Economic Analysis of Geologic Carbon Sequestration Potential for the BSCSP Region using Enhanced Coalbed Methane Recovery and Enhanced Oil Recovery[1]

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1. Introduction

This report describes an economic analysis of the potential for geologic carbon sequestration using enhanced coalbed methane recovery (ECBM) and enhanced oil recovery (EOR) in the Big Sky Partnership (BSP) region. For the analysis of ECBM, data on the Wyodak-Anderson coal zone in Wyoming's Powder River Basin (PRB) were assembled and used to parameterize a model for the net cost of sequestering CO_2, net of incremental revenues from additional quantities of methane recovered as a result of CO_2 injection. Similarly, for the analysis of EOR, data on currently producing oil fields in Wyoming's Powder River Basin and Green River Basin (GRB) were assembled and used to parameterize a model for the net cost of sequestering CO_2 in each field, net of incremental revenues from additional quantities of oil recovered as a result of CO_2 injection. The results of the analysis are summarized in a set of carbon sequestration supply curves which show the relationship between quantities of CO_2 sequestered and the cost of sequestration, from lowest to highest cost, at benchmark oil and gas prices.

2. Methodological Approach for ECBM

The economic analysis of ECBM makes use of the Comet3 commercial reservoir simulation program developed by Advanced Resources International. To keep the analysis manageable, simulations were run for just 24 scenarios, corresponding to two representative overburden depths (1,250 and 1,750 ft), three representative coal thicknesses (35, 75, and 125 ft), and four times at which CO_2 injection might be started (immediately upon drilling; after 5 years of conventional coalbed methane recovery (CBM); after 10 years of CBM; and never).

The analysis is complicated by the fact that a good portion of the Wyodak-Anderson coal zone has already been developed for CBM. Table 1 shows our estimates of the total area of the zone that can be considered "unminable," defined as having an overburden depth >1,000 ft, as well as the breakdown of this area by overburden depth, coal thickness, and CBM development status.

These estimates are based on isopach maps from the U.S. Geological Survey (USGS) and CBM well location data from the Wyoming Oil and Gas Conservation Commission (WOGCC).

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[1] This document was prepared as Deliverable ED3 for the Big Sky Carbon Sequestration Partnership Phase II.

		Average coal thickness			CBM development status			
					Developed	Undeveloped		
		35 ft	75 ft	125 ft	("brownfield")	("greenfield")	% Dev.	Total
Average overburden	**1,250 ft**	423,590	510,499	505,202	731,794	707,497	51%	1,439,291
	1,750 ft	258,518	172,169	67,509	481,646	16,550	97%	498,196
Total		682,108	682,668	572,711	1,213,440	724,047		1,937,487

Table 1: Breakdown of Wyodak-Anderson total unminable area of 1,937,487 acres by overburden depth, coal thickness, and CBM development status.

For both overburden depths, the estimated fractions already under CBM development (51% and 97% for areas with overburden depths of 1,250 and 1,750 ft, respectively) are applied equally to the three coal thickness categories.

Well spacing. According to Ross (2007), the average well spacing for areas of the PRB currently under CBM development is 80 acres. That is, CBM wells are laid out on a more or less regular grid, with each well draining a roughly square area of 80 acres. We assume that this well spacing would be maintained under ECBM, both in "brownfield" areas already under CBM development and in newly developed, "greenfield" areas. For brownfield areas, the assumption is therefore that no infill drilling would take place. Instead, roughly every second CBM producer well would be converted to a CO_2 injector well. On a perfectly regular grid, this would yield a pattern of "five-spot" squares, each 160 acres in area, with an injector in the center and four producers at the corners.

In the simulations, this implies that the CBM phase of any project would involve two producers at diagonally opposite corners of a 40-acre quadrant, while the ECBM phase would change one of those producers to a CO_2 injector. Simulated flows for both phases are then multiplied by four to arrive at the flows for a single five-spot pattern, and by the respective acreages in Table 1 divided by 160 to arrive at estimated flows for the PRB as a whole.

Simulation parameters. Table 2 shows the values used for various physical parameters required in the ECBM simulations, as well as the sources from which these values were derived. Table 3 shows the relative permeability curves used in the simulations.

Simulation results. Figures 1 and 2 show the simulation results for eight of the scenarios described above, namely those for a depth of 1,250 and 1,750 ft, respectively, for each of the four ECBM starting times considered, at a coal thickness of 35 ft. The results for the remaining two coal thicknesses considered, 75 and 125 ft, scale up almost exactly in proportion to thickness. Figure 1 shows, for example, that when ECBM is started immediately (with no preceding CBM phase) in a 35 ft thick coal seam at a depth of 1,250 ft, CO_2 injection tops out at about 350 Mcf/day after about 7 years, at which point gas production is about 50 Mcf/day, and water production about 25 bw/day. If instead the seam is 75 ft thick, the predicted injection and production flows follow almost exactly the same trajectories over time, but CO_2 injection tops

Physical parameters	Value [1]		Source
Pressure gradient	14.7 + 0.127366*depth + 0.0001007*depth^2	psi/ft	Estimated from data in Table 18B of Bank and Kuuskraa (2006)
Coal density	1.33	g/cm3	Nelson et al. (2005)
Fracture permeabilities			Ross (2007)
Horizontal face cleat	24	mD	
Horizontal butt cleat	7	mD	
Vertical face cleat	7	mD	
Fracture porosity (fraction)	0.02		Ross (2007)
CO_2 Langmuir volume			Nelson et al. (2005)
Depth ≤ 1200 ft	1,045	scf/ton	
Depth > 1200 ft	1,100	scf/ton	
CO_2 Langmuir pressure			Nelson et al. (2005)
Depth ≤ 1200 ft	650	psi	
Depth > 1200 ft	620	psi	
CH_4 Langmuir volume			Nelson et al. (2005)
Depth ≤ 1200 ft	95	scf/ton	
Depth > 1200 ft	150	scf/ton	
CH_4 Langmuir pressure			Nelson et al. (2005)
Depth ≤ 1200 ft	330	psi	
Depth > 1200 ft	450	psi	
N_2 Langmuir volume	226	scf/ton	Tang et al. (2005)
Sorption times			Robertson (2009)
CO_2	25	days	
CH_4	10	days	
N_2	25	days	
Reservoir temperature	50+0.02*depth	°F	Nelson et al. (2005)
Initial gas composition (mole fractions)			Ross et al. (2009)
CH_4	0.9		
N_2	0.1		
Max. bottomhole pressure at injection well	0.5*depth (ft)	psi	Half of overburden stress as estimated by Colmenares and Zoback (2007)
Min. bottomhole pressure at production well	50	psi	Ross et al. (2009)
Max. CO_2 injection rate (per well quadrant)	50*thickness (ft)	Mcf/day	
Max. water production rate (per well quadrant)	5*thickness (ft)	bw/day	

[1] The values shown are from (or based on) the original sources, before conversion to units used in Comet3.

Table 2: Physical parameters used in ECBM analysis

Sw	**Krw**	**Krg**
0.000	0.0000	1.0000
0.050	0.0020	0.8470
0.100	0.0035	0.7240
0.150	0.0060	0.6220
0.200	0.0090	0.5370
0.250	0.0140	0.4650
0.300	0.0230	0.4020
0.350	0.0350	0.3480
0.400	0.0510	0.2990
0.450	0.0710	0.2550
0.500	0.0940	0.2150
0.550	0.1220	0.1790
0.600	0.1560	0.1470
0.650	0.1960	0.1180
0.700	0.2450	0.0920
0.750	0.3060	0.0710
0.800	0.3830	0.0520
0.850	0.4820	0.0370
0.900	0.6090	0.0240
0.950	0.7730	0.0120
0.975	0.8710	0.0060
1.000	1.0000	0.0000

Table 3: Relative permeability curves used in ECBM analysis, estimated from Fig 2.14 in Ross (2007), which in turn is based on Gash (1991).

out at 75/35 x 350 = 750 Mcf/day, at which point gas production is about 75/35 x 50 = 107 Mcf/day, etc.

Note that all flows shown are for the 40-acre simulation quadrant, and must therefore be multiplied by four to arrive at the flows for an entire 160-acre pattern.

After generating the simulation results, the estimated time paths of methane and water production for the CBM phases, and the additional time paths of CO_2 injection and production for the ECBM phases are converted to time paths of monthly revenues and costs, including up-front capital costs incurred when developing a greenfield area, as well as any additional capital costs incurred when switching a CBM project to ECBM.

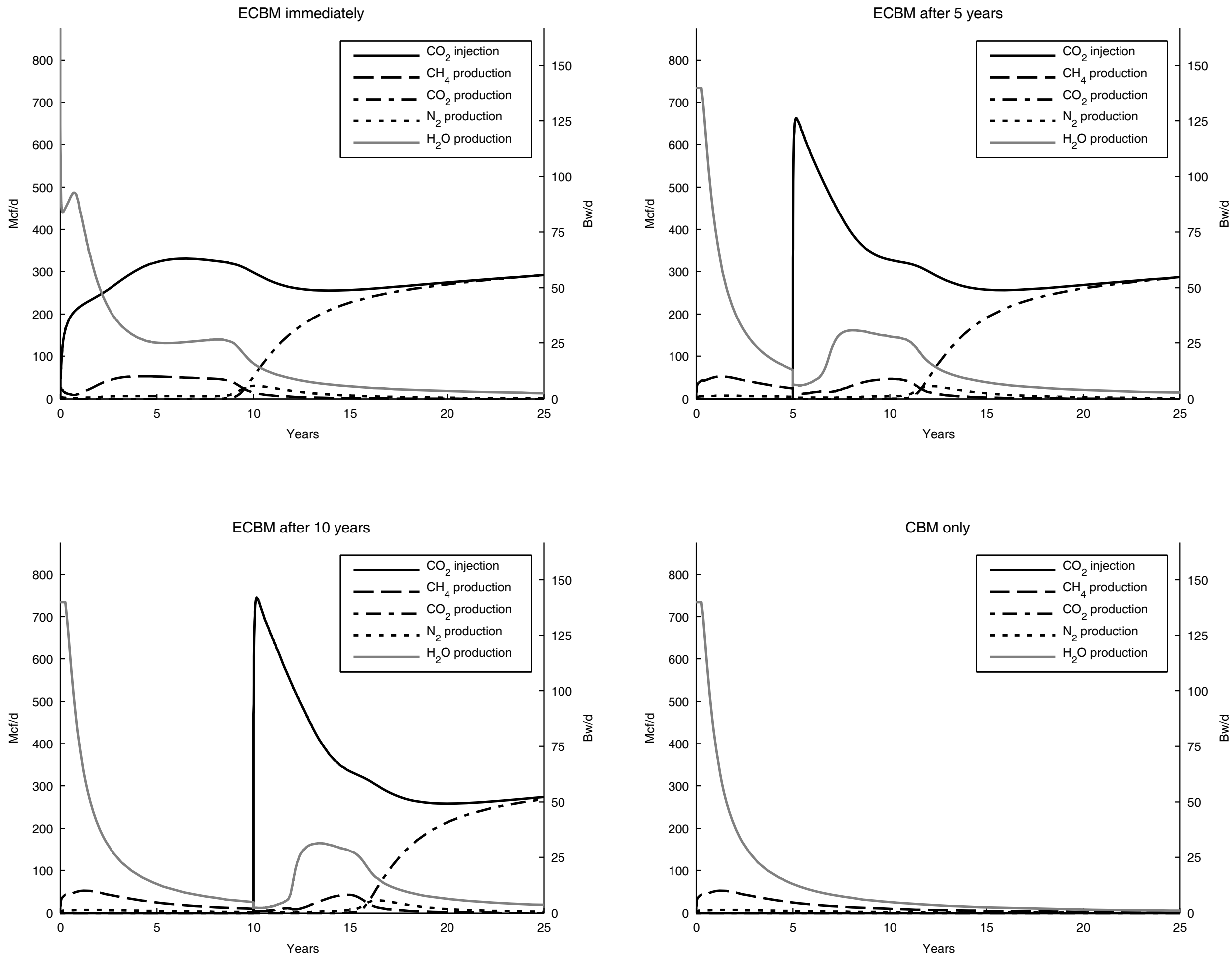

Figure 1: Predicted injection and production flows for a 40-acre quadrant at 1,250 ft depth, producing from a 35-ft thick coal seam. Flows for 75- and 125-ft thick seams scale up almost exactly in proportion to thickness.

Greenfield areas. Mathematically, for greenfield areas, four net present values are calculated:

$$NPV^{CBM} = \sum_{t=1}^{T^{CBM}} \frac{p^g Q_t^{gp,CBM}(1-\tau^R)(1-\tau^{SP}) - C^o\left(Q_t^{wp,CBM}\right)}{(1+r)^t} - K^{CBM}$$

for CBM production without ever switching to ECBM,

$$NPV^{ECBM,0} = \sum_{t=1}^{T^{ECBM,0}} \frac{p^g Q_t^{gp,ECBM,0}(1-\tau^R)(1-\tau^{SP}) - p^c Q_t^{ci,ECBM,0} - C^o\left(Q_t^{wp,ECBM,0}\right)}{(1+r)^t} - K^{ECBM,0}$$

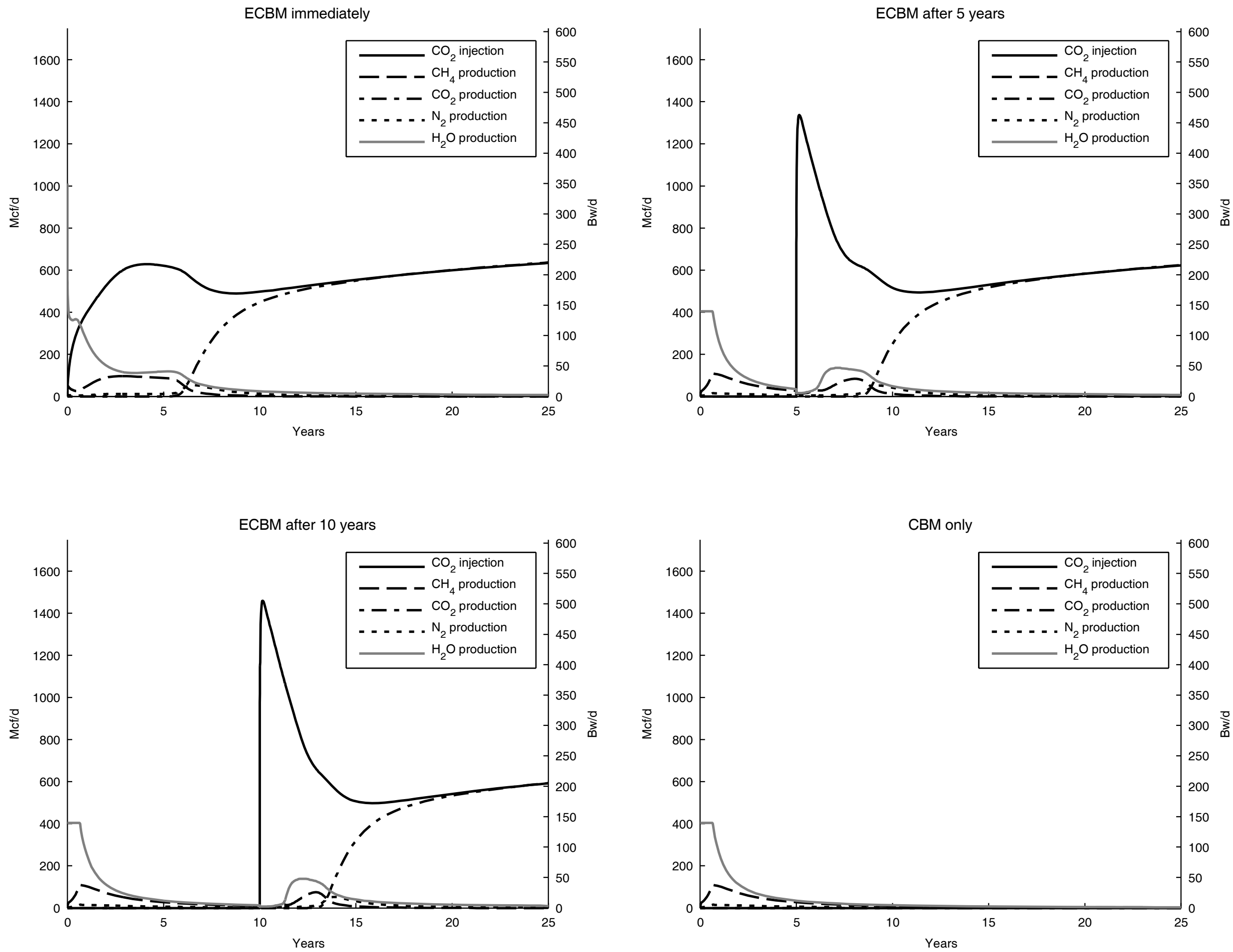

Figure 2: Predicted injection and production flows for a 40-acre quadrant at 1,750 ft depth, producing from a 35-ft thick coal seam. Flows for 75- and 125-ft thick seams scale up almost exactly in proportion to thickness.

for immediately starting with ECBM, and

$$
\begin{aligned}
NPV^{ECBM,s} = \sum_{t=1}^{s} \frac{p^g Q_t^{gp,CBM}(1-\tau^R)(1-\tau^{SP}) - C^o\left(Q_t^{wp,CBM}\right)}{(1+r)^t} - K^{CBM} \\
+ \sum_{t=s+1}^{T^{ECBM,s}} \frac{p^g Q_t^{gp,ECBM,s}(1-\tau^R)(1-\tau^{SP}) - p^c Q_t^{ci,ECBM,s} - C^o\left(Q_t^{wp,ECBM,s}\right)}{(1+r)^t} \\
- \frac{K^{ECBM,s}}{(1+r)^s}
\end{aligned}
$$

for starting with CBM but then switching to ECBM in after either $s = 60$ months (5 years) or $s = 120$ months (10 years). In these expressions, p^g represents the price of gas (assumed constant over the lifetime of the project), $Q_t^{gp,CBM}$, projected baseline gas recovery in month *t* under CBM, and $Q_t^{gp,ECBM,s}$, projected gas recovery in that same month under ECBM, given that ECBM is started in month $s \geq 0$. To arrive at net operating profits in each month, we subtract from pre-tax gas revenues any royalties at rate τ^R, as well as severance and property taxes at combined rate τ^{SP}. Under ECBM, we also subtract the projected cost of CO_2 purchases, equal to the CO_2 purchase price p^c (also assumed constant over the lifetime of the project, and possibly negative if the project receives carbon credits) times the projected quantity purchased, $Q_t^{ci,ECBM,s}$, given that ECBM is started in month $s \geq 0$. Lastly, we subtract other operating costs C^o, which depend in part on projected water production, $Q_t^{wp,CBM}$ and $Q_t^{wp,ECBM,s}$. The remaining net operating profits are discounted to the present at the internal rate of return required by the operator, converted to a monthly rate r.

The economic lifetime of the project, denoted T^{CBM} for a pure CBM project and $T^{ECBM,s}$ for an ECBM project, is reached when operating profits turn negative or when, in the ECBM case, CO_2 breaks through in the production stream, whichever comes sooner. More specifically, for the pure-CBM scenario, the optimal termination time of the project is determined by working backwards from the simulation time horizon of 300 months (25 years). For each month, discounted future net cash flows are calculated, and the month is dropped (i.e., its net cash flow is effectively set to zero) if these were found to be negative. The termination time is then the last non-dropped month, i.e., the last month for which future net cash flows are positive, conditional on dropping subsequent months for which they are negative. Note that this procedure yields a "termination" time of zero if the project is never profitable at the given gas and CO_2 prices, and would therefore never be undertaken in the first place.

For scenarios involving ECBM, either immediately or after 60 or 120 months (5 or 10 years), we first determine the month in which CO_2 "breaks through" in the production stream, defined as the point where the ratio of CO_2 to methane production exceeds 2.5%. This month is then used as the final month for the above-described calculation of the optimal termination time. In effect, then, the termination time is the earlier of the break-through time and the time beyond with net cash flow turns negative.

There is in addition an up-front investment cost, which comprises costs of leasing and permitting; capital costs associated with water disposal; and costs of drilling, completing, and equipping either two production wells per pattern (if there is an initial CBM phase, in which case the up-front cost is denoted K^{CBM}) or one injection and one production well (if ECBM is started immediately, in which case the up-front cost is denoted $K^{ECBM,0}$). We assume that this entire cost is incurred immediately at time 0. Lastly, switching to ECBM after an initial CBM phase involves an additional investment cost $K^{ECBM,s}$, which comprises costs of converting one of the production wells to CO_2 injection, and equipping it accordingly. We assume that this additional investment cost is incurred immediately at the switching time *s*.

By next comparing NPV^{CBM} and $NPV^{ECBM,s}$ for $s = 0, 60,$ or 120, the optimal scenario is determined as the one that maximizes net present value. If this scenario involves ECBM, its time path of CO_2 sequestration (CO_2 injection less any CO_2 production) up to the termination time is added to the PRB total sequestration supply.

Brownfield areas. For brownfield areas, we assume that all projects have been operating under CBM production for 60 months (5 years). As a result, the immediate-ECBM scenario becomes irrelevant, and the three net present values compared are

$$NPV^{CBM,60} = \sum_{t=61}^{T^{CBM}} \frac{p^g Q_t^{gp,CBM}(1-\tau^R)(1-\tau^{SP}) - C^o\left(Q_t^{wp,CBM}\right)}{(1+r)^{(t-60)}}$$

for continued CBM production without ever switching to ECBM,

$$NPV^{ECBM,60} = \sum_{t=61}^{T^{ECBM,60}} \frac{p^g Q_t^{gp,ECBM,60}(1-\tau^R)(1-\tau^{SP}) - p^c Q_t^{ci,ECBM,60} - C^o\left(Q_t^{wp,ECBM,60}\right)}{(1+r)^{(t-60)}} - K^{ECBM,s}$$

for immediate switching to ECBM, and

$$\begin{aligned} NPV^{ECBM,120} &= \sum_{t=61}^{120} \frac{p^g Q_t^{gp,CBM}(1-\tau^R)(1-\tau^{SP}) - C^o\left(Q_t^{wp,CBM}\right)}{(1+r)^{(t-60)}} \\ &+ \sum_{t=121}^{T^{ECBM,120}} \frac{p^g Q_t^{gp,ECBM,120}(1-\tau^R)(1-\tau^{SP}) - p^c Q_t^{ci,ECBM,120} - C^o\left(Q_t^{wp,ECBM,120}\right)}{(1+r)^{(t-60)}} \\ &- \frac{K^{ECBM,s}}{(1+r)^{60}} \end{aligned}$$

for continued CBM production for 60 more months, but then switching to ECBM in month 120. Note that in the latter two expressions, $K^{ECBM,s}$ is the capital cost of converting and equipping an existing production well for CO_2 injection.

The optimal termination times are calculated in the same manner as for greenfield projects, and the optimal continuation scenario (switching to ECBM at the 5-year point, switching after continuing CBM for another 5 years, or continuing CBM without ever switching to ECBM) is determined as the one with the highest net present value. If this continuation scenario involves ECBM, its time path of CO_2 sequestration from the 5-year point up to the termination time is added to the PRB total.

Cost parameters	Value [1]		Source
Capital costs			
Mineral lease cost (per acre)	$200	per acre	Bank and Kuuskraa (2006)
Permitting cost for regular lease (per acre)	$7,000	per acre	Bank and Kuuskraa (2006)
Additional permitting cost for Federal lease (per acre) [2]	$14,000	per acre	Bank and Kuuskraa (2006)
Well drilling cost (per well)		per well	Bank and Kuuskraa (2006)
Depth ≤ 1,000 ft	$[(45,000 + 50*depth) *1.10]		
Depth > 1,000 ft	$[(145,000 + 100*(depth-1,000))*1.10]		
Well equipment cost for CBM producers	$81,900	per well	Bank and Kuuskraa (2006)
Well conversion and equipment cost for CO_2 injectors	$[120,000 + 15*depth]	per well	Fox (2005)
Water disposal capital cost [3]	$1,500	per well	Bank and Kuuskraa (2006)
Operating costs			
Producers		per well-month	Bank and Kuuskraa (2006)
Year 1	$3,940		
Year 2-4	$1,800		
Year 5 and up	$1,140		
Injectors	$1,000	per well-month	Reeves et. al (2004)
Water disposal [3]	$0.04	per bw	Bank and Kuuskraa (2006)
MMV	$10,000/12	per pattern-month	Reeves et. al (2004)
Royalties and taxes			
Royalty	16%		
Severance tax	6%		
Property tax	6%		

[1] The values shown are from the original sources, before applying cost inflation factors to convert to 2005 dollars. Bank and Kuuskraa (2006) values are in 2003 dollars and were converted to 2005 dollars using the EIA (2010) cost indices for CBM leases in the Powder River Basin (Table 23 for capital costs, Table 25 for operating costs). Reeves et. al (2004) values were assumed to be in 2003 dollars as well, and were similarly converted. Fox (2005) values are in 2005 dollars.

[2] In all scenarios, half of all patterns were assumed to be Federal leases

[3] Water disposal costs assume surface discharge, the cheapest option considered in Bank and Kuuskraa (2006)

Table 4: Cost parameters used in ECBM analysis

Economic parameters. Table 4 shows the values of the various cost parameters used in the economic analysis, as well as the sources from which those values were derived. The rate of return "hurdle rate" used to calculate NPV was 20%. Although this is well above standard hurdle rates used in analyses of government policies, its value incorporates a significant premium to compensate for the high anticipated risk of ECBM projects.

3. Results for ECBM: Sequestration Supply Curves

The above-described economic analysis is conducted for three different gas prices, namely \$5.46, \$5.72, and \$5.94 per million Btu. These correspond to the Energy Information Administration's "low," "reference," and "high" Henry Hub gas price projections for 2021-2030 in its Annual Energy Outlook report for 2009 (EIA 2009), when converted to 2005 dollars and then to Wyoming wellhead prices based on the data given in Bank and Kuuskraa (2006).

Figure 3 shows the estimated sequestration supply curves for ECBM at each of these gas prices. On the vertical axis, the cost of CO_2 corresponds to the price *received* by the ECBM project for each tonne of CO_2 sequestered, and thereby to the per-tonne cost of ECBM sequestration to a CO_2 emissions source. On the horizontal axis, the quantity of sequestration supplied at each cost is expressed on an annualized basis. That is, the rate shown is the constant rate of sequestration $\bar{Q}$ that, when multiplied by any constant CO_2 price p^c, would over a 70-year time horizon yield the same present value as the actual, time-varying rates Q_t shown in Figure 2 for each of the 24 scenarios (after converting units from Mcf/day to tCO_2). Mathematically, for any given scenario, with sequestration rate Q_t expressed in tCO_2/year for year t, the annualized equivalent sequestration rate is implicitly defined by

$$\sum_{t=1}^{70} \frac{\bar{Q}}{(1+r)^t} = \sum_{t=1}^{70} \frac{Q_t}{(1+r)^t},$$

and can therefore be calculated explicitly as

$$\bar{Q} = \frac{r}{1 - 1/(1+r)^{70}} \times \sum_{t=1}^{70} \frac{Q_t}{(1+r)^t}.$$

The discount rate r used in these calculations is 5%.

A central result of the analysis is that no ECBM project is estimated to be profitable if the operators have to pay more than \$2 per tonne of CO_2. Conversely, all projects are estimated to be profitable if operators receive more than about \$3 per tonne. The resulting upper bound on ECBM sequestration is about 200 $MtCO_2$/year on an annualized basis.

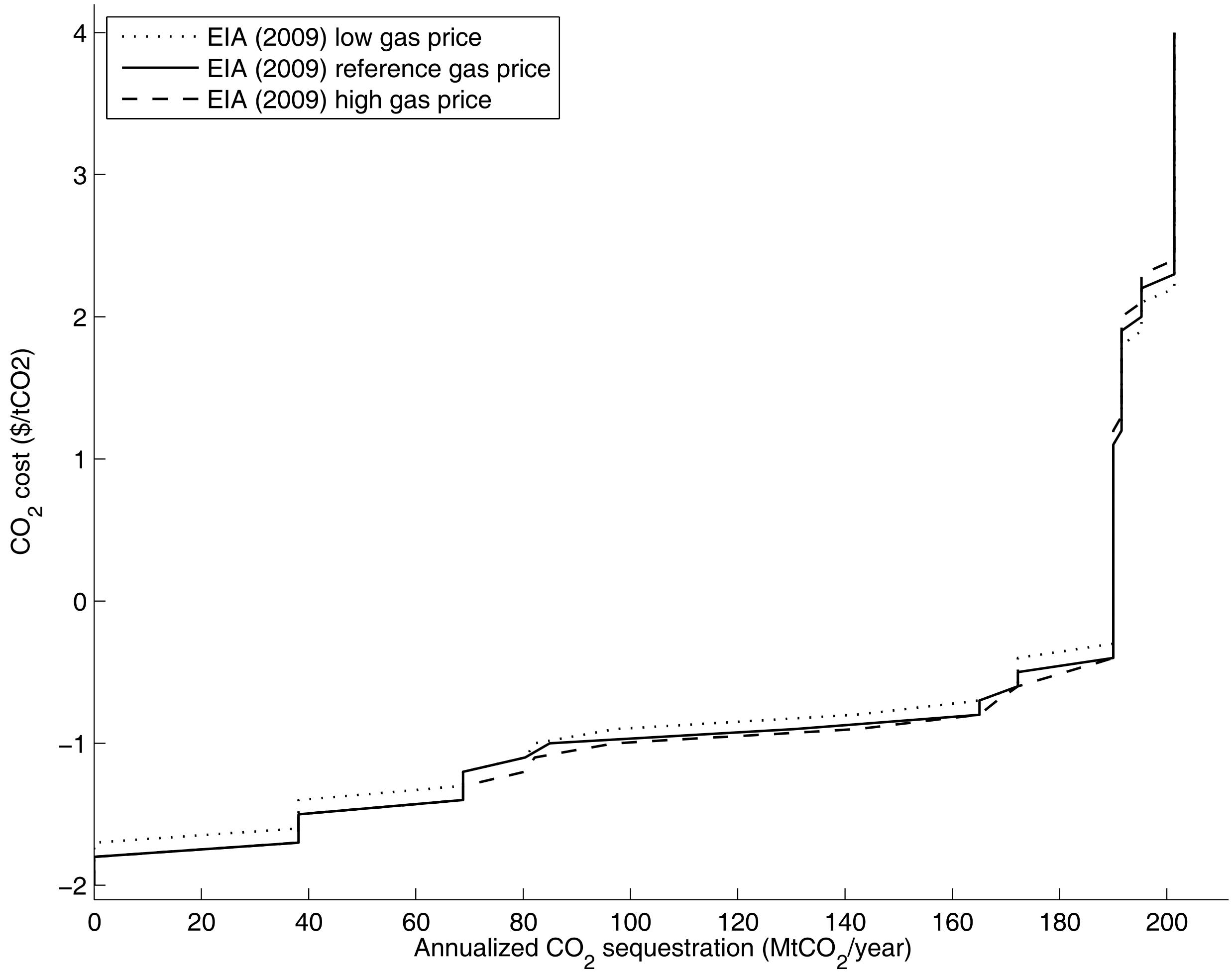

Figure 3: Estimated sequestration supply curves for ECBM at EIA (2009) low, reference, and high gas price projections for 2021-2030.

4. Methodological Approach for EOR

The economic analysis of EOR makes use of the "analog" method of estimating incremental oil recovery from injecting CO_2 into oil reservoirs. This method, discussed in Jarrell et al.'s (2002) monograph on CO_2 flooding published by the Society of Petroleum Engineers, essentially scales the historical production and injection flows observed at some existing, mature EOR project (the analog) to predict those of a new, proposed EOR project. The validity of doing so relies on a central assumption of the method, namely that all the various dimensions across which reservoirs may differ—lithology, area, thickness, porosity, permeability, etc.—are relevant to incremental oil and CO_2 production only insofar as they affect two key scaling factors: (i) per-pattern hydrocarbon pore volume (HCPV) and (ii) injectivity expressed in units of HCPV per unit time.

Specifically, the analog method predicts that if the proposed EOR project happens to have the same per-pattern HCPV and injectivity as the EOR analog project, each of its patterns will generate roughly the same incremental oil and CO_2 flows over time as the analog project did historically. More generally, the proposed project will differ from the analog project in terms of either HCPV or injectivity, in which case the predicted flows are scaled accordingly. If, for example, the proposed project has twice the per-pattern HCPV but the same injectivity, it is predicted to cumulatively produce twice as much from each pattern as the analog project did at any given time after switching to EOR; if, on the other hand, the proposed project has the same per-pattern HCPV but twice the injectivity, it is predicted to cumulatively produce as much as the analog project did, but in half the time; etc.

We apply the analog method to oil fields in the Powder River Basin (PRB) and Green River Basin (GRB) that are not already subjected to CO_2 flooding. Since many oil fields produce from several reservoirs, the unit of analysis is a field-reservoir combination (FRC). Not all FRCs are suitable for EOR, however. For a given FRC, the size and geological properties of the reservoir are factors that decide the profitability of EOR, along with expected revenues from incremental oil production and costs related to CO_2 injection and recycling. As oil prices increase or CO_2 prices decline, more FRCs become profitable for EOR, giving rise to the CO_2 sequestration supply curves that we estimate for the two basins.

Extensive data were collected on all FRCs in the PRB and GRB. These data describe the geology, oil composition, and production and injection history of identified FRCs. Our data were collected from numerous primary sources, including the Wyoming Geological Association, the Wyoming Oil and Gas Conservation Commission, and the proprietary IHS data bank. Journal descriptions of a number of FRCs were consulted to fill gaps. Considerable work continues in updating and checking these data against different source materials.

To estimate sequestration supply curves for the two basins, we examined all FRCs that met two criteria. First, given the large up-front capital costs of EOR projects, we required the fields to be "large." The cutoff chosen was an FRC that had cumulative production of at least 5 million barrels of oil (MMbo) through the end of 2005. Smaller reservoirs were included if another reservoir in the same field met the 5-MMbo cumulative production criterion. This is because reservoirs in the same field can share capital facilities required for EOR. A total of 137 FRCs in the PRB and 181 FRCs in the GRB met the first criterion. The second criterion is that a complete set of data had to be available for the demand analysis. Key data were unavailable for 37 of the 137 FRCs in the PRB, leaving 100 FRCs, and for 121 FRCs in the GRB, leaving 60 FRCs.

For each of these remaining FRCs, we first determined whether the reservoir passed a key physical hurdle, namely the capability to be pressured to a level at which injected CO_2 mixes with the oil. If this so-called minimum miscibility pressure (MMP), which depends on the reservoir's temperature and the oil's API gravity, exceeds the maximum pressure that the reservoir's caprock can withstand, then using CO_2 for EOR becomes far less attractive. This was found to be the case for 3 FRCs in the PRB and for 6 FRCs in the GRB, and these were dropped from consideration as well.

For each of the remaining FRCs, we estimated both the "baseline" net present value NPV^{BAS} of continuing with secondary oil recovery using water injection,

$$NPV^{BAS} = \sum_{t=1}^{T^{BAS}} \frac{p^o Q_t^{op,BAS}(1-\tau^R)(1-\tau^{SP}) - C^o\big(Q_t^{lp,BAS}\big)}{(1+r)^t}$$

and the net present value NPV^{EOR} of switching to EOR,

$$NPV^{EOR} = \sum_{t=1}^{T^{EOR}} \frac{p^o Q_t^{op,EOR}(1-\tau^R)(1-\tau^{SP}) - p^c Q_t^{cm} - C^r\big(Q_t^{cp}\big) - C^o\big(Q_t^{lp,EOR}\big)}{(1+r)^t} - K^{EOR}$$

In these expressions, p^o represents the price of oil (assumed constant over the lifetime of the project), $Q_t^{op,BAS}$, projected baseline oil recovery in period t under the continued waterflood, and $Q_t^{op,EOR}$, projected oil recovery in that same period were the project to switch to a CO_2 flood. To arrive at net operating profits in each period, we subtract from pre-tax oil revenues any royalties at rate τ^R, as well as severance and property taxes at combined rate τ^{SP}. For the EOR project, we we also subtract the projected cost of CO_2 purchases, equal to the CO_2 purchase price p^c (also assumed constant over the lifetime of the project) times the projected quantity purchased, Q_t^{cm}, as well as the projected cost C^r of recycling and re-injecting CO_2. This cost depends on the quantity Q_t^{cp} of CO_2 that is produced together with the oil. Lastly, we subtract other operating costs C^o, which depend in part on the total amount of liquids produced. For the baseline without EOR, liquid production $Q_t^{lp,BAS}$ is just the sum of water and oil produced; for the EOR project, $Q_t^{lp,EOR}$ is the sum of water, oil, and CO_2 produced, since before recycling the CO_2 is mixed in with the oil.

The remaining net operating profits are discounted to the present at the internal rate of return r required by the FRC operator. The economic lifetime of the project, denoted T^{BAS} for the continued waterflood and T^{EOR} for the CO_2 flood, is reached when operating profits turn negative. Switching to EOR in addition involves an up-front investment cost K. We assume that this entire cost is incurred immediately at time 0. Switching is optimal if and only if NPV^{EOR} exceeds NPV^{BAS}.

Implementing the above estimation of NPV^{EOR} requires estimates of an FRC's "response" to EOR—essentially a production function that projects time paths of incremental oil recovery and CO_2 production. As noted above, we use the analog method to generate these estimates. Two analog schedules are necessary to calculate NPV^{EOR}. One schedule predicts incremental oil production, $Q_t^{op,INC}$, which is then added to predicted baseline production to obtain overall EOR production. The other schedule predicts CO_2 production, Q_t^{cp}, all of which is assumed to be recycled and re-injected. Carbon purchases, Q_t^{cm}, are calculated by subtracting predicted production from CO_2 injection. Figure 4 shows the analog schedules used for the analysis. Both are based on historical performance of the Lost Soldier-Tensleep FRC in Southwest Wyoming, which has been under CO_2 flood since 1989 (for more detail on this project, see Brokmeyer et al., 1996).

Economic parameters. Completing the economic analysis (for a given oil price and CO_2 price) requires combining the predicted production, recycling, and purchase paths with cost data. Table 5 shows the values of the various cost parameters used, as well as the sources from which those values were derived. There are a number of cost categories that enter in the NPV calculation.

Investment costs are the up-front expenditures needed to get an EOR project underway; they are the variable K in the expression for NPV^{EOR} and are typically large. Apart from the cost of constructing spur pipelines to connect a project with trunk pipelines for CO_2 and oil (a cost not included in our analysis), the three main cost components are those of (i) drilling new wells, (ii) reconfiguring ("working over") well equipment, and (iii) constructing a CO_2 recycling plant. Costs of drilling new wells are typically very high. This is particularly true in older fields, where many original wells may have been capped because their secondary-phase production declined to unprofitable levels. The spacing between the remaining, active wells may then be too large for an EOR project. Well-workover costs include the costs of replacing tubing in existing wells with tubing that can resist the corrosion by carbonic acid created when CO_2 mixes with water, as well as the costs of laying new pipelines in the field to pump CO_2 to individual wells. Lastly, CO_2 recycling plant costs must be incurred to process the CO_2 that eventually comes back to the surface through producing wells.

Incremental operating costs for EOR projects also have three main components. They consist of (i) costs of purchasing CO_2, (ii) costs of recycling CO_2, and (iii) standard operating costs for incremental liquid production and incremental wells. CO_2 recycling costs consist largely of the costs of energy (electricity or gas) required to fuel the recompression pumps in the recycling plant, together with some labor and maintenance costs associated with that plant. Standard operating costs are those of labor, maintenance, and other inputs required for both waterflooding and EOR operations. Some of these are roughly proportional to the amount of liquids produced, others to the number of wells operated.

3. Results for EOR: Sequestration Supply Curves

The above-described economic analysis is conducted for three different oil prices, namely \$40, \$98, and \$153 per barrel. These correspond to the Energy Information Administration's "low," "reference," and "high" oil price projections for 2021-2030 in its Annual Energy Outlook report for 2009 (EIA 2009), when converted to 2005 dollars and then to Wyoming wellhead prices.

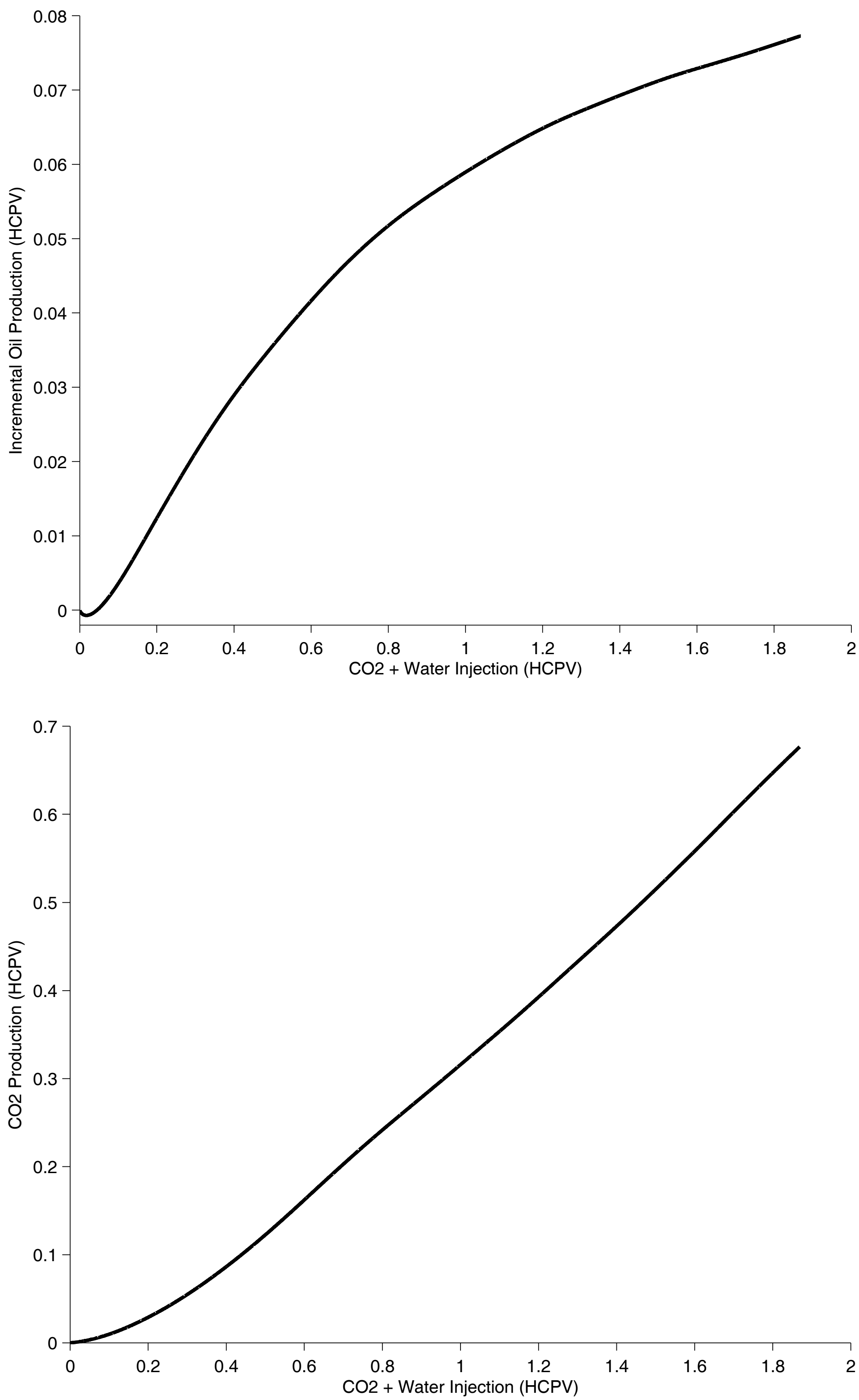

Figure 4: Analog schedules of incremental oil production (top) and CO_2 production (bottom) used in EOR analysis.

Cost parameters	Value [1]		Source
Capital costs			
Well drilling cost		per well	King (2005)
Depth ≤ 3,750 ft	$124*depth		
3,750 < Depth ≤ 5,000 ft	$465,000 + $139*(depth-3,750)		
5,000 < Depth ≤ 7,500 ft	$638,750 + $118*(depth-5,000)		
7,500 < Depth ≤ 10,000 ft	$933,750 + $116*(depth-7,500)		
Depth > 10,000 ft	$1,223,750 + $131*(depth-10,000)		
Well conversion and equipment cost for existing producers	$112,000	per well	Fox (2005)
Well conversion and equipment cost for CO_2 injectors	$120,000 + $15*depth	per well	Fox (2005)
Well conversion and equipment cost for newly drilled wells or existing non-producers	$257,000 + $15*depth	per well	Fox (2005)
CO_2 recyling plant	$1,200	per hp	Nicholas (2005)
CO_2 recycling costs			
Labor	$45	per hp-year	Fox (2005)
Maintenance	$25	per hp-year	Fox (2005)
Electricity	$0.0399	per kWh	EIA (2005)
Field operating costs for waterflood [2]			
Variable	$\$[0.079+2.45*10^{-5}*\text{depth}-6.2*10^{-10}*\text{depth}^2]$	per barrel	EIA (2007)
Fixed	$[(1.25-2.95*depth)*(0.27-0.23*exp(-0.00024*depth))]	per well	EIA (2007)
Field operating costs for CO_2 flood	10% above those for waterflood		Fox (2005)
Royalties and taxes			
Royalty	16%		
Severance tax	6%		
Property tax	6%		

[1] All values are in 2005 dollars

[2] Variable costs are based on fuel, power, and water costs in EIA (2007); fixed costs on all other operating costs

Table 5: Cost parameters used in EOR analysis

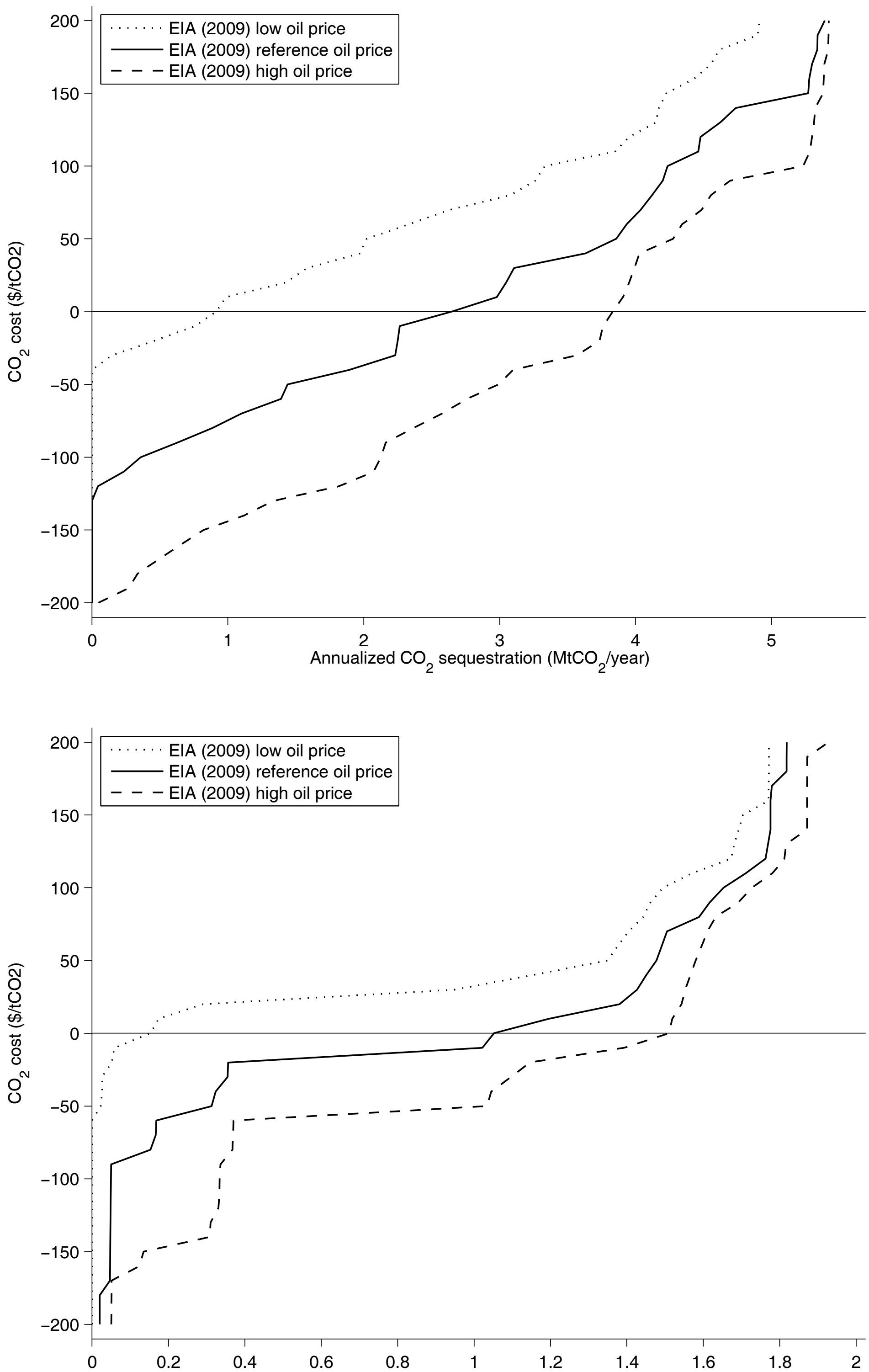

Figure 5: Estimated sequestration supply curves for EOR at EIA (2009) low, reference, and high oil price projections for 2021-2030, for the Powder River Basin (top) and the Green River Basin (bottom).

Based on Plains Marketing (2010), we discount Wyoming oil from the PRB by 16% and from the GRB by 10% relative to the standard West Texas Intermediate crude benchmark, but make no adjustments for oil gravity differences across fields.

The appendix to this report provides a fully worked example of the EOR analysis, using the Raven Creek-Minnelusa FRC in the PRB as an example. Figure 5 shows the estimated sequestration supply curves for EOR for all FRCs combined, though separately for the PRB and GRB. As with the ECBM curves shown in Figure 3, the cost of CO_2 on the vertical axis corresponds to the price *received* by the EOR project for each tonne of CO_2 sequestered, and the quantity of sequestration supplied on the horizontal axis is expressed on an annualized basis.

In comparison with our estimates for ECBM, sequestration by EOR projects is far less sensitive to the CO_2 cost. Underlying this is the much greater heterogeneity of EOR projects, with respect to both size and injectivity. We find that at the EIA's reference oil price, some FRCs can profitably switch to CO_2 flooding even if they have to pay a positive price for CO_2 as high as $200/tonne (about $10/Mcf). At the other extreme, if EOR projects were to receive CO_2 credits of $200/tonne, annualized sequestration of all profitable EOR projects combined would be about 5.4 $MtCO_2$/year in the PRB, and 1.9 $MtCO_2$/year in the GRB.

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Appendix

In this appendix, we illustrate the analog method using a medium-sized field in the PRB, Raven Creek-Minnelusa (RCM), as a worked example. Table 6 lists the data required for applying the analog method, although strictly speaking the list contains some redundancies. Reservoir HCPV, for example, can be estimated either as $OOIP \cdot B_{oi}$ or as $Ah\phi S_{oi}$ · $43{,}560$(ft^2/acre)/5.615 (ft^3/rb). Similarly, injectivity can be estimated either from past water injection rates or from reservoir thickness h and permeability k.

Step 1: Estimate per-pattern $HCPV$. Mack and Duvall (1984) provide a direct estimate of RCM's $OOIP$, so we estimate $HCPV$ for the reservoir as a whole as $OOIP \cdot B_{oi}$= $81{,}169{,}000$ rb. (The alternative formula $Ah\phi S_{oi} \cdot 43{,}560/5.615$ would yield a somewhat higher estimate of $85{,}052{,}000$ rb.) Assuming that 80% of the total reservoir area will be covered with 80-acre patterns (our baseline maximum pattern size) the CO_2 flood will have $n = \text{ceil}(0.8 \cdot 2{,}975/80) = 30$ patterns. Letting H denote per-pattern $HCPV$, we therefore have $H = 2{,}706{,}000$ rb.

Step 2: Estimate water and CO_2 injection rates. We assume that, averaged over the water and CO_2 injection cycles, per-well injectivity for the EOR project is equal to that for the waterflood, so $q^{i,EOR} = q_0^{wi} = 36{,}833$ bl/ptn-mnth. Assuming equal-sized alternating slugs of water and CO_2 will be injected (i.e., a 1:1 WAG ratio), the average rate of water injection will then be $q^{wi,EOR} = 0.5q_0^{i,EOR} = 18{,}416$ bl/ptn-mnth, while that of CO_2 will be $q^{ci} = 0.5q_0^{i,EOR}/B_{CO2} = 41{,}788$ Mcf/ptn-mnth.

Step 3: Estimate time paths of incremental oil and CO_2 production using the dimensionless curves. Dividing $q^{i,EOR}$ by H gives a total injectivity of 0.01361 $HCPV$/ptn-mnth. Cumulating this for any given number of months after starting the CO_2 flood yields a point on the horizontal axis of the dimensionless curve for incremental oil production (see Figure 4). Reading off the corresponding point on the vertical axis yields cumulative incremental oil production by that same number of months in *HCPV*/ptn, or, after multiplying by H/B_{oc}, in stb/ptn. Differencing the cumulative values yields the corresponding time path of incremental oil production rates, $q_t^{op,INC}$, in stb/ptn-mnth. Lastly, multiplying by the number of patterns n yields the predicted time path of incremental oil production for the field as a whole, $Q_t^{op,INC}$, in stb/mnth. Applying the same steps to the dimensionless curve for CO_2 production (but multiplying cumulative production in HCPV/ptn on the vertical axis by H/B_{CO2}) yields the predicted time path of CO_2 production, Q_t^{cp}, in Mcf/mnth.

Step 4: Estimate time paths of baseline and EOR oil production, water production, non-CO_2 (hydrocarbon) gas production, and EOR purchases of CO_2. Baseline oil production $Q_t^{op,BAS}$ from a continued waterflood is assumed to continue declining at rate δ, so $Q_t^{op,BAS} = Q_0^{op}e^{-\delta t}$.

EOR oil production is then $Q_t^{op,EOR} = Q_t^{op,BAS} + Q_t^{op,INC}$. Overall water production is assumed to change in a manner that keeps overall liquids (oil plus water plus possibly CO_2) production at

Variable		Value		Source
$OOIP$	Original oil in place	73,790,000	stb [1]	Mack and Duvall (1984)
B_{oi}	Oil formation vol. factor (initial)	1.1	rb/stb [2]	TORIS [3]
B_{oc}	Oil formation vol. factor (current)	1.089	rb/stb	TORIS
API	Oil gravity	33	°API	TORIS
T	Temperature	200	°F	TORIS
MMP	Minimum miscibility pressure	3,082	psi	Derived [4]
B_{CO2}	CO_2 formation vol. factor	0.7001	rb/Mcf	Derived [5]
p^f	Fracture pressure	5,548	psi	WOGCC [6]
d	Depth	8,380	ft	Lucken (1969)
h	Thickness	37	ft	Lucken (1969)
A	Area	2,975	acres	Lucken (1969)
ϕ	Porosity	0.12	(fraction)	Lucken (1969)
k	Permeability	50	md	Lucken (1969)
S_{oi}	Oil saturation (initial)	0.83	(fraction)	TORIS
n_c^p	Existing producer wells	15		WOGCC
n_c^i	Existing injector wells	13		WOGCC
n_c^{ta}	Temporarily abandoned wells	12		WOGCC
Q_0^{op}	Oil production (end of waterflood)	6,833	stb/mo	IHS [7] (estimated) [8]
δ	Oil production decline rate (e.o.w.)	0.45	%/mo	IHS (estimated) [9]
Q_0^{wp}	Water production (e.o.w.)	396,536	bl/mo	IHS (estimated) [10]
q_0^{wi}	Water injection per well	36,833	bl/wl-mo	IHS (estimated) [11]
R	Gas-oil ratio	0	Mcf/bl	IHS (estimated) [12]

[1] Stock-tank barrels (42 gallons U.S. at 60 °F and 14.7 psi).
[2] Reservoir barrels (42 gallons U.S. at reservoir temperature and pressure).
[3] Total Oil Recovery Information System database, U.S. Department of Energy, National Petroleum Technology Office.http://www.netl.doe.gov/technologies/oil-gas/Software/database.html.
[4] Derived from API and T using DOE (2006) correlation $MWC_5^+ = 4247.98641 API^{-0.87022}$ combined with Emera and Sarma (2005) correlation $MMP = 0.00726538 T^{1.164} (MWC_5^+)^{1.2785}$.
[5] Derived from T and MMP using sw_SPECIFIC_DENSITY.m Matlab subroutine provided by McPherson et al. (2008) at http://www.iamg.org/documents/oldftp/VOL34/v34-05-01.zip
[6] Wyoming Oil and Gas Conservation Commission. http://wogcc.state.wy.us.
[7] IHS PI/Dwights PLUS database. http://energy.ihs.com.
[8] Predicted end value $\hat{Q}_0^{op}$ from linear regression $\log Q_t^{op} = \alpha + \delta t$ of log monthly oil production on a time trend $t = -35, -34, \dots, 0$ for the most recent 36 months of production data.
[9] Estimated coefficient on t in above regression.
[10] Estimated using same procedure as that for oil production, but using log monthly water production.
[11] Median water injection rate per actively injecting well since 1985.
[12] Median ratio of monthly hydrocarbon gas production to oil production for the most recent 36 months of production data.

Table 6: Data requirements for the analog method, with example values for the Raven Creek-Minnelusa field.

reservoir conditions constant over time, and equal to overall liquids injection. Baseline water production is therefore $Q_t^{wp,BAS} = Q_0^{wp} + Q_0^{op}(1 - e^{-\delta t})B_{oc}$. EOR water production is $Q_t^{wp,EOR} = nq^{i,EOR} - Q_t^{op,EOR}B_{oc} + Q_t^{cp}B_{CO2}$. Hydrocarbon gas production is assumed to maintain a constant ratio to oil production, so $Q_t^{gp,BAS} = RQ_t^{op,BAS}$ and $Q_t^{gp,EOR} = RQ_t^{op,EOR}$. For RCM, no gas production is reported, however, which we interpret to imply that $R \approx 0$. Lastly, CO_2 purchases Q_t^{cm} are calculated as the difference between CO_2 production (all of which is recycled) and injection, so $Q_t^{cm} = Q_t^{cp} - nq^{ci}$.

Step 5: Estimate up-front costs of well drilling, conversion, and equipment. With on average one injector and one producer for each of $n = 30$ patterns, the CO_2 flood will require $2n - n_c^p - n_c^i - n^{ta} = 20$ new wells to be drilled, at (given RCM's depth in the PRB) $1.04 million per well. Converting and equipping any kind of well (newly drilled, existing injector, existing producer, or temporarily abandoned) for use as a CO_2-flood injector cost $120,000 plus $15/ft; converting and equipping wells for use as CO_2-flood producers cost $112,000 for existing producers, and $257,000 plus $15/ft for newly drilled wells or existing non-producers. Total costs sum to about $35.5 million.

Step 6: Estimate the up-front capital cost of gas recycling. The required capacity of the gas recycling plant is determined by the peak of projected combined production of CO_2 and (in this case zero) hydrocarbon gas, which for RCM is 31.4 thousand Mcf/day. We assume the gas plant operates at inlet pressure $p^s = 225$ psi, and that the CO_2 flood is operated at a reservoir injection pressure of $\max(p^f - 200, MMP) = 5{,}348$ psi. Subtracting from this the pressure gain of 0.28(psi/ft)$\times$ $8{,}380 = 2{,}346$ psi obtained from the CO_2 column in the injection well yields the plant's required discharge pressure, $p^d = 3{,}001$ psi. Based on a rule-of-thumb formula provided by Fox (1995), the gas throughput capacity and p^d/p^s ratio combined yield an estimated power requirement for the plant of 5,407 hp, which at a cost per hp of $1,200 yields a capital cost for the recycling plant of about $6.5 million.

Step 7: Estimate operating costs of gas recycling. Labor and maintenance operating costs for gas recycling are $70 per hp-year. Electricity costs, at 7,000 kWh/hp-year and Wyoming's electricity price for industrial users of 3.99 cents/kWh, amount to an additional $279 per hp-year. The overall gas recycling operating cost is about $1.9 million/year.

Step 8: Estimate other operating costs. Based on data in EIA (2007), operating costs were the waterflood to continue are estimated at $0.24 per barrel of total liquids produced plus $25,000 per well-year for each of RCM's current 28 wells. Based on a rule of thumb given in Fox (1995), the corresponding costs for the CO_2 flood are assumed to be 10% higher, whereby the per-well costs apply to the CO_2 flood's 60 wells.

Step 9: Determine the terminal times for the continued waterflood and CO_2 flood. At our reference oil price of \$98 at the Wyoming wellhead, oil revenues net of 16% royalty, 6% severance tax, and 6% property tax drop below operating costs after $T^{BAS} = 21.5$ years of continued waterflooding. At the same oil price and a CO_2 tax (i.e., a negative cost to the operator) of $\$20$/t$CO_2$, net revenues from the CO_2 flood's total oil production (i.e., baseline and incremental oil production combined) drop below operating costs, including the cost of CO_2 purchases, after $T^{EOR} = 22.75$ years.

Step 10: Compare the NPV of the continued waterflood and CO_2 flood. At the reference prices and our baseline internal rate of return of $r = 0.20$, the NPV^{BAS} of continuing the waterflood is \$15.2 million, while the NPV^{EOR} of switching to a CO_2 flood, net of initial capital costs, is substantially higher, at $\$190.4$ million. Switching is therefore optimal.

Step 11: Calculate cumulative incremental oil production and CO_2 demand. Cumulative oil production under the continued waterflood, up to T^{BAS}, is 1.04 million barrels, while that under the CO_2 flood, up to T^{EOR}, is 7.52 million barrels. Incremental production is therefore 6.48 million barrels, or 8.8% of *OOIP*. Cumulative CO_2 sequestration is 59.4 Bcf.