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Economic analysis of CO_2-enhanced oil recovery in Ohio: Implications for carbon capture, utilization, and storage in the Appalachian Basin region

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ABSTRACT

A cost-benefit analysis is presented to evaluate the economic feasibility of carbon dioxide (CO_2)-enhanced oil recovery (EOR) in Ohio. Ohio-specific data is integrated with reservoir performance and economic models to define the analysis framework. The analysis is applied to two Ohio oil fields to illustrate how the methodology can be used to constrain project economics and profitability. The regression derived from the CO_2 break-even price calculated for a range of oil prices indicates that the change in the unit value of CO_2 for EOR is approximately four times the corresponding change in the unit value of oil. A similar correlation observed in other oil fields suggests differences in reservoir properties may not significantly alter the price elasticity of CO_2 relative to the prevailing oil price. The break-even correlation presented here represents a standalone metric that can be applied for project screening purposes to determine the price conditions at which CO_2 becomes a viable purchase for EOR and a marketable asset for power plants with capture technology.

1. Introduction and scope

Carbon capture, utilization, and storage (CCUS) is a vital component of the strategy to achieve CO_2 emission reductions in the power generation sector (Benson and Friedmann, 2014). In the state of Ohio, the latest EPA data indicate that 129 million metric tons of CO_2 were emitted in 2013 from 229 stationary sources, with twenty-two coal-fired power plants contributing 63% of total emissions (EPA, 2014; Battelle, 2015). Coal is projected to remain an important fossil fuel for electricity generation along with natural gas for the next several decades in the United States (U.S.). As such the decreased but continued use of coal will likely be instrumental in maintaining affordable electricity prices and meeting rising energy demands (CURC-EPRI, 2015; EIA, 2015a).

Balancing potential CO_2 emission reduction requirements with the high costs of modern CCUS technology is currently a major challenge for coal-fired power plants (Hamilton et al., 2009; Zhai et al., 2015). The oil industry practice of CO_2-EOR (enhanced oil recovery) is a utilization pathway that could provide a revenue stream and market for captured CO_2 to help improve CCUS project economics (Monea, 2014; Rubin et al., 2015). The economic incentives associated with CO_2 utilization and storage via EOR may be especially important for deploying CCUS in regions where the economic welfare is strongly tied to coal and coal-fired power generation, such as the Appalachian Basin in the U.S.

Ohio ranks among the top ten states for highest coal-production, electricity generation, and CO_2 emissions in the U.S. (EIA, 2015b). The potential for utilization and storage of captured CO_2 via EOR in Ohio exists in depleted oilfields that contain as much as 80–90% of the original oil in place (OOIP) due to poor primary recovery (Sutton, 1965; Overby and Henniger, 1971; Riley et al., 2002; Riley et al., 2010; ODNR, 2013; Mishra et al., 2014) which occur alongside twenty-two major CO_2-emitting coal-fired power plants located in the state (Fig. 1). The objective of this study is to conduct a cost-

Abbreviations: AFE, Authorization for Expenditure; ARI, Advanced Resources International; BLS, US Bureau of Labor Statistics; CCS, carbon capture and storage; CCUS, carbon capture, utilization, and storage; CMU, Carnegie Mellon University; CO_2, carbon dioxide; CPI, Consumer Price Index; CURC, Coal Utilization Research Council; D&C, drilling and completion; DOE, Department of Energy; ECOF, East Canton Oilfield; EIA, Energy Information Administration; EOR, enhanced oil recovery; EPA, Environmental Protection Agency; EPRI, Electric Power Research Institute; ft, feet; G&A, general and administrative; HCPV, hydrocarbon pore volume; IEAGHG, International Energy Agency Greenhouse Gas Programme; kt, kilotonne; M, thousand; MCOF, morrow consolidated oilfield; mD, millidarcy; NETL, National Energy Technology Laboratory; NPV, net present value; O&M, operation and maintenance; OOIP, original oil in place; RMSE, root mean square error; scf, standard cubic foot; STB, stock tank barrel; t, tonne; U.S., United States; USD, U.S. dollars.

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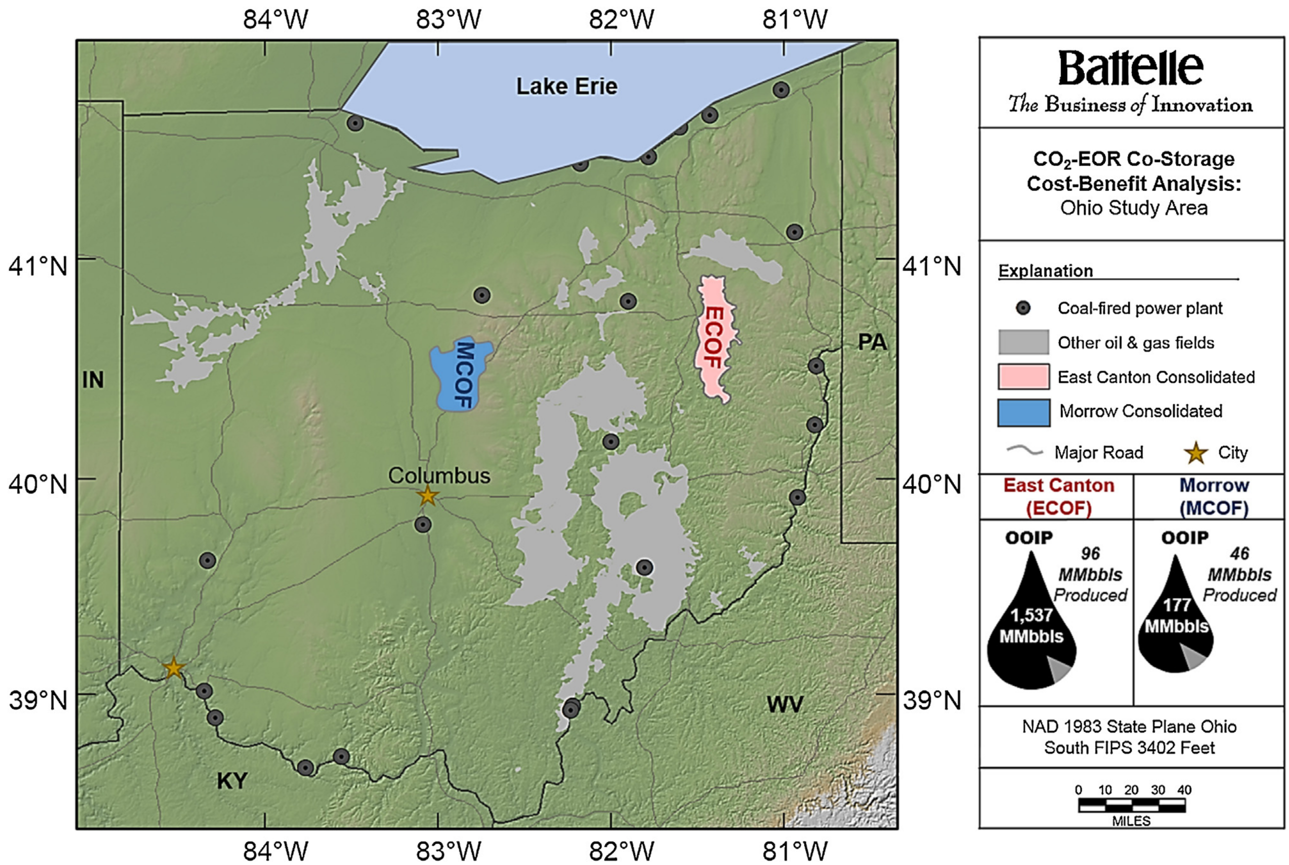

Fig. 1. Map showing the East Canton and Morrow consolidated oilfields in Ohio along with the locations of major CO_2-emitting coal-fired power plants (ODNR, 2013; EPA, 2014). Note: Other large oil fields are shown in gray.

benefit analysis to evaluate the economic feasibility of CO_2-EOR to act as a commercial driver for CCUS in the Appalachian Basin region.

The cost of CO_2 capture from power plants has been evaluated in several techno-economics studies on CCUS (e.g., David and Herzog, 2000; Rubin et al., 2007, 2015; IEAGHG, 2009; Rubin, 2012; Tola and Pettinau, 2014), with reported CO_2 capture costs ranging from \$28 to \$87 2013 U.S. dollars (USD) per tonne (t) for new coal-fueled power plants (supercritical pulverized coal and integrated gasification combined cycle) and a variety of capture systems (pre-, post-, and oxy combustion) (see Tables 2, 4–6 in Rubin et al., 2015). Fewer assessments have been conducted on the costs and economics of CO_2-EOR co-storage projects, with existing studies focused primarily on states in the southwestern U.S. such as Texas, Louisiana, and New Mexico (ARI, 2006; McCoy, 2009; McCoy and Rubin, 2009; King et al., 2013). A detailed economic analysis of CO_2 utilization and storage via EOR has not been published for Ohio.

This study integrates Ohio-specific reservoir and cost data with CO_2-EOR performance-cost models established in previous studies to evaluate the economic feasibility of CO_2-EOR in Ohio, and the resulting implications for CCUS deployment in the region. The cost-benefit analysis methodology is applied to the East Canton (ECOF) and Morrow Consolidated (MCOF) oil fields (Fig. 1) for various CO_2 and oil price scenarios to illustrate how key parameters of the analysis can be used to derive high-level estimates of CO_2-EOR project economics and profit potential in Ohio. These depleted oil fields represent two of the more attractive targets for CO_2-EOR in the state (Sutton, 1965; Riley et al., 2011; Mishra et al., 2014). An important outcome of this study is the correlation established through the CO_2 break-even analysis that can be used to determine the potential market value of captured CO_2 for EOR as a function of the prevailing oil price (McCoy, 2009; McCoy and Rubin, 2009). The cost-benefit analysis presented in this study can be used to help guide decision-making processes related to CCUS policy, investments, and marketing strategies in Ohio and neighboring states in the Appalachian Basin.

The paper is organized as follows: Section 2 of this paper begins with an overview of the cost-benefit analysis methodology, followed by detailed descriptions of the reservoir performance, revenue and cost models. Application of the methodology to the ECOF and MCOF is detailed in Sections 3 and 4 respectively, including reservoir performance and economic outcomes for various oil and CO_2 price scenarios. Section 5 examines the specific price points at which captured CO_2 can be economically purchased for EOR in the two fields, with implications for CCUS commercialization in the study region. The significance and utility of the correlation established in this study for CO_2 break-even price is discussed in concluding remarks.

2. Cost-benefit analysis methodology

2.1. Analysis framework

The framework employed in this cost-benefit analysis of CO_2-EOR co-storage in Ohio includes a reservoir performance model, a revenue model, and a cost model (Fig. 2). This analysis framework builds upon previous work by Advanced Resources International (ARI) and researchers at Carnegie Mellon University (CMU) in collaboration with the U.S. Department of Energy's National Energy Technology Laboratory (U.S. DOE-NETL) (ARI, 2006; McCoy and Rubin, 2006, 2009; McCoy, 2009; U.S. DOE-NETL, 2011,2014a). These previous studies are widely reviewed and accepted methods for estimating CO_2-EOR and storage costs (Jablonowski and

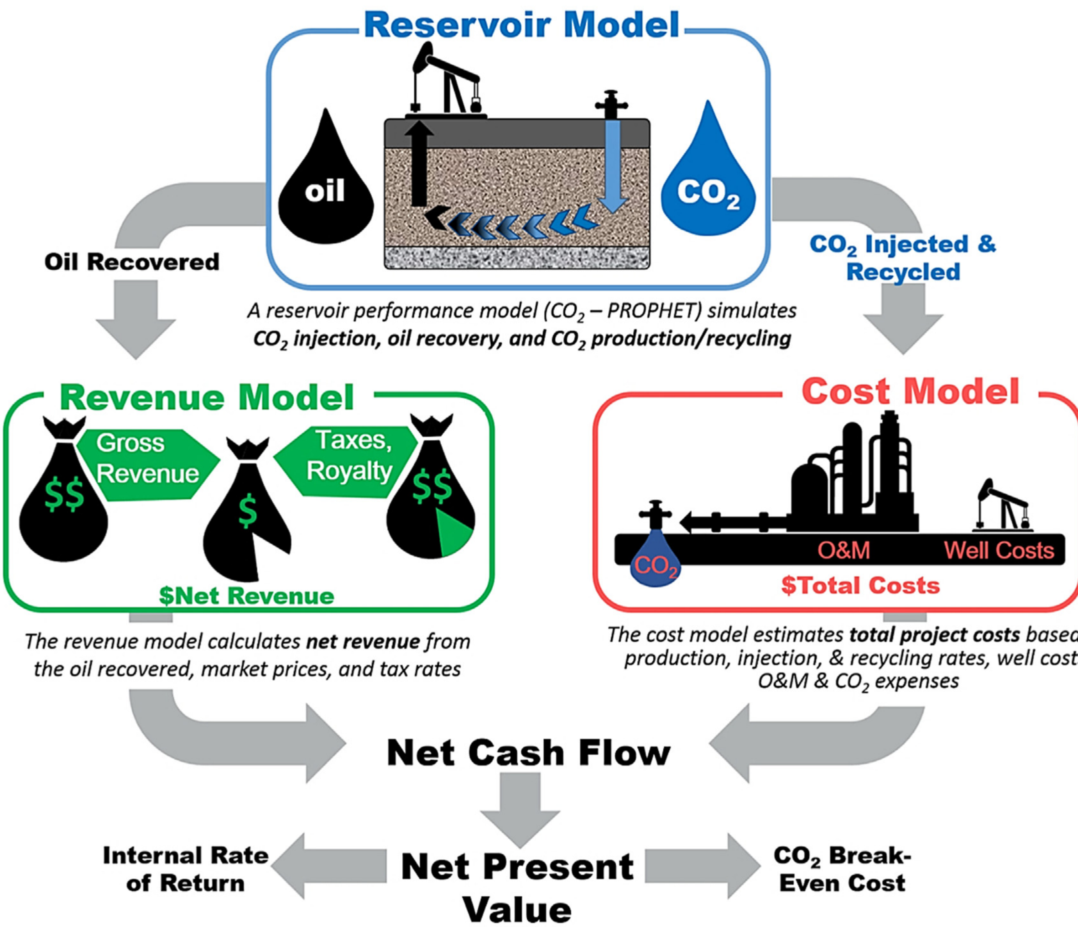

Fig. 2. Schematic of the cost-benefit analysis framework used in this work.

Singh, 2010; U.S. DOE-NETL, 2014a; Wei et al., 2015). Calculation schemes were selected from these existing studies and populated with Ohio-specific data to define the components of the reservoir performance, revenue, and cost models in this study.

CO_2-EOR performance results from the reservoir model are integrated into separate revenue and cost models that calculate net revenue and total project costs, respectively. The resulting net cash flow is then discounted to derive the net present value (NPV) of the project. The break-even price of CO_2 is calculated to representing the maximum price a CO_2-EOR operator could pay for CO_2 without incurring loss on the project, and is calculated as a function of oil price to help determine a viable market price for captured CO_2 based on the prevailing price of oil.

Due to the uncertainty in the regulatory landscape of CCUS the cost model does not consider the value of incentives and credits that could potentially be received for CO_2 storage, which could help offset costs. CO_2 storage is treated as a byproduct of EOR operations and is not directly associated with incurrence of project costs. As such, injection wells considered in this assessment can be categorized as Class II EOR wells, rather than Class VI under the U.S. EPA Underground Injection Control program (EPA, 2012). Similarly the costs of CO_2 site monitoring, verification, and accounting are cited as being a negligible part of total CO_2-EOR project costs, with estimates reported at \$0.04–0.09 USD per tonne of CO_2 stored (Benson et al., 2004; Jablonowski and Singh, 2010), and are not included in the analysis. Studies conducted on CO_2 transport costs indicate estimates can vary greatly due to dependence on factors that are difficult to systematically correlate with costs, such as transport terrain, existing land use, and sharing of pipeline networks (e.g., McCoy and Rubin, 2008; Rubin et al., 2013, 2015; IEAGHG, 2014; U.S. DOE-NETL, 2014b). The cost model employed in this study only considers transport costs associated with local CO_2-EOR site operations, and does not account for the costs associated with CO_2 capture and regional pipeline transport. The cost model assumes the CO_2 initially delivered to the site via trunkline will be of sufficient purity and pressure for miscible injection. The costs and revenue associated with recovery of natural gas and natural gas liquids were not included in the analysis.

2.2. Reservoir performance model

The oil recovery, and CO_2 injection, production, and recycling performance of the reservoir must be known in order to evaluate the potential of CO_2-EOR as a viable avenue (and economic incentive) for commercial-scale CCUS implementation. A simplified stream tube reservoir performance model (CO_2-PROPHET) was used to estimate incremental oil recovery from CO_2 injection for the ECOF and MCOF. CO_2-PROPHET is a predictive model for CO_2-EOR reservoir performance developed by Texaco (Dobitz and Prieditis, 1994) for the U.S. Department of Energy, and has been used as a screening tool in several techno-economic studies on CO_2-EOR (e.g., ARI, 2006; King et al., 2013; DiPietro et al., 2015). CO_2-PROPHET requires input to define the field/operational parameters, reservoir characteristics, and fluid properties for the CO_2-EOR simulation, as shown in Table 1.

Water, oil and gas are the three fluid components included in the model, with the terms "gas" and "solvent" used interchangeably with CO_2. Based on input provided by the user, the model generates

Table 1
Parameters and definitions of input required for CO_2-PROPHET CO_2-EOR simulation.

CO_2-Prophet Designation	Input Definition
Field/Operational Conditions	
PATTERNS	Well Pattern
NWELLS, NOINJ	No. of total wells, No. of injection wells
WELLX, WELLY, WELLQ	Well coordinates, flow rates
NTIMES	No. of injection periods
OUTTIM	Time increment for output (year)
SOLRAT	Surface injection rate of CO_2 (MMscf[a]/day)
HCPVI	Incremental hydrocarbon pore volumes of CO_2 injected
TMROVL	Fraction of injection which is water
Reservoir Characteristics	
AREA	Pattern area (ft^2)
TRES	Reservoir temperature (°F)
P	Initial reservoir pressure (psia)
MMP	Minimum miscibility pressure (psia)
DPCOEF	Dykstra-parsons coefficient in the producing zone
PERMAV	Average permeability in the producing zone (mD)
THICK	Net thickness of the producing zone (ft)
POROS	Porosity of the field (dec.)
SOINIT	Initial oil saturation (dec.)
SWINIT	Initial water saturation (dec.)
SGINIT	Initial gas saturation (dec.)
XKVH	Ratio of vertical to horizontal permeability
Fluid Properties	
VISO	Viscosity of oil, cP
VISW	Viscosity of water, cP
BO	Oil formation volume factor (rb/STB)
RS	Solution gas-oil ratio (scf/sSTB)
API	Oil gravity (°API)
SALN	Brine salinity, ppm TDS
GSG	Gas-specific gravity

[a] M represents one thousand.

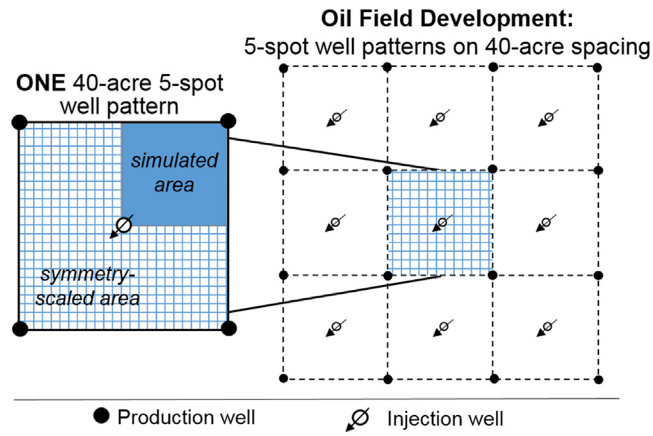

Fig. 3. Schematic showing 40-acre 5-spot well pattern spacing and the CO_2-EOR simulation method employed by CO_2-PROPHET.

Table 2
Inputs and definitions of parameters included in the revenue model.

Revenue Model Parameter	Input/Definition
Oil Produced (STB)	Volume of incremental or cumulative oil produced during reservoir performance simulations
Oil Price (USD/STB)	Market price of oil
Gross Revenue (USD)	Revenue from oil recovered and sold at the specified market price; *oil recovered (STB) × oil price ($/STB)*
Royalty (%)[a]	15% of gross revenue; *0.15 × gross revenue ($)*
Severance Tax (%)[a]	2.0% of revenue after royalty tax; *0.02 × (0.15 × gross revenue $)*
Ad Valorem Tax (%)[a]	1.5% of revenue after royalty tax; *0.015 × (0.15 × gross revenue $)*
Net Revenue (USD)	Revenue after deduction of royalty, severance, and ad valorem taxes; *Gross revenue ($) – Royalty ($) – Severance ($) – Ad Valorem ($)*

[a] See Section 2.3 text for explanation.

streamlines to simulate fluid flow between the injection and production wells, assuming no crossflow occurs between layers of the reservoir. OOIP is user-specified or calculated volumetrically based on pattern area, net thickness, porosity, and fluid saturation inputs. Oil displacement and recovery is then calculated along streamlines, with areal sweep efficiency incorporated within the well spacing coordinates, fluid mobility ratios, and reservoir heterogeneity inputs that define the streamline boundaries. The mixing parameters defined by Todd and Longstaff (1972) are used to simulate CO_2 miscibility. The effects of gravity on fluid segregation and mixing are not considered in the model.

CO_2-EOR performance results were simulated for one 40-acre 5-spot well pattern at a constant CO_2 injection rate until two hydrocarbon pore volumes (HCPV) of total CO_2 injection was achieved. An injection rate of 0.5 MMscf/day is consistent with injection rates observed in present-day CO_2-EOR field operations, and was chosen for both the ECOF and MCOF to facilitate comparisons between the two fields and with other studies that employ similar injection rates (Mortis, 2006; McCoy and Rubin, 2009). In CO_2-PROPHET the simulation is conducted over a quarter of the area in a 5-spot well pattern, and the results are scaled over the entire pattern following symmetry operations associated with well coordinate information (Fig. 3). Other simplifying assumptions of the simulation include delivery of supercritical CO_2 of suitable purity for injection and miscible flood conditions. The volume of CO_2 recycled and reused for injection was assumed to be equal to the volume of CO_2 produced. The difference between the volume of CO_2 injected and produced represents the volume of CO_2 permanently stored in the reservoir. The CO_2 stored via physical and/or chemical trapping in the reservoir (within and outside of the pattern simulation) becomes unavailable for subsequent injection, and is used to calculate the volume of new CO_2 required for purchase to maintain the specified injection rate. Oil recovery results were used in the revenue model to calculate net revenue for the project. Results of oil, water, and CO_2 production, along with CO_2 recycling rates were incorporated into the cost model to calculate costs of CO_2, capital, and operation and maintenance (O&M).

2.3. Revenue model

The revenue model calculates net revenue from oil recovered and sold at a specified oil price, with relevant tax deductions (Table 2). Royalties comprising 15% of the gross revenue were included in the calculation, derived from the average royalty percentage employed in the ARI and CMU models. A severance tax of 2.0% was chosen as a representative value based on the current Ohio severance tax on conventional crude oil production ($0.20/STB), and a 6.6% tax rate imposed in Michigan; the nearest state with large-scale CO_2-EOR (Michigan Department of Treasury, 2014; Weinstein et al., 2015). An Ad Valorem tax of 1.5% was derived from the average tax percentage levied on mineral properties in Ohio counties (Ohio Department of Taxation, 2014). Severance and Ad Valorem taxes were deducted from the remaining revenue after royalty taxes. The revenue model calculation scheme produces a time series of incoming net cash flows in which the resulting net revenue of the project can be evaluated incrementally during specific periods of operation, and cumulatively at the end of the project life.

2.4. Cost model

The cost model calculated total costs for the CO_2-EOR project, and can be broken into three main categories: well costs, CO_2 costs, and O&M costs. Well costs account for equipment, services, labor and site-related capital costs associated with well drilling and completion (D&C), new production and injection well equipment, and existing well conversion. CO_2 costs include the capital and operational costs associated with CO_2 purchase for injection, trunkline transport and on-site distribution, and CO_2 recycling. Capital costs in the cost model are accrued at of the beginning of the project. Total O&M costs account for consumables, services, and labor associated with ongoing site operation and maintenance (surface and subsurface), liquid lifting/handling, and general and administrative (G&A) expenses. A comprehensive table of definitions and list of expense items associated with each cost model parameter is provided in Appendix A (Table A1).

Cost data were acquired for Ohio wells to derive calculation schemes for estimating well costs in the cost model (see Table 3 for details). Equations established by the previous studies described in Section 2.1 were used to calculate costs of parameters for which Ohio data was insufficient or unavailable. All cost data was adjusted to represent constant 2014 U.S. dollars (USD) using the Bureau of Labor Statistics (BLS) Consumer Price Index (CPI) (BLS, 2015). It is noted that relative to the inflation-based, constant-dollar analysis employed in this paper using the BLS-CPI, other industry-specific indices may be better suited for tracking the escalation of costs in the oil and gas sector, such as the IHS Upstream Capital Cost Index (UCCI). While the BLS-CPI-based inflation adjustment may be appropriate for a methodological study such as this one, we recommend that any field-specific, cost-benefit analysis take into account historical trends in upstream capital costs for that geographic region vis-à-vis oil price fluctuations in its cost model. Additionally, costs (capital and operational) associated with the oilfield industry can be very volatile due to many factors that are difficult to constrain, such as market and field conditions. The calculation schemes used in this study represent correlations derived from the best available data, and are inherently subject to the price volatility of the industry. The equations for each cost parameter and the associated data sources are defined in Table 3.

Well cost calculations for the ECOF and MCOF example cases considered new well drilling, completion and equipment costs for a quarter of an injection well and a quarter of a production well in the 5-spot patterns in each field. This balances the fixed capital costs of the CO_2 recycling facility to one pattern to allow for scaling of results in accordance to phased field development scenarios (see Section 2.5.1). There are no costs incurred for existing well conversions in the two examples. In practice, some existing wells would likely be converted/reworked to satisfy pattern requirements, resulting in lower total well costs relative to the higher costs associated with drilling and completing all new wells. The trunkline distance for transport of CO_2 from the regional pipeline to the EOR site was assumed to be 10 miles.

2.4.1. Well costs

Well costs are capital costs of well design and installation incurred during the initial stages of the EOR project. Well costs can be subdivided into new well D&C costs, production and injection well equipment costs, and well conversion costs. D&C costs are defined as the tangible and intangible costs of on-site drilling and completion phases for new production and injection wells, including leasehold, rig, cementing, casing, site reclamation and plugging costs. Production and injection well equipment costs include purchase and installation of items such as tubing, rods, storage tanks, electrical services, pumps, separators, and wellheads. Well conversion costs are defined as the tangible and intangible costs of updating or converting existing wells to establish the number of suitable injection and production wells required for the well pattern/project, such as stimulation treatment, pressure tested lines, and fabrication materials and services. A more comprehensive list of items associated with each well cost category in the cost model is provided in Appendix A (Table A1).

Ohio data from itemized cost reports and Authorization for Expenditures (AFEs) were supplemented by informal expert elicitation to estimate well costs in the cost model. Inputs were provided by six operators for twenty-six wells drilled and operated in Ohio between 2005 and 2015 at depths of 1308–9200 ft. Well type, configuration, depth, and associated costs for each well are included in Appendix A (Table A2). The 2014 adjusted well cost data was plotted as a function of depth to derive Ohio-specific regressions for cost model calculations. D&C costs and associated depths reported for Ohio wells exhibit an exponential regression trend (Fig. 4), represented by Equation (1) in Table 3. The higher costs of the two injection wells shown in Fig. 4 represent costs of brine injection wells in Ohio, and relative to production wells, have slightly higher D&C costs associated with factors such as larger well diameters, and higher completion costs. The cost data from these two brine injection wells may therefore not be representative of CO_2-EOR injection well costs and other practitioners are strongly encouraged to use their own regional well data to develop more reliable cost regressions. The regression[1] derived from production well equipment costs plotted against depth takes on a linear form as shown in Fig. 5. The cost data received for injection well equipment and well conversion was insufficient to develop robust regressions. The regression Equation (3) from the ARI (2006) cost model was used to calculate injection well equipment costs (e.g., Table 3). The Equation (4) developed by McCoy and Rubin (2009) was incorporated into the cost model to estimate the costs of well conversion.

2.4.2. CO_2 costs: purchase, transport, & recycling

CO_2 costs include the fixed and variable costs associated with CO_2 purchase, transport from the regional pipeline to on-site distribution, recycling, processing, and recompression. CO_2 transport and on-site distribution costs were estimated based on a cost per distance of trunkline for transport of the CO_2 from the regional pipeline to the site, the trunkline diameter required to facilitate the maximum CO_2 injection rate, and all flow lines and manifolds required for on-site distribution of CO_2 (Table 3, Equation (5)). The maximum CO_2 recycling rate derived from the CO_2-PROPHET simulation in standard cubic feet (scf; 60 °F, 1 atm) per day was used to estimate the capital costs of the CO_2 recycling facility (Equation (6)). CO_2 recycling including on-site separation, processing, and compression as shown in Fig. 6, with ongoing O&M costs determined by the volume of CO_2 recycled (scf) per time series set at 1% of the price of oil per barrel (STB) to reflect the cost of on-site generation of the energy required for operation (Equation (7)).

2.4.3. Total O&M costs

Total O&M costs for the site include periodic O&M costs, liquid lifting costs, and G&A expenses. Periodic O&M costs reflect ongoing expenses associated with operation and maintenance of the

[1] A root mean square error of ±\$16,281 is associated with the production well equipment cost regression (Equation (2)), and can be used an as error estimate in cost calculations to account for the relatively low coefficient of determination (R^2) of the regression.

Table 3
Cost model parameters, equations, and associated references.

Cost Model Parameter	Equations[a]	Study Referenced
Well Costs		
Drilling & Completion (D&C)	$\$65,703e^{(0.0004 \times \text{depthft})}$ (1)	Ohio cost data (this study)
Production Well Equipment (EQ_p)	$\$10.12 \times \text{depthft}) + \$20,210$ (2)	Ohio cost data (this study)
Injection Well Equipment (EQ_i)	$\$18.33 \times \text{depthft}) + \$11,626$ (3)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)
Well Conversion	$0.48 \times \$D\&C) + (0.50 \times \$EQ_{p,i}$ (4)	McCoy (2009), McCoy and Rubin (2009)
CO_2 Costs		
CO_2 Transport & Distribution	$\$187,985 + (\text{mi} \times \text{USD/mi}$ (5)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)
CO_2 Recycling Plant	$\$877,264 \times \text{Max.}CO_2\text{recyclingrateMMscf/day}$ (6)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)
CO_2 Recycling O&M	$0.01 \times \text{USD/STBoil}) \times CO_2\text{recycledMMscf}$ (7)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)
Total O&M Costs		
Periodic O&M	$\$33,684e^{(0.0001 \times \text{depthft})} \times \text{no.ofwells}$ (8)	McCoy (2009), McCoy and Rubin (2009)
Liquid Lifting Costs	$\$0.25 \times (\text{producedBBLswater} + \text{oil}$ (9)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)
General & Administrative (G&A)	$.20 \times (\$O\&M + \$\text{LiquidLifting}$ (10)	ARI (2006), U.S. DOE-NETL (2011, 2014a,b)

[a] Values reported in constant 2014 USD.

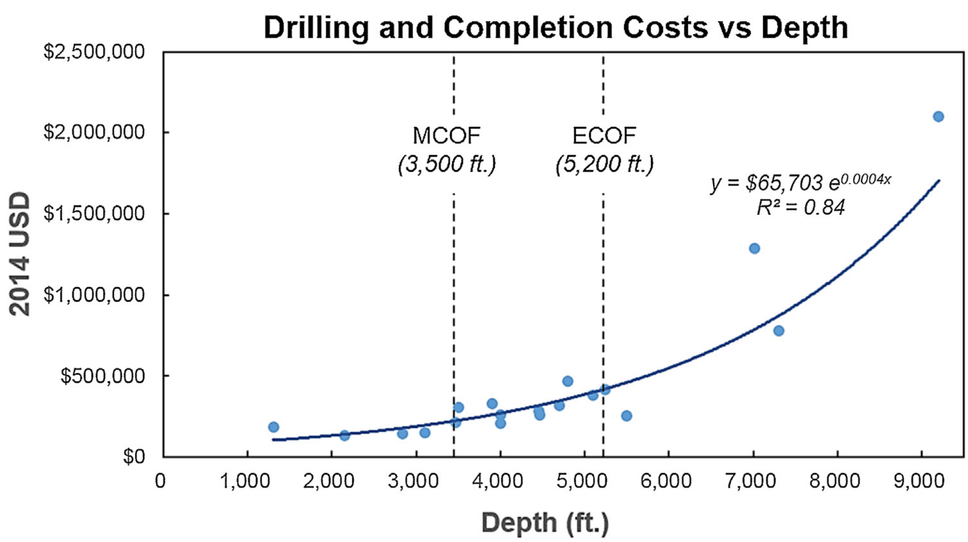

Fig. 4. Drilling and completion well cost regression derived from Ohio well data and used in cost model calculation scheme. Note: depths of the producing formations from the MCOF and ECOF are also indicated by the dashed lines on the plot.

CO_2-EOR site at the required capacity over a given time period, including electricity, consumables, periodic well work over, surface and subsurface repairs (Equation (8)). Periodic O&M costs are also dependent on the number and depth of wells used in the project. Liquid lifting costs are estimated as $0.25 per volume of oil and water produced (Equation (9)). G&A costs are calculated as 20% of the sum of periodic O&M and liquid lifting costs (Equation (10)).

2.5. Analysis scenarios and evaluation metrics

2.5.1. Price scenarios

For the purposes of this analysis, cost model results are reported on a per pattern basis, and can be scaled in accordance with any field development schedule of interest. It should be noted that certain cost components will not scale linearly with pattern development, such as CO_2 recycling facility costs, and capital well costs. For example, in a phased development scenario, the recycling facility will be constructed for a maximum injection capacity determined by aggregation of flows from multiple patterns. If pre-existing wells are expected to be used to meet well requirements for a certain percentage of patterns, the capital costs of well conversion should be included in place of new well drilling and completion costs.

Several market scenarios were examined for the cost-benefit analysis of potential CO_2-EOR co-storage projects in the ECOF and MCOF: oil prices of $40, $70, and $100 per barrel were each evaluated at CO_2 prices of $40, $80, and $120/t. $70/STB oil and $80/t CO_2 was defined as the median price scenario, bound by the lowest ($40/STB oil and $120/t CO_2) and highest ($100/STB oil and $40/t CO_2) NPV calculated in the analysis. The CO_2 prices analyzed in this study are slightly higher (~40% markup) than CO_2 capture costs reported in Rubin et al. (2015) for new coal-fired power plants ($28–$87/t CO_2 in 2013 USD).

The effect of discount rate on CO_2-EOR project economics was also evaluated at the median price scenario analyzed. The discount rate represents the percentage difference between the present and future value of an expected cash flow, accounting for the time-dependent value of money and risk associated with a future investment. Discount rates of 10%, 15%, and 20% were examined for

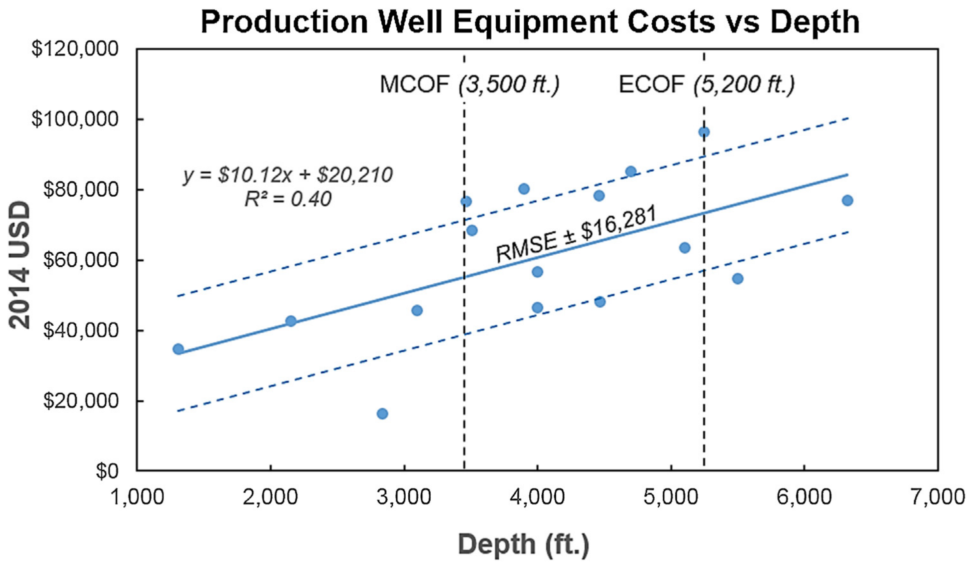

Fig. 5. Production well equipment cost regression derived from Ohio well data and used in cost model calculation scheme. Depths of the producing formations from the MCOF and ECOF are also indicated by the dashed lines on the plot. A root mean square error (RMSE) of ±$16,281 associated with the relatively low R-squared value can be used an as error estimate.

Table 4
Key reservoir performance model parameters for the ECOF.

Parameter	ECOF Input
Reservoir	Clinton sandstone
Pattern	5 spot
Production History	Primary
Injection Rate	0.5 MMscf/day (26 t/day)
HCPV CO_2	2
Field Area	175,000 acres (708 km^2)
Reservoir Temperature	107 °F (314.8 K)
Initial Reservoir Pressure	1450 psia (10 MPa)
Reservoir Depth	5200 ft (1585 m)
Minimum Miscibility Pressure (MMP)	1450 psia (10 MPa)
Dykstra-Parsons Coefficient	0.70
Permeability	5.2 mD
Net Thickness	20 ft (6 m)
Porosity	0.06
OOIP	1537 MMSTB
Initial Oil Saturation	0.40
Initial Water Saturation	0.40
Initial Gas Saturation	0.20
Vertical:Horizontal Permeability	0.10
Viscosity of Oil	1.00 cP
Viscosity of Water	0.68 cP
Formation Volume Factor, B_o	1.21 rb/stb
Solution Gas:Oil Ratio, R_s	443 scf/stb
Oil API Gravity	41°

the price scenario of $70/STB oil and $80/t CO_2, and are within the range of discount rates used in the ARI and CMU studies. A discount rate of 15% was used for all other calculations as a representative, median discount factor. These different analysis scenarios are intended to represent relevant market conditions that may influence CO_2-EOR project economics in Ohio, based on historical and of current interest rates in the U.S. (e.g., Federal Reserve).

2.5.2. Net present value

The value of future cash flows accrued incrementally and cumulatively over the duration of the CO_2-EOR project is represented by the NPV. The NPV is calculated as the sum of cash inflows and outflows, discounted to account for the time value of money and the risk/uncertainty associated with future cash flows. The net revenues (incoming cash flows) from the revenue model were integrated with total costs (outgoing cash flows) calculated by the cost model to derive a time series (years) of NPV estimates. The cumulative NPV calculated at the end of the operation was then used to evaluate the profitability of the CO_2-EOR operation, such that positive values represent scenarios of profit and negative values represent financial losses incurred by investor(s) in the project.

2.5.3. CO_2 break-even price

The break-even price of CO_2 is the CO_2 purchase price that results in a NPV to equal to zero, and can be interpreted as the maximum price an EOR operator could pay for CO_2 without incurring loss on the project (McCoy, 2009; McCoy and Rubin, 2009). The break-even price of CO_2 was calculated as a function of various oil prices ($40–100/STB) to define the specific price conditions at which CO_2 becomes a viable purchase for EOR, and a marketable asset for capture facilities. The overall trend observed in the CO_2 break-even price[2] calculated over the range of oil prices was used to derive the unit value of CO_2 relative to oil for the oil field of interest. We note the possibility that our capital cost assumptions using an inflation-based constant dollar scenario may not fully reflect any downward adjustments in capital costs due to drop in oil prices. The net effect is that breakeven costs calculated using our model can be expected to be an upper bound. However, since upstream capital cost reductions are generally muted compared to changes in oil price, the degree of conservatism reflected in our calculations should be moderate.

3. Application of methodology to the ECOF

3.1. Reservoir description

The ECOF is an oil field located in northeast Ohio that produces from the Silurian “Clinton” sandstone. Active drilling begin in the 1960′s, with 96 MMSTB of oil produced to-date from the estimated 1537 MMSTB of OOIP. Approximately 3100 wells have been drilled in the field, following a 40 acre pattern spacing (Perry and Riley, 2011). The Clinton sandstone occurs at an average depth of 5200 ft

[2] It should be noted that CO_2-EOR requires higher upfront capital and operational investments, such that the break-even price represents a different timeline compared to primary oil production.

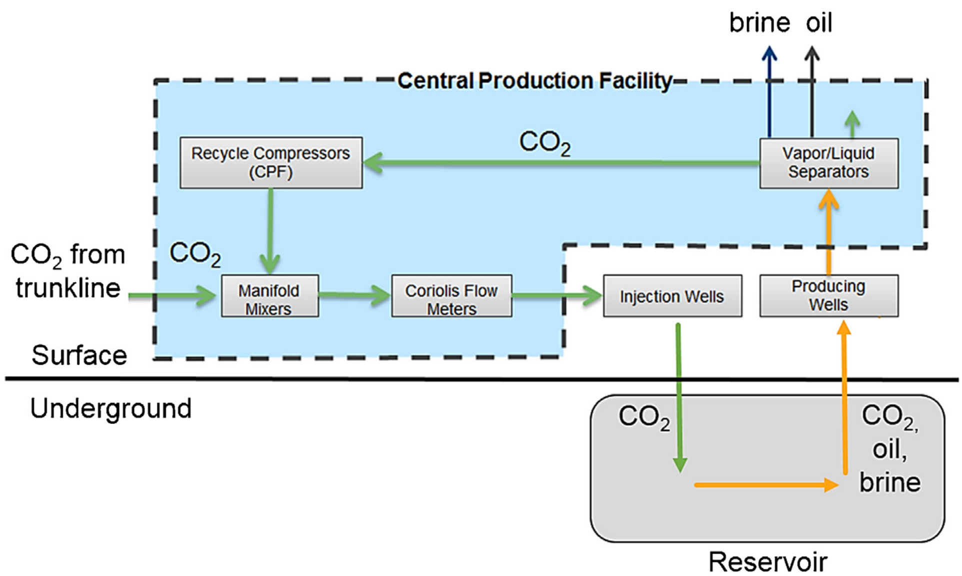

Fig. 6. Simplified diagram showing components of CO_2 injection and recycling operations.

Table 5
CO_2-PROPHET results of the CO_2-EOR simulation for the ECOF.

Time (years)	1	2	3	4	5	6	Cumulative
Oil Produced (MSTB)	24	10	7	6	4	4	56
H_2O Produced (MSTB)	14	4	3	2	2	2	27
CO_2 Injected (MMscf)	183	183	183	183	183	172	1085
CO_2 Produced/Recycled (MMscf)	106	153	162	166	170	162	918
CO_2 Stored (MMscf)	77	30	21	16	13	10	167

Table 6
Field and operational input for the ECOF and per pattern capital cost calculations from the cost model.

Field/Operational Parameters	Input
Field	ECOF
State	OH
Formation	Clinton
# of patterns	1
Depth (ft)	5200
Distance of trunkline (mi)	10
Cost of trunkline $/mi	$33,475
On-site distribution lines	$187,985
Max. CO_2 recycling rate (MMscf/day)	0.47
Max. CO_2 injection rate (MMscf/day)	0.50
New injector wells	0.25
New producer wells	0.25
Total wells required	0.5
Cost Model Calculations—Capital Costs in Millions of 2014 US Dollars (USD)[a]	
New well D&C	$ 0.26
Production Well Equipment	$ 0.02
Injection Well Equipment	$ 0.03
CO_2 Recycling Plant	$ 0.41
CO_2 Transport & On-Site Distribution	$ 0.22
Total Capital Costs	$ 0.94

[a] Capital costs represent one 40-acre 5-spot well pattern.

in the ECOF, with the productive zone comprising approximately 175,000 acres. On average, the reservoir exhibits a net thickness of 20 ft, matrix porosity of 6%, and permeability of 5.2 millidarcies (mD). Secondary and enhanced recovery in the ECOF has been limited to small-scale water flood tests. Average reservoir, field, and fluid characteristics for the Clinton sandstone are included in Table 4.

3.2. Reservoir performance results

CO_2-PROPHET results of oil production, water production, CO_2 production/recycling, and CO_2 injection, were simulated for one 40-acre 5-spot well pattern in the ECOF, assuming a ready supply of CO_2 available to maintain an injection rate of 0.5 MMscf/day (26 t CO_2/day). Incremental and cumulative results of the CO_2-PROPHET simulation are shown in Figs. 7 and 8, respectively for 2 HCPV of total CO_2 injection. The maximum CO_2 production/recycling rate simulated in the ECOF is 0.47 MMscf/day (25 t CO_2/day). A total of 56 thousand (M) barrels (STB) of oil production and a cumulative volume of 1085 MMscf of CO_2 injection (57,505 t), is predicted over a pattern life of ~6 years (Table 5). Of the cumulative volume of CO_2 injected, 918 MMscf (48,654 t) was produced, and 167 MMscf (8851 t) was purchased and permanently stored in the formation, corresponding to net and gross CO_2 utilization factors of 3 Mscf (0.16 t) and 19 Mscf CO_2 (1 t) per barrel of oil, respectively.

3.3. Revenue & cost model results

Well costs calculated for the ECOF pattern total to $0.31 million for a reservoir depth of 5200 ft. Costs of the CO_2 recycling facility, trunkline, and on-site distribution equipment were estimated at $0.63 million, with total capital costs for the ECOF totaling to $0.94 million. The capital cost estimates and associated cost model input for the ECOF pattern are shown in Table 6.

3.3.1. $120/t CO_2 scenario

The NPV accumulated at the end of the CO_2-EOR project in the ECOF was assessed for a CO_2 price scenario of $120/t at oil prices of $40/STB, $70/STB, and $100/STB and, all other parameters held constant (Fig. 9). At $120/t CO_2 and an oil price of $40/STB, a potential CO_2-EOR project in the ECOF would not break-even; generating

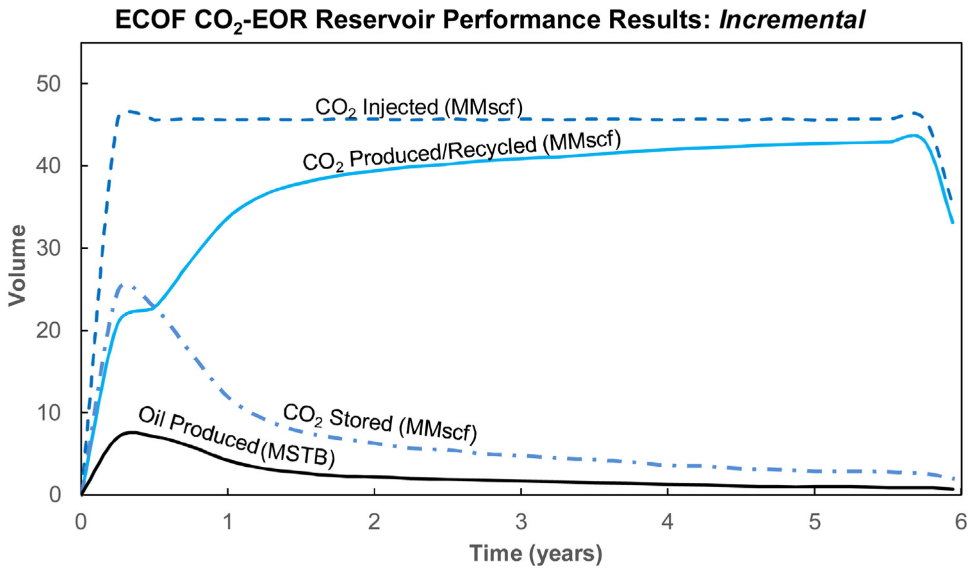

Fig. 7. Incremental CO_2-EOR reservoir performance in the ECOF pattern shown in volumes per quarter year for 2 HCPV of total CO_2 injection and a constant injection rate.

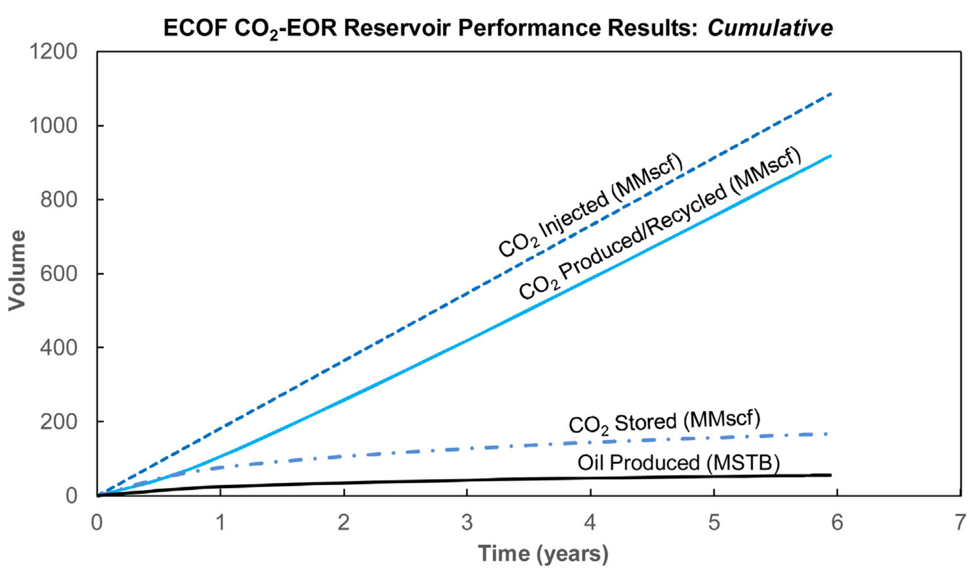

Fig. 8. Cumulative CO_2-EOR reservoir performance in the ECOF at 2 HCPV of total CO_2 injection and a constant injection rate.

$1.82 million in net revenue from the 56 MSTB of oil recovered, and $2.60 million in total costs at the end of the ~6 year pattern life (NPV of −$0.75 M). At an oil price of $70/STB, the net revenue at the end of the pattern life is estimated to be $3.18 million, with total costs of $2.87 million. The CO_2-EOR project breaks-even during year two and begins to accrue profit totaling to a NPV of $0.13 million. An oil price of $100/STB results in a net revenue of $4.54 million and total costs of $3.14 million. The project begins to accrue profit at this price scenario during year 0.75, with an estimated NPV of $1.02 million.

3.3.2. $80/t CO_2 scenario

The cumulative NPV of a potential ECOF CO_2-EOR project was calculated for oil prices of $40/STB, $70/STB, and $100/STB, a discount rate of 15%, and a CO_2 price of $80/t (Fig. 10). The project does not break-even at an oil price of $40/STB, with pattern costs of $2.25 million resulting in a NPV of −$0.48 million. At an oil price of $70/STB the project is estimated to break-even shortly after one year, ending with a net revenue of $3.18 million, total costs of $2.52 million, and a NPV of $0.41 million (Table 7). At an oil price of $100/STB the CO_2-EOR project breaks even after six months of operation, accruing a NPV of $1.29 million.

3.3.3. $40/t CO_2 scenario

The resulting NPV of the CO_2-EOR operation in the ECOF pattern is shown in Fig. 11 for oil prices of $40/STB, $70/STB, and $100/STB and a low CO_2 price scenario of $40/t. An oil price of $40/STB incurs total costs of $1.90 million, and does not break-even during the life of the project. A price scenario of $70/STB oil results in a net revenue of $3.18 million and total cost of $2.17 million, breaking even during the first year to accrue a NPV of $0.70 million. At an oil price of $100/STB the CO_2-EOR project in the ECOF breaks-even after six months of operation, accruing a NPV of $1.56 million.

3.3.4. Median price scenario: $80/t CO_2, & $70/STB oil

The effect of discount rate on CO_2-EOR project economics was also evaluated for the ECOF at the median price scenario analyzed. Market prices of $80/t CO_2 and $70/STB oil result in a net revenue

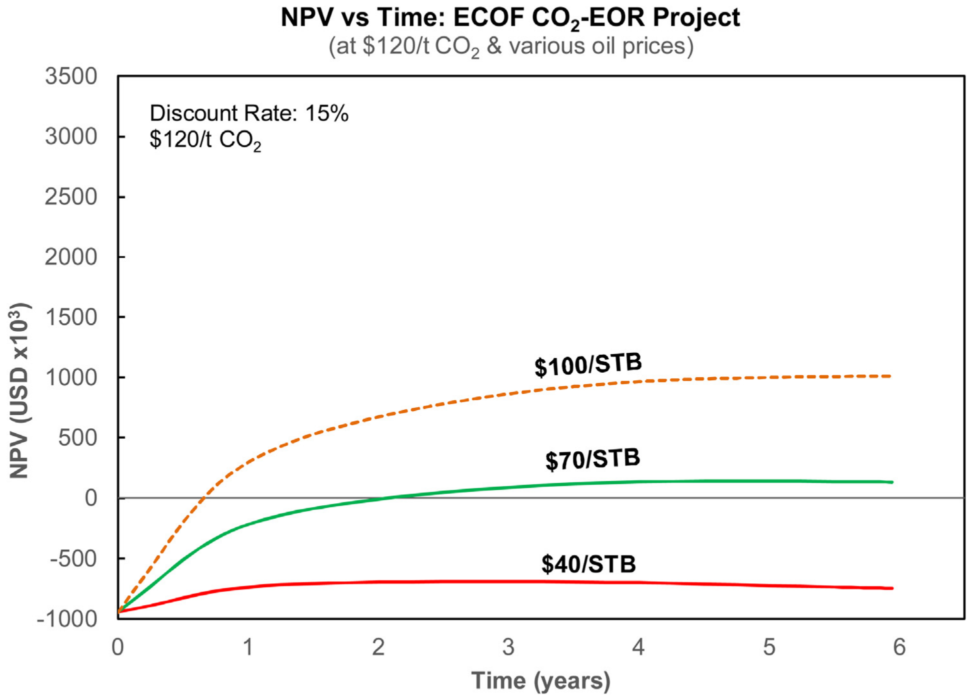

Fig. 9. NPV curves for a CO_2-EOR operation in the ECOF at $40, $70, and $100 per barrel of oil and a CO_2 price of $120/t.

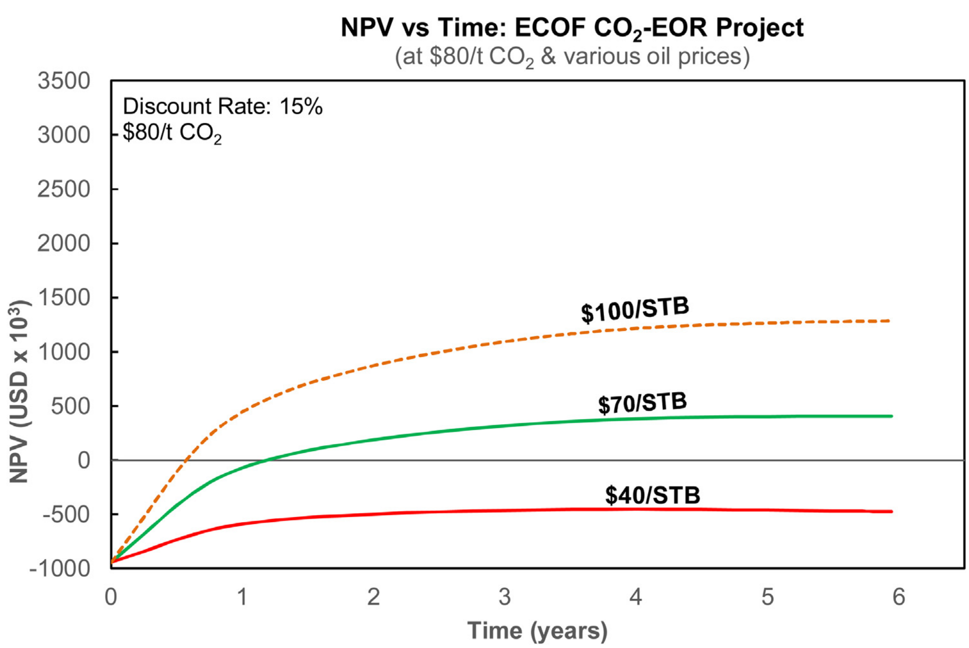

Fig. 10. NPV curves for a CO_2-EOR operation in the ECOF at $40, $70, and $100 per barrel of oil and a CO_2 price of $80/t.

of $3.18 million and total costs of $2.52 million. At a discount rate of 15%, this results in a NPV of $0.41 million at the end of the 6-year operation. The NPV curves for the median price scenario at this reference discount rate and those at 10%, and 20% are shown in Fig. 12. The time at which the NPV equals zero and the project breaks even increases slightly (∼1.5 months) as discount rates increase from 10% to 20%.

3.3.5. CO_2 break-even price vs. oil price

The break-even price of CO_2 is the price of CO_2 that results in a NPV equal to zero at the end of the project, all other parameters held constant. As such, a CO_2 purchase price greater than the calculated break-even price will result in a financial loss on the CO_2-EOR project, whereas a CO_2 price lower than the break-even price will result in financial gains. The break-even CO_2 price was calculated as a function of oil prices between $20/STB and $150/STB (Fig. 13). At a discount rate of 15%, the break-even price was found to be $10/t at an oil price of ∼$40/STB. At a higher oil price of $100/STB, the calculated CO_2 break-even price suggests that an EOR operator would be willing to pay up to $269/t for CO_2. The slope of the line (in USD/t/STB) shown in Fig. 13 defines the relationship between oil price and economic viability of captured CO_2 for EOR in the ECOF pattern, indicating that for every $1 dollar

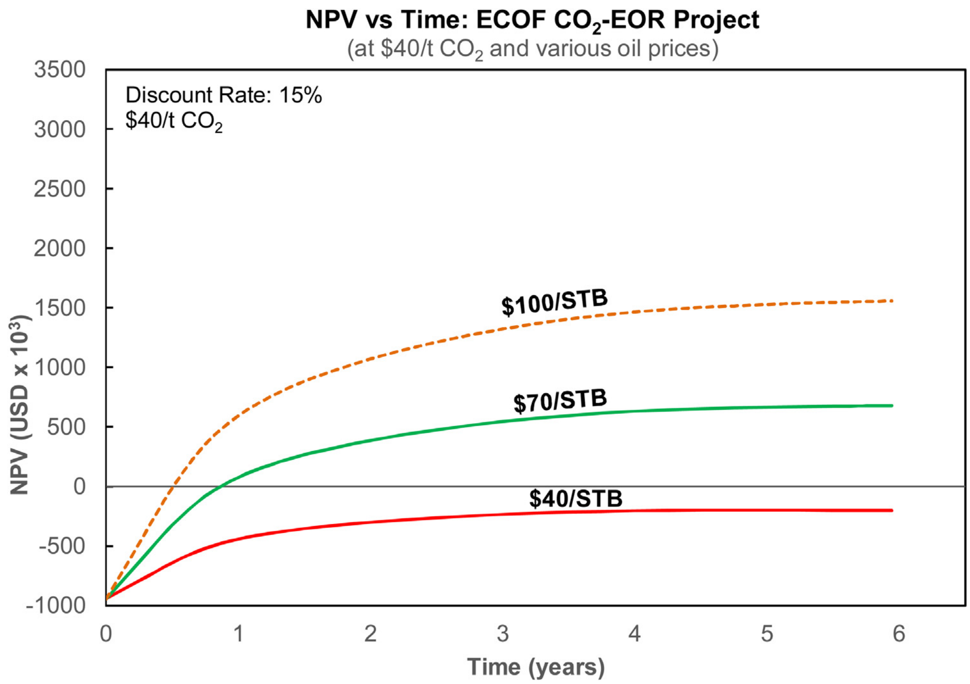

Fig. 11. NPV curves for A CO_2-EOR operation in the ECOF at \$40/STB, \$70/STB, and \$100/STB and a CO_2 price of \$40/t.

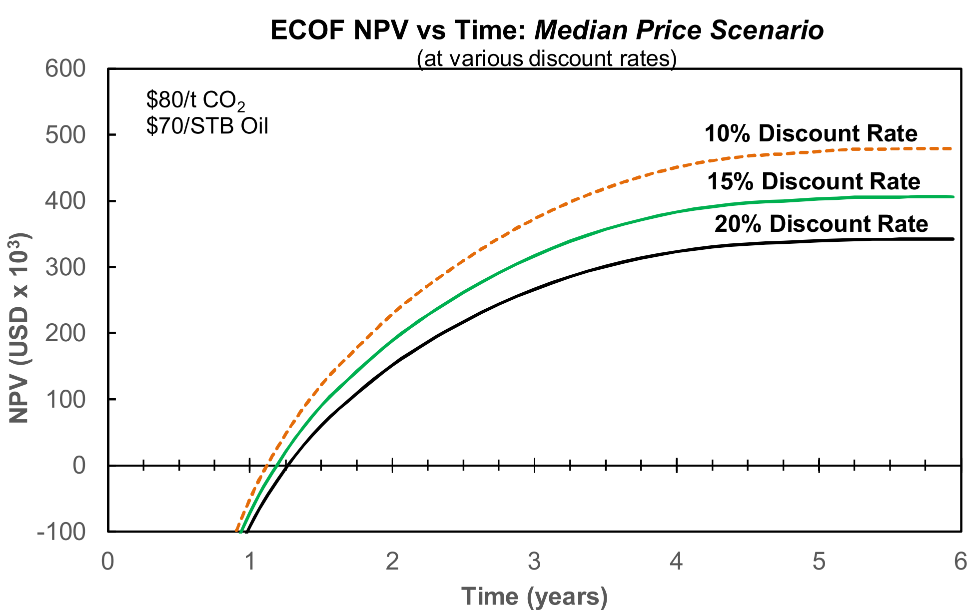

Fig. 12. Graph of the NPV curves for the median price scenario of \$80/t CO_2 and \$70/STB oil at discount rates of 10%, 15%, and 20% for the ECOF.

increase in the market price of oil per barrel, the value of one tonne of CO_2 increases by \$4.31.

4. Application of methodology to the MCOF

4.1. Reservoir description

The MCOF is one of the most prolific oil fields in Ohio, located in the north-central part of the state. Since discovery of the MCOF in 1959, 46 MMSTB of oil produced have been produced out of estimated 177 MMSTB of OOIP (McDowell, 2005). Production has occurred primarily from the Copper Ridge Dolomite, with approximately 1000 wells drilled at an average depth of 3500 ft and 10–40 acre spacing (Baranoski and McDonald, 1995; Riley et al., 2010). The productive zone occurs within erosional remnants of the Upper Copper Ridge that comprise a total of 16,000 acres in the MCOF and have an average thickness of 34 ft. The reservoir exhibits an average porosity of 7% and an average permeability of 18 mD. Secondary water flooding and air injections were attempted in the MCOF Copper Ridge Dolomite during the 1960s, but resulted in little to no success due to poor well management and pattern design (Riley et al., 2010). Reservoir, field, and fluid characteristics of the MCOF Copper Ridge Dolomite are included in Table 8.

4.2. Reservoir performance results

At a constant injection rate of 0.5 MMscf/day (26 t CO_2/day), cumulative production of 112 MSTB oil, and injection of 2326

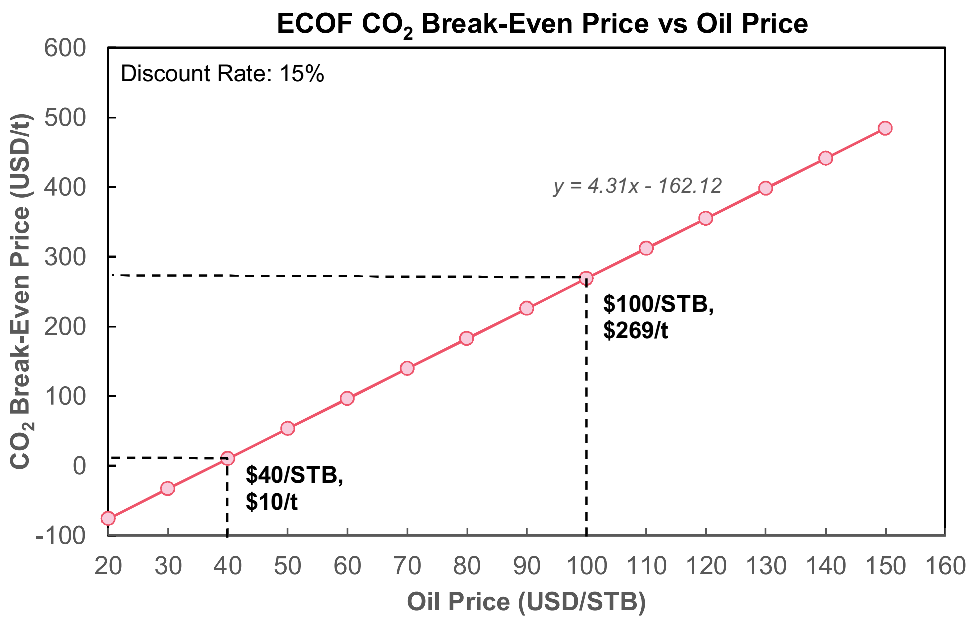

Fig. 13. Plot of the CO_2 break-even price calculated as a function of the price of oil for the CO_2-EOR operation modeled for the ECOF pattern.

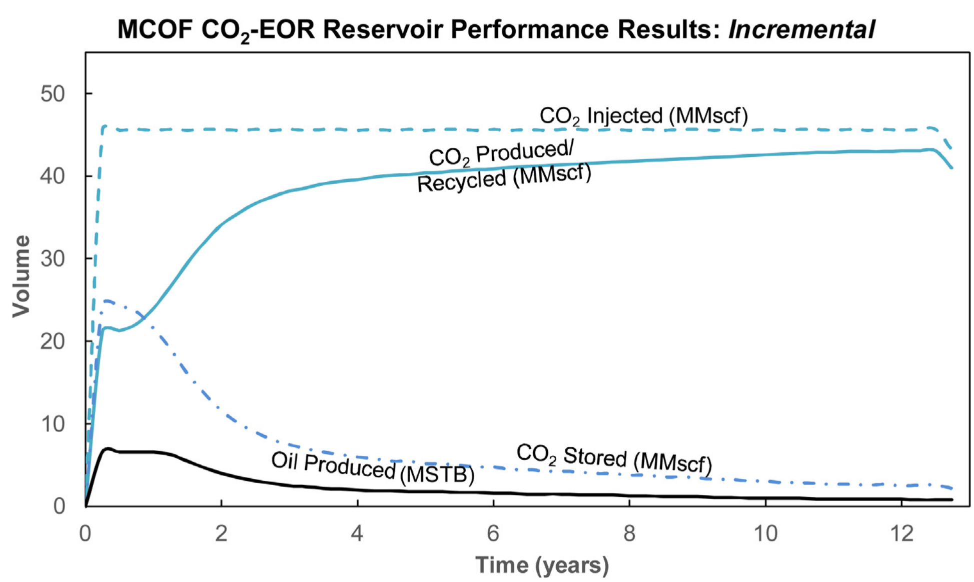

Fig. 14. Incremental CO_2-EOR reservoir performance in the MCOF pattern shown in volumes per quarter year at 2 HCPV of total CO_2 injection and a constant injection rate.

Table 7
Break down of ECOF EOR pattern costs for a price scenario of $70/STB oil and $80/t CO_2.

Cost Item	Cost (Million USD)
New well D&C	0.26
Production well equipment	0.02
Injection well equipment	0.03
Total Well Costs ($M)	*0.31*
CO_2 purchase cost	0.70
CO_2 recycling facility	0.41
CO_2 recycle O&M	0.64
CO_2 trunkline & on-site distribution	0.22
Total CO_2 Costs ($M)	*1.97*
Periodic O&M	0.18
Liquid lifting	0.02
G&A	0.04
Total O&M ($M)	*0.24*
Total Costs ($M)	*2.52*

MMscf of CO_2 (122,348 t) was simulated over a 13 year lifespan for the 40-acre 5-spot well pattern in the MCOF. Similar to the ECOF, the maximum CO_2 production/recycling rate in the MCOF is 0.47 MMscf/day (24 t/day). Incremental and cumulative results of the CO_2-PROPHET simulation are show in Figs. 14 and 15, respectively, for 2 HCPV of cumulative CO_2 injection. Of the cumulative volume of CO_2 injected, 1979 MMscf (104,095 t) was produced and 347 MMscf (18,252 t) was permanently stored in the formation. This corresponds to a gross CO_2 utilization factor of 21 Mscf/STB (1.1 t/STB) and net CO_2 utilization of 3 Mscf/STB (0.16 t/STB). Table 9 lists results of the CO_2-EOR simulation for the MCOF.

4.3. Revenue & cost model results

Well costs for the MCOF pattern were calculated at $0.16 million for a depth of 3500 ft in the Copper Ridge Dolomite. Using the CO_2 injection rate of 0.5 MMscf/day, the estimated costs of the CO_2

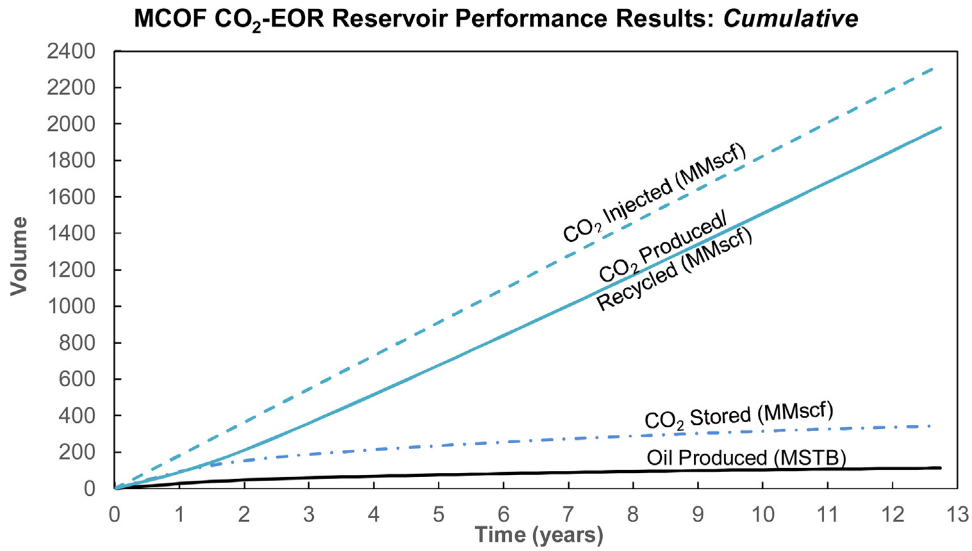

Fig. 15. Cumulative CO_2-EOR reservoir performance in the MCOF at 2 HCPV of total CO_2 injection and a constant injection rate.

Table 8
Key reservoir performance model parameters for the MCOF.

Parameter	MCOF Input
Reservoir	Copper Ridge Dolomite
Pattern	5 spot
Production History	Secondary
Injection Rate	0.5 MMscf/day (26 t/day)
HCPV CO_2	2
Field Area	16,000 acres (64.7 km^2)
Reservoir Temperature	87 °F (303.7 K)
Initial Reservoir Pressure	1087 psia (7.5 MPa)
Reservoir Depth	3500 ft (1067 m)
Minimum Miscibility Pressure (MMP)	1087 psia (7.5 MPa)
Dykstra-Parsons Coefficient	0.70
Permeability	18.1 mD
Net Thickness	34 ft (10.4 m)
Porosity	0.07
OOIP	177 MMSTB
Initial Oil Saturation	0.40
Initial Water Saturation	0.40
Initial Gas Saturation	0.20
Vertical:Horizontal Permeability	0.30
Viscosity of Oil	1.42 cP
Viscosity of Water	0.81 cP
Formation Volume Factor, B_o	1.13 rb/stb
Solution Gas:Oil Ratio, R_s	300 cf/stb
Oil API Gravity	41°

Table 10
Field and operational input for the MCOF and per pattern capital cost estimates from the cost model.

Field/Operational Parameters	Input
Field	MCOF
State	OH
Formation	Copper Ridge Dolomite
# of patterns	1
Depth (ft)	3500
Distance of trunkline (mi)	10
Cost of trunkline $/mi	$33,475
On-site distribution lines	$187,985
Max. CO_2 recycling rate (MMscf/day)	0.47
Max. CO_2 injection rate (MMscf/day)	0.50
New injector wells	0.25
New producer wells	0.25
Total wells required	0.5
Cost Model Calculations – Capital Costs in Millions of US Dollars (USD)[a]	
New well D&C	$ 0.13
Production Well Equipment	$ 0.01
Injection Well Equipment	$ 0.02
CO_2 Recycling Plant	$ 0.41
CO_2 Transport & On-Site Distribution	$ 0.22
Total Capital Costs ($M)	$ 0.80

[a] Capital costs reflect one 40-acre, 5-spot well pattern.

recycling facility, trunkline, and on-site distribution equipment are $0.63 million, the same as the ECOF. Total capital costs for the MCOF pattern equal $0.80 million (Table 10).

4.3.1. $120/t CO_2 scenario

The CO_2-EOR project modeled in the MCOF pattern for a high CO_2 price scenario of $120/t does not break-even at oil prices of $40/STB, with a negative NPV calculated for the entire duration of the operation (Fig. 16). At $70/STB the 112 MSTB of oil recovered from the MCOF results in a net revenue of $6.42 million and total costs of $4.80 million, breaking even after year one to accrue a total NPV of $1.03 million at end of the ~13 year pattern life. An oil price of $100/STB the EOR project is estimated to gain $9.17 million in revenue and incur a total cost of $5.37 million. The project breaks even at the $100/STB oil price scenario after 0.75 years of operation, with a NPV of $2.49 million estimated at the end of the operation.

Table 9
CO_2-PROPHET results of the CO_2-EOR simulation for the MCOF.

Time (years)	1	2	3	4	5	6	7	8	9	10	11	12	12.7	Cumulative
Oil Produced (MSTB)	26	21	12	9	7	7	6	6	5	4	4	4	2	112
H_2O Produced (MSTB)	19	8	5	4	3	3	2	2	2	2	2	2	1	54
CO_2 Injected (MMscf)	183	183	183	183	183	183	183	183	183	183	183	183	135	2326
CO_2 Produced/Recycled (MMscf)	89	122	148	157	161	163	165	167	168	170	171	172	127	1979
CO_2 Stored (MMscf)	94	61	35	26	22	20	18	16	15	13	11	10	7	347

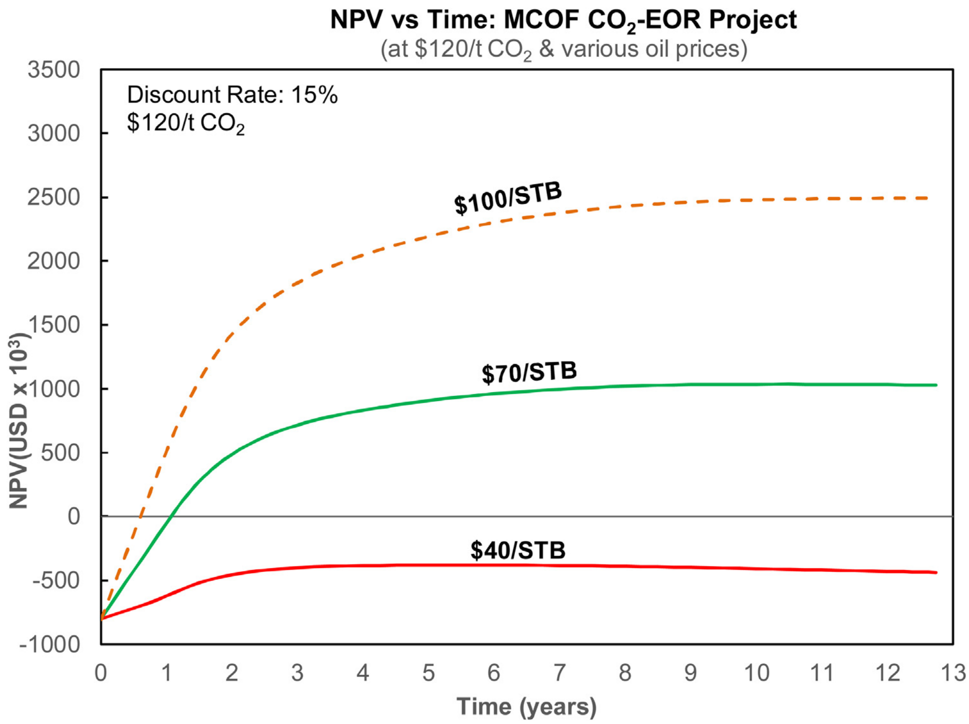

Fig. 16. NPV curves for a CO_2-EOR operation in the MCOF at \$40, \$70, and \$100 per barrel of oil and a CO_2 price of \$120/t.

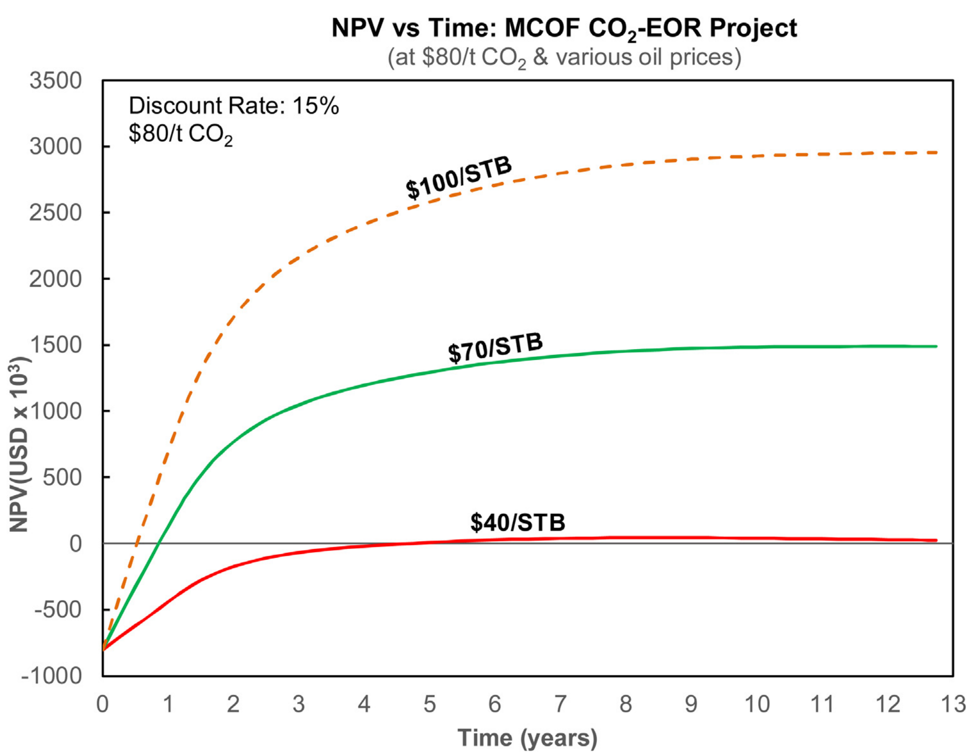

Fig. 17. NPV curves for a CO_2-EOR operation in the MCOF at \$40, \$70, and \$100 per barrel of oil and a CO_2 price of \$80/t.

4.3.2. \$80/t CO_2 scenario

At a CO_2 price scenario of \$80/t the EOR project in MCOF incurs \$4.06 million in total costs at a market price of \$40/STB oil, resulting in a NPV of \$24,000 after breaking-even at 4.5 years of operation (Fig. 17; Table 11). An oil price of \$70/STB the project breaks-even during year one and accrues a total NPV of \$1.49 million. The EOR project breaks-even after 0.5 years of operation at a higher oil price of \$100/STB, resulting in a NPV of \$2.95 million at the end of the project.

4.3.3. \$40/t CO_2 scenario

At a low CO_2 price scenario of \$40/t, the CO_2-EOR project in the MCOF is estimated to break-even before year two in all three oil price scenarios analyzed (Fig. 18). A CO_2 price of \$40/t and an

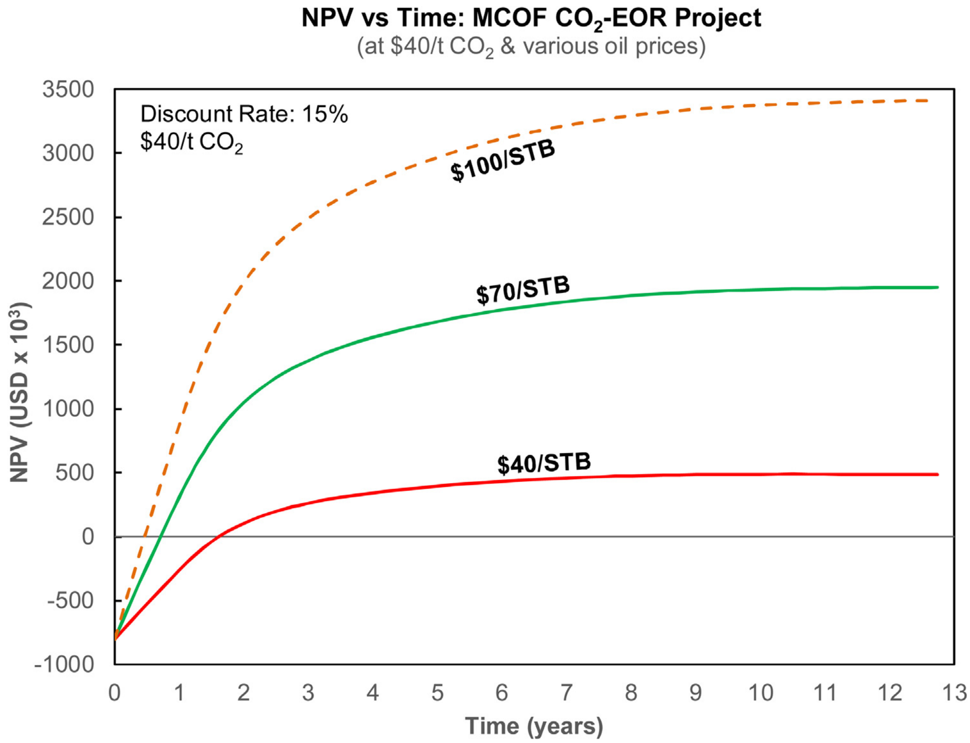

Fig. 18. NPV curves for a CO_2-EOR operation in the MCOF at \$40, \$70, and \$100 per barrel of oil and a CO_2 price of \$40/t.

Table 11
Break down of MCOF EOR pattern costs for a market scenario of \$70/STB oil and \$80/t CO_2.

Cost Item	Cost (Million USD)
New well D&C	0.13
Production well equipment	0.01
Injection well equipment	0.02
Total Well Costs ($M)	0.17
CO_2 purchase cost	1.44
CO_2 recycling facility	0.41
CO_2 recycle O&M	1.39
CO_2 trunkline & on-site distribution	0.22
Total CO_2 Costs ($M)	3.46
Periodic O&M	0.32
Liquid lifting	0.04
G&A	0.07
Total O&M ($M)	0.43
Total Costs ($M)	4.06

oil price of \$40/STB results in total costs of \$2.74 million and net revenue of \$3.67 million, breaking even at 1.75 years to accrue a total NPV of \$0.49 million. At \$70/STB oil the EOR project breaks-even at 0.75 years of operation, resulting in a NPV of \$1.95 million at the end of the recovery operation. At the high oil price scenario of \$100/STB the project breaks-even at 0.5 years and accrues a NPV of \$3.42 million.

4.3.4. Median price scenario: \$80/t CO_2 & \$70/STB oil

Net revenue of \$6.42 million and total costs of \$4.06 million were calculated for the MCOF EOR project at market prices of \$80/t CO_2 and \$70/STB oil (Table 11). At a discount rate of 15% this results in a NPV of \$1.49 million at the end of the 13 year project. Decreasing the discount rate to 10% increases the NPV of the project to \$1.71 million. A higher discount rate of 20% results in a lower NPV of \$1.44 million. The NPV curves at different discount rates are shown in Fig. 19 for the MCOF EOR project at this median price scenario.

Table 12
Comparison of CO_2-EOR reservoir performance results[a] from the ECOF and MCOF.

Performance Results	ECOF		MCOF	
Pattern Life	6 years		13 years	
Oil Produced	56 MSTB		112 MSTB	
Recovery (% OOIP)	22%		21%	
H_2O Produced	27 MSTB		53 MSTB	
CO_2 Injected	1085 MMscf	(57 kt)[b]	2326 MMscf	(122 kt)
CO_2 Produced/Recycled	918 MMscf	(48 kt)	1979 MMscf	(104 kt)
CO_2 Stored	167 MMscf	(9 kt)	347 MMscf	(18 kt)

[a] Cumulative results for one 40 acre 5-spot well pattern in each field.
[b] kt, kilotonne.

4.3.5. CO_2 break-even price vs. oil price

In the MCOF the calculated CO_2 break-even price is \$82/t at an oil price of \$40/STB (Fig. 20), indicating that at this oil price the CO_2-EOR operation simulated in this field will accrue profit when CO_2 purchase prices are less than \$82/t. At an oil price of \$100/STB the calculated break-even price suggests an EOR operator could pay up to \$336/t CO_2 before incurring loss on the project. Similar to the break-even analysis for the ECOF, the slope of the line in Fig. 20 indicates the change in the CO_2 break-even price associated with the EOR operation is 4.2 times the corresponding change in the unit value of oil.

5. Discussion

Reservoir performance results indicate similar average rates of oil production and CO_2 storage in the ECOF and MCOF (Table 12). Greater net thickness and porosity values of the MCOF resulted in OOIP estimates that are approximately twice that of the ECOF, with the MCOF having a longer pattern life and higher cumulative values for the two HCPVs of total CO_2 injection simulated (see Tables 5 and 9).

For the price scenarios analyzed, higher accrual of costs associated with ongoing CO_2 purchase, CO_2 recycling O&M, and total O&M in the MCOF relative to the ECOF are also due to the longer

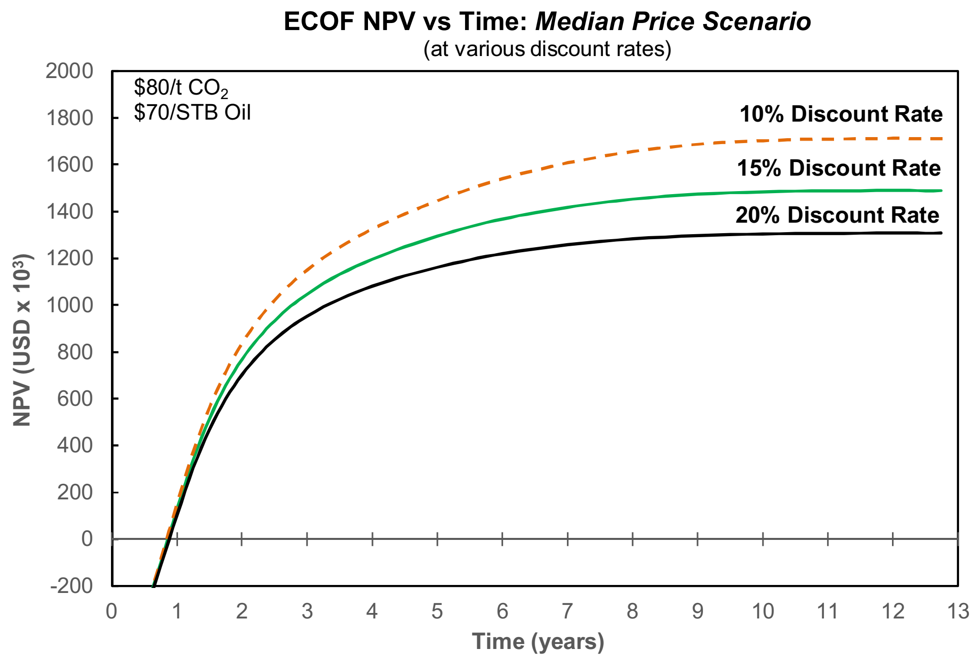

Fig. 19. Graph of the NPV curves for the median price scenario of \$80/t CO_2 and \$70/STB oil at discount rates of 10%, 15%, and 20% for the MCOF.

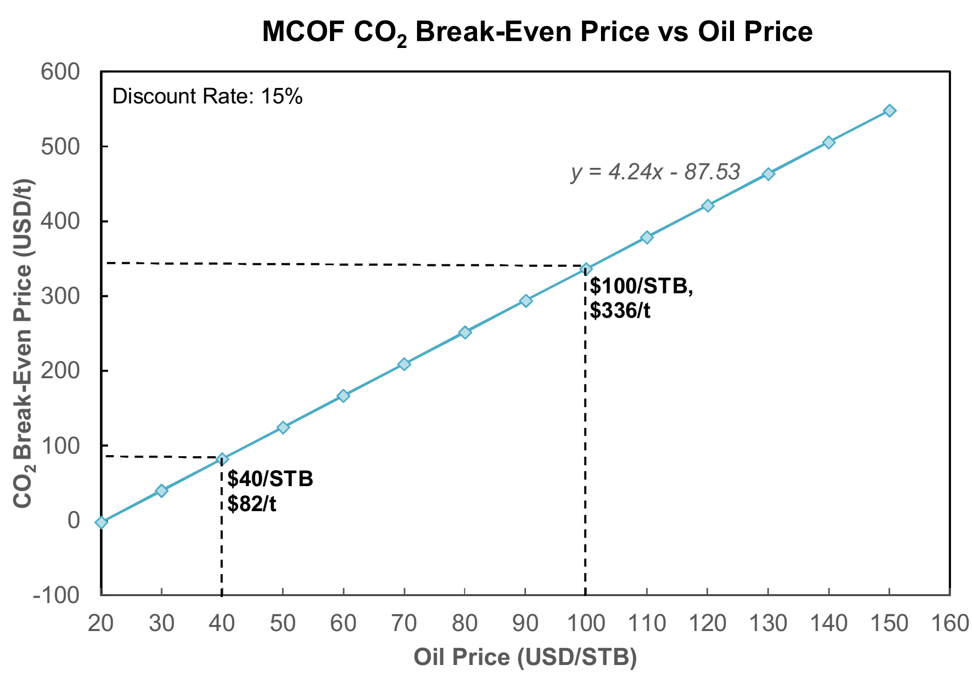

Fig. 20. Plot of the CO_2 break-even price calculated as a function of oil price for the CO_2-EOR operation modeled for the MCOF pattern.

pattern life in the MCOF (Table 13). Higher well costs account for 12% of total project costs in the ECOF, reflecting the greater depth of the Clinton Sandstone (5200 ft) compared to the Copper Ridge Dolomite in the MCOF (3500 ft). At the median price scenario of \$80/t CO_2 and \$70/STB oil, total CO_2 costs represent 78% of total project costs in the ECOF and 85% in the MCOF, while total O&M accounts for 9.5% and 10.6%, respectively. These results suggest that well depth and pattern life are important considerations for constraining total CO_2-EOR project costs on a per pattern basis in the study area, with a majority of the total cost associated with CO_2 purchase, distribution, and processing.

In both the ECOF and MCOF, the average rate of CO_2 purchase and storage simulated for one 40 acre 5-spot pattern ranges from 1.4 to 1.5 kt per year. This scales to CO_2 storage potential of ~6.6 Mt per year via EOR in the 175,000 acres of the ECOF (for 6 years), and ~0.6 Mt per year in the 16,000 acres of the MCOF (for 13 years). The average annual CO_2 emission rate from one coal fired power plant in Ohio is 3–4 Mt per year. The representative CO_2 capture costs reported in Rubin et al. (2015) for post-combustion capture at a new supercritical pulverized coal plant (bituminous coal) is ~\$47/t CO_2 in 2014 USD (\$46/t in 2013 USD; see Table 2 of referenced study). Assuming this capture cost for a similar plant in Ohio, negative or low NPVs in both the ECOF and MCOF suggest

Table 13
Break down of EOR project costs for a market scenario of $70/STB oil and $80/t CO_2 in the ECOF and MCOF.

Cost Item	ECOF		MCOF	
	Cost (Million USD)	% of Total Cost	Cost (Million USD)	% of Total Cost
New well D&C	0.26	10.4%	0.13	3.3%
Production well equipment	0.02	0.7%	0.01	0.3%
Injection well equipment	0.03	1.1%	0.02	0.5%
Total Well Costs ($M)	0.31	12.2%	0.17	4.1%
CO_2 purchase cost	0.70	27.6%	1.44	35.6%
CO_2 recycling facility	0.41	16.4%	0.41	10.2%
CO_2 recycle O&M	0.64	25.5%	1.39	34.1%
CO_2 trunkline & on-site distribution	0.22	8.8%	0.22	5.4%
Total CO_2 Costs ($M)	1.97	78.3%	3.46	85.3%
Periodic O&M	0.18	7.1%	0.32	7.8%
Liquid lifting	0.02	0.8%	0.04	1.0%
G&A	0.04	1.6%	0.07	1.8%
Total O&M ($M)	0.24	9.5%	0.43	10.6%
Total Costs ($M)	2.52		4.06	

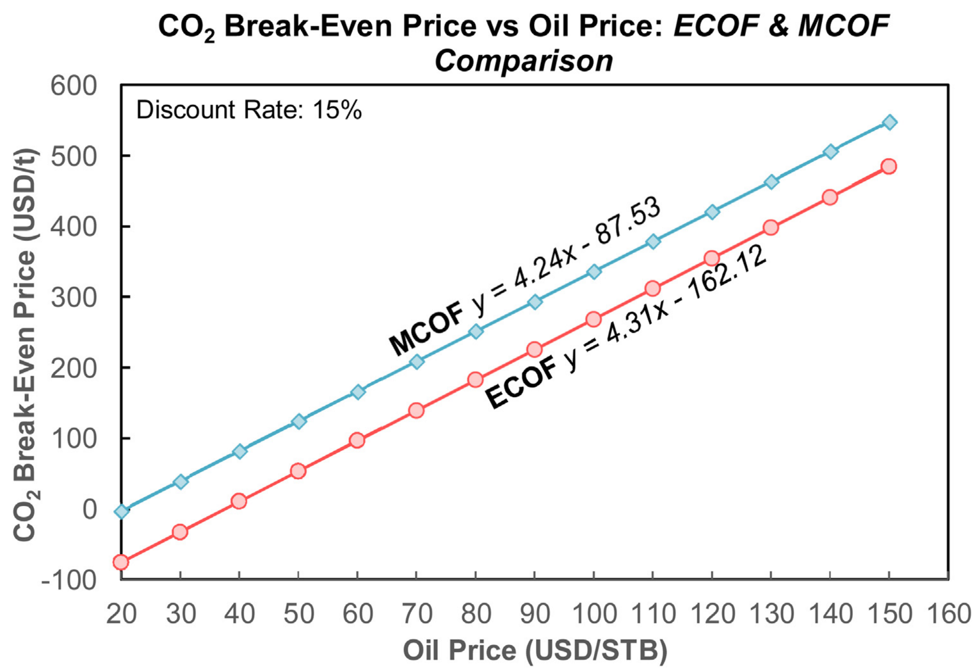

Fig. 21. Comparison of the CO_2 break-even price calculated as a function of oil price for the ECOF and the MCOF. The slope is in USD/t/STB units.

CO_2-EOR may not be economically feasible at oil prices of $40/STB and below. The economics of CO_2-EOR are more promising in each field at oil prices of $70/STB, though negative outcomes and low returns are still possible. High NPVs suggest that when the price of oil is $100/STB CO_2-EOR in Ohio is economically feasible at all of the CO_2 prices analyzed.

The CO_2 break-even analysis can be used to quantify the potential commercial viability of captured CO_2 as a function of the prevailing oil price for the oil field of interest. In both the ECOF and MCOF high CO_2 break-even prices and NPVs suggest that at an oil price of $100/STB, captured CO_2 could be sold for EOR at prices at least twice as high (e.g. $120/t) as the representative capture cost of $47/t. At a discount rate of 15% and any specific oil price, the CO_2 break-even price calculated for the MCOF is ~$65–70 higher than that calculated for the ECOF (Fig. 21). This indicates that increased revenue associated with higher cumulative oil recovery in the MCOF enabled greater affordability for CO_2 than did the lower total project costs in the ECOF. Despite this difference, the relationship between the break-even price of CO_2 and the corresponding price of oil is similar in both fields, depicting a ~$4 increase (or decrease) in the value of one tonne of CO_2 for every $1 increase (or decrease) in the price of oil per barrel. These values fall within range of values ($4–$6/t/STB) derived from the CO_2 break-even analysis in McCoy and Rubin (2009) for oil fields in Texas and Canada (Fig. 22).

6. Concluding remarks

This study outlines a cost-benefit analysis methodology to determine of the economic feasibility of CO_2-EOR in Ohio and assess the potential of CO_2-EOR to act as a commercial driver for CCUS in the Appalachian Basin region. Ohio-specific reservoir and cost data is integrated with reservoir performance and economic models from previous studies to establish the analysis framework. The cost-benefit analysis is applied to the ECOF and MCOF in Ohio to illustrate how the methodology can be used to derive high-level estimates of CO_2-EOR project economics and profit potential for various scenarios. Based on detailed NPV calculations, the break-even price of CO_2 is calculated as a function of various oil price scenarios to define specific price points at which captured CO_2 becomes an economically viable option for EOR.

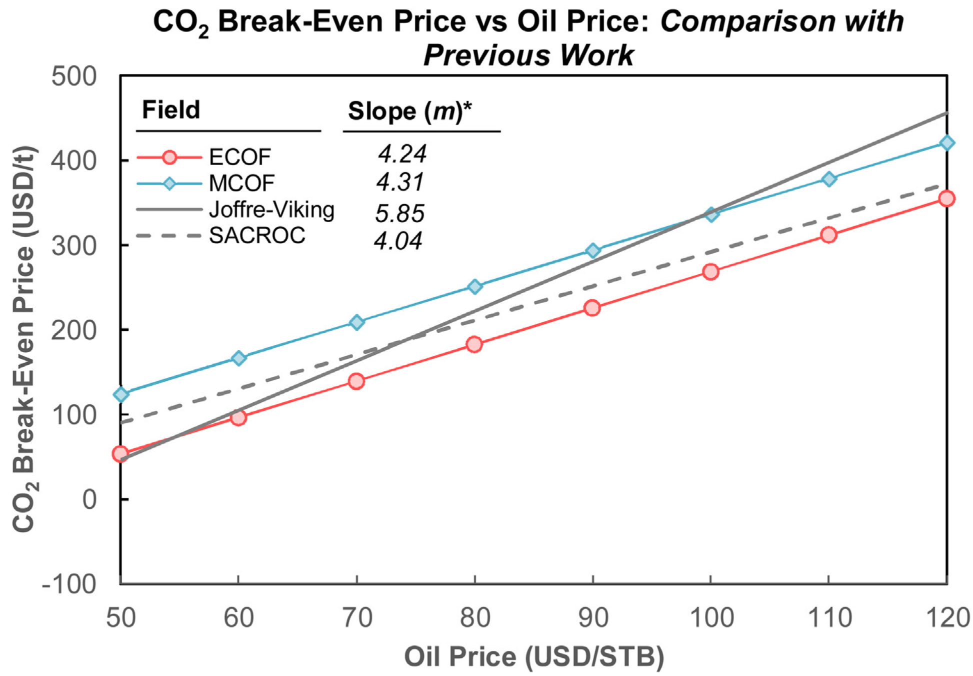

Fig. 22. CO_2 break-even price as a function of the oil price for the ECOF and MCOF at a discount rate of 15%, compared with previous work by McCoy and Rubin (2009) at a discount rate of 12%. *Slope (m) is in USD/t/STB units.

In both the ECOF and MCOF, positive NPVs generated at CO_2 prices of \$40/t suggest that CO_2-EOR may be economically feasible in the study area when oil prices are \$70/STB or higher. At oil prices of \$100/STB captured CO_2 could be sold for EOR at prices well above the representative cost of \$47/t for post-combustion capture on a new supercritical pulverized coal-fired plant (e.g. Rubin et al., 2015). Differences observed between the ECOF and MCOF in capital and operational costs suggest well depth and pattern life are important considerations for constraining total CO_2-EOR project costs in the study region, with a majority of the cost associated with CO_2 purchase, distribution, and processing.

At any specific oil price, the CO_2 break-even price can be calculated based on the regression equations shown in Fig. 21. In the MCOF the calculated CO_2 break-even prices are ~\$65–\$70 higher than those calculated for the ECOF at a given price of oil. The overall trend of the correlation is similar in both fields, indicating the change in the unit value of CO_2 required to break-even is approximately four times the corresponding change in the unit value of oil. This is consistent with values reported for CO_2-EOR operations in other regions of North America (e.g. McCoy and Rubin, 2009), suggesting differences in reservoir properties and costing methodologies may not significantly alter the price elasticity of CO_2 relative to the prevailing price of oil.

The value of the cost-benefit analysis framework presented in this paper is that it can be readily applied with limited information for project screening purposes. The break-even correlation represents a standalone metric that can be used to (re)estimate the CO_2 break-even price during times of oil price volatility, helping to constrain the specific price conditions at which CO_2 becomes a viable purchase for EOR and a marketable asset for coal-fired power plants with capture technology. Finally, a probabilistic analysis that takes into account uncertainties in reservoir performance, cost modeling, and price scenarios would help to refine the cost-benefit analysis, and provide additional useful information to decision makers regarding the techno-economic feasibility of the project.

Acknowledgments

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Appendix A. Supporting data

This Appendix contains two tables. Table A1 lists the categorization and definitions of well cost parameters included in the cost model; Table A2 lists the well type, configuration, depth, and associated cost data acquired for Ohio-specific well cost calculations.

Table A1
Categorization and definitions of well cost parameters included in the cost model.

Cost Category	Definition	Items Included
Well Costs		
Drilling & Completion	Tangible and intangible costs associated with on-site drilling and completion phases for production and injection wells.	site survey, leasehold and prospect costs, site preparation and reclamation, labor, supervision, surface and downhole drilling equipment, drilling cost per foot, drilling cost per hour (dayrate), logging costs, perforating, hydraulic fracturing treatment, acid jobs, chemicals, drilling and completion fluid management, completion rig, all casing, cementing, plugging
Production Well Equipment	Capital costs of tangible and, to a lesser extent, intangible items associated with production well equipment and installation	electric services, all surface and subsurface production well equipment costs: tubing, rods, down-hole pump, pumping unit, motor, well head, hookups, and controller, separator, storage tanks, walkways gas sales meter, flowlines, gauges and valves
Injection Well Equipment	Capital costs of tangible and, to a lesser extent, intangible items associated with injection well equipment and installation	electrical services, all surface and subsurface injection well equipment costs: unloading pad, storage tanks, oil separation equipment, filtering system, injection pump, injection lines, injection tubing, injection packer, buildings/shelters, well head, pressure monitoring system, flow meter/totalizer, gauges and valves
Well Conversion	Tangible and intangible capital costs of updating or converting existing injection and production wells to establish the number of suitable injection and production wells required for the well pattern/project	labor, mechanical integrity testing, re-perforating, stimulation, acid or clean up treatment, cement bond logging, fabrication services and materials, equipment replacement costs, pressure test lines, all other surface and subsurface well equipment and rework costs: packer, tubing, well head/tubing head, fittings, regulator, monitoring equipment, gauges and valves
CO_2 Costs		
CO_2 Transport & Distribution	Fixed and variable capital costs associated with transporting the volume of CO_2 required for injection from the regional pipeline to the EOR site, as well all manifolds and flow lines required for on-site CO_2 distribution	high pressure trunkline pipe material, mileage, and diameter; similar to natural gas gathering systems (variable components), manifolds, values, flow controls, and distribution lines required for transport to and from wells and the recycling facility
CO_2 Recycling Plant	Capital costs of a recycling facility of sufficient size to facilitate CO_2 separation from produced fluids during peak production and recycling operations	CO_2/hydrocarbon & CO_2/water separators, fluid distribution lines, gas stream flow lines, CO_2 compression equipment, pumps, storage tanks (crude and water), manifolds, valves, flow controls, processing equipment
CO_2 Recycling (O&M)	Expenses related to operation of the recycling facility corresponding to the rate of production, recycling, and injection simulated for a specific time period, with the energy required for CO_2 surface management, treatment and compression generated on-site	energy required for recycling facility operation over a given time period, including power for separation, processing, CO_2 CO2compression to the MMP required for injection
O&M Costs		
Periodic O&M	Costs associated with operation and maintenance of a CO_2-EOR site at the required capacity over a given time period, including periodic well workover, and other surface and subsurface repairs/remediation	periodic well workover, servicing, operating expenses for labor, personnel, electricity, consumables, surface and subsurface equipment maintenance and replacement
Liquid Lifting Costs	Operational costs of pumping (to surface), managing, and (re)distributing liquids produced during a given time period of CO_2-EOR operation, with the required energy generated on-site	energy required for lifting liquids up the wellbore and surface routing
General and Administrative (G&A)	Other expenses associated with routine activities and processes required for effective operation of the overall project, but not directly related to the production of marketable goods and services	staff salaries/wages, insurance, accounting, consulting, management, accounting and record keeping supplies

Table A2
Well type, configuration, depth, and associated cost data acquired for Ohio-specific well cost calculations.

Well #	Well Type	MD Depth (ft)	Year of Cost Accrual	Adjusted Costs (2014 USD)								Total
				Leasehold & Prospect	Drilling	Completion	Plugging	D&C Total	Work-over	Production Well Equipment Costs	Injection Well Equipment Costs	
1	production	3509	2011	$ 2462	$ 155,020	$ 139,869	$11,447	$ 308,797	$ –	$ 68,347	$ –	$ 377,144
2	production	3467	2012	$ –	$ 112,467	$ 96,750	$ 2439	$ 211,655	$ –	$ 76,606	$ –	$ 288,261
3	production	4700	2014	$ 32,500	$ 184,687	$ 87,974	$11,000	$ 316,161		$ 85,222		$ 401,383
4	production	4460	2013	$ 45,730	$ 132,435	$ 91,848	$11,178	$ 281,191	$ –	$ 78,431	$ –	$ 359,621
5	–	4033						$ –	$ 77,649			$ 77,649
6	production	4800	2014		$ 333,366	$ 133,203		$ 466,568		$ 113,140		$ 579,708
7	production	3900	2015	$ –	$ 214,550	$ 116,573	$ –	$ 331,123	$ –	$ 80,362	$ –	$ 411,485
8	production	3100	2014		$ 102,450	$ 50,350		$ 152,800		$ 45,650		$ 198,450
9	production	2150	2014		$ 87,963	$ 46,550		$ 134,513		$ 42,625		$ 177,138
10	production	1308	2014		$ 84,213	$ 103,500		$ 187,713		$ 34,825		$ 222,538
11	production	4451	2012	$ –	$ –	$ –	$ –	$ 671,804	$ –	$ 128,548	$ –	$ 800,352
12	production	5247	2010	$ –	$ –	$ –	$ –	$ 414,736	$ –	$ 96,577	$ –	$ 511,314
13	production	4240	2013	$ –	$ 350,344	$ 174,207	$ –	$ 524,550	$ –	$ 123,090	$ –	$ 647,641
14	production	4305	2014		$ 356,750	$ 171,425		$ 528,175		$ 124,050		$ 652,225
15	injection	9200	2014		$ 1,262,200	$ 837,200		$ 2,099,400			$ 846,800	$2,946,200
16	production	5100	2008	$ –	$ 293,564	$ 85,288		$ 378,853	$ –	$ 63,465	$ –	$ 442,317
17	production	6575	2010	$ 12,747	$ 215,319	$ 82,457	$ –	$ 305,574	$ –	$ 45,171	$ –	$ 350,745
18	production	2835	2008	$ 5403	$ 77,301	$ 63,478	$ –	$ 146,182	$ –	$ 16,373	$ –	$ 162,555
19	injection	7305	2012	$ –	$ 488,784	$ 287,861	$ –	$ 776,645	$ –	$ –	$ 102,873	$ 879,519
20	injection	7016	2013	$ –	$ 805,166	$ 480,166	$ –	$1,285,331	$ –	$ –	$ 432,240	$1,717,571
21	production	5500	2011	$ –	$ 141,368	$ 110,828	$ –	$252,196	$ –	$ 54,639	$ –	$ 306,835
22	production	6700	2011	$ –	$ 230,923	$ 104,806	$ –	$335,728	$ –	$ 49,540	$ –	$ 385,268
23	production	3997	2012	$ –	$ 116,203	$ 92,779	$ –	$208,982	$ –	$ 46,444	$ –	$ 255,426
24	production	4470	2012	$ –	$ 164,017	$ 94,613	$ –	$258,630	$ –	$ 48,254	$ –	$ 306,884
25	production	6319	2012	$ –	$ 217,368	$ 102,144	$ –	$319,512	$ –	$ 76,846	$ –	$ 396,358

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