No end in sight: end-of-life management of oil wells in Alberta

Gregory Galay

School of Public Policy, University of Calgary

Jennifer Winter

Department of Economics and School of Public Policy, University of Calgary and Environment and Climate Change Canada

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Abstract

The development of oil and gas resources while maximizing production has been the primary objective of policymakers and regulators in Alberta, Canada for many decades. When oil prices were sufficiently high, environmental risks and other concerns received little attention. When oil prices collapsed in 2014, Alberta's inventory of inactive, decommissioned, and orphaned wells grew dramatically. It is now a complex problem for operators, regulators, and policymakers and the return of high oil prices has not resolved the issue. This article uses a real options model to evaluate firms' end-of-life decisions for oil wells in Alberta subject to mean-reverting oil prices, to understand the factors that affect a firm's decision to reclaim an oil well at the end of its useful life versus leaving it unreclaimed. We focus on a firm's optimal management of a representative oil well to different policy decisions, rather than a socially optimal outcome that internalizes the negative externalities of oil and gas development. Results under our baseline parameters show that firms operating a representative oil well will extract over 95 per cent of the reserves in place and reclaim the well. When the cost to decommission or cost to reclaim a well is larger than the cost of maintaining an inactive well, the firm will still extract over 95 per cent of reserves but will leave the well in an inactive state (not able to produce) and never reclaim the well. This suggests that some of the unreclaimed oil and gas wells have high decommissioning or reclamation costs. If those cleanup costs are correlated with environmental risks (groundwater contamination, gas migration, etc.) then the inventory of inactive oil and gas wells could be populated with the riskiest wells, adding an additional level of complexity to the issue of unreclaimed oil and gas wells in Alberta. We examine the effect of a time limit on inactivity or a bond has on end-of-life decisions. Our results suggest that neither policy on its own ensure wells with high decommission or reclamation costs are reclaimed at the end of useful life. However, a combination of a time limit on inactivity and a bond could be useful policy instruments to help ensure high-cost oil and gas wells are reclaimed at the end of their life.

JEL classification: L71, Q35, Q38, Q52, Q54, Q58

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1 Introduction

Alberta's large and persistent inventory of unreclaimed oil and gas wells is a long-standing policy problem, prompting several changes to its liability management framework between the 1980s and 2022, with little notable success (Robinson, 2014; Dachis et al., 2017; Green, 2019; Goodday and Larson, 2021; Yewchuk et al., 2023).¹ Despite the Alberta Energy Regulator (AER) stating that "if energy companies are going to profit from the province's energy resources, they must be responsible and properly abandon, remediate, and reclaim their sites" (Alberta Energy Regulator, n.d.b), current evidence suggests firms are optimizing by not fulfilling their responsibility. This is likely due to a regulatory system that prioritizes resource conservation — including preservation of an asset for potential future production in the event of technological improvements — and historical failure to enforce Alberta's liability management rules. Figure 1 shows the consequences of these policy choices are significant, where the annual inventory of active (producing) wells is much smaller than the sum of other states (all non-producing), and a small proportion of wells are fully reclaimed.² Goodday and Larson (2021) find that 54.8 per cent of non-producing and unreclaimed wells in Alberta have been so for more than five years, while 29.2 per cent are non-producing and unreclaimed for more than a decade. Muchlenbachs (2015) shows that it is very unlikely for high prices or technological improvements to bring oil and gas wells back into production once they move to a non-producing state. Muchlenbachs (2017) concludes that temporary closure is in fact permanent closure and wells are being left inactive to avoid the sunk cost of decommissioning wells and argues that policies should recognize that most inactive wells will likely never produce oil or gas again. With liability management gaining increasing policy attention, we analyze the management of oil wells from the active stage until they are reclaimed to understand the incentives behind why so many oil and gas wells remain unreclaimed. We focus on a firm's optimal management of a representative oil well to government policy decisions. Our goal is to characterise when and how firms respond to policy and what policy choices prompt reclamation, rather than a socially optimal outcome that internalizes the negative externalities of oil and gas development. Our research question is will firms meet their regulatory requirement and reclaim their oil and gas wells at the end of the wells' productive life?

Alberta's guiding legislation for oil and gas development is the Oil and Gas Conservation Act (OGCA),

¹See Robinson (2014), Green (2019) and Yewchuk et al. (2023) for a discussion of the history of the inactive well problem and policy responses.

²As of May 2024, Alberta has 157,033 active wells, 78,136 inactive wells, 91,982 decommissioned wells, and 140,784 reclaimed wells (Alberta Energy Regulator, 2023b). Of these, 1,724 are orphaned wells — where the responsible firm has become insolvent, transferring the reclamation requirement back to the province — awaiting decommissioning and 2,542 are fully reclaimed orphan wells (Orphan Well Association, 2023b). Inactive wells are in a temporary non-producing state, while decommissioned wells have permanent sealing. Terms differ across regulators and jurisdictions. The AER defines a well as suspended when an inactive well is placed in a safe condition, with non-permanent sealing, and an abandoned well as one with permanent sealing. We use mothballed instead of suspended, and decommissioned instead of abandoned to avoid confusion of terms. See Figure 2 for a full taxonomy of well life-cycle terms.



Figure 1: Current status of Alberta oil and gas wells, 2010 to 2022

Notes: Status is the well inventory status as of December 31 in a given year. *Source*: Evaluate Energy's CanOils Well and Land Database.

with the purposes of conserving and preventing the waste of oil and gas resources; ensuring the safe and efficient locating, development, operation, maintenance, and decommissioning of wells and facilities; providing efficient and responsible development of oil and gas resources in the public interest; and controlling pollution. The province owns 81% of mineral rights, and it leases these rights to firms to develop on behalf of the province and its citizens.³ The OGCA requires the owners of oil and gas wells to pay the costs of decommissioning and reclaiming their wells. However, if the owners go bankrupt or become insolvent during the life of the well, and no other firm is willing to take over the well, the costs of decommissioning and reclaiming fall on the province. In practice, these costs are covered by the Orphan Well Association (OWA).⁴ Dachis et al. (2017) estimate the cost of plugging and reclaiming 3,200 orphaned wells in 2017 to be \$129-257 million. When they include wells of insolvent and close-to-insolvent firms, the cost increases to \$4.2-8.6 billion.⁵ More recently, Canada's Office of the Parliamentary Budget Officer (PBO) estimates the cost of cleaning up orphaned wells in Alberta was \$415 million in 2021 (Forsyth and Nahornick, 2022).⁶ The PBO report notes that the inventory of non-producing and orphan wells poses a fiscal risk due to the rising costs associated with cleanup, insufficient amounts of security being held to cover closure expenses, and a growing number of companies with a lack of financial capacity to meet closure obligations. The governments of Alberta and Canada have responded by providing loans and grants to support efforts to reduce the inventory

³Specifics of the institutional environment are discussed in the next section.

⁴The OWA manages the closure of orphaned oil and gas wells, pipelines, and facilities, and the reclamation of associated sites, across Alberta. The OWA is funded via government grants and a levy on producers.

 $^{{}^{5}}$ In the low-cost scenario, Dachis et al. (2017) assume the costs of plugging and reclamation are \$80,000 and \$20,000, respectively. In the high-cost scenario, those costs are doubled.

⁶The PBO estimates average costs of \$58,000 and \$28,000 to plug and reclaim a well, respectively.

of non-producing and orphaned oil and gas wells in Alberta.⁷ Alberta's oil and gas sector faces large costs to meet its end-of-life obligations. Using the PBO estimates, the total estimated cost of decommissioning and reclaiming Alberta's current inventory of inactive oil and gas wells is approximately \$10 billion. For comparison, the AER reports that in 2022 the oil and gas sector spent \$16 billion on capital expenditures, rising 73% from 2021 as a result of increased drilling activity (Alberta Energy Regulator, 2023a).

Non-producing oil and gas wells present an environmental risk in addition to being a financial risk. Inactive oil and gas wells are a significant source of methane emissions, a potent greenhouse gas and a contributor to groundwater contamination (Kang et al., 2014; Schiffner et al., 2021; Williams et al., 2021; Bowman et al., 2023; El Hachem and Kang, 2023). Methane makes up about 13% of Canada's total GHG emissions and the oil and gas sector accounts for about 40% of Canada's methane emissions (Environment and Climate Change Canada, 2021), and has a global warming potential 34 times stronger than that of carbon dioxide over a 100-year period and 86 times stronger over a 20-year period. Moreover, there is growing evidence that methane emission estimates from Canadian and Albertan oil and gas wells could be under-estimated by as much as 150 per cent (Johnson et al., 2017; Chan et al., 2020; MacKay et al., 2021; Williams et al., 2021; Conrad et al., 2023a,b). Alberta and Canada have committed to reduce methane emissions by 45 per cent by 2025.⁸ Kang et al. (2019) and Schiffner et al. (2021) suggest that policies aimed at incentivizing owners to remediate and reclaim their oil and gas wells could be a cost-effective strategy to reduce methane emissions and meet Alberta and Canada's methane emission targets. Importantly, the main emissions-related environmental benefit is in a well moving from a state where it is non-producing but unplugged to where it is plugged, as an unplugged well generally has higher emissions than plugged wells (Kang et al., 2014; Bowman et al., 2023; El Hachem and Kang, 2023). However, there is evidence that plugged wells still leak Williams et al. (2021); El Hachem and Kang (2023), and so the reclamation phase that requires eliminating residual contamination (e.g., leaks) would have some additional environmental benefit. The main benefit of full reclamation is the land returning to (close to) its original state and allowing for alternative uses.

In this paper we evaluate the life cycle (from production to reclamation) of a representative oil well in Alberta using real options analysis. Real options analysis allows us to incorporate managerial flexibility into the life of an oil well while allowing for uncertainty in future oil prices. Specifically, throughout the life of an oil well, the firm will have options to mothball production, restart production, decommission, restart from decommissioned, and reclaim an oil well. We identify policy functions and decision thresholds that

⁷In 2017, the OWA received interest-free loans of \$335 million and \$200 million from Alberta and Canada, respectively. As part of the federal COVID-19 Economic Response Plan, a \$1 billion grant was provided to support Alberta's Site Rehabilitation Program in an effort to decommission and reclaim oil and gas sites in Alberta.

⁸In 2015, the Government of Alberta committed to reduce methane emissions from upstream oil and gas operations by 45 per cent (relative to 2014 levels) by 2025. In 2016, the Government of Canada committed to a national 40 to 45 per cent methane reduction relative to 2012 levels by 2025.

determines the optimal operational state of an oil well conditional on current oil prices, reserves in place, the current state of the well, well-specific parameters, and government policy choices. Our contribution is two-fold. First, to model in detail a firm's end-of-life decisions and try and explain observed firms' behaviour in Alberta. Second, to explore how policy choices to address environmental problems — a carbon tax on emissions and policy to incentivize reclamation activities — affect a firm's optimal decisions for operating an oil well in Alberta.

Results under our baseline parameters show that firms operating a representative oil well will extract over 95 per cent of the reserves in place and reclaim the well. This result is inconsistent with observed behaviour by firms in Alberta. We offer two explanations: first, we use baseline parameters that reflect historical costs. All else equal, we would expect firms to reclaim the lowest-cost wells first and so it is entirely possible these parameters are underestimates of the true cost of decommissioning and reclaiming the majority of wells in Alberta. Second, we may be over-estimating monitoring costs; higher monitoring costs for inactive wells increase the incentive to decommission and reclaim.

We engage in sensitivity analysis on costs firms face, and find that if cleanup costs are large (relative to the cost of remaining inactive) the firm will never reclaim the well. If cleanup costs are a function of environmental damage that needs to be repaired or to mitigate future environmental risks (Kiran et al., 2017), we find that environmentally risky oil wells are the least likely to be reclaimed under current policies. Our results are similar to those in Lohrenz (1991) and Muehlenbachs (2015). Like them, we find firms may be mothballing or decommissioning oil wells to avoid high cleanup costs for oil wells that are unlikely to be brought back into production. We analyze how optimal management changes under a carbon tax, a limit on how long a well can be inactive, and bonding requirements. The carbon tax does not affect transition costs. but it lowers the value of the well (via increased costs) and decreases cumulative production, changing the thresholds for switching between states. Importantly, the time limit on inactivity does not ensure the firm will reclaim the well in a timely manner when it faces high decommissioning or reclamation costs. Instead, firms find it optimal remain in the inactive state for the maximum allowable time and then switch to active for short periods of production to avoid these costs and restart the inactive clock. When a policymaker requires a firm to post an upfront bond valued at expected clean-up costs, the bonding system matters for the incentives firms have to reclaim a well. When a firm receives interest payments from the bond, it has no effect on its decision-making. Requiring a bond, without interest payments, increases the opportunity costs of the firm keeping the well in an inactive state and shifts the threshold for decommissioning and reclamation, so higher cleanup cost oil wells will be reclaimed.

Real option analysis is a standard approach for evaluating non-renewable resource projects. The Alberta oil sands have received attention in the real options analysis literature over the past few years (Kobari et al., 2014; Almansour and Insley, 2016; Insley, 2017; Galay, 2018). Closest to our work, Insley (2017) examines the effect of several carbon tax schemes on the optimal timing of construction, production, and decommissioning of an oil sands project. Kobari et al. and Insley both find firms have an incentive to speed up development to avoid increasing environmental costs and regulations. Insley concludes that the same intuition would apply to other sorts of regulations, such as gradually increasing requirements for monitoring, abatement of emissions and remediation of environmental damages. We apply real options analysis to conventional oil wells in Alberta to evaluate the optimal management of an oil well from production to reclamation. Similar to Muchlenbachs (2015), we focus on the extensive margin (whether to operate) rather than the intensive margin (how much to extract), as the decision to operate or not is what has created the liability problem motivating our analysis.

Our work is most similar to Muehlenbachs (2015), who considers a firm's decision to temporarily close an oil and gas well in Alberta. Using well-specific data, they estimate a dynamic discrete choice model under price and quantity uncertainty, finding it is very unlikely that high prices or technological improvements would bring oil and gas wells back into production once they have been mothballed or decommissioned. They find the number of decommissioned wells is very elastic to the cost of decommissioning. Muehlenbachs's results suggest that increasing the cost of leaving a well inactive or decreasing the cost of decommissioning a well could increase the number of decommissioned wells without decreasing the number of active wells. They conclude that the current behaviour is not socially optimal given that there are externalities from idling the wells that are not accounted for in the decision. We build on Muehlenbachs (2017) by examining firm's endof-life decision-making using a real options framework and explicitly examining the effect of policy choices on firm's decisions. We find that wells that have high decommissioning or reclamation costs will never be fully reclaimed and will either be left mothballed or decommissioned, as the oil prices required to restart production are improbably high.

Other work examines how regulations can be used to ensure end-of-life environmental cleanup costs are borne by those that benefit during the life of a project. Gerard (2000) and Boyd (2001) discuss the rationale of financial assurance rules as a complement to liability rules. Boomhower (2019) examines the effect of financial assurance on the structure of the oil and gas industry and environmental outcomes in Texas. They find that the policy substantially improved environmental outcomes and reduced production from smaller firms, production shifted to larger firms with better environmental records, and production from high-cost wells decreased. Lappi (2020) suggests that the combination of a pollution tax, a project shutdown date, and financial assurance can incentivize socially optimal extraction of an exhaustible resource. Aghakazemjourabbaf and Insley (2021) demonstrate that a bond can be enough to ensure that a firm acts optimally and no efficiency loss is imposed on society. We contribute to this literature by examining the outcomes associated with different policy choices, using the case of Alberta, a jurisdiction already shown to have a suboptimal policy environment for effective reclamation. Our results suggest that additional policies to incentivize reclamation are required to ensure financially and environmentally risky oil wells are cleaned up in a safe and timely manner. A bond is likely the most effective policy intervention.

The rest of the paper is organized as follows. Section 2 specified the real options model for the valuation of an oil well in Alberta. Section 3 describes the data that we use to calibrate the model. Section 4 outlines the numerical methods that we use to solve the partial differential equations that govern the evolution of the value of an oil well. Section 5 presents the results and evaluates the impact of different policy interventions (a carbon tax, time limits on inactivity, and bonding requirements) on the value of an oil well and optimal policy functions. Section 6 summarizes our results and discusses current policy developments in Alberta.

2 A Real Options Model of An Oil Well Life Cycle

Before explaining the model, we provide some institutional details motivating our modelling choices ans assumptions. In Alberta, 81% of mineral rights are held by the province and it leases these rights to firms to develop in exchange for annual fixed rental payments and royalties on production. Initial tenure disposition is via auction (with some instances of direct sale), and firms have between two and five years to drill a well and show the leased property is productive (two months of consecutive production above a minimum volume); when firms fail to prove a lease productive the mineral rights revert to the province (Alberta, 2024; Government of Alberta, n.d.). The initial licence term upon first production is five years, and if the property remains productive at the end of the five years the right to produce continues indefinitely. This gives firm an infinite time horizon so long as they fulfill the requirements for a well to maintain its active classification. Moreover, there is no legal requirement to decommission and reclaim a well unless it has been inactive for five or more years and the AER issues a closure request (Alberta, 2024); this does not appear to bind as the last time its closure and abandonment orders were updated was September 2016 (Alberta Energy Regulator, 2016a,b). Recently, the AER has implemented an industry-wide and firm-specific closure spend quota to help reduce the outstanding closure liabilities but this still does not impose decommissioning or reclamation requirements on specific wells (Alberta Energy Regulator, n.d.a).

The life cycle of a conventional oil and gas project has eight phases: exploration, appraisal, development, production (active), inactive, mothballed (suspended), decommissioned (abandoned or plugged), and reclamation.⁹ Figure 2 illustrates the life cycle of a conventional oil and gas well and provides brief descriptions

⁹The Alberta Energy Regulator categorizes oil and gas wells as active, inactive, suspended (which we refer to as mothballed), abandoned (decommissioned), reclaimed, and orphaned. An active well is a well that is producing oil or gas; an inactive well is a well that has not produced oil or gas, injected fluids, or disposed of waste for 6 or 12 months; a suspended well has been secured to ensure public safety and environmental protection; an abandoned well

of the activities in each stage. The figure also shows that the life of an oil and gas well is not necessarily a straight line through stages, but can cycle between different stages. For example, a producing well can be mothballed then brought back into production. However, decisions to mothball, restart production, decommission, and reclaim are costly decisions that are not easily reversed. For example, decommissioning requires the owner to permanently shut down and plug the well, and remove the wellhead. Reclamation requires the firm to remove all equipment from the site, and decontaminate and return the land to the state it was in before development. Our model focuses on the last five phases in the life cycle, modelling the optimal management of a non-renewable resource extraction project with future price uncertainty that must be decommissioned and reclaimed at the end of its life. We assume all efforts associated with exploration, appraisal, and development have already been undertaken. We also abstract from modelling a firm's insolvency; while interesting, our intuition is that firms would prefer to remain solvent and the orphan well problem is a small proportion of the total inventory of wells in Alberta. While our application is optimal management of oil wells in Alberta, the model can be applied to any non-renewable resource project already in its production stage that has significant cleanup costs.

Figure 2: Oil and gas well Life cycle taxonomy



The firm's objective is to maximize the expected value of the oil well by optimally choosing an extraction path over time, as well as determining the optimal timing for production, mothballing, restarting production,

is permanently shut down, plugged, the wellhead is removed, and considered safe and secure; a well is reclaimed when the site has been returned to a comparable state prior to development; and an orphan well has no identifiable owner and can have any status (Alberta Energy Regulator, 2020, 2023b). We use mothballed and decommissioned instead of suspended and abandoned to follow the convention in the literature and to avoid potential confusion.

decommissioning, and reclaiming the asset:

$$V^{s}(P, R, t; \theta) = \max_{q, s} E^{\mathbb{Q}} \int_{t}^{\infty} \exp^{-\rho z} \pi^{s}(P, q, R; \theta) dz$$

Subject to:
$$s = a, m, d, \text{ or } r$$

$$R_{0} - \int_{t}^{\infty} q(z) dz \ge 0.$$
(1)

Here $V^{s}(P, R, t; \theta)$ is the value of an oil well in state s at time t, P is the current oil price, R is the resource stock, θ is a vector of known well-specific characteristics such as depth, formation, well-type, etc., π^{s} are the state dependent cash flows of the well, and ρ is the risk-free rate of return. The well is in one of four states, s = a, m, d, r, corresponding to active, mothballed, decommissioned, and reclaimed.¹⁰ Production over the life of the well cannot exceed initial reserves in place. Following Conrad and Kotani (2005) and Galay (2018) we assume oil prices evolve according to a known Ornstein-Uhlenbeck process,

$$dP = \kappa (\bar{P} - P)dt + \sigma dW, \tag{2}$$

where κ is the speed of reversion to the risk-adjusted long-run average log price, \bar{P} , σ is the standard deviation, and dW is an increment of a Wiener process.

2.1 Active (Production) Stage

When the oil well is in the production stage, the firm extracts oil and sells it at the prevailing market price. Should market conditions deteriorate the firm has the options to mothball, decommission, or reclaim the well. If it decides to reclaim the oil well from the producing stage it has to undertake both decommissioning and reclamation activities, $C_{a,r} = C_{a,d} + C_{d,r}$.

The firm's problem of valuing a producing oil well with the options to mothball, decommission, and reclaim can be shown as an optimal stopping problem:

$$V^{a}(P, R, t; \theta) = \max\left\{\max_{q \in (0, \bar{R}]} \pi(q; \theta) dt + \frac{E^{\mathbb{Q}}[V^{a}(P + dP, R + dR, t + dt; \theta)]}{1 + \rho dt}, \\ \max_{s \neq a} V^{s}(P, R, t; \theta) - C_{a,s}(R; \theta)\right\}.$$
(3)

The firm will exercise one of its options if the value of the oil well in that state is larger than continuing

¹⁰The AER classifies wells that have not produced in 6 to 12 months as inactive. We do not include this stage in our model as it is a temporary state where at the end of the inactive period the well will start production again or it will be mothballed or decommissioned. However, we do effectively model it as we allow for temporary mothballing.

to produce minus the costs of transitioning to that state, $C_{a,s}$. The cost of transitioning can be affected by remaining reserves (or aggregate production), and other well-specific characteristics (e.g., well depth, formation, etc.).

While the oil well is producing, its value is determined by the following Bellman equation:

$$\rho V^{a} = \max_{q \in (0,\bar{R}]} \pi^{a}(q) + (1/\mathrm{d}t) E^{\mathbb{Q}}[\mathrm{d}V^{a}],$$
(4)

where q represent the quantity of reserves extracted and sold at a particular point in time when the oil well is active. $\bar{R}(t)$ represents the maximum amount of stock that can be extracted from the reserves with R(t)remaining. The change in the stock of the resource, R(t), is then

$$dR = \begin{cases} -qdt, & \text{if } S = a \\ 0, & \text{otherwise.} \end{cases}$$
(5)

To ensure non-negativity of reserves we have two conditions:

$$q(t) \le R(t)$$
$$\int_{t_0}^{\infty} q(z) dz \le R_0$$

The first condition does not allow the firm to extract more reserves than are currently in place at any point in time. The second condition requires that total production over the life of the well does not exceed initial reserves.

Applying Itô's Lemma to Equation (4), we obtain a partial differential equation (PDE) for the value of an active oil well:

$$\rho V^{a} = \sigma^{2} \frac{\partial^{2} V^{a}}{\partial P^{2}} + \kappa (\bar{P} - P) \frac{\partial V^{a}}{\partial P} + \frac{\partial V^{a}}{\partial t} + \max_{q \in (0,\bar{R}]} \left\{ \pi^{a}(q) - q \frac{\partial V^{a}}{\partial R} \right\}.$$
(6)

Equation (6) is subject to the boundary condition that if reserves are exhausted the oil well is reclaimed,

$$V^{a}(P, R = 0, t) = V^{r}(P, R = 0, t) - C_{a,r}.$$
(7)

We can identify mothballing, decommissioning, and reclamation thresholds by using value matching and smooth-pasting conditions.¹¹ The value-matching condition matches the value of a producing oil well with the value of the well in another state, less the cost of transitioning from producing to that state. The smooth

¹¹See Dixit and Pindyck (1994) for a detailed discussion on value-matching and smooth-pasting conditions.

pasting condition requires the functions to meet tangentially at the optimal stopping boundary.

$$V^{a}(P_{a,s}^{*}, R, t) = V^{s}(P_{a,s}^{*}, R, t) - C_{a,s}$$
(8)

$$\frac{\partial V^a(P_{a,s}^*, R, t)}{\partial P} = \frac{\partial V^s(P_{a,s}^*, R, t)}{\partial P},\tag{9}$$

where $C_{a,s}$ is the cost of transitioning from producing to another state s.

Equations (6), (7), (8), and (9) define a free boundary problem for valuing an active oil well with the options to mothball, decommission, or reclaim. The solution to the free boundary problem determines the value of a producing oil well and the mothballing, decommissioning, and reclamation thresholds.

2.2 Mothballed and Decommissioned Stages

If the oil well is either mothballed or decommissioned the firm is required to monitor and inspect the well periodically to ensure that is is not leaking or contaminating the soil or ground water.¹² The firm's objective is to determine the prices where it is optimal to restart production, decommission, or reclaim the well. The options available to the firm when the oil well is not producing will depend on whether the oil well is mothballed or decommissioned. If the oil well is mothballed, the firm has three choices. It can restart production (if the price is high enough), or, if prices deteriorate, the firm can decommission or reclaim the well. If the oil well is decommissioned, the firm can restart production, conditional on a sufficiently high price. Restarting production from a decommissioned has higher costs than from mothballed due to the firm needing to re-enter the well. If prices deteriorate, the firm can reclaim the well. We assume a firm will never pay the cost to transition from decommissioned to mothballed. We also assume that if a firm chooses to reclaim a well, it eliminates the option to restart production.¹³

The firm's problem of valuing a mothballed or decommissioned oil well with the options to restart, decommission (if mothballed), and reclaim is represented by the following optimal stopping problem:

$$V^{n}(P, R, t; \theta) = \max\left\{-MC_{n}dt + \frac{E^{\mathbb{Q}}[V^{n}(P+dP, R+dR, t+dt; \theta)]}{1+\rho dt}, \max_{s \neq n} V_{s}(P, R, t; \theta) - C_{n,s}(R; \theta)\right\},$$
(10)

where $MC_n \equiv \pi^n (q = 0; \theta)$ are annual monitoring costs when n = m or d. Well-specific variables, θ , can affect annual monitoring costs. For example, the AER requires more rigorous testing of high-risk wells than

¹²For example, the AER requires all non-producing wells to meet initial suspension and reporting requirements within 12 months of inactive status date. To remain in compliance the firm must complete ongoing well inspection requirements. Inspection frequency (one to five years) is determined by the risk class of the well.

¹³Firms can re-enter previously reclaimed oil wells; however, the decision to re-enter is more similar to the decision to drill a new well then re-starting production for a mothballed or decommissioned oil well.

low-risk wells. The Bellman equation for a mothballed or decommissioned well is

$$\rho V^n = -\mathrm{MC}_n + (1/\mathrm{d}t) E^{\mathbb{Q}}[\mathrm{d}V^n].$$
(11)

Applying Itô's Lemma to Equation (11) we derive a PDE for the value of a mothballed or decommissioned oil well:

$$\rho V^{n} = \sigma^{2} \frac{\partial^{2} V^{n}}{\partial P^{2}} + \kappa (\bar{P} - P) \frac{\partial V^{n}}{\partial P} - MC_{n} + \frac{\partial V^{n}}{\partial t}$$
(12)

We require the same boundary conditions for the mothballed and decommissioned PDEs as for a producing well: if reserves are exhausted the oil well is reclaimed.

$$V^{n}(P, R = 0, t) = V^{r}(P, R = 0, t) - C_{n,r}$$
(13)

We identify re-start, decommissioning (if mothballed), and reclamation thresholds by using value matching and smooth-pasting conditions:

$$V^{n}(P_{n,s}^{*}, R, t) = V^{s}(P_{n,s}^{*}, R, t) - C_{n,s},$$
(14)

$$\frac{\partial V^n(P_{n,s}^*, R, t)}{\partial P} = \frac{\partial V^s(P_{n,s}^*, R, t)}{\partial P}.$$
(15)

Similar to the producing well, equations (12), (13), (14), and (15) define a free boundary problem with its solution determining the value of a mothballed or decommissioned oil well with the options to restart production, decommission (if mothballed), or reclaim.

3 Data, Calibration and Parameter Assumptions

Table 1 summarizes our parameter assumptions for a representative oil well in Alberta. Historically, vertical wells accounted for the majority of non-oil-sands oil production in Alberta. However, starting in 2012 the share of oil production from horizontal wells increased and it now accounts for the majority of Alberta's non-oil-sands oil production. Accordingly, we consider horizontal oil wells that produce light sweet crude oil to be the representative oil well. We estimate capital costs, production costs (variable and fixed), and productivity parameters for the representative oil well using data from the AER's Supply Cost Study (Alberta Energy Regulator, 2023a). The supply cost of an oil well is the minimum constant dollar price needed to recover all capital expenditures, operating costs, royalties, taxes, and earn a specified return on investment. The AER estimates supply costs for various types of oil wells extracting oil from

different geological formations in the province of Alberta.¹⁴ We construct our estimates of capital costs, production costs, and productivity parameters for the representative oil well by taking the simple average of these parameters for horizontal oil wells that produce light sweet crude oil that are included in Alberta Energy Regulator (2023a). The representative well has capital costs of \$3,559,000. These costs include drilling, casing, completion, and land acquisition costs. Variable and fixed operating costs are \$8.07 per barrel and \$95,800 per year, respectively. Operating costs include processing and transportation costs. We exclude the AER values of taxes, royalties and a required rate of return from our supply costs. We calculate taxes and royalties, and do not have a required rate of return in our analysis. Our decommissioning and reclamation costs are the simple average of decommissioning and reclamation costs for horizontal oil wells that produce light sweet oil in the Evaluate Energy's CanOils Well and Land Database (CanOils). The CanOils database includes estimated reclamation and decommissioning costs for each well in the database. Decommissioning and reclamation cost estimates factor in well depth and requirements for groundwater protection, gas migration, and surface casing vent flow repair. The representative well has a decommissioning cost of \$124,403 and a reclamation cost of \$25,914. Our decommissioning and reclamation costs are in line with estimates used by Dachis et al. (2017) and Forsyth and Nahornick (2022). All costs are in real 2022 Canadian dollars and assumed to be constant over time. If the oil well is reclaimed from a producing state the firm will need to pay both the decommission and reclamation costs. We also assume productivity declines at 10 per cent per year and an oil well can produce for up to 40 years.¹⁵ With initial production of 31,500barrels, over the 40 years the representative oil well can produce over 300,000 barrels of oil.

Table 1: Representative horizontal oil well parameters

Parameter	Value	
Total measured depth (meters)	$3,\!596$	
Initial productivity (bbl/year)	31,500	
Decline rate (percent/year)	10	
Total capital cost $(2022 \text{ constant CAD})$	$3,\!559,\!000$	
Fixed operating cost (2022 constant CAD/year)	95,800	
Variable operating cost (2022 constant CAD/bbl)	8.07	
Decommissioning costs (2022 constant CAD)	124,403	
Reclamation costs (2022 constant CAD)	25,914	

Notes: Estimated supply costs using well characteristics and oil supply costs from Alberta Energy Regulator (2023a).

To estimate the parameters in equation (2) we use weekly spot price data for West Texas Intermediate (WTI) crude oil price for the period June 5, 2009 to March 6, 2020, converted to 2022 real Canadian dollars.

¹⁴Crude oil supply costs are available at: https://www.aer.ca/providing-information/data-and-reports/ statistical-reports/st98/crude-oil/supply-costs.. These areas are called Petroleum Services Association of Canada (PSAC) areas, based on geology.

¹⁵Our numerical solution and results are not sensitive to the well's lifetime of 40 years or the amount of inactive time. Technically only the active and reclamation states are terminal states. If no options are exercised, the active well will exhaust its reserves and be reclaimed. The reclamation state is a terminal state by definition. However, given our boundary conditions, the mothballed and decommissioned states are not terminal states.

The sample begins after the 2008 financial crisis and ends before the COVID-19 pandemic. Table 2 shows the summary statistics for WTI over the sample period. The average price was 98.52 with a standard deviation of 22.22. Oil prices reached their lowest value of 46.19 on February 12, 2016 and their highest value of 139.46 on June 20, 2014.

Summary Statistic	Value
Mean:	98.5216
St. Dev.:	22.22
Skew:	-0.0239
Kurt:	-1.0406
Min (2016-02-12):	46.19
Max (2014-06-20):	139.46
Obs:	562

Table 2: WTI summary statistics (real 2022 Canadian dollars)

Notes: Weekly spot price data is West Texas Intermediate (WTI) crude oil prices. We convert the WTI series to Canadian dollars using Canada/U.S. exchange rate data from the Federal Reserve Bank of St. Louis and then converted into real 2022 dollars using Canada's CPI from Statistics Canada.

Sources: WTI: the U.S. Energy Information Administration for the period June 5, 2009 to March 6, 2020. WTI data was retrieved from https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=W. CAD/USD exchange rate: Board of Governors of the Federal Reserve System (US), Canadian Dollars to U.S. Dollar Spot Exchange Rate [DEXCAUS], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/DEXCAUS, March, 2024. CPI: Statistics Canada. Table 18-10-0004-01 Consumer Price Index, monthly, not seasonally adjusted; https://doi.org/10.25318/1810000401-eng, March, 2024.

Following Dixit and Pindyck (1994) we estimate the parameters of equation (2) by running the regression

$$x_t - x_{t-1} = a + bx_{t-1} + \epsilon_t, \tag{16}$$

where ϵ_t is normally distributed with mean zero and standard deviation σ_{ϵ} . The parameters of equation (2) are recovered as follows

$$\begin{split} \bar{P} &= -\hat{a}/\hat{b}, \\ \hat{\kappa} &= -\log(1+\hat{b}), \\ \hat{\sigma} &= \hat{\sigma_{\epsilon}} \sqrt{\frac{\log(1+\hat{b})}{(1+\hat{b})^2 - 1}}. \end{split}$$
(17)

Table 3 presents the regression results for equation (16) and the resulting parameter estimates for equation (2). The estimated long run average price is 92.84 per barrel in real 2022 Canadian dollars. The estimated annual speed of reversion is 0.4931 and the annual standard deviation is 16.7506.

Although we use a constant standard deviation mean-reverting process, our speed of reversion ($\kappa = 0.4931$ and standard deviation ($\sigma = 16.7506$) parameter estimates are in line with the long-run parameter estimates from Insley (2017). Insley considers two price regimes with a mean-reverting process with a variance rate grows with price. In Regime 1, the speed of reversion was 0.44 and the standard deviation at long-run average price was 17.25 (0.23×75). In Regime 2, the speed of reversion was 1.05 and the standard deviation at the long-run average price was 13.2 (0.44×30).

Parameter Value					
i diameter value					
Regression Results					
\hat{a} : 0.8762 (0.6285)					
\hat{b} : -0.0094					
$\hat{\sigma}_e:$ 3.2695					
Demonstern Estimater					
Parameter Estimates					
\bar{P} : 92.84					
<i>κ</i> : 0.4931					
σ : 16.7506					

Table 3: Ornstein-Uhlenbeck process parameters

Notes: Presents equation (16) regression results (top panel) and equation (2) parameter estimates (bottom panel). Regression $R^2 = 0.0041$.

We assume annual after-tax cash flows for a producing oil well is given by

$$\pi(P,q) = \left((1 - t_R(P,q))P - c_v \right) q - c_f - \max\left\{ t_I \times \left[\left((1 - t_R(P,q))P - c_v \right) q - c_f - d(q) \right], 0 \right\},$$
(18)

where c_v are variable costs, c_f are fixed costs, $t_R(P,q)$ is the royalty rate, t_I is the income tax rate, and d(q) are depreciation expenditures.

We use Alberta's Modernized Royalty Framework (MRF) to determine royalty rates and payments. We use post- C^* royalty rates; these rates vary from 5 to 40 per cent depending on the price of WTI and level of production. The Government of Alberta changed the royalty framework for crude oil, natural gas, natural gas liquids and non-project crude bitumen wells in 2017. The MRF introduced a Drilling and Completion Cost Allowance (DCCA), C^{*}, as part of the new framework. The DCCA is a function of a well's depth, length, and proppant used, and is a proxy for well costs. The royalty rate is 5 per cent until cumulative revenue reaches C^{*}. The MRF mimics a revenue-minus-cost royalty system (Shaffer, 2016), where C^{*} is the average industry cost to bring a well on production.

We divide capital expenditures into two categories, oil and gas equipment expenses and Canadian oil and gas property expenses, for income tax expense calculations. The first category includes all oil and gas well equipment (above and below ground). Drilling, casing and pumping equipment are the largest expenditures when developing the oil well; we assume they are 85 per cent of initial capital expenditures. These expenditures are deducted at a 25 per cent declining balance, in line with Canada Revenue Agency treatment of Class 41 property. The remaining capital costs are treated as Canadian oil and gas property expenses and is deducted at a 10 per cent declining balance, in line with Canada Revenue Agency treatment. The income tax rate includes both provincial and federal taxes and is 23 per cent.

Table 4 displays our full set of parameter assumptions for the baseline and sensitivity analysis.

		Baseline	e Scenario Paramet	ers	
Produc	tion Parameters		Maximum Possible	Time	
$\overline{q_0}$	31,500		T_a	40	
λ	0.1		T_m	20	
R_0	302,381		T_d	20	
	Prod	uction Co	sts		
c_v	8.07	c_f	95,800		
	Moni	toring Co	sts		
MC_m	19,160	MC_d	9,580		
MC_r	0				
			Transition Costs		
$C_{a,m}$	0	$C_{m,a}$	0	$C_{d,a}$	1,108,000
$C_{a,d}$	124,403	$C_{m,d}$	124,403	·	
$C_{a,r}$	150,317	$C_{m,r}$	150,317	$C_{d,r}$	25,914
]	Price Parameters		
\bar{P}	92.836	P_{max}	300		
κ	0.4931	P_{min}	0		
σ	16.7506	ρ	0.05		
		Sei	nsitivity Analysis		
Mothb	all Costs $(C_{a\ m})$	Decom	mission Costs $(C_{a,d})$	Reclar	mation Costs $(C_{d,r})$
	6.220		62.210		77.742
	18.660		248.806		129.570
	62,201		373,209		259,140
Price	e volatility (σ)	R	isk-free rate (ρ)		
8.3753 33.5012		0.02 0.10			
	67.0024				

Table 4: Baseline Scenario and Sensitivity Analysis Parameters

4 Numerical Methods

In section 2 we define three free-boundary problems that determines the value of an oil well in each possible state: active, mothballed, and decommissioned, as well as optimal policy functions and decision thresholds for management of the well. Free boundary problems of this form do not have known analytical solutions but can be approximated using numerical methods. Here, we outline our numerical approach for solving the free boundary problems to value an oil well.

The function $V : \mathbb{R}^3_+ \to \mathbb{R}$ determines the value of an oil well. For computational purposes the value of an oil well is solved over a finite domain $P \in [0, P_{max}]$, $t \in [0, T_s]$, and $R \in [0, R_0]$. Where T_s can be state specific. For convenience we define $\tau_s = T_s - t$ as time remaining so that $d\tau_s = -dt$ when in state s, 0 otherwise and $\tau_s \in [T_s, 0]$. Specifying Equations (6) and (12) in terms of τ_s gives:

$$\frac{\partial V^a}{\partial \tau_a} = \sigma^2 \frac{\partial^2 V^a}{\partial P^2} + \kappa (\bar{P} - P) \frac{\partial V^a}{\partial P} - \rho V^a + \max_{q \in (0,\bar{R}]} \left\{ \pi^a(q) - q \frac{\partial V_R}{\partial R} \right\},\tag{19}$$

$$\frac{\partial V^n}{\partial \tau_n} = \sigma^2 \frac{\partial^2 V^n}{\partial P^2} + \kappa (\bar{P} - P) \frac{\partial V^n}{\partial P} - \rho V^n - \mathrm{MC}_n.$$
(20)

The focus of this paper is modelling the extensive margin (the choice to produce or not) rather than the intensive margin (how much to produce). Therefore, we assume that annual oil production is not a choice variable once the oil well has been drilled. Let q_0 be the initial annual production for a newly drilled well and let λ be the annual production decline rate. Then annual production in any year is determined by $q_t = q_0(1-\lambda)^t$. With deterministic production the optimization in equations (19) can be excluded. If an oil well has an expected life of T_a years and in production year T_a production falls to $q_{T_a} = 0$ then initial reserves are $R_0 = \int_0^{T_a} q_z dz$. Given that both τ_a and R are functions of the number of periods that the oil well has produced then we can exclude one of $\frac{\partial V^a}{\partial \tau_a}$ or $\frac{\partial V^a}{\partial R}$ as they are measuring the sensitivity of V^a to more years of production. Note we will exclude $\frac{\partial V^a}{\partial R}$ from the below equations.

Additional boundary conditions must be specified to fully characterise the oil well valuation problem. Equations (7) and (13) specify the boundary condition along the R = 0 and $\tau_a = 0$ boundary. Additional boundary conditions are needed for price and when $\tau_n = 0$.

Along the P = 0 boundary, equations (19) and (20) become

$$\frac{\partial V^a}{\partial \tau_a} = \sigma^2 \frac{\partial^2 V^a}{\partial P^2} + \kappa(\bar{P}) \frac{\partial V^a}{\partial P} - \rho V^a + \pi^a, \tag{21}$$

$$\frac{\partial V^n}{\partial \tau_n} = \sigma^2 \frac{\partial^2 V^n}{\partial P^2} + \kappa(\bar{P}) \frac{\partial V^n}{\partial P} - \rho V^n - \mathrm{MC}_n.$$
(22)

Following Insley (2017), we assume that as $P \to P_{max}$ then $\frac{\partial^2 V^s}{\partial P^2} \to 0$. This is a common assumption used in the literature and means the value of the project is linear in P as price gets very large. At P_{max} , equations (19) and (20) become

$$\frac{\partial V^a}{\partial \tau} = \kappa (\bar{P} - P_{max}) \frac{\partial V^a}{\partial P} - \rho V^a + \pi^a, \qquad (23)$$

$$\frac{\partial V^n}{\partial \tau} = \kappa (\bar{P} - P_{max}) \frac{\partial V^n}{\partial P} - \rho V^n - MC_n.$$
(24)

Along the $\tau_m = 0$ boundary when the oil well is mothballed and R > 0, the firm can either restart production, decommission the well, reclaim it, or maintain it as mothballed forever. There is no limit on how long an oil well can remain inactive so long as the owner of the oil well is meeting its regulatory requirements. Based off of Goodday and Larson (2021) results, we set the time limit for mothballed at 20 years. If the firm decides to remain mothballed forever the firm will continue to pay monitoring costs each period. Similarly, when the oil well is decommissioned, along the $\tau_d = 0$ boundary, if the firm decides to keep it decommissioned forever the firm will continue to pay monitoring costs each period. The boundary conditions are:

$$V^{m}(P, R, \tau = 0) = \max\{V^{a}(P, R, T_{a}) - C_{m,a}, -MC_{m}/\rho, V^{d}(P, R, T_{d}) - C_{m,d}, V^{r}(P, R) - C_{m,r}\},$$

$$V^{d}(P, R, \tau = 0) = \max\{V^{a}(P, R, T_{a}) - C_{d,a}, -MC_{d}/\rho, V^{r}(P, R) - C_{d,r}\}.$$
(25)

Following Wilmott et al. (1993), Insley and Rollins (2005), and Galay (2018) we redefine the free boundary problems as linear complementarity problems (LCPs).¹⁶ A solution to the LCP is a solution to the free-boundary problem (and vice versa).¹⁷ A benefit of redefining the free boundary problems as LCPs is that it eliminates the complications caused by the free boundary, and the free boundary can be recovered after solving the LCP. When the well is producing it satisfies the following LCP:

$$\frac{\partial V^{a}}{\partial \tau_{a}} - \pi(q_{\tau_{a}}) - \sigma^{2} \frac{\partial^{2} V^{a}}{\partial P^{2}} - \kappa(\bar{P} - P) \frac{\partial V^{a}}{\partial P} + \rho V^{a} \ge 0,$$

$$V^{a} - \max_{s \neq a} \left\{ V^{s} - C_{a,s} \right\} \ge 0,$$

$$\left(\frac{\partial V^{a}}{\partial \tau_{a}} - \pi(q_{\tau_{a}}) - \sigma^{2} \frac{\partial^{2} V^{a}}{\partial P^{2}} - \kappa(\bar{P} - P) \frac{\partial V^{a}}{\partial P} + \rho V^{a} \right) \times \left(V^{a} - \max_{s \neq a} \left\{ V^{s} - C_{a,s} \right\} \right) = 0.$$
(27)

When the well is mothballed or decommissioned it satisfies the LCP:

$$\frac{\partial V^n}{\partial \tau_n} - \mathrm{MC}_n - \sigma^2 \frac{\partial^2 V^n}{\partial P^2} - \kappa (\bar{P} - P) \frac{\partial V^n}{\partial P} + \rho V^n \ge 0,$$

$$V^n - \max_{s \ne n} \left\{ V^s - C_{n,s} \right\} \ge 0, \qquad (28)$$

$$\left(\frac{\partial V^n}{\partial \tau_n} - \mathrm{MC}_n - \sigma^2 \frac{\partial^2 V^n}{\partial P^2} - \kappa (\bar{P} - P) \frac{\partial V^n}{\partial P} + \rho V^n \right) \times \left(V^n - \max_{s \ne n} \left\{ V^s - C_{n,s} \right\} \right) = 0.$$

Another benefit of redefining the free boundary problems as LCPs is equations (27) and (28) have the intuitive interpretation of a rational investor's strategy with regard to holding versus exercising an option to switch operating states. The first line in equations (27) and (28) can be interpreted as the difference between the required return for holding the option to switch an oil well to another operating state and the actual return from holding the option. When the required return equals the actual return it is optimal to maintain the current operational state of the oil well. When the required return exceeds the actual return it is optimal to exercise an option. The first line is nonnegative as realized returns cannot be consistently greater than required returns in equilibrium. The second line is nonnegative, if negative it is optimal to exercise an option immediately.

Equations (27) and (28) are discretized using implicit finite difference methods. We use Lemke's algorithm to numerically solve the LCP.¹⁸

$$x, F(x) \ge 0,$$

$$x^T F(x) = 0$$
(26)

where x is a vector and F(x) is a linear vector value function.

¹⁶A LCP has the following form:

 $^{^{17}}$ See Elliot and Ockendon (1982), Friedman (1988), and Kinderlehrer and Stampacchia (1980) for proofs of the existence and uniqueness of the solutions.

¹⁸Lemke's algorithm is a pivot or basis-exchange procedure for solving LCPs. See Lemke (1968) and Kostreva (2001) for more detailed discussions of Lemke's algorithm.

5 Results

The numerical solution to the LCP is the value of an oil well in each state: active, mothballed, decommissioned, and reclaimed. Using the numerical solution we can retrieve a set of optimal policy functions $S^*(P, R, s_t, \tau_{s_t})$ and decision thresholds $P^*(R, s_t, s_{t+1}, \tau_{s_t})$ for the management of the well. Policy functions show the optimal state of the oil well conditional on the current oil price, remaining reserves (or aggregate production), the current state, and time remaining. A decision threshold is the oil price where the well switches from one state to another (e.g. from active to mothballed) conditional on remaining reserves and time remaining. To illustrate, for an oil well that is currently active, the policy function $S^*_a(P, R) = S^*(P, R, s_t = a, \tau_a)$ determines the optimal future state of the oil well (active, mothballed, decommissioned, or reclaimed). The set of decision thresholds for an active well are the prices where the well will be mothballed, decommissioned, or reclaimed. We first present baseline results, then present sensitivity analysis on our baseline parameters, then discuss the effect of a carbon tax on firm decisions, and finally explore policy alternatives to incentivize reclamation.

5.1 Baseline Results

Figure 3 plots the value of a producing representative oil well in Alberta with options to mothball, decommission, and reclaim at different levels of aggregate production and oil prices. At the beginning of the producing stage, when reserves are equal to 302,381 barrels, if the price is equal to the long-run average of \$92.84, the value of the representative oil well is \$8,677,000. The value of the oil well exceeds its capital costs, \$3,559,000 (Table 1). As we use post-C* royalty rates, our valuations underestimate the value of an oil well in the early stages of it life (the pre-C* royalty rate is 5 per cent, and so our calculated royalty payments are higher). (Recall that C* is a Drilling and Completion Cost Allowance, and a proxy for well costs. The lower royalty rate applies so long as a well's cumulative revenue is below C*.) At long-run average prices, given initial productivity estimates, oil wells' cumulative revenue will exceed the value of C* one to three years after production begins.

Figure 4 shows the decision thresholds $P_{k,l}^* \equiv P^*(R, s_t = k, s_{t+1} = l, \tau)$ in each possible state: active, mothballed, and decommissioned. The color of the line represents the current state of the oil well and the type of line represents the state the oil well is moving to. For example, the red dotted line in Figure 4c is the decision threshold where a decommissioned oil well will be brought back into production if oil prices rise above the threshold price $(P \ge P_{d,a}^*)$. Figure 4 shows that there is no risk of an oil well entering an inactive state (mothballed or decommissioned) and remaining there forever. Under our baseline parameters, the firm will extract about 98 per cent of reserves and reclaim the well. If price is equal to the long-run average over the well's life an expected 296,379 barrels will be extracted over 31.5 years of operations. When the oil well





is reclaimed, oil well production will have fallen to about 1,110 barrels per year.

There is a possibility that the representative oil well will be temporarily mothballed during its life. The black dash-dot line in Figure 4a represents the mothballing threshold for active wells $(P_{a,m}^*)$ and the blue dotted line in Figure 4b represents the restart threshold for mothballed wells $(P_{m,a}^*)$. The firm will mothball the well when price falls below \$37, with the threshold price decreasing as reserves are depleted. Production will restart when oil prices rise above \$56.50, with the threshold price increasing as reserves are depleted. Using equation (2), we calculate the expected length of time an oil well is mothballed before production restarts $(P_{m,a}^* - P_{a,m}^*)/\kappa(\bar{P} - P_{a,m}^*)$. Wells are temporarily mothballed for 8.5 months when reserves are high and 14.9 months when reserves are low (around 50,000 barrels). The difference between the mothball threshold $(P_{a,m}^*)$ and the restart threshold $(P_{m,a}^*)$ is initially around \$20 per barrel then gradually grows as reserves are exhausted reaching a maximum of \$84.50 per barrel when the mothballing threshold goes to zero. The firm will never decommission the well under the baseline parameters, and instead will proceed to reclamation. The decommission threshold $(P_{a,d}^*)$ is represented by a dashed line in Figure 4a is equal to zero for all levels of reserves. An oil well will be temporarily mothballed if reserves are large enough or it will be

reclaimed if reserves are low enough when oil prices fall.

These baseline parameters give a result that is inconsistent with observed behaviour by firms in Alberta. We offer two explanations: first, we use baseline parameters that reflect historical costs. All else equal, we would expect firms to reclaim the lowest-cost wells first and so it is entirely possible these parameters are underestimates of the true cost of decommissioning and reclaiming the majority of wells in Alberta. Some evidence in support of this is the 2022/23 annual report from Alberta's Orphan Well Association, which states: "The average cost of decommissioning a well in 2022/23 was \$35,000, with most in the range of \$9,000 to \$100,000. The average cost of reclaiming a site was \$24,000, with most ranging between \$2,3000 to \$88,000. The upper end of the ranges has increased as we are addressing more complex sites than in previous years" (Orphan Well Association, 2023a). These values suggest substantial variation not captured by a "typical" oil well. Second, we may be over-estimating monitoring costs; higher monitoring costs for inactive wells increase the incentive to decommission and reclaim. We now turn to sensitivity analyses of these parameters.





(a) Decision thresholds for an active well

(b) Decision thresholds for a mothballed well



(c) Decision thresholds for a decommissioned well

5.1.1 Sensitivity Analysis: Mothballing Costs

Under the baseline parameterization, we assume the costs to mothball a producing oil well are zero. To properly mothball well the AER requires firms to take reasonable steps to contain and clean up spills, ensure there are no wellhead leaks, and service and pressure-test the wellhead (Alberta Energy Regulator, 2022). Mothballing costs are not publicly reported; generally they should be low but could be large for some wells. To test how sensitive the option to mothball is to the cost of mothballing we adjust $C_{a,m}$ from zero to the cost of decommissioning, \$124,403. The requirements for decommissioning and reclamation are different than mothballing, so the firm will still need to pay the full decommissioning and reclamation costs regardless of the cost of mothballing. The firm does not need to pay the cost of mothballing if the well switches from operating to decommissioned or from operating to reclamation. We do not change the cost of restarting production from mothballed.

Figure 5 shows that the mothball decision threshold $P_{a,m}^*$ for oil wells is sensitive to mothballing costs. Increasing the mothballing costs shifts the mothball threshold down; the firm is less likely to mothball at a given price level. Increasing mothballing costs does not shift the reclamation threshold. Increased mothballing costs lowers the value of a well, as firms delay exercising the option to mothball the well when oil prices are low. The lower value of the well results in the restart threshold shifting upward slightly. Oil wells that face higher mothball costs will operate longer when prices are low compared to an oil well with low mothballing costs. Similar to the baseline results, the decommission decision threshold $(P_{a,d}^*)$ is equal to zero for all levels of reserves so we exclude it from Figure 5.

Figure 5: Effect of mothballing costs on the operation of the representative oil well



5.1.2 Sensitivity Analysis: Decommissioning Costs

Decommissioning an oil well requires plugging the well, cutting and capping the wellhead, and removing surface facilities. It is the most expensive step in the cleanup process. The cost of decommissioning will depend on the condition of the wellbore and potential environmental risks. To evaluate the effect of decommissioning costs on the decision to decommission and reclaim an oil well, we consider a range of decommissioning costs from a 50 per cent reduction of our baseline value of \$124,403 to an increase by a factor of 5 relative to baseline decommission costs.¹⁹ Changing the decommissioning cost also affects the cost of reclaiming from the active or mothballed states as decommissioning is a required action along the path to reclamation.

At the end of the well's life, the firm switches to the state that has the lowest expected present value of monitoring costs plus switching costs ($MC_s/\rho + C_{a,s}$). Under our baseline parameters, the lifetime cost of remaining mothballed forever is \$19,160/0.05 + \$0 = \$383,200. The cost of decommissioning from active is 9,580/0.05 + 124,403 = 316,003 and the cost of reclaiming from active is 0/0.05 + 124,403 + 25,914= \$150.317. Reclamation is the lowest cost option so firms will always reclaim oil wells at the end of its life. As decommissioning costs change so does the value of an oil well in the decommissioned and reclaimed states. As those values change so does the optimal time to exercise those options. Figure 6 shows the effect of decommissioning costs on decision thresholds for the representative oil well. Cutting decommissioning costs in half (blue lines) results in the mothball threshold shifting down by an average of \$2.51 per barrel and the reclamation threshold shifting up by an average of \$5.79. Doubling decommissioning costs (red line) results in the mothball threshold shifting up by an average of \$5.07 per barrel and the reclamation threshold shifting down by an average of \$11.77 per barrel. In this range of decommissioning costs, reclamation remains the lowest cost option when it is no longer optimal to operate the oil well. The decommissioning cost where the firm is indifferent between mothballing and reclaiming the oil well $(TC_{a,d} = MC_M/\rho + TC_{a,m} - TC_{d,r})$ is 19,160/0.05 + 0 - 25,914 = 357,403. This is 2.87 times larger than baseline decommissioning costs. The green line in Figure 6 shows how the end-of-life decision changes when decommissioning costs are \$373,209 (three times baseline costs). Instead of reclaiming the well, the firm will choose to mothball the well forever to avoid high decommissioning costs. The firm will operate the oil well slightly longer when decommissioning costs are high then the oil well will be mothballed and left in that state forever. Like above, the decommission decision threshold $(P_{a,d}^*)$ is equal to zero for all levels of reserves so we exclude it from Figure 6. These results are similar to Lohrenz (1991), who finds that there are conditions under which oil wells are closed immediately and conditions where decommissioning is deferred forever. Our results are also consistent with Muehlenbachs

¹⁹The AER classifies a site as a potential problem site if it has a potential decommissioning or reclamation liability equal to or greater than four times the amount normally calculated for that type of site in that regional abandonment cost area.

(2015), who finds firms use temporary closure of wells to avoid decommissioning costs.

Figure 6: Effect of decommissioning costs on the operation of the representative oil well



5.1.3 Sensitivity Analysis: Reclamation Costs

Reclamation requires the firm to clean up any contamination and return the land to its previous state. Similar to decommissioning costs, reclamation costs will vary from site to site depending on the level of contamination and type of environment being restored (e.g., forest, native grassland, peatland, or farm land). To evaluate the effect of reclamation costs on the decision to reclaim a well we consider increases ranging from two to 10 times relative to baseline reclamation costs. Figure 7 shows the effect of reclamation costs on the decision thresholds. Similar to our results when varying decommissioning costs, there is a range of reclamation costs where firms still reclaim the well despite rising costs. Temporary mothballing and restarting will happen at the same oil prices as in the decommissioning costs sensitivity analysis and reclamation will happen when reserves are low. When reclamation costs get too large, the firm will forgo the high reclamation costs and transition the well to decommissioned. The reclamation cost where the firm is indifferent between decommissioning and reclaiming the oil well is \$191,504 (7.39 times baseline reclamation costs). The decommissioning threshold is very similar to the reclamation threshold. The increased costs of reclamation does not affect the operation of the well during its life; it only changes the firm's decision at the end of the well's life from reclamation to decommissioning. Though the oil well is decommissioned, Figure 7 shows the well will never be brought back into production (green dotted line). Our results for decommissioning costs and reclamation costs are in line with the results of Muehlenbachs (2015), who found that many companies opt to mothball wells to avoid cleanup costs, rather than decommissioning and reclaiming them.



Figure 7: Effect of reclamation costs on operation of the representative oil well

5.1.4 Sensitivity Analysis: Volatility and Risk

Figure 8 shows the effect of oil price volatility and risk-free rates on a firm's decision thresholds. Oil price volatility has the expected impact on decision thresholds as predicted in the real options literature. Increasing volatility leads to an increase in the value of an oil well as the probability of higher prices increases and the option to mothball or reclaim limits risks associated with low prices. As a result of the increased value of the oil well the mothballing threshold shifts down for all levels of reserves and the reclamation threshold shifts to the left. When the oil well is mothballed, increased volatility shifts the restart threshold upward for all levels of reserves. However, when oil price volatility gets large, here four times baseline volatility, the firm will no longer exercise any of its operational options as low prices are not likely to persist for a long time.

Figure 8: Effect of oil price volatility and the risk-free rate on the operation of the representative oil well



The risk-free rate has a more complicated impact on the operation of the well. Our baseline assumption is that the risk-free rate is 5 per cent. Lowering the risk-free rates to 2 per cent causes the mothball threshold $(P_{a,m}^*)$ to have a steeper negative slope and the restart threshold $(P_{m,a}^*)$ shifts upward. The well is mothballed earlier when reserves are high, mothballed later when reserves are low, and restarted later at all reserve levels. Increasing the risk-free rates to 10 per cent causes the mothball threshold to have a flatter slope and shifts the restart threshold down. The well is mothballed later when reserves are high and mothballed earlier when reserves are low. The length of time a oil well is temporarily mothballed decreases. At the end of their life wells are reclaimed regardless of the risk-free rate. These twists in the mothball thresholds presented in Figure 8b are the result of the ambiguous net impact the risk-free rate has on the value of an representative oil well. Dixit and Pindyck (1994) note that in real options analysis the net impact of interest rates changes can be ambiguous as a reduction in the interest rate makes future cash flows more valuable relative to the present, but it also increases the value of delaying. When reserves are high and the risk-free rate decreases, the incentive to delaying production (mothball the oil well) and wait for higher prices is larger than continuing to produce. When reserves are low, the incentive switches so now it is optimal to continue to produce instead of waiting for higher prices. Decommissioning decision thresholds $(P_{a,d}^*)$ are equal to zero for all levels of reserves so we exclude them from Figure 8.

5.2 Carbon Tax

In this subsection we evaluate how a carbon tax on production effects the operation and end-of-life decision for an oil well in Alberta. Following Abdul-Salam (2022) we incorporate a carbon tax into the profit function. The firm pays a carbon tax based on the intensity of emissions and quantity of barrels produced. Emissions intensity per barrel is determined according to

$$e(t) = \psi + \omega * i, \tag{29}$$

where ψ and ω are (in tonnes of CO₂ per barrel) the intercept and slope of the linear unit emissions function and *i* is the operating age of the well in years. The parameter estimates for equation (29) are from Abdul-Salam (2022); ψ is set to 50×10^{-3} and ω is 1.667×10^{-3} . The price of carbon is constant over the life of the well. We vary the price from \$50/per tonne to \$200/per tonne. The emissions intensity per barrel ranges from 0.05 to 0.12 tonnes CO₂ over the well's 40-year life. The introduction of a carbon tax does not affect the cost of transitioning from producing to any other state nor does it affect monitoring costs in non-producing states.

Figure 9 shows the effect of a carbon tax on the decision thresholds. The carbon tax affects the profitability of the oil well, lowering the value of a producing well via increased costs. This causes the reclamation threshold to shift left as the carbon tax increases; this lowers expected production. Interestingly, the mothballing threshold decreases compared to the baseline when the carbon tax is \$50 per tonne, then increases as the carbon tax increases. When the carbon tax is \$200 per tonne the mothball threshold is very similar to the baseline mothballing threshold. The firm never decommissions the oil well when a carbon tax is introduced. These results are similar to Abdul-Salam (2022); a carbon tax causes expected production to decrease (shifts the reclamation threshold to the left).



Figure 9: Effect of a carbon tax on operation of the representative oil well

5.3 Policy Alternatives to Incentivize Reclamation

Under our baseline assumptions, over 95 per cent of reserves are extracted and the oil well is reclaimed at the end of its life. If oil prices fall, the oil well will be mothballed. When prices recover to a sufficient level production will restart. However, when decommissioning or reclamation costs are high, oil wells are either left mothballed or decommissioned forever without being reclaimed. In this subsection we consider whether a time limit on oil well inactivity or bonding requirements could ensure oil wells are reclaimed at the end of their life. Both policy alternatives have been recommended as potential solutions for the issue of inactive oil and gas wells in Alberta (Auditor General of Alberta, 2005; Dachis et al., 2017; Muehlenbachs, 2017).

5.3.1 Time Limit on Inactivity

Under our baseline parameters a time limit on inactivity would not affect the operation or end-of-life decisions, as it is already optimal to reclaim at the end of life after extracting nearly all the reserves. When decommissioning or reclamation costs are high the oil well will be left inactive (mothballed or decommissioned) forever instead of being decommissioned and reclaimed. To evaluate how a time limit on oil well inactivity will affect the management of an oil well we consider oil wells that face high decommissioning and reclamation costs, so that under current policies the oil well will not be reclaimed once production has stopped and we impose a limit of 10 years on well inactivity. At the end of the 10 year period the firm chooses between restarting production or reclaiming the well. If the oil well is mothballed the firm can also choose to decommission the well and remain in that state for an additional 10 years.

Table 5 shows the total cost assumptions (monitoring costs plus transition costs) of switching from active to mothballed, decommissioned, or reclaimed, and remaining in that state forever. When decommissioning costs are high — 5 times the baseline decommissioning cost — the reclamation state is less costly to move to from active than decommissioned. In this case we would not expect the firm to exercise the option to decommission. When reclamation costs are high — 10 times baseline reclamation costs — the decommissioned state is less costly than reclamation.

Table 5: Monitoring and transition costs of switching from active production to an inactive state and remaining there forever

	High Decommissioning Cost Scenario				
	Monitoring Costs	Transition Costs	Total Costs		
Mothballed	\$383,200	\$0	\$383,200		
Decommissioned	\$191,600	\$622,015	\$813,615		
Reclaimed	\$0	\$647,929	\$647,929		
	High Reclamation Cost Scenario				
	Monitoring Costs	Transition Costs	Total Costs		
Mothballed	\$383,200	\$0	\$383,200		
Decommissioned	\$191,600	\$124,403	\$316,003		
Reclaimed	\$0	\$383,543	\$383,543		

Notes: High decommissioning cost scenario has decommissioning costs five times the baseline decommissioning costs. High reclamation costs scenario has reclamation costs of 10 times baseline reclamation costs.

Figure 10 shows the effect of a 10-year time limit on well inactivity on the operation of an oil well. The black lines represent the decision threshold for the situation where an oil well faces high decommission or reclamation costs but has no limit on inactivity. The blue line is the mothball threshold $(P_{a,m}^*)$ when the oil well is active. The red lines represent decision thresholds when the oil well is mothballed. The red dash-dot line is a knife-edge decision threshold when the well has been mothballed for 10 years ($\tau_m = 0$). If the price is above the line, the firm will restart production $(P_{m,a}^*(\tau_m = 0))$. If the oil price is below the line, the firm will reclaim $(P_{m,r}^*(\tau_m = 0))$. The red dotted line is the restart boundary $(P_{m,a}^*(\tau_m \neq 0))$ at every other point prior to hitting the 10 year limit. There are decision thresholds for decommissioning the oil well as the firm will never exercise that option.

Figure 10a shows that the introduction of a time limit does not ensure the firm will reclaim the well in a timely manner when it faces high decommissioning costs. The firm will operate until it reaches the mothball threshold (blue line). Then the well will stay mothballed until the 10 year limit is reached, at which point the firm will likely restart production then immediately re-mothball the well. If the well has produced 290,000

to 300,000 barrels of oil and oil prices are below \$50 per barrel, the well will be reclaimed.



Figure 10: Effect of a 10 year time limit on inactivity on operation of the representative oil well

Figure 10b shows the effect of a 10 year time limit on well inactivity when reclamation costs are high. Again, the black line is the decision threshold when an oil well faces high reclamation costs but has no limit on inactivity. The blue line is the mothball threshold $(P_{a,m}^*)$ when the well is active. The red lines are decision thresholds when the oil well is mothballed. The red dash-dot line is a knife-edge decision threshold when the well has been mothballed for 10 years ($\tau_m = 0$). If the oil price is above the line, the firm will restart production $(P_{m,a}^*(\tau_m = 0))$. If the price is below the line, the firm will decommission $(P_{m,d}^*(\tau_m = 0))$. The green lines are decision thresholds when the oil well is decommissioned. Similar to the red dash-dot line, the green dot line is a knife-edge decision threshold when the well has been decommissioned for 10 years $(\tau_d = 0)$. If the price is above the line, the firm restarts production and if the price is below the line, the firm reclaims the well. The red and green dotted lines are the restart boundaries when the well is mothballed and decommissioned, respectively, prior to reaching the 10 year limit $(P_{m,a}^*(\tau_m \neq 0) \text{ and } P_{d,a}^*(\tau_d \neq 0))$. The results are similar to the case when decommissioning costs are high and there is a 10 year limit on inactivity. The oil well will never be reclaimed and it will essentially be mothballed forever. The firm will leave the well mothballed until reaching the 10 year limit, and then it will restart the well then immediately mothball to avoid decommissioning and reclamation costs. Starting and stopping is an optimal strategy to avoid high decommissioning or reclamation costs if a policymaker does not require wells to be active for multiple consecutive periods or meet minimum production targets. The effectiveness of a time limit would depend on the conditions for restarting production. Production requirements, for example barrels produced or periods active, may shift up the reclamation threshold so wells are reclaimed instead of re-started.

5.3.2 Bonding Requirements

In this section, we explore the effect when the firm supplies a bond at the beginning of the life of the well and a policymaker returns the bond after the firm reclaims the well. We examine the effect on a firm's operating choices for an oil well that faces high decommissioning or reclamation costs (so that it is not optimal to reclaim at the end of its life). We assume the firm supplies a bond equal to expected (baseline) decommissioning and reclamation costs, \$150,317, at the beginning of the life of the oil well. When the oil well is reclaimed the firm receives the value of the bond. Prior to reclamation, while the bond is held, the firm receives interest payments at the risk-free rate to compensate it for the opportunity cost of providing the bond. The firm receives the interest payment every period the oil well is not reclaimed.



Figure 11: Effect of a bond requirement on operation of the representative oil well

Figure 11 shows that requiring a firm to provide a bond that covers expected cleanup costs (baseline decommissioning and reclamation costs) will have no impact on the operation of an oil well, in that the bond does not shorten the well's operating life. The changes in decision thresholds in Figure 11 are the result of changing decommissioning and reclamation costs and not the result of the bond requirement. This result is driven by the fact that we allow the firm to receive interest payments, at the risk-free rate, in exchange for providing the bond. This interest payment is enough to compensate the firm so the relative value of the well remaining mothballed or decommissioned forever does not change compared to reclamation. Repayment of the bond, $TC_{s,r} - Bond$. However, interest payments shift the cost of being mothballed or decommissioned by the same amount. With the interest payments from the bond, the per year cost of a mothballed well is now $MC_M - Bond * \rho$ and the cost of being mothballed forever is $MC_M/\rho - Bond$. The cost of the well being mothballed and decommissioned forever is reduced by the value of the bond.

If the firm does not receive interest payments from the bond, the cost of mothballing or decommissioning forever is unchanged while the threshold for reclamation changes. Without a bond, if decommissioning costs are at least 2.87 times baseline decommission costs or if reclamation costs are at least 7.39 time baseline reclamation costs the firm will not reclaim the well. Requiring a bond, without interest payments, will shift the threshold for decommissioning and reclamation costs up, so higher cleanup cost oil wells will be reclaimed. The decommissioning cost threshold moves from 2.87 times baseline to 4.08 times baseline decommissioning costs. The reclamation cost threshold moves from 7.39 times baseline to 13.19 times the baseline. Requiring a bond that equals expected baseline decommissioning and reclamation costs at the beginning of the life of the oil well has a large impact on reclamation decisions for the firm, suggesting it is a more promising policy intervention.

6 Conclusion

We develop a real options model to value oil wells and identify decision thresholds for mothballing, restarting, decommissioning, and reclaiming under a mean-reverting oil price process. We use this model to examine firms' end-of-life decisions to try to understand why Alberta's inventory of inactive oil and gas wells is so large. Our contribution is two-fold. First, to model in detail the end-of-life decisions and try and explain observed firms' behaviour in Alberta. Second, to explore how policy choices to address environmental problems — a carbon tax on emissions and policy to incentivize reclamation activities — affect a firm's optimal decisions for operating an oil well in Alberta.

Under our baseline assumptions, we find that owners of oil wells will extract over 98 per cent of the reserves in place and reclaim the well. The decision to reclaim an oil well at the end of its life is sensitive to decommissioning and reclamation costs. When those costs are high (relative to the cost of remaining mothballed or decommissioned) firms will no longer reclaim the well. Instead, a firm will leave the well inactive even though it has no expectation of restarting production. The baseline result is inconsistent with observed behaviour, and our sensitivity analysis with higher costs is consistent with the actions taken by firms in Alberta. Together, these results suggest that costs to properly decommission and reclaim a well site are higher than our baseline, which is based on historical data. A corollary is that public estimates of costs from historical data are likely downward-biased, and the liability problem is larger than previously thought.

Oil price volatility, risk-free rates, and a carbon tax do not change the outcome that oil wells are reclaimed at the end of their life. However, these parameters and policies do affect the expected length of a well's life.

These results are in line with Lohrenz (1991) and Muehlenbachs (2015). There are conditions where firms will defer reclamation forever and use the mothballed or decommissioned state to avoid clean up costs. We test to see if a time limit on inactivity or a bond is a sufficient policy intervention to cause firms to reclaim their wells. With a time limit, the firm still chooses to mothball the well; when the limit is reached, they restart production then immediately mothball again to reset the inactive clock. With a bond, if interest payments are made to the firm as compensation for providing the bond, then requiring a bond has no effect on the firm's decision thresholds. Low cleanup cost oil wells will be reclaimed at the end of their life while high cleanup cost oil wells will be mothballed or decommissioned. If the firm does not receive interest payments, then providing a bond that gets repaid after the oil well has been reclaimed will result in higher cleanup cost oil wells being reclaimed at the end of their life.

Alberta's inventory of mothballed and decommissioned oil and gas wells represents a large financial and environmental risk. Our research, and that of others, suggests that firms are choosing to leave wells mothballed or decommissioned to avoid large cleanup costs. Current policies are not stringent enough to ensure firms reclaim their oil and gas wells in a reasonable time frame. Recently, the AER introduced a new program (the Inventory Reduction Program) aimed at increasing the amount of closure work in Alberta. The program requires firms to meet annual spending targets. This program should be effective in reducing the inventory of inactive oil and gas wells but there is a risk that the most expensive (and therefore the most risky) wells will be left inactive. Our results suggest that additional policies are required to make sure firms address the liability of their oil and gas wells. For example, a combination of a limit on the length of time a well can be inactive and a bond could reduce the inventory of mothballed or decommissioned wells. Careful production requirement design (either time or volumes produced) is likely needed should a firm choose to restart production, to eliminate the possibility that a firm switches a well on and off in an effort to avoid those costs. The introduction of a bond would increase the amount of security held to cover cleanup costs, which was a concern raised by Forsyth and Nahornick (2022). A time limit would make sure the firm does not forego the bond when they face high cleanup costs. Boomhower (2019) shows these types of policies could result in improved environmental outcomes but could shift production from smaller firms to larger firms.

There are several limitations to our work that point to areas for future research. In our modelling, we abstract from the potential of a firm becoming insolvent as an optimal response to end-of-life costs. Similarly, we only model a representative oil well, whereas there is clearly a distribution of wells with differing production characteristics and end-of-life costs which would likely influence firm's behaviour. Future research could model individual firms with a portfolio of heterogeneous oil and gas wells to evaluate how firms might respond to alternative end-of-life policies. We also take government policy as given, assuming full reclamation has a positive benefit, and explore a firm's profit-maximizing response to policy. Future work would benefit from explicitly quantifying the external costs of firms' choices and making policy decisions a function of those external costs; the benefit of this approach is it would lay out the socially optimal regulatory approach. Given

increasing evidence of the environmental damages from inactive wells (Kang et al., 2014; Schiffner et al., 2021; Williams et al., 2021; Bowman et al., 2023; El Hachem and Kang, 2023), this provides additional justification for work exploring the financial and environmental risks of inactive wells and policy steps to mitigate this problem.

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