How does the cost of capital affect oil supply?*

Helena Cordt[a] Julien Daubanes[b] Yiding Ma[c]

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Abstract

In the past decade, a rapidly growing number of investors have divested from the oil-producing industry. The financial approach to the climate problem—e.g., the burgeoning green finance taxonomies—hopes that such divestment will contribute to aligning the industry's incentives with climate policy targets by increasing targeted firms' cost of financial capital. We ask how an augmented cost of capital might affect oil supply and equilibrium production. On the one hand, the cost of capital should reduce oil projects' net present value, inducing projects' abandonment. On the other hand, it makes the industry more short-termist, advancing projects to generate revenues earlier. We develop a model of oil supply in which the industry's cost of financial capital—isolated from the cost of physical capital—affects drilling decisions and oil production. The model is calibrated using data covering all US oil assets and used to simulate the dynamic competitive equilibrium under various counterfactual policy scenarios for the period 2000-2030, including carbon pricing and "green finance," modeled as an augmented cost of financial capital. Our results suggest that increasing the cost of capital by up to a few percentage points is counterproductive in the short run, because it encourages industry short-termism. Green finance becomes effective at deterring oil production only over longer horizons or under greater capital penalties. Yet the returns that financial markets would need to forgo to replicate the effect of a $100 carbon price are unrealistically high.

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[a]Department of Technology, Management and Economics, Technical University of Denmark (DTU).

[b]Department of Technology, Management and Economics, Technical University of Denmark (DTU), Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology (MIT), and CESifo. Corresponding author: jxada@dtu.dk.

[c]Department of Technology, Management and Economics, Technical University of Denmark (DTU).

Detailed summary

1 Introduction

In the past decade, a rapidly growing number of investors—representing more than $40 trillion in assets as of April 2025, about one third of all financial assets under management worldwide—have committed to ceasing their financing of the production of oil (Global Fossil Fuel Divestment Commitments Database, 2025). These investors mainly include pension funds, banks, and climate-themed asset managers. Less funding for oil production is hoped to increase producers' cost of capital, thus constraining their operations. The goal of this paper is to explore how an augmented cost of capital affects oil exploitation decisions and oil production.

Our main question of interest concerns how the assessment of real oil production projects and producers' profit-maximizing decisions are affected by the cost of capital. This cost, as finance theory explains, is the profit-maximizing firm's opportunity cost of funds, which determines the rate at which its projects' future cash flows are discounted. Oil projects typically involve both upfront development costs and future benefits that depend on the oil price. The first effect of the cost of capital is to reduce the net present value of firms' oil projects. The second effect is that the cost of capital induces producers to give priority to projects that generate cash in the short run.

The resource economics literature has long warned that higher discount rates may increase oil production in the short run—see, e.g., Long and Sinn (1985), Sinn (2008), van der Ploeg and Withagen (2012), among many others. This short-termist response to bad future prospects was recently revived by Kellogg's (2024) study of the anticipated effect of the long-term destruction of oil demand.

For example, anecdotal evidence suggests that the 2022-2023 rise in interest rates and, thus, in investors' expected returns not only pressured oil majors into reducing their long-term investment in the development of future projects, but also induced them to prioritize "short-cycle" projects—see *The Economist*, February 6, 2023.[1]

The financial approach to the climate problem seeks to deprive carbon-producing industries of

[1] Available at: `https://www.economist.com/business/2023/02/06/where-on-earth-is-big-oil-spending-its-150bn-profit-bonanza`. This short-termist response is consistent with the fact that oil companies' profits were higher in 2022-2023 than in the period 2010-2014, despite lower prices.

financial resources. Although this approach sharply contrasts with economists' traditional call for pricing the carbon externality directly, policymakers and financial regulators have rapidly embraced it. For example, following the EU-ETS carbon pricing scheme, the second pillar of the EU climate action is its "green finance taxonomy"—followed by many similar initiatives worldwide—aimed to make financial capital more costly for climate-harmful activities.

The literature in finance has recently paid attention to the effect of the cost of capital on carbon-intensive industries. Pedersen (2025) is the first to point to a theoretical equivalence between carbon pricing and green finance, modeled as an increase in firms' cost of capital. Quantifying this equivalence—for recent attempts, see Pedersen (2025), Chittaro et al. (2025), and Gollier (2025)—yields industry-level benchmark costs of capital, indicating the financial returns that markets should forego to produce incentives in line with climate objectives. To our knowledge, existing attempts have focused on calibrated static marginal cost formulas relating the price of carbon and the cost of the capital input, leaving unexplored the effect of the cost of financial capital on the assessment of real projects' generating cash flows over time, the gap that we seek to fill.

In this paper, we focus on the oil production industry, examining how the cost of capital affects the profitability of oil exploitation projects and changes oil production decisions. Oil accounts for approximately one third of global greenhouse gas emissions and is expected to remain an important component of the energy mix for decades. At the same time, meeting climate targets implies that a substantial share of proven reserves must remain unexploited (McGlade and Ekins, 2015; Welsby et al., 2021; Trout et al., 2022). We examine how oil production responds to (i) a carbon price and (ii) an increase in the cost of capital.

2 Modeling approach

Since a persistent increase in the cost of capital is without historical precedent, the prediction of market responses must rely on economic theory supplemented by calibrated simulations.

We model intertemporal oil supply decisions and characterize the dynamic equilibrium of the oil market. Our model focuses on producers' choices as to when to undertake their extraction projects, capturing empirically relevant rigidities and production constraints. We then calibrate model parameters using fundamental data covering all real oil projects' recoverable reserve, production path,

as well as development and operational costs.

Facts about oil projects. Our model's specification and calibration are guided by facts about oil extraction projects and aim to rationalize the dynamics of oil production in the past decades.

(1) In reality, the economic commitment to undertake an oil exploitation project, including its financing, is typically made at the "asset" level as defined in Rystad Energy data.[2] Assets may include a single well or multiple wells, typically aimed at exploiting the same field-level geological resource. Reserves are assessed at the field level, and a project seeks to exploit all of them. Fields are first discovered, then developed, and exploited. (2) Once a field is discovered, it may be developed and exploited as soon as possible thereafter or may be delayed until prices and financing conditions warrant exploitation. (3) After an asset is developed and tapped, its exploitation is virtually uninterrupted; exceptions may be explained by unanticipated demand (e.g., covid crisis) or supply (e.g., sanctions) shocks.[3] The asset-level production trajectory is governed both by wells' production and by the opening of additional wells, if any. The former is known to be determined by physical factors (Anderson et al., 2018); the dispersion of wells is constrained by pre-determined capacity constraints (e.g., transportation) and by inter-wells competition for pressure.

Financial capital vs. physical capital. Besides the dynamic dimension of oil supply and its calibration based on real projects, the novelty of our model is that it distinguishes the cost of financial capital and the cost of physical capital (e.g., pipelines, platforms, etc) whose costs are determined by the price of material rather than by the cost of funds. Apart from these characteristics, the main assumption of our theory is that supply decisions are solely guided by the net present value of oil extraction projects.

Model's structure. Each field is characterized by (i) an earliest feasible production date, (ii) fixed development costs incurred before production begins, (iii) a constant marginal cost of extraction, (iv) finite recoverable reserves, and (v) an exogenously specified production profile once drilling occurs. The key endogenous choice is the initial drilling date τ_i for each asset i. Once drilled, the asset produces according to a predetermined extraction path (reflecting technological

[2] In the rest of the paper, we will use interchangeably asset or project to refer to an asset.

[3] Our calibration and therefore our counterfactual simulations abstract from these shocks, assuming regular market conditions.

and geological constraints) until its recoverable reserves are depleted. Given prices, each field's drilling date, if any, is determined so as to maximize the net present value of its exploitation. Prices are established on a competitive market, balancing supply and demand at all times.

To sum up, our model captures physical production rigidities accounting for realistic supply dynamics. These constraints focus our analysis on two main margins determining the impact of policies on oil production: At the extensive margin, producers decide whether or not to exploit an asset; at the intensive margin, they decide whether each produced asset should be started earlier or later.

Besides its empirical relevance, our new formulation of the oil-supply problem as a choice of start dates provides significant computational advantages with respect to conventional models in which production is determined, under production constraints, for each asset and each year.

3 Data and calibration

We seek to capture the potential of the US oil extraction industry between 2000 and 2030.

To calibrate our model, we use Rystad Energy data covering all US oil fields. Besides discovery dates, reserves, and production, we estimate the leverage cost of extraction (LCOE) of all oil projects, which we use as a proxy for marginal production costs. Following Coulomb et al. (2025), pre-production investment (well and facility CapEx) costs are aggregated as a single fixed cost per asset. We allow for different development-cost structures across shale and non-shale fields: Shale developments involve primarily well-level CapEx, whereas non-shale fields also incur substantial multi-year facility investments. The LCOE and the pre-production costs capture the costs of physical inputs required for extraction, which are independent of the cost of financial capital.

The assets' flow production profile is modeled as a discrete Weibull trajectory, whose parameters are estimated at the asset level by maximum likelihood based on historical production data and Rystad Energy's projections. Additionally, our model captures short-term rigidities by taking as exogenous the continued production from all fields that were started before 2000.

For simplicity, we assume that all assets are equally emission-intensive, generating lifetime emissions of 0.544 tCO2 per barrel.

Finally, demand is assumed to be isoelastic, with an elasticity in line with recent estimates and

with the US production market share. We calibrate its initial level so as to match observed US oil production and assume it to grow by 1.3% annually.

4 Results of counterfactual analysis

Based on the above calibrated model, we build a resolution algorithm that solves for the dynamic competitive equilibrium of the market for US oil over the 2000-2030 period. The equilibrium establishes drilling dates of all assets and, therefore, US oil production over time.

In the baseline scenario, we set the cost of capital to 3%.[4] The numerical simulation reflects well the technological variation within US oil production over time, such as the shale boom, as reflected in the baseline trajectory in Figure 1.

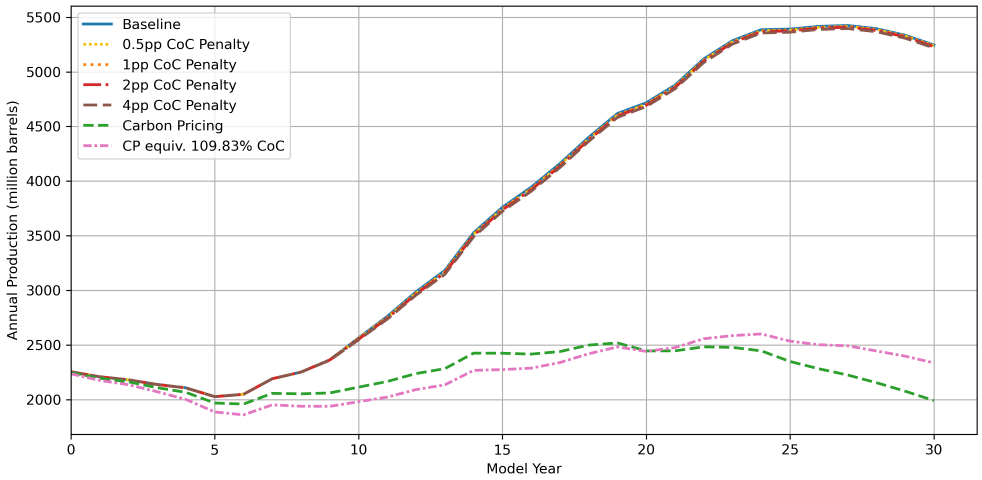


Figure 1: Oil production equilibrium response to cost-of-capital penalties and carbon pricing (2000-2030)

We consider two counterfactual scenarios, both assuming perfect competition and perfect foresight for comparison purposes.

Carbon pricing. In the first scenario, oil traded is subject to a carbon price of $100 per ton of CO2—in 2023 real terms, constant in real present value—while the cost of capital remains unchanged at the baseline level. Our simulation shows that a $100 carbon price—a wedge of around $54 per barrel between producer and final prices—reduces total production (and emissions)

[4]This baseline level is purposely assumed lower than the industry's WACC because there is no risk in our model.

by 40% over the model period 2000-2030. As expected, the main mechanism of carbon pricing effectiveness is that it generates a lower producer price, depressing the net present value of all assets, and making a number of them unprofitable.

Cost of capital. In the second scenario, we examine green finance by increasing the cost of financial capital while imposing no carbon price. We consider increases in the cost of capital from 50 basis points to 4 percentage points (see Figure 1). Perhaps surprisingly, our simulations indicate that the cost of capital has a very weak effect on production. Also, surprisingly, an increase of up to 4 percentage points results in more emissions in the first years.

While oil asset NPVs are negatively impacted by the cost of capital, firms limit this impact by advancing the dates when they start exploiting their assets. In other words, the rise in the cost of capital makes the industry more short-termist, inducing it to exploit more oil fields immediately.

In fact, green finance becomes effective at discouraging production only over longer horizons or when the cost of capital increases sufficiently to make a substantial number of oil fields unprofitable. Yet, it does not affect oil production by the same order of magnitude as carbon penalties. For instance, achieving an environmental impact equivalent to a $100 carbon price would require increasing the cost of capital by 110 percentage points.

We also explain the surprisingly weak effect of the cost of capital on oil production. First, we calculate the internal rate of return (IRR) of oil exploitation projects at fixed baseline prices based on their lifetime development and operational costs. We find that oil assets' IRRs are, in general, very high, with a median above 50%.[5] Second, oil assets' IRRs do not directly indicate the cost of capital required to turn them unprofitable. This is mainly because, as the cost of capital increases and discourages some production, the equilibrium adjustment of oil prices increases IRRs further. This effect is even stronger as demand for US oil is not highly elastic.

5 Conclusion and contribution

Concerned investors' sacrifice is hoped to curb the production of carbon resources by raising oil firms' cost of capital. Our analysis shows, however, that such capital penalties have limited effects,

[5]The obtained distribution of IRRs is in line with other studies such as Erickson et al. (2017) on the public policy support to oil production.

and can potentially turn counterproductive in the short run. Because greater financing costs induce investor short-termism, small increases in the cost of capital can accelerate drilling and bring additional marginal fields into production, raising rather than reducing emissions in the short run. Green finance becomes effective at reducing oil supply only when capital-cost premia are sufficiently large or sustained over long horizons. Yet, we find that its effect is not comparable in magnitude to that of conventional carbon pricing. In fact, to mimic the effect of a moderate carbon tax, the cost of capital would need to rise to economically unrealistic rates.

More related literature and contribution. Our analysis mainly contributes to the recent finance literature comparing green finance with carbon pricing (Pedersen, 2025; Chittaro et al., 2025; Gollier, 2025). The novelty of our study is to assess the effect of the cost of capital using real projects' data in a setting that allows us both to distinguish the cost of financial capital from the cost of physical capital inputs and to take equilibrium price adjustments into account.

Our paper is also related to a set of recent papers modeling and simulating the dynamic equilibrium of the oil market based on the same oil data as we use here. This literature studies various sources of inefficiency in the actual allocation of oil—see, e.g., Asker et al. (2019), Coulomb et al. (2025), and Asker et al. (2024). Our objective is very different: Our simulation exercises do not seek to assess the real allocation of oil but to compare various policies under the same setting featuring realistic economic responses. Yet, our paper makes a methodological contribution to this literature by developing and solving a model that departs from Hotelling's (1931) conventional model of nonrenewable resource management, in the spirit of Anderson et al.'s (2018) criticism of this model's relevance for oil supply.

Finally, our paper extends the study of supply-side climate policies initiated by Harstad (2012)—see also, e.g., Asheim et al. (2019)—to the analysis of financial penalties.

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