Economic Co-optimization of Enhanced Oil Recovery and Carbon Sequestration

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1. Introduction

There is a growing consensus in both policy circles and in the energy industry that within the next few years, the US Federal government will adopt some form of regulation of CO_2 emissions.[1,2] At the same time, it is widely believed that much of the nation's energy supply over the coming decades will continue to come from fossil fuels, coal in particular (MIT; 2007). Many analysts believe the only way to reconcile the anticipated growth in the use of coal with anticipated limits on CO_2 emissions is through the development and deployment of carbon capture and geological sequestration (CCS). However, many key players are hesitant to undertake CCS. The recent cancellation of clean-coal power plants in Tampa, Florida and in Saskatchewan, Canada speaks to this hesitation. In light of this hesitancy, the first geologic sequestration projects to gain a foothold are likely to be those exploiting CO_2-enhanced oil recovery (EOR).

This technique, which has been used successfully in a number of oil plays (notably in West Texas, Wyoming, and Saskatchewan), entails injection of CO_2 into mature oil fields in a manner that causes the CO_2 to mix with some fraction of the oil that still remains underground. Doing so reduces the oil's viscosity, thereby making it possible to extract additional, otherwise unrecoverable oil.[3]Although some of the CO_2 resurfaces with the oil, it can be separated from the output stream, recompressed, and reinjected. Eventually, when the EOR project is terminated, all the injected CO_2 is sequestered.

EOR is a "game-changing" technology for the recovery of oil from depleted reserves. Estimates suggest that recovery rates for existing reserves could be approximately doubled, while the application of EOR on a broad scale could raise domestic recoverable oil reserves in the United States by over 80 billion barrels (ARI; 2006). Similarly, Shaw and Bachu (2003) claim that 4,470 fields, just over half of the known oil reservoirs in Alberta, are amenable to CO_2 injection for enhanced oil recovery. Babadagli (2006) states that enhanced oil recovery applied in these reservoirs could

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[1] Consider that among the current candidates for the US presidency, John McCain was the lead author of a Senate proposal to reduce carbon emissions by 65 percent by 2050, while Barack Obama is on record as supporting a cut in carbon emissions of 80 percent by 2050. (Scott Horsley, *2005 Election Issues: Climate Change*, National Public Radio, http://www.npr.org/news/specials/election2005/issues/climate.html).

[2] For example, the Vice President of Environmental Policy for Duke Energy stated in a Washington Post article, "Our viewpoint is that it's going to happen. There's scientific evidence of climate change. We'd like to know what legislation will be put together so that, when we figure out how to increase our load, we know exactly what to expect." (Steven Mufson and Juliet Eilperin, "Energy Firms Come to Terms With Climate Change," Washington Post, Saturday, November 25, 2005, p. A01)

[3] Other methods of enhanced oil recovery exist as well, including injection of nitrogen, methane, and various polymers. Because these methods are not the focus of this paper, we use the term enhanced oil recovery, or EOR, as shorthand for CO_2-enhanced oil recovery.

translate in an additional 165 billion barrels of oil recovered and over 1 Gt of CO_2 sequestration. (Snyder et al.; 2008) estimate that at current oil and carbon prices and with current technology, approximately half of this capacity is economically viable.

It is important to stress, nevertheless, that the overall sequestration capacity of EOR projects is not very large, whether in comparison to CO_2 emissions or to other geological sequestration options. For example, Canada's CO_2 emissions in a single year are roughly half of 1 Gt (Environment Canada; 2008a), suggesting that the potential sequestration capacity from EOR is no more than two years' worth of emissions. Similarly, Dooley et al. (2006) estimate the theoretical sequestration capacity of depleted U.S. oil reservoirs (including those depleted through EOR) at 12 $GtCO_2$ or roughly two years' worth of U.S. CO_2 emissions (EPA; 2008). By contrast, Dooley et al. estimate the theoretical sequestration capacity of U.S. saline aquifers to be as large as 3,630 Gt CO_2. Plainly, the main contribution to geological sequestration will eventually have to come from saline aquifers.

Rather than offering an important immediate source of sequestration, the importance of EOR may lie in its ability to provide a bridge to potential long run sequestration. That is, profits from enhanced oil revenues can be used to "jump-start" the building of pipelines and other infrastructure required for ultimately much larger-scale sequestration in saline aquifers.[4]

In this paper, we present what is to our knowledge the first theoretical economic analysis of CO_2-enhanced oil recovery. In the tradition of Hotelling (1931), an oil field contains a physical quantity of oil which the producer seeks to extract at a particular rate over time so as to maximize the economic rents from extraction. The ability to enhance oil extraction rates through injection of CO_2 alters this extraction problem in a number of non-trivial ways.

First, CO_2 is not a costless input. Significant up-front investments are required to make production and injection wells suitable for CO_2 use. In addition, maintaining a given injection rate over time requires continuous purchases make up for the fraction of injected CO_2 that remains sequestered in the reservoir. Separating the remaining fraction that resurfaces with the produced oil, and then dehydrating and recompressing it, is costly as well, requiring both up-front capital costs and variable processing costs.

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[4] This view was expressed succinctly in recent testimony by William L. Townsend, CEO of a company group that has been involved in the construction of most major existing CO_2 pipelines in the U.S., before the Energy Subcommittee of the U.S. Senate's Finance Committee: "It is clear that the long-term geologic sequestration answer to single-point, industrial CO_2 emissions capture and storage is in saline aquifers, not EOR projects. That being said, there is a very strong, cost-effective interim answer for the next ten years that employs the oil-based revenues in EOR to subsidize the infrastructure build-out and prepare the foundation of a carbon highway for the next generation of cost-effective CCS in power generation." (Towsend; 2007)

Second, even at a constant injection rate, the amount of oil recovered declines over time, as does the fraction of injected CO_2 that remains sequestered in the reservoir. Both the producer's revenue stream and cost stream are therefore time varying.

Third, while sequestration of CO_2 currently yields no economic benefits in jurisdictions without carbon emissions restrictions, future regulations of CO_2 emissions in the context of climate-change policies may generate such benefits if EOR projects are allowed to earn credits for units of CO_2 sequestered. The producer's objective would then be the maximization of the combined revenue streams from both oil production and CO_2 sequestration, net of CO_2 purchase and recycling costs.

Fourth, carbon taxes affect these revenue and cost streams in multiple ways. While a carbon tax effectively reduces the input cost for EOR and increases the net present value of the CO_2-storage potential of the oil field, the incidence of the tax on the price of oil reduces the value of the traditional use of the asset.

Fifth, in addition to these economic tradeoffs, fluid-dynamic interactions of CO_2, water, and oil inside the reservoir give rise to a further, physical tradeoff faced by the producer. Whereas injecting pure CO_2 maximizes oil recovery from the area of the reservoir that the CO_2 sweeps through, that area itself may be small, as pure CO_2 tends to "finger" or "channel" between injection and production wells, bypassing some of the oil. In comparison, injecting pure water increases the area that is swept, but reduces recovery from that area. Reservoir-engineering studies[5] indicate that both oil recovery and CO_2 sequestration are maximized when a mix of CO_2 and water is injected (whereby the CO_2 fraction that maximizes oil recovery typically differs from that maximizing sequestration).

Our paper provides an evaluation of the role of all five factors. We start by developing a theoretical framework that analyzes the dynamic co-optimization of oil extraction and CO_2 sequestration, through the producer's choice at each point in time of an optimal CO_2 fraction in the injection stream (the control variable). The decision to cease extraction is determined by a transversality condition. Both the injection and termination decisions depend in part on the anticipated price of oil and the carbon tax or credit price. The paper concludes with a series of simulations that are based on an ongoing project, namely the Lost Soldier-Tensleep field in Wyoming. These simulations generate time paths of CO_2 injections. In turn, these time paths of injection imply time paths of oil

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[5] See, e.g., Al-Shuraiqi et al. (2003), Jessen et al. (2005), Juanes and Blunt (2006), Guo et al. (2006), and Trivedi and Babadagli (2007).

extraction; comparing against the corresponding time path of oil production under secondary production (which relies on injecting water but not gas) allows one to estimate the additional volume of oil produced under EOR and the amount of CO_2 that is ultimately sequestered. It also allows estimation of the net present value of incremental profits from EOR (over and above those that would be earned by continuing secondary production), and thereby of the potential contribution that EOR might make to the development of CCS infrastructure.

2. The Model

Our model of oil production is based on the physical reality that input injections (water, gas, or some mixture of the two) must balance with fluid output (oil, water, and gas).[6] In addition, the rate of oil production is linked to remaining reserves by the so-called "decline curve."[7] This relation specifies output as a particular fraction of remaining reserves, where that fraction is itself linked to the fraction of CO_2 in the injection stream. Upon specifying the relation between rate of CO_2 injection and oil production we may write down the formal dynamic optimization model, which we then use to describe the time path of CO_2 injection. Ultimately, this allows us to describe the rate of CO_2 that is sequestered at every point in time, and thereby to determine the total amount sequestered.

We begin with some notation. Let the physical capacity of input injections be I, which can be thought of as the capacity of the injecting wells. We write the rate of CO_2 injection at time t as $c(t)$, and the rate of water injection at time t as $h_i(t)$. We assume the total rate of injection is constant across time. This reflects the fact that CO_2-EOR projects are usually operated at "minimum miscibility pressure," which is the minimum pressure required to make the CO_2 mix with the oil. Maintaining that pressure requires a roughly constant overall injection rate. In light of this assumption, $c(t) + h_i(t) = I$ at each point in time.

Let the rate of oil production at time t be $q(t)$, the rate of CO_2 production (or "leakage") at time t be $\ell(t)$, and the rate of water production at time t be $h_p(t)$. Materials balance then requires

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[6] Reservoir engineers refer to this as "materials balance." It should be noted that this requirement applies at the temperature and pressure conditions that obtain inside the reservoir. At these conditions, CO_2 exists in a highly compressed, "supercritical" state and behaves much like a fluid.

[7] Fetkovitch (1980) provides an in-depth discussion of decline curves, and of the justification for their widespread use in predicting oil production from reservoirs.

that

$$q(t) + l(t) + h_p(t) = c(t) + h_i(t)$$

at each point in time (with both sums equaling I). The leaked CO_2 can be vented or recycled. Let the price of a unit of newly purchased CO_2 equal w_s and the unit cost of recycling CO_2 equal w_ℓ. We assume that $w_s > w_\ell$, so that it is cheaper for the firm to recycle than to vent.[8]

Since all leakage is re-injected, total CO_2 injection is the sum of new purchases and leakage, or

$$c(t) = s(t) + \ell(t). \tag{1}$$

The rate at which CO_2 is sequestered depends on the linkage between injected CO_2 and produced oil. We assume that the fraction of oil production displaced by CO_2 (as opposed to that displaced by water) is proportional to the fraction of CO_2 in the total injection stream. We also assume that sequestered CO_2 takes up the underground space vacated by the oil that it displaces. To simplify the exposition, units of oil are chosen such that in the reservoir, vacating the space taken up by one unit of oil creates space for sequestering exactly one unit of CO_2. As a result, we have $s(t) = c(t)q(t)/I$. As we are focusing on an individual firm and a particular oil reservoir, we may normalize so that $I = 1$. Accordingly,

$$s(t) = c(t)q(t). \tag{2}$$

At any point in time, the amount of recoverable oil is $R(t)$; we write the initial amount of oil at the moment the EOR project is undertaken as R_0. As usual, this variable plays the role of the state variable in our analysis, and it evolves via

$$\dot{R} = -q. \tag{3}$$

In keeping with the physical reality of oil recovery, we assume that the rate of production can be described by a decline curve: $q(t) = \delta R(t)$. In our setting, however, the ratio of output to reserves—which plays the role of the decline rate—is linked to the rate of injection: $\delta = \delta(c)$. We therefore have the relation

$$q(t) = \delta(c)R(t). \tag{4}$$

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[8] In practice, the purchase price of CO_2 is several times higher than the cost of recycling. Thus, firms undertaking EOR do generally recycle CO_2. Importantly, the presence of a carbon price τ does not change the relevant comparison: the cost of a newly purchased unit becomes $w_s - \tau$ (as the seller of the CO_2 avoids the carbon tax or receives a credit for sequestering), while the opportunity cost of recycling becomes $w_\ell - \tau$ (as venting would obligate the producer to pay the carbon tax or purchase a credit).

Combining (3) and (4), we obtain

$$\dot{R} = -\delta(c)R. \tag{5}$$

Consistent with results from the reservoir-engineering studies cited in the introduction, we assume that the $\delta(c)$ function relating the rate of injection to the decline rate is concave, with an interior maximum. If only water is used (termed a "waterflood"), the decline rate is $\delta_w \equiv \delta(0) > 0$. If only CO_2 is used (termed a "pure CO_2 flood"), the decline rate is $\delta(1)$. We assume, consistent again with reservoir-engineering studies, that $\delta(1) > \delta_w$. In light of the concavity of $\delta(c)$, $\delta'(0) > 0 > \delta'(1)$.

The economic environment depends on three ingredients: the price of oil, p; the carbon tax, τ; and operating costs. For now, we take both the price of oil and the price of carbon as atemporal; we consider the implications of time-varying prices later in the paper. We assume that all costs other than those of CO_2 purchases and CO_2 recycling are tied to the overall amount of fluids injected and the amount of fluids produced. As both amounts are constant and equal to I, these other costs are a constant F. Accordingly, the firm earns a rate of profits equal to

$$\pi = pq - (w_s - \tau)s - w_\ell \ell - F.$$

Using (1), (2), and (5), we may rewrite the profit rate as

$$\pi = p\delta(c)R - [w_s - \tau]c\delta(c)R - w_\ell c[1 - \delta(c)R] - F$$

$$= p\delta(c)R - [w_s - \tau - w_\ell]c\delta(c)R - w_\ell c - F. \tag{6}$$

Since the combustion of oil generates CO_2 as a by-product, it seems reasonable to expect that there will be a tax liability embedded within the market price. To facilitate further discussions of the role played by the carbon tax, it will be convenient to isolate this effect in the expression of profits. To that end, we denote the induced tax liability for a one dollar increase in the carbon tax by β. This parameter combines tax incidence effects with unit conversions associated with the transformation of a unit of produced oil into carbon units. Adjusting (6) to take account of these aspects, we may write the rate of profits as

$$\pi = (p - \beta\tau)\delta(c)R - [w_s - \tau - w_\ell]c\delta(c)R - w_\ell c - F.$$

To save on notation, we will typically summarize the combination $p - \beta\tau$ as Y and the combination $w_s - \tau - w_\ell$ as Z. Using this notational convention, the profit rate is

$$\pi = Y\delta(c)R - Zc\delta(c)R - w_\ell c - F.$$

3. ANALYSIS

The goal of the firm is to choose a time path of the injection rate $c(t)$ so as to maximize its present discounted value, subject to the state equation (5), the initial value of the state variable, R_0, and the constraints $0 \leq c \leq 1$, $R \geq 0$. Both the terminal time T and the terminal stock $R(T)$ are free, and so the optimal choices of these values will be governed by transversality conditions. To solve this dynamic optimization problem, we first define the current-value Hamiltonian

$$H = \pi - mq = Y\delta(c)R - Zc\delta(c)R - w_\ell c - F - m\delta(c)R, \tag{7}$$

where m is the current-value multiplier (shadow price) associated with a unit of oil *in situ*.

The optimal path of extraction satisfies the maximum principle, which consists of the state equation, an equation for identifying the optimal extraction rate at a given point in time, and an equation of motion for the shadow price. If the optimal extraction rate is described by an interior solution, we have

$$H_c = (Y - Zc - m)\delta'(c)R - Z\delta(c)R - w_\ell = 0, \tag{8}$$

where $H_c = \partial H/\partial c$. The state equation is given by (5), and the equation of motion for the shadow price is

$$\dot{m} = rm - (Y - Zc - m)\delta(c). \tag{9}$$

Because the end time is free, the value of the current-value Hamiltonian at the terminal time T must be zero. As the end state is free, the product of the shadow price and the state variable at the terminal time must also be zero: $m(T)R(T) = 0$. As the extraction rate is proportional to the stock, we infer from (7) that the profit rate must be zero at time T. But for that to happen there must be positive revenues, which in turn requires a positive production rate. It follows that the terminal stock is positive, so that the terminal value of the shadow price must be zero.

We now turn to a discussion of the time path of injection. Assuming an interior solution over an interval, we may time-differentiate (8) to get

$$\dot{c} = [-H_{cm}\dot{m} - H_{cR}\dot{R}]/H_{cc},$$

where $H_{cx} = \partial^2 H/\partial c \partial x$, $x = m, c$ or R. From (8), we see that $H_{cm} = -\delta'(c)R$ and $H_{cR} = (Y - Zc - m)\delta'(c) - Z\delta(c) = w_\ell/R$ (where we use (8) to extract the last relation). Combining these observations with the state equation, we get

$$\dot{c} = [\delta'(c)R\dot{m} + w_\ell\delta(c)]/H_{cc}. \tag{10}$$

At an interior solution, the denominator is negative and the second term within square brackets is positive. It follows that injection is falling at any moment where $\delta'(c)\dot{m}$ is positive; if it is negative, the sign of $\dot{c}$ is ambiguous.

To further explore the time path of c, we combine (8) and (9) to get

$$\delta'(c)R\dot{m} + w_\ell\delta(c) = [r\delta'(c)m - Z\delta(c)^2]R. \tag{11}$$

Comparing (10) and (11), it is apparent that a sufficient condition for $\dot{c}$ To be negative is for the right-hand side of (11) to be positive. This will occur, for example, if $\delta' > 0$ and Z is not large and positive, or if Z is negative and large in magnitude. Heuristically, $\delta' > 0$ is consistent with the notion of restraining current production so as to allow rents to rise over time, which seems plausible. For Z to be small is a bit less obvious. Recall that $Z = w_s - \tau - w_\ell$, and that by assumption $w_s - w_\ell > 0$. If $w_s - w_\ell$ is small, which is the case in our simulations and seems to be the empirically important case, then Z will be small irrespective of the size of the carbon tax. On the other hand, if the carbon tax is particularly large then Z will be negative. On balance, then, the right-hand side of (11) will be positive in a range of cases that seem empirically relevant. As such, the rate of injection will commonly be declining.

The preceding discussion focuses on interior solutions. While these will be common, there are circumstances under which corner solutions obtain. We now discuss those conditions. First, suppose the optimal rate of CO_2 injection is zero (i.e., it is optimal to undertake a waterflood); in that case $H_c \leq 0$ when evaluated at $c = 0$. The condition of interest is

$$(Y - m)\delta'(0)R - Z\delta_w R - w_s \leq 0.$$

Because m and R do not change discontinuously, if this condition holds with strict inequality at a particular moment t, it must hold for an interval of time following t. Accordingly, during this interval the optimal level of c remains equal to zero. It follows that during this interval

$$\dot{H}_c = -\delta'(0)[R\dot{m} - (Y - m)\dot{R}] - Z\delta_w \dot{R},$$

or, upon using (5),

$$\dot{H}_c = -\left\{\delta'(0)[\dot{m} + \delta_w(Y - m)] - Z\delta_w^2\right\} R. \tag{12}$$

Combining (9) and (12), taking note of the fact that $c = 0$, we deduce that

$$\dot{H}_c = -[rm\delta'(0) - Z\delta_w^2]R. \tag{13}$$

The important thing to note here is that for negative values of Z, or values of Z that are positive but relatively small in magnitude, the right-hand side of (13) will be non-positive; as we noted above, this restriction does not seem to be terribly demanding. In such a scenario, once H_c becomes negative, it tends to stay negative. We conclude that it will be typical for firms to stay in a waterflood regime once it is initiated.

Now suppose the optimal rate of CO_2 injection is one (i.e., it is optimal to undertake a pure CO_2 flood); in that case $H_c \geq 0$ when evaluated at $c = 1$. The condition of interest is

$$(Y - Z - m)\delta'(1)R - Z\delta(1)R - w_s \geq 0.$$

As with the $c = 0$ corner solution, if this condition holds with strict inequality, it must apply for an interval of time; during that interval we have

$$\dot{H}_c = -[rm\delta'(1) - Z\delta(1)^2]R. \tag{14}$$

As noted above, the only way this corner solution can obtain is if Z is negative and large in magnitude. On the other hand, $\delta'(1) < 0$. Thus, depending on the relative magnitudes of Z and m, $\dot{H}_c$ can either be rising or falling. Importantly, as m is likely to fall over time, eventually $\dot{H}_c$ will become negative. It follows that the pure CO_2 flood cannot last indefinitely: at some point, it will be optimal to adopt an interior solution.

The forgoing discussion was couched in the context of atemporal prices. While we adopted that assumption for analytical convenience, it is plainly an oversimplification. Oil prices have increased dramatically in the last 12 months, and the U.S. Energy Information Administration expects them to rise in real terms by an average of 0.5% per year over the period from 2000 through 2030 under its reference scenario, and 2.8% per year under its high-price scenario (EIA; 2008). Both scenarios adopt a baseline price of $100.6/bl for 2008. Carbon prices may also grow significantly. For example, modeling conducted for the Canadian government suggests that under current policies, the average cost of carbon abatement faced by Canadian firms will grow at a rate of almost 12% per year between 2005 and 2020 (Environment Canada; 2008b). These changes will alter the value of EOR projects and will have significant effects on the optimal time path for CO_2 injection.

Before proceeding to a discussion of our simulation analysis, let us briefly consider the implications of changing prices. Such a revision would not change the first-order condition for c, but it would alter the resultant time path for an interior solution. With time-varying prices, both Y and Z can be time-varying. As such, the equation of motion for optimal carbon injection is

$$\dot{c} = [-\delta'(c)R\dot{Y} + (c\delta'(c) + \delta(c))R\dot{Z} - H_{cm}\dot{m} - H_{cR}\dot{R}]/H_{cc}. \tag{15}$$

Relative to the earlier discussion, there is a new effect associated with changes in Y and Z. If the price of oil is rising over time, then so is Y. Accordingly (since $H_{cc} < 0$ at an interior solution), a positive influence on the rate of change in c is introduced. If prices are rising fast enough, it is conceivable that this influence will lead to a rising rate of CO_2 injection at some point in time (as our simulations show). On the other hand, if the price of carbon is rising over time, then both Y and Z fall. The net impact on the first two terms in (15) is ambiguous, and indeed depends on the parameter β.

4. Simulation Framework

In order to add greater context to the results derived above, we have solved and simulated the model numerically to yield optimal transition paths under an array of exogenous price paths for carbon and oil. Below we first discuss the solution algorithm and then present results.

The optimization problem is reasonably straightforward, in that it involves a single control variable, CO_2 injection c, which is optimized given a single state variable, remaining physical

reserves R. The problem is solved by first converting it to discrete time and then solved using an algorithm which iterates on an approximation to the solution to the Bellman equation. Here, the solution to the dynamic program is computed using a neural-network approximation defined over a finite set of grid points distributed within the state space.[9]

Let $V(R)$ denote the optimal value function:

$$V(R) = \max_c Y\delta(c)R - Zc\delta(c)R - w_\ell c - F + V(R - \delta(c)R). \tag{16}$$

Write $\Phi(R|\phi)$ as an approximation of $V(R)$ over a grid defined by neural network parameter values ϕ. The algorithm consists of 5 steps:

(1) Draw a distribution of grid points in R space.

(2) Begin with an initial guess of $\Phi^0(R) = 0, \forall R$ and solve (16) given this guess at each grid point. Denote the solution to this iteration by $V^1(R)$.

(3) Compute the approximation for iteration $i = 1, 2, \ldots$ by solving $\min_\phi\{\Phi(R|\phi) - V^i(R)\}^2$ and denote the solution $\Phi^i(R)$.

(4) Solve $V^{i+1} = \max_c Y\delta(c)R - Zc\delta(c)R - w_\ell c - F + \Phi^i(R - \delta(c)R)$.

(5) Return to step 3 unless $||V^i(R) - V^{i-1}(R)|| < 10^{-6}$.

The final approximation, $\Phi(R, \phi)$, represents an approximate solution to the dynamic program.

We compute the solution for scenarios with oil prices of \$100, \$200, and \$300 per barrel (bl), taking \$100/bl as our baseline price, and for carbon taxes of \$0, \$40, \$80, and \$120 per tonne of $CO_2(tCO_2)$, taking the absence of any tax as our baseline. We also augment the model by adding a time index as a state variable and allowing for carbon and oil prices that increase over time, in which case we take \$100/bl as the initial oil price, and \$40/tCO$_2$ as the initial tax. The rates of increase are given as the initial rate, whereby this rate itself is assumed to decline over time, at 4%/year. We examine initial rates of increase of 2.5%, 5%, and 7.5%.

Table 1 shows the baseline parameter values of the numerical model. All quantity flows are in units of 1 million "reservoir" barrels (rb) per year (1 barrel= 42 gallons (US) $\approx 0.16m^3$), meaning barrels at the temperature and pressure conditions that obtain inside the reservoir. Overall injection I is normalized to 1 million such barrels.

The initial stock of oil in the reservoir, R_0 is set at 1 million barrels as well. For comparison, the Lost Soldier–Tensleep (LSTP) EOR project in Wyoming injects about 44 million barrels per year,

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I	1	overall rate of injection and production ($\times 1$ million barrels)
R_0	1	initial stock of oil in reservoir ($\times 1$ million barrels)
w_s	4	per-barrel cost of purchased CO_2
w_ℓ	1	per-barrel cost of separating and recycling "leaked" CO_2
F	0.1	fixed costs ($\times \$1$ million)
K	2.7	up-front capital costs of switching to CO_2 flood ($\times \$1$ million)
β	1	incidence of the carbon tax on the oil producer
r	0.05	discount rate
δ_w	0.06	intercept of $\delta(c)$ function
δ_1	0.20	first coefficient of $\delta(c)$ function
δ_2	0.16	second coefficient of $\delta(c)$ function

TABLE 1. Baseline parameter values.

and extrapolating the decline curve for its oil production since starting the CO_2 flood suggests that ultimately about 36 million barrels of oil would be recovered over the course of that flood were it to be continued forever. In effect, then, our simulation applies a scaling factor of about 1/40 to the LSTP project.

Oil producers commonly measure CO_2 in units of 1,000 cubic feet (*mcf*) at standard surface temperature and pressure conditions. In Wyoming, the purchase price of CO_2 is currently about \$2 per *mcf*. To convert this price to reservoir barrels, we have to take account of the fact that the CO_2 is greatly compressed when it is injected into the reservoir. At LSTP, the compression factor (referred to by reservoir engineers as "formation volume factor for CO_2") is 0.471 *rb/mcf* (which, since 1 *mcf* corresponds to about 178 barrels, amounts to a compression rate of about 380 times). Rounding this factor up to 0.5, we end up with a gross CO_2 purchase price w_s of \$4/*rb*.

The various cost parameters of the model are based on a variety of sources, including data presented in McCoy (2008) and EIA (2007), as well as personal communication with industry experts,[10] we take the unit cost w_ℓ of separating and recycling "leaked" CO_2 that is mixed in with the produced oil to be on the order of \$0.50/*mcf*, or \$1/*rb*.

It is important to note at this point that, although we express carbon taxes throughout the paper in terms of dollars per tCO_2, the parameter τ in the numerical model is expressed in dollars per *rb*, for conformity with the other prices in the model (including w_s and w_ℓ). Since one tCO_2 corresponds to about 19.05 *mcf*, the above-mentioned conversion factor for LSTP of 0.5 *mcf/rb* results in a combined conversion factor of 9.5 *rb*/tCO_2, which we round up to 10. In other words, a carbon tax of \$40/tCO_2 translates to a per-barrel tax of \$4.

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[10] In particular, Charles Fox of Kinder Morgan, Inc. and Mark Nicholas of Nicholas Consulting Group.

Operating costs unrelated to injection or recyling of CO_2 amount to about $24,000 per well per year in non-injection or production-related expenses, plus about $0.0125 per barrel of overall injection or production. Applying our scaling factor of $1/40$ to LSTP's total of about 110 active wells, each producing or injecting about 800,000 rb per year, this works out to fixed costs F of about $0.1 million dollars per year.

Up-front investment costs K have two main components. One is the cost of converting the field to CO_2 use, which includes changing well equipment and adding metering equipment and pipelines in the field. The other is the cost of a plant for separating produced CO_2 from the oil, and then dehydrating and recompressing it. While the field conversion cost is roughly proportional to the number of wells operated, the recycling-plant cost is roughly proportional to the maximum flow of leaked CO_2 that must be processed. Based mainly on data in McCoy (2008), and again applying a scaling factor of $1/40$ to LSTP's number of wells and CO_2 throughput, we set the conversion cost at $0.6 million and the recyling-plant at $2.1 million, for an overall up-front cost of $2.7 million.

The parameter β, which we refer to as the carbon tax incidence on oil Producers below, is actually a combination of tax incidence effects with unit conversions associated with the transformation of a unit of produced oil into carbon units. Tax incidence effects depend on supply and demand elasticities. We assume that the elasticity of demand in global oil markets is around three times as high as the elasticity of supply, implying that the incidence on producers of a given tax expressed in dollars per barrel of oil is 25%. Based on data reported in EPA (2007), we estimate the quantity of CO_2 generated by combusting one barrel of oil at around $0.4tCO_2$, or $4rb$. Multiplying this by the incidence of 25%, and recalling that τ in the numerical model is expressed in dollars per rb, we end up with a combined incidence parameter of $\beta = 1$.[11]

Lastly, the parameters of $\delta(c)$ function are based on a combination of production experience at LSTP and simulation results in the literature. Specifically, the decline rate of overall oil production at LSTP since it started its CO_2-flood is about 11.5%, whereby the fraction of CO_2 in overall injection has been held roughly constant over time at about 0.35. Also, simulation data in Guo et al. (2006) based on data from an oil field in China indicate that, compared to cumulative oil recovery after 6 years of injecting pure water, recovery after 6 years of injecting a mix of half-CO_2 half water is about twice higher, while recovery after 6 years of injecting pure CO_2 is about

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[11] At the end of the next section, we perform some sensitivity analysis on this parameter. Specifically, we consider the two extreme cases where the incidence is zero, so that $\beta = 0$ also, and where the incidence is 100%, so that $\beta = 4$.

five-thirds higher. These data are roughly consistent with a quadratic $\delta(c)$ function

$$\delta(c) = \delta_w + \delta_1 c - \delta_2 c^2$$

with parameters $\delta_w = 0.06$, $\delta_1 = 0.2$, and $\delta_2 = 0.16$. Based on this parameterization, one finds that $\delta(0) = 0.06$, $\delta(0.5) = 0.12$, and $\delta(1) = 0.09$.

5. Simulation Results

The first element of behavior that we wish to define is the optimal extraction and sequestration path for our benchmark assumptions. Here, we use an oil price of \$100 (constant over time) with no carbon tax. Figure 1 shows the optimal paths of CO_2 injection (c), CO_2 leakage (ℓ), oil production (q), and flow CO_2 sequestration (s).
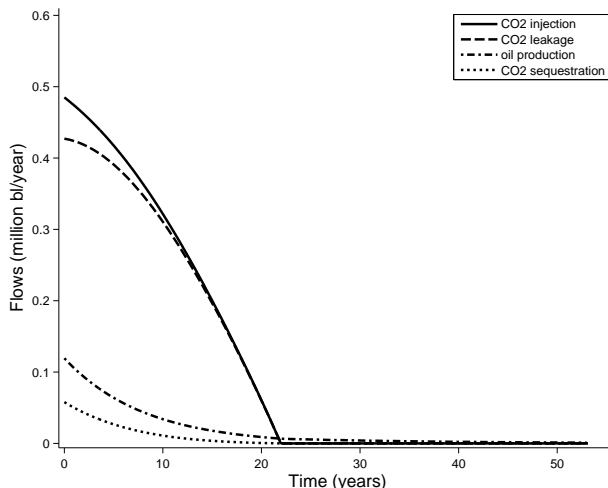
FIGURE 1. CO_2 injection, leakage, and sequestration, and oil production over time.

The optimal initial injection rate is 0.485 million barrels/year, somewhat smaller than the instantaneous oil-production maximizing rate of 0.625. This reflects the producer's tradeoffs of current against future extraction (the myopic profit-maximizing injection rate is 0.582) and of oil revenues against CO_2 injection costs. Note also that a large fraction (initially about 88%) of the injected CO_2 resurfaces with the produced oil and must be recycled. As oil production declines over time from its initial rate of 0.119 million barrels/year, the producer's revenues decline as well, as does CO_2 sequestration in the space vacated by the oil. As a result, CO_2 leakage, and thereby recycling costs, would increase over time even if the producer chose to hold CO_2 injection constant. This

changing balance between oil revenues and recycling costs makes it optimal for the producer to instead gradually reduce the injection rate over time, as predicted by the theory.

After about 22 years, the optimal CO_2 injection rate drops to zero, at which point the producer switches to a pure waterflood, thereby completely avoiding CO_2 injection costs. From that point in time forward, profits consist of the (declining) oil revenues less fixed costs. These remain positive for another 31 years, after which the field is shut down.

5.1. Effects of oil price

Our investigation of the comparative dynamics of the model starts with the effect of higher oil prices. Panel (a) of Figure 2 shows how the optimal CO_2 injection path changes as the oil price level is raised from a constant \$100 to a constant \$300/bl. Panel (c) of Figure 2 shows how the optimal time path of oil production changes with price; for reference, we also plot the time path under pure water flood. The higher resulting oil revenues make it optimal to initially raise the CO_2 injection rate, bringing it closer to the output-maximizing level. However, because even at the baseline price of \$100, initial revenues are already very high relative to CO_2-related costs, baseline oil production is already very close to its revenue-maximizing rate at each point in time. Raising the price therefore has a negligibly small effect on the oil production path, as is evident from panel (c) of the graph; it also has a negligible effect on cumulative oil production, as shown in panel (d). Nevertheless, the fact that the oil is produced with a more CO_2-rich injection mix implies that cumulative sequestration over the productive lifetime of the field increases, as shown in panel (b) of Figure 2.

Figure 3 shows oil supply and resulting CO_2 sequestration as a function of the oil price. Panel (a) shows cumulative levels of both, whereas panel (b) shows the annualized equivalent.[12] Note that the CO_2 sequestration supply curves are discontinuous at a price of \$52 barrel, below which incremental profits from CO_2 injection no longer justify the up-front investment cost. At lower prices, the producer therefore optimally sticks with a waterflood, resulting in zero sequestration and in slower oil extraction (hence the downward jump in annualized production).

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[12] The annualized values are calculated as the constant rate $\bar{s}$ or $\bar{q}$ that, when multiplied by the relevant price τ or p, would over an infinite time horizon yield the same present value as the actual, time-varying rate $s(t)$ or $q(t)$. That is, $\bar{s}$ is implicitly defined by

$$\int_0^\infty e^{-rt}\tau\bar{s}\,dt = \int_0^\infty e^{-rt}\tau s(t)\,dt.$$
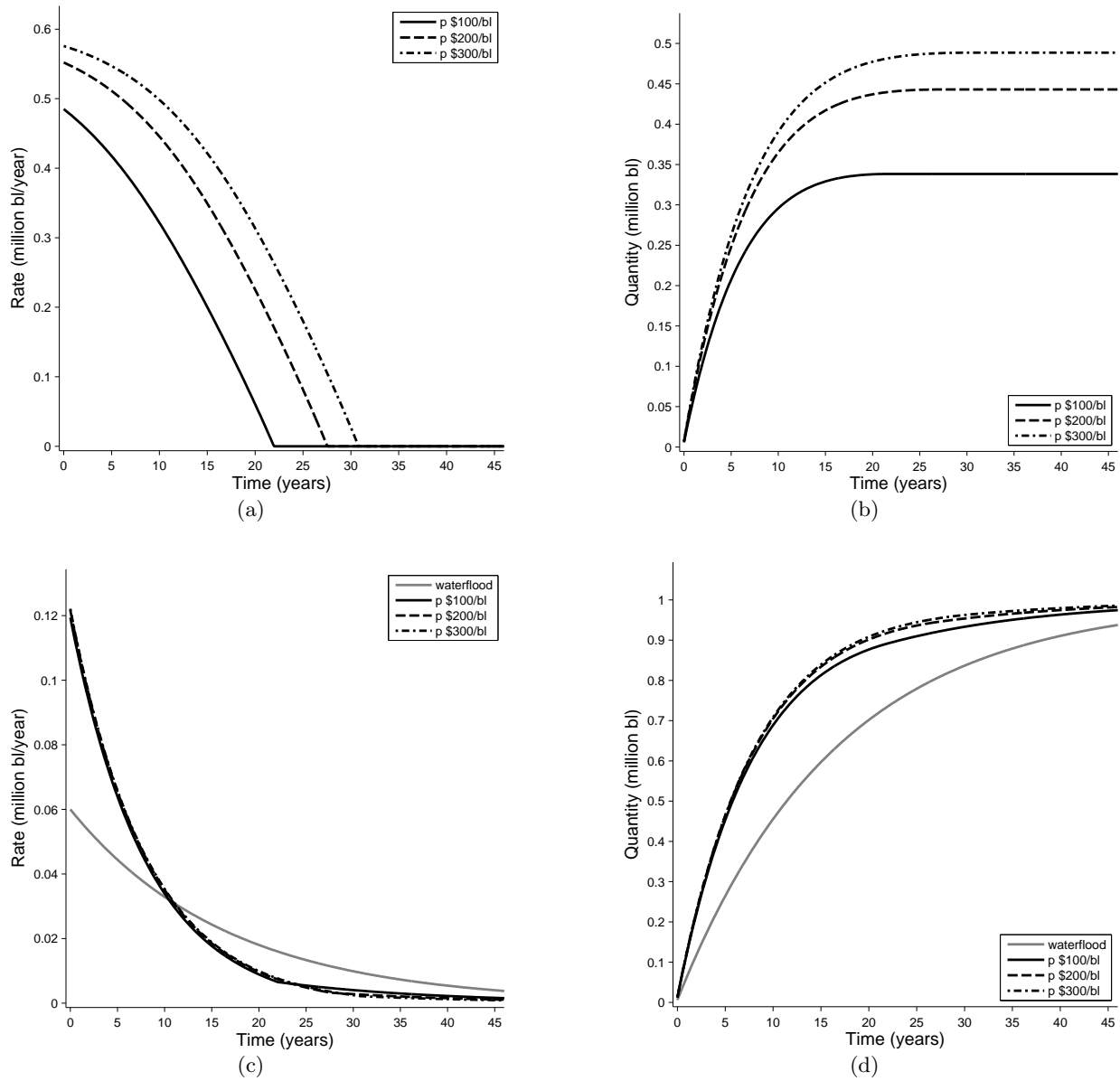
and $\bar{q}$ is defined analogously.

FIGURE 2. Change in (a) CO_2 injection, (b) cumulative sequestration, (c) oil production, and (d) cumulative oil production paths as a result of oil price changes.

Even at \$52/bl, the *variable* costs of CO_2 injection are so low, however, that the optimal oil extraction path is very close to the optimal path that would obtain if variable costs were zero (i.e., the revenue-maximizing path). As a result, variation in oil prices has almost no effect on oil output. The effect on sequestration is more substantial, however: at the baseline price of \$100, the elasticity of cumulative sequestration is 0.57, while that of annualized sequestration is 0.47.
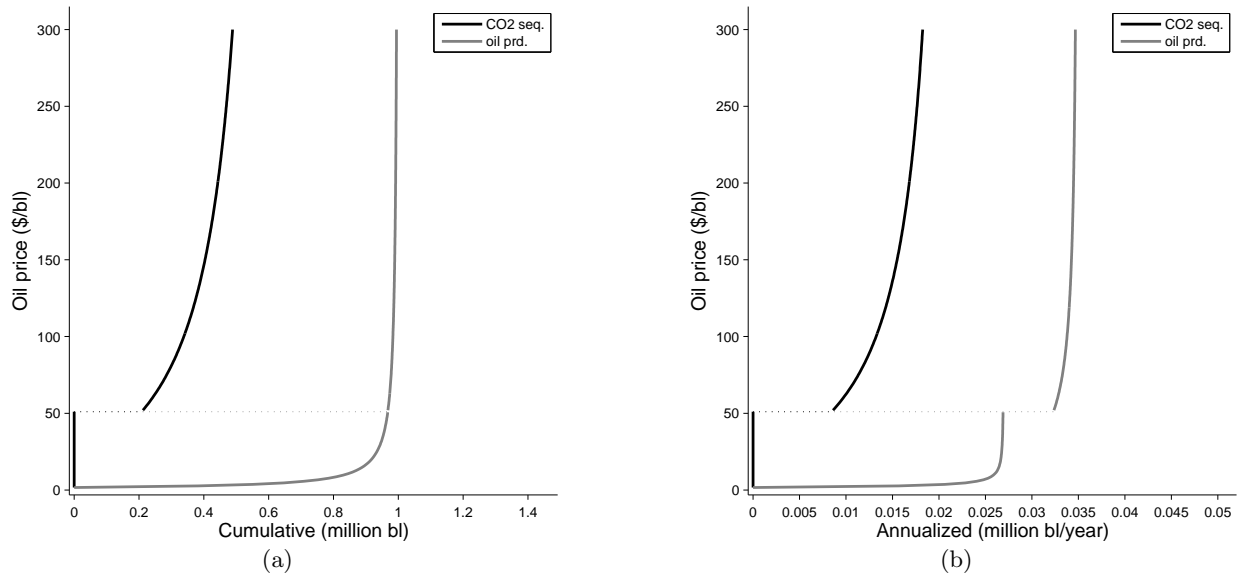
FIGURE 3. CO_2 sequestration and oil production, both cumulative (a) and annualized (b), as a function of the oil price.
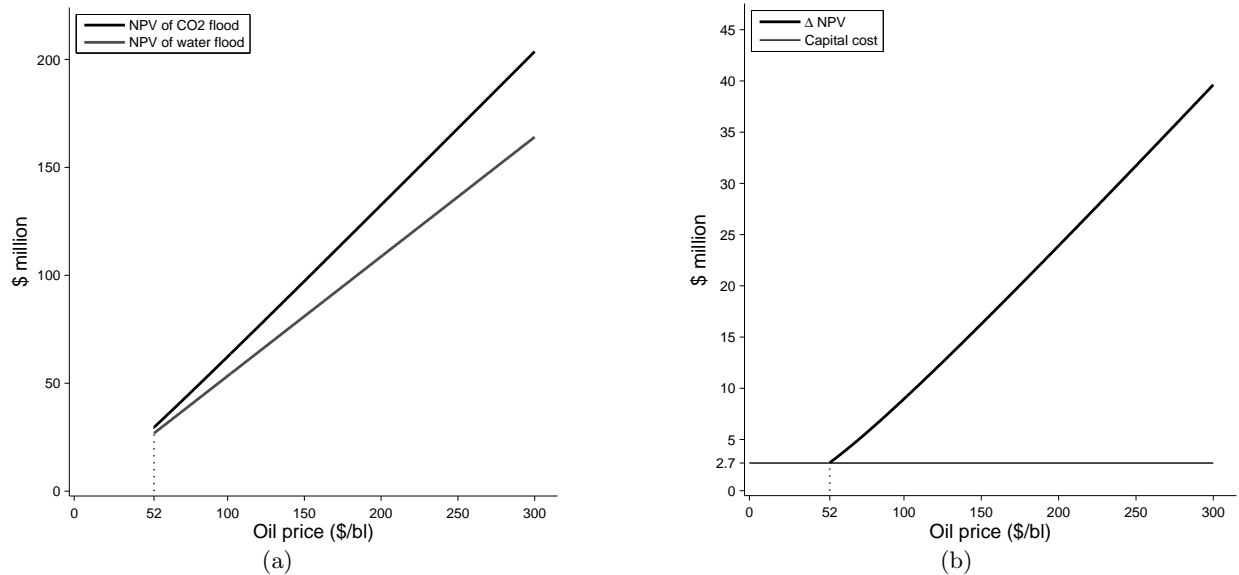
FIGURE 4. Change in present value of incremental profits from EOR as a result of oil price changes.

Figure 4 shows a final result pertaining to changes in the oil price level, namely their effect on the net present value of the field. Panel (a) compares the net present value NPV^w of operating the field as a waterflood, i.e., operating it subject to the constraint that $c = 0$, to the net present value NPV^c of optimally injecting CO_2. The difference between these values at any point in time,

denoted ΔNPV, is the present value of *incremental* profits from EOR. Moreover, when the oil price and all other model parameters are constant over time, this present value necessarily declines over time. As a result, the producer will immediately start a CO_2 flood if and only if ΔNPV exceeds the up-front capital cost K.

Panel (b) of the figure graphs ΔNPV against oil price. For prices below \$52/bl, ΔNPV is less than K, and the producer will therefore stick with a waterflood. Above this cutoff price, however, NPV^c increases much faster than does NPV^w, implying that ΔNPV increases rapidly as well. The reason is that under a CO_2 flood, the higher oil price applies to higher levels of output early on.[13]

A potentially important implication of this finding is that higher oil prices greatly enhance the potential for EOR to cover the cost of pipelines and other CCS infrastructure discussed in the introduction to this paper—costs which are not included in K. In effect, the gap between the ΔNPV curve and the horizontal K curve in panel (b) represents this potential.

Of course, scenarios with atemporal oil prices are clearly not very realistic. Given the consistent increases in oil prices over the last five or so years, the more policy-relevant question is how producers might respond to different anticipated oil price growth rates. As we shall see, scenarios incorporating this assumption yield quite different results from scenarios with atemporal prices, both quantitatively and qualitatively.

Panels (a) and (c) of Figure 5 show how the optimal CO_2 injection and oil production paths change as, starting from an initial level of \$100, oil prices grow at initial rates varying from 2.5% to 7.5%/year.[14]

As oil prices increase, the incentive to shift oil production to the future grows; this shift is achieved by reducing or delaying CO_2 injection and thereby also CO_2 sequestration. On the other hand, higher future oil prices also create an incentive to continue injection for a longer period of time than with atemporal oil prices. Panel (b) shows that the first effect dominates in terms of the total sequestered CO_2 (perhaps because the second effect comes into play only after oil reserves have already dropped substantially). In other words, if oil prices increase over time, as opposed

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[13]% By the dynamic envelope theorem,

$$\frac{dV}{dp} = \frac{\partial V}{\partial p} = \int_0^T \frac{\partial H}{\partial p}\, dt = \int_0^T e^{-rt} q(t)\, dt.$$

It can be shown that the last expression is strictly greater under a CO_2 flood than it is under a waterflood starting from the same initial stock.

[14] To keep the price from growing without bound, we assume that the growth rate itself declines at 4%/year. As a result, the oil prices attained after 22 years, for example, are \$144, \$208, and \$300, by which point the rates of growth have fallen to 1.04%, 2.08%, and 3.11%/year.
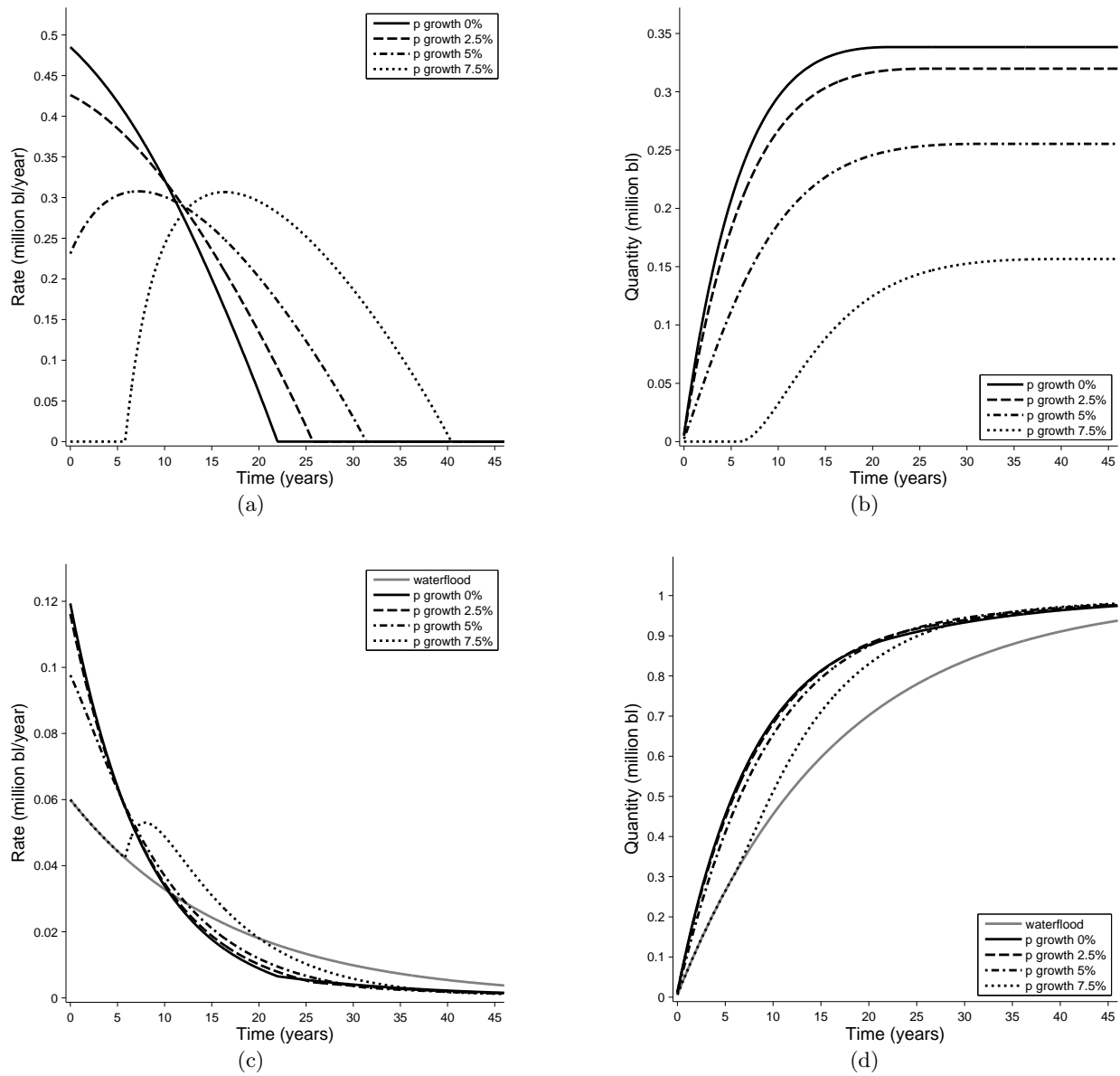
FIGURE 5. Change in (a) CO_2 injection, (b) cumulative sequestration, (c) oil production, and (d) cumulative oil production paths as a result of oil price growth.

to remaining constant, cumulative sequestration falls. Panel (a) also shows that —CO— injection can rise over time if oil prices increase sufficiently rapidly, a point we alluded to above. Indeed, if prices rise sufficiently fast, it behooves the producer to delay injection for a period of time, so as to take advantage of the increased production (relative to pure waterflood) that obtains when injection commences at a point in time where oil prices are higher.
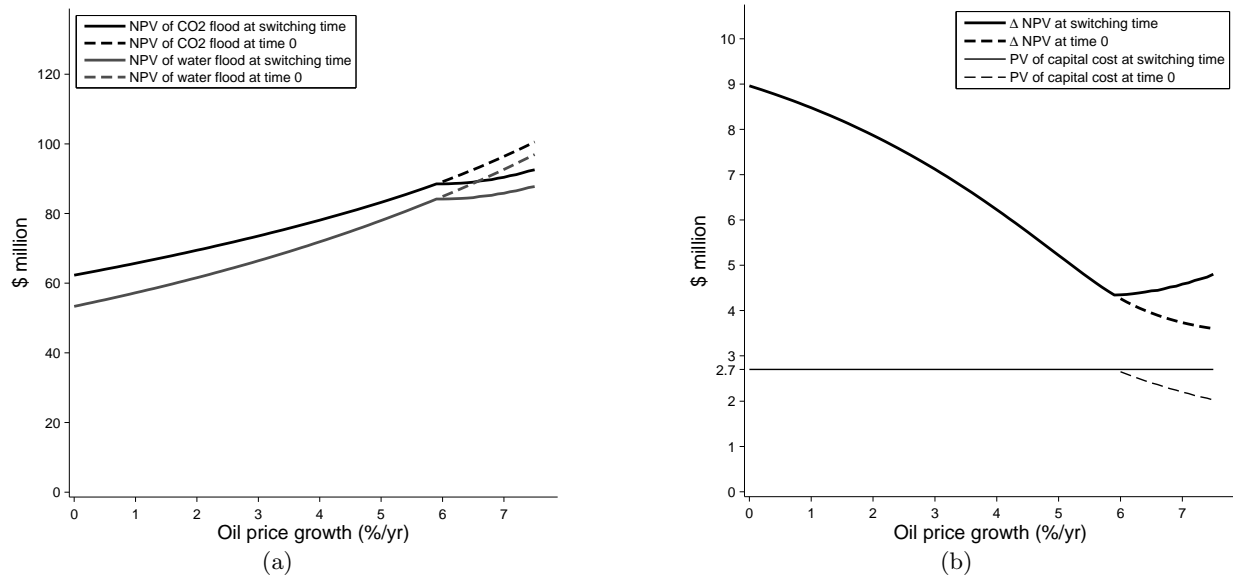
FIGURE 6. Change in present value of incremental profits from EOR as a result of oil price growth.

Figure 6 shows the effect of different rates of oil price growth on the incremental profits from EOR. Not surprisingly NPV^c and NPV^w are found to both increase in the growth rate of oil prices. What is less easily anticipated is the decline in ΔNPV as the rate of increase in oil prices is increased, at least initially. The explanation lies in the progressive shift of the optimal CO_2 injection path toward the future as oil-price growth rates increase (evident in panel (a) of Figure 5). This shift implies that, even though the output boost from CO_2 injection becomes more valuable at any given point in time, it tends to occur later in time, when the oil stock has declined (perhaps significantly). As a result, the output boost tends to be smaller in absolute terms; it is also discounted more heavily. The net effect is to lower ΔNPV.

This explanation applies up to a critical growth rate (in our simulations, of about 6%). Beyond this critical growth rate, it becomes optimal to delay *any* injection of CO_2 until some switching time t^s strictly after time 0 (as Figure 5 indicates). As a result, the relevant time at which the producer must invest capital K is delayed until t^s as well. The relevant value of ΔNPV that the producer will compare with K therefore becomes the gap evaluated at time t^s, and this gap turns out to widen slightly as growth rates increase beyond 6%. Equivalently, the ΔNPV gap evaluated at time 0, indicated by the dashed curves in Figure 6, must be compared to the discounted cost of investing K at t^s.
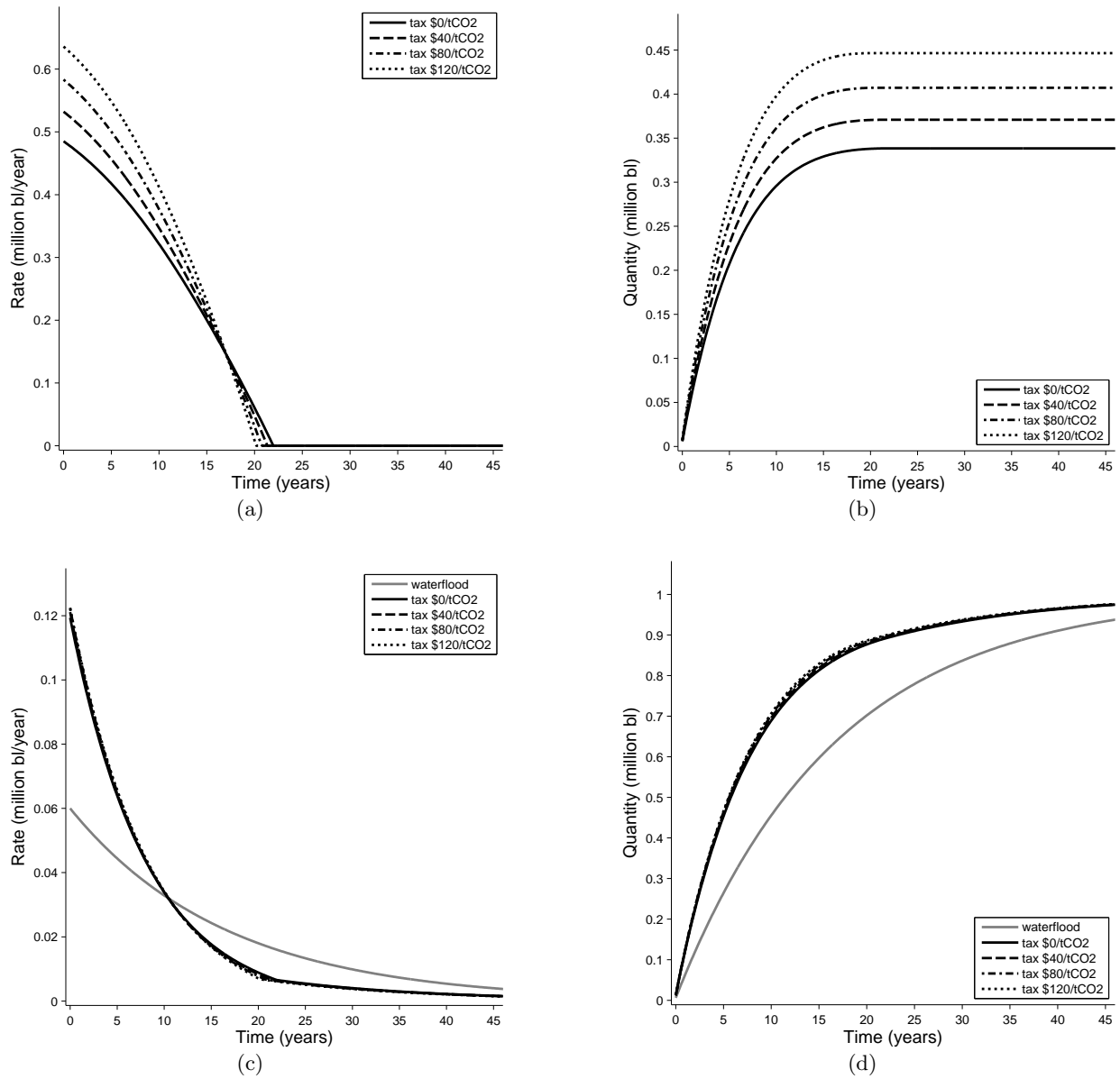
5.2. *Effects of carbon tax changes*

FIGURE 7. Change in (a) CO_2 injection, (b) cumulative sequestration, (c) oil production, and (d) cumulative oil production paths as a result of carbon tax changes.

Figures 7 through 9 illustrate the effects of higher constant carbon taxes. At higher constant carbon-tax levels, both the net-of-tax oil price received by the producer and the net-of-tax input price of CO_2 are lower. However, at a given injection rate $c(t)$, the change in oil revenues from a marginal tax change is is $-q(t)\,d\tau$, whereas the change in input costs is $-c(t)q(t)\,d\tau$. As long as $c(t)$ is below its upper bound of 1, the cost effect therefore dominates, in which case the firm is

motivated to move the injection schedule forward in time. Indeed, panel (a) of Figure 7 does show that the optimal initial injection rate increases in the tax rate. However, it also shows that the optimal time to switch to pure water injection is accelerated. As a result, injection rates decline more rapidly over time the higher is the tax. Even so, the overall effect of higher carbon taxes on cumulative sequestration is positive, as shown in panel (b). We note in passing that oil production tends to be insensitive to the level of the carbon tax, which coincides with our earlier observation that revenue effects from oil sales tend to be more important than input costs in driving the firms output decisions.
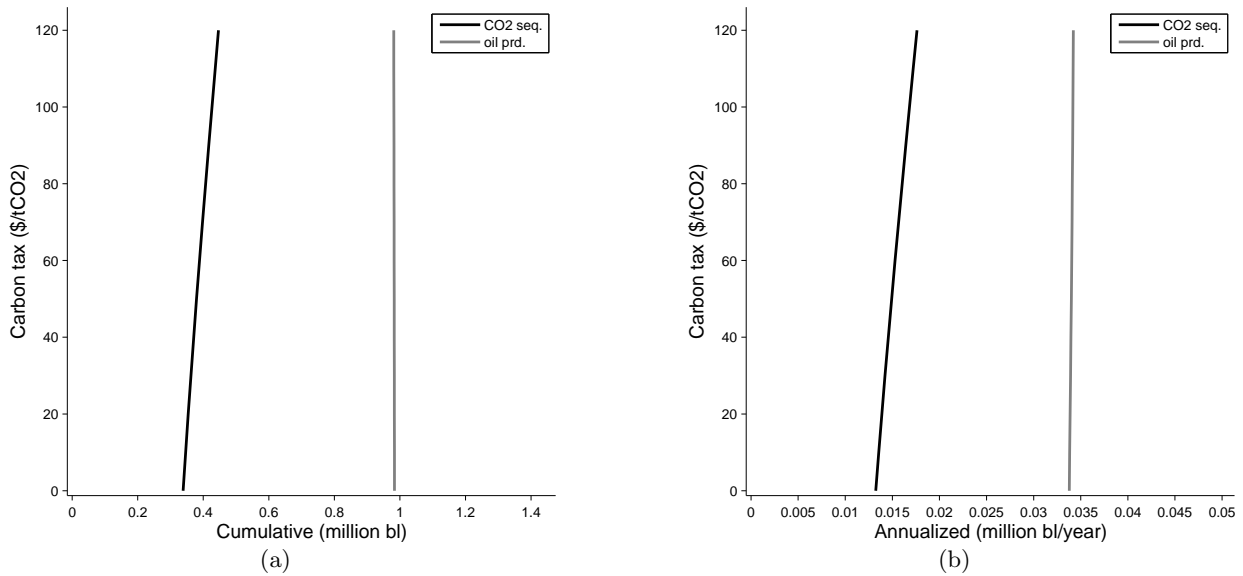

(a)   (b)

FIGURE 8. CO_2 sequestration and oil production, both cumulative (a) and annualized (b), as a function of the carbon tax.

Figure 3 shows CO_2 sequestration supply and associated oil output as a function of the carbon tax. Because the oil extraction paths are very close to their revenue-maximizing values regardless of the level of the carbon tax, the elasticity of oil output with respect to the carbon tax is quite small. More surprising is that the sequestration supply curves are quite inelastic as well. At the current European tax level of about \$40/tCO_2, the elasticity of cumulative sequestration is only 0.09, and that of annualized sequestration only 0.10.

Figure 9 shows the effect of higher carbon taxes on the incremental profits from EOR. Here we consider a range of growth rates, starting from an initial tax of \$40/tCO_2 To facilitate comparisons with the previous subsection, we consider the same three growth rates as were used for oil prices. Similarly, the highest carbon tax level of \$120/t CO_2 considered here is attained after 22 years at
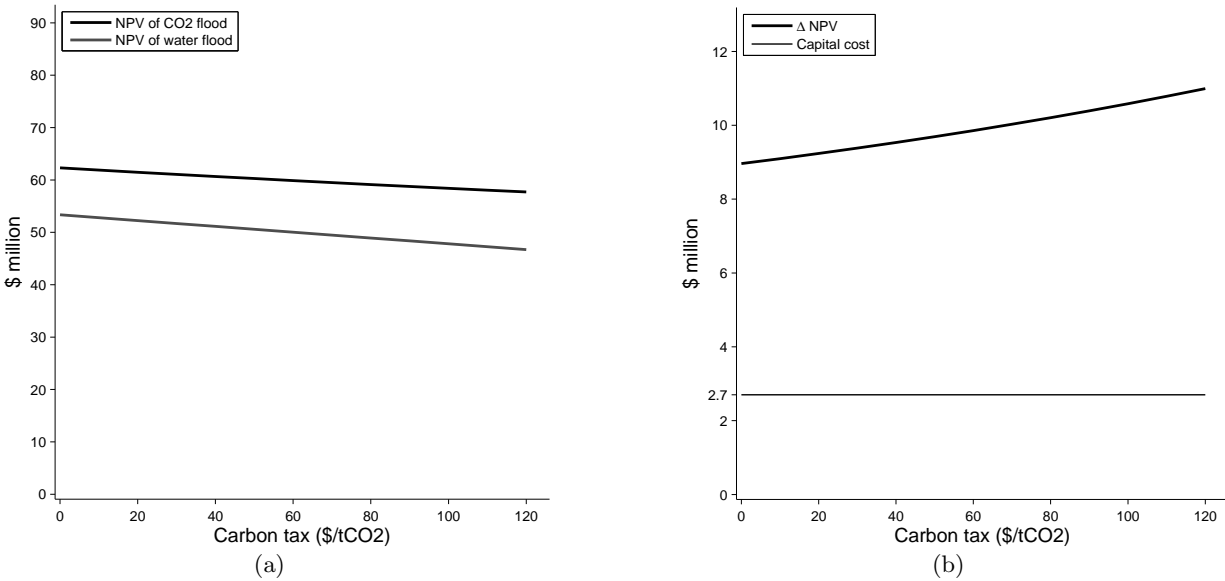
FIGURE 9. Change in present value of incremental profits from EOR as a result of carbon tax changes.

an initial growth rate of 7.5% (just as the highest oil price level of $300/bl considered above was attained after 22 years at an initial growth rate of 7.5reduces revenues by more than CO_2 injection costs, NPV^c is found to decline with the tax. Moreover, because for a waterflood there are no CO_2 injection costs to reduce (and thereby partially offset the revenue reduction) NPV^w declines more rapidly. As a result, the ΔNPV gap increases with the tax—though the effect is small.

As with the constant-price scenarios compared in the previous subsection, it can be argued that the foregoing comparisons of constant-tax scenarios, while perhaps useful to gain understanding of the model, have limited policy relevance. Realistically, tax levels on the order of $120/tCO_2$ will not be imposed overnight and then maintained indefinitely. More plausible scenarios would have the tax gradually increase from an initial level of, say, $40/tCO_2$.

Figure 10 compares such scenarios, using the same growth rates as used earlier for oil prices. In both panels of the figure, the effects of anticipated increases in carbon taxes turn out to become almost negligibly small, even at the a high growth rate of 7.5%. The explanation lies in the fact that, even at this high growth rate, it would take 22 years for a current tax of $40/tCO_2$ to triple to $120 and start having a significant effect on the producer's optimal injection rates. Given realistic oil-production decline rates, most oil fields currently under production will at that point be significantly depleted, implying that increases in CO_2 injection will no longer result in significant additional production or sequestration.
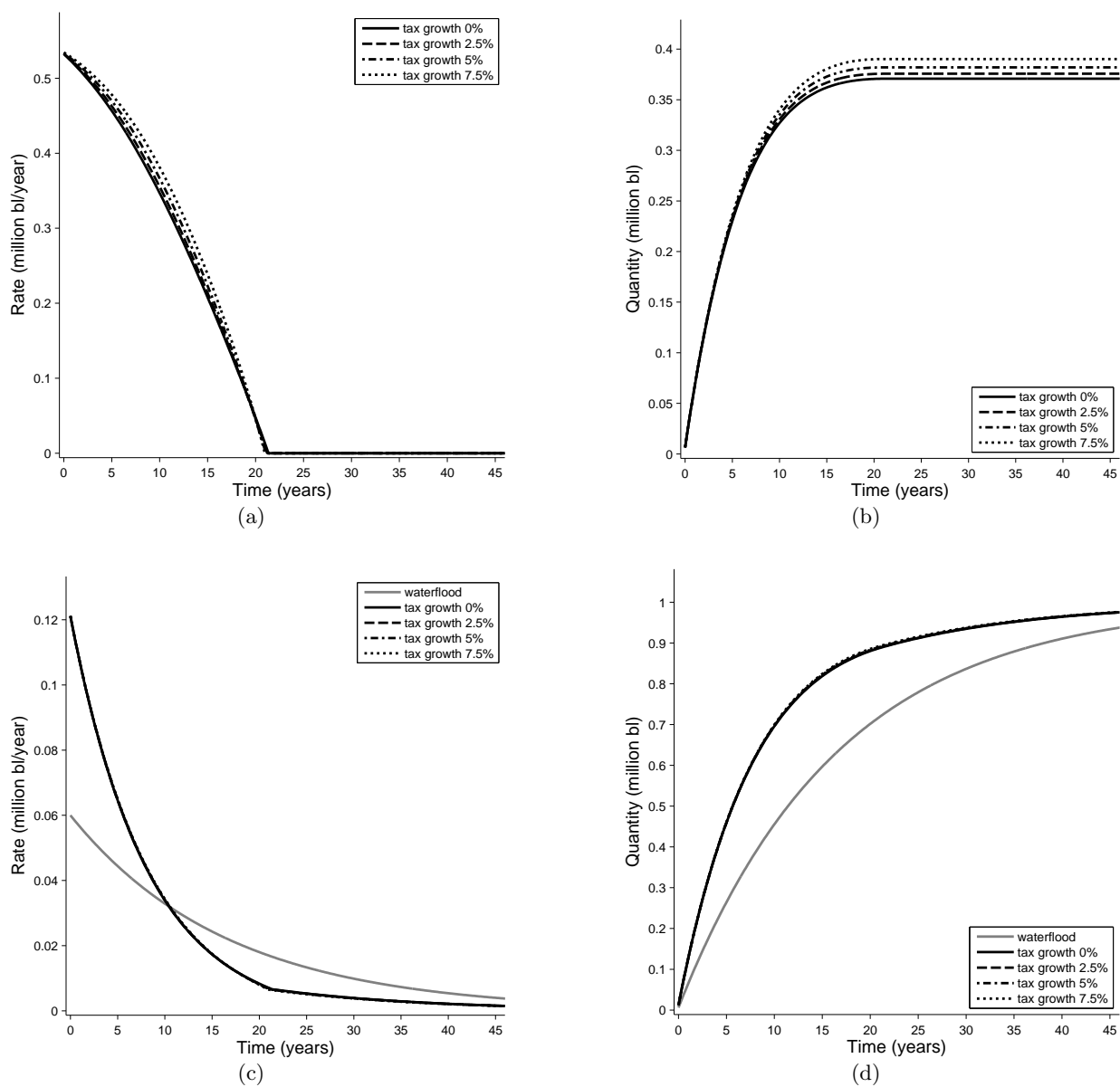
FIGURE 10. Change in (a) CO_2 injection, (b) cumulative sequestration, (c) oil production, and (d) cumulative oil production paths as a result of carbon tax growth.

Figure 11, which compares the net present value of EOR at different tax growth rates, further confirms this finding. Neither the NPV^c and NPV^w levels nor the gap between them are signficantly affected by even large variation in these growth rates.
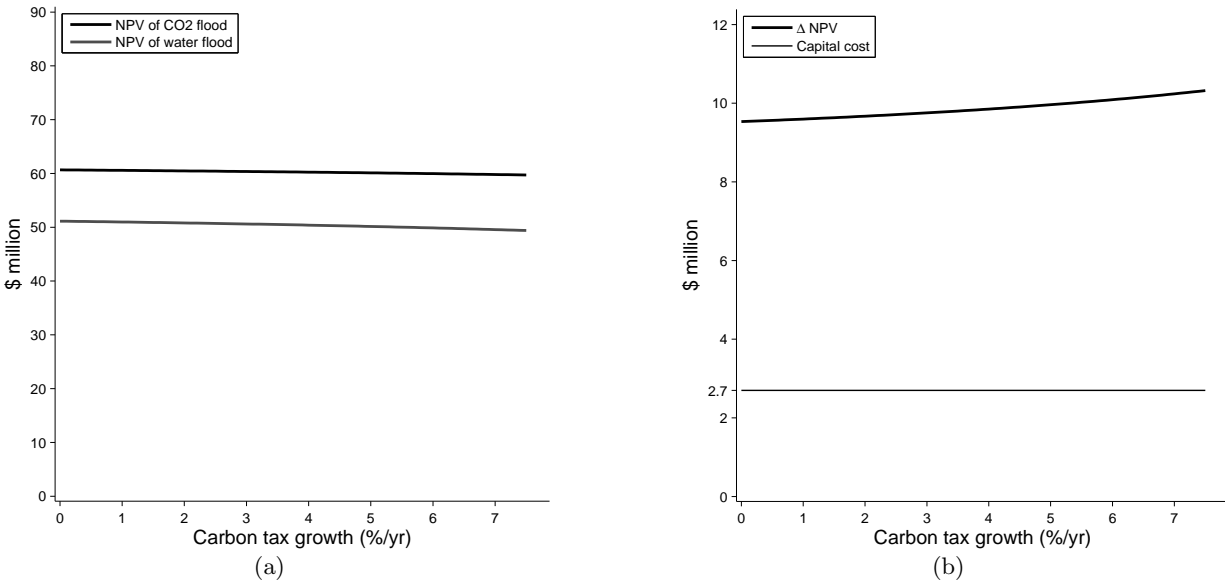
FIGURE 11. Change in present value of incremental profits from EOR as a result of carbon tax growth.

5.3. *Effects of oil price and carbon tax changes combined*

To recap, the results of subsection 5.1 suggest that if producers come to expect oil prices to steadily increase, sequestration in EOR projects will be reduced, as will incremental profits available from such projects to finance CCS infrastructure. Additionally, at high rates of price increase (though still well below recently observed rates), investment in EOR may be delayed altogether. The results of subsection 5.2 suggest, moreover, that imposing carbon taxes to reward CO_2 sequestration is unlikely to offset the effect of increasing oil prices to a significant extent.

Figure 12 confirms the latter conjection. Panel (a) displays four scenarios, each with an initial oil price of \$100/bl and initial carbon tax of \$40/tCO$_2$. The baseline, no-growth scenario keeps both the price and tax constant; the scenarios with only price growth or only tax growth at initially 5%/yr replicate the findings of Figures 5 and 10 above; and the new scenario with both price and tax growth at 5%/yr confirms that the tax-growth effect, which accelerates CO_2 injection and increases overall sequestration, is swamped by the price-growth effect, which works in the opposite direction. Panel (b) of the figure shows ΔNPV for various combinations of growth rates. While the tax-growth effect increases incremental profits from EOR, this effect is swamped by the price-growth effect. On balance, then, ΔNPV is declining in the rate of growth in oil prices up to a rate of about 6%, for every growth rate in the carbon tax.
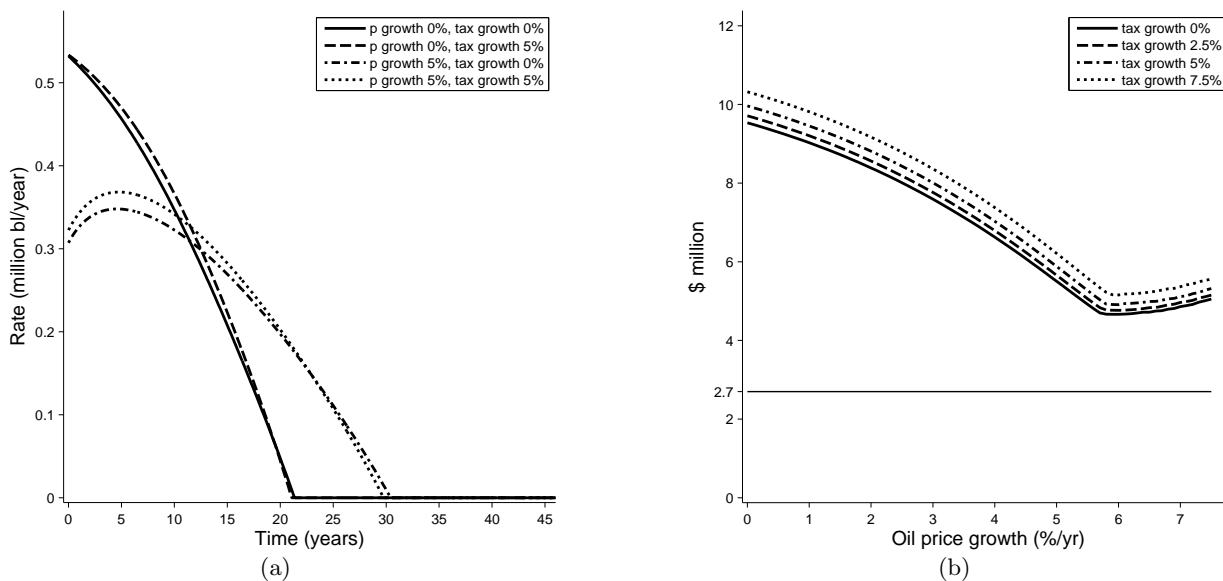
FIGURE 12. CO_2 injection paths and net present value of incremental EOR profits under no-growth scenario compared to scenarios with growth in carbon taxes and oil prices.
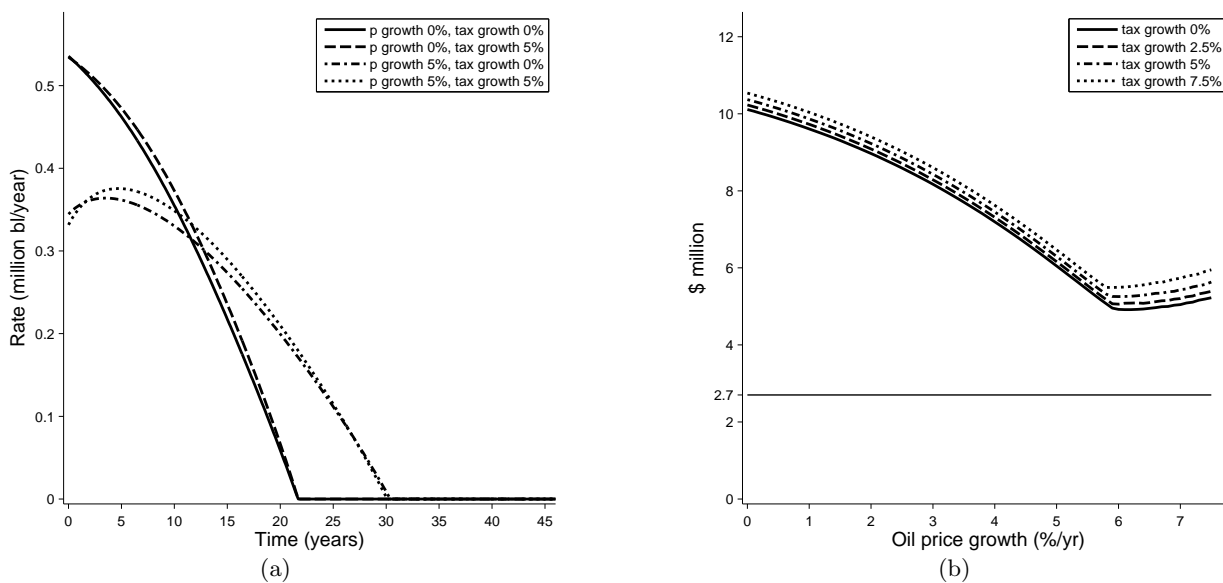

FIGURE 13. CO_2 injection and *NPV* comparisons when the carbon tax incidence on producer oil prices is zero, $(\beta = 0)$.

5.4. *Sensitivy analysis with respect to tax incidence*

Among the various parameters of the model, the one that seems most likely to potentially change the above findings, and that is at the same time very difficult to pin down, the incidence of the
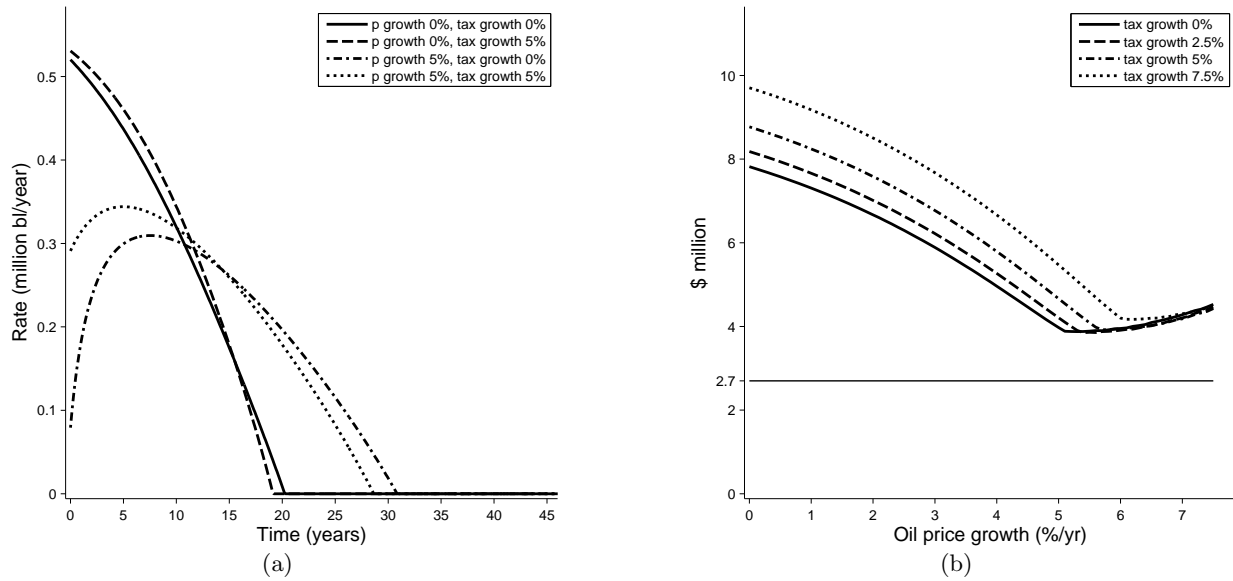
FIGURE 14. CO_2 injection and NPV comparisons when the carbon tax incidence on producer oil prices is 100%, ($\beta = 4$).

carbon tax on the oil price, β. While we believe the value $\beta = 1$ used in our baseline simulations is defensible, it seems prudent to investigate the sensitivity of the numerical results with respect to this parameter. We therefore replicate the key results from the previous subsection for the two extreme values of $\beta = 0$ and $\beta = 4$, corresponding to zero incidence and 100% incidence, respectively.

In the extreme case $\beta = 0$, shown in Figure 13, producers face the same oil price path regardless of the level of the tax, because either the global supply curve for oil is perfectly elastic or the demand curve perfectly inelastic. Comparing this figure with the baseline case scenario of Figure 12, we see that the effect of carbon tax growth is even smaller. Intuitively, since the increasing tax no longer depresses the oil price, it is even less effective at moving producers away from oil-revenue maximizing behavior.

In the extreme case $\beta = 4$, in contrast, shown in Figure 14, the tax has the maximum possible impact on oil prices, because either the global supply curve for oil is perfectly inelastic or the demand curve perfectly elastic. While there are some minor differences between the simulations results with this parameter value and the corresponding results with $\beta = 1$, the major results do not change. In particular, the price growth effects still clearly outweigh the tax growth effects, even at the highest tax growth rate considered, of 7.5%/yr.

6. Conclusion

In this paper, we have examined how the standard resource-economics problem of optimizing the rate of oil extraction from a field is altered when the producer has the option of increasing the rate of oil extraction through continuous injections of a mix of CO_2 and water into the reservoir. Such CO_2-enhanced oil recovery is a natural stepping stone to future sequestration of CO_2 in saline (non-oil-bearing) aquifers, because incremental oil revenues can pay for pipelines, injection wells, and other capital infrastructure required.

Our focus in the paper is on the producer's problem of determining the optimal CO_2 injection rate over time. Our theoretical analysis of this problem indicates that, unless oil prices are increasing at a sufficiently rapid rate, the optimal CO_2 injection rate will typically decline over time, and may eventually drop to zero before it becomes optimal to terminate the extraction process.

Numerical simulations confirm these results and allow us to further investigate comparative dynamics of the model. As one would expect, higher oil prices (constant over time) are found to shift the optimal CO_2 injection rate in the direction of output-maximizing levels at each point in time, but the effect is generally small. This is because the baseline oil price of \$100 is already very high relative to CO_2-related costs, and the oil production rate in the baseline scenario therefore already very close to maximal.

Anticipated increases in the oil price over time are found to reduce CO_2 injections early on but increase them later. In fact, at sufficiently high rates of price increase, the producer optimally starts with a period of zero CO_2 injection, only ramping up to positive rates later. Because by that time the stock of oil has dropped, however, and thereby the space available for CO_2 to occupy underground, rising oil prices reduce cumulative CO_2 sequestration.

In contrast, higher (atemporal) carbon-tax levels are found to increase the optimal CO_2 injection rate early on, but reduce it later, with the same qualitative effects on the induced CO_2 sequestration rate. The initial increase in sequestration dominates, however, resulting in higher levels of annualized or cumulative sequestration overall. At tax rates that are high enough to turn the net CO_2 price negative, we also find that oil production is reduced early on, because CO_2 injection is optimally pushed to levels where its marginal effect on oil production becomes negative. In effect, the producer sacrifices oil output and revenues early on in return for higher sequestration revenues that result from higher CO_2 injection rates.

A key finding is that, even though higher carbon taxes do induce higher sequestration, the effect is quite small: at tax levels comparable to current carbon-credit prices in Europe (about $40/tCO$_2$), we estimate the elasticity of sequestration supply to be around 0.06. Moreover, even quite rapid anticipated increases in the tax from those initial levels have only very small effects on sequestration rates.

Our simulation results suggest good news and bad news for potential carbon sequestration from EOR. The bad news is that EOR-based carbon sequestration appears to be highly inelastic. As such, there is little hope that higher carbon prices will induce large increases in EOR-based sequestration. The good news is that for a range of combinations of oil price and carbon price, and for what seem to be reasonable parameter values, EOR has the potential to generate sufficient increases in profits to cover the up-front costs associated with EOR. The difference between these increases in profits and the up-front costs provides a legitimate source for funding new infrastructure such as pipelines, which in turn would be readily available for later use by more efficacious sequestration projects such as the use of deep saline aquifers.

It should be noted, moreover, that even the bad news—the apparent inelasticity of sequestration supply from EOR—is subject to two important caveats. One caveat is that our numerical model should be regarded as representing a single oil-producing unit—essentially a small section of a single oil reservoir. Because oil reservoirs are generally not spatially homogeneous with respect to relevant physical parameters such as depth, temperature, thickness, and injectivity, however, it is conceivable that EOR would be attractive in some sections of a reservoir, but not others, for a given combination of economic parameters.[15] In such a scenario, the supply of sequestration services for the oil reservoir might be less inelastic than our results indicate. Additionally, if one imagines comparing across different reservoirs, it seems likely that EOR projects would come on-line at different points in time or at different combinations of oil price and carbon price. Again, this observation suggests that the sequestration supply curve for a broader geographic entity, such as a state or country as a whole, would likely be less inelastic than is true for the single unit that we study.

A second caveat, on the other side of the ledger, concerns a counter-balancing effect that applies at the larger geographic level, but is insignificant at the single-unit level. Because EOR will

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[15] This is true, for example, of the Salt Creek field in Wyoming, one of the largest EOR projects currently operating in the US.

generally raise oil production, there will be an associated increase in consumption of petroleum-based products, such as motor vehicle fuel. This extra consumption will, of course, generate increased carbon emissions in its own right. It is not clear how these additional emissions compare to the sequestration associated with EOR. It is conceivable that, on balance, EOR leads to a net increase in carbon emissions at the state or national level. As such, it is probably best to view EOR as a means to an end—a stepping stone towards larger-scale sequestration in aquifers—rather than an end in itself.

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