Commercialization Plan for Carbon Capture and Utilization in Kansas

1.0 Introduction

Kansas is an oil rich state with numerous oil and gas fields in the state (Figure 1). The most productive formations are the Arbuckle, Lansing-Kansas City, and the Mississippian (Figure 2). Approximately 6.6 billion barrels of oil has been recovered in the state since production commenced in the late 1800s (Figure 3). Oil production peaked in the late 1950s and has been declining in recent decades as oil fields mature. Present production in the state stands at approximately 36 million barrels per year (mmbo/yr). The production rate however can be increased from existing wellfields by injecting CO_2 in order to release trapped oil, a process referred to as Enhanced Oil Recovery (EOR). Based on a study prepared for the Midwest Governor's Association (MGA), Kansas has the largest recoverable oil holdings in the MGA region, with approximately 750 million barrels of oil that can be recovered from existing wellfields by implementing tertiary oil recovery techniques such as CO_2-EOR (Table 1). The CO_2 needed to recover this amount of oil is estimated to be between 240-370 million metric tons. While an oil rich state, Kansas has no appreciable naturally occurring CO_2. Therefore, CO_2 would need to be captured from both in-state and out of state industrial facilities and transported to the oil fields.

In order to realize the EOR potential, Kansas Geological Survey (KGS) has been conducting research funded by the U.S. Department of Energy (DOE) since 2009 in order to characterize the subsurface formations for determining the feasibility of EOR as well as CO_2 storage in the state. These efforts have identified several sites that are suitable for EOR and geologic storage of CO_2. Additionally, in order to demonstrate the effectiveness of EOR, approximately 19,800 tonnes were injected in the Mississippian oil reservoir over 165 days in 2016 at the Wellington pilot-scale site (Figure 4). The injected CO_2 increased average daily production in the wellfield from approximately 10 barrels per day to 26 barrels day; an increase of 160%. These results are promising and suggest that the subsurface formations in Kansas can both store and utilize CO_2 to increase oil production.

The KGS estimates that approximately 250 mmbo of incremental oil can be recovered from existing wellfields over the next 25 years (10 MBO/yr) utilizing CO_2-EOR (Dubois, 2017). This is a 28% increase over the present KS production of 36 mmbo/yr. The amount of CO2 required to extract this additional oil is estimated to be 4.3Mtonnes/yr. At $50 per barrel, the market value of this recovered oil over the 25 year period is $12.5B. Therefore, a significant financial benefit can be realized by implementing a CO_2 based EOR initiative. Several (economically feasible) capture and transportation scenarios are discussed below in order to obtain an estimate the necessary capital and operating costs necessary to deliver the CO_2 at EOR-ready oil fields in Kansas.

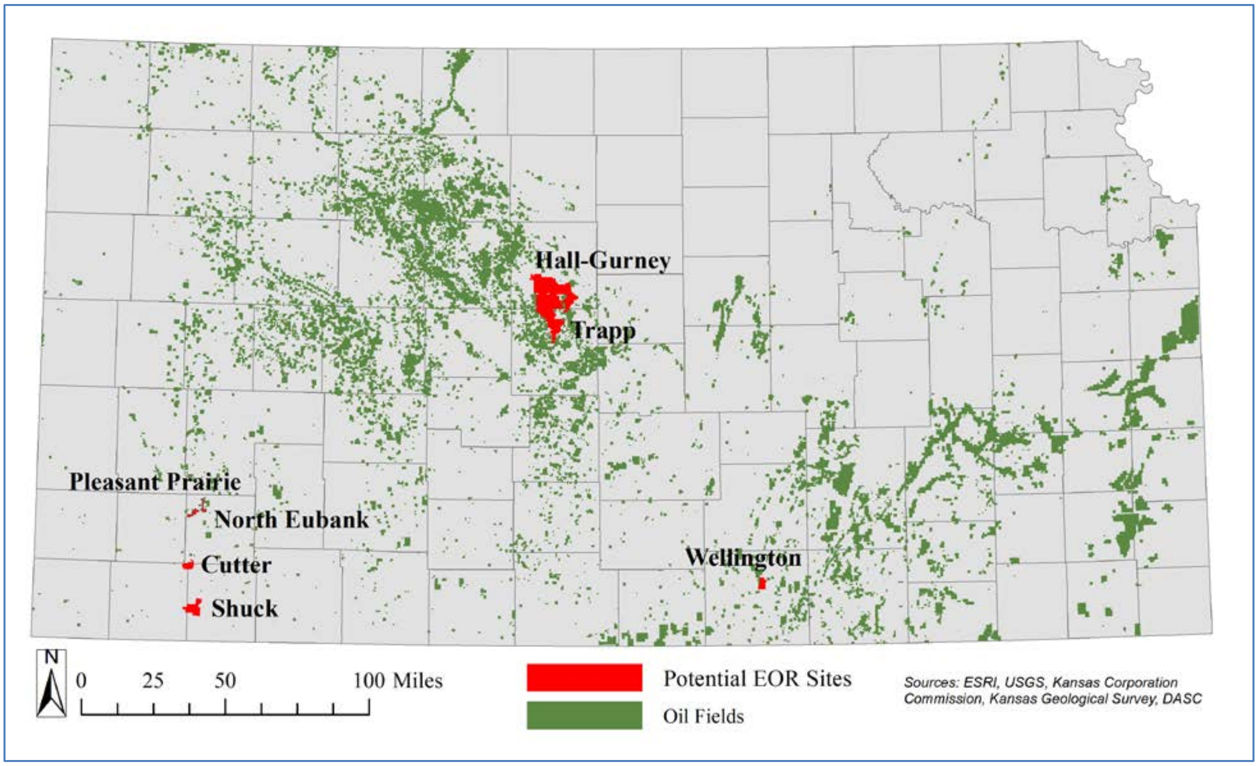


Figure 1. Oil fields and potential Enhanced Oil Recovery sites in Kansas.

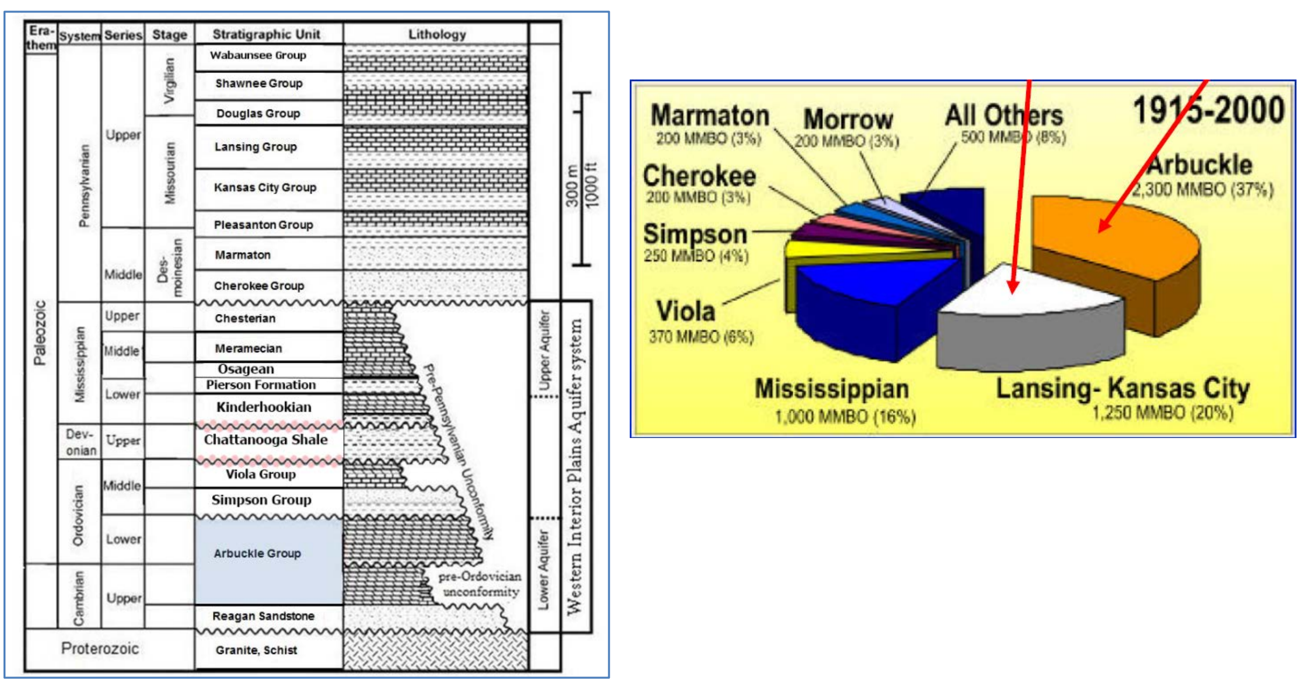


Figure 2. Oil and gas bearing formations in Kansas.

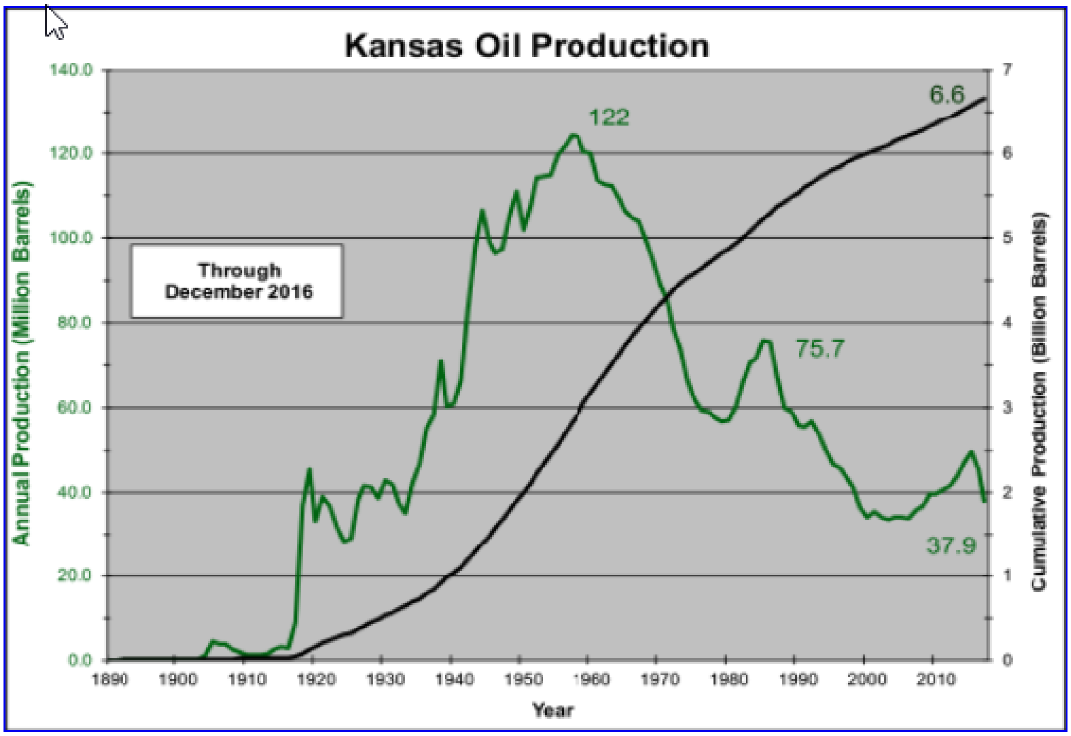


Figure 3. Oil production trends in Kansas.

Table 1. Recoverable oil in the Midwest Governors Association states.

Basin	EOR potential (Mil bbl)	Net CO_2 Demand (MMT)	Direct Jobs Created
Illinois/Indiana	500	160 – 250	1,550 – 3,100
Ohio	500	190 – 300	1,550 – 3,100
Michigan	250	80 – 130	800 – 1,800
Kansas	750	240 – 370	2,300 – 4,600
TOTALS	**2,000**	**670 – 1,050**	**6,200 – 12,400**

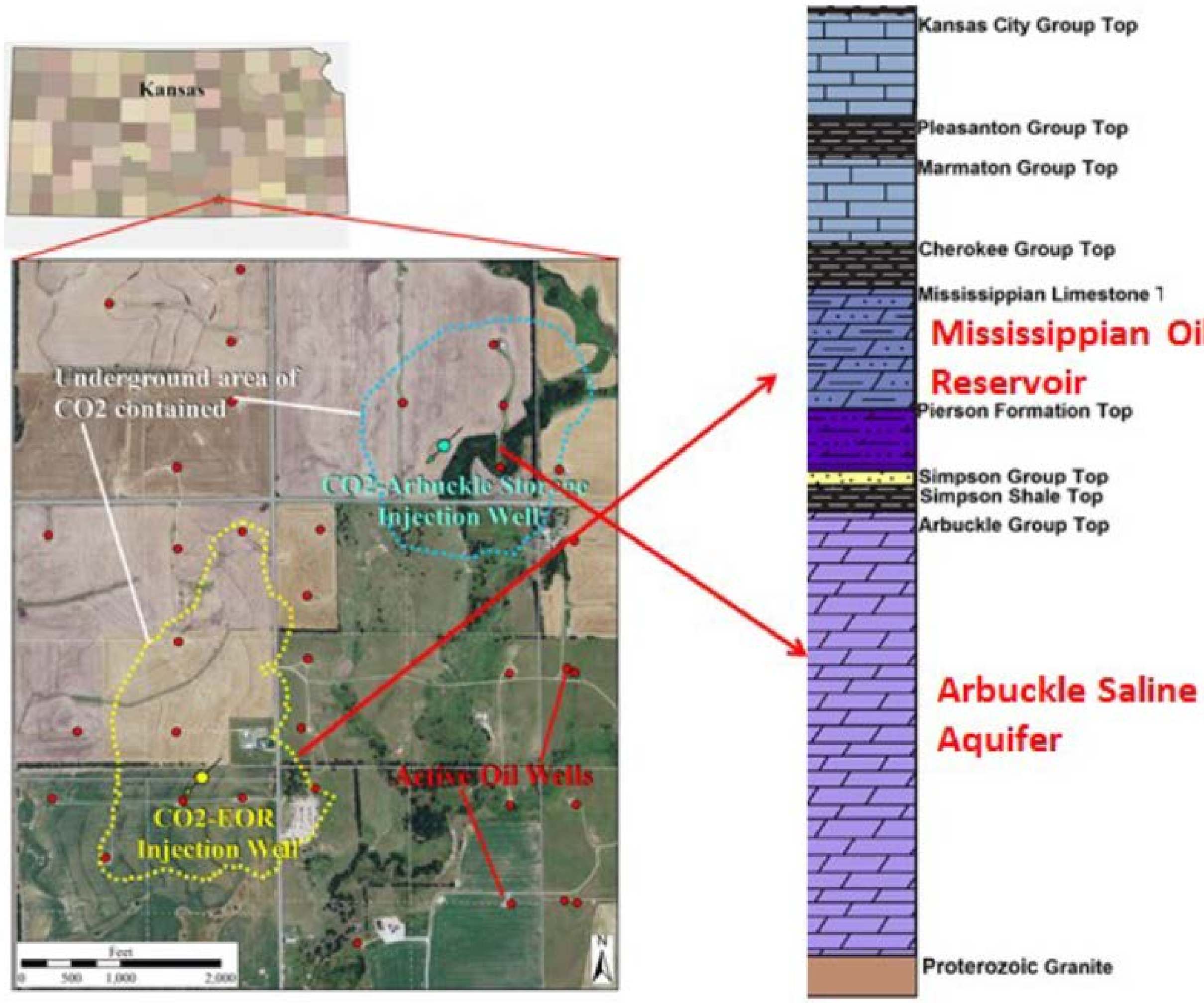


Figure 4. Location of CO2-EOR and storage pilot-scale test site at Wellington, KS.

2.0 Potential EOR Sites

As part of a DOE funded regional characterization effort, ten sites were identified with potential for storing at least 50 million metric tons (MT) at each site in the Arbuckle saline aquifer (Figure 5). Based on research conducted by KGS, there are several promising (CO_2-ready) EOR sites in close proximity to the storage sites (Figure 5). As shown in Table 2, 3.9 MT/yr could be injected into these CO2-ready wellfields, yielding an additional 55.7 mmbo. It is estimated that approximately 22.8 MT of the injected CO2 will remain stored in the oil reservoirs.

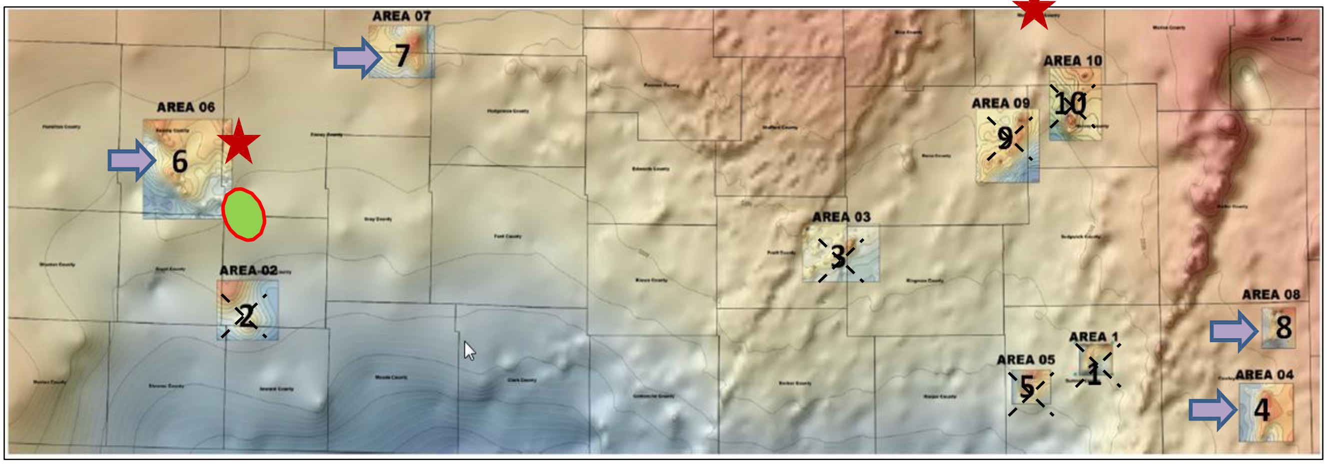


Figure 5. Potential CO_2 storage and EOR sites in Kansas.

Table 3. Tertiary oil recovery potential of CO2-ready sites in Kansas (source: Dubois, 2017).

	CO2 EOR Ready Level	Inject. Rate (Mt/yr)	CO2 Stored (Mt)	Primary & Secondary (mmbo)*	CO2 EOR (mmbo	Basis for Estimate
Shuck	1	0.4	1.5	7.9	3.6	DE-FE000256
Cutter	1	0.5	1.3	5.4	2.8	DE-FE000256
N Eubank	1	0.6	1.5	7.4	4.6	DE-FE000256
Pleasant Prairi	1	0.3	0.5	4.7	2.2	DE-FE000256
Hall Gurney	1	1	11.3	62.5	26.8	DE-AC26-00BC15124 PILOT & C12 Ener
Trapp	2	0.5	4.3	31.3	10.3	KGS reports
Wellington	1	0.6	2.2	16.2	5.3	DE-FE0002056 and PILOT
		3.9	**22.8**	**135.4**	**55.7**	

3.0 CO2 Sources

The sources of anthropogenic CO2 in Kansas and nearby states are shown in Figure 6. CO_2 can be captured from coal fired power plants as well as ethanol/industrial facilities and transported to EOR sites. The largest source of CO_2 are coal fired power plants. Relatively small amount of CO_2 is captured from ethanol plants. The ethanol plants are also located mostly in Nebraska and Iowa, at further distance from the EOR and storage sites in Kansas. However, the cost of CO_2 capture per ton from an ethanol plant is substantially less than the cost of capture from power plants, which can compensate for the additional transportation distance. Therefore, various commercialization scenarios are considered below, which involve capturing and transporting CO_2 source from a combination of ethanol and power plants. The economics of these scenarios was derived by team members of the ICKan CarbonSafe project (Dubois, 2017, and McFarlane and Dubois, 2017).

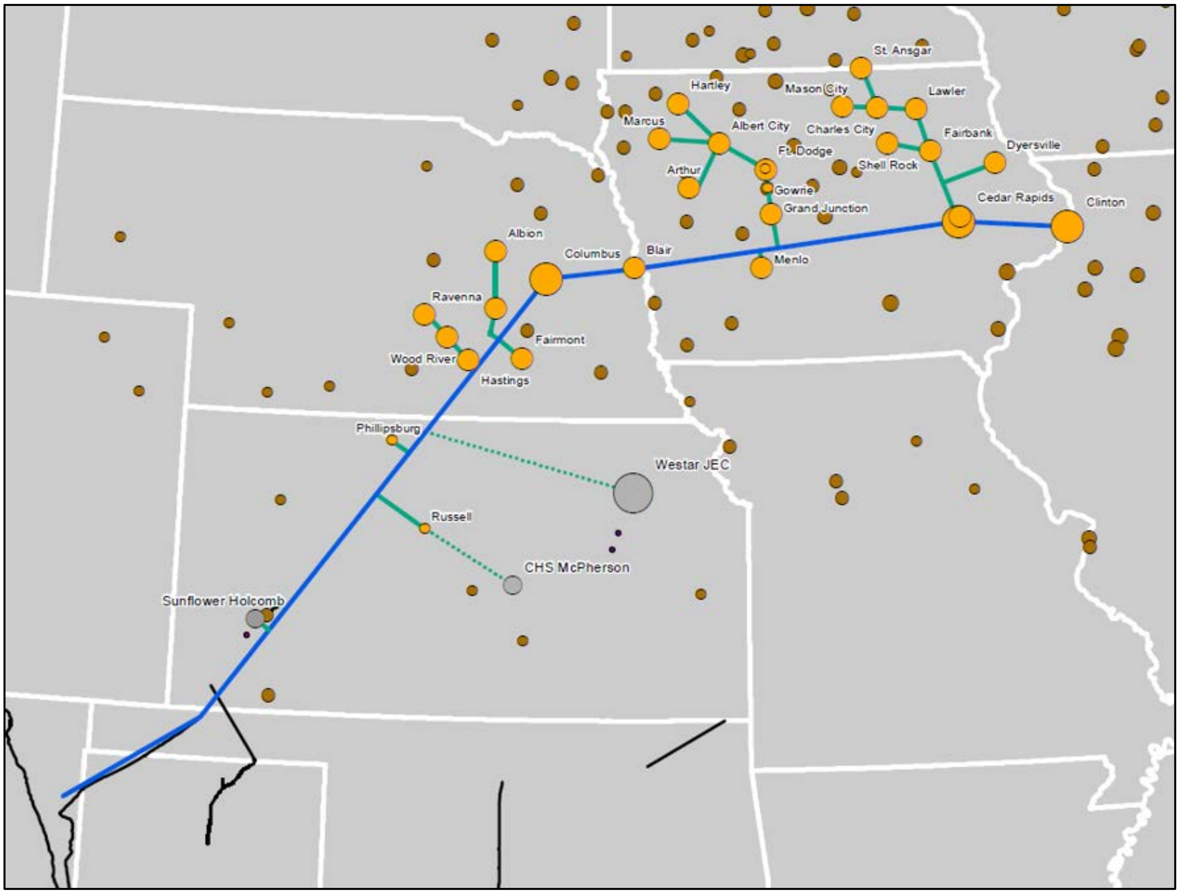


Figure 6. Location of potential CO2 sources in the Midwest {Symbol legend: yellowish-brown and dark brown (ethanol), and light grey (industrial and coal-fired electric plant)}.

4.0 Itemized Cost Estimates

4.1 Capture and Operating Costs

Ethanol Plant

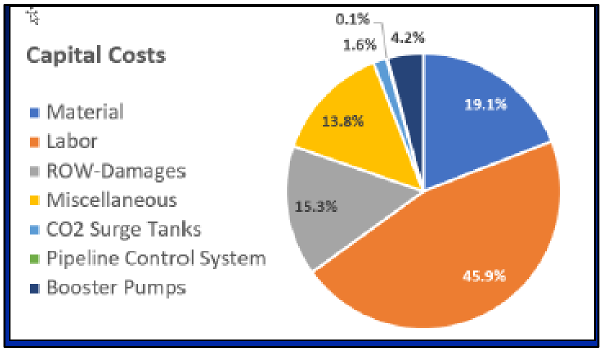
The capital expense for carbon capture at an ethanol is estimated at:

$ 9 million + $0.146 MGY (where, MGY is million gallons of ethanol per year that the plant produces)

This estimate is derived from a DOE-funded project of three plant sizes. The operating expense for carbon capture is estimated at $8.58/tonne. This cost is based on DOE-funded study of two 55 MGY plants.

4.2 Pipeline Costs

The NETL CO2 Transport Cost Model (Grant & Morgan, 2014) was used for calculating pipeline costs. The model estimates the itemized capital and operations/management (O&M) cost for transporting dense (liquid) phase CO_2 in a pipeline. A typical breakup of the itemized cost is provided in Figure 7. The cost of constructing a pipeline is approximately $100,000/inch-dia/mile.



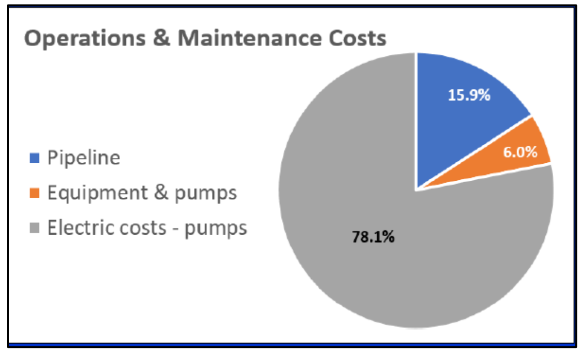


Figure 7. Estimated break up of pipeline costs associated with capital and O&M (source: McFarlane and Dubois, 2017).

5.0 Technical and Financial Assmptions

5.1 Financing Options and Cost Assumption

Two equity-debt financing rates are considered: 10% and 6.7%. For the 10% weighted return case, the project is to be financed by issuing a combination of a BB rated taxable bond (50% @ 5%) and establishing a Limited Liability Corporation (50% @15%). For the second 6.7% targeted weighted average return case, 55% is to be financed by a tax-exempt Private Activity Bond (PAB) yielding 4%, and 45% is to be financed by a publically traded master limited partnership (MLP) at the rate of 10%.

In our analysis, we assume that all components of the project (capture, dehydration, compression, pipeline construction, transportation) are financed similarly. Also, all operations are assumed to commence simultaneously: capture facilities, pipeline, and sales points (oil fields). A zero percent inflation rate is assumed for the duration of the project.

5.2 Project Life Cycle and Technical Assumptions

The construction phase of the project is to occur over a period of two years, followed by operations for a period of 20 years. The following technical assumptions apply:

- Average production of CO_2 is 90% of plant rating (as per EIA, 2016)
- Total pipeline length is 110% of straight miles from source to end point
- Pressure drops from 2,000 psi at the capture source to 1,400 psi at the EOR/storage site
- Boosters stations are to be installed as necessary

5.3 Credits

Q45 Credit

In the economic analysis, we initially recognized the $10/ton credit presently available by Q45. With the recently legislation passed in the U.S. congress, the amount of credit increases to $30. This makes the CCUS even more attractive.

5.4 Incremental Oil Recovery Rate

The amount of incremental oil per ton of CO2 injected is expected to vary from site to site and also over the course of the EOR operations. For the commercialization plan, it is assumed that a constant annual increase in oil production of 28% can be achieved over the next 25 years.

6.0 Modeled Scenarios

The economics of capture and transportation for multiple scenarios are considered in order to evaluate the commercial potential of CCUS and to better understand the interplay of various cost items. The economics of four commercialization scenarios are discussed in this document. They range from a simple point-to-point (one source) case to a complex multiple (32) source scenario.

6.1 Scenario 1 (Capture from 15 plants to Kansas oil fields)

This scenario involves capture and transportation from 15 largest ethanol plants in Nebraska and delivering 4.3 Mt/yr to CO2 ready oil fields in Kansas (Figure 8). The total production capacity of these 15 ethanol plants is 1,575 MGY. The pipeline covers a distance of 737 mile with the diameter of the pipe segments varying from 4 to 12 inches. The estimated capture, pipeline, and operating costs for this scenario are presented in Table 4. A breakup of the costs for the two rate return cases being considered is presented in table 5 and 6.

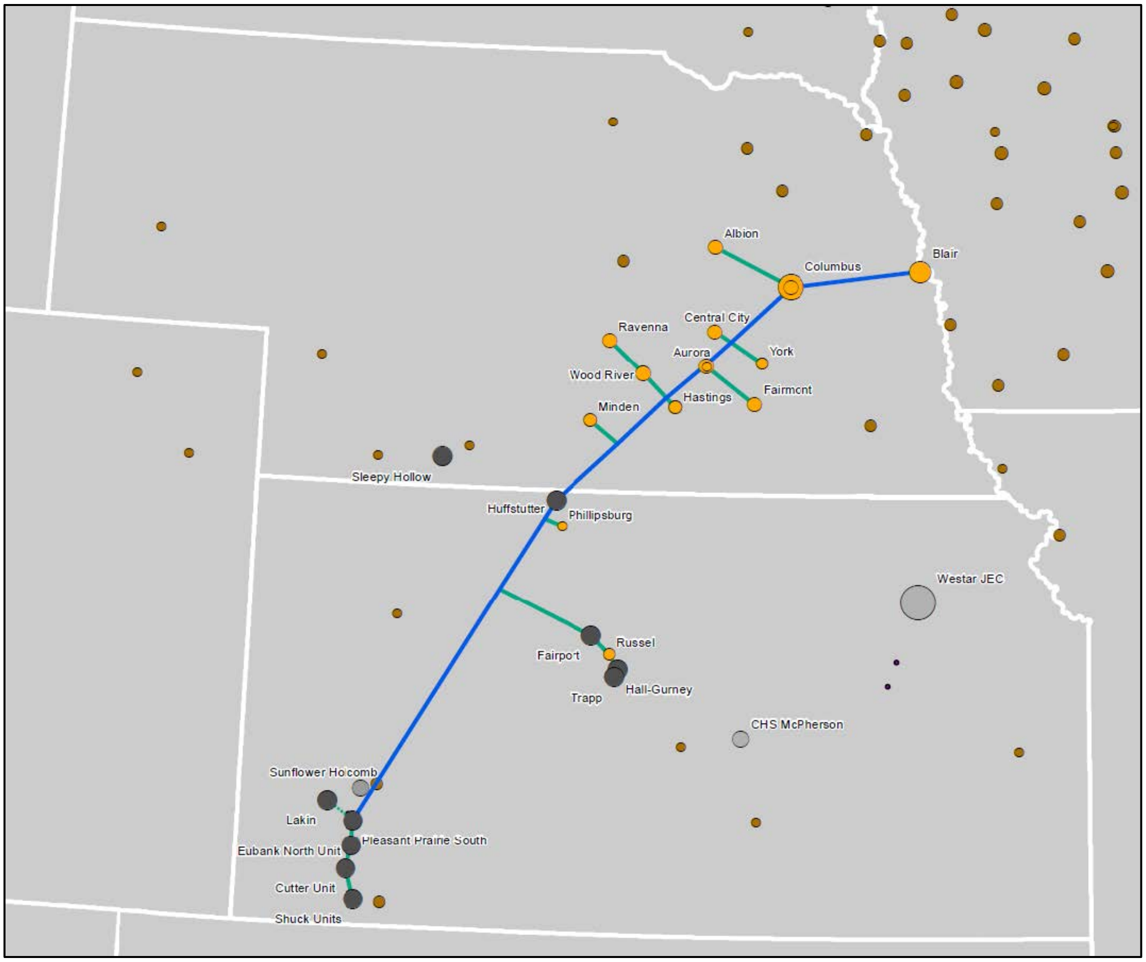


Figure 8. Location of CO2 sources, receiving oil fields, and pipeline route for Scenario 1 {Symbol legend: yellow-brown (ethanol), black (industrial), and light grey (coal-fired electric plant)}.

Table 4. Itemized capital and operating costs for Scenario 1

Cost Item	Plant Capture	Pipeline Transport	Total
Capital Expenditure	$364	$642	$1,006
Annual Operating Expense	$37	$16	$53

Table 5. Cost breakdown for the 10% cost of capital case for Scenario 1

	Cost Item	Pipeline	Ethanol	Combined
In $/tonnes	Capital Expense	$18.60	$10.55	$29.15
	Operating Expense	$3.80	$8.58	$12.39
	Total ($/tonne)	$22	$19	$42
In $/mcf	Capital Expense	$0.98	$0.56	$1.53
	Operating Expense	$0.20	$0.45	$0.65
	Total ($/tonne)	$1.18	$1.01	$2.19

Table 6. Cost breakup for the 6.7% cost of capital case for Scenario 1

	Cost Item	Pipeline	Ethanol	Combined
In $/tonnes	Capital Expense	$14.37	$8.15	$22.52
	Operating Expense	$3.80	$8.58	$12.39
	Total ($/tonne)	$18	$17	$35
In $/mcf	Capital Expense	$0.76	$0.43	$1.19
	Operating Expense	$0.20	$0.45	$0.65
	Total ($/tonne)	$0.96	$0.88	$1.84

6.2 Scenario 2 (Large point to point)

This scenario involves capturing approximately 1.1 MT/y of CO_2 from the largest ADM ethanol plant in Nebraska at Columbus and transporting the same to the Sleepy Hollow oil field in Southwest Nebraska. The 201 mile route of the 8 inch pipeline is shown in Figure 9. There are two additional ethanol plants (with an annual capacity of 413 MGY) along the route that can be brought online should there be demand for additional CO_2. The capital and operating costs for this case are shown in Table 7. In order for this scenario to be economically viable, the price of the CO_2 per tonne would need to be $31 and $37 for the 6.7% and 0% cases (Table 8).

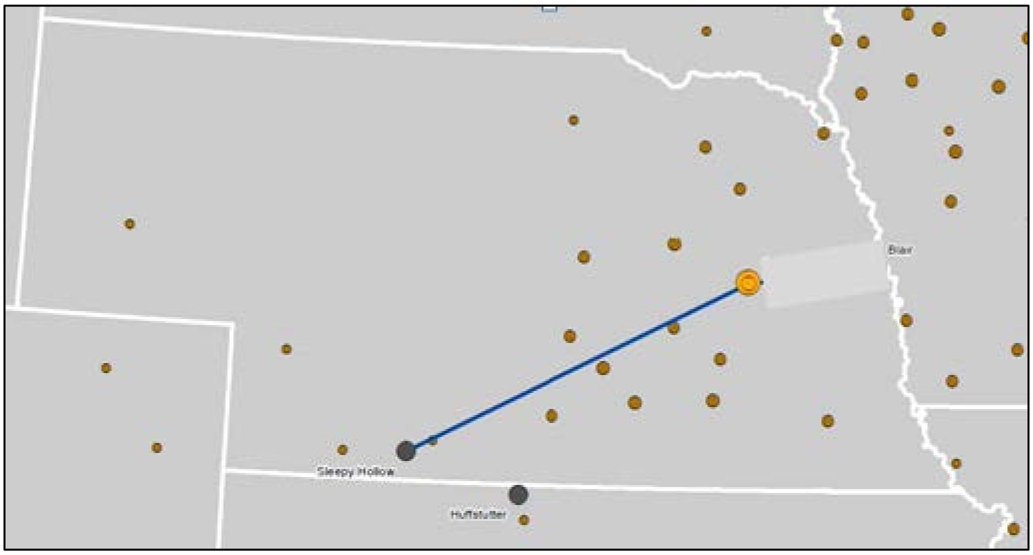


Figure 9. CO2 sources and EOR locations for Scenario 2 {Symbol legend: yellow-brown ethanol plant}.

Table 7. Itemized capital expenditure and operating costs (in $M) for Scenario 2.

Item	**Plant Capture**	**Pipeline Transport**	**Total**
Capital Expenditure	$78M	$154M	$232M
Annual Operating Expense	$10M	$3M	$13M
Total			**$245M**

Table 8. Required cost of delivered CO2 per tonne for the two assumed rates of return for Scenario 2.

10%	**6.7%**
$37	$31

6.3 Scenario 3 (Small point to point)

This scenario is an example of a small point-to-point carbon capture and transportation of CO2 to oil fields. It involves capture at the Kansas Ethanol, USEP, and Prairie Horizon ethanol plants and transporting CO2 to the Geneseo Edwards, Hall-Gurney, and Huffstutter oil fields. A total of 148,000 tonnes/yr is to be captured and transported for a relatively small distance of 16 miles.

The capital and operating costs for this case are shown in Table 9 along with the cost of carbon capture and transportation for the two cost-of-capital cases being considered. In order for this scenario to be economically viable, the price of the CO2 per tonne at the capture facility would need to be $33 and $28 for the 6.7% and 0% cases respectively (Table 10).

Table 9. CO2 source and supplied oil field for Scenario 1B.

Ethanol Plant (capacity)	Supplied Oil Field
Kansas Ethanol (55 MGY)	Lyons
USEP (55MGY)	Russell
Prairie Horizon (40 MGY)	Phillipsburg

Table 10. Cost breakdown (in $/tonne) for Scenario 1B.

	Expense Type	10% ROR	6.7% ROR
Pipeline	Capital	$9.12	$7.05
	Operations	$1.48	$1.48
Ethanol Plant	Capital	$14.09	$10.89
	Operations	$8.58	$8.58
Total $/tonne		**$33**	**$28**
Total $/mcf		**$1.75**	**$1.47**
Total $/gallon		**$0.11**	**$0.09**

6.4 Scenario 4 (large Scale)

This scenario represents large-scale, approximately 10MT/yr capture and transport from 32 largest ethanol plants in the upper mid-west and transporting to the Permian Basin (Figure 10). It involves construction of 1,546 miles of (4-20 inch diameter) pipeline. The total production at the 32 ethanol plants is 3,643 MGY. The capital and operating costs for capture and transport of CO2 for this case are presented in Table 11. The required price (in$/tonne) for the two cost of capital cases being considered is presented in Table 11.

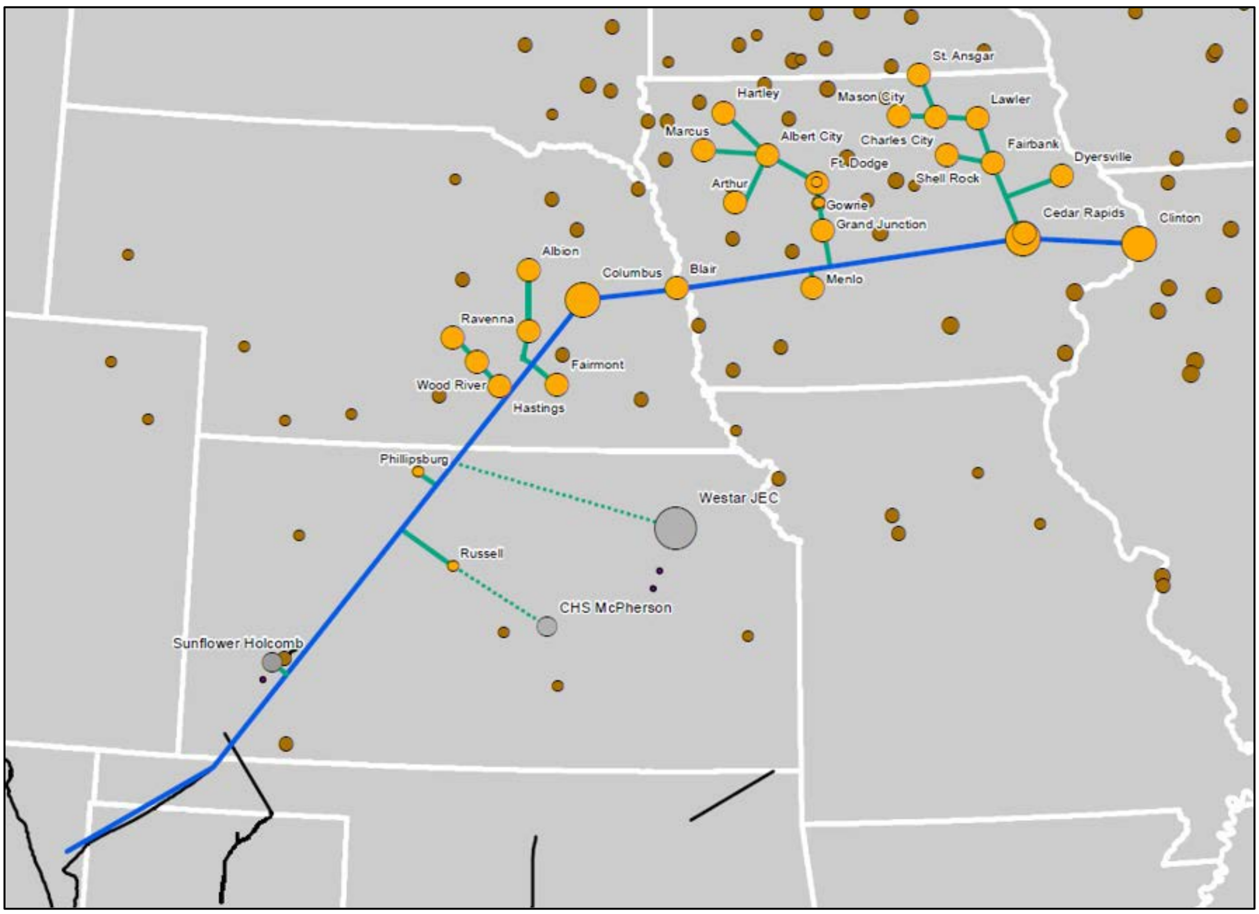


Figure 10. Location of CO2 sources, receiving oil fields, and pipeline route for Scenario 3 {Symbol legend: yellow-brown (ethanol), and light grey (industrial and coal-fired electric plant)}.

Table 11. Capital and operating costs for Scenario 4.

Cost Item	Plant Capture	Pipeline Transport	Total
Capital Expenditure	$809	$1,857	$2,667
Annual Operating Expense	$85	$47	$131

Table 12. Required Price in $/tonne for Scenario 4 for the two rates of return being considered.

10%	6.7%
$47	$39

The cost of transportation for this case can be reduced by capturing CO_2 from the Westar's Jeffrey Energy Center coal fired power plants near St Marys, KS and the CHS refinery at McPherson, KS (Figure 11) and transporting to the main pipeline running through western Kansas. The larger volumes and shorter distances are expected to result in a lower cost/tonne for transportation. Two separate routes (JEC-Trunk and JEC-CHS-Trunk) were considered. The cost of capture for the power plant and refinery are presently being estimated. The transportation costs are presented in Table 12. The average cost per ton for the added segment is $11.5/tonne and $9.5/tonne for the 10% and 6.7% cases. This compares favorably average transportation cost of $23 and $19 for the average for scenarios 1, 2, and 4 (Table 12).

Table 12 Breakup of transportation cost and comparison for Scenario 4 and comparison with alternative scenarios.

Pipe Segment	Pipe Miles	Pipe Diam. (in)	CO2 (MT/yr)	Transport ($/tonne)	
				10%	6.7%
JEC-Trunk	167	12	2.50	$9	$7
JEC-CHS-Trunk	323	12	3.25	$14	$12
Average cost				11.5	9.5
Average costs for scenarios 1, 2, and 4				$23	$19
Average Difference ($/tonne)				$11.5	$9.5

Summary of Scenarios

A summary of the required price for the four scenarios is presented in Table 13. The required price of CO2 per tonne ranges from $33 to $47 for the 10% rate of return case. The required price for the 6.7% ROR case is approximately 16% less. Neglecting the ultra-small Scenario 3, the average price of CO2 per tonne required to meet the two cost of capital rates being considered are shown in Table 14 for scenarios 1, 2, and 4. The average price is approximately $42 and $35 for the 10% and 6.7% costs of capital.

Table 13. Summary of required CO2 price for the four capture scenarios and two cost of capital cases

Scenario	**Ethanol Plants**	**Plant Capacity (MGY)**	**Pipeline Miles**	**CO2 (Mt/yr)**	**Required Price $/tonne**		**Required Price $/mcf**	
					10%	**6.7%**	**10%**	**6.7%**
1	15	1575	737	4.26	$42	$35	$2.19	$1.84
2	2	413	201	1.12	$37	$31	$1.95	$1.64
3	1	55	16	0.15	$33	$28	$1.75	$1.47
4	34	3643	1546	9.85	$47	$39	$2.46	$2.06

Table 14 Average CO2 price for Scenarios 1, 2, and 4

Required ROR	**10%**	**6.7%**
$/tonne	$42	$35
$/mcf	$2.20	$1.85
$gal Ethanol	$0.14	$0.12

The average cost allocation for the three scenarios for the 10% rate of return case is presented in Figure 11. The largest cost component is the capex for constructing the pipeline followed by capture, plant operations, and pipeline operating costs. As listed in Table 15, the cost of construction and operation of the pipeline is approximately $23/tonne ($0.078/gal), while the cost for capture and compression is approximately $18/tonne (0.061/gal of ethanol). A detailed cost allocation is presented in tables 16 and 17 for the 6.7% and 10% rates of return respectively.

Based on historical experience, the economical price of CO2 in west Texas is approximately 2% of West Texas Intermediate (WTI). For $50/BO (WTI), a feasible price for EOR is $1/mcf. This is less than the $1.85/mcf price required for the 6.7% rate of return, and $2.20/mcf for the 10% rate of return (tables 16 and 17). Without any credits, the scenarios would be economical at a WTI price of $92.5 ($1.85/.02)for the 6.7% rate of return (ROR) case and $110 for the 10% rate of return case. If 45Q credits are considered (presently at $0.53/mcf), the economics becomes more favorable and EOR would be economical at a WTI price of $66 for the 6.7% ROR and $83.5 for the 10% ROR of return cases. With the recently passed 45Q credits of $30/tonne ($1.59/mcf), then EOR would be economical at a WTI price of only $13/BO for the 6.7% case and $30.5/BO for the 10% rate of return.

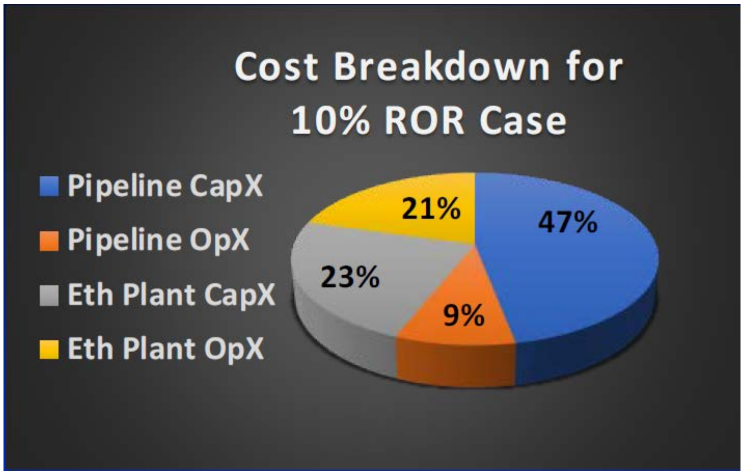


Figure 11. Average cost allocation for Scenarios 1, 2, and 4.

Table 15. Average cost of capture and transportation for Scenarios 1, 2, and 4.

Expenditure Type	**Cost per tonne**	**Cost per mcf**	**Cost per gallon**
Ethanol Plant (Capture and compression)	$18	$0.85	$0.061
Pipeline (Transport)	$23	$1.23	$0.078

Table 16. Detailed cost allocation for 6.7% Rate of Return

Cost Category	**Cost Item**	**$/tonne**	**$/mcf**	**$/gal**
Pipelines	Capital Expenditure	$15.15	$0.80	$0.051
	Operating Expenditure	$3.79	$0.20	$0.013
Ethanol Plants	Capital Expenditure	$7.55	$0.40	$0.025
	Operating Expenditure	$8.58	$0.45	$0.029
	Total	**$35**	**$1.85**	**$0.117**

Table 17. Detailed cost allocation for 10% Rate of Return

Cost Category	**Cost Item**	**$/tonne**	**$/mcf**	**$/gal**
Pipelines	Capital Expenditure	$19.60	$1.03	$0.065
	Operating Expenditure	$3.79	$0.20	$0.013
Ethanol Plants	Capital Expenditure	$9.77	$0.51	$0.033
	Operating Expenditure	$8.58	$0.45	$0.029
	Total	**$42**	**$2.20**	**$0.139**

References

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