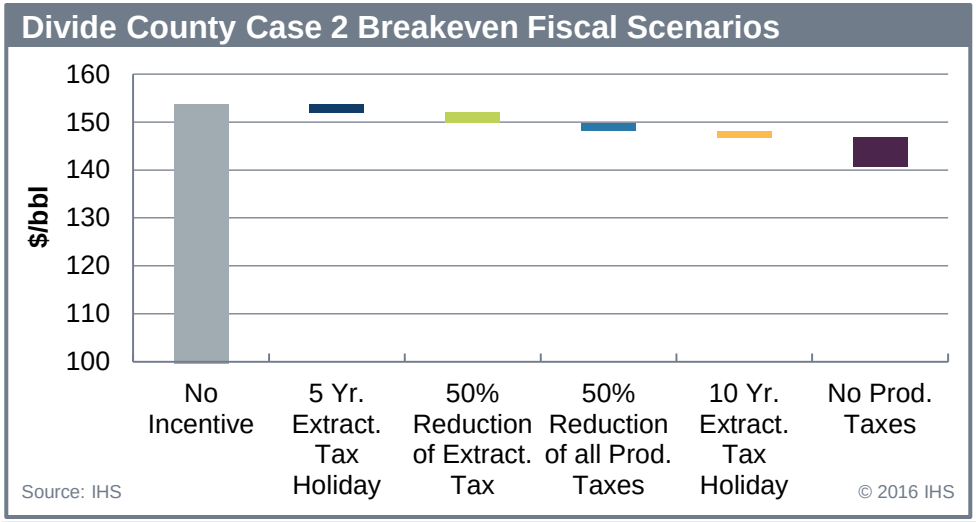
Fiscal Analysis – Bakken in Divide County (Elm Coulee)





- Case 1's break even price at 10% IRR is $104/bbl and Case 2's break even price is $154/bbl under current fiscal terms
- Fiscal incentives may only be able to improve the break even price by $5.6/bbl for Bakken Case 1
- For Bakken Case 2, which is much more capital intensive than Case 1, fiscal incentives may improve the break even price by as much as $13.20/bbl.

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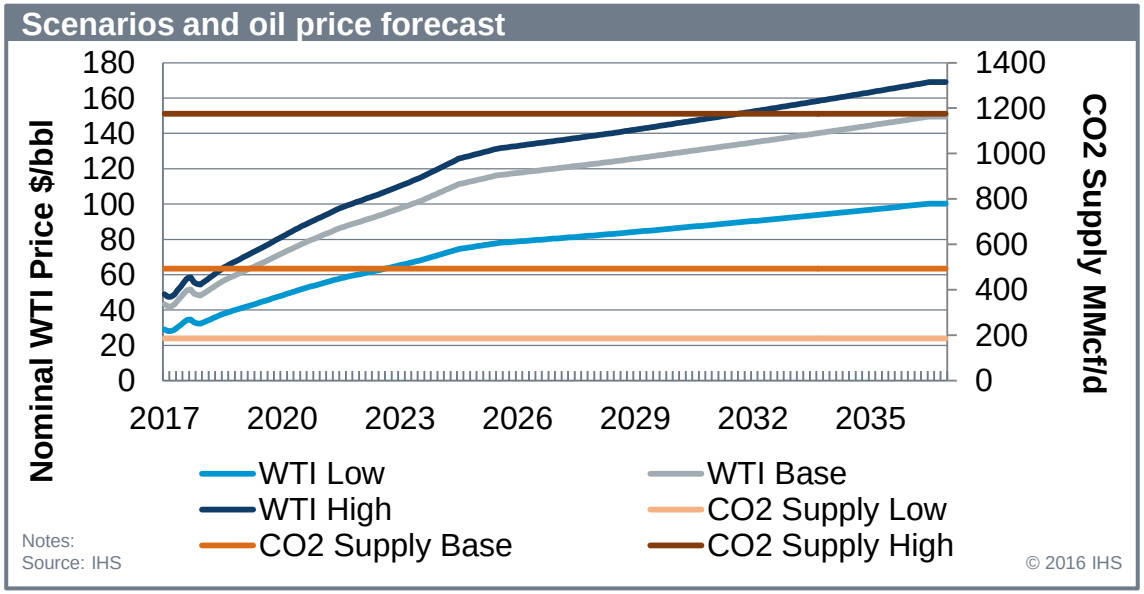
Scenarios - Commercial assumptions

- Projects are scheduled to begin when the forecasted price needed to achieve a 10% IRR is reached
- For conventional fields each scenario is constrained by a respective CO2 amount
- Amount of CO2 for Bakken is unconstrained



Scenario	Costs**	Prices***	Purchase of CO2* $/Mcf	Supply of CO2 MMcf/d
Low Case	-3%	-33%	1.56	187
Base	0%	0%	1.61	493
High Case	+6%	+13%	1.71	1,175

*Bakken development will require large amounts of CO2, $2.00/mcf for transportation is included
**Based on IHS UCCI scenarios
***Base on IHS Price outlook scenarios

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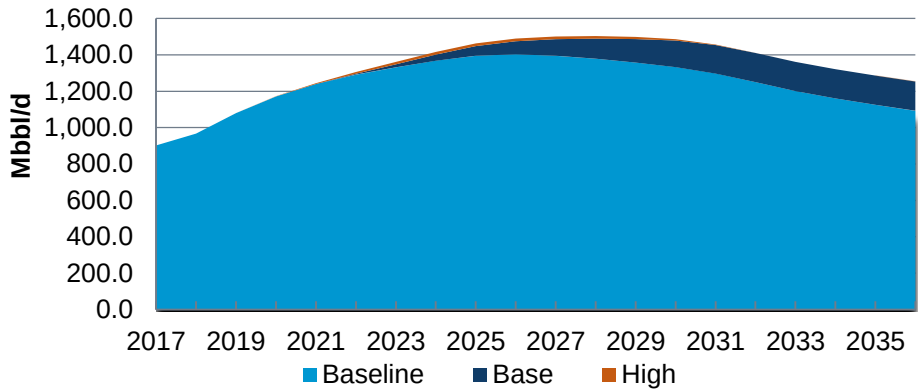
Bakken CO2 EOR

ND Production and Revenue Outlook - Case 1

ND Bakken Tertiary Recovery Forecast - Case 1



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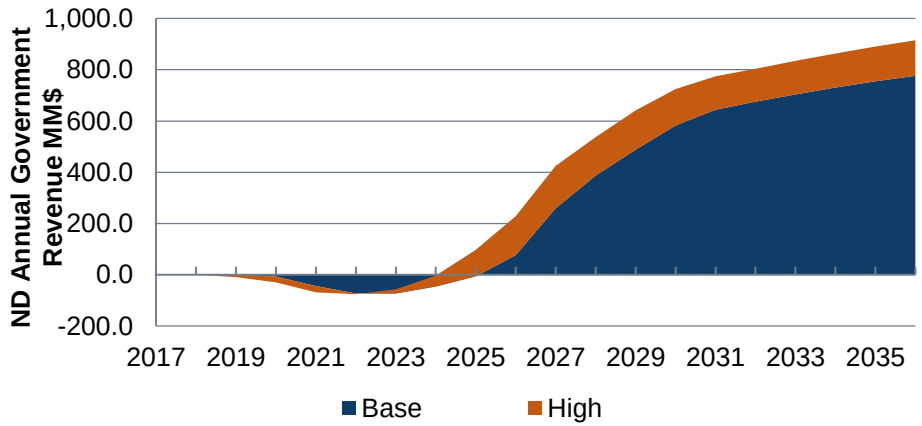
ND Bakken Incremental Government Revenue – Case 1



Source: IHS

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- Incremental Bakken CO2 EOR production
- Base Case – 590 MMbbls
- High Case – 635 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base Case - $5.8 B
- High Case - $7.5 B

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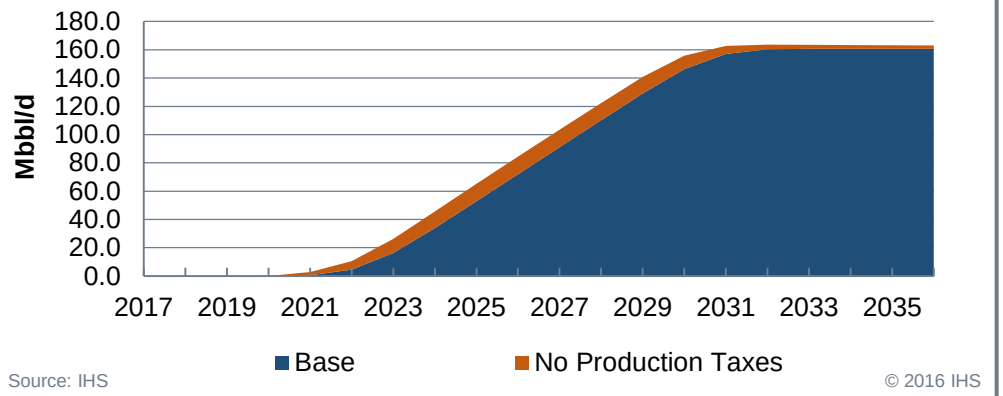
Bakken Case 1 – ND Production and Revenue

Eliminating production taxes altogether has a marginal effect on production while impacting significantly government revenue

ND Bakken Tertiary Incremental Recovery Forecast - Case 1



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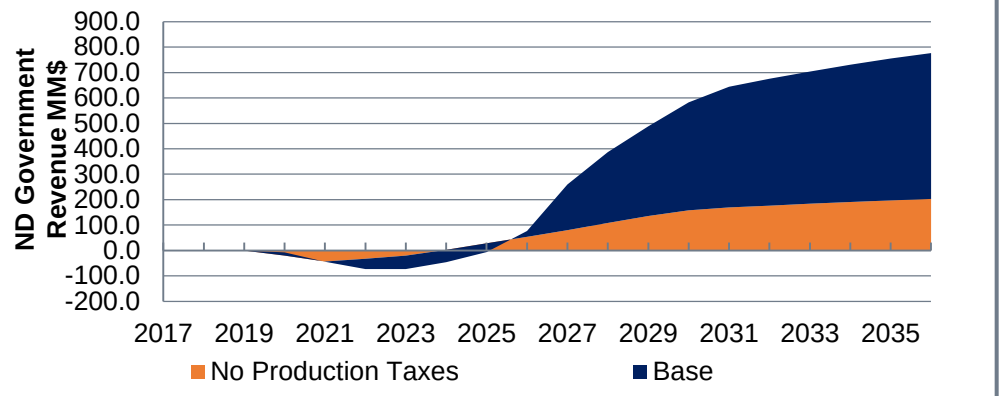
- Incremental Bakken CO2 EOR production
- Base Case – 590 MMbbls
- No Prod Tax - 633 MMbbls

ND Bakken Incremental Government Revenue – Case 1



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- Incremental direct revenue to the state over the next 20 years
- Base sc – $5.8 B
- No Prod Tax- $1.6 B

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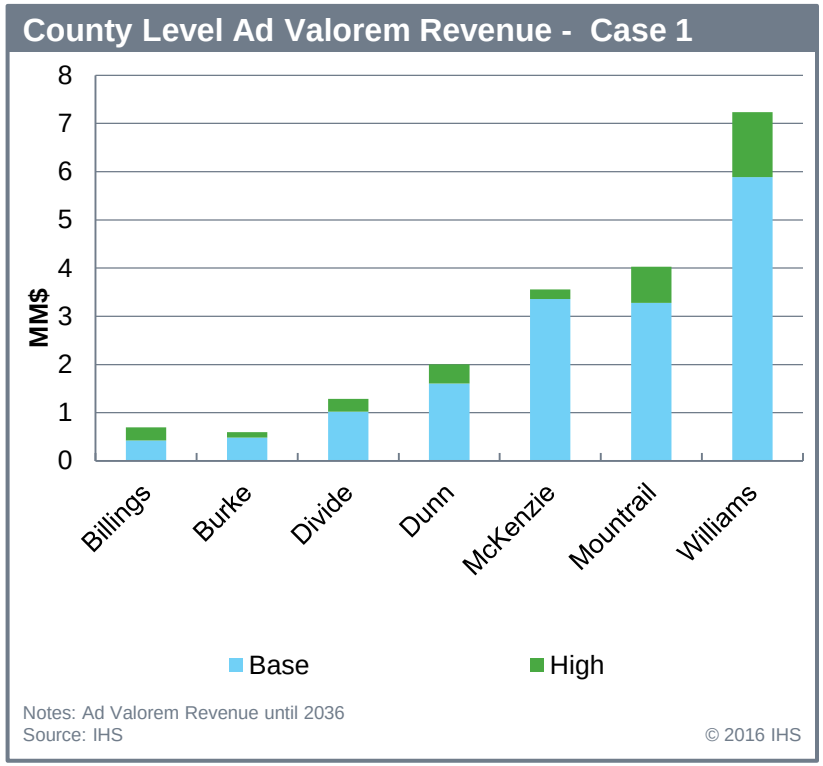
Bakken Revenue by County – Case 1



- Williams currently is one of the most active counties and has the most potential for Bakken EOR
- Dunn, McKenzie and Mountrail counties are expected to have significant activity too.
- Billings, Burke and Divide counties will likely not see much EOR activity

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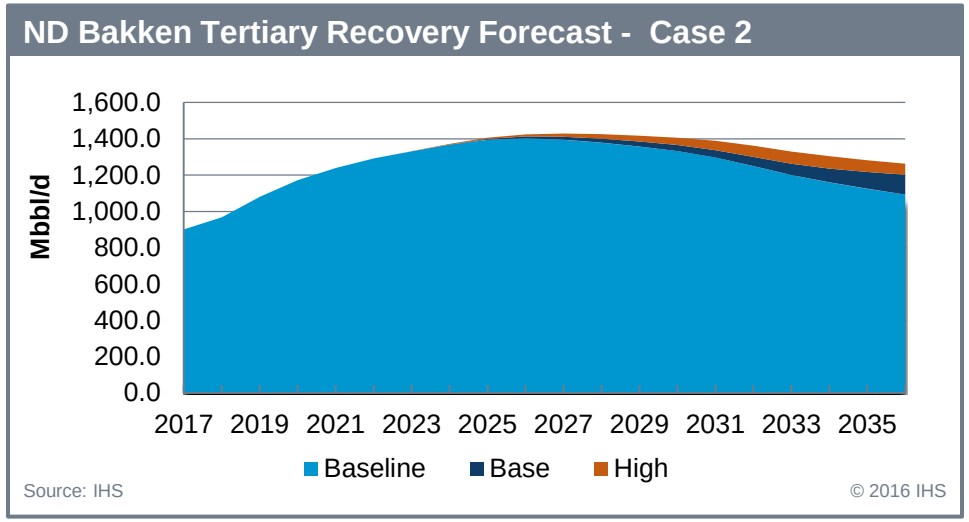
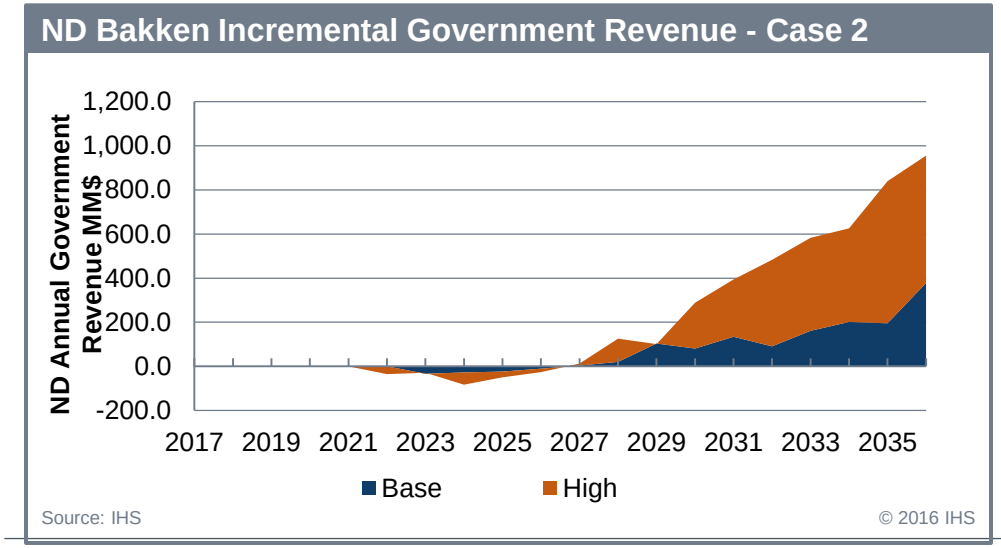
Bakken Co2 EOR
ND Production and Revenue Outlook - Case 2



- Incremental Bakken CO2 EOR production
- Base sc – 199 MMbbls
- High sc – 385 MMbbls



- Incremental direct revenue to the state over the next 20 years
- Base sc - $1.3 B
- High sc - $4.2 B

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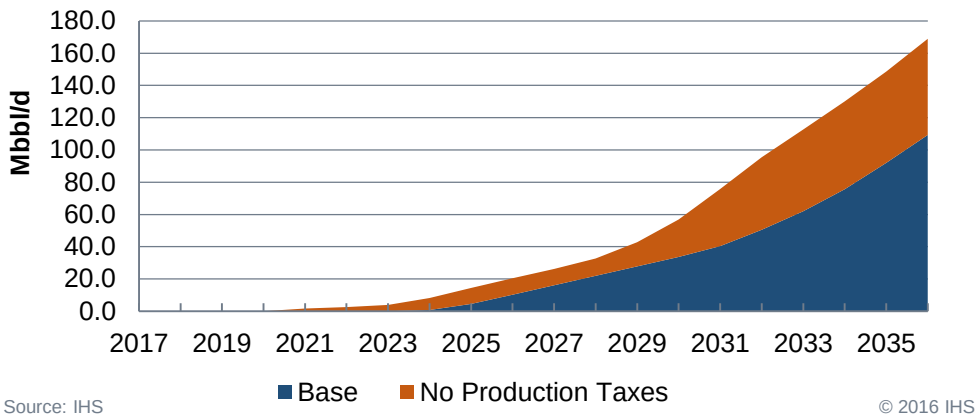
Bakken Case 2 – ND Production and Revenue

Eliminating production taxes altogether results in additional $145 MMbbl of incremental production – however impact on government revenue is significant

ND Bakken Tertiary Incremental Recovery Forecast - Case 2



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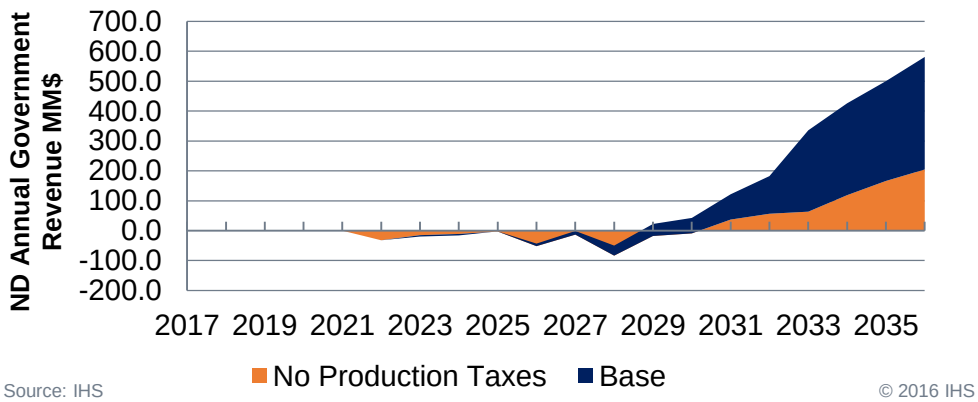
ND Bakken Incremental Government Revenue - Case 2



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- Incremental Bakken CO2 EOR production
- Base sc – 199 MMbbls
- No Prod Tax- 344 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Base sc - $1.3 B
- No Prod Tax- $276 MM

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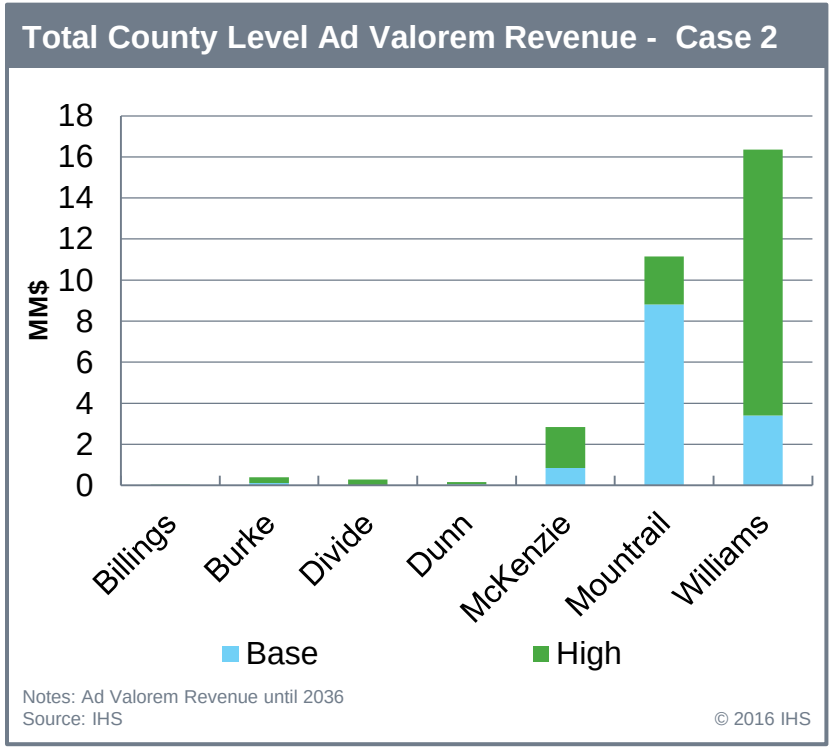
Bakken Revenue by County – Case 2



- Williams County has the most potential under the high scenario
- Mountrail County is projected to have the best recovery and has the best potential under scenario 1
- Billings, Burke, Dunn and Divide counties will likely not see much EOR activity as recoveries in these counties is lower and these may not be economic

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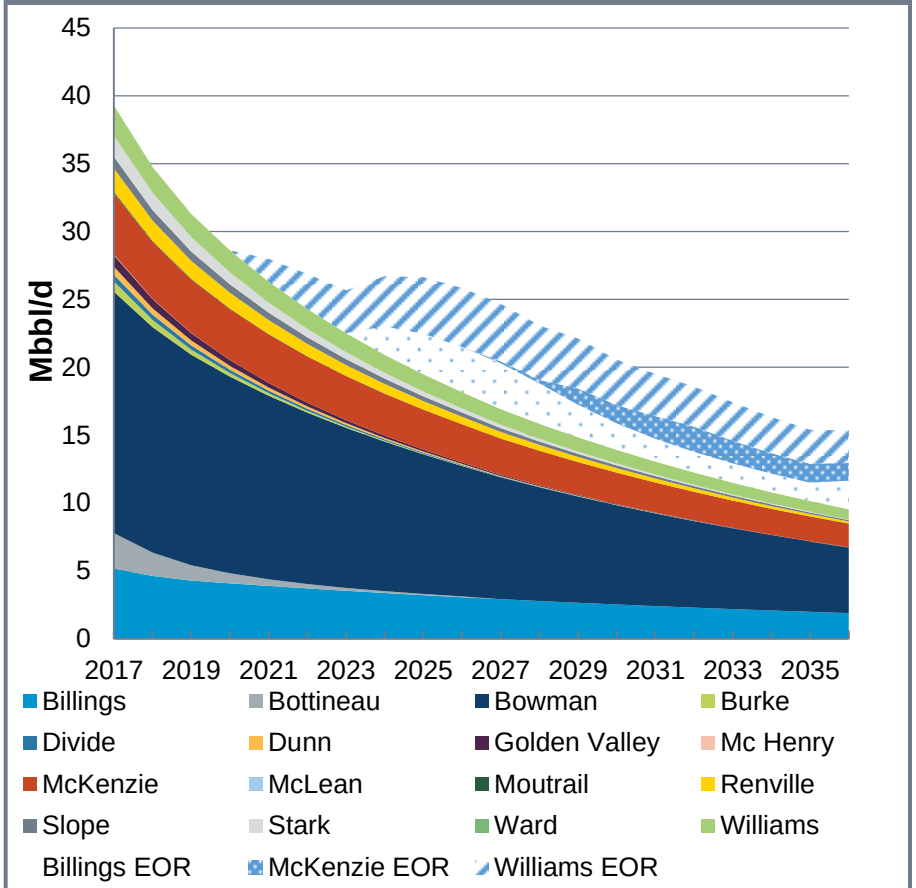
Conventional Field CO2 EOR

ND Production Outlook by County

Scenario 1 Base case - Conventional Production with Tertiary Recovery by County



Source: IHS

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- Few EOR projects have low enough costs to be developed within the study period
- Only Billings, McKenzie and Williams counties are expected to have CO2 EOR projects

Production Unit	EOR Unit Cost $/bbl
BEAVER LODGE DEVONIAN	30
FRYBURG HEATH-MADISON	48
ROUGH RIDER MADISON	48
CHARLSON MADISON	50
BIG STICK MADISON	58
BLUE BUTTES MADISON	68
NEWBURG SPEARFISH / CHARLES	109
ELKHORN RANCH N MADISON	133
MEDORA HEATH /LM/	134
CEDAR HILLS RED RIVER	143
T R MADISON	160
HORSE CREEK RED RIVER	164
BEAR CREEK DUPEROW	234
HOFFLUND MADISON	268
DICKINSON HEATH /LM/	300

Note: Green – may start development by 2036
Orange – unlikely to be developed by 2036

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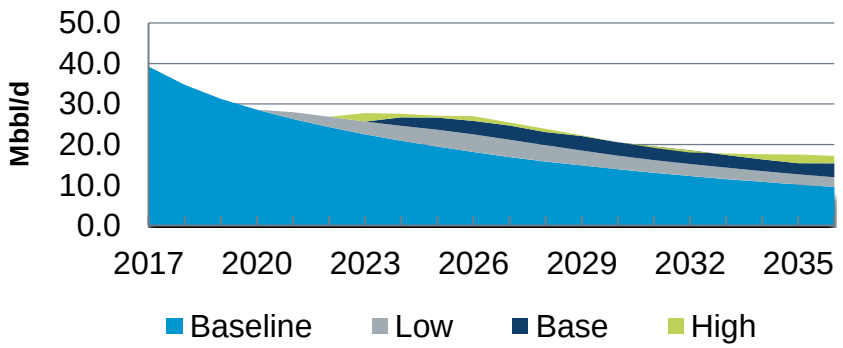
Conventional Field CO2 EOR

ND Production and Revenue Outlook

ND Conventional Tertiary Recovery Forecast



Notes: Only conventional production is included
Source: IHS

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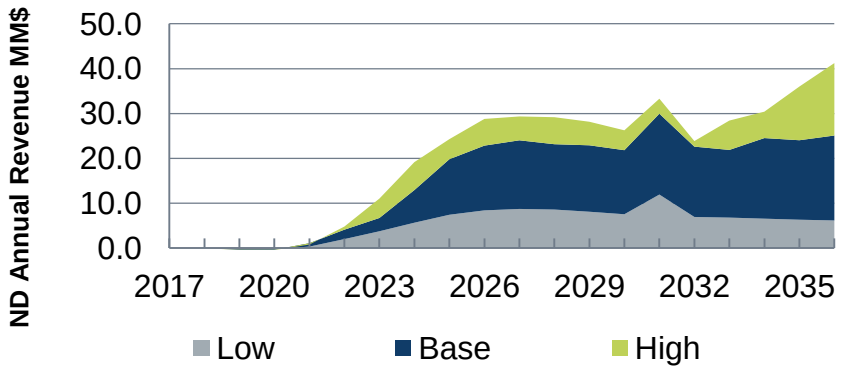
ND Incremental Revenue - Conventional EOR



Notes: Only revenue from conventional projects is linculded
Source: IHS

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- Incremental Bakken CO2 EOR production
- Low sc – 19 MMbbls
- Base sc – 34 MMbbls
- High sc - 38 MMbbls

- Incremental direct revenue to the state over the next 20 years
- Low sc - $105 MM
- Base sc - $307 MM
- High sc - $394 MM

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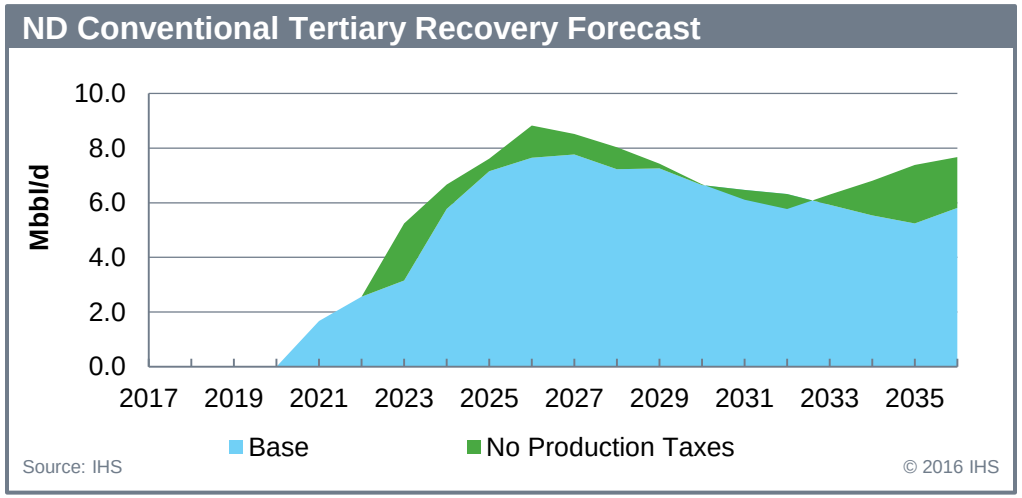
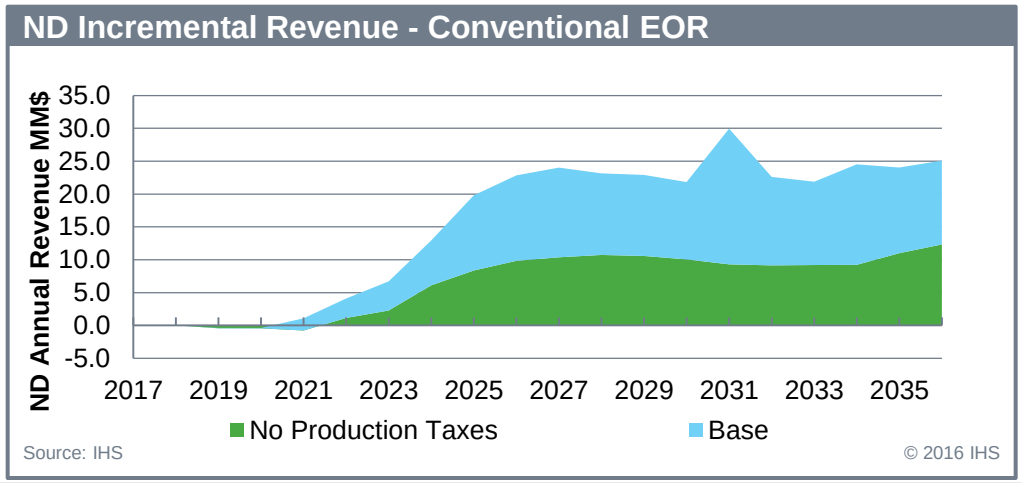
Conventional EOR – ND Production and Revenue

Eliminating production taxes altogether has a marginal effect on production while impacting significantly government revenue



- Incremental Bakken CO2 EOR production
- Base sc – 34 MMbbls
- No Prod Tax - 38 MMbbls



- Incremental direct revenue to the state over the next 20 years
- Base case - $307
- No Prod Tax- $128

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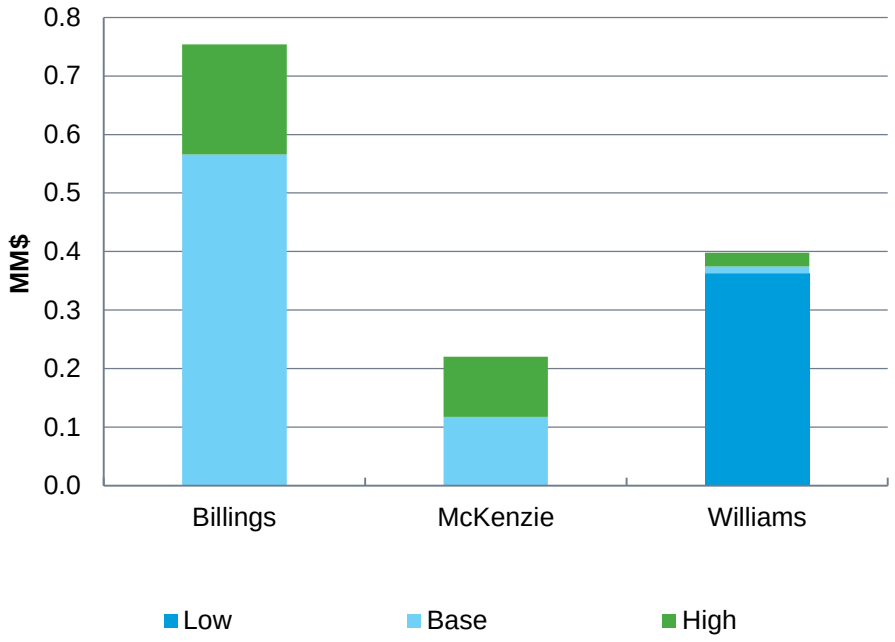
Conventional County Level EOR Activity

For the base case most of the potential resides in the Billings county while in the low case most of the potential resides in the Williams county

County Level Property Tax Revenue – Conventional EOR



Notes: EOR ad valorem tax revenue until 2036
Source: IHS

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- Williams county will see the largest project activity with Beaver Lodge expected to be developed despite a poor economic climate
- Billings and McKenzie counties need strong markets to justify developments before 2036

EOR Project	County
Beaver Lodge Devonian	Williams
Bid Stick Madison	Billings
Charlson Madison	McKenzie*
Fryburg Heath-Madison	Billings
Rough Rider East Madison	McKenzie

*1% is in Williams county

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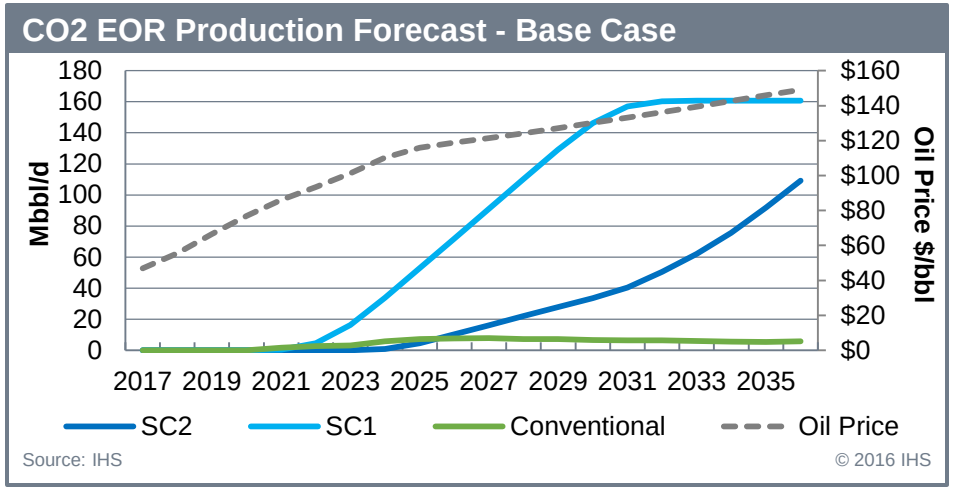
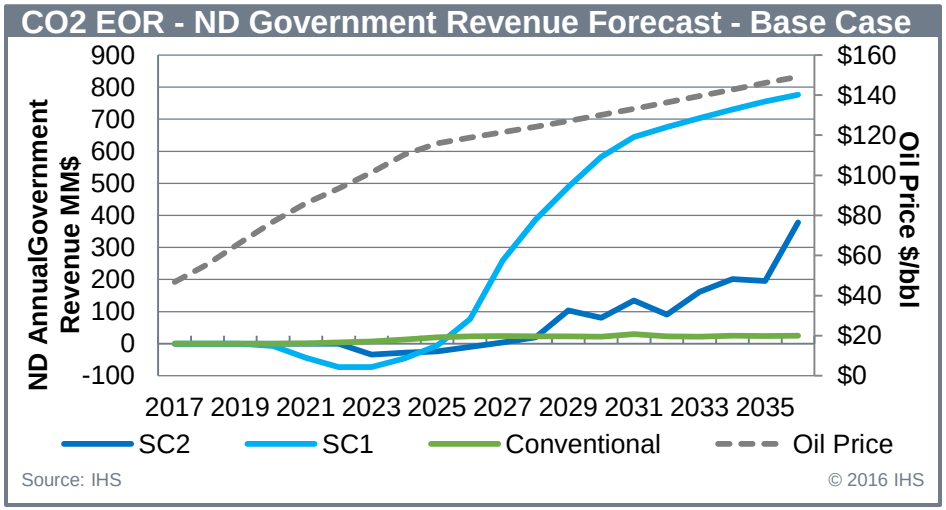
CO2 EOR Economic Summary

The Bakken will have a much higher impact than the conventional production, however, its future success in less certain





- Proof of concept for CO2 EOR in the Bakken still needs to be established
- Based on our current knowledge and assumptions significant long-term price recovery will be required for the Bakken CO2 EOR to produce large revenues
- Significant revenues are likely to occur in the mid to late 2020s – by that time there may be improved technology for CO2 EOR and CO2 capture and transport

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Recommendations and next steps

- Complete the economic impact portion of the study and benchmark such activity against primary Bakken economic impact
- Encourage and help fund future activities to determine the technical and commercial feasibility of CO2 EOR in the Bakken including
  - Research and development activities such as geologic and engineering studies and EOR CO2 modelling
  - Pilot programs which include more costly drilling and development testing
  - Development of CO2 capture as large amounts of CO2 will be required
- As it will take time to progress through optimization phases to commercial manufacturing maintaining current tax policies will be important
- If it appears that large capital outlays will be required to drill additional wells (as modelled in Bakken case 2), give consideration to extended tax breaks to stimulate more production.

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