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

November 2023

Abstract

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 problem. This article uses a real options model to evaluate end-of-life decisions of oil wells in Alberta subject to mean-reverting oil prices, with low or high average prices, to understand which oil wells will be reclaimed at the end of their useful lives versus those left unreclaimed. Results under our baseline parameters show that firms operating a typical oil well will extract over 95 per cent of the reserves in place and reclaim the well. When the cost to decommission or reclaim a well is larger that the cost of maintaining an inactive well, the firm will still extract over 95 per cent of reserves, but will leave the well in a decommissioned state and never reclaim the well. This suggests that some of the oil and gas wells that have been left unreclaimed have high decommission 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 also examine the effect of a time limit on inactivity or a bond on end-of-life decisions. Our results suggest that 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

Keywords: liability management, environmental economics, non-renewable natural resources, real options

---

This research was undertaken thanks in part to funding from the Canada First Research Excellence Fund. We thank conference participants at the 2022 Canadian Economics Association meeting for useful comments on an earlier draft of this paper.

Corresponding author: Gregory Galay, gregory.galay@ucalgary.ca

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] 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.[2] Goodday and Larson (2021) find that 54.8 per cent of mothballed[3] and decommissioned oil and gas wells in Alberta have been so for more than five years while 29.2 per cent have been mothballed or decommissioned for more than a decade. Muehlenbachs (2015) shows that it is very unlikely for high prices or technological improvements to bring oil and gas wells back into production once they have been mothballed or decommissioned. Muehlenbachs (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 mothballed and decommissioned oil and gas wells are not reclaimed.

Alberta enacted the *Oil and Gas Conservation Act* (*OGC Act*) 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. Roughly 80% of mineral rights are owned by the province, and it leases these rights to firms to develop on behalf of the province and its citizens. The *OGC Act* 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) estimated the cost of plugging and reclaiming 3,200 orphaned wells in 2017 to be $129-257

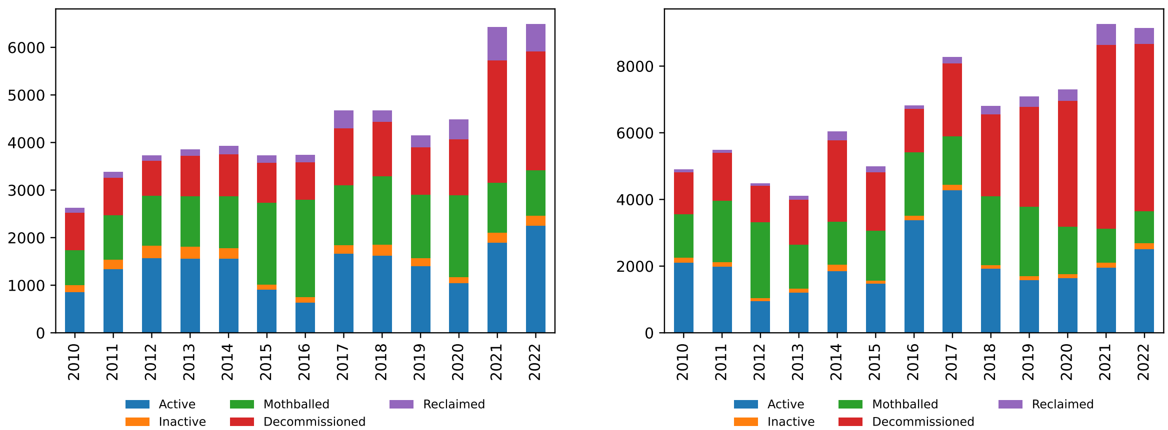
[1] See Robinson (2014), Green (2019) and Yewchuk et al. (2023) for a discussion of the history of the inactive well problem and policy responses.

[2] As of December 2022, Alberta has 156,066 active wells, 84,120 inactive wells, 88,540 decommissioned wells, and 133,516 reclaimed wells (Alberta Energy Regulator, 2023b); of these, 2,565 are orphaned wells awaiting decommissioning and 1,642 are fully reclaimed orphan wells (Orphan Well Association, 2023).

[3] Terms differ across regulators; the Alberta Energy Regulator defines a well as suspended when an inactive well is placed in a safe condition, with non-permanent sealing. We use the term mothballed to avoid confusion of terms.

[4] The 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.

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



(a) Alberta oil wells

(b) Alberta gas wells

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

million. When they include wells of insolvent and close-to-insolvent firms, the cost increases to \$4.2-8.6 billion.[5] More recently, the 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 notes that the inventory of mothballed, decommissioned, 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. Recently, the governments of Alberta and Canada have provided loans and grants to support efforts to reduce the inventory of mothballed, decommissioned, 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 mothballed and decommissioned 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).

Mothballed and decommissioned oil and gas wells present an environmental risk in addition to being a financial risk. Recent work by Kang et al. (2014), Schiffner et al. (2021), and Williams et al. (2021) shows that mothballed and decommissioned oil and gas wells are a significant source of methane emissions, a potent

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

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

[7] In 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.

greenhouse gas. 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, MacKay et al. (2021) and Williams et al. (2021) have both shown that methane emission estimates from Canadian oil and gas wells could be under-estimated by as much as 150 per cent. Most recently, and specific to Alberta, Conrad et al. (2023) find a similar result. 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.

In this paper we evaluate the life cycle (from production to reclamation) of typical oil wells in Alberta using real options analysis (ROA). ROA allows us to incorporate managerial flexibility into the life of an oil well while also allowing for uncertainty in future oil prices. Specifically, throughout the life of an oil well, the owner of the well 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 determines the optimal operational state of an oil well conditional on current oil prices, reserves in place, the current state of the well, and well-specific parameters. We find that if cleanup costs are too large (relative to the cost of remaining inactive) the firm will never reclaim. 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 reclamation costs for oil wells that are unlikely to be brought back into production. We analyze how optimal management changes under a carbon tax, bonding requirements and a limit on how long a well can be inactive. Our results suggest that additional policies to incent reclamation are required to ensure financially and environmentally risky oil wells are cleaned up in a safe and timely manner.

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). 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 an incentive to speed up development to avoid

[8] In 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.

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.

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 oil and gas well level 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. Their 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 end-of-life decision-making using a real options framework. We find that wells that have high decommission 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.

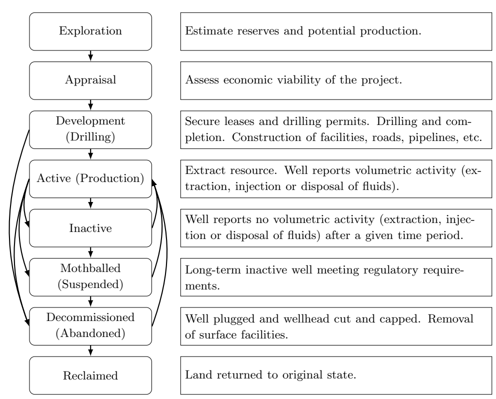
Other work examines how regulations can be used to ensure end-of-life environmental cleanup costs are borne by those that benefit during the life of a project. Gerard (2000) and Boyd (2001) discuss the rationale of financial assurance rules as a complement to liability rules. Boomhower (2019) examines the effect of financial assurance on the structure of the oil and gas industry and environmental outcomes in Texas. They found 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 shut-down 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.

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 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 4 describes the data that we use to calibrate the model. Section 5 presents the results and evaluates the impact of different policy interventions 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

The life cycle of a typical 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 typical oil and gas well and provides brief descriptions of the activities in each stage. It also shows 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. 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. While our empirical 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



We assume all efforts associated with exploration, appraisal, and development have already been undertaken. The firm's objective is to maximize the 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,

[9]The 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 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.

$$
\begin{aligned}
V^s(P,Q,t;\theta) = \max_{q(t),s(t)} E_t \int_t^{\infty} \exp^{-\rho z} \pi(P,Q,S=s_z;\theta) dz \\
\text{Subject to:} \\
s = a, m, d, \text{ or } r \\
Q - \int_t^{\infty} q(z) dz \geq 0
\end{aligned}
\tag{1}
$$

Where $V^s(P,Q,t;\theta) \equiv V(P(t),Q(t),t,S=s;\theta)$ is the value of an oil well at time t, P is the price of the resource and Q is the resource stock. θ is a vector of known well-specific characteristics such as depth, formation, etc. S is the current the stage of the well, with $S = a, m, d, r$ corresponding to active, mothballed, decommissioned, and reclaimed.[10] Cash flows when the well is in state s is represented by π^s, and ρ is the risk-adjusted real discount rate. The 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.

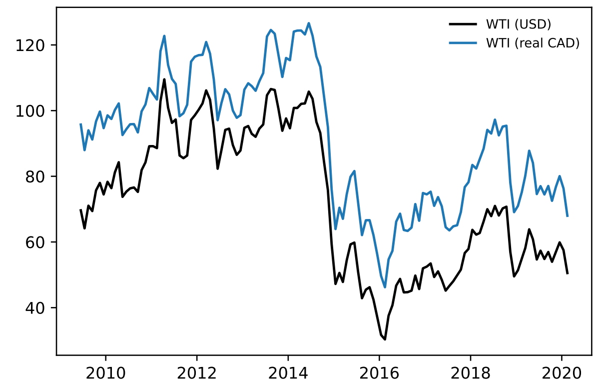
We model price uncertainty via a continuous-time stochastic process. The assumption about the stochastic process of the underlying asset has important implications for the value of the real option. Conrad and Kotani (2005) and Galay (2018) show the choice between a geometric Brownian motion (GBM) or a mean-reverting process can affect the value of oil development and the threshold where investment is triggered. A standard assumption in the real options literature is that oil prices follow a GBM process. However, since the financial crisis in 2008 oil prices do not appear to be following a GBM process (Figure 3). Here, we assume oil prices, $P(t)$, evolve according to a known Ornstein-Uhlenbeck (OU) process.

$$
\mathrm{d}P = \eta(\bar{P} - P)\mathrm{d}t + \sigma \mathrm{d}W, \tag{2}
$$

where η is the speed of reversion to the long-run average, $\bar{P}$ is the long-run average price, σ is the standard deviation, and $\mathrm{d}W$ is an increment of a Wiener process. This approach assumes that the standard deviation in price changes is constant over time. In Figure 3 oil prices appear to be in two regimes: one with a high average price from 2008 to 2014 and a low average price from 2014 to 2020.

[10] We do not include an inactive stage in our model. It is a temporary state (the AER classifies a well as inactive if it has not produced in 6 to 12 months); and either the well will start production again or it will be mothballed or decommissioned.

Figure 3: Monthly WTI prices, nominal USD and real CAD per barrel, June 2009 to February 2020.



Notes: Converted to real Canadian dollars using CPI and Canada/U.S. exchange rate data from the Federal Reserve Bank of St. Louis.
Source: WTI data: `https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET\&s=RWTC\&f=M`. Canadian Dollars to U.S. Dollar Spot Exchange Rate [DEXCAUS], `https://fred.stlouisfed.org/series/DEXCAUS` and U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers: All Items in U.S. City Average [CPIAUCSL], retrieved from FRED, Federal Reserve Bank of St. Louis; `https://fred.stlouisfed.org/series/CPIAUCSL`. Retrieved August, 2022.

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.

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:

$$V^a(P,Q,t;\theta) = \max\left\{ \max_{q\in(0,\bar{Q}]} \pi(q;\theta)\mathrm{d}t + \frac{E_t[V^a(P+\mathrm{d}P,\, Q+\mathrm{d}Q,\, t+\mathrm{d}t;\theta)]}{1+\rho\mathrm{d}t},\ \max_{s\neq a} V^s(P,Q,t;\theta) - C_{a,s}(Q;\theta)\right\}. \tag{3}$$

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

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

where $q(t)$ represent the quantity of reserves extracted and sold at a particular point in time when the oil well is active, $S = a$. $\bar{Q}(t)$ represents the maximum amount that can be extracted from the reserves with

$Q(t)$ remaining. The change in the stock of the resource, $Q(t)$, is then

$$\mathrm{d}Q = \begin{cases} -q(t)\mathrm{d}t, & \text{if } S = a \\ 0, & \text{otherwise.} \end{cases} \tag{5}$$

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

$$q(t) \leq Q(t)$$
$$\int_{t_0}^{\infty} q(z)\mathrm{d}z \leq Q_0$$

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:

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

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

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

We can identify mothball, 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 pasting condition requires the functions to meet tangentially at the optimal stopping boundary.

$$V^a(P^*_{a,s}, Q, t) = V^a(P^*_{a,s}, Q, t) - C_{a,s} \tag{8}$$
$$\frac{\partial V^a(P^*_{a,s}, Q, t)}{\partial P} = \frac{\partial V^a(P^*_{a,s}, Q, t)}{\partial P}, \tag{9}$$

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 mothball, decommissioning, and reclamation thresholds.

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

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 decide at what price it is optimal to restart production 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 ($s = m$), 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. Similarly, if the oil well is decommissioned ($s = d$), the firm can restart production, conditional on a sufficiently high price. Restarting production for a decomissioned well is higher cost than a mothballed well, due to the firm needing to re-enter the well. If prices deteriorate, the firm can reclaim the well. 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:

$$V^s(P, Q, t; \theta) = \max\left\{-\mathrm{MC}_s \mathrm{d}t + \frac{E_t[V^s(P + \mathrm{d}P,\, Q + \mathrm{d}Q,\, t + \mathrm{d}t; \theta)]}{1 + \rho \mathrm{d}t},\ \max_{n \neq s} V_n(P, Q, t; \theta) - C_{s,n}(Q; \theta)\right\}, \quad (10)$$

where $\mathrm{MC}_s \equiv \pi^s(q = 0; \theta)$ are annual monitoring costs when $s = m$ of $s = d$. Well-specific variables, θ, can affect annual monitoring costs. For example, the AER requires more rigorous testing of high-risk wells than low-risk wells. The Bellman equation for a mothballed or decommissioned well is

$$\rho V^s = -\mathrm{MC}_s + (1/\mathrm{d}t) E_t[\mathrm{d}V^s]. \quad (11)$$

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

$$\rho V^s = \sigma^2 \frac{\partial^2 V^s}{\partial P^2} + \eta(\bar{P} - P)\frac{\partial V^s}{\partial P} - \mathrm{MC}_s + \frac{\partial V^s}{\partial t} \quad (12)$$

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.

$$V^s(P{\cdot}Q = 0, t) = V^r(P, Q = 0, t) - C_{s,r} \quad (13)$$

[12] For example, the AER requires all inactive 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 (1 to 5 years) is determined by the risk class of the inactive well.

[13] Firms 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.

We identify re-start, decommission and reclamation thresholds by using value matching and smooth-pasting conditions:

$$V^s(P^*_{s,n}, Q, t) = V_n(P^*_{s,n}, Q, t) - C_{s,n}, \tag{14}$$

$$\frac{\partial V^s(P^*_{s,n}, Q, t)}{\partial P} = \frac{\partial V_n(P^*_{s,n}, Q, t)}{\partial P}. \tag{15}$$

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 Numerical Methods

In the previous section we define three free-boundary problems that determine the value of an oil well when it is active, mothballed, and decommissioned. 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 $P \in [0, P_{max}]$, $t \in [0, T]$, and $Q \in [0, Q_0]$. For convenience we define $\tau = T - t$ as time remaining so that $\mathrm{d}\tau = -\mathrm{d}t$ and $\tau \in [T, 0]$. Specifying equations (6) and (12) in terms of τ gives:

$$\frac{\partial V^a}{\partial \tau} = \sigma^2 \frac{\partial^2 V^a}{\partial P^2} + \eta(\bar{P} - P)\frac{\partial V^a}{\partial P} - \rho V^a + \max_{q \in (0, \bar{Q}]} \left\{ \pi^a(q) - q\frac{\partial V_Q}{\partial Q} \right\}, \tag{16}$$

$$\frac{\partial V^s}{\partial \tau} = \sigma^2 \frac{\partial^2 V^s}{\partial P^2} + \eta(\bar{P} - P)\frac{\partial V^s}{\partial P} - \rho V^s - \mathrm{MC}_s. \tag{17}$$

Boundary conditions must be specified to fully characterise the oil well valuation problem. As $P \to 0$ we assume $\sigma \to 0$ so that equations (16) and (17) become

$$\frac{\partial V^a}{\partial \tau} = \eta(\bar{P})\frac{\partial V^a}{\partial P} - \rho V^a + \max_{q \in (0, \bar{Q}]} \left\{ \pi^a(q) - q\frac{\partial V_Q}{\partial Q} \right\}, \tag{18}$$

$$\frac{\partial V^s}{\partial \tau} = \eta(\bar{P})\frac{\partial V^s}{\partial P} - \rho V^s - \mathrm{MC}_s. \tag{19}$$

This assumption ensures that price does not become negative. 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 (16) and (17) become

$$\frac{\partial V^a}{\partial \tau} = \eta(\bar{P} - P_{max})\frac{\partial V^a}{\partial P} - \rho V^a + \pi^a(\bar{Q}) - \bar{Q}\frac{\partial V_Q}{\partial Q}, \tag{20}$$

$$\frac{\partial V^s}{\partial \tau} = \eta(\bar{P} - P_{max})\frac{\partial V^s}{\partial P} - \rho V^s - \mathrm{MC}_s. \tag{21}$$

When the oil well is mothballed or decommissioned, $\tau = 0$ and $Q > 0$ the firm can restart production, decommission (if mothballed), reclaim, or remain in the current state. If the firm decides to remain in the current state the value of a oil well is $V^s(P, Q, \tau = 0) = -\mathrm{MC}_s/\rho$. The boundary condition along $\tau = 0$ when the well is mothballed or decommissioned is:

$$\begin{aligned} V^m(P, Q, \tau = 0) &= \max\{V^a - C_{m,a}, -\mathrm{MC}_m/\rho, V^d - C_{m,d}, V^r - C_{m,r}\}, \\ V^d(P, Q, \tau = 0) &= \max\{V^a - C_{d,a}, -\mathrm{MC}_d/\rho, V^r - C_{d,r}\}. \end{aligned} \tag{22}$$

In addition to the boundary conditions, we assume that annual oil production declines exponentially. Let q_0 be annual production for a newly drilled well and let λ be the annual production decline rate. Annual production in any year is determined by $q_t = q_0(1 - \lambda)^t$. If a well has an expected life of T years, in year T production falls to $q_T = 0$ and total production was $Q_0 = \int_0^T q_z dz$. With deterministic production the optimization in equations (16), (18) and (20) can be excluded.

Following Wilmott et al. (1993), Insley and Rollins (2005), and Galay (2018) we redefine the free boundary problems as a linear complementarity problem (LCP).[14] A solution to the LCP is a solution of the free-boundary problem (and vice versa).[15] The benefit of redefining the free boundary problem as an LCP 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:

$$\begin{aligned} \frac{\partial V^a}{\partial \tau} - \pi(q) - \sigma^2\frac{\partial^2 V^a}{\partial P^2} - \eta(\bar{P} - P)\frac{\partial V^a}{\partial P} + \rho V^a &\geq 0, \\ V^a - \max_{s \neq a}\left\{V^s - C_{a,s}\right\} &\geq 0, \\ \left(\frac{\partial V^a}{\partial \tau} - \pi(q) - \sigma^2\frac{\partial^2 V^a}{\partial P^2} - \eta(\bar{P} - P)\frac{\partial V^a}{\partial P} + \rho V^a\right) \times \left(V^a - \max_{s \neq a}\left\{V^s - C_{a,s}\right\}\right) &= 0. \end{aligned} \tag{24}$$

[14] An LCP has the following form:

$$\begin{aligned} x, F(x) &\geq 0, \\ x^T F(x) &= 0 \end{aligned} \tag{23}$$

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

[15] See Elliot and Ockendon (1982), Friedman (1988), and Kinderlehrer and Stampacchia (1980) for proofs of the existence and uniqueness of the solutions.

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

$$\begin{aligned}
\frac{\partial V^s}{\partial \tau} - \mathrm{MC}_s - \sigma^2 \frac{\partial^2 V^s}{\partial P^2} - \eta(\bar{P} - P)\frac{\partial V^s}{\partial P} + \rho V^s \geq 0, \\
V^s - \max_{n \neq s} \left\{ V^n - C_{s,n} \right\} \geq 0, \\
\left(\frac{\partial V_a}{\partial \tau} - \mathrm{MC}_s - \sigma^2 \frac{\partial^2 V^s}{\partial P^2} - \eta(\bar{P} - P)\frac{\partial V^s}{\partial P} + \rho V^s \right) \times \left(V^s - \max_{n \neq s} \left\{ V^n - C_{s,n} \right\} \right) = 0.
\end{aligned} \tag{25}$$

Equations (24) and (25) are discretized using implicit finite difference methods. We use Lemke's algorithm to numerically solve the LCP.[16]

4 Data and Calibration

To estimate the parameters in equation (2) we collect monthly spot price data for West Texas Intermediate (WTI) from the U.S. Energy Information Administration (EIA) for the period March 2009 to February 2020.[17] The WTI series was converted to real Canadian dollars using CPI and Canada/U.S. exchange rate data from the Federal Reserve Bank of St. Louis.[18] The sample period begins in March 2009 (after the 2008 financial crisis) and ends in February 2020 (before the COVID-19 pandemic). Table 1 shows basic summary statistics for WTI in US dollars (USD) and Canadian dollars (CAD). The sample mean is CAD 90.808 with a standard deviation of CAD 20.143.

Table 1: WTI summary statistics and Ornstein-Uhlenbeck parameter estimates.

	Summary statistics			OU parameters	
	WTI (in USD)	WTI (in real CAD)		Low price regime (real CAD)	High price regime (real CAD)
Mean	72.098	90.808	$\bar{P}$	72.49	107.56
St. Dev.	21.272	20.143	σ	2.872	2.883
			η	0.142	0.152
Obs.	129		Obs.	66	63

Notes: OLS estimates of equation (2). Nominal WTI in USD converted to real Canadian dollars using CPI and Canada/U.S. exchange rate data from the Federal Reserve Bank of St. Louis.
Sources: WTI: `https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET\&s=RWTC\&f=M`. Canadian Dollars to U.S. Dollar Spot Exchange Rate [DEXCAUS]: `https://fred.stlouisfed.org/series/DEXCAUS`. U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers: All Items in U.S. City Average [CPIAUCSL], retrieved from FRED, Federal Reserve Bank of St. Louis: `https://fred.stlouisfed.org/series/CPIAUCSL`. Retrieved August, 2022.

Figure 3 shows WTI in USD and real CAD. Two distinct price regimes appear to be present in the data;

[16] Lemke'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.

[17] WTI data was retrieved from `https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET\&s=RWTC\&f=M`.

[18] 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`, August, 2022.
U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers: All Items in U.S. City Average [CPIAUCSL], retrieved from FRED, Federal Reserve Bank of St. Louis; `https://fred.stlouisfed.org/series/CPIAUCSL`, August, 2022.

we split the sample into two subsamples for estimation. The first subsample is March 2009 to November 2014 (high-price regime) and the second is December 2014 to February 2020 (low-price regime). We use OLS to estimate the parameters of equation (2) using the two subsamples in real CAD; Table 1 presents the results. The regimes are fairly similar in terms of their speed of reversion (0.142 and 0.152) and standard deviations (2.872 and 2.883). The low-price regime has a long-run average price of $72.49 CAD and the high-price regime has a long-run average price of $107.56 CAD. We value an oil well under both high price and low price regimes.

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

$$\pi(P,q) = \big((1-t_R(P,q))P - c_v\big)q - c_f - \max\Big\{t_I \times \big[\big((1-t_R(P,q))P - c_v\big)q - c_f\big], 0\Big\}, \tag{26}$$

where c_v are average variable costs, c_f are total fixed costs, $t_R(P,q)$ is the royalty rate and t_I is the income tax rate. We assume well-specific parameters, θ, affect the cost structure of production, initial productivity, and decommissioning and reclamation costs.

Historically, vertical wells accounted for the majority of non-oil–sands oil production in Alberta. Since 2012 the share of oil production from horizontal wells has been increasing and it now accounts for the majority of Alberta's non-oil–sands oil production. Accordingly, we use horizontal oil wells as the representative oil well.[19] Table 2 reports our cost and initial productivity estimates for a representative oil well in Alberta. The AER publishes cost and initial productivity estimates for representative wells using well characteristics and geographic location.[20] We estimate the parameters for the representative oil wells using the AER's supply cost data (Alberta Energy Regulator, 2023a). We assume costs are in real Canadian dollars and constant over time. We also assume productivity declines at 10 per cent per year and an oil well can produce for up to 40 years. Over 40 years of potential production the representative oil well can produce over 300,000 barrels of oil. Figure 4 shows the production profile and average total cost to produce a barrel of oil over the life of a representative well. We determine royalty rates and payments using the Modernized Royalty Framework (MRF) Post C* rates; rates vary from 5 to 40 per cent depending on the price of WTI and production.[21] The income tax rate includes both provincial and federal taxes and is 23 per cent. We assume the risk-adjusted real discount rate is 10 per cent.

We estimate decommissioning and reclamation costs using data from Evaluate Energy's CanOils Well

[19] We also solve the model for a typical vertical oil well in Appendix A.

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

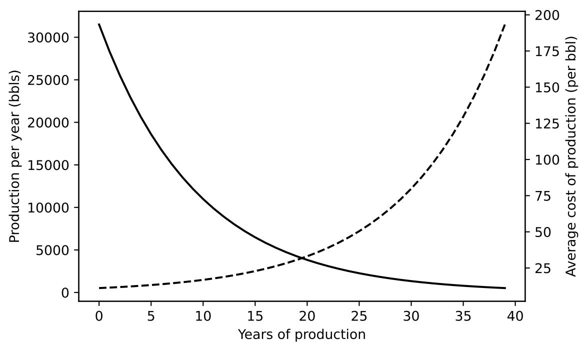
[21] The Government of Alberta changed the royalty framework for crude oil, natural gas, natural gas liquids (NGLs) and non-project crude bitumen wells in 2017. The MRF introduced a Drilling and Completion Cost Allowance (DCCA), C*, as part of the new framework. The DCCA is a function of a well's depth, length and proppant used, and is a proxy for well costs. The royalty rate is 5 per cent until cumulative revenue reaches C*.

Table 2: Representative oil well parameters

Parameter	Units	
Total measured depth	meters	3,596
Initial productivity	bbl/year	31,498
Total capital cost	CAD (1,000s)	3,559
Fixed operating cost	CAD/year	95,822
Variable operating cost	CAD/bbl	8.07
Crude oil supply cost	CAD/bbl	48.57

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

Figure 4: Production and average cost of production for the representative oil well in Alberta



and Land Database (CanOils). CanOils reports estimated reclamation and decommissioning costs at the well level. Decommissioning 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).

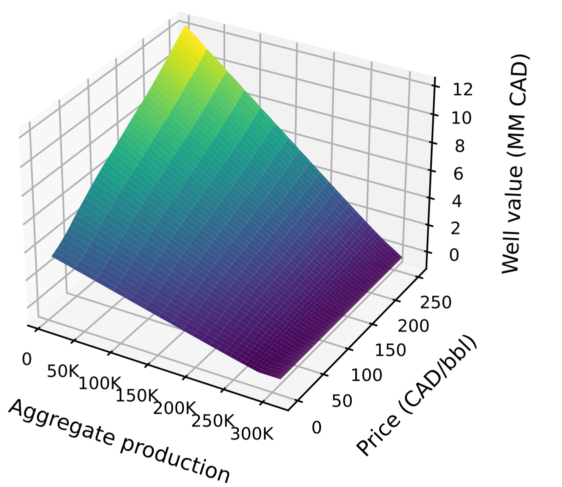
5 Results

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 $S^*(P, Q, s_t, \tau)$ and decision thresholds $P^*(Q, s_t, s_{t+1}, \tau)$ 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 $S_a^*(P, Q) = S^*(P, Q, s_t = a, \tau)$ 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 discuss the effect of a carbon tax on firm decisions, and then explore policy alternatives to incent reclamation.

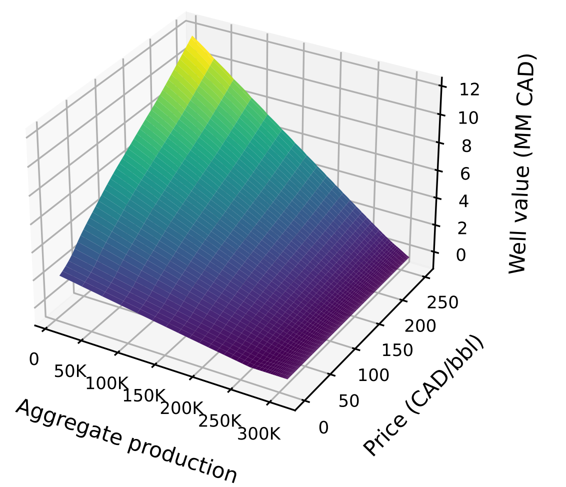
5.1 Baseline Results

Figure 5 plots the value of a producing representative well with options to mothball, decommission, and reclaim under high and low price regimes at different levels of aggregate production and oil prices. At the beginning of the producing stage (aggregate production is zero) in a high price regime when the current price is equal to the long-run average (\$107.50), the value of the representative oil well is \$7,372,000. In the low price regime when the current oil price is equal to the long-run average (\$72.50) the value is \$5,181,000. In each price regime, when the current oil price equals the long-run average the value of the oil well exceeds its capital costs at the beginning of its life (Table 2). 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). At long-run average prices, given initial productivity estimates, oil wells will exceed the MRF Drilling and Completion Cost Allowance 1 to 3 years after production begins.

Figure 5: Value of a representative oil well in Alberta



(a) Value of an oil well in a high oil price regime

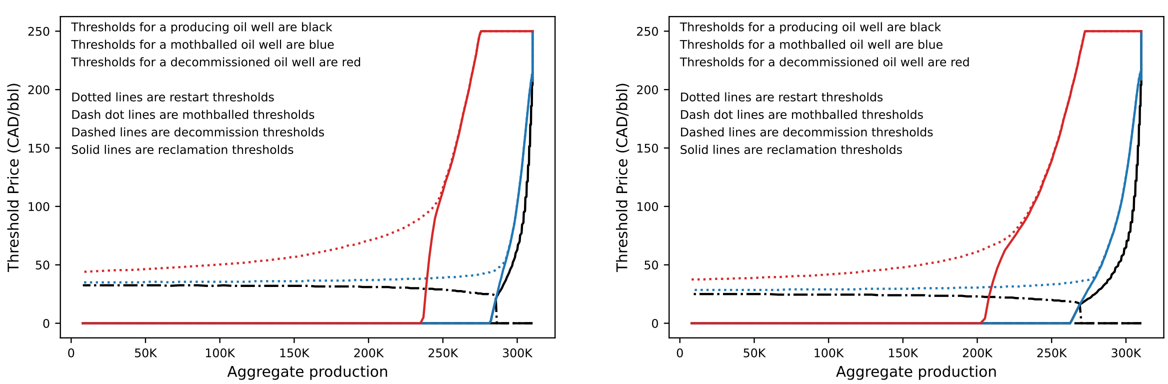


(b) Value of an oil well in a low oil price regime

Figure 6 shows the decision thresholds $P^*_{s,n} \equiv P^*(Q, s_t = s, s_{t+1} = n, \tau)$ in each possible state under high and low price regimes at different levels of aggregate production. 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 6 is the decision threshold where a decommissioned oil well will be brought back into production if oil prices rise above the threshold price ($P \geq P^*_{d,a}$). From Figure 6, under the baseline parameters oil wells are operated in a responsible manner regardless of the prevailing price regime. The owner of the oil well will extract 97 to 98.5 per cent of reserves over 30 to 33.25 years of operation, and then they will reclaim it. At the end of its life, the well will produce 974 barrels per year in the high price regime and 1,335 bbl per year in the low price regime.

There is a possibility that wells will be temporarily mothballed during its life. The black dash-dot line in Figure 6 represents the mothball threshold for active wells ($P^*_{a,m}$) and the blue dotted line represents the restart threshold for mothballed wells ($P^*_{m,a}$). Oil wells that are in a high oil price regime (Figures 6a) will be mothballed when price falls below \$32.50, with the threshold price decreasing to \$23.50 as reserves are depleted. Production will restart in the high price regime when oil prices rise above \$35, with the threshold price increasing to \$45.50 as reserves are depleted. In the low price regime (Figures 6b), wells will be mothballed when price falls below \$25, with the threshold decreasing to \$16.50 as reserves are depleted. Production will restart in the low price regime when prices rise above \$28.50, increasing to \$35.50 as reserves are depleted. Using equation (2), we calculate the expected number of months an oil well will be mothballed before production restarts $(P^*_{m,a} - P^*_{a,m})/\eta(\bar{P} - P^*_{a,m})$. Wells are temporarily mothballed for 3 months when reserves are high and 29 months when reserves are low. The difference between the mothball threshold ($P^*_{a,m}$) and the restart threshold ($P^*_{m,a}$) is small at the beginning of the life of the well then gradually grows as reserves are exhausted. Note that there are no dashed lines in Figure 6; a well is never decommissioned under the baseline parameters. A well will be temporarily mothballed if reserves are large enough or it will be reclaimed if reserves are low enough when oil prices fall.

Figure 6: Decision thresholds for an oil well in Alberta

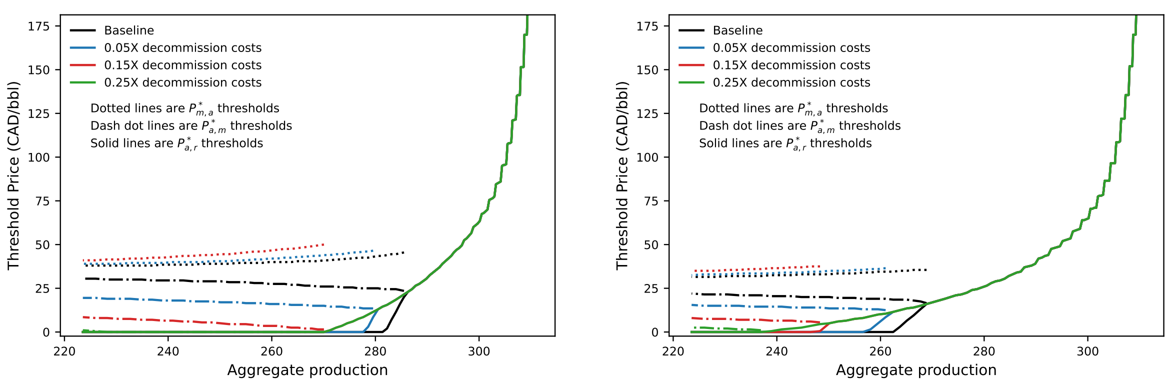


(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

Under the baseline parameterization, we assume the costs to mothball a producing oil well are zero. To properly mothball an oil 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. The requirements for decommissioning are different than mothballing so the firm will still need to pay the full decommissioning cost regardless of the cost of mothballing. The firm does not need to pay the cost of mothballing if they switch from operating to decommissioned or from operating to reclamation. We do not change the cost of restarting production from mothballed. Figure 7 shows that the mothball decision threshold $P^*_{a,m}$ for oil wells in both price regimes is sensitive to mothballing costs. Increasing the mothballing costs shifts the threshold down to the point where mothball costs are large and the option is not exercised, in this case when $C_{a,m}$ is equal to \$31,100.75. Increasing mothballing costs does not shift the reclamation threshold. Increased mothballing costs lowers the value of a well, as firms will not temporarily mothball the oil well when oil prices are low. The lower value of the well results in the restart threshold shifting upward. Oil wells that face higher mothball costs will operate longer when prices are low, and when they are temporarily mothballed they will be brought back into production later.

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



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

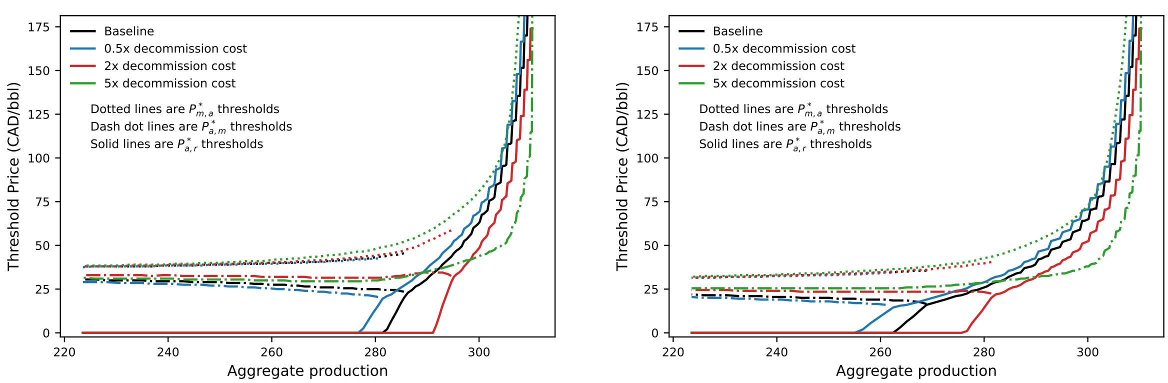
Decommissioning an oil well requires plugging the well, cutting and capping the wellhead, and removing surface facilities. It is the most expensive step in the cleanup process. The cost of decommissioning will depend on the condition of the wellbore and potential environmental risks. To evaluate the effect of decommissioning costs on the decision to decommission and reclaim an oil well, we consider a 50 per cent reduction in decommissioning costs and increases of 2, 3, 4, and 5 times relative to baseline decommission costs.[22] Figure 8 shows the effect of decommissioning costs on decision thresholds for oil wells in both price regimes. There is a range of decommissioning costs where the mothball threshold moves down and the reclamation threshold moves up as decommission costs increase. Cutting decommissioning costs in half (blue lines) results in the mothball threshold shifting down by an average of \$1.45 and the reclamation threshold shifting up by an average of \$9.44 in the high price regime. In the low price regime the shifts are \$1.10 and \$7.74 for

[22]The 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.

the mothball and reclamation thresholds. Doubling decommissioning costs (red line) results in the mothball threshold shifting up by an average of \$3.10 and the reclamation threshold shifting down by an average of \$21.12 in the high price regime. In the low price regime, the shifts are \$2.34 and \$17.06 for the mothball and reclamation thresholds.

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 ($\mathrm{MC}_s/\rho + C_{a,s}$). Under our parameters, the cost of mothballing forever from active is \$479,110. Under baseline parameters the cost of decommissioning from active is \$95,822 + \$124,403 = \$220,225 and the cost of reclaiming from active is \$124,403 + \$25,914 = \$150,317. Reclamation is the lowest cost option so firms will reclaim oil wells at the end of their life under those parameters. 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. Decommissioning will never be an optimal option as reclaiming will always be preferred. The decommissioning cost where the firm is indifferent between mothballing and reclaiming the oil well is \$453,196. This is 3.64 times larger than baseline decommissioning costs. The green line in Figure 8 shows how the end-of-life decision changes when decommissioning costs exceed \$453,196 (5 times baseline costs). Instead of reclaiming the well, the firm will choose to mothball the well forever to avoid high decommissioning costs. More reserves are extracted but the oil well is never reclaimed. This result is in line with Muehlenbachs (2015), who found that many companies opt to mothball wells to avoid cleanup costs, rather than decommissioning and reclaiming them.

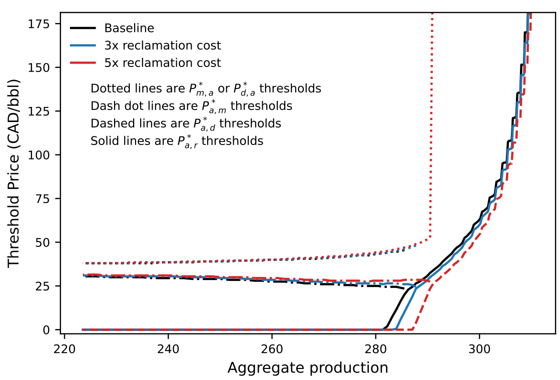
Figure 8: Effect of decommissioning costs on the operation of the representative oil well



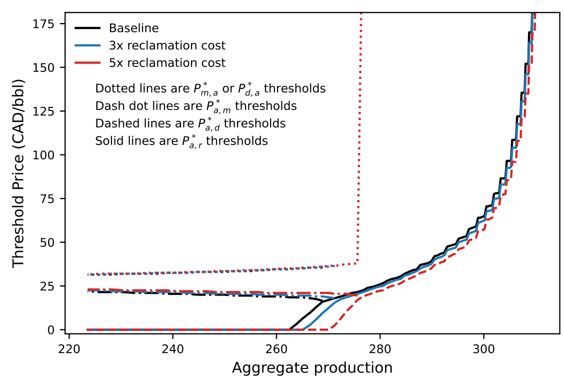
(a) High-price regime decision thresholds (b) Low-price regime decision thresholds

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 of 2, 3, 4, and 5 times relative to baseline reclamation costs. Figure 9 shows the effect of reclamation costs on the decision thresholds for both price regimes. 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 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 $95,822 (3.7 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 decommission. Though the oil well is decommissioned, Figure 9 shows the well will never be brought back into production (red dotted line). 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.

Figure 9: Effect of reclamation costs on operation of the representative oil well



(a) High-price regime decision thresholds

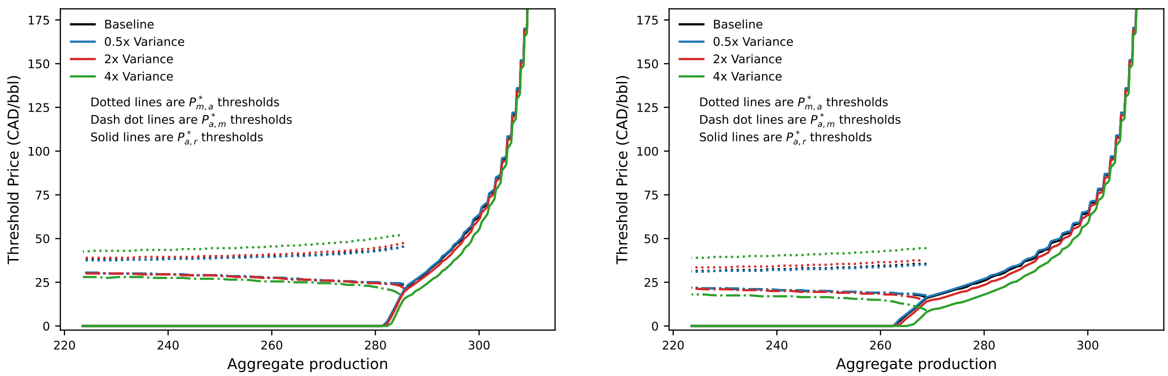


(b) Low-price regime decision thresholds

Figures 10 and 11 show the effect of oil price volatility and discount rates on a firm's decision thresholds. We assume oil prices follow a mean-reverting process; because of this assumption price variance has a small effect on the operation of a well because price shocks are temporary. Oil price volatility has very little effect on the decision to reclaim oil wells at the end of life. Price volatility does affect how long an oil well is temporarily mothballed. The mothball threshold ($P^*_{a,m}$) is mostly unaffected by changes in volatility. However, oil price volatility affects the restart threshold ($P^*_{m,a}$). Higher volatility results in a higher restart thresholds. Increasing the variance by a factor of 4 increases the expected time mothballed by 7.5 months in the high price regime and 17.5 months in the low price regime.

The discount rate has a more significant effect on the operation of the well. Our baseline assumption is that the risk-adjusted real discount rate is 10 per cent. Lower discount rates 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

Figure 10: Effect of oil price volatility on operation of the representative oil well

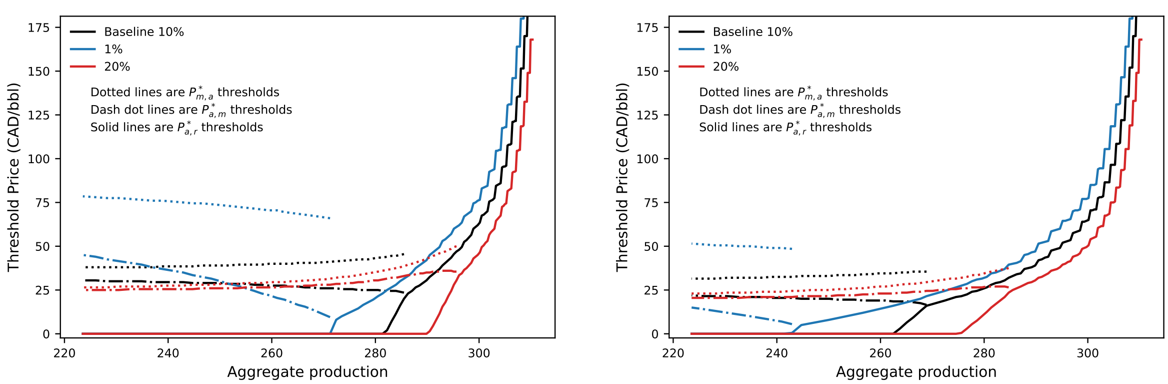


(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

earlier when reserves are high, mothballed later when reserves are low, and restarted later at all reserve levels. Higher discount rates cause the mothball threshold to have a positive 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 discount rate. However, wells are reclaimed earlier when discount rates are low and reclaimed later when discount rates are high. In the high oil price regime, if the discount rate is one per cent a well is expected to operate for 31.5 years. If the discount rate increases to 20 per cent the well is expected to operate for slightly longer at 35.5 years.

Figure 11: Effect of discount rates on operation of the representative oil well



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

5.2 Carbon Tax

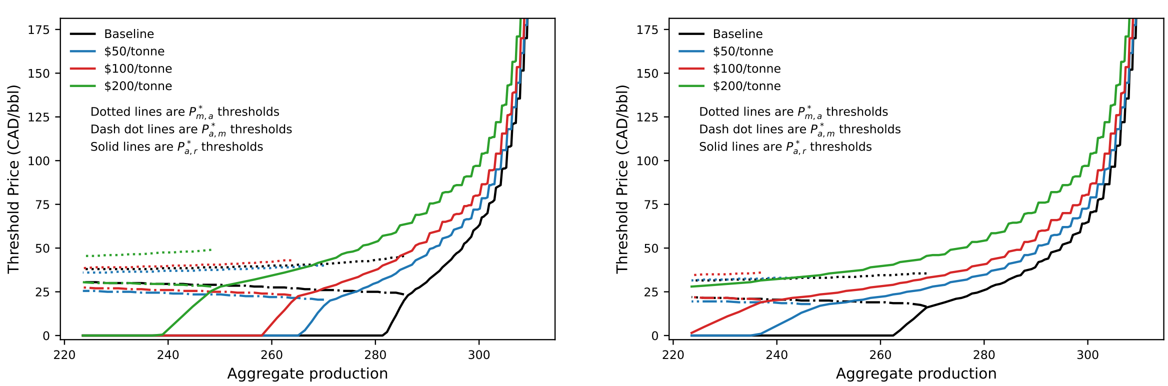
In this subsection we evaluate how a carbon tax on production would impact the operation and end-of-life decision for an oil well in Alberta. Following Abdul-Salam (2022) we incorporate a carbon tax into the profit function. The firm pays a carbon tax based on the intensity of emissions and quantity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

$$e(t) = \psi + \omega * i \tag{27}$$

where ψ and ω are (in tonnes of CO_2 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 (27) 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 CO_2 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 12 shows the effect of a carbon tax on the decision thresholds under each price regime. 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 regardless of the price regime. Interestingly, the mothball threshold threshold decreases compared to the benchmark 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 mothball threshold. These results are similar to Abdul-Salam (2022); a carbon tax causes expected production to decrease (shifts the reclamation threshold to the left).

Figure 12: Effect of a carbon tax on operation of the representative oil well



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

5.3 Policy Alternatives to Incent Reclamation

Under our baseline assumptions, oil wells are operated in a responsible manner: over 95 per cent of reserves are extracted, mothballing is a temporary state, and the oil well is reclaimed at the end of its life. 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

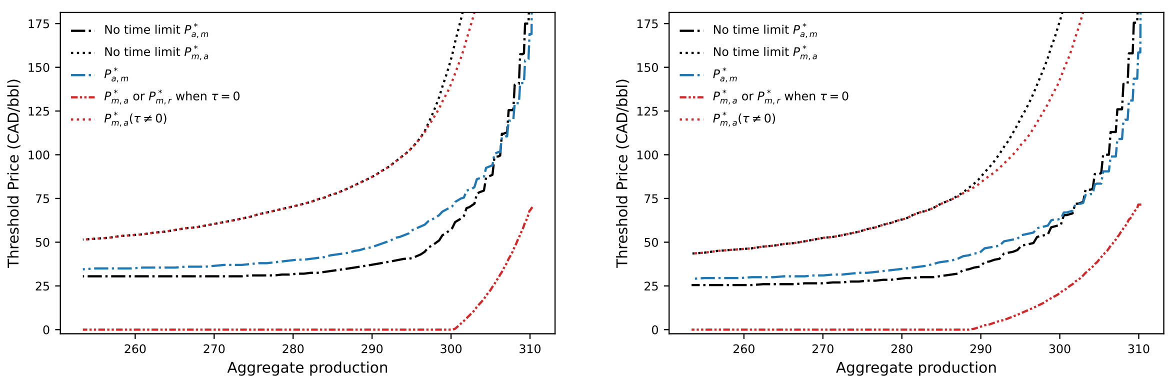
Under our baseline parameters a time limit on inactivity would not affect the operation or end-of-life decisions, as it is already optimal to reclaim at the end of life after extracting nearly all the reserves. When decommissioning or reclamation costs are high the oil well will be left inactive (mothballed 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 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 decommission the oil well. Table 3 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. In both scenarios, choosing to mothball the well forever will be the lowest-cost option when the firm switches from active. 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 — 5 time baseline reclamation costs — the decommissioned state is less costly than reclamation. There, the firm exercises the option to decommission.

Table 3: Monitoring and transition costs of switching from active production to an inactive state

State	High Decommissioning Cost Scenario	High Reclamation Cost Scenario
Mothballed	\$200,000	\$200,000
Decommissioned	\$717,837	\$220,225
Reclaimed	\$647,929	\$253,973

Figure 13 shows the effect of a 10-year time limit on well inactivity on the operation of an oil well when decommissioning costs are high. The black lines represent the decision threshold for the situation where an oil well faces high decommissioning 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 ($\tau = 0$). If the price is above the line, the firm will restart production ($P^*_{m,a}(\tau = 0)$). If the oil price is below the line, the firm will reclaim ($P^*_{m,r}(\tau = 0)$). The red dotted line is the restart boundary ($P^*_{m,a}(\tau \neq 0)$ at every other point prior to hitting the 10 year limit. 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 over 290,000 to 300,000 barrels of oil and oil prices are below \$50 per barrel, the well will be reclaimed.

Figure 13: Effect of a 10 year time limit on inactivity on operation of the representative oil well with high decommissioning costs (5x baseline)



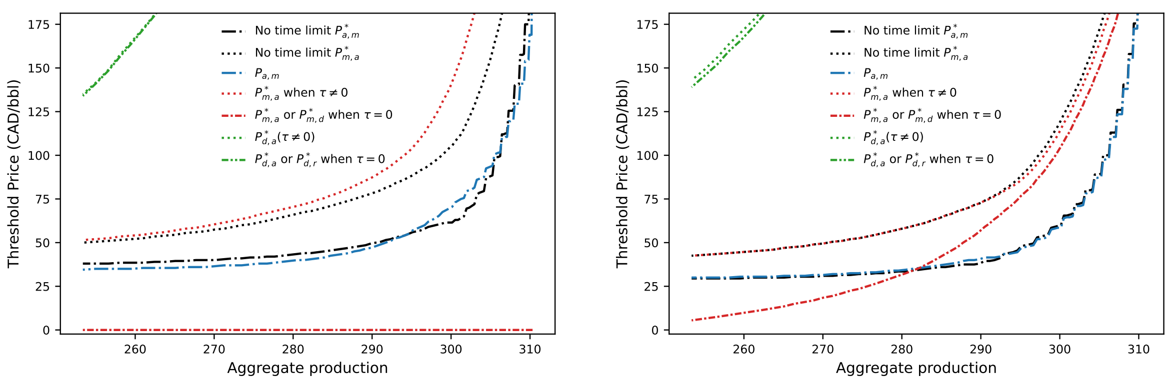
(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

Figure 14 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 ($\tau = 0$). If the oil price is above the line, the firm will restart production ($P^*_{m,a}(\tau = 0)$). If the price is below the line, the firm will decommission ($P^*_{m,d}(\tau = 0)$). 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 ($\tau = 0$). 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 ($P^*_{m,a}(\tau \neq 0)$ and $P^*_{d,a}(\tau \neq 0)$. In the high-price regime, the results are the same as when decommissioning costs are high and there is a 10 year limit on inactivity.

The 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. In the low-price regime, the firm will eventually reclaim the well but the well spends 10 years mothballed before spending another 10 years decommissioned. 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.

Figure 14: Effect of a 10-year time limit on inactivity on operation of the representative oil well with high reclamation costs (5x baseline)



(a) Decision thresholds for an oil well in a high oil price regime

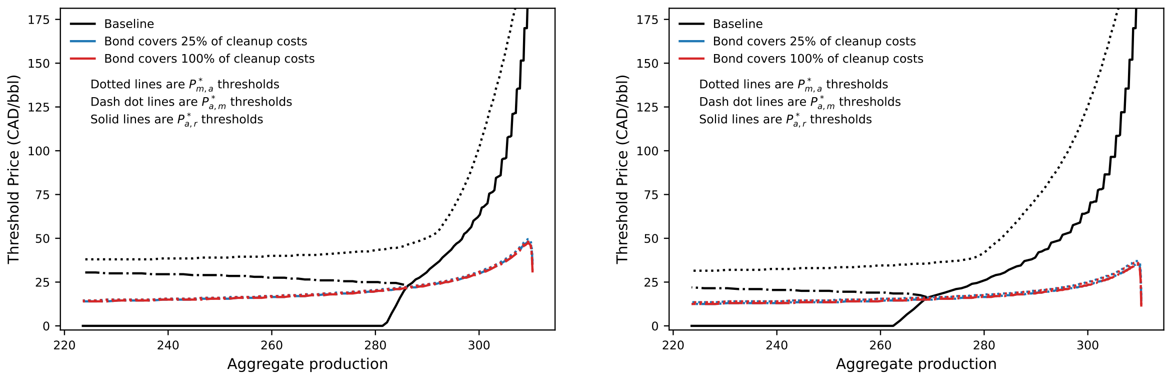
(b) Decision thresholds for an oil well in a low oil price regime

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 it after the firm reclaims after the well. The bond is set to cover part of both decommissioning and reclamation costs (i.e., as a percentage of total cleanup costs). We consider bond values that cover 25 to 100 per cent of expected decommissioning and reclamation costs. The introduction of a bond may affect the operation of a well during its life, so we evaluate the effect of bonds using baseline parameters and cases with high decommissioning and reclamation costs.

Figure 15 shows the effect of a bond on operation of a well under baseline parameters. The introduction of a bond does not have a negative effect on well operation in either price regime. Returning the bond after reclamation lowers the cost of reclamation. This shifts the value of the option to reclaim the well, which could cause the owner to exercise that option earlier (producing less). However, the firm will not exercise the option earlier when a bond is introduced. It will operate the well until all reserves are extracted then reclaim the well. The bond does lower the mothball and restart thresholds. The well spends less time inactive when the price is low.

Figure 15: Effect of a bond requirement on operation of the representative oil well



(a) High-price regime decision thresholds

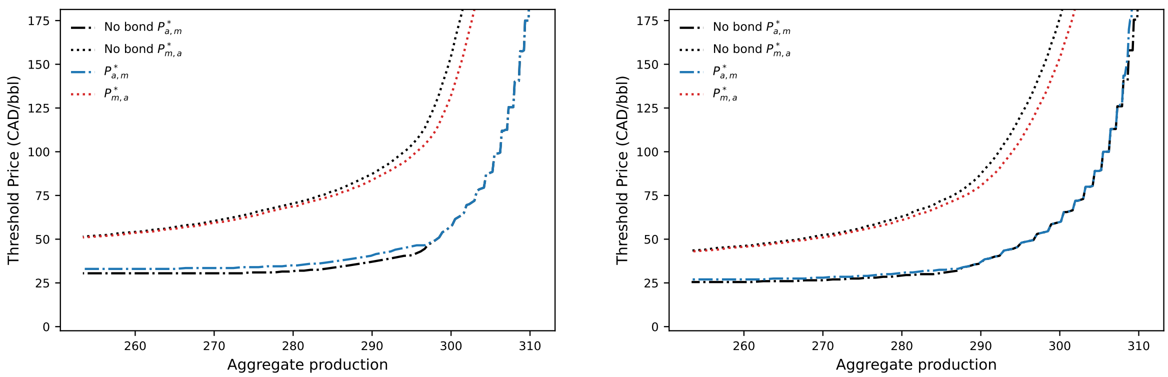
(b) Low-price regime decision thresholds

Figures 16 and 17 show the effect of a bond on decision thresholds when decommissioning and reclamation costs are high. In these scenarios the bond value is set to cover expected decommissioning and reclamation costs, \$124,403 + \$25,914 = \$150,317. The black lines are the decision thresholds for when the well faces high decommissioning or reclamation costs but there is no bond in place. Blue lines are decision thresholds when the well is active and red lines are decision thresholds when the well is mothballed. Figure 16 shows that even though a bond is place that covers expected clean-up costs, it is not large enough to ensure the oil well is reclaimed at the end of its life when decommissioning costs are high. If actual decommissioning plus reclamation costs are \$622,015 + \$25,914 = \$647,929, after return of the bond the reclamation cost is \$497,612, still much larger than keeping the well mothballed forever (\$200,000). Figure 17 shows that a bond equal to expected clean up costs is large enough to make the firm reclaim the oil well even with high reclamation costs. If actual decommissioning plus reclamation costs are \$253,973, with return of the bond the cost of reclaiming the well is \$103,656. This is lower than keeping the well mothballed forever (\$200,000). The relative size of the bond is important in ensuring that well with high clean-up costs are reclaimed at the end of their life. If the value of the bond is small relative to reclamation costs, the firm will forgo the bond and keep the oil well in an inactive state.

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 that can have a low

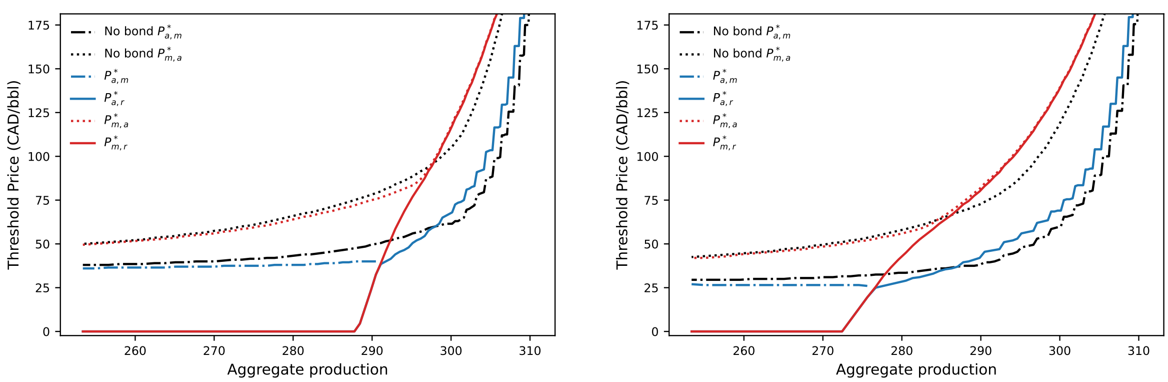
Figure 16: Effect of a bond requirement on operation of the representative oil well when decommissioning costs are high (5x baseline)



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

Figure 17: Effect of a bond requirement on operation of the representative oil well when reclamation costs are high (5x baseline)



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

or high average price. 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. Under our baseline assumptions, we find that owners of oil wells will extract over 95 per cent of the reserves in place and reclaim the well regardless of the prevailing oil price regime. Oil price volatility, changing discount rates, and a carbon tax do not change the outcome that oil wells are reclaimed at the end of their life. These parameters do affect the expected length of a well's life. Our main result is that the decision to reclaim a 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. 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 enough of a 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 then immediately mothball again to reset the inactive clock. With a bond, if decommissioning costs are high the value of a bond is not large enough to incent the firm to reclaim. However, a bond is sufficient when the firm faces high reclamation costs.

Alberta's inventory of mothballed and decommissioned oil and gas wells represents a large financial and environmental risk. Our research 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 cleanup all 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 volume) 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. 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.

A Vertical oil wells

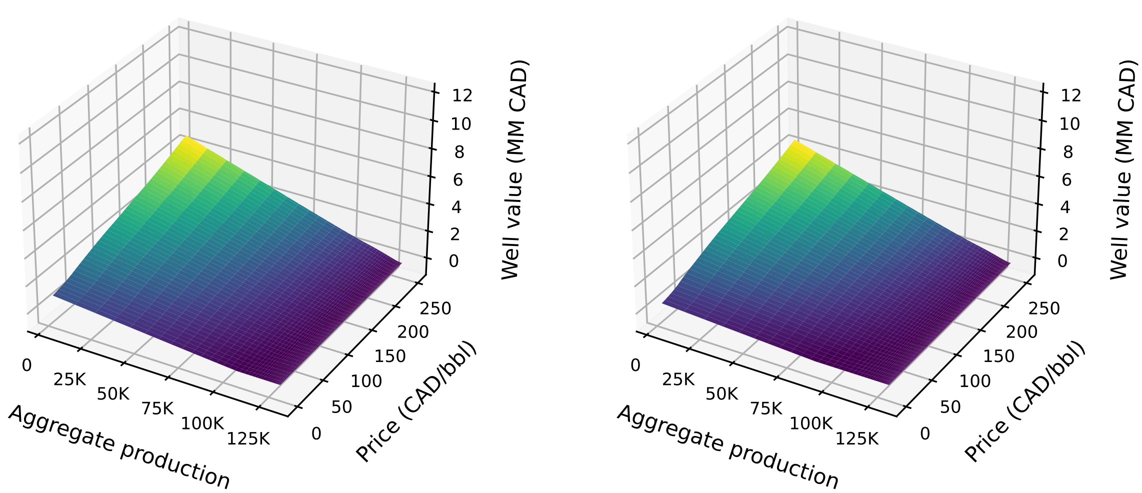
In this appendix we evaluate the representative vertical oil well in Alberta. Table A1 reports our cost and productivity estimates. Similar to the representative horizontal oil well, we also assume productivity declines at 10 per cent per year and production up to 40 years. Vertical wells have average decommissioning costs of $102,189 and average reclamation costs of $26,184.

Table A1: Representative vertical oil well parameters

Parameter	Units	
Total measured depth	meters	1,770
Initial productivity	bbl/year	13,316
Total capital cost	CAD (1,000s)	1,417
Fixed operating cost	CAD/year	69,700
Variable operating cost	CAD/bbl	12.69
Crude oil supply cost	CAD/bbl	42.37

Figure A1 plots the value of operating vertical oil wells with options to mothball, decommission, and reclaim under high and low price regimes at different levels of aggregate production and oil prices. At the beginning of the production stage in a high price regime when the current price is equal to the long-run average ($107.50), the value of a vertical oil well is $2,670,000. In the low price regime when the current oil price is equal to the long-run average ($72.50), the value of a vertical oil well is $1,743,000. Vertical oil wells are less valuable than horizontal oil wells because of lower initial productivity.

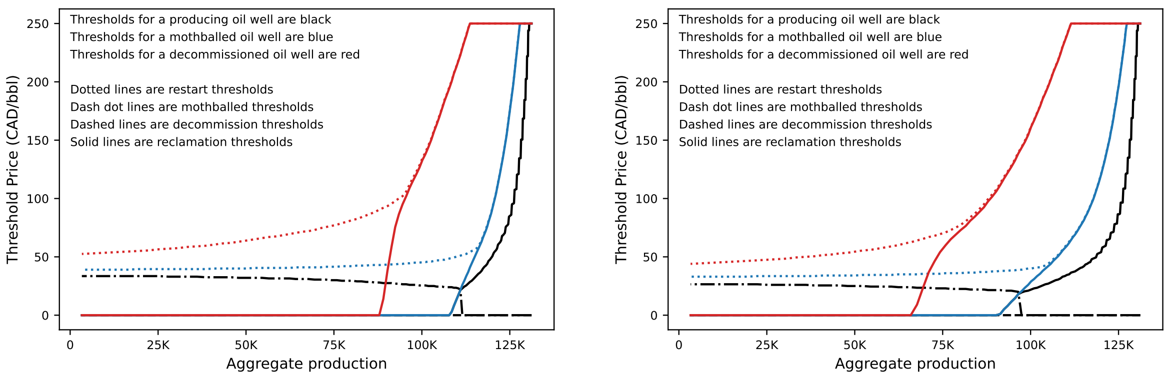
Figure A1: Value of a typical vertical oil well in Alberta



(a) Value of a vertical oil well in a high price regime (b) Value of a vertical oil well in a low price regime

Figure A2 shows the decision thresholds for a typical vertical oil well under high and low price regimes at different levels of aggregate production. Similar to horizontal oil wells, vertical oil wells are operated in a responsible manner regardless of the prevailing price regime. The owner will likely extract 94 to 96 per cent of reserves over 24.5 to 28 years of operation. At the end of their life vertical wells will produce 697 barrels per year in the high price regime and 956 barrels per year in the low price regime. There is a possibility that oil wells will be temporarily mothballed during the life of the well and they will not be decommissioned under baseline parameters.

Figure A2: Decision thresholds for a vertical oil well in Alberta



(a) High-price regime decision thresholds

(b) Low-price regime decision thresholds

References

Y. Abdul-Salam. A real options analysis of the effects of oil price uncertainty and carbon taxes on the optimal timing of oil field decommissioning. *The Energy journal*, 43(6), 2022. ISSN 0195-6574. doi: 10.5547/01956574.43.6.yabd.

S. Aghakazemjourabbaf and M. Insley. Leaving your tailings behind: Environmental bonds, bankruptcy and waste cleanup. *Resource and Energy Economics*, 65, 2021. doi: https://doi.org/10.1016/j.reseneeco.2021.101246. URL https://www.sciencedirect.com/science/article/pii/S0928765521000312.

Alberta Energy Regulator. Well, What's the Difference?, 2020. Accessed 2 January 2023 via https://resource.aer.ca/stories/well-whats-the-difference.

Alberta Energy Regulator. Directive 013. Technical report, Alberta Energy Regulator, 2022. URL https://static.aer.ca/prd/documents/directives/Directive013.pdf.

Alberta Energy Regulator. ST98: Alberta Energy Outlook, 2023a. URL https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98.

Alberta Energy Regulator. Well Status, 2023b. Accessed 2 January 2023 at https://www.aer.ca/providing-information/data-and-reports/data-hub/well-status.

A. Almansour and M. Insley. The Impact of Stochastic Extraction Cost on the Value of an Exhaustible Resource: An Application to the Alberta Oil Sands. *The Energy Journal*, 37, 2016. doi: 10.5547/01956574.37.2.aalm.

Auditor General of Alberta. Annual Report of the Auditor General of Alberta, 2004-2005, 2005. URL https://www.oag.ab.ca/reports/report-auditor-general-october-2005/.

J. Boomhower. Drilling like there's no tomorrow: Bankruptcy, insurance, and environmental risk. *American Economic Review*, 109(2):391–426, February 2019. doi: 10.1257/aer.20160346. URL https://www.aeaweb.org/articles?id=10.1257/aer.20160346.

J. Boyd. Financial responsibility for environmental obligations: Are bonding and assurance rules fulfilling their promise? Discussion Papers 10809, Resources for the Future, 2001. URL https://ideas.repec.org/p/ags/rffdps/10809.html.

B.M. Conrad, D.R. Tyner, H.Z. Li, D. Xie, and M.R. Johnson. A measurement-based upstream oil and gas methane inventory for Alberta, Canada reveals higher emissions and different sources than official estimates. *Communications Earth Environment*, 4, 2023. doi: https://doi.org/10.1038/s43247-023-01081-0.

J.M. Conrad and K. Kotani. When to drill? trigger prices for the arctic national wildlife refuge. *Resource and Energy Economics*, 27(4):273–286, 2005. doi: https://doi.org/10.1016/j.reseneeco.2005.01.001. URL `https://www.sciencedirect.com/science/article/pii/S0928765505000096`.

B. Dachis, B. Shaffer, and V. Thivierge. All's well that ends well: Addressing end-of-life liabilities for oil and gas wells. *C.D. Howe Institute Commentary 492*, 2017. doi: http://dx.doi.org/10.2139/ssrn.3044449. URL `https://ssrn.com/abstract=3044449`.

A.K. Dixit and R.S. Pindyck. *Investment Under Uncertainty.* Princeton University Press, 1994.

C.M. Elliot and J.R. Ockendon. *Weak and Variational Methods for Free and Moving Boundary Problems.* Pitman, 1982.

Environment and Climate Change Canada. Review of Canada's methane regulations for the upstream oil and gas sector. Technical report, Government of Canada, 2021.

Evaluate Energy. CanOils Well and Land Database, 2023.

J. Forsyth and N. Nahornick. Estimated cost of cleaning Canada's orphan oil and gas wells. Technical report, Office of the Parliamentary Budget Officer, 2022.

A. Friedman. *Variational Principles and Free Boundary Problems.* Robert Krieger Publishing, 1988.

G. Galay. The impact of spatial price differences on oil sands investments. *Energy Economics*, 69:170–184, 2018. doi: https://doi.org/10.1016/j.eneco.2017.11.008. URL `https://www.sciencedirect.com/science/article/pii/S0140988317304000`.

D. Gerard. The law and economics of reclamation bonds. *Resources Policy*, 26(4):189–197, 2000. doi: https://doi.org/10.1016/S0301-4207(00)00033-7. URL `https://www.sciencedirect.com/science/article/pii/S0301420700000337`.

V. Goodday and B. Larson. The surface owner's burden: Landowner rights and alberta's oil and gas well liabilities crisis. *The School of Public Policy Publications Research Paper*, 14(1), May 2021. doi: https://doi.org/10.11575/sppp.v14i1.70846.

R. Green. Reducing Alberta's Oil & Gas Liabilities via Timelines on Well Abandonments. Master's thesis, University of Calgary, 2019. Master of Public Policy Capstone Project. Accessed via `https://prism.ucalgary.ca/handle/1880/112187`.

M. Insley. Resource extraction with a carbon tax and regime switching prices: Exercising your options. *Energy Economics*, 67:1–16, 2017. doi: https://doi.org/10.1016/j.eneco.2017.07.013. URL https://www.sciencedirect.com/science/article/pii/S0140988317302505.

M. Insley and K. Rollins. On solving the multirotational timber harvesting problem with stochastic prices: A linear complementarity formulation. *American Journal of Agricultural Economics*, 87:735–755, August 2005. doi: http://dx.doi.org/10.1111/j.1467-8276.2005.00759.x.

M. Kang, C.M. Kanno, M.C. Reid, X. Zhang, D.L. Mauzerall, M.A. Celia, Y. Chen, and T.C. Onstott. Direct measurements of methane emissions from abandoned oil and gas wells in pennsylvania. *Proceedings of the National Academy of Sciences*, 111(51):18173–18177, 2014. doi: 10.1073/pnas.1408315111. URL https://www.pnas.org/doi/abs/10.1073/pnas.1408315111.

M. Kang, D.L. Mauzerall, D.Z. Ma, and M.A. Celia. Reducing methane emissions from abandoned oil and gas wells: Strategies and costs. *Energy Policy*, 132:594–601, 2019. doi: https://doi.org/10.1016/j.enpol.2019.05.045. URL https://www.sciencedirect.com/science/article/pii/S0301421519303490.

D. Kinderlehrer and G. Stampacchia. *An Introduction to Variational Inequalities and Their Applications*. Academic Press, 1980.

R. Kiran, C. Teodoriu, Y. Dadmohammadi, R. Nygaard, D. Wood, M. Mokhtari, and S. Salehi. Identification and evaluation of well integrity and causes of failure of well integrity barriers (a review). *Journal of Natural Gas Science and Engineering*, 45:511–526, 2017. doi: https://doi.org/10.1016/j.jngse.2017.05.009. URL https://www.sciencedirect.com/science/article/pii/S1875510017302184.

L. Kobari, S. Jaimungal, and Y. Lawryshyn. A real options model to evaluate the effect of environmental policies on the oil sands rate of expansion. *Energy Economics*, 45:155–165, 2014. doi: https://doi.org/10.1016/j.eneco.2014.06.010.

M.M. Kostreva. *Lemke method Lemke Method*, pages 1262–1263. Springer US, Boston, MA, 2001. ISBN 978-0-306-48332-5. doi: 10.1007/0-306-48332-7_256. URL https://doi.org/10.1007/0-306-48332-7_256.

P. Lappi. A model of optimal extraction and site reclamation. *Resource and Energy Economics*, 59, 2020. doi: https://doi.org/10.1016/j.reseneeco.2019.101126. URL https://www.sciencedirect.com/science/article/pii/S0928765519300120.

C.E. Lemke. *On complementary pivot theory*, pages 95–114. American Mathematical Society, Providence, Rhode Island, 1968.

J. Lohrenz. Shut-in and abandonment decision economics. In *SPE Hydrocarbon Economics and Evaluation Symposium*, Dallas, Texas, 1991. doi: https://doi.org/10.2118/22014-MS.

K. MacKay, M. Lavoie, E. Bourlon, E. Atherton, E. O'Connell, J. Baillie, C. Fougère, and D. Risk. Methane emissions from upstream oil and gas production in canada are underestimated. *Scientific Reports*, 11(1), 2021. doi: 10.1038/s41598-021-87610-3. URL `https://doi.org/10.1038/s41598-021-87610-3`.

L. Muehlenbachs. A dynamic model of cleanup: Estimating sunk costs in oil and gas production. *International Economic Review*, 56(1):155–185, 2015. doi: https://doi.org/10.1111/iere.12098. URL `https://onlinelibrary.wiley.com/doi/abs/10.1111/iere.12098`.

L. Muehlenbachs. 80,000 inactive oil wells: A blessing or a curse? *The School of Public Policy Briefing Papers*, 10(3), February 2017. doi: https://doi.org/10.11575/sppp.v10i0.42617.

Orphan Well Association. Orphan Inventory, 2023. Accessed 2 January 2023 at `https://www.orphanwell.ca/about/orphan-inventory/`. Inventory current to 1 January 2023.

B. Robinson. The inactive well compliance program: Alberta's latest attempt to bring the inactive well problem under control. Technical report, Ecojustice, 2014. URL `https://ecojustice.ca/wp-content/uploads/2014/12/IWCP-Paper-FINAL-20-Nov-2014.pdf`.

D. Schiffner, M. Kecinski, and S. Mohapatra. An updated look at petroleum well leaks, ineffective policies and the social cost of methane in canada's largest oil-producing province. *Climatic Change*, 164(3), 2021. doi: 10.1007/s10584-021-03044-w. URL `https://doi.org/10.1007/s10584-021-03044-w`.

J.P. Williams, A. Regehr, and M. Kang. Methane emissions from abandoned oil and gas wells in canada and the united states. *Environmental Science & Technology*, 55(1), 2021. doi: 10.1021/acs.est.0c04265. URL `https://doi.org/10.1021/acs.est.0c04265`.

P. Wilmott, J. Dewynne, and S. Howison. *Option Pricing: Mathematical Models and Computation*. Oxford Financial Press, 1993.

D. Yewchuk, S. Fluker, and M. Olszynski. A Made-in-Alberta Failure: Unfunded Oil and Gas Closure Liability. *The School of Public Policy Publications Research Paper*, 16(31), October 2023. doi: http://dx.doi.org/10.11575/sppp.v16i1.77468.