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ABSTRACT

Reallocation of assets across firms can lead to efficiency gains, but it can also lead to distortions via rent-seeking. We examine the link between asset reallocation and rent-seeking enabled by differences in the expected cost of environmental liabilities. Focusing on the US oil and gas industry, we develop a conceptual framework that incorporates both firm specialization in well types and the judgment-proof problem, by which undercapitalized firms can avoid environmental liabilities. We then build a novel dataset with hundreds of thousands of well transfers over 1992 to 2023, showing that oil and gas wells are transferred frequently, particularly as they age and their revenues decline. Moreover, low-value wells are especially likely to be transferred to low-value firms. Transferred wells produce similar amounts in later years, but are less likely to be plugged – thus posing greater environmental risk. We conclude with policy implications related to well plugging, bonding requirements, and decarbonization.

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1 Introduction

Why do firms reallocate assets? On the one hand, reallocating assets allows firms to realize efficiency gains that lead to increases in social welfare. On the other hand, the private benefits of asset reallocation may arise from rent-seeking behaviors that decrease social welfare, ranging from exploitation of regulatory loopholes to various forms of anti-competitive behavior. In this paper, we emphasize the link between asset reallocation and rent-seeking enabled by differences in the expected cost of environmental liabilities. In our setting – the US oil and gas sector – these differential environmental costs arise from differences in firm size as assets age (Shavell, 1986). Building a multi-decade dataset with hundreds of thousands of oil and gas asset transfers, we examine the impact of transfers on both productive efficiency and environmental liabilities. Our results speak to ongoing policy discussions about environmental policy for millions of aging oil and gas wells. They also speak to other sectors where assets may pose environmental or safety risks as they age, including other natural resource extraction (e.g., mines), energy infrastructure (e.g., underground storage tanks), and tail-risk industries (e.g., nuclear power plants).

The oil and gas sector provides a useful context for studying the role of environmental liabilities in firm incentives for asset reallocation. At the end of their productive lives, many low-producing oil and gas wells are owned by small, poorly capitalized firms, leading to a canonical judgment-proof problem (Boomhower, 2019).[1] Wells are not typically drilled by such small operators; instead, they are acquired by their final operators through an active secondary market. Asset transfers in this industry have received considerable public attention, with environmental groups emphasizing environmental harms (Mider and Adams-Heard, 2021; Jaffe and Najmabadi, 2022; Olalde, 2022; Lutz and Rowland-Shea, 2023). Industry groups, however, highlight that small producers may be able to leverage cost savings, potentially justifying the transfers (National Stripper Well Association, 2014; McGowen, 2025). Numerous features of the oil and gas industry enable detailed empirical analysis of these claims: production and revenue associated with individual assets are observable, firm sizes are heterogeneous, and actions taken to mitigate environmental issues are observable. Moreover, understanding the impact of asset transfers is important in an industry where outstanding environmental liabilities are estimated at tens to hundreds of billions of dollars.[2]

[1] The "judgment-proof problem" refers to the idea that firms in a limited liability regime do not fully internalize the expected costs of risky behavior, given the option to declare bankruptcy.

[2] There are an estimated 2.1 million abandoned and unplugged oil and gas wells in the U.S. (U.S. Environmental Protection Agency, 2020), plus nearly one million still-producing wells (`https://www.eia.gov/petroleum/wells/`, accessed March 3, 2026), with estimated plugging costs in the tens of thousands of dollars per well (see Appendix Section A3.9).

We begin with a conceptual framework in which oil and gas operators endogenously specialize in well types, such that asset reallocation as a well ages increases productive efficiency. The model also allows for the judgment-proof problem: firms have the option to declare bankruptcy if environmental liabilities exceed expected future profits. We show that asset reallocation can serve as a mechanism by which large, well-capitalized operators consistently discharge environmental liabilities. Our analytical model yields several predictions about the timing, operator types, and outcomes associated with well transfers, which we then take to data.

To enable our empirical analysis, we assemble a novel dataset of well operator histories, production volumes, and environmental outcomes across four major oil- and gas-producing states. While common oil and gas datasets only name current operators, we track operator histories over decades (1992 to 2023) – requiring us to assemble data from many different sources and carefully harmonize across multiple state-level reporting conventions. Using our dataset, we document several novel empirical facts about asset transfers in the oil and gas industry. First, well transfers are common, with 7.8 percent of wells experiencing a transfer in a typical year. Second, wells are more likely to be transferred as they age and their expected future value declines: the lowest value wells are nearly twice as likely to be transferred in any given year as the highest value wells. Third, the typical transfer is to a smaller operator, and low-value *wells* are especially likely to be transferred to low-value *firms*.[3] These patterns are consistent with predictions of our analytical model and highlight a potential problem for policymakers: firms with low expected future profits may be less likely to fulfill environmental remediation obligations for aging wells – because they lack the financial resources to do so, because they have fewer reputational concerns with regulators and investors, because they can declare bankruptcy if there is an accident, or some combination thereof.

We then show that transfers of aging wells predict a host of long-run outcomes. We leverage multiple identification strategies, beginning with regressions that condition on a rich set of well-level observables and then focusing on transfers less likely to be driven by well-specific characteristics or profitability. We find that non-producing wells are five percentage points less likely to have completed end-of-life environmental remediation – that is, well plugging – in the years following a well transfer, relative to a sample mean of 25 percent. That is, aging wells experience a sustained period after transfer in which they are more likely to contribute to environmental problems such as groundwater contamination and methane emissions. In contrast, we do not detect meaningful differences in production volumes for the typical well after transfer.

[3] We use "low-value" throughout the paper to refer to wells and operators with low revenues, i.e., in a descriptive, not normative, sense.

These overall outcomes mask important differences by operator size. Consistent with our theoretical framework, we find that plugging outcomes follow a clear gradient by operator size. Wells operated by or transferred to small firms are the least likely to be plugged five years after transfer. Our results are consistent with transfers of aging wells acting as a mechanism for the judgment-proof problem in this industry. We also find a gradient in production outcomes: wells operated by and transferred to small firms are more likely to be producing, consistent with cost efficiencies. But overall production volumes for these wells are lower than for those operated by larger firms – effects on the intensive margin outweigh those on the extensive margin. To place these environmental and production outcomes in context, we conduct an illustrative back-of-the-envelope welfare assessment. For aging wells transferred to smaller operators, this exercise suggests that production cost savings would need to be economically meaningful for transfers to be welfare enhancing ten years after transfer; for aging wells transferred to any operators, modest production cost efficiencies are sufficient. In light of these findings, we discuss policy implications related to financial assurance.

This paper contributes to several strands of the literature. First, our paper relates to literature on the reallocation of capital across its lifecycle. Existing research has documented that capital reallocation represents a substantial portion of overall investment and that young and small firms are more likely to purchase used capital, while older and larger firms are more likely to purchase new capital (Eisfeldt and Rampini, 2007; Eisfeldt and Shi, 2018; Ersahin, 2020; Ma, Murfin and Pratt, 2022). The pattern of well transfers that we document is consistent with this more general phenomenon. We emphasize the role of differences in the expected cost of environmental liabilities – in this setting created by differences in firm size and the judgment-proof problem – as one motivation for the reallocation of assets over their life cycle.[4] More broadly, the extensive literature on firm acquisitions has highlighted other types of rent-seeking behaviors (Asker and Nocke, 2021; Cunningham, Ederer and Ma, 2021) and productive efficiencies (Demirer and Karaduman, forthcoming) as reasons why firms frequently reallocate assets. In an environmental context, Weber and Yang (2025) emphasize differences in the stringency of environmental regulations across geographic regions as a reason for reallocating aging trucks; Davis and Kahn (2010) also consider the environmental consequences of geographic trade in aging vehicles.

[4]The existing literature on capital reallocation has largely focused on credit constraints facing young and small firms as the underlying mechanism for aging capital moving from older to younger firms. The literature finds that stronger rights for contractual creditors effectively decrease the cost of new capital for small firms (Ersahin, 2020). Drawing on the law literature, our analytical model focuses on obligations to "involuntary creditors," such as tort creditors after an environmental accident (Macey and Salovaara, 2019). In our model, stronger protections for involuntary creditors would also drive small firms away from older capital, in this case by increasing the cost of old capital.

This paper is also closely related to the literature in law and economics on the judgment-proof problem. Boomhower (2019) shows that changes in bonding requirements caused significant changes in the structure of Texas's oil and gas industry, consistent with the judgment-proof problem having important impacts on environmental and safety outcomes. Gerard (2000); Mitchell and Casman (2011); Davis (2015); Lange and Redlinger (2019); Macey and Salovaara (2019), and Yang and Davis (2021) also look at policy solutions such as bonding requirements in theory and in practice. Other papers in this literature examine the relationship between firm size and environmental outcomes (Eyer, 2018; Cohn and Deryugina, 2018). We extend this literature to focus on the role of asset reallocation. A key prediction from our model is that in industries where asset reallocation is common, it is not *just* small, under-capitalized firms that we typically think of as "judgment-proof" that are able to socialize risks and end-of-life liabilities: larger firms can extract some of the associated surplus by transferring assets as end-of-life liabilities loom or as risks increase. A closely related idea is "contracting out" in the law and economics literature, whereby large firms obtain inputs with significant potential liabilities from outside the boundaries of the firm (Ringleb and Wiggins, 1990; Brooks, 2002).

Our paper also contributes to a large literature on the market structure of the oil and gas industry (Kellogg, 2011, 2014; Anderson, Kellogg and Salant, 2018; Newell, Prest and Vissing, 2019; Newell and Prest, 2019; Herrnstadt, Kellogg and Lewis, 2024). Most of these papers focus on initial exploration, drilling, and early production decisions. In contrast, we focus on the economics of oil and gas wells as they age and decline in value. For outcomes that scale with the number of wells rather than the quantity of oil and gas produced, including many environmental outcomes, this long tail of low production is critical to understanding the economics of the industry. Two notable exceptions are Muehlenbachs (2015) and Weber et al. (2021), which focus on the decisions operators make towards end of life, but which do not address well transfers.

Our paper also relates to interdisciplinary work across economics, engineering, and policy on abandoned and orphaned wells – the latter defined as wells for which there is no existing firm responsible for plugging or liable in the event of contamination, because the past operator cannot be traced or has gone out of business. This work includes efforts to estimate the total number of orphaned and abandoned wells, document the risks associated with unplugged wells, and estimate the costs of plugging wells (Kang et al., 2014; Ho et al., 2018; Kang et al., 2021; Raimi et al., 2021; Boutot et al., 2022; Harleman, Weber and Berkowitz, 2022; McClure, Simonides and Weber, 2022; Kang et al., 2023). We emphasize how industry structure has contributed to the present large stock of abandoned wells and affects policy considerations going forward.

Finally, we contribute to policy discussions on aging infrastructure and sunk assets during an energy transition (van der Ploeg and Rezai, 2020; Davis and Hausman, 2022; Purvis, 2023; Im, 2023). We argue that understanding the historical patterns of asset transfers in the oil and gas industry, particularly for wells with low profits, is crucial for navigating decarbonization policy.[5] As the chairman of the National Stripper Well Association – an organization representing the interest of low-producing, so-called 'stripper' wells – testified, "[a]ll producing wells in America are either a stripper producing well or will eventually become a stripper producing well" (Montalban, 2025). This process will only accelerate with decarbonization efforts.

This paper provides as follows. Section 2 provides contextual background. Section 3 builds a conceptual framework. Section 4 describes our data, and Section 5 provides empirical results. Section 6 develops policy implications, and Section 7 concludes with directions for future work.

2 Institutional Background

A well-documented property of oil and gas wells is that initial production volumes are high, but production falls rapidly as geologic pressure declines (Kellogg, 2014). Production may then continue at low levels for decades, as we document below. As a corollary, we also document below that a "typical" well in an area with a long-established oil and gas industry – such as many parts of the United States – is low producing.[6] During this long tail of low production volumes, minimizing production costs is essential to well profitability (Inkpen and Moffett, 2011). Ongoing production costs include both fixed and variable components, such as maintenance and monitoring, well-specific overhead, taxes, and transporting product to market (Inkpen and Moffett, 2011; Energy Information Administration, 2016; Purvis, 2023).

At the end of a well's productive life, a process known as "plugging and abandonment," or simply "plugging," seals off the well to prevent the continued flow of liquids and gases, by installing physical plugs at various depths of the wellbore. There are many components to the social benefit of plugging wells at the end of their productive lives. Multiple studies have documented higher average methane emissions at unplugged wells than plugged wells, while also noting that a small number of unplugged wells contribute a disproportionate share of

[5] A related but somewhat separate point is that oil and gas majors, which are facing increasing levels of regulatory and public scrutiny for the carbon dioxide emissions from their product, may increasingly sell off wells to be able to make claims about climate action.

[6] States have different regulatory classifications for low- and non-producing wells, as reviewed in Weber et al. (2021).

overall methane emissions (Kang et al., 2014, 2016; Townsend-Small and Hoschouer, 2021).[7] Unplugged wells also pose a risk of groundwater contamination, which is capitalized into nearby land values (Harleman, Weber and Berkowitz, 2022). Additional social costs from unplugged wells that have not yet been well quantified in the existing literature include emissions of local air pollutants such as benzene and volatile organic compounds (VOCs); soil contamination; ecosystem impacts; and explosion risk (Kang et al., 2021; Raimi et al., 2021).[8]

Recent estimates of the cost of plugging end-of-life wells have varied.[9] Across several studies using different methodologies, typical end-of-life costs range from \$22,000 to \$180,000, with some wells facing even higher or lower costs; see Appendix Section A3.9 for additional detail. (Here and throughout the paper, we use 2023 dollars.) This heterogeneity stems in part from differences in site characteristics: well age, site terrain, and especially well depth are associated with higher plugging costs. Other cost determinants include whether state regulations specify particular plugging procedures or materials; the number of wells being plugged in a geographic area (to enable economies of scale); and oil versus gas well type (Raimi et al., 2021). Despite these costs, operators might choose to plug their wells to enable production at nearby sites, or to reduce potential liability from accidents at unplugged sites. However, operators may also find it profitable to defer plugging for years, even if wells are producing very little or zero oil and gas (Weber et al., 2021). Without adequate regulatory incentives, some operators may avoid plugging wells altogether. In all, one industry report documents around 20,000 wells being plugged by their operators annually (Interstate Oil and Gas Compact Commission, 2024).[10] Here and throughout the paper, we follow the terminology of state regulators and refer to the "operator of record" as the responsible party for well drilling, production, and plugging.

To incentivize operators to plug wells, thereby reducing potential damages, states require operators to provide some form of financial assurance (e.g., a bond) to ensure funds will be available for end-of-life cleanup costs. This financial assurance can cover both known or expected clean-up obligations and uncertain or probabilistic damages, for instance from accidents (Boyd, 2001). Though specific bonding requirements vary by jurisdiction, researchers

[7] Researchers have also noted that well plugging, on its own, is not a panacea for methane emissions, as plugging regulations were not generally designed with the goal of minimizing methane emissions. In coal-producing areas, for example, plugged wells may be vented for safety reasons, leading to significant methane emissions even from plugged wells (Kang et al., 2014).

[8] Unplugged wells may also create negative externalities for operators of nearby wells – for example, by reducing reservoir pressure (Weber et al., 2021).

[9] For a detailed description of the steps required to plug a well, see McClure, Simonides and Weber (2022).

[10] States also plug orphan wells. Over 2018-2022, the same report documented around 2,000 to 4,000 orphan wells plugged by states every year, with a surge to over 8,000 in 2023 thanks to federal funding (Interstate Oil and Gas Compact Commission, 2024).

and environmental advocates generally agree that existing bond requirements are too low relative to actual end-of-life costs, and therefore existing bond policies provide inadequate incentives to ensure that wells are eventually plugged (Ho et al., 2018; Yang and Davis, 2021; McClure, Simonides and Weber, 2022).[11] Bonding requirements have evolved over decades, and state regulators are actively exploring further reforms.

In addition to financial assurance requirements, states have idle well management programs, which can include plugging requirements. These rules might, for instance, take the form of requiring that a well be capped after it has been idle a certain length of time. Penalties for noncompliance might include fines, or in the extreme, the loss of the license to operate the company's other wells.[12] Other state-level management strategies include annual fees on non-producing wells, or requirements that operators "demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status" (Interstate Oil and Gas Compact Commission, 2021, page 3).

State programs to either incentivize or enforce well plugging are limited, however. News reports give anecdotes of wells remaining unplugged despite state efforts (Aldern, Collins and Sadasivam, 2024), and similarly of low-producing wells nearing their end of life, already with unaddressed safety and environmental problems despite state enforcement actions (Albaladejo, 2024). Some of these reports specifically cite worries that if regulators push a company too hard, the company will simply declare bankruptcy and walk away (Mider and Adams-Heard, 2021; Sadasivam, 2022; Olalde, 2024).

And indeed, many wells remain unplugged. The U.S. EPA has estimated that there are 2.1 million abandoned and unplugged wells across the United States – that is, wells "with no recent production, injection, or other uses" where the site has not been stabilized and environmental remediation has not been completed (U.S. Environmental Protection Agency, 2020; Raimi et al., 2021). About 120,000 of these wells are documented orphaned wells, meaning that the state has determined that the operator is insolvent or unknown, with an additional 310,000 to 800,000 wells believed to be orphaned but not yet documented (Boutot et al., 2022; Merrill et al., 2023). In 2024, a federal report on the orphaned wells program estimated that the social cost of methane emissions from unplugged orphaned wells alone (that is, not including non-producing wells with known operators) could be as large as $1 to 2.2 billion per year (U.S. Department of the Interior, 2024).[13]

[11] In theory, landowners might also negotiate bonding requirements with well operators directly. These arrangement may be limited in practice, however. For example, the separation of surface rights and subsurface rights – a "split estate" – may reduce the bargaining power of surface owners (Weber et al., 2021; Collins and Nkansah, 2015).

[12] For instance, California's A.B. 1866 (signed into law in 2024) escalates existing fees for unplugged idle wells.

[13] The report's calculations include both climate damages and ozone-related health impacts, applied to

3 Conceptual Framework

To fix ideas, we adapt the model in Boomhower (2019) for a dynamic setting with well transfers. Each firm i produces oil and gas from wells in its portfolio, given by the set $\{J_{it}\}$ in period t. Well-level production depends on both well quality ρ_{jt} and firm technology A_i, such that $q_{ijt} = A_i\rho_{jt}$, where q_{ijt} is the quantity of oil and gas produced from well j in period t. This complementarity between project quality and firm technology follows recent literature on assortative matching in mergers and acquisitions (Rhodes-Kropf and Robinson, 2008).

Well quality is given by $\rho_{jt} = \rho_{j0}\exp(-d(t-t_{0j}))$, where ρ_{j0} is exogenous site quality, d is the decline rate, and t_{0j} is the initial drilling time for the well. Thus current well-level quality is a function both of time elapsed and of idiosyncratic initial quality. One consequence of the persistent decline in well-level production is that $\rho_{jt} > \rho_{j,t+1}, \forall j, t$.[14] We assume an exogenous world price p for oil and gas.

There are two types of firms: type H makes costly investments in superior technology, incurring per-period fixed cost F_H and producing with technology A_H; type L has fixed cost F_L and technology A_L. We assume $F_H > F_L$ and $A_H > A_L$. Firms pay variable costs that depend on the number of wells in the firm's portfolio k; variable costs are given by $c(k)$, with $c'(k) > 0$ and $c''(k) > 0$.

Each well faces a per-period risk of environmental incident, which requires cleanup at cost ω_{jt}. We assume that cleanup costs are independent and identically distributed across wells and periods, with expected value equal to ω_{avg}. If no incident occurs, then $\omega_{jt} = 0$. We assume that an environmental incident produces social damages if not cleaned up; damages are greater than cleanup costs, so it is socially beneficial to clean up after an incident.[15]

Total per-period profits from firm i's producing wells are given by:

$$\pi_{it} = \left(\sum_{j\in\{J_{it}\}} pA_i\rho_{jt} - \omega_{jt} \right) - c(k_i) - F_i \tag{1}$$

both documented orphaned wells and estimated undocumented orphaned wells; for climate impacts alone, the range is \$0.7 to \$1.6 billion per year. Using a lower methane emissions rate from Williams, Regehr and Kang (2021) (which we use in our back-of-the-envelope welfare assessment), total estimated damages are \$190 to \$410 million annually, or \$130 to \$290 million including only climate impacts.

[14] While our conceptual framework does not allow for restimulation, our empirical analysis of production volumes allows for such (temporary) quantity increases over time.

[15] Formally, let potential social damages D_{jt} be independent and identically distributed across periods and wells, with the distribution of D_{jt} first-order stochastic dominant over the distribution of ω_{jt}. Damages are realized only if an environmental incident occurs but cleanup does not occur.

Additionally, the marginal surplus associated with firm i operating well j is given by:

$$\Delta\pi_{ijt} = pA_i\rho_{jt} - \omega_{jt} - c'(k_i) \tag{2}$$

At the start of each period, firms ("operators" in industry parlance) choose whether to sell ("transfer") a well to another firm or to produce from the well in that period. There are no transaction costs associated with transfers. Given free entry of both H-type and L-type firms, one implication of the option to transfer wells is that each well will be operated by the firm type that extracts the maximum surplus from the well, and each firm type will operate at its efficient scale k_i^*. Moreover, in equilibrium, $k_H^* > k_L^*$; that is, H-type firms operate a larger number of wells than L-type firms. See Appendix Sections A2.1, A2.2, and A2.3 for the full derivation of these results.

Each well faces some "economic" end of life T_{ij} (following industry terminology), at which the well no longer creates positive expected surplus.[16] At this point, operators are responsible for plugging wells at cost χ. If operators do not plug wells, then the decommissioning process falls to the state at a cost of X, if it occurs at all. If end-of-life costs are not paid, wells continue to incur a per-period risk of environmental incident. We assume $\chi < X < \frac{\omega_{avg}}{1-\beta}$. That is, it is less socially costly for firms to pay end-of-life costs than for the state to pay, and it is less socially costly for the state to pay than for the well to remain unplugged indefinitely.[17]

We assume that the opportunity to drill new wells at cost I arises exogenously over time, with a finite number of new drilling opportunities per period. Because firms maximize surplus at k_i^*, firms will drill a new well in the period after transferring or retiring an existing well to maintain their overall portfolio size.

[16] Formally, T_{ij} is defined such that $pA_i\rho_{jT_{ij}} = c'(k_i) + \omega_{avg}$.

[17] The firm's lower cost of plugging relative to the state may reflect the fact that the firm has greater knowledge of well and site characteristics, and the regulator must expend costly public resources to pay for plugging. More generally, this assumption may reflect that end-of-life cleanup costs may be lowered when the firm internalizes those costs and therefore faces an "incentive to take care," though we do not model costly safety effort directly.

3.1 Transfers due to productive reallocation

The change in marginal surplus associated with transferring well j from firm H to firm L is given by:[18]

$$\Delta\pi_{Ljt} - \Delta\pi_{Hjt} = \underbrace{p(A_L - A_H)\rho_{jt}}_{<0} - \underbrace{(\frac{F_L + c(k_L)}{k_L} - \frac{F_H + c(k_H)}{k_H})}_{<0 \text{ for } k_H > k_L} \tag{3}$$

Proposition 1. *There exists a well production threshold $\bar{\rho}$ such that wells are more profitably operated by L-type firms than H-type firms.*[19]

Proof. See Appendix Section A2.4. □

Since ρ_{jt} monotonically decreases to 0 over time, $\bar{\rho}$ would eventually be crossed for each well j. Once $\bar{\rho}$ is crossed, the well is more profitably operated by an L firm. However, $\bar{\rho}$ may not be crossed before the well reaches its economic end of life.[20] Therefore, there are three possible equilibria for each active well, depending on parameter values: the well is always operated by an L firm ($\rho_{j0} < \bar{\rho}$); the well is always operated by an H firm ($\bar{\rho}$ occurs after the well reaches the end of its economic life); or the well is first operated by an H firm and then transferred to an L firm ($\rho_{j0} \geq \bar{\rho}$ and $\bar{\rho}$ is crossed before the economic end of life).[21] In the discussion that follows, we focus especially on the equilibrium where a well is transferred from firm H to firm L, as it is most relevant for our empirical results.

Corollary 1.1. *If a well is transferred from H firm to L firm, the impact on remaining well-level production is ambiguous. On the one hand, L firms have a less effective production technology ($A_L < A_H$), so production volumes decrease in each period relative to a no-transfer counterfactual. On the other hand, L firms extend the economic life of a well ($T_{Lj} > T_{Hj}$), so the number of producing periods increases. The net effect of the intensive and extensive margin responses is ambiguous.*

Proof. See Appendix Section A2.5. □

[18] Because revenues are invariant to the scale of the firm and average costs are equal to marginal costs in long-run equilibrium, we can also write marginal expected surplus as $\Delta\pi_{ijt} = pA_i\rho_{jt} - \frac{F_i + c(k_i)}{k_i}$, which gives rise to the equation in the text. See Appendix Section A2.2 for additional details.

[19] This proposition is adapted from Boomhower (2019) for a dynamic setting.

[20] If the well reaches the end of its economic life before reaching $\bar{\rho}$, then $\bar{\rho}$ represents the threshold at which profits are *less negative* if the well is operated by firm L.

[21] Free entry of H and L firms and finite new drilling opportunities ensure that a) all drilling opportunities will be exploited; b) all wells with $\rho_{jt} \geq \bar{\rho}$ will be operated by H firms (provided they have not yet reached their economic end of life), and all wells with $\rho_{jt} < \bar{\rho}$ will be operated by L firms; and c) firms will hold wells in their portfolio until they reach $\bar{\rho}$ or the economic end of life, whichever occurs first (for H firms), or until they reach the economic end of life (for L firms).

For wells that are transferred from H firms to L firms, there are two sources of productive reallocation. First, production costs are lower for small firms. Second, lower production costs mean that the economic end of life is reached later. These benefits are mitigated somewhat by the lower per-period production quantities due to L firm's inferior technology. Note that we have not yet introduced market imperfections in the model, so productive reallocation through transfers increases social surplus.[22]

3.2 Transfers due to liability shielding

Now we introduce the option to declare bankruptcy at the firm level. Bankruptcy could occur for two reasons: 1) to avoid paying unexpected environmental incident costs ("unanticipated bankruptcy") or 2) to avoid paying known end-of-life costs ("anticipated bankruptcy").[23] We use the term "bankruptcy" throughout this section to be consistent with the literature on the judgment proof problem. In practice, rather than formally filing for bankruptcy, firms may simply stop reporting to the state and meeting other compliance obligations, leaving state regulators uncertain about the identity or whereabouts of the responsible party.[24]

Lemma 1. *An operator's willingness to pay end-of-life and environmental incident cleanup costs is increasing in the expected continuation value of its overall portfolio, where the expected continuation value is defined as the expected surplus from each of the firm's current and future wells over their remaining lifetime, less end-of-life cleanup costs.*

Proof. See Appendix Section A2.7. □

Lemma 2. *H firms have higher expected portfolio continuation value than L firms.*

Proof. See Appendix Section A2.6. □

To build intuition, consider the extreme case where the operator owns only one well. In this case, receiving a scrap value of 0 is more profitable than paying plugging costs of χ, so the operator of a single well will declare bankruptcy when the well reaches the end of its economic life at T_{ij} (or before, depending on the realization of environmental incidents).

Likewise, if the operator owns a portfolio of multiple wells but $T_{ij} = \tau$, a constant, $\forall j \in \{J_{it}\}$, then the operator will also find it optimal to declare bankruptcy rather than pay

[22]We ignore externalities associated with the *use* of oil and gas, such as greenhouse gas emissions from burning fossil fuels.

[23]Note that this formulation is a departure from the standard judgment proof literature, which focuses on firms being judgment proof against harms from unexpected accidents – but one that we think is appropriate for this setting in which end-of-life costs are reasonably well known in advance and often left unpaid.

[24]Indeed, state definitions of orphaned wells encompass cases where the operator of record cannot be traced, not merely cases where the operator of record has formally filed for bankruptcy.

end-of-life cleanup costs, which are all due in the same period. This idea leads to our next theoretical result.

Proposition 2. *In equilibrium, L-type firms will acquire correlated portfolios, with* $T_{ij} = \tau$ $\forall j \in \{J_{it}\}$.[25] *End-of-life costs will not be paid in equilibrium, as operators will find it optimal to declare bankruptcy instead.*

Proof. See Appendix Section A2.8. □

By transferring aging wells to L firms, H firms are able to extract additional private surplus in a limited liability regime by avoiding end-of-life costs (and potentially costs of environmental incident cleanup) that they would otherwise expect to pay. Indeed, in this set-up, H firms receive *all* of the private surplus associated with these avoided costs, given fixed-cost drilling opportunities paired with free entry of L firms.[26] In contrast to productive reallocation, which increases both private and social surplus, this source of private transfer surplus represents an externality that reduces social surplus. Moreover, our model predicts that L firms will organize their portfolios to maximize these externalized costs.

Our conceptual framework therefore develops two explanations for why wells might be transferred in equilibrium – productive reallocation and liability shielding – and particularly why aging, low-value wells might be transferred. We next turn to empirical results documenting the patterns of well transfer that we observe in practice.

4 Data and Summary Statistics

To study asset transfers of oil and gas wells, we assemble a rich panel dataset from state regulators in four major oil and gas producing states: California, Colorado, Pennsylvania, and Texas. Data from state regulatory agencies is necessary because commercial datasets with nationwide coverage, such as Enverus, do not maintain past histories of well operators. These four states, however, maintain a history of well operators, which is necessary for identifying asset transfers. These states also maintain histories of well plug dates, whereas commercial sources such as Enverus merely report current plugged status. State regulators

[25] In the parameter space where wells are most profitably operated by H firms over their entire economic lifetime, our model would also predict that H operators would acquire correlated portfolios to avoid paying end-of-life costs. However, this endeavor may be more challenging for H firms than L firms in practice, due to the capital requirements for drilling a large portfolio of wells at once, frictions in acquiring a large quantity of correlated wells, and so forth.

[26] See Appendix Section A2.6 for additional details. While a stylized result, there are also reasons to believe H firms would extract a greater share of transfer surplus in the real world, including surplus from avoided end-of-life and other liabilities. Large oil and gas firms are more concentrated than small producers and have more sophisticated management and legal teams.

collect information on well operators, production levels, and plugging status for tax and royalty purposes and for environmental monitoring.[27]

These four states together represent around half of US oil and gas production;[28] they cover major conventional and unconventional oil and gas regions such as the Permian basin and Marcellus formation; and they allow us to examine both regions with declining production and a large number of aging wells (notably, California) and areas with a mix of newer and older wells (such as Pennsylvania). Our panel is unbalanced, based on the time periods that state agencies have made publicly available: California covers 1977-2023;[29] Colorado, 1999-2021; Pennsylvania, 1997-2023;[30] and Texas, 1993-2021.

A time series of oil and gas production from each state is shown in Appendix Figure A1. Our observed oil production closely matches annual totals reported by the US Energy Information Administration (EIA). Across the four states, we see a range of patterns over time: California oil production peaked in the mid-1980s and has steadily declined. In contrast, Colorado and Texas oil production has sharply increased since around 2010. In Pennsylvania, we see low oil volumes overall.[31] For gas production, our totals are generally within five percent of the annual totals reported by EIA; the state-level time paths of our variables also match what is reported by EIA. Just as with oil production, California has seen a steady decline in gas production, whereas the other three states have seen an increase: a gradual increase over time in Colorado and Texas, and a sharp increase post-2010 in Pennsylvania.

We augment the state data with additional well characteristics from Enverus, including elevation, well depth, drilling type (e.g., horizontal or vertical), peak production volumes, and spud date. We also combine the well-level data with oil and gas prices from the EIA. For natural gas, we observe both Henry Hub prices and citygate prices; for oil, we observe both West Texas Intermediate prices and first purchase prices; for condensate, we observe natural gas liquid composite prices.

Assembling the four different states into one panel requires significant effort to harmonize data definitions and reporting processes. Here we briefly describe key differences across the

[27]We note that while plugging requirements may be imperfectly enforced, one state regulator explained to us that public records on well plugging are likely to be reasonably comprehensive, given operators' strong incentives to ensure that any plugging activity is recorded by state regulators.

[28]Together, these four states constitute around 40 percent of oil and gas production over 1993-2023; over 2020-2023, the percentage is around 50 percent.

[29]In practice, we limit most of our empirical analyses to 1991-2023, since transfer reporting is limited before 1992. See Data Appendix for additional details.

[30]Earlier data are available for Pennsylvania on the state agency's website, but they appear to be incomplete: annual state-wide production totals do not match totals in EIA reports. We were unable to obtain more complete data for the earlier years.

[31]The jump up in recent years is driven an increase in condensate from unconventional wells (reported jointly with oil in Pennsylvania).

state-level datasets; additional details about each state's data are provided in the Data Appendix. First, in Colorado, Pennsylvania, and Texas, we identify operator transfers based on changes in the unique operator identifier within a state over time. In California, by contrast, we have a separate dataset of operator transfers. Second, although for simplicity we refer to a well as the unit of observation, the Texas production data are provided at the lease, not well level. Third, we observe annual production for conventional wells in Pennsylvania and semi-annual production for early unconventional wells, while all other production information is provided at the monthly level. Fourth, the four states have slightly different reporting conventions for natural gas liquids and condensate. The Data Appendix describes how we handle each of these reporting differences across states, as well as other decisions about data construction such as handling of outliers.

An important limitation of the production datasets provided by the states is that wells tend to cease reporting after they stop producing. Regression analysis using these datasets as-is would thus systematically exclude non-producing wells. To address this, we expand the dataset to create a quasi-balanced panel that continues to track wells in *all* years after production begins ('quasi-balanced' because we do not track wells before they begin reporting production). For this constructed panel, we infer production and plugging status, but we are unable to infer operator identity (except in California, where we have a separate dataset of transfers). For a small number of wells, production and plugging status are ambiguous; see Data Appendix for details.

Summary statistics at the well-by-year level are provided in Appendix Tables A1 and A2. Our data includes a mix of oil-only, gas-only, mixed oil and gas, and zero-production wells. Our study period covers years with both high and low oil and gas prices. We show both median and mean values of variables in our dataset, as production quantities and revenues exhibit significant skew.

Our data reinforce that a significant portion of wells in the United States are operating at low volumes, with low current revenue and low expected future profitability. As shown in Table 1, the median well in our sample receives only $29,000 in annual revenue (or $61,000 when excluding non-producing wells).[32] Both values are substantially lower than the *average* revenue ($222,000 across all wells, $283,000 across producing wells). Wells typically earn substantially larger annual revenues at their peak production ($686,000 at the median well, and $2.3 million at the average well); indeed, the median well brings in roughly as much revenue during its peak month as it does during a typical year throughout its life.[33] However,

[32] $29,000 is our sample-wide median; note that the median in recent years is even lower.

[33] These values represent revenue during the 12-month period of maximum production, limiting the sample to wells for which we observe initial production. Note that median revenue for wells where we observe initial production is approximately twice as large as median revenue for all wells (see Appendix Table A3). Finally,

Table 1: Many wells have low production and low profitability

	N	Median	Mean
Annual revenue (dollars), all wells	10,514,093	28,584	221,718
Producing wells	7,372,605	60,580	282,795
Producing wells, 2018-2023	1,565,111	37,002	365,959
Revenue at time of maximum 12-month production	373,586	685,827	2,297,174
Continuation revenue (lifetime), all wells	10,513,837	79,015	631,199
Producing wells	7,372,605	184,487	805,065
Producing wells, 2018-2023	1,565,111	107,776	894,538

Note: A unit of observation is a well-year, covering four states (unbalanced) over the period 1991-2023. Wells known to be plugged are not included. Revenue is calculated using quantities reported to state agencies and prices from EIA; and various estimates of continuation revenue are calculated using assumptions on future well decline and future commodity prices. The sample size decreases for maximum revenue because we have only one *initial* observation per well, rather than a panel over time, and we because we drop wells that initiated production before 1991 (such that their maximum production could have occurred before our sample begins). Alternative assumptions and subsamples are provided in the Appendix.

the population of wells in our sample – and across the United States more broadly – includes many older sites.

Because the difference in peak revenue versus revenue over the rest of a well's life is driven by the decline curve that a typical well follows, expected *future* profitability is also low for many wells in our sample. To illustrate, we calculate the continuation revenue – expected (discounted) revenue over the well's remaining lifetime – for each well in our sample, under plausible assumptions about decline curves, future oil and gas prices, and discount rates. As shown in Table 1, our preferred estimate of continuation revenue is $79,000 for the median well in our sample ($184,000 for the median producing well), about three times current annual revenues at the median well.[34] Understanding the behavior of this large stock of low-producing, low-profitability wells remains understudied in the literature, with policy implications for well clean-up and for the broader energy transition.

revenue during the 12-month period of maximum production is around $686,000; dividing this amount by twelve gives a conservative approximation of production in the peak month.

[34]We use continuation *revenue* here and in the analysis that follows rather than continuation *value* as in our conceptual framework. This choice was made for transparency: we do not observe differences in operating costs, so differences in estimated continuation values would ultimately stem from differences in estimated continuation revenues. To obtain an approximate magnitude of continuation value, industry reports suggests ongoing operations and maintenance costs on the order of $25,000 to $85,000 per year, suggesting that many wells are close to break-even. And typical plugging costs are on the order of $22,000 to $180,000 – with both lower and higher values also documented – depending on location, well characteristics, and whether surface remediation costs are included; see Data Appendix for additional discussion. Note these plugging costs are not much lower than – and in some cases may exceed – continuation revenues.

5 Empirical Results

We next turn to an empirical investigation of transfers across the well lifecycle.

5.1 Well transfers are common

Empirical analysis of well transfers is largely missing from the economics literature, so we begin by providing descriptive evidence on the frequency of well transfers. We first document that asset transfers are observed frequently in the data: this finding is important both because it suggests that transfers are an important component of oil and gas markets and because it implies that we have statistical power for additional empirical analysis.

Table A4 in the Appendix shows that wells are frequently transferred. We consider three definitions of a transfer, all inferred from a change in the operator identifier from one year to the next. Our preferred definition counts as a transfer any change in operator *except* where the old and new operator names are similar (e.g., Diversified Oil & Gas LLC and Diversified Production LLC) or where the well transfer was part of a prominent merger (e.g., Chevron-Texaco in 2001); we also exclude transfers before production begins.[35] We do not consider these excluded transfers to be "typical" as many represent corporate reorganizations rather than true transfers from one operator to another. Using our preferred definition, 7.8 percent of wells experience a transfer in a typical year, or around one transfer per well every 13 years.

We also consider, here and throughout our analysis, two alternative definitions of a transfer. Our broadest definition includes *any* change in the operator identifier, even if the names are similar or it was part of a known merger. By this definition, the typical well experiences a transfer every ten years. Our narrowest definition of a transfer begins with our preferred definition, but then further excludes transfers to newly created firms, transfers from disappearing firms, and transfers immediately after the start of production. By this measure, the typical well experiences a transfer approximately every 21 years.

By any of our three definitions, transfers are frequent, occurring in five to ten percent of years for a typical well. Using our preferred definition, we observe around 20,000 to 30,000 well transfers in a typical year, and hundreds of thousands of transfers across our sample as a whole. Finally, Appendix Table A4 shows that transfers are common in various sub-samples – by state, time period, commodity type, well size, well age, and production status. Below we analyze the characteristics of wells that are transferred more often, but Appendix Table A4 shows that well transfers are not limited to any particular kind of well.

[35] One industry analyst told us that internal reorganizations from the initial drilling stage to the production stage can appear as changes in operator identifier but do not involve true changes in operator.

5.2 Low-value wells are transferred more often

Both industry and environmental groups have noted that well transfers are common for low-production wells. In industry reports, this pattern is described as part of the "food chain" of oil and gas production. Before exploring the potential reasons for transfers of low-producing wells, we first document that the likelihood of a transfer does indeed increase as well production declines.

Our descriptive regression takes the form

$$s_t = \beta_1 r_t + X_t \Theta + \varepsilon_t \tag{4}$$

where s_t is an indicator for whether the well experiences a transfer in a year; r_t is some measure of well value or age; and X_t is a suite of controls. The unit of observation is a producing well in a year. Standard errors are two-way clustered by well and by year.

To illustrate this regression, Figure 1 shows the correlation between transfer frequency and well continuation revenue (the latter in logs) after accounting for basin effects (e.g., California has four basins; Texas has 17), well type effects (gas-only versus oil-only versus mixed, and horizontal versus vertical versus directional), and a linear time trend.[36] Transfer likelihood declines with estimated continuation revenue: lower value wells are transferred more often, and higher value wells are transferred less often. The relationship is remarkably stable across the range of continuation revenues that we see in our 7 million observations.

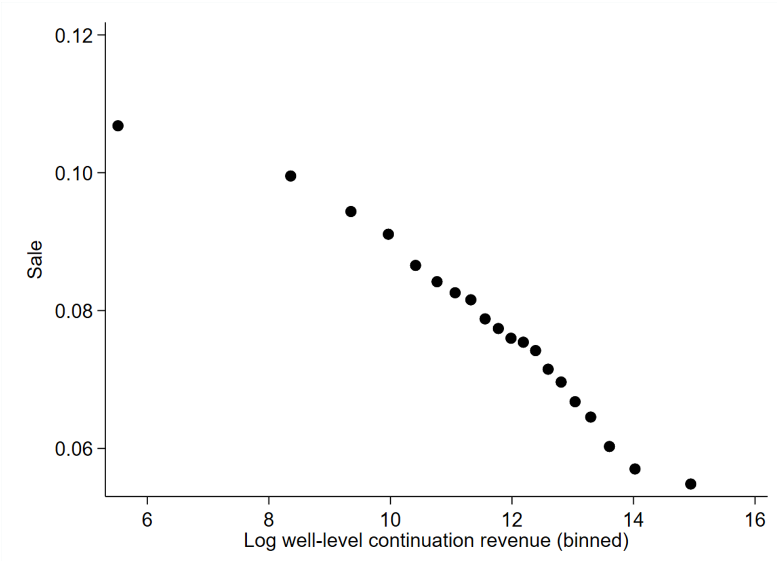
In these regressions, we would like to interpret the right-hand side variable r_t as exogenous to transfer decisions. Our primary measure of well value r_t is the well's continuation revenue, which depends on well production, decline rates, and commodity prices. The well's production trajectory is largely determined by the well's life-cycle and the geology of the site, given the decline rate inherent at each well (Anderson, Kellogg and Salant, 2018).[37] Similarly, commodity prices are also close to exogenous to operator decisions, under the assumption that operators are price-takers in larger oil and gas markets.[38] To verify that the declining value over the well life cycle is driven primarily by factors exogenous to transfers, Appendix Table A5 shows results using well age (in logs) as the independent variable of interest. In that analysis, we find that older wells are more likely to be transferred, consistent with the Figure 1.

[36] Our sample of interest in this analysis is wells with positive production, so we do not have a problem with taking logs of zero values.

[37] Production levels could also depend on operators if different operators have different rates of well restimulation and/or different thresholds for shutting in wells; we explore the impact of transfers on these production outcomes below.

[38] Prices may also respond to aggregate shocks common to many wells (as indeed, they did when the fracking revolution took hold) which may be related to transfer decisions.

Figure 1: Low-value wells are transferred more often



Note: This graph shows transfer frequencies against expected future revenues. The sample consists of 7 million well-by-year observations, covering 1992 to 2023 (unbalanced across states, depending on data availability). The binned continuation revenue variable is the residual expected future revenue after conditioning on various well characteristics and a time trend. See text for details. Comparable regression versions are shown in Table 2, with robustness checks in Appendix Table A5.

In both Figure 1 and our regression analysis, our control variables include basin effects, well type effects, and a linear time trend. Ideally, our controls would be very fine-grained: well effects to control for heterogeneity in time-invariant well quality, and year effects to account for broad market trends. However, this specification leads to an age-period-cohort problem.[39] As such, we do not estimate a specification with both well effects and year effects.

Instead, to address the age-period-cohort problem, we explore several specifications with various combinations of controls. We begin with the specification from Figure 1 (basin effects, to account for regional differences in geology; well type effects, to account for differential profitability across oil, gas, and mixed wells, and across horizontal versus vertical wells; and a time trend, to account for broad national changes in the oil and gas market), to which we add time-invariant well characteristics.[40] These well characteristics include depth, ground elevation, peak oil production, and peak gas production (all from Enverus). We interact these controls with indicators for whether the variables are missing in Enverus, so as not to drop observations with imperfect coverage in Enverus. We also interact these controls with a Texas indicator, as these variables measured at the lease level have different interpretations than when measured at the well level.

Remaining variation thus comes from idiosyncratic well quality within a basin and a well type, conditional on time-invariant characteristics such as peak production and well depth; from idiosyncratic variation in well decline rates, again within a basin and well type and conditional on time-invariant observables; and from regional price shocks that deviate from national trends. We then consider two specifications with alternative fixed effects: one that uses type-by-year and basin-by-year effects, and one that uses well effects with a time trend.

Table 2 shows the estimated β_1 coefficient from Equation 4 for these alternative specifications. Given the age-period-cohort problem and because the primary identifying variation in prices is a national time series, there is not an obvious ex-ante preferred set of fixed effects. But across all four specifications, we find that low-value wells are more likely to be transferred, consistent with our conceptual framework. The estimated coefficient of interest is quite stable, ranging from -0.005 to -0.007. To put the magnitude in context, a well moving from the 75th to the 25th percentile of (non-zero) continuation revenue is around 2

[39] To illustrate, consider a specification in which age (in levels) is the right-hand side measure of interest: we seek to determine if wells are transferred more often as they age and exogenously transition to low production. However, age is an exact linear combination of well effects (cohort) and year effects (period). Using production levels or continuation revenue (or age in logs) as the dependent variable partly alleviates this problem but also partly masks it: we still want to rely for identification on exogenous declines in well productivity as wells age, which fundamentally has an age-period-cohort problem, even when we do not have an exact linear combination of right-hand side variables.

[40] Robustness checks in the Appendix also show a specification that matches Figure 1, i.e. without the additional time-invariant well characteristics.

Table 2: Low-value wells are transferred more often

	(1)	(2)	(3)	(4)
Continuation revenue (log)	-0.007***	-0.005***	-0.005***	-0.006***
	(0.001)	(0.001)	(0.001)	(0.001)
Observations	7,322,374	7,322,374	7,322,001	7,291,190
R^2	0.01	0.03	0.08	0.10
Controls	Well characteristics	Well char.	Well char.	[Well char. subs.]
	Well type	Well type		Well effect
	Basin	Basin	Type-basin-year	[Basin subs.]
	Time trend	Year effect		Time trend

Note: The negative coefficient on (log) continuation revenue implies that high-value wells are transferred less often, i.e., low-value wells are transferred more often. The unit of observation is a well in a year. The dependent variable is an indicator for a well transfer. The independent variable of interest is expected continuation revenue, logged. All columns include controls; see text for details. Alternative specifications are given in Appendix Table A5. Standard errors are two-way clustered by year and by well.

percentage points more likely to be transferred, relative to a mean annual transfer rate of 8 percent for wells with positive production.

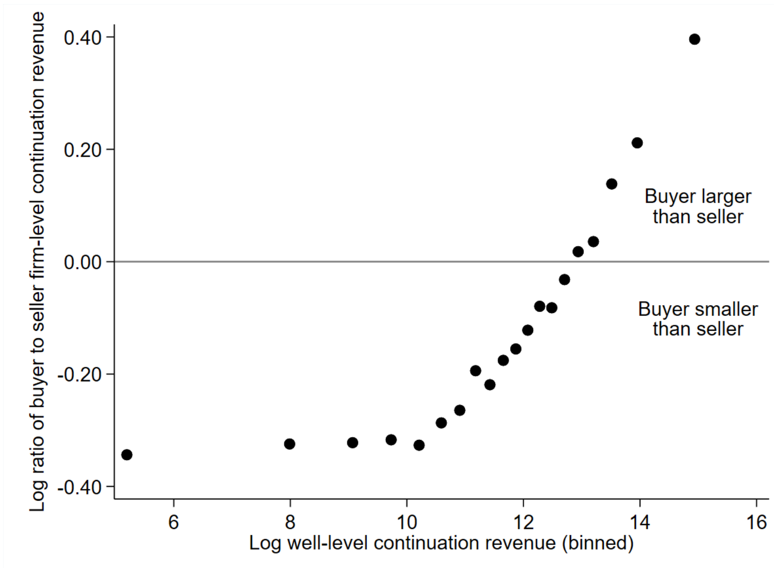
In Appendix Table A5, we consider a suite of alternative specifications. These include alternative right-hand side variables (e.g., production levels or age); alternative sub-samples (e.g., recent years only, or specific states); alternative controls (e.g., adding field effects); and alternative scaling and weighting by the number of wells on Texas leases. The results are remarkably stable across these specifications.

5.3 Low-value wells are transferred to low-value firms

We next ask: when wells are transferred, who are the new operators? Our conceptual framework predicts that low-value wells will be transferred to low-value firms, but the extent to which this bears out in real-world data has not been comprehensively documented. We first construct a new variable at the firm-by-state-by-year level: the aggregate continuation revenue of all the wells operated by the firm, as an additional measure of firm value. Because firm identification numbers are not harmonized across states, we are limited to a measure of firm value within each state. We then take the log of the ratio of buyer to seller size. A ratio greater than one (i.e., a log ratio greater than zero) indicates that the buyer is larger than the seller. For the sample of wells that are transferred in any year, we then examine the descriptive relationship between this buyer-seller ratio and the value of transferred wells.

We begin by plotting, in Figure 2, the log ratio of buyer to seller size against the log

Figure 2: Low-value wells are transferred to low-value firms



Note: This figure shows the logged ratio of buyer to seller continuation revenue plotted against the logged continuation revenue of a transferred well (binned). The sample consists of roughly 570,000 well-by-year observations, covering 1992 to 2023. The binned continuation revenue variable is the residual expected future revenue after conditioning on various well characteristics and a time trend. See text for details. Comparable regression versions are shown in Table 3, with robustness checks in Appendix Table A6.

continuation revenue of the transferred well. We again control for basin effects, well type effects, and a linear time trend. Figure 2 shows a clear, strong relationship: high-value wells are involved in transfers where the buyer is relatively larger; low-value wells are involved in transfers where the buyer is relatively smaller. The binscatter line crosses a buyer-seller ratio of zero at roughly the 75th percentile of well-level continuation revenue. That is, top-quartile wells are involved in transfers where the buyer is larger than the seller, and wells below the top quartile are involved in transfers where the buyer is smaller than the seller. At the 25th percentile of continuation revenue, the predicted ratio of buyer to seller size is approximately 0.7.[41]

We then formalize our analysis of this relationship with regression specifications similar to those used in the previous section:

$$f_t = \beta_1 r_t + X_t\Theta + \varepsilon_t \tag{5}$$

where f_t is the log ratio of buyer to seller continuation revenue; r_t is well-level continuation

[41]That is, $\exp(-0.3) = 0.7$.

revenue; and X_t is a suite of controls. The unit of observation is a well in a year, conditional on the well experiencing a transfer in that year. As before, mindful of the age-period-cohort problem, we show four specifications with differing combinations of well and time controls. Other controls again include well depth, ground elevation, peak oil production, and peak gas production, all interacted with a Texas indicator. We again two-way cluster standard errors by well and by year.

Table 3 shows our results. Across all four columns, we see that the ratio of buyer to seller size is positively correlated with the continuation revenue of transferred wells. The magnitude varies with the controls we include. In the baseline specification, with basin effects, type effects, various time-invariant well characteristics, and a time trend, the coefficient on log continuation revenue is 0.09, statistically significant at the one-percent level. To understand the magnitude, suppose that a selling firm offloads two wells and that one of the wells is 10 log points smaller than the other well. The smaller well would be predicted to go to an operator that is 0.9 log points smaller than the operator acquiring the larger well. When controlling for year effects, or basin-by-year and type-by-year effects, the magnitude is smaller. However, controlling for well effects, the magnitude is substantially larger. Note that when controlling for well effects, the regression is identified from wells with repeat transfers; this specification reduces the sample size and changes the interpretation, as wells with repeat transfers may be of differing quality than wells with only a single transfer. Results in Appendix Table A6 again show the robustness of this positive relationship to a variety of alternative variable construction procedures, sub-samples, and controls.

These results suggest that transfers are a mechanism by which low-value wells end up with low-value operators, while high-value wells are typically operated by high-value operators. In addition, consistent with our conceptual framework, in Appendix Table A7 we document that low-value firms are more likely to hold well portfolios with lower variance in well size, even after accounting for the number of wells in the portfolio.

5.4 Transferred wells produce similar amounts, but are less likely to be plugged

We next examine whether transfers predict the dynamic trajectory of wells, across both production and plugging outcomes. In an ideal experiment, we would randomly alter the ease with which operators are able to transfer their wells, and we would examine whether transferred wells have different long-run outcomes. However, we face the identification challenge that well transfers are not exogenously determined but are instead the result of both buyer and seller strategic priorities and cost structures.

Table 3: Low-value wells are transferred to low-value firms

	(1)	(2)	(3)	(4)
Continuation revenue (log)	0.087***	0.041***	0.029***	0.158***
	(0.012)	(0.007)	(0.005)	(0.017)
Observations	566,420	566,420	565,946	410,086
R^2	0.03	0.11	0.25	0.26
Controls	Well characteristics	Well char.	Well char.	[Well char. subs.]
	Well type	Well type		Well effect
	Basin	Basin	Type-basin-year	[Basin subs.]
	Time trend	Year effect		Time trend

Note: The positive coefficient on (log) continuation revenue implies that high-value wells are transferred to higher-value firms, i.e., low-value wells are transferred to lower-value firms. The unit of observation is a transferred well in a year. The dependent variable is the ratio of buyer to seller continuation revenue, logged. The independent variable of interest is the well-level expected continuation revenue, logged. All columns include controls; see text for details. Alternative specifications given in Appendix Table A6. Standard errors are two-way clustered by year and by well.

To come closer to a regression interpretation of how wells would have evolved with transfers versus without, we first condition on many observable well features that are likely to be correlated with the decision to transfer an asset. These characteristics include: a time-invariant measure of the well's production decline rate (the ratio of production in the first twelve months to peak production), a lagged measure of recent decline rate (median year-on-year decline over five years), lagged production volumes, a lagged indicator for whether the well is producing at all, peak production volumes, well age, well depth, and ground elevation. All controls are interacted with an indicator for whether the observation is in Texas, given that Texas production data is reported at the lease level. We also condition on the interaction of basin, well type (e.g., oil or gas production, horizontal or vertical drilling), state, and year fixed effects. Standard errors are two-way clustered by well and by operator-year (the latter with a five-year lag, to account for bundles of transfers).

The thought experiment underlying the regression analysis is to compare two wells in the same basin extracting the same commodity and on similar pre-transfer production paths – one transferred, and one not transferred – to see how production and environmental compliance evolve in the long run. Our controls for well age, well depth, and ground elevation also seek to capture observable determinants of plugging costs (Raimi et al., 2021). This regression does not completely solve the underlying problem of selection into treatment status, but it does indicate whether wells that are transferred eventually end up producing more or less, and whether they ultimately are more or less likely to be closed in an environmentally responsible way.

To improve identification of long-run transfer outcomes, we also focus on specific sets of transfers that are less likely to be driven by unobservable well characteristics or well-to-operator matching. First, we examine outcomes for wells that were transferred incidentally to large mergers and acquisitions (M&A). Specifically, we identify cases in which either operator involved in a large M&A transaction transferred a well to a third operator within three years of the M&A deal. These transfers are arguably more likely to be driven by broader strategic realignment and less likely to be driven by unobserved well characteristics. Second, we examine outcomes for wells that were transferred as part of firm creations. This approach helps to overcome the challenge that buyers typically select which wells in their portfolio to acquire – in this case, wells are transferred for reasons that are less likely to be correlated with individual well characteristics. Third, we focus on transfers that were part of firm liquidations; this approach similarly helps reduce the endogeneity of operator decisions to sell wells.

In each of these specifications, well type, year, and basin fixed effects help to control for negative (or positive) shocks to the production environment that might simultaneously change the likelihood of producing or plugging and induce M&A activity, firm liquidations, or new firm creations. Moreover, because we are interested in the long-run trajectory of a well, and because production and plugging decisions may be temporarily distorted in the immediate aftermath of a transfer, our right-hand side variable of interest is whether a transfer occurred five years prior. In the Appendix, we examine alternate lag lengths, both to test the robustness of our main result and to examine the persistence of production and plugging outcomes after a transfer. (Below we also present numerous other robustness tests, on variable definitions, controls, etc.) Across all specifications, we focus on older wells: those aged 20 and older, which means we consider transfers that occurred at ages 15 and older.

In Panel A of Table 4, we examine the relationship between well transfers and eventual plugging outcomes. We limit the sample to wells not currently producing, the population of interest for plugging. (Below we consider the extent to which transfers impact the likelihood of producing.) Using our main definition of transfers, we find that transferred wells are 4.6 percentage points less likely to be plugged five years later (Column 1), relative to a sample mean of 25 percent. This result is statistically significant at the one-percent level.

When limiting the analysis to transfers that are more plausibly exogenous with respect to individual well characteristics, we again find that transferred wells are less likely to be plugged, with slightly larger magnitudes than the main transfer variable (Columns 2 to 4). Negative plugging outcomes also persist at least ten years after transfers (Appendix Table A8), suggesting that these results are not easily explained by operators waiting to re-stimulate wells in the near term. Negative plugging impacts are consistent with either intentional liability shedding via transfers, or buyers of old wells being unable to afford proper plugging procedures (or both). In either case, the results support claims by environmental advocates that well transfers predict poor environmental outcomes.

Next, in Panel B of Table 4, we examine the relationship between well transfers and overall production outcomes. Industry associations often highlight positive production outcomes in discussing well transfers – keeping wells producing for longer or re-stimulating old wells, for example. In Column 1 of Panel B, we find very small increases in production at transferred wells (approximately $800 per year, assuming $4 per thousand cubic foot of natural gas, $70 per barrel of oil, and $9 per MMBtu of condensate). We cannot rule out that transferring has zero impact on production volumes, but we can rule out that transfers of older wells lead to moderately larger production volumes (over $6,600 per year at 95 percent confidence).[42] In Columns 2 to 4 of Panel B, changes in annual production range from -$1,400 to $5,200 when we limit the analysis to more plausibly exogenous transfers, though none of these estimates are statistically different from zero. Note that these production volumes do not account for production costs. These patterns also hold at least ten years after transfer (Appendix Table A12). Overall, we conclude that production volumes after transfer are similar to those of non-transferred wells. It may be that industry claims about improved production outcomes are true and the resulting production volume is too small for us to detect statistically – but we are able to rule out large increases in production across the full sample of transfers.

We also distinguish between the intensive and extensive margin of production outcomes. Panel C of Table 4 presents the relationship between well transfers and production volumes, conditional on producing at all. We again find small effects on production volumes that are statistically indistinguishable from zero. In Panel D of Table 4, the dependent variable is an indicator for whether a well is producing; we see that transferred wells are slightly less likely to be producing *any* oil or gas five years after transfers. The magnitude of this coefficient is small: transferred wells are 0.7 to 1.8 percentage points less likely to be producing five years later.

[42] Our main production outcome is the value of oil and gas production, winsorized at the 99th percentile, assuming typical prices. One potential concern with this outcome variable is that it ignores the extreme upper bound of production outcomes, which would be important with a "lottery ticket" interpretation of well transfers, where a few wells have very large positive production outcomes while others have zero or small negative production outcomes. However, we note that results are consistent when we do not winsorize production volumes but instead rescale by the number of unplugged wells on a Texas lease, using raw production volumes in all other states (Appendix Table A21). Additionally, we obtain similar results when we use raw production volumes and exclude Texas from the sample. For this reason, we view the winsorized size variable as a transparent approach to addressing outliers on Texas oil leases, rather than ignoring a "lottery ticket" interpretation of production outcomes.

Table 4: Transferred wells produce similar amounts, but are less likely to be plugged

	All transfers	Incidental to known M&A	Part of firm creation	Part of firm liquidation
Panel A: Plugging status (conditional on not producing)				
Transfer, five years prior	-0.046***	-0.053*	-0.064***	-0.049***
	(0.006)	(0.028)	(0.009)	(0.008)
Observations	1,249,902	1,249,902	1,249,902	1,249,902
R^2	0.09	0.09	0.09	0.09
Panel B: Production volumes				
Transfer, five years prior	0.834	5.150	-1.307	-1.376
	(2.951)	(11.412)	(4.585)	(3.686)
Observations	3,597,133	3,597,133	3,597,133	3,597,133
R^2	0.30	0.30	0.30	0.30
Panel C: Production volumes (conditional on producing)				
Transfer, five years prior	0.045	8.457	-1.494	-1.485
	(4.056)	(17.987)	(6.644)	(5.213)
Observations	2,346,819	2,346,819	2,346,819	2,346,819
R^2	0.35	0.35	0.35	0.35
Panel D: Production status				
Transfer, five years prior	-0.018***	-0.008	-0.013**	-0.007
	(0.003)	(0.015)	(0.005)	(0.005)
Observations	3,597,123	3,597,123	3,597,123	3,597,123
R^2	0.51	0.51	0.51	0.51

Note: The dependent variable in Panel A is an indicator for whether a well is reported as plugged by the state, conditional on not producing. The dependent variable in Panel B is well production in thousands of dollars per year, assuming typical prices. The dependent variable in Panel C is well production in thousands of dollars per year, conditional on producing at all. The dependent variable in Panel D is an indicator for whether a well is producing. A unit of observation is a well in a year. The sample is wells aged 20 years and older that were not plugged at age 15. Controls include various well characteristics and interactions of basin, well type, and year fixed effects (see text for details). Standard errors are two-way clustered by well and by operator-year at age 15. Robustness checks with alternative transfer lag lengths, alternative controls, or various sub-samples are in the Appendix.

5.5 Production and plugging outcomes follow a gradient by operator size

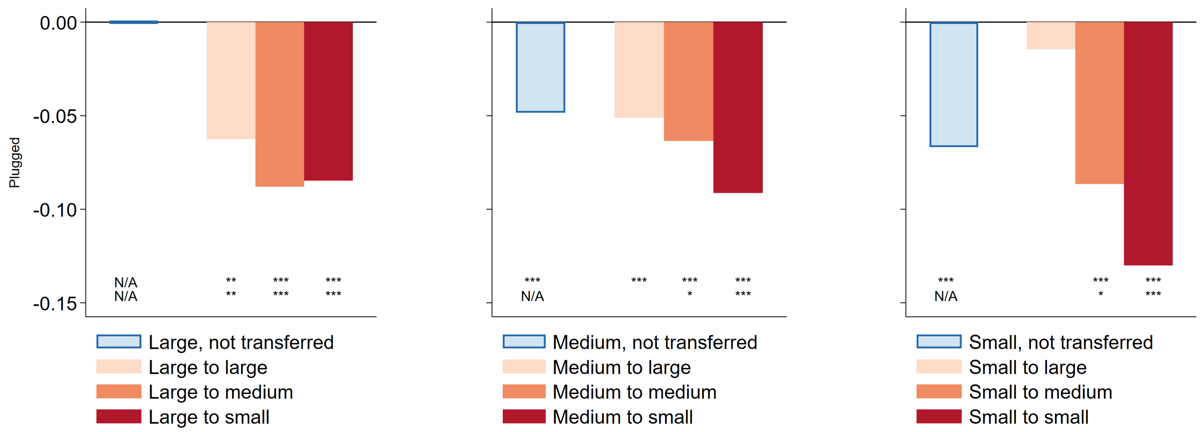
Of course, well transfers occur for many different reasons, which are amalgamated in the previous analyses of overall transfer outcomes for older wells. Our analytical model highlights the importance of transfers from larger operators to smaller operators in generating negative plugging outcomes, and predicts differential production outcomes for wells moving up versus down the operator "food chain." We next examine heterogeneous effects of transfers, using the regression analysis described in the previous section but now allowing the coefficient on transfer to vary across three bins of buyer and seller size. "Small" operators are those with annual state-wide revenues below $10 million; "medium" operators have revenues between $10 million and $1 billion; and "large" operators have revenues above $1 billion. In analyzing outcomes by operator size, we use the main transfer variable rather than transfers incidental to M&A or transfers part of firm creation or liquidation, as the numbers of transfers observed in some buyer-seller size bins are too small when limited to those specific transfer types. Consistent with the previous section, our main specifications examine outcomes for transfers five years ago, and we examine alternative lag lengths (and numerous other robustness checks, described below) in the Appendix.

Figure 3 shows plugging outcomes for transfers involving different operator sizes. The left panel shows results for wells initially operated by large firms and either not transferred or transferred to large, medium, or small operators, respectively. The central panel shows analogous results for wells initially operated by medium firms, and the right panel shows results for wells initially operated by small firms. All twelve estimates come from the same regression, and regression coefficients and numerical standard errors are provided in Column 1 of Appendix Table A28. Note that the values of the bars in Figure 3 are linear combinations of the underlying regression coefficients, such that the all the red bars represent comparisons to wells operated by large firms and not subsequently transferred (i.e., the blue bar in the left-most panel). The asterisks under each bar indicate two measures of statistical significance: first, relative to the omitted category (large, not transferred) and second, relative to not transferred wells in each initial size group.

We highlight three main findings in this figure. First, the blue bars across the three panels show that wells operated by large firms are more likely to be plugged – after controlling for a suite of well characteristics such as initial production, age, and production trajectory – followed by wells operated by medium firms and then small firms.[43] Second, the three reddish

[43] Our specification does not rule out that wells were transferred more recently than five years ago. Below we discuss an alternative analysis that directly examines plugging (and production) outcomes by most recent operator.

Figure 3: Wells transferred to smaller companies are less likely to be plugged



Note: This figure shows the likelihood of well plugging for non-producing wells, relative to a well operated by a large company and not transferred. The left panel shows wells that were initially operated by large companies; the middle panel shows wells were initially operated by medium-size companies; the right panel shows wells that were initially operated by small companies. Within each panel, the blue bar shows the plugging likelihood for wells not transferred. The reddish bars show the plugging likelihood for wells transferred five years ago to large, medium, or small companies, respectively, relative to the omitted category: wells operated by large firms and not transferred. A gradient is visible both within and across panels, with wells operated by or transferred to smaller companies less likely to be plugged. All twelve estimates are from a single regression, which conditions on various controls, matching Column 1 of Appendix Table A28 (details in text). The first line of asterisks shows statistical significance of each bar relative to the omitted category: wells initially operated by large companies and not transferred. The second line of asterisks shows statistical significance of each bar relative to the not-transferred group in each panel. Numerical standard errors are shown in Appendix Table A28.

bars in each panel show that wells transferred from large firms to medium or small ones, or from medium firms to small ones, are less likely to be plugged.[44] Third, we observe a striking gradient in the likelihood of plugging both within and across panels, as wells are transferred to smaller or larger operators. All coefficients are statistically different from both comparison groups, except those for transfers from small or medium operators to large ones.

At first glance, it may appear puzzling that wells transferred from large sellers to large buyers also exhibit negative plugging outcomes relative to wells not transferred from large sellers, albeit lower in magnitude than wells transferred from large operators to small or medium ones. However, we note that these effects do not persist: by ten years after transfer, we see no negative impact of large-to-large transfers on plugging outcomes (Appendix Table A27). These results are therefore consistent with large companies sitting on newly acquired wells for some years before eventually plugging (or resuming production). By contrast, the negative plugging impacts of being transferred to smaller firms or being continuously operated by smaller firms do persist at least ten years after transfer.

Taken together, these estimates are consistent with small companies being less likely to plug, and with wells transferred to smaller companies also less likely to be plugged. Both results match the intuition from our conceptual framework: small companies are more likely to be "judgment proof" and therefore fail to fully internalize end-of-life costs for their wells. Likewise, transfers of aging wells are a mechanism by which well-capitalized initial operators may also fail to internalize end-of-life costs.

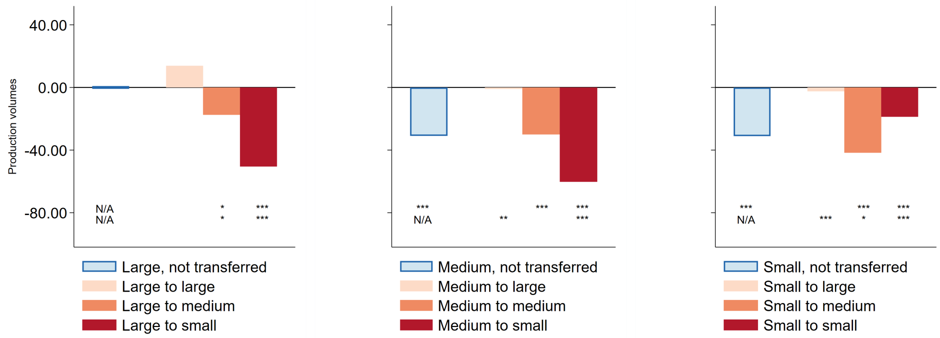
We also analyze production outcomes for transfers involving different operator sizes, with results presented in Figure 4. The top row of this figure shows annual production volumes, measured in thousands of dollars, assuming typical prices. We again find a gradient both within and across panels. Small firms produce lower overall volumes, conditioning on many observable dimensions of well quality, and these differences are statistically significant at the one-percent level. In addition, wells transferred from large or medium operators to smaller operators produce lower volumes after the transfer; these results are also statistically significant. One exception to the overall gradient is that wells transferred from small to medium operators exhibit significantly lower production volumes. Regression coefficients and numerical standard errors are provided in Column 1 of Appendix Table A30.

The bottom two rows of Figure 4 examine the intensive and extensive margin separately. The middle row shows annual production volumes conditional on producing at all. Results are similar to the previous panel; the gradient largely persists within and across panels.

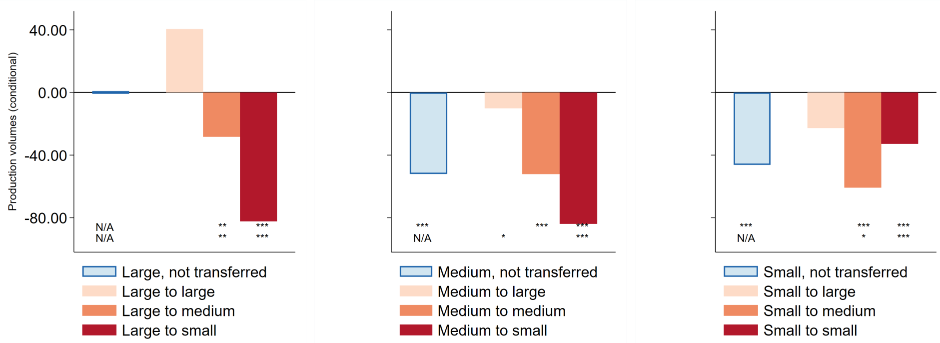
[44] Note this statement is true whether the counterfactual is a well operated by a large firm and not transferred (the blue bar in the left-most panel), or a well not transferred within the same initial operator size category (the blue bar in the same panel of interest).

Figure 4: Production outcomes for wells transferred to smaller operators

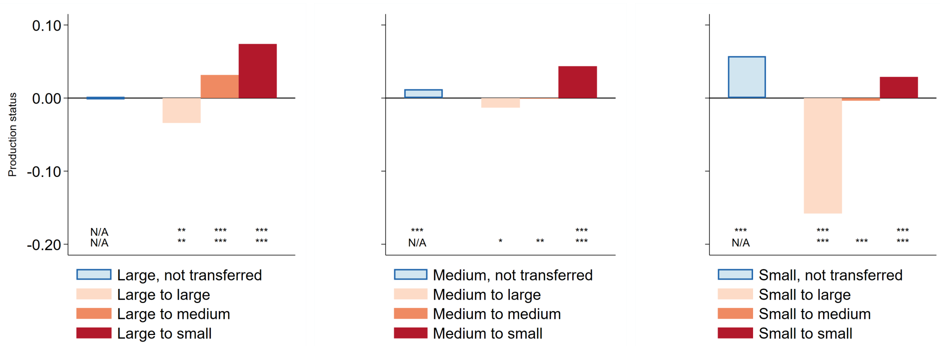
A: Production volumes



B: Production volumes (conditional on producing)



C: Production status



Note: This graph shows production outcomes relative to a well operated by a large company and not transferred, following the same structure as in Figure 3. The top two rows show production volumes in dollars, assuming typical prices; the bottom row shows the likelihood of producing any oil or gas. An overall gradient is visible both within and across panels, with wells operated by or transferred to smaller companies producing lower volumes but more likely to be producing at all. Within each row, all twelve estimates are from a single regression, which conditions on various controls, matching Column 1 of Appendix Tables A30, A32, and A34 (details in text). The first line of asterisks shows statistical significance of each bar relative to the omitted category: wells initially operated by large companies and not transferred. The second line of asterisks shows statistical significance of each bar relative to the not-transferred group in each panel. Numerical standard errors are shown in Appendix Tables A30, A32, and A34.

The bottom row of Figure 4 shows the likelihood of producing *any* oil or gas. Here, too, a gradient exists within and across panels, but in the reverse direction: small firms are more likely to be producing any oil or gas, again conditional on observable well characteristics, and wells transferred to small firms are more likely to be producing. Regression coefficients for the figures in the bottom two rows are provided in Column 1 of Appendix Tables A32 and A34, respectively.

These results are consistent with several predictions of our conceptual framework: small firms recover less quantity from a well of a given quality, but small firms are more likely to extend a well's production lifetime. In our analytical model, the net effect of the intensive and extensive margin responses is ambiguous; here we find overall decreases in production volumes for wells transferred to smaller operators over five to ten years after the transfer.

5.6 Robustness of long-run results

We next discuss extensive robustness checks on the long-run results, considering alternative subsamples, lag lengths, regression specifications, and variable definitions. We also discuss instrumental variables. We first present results for the overall effect of transfers, followed by the results on gradients across operator size.

5.6.1 Robustness: Plugging and production outcomes after transfers

We show these robustness tests for each transfer variable and each outcome considered above, beginning with overall transfer results (i.e., not disaggregating by operator size).[45] The robustness tests are as follows. Given reporting differences between states, we drop each state from the sample to ensure that our main results are not driven solely by one state. Since Texas reports production at the lease level rather than at well level, we also closely evaluate our modeling decisions in Texas. In one alternative specification, we weight observations by the number of wells on Texas leases; in another, we limit the sample to leases with no plugged wells at the time of transfer, rather than leases where not all wells were plugged as in the main specification.

We next consider alternative definitions of each of our transfer variables: using broader or narrower definitions of transfer, using alternative transfer dates in California, using alternative M&A data sources, and limiting to transfers with only firm creation (no simultaneous firm liquidation by the other party) or only firm liquidation (no simultaneous firm creation). Other alternative specifications add or drop controls, limit the sample to wells age 15 and

[45] See Appendix Tables A8 to A9 for plugging outcomes, A12 to A13 for production volumes, A15 to A16 for production volumes (conditional on producing), and A18 to A19 for production status.

older or wells age 25 and older, and limit the sample to more recent observations (2012-2023). For our analysis of plugging outcomes, we also consider alternative definitions of plugging status: using alternative data sources in California and considering whether *any* or *all* wells on Texas leases are plugged. (The main specification uses the portion of wells plugged in Texas leases.)

Across these alternative models, results are qualitatively consistent with the discussion in the main text. Transferred wells have negative plugging outcomes overall, and the estimated coefficients are quite stable across many different specifications. For plugging outcomes, the coefficient on our main transfer variable ranges from -0.02 to -0.05, in all cases statistically significant at the one-percent level (Table A10). The coefficient on transfers with different lag lengths ranges from -0.03 to -0.09, again almost always statistically significant at the one-percent level (Table A8). Alternative transfer definitions also support the result that transferred wells are less likely to be plugged. For production volumes, estimated coefficients are consistently small and statistically indistinguishable from zero. Transferred wells are slightly less likely to be producing at all, even ten years after the transfer, though estimated coefficients are at times imprecisely estimated.

In addition to addressing unobserved selection into transfer by analyzing outcomes for specific types of transfers (incidental to M&A, part of firm creation or liquidation), we also use a price-related instrument for transfers as an alternative approach to identification. One industry consultant told us that price volatility can arrest transfers, while operators wait to see how new market dynamics will shake out. We therefore construct instruments using the absolute percentage change in WTI and Henry Hub prices. First-stage results are consistent with the above intuition: price volatility leads to fewer transfers, even conditional on current price *levels* (Appendix Tables A23-A26). Moreover, the second-stage coefficients for plugging outcomes are negative, in keeping with our OLS results in Table 4 (Appendix Table A22). However, both first-stage and second-stage power are sensitive to how we cluster standard errors: two-way clustered standard errors, as we have used throughout, indicate the regressions are underpowered, while one-way clustering at the well level yields adequate first-stage F-stats. Thus these results should be taken with a grain of salt, but they provide a reassuringly consistent picture of the impact of transfers on plugging outcomes. For production outcomes, signs of the estimated second-stage coefficients depend on the IV specification but estimates are within one standard deviation of our main text results when using two-way clustered standard errors.

5.6.2 Robustness: Gradients across operator size

We then examine robustness of the results that disaggregate by operator size, again considering alternative lag lengths and subsamples, including limiting the sample to more recent years, using different age cutoffs, and dropping each state individually.[46] Our core plugging results are robust to many alternative specifications. We continue to see a gradient in the likelihood of plugging across initial operator size, with smaller operators less likely to plug their wells. Wells transferred from large operators to small or medium ones, or from medium operators to small ones, are consistently less likely to be plugged. Across most specifications, we also continue to see the full gradient within each initial operator size, as wells are transferred to larger or smaller operators.

For production outcomes, alternative specifications consistently rule out large positive increases in production volumes for wells transferred to smaller operators. In fact, most specifications suggest negative impacts on production volumes for wells transferred to smaller operators, consistent with our preferred specification and our theoretical model. However, we caution readers against over-interpreting specific magnitudes given varying observation counts in different transfer bins and the fact that we are not able to conduct this analysis specifically for transfers incidental to M&A or part of firm creation or liquidation. Lastly, we consistently see that wells operated by smaller firms are more likely to be producing at all, as are wells transferred to smaller firms. These gradients in the likelihood of producing are quite stable across alternative specifications.

5.6.3 Robustness: Alternative approaches to evaluating operator size effects

In addition to analyzing outcomes for wells transferred between operators of different size, we also conduct a separate set of analyses that directly examine production and plugging outcomes by current operator size. These analyses complement our regressions based on nonparametric bins of operator size by exploiting continuous variation in operator size. In Column 1 of Appendix Table A35, we regress outcomes on logged operator revenue, controlling for a rich set of observable well characteristics and the interaction of well type, basin, and year fixed effects. We leave out the revenue associated with the well in question because otherwise operator revenue is mechanically related to decisions regarding whether to cease production at a well. The thought experiment is to compare two wells with similar production histories, sizes, locations, and time periods, one operated by a smaller firm and the other operated by a larger firm. Consistent with previous results, we find that wells

[46] These results are presented in Appendix Tables A27 and A28 for plugging outcomes; A29 and A30 for production volumes; A31 and A32 for production volumes (conditional on producing); and A33 and A34 for production status.

operated by small firms are less likely to be plugged when not producing, produce slightly smaller amounts, and (in some specifications) are more likely to be producing at all.

Of course, operator size is endogenous to many unobserved well characteristics, so we also instrument for operator size. In Columns 2 and 3, we instrument for operator size using recent transfers that were part of firm creation or liquidation. As in our main analyses of long-run transfer outcomes, the assumption is that these types of transfers are more plausibly exogenous to potential outcomes at the well level. For both specifications, the first stage F-stat is large.[47] With our IV specifications, we find that smaller firms are less likely to plug comparable wells, with coefficients that are larger in magnitude than our OLS results. These results are again consistent with our previous empirical findings and our analytical model. We also find that smaller firms produce lower volumes, again with coefficients that are larger in magnitude. For production status, coefficients become smaller in magnitude and imprecisely estimated.

6 Policy Implications

We conclude by tying our theoretical and empirical results to ongoing policy discussions. In our empirical analysis, we find that low-value wells are more likely to be transferred, and low-value wells specifically are more likely to be transferred to low-value operators. Both of these findings are consistent with two potential motivations for well transfers explored in our conceptual framework: productive reallocation and liability shielding. In examining long-run outcomes for transferred wells, we find that older wells transferred to smaller firms are more likely to be producing at all, which is consistent with lower operating costs for small firms. Transferred wells are also less likely to have environmental remediation completed – an outcome which is especially stark for wells transferred to smaller firms – consistent with transfers being a mechanism by which the judgment proof problem unfolds in the oil and gas industry.

At a high level, these results underscore what is already known by researchers, advocates, and regulators: requiring adequate financial assurance, for instance in the form of bonding, from the very start of a well's life would avoid the problems we have laid out regarding unfulfilled environmental obligations. Adequate bonding ensures that companies can afford to pay both unexpected accident costs and expected end-of-life plugging and reclamation costs. Details about how to implement adequate financial assurance are laid out in, e.g.,

[47]The first-stage coefficients on the firm creation and liquidation instruments are negative, reflecting the fact that wells recently part of these transfers are operated by smaller firms on average. We separately considered transfers that were incidental to large M&A deals but the first-stage was very weak – consistent with the intuition that operators involved in these transfers are more heterogeneous in size.

Boyd (2001); Davis (2015); Ho et al. (2018); and Boomhower (2019). Considering transfers as a predictable component of the well lifecycle does not alter this basic intuition. Indeed, our theoretical model implies that requiring financial assurance at the time of initial drilling would still encourage transfers motivated by productive reallocation (which increase market efficiency) while reducing incentives for transfers due to liability shielding (which do not).[48]

A challenge facing regulators today is that there are millions of wells already drilled with inadequate bond levels (Ho et al., 2018; Yang and Davis, 2021; McClure, Simonides and Weber, 2022). Our results also inform regulatory options moving forward given this problem. To understand these options, it is useful to categorize existing wells according to three common scenarios, with different policy needs. First, there are thousands of wells already orphaned. Cleaning up these wells is an active policy issue, with both state and federal initiatives, past and present, aimed at government-funded remediation.[49] Second, there are wells already operated by under-capitalized firms.[50] Third, there are wells currently operated by adequately capitalized firms, which may in the future be transferred to less-well-capitalized operators as they age, consistent with the patterns that we document. How might policymakers induce responsible end-of-life management at these existing, not-yet-orphaned wells?

One possibility is increased regulations on transfers. This approach may prevent low-value wells from being transferred to under-capitalized operators in the future, though it does not address the group of wells that have already experienced such a transfer. These regulations could include, for example: (1) increased scrutiny of new operators' ability to cover future environmental costs,[51] or (2) increased bonding at the point of transfer. In the absence of other market frictions, our theoretical framework suggests that such regulations would reduce transfers that are motivated by liability shielding without dis-incentivizing

[48]One potential complication, noted in Davis (2015), is that smaller firms may face a higher cost of capital and therefore higher costs in obtaining financial assurance. Insofar as these higher costs reflect greater risk of anticipated or unanticipated bankruptcy, bonding requirements would not create inefficiencies, in transfers or otherwise. However, insofar as these higher costs reflect greater asymmetric information in financial transactions, there would be a tradeoff between avoiding liability shielding and exacerbating financial frictions.

[49]Advocates have proposed various policy changes to address these wells, for instance increased fees on the industry as a whole, to fund state clean-up of orphaned wells (Sierra Club, 2020). In 2021, the Bipartisan Infrastructure Law provided $4.7 billion in public funds to plug and remediate orphan wells.

[50]For low-value wells already operated by low-value firms, a challenge noted in several news articles and white papers is that additional regulations (such as a newly imposed bonding requirement, or idle well fees) can make a low-production well unprofitable. As such, it is possible that increased regulatory costs could *cause* a low-volume well to be abandoned without being plugged – worsening the very problem regulators are trying to solve (Mider and Adams-Heard, 2021; Boettner, 2021; Jaffe and Najmabadi, 2022). Further understanding these tradeoffs is an excellent topic for future research.

[51]Some states do use increased scrutiny at the time of transfer (Interstate Oil and Gas Compact Commission, 2021), although one report notes difficulty with enforcement (Mider and Adams-Heard, 2021).

productive reallocation, just as with bonding at the initial time of drilling.

Our long-run regression results suggest that these approaches may be especially effective for transfers of aging wells to smaller operators. In Appendix Section A4, we conduct an illustrative back-of-the-envelope welfare assessment of well transfers, using our estimated outcomes ten years after transfer. For aging wells transferred to smaller operators, we conclude that economically meaningful cost savings are required for well transfers to be welfare enhancing; without them, the environmental and production outcomes combine to imply welfare losses for society as a whole. By contrast, for all transfers of aging wells regardless of operator size, more modest production efficiencies are sufficient. Empirical evaluation of enacted reforms, such as the Arkansas Oil and Gas Commission's recent bonding on transfer requirement for low-producing gas wells, will be important going forward, particularly given the overlapping frictions that exist in real-world markets (Arkansas Oil and Gas Commission, 2024).[52]

Overall, our results point to a need for policy solutions that address the risk of abandoning unprofitable oil and gas wells at the end of life, especially for the large stock of wells currently operated by well-capitalized firms but at risk of being sold "down the food chain." More broadly, our results underscore the importance of adequate financial assurance early in the lifecycle, whether for newly drilled fossil assets or newly developed mines for critical minerals.

7 Conclusion

In this paper, we examine patterns of oil and gas asset transfers and their relationship to long-run production and environmental outcomes. We find that wells transferred beyond middle age are, on average, approximately five percentage points less likely to be plugged five years later, even when not producing; wells transferred to smaller firms are between four and 17 percentage points less likely to be plugged over five to ten years after a transfer. Wells transferred to smaller firms are between one and seven percentage points more likely to be producing at all, but at lower volumes. Taken together, these results are consistent with transfers motivated by both liability shielding and productive reallocation. Back-of-the-envelope calculations suggest that some transfers may be welfare enhancing, but it is unlikely that they all are, particularly for wells transferred to smaller operators. Thus some

[52]Beyond the forward-looking policies described above, California has taken the approach of a liability look-back, where previous operators can be held responsible for plugging and abandonment costs if the subsequent operator "lacks the financial resources" (Guerard, 1997). However, legal uncertainty means it is not clear whether this binds in practice in California. Moreover, relying on this look-back presumes that the previous owners are still profitable. If this ceased to be true in an energy transition, this policy approach could be inadequate.

current policy discussions around abandoned, end-of-life wells may be missing the crucial role of asset reallocation in giving rise to this situation—and millions more wells may be on their way to ending up in the hands of undercapitalized operators.

We suggest several areas for future research. First, we do not examine changes in internal corporate structure and their impact on production or plugging outcomes, though our data suggests that such internal reorganizations are common. Second, future research on the impact of well transfers in other oil- and gas-producing states could be valuable, given state-level regulatory differences; ex post evaluations of state reforms and other changes in regulatory environments would also be informative. Third, given our focus on transfers of aging wells, we are only able to evaluate outcomes for a small sample of unconventional wells drilled during the fracking boom; future research could take advantage of larger numbers of hydraulically fractured wells reaching advanced ages. Finally, structural methods could be used to infer additional information about differences in production costs across operators.

Beyond the immediate implications for environmental policy around end-of-life oil and gas wells, our results also speak to the management of the energy transition. Other types of energy infrastructure and extractable resources also decline in value over time, whether aging fossil resources or newly drilled mines for critical minerals. Our results highlight that capital reallocation may be used as a tool for shedding environmental liabilities, by taking advantage of differences in firm size over the asset's life cycle. While creative policy solutions such as bonding on transfer may help to address this issue for today's aging assets, adequate upfront bonding may prevent newly developed resources from falling into this problem in the future.

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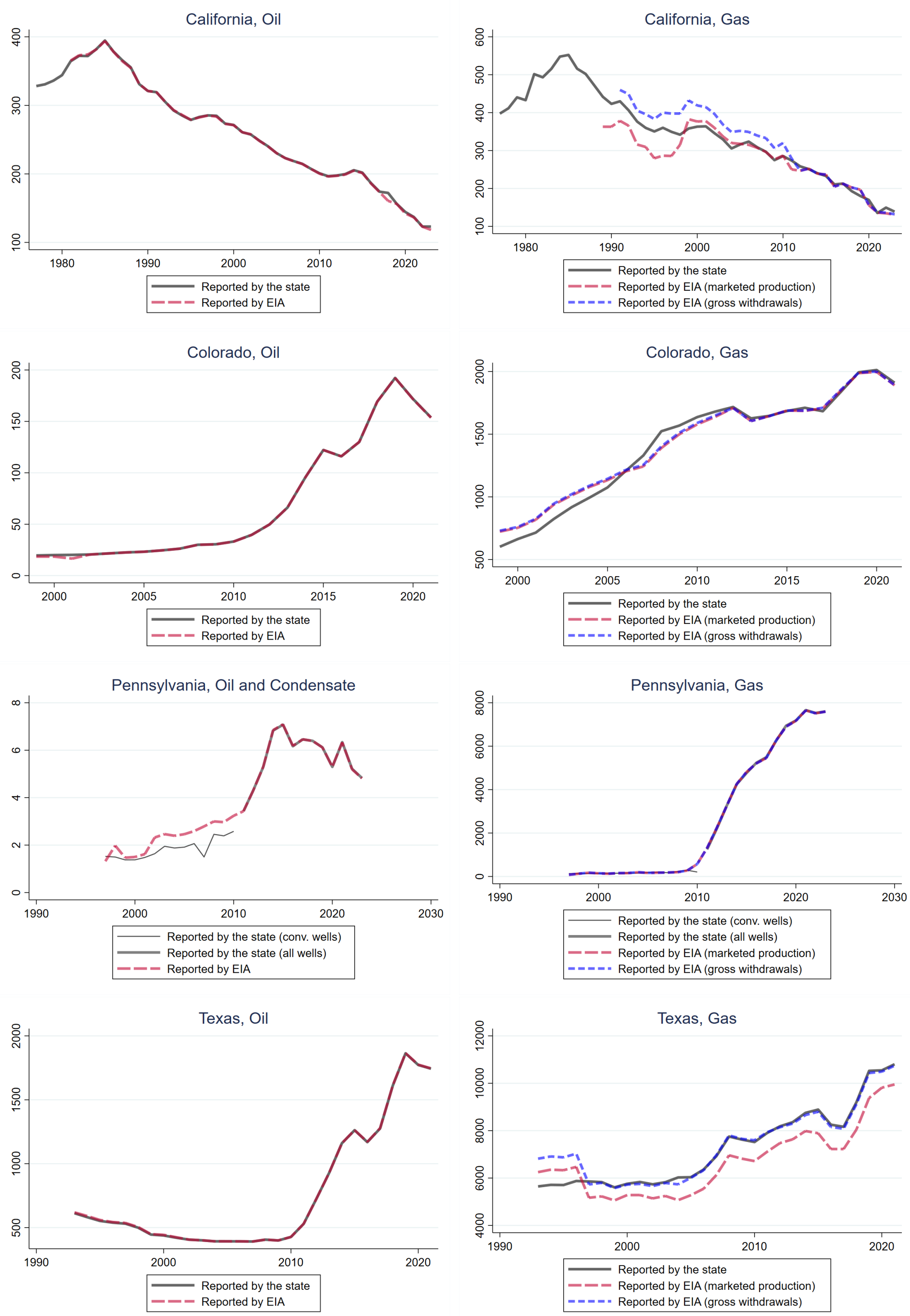
A1 Appendix: Additional Analyses and Robustness Tests

This Appendix shows additional tables and figures, referenced in the main text. To orient the reader, tables are organized into subsections corresponding to each of our main empirical results in the text. While this section includes many different robustness tables, we note that they follow a consistent format. For example, for each of the long-run transfer outcomes discussed in Section 5.4, we show the robustness of our results to a) alternative lag lengths, b) alternative subsamples and controls, and c) alternative transfer definitions.

A1.1 Summary statistics

Figure A1: Observed production compared to EIA totals



Note: This figure compares observed oil and gas production in each state to what is reported by the EIA. Oil production is in million barrels per year. Gas production is in billion cubic feet per year. Sample periods vary across states because of data availability. Oil totals match well in most states, except that Pennsylvania data exclude oil and condensate from unconventional wells prior to 2011. Gas totals are highly correlated with EIA magnitudes and of comparable magnitude to EIA totals, but match less well than do oil totals. Pennsylvania also excludes gas from unconventional wells prior to 2011.

Table A1: Summary statistics

	N	Mean	Median	S.D.	Min	Max
Year	12,719,471	2009.6	2011	8.4	1991	2023
State==CA	12,719,471	0.3	0	0.5	0	1
State==CO	12,719,471	0.07	0	0.3	0	1
State==PA	12,719,471	0.2	0	0.4	0	1
State==TX	12,719,471	0.4	0	0.5	0	1
Oil (barrels)	7,106,761	1088.5	0	4782.0	-90	716948.0
Texas leases	5,596,820	3974.3	0	62337.1	0	20505980
Gas (Mcf)	7,110,688	15619.9	0	135965.9	0	10862707
Texas leases	5,596,820	37543.5	2060	274837.9	0	106993784
Condensate (barrels)	12,708,530	4.2	0	312.3	0	219008.1
Revenue, '000s	7,109,024	144.2	1.7	698.3	-9.3	81083.3
Texas leases	5,596,820	485.9	40.3	5278.9	0	1758112.3
Revenue, '000s, alt. prices	7,109,431	151.5	1.7	712.3	-10.5	81083.3
Texas leases	5,596,820	501.8	41.4	5517.0	0	1797663
Expected future revenue, '000s,	7,106,593	362.9	2.5	1957.9	0	386486.5
Texas leases	5,596,820	1442.2	100.2	30629.6	0	12831785
Gas quantity, peak, bcf	7,122,620	7.3	0.1	40.1	0	3188.3
Texas leases	5,578,917	46.5	13.0	390.9	0	108571.7
Oil quantity, peak, thousand barrels	7,122,620	1.2	0.1	3.7	0	1307.9
Texas leases	5,578,917	5.6	0.5	134.2	0	32929.4
Elevation	12,701,537	1501.3	1100	1415.5	-161	10482
Depth	11,244,883	5619.0	4548	4069.2	20	38387
Type==gas	12,719,471	0.4	0	0.5	0	1
Type==mixed	12,719,471	0.1	0	0.3	0	1
Type==oil	12,719,471	0.4	0	0.5	0	1
Type==prod_zero	12,719,471	0.1	0	0.3	0	1
Drilltype==D	12,701,537	0.07	0	0.3	0	1
Drilltype==H	12,701,537	0.07	0	0.3	0	1
Drilltype==U	12,701,537	0.002	0	0.05	0	1
Drilltype==V	12,701,537	0.9	1	0.3	0	1
Decline: first year's monthly prod. divided by peak month prod.	11,437,337	0.5	0.5	0.2	0	1
Decline: median of year-on-year decline, across most recent five years	10,959,570	0.9	0.9	0.3	0.1	1.8
Unplugged wells per lease, TX	5,578,923	2.1	1	13.2	0	1919
Sale, broad	11,884,838	0.09	0	0.3	0	1
Sale, preferred	11,884,838	0.07	0	0.3	0	1
Sale, narrow	11,884,838	0.04	0	0.2	0	1
Sale, alt. date in CA	11,884,838	0.07	0	0.3	0	1
Oil, first price ($/barrel)	12,719,471	72.8	68.1	33.1	17.8	139.0
WTI oil price ($/barrel)	12,719,471	77.7	67.9	32.4	27.0	140.9
Henry Hub gas price ($/mmbtu)	11,629,875	5.8	4.9	3.0	2.4	13.7
Imputed Henry Hub gas price	12,719,471	5.6	4.7	2.9	2.4	13.7
Natural gas liquids price ($/mmbtu)	7,399,047	10.6	10.1	4.2	5.2	20.4
Birth year, with interpolation	12,679,373	1985.6	1987	20.0	1882	2025
First year of production	5,861,037	2001.1	2003	9.8	1978	2023
Start of production not observed	12,719,471	0.5	1	0.5	0	1
Age	12,679,839	24.0	19	19.3	-29	100
Plugged	11,840,699	0.2	0	0.4	0	1
Operator producing well count	12,719,471	3566.7	976	5003.8	0	19363
Operator state-wide revenue, '000,000's	12,719,471	1270.1	223.8	1999.2	0	15208.4

Note: This table shows summary statistics for the main estimation sample: well-years where the operator is known and production quantity is known or can be inferred. Alternative sample definitions are shown in Table A2. The panel is an unbalanced panel covering California, Colorado, Pennsylvania, and Texas; details in text.

Table A2: Summary statistics, alternative samples

	Alt. Sample 1		Alt. Sample 2	
	N	Mean	N	Mean
Year	16,733,387	2007.9	7,895,406	2009.4
State==CA	16,733,387	0.4	7,895,406	0.2
State==CO	16,733,387	0.06	7,895,406	0.1
State==PA	16,733,387	0.2	7,895,406	0.2
State==TX	16,733,387	0.4	7,895,406	0.5
Oil (barrels)	9,629,793	1351.3	3,951,077	1957.9
Texas leases	6,817,590	3262.7	3,944,329	5639.4
Gas (Mcf)	9,615,198	12425.6	3,951,077	28110.8
Texas leases	6,807,479	30866.7	3,944,329	53272.5
Condensate (barrels)	16,537,709	3.2	7,895,406	6.8
Revenue, ’000s	9,564,524	126.5	3,951,077	259.4
Texas leases	6,806,249	399.6	3,944,329	689.5
Revenue, ’000s, alt. prices	9,565,031	128.7	3,951,077	272.6
Texas leases	6,806,249	412.6	3,944,329	712.0
Expected future revenue, ’000s,	9,561,041	360.0	3,951,077	652.8
Texas leases	6,806,249	1185.9	3,944,329	2046.4
Gas quantity, peak, bcf	9,909,299	6.0	3,951,065	10.6
Texas leases	6,792,996	42.8	3,935,628	49.3
Oil quantity, peak, thousand barrels	9,909,299	1.2	3,951,065	1.2
Texas leases	6,792,996	4.9	3,935,628	6.8
Elevation	16,702,295	1400.3	7,886,693	1754.2
Depth	14,528,217	5402.2	7,352,939	6167.4
Type==gas	16,733,387	0.3	7,895,406	0.5
Type==mixed	16,733,387	0.1	7,895,406	0.2
Type==oil	16,733,387	0.4	7,895,406	0.4
Type==prod_zero	16,733,387	0.2	7,895,406	0
Drilltype==D	16,702,295	0.08	7,886,693	0.06
Drilltype==H	16,702,295	0.06	7,886,693	0.09
Drilltype==U	16,702,295	0.003	7,886,693	0.0002
Drilltype==V	16,702,295	0.9	7,886,693	0.8
Decline: first year’s monthly prod. divided by peak month prod.	14,470,376	0.4	7,872,318	0.5
Decline: median of year-on-year decline, across most recent five years	13,620,134	0.9	7,895,395	0.9
Unplugged wells per lease, TX	6,793,029	1.8	3,935,632	2.5
Sale, broad	11,884,838	0.09	7,344,929	0.10
Sale, preferred	11,884,838	0.07	7,344,929	0.08
Sale, narrow	11,884,838	0.04	7,344,929	0.05
Sale, alt. date in CA	11,884,838	0.07	7,344,929	0.08
Oil, first price ($/barrel)	16,733,387	71.5	7,895,406	72.8
WTI oil price ($/barrel)	16,024,357	77.1	7,895,406	78.2
Henry Hub gas price ($/mmbtu)	14,239,990	5.8	7,238,397	5.9
Imputed Henry Hub gas price	16,204,664	5.6	7,895,406	5.7
Natural gas liquids price ($/mmbtu)	9,109,813	10.6	4,527,489	10.8
Birth year, with interpolation	16,627,574	1982.9	7,885,056	1989.4
First year of production	6,804,154	2000.0	4,370,044	2003.0
Start of production not observed	16,733,387	0.5	7,895,406	0.4
Age	16,629,619	25.0	7,885,249	20.0
Plugged	15,262,442	0.2	7,219,161	0.01
Operator producing well count	12,719,471	3566.7	7,895,406	2830.7
Operator state-wide revenue, ’000,000’s	12,719,471	1270.1	7,895,406	1077.4

Note: This table is similar to Table A1 but for alternative samples. Alternative Sample 1 *expands* the sample to include well-years with unknown operators; the primary changes this entails are (A) incorporating California wells from the late 1970s to early 1990s with known production history but unknown operator, and (B) incorporating late-in-life observations where wells have ceased appearing in production reports, such that we can infer production is zero but do not observe the operator identity. Alternative Sample 2 instead *narrows* the original sample, limiting it to wells with known non-zero production.

Table A3: Many wells have low production and low profitability, robustness

	N	Median	Mean
Revenue, all wells, not weighting by count of wells on Texas leases	10,514,093	20,655	261,720
Revenue, all wells, not re-scaling Texas leases	10,514,093	24,777	359,318
Revenue, all wells, not including partially-plugged Texas leases	10,191,511	20,011	254,435
Revenue, all wells, dropping Texas leases with multiple APIs	9,574,299	20,460	269,426
Revenue, all non-truncated wells	5,437,051	65,942	428,874
Oil production (barrels), oil wells	4,053,420	567	2,574
Oil production, mixed wells	1,410,413	320	2,517
Gas production (mcf), gas wells	3,852,606	7,037	57,266
Gas production, mixed wells	1,410,413	4,699	31,624
Oil production, producing oil wells	2,892,720	897	3,055
Oil production, producing mixed wells	1,113,438	509	3,015
Gas production, producing gas wells	3,270,839	12,050	67,559
Gas production, producing mixed wells	1,164,229	7,059	37,057
Peak revenue (one month), Enverus quantities at typical prices, producing wells	744,348	76,841	250,496
Continuation revenue, alternative commodity price assumptions	10,514,186	83,746	656,620
Continuation revenue, alternative decline curve	10,513,837	79,445	607,472

Note: This table is similar to Table 1, but for alternative subsamples and alternative variable definitions. Note that revenue and production numbers are annual, but continuation revenue aggregates over all future years.

Table A4: Wells are frequently transferred

	N	Mean
All wells, preferred transfer variable	9,505,924	0.078
All wells, narrow transfer definition	9,505,924	0.047
All wells, broad transfer definition	9,505,924	0.096
Alternative transfer date in CA	9,505,924	0.077
Recent observations (2012-2023)	4,837,986	0.076
Producing (at time of transfer) wells only	6,755,666	0.081
Non-producing (at time of transfer) wells only	2,740,721	0.070
Gas-only wells	3,609,586	0.093
Wells with both oil and gas	1,302,785	0.088
Oil-only wells	3,554,854	0.064
Wells that don't produce in the sample	1,038,699	0.059
Small wells	6,352,398	0.079
Large wells	3,153,526	0.076
Wells age less than 20	5,031,166	0.082
Wells age at least 20	4,463,736	0.073
Wells with small peak size	2,494,113	0.079
Wells with large peak size	2,438,148	0.073
California	2,479,590	0.044
Colorado	844,133	0.075
Pennsylvania	1,195,081	0.060
Texas	4,987,120	0.099

Note: This table displays summary statistics on transfers – first for our preferred transfer variable, across all observations; then for alternative transfer definitions, across all observations; then for various sub-samples.

A1.2 Low-value wells are transferred more often

Table A5: Low-value wells are transferred more often, robustness

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
CV (log)	-0.007***	-0.006***	-0.004***	-0.005***	-0.005***	-0.006***	-0.006***	-0.010***
	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Observations	7,322,374	7,322,374	3,509,944	7,322,374	7,322,374	7,322,374	7,321,848	7,322,374
R^2	0.01	0.01	0.02	0.01	0.01	0.01	0.03	0.01

	(9)	(10)	(11)	(12)	(13)	(14)	(15)
CV (log), TX leases not re-scaled	-0.006***						
	(0.001)						
CV (log)		-0.007***	-0.008***	-0.007***	-0.004***		
		(0.001)	(0.001)	(0.001)	(0.001)		
Revenue, time-invariant prices (log)						-0.006***	
						(0.001)	
Age (log)							0.002**
							(0.001)
Observations	7,337,313	5,991,608	6,557,421	5,735,488	3,682,605	7,337,316	7,305,603
R^2	0.01	0.01	0.02	0.01	0.01	0.01	0.01

Note: This table is similar to Table 2 in the main text, but with alternative variable definitions and sub-samples. Column 1 recreates the results from Column 2 of Table 2. Column 2 uses controls that match Figure 1: well type (oil vs gas, horizontal vs vertical), basin effects, and time trends. The specification matches Column 2 of Table 2 without the additional continuous controls (depth, elevation, and peak production). Column 3 limits the sample to recent years (2012-2023). Column 4 uses a broader definition of a transfer; Column 5 uses a narrower definition. Column 6 uses an alternative transfer date in California. Column 7 includes field effects rather than basin effects. Column 8 weights the Texas observations by the count of wells on each lease. Column 9 does not rescale the Texas observations by the count of wells on each lease. Columns 10-13 each exclude one state: CA, CO, PA, TX, in that order. Column 14 uses logged revenue rather than logged continuation revenue. Column 15 uses logged age rather than logged continuation revenue (and so the opposite sign is expected: as a well increases in age, it decreases in continuation revenue); the sample is still limited to wells with positive continuation revenue (i.e., producing wells).

A1.3 Low-value wells are transferred to low-value firms

Table A6: Low-value wells are transferred to low-value firms, robustness

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Continuation revenue (log)	0.087***	0.075***	0.049***	0.085***	0.079***	0.087***	0.093***	0.090***
	(0.012)	(0.011)	(0.013)	(0.011)	(0.016)	(0.013)	(0.010)	(0.012)
Observations	566,420	566,420	277,523	705,474	331,554	564,819	564,182	566,420
R^2	0.03	0.03	0.07	0.03	0.04	0.04	0.13	0.02

	(9)	(10)	(11)	(12)	(13)	(14)	(15)
CV (log), TX leases not re-scaled	0.088***						
	(0.012)						
Continuation revenue (log)		0.082***	0.092***	0.075***	0.107***		
		(0.012)	(0.012)	(0.011)	(0.022)		
Revenue, time-invariant prices (log)						0.060***	
						(0.009)	
Age (log)							-0.131***
							(0.026)
Observations	567,455	511,312	509,470	479,835	198,643	567,455	565,567
R^2	0.03	0.05	0.03	0.03	0.06	0.03	0.03

Note: This table is similar to Table 3 in the main text, but with alternative variable definitions and sub-samples. Column 1 recreates the results from Column 1 of Table 3. Column 2 uses controls that match Figure 2: well type (oil vs gas, horizontal vs vertical), basin effects, and time trends. The specification matches Column 2 of Table 3 without the additional continuous controls (depth, elevation, and peak production). Column 3 limits the sample to recent years (2012-2023). Column 4 uses a broader definition of a transfer; Column 5 uses a narrower definition. Column 6 uses an alternative transfer date in California. Column 7 includes field effects rather than basin effects. Column 8 weights the Texas observations by the count of wells on each lease. Column 9 does not rescale the Texas observations by the count of wells on each lease. Columns 10-13 each exclude one state: CA, CO, PA, TX, in that order. Column 14 uses logged revenue rather than logged continuation revenue. Column 15 uses logged age rather than logged continuation revenue (and so the opposite sign is expected: as a well increases in age, it decreases in continuation revenue); the sample is still limited to wells with positive continuation revenue (i.e., producing wells).
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Table A7: Low-value firms have lower variance in well size

	(1)	(2)
Operator Size (logged)	0.081***	0.045***
	(0.016)	(0.014)
Observations	22,641	22,641
R^2	0.02	0.03

Note: An observation is an operator in a year. The dependent variable is the variance of logged well size in an operator's portfolio, calculated as the sum of squared deviations of logged well size from the operator's mean logged well size, divided by the operator's well count minus one. In column 1, the well count includes only producing wells; in column 2, the well count includes producing and non-producing (unplugged) wells. Both specifications include state-year fixed effects; standard errors are clustered at the operator level. We exclude Texas from the analysis as we do not observe the variance of well size on a lease.

A1.4 Transferred wells produce similar amounts but are less likely to be plugged

A1.4.1 Plugging status

Table A8: Transferred wells are less likely to be plugged, even ten years after transfer

	(5)	(6)	(7)	(8)	(9)	(10)
Panel A: All transfers						
Transfer, five years prior	-0.05***	-0.05***	-0.04***	-0.04***	-0.04***	-0.03***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,264,134	1,272,907	1,273,854	1,267,937	1,255,404
R^2	0.09	0.09	0.09	0.09	0.09	0.10
Panel B: Incidental to M&A						
Transfer, five years prior	-0.05*	-0.06*	-0.05**	-0.07***	-0.08***	-0.09***
	(0.03)	(0.03)	(0.02)	(0.02)	(0.02)	(0.02)
Observations	1,249,902	1,264,134	1,272,907	1,273,854	1,267,937	1,255,404
R^2	0.09	0.09	0.09	0.09	0.09	0.10
Panel C: Part of firm creation						
Transfer, five years prior	-0.06***	-0.07***	-0.08***	-0.08***	-0.06***	-0.06***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,264,134	1,272,907	1,273,854	1,267,937	1,255,404
R^2	0.09	0.09	0.09	0.09	0.09	0.10
Panel D: Part of firm liquidation						
Transfer, five years prior	-0.05***	-0.05***	-0.05***	-0.05***	-0.05***	-0.04***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,264,134	1,272,907	1,273,854	1,267,937	1,255,404
R^2	0.09	0.09	0.09	0.09	0.09	0.10

Note: This table uses the same specification as Panel A Table 4 in the main text, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is a plugging indicator for non-producing wells age 20 or above.

Table A9: Transferred wells are less likely to be plugged, robustness to alternative transfer definitions

	Alternative date in CA	Broad definition	Narrow definition	Incidental to M&A, alt. 1	Incidental to M&A, alt. 2	Part of firm creation only	Part of firm liquidation only
Trans., five yrs pr.	-0.05***	-0.03***	-0.03***	-0.05	-0.07*	-0.06***	-0.04***
	(0.01)	(0.01)	(0.01)	(0.04)	(0.03)	(0.01)	(0.01)
Observations	1,249,902	1,249,902	1,249,902	1,249,902	1,249,902	1,249,902	1,249,902
R^2	0.09	0.09	0.09	0.09	0.09	0.09	0.09

Note: This table uses the same specification as Panel A Table 4 in the main text, but with alternative transfer date variables. The outcome of interest is a plugging indicator for non-producing wells age 20 or above. Columns 1-3 are comparable to the "All transfers" column in Table 4 in the main text, but with alternative transfer variable definitions, as follows. Column 1 uses an alternative transfer date in California. Column 2 uses the broadest definition of a transfer; Column 3 uses the narrowest definition; see text for additional details on these definitions. Columns 4-5 are comparable to the "Incidental to known M&A" column in Table 4, but with alternative transfer definitions, as follows. Column 4 uses only M&A data from SDC Platinum; Column 5 uses only M&A data from our dataset (Table 4 uses both sources). Column 6 is comparable to the "Part of firm creation" column in Table 4, but considers transfers that were part of firm creation only, not both firm creation and liquidation. Column 7 is comparable to the "Part of firm liquidation" column in Table 4, but considers transfers that were part of firm liquidation only.

Table A10: Transferred wells are less likely to be plugged, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Panel A: All transfers												
Trans., five yrs pr.	-0.05***	-0.04***	-0.03***	-0.05***	-0.05***	-0.05***	-0.04***	-0.05***	-0.05***	-0.04***	-0.02***	-0.04***
	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)
Observations	1,249,902	1,720,013	1,249,399	705,813	1,464,316	1,032,803	708,716	1,197,259	1,198,308	645,423	1,115,677	1,190,065
R^2	0.09	0.03	0.19	0.12	0.09	0.09	0.10	0.07	0.09	0.11	0.17	0.08
Panel B: Incidental to M&A												
Trans., five yrs pr.	-0.05*	-0.06**	-0.03	0.03	-0.06**	-0.05	-0.00	-0.06**	-0.05*	-0.07*	-0.04	-0.05*
	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)	(0.02)	(0.03)	(0.03)	(0.04)	(0.02)	(0.03)
Observations	1,249,902	1,720,013	1,249,399	705,813	1,464,316	1,032,803	708,716	1,197,259	1,198,308	645,423	1,115,677	1,190,065
R^2	0.09	0.03	0.19	0.12	0.09	0.09	0.10	0.07	0.09	0.11	0.17	0.08
Panel C: Part of firm creation												
Trans., five yrs pr.	-0.06***	-0.06***	-0.04***	-0.07***	-0.06***	-0.06***	-0.06***	-0.07***	-0.07***	-0.05**	-0.03***	-0.06***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)
Observations	1,249,902	1,720,013	1,249,399	705,813	1,464,316	1,032,803	708,716	1,197,259	1,198,308	645,423	1,115,677	1,190,065
R^2	0.09	0.03	0.19	0.12	0.09	0.09	0.10	0.07	0.09	0.11	0.17	0.08
Panel D: Part of firm liquidation												
Trans., five yrs pr.	-0.05***	-0.04***	-0.04***	-0.05***	-0.05***	-0.05***	-0.04***	-0.05***	-0.05***	-0.05***	-0.01**	-0.05***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.00)	(0.01)
Observations	1,249,902	1,720,013	1,249,399	705,813	1,464,316	1,032,803	708,716	1,197,259	1,198,308	645,423	1,115,677	1,190,065
R^2	0.09	0.03	0.19	0.12	0.09	0.09	0.10	0.07	0.09	0.11	0.17	0.08

Note: This table uses the same specification as Panel A Table 4 in the main text, but with alternative controls and sub-samples. The outcome of interest is a plugging indicators for non-producing wells age 20 or above. Column 1 recreates Table 4. Column 2 uses fewer controls: only state by year interacted fixed effects. Column 3 adds controls: field fixed effects. Column 4 limits the sample to 2012-2013. Column 5 uses wells age 15+; Column 6 ages 25+. Columns 7-10 each exclude one state: CA, CO, PA, TX, in that order. Column 11 weights by the number of wells in Texas leases. Column 12 limits the sample to fully unplugged observations at age 15, rather than not fully plugged (relevant for TX leases only).

Table A11: Transferred wells are less likely to be plugged, robustness to alternative plugging definitions

	(1)	(2)	(3)	(4)	(5)	(6)
Panel A: All transfers						
Trans., five yrs pr.	-0.05***	-0.05***	-0.05***	-0.05***	-0.04***	-0.04***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,730,118	1,249,016	1,249,902	1,190,065	1,249,902
R^2	0.09	0.31	0.09	0.09	0.08	0.08
Panel B: Incidental to M&A						
Trans., five yrs pr.	-0.05*	-0.01	-0.05*	-0.05*	-0.05*	-0.06**
	(0.03)	(0.01)	(0.03)	(0.03)	(0.03)	(0.03)
Observations	1,249,902	1,730,118	1,249,016	1,249,902	1,190,065	1,249,902
R^2	0.09	0.31	0.09	0.09	0.08	0.08
Panel C: Part of firm creation						
Trans., five yrs pr.	-0.06***	-0.08***	-0.06***	-0.06***	-0.06***	-0.06***
	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,730,118	1,249,016	1,249,902	1,190,065	1,249,902
R^2	0.09	0.31	0.09	0.09	0.08	0.08
Panel D: Part of firm liquidation						
Trans., five yrs pr.	-0.05***	-0.04***	-0.05***	-0.05***	-0.05***	-0.05***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,730,118	1,249,016	1,249,902	1,190,065	1,249,902
R^2	0.09	0.31	0.09	0.09	0.08	0.08

Note: This table uses the same specification as Panel A of Table 4 in the main text, but with alternative definitions of plugging status. In all cases, the outcome of interest is a plugging indicator for non-producing wells age 20 or above. Column 1 repeats results from Table 4. Column 2 uses plugging data from one source for older California data (CalWIMS); Column 3 uses plugging data from another source (WellSTAT). Column 4 does not fill forward any information about plugging status between older (1977-2017) and newer (2018-2023) California data. Column 5 defines an observation as plugged if any wells on the lease are plugged (relevant for Texas leases only); Column 6 defines an observation as plugged if all wells on the lease are plugged.

A1.4.2 Production volumes

Table A12: Transfers have little effect on production volumes winsorized, even ten years after transfer

	(5)	(6)	(7)	(8)	(9)	(10)
Panel A: All transfers						
Transfer, five years prior	0.8	0.9	1.1	-0.4	-0.9	-1.9
	(3.0)	(3.0)	(3.0)	(2.9)	(2.7)	(2.7)
Observations	3,597,133	3,498,168	3,389,943	3,270,430	3,140,208	3,001,550
R^2	0.30	0.29	0.28	0.27	0.26	0.25
Panel B: Incidental to M&A						
Transfer, five years prior	5.2	0.5	-3.5	-3.0	0.3	0.5
	(11.4)	(10.3)	(10.0)	(8.6)	(8.0)	(7.5)
Observations	3,597,133	3,498,168	3,389,943	3,270,430	3,140,208	3,001,550
R^2	0.30	0.29	0.28	0.27	0.26	0.25
Panel C: Part of firm creation						
Transfer, five years prior	-1.3	-2.0	-1.3	-0.6	-0.4	-1.3
	(4.6)	(4.7)	(5.1)	(5.2)	(5.2)	(5.2)
Observations	3,597,133	3,498,168	3,389,943	3,270,430	3,140,208	3,001,550
R^2	0.30	0.29	0.28	0.27	0.26	0.25
Panel D: Part of firm liquidation						
Transfer, five years prior	-1.4	-0.6	-0.6	-1.7	-3.9	-3.5
	(3.7)	(3.8)	(3.5)	(3.4)	(3.3)	(3.3)
Observations	3,597,133	3,498,168	3,389,943	3,270,430	3,140,208	3,001,550
R^2	0.30	0.29	0.28	0.27	0.26	0.25

Note: This table uses the same specification as Panel B of Table 4 in the main text, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is production volumes (in thousands of dollars) for wells age 20 or above, assuming typical prices.

Table A13: Transfers have little effect on production volumes winsorized, robustness to alternative transfer definitions

	Alternative date in CA	Broad definition	Narrow definition	Incidental to M&A, alt. 1	Incidental to M&A, alt. 2	Part of firm creation only	Part of firm liquidation only
Trans., five yrs pr.	1.0	-0.2	1.1	7.4	4.4	1.5	4.0
	(3.0)	(2.7)	(4.0)	(16.3)	(14.1)	(5.5)	(4.7)
Observations	3,597,133	3,597,133	3,597,133	3,597,133	3,597,133	3,597,133	3,597,133
R^2	0.30	0.30	0.30	0.30	0.30	0.30	0.30

Note: This table uses the same specification as Panel B of Table 4 in the main text, but with alternative transfer date variables. The outcome of interest is production volumes (in thousands of dollars) for wells age 20 or above, assuming typical prices. Columns 1-3 are comparable to the "All transfers" column in Table 4 in the main text, but with alternative transfer variable definitions, as follows. Column 1 uses an alternative transfer date in California. Column 2 uses the broadest definition of a transfer (including apparent internal reorganizations, and including pre-production transfers); Column 3 uses the narrowest. Columns 4-5 are comparable to the "Incidental to known M&A" column in Table 4, but with alternative transfer definitions, as follows. Column 4 uses only M&A data from SDC Platinum; Column 5 uses only M&A data from our dataset (Table 4 uses both sources). Column 6 is comparable to the "Part of firm creation" column in Table 4, but considers transfers that were part of firm creation only, not both firm creation and liquidation. Column 7 is comparable to the "Part of firm liquidation" column in Table 4, but considers transfers that were part of firm liquidation only.

Table A14: Transfers have little effect on production volumes winsorized, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Panel A: All transfers												
Trans., five yrs pr.	0.8	-9.5**	2.4	3.5	0.7	0.9	3.3	1.1	2.1	-7.4	-4.6	-1.9
	(3.0)	(4.2)	(2.2)	(2.2)	(2.8)	(3.1)	(2.5)	(3.1)	(3.1)	(6.2)	(15.8)	(2.6)
Observations	3,597,133	4,073,573	3,596,873	2,007,589	4,394,288	2,905,729	2,536,166	3,364,130	3,247,187	1,643,916	3,459,076	3,380,375
R^2	0.30	0.01	0.38	0.28	0.29	0.32	0.31	0.30	0.30	0.25	0.81	0.24
Panel B: Incidental to M&A												
Trans., five yrs pr.	5.2	37.7*	7.0	9.6	0.7	2.3	34.9**	4.4	7.8	-17.5	139.5	-4.9
	(11.4)	(19.9)	(8.5)	(9.8)	(9.7)	(12.7)	(14.7)	(12.0)	(11.3)	(13.5)	(90.3)	(9.8)
Observations	3,597,133	4,073,573	3,596,873	2,007,589	4,394,288	2,905,729	2,536,166	3,364,130	3,247,187	1,643,916	3,459,076	3,380,375
R^2	0.30	0.01	0.38	0.28	0.29	0.32	0.31	0.30	0.30	0.25	0.81	0.24
Panel C: Part of firm creation												
Trans., five yrs pr.	-1.3	-17.7**	-4.9	1.0	-1.7	-2.5	4.6	-0.5	-1.5	-15.9***	-8.4	-6.1**
	(4.6)	(7.1)	(4.2)	(2.6)	(4.0)	(5.1)	(5.4)	(4.9)	(5.2)	(4.4)	(24.2)	(2.8)
Observations	3,597,133	4,073,573	3,596,873	2,007,589	4,394,288	2,905,729	2,536,166	3,364,130	3,247,187	1,643,916	3,459,076	3,380,375
R^2	0.30	0.01	0.38	0.28	0.29	0.32	0.31	0.30	0.30	0.25	0.81	0.24
Panel D: Part of firm liquidation												
Trans., five yrs pr.	-1.4	-20.0***	0.4	6.1	0.2	-3.5	1.8	-1.5	0.5	-12.8***	-52.6	-1.4
	(3.7)	(5.0)	(3.0)	(4.8)	(3.1)	(4.4)	(3.9)	(3.8)	(4.1)	(4.9)	(34.2)	(3.1)
Observations	3,597,133	4,073,573	3,596,873	2,007,589	4,394,288	2,905,729	2,536,166	3,364,130	3,247,187	1,643,916	3,459,076	3,380,375
R^2	0.30	0.01	0.38	0.28	0.29	0.32	0.31	0.30	0.30	0.25	0.81	0.24

Note: This table uses the same specification as Panel B of Table 4 in the main text, but with alternative controls and sub-samples. The outcome of interest is production volumes (in thousands of dollars) for wells age 20 or above, assuming typical prices. Column 1 recreates Table 4. Column 2 uses fewer controls: only state by year interacted fixed effects. Column 3 adds controls: field fixed effects. Column 4 limits the sample to 2012-2023. Column 5 uses wells age 15+; Column 6 ages 25+. Columns 7-10 each exclude one state: CA, CO, PA, TX, in that order. Column 11 weights by the number of wells in Texas leases. Column 12 limits the sample to fully unplugged observations at age 15, rather than not fully plugged (relevant for TX leases only).

A1.4.3 Production volumes (conditional on producing)

Table A15: Transfers have little effect on production volumes winsorized, conditional on producing, even ten years after transfer

	(5)	(6)	(7)	(8)	(9)	(10)
Panel A: All transfers						
Transfer, five years prior	0.0	0.4	1.2	-1.3	-1.6	-3.2
	(4.1)	(4.1)	(4.2)	(4.0)	(3.8)	(3.8)
Observations	2,346,819	2,233,655	2,116,688	1,996,255	1,871,971	1,745,866
R^2	0.35	0.34	0.33	0.33	0.32	0.31
Panel B: Incidental to M&A						
Transfer, five years prior	8.5	3.3	-0.0	3.9	4.8	3.5
	(18.0)	(16.6)	(17.2)	(14.8)	(13.9)	(13.2)
Observations	2,346,819	2,233,655	2,116,688	1,996,255	1,871,971	1,745,866
R^2	0.35	0.34	0.33	0.33	0.32	0.31
Panel C: Part of firm creation						
Transfer, five years prior	-1.5	-2.7	-1.0	-0.2	0.4	-2.2
	(6.6)	(7.0)	(7.5)	(7.7)	(7.9)	(8.1)
Observations	2,346,819	2,233,655	2,116,688	1,996,255	1,871,971	1,745,866
R^2	0.35	0.34	0.33	0.33	0.32	0.31
Panel D: Part of firm liquidation						
Transfer, five years prior	-1.5	-0.3	-0.2	-2.6	-5.0	-4.0
	(5.2)	(5.5)	(5.3)	(5.0)	(5.1)	(5.1)
Observations	2,346,819	2,233,655	2,116,688	1,996,255	1,871,971	1,745,866
R^2	0.35	0.34	0.33	0.33	0.32	0.31

Note: This table uses the same specification as Panel C of Table 4 in the main text, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is production volumes (in thousands of dollars) for *producing* wells age 20 or above, assuming typical prices.

Table A16: Transfers have little effect on production volumes winsorized, conditional on producing, robustness to alternative transfer definitions

	Alternative date in CA	Broad definition	Narrow definition	Incidental to M&A, alt. 1	Incidental to M&A, alt. 2	Part of firm creation only	Part of firm liquidation only
Trans., five yrs pr.	0.2	-1.2	-0.0	17.4	5.1	1.6	3.8
	(4.1)	(3.7)	(5.4)	(23.2)	(22.3)	(8.1)	(6.7)
Observations	2,346,819	2,346,819	2,346,819	2,346,819	2,346,819	2,346,819	2,346,819
R^2	0.35	0.35	0.35	0.35	0.35	0.35	0.35

Note: This table uses the same specification as Panel C of Table 4 in the main text, but with alternative transfer date variables. The outcome of interest is production volumes (in thousands of dollars) for *producing* wells age 20 or above, assuming \$70 per barrel of oil, \$4 per mcf of gas, and \$9 per MMBtu of condensate. Columns 1-3 are comparable to the "All transfers" column in Table 4 in the main text, but with alternative transfer variable definitions, as follows. Column 1 uses an alternative transfer date in California. Column 2 uses the broadest definition of a transfer (including apparent internal reorganizations, and including pre-production transfers); Column 3 uses the narrowest. Columns 4-5 are comparable to the "Incidental to known M&A" column in Table 4, but with alternative transfer definitions, as follows. Column 4 uses only M&A data from SDC Platinum; Column 5 uses only M&A data from our dataset (Table 4 uses both sources). Column 6 is comparable to the "Part of firm creation" column in Table 4, but considers transfers that were part of firm creation only, not both firm creation and liquidation. Column 7 is comparable to the "Part of firm liquidation" column in Table 4, but considers transfers that were part of firm liquidation only.

Table A17: Transfers have little effect on production volumes winsorized, conditional on producing, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Panel A: All transfers												
Trans., five yrs pr.	0.0	-9.9	2.9	5.1	-0.0	-0.3	3.8	0.3	1.6	-13.4	-0.4	-2.5
	(4.1)	(7.1)	(2.7)	(3.7)	(3.7)	(4.3)	(3.5)	(4.3)	(4.4)	(8.6)	(18.7)	(3.5)
Observations	2,346,819	2,353,535	2,346,436	1,301,583	2,929,507	1,872,453	1,827,054	2,166,604	2,048,478	998,321	2,342,960	2,189,888
R^2	0.35	0.02	0.45	0.33	0.33	0.37	0.36	0.35	0.34	0.30	0.82	0.28
Panel B: Incidental to M&A												
Trans., five yrs pr.	8.5	81.8**	14.6	5.0	4.4	4.0	48.1**	6.9	13.9	-33.2	351.0***	-8.0
	(18.0)	(35.8)	(12.4)	(16.0)	(14.9)	(20.1)	(21.7)	(19.2)	(17.8)	(21.1)	(126.9)	(15.0)
Observations	2,346,819	2,353,535	2,346,436	1,301,583	2,929,507	1,872,453	1,827,054	2,166,604	2,048,478	998,321	2,342,960	2,189,888
R^2	0.35	0.02	0.45	0.33	0.33	0.37	0.36	0.35	0.34	0.30	0.82	0.28
Panel C: Part of firm creation												
Trans., five yrs pr.	-1.5	-17.9	-7.0	3.6	-2.5	-3.3	7.1	-1.2	-1.8	-24.7***	-32.1	-8.3*
	(6.6)	(12.0)	(5.4)	(4.3)	(5.8)	(7.4)	(7.2)	(7.2)	(7.9)	(7.2)	(27.6)	(4.2)
Observations	2,346,819	2,353,535	2,346,436	1,301,583	2,929,507	1,872,453	1,827,054	2,166,604	2,048,478	998,321	2,342,960	2,189,888
R^2	0.35	0.02	0.45	0.33	0.33	0.37	0.36	0.35	0.34	0.30	0.82	0.28
Panel D: Part of firm liquidation												
Trans., five yrs pr.	-1.5	-31.1***	0.8	7.1	-0.4	-4.1	3.2	-2.2	1.7	-17.0**	-49.9	-0.7
	(5.2)	(7.6)	(4.0)	(7.3)	(4.4)	(6.3)	(5.3)	(5.4)	(6.0)	(7.1)	(38.4)	(4.5)
Observations	2,346,819	2,353,535	2,346,436	1,301,583	2,929,507	1,872,453	1,827,054	2,166,604	2,048,478	998,321	2,342,960	2,189,888
R^2	0.35	0.02	0.45	0.33	0.33	0.37	0.36	0.35	0.34	0.30	0.82	0.28

Note: This table uses the same specification as Panel C of Table 4 in the main text, but with alternative controls and sub-samples. The outcome of interest is production volumes (in thousands of dollars) for *producing* wells age 20 or above, assuming typical prices. Column 1 recreates Table 4. Column 2 uses fewer controls: only state by year interacted fixed effects. Column 3 adds controls: field fixed effects. Column 4 limits the sample to 2012-2013. Column 5 uses wells age 15+; Column 6 ages 25+. Columns 7-10 each exclude one state: CA, CO, PA, TX, in that order. Column 11 weights by the number of wells in Texas leases. Column 12 limits the sample to fully unplugged observations at age 15, rather than not fully plugged (relevant for TX leases only).

A1.4.4 Production status

Table A18: Transfers have little effect on whether a well is producing, even ten years after transfer

	(5)	(6)	(7)	(8)	(9)	(10)
Panel A: All transfers						
Transfer, five years prior	-0.02***	-0.02***	-0.02***	-0.02***	-0.02***	-0.03***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Observations	3,597,123	3,498,159	3,389,934	3,270,421	3,140,199	3,001,541
R^2	0.51	0.47	0.43	0.41	0.38	0.36
Panel B: Incidental to M&A						
Transfer, five years prior	-0.01	-0.01	-0.03**	-0.04**	-0.02*	-0.02
	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.02)
Observations	3,597,123	3,498,159	3,389,934	3,270,421	3,140,199	3,001,541
R^2	0.51	0.47	0.43	0.41	0.38	0.36
Panel C: Part of firm creation						
Transfer, five years prior	-0.01**	-0.02***	-0.02***	-0.02***	-0.02***	-0.02***
	(0.01)	(0.01)	(0.00)	(0.00)	(0.01)	(0.01)
Observations	3,597,123	3,498,159	3,389,934	3,270,421	3,140,199	3,001,541
R^2	0.51	0.47	0.43	0.41	0.38	0.36
Panel D: Part of firm liquidation						
Transfer, five years prior	-0.01	-0.01*	-0.01**	-0.01	-0.01	-0.01**
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	3,597,123	3,498,159	3,389,934	3,270,421	3,140,199	3,001,541
R^2	0.51	0.47	0.43	0.41	0.38	0.36

Note: This table uses the same specification as Panel D of Table 4 in the main text, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is a production indicator for wells age 20 or above.

Table A19: Transfers have little effect on whether a well is producing, robustness to alternative transfer definitions

	Alternative date in CA	Broad definition	Narrow definition	Incidental to M&A, alt. 1	Incidental to M&A, alt. 2	Part of firm creation only	Part of firm liquidation only
Trans., five yrs pr.	-0.02***	-0.01***	-0.02***	-0.01	-0.01	-0.01**	-0.00
	(0.00)	(0.00)	(0.00)	(0.01)	(0.02)	(0.01)	(0.01)
Observations	3,597,123	3,597,123	3,597,123	3,597,123	3,597,123	3,597,123	3,597,123
R^2	0.51	0.51	0.51	0.51	0.51	0.51	0.51

Note: This table uses the same specification as Panel D of Table 4 in the main text, but with alternative transfer date variables. The outcome of interest is a production indicator for wells age 20 or above. Columns 1-3 are comparable to the "All transfers" column in Table 4 in the main text, but with alternative transfer variable definitions, as follows. Column 1 uses an alternative transfer date in California. Column 2 uses the broadest definition of a transfer (including apparent internal reorganizations, and including pre-production transfers); Column 3 uses the narrowest. Columns 4-5 are comparable to the "Incidental to known M&A" column in Table 4, but with alternative transfer definitions, as follows. Column 4 uses only M&A data from SDC Platinum; Column 5 uses only M&A data from our dataset (Table 4 uses both sources). Column 6 is comparable to the "Part of firm creation" column in Table 4, but considers transfers that were part of firm creation only, not both firm creation and liquidation. Column 7 is comparable to the "Part of firm liquidation" column in Table 4, but considers transfers that were part of firm liquidation only.

Table A20: Transfers have little effect on whether a well is producing, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Panel A: All transfers												
Trans., five yrs pr.	-0.02***	-0.02**	-0.01***	-0.02***	-0.02***	-0.02***	-0.02***	-0.02***	-0.02***	-0.02**	-0.02***	-0.02***
	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)
Observations	3,597,123	4,073,563	3,596,863	2,007,580	4,394,277	2,905,721	2,536,156	3,364,130	3,247,177	1,643,906	3,459,066	3,380,365
R^2	0.51	0.06	0.54	0.52	0.50	0.51	0.47	0.51	0.51	0.51	0.52	0.50
Panel B: Incidental to M&A												
Trans., five yrs pr.	-0.01	-0.02	-0.02	-0.00	-0.01	-0.01	-0.01	-0.00	-0.01	-0.01	-0.02	-0.01
	(0.01)	(0.03)	(0.01)	(0.03)	(0.01)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Observations	3,597,123	4,073,563	3,596,863	2,007,580	4,394,277	2,905,721	2,536,156	3,364,130	3,247,177	1,643,906	3,459,066	3,380,365
R^2	0.51	0.06	0.54	0.52	0.50	0.51	0.47	0.51	0.51	0.51	0.52	0.50
Panel C: Part of firm creation												
Trans., five yrs pr.	-0.01**	-0.03***	-0.01***	-0.01	-0.01	-0.02***	-0.02***	-0.01***	-0.01***	0.00	-0.03***	-0.01**
	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	3,597,123	4,073,563	3,596,863	2,007,580	4,394,277	2,905,721	2,536,156	3,364,130	3,247,177	1,643,906	3,459,066	3,380,365
R^2	0.51	0.06	0.54	0.52	0.50	0.51	0.47	0.51	0.51	0.51	0.52	0.50
Panel D: Part of firm liquidation												
Trans., five yrs pr.	-0.01	0.01	-0.01	0.00	-0.00	-0.01	-0.01	-0.01	-0.01*	0.00	-0.01*	-0.01
	(0.01)	(0.01)	(0.00)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)
Observations	3,597,123	4,073,563	3,596,863	2,007,580	4,394,277	2,905,721	2,536,156	3,364,130	3,247,177	1,643,906	3,459,066	3,380,365
R^2	0.51	0.06	0.54	0.52	0.50	0.51	0.47	0.51	0.51	0.51	0.52	0.50

Note: This table uses the same specification as Panel D of Table 4 in the main text, but with alternative controls and sub-samples. The outcome of interest is a production indicator for wells age 20 or above. Column 1 recreates Table 4. Column 2 uses fewer controls: only state by year interacted fixed effects. Column 3 adds controls: field fixed effects. Column 4 limits the sample to 2012-2013. Column 5 uses wells age 15+; Column 6 ages 25+. Columns 7-10 each exclude one state: CA, CO, PA, TX, in that order. Column 11 weights by the number of wells in Texas leases. Column 12 limits the sample to fully unplugged observations at age 15, rather than not fully plugged (relevant for TX leases only).

Table A21: Transfers have little effect on production, various margins

	All transfers	Incidental to M&A	Part of firm creation	Part of firm liquidation
Panel A: Production volume (winsorized)				
Transfer, five years prior	0.834	5.150	-1.307	-1.376
	(2.951)	(11.412)	(4.585)	(3.686)
Observations	3,597,133	3,597,133	3,597,133	3,597,133
R^2	0.30	0.30	0.30	0.30
Panel B: Production volume				
Transfer, five years prior	15.124	-38.469	75.314	-2.797
	(19.034)	(42.133)	(47.687)	(15.970)
Observations	3,597,133	3,597,133	3,597,133	3,597,133
R^2	0.03	0.03	0.03	0.03
Panel C: Production volume (TX leases rescaled)				
Transfer, five years prior	-4.443**	-7.177	-6.413***	-4.582**
	(2.255)	(9.409)	(1.915)	(1.888)
Observations	3,593,274	3,593,274	3,593,274	3,593,274
R^2	0.22	0.22	0.22	0.22
Panel D: Production volume, conditional on producing (logged)				
Transfer, five years prior	0.022*	0.061	-0.051***	-0.013
	(0.013)	(0.056)	(0.018)	(0.020)
Observations	2,346,819	2,346,819	2,346,819	2,346,819
R^2	0.67	0.67	0.67	0.67
Panel E: Production volume, conditional on producing (winsorized)				
Transfer, five years prior	0.045	8.457	-1.494	-1.485
	(4.056)	(17.987)	(6.644)	(5.213)
Observations	2,346,819	2,346,819	2,346,819	2,346,819
R^2	0.35	0.35	0.35	0.35
Panel F: Production volume, conditional on producing				
Transfer, five years prior	5.713	-76.810	109.252	-9.994
	(28.524)	(78.120)	(72.297)	(23.546)
Observations	2,346,819	2,346,819	2,346,819	2,346,819
R^2	0.04	0.04	0.04	0.04
Panel G: Production volume, conditional on producing (TX leases rescaled)				
Transfer, five years prior	-6.422**	-10.335	-9.444***	-5.766**
	(2.901)	(14.180)	(2.831)	(2.785)
Observations	2,342,960	2,342,960	2,342,960	2,342,960
R^2	0.26	0.26	0.26	0.26
Panel H: Production indicator				
Transfer, five years prior	-0.018***	-0.008	-0.013**	-0.007
	(0.003)	(0.015)	(0.005)	(0.005)
Observations	3,597,123	3,597,123	3,597,123	3,597,123
R^2	0.51	0.51	0.51	0.51

Note: This table is similar to Table 4 in the main text, but for additional measures of production outcomes. Panels A, E, and H match the main text. Panels B and F do not winsorize production outcomes. Panels C and G rescale production volumes by the number of wells on Texas leases. Panel E uses production volume in logs (which drops non-producing wells).

Table A22: Transferred wells produce similar amounts, but are less likely to be plugged, price volatility IV specifications

	(1)	(2)	(3)	(4)
Panel A: Plugging status (conditional on not producing)				
Transfer, five years prior	-0.103***	-0.103	-0.085***	-0.085
	(0.019)	(0.206)	(0.018)	(0.183)
Observations	1,250,341	1,250,341	1,250,341	1,250,341
R^2	0.02	0.02	0.02	0.02
First stage F	1942.50	6.73	638.68	4.15
Panel B: Production volumes				
Transfer, five years prior	22.94***	22.94	-26.09***	-26.09
	(5.09)	(56.62)	(5.36)	(55.86)
Observations	3,597,585	3,597,585	3,597,585	3,597,585
R^2	0.24	0.24	0.24	0.24
First stage F	4651.68	7.28	1398.75	2.89
Panel C: Production volumes (conditional on producing)				
Transfer, five years prior	16.39**	16.39	-51.43***	-51.43
	(7.75)	(78.13)	(8.21)	(76.62)
Observations	2,347,220	2,347,220	2,347,220	2,347,220
R^2	0.27	0.27	0.27	0.27
First stage F	2676.93	6.46	770.27	2.49
Panel D: Production status				
Transfer, five years prior	0.045***	0.045	0.073***	0.073
	(0.009)	(0.144)	(0.009)	(0.113)
Observations	3,597,575	3,597,575	3,597,575	3,597,575
R^2	0.45	0.45	0.45	0.45
First stage F	4651.68	7.28	1398.75	2.89

Note: This table is similar to Column 1 of Table 4 in the main text, but with a 2SLS rather than OLS specification. The first and second columns instrument for transfers using absolute percentage changes in Henry Hub and oil first prices. The third and fourth columns use absolute percentage changes in Henry Hub and oil first prices interacted with well type (mostly oil production, mostly gas production, or mixed). All specifications control for current and lagged price levels. The first and third columns cluster standard errors at the well level. The second and fourth columns use two-way clustering, by well and operator-year.

Table A23: Transferred wells produce similar amounts, but are less likely to be plugged, first stage for price volatility IV specifications, when second stage outcome is plugging status

	(1)	(2)	(3)	(4)
L5.oilfirst_pctchange	-0.05***	-0.05		
	(0.002)	(0.064)		
L5.henry_pctchange	-0.10***	-0.10***		
	(0.002)	(0.034)		
L5.txoilfirst_pctchange	-0.03***	-0.03		
	(0.004)	(0.068)		
L5.txhenry_pctchange	0.09***	0.09**		
	(0.003)	(0.039)		
L5.gas_vol_gas_wells			-0.15***	-0.15**
			(0.008)	(0.073)
L5.gas_vol_mixed_wells			-0.14***	-0.14*
			(0.007)	(0.084)
L5.gas_vol_oil_wells			-0.08***	-0.08**
			(0.002)	(0.034)
L5.oil_vol_gas_wells			-0.11***	-0.11
			(0.010)	(0.126)
L5.oil_vol_mixed_wells			-0.01	-0.01
			(0.008)	(0.089)
L5.oil_vol_oil_wells			-0.05***	-0.05
			(0.002)	(0.063)
L5.txgas_vol_gas_wells			0.12***	0.12
			(0.009)	(0.079)
L5.txgas_vol_mixed_wells			0.12***	0.12
			(0.010)	(0.087)
L5.txgas_vol_oil_wells			0.11***	0.11***
			(0.004)	(0.036)
L5.txoil_vol_gas_wells			0.04***	0.04
			(0.011)	(0.131)
L5.txoil_vol_mixed_wells			-0.07***	-0.07
			(0.011)	(0.093)
L5.txoil_vol_oil_wells			-0.05***	-0.05
			(0.005)	(0.065)
Observations	1,250,341	1,250,341	1,250,341	1,250,341
R^2	0.02	0.02	0.02	0.02

Note: This table provides first-stage coefficients associated with Appendix Table A22. The first and second columns instrument for transfers using absolute percentage changes in Henry Hub and oil first prices. The third and fourth columns use absolute percentage changes in Henry Hub and oil first prices interacted with well type (mostly oil production, mostly gas production, or mixed). All specifications control for current and lagged price levels. The first and third columns cluster standard errors at the well level. The second and fourth columns use two-way clustering, by well and operator-year.

Table A24: Transferred wells produce similar amounts, but are less likely to be plugged, first stage for price volatility IV specifications, when second stage outcome is production volume

	(1)	(2)	(3)	(4)
L5.oilfirst_pctchange	-0.04***	-0.04		
	(0.001)	(0.048)		
L5.henry_pctchange	-0.09***	-0.09***		
	(0.001)	(0.031)		
L5.txoilfirst_pctchange	-0.04***	-0.04		
	(0.002)	(0.054)		
L5.txhenry_pctchange	0.07***	0.07**		
	(0.002)	(0.036)		
L5.gas_vol_gas_wells			-0.14***	-0.14
			(0.004)	(0.097)
L5.gas_vol_mixed_wells			-0.10***	-0.10
			(0.005)	(0.098)
L5.gas_vol_oil_wells			-0.07***	-0.07***
			(0.001)	(0.029)
L5.oil_vol_gas_wells			-0.06***	-0.06
			(0.004)	(0.151)
L5.oil_vol_mixed_wells			-0.03***	-0.03
			(0.004)	(0.077)
L5.oil_vol_oil_wells			-0.02***	-0.02
			(0.001)	(0.047)
L5.txgas_vol_gas_wells			0.09***	0.09
			(0.004)	(0.102)
L5.txgas_vol_mixed_wells			0.08***	0.08
			(0.006)	(0.100)
L5.txgas_vol_oil_wells			0.08***	0.08***
			(0.002)	(0.031)
L5.txoil_vol_gas_wells			-0.03***	-0.03
			(0.005)	(0.156)
L5.txoil_vol_mixed_wells			-0.05***	-0.05
			(0.006)	(0.082)
L5.txoil_vol_oil_wells			-0.05***	-0.05
			(0.003)	(0.050)
Observations	3,597,585	3,597,585	3,597,585	3,597,585
R^2	0.02	0.02	0.02	0.02

Note: This table provides first-stage coefficients associated with Appendix Table A22. The first and second columns instrument for transfers using absolute percentage changes in Henry Hub and oil first prices. The third and fourth columns use absolute percentage changes in Henry Hub and oil first prices interacted with well type (mostly oil production, mostly gas production, or mixed). All specifications control for current and lagged price levels. The first and third columns cluster standard errors at the well level. The second and fourth columns use two-way clustering, by well and operator-year.

Table A25: Transferred wells produce similar amounts, but are less likely to be plugged, first stage for price volatility IV specifications, when second stage outcome is production volume (conditional on not producing)

	(1)	(2)	(3)	(4)
L5.oilfirst_pctchange	-0.03***	-0.03		
	(0.002)	(0.049)		
L5.henry_pctchange	-0.09***	-0.09***		
	(0.001)	(0.035)		
L5.txoilfirst_pctchange	-0.05***	-0.05		
	(0.003)	(0.056)		
L5.txhenry_pctchange	0.06***	0.06		
	(0.002)	(0.040)		
L5.gas_vol_gas_wells			-0.15***	-0.15
			(0.004)	(0.107)
L5.gas_vol_mixed_wells			-0.09***	-0.09
			(0.006)	(0.127)
L5.gas_vol_oil_wells			-0.07***	-0.07***
			(0.001)	(0.026)
L5.oil_vol_gas_wells			-0.04***	-0.04
			(0.005)	(0.168)
L5.oil_vol_mixed_wells			-0.04***	-0.04
			(0.006)	(0.094)
L5.oil_vol_oil_wells			0.01***	0.01
			(0.002)	(0.038)
L5.txgas_vol_gas_wells			0.09***	0.09
			(0.005)	(0.112)
L5.txgas_vol_mixed_wells			0.06***	0.06
			(0.008)	(0.130)
L5.txgas_vol_oil_wells			0.07***	0.07**
			(0.003)	(0.029)
L5.txoil_vol_gas_wells			-0.05***	-0.05
			(0.006)	(0.174)
L5.txoil_vol_mixed_wells			-0.04***	-0.04
			(0.008)	(0.098)
L5.txoil_vol_oil_wells			-0.06***	-0.06
			(0.003)	(0.043)
Observations	2,347,220	2,347,220	2,347,220	2,347,220
R^2	0.02	0.02	0.02	0.02

Note: This table provides first-stage coefficients associated with Appendix Table A22. The first and second columns instrument for transfers using absolute percentage changes in Henry Hub and oil first prices. The third and fourth columns use absolute percentage changes in Henry Hub and oil first prices interacted with well type (mostly oil production, mostly gas production, or mixed). All specifications control for current and lagged price levels. The first and third columns cluster standard errors at the well level. The second and fourth columns use two-way clustering, by well and operator-year.

Table A26: Transferred wells produce similar amounts, but are less likely to be plugged, first stage for price volatility IV specifications, when second stage outcome is production status

	(1)	(2)	(3)	(4)
L5.oilfirst_pctchange	-0.04***	-0.04		
	(0.001)	(0.048)		
L5.henry_pctchange	-0.09***	-0.09***		
	(0.001)	(0.031)		
L5.txoilfirst_pctchange	-0.04***	-0.04		
	(0.002)	(0.054)		
L5.txhenry_pctchange	0.07***	0.07**		
	(0.002)	(0.036)		
L5.gas_vol_gas_wells			-0.14***	-0.14
			(0.004)	(0.097)
L5.gas_vol_mixed_wells			-0.10***	-0.10
			(0.005)	(0.098)
L5.gas_vol_oil_wells			-0.07***	-0.07***
			(0.001)	(0.029)
L5.oil_vol_gas_wells			-0.06***	-0.06
			(0.004)	(0.151)
L5.oil_vol_mixed_wells			-0.03***	-0.03
			(0.004)	(0.077)
L5.oil_vol_oil_wells			-0.02***	-0.02
			(0.001)	(0.047)
L5.txgas_vol_gas_wells			0.09***	0.09
			(0.004)	(0.102)
L5.txgas_vol_mixed_wells			0.08***	0.08
			(0.006)	(0.100)
L5.txgas_vol_oil_wells			0.08***	0.08***
			(0.002)	(0.031)
L5.txoil_vol_gas_wells			-0.03***	-0.03
			(0.005)	(0.156)
L5.txoil_vol_mixed_wells			-0.05***	-0.05
			(0.006)	(0.082)
L5.txoil_vol_oil_wells			-0.05***	-0.05
			(0.003)	(0.050)
Observations	3,597,575	3,597,575	3,597,575	3,597,575
R^2	0.02	0.02	0.02	0.02

Note: This table provides first-stage coefficients associated with Appendix Table A22. The first and second columns instrument for transfers using absolute percentage changes in Henry Hub and oil first prices. The third and fourth columns use absolute percentage changes in Henry Hub and oil first prices interacted with well type (mostly oil production, mostly gas production, or mixed). All specifications control for current and lagged price levels. The first and third columns cluster standard errors at the well level. The second and fourth columns use two-way clustering, by well and operator-year.

A1.5 Production and plugging outcomes follow a gradient by operator size

A1.5.1 Plugging status

Table A27: Wells transferred to small firms are less likely to be plugged, even ten years after transfer

	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	-0.06**	-0.06	-0.04	-0.00	0.02	0.02
	(0.03)	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)
Large to medium	-0.09***	-0.12***	-0.13***	-0.13***	-0.15***	-0.16***
	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
Large to small	-0.08***	-0.10***	-0.14***	-0.15***	-0.17***	-0.17***
	(0.02)	(0.03)	(0.02)	(0.03)	(0.03)	(0.04)
Previously operated by medium	-0.05***	-0.05***	-0.05***	-0.06***	-0.06***	-0.06***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to large	-0.00	-0.01	-0.02	-0.01	-0.01	-0.02
	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Medium to medium	-0.02*	-0.01	-0.01	-0.01	-0.01	-0.01
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to small	-0.04***	-0.05***	-0.05***	-0.06***	-0.04***	-0.05***
	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)
Previously operated by small	-0.07***	-0.07***	-0.08***	-0.08***	-0.08***	-0.09***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Small to large	0.05	0.04	0.06	0.05	0.08	0.10**
	(0.04)	(0.04)	(0.05)	(0.05)	(0.05)	(0.05)
Small to medium	-0.02*	-0.03***	-0.02**	-0.02	-0.03**	-0.02*
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Small to small	-0.06***	-0.06***	-0.06***	-0.05***	-0.05***	-0.04***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Observations	1,249,902	1,264,134	1,272,907	1,273,854	1,267,937	1,217,763
R^2	0.09	0.09	0.10	0.10	0.10	0.10

Note: This table uses the same specification as Figure 3 in the main text and Column 1 of Appendix Table A28, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is a plugging indicator for non-producing wells age 20 or above.

Table A28: Wells transferred to small firms are less likely to be plugged, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	-0.06**	-0.04*	-0.10***	-0.06*	-0.07***	0.01	-0.07**	-0.06**	-0.07**	-0.06**
	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0.04)	(0.03)	(0.03)	(0.03)	(0.03)
Large to medium	-0.09***	-0.06***	-0.05*	-0.08***	-0.09***	-0.05***	-0.10***	-0.09***	-0.08	-0.09***
	(0.02)	(0.02)	(0.03)	(0.02)	(0.03)	(0.02)	(0.02)	(0.02)	(0.05)	(0.03)
Large to small	-0.08***	-0.04	-0.10**	-0.09***	-0.10***	-0.04	-0.08***	-0.08***	-0.11***	-0.09***
	(0.02)	(0.02)	(0.05)	(0.02)	(0.02)	(0.03)	(0.02)	(0.02)	(0.03)	(0.02)
Previously operated by medium	-0.05***	-0.05***	-0.03***	-0.05***	-0.05***	-0.01	-0.05***	-0.05***	-0.07***	-0.05***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to large	-0.00	0.01	-0.01	-0.01	0.01	0.01	-0.01	-0.00	-0.01	-0.01
	(0.02)	(0.02)	(0.02)	(0.01)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Medium to medium	-0.02*	-0.02**	-0.02*	-0.02**	-0.01	-0.03***	-0.02**	-0.01	0.00	-0.02*
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)
Medium to small	-0.04***	-0.03***	-0.04**	-0.03**	-0.05***	-0.04***	-0.04***	-0.05***	-0.04	-0.04***
	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.05)	(0.01)
Previously operated by small	-0.07***	-0.06***	-0.05***	-0.06***	-0.08***	-0.03***	-0.06***	-0.06***	-0.11***	-0.06***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Small to large	0.05	0.03	0.01	0.03	0.05	0.12**	0.04	0.06	0.02	0.04
	(0.04)	(0.03)	(0.04)	(0.04)	(0.04)	(0.06)	(0.04)	(0.05)	(0.04)	(0.04)
Small to medium	-0.02*	-0.01	-0.02	-0.03***	-0.01	-0.02*	-0.03***	-0.01	-0.01	-0.02*
	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)
Small to small	-0.06***	-0.05***	-0.08***	-0.07***	-0.06***	-0.07***	-0.06***	-0.07***	-0.02	-0.06***
	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)
Observations	1,249,902	1,249,399	705,813	1,420,171	1,032,803	708,716	1,197,259	1,198,308	645,423	1,190,065
R^2	0.09	0.19	0.12	0.09	0.10	0.10	0.07	0.09	0.12	0.08

Note: This table uses the same specification as Panel A of Figure 4 in the main text, with alternative subsamples and controls. Column 1 replicates the analysis from Figure 4. Column 2 adds controls: field fixed effects. Column 3 restricts the analysis to recent years (2012-2023). Column 4 includes wells age 15+; Column 5 age 25+. Columns 6-9 drops one state at a time: CA, CO, PA, TX, in that order. Column 10 limits the sample to fully unplugged wells at age 15, rather than not fully plugged (relevant for TX leases only). The outcome of interest is an indicator for whether the (non-producing) well is plugged.

A1.5.2 Production volumes

Table A29: Production volumes winsorized for wells transferred to smaller operators, robustness to alternative lag length

	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	13.8	12.1	7.9	14.7	9.6	8.2
	(25.7)	(23.9)	(22.0)	(29.0)	(24.9)	(23.1)
Large to medium	-17.5*	-11.5	-12.3	-7.3	-2.5	-1.6
	(9.1)	(10.5)	(10.3)	(10.6)	(10.7)	(10.8)
Large to small	-50.5***	-48.9***	-44.6***	-42.5***	-39.5***	-38.8***
	(11.7)	(11.8)	(11.7)	(11.5)	(10.8)	(10.9)
Previously operated by medium	-30.9***	-28.9***	-27.3***	-25.8***	-25.3***	-26.1***
	(4.1)	(4.0)	(4.0)	(4.0)	(4.0)	(4.1)
Medium to large	29.9**	25.3*	24.2*	2.7	1.6	-0.5
	(14.3)	(14.0)	(14.1)	(8.4)	(8.0)	(8.1)
Medium to medium	0.9	0.8	1.0	-0.7	-2.2	-3.6
	(3.5)	(3.6)	(3.7)	(3.6)	(3.6)	(3.7)
Medium to small	-29.3***	-33.2***	-36.6***	-36.6***	-36.0***	-37.4***
	(4.4)	(4.6)	(4.3)	(4.2)	(4.1)	(4.1)
Previously operated by small	-31.1***	-28.8***	-26.9***	-25.5***	-25.2***	-25.3***
	(3.5)	(3.4)	(3.4)	(3.3)	(3.3)	(3.4)
Small to large	28.6***	27.3***	29.6***	30.3***	34.4***	36.3***
	(9.9)	(8.7)	(8.2)	(8.7)	(9.5)	(10.4)
Small to medium	-10.6*	-10.7**	-11.3**	-12.9***	-13.6***	-15.5***
	(5.7)	(5.4)	(5.0)	(4.9)	(4.7)	(4.6)
Small to small	12.4***	12.2***	12.4***	12.4***	12.6***	11.9***
	(2.0)	(2.0)	(2.1)	(2.2)	(2.1)	(2.0)
Observations	3,597,133	3,498,168	3,389,943	3,270,430	3,140,208	2,896,296
R^2	0.30	0.29	0.28	0.27	0.26	0.25

Note: This table uses the same specification as Panel A of Figure 4 in the main text and Column 1 of Appendix Table A30, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is production volumes (in thousands of dollars) for wells age 20 or above, assuming \$70 per barrel of oil, \$4 per mcf of gas, and \$9 per MMBtu of condensate.

Table A30: Production volumes winsorized for wells transferred to smaller operators, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	13.8	5.1	-4.2	3.5	19.9	42.0	12.5	12.5	8.0	6.9
	(25.7)	(17.9)	(5.6)	(23.5)	(26.0)	(56.9)	(27.3)	(24.9)	(26.1)	(22.2)
Large to medium	-17.5*	-5.7	-16.9**	-15.8*	-19.7*	-13.0	-21.7**	-15.1*	-38.7***	-19.3***
	(9.1)	(7.3)	(7.7)	(8.1)	(10.5)	(11.2)	(9.6)	(9.0)	(12.8)	(6.7)
Large to small	-50.5***	-49.5***	-5.0	-45.6***	-48.4***	-43.6***	-57.1***	-41.7***	-57.5***	-37.8***
	(11.7)	(12.2)	(20.1)	(11.1)	(12.9)	(15.4)	(12.1)	(11.3)	(14.1)	(10.6)
Previously operated by medium	-30.9***	-26.8***	-14.4***	-26.5***	-34.6***	-41.8***	-37.2***	-27.4***	-12.3***	-14.7***
	(4.1)	(3.5)	(3.9)	(3.7)	(4.5)	(6.7)	(4.2)	(4.1)	(3.5)	(2.7)
Medium to large	29.9**	29.5***	51.8***	31.4**	32.9**	36.9**	33.3**	28.2**	-4.3	22.5*
	(14.3)	(7.2)	(14.9)	(14.6)	(15.3)	(17.5)	(14.7)	(14.4)	(14.1)	(11.5)
Medium to medium	0.9	0.2	0.1	1.5	0.2	1.8	3.3	-0.4	-4.0	-2.3
	(3.5)	(2.8)	(3.6)	(3.2)	(4.0)	(3.7)	(3.6)	(3.7)	(5.2)	(2.7)
Medium to small	-29.3***	-22.0***	-1.2	-27.0***	-34.1***	-31.7***	-27.5***	-37.9***	-3.6	-19.6***
	(4.4)	(3.6)	(4.5)	(3.9)	(5.2)	(4.5)	(4.5)	(4.7)	(5.0)	(3.0)
Previously operated by small	-31.1***	-36.7***	-16.1***	-29.2***	-32.6***	-48.4***	-34.0***	-31.1***	-2.4	-16.6***
	(3.5)	(3.5)	(3.4)	(3.2)	(3.8)	(5.9)	(3.7)	(3.4)	(3.0)	(2.4)
Small to large	28.6***	22.2***	3.2	27.5***	31.7***	36.6**	27.9***	38.2***	0.7	16.2**
	(9.9)	(8.1)	(10.6)	(8.8)	(12.0)	(14.4)	(10.2)	(9.9)	(9.8)	(7.7)
Small to medium	-10.6*	0.9	1.3	-9.9*	-12.3*	-9.0	-11.7*	-8.8	-10.1	-2.8
	(5.7)	(4.8)	(6.9)	(5.2)	(6.7)	(6.1)	(6.0)	(6.8)	(6.2)	(5.2)
Small to small	12.4***	11.2***	12.6***	13.0***	12.8***	15.6***	13.0***	16.0***	-14.7***	3.5**
	(2.0)	(1.6)	(2.4)	(1.9)	(2.2)	(2.1)	(2.0)	(2.0)	(3.5)	(1.4)
Observations	3,597,133	3,596,873	2,007,589	4,218,213	2,905,729	2,536,166	3,364,130	3,247,187	1,643,916	3,380,375
R^2	0.30	0.38	0.28	0.29	0.32	0.31	0.30	0.30	0.25	0.24

Note: This table uses the same specification as Panel A of Figure 4 in the main text, with alternative subsamples and controls. Column 1 replicates the analysis from Figure 4. Column 2 adds controls: field fixed effects. Column 3 restricts the analysis to recent years (2012-2023). Column 4 includes wells age 15+; Column 5 age 25+. Columns 6-9 drops one state at a time: CA, CO, PA, TX, in that order. Column 10 limits the sample to fully unplugged wells at age 15, rather than not fully plugged (relevant for TX leases only). The outcome of interest is production volumes (in thousands of dollars), assuming $70 per barrel of oil, $4 per mcf of gas, and $9 per MMBtu of condensate.

A1.5.3 Production volumes (conditional on producing)

Table A31: Production volumes winsorized (conditional on producing) for wells transferred to smaller operators, robustness to alternative lag length

	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	40.5	34.7	24.0	46.4	36.9	34.2
	(44.6)	(41.0)	(37.1)	(43.5)	(37.3)	(35.1)
Large to medium	-28.3**	-20.7	-25.4	-18.5	-9.3	-9.9
	(13.8)	(15.8)	(15.6)	(16.5)	(17.0)	(17.5)
Large to small	-82.3***	-85.3***	-71.5***	-79.8***	-74.8***	-81.5***
	(19.7)	(20.3)	(20.8)	(20.4)	(20.2)	(20.4)
Previously operated by medium	-52.1***	-50.0***	-48.7***	-47.4***	-47.5***	-50.8***
	(6.4)	(6.5)	(6.6)	(6.6)	(6.7)	(7.0)
Medium to large	42.0*	36.0	37.0	-4.7	-6.9	-8.4
	(24.7)	(24.8)	(26.1)	(14.1)	(13.9)	(15.1)
Medium to medium	-0.0	-0.1	1.6	-2.0	-3.5	-4.5
	(4.9)	(5.2)	(5.5)	(5.4)	(5.4)	(5.6)
Medium to small	-31.8***	-38.7***	-44.0***	-44.2***	-42.9***	-45.4***
	(6.4)	(7.0)	(6.5)	(6.6)	(6.6)	(6.8)
Previously operated by small	-46.3***	-44.2***	-42.7***	-41.3***	-41.6***	-43.8***
	(5.7)	(5.7)	(5.8)	(5.8)	(5.9)	(6.1)
Small to large	23.5	31.3*	39.0**	43.2*	50.8**	46.8*
	(17.9)	(16.8)	(18.5)	(22.8)	(21.8)	(25.0)
Small to medium	-14.5*	-14.7*	-16.9**	-21.0***	-23.4***	-25.9***
	(8.2)	(8.0)	(7.6)	(7.6)	(7.4)	(7.3)
Small to small	13.4***	14.6***	15.5***	15.6***	16.9***	16.0***
	(3.0)	(3.2)	(3.4)	(3.6)	(3.5)	(3.5)
Observations	2,346,819	2,233,655	2,116,688	1,996,255	1,871,971	1,678,250
R^2	0.35	0.34	0.33	0.33	0.32	0.32

Note: This table uses the same specification as Panel B of Figure 4 in the main text and Column 1 of Appendix Table A32, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is production volumes (in thousands of dollars) for *producing* wells age 20 or above, assuming $70 per barrel of oil, $4 per mcf of gas, and $9 per MMBtu of condensate.

Table A32: Production volumes winsorized (conditional on producing) for wells transferred to smaller operators, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	40.5	16.6	-4.0	22.3	53.5	55.9	38.1	32.7	34.1	25.1
	(44.6)	(28.2)	(13.9)	(38.8)	(48.3)	(76.7)	(46.2)	(42.6)	(52.2)	(38.4)
Large to medium	-28.3**	-5.4	-26.7**	-26.4**	-31.5*	-10.5	-34.4**	-24.6*	-85.3***	-30.5***
	(13.8)	(10.9)	(12.2)	(12.0)	(16.1)	(15.4)	(14.4)	(13.6)	(24.0)	(9.9)
Large to small	-82.3***	-81.9***	7.1	-72.8***	-80.1***	-42.7**	-90.8***	-66.4***	-132.1***	-68.2***
	(19.7)	(18.9)	(23.9)	(18.7)	(20.8)	(19.3)	(20.3)	(19.3)	(27.8)	(18.4)
Previously operated by medium	-52.1***	-46.2***	-22.5***	-43.7***	-58.9***	-50.5***	-60.7***	-48.3***	-34.8***	-27.7***
	(6.4)	(5.1)	(6.2)	(5.7)	(7.3)	(8.6)	(6.7)	(6.5)	(7.1)	(4.6)
Medium to large	42.0*	46.5***	89.0***	44.3*	48.5*	45.8*	46.5*	40.7*	-17.8	32.5*
	(24.7)	(11.6)	(23.2)	(25.2)	(26.2)	(26.6)	(25.5)	(24.6)	(34.8)	(18.6)
Medium to medium	-0.0	-1.1	-1.0	1.2	-1.6	1.8	2.6	-1.6	-8.3	-3.0
	(4.9)	(3.4)	(5.4)	(4.5)	(5.6)	(4.9)	(5.2)	(5.4)	(7.8)	(3.9)
Medium to small	-31.8***	-23.0***	0.8	-29.3***	-36.8***	-33.5***	-29.2***	-44.3***	-8.9	-23.2***
	(6.4)	(4.8)	(6.1)	(5.5)	(7.8)	(6.3)	(6.7)	(7.2)	(6.6)	(4.4)
Previously operated by small	-46.3***	-53.6***	-22.2***	-41.1***	-50.3***	-50.9***	-50.0***	-44.2***	-27.4***	-29.3***
	(5.7)	(5.0)	(5.5)	(5.2)	(6.4)	(7.8)	(6.0)	(5.7)	(6.1)	(4.1)
Small to large	23.5	13.3	-0.5	32.2*	26.1	38.4*	22.8	32.0*	-25.1*	16.2
	(17.9)	(15.6)	(26.4)	(17.8)	(21.4)	(20.2)	(19.2)	(18.2)	(13.5)	(15.4)
Small to medium	-14.5*	1.0	1.2	-15.5**	-15.2	-11.3	-15.3*	-13.7	-13.7	-1.9
	(8.2)	(6.9)	(9.9)	(7.5)	(9.6)	(8.3)	(8.7)	(10.4)	(8.7)	(7.7)
Small to small	13.4***	12.4***	17.4***	13.7***	12.8***	18.4***	13.9***	18.1***	-22.2***	3.2
	(3.0)	(2.2)	(3.7)	(2.8)	(3.3)	(3.1)	(3.1)	(3.1)	(5.7)	(2.3)
Observations	2,346,819	2,346,436	1,301,583	2,797,596	1,872,453	1,827,054	2,166,604	2,048,478	998,321	2,189,888
R^2	0.35	0.45	0.33	0.34	0.37	0.36	0.35	0.35	0.30	0.28

Note: This table uses the same specification as Panel A of Figure 4 in the main text, with alternative subsamples and controls. Column 1 replicates the analysis from Figure 4. Column 2 adds controls: field fixed effects. Column 3 restricts the analysis to recent years (2012-2023). Column 4 includes wells age 15+; Column 5 age 25+. Columns 6-9 drops one state at a time: CA, CO, PA, TX, in that order. Column 10 limits the sample to fully unplugged wells at age 15, rather than not fully plugged (relevant for TX leases only). The outcome of interest is production volumes (in thousands of dollars) for *producing* wells, assuming $70 per barrel of oil, $4 per mcf of gas, and $9 per MMBtu of condensate.

A1.5.4 Production status

Table A33: Production status for wells transferred to smaller operators, robustness to alternative lag length

	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	-0.03**	-0.03	-0.02	-0.05*	-0.05*	-0.05*
	(0.02)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)
Large to medium	0.03***	0.02**	0.03**	0.02	0.01	0.01
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Large to small	0.07***	0.07**	0.02	0.05	0.05*	0.06**
	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)
Previously operated by medium	0.01***	0.01	0.01	0.00	-0.00	-0.00
	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to large	-0.03*	-0.01	-0.02	-0.05***	-0.03*	-0.03*
	(0.01)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Medium to medium	-0.01**	-0.01**	-0.01	-0.01*	-0.01**	-0.01
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to small	0.03***	0.03***	0.03***	0.03***	0.03***	0.03***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Previously operated by small	0.06***	0.06***	0.06***	0.05***	0.05***	0.05***
	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)
Small to large	-0.22***	-0.22***	-0.19***	-0.18***	-0.11***	-0.13***
	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.03)
Small to medium	-0.06***	-0.07***	-0.06***	-0.07***	-0.07***	-0.07***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Small to small	-0.03***	-0.03***	-0.03***	-0.03***	-0.03***	-0.04***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Observations	3,597,123	3,498,159	3,389,934	3,270,421	3,140,199	2,896,287
R^2	0.51	0.47	0.44	0.41	0.39	0.37

Note: This table uses the same specification as Panel C of Figure 4 in the main text and Column 1 of Appendix Table A34, but varying the lag length on the transfer indicator. Column headers indicate the lag length: 5 years matches Table 4, and the additional columns show longer lag lengths. The outcome of interest is a production indicator for wells age 20 or above.

Table A34: Production status for wells transferred to smaller operators, robustness to alternative controls and sub-samples

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Large to large	-0.03**	-0.03***	-0.03	-0.04**	-0.04**	-0.02	-0.03*	-0.03**	-0.04**	-0.03**
	(0.02)	(0.01)	(0.02)	(0.02)	(0.02)	(0.03)	(0.02)	(0.02)	(0.02)	(0.02)
Large to medium	0.03***	0.04***	0.05***	0.03**	0.03**	0.03**	0.02*	0.04***	0.06**	0.03**
	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.03)	(0.01)
Large to small	0.07***	0.09***	0.08***	0.07***	0.08***	0.07***	0.07***	0.08***	0.09**	0.07***
	(0.02)	(0.02)	(0.03)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.03)	(0.02)
Previously operated by medium	0.01***	0.03***	0.01*	0.01***	0.01**	0.01***	0.01	0.02***	0.02**	0.01**
	(0.00)	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)
Medium to large	-0.03*	-0.02*	-0.04*	-0.02	-0.03	-0.02	-0.02	-0.02*	-0.08***	-0.02
	(0.01)	(0.01)	(0.02)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.03)	(0.02)
Medium to medium	-0.01**	-0.01***	-0.02*	-0.01**	-0.01**	-0.01***	-0.01**	-0.02***	-0.01	-0.01**
	(0.01)	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)
Medium to small	0.03***	0.04***	0.03***	0.03***	0.03***	0.02***	0.03***	0.03***	0.07***	0.03***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)
Previously operated by small	0.06***	0.08***	0.05***	0.05***	0.06***	0.04***	0.06***	0.06***	0.09***	0.06***
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)
Small to large	-0.22***	-0.21***	-0.26***	-0.21***	-0.24***	-0.17***	-0.22***	-0.20***	-0.28***	-0.22***
	(0.04)	(0.05)	(0.06)	(0.04)	(0.05)	(0.04)	(0.05)	(0.04)	(0.07)	(0.05)
Small to medium	-0.06***	-0.06***	-0.06***	-0.06***	-0.06***	-0.05***	-0.06***	-0.06***	-0.07***	-0.06***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Small to small	-0.03***	-0.02***	-0.03***	-0.03***	-0.03***	-0.03***	-0.03***	-0.03***	-0.02*	-0.03***
	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)
Observations	3,597,123	3,596,863	2,007,580	4,218,203	2,905,721	2,536,156	3,364,130	3,247,177	1,643,906	3,380,365
R^2	0.51	0.54	0.53	0.50	0.51	0.47	0.51	0.51	0.52	0.51

Note: This table uses the same specification as Panel A of Figure 4 in the main text, with alternative subsamples and controls. Column 1 replicates the analysis from Figure 4. Column 2 adds controls: field fixed effects. Column 3 restricts the analysis to recent years (2012-2023). Column 4 includes wells age 15+; Column 5 age 25+. Columns 6-9 drops one state at a time: CA, CO, PA, TX, in that order. Column 10 limits the sample to fully unplugged wells at age 15, rather than not fully plugged (relevant for TX leases only). The outcome of interest is an indicator for whether the well is producing.

Table A35: Small firms are less likely to plug but produce similar amounts

	OLS	IV: firm creation	IV: firm liquidation
Panel A: Plugging status (conditional on not producing)			
Operator revenue (leave-one-out, logged)	0.004***	0.013***	0.012***
	(0.000)	(0.002)	(0.003)
Observations	1,258,642	1,214,433	1,214,433
R^2	0.06	0.00	0.00
First stage F		235.49	95.05
Panel B: Production volumes			
Operator revenue (leave-one-out, logged)	0.713**	0.218	6.344*
	(0.292)	(2.249)	(3.745)
Observations	4,880,697	4,710,158	4,710,158
R^2	0.36	0.29	0.29
First stage F		217.03	66.43
Panel C: Production volumes (conditional on producing)			
Operator revenue (leave-one-out, logged)	-0.079	2.113	11.051**
	(0.364)	(3.313)	(5.558)
Observations	3,621,449	3,495,150	3,495,150
R^2	0.38	0.29	0.29
First stage F		151.09	48.85
Panel D: Production status			
Operator revenue (leave-one-out, logged)	-0.005***	-0.001	0.003
	(0.000)	(0.001)	(0.002)
Observations	4,880,685	4,710,147	4,710,147
R^2	0.78	0.75	0.75
First stage F		217.03	66.43

Note: The unit of observation is a well (aged at least 15 years) in a year. The dependent variables are an indicator for whether the well is plugged, for non-producing wells only (Panel A); production volumes in thousands of dollars, assuming $70 per barrel of oil, $4 per mcf of gas, and $9 per MMBtu of condensate (Panel B); production volumes in thousands of dollars, producing wells only (Panel C); and an indicator for whether the well is producing (Panel D). The independent variable of interest is the operator's logged revenues in the same state, leaving out revenues from the well in question. The sample is limited to wells that were not plugged in the previous year. All columns include controls, each interacted with a TX indicator: well decline rates, lagged production, age, well depth, ground elevation, and peak production. Standard errors are two-way clustered by well and by operator-year.

Table A36: Small firms are less likely to plug, first stage

	Operator revenue (leave-one-out, logged)	Operator revenue (leave-one-out, logged)
Recent firm creation	-1.485***	
	(0.097)	
Recent firm liquidation		-0.825***
		(0.085)
Observations	1,214,433	1,214,433
R^2	0.48	0.47

Note: This table shows the first stage coefficients for the regressions shown in Appendix Table A35. The unit of observation is a well (aged at least 15 years) in a year. Standard errors are two-way clustered by well and by operator-year.

A2 Appendix: Conceptual Framework

A2.1 Each well is operated by the firm that extracts the maximum surplus

Suppose a well is operated by a firm that does not extract the maximum surplus from the well. Then another firm could offer to acquire the well, offering the initial operator an ϵ share of the surplus. The initial operator would accept this offer and cease to operate the well. Therefore, in equilibrium, the possibility of transfers guarantees that all wells are operated by the firm that extracts the maximum surplus.

A2.2 Each firm operates at its efficient scale

Following Boomhower (2019), well-level revenues do not change with the number of wells in the operator's portfolio (k_i). Average costs are given by $AC_i(k_i) = F_i/k_i + c(k_i)/k_i$. Because of our assumptions about the convexity of variable costs $c(\cdot)$, there is an unique k_i^* that minimizes $AC_i(k_i)$: $k_i^* = \frac{F_i + c(k_i)}{c'(k_i)}$. If a firm were not operating at k_i^*, then another firm could create surplus by transferring wells from or to the firm. Therefore, in long-run equilibrium, all firms operate at k_i^* and $AC(k_i^*)$.

Therefore, in long-run equilibrium, average costs per well are equal to marginal costs:

$$AC(k_i^*) = \frac{F + c(k_i^*)}{k_i^*} = \frac{(F + c(k_i^*))c'(k_i^*)}{F + c(k_i^*)} = c'(k_i^*)$$

We can therefore rewrite per-period transfer surplus for well j transferred from operator i to operator i' in terms of average costs instead of marginal costs:

$$\Delta\pi_{i'jt} - \Delta\pi_{ijt} = p(A_{i'} - A_i)\rho_{jt} - (\frac{F_{i'} + c(k_{i'})}{k_{i'}} - \frac{F_i + c(k_i)}{k_i})$$

A2.3 H firms operate more wells than L firms

The optimal scale for firm i is given by $k_i^* = \frac{F_i + c(k_i^*)}{c'(k_i^*)}$. Rearrange and totally differentiate with respect to F_i: $\frac{d}{dF_i}[k_i^* c'(k_i^*) = F_i + c(k_i^*)] \rightarrow \frac{dk_i^*}{dF_i}c'(k_i^*) + \frac{dk_i^*}{dF_i}k_i^* c''(k_i^*) = 1 + \frac{dk_i^*}{dF_i}c'(k_i^*) \rightarrow \frac{dk_i^*}{dF_i} = \frac{1}{k_i^* c''(k_i^*)} > 0$. Therefore, firms with higher F_i (i.e., H firms) will have higher k_i^*.

A2.4 Wells are operated more profitably by L firms after some threshold

The change in surplus from transferring well j from a firm of type H to a firm of type L in period t is given by:

$$\Delta\pi_{Ljt} - \Delta\pi_{Hjt} = \underbrace{p(A_L - A_H)\rho_{jt}}_{<0} - \underbrace{(\frac{F_L + c(k_L)}{k_L} - \frac{F_H + c(k_H)}{k_H})}_{<0 \text{ for } k_H > k_L}$$

Unit costs are lower if the well is operated by firm L, as $c'(k_L^*) < c'(k_H^*)$ given that $k_L^* < k_H^*$. Therefore, the second term in the expression above (which is subtracted) is negative. However, the quantity of oil and gas produced is lower if the well is operated by firm L, as $pA_L\rho_{jt} < pA_H\rho_{jt}$ given that $A_L < A_H$. Therefore, the first term is also negative. As $\rho_{jt} \rightarrow 0$, the impact on unit costs (the second term) eventually dominates, and the well is more profitably owned by firm L. By contrast, for sufficiently large ρ_{jt}, the impact on production (the first term) dominates, and the well is more profitably owned by firm H. Because the difference in per-period surplus from an L firm operating the well instead of an H firm is decreasing in ρ_{jt}, there exists a unique threshold $\bar{\rho}$ that determines whether the well is more profitably operated by firm H or L.

A2.5 Transfers from H firms to L firms have an ambiguous effect on lifetime production

When well j is transferred from H firm to L firm, per-period production decreases: $pA_L\rho_{jt} < pA_H\rho_{jt}$ by construction. Therefore, per period production is lower when the well is operated by firm L.

When well j is transferred from H firm to L firm, the number of producing periods increases: The well's economic end of life is T_{ij}, such that the well no longer creates positive expected surplus after T_{ij}. For all t such that $\rho_{jt} \leq \bar{\rho}$, the surplus from operating well j is greater for firm L than for firm H. Therefore, for a given well still operating profitably at $\rho_{jt} < \bar{\rho}$, it must be the case that the economic end of life occurs later if the well is operated by firm L than if the well is operated by firm H. That is, transfers from H firms to L firms not only increase the per-period surplus for older wells, but also extend their economic lifetime.

The net lifetime impact of decreasing production on the intensive margin and increasing production on the extensive margin is ambiguous.

A2.6 H firms have larger expected portfolio continuation value than L firms

To fix ideas, first consider continuation value without explicitly accounting for transfers or limited liabiltiy. Because the firm's costs depend on the total number of wells operated by the firm, not just well-level characteristics, the continuation value requires assumptions about the firm's well portfolio even after current wells are no longer producing. We therefore sum discounted expected surplus over all current and expected future wells.

Without transfers or limited liability, continuation value as of the current period τ is given by:

$$\mathrm{E}[V_{i\tau}] = \sum_{t=\tau}^{\infty} \left[\beta^{t-\tau} \left(\sum_{j\in\{J_{it}\}} (pA_i\rho_{jt} - \omega_{avg}) - c(k_i) - F_i - \mathbb{1}\{t = T_{ij}\} \cdot \chi - \mathbb{1}\{t = T_{ij}\} \cdot \beta I \right) \right]$$

Now let's explicitly incorporate transfers into the expression for operator continuation value. Because it is most relevant for the results that follow, we will consider the parameter space in which all wells are transferred from H firms to L firms in equilibrium. Let $\bar{t}_j$ denote the first period such that $\rho_{jt} < \bar{\rho}$, i.e., the first period such that well j is more profitably operated by the L-type operator. With transfers, continuation value for H firms is given by:

$$\mathrm{E}[V_{H\tau}] = \sum_{t=\tau}^{\infty} \left[\beta^{t-\tau} \left(\sum_{j\in\{J_{Ht}\}} (pA_H\rho_{jt} - \omega_{avg}) - c(k_H) - F_H + \mathbb{1}\{t = \bar{t}_j\} \cdot w_j - \mathbb{1}\{t = \bar{t}_j\} \cdot \beta I \right) \right]$$

where w_j is the equilibrium price from selling well j to an L-type operator.

With transfers, the continuation value for L firms is given by:

$$\mathrm{E}[V_{L\tau}] = \sum_{t=\tau}^{\infty} \left[\beta^{t-\tau} \left(\sum_{j\in\{J_{Lt}\}} (pA_L\rho_{jt} - \omega_{avg}) - c(k_L) - F_L - \mathbb{1}\{t = \bar{t}_j\} \cdot w_j - \mathbb{1}\{t = T_{Lj}\} \cdot \chi \right) \right]$$

Note the temporal linkage between an existing well reaching the end of its life and the L operator purchasing a new well from an H operator: $\exists j'$ s.t. $T_{Lj} + 1 = \bar{t}_{j'}, \forall j$.

Now let us consider the equilibrium well price in more detail. Without limited liability, the price w_j consists of three terms:

$$w_j = \underbrace{\left(\sum_{t=\bar{t}_j}^{T_{Hj}} \beta^{t-\bar{t}_j} \left(pA_H \rho_{jt} - \frac{c(k_H) + F_H}{k_H} - \omega_{avg} \right) \right) - \beta^{T_{Hj}-\bar{t}_j} \chi}_{\text{Remaining value to } H \text{ firm (i.e., reserve price)}}$$
$$+ \gamma \underbrace{\left[\sum_{t=\bar{t}_j}^{T_{Hj}} \beta^{t-\bar{t}_j} \left(p(A_L - A_H)\rho_{jt} - \left(\frac{c(k_L) + F_L}{k_L} - \frac{c(k_H) + F_H}{k_H}\right) \right) \right]}_{\text{Transfer surplus from operational efficiency}}$$
$$+ \gamma \underbrace{\left[\left(\sum_{t=T_{Hj}+1}^{T_{Lj}} \beta^{t-T_{Hj}-1} \left(pA_L \rho_{jt} - \frac{c(k_L) + F_L}{k_L} - \omega_{avg} \right) \right) - \beta^{T_{Lj}-\bar{t}_j} \chi + \beta^{T_{Hj}-\bar{t}_j} \chi \right]}_{\text{Transfer surplus from extended lifetime}}$$

Here $0 \leq \gamma \leq 1$ represents a bargaining parameter that determines the division of transfer surplus between H and L firms. Firm H receives γ share of the transfer surplus, while firm L receives $1 - \gamma$ share.

In the expression above, the first term could be negative or positive, depending on the magnitude of the end-of-life cleanup costs and the well's remaining production value. The second and third terms are positive, as derived above.

Finally, to show that expected continuation value is larger for H firms than L firms, note that free entry of L firms drives the bargaining parameter to $\gamma = 1$. To see this result, consider the case where an L firm offers to purchase well j at a price such that $\gamma \in [0, 1)$. Then another L firm could enter the market and offer an ϵ higher price, which the H firm will prefer. Eventually competition among L firms will drive the price of transferred wells to the maximum willingness-to-pay of L firms, and all transfer surplus will be received by H firms (i.e., $\gamma = 1$). By contrast, surplus for H firms is not driven to 0 by free entry, given fixed drilling costs at the start of a well's life. This argument also applies in the limited liability regime.

Next, we use $\gamma = 1$ to rewrite total per-well expected surplus for H and L firms. Let $\mathrm{E}[V_{Hj}]$ represent the lifetime expected surplus from well j for firm H, and define $\mathrm{E}[V_{Lj}]$ analogously.

$$\mathrm{E}[V_{Hj}] = \underbrace{-I + \left(\sum_{t=t_{0j}}^{\bar{t}_j - 1} \beta^{t-t_{0j}} (pA_H \rho_{jt} - \omega_{avg} - \frac{c(k_H) + F_H}{k_H}) \right)}_{\text{Surplus when operated by } H \text{ firm}} + \underbrace{\beta^{\bar{t}_j - t_{0j}} w_j}_{\text{Transfer price}}$$

Substituting the expression for the equilibrium well price w_j (with $\gamma = 1$) and combining terms yields:

$$= -I + \left(\sum_{t=t_{0j}}^{\bar{t}_j - 1} \beta^{t-t_{0j}} (pA_H \rho_{jt} - \omega_{avg} - \frac{c(k_H) + F_H}{k_H}) \right)$$
$$+ \left(\sum_{t=\bar{t}_j}^{T_{Lj}} \beta^{t-\bar{t}_j} (pA_L \rho_{jt} - \omega_{avg} - \frac{c(k_L) + F_L}{k_L}) \right) - \beta^{T_{Lj}-t_{0j}} \chi$$

The H firm will only drill a new well if its lifetime expected surplus is weakly positive, so the total H-firm expected value from each well is weakly positive, with some strictly positive given heterogeneity in well quality.

Likewise, the lifetime expected surplus from well j for firm L is given by:

$$\mathrm{E}[V_{Lj}] = \underbrace{-w_j}_{\text{Transfer price}} + \underbrace{\left(\sum_{t=\bar{t}_j}^{T_{Lj}} \beta^{t-\bar{t}_j}(pA_L\rho_{jt} - \omega_{avg} - \frac{c(k_L)+F_L}{k_L})\right)}_{\text{Surplus when operated by } L \text{ firm}} = 0$$

The second equality stems from substituting the transfer price and combining terms. For L firms, all terms cancel, and the total L-firm expected value from each well is 0.

Of course, at a given moment in time, the remaining value of each *existing* well in an operator's portfolio is no longer equal to the lifetime expected value given above. Drilling (for H firms) and well acquisition (for L firms) is sunk for existing wells, and some production value has already been realized (for both H and L firms). Let $\mathrm{E}[V_{Hj\tau}]$ represent the expected remaining value to H firm from well j as of the current period $\tau > t_{0j}$. To obtain this value, we simply truncate the expected value above at $t = \tau$:

$$\begin{aligned}\mathrm{E}[V_{Hj\tau}] = &\left(\sum_{t=\tau}^{\bar{t}_j - 1} \beta^{t-\tau}(pA_H\rho_{jt} - \omega_{avg} - \frac{c(k_H)+F_H}{k_H})\right) \\ &+ \left(\sum_{t=\bar{t}_j}^{T_{Lj}} \beta^{t-\tau}(pA_L\rho_{jt} - \omega_{avg} - \frac{c(k_L)+F_L}{k_L})\right) - \beta^{T_{Lj}-\tau}\chi\end{aligned}$$

Define $\mathrm{E}[V_{Lj't\tau}]$ analogously (for $j' \neq j$, as a well cannot be owned by both H firm and L firm simultaneously):

$$\mathrm{E}[V_{Lj'\tau}] = \left(\sum_{t=\tau}^{T_{Lj'}} \beta^{t-\tau}(pA_L\rho_{j't} - \omega_{avg} - \frac{c(k_L)+F_L}{k_L})\right) - \beta^{T_{Lj'}-\tau}\chi$$

We immediately see that the expected remaining surplus is larger for wells owned by H firms than wells owned by L firms. The remaining H-firm surplus includes the remaining production value while operated by the H firm, plus the production value while operated by an L firm. By contrast, the remaining L firm surplus includes only the remaining production value while operated by the L firm. Both firms account for end-of-life costs in the remaining well value, but these costs are more discounted for H firms, as a well in an H-firm portfolio is further from T_{Lj} than a well in an L-firm portfolio.

Therefore, the expected value of both existing and future wells in an H-firm portfolio is larger than the expected value of existing and future wells, respectively, in an L-firm portfolio. H firms also have more wells in their portfolios. Consequently, at any period, the firm-level continuation value is larger for H firms than L firms.

A2.7 Willingness-to-pay for end-of-life costs and environmental incident cleanup costs are increasing in expected continuation value of portfolio

With limited liability, we assume that the sequence of events within a period is as follows: 1) transfer decisions occur; 2) production occurs; 3) environmental incidents are realized; 4) bankruptcy decision occurs; 5) environmental cleanup costs and end-of-life costs are paid. An operator can therefore choose whether to declare bankruptcy or to continue operating after observing (but before paying) realized environmental cleanup costs in a given period. The firm also knows the economic end of life for each of its wells. Therefore, the firm will find it optimal to declare bankruptcy whenever:

$$\Omega_{it} + \sum_{j \in \{J_{it}\}} \mathbb{1}\{t = T_{ij}\}\chi > \beta \mathrm{E}[\tilde{V}_{i,t+1}]$$

where $\Omega_{it} = \sum_{j \in \{J_{it}\}} \omega_{jt}$. i.e., the realized per-period environmental incident costs across all wells in the operator's portfolio. We use $\mathrm{E}[\tilde{V}]$ to denote the operator's continuation value in a limited liability regime.

It is immediately apparent from the inequality that as $\mathrm{E}[\tilde{V}_{i,t+1}]$ increases, operators are less likely to declare (anticipated or unanticipated) bankruptcy.

A2.8 L firms acquire correlated portfolios and end-of-life costs are not paid in equilibrium

Suppose an operator's portfolio consists of wells at different stages of the life cycle, including at least one well at the economic end of life. Then either the operator will forfeit otherwise profitable wells by declaring bankruptcy to avoid paying end-of-life costs, or the operator will pay end-of-life costs as they come due. In the former case, the firm's surplus could be increased by transferring the still-profitable wells to another operator not on the verge of declaring bankruptcy. In the latter case, the wells could be more profitably operated by operators with homogeneous portfolios that declare bankruptcy to avoid end-of-life costs for all of their wells simultaneously.

A3 Appendix: Data

In the discussion that follows, "API" refers to the 10-digit API number unless otherwise noted.

A3.1 California Wells

Data on California wells comes from several sources. For 1977-2017, we obtained directly from state regulators separate datasets on transfers, plugging dates, production volumes, and well characteristics, which were linked at the API level. For 2018-2023, we downloaded information on well production and characteristics from the state's WellSTAR database.

For both older (1977-2017) and more recent (2018-2023) years, we retain only APIs that appeared at some point in the production data (regardless of whether they reported positive production), to be consistent with other states. We drop a small number of APIs that appeared in the production data but only reported water production. Unlike other states, however, the separate dataset on well transfers allows us to obtain operator information even after wells stopped reporting production, at least through 2017. (In other states, the operator is set to missing after wells stop reporting; this is also true in California when a well stops reporting in the 2018-2023 data, where we do not have a separate dataset on transfers.) Recent data sometimes includes multiple production records per API (e.g., across multiple field codes, pool codes, or area codes); following our treatment of other states, we add production across multiple records to obtain total API-level production.

For older years (1977-2017), plugging dates come from two sources: WellSTAT and CalWIMS, which "were maintaining these dates separately and in two formats" according to state regulators. As such, we test robustness of our results to several different ways of using this plugging data: using the earliest plug date across these two sources, using the latest date, and using dates from only one source. Additionally, in one specification, we do not fill forward plugging information from these sources into more recent years to avoid propagating any potential data errors. For more recent years (2018-2023), plugging status is provided in an annual well characteristics file. In both the older and more recent data, plugging date or status is unique at the API-10 level.

For older years (1977-2017), we use data on transfer dates to infer an API's operator in each month. The transfer dataset provides two dates for each transfer. From comparing these dates to known transfers, it is not clear that one variable is more accurate than the other, so we test the robustness of our results to both sets of dates. (Multiple follow-up inquiries to state regulators were unanswered.) If a well does not appear in the transfer database at all, then we assume its historical operator is the "most recent operator" in the well characteristics file. In some cases, multiple transfers are listed for the same API on the same day, sometimes with the same time stamp. In these cases, we use previous and subsequent transfers and the most recent operator to infer the original seller and the final buyer in that month. We set operator information to missing before 1991 in districts 4 and 5 (using California's historical district definitions) and before 2012 in all other districts, as transfer information is incomplete or nonexistent before these years. In more recent years (2018-2023), operator information is provided in the production dataset, and we infer transfers from changes in the operator from one month to the next.

Across all years, we drop apparent gas storage wells: any well that lists well type as gas storage ("GS"), even if other types are also listed, in addition to wells operated by Pacific Gas & Electric, Southern California Gas, or other apparent gas storage firms. These sample restrictions improve our match with EIA's gas production totals.

A3.2 Colorado Wells

We obtained well production reports from the Colorado Oil and Gas Conservation Commission. Information is provided at the well-formation-sidetrack level; as in other states, we take production totals as given, assuming that multiple entries per API reflect non-duplicative production from multiple sidetracks or formations. We obtain plugging information from a separate dataset with plugging dates at the well level.

We drop wells in natural carbon fields: McElmo Dome, Sheep Mountain, Doe Canyon, and Southern Ute, in addition to wells operated by Kinder Morgan CO_2 Company; removing these wells substantially improves our match with EIA's gas production totals.

A3.3 Pennsylvania Wells

Our Pennsylvania dataset aggregates three different types of well data, all downloaded from the Pennsylvania Department of Environmental Protection: annual information on conventional wells (1997-2023), semi-annual information on unconventional wells (2011-2014), and monthly information on unconventional wells (2015-2023).

Pennsylvania separately reports condensate production, which we track separately from oil and gas in our final dataset. We do not have natural gas liquids prices until 2009, but we verified that condensate volumes are not economically meaningful before then.

In the Pennsylvania production reports, we primarily rely on the well status variable to obtain plugging information. However, sometimes the unstructured comment field notes that a well is plugged or provides a plugging date. We assume that a well is plugged based on the comment field when the listed plug date is earlier than the observation's reporting period (i.e., the date listed is not in the future at the time of reporting) and when there is no positive production during the reporting period. Additionally, across both the well status variable and the comment field, some observations report plugged status for a short period and then revert to reporting unplugged status; we require that an observation reports plugged status for more than one consecutive period, unless the well stops reporting altogether. In cases where these conditions are not met, we set plugging status to missing.

Across all three data types in Pennsylvania, but most commonly for the annual conventional data, there are many instances of multiple records at the API-time period level. In contrast to other states, there are often different operators listed for different records, so we cannot simply add production totals and collapse to a unique observation at the API-period level. Instead, we follow a multi-step procedure to extract accurate information about production, operator, and plugging status.

For plugging status, we manually review all instances in which status differs across observations within a period, and we use previous and subsequent values of plugging status and production volumes to infer the correct status in that period. In instances where the correct plugging status cannot be determined, we retain the plugging status associated with the final operator for that period, and we add a flag for uncertain plugging status.

For production, we combine production volumes in cases where production days sum to the total number of days in the reporting period (e.g., 365 days for annual reporting). In all other cases, we use the maximum reported production across observations. Operators were instructed to submit total production volumes from the reporting period, even production that occurred before they took over operating the well.

For operators, we use previous and subsequent operator information to infer sellers and buyers from a transfer; we drop operators where comments suggest that they were no longer the operator (e.g., "We sold this well"); and we retain operators reporting for a plurality of production days and those with non-zero production. We manually identify the likely operator for a small number of observations in the monthly and biannual data, and for the largest bundles of wells in the annual data. After many layers of attempting to identify the correct operator, we are still left with several hundred repeat observations in the annual data; for these records, we select an operator at random, but we add a flag noting that the operator identity is uncertain.

A3.4 Texas Wells

Data on Texas wells was obtained from the Texas Railroad Commission's Production Data Query. This dataset provides production at the lease level rather than the API level, though gas leases correspond to unique APIs. We combine production volumes for oil and condensate, and for gas and casinghead gas. In Texas, all liquids extracted from gas wells are reported as "lease condensate." We treat condensate in Texas like crude oil, in contrast to our treatment in Pennsylvania, as the oil first price is closer to an Enverus-reported East Texas condensate cost than is the natural gas liquids price that we use for Pennsylvania condensate.

Unlike production volumes, the state provides plug dates at the API level, and Enverus also reports various well characteristics at the API level. To align the lease-level data with API-level variables, we constructed a time-varying lease-to-API crosswalk. Using data on well birth dates (described further below), we dynamically add APIs to leases as wells are "born" over time. This method allows for the creation of time-varying lease-level summary statistics based on API-level attributes, including Enverus-derived variables such as drilling depth, drilling type, elevation, and peak production measures; plugging status; and well counts on the lease.

For analyses of plugging outcomes, our preferred specifications use the portion of wells plugged on a lease. In robustness tests, we also consider alternative constructions: an indicator for whether *any* wells on the lease are plugged and an indicator for whether *all* wells on the lease are plugged. In analyses restricted to unplugged wells, we use both samples in which *all* wells on a lease are unplugged and samples in which *some* wells on a lease are unplugged. We consider an API-10 to be plugged once all records associated with the API have a plug date.

A3.5 Well Characteristics from Enverus

We use various well characteristics from Enverus (Drilling Info), including basin, field, peak production, initial production, elevation, drilling type, depth, spud date, completion date, and first production date. Some of these characteristics may change slightly over time – for example, if a well is drilled deeper – but Enverus does not provide panel variation so we treat them as time-invariant characteristics in our analysis. We combine this information with data from each of our states by merging at the API-10 level.

A3.6 Prices

We obtain monthly and annual commodity prices from the EIA – Henry Hub and citygate gas prices for natural gas, WTI and first oil prices for oil, and natural gas liquids for condensate. For first oil prices, a few month-state combinations are missing; we compute the ratio of the state price to the US average price in each month, take the average ratio of the previous month and the following month, and then multiply this average ratio by the US average price in the missing month. For Henry Hub prices, we extend the years for which price information is available by regressing Henry Hub prices on US average citygate prices with month fixed effects; we then use predicted values as imputed Henry Hub prices in the early 1990s.

A3.7 Aggregating All States

Across all states, our main sample consists of observations that appear in the production data or where we have good reason to believe that the well is not producing, and where we know the operator identity. We drop offshore wells, gas storage wells, and pure carbon wells (as described above). We manually inspect wells with the five largest oil and gas production volumes in each state; we correct apparent reporting errors and winsorize others at the 99.9th percentile.

After aggregating data from each state, we expand the dataset to create a balanced panel over APIs and years, though we retain only observations after the well first appears in the state's production data. For observations newly added to the balanced panel, we fill forward plugging status with the most recent observed status in Pennsylvania and more recent California data; in Texas, Colorado, and older California data, we use plugging dates to determine plugging status. Per our conversation with state regulators, operators have a strong incentive to report any new plugging to the state to reduce future liability. We generally cannot fill forward production-related information, as it is time varying. However, after a well last appears in the state's data, we fill forward zero production (and revenue, continuation revenue) if the final reporting period had zero or missing production volumes.

We define well type – primarily oil, primarily gas, mixed, or zero production – using a 20%/80% threshold: a well is "primarily oil" if more than 80% of its total observed production volume comes from oil, "primarily gas" if less than 20% comes from oil, and mixed (or zero production) otherwise. As with all variables that aggregate production across commodities, we use \$70 per barrel of oil, \$4 per mcf of gas, and \$9 per MMBtu of condensate to aggregate production quantities; these are "typical" prices for our study period.

We calculate well age as the number of years since well "birth." To compute the birth variable, we follow a hierarchy of date sources and interpolation steps:

1. First, use the spud date from Enverus or state data, taking the earliest date if multiple spud dates exist for the same API.

2. If the spud date is unavailable, interpolate it by examining the spud dates of the previous and next consecutive APIs within the same county, a method suggested to us by an industry consultant. The interpolation requires that spud dates of the previous and next APIs be fewer than ten years apart if the subsequent API has a later spud date, or fewer than two years apart if the subsequent API has an earlier spud date.

3. If still missing, use the well completion date from Enverus.

4. If still missing, use the first production date from Enverus.

5. If none of the above are available, use the interpolated spud date without applying any threshold.

6. If still missing, set the well's birth to the first production period in the state data (only for wells where first production occurs after the first year of the state's data).

We top code well age at 100 years.

We construct several versions of decline rates for various components of our analysis. To calculate continuation revenue (described further below), we construct both a recent and a time-invariant decline rate. For the recent decline rate, we calculate the ratio of current year production to previous year production, for years where production declines from one year to the next, and then take the median of this ratio over the past five years for a given well; for the time-invariant decline rate, we take the median over the well's entire production history. For our regression controls, we calculate recent decline rates in the same manner, though we no longer restrict our calculations to years where production declines relative to the previous year. We also calculate time-invariant decline rates as the monthly average production in the well's first 12 months divided by the well's monthly peak production (both from Enverus); this approach is based on Newell, Prest and Vissing (2019) and replicates their results for decline rates of recent gas wells in Texas.

To obtain well-level continuation revenues, we simulate revenues for the next 50 years, using current oil, gas, and condensate production volumes as a baseline; applying estimated commodity-specific decline rates; and assuming constant commodity prices. We also apply a discount rate of 9.1%. In alternative specifications, we vary the choice of decline rate and assume either high or low commodity prices.

As noted in the main text, we infer transfers from changes in the unique operator code from one period to the next (except in older California data, where we have a separate dataset on transfers which we use to construct the operator history). Our broadest definition of transfer includes any change in the operator code from one period to the next. Our preferred definition excludes apparent internal reorganizations, which we identify by matching the first word of the buyer/seller name and/or the buyer/seller initials, in addition to some manual review. Our preferred definition also excludes several large known mergers, identified through the SDC Platinum dataset on M&A activity in the oil and gas industry and a manual review of the largest bundles of wells transferred in our data. Our preferred definition also drops pre-production transfers (age < 0 years). Our narrowest definition excludes firm creations and firm liquidations, identified as transfers to or from operators that enter or leave the sample concurrently. We also use these definitions of firm creation and liquidation in various subsample and IV analyses. Our narrowest definition also excludes transfers very early in a well's production history (age < 1 year).

In some specifications, we focus on transfers that were incidental to broader M&A transactions. Specifically, we search for transfers in which either operator involved in a large M&A transaction transferred wells to a third operator within three years of the M&A deal; the idea is that these transfers are more likely to have been motivated by large-scale strategic realignment within the M&A firms, rather than unobserved well characteristics or well-to-operator matching. To identify the M&A deals, we combine two datasets. First, we identify the twenty largest M&A transactions during our study period among upstream oil and gas companies with assets in our four states, using data on M&A transactions from SDC Platinum. Second, we use our data to identify the twenty largest bundles of wells transferred between a pair of operators in a given year. Our preferred specification uses both data sources; in robustness tests, we also consider each source in isolation.

A3.8 Operating Costs

Here we collect operating and maintenance costs from the literature.

- The Dallas Fed Energy Survey asks respondents (executives of exploration and production companies): "In the top two areas in which your firm is active: What West Texas Intermediate (WTI) oil price does your firm need to cover operating expenses for existing wells?" In the first quarter of 2025, the average response across all firms was $41 per barrel (Federal Reserve Bank of Dallas, 2025). For the median oil well in our sample, producing 986 barrels annually, this value translates to $39,000 in annual costs (in 2023 dollars).
  - For the median well producing both oil and gas in our sample, producing 1244 barrels of oil equivalent (boe) annually, this value translates to $50,000 in annual costs.
- In the Q1 2025 Dallas Fed Energy Survey, the average response among small firms (fewer than 10,000 barrels per day) was $44 per barrel (Federal Reserve Bank of Dallas, 2025). For the median oil well in our sample, this value translates to $42,000 in annual costs (in 2023 dollars).

- We document that smaller wells are more likely to be transferred to smaller operators. For the 25th percentile oil well in our sample, producing 228 barrels annually, this value translates to $10,000 in annual costs.

- A *Wall Street Journal* article on low-producing "stripper" wells reported average monthly operating costs of $2,000, according to a managing director at a Houston investment bank. Adjusted for inflation, this value corresponds to $31,000 in annual costs (in 2023 dollars) (Friedman, 2015).

- A 2007 fact sheet on "marginal wells" issued by the Independent Petroleum Association of America reports $17.96 per barrel in operating costs, royalties, and severance taxes for a marginal oil well ($26.39 in 2023 dollars) (Independent Petroleum Association of America, 2007). IPAA defines a marginal well as a well with less than 15 barrels of oil per day (or less than 90 mcf of natural gas per day). For the median oil well in our sample, this value translates to $26,000 in annual costs.
  - For the 25th percentile oil-only well in our sample, this value translates to $10,000 in annual costs (in 2023 dollars).
  - For the median well producing both oil and gas in our sample, this value translates to $48,000 in annual costs.
  - For the 25th percentile well producing both oil and gas in our sample, this value translates to $11,000 in annual costs.

- A report on aging wells in California estimates monthly operating costs of $1,400 to $12,000 per well, or $9.40 to $29.65 per boe (in 2021 dollars). These values translate to $19,000 to $162,000 in annual costs, updated for inflation (Purvis, 2023).

A3.9 Plugging Costs

Here we collect plugging costs from the literature.

- One study of orphaned wells in California (Boomhower et al., 2018) reports that "The average contract cost in this sample is $68,000 per well. The range of costs is large, with a minimum value of $1,200 and a maximum of $391,000" (p. 21). These estimates are based on a sample of 86 wells plugged at state expense between 2013 and 2018.

- Another study of California wells estimates $69,000 per well for downhole plugging (Purvis, 2023), following the state's methodology for estimating plugging costs.

- In a study of nearly 20,000 wells, Raimi et al. (2021) estimate that "median decommissioning costs are roughly $20,000 for plugging only and $76,000 for plugging and surface reclamation" (p. 1). The authors note a wide range of potential costs: "In rare cases, costs exceed $1 million per well" (p. 1). These estimates are based on wells plugged at state expense in Kansas, Montana, Pennsylvania, and Texas, as well as proprietary plugging data from a large oil and gas operator in New Mexico and Texas.

- Mitchell and Casman (2011) estimate plugging and reclamation costs averaging around $100,000 for Marcellus Shale gas wells, applying estimates of reclamation costs per foot of well depth from 255 wells in Wyoming.

- McClure, Simonides and Weber (2022) estimate a range of $91,980 to $128,520 (in 2010 dollars) for reclamation costs for unconventional wells in Pennsylvania. They first estimate the plugging cost per foot of well depth for 1,205 conventional wells plugged at state expense over 2005 to 2015, which they apply to average-depth unconventional wells.

- Weber (2021) recommends bonding amounts of $25,000 per conventional well and $70,000 per unconventional well [in Pennsylvania]... [to] match projected plugging costs" (p. 2). These estimates are based on wells plugged at state expense in Pennsylvania over 1989 to 2020, accounting for inflation-adjusted increases in plugging cost over time, costs at gas versus oil wells, and well depth.

A4 Appendix: Welfare Assessment

In this section, we discuss amalgamating our estimates of the long-run effects of well transfers into an overall welfare assessment. We focus primarily on the consequences of transfers to smaller operators.

First, our long-run regression results suggest that environmental risks increase when aging wells are transferred to smaller operators. We find that non-producing wells are less likely to be plugged, with the concomitant risks of groundwater contamination, methane emissions, and other environmental costs (Kang et al., 2014, 2016, 2021; Raimi et al., 2021; Weber et al., 2021; Williams, Regehr and Kang, 2021; Harleman, Weber and Berkowitz, 2022). This response among non-producing wells is somewhat but not fully offset by the finding that the number of non-producing wells decreases (i.e., we observe a positive extensive margin response in production). Existing research has documented that low-producing wells also create environmental risks, including emitting a disproportionate share of methane emissions from producing wells (Deighton et al., 2020; El Hachem and Kang, 2022; Townsend-Small et al., 2024). Overall, we find that wells transferred to smaller operators are less likely to be plugged (whether producing or not), with a larger number of wells in the "higher risk" category of not producing and not plugged.[53]

These increased environmental costs are not offset by increases in variable surplus from higher production volumes. Instead, we find that wells transferred to smaller operators produce at lower volumes. Even further, because we find a positive extensive margin production response, more wells are incurring fixed operating costs to produce at lower overall volumes. Like increased environmental costs, this component of the change in welfare for wells transferred to smaller operators is also negative.

Fewer plugged wells also mean avoided or deferred plugging costs. These cost savings are relevant both for wells that would have been plugged and instead remain unplugged and not producing and those that are instead producing. Given reasonable assumptions about the social cost of unplugged wells and fixed operating costs from continuing to produce, described further below, the avoided costs of plugging do not offset these costs of remaining unplugged for typical wells.[54]

Therefore, in order for transfers of aging wells to smaller operators to increase welfare, we conclude that meaningful operational efficiencies that decrease production costs, whether fixed or variable, are required. The fact that we observe a positive extensive margin production response provides suggestive evidence that operational efficiencies are present. We emphasize that these cost reductions must be sufficiently large to offset the other negative components of the change in welfare.

Precisely quantifying these changes in welfare is challenging for several reasons. Existing literature has only partially quantified the environmental risks of unplugged wells, focusing especially on methane emissions (Kang et al., 2014, 2016; Williams, Regehr and Kang, 2021) with rudimentary estimates available for groundwater contamination (Boomhower, 2019). The literature also emphasizes the importance of heterogeneity in these environmental costs — across marginally producing versus non-producing versus orphaned wells, large operators versus small operators, dense versus sparsely populated areas, and so forth (Kang et al., 2023) — but has not yet robustly quantified typical costs across these different groups. Moreover, variation in operating costs is hard to observe. Industry sources cite a wide range of typical production costs, often providing cost estimates in "$ per boe" or "$ per month" without distinguishing between fixed and variable operating costs; see Appendix Section A3.8 for examples. Plugging costs are also heterogeneous; see Appendix Section A3.9 for examples.

For these reasons, we do not attempt to definitively quantify the change in welfare associated with

[53] Operators may also differ in the extent to which they undertake costly effort to prevent environmental harms. We are not able to measure this response directly but the existing judgment-proof literature suggests that small firms are generally less likely to take costly precautions to reduce accident risk (Shavell, 1986, 2005).

[54] We note, however, that there is large heterogeneity in each of these cost components, so some wells may serve as exceptions to these typical patterns. Identifying wells with the highest social value of plugging remains an important direction for future research.

transferred wells. Instead, we provide a sample welfare calculation that illustrates the tradeoffs outlined above, reinforcing our qualitative conclusion that meaningful operational efficiencies are needed to offset other welfare costs associated with transferred wells. From this exercise, we conclude that it is plausible that some transfers to smaller operators are welfare enhancing, but it is unlikely that they all are. Moreover, as noted in the main text, adequate bonding at drilling is expected to align private and social incentives for transfers, and remedial bonding at the point of transfer may preserve incentives for welfare-enhancing transfers while diminishing incentives for transfers motivated by liability shielding.

For all transfers of aging wells, not just transfers to smaller operators, our results suggest that much smaller production cost efficiencies are sufficient for transfers to be on average welfare enhancing. Rather than observing meaningful differences in production volumes, we see overall production changes that are close to zero in our long-run regression results. We also observe smaller changes in the share of non-producing wells that are unplugged, though this estimate is no longer offset by fewer non-producing wells on the extensive margin.

A4.1 Sample Welfare Calculation

Below we conduct a sample welfare assessment for transfers of aging wells to smaller operators and for all transfers of aging wells, based on our estimated outcomes ten years after transfer.

We define per-period welfare as follows:

$$
\begin{aligned}
W = {} & \text{Share(Producing)} \cdot (P \cdot Q - VOM \cdot Q - FOM - \omega) \\
& - \text{Share(Not Producing, Unplugged)} \cdot (\text{Social Cost of Unplugged Well}) \\
& - \text{Share(Plugged)} \cdot (\text{Annualized Plugging Cost})
\end{aligned}
$$

where P represents the world price of oil and gas, Q represents quantity of oil and gas produced, VOM represents variable production costs, FOM represents fixed production costs, and ω represents expected accident costs from producing wells (e.g., explosion risk, fugitive methane emissions). In this formulation of welfare, we assume that the surplus associated with oil and gas production is given by the global commodity price less production costs; we ignore externalities associated with the *use* of the product such as carbon emissions, as well as inframarginal consumer surplus.

Therefore, the change in welfare for transferred wells is given by:

$$
\begin{aligned}
\Delta W = {} & \Delta\text{Share(Producing)}(P \cdot Q - VOM \cdot Q - FOM - \omega)_{\text{transferred}} \\
& + \text{Share(Producing)}_{\text{not transferred}}(\Delta(P \cdot Q) - \Delta(VOM \cdot Q) - \Delta FOM - \Delta\omega) \\
& - \Delta\text{Share(Plugged)} \cdot (\text{Plugging Cost})_{\text{transferred}} \\
& - \text{Share(Plugged)}_{\text{not transferred}}(\Delta\text{Plugging Cost}) \\
& - \Delta\text{Share(Not Producing, Unplugged)} \cdot (\text{Social Cost of Unplugged Well})_{\text{transferred}} \\
& - \text{Share(Not Producing, Unplugged)}_{\text{not transferred}}(\Delta\text{Social Cost of Unplugged Well})
\end{aligned}
$$

where ΔX represents $X_{\text{transferred}} - X_{\text{not transferred}}$.

We then make several assumptions and simplifications to enable us to approximate the change in welfare using our data, our empirical results, and additional results from the published literature. Given our assumption of an exogenous world price for oil and gas, we can rewrite $\Delta(P \cdot Q) = P \cdot \Delta Q$. We can rewrite $\Delta(VOM \cdot Q) = VOM_{\text{transferred}} \cdot \Delta Q + \Delta VOM \cdot Q_{\text{not transferred}}$. We ignore ongoing accident risk for producing wells. The judgment proof literature suggests that smaller operators are expected to exercise less care in the prevention of accidents, so omitting this term means that we are likely to underestimate any welfare costs from transfers to smaller firms; we also underestimate the cost of the positive extensive margin production response. We assume that the plugging cost and the social cost of an unplugged well do not depend on the identity of the operator. Lastly, note that the statuses Producing, Not Producing & Unplugged, and Plugged partition the state space of wells (completely and mutually exclusively).[55] Therefore, we can write $\Delta\text{Share(Plugged)} = -\Delta\text{Share(Producing)} - \Delta\text{Share(Not Producing, Unplugged)}$.

We obtain the following expression for the change in welfare, which we take to data:

$$\begin{aligned}\Delta W = &(P - VOM_{\text{transferred}}) \cdot (\Delta\text{Share(Producing)}Q_{\text{transferred}} + \text{Share(Producing)}_{\text{not transferred}}\Delta Q) \\ &- \Delta\text{Share(Producing)} \cdot (FOM_{\text{transferred}} - \text{Annualized Plugging Cost}) \\ &+ \text{Share(Producing)}_{\text{not transferred}}(-\Delta VOM \cdot Q_{\text{not transferred}} - \Delta FOM) \\ &- \Delta\text{Share(Not Producing, Unplugged)} \cdot (\text{Social Cost of Unplugged Well} - \text{Annualized Plugging Cost})\end{aligned} \tag{6}$$

The first term represents changes in variable production surplus from combined intensive and extensive margin changes in production volumes. The second term represents the change in fixed costs associated with extensive margin changes in production, net of deferred plugging costs. The third term represents production cost efficiencies for producing wells. The fourth term represents the change in the external cost of unplugged, non-producing wells stemming from change in the probability of plugging, net of deferred plugging costs. We do not have reliable estimates of production cost efficiencies associated with well transfers, so we ask: how large would these efficiencies need to be for typical transfers to be welfare enhancing?

A4.1.1 Environmental Costs

As noted above, there are many components of the external cost of an unplugged well that have not been quantified in the literature. Therefore, we focus on external costs for which published estimates exist. Our preferred specification focuses on expected external costs from fugitive methane emissions and groundwater contamination. For methane emissions, we use a per-well methane emissions rate of 13 grams per hour, or 0.113 metric tons per year (Williams, Regehr and Kang, 2021; Boutot et al., 2022) and \$2400 as the social cost of methane emissions (in 2020 dollars) (U.S. Environmental Protection Agency, 2023). For groundwater contamination, we use \$4,281,500 for the cost of a contamination event (in 2012 dollars) and 0.21% as the annual probability of contamination from an orphan well (both from Boomhower (2019)). These values are based on Texas data; we apply them to our full sample. We also assume that the probability of groundwater contamination from an orphan well can be applied to unplugged, non-producing, but not necessarily orphaned wells in our sample. These values should be interpreted with caution given these assumptions and remaining scientific uncertainty.

For the change in the probability that a non-producing well remains unplugged, we use ten-year estimates from Appendix Tables A27 (for transfers to smaller operators) and A8 (for all transfers).[56] For transfers to smaller operators, we take the simple average of the estimated coefficients for wells transferred from large to medium operators, from large to small operators, and from medium to small operators.

[55] This statement is approximately true in our constructed dataset. A small number of wells are both producing and plugged in a given year, e.g., when the final year of production coincides with the year in which they are newly plugged.

[56] Note that we can rewrite the joint probability that a well is not producing and remains unplugged in terms of the conditional probability using Bayes Rule:

$$\begin{aligned}&\Delta\text{Share(Not Prod., Unplugged)} \\ &= \Delta\text{Share(Unplugged}|\text{Not Prod.)} \cdot \text{Share(Not Prod.)}_{\text{transf.}} + \Delta\text{Share(Not Prod.)} \cdot \text{Share(Unplugged}|\text{Not Prod.)}_{\text{not transf.}} \\ &= -\Delta\text{Share(Plugged}|\text{Not Prod.)} \cdot (1 - \text{Share(Prod.)}_{\text{transf.}}) - \Delta\text{Share(Prod.)} \cdot (1 - \text{Share(Plugged}|\text{Not Prod.)}_{\text{not transf.}})\end{aligned}$$

To estimate the value of deferring plugging costs, we use the midpoint of our range of typical plugging costs from Appendix Section A3.9 ($101,000). We assume that these costs are deferred for one year, at a social discount rate of 5%, to harmonize our estimates with the annual social cost of an unplugged well.

A4.1.2 Production Outcomes

For the overall change in production volumes for transferred wells (combining the intensive and extensive margins), we use ten-year estimates from Appendix Tables A29 (for transfers to smaller operators) and A12 (for all transfers). For transfers to smaller operators, we again take the simple average of the estimated coefficients for wells transferred from large to medium operators, from large to small operators, and from medium to small operators. To estimate revenues, this approach assumes typical commodity prices ($70 per barrel of oil, $4 per thousand cubic feet of gas, $9 per MMBtu of condensate).

To obtain typical variable costs, we use operating cost estimates from the Dallas Fed Energy Survey, which surveys executives from exploration and production firms (Federal Reserve Bank of Dallas, 2025). Small firms (defined in the survey as fewer than 10,000 barrels per day) reported average operating costs of $44 per barrel (in 2024 dollars). These responses do not differentiate between variable and fixed operating costs costs. We therefore multiply this unit cost by 986 boe at the median oil well in our sample, which yields total annual costs of $42,000 per well (in 2023 dollars). We assume half of these typical costs are variable and half are fixed – so $21 per boe in variable costs and $21,000 per year in fixed costs.

We also estimate the change in fixed costs associated with changes in production on the extensive margin. Differences in production probabilities are taken from Appendix Tables A33 (transfers to smaller operators) and A18 (all transfers). We use $21,000 per year for typical per-well fixed costs, following the assumptions described in the previous paragraph.

A4.1.3 Overall Welfare Assessment

Results from our illustrative back-of-the-envelope welfare assessment are provided in Table A37. From this exercise, we draw the qualitative conclusion that production cost efficiencies must be economically meaningful for transfers of aging wells to smaller operators to be welfare enhancing on average. By contrast, for aging wells transferred to any operator, modest production cost efficiencies are sufficient.

Perhaps surprisingly, this conclusion for wells transferred to smaller operators is largely driven by negative production responses. Two further comments are in order. First, we emphasize that the estimated changes in annual welfare from the change in production volumes in the second row of Table A37 should not be interpreted as equivalent to the production response that we would observe absent the judgment-proof problem. In our conceptual model, when large and small operators differ in the extent to which they internalize end-of-life cleanup costs and other environmental liabilities, transfers may occur earlier in the well's life cycle. Given the assumptions of our conceptual model, transferred wells would then see even larger negative production responses on the intensive margin, relative to transfers motivated solely by productive reallocation. For this reason, it is possible that private production cost efficiencies (not including any un-internalized environmental costs) do not outweigh private revenue losses from decreases in production.

Second, in the main text, we caution readers against over-interpreting specific magnitudes for changes in production volumes by buyer/seller size, given varying observation counts in different transfer bins and the fact that we are not able to conduct our heterogeneity analysis specifically for transfers incidental to M&A or part of firm creation or liquidation. This comment also applies to our illustrative back-of-the-envelope welfare calculation. Using our estimated production volume responses plus one standard deviation (i.e., responses that are smaller in magnitude) results in $22,900 in annual production cost efficiencies required for well transfers to smaller operators to be welfare enhancing. That is, our qualitative conclusion – that economically meaningful production cost efficiencies are required – continues to hold.

Finally, we note that this welfare assessment relies on estimates of *typical* environmental costs, plugging costs, operating costs, and production responses. Existing literature has documented that many of these inputs exhibit significant heterogeneity across wells. For example, the expected cost of groundwater contamination varies depending on the geology of the site and the population density; methane emissions also vary across wells, with some wells emitting little to no methane and others having high emissions rates (Kang et al., 2023). Another key qualitative conclusion from this exercise is that it is likely that some well transfers are welfare enhancing, including some well transfers to smaller operators, though it is unlikely that all are. An important research frontier is identifying the wells with the highest social return to plugging and structuring operator incentives and policy responses accordingly.

Table A37: Illustrative Back-of-the-Envelope Welfare Assessment

Welfare Term (in $)	**Aging Wells Transferred to Smaller Operators**	**All Transfers of Aging Wells**
Change in annual welfare from external cost of unplugged, non-producing wells, net of deferred plugging costs	-300	-200
Change in annual welfare from change in production volumes (at typical prices and variable production costs)	-18,000	-1,300
Change in annual welfare from fixed production costs, net of deferred plugging costs	-500	500
Change in annual welfare, assuming no variable or fixed production cost efficiencies	-18,800	-1,100
Total annual production cost efficiencies needed to render typical transfer socially optimal	33,500	1,800

Note: The first row calculates the expected cost of an unplugged, non-producing well using results from the literature, including groundwater contamination risk and methane emissions; this cost is partly offset by savings from deferred plugging costs. The net value is multiplied by the difference in the joint probability of being unplugged and non-producing for transferred versus not transferred wells, which is derived from our long-run regression results. The second row estimates the change in variable production surplus from combined intensive and extensive margin changes in production volumes for transferred versus not transferred wells, again obtained from our regression estimates. The third row estimates the change in fixed production costs, net of deferred plugging costs, from production changes on the extensive margin. The fourth row sums these three welfare terms; values in this row should be interpreted as average welfare changes per well ten years after transfer, before accounting for any production cost efficiencies. The fifth row reinterprets this partial welfare estimate as the change in total production costs (whether fixed or variable) needed for typical well transfers to be welfare-enhancing; this value is obtained by dividing the partial welfare estimate by the share of producing wells.