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Taxes and US Oil Production: Evidence from California and the Windfall Profit Tax†

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The recent boom in US oil production has prompted debates on levying new taxes on oil. This paper uses new well-level production data and price variation from federal oil taxes and price controls to assess how taxes affected production. After-tax price elasticity estimates range between 0.295 (0.038) and 0.371 (0.025). Response along the shut-in margin is minimal. There is no evidence of spatial shifting of production to minimize tax liabilities. Taken together, the results suggest that taxes reduced domestic production in the 1980s, and the response largely came from wells that continued to pump oil, but at a reduced rate. (*JEL* H25, H32, L71, L78, Q35, Q38)

The boom in US oil production in recent years has been remarkable. Harnessing new drilling techniques and technologies to extract oil formerly deemed too costly, between 2008 and 2013, the US oil industry effectively reversed two decades of decline.[1] In 2015, the United States pumped 9.4 million barrels of oil daily—more than any point since 1972. More crude is now pumped in more states than ever before, raising questions of how states should tax this production.

The spread and scope of the boom has drawn the attention of policymakers at the federal level and in a wide array of states. Oklahoma doubled its tax rate on new wells in May 2014, while Governor John Kasich of Ohio proposed raising the oil tax to 2.75 percent from 2.25 percent and California debated imposing a severance tax on oil production for the first time. Advocates for higher taxes in these states and others point to North Dakota's 11.5 percent severance tax on oil production and accompanying billion-dollar surplus.[2] Interestingly, Alaska took the opposite tack in 2013, reversing course and repealing tax provisions that increased severance tax rates as oil prices rose. The policy reversal in Alaska was motivated by declining state production; the lower tax rates are aimed at encouraging Alaskan production.

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[1] While domestic oil production fell every year between 1991 and 2008—a cumulative decline of 33 percent—since 2008, daily production has increased by 88 percent.

[2] Ohio's Governor Kasich argues "An increase—a modest increase—in the severance tax on Big Oil will allow us to reap some of the benefit of that oil, which they're pulling out of the ground and is a diminishing resource."

In these states and others mulling alterations to their tax treatment of oil production, the impact of taxes on production is a key consideration. The degree to which imposing higher taxes will alter producer behavior determines both the deadweight loss of such taxes and how effectively they will raise revenue. While drilling and casing a well may be an irreversible investment, production itself is often costly, meaning that taxes could potentially reduce production. The economic impact of oil taxes hinges critically on how producers respond to changes in after-tax price. If supply is inelastic, then these states could raise substantial revenue without triggering deadweight loss; if producers are sensitive to after-tax price, these taxes will be far less efficient. This paper examines the impact of an earlier federal excise tax to understand how taxes affect US production. While taxes could affect exploration or drilling activities, the analysis here focuses on the effect of excise taxes on oil production from existing wells.

Despite the importance of estimates of the elasticity of US supply for assessing the impact of policy changes, consensus elasticity estimates have been lacking. Key prior studies are summarized in Table 1. Most previous studies have relied exclusively on aggregate time-series variation and have mostly found very small and economically insignificant elasticities. Hogan (1989) and Ramcharran (2002) found statistically significant but economically minor supply elasticities of 0.09 (0.03) and 0.05 (0.02), respectively. Jones (1990) and Dahl and Yücel (1991) found insignificant elasticities of 0.07 (0.04) and −0.08 (0.06), and Griffin (1985) found a significant negative elasticity, −0.05 (0.02). Hogan (1989) also estimated a longer-run elasticity of 0.58 (0.18). The aggregate data used in these studies can lead to mismeasured estimates; Stoker (1993), Blundell and Stoker (2005), and Lewbel (1994) detail the difficulties in inferring behavioral reactions from time series results in the presence of individual heterogeneity. More recently, Anderson, Kellogg, and Salant (2014) uses Texas lease-level data from 1990 to 2007, which can address the potential heterogeneity among leases, to examine the responsiveness of production to contemporaneous West Texas Intermediate (WTI) prices and future prices. They find that production is not sensitive to either spot or expected future prices.

Most policy studies regarding oil markets rely on a range of plausible elasticities due to the lack of consistent credible estimates. In fact, the 2006 Congressional Research Service (CRS) report on proposed windfall profit taxes stated, “Few studies generate reliable estimates and in fact some studies estimate negative supply elasticities, which are not plausible” (Lazzari 2006). Thus, the CRS report, like other recent studies by federal agencies and the Organisation for Economic Co-operation and Development (OECD), employed a number of assumed elasticities—CRS used supply elasticities of 0.2, 0.5, and 0.8—rather than settling on a specific elasticity estimate.[3]

This paper estimates the responsiveness of domestic oil producers using a new rich dataset that reports monthly production for all onshore wells in the state of California—the third-ranking state in oil production—over a 31-year period

[3] The OECD in its 2004 Economic Outlook based its projection of production by countries that are not members of the Organization of the Petroleum Exporting Countries on elasticities of 0.1, 0.3, and 0.5. The US Energy Information Administration does not explicitly state the elasticities it uses in its analyses, but its forecasts indicate that it used an elasticity of 0.2 over a 10-year window and virtually 0 for 1-year responses.

Table 1—US Supply Elasticity Estimates from Previous Studies

Study	Sample period	Data	Elasticity estimate
Griffin (1985)	1971:I–1983:III	Quarterly data on total US production and average pretax posted price from 1971:I to 1976:II, average pretax first purchase price from 1976:III to 1983:III. No controls.	−0.05 (0.02)
Hogan (1989)	1966–1987	Annual data on total US production and average pretax first purchase price.	0.09 (0.03)
Jones (1990)	1983:III–1988:IV	Quarterly data on total US production and average pretax first purchase price. No controls.	0.07 (0.04)
Dahl and Yücel (1991)	1971:I–1987:IV	Quarterly data on total US production and average pretax first purchase price. Added annual controls for production costs, number of wells drilled, US income, and world oil production.	−0.08 (0.06)
Ramcharran (2002)	1973–1997	Annual data on total US production and average pretax first purchase price. Linear time trend included.	0.05 (0.02)

Notes: This table reports estimates of the elasticity of US oil supply from selected studies. Some of these studies estimated supply elasticities for total US production as a part of examinations of market structures among OPEC and non-OPEC countries; nonetheless, they are the studies cited in supply elasticity surveys such as Dahl and Duggan (1998). All of these analyses rely on aggregate time-series data for the United States. Standard errors are in parentheses.

beginning in 1977. The empirical strategy makes use of the variation in after-tax price induced by the end of price controls and the 1980 Windfall Profit Tax (WPT), which levied substantial and varying excise taxes on US wells. Under the WPT, marginal tax rates ranged from 22.5 to 70 percent. The constructed dataset of 30,025,957 observations describing 140,672 wells includes wells that were already completed and wells completed during the period. In addition to monthly production, the data report monthly values for each well, describing the quality of oil produced, the firm operating the well, the method of pumping, exact location, the field, and pool it taps, and whether it is capable of producing or is shut-in. This level of detail is necessary for determining each well's correct regulatory and tax treatment, as prescribed by the Code of Federal Regulations for each year. Using this policy detail and monthly field-by-grade prices from Platt's "Oil Price Handbook and Oilmanac" for each year, the path of after-tax prices for each well is accurately traced over time, taking into account differential regulatory and tax treatment across wells.

This new data allows for two improvements over previous studies. First, well-level data allow for better controls for time-varying factors (such as changing price expectations) and well heterogeneity. Because federal policies created substantial variation in after-tax price across wells and over time, the supply response is identified here using only within-well variation. In fact, regulatory and tax policy generate enough across-well variation in after-tax price in each month-year that nonparametric controls for common unobserved time factors affecting well productivity can also be included. Second, because the data track wells individually, the estimates can separate the extensive response—closing or shutting-in wells—from the intensive response—reducing output from wells that continue to produce. Distinguishing between these margins is important; if the supply response is driven by the shutting-in of wells, the high cost of reversing shut-in makes this a potentially permanent loss of oil.

The estimates make clear that production from existing wells is price-responsive—much more so than previous estimates of the same era suggest. The main results show an after-tax price elasticity of oil production in California ranging between 0.295 (0.038) and 0.371 (0.025). Response along the extensive margin is minimal; a 10 percent decrease in after-tax price would lead to at most a 1.67 percentage point increase in the absolute probability that a drilled well is shut-in. Like many currently proposed taxes, the WPT subjected different types of wells to different tax rates, creating an opportunity for producers to strategically shift production from tax-disadvantaged wells to tax-advantaged wells without changing or minimally changing total production. The empirical analysis does not find significant evidence of such strategic spatial shifting. Taken together, the results suggest that the WPT did in fact reduce domestic production, and most of the response came from wells that continued to pump oil, but at a reduced rate.

While the estimates here are the first oil supply responses to be identified using plausibly exogenous variation, there are several factors to consider in applying these estimates to the current policy context. First, although as new wells are completed they are added to the sample used to generate the empirical estimates, because the analysis examines the within-well supply response, the exploration and well drilling margins are not a part of the assessment. To the degree taxes delay or curtail these exploration and development activities, the response estimated here will underestimate the full impact of taxes on production.[4] Second, the tax-based variation in after-tax price used to identify the supply response dates back to the 1980s, and the analysis uses data exclusively from California where extraction costs are higher than average. Oil production today, particularly from reserves added over the last 10 to 15 years, harnesses new technologies. The most important of these is the widespread adoption of hydraulic fracturing methods that in conjunction with horizontal drilling techniques have allowed US producers to cost effectively access oil in shale deposits and other reservoirs. In 2015, oil production from hydraulically fractured wells comprised roughly half of total US crude oil production (Cook and Perrin 2016). It is unclear if this production is as sensitive to changes in after-tax price as production observed in California during the 1977 to 1985 period. Unfortunately, the data do not describe whether hydraulic fracturing techniques were used for any of the wells during the study period. The similarity of responses of wells of different ages in the data does suggest that simple aging may not be a crucial factor determining well productivity. Finally, the variation in after-tax price exploited here arises from a legislatively temporary excise tax—the WPT was slated to last only 11 years. Most oil excise taxes under consideration today would be legislated as permanent taxes. Permanent taxes on exhaustible resources change the opportunity cost of extraction identically for all future periods, while temporary taxes incentivize retiming production. As such, it is reasonable to consider the estimates here an upper bound on the reaction of producers to permanent taxes.

The empirical results can nonetheless help inform current policy considerations. Much like the WPT, many state oil tax regimes attempt to tax different types of

[4] For a theoretical investigation of the effect of taxes on exploration and development, see Smith (2012).

wells at differential rates, opening the potential for strategic spatial shifting. The estimates here suggest that this type of reallocation is not significant. Further, though states may legislate taxes permanently, the experience of Alaska and current attempts in Oklahoma to reverse the recent tax increase suggest that oil taxes may be subject to considerable policy uncertainty, rendering even legislatively permanent tax changes potentially temporary in the minds of producers. If current taxes are expected to be reversed with some probability, then the estimates reported here may be more applicable. The much higher elasticities estimated here relative to previous time-series estimates from the same era suggest that policymakers considering higher taxes on oil production should expect those taxes to slow production.

The paper proceeds as follows. The next section provides the relevant institutional knowledge regarding the decontrol of oil prices and the introduction of the WPT. Section II details the conceptual framework. Section III describes the new rich production and price data I assembled and details the estimation strategy. Section IV presents the empirical results. Section V concludes and discusses the relevancy of the results for oil tax policy.

I. Background: Decontrol and the 1980 Windfall Profit Tax

The estimation strategy makes use of price changes driven by price regulation, decontrol, and the imposition of federal excise taxes. These policies significantly altered producer prices and created considerable differences in producer price across wells. These policies are detailed below.

Before decontrol, of course, came price controls. President Richard Nixon implemented a system of wage and price controls in August 1971. Prices were capped in conjunction with the suspension of the convertibility of dollars into gold that effectively ended the Bretton Woods system, leading to a depreciation of the dollar and rising dollar prices for most internationally traded commodities.[5] After a brief phasing out, firm price ceilings were reinstated in June 1973, capping the price of oil at $4.25 a barrel. Following a steep increase in OPEC oil prices in October 1973, the US oil price ceiling was raised to $5.25 in early December 1973. OPEC again doubled its oil prices in late December 1973. To incentivize new production while retaining some price control, the Emergency Petroleum Allocation Act (EPAA) of 1973 established a two-tiered pricing system for domestic crude. "Old" oil—crude from wells producing at or below their 1972 production levels—was subject to price caps while "new" oil and oil from "stripper" wells, which produce, on average, less than 10 barrels of oil per day for at least 12 months, could be sold at market prices. In addition, for each barrel of new oil produced a barrel of old oil was released from price controls. Prices for old oil were capped at the May 13, 1973 selling price plus $0.35 (Viscusi, Vernon, and Harrington 2005).

The EPAA also created an allocation system to equitably distribute low-cost domestic crude across refiners. These regulatory programs included the Supplier-Purchaser rule, which froze buyer-seller relationships as of 1972 among

[5] For an excellent chronology of US oil prices, please see Hamilton (2013).

domestic petroleum producers, refiners, resellers, and retailers, and the Buy-Sell Program, eventually limited to just the 15 largest integrated refiners, which required refiners with access to above-average quantities of less expensive crude to sell crude to other refiners. The Crude Oil Entitlements Program created a permits system in which refiners with access to above-average quantities of controlled oil were required to buy rights to their supplies from refiners with access to below-average quantities with a special provision to aid small refiners who faced higher operating and capital costs.

In addition to establishing the Strategic Petroleum Reserve and Corporate Average Fuel Economy (CAFE) Standards, the 1975 Energy Policy and Conservation Act replaced the two-tier system with a three-tier system. Production below a well's baseline production control level (BPCL) was classified lower tier. Production above a well's BPCL was deemed upper tier, except for oil from wells that began producing after 1975, which was all upper tier oil. Upper and lower tier oil was priced at \$11.28 and \$5.25, respectively. Initially, the BPCL was set at a well's average monthly production during 1975. The third tier, which consisted of oil from stripper wells, and some other special sources, was not subject to price controls.[6]

The decontrol of oil prices began in 1976 with stripper wells.[7] Rising prices and less stable foreign sources prompted concerns regarding US oil independence and generated interest in increasing domestic oil production. The Carter administration began decontrolling non-stripper domestic crude in June 1979. Decontrol went forward with the understanding that the sudden increase in domestic producer prices would be taxed at the federal level.[8] The 1980 Windfall Profit Tax (WPT) was signed into law April 2, 1980, and virtually all non-Alaskan oil owned by a taxable private party was subject to the tax. Although the WPT was an excise tax levied on revenues rather than a profit tax that explicitly allowed for the deduction of costs, the excise tax was structured such that it taxed typically more costly or lower value oil production at lower rates and so crudely approximated a profits tax. Purchasers withheld the tax from payments to producers and filed quarterly WPT tax returns with the Internal Revenue Service.[9]

The timing of decontrol and WPT tax treatment varied by oil specific gravity, and by the age and productivity of the well from which oil was extracted. The WPT taxed oil that was typically more costly to extract and refine at a lower tax rate. American Petroleum Institute (API) gravity measures the specific gravity, or "heaviness" of oil, which determines how efficiently the crude can be refined into petroleum

[6] The determination of whether a barrel of oil subject to price controls was upper or lower tier is beyond the capacity of the data used here. This analysis assigns all price-controlled wells the upper-tier selling price, as it is the more likely price for marginal production from a California well.

[7] Vietor (1984) provides excellent detail on the timing and nature of these policy changes.

[8] According to the Joint Committee on Taxation's General Explanation of the Crude Oil Windfall Profit Tax of 1980, "without such a tax, decontrol probably could not [have gone] forward." For more detail on the decontrol and levying of the WPT, see Kalt (1981).

[9] Enforcement of the complicated WPT was costly. Oil industry representatives claimed annual compliance costs of \$40 to \$50 million while the IRS spent as much as \$15 million administering the tax. A General Accounting Office report referred to the WPT as "perhaps the largest and most complex tax ever levied on a US industry" (Thorndike 2005). Enforcement issues centered on the prices used to determine WPT liability on Alaskan North Slope oil rather than misclassifications among WPT tiers.

products. Heavier oil sells for lower prices.[10] Tax-favored oil included heavy oil that had an API gravity of 16 or less, and oil from stripper wells.

All taxable oil was divided into three tiers under the WPT; each tier corresponded to a different tax rate.[11] An operator's WPT tax liability was equal to the product of the WPT tax rate and the difference between the selling price and a tier-specific base price for each barrel of oil he sold. WPT payments were deductible from corporate taxable income, meaning that the after-tax price (ATP_{it}) received by the operator of well i at time t was:

$$ATP_{it} = \begin{cases} \left(1 - \tau_t^{Corp}\right)\left(P_{it} - \tau_{it}^{W}\left(P_{it} - B_{it}\right)\right) & \text{if } P_{it} > B_{it} \\ \left(1 - \tau_t^{Corp}\right)P_{it} & \text{otherwise} \end{cases},$$

where τ_t^{Corp} is the prevailing corporate tax rate, P_{it} is the real selling price, τ_{it}^{W} is the WPT rate, and B_{it} is the real base price for oil pumped from well i at time t. Note that real selling prices were common across all wells that produced oil of the same quality, while base prices and WPT tax rates potentially varied among wells producing the same grade of oil.

The WPT was legislated as a temporary tax. In total, the WPT raised nearly \$80 billion in revenue despite corporate income tax deductibility. Statute required the tax to expire by 1991. In reality, the tax became ineffective due to sharp decreases in oil prices in 1986; 1985 was the last year it raised any revenue. In fact, the WPT was repealed in 1988 to eliminate the administrative burden of a tax that did not raise revenue. The timing of decontrol and the simplified details of WPT treatment for each of the three tiers of oil follow. Figure 1 presents a timeline, while the key characteristics of the tiers are described by Table 2.[12]

Tier I Oil.—Tier I oil was non-heavy oil extracted from a non-stripper well that produced oil in 1978. Tier I oil was subject to price controls through 1979. Price controls on Tier I oil were initially phased out gradually.[13] At the end of January 1981, the phase-out of price controls was abruptly ended and Tier I oil was fully decontrolled. The base price for Tier I oil was \$0.21 less than the May 1979 price control price for the property. The tax rate on Tier I oil was 70 percent.

Tier II Oil.—Tier II oil consisted of non-heavy oil from stripper wells that produced oil in 1978, and oil produced from a Naval Petroleum Reserve (NPR) field. A well was considered a stripper well if it ever averaged less than 10 barrels of oil per day for 12 consecutive months after 1972. Oil produced from stripper wells

[10] API gravity is an inverse function of specific gravity: API Gravity $=$ (141.5/Specific Gravity) $-$ 131.5.

[11] Specific categories of oil, largely state-owned, Native American-owned, or charitable trust-owned oil, were exempt from the WPT. See Lazzari (2006) for further details.

[12] For further detail, see Joint Committee on Taxation (1981).

[13] Beginning in January of 1980, the selling price was a weighted average of the world market price and the price control price with the weight on the market price equal to 0.046 multiplied by the number of months since December 1979.

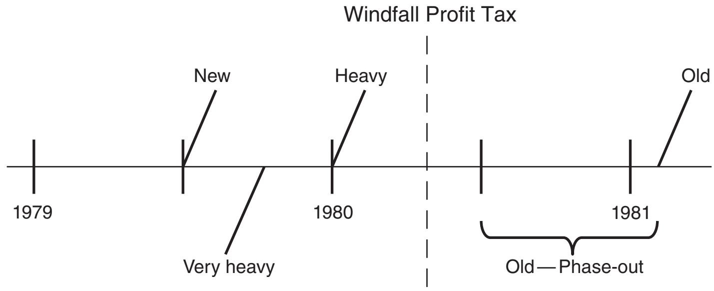

Figure 1. Timeline of Price Decontrol and Enactment of 1980 Windfall Profit Tax

Notes: This figure provides a timeline of the decontrol of US oil prices and the introduction of the Windfall Profit Tax. New oil (oil extracted from wells that did not produce oil in 1978) was decontrolled in June 1979. Very heavy oil (oil with an API gravity of less than 16 degrees) was decontrolled in September 1979. Heavy oil (oil with an API gravity of less than 20 but at least 16 degrees) was decontrolled in January 1980. Old oil (oil extracted from wells that produced oil in 1978) was gradually decontrolled between January 1980 until January 28, 1981. During the phase-out period, old oil sold at a price that was equal to the weighted average of the world market price and the price control price ceiling, with the weight on the world market price growing by 0.046 each month. Old oil was fully decontrolled by President Reagan on January 28, 1981. February 1981 was the first full month in which old oil was decontrolled. 1980 Windfall Profit Tax was signed into law April 2, 1980 and went into effect immediately.

Table 2—Tier Classifications

	Heavy	Stripper	Produced in 1978	WPT tax rate
Tier I	No	No	Yes	70%
Tier II	No	Yes	Yes	60%
Tier III				
(a)	All	All	No	30% initially, then reduced to 22.5%
(b)	Yes	All	Yes	30%

Notes: This table describes the oil and well characteristics that determined Windfall Profit Tax rates. Tier I oil was non-heavy oil extracted from a non-stripper well that produced oil in 1978. Tier II oil consisted of non-heavy oil from stripper wells that produced oil in 1978, and oil produced from a Naval Petroleum Reserve (NPR) field. Tier III oil was either new oil from wells that did not produce oil in 1978 or heavy oil with an API gravity of 16 or less.

was exempted from price controls in August 1976. An NPR field is one of four fields owned by the federal government to which access is leased to private operators. The base price for Tier II oil was the December 1979 selling price of oil from the same property multiplied by 0.425, a conversion factor that achieved a statutorily set average base price of $15.20. The tax rate on Tier II oil was 60 percent.

Tier III Oil.—Tier III oil was composed of two types of oil: new oil from wells that did not produce oil in 1978 and heavy oil with an API gravity of 16 or less. New oil was fully decontrolled in June 1979. Price controls on heavy oil were lifted August 17, 1979. The base price for both new and heavy oil was the December 1979 selling price of oil from the same property multiplied by 0.462. Heavy and new oil were the most tax-favored types of oil; the tax rate on Tier III oil was 30 percent initially and for new oil was gradually reduced to 22.5 percent beginning in 1982.

The three tiers of oil, and even different categories of oil within Tier III, were treated very differently by government policies. Differences in the timing of decontrol and differential tax treatment provide the variation in after-tax price that generates the supply elasticities estimated here. These policies created cross-sectional variation in after-tax price allowing for flexible controls for underlying common time-varying factors, including future price expectations.

II. Conceptual Framework

A. *Tax Incidence*

As they account for a small share of world production and operate in a market alongside a cartel, US oil producers—including the California producers examined here—can reasonably be assumed to be price-takers.[14] Furthermore, the availability of tax-exempt imports fixed the refiner price at the world price, meaning that US producer prices were reduced by the full amount of the tax and the incidence of the WPT fell wholly on US oil producers.[15]

B. *Incentives to Shift Production*

As first shown by Hotelling (1931), exhaustibility makes oil extraction a "pump today or pump tomorrow" decision.[16] Consider a well operator choosing an extraction path to maximize the present value of total profit over the life of the well, taking into account the exhaustibility of the reserves of his well. Assuming for simplicity that both the full price path and total reserves, R_0, are known at time 0, the producer's problem can be written as a Lagrangian:

$$(1) \qquad \Lambda(q_t, \lambda_t) = \int_0^{T(\mathbf{p})} e^{-rt}\left[p_t q_t - c(q_t)\right] dt - \lambda_t\left[\int_0^{T(\mathbf{p})} q_t dt - R_0\right],$$

[14] Kilian (2009) asserts "the price of crude oil is determined in global markets." As in other empirical studies, such as Smith, Bradley, and Jarrell (1986), here production decisions in California are assumed to not affect pretax prices.

[15] Though transportation costs are small—roughly 5 percent of oil prices—domestic producers may have been able to pass a fraction of the tax, equal to the transport cost, on to purchasers. All oil produced in California is refined within the state, but refiner demand exceeds production with imports filling the gap. Imports come largely from Canada and Mexico, and average transport costs run roughly $1.30 per barrel according to Rodrigue, Comtois, and Slack (2013).

[16] Hotelling's seminal work has been extended and discussed by numerous authors, including Dasgupta and Heal (1980). Robert M. Solow's 1974 Richard T. Ely lecture (Solow 1974) provides an insightful (and humorous) summary of Hotelling's work, subsequent efforts, and their implications.

where q_t is the extraction quantity at time t, p_t is the price, $c(q_t)$ is the cost of extraction, λ_t is the shadow value of reserves, and $T(\mathbf{p})$ is the time at which all profitable oil has been extracted and the economic limit of the well has been reached.

Because the typical California well lacks sufficient natural subsurface reservoir pressure for the oil to flow to the surface, most wells are pumped, making extraction costly. Extraction costs include fixed costs, such as the user cost or rental cost of pumping equipment, and operating costs, such as energy inputs to drive the pump and labor costs of monitoring. The cost function is modeled as convex in the extraction quantity with an additional fixed cost of operating. Letting f represent the fixed cost of operation, the cost function can be written as

$$c(q_t) \;=\; \begin{cases} cq_t^2 + f & \text{if the well produces} \\ 0 & \text{if the well does not produce} \end{cases},$$

where c is a parameter of the cost function.

When $q_t \;>\; 0$, production will be determined by the first-order condition:

$$p_t - c'(q_t^*) \;=\; \lambda e^{rt} \tag{2}$$

meaning that in each period of production the last barrel extracted will generate the same present value profit. The shadow value of reserves represents the value of an incremental addition to the reserves, that is the opportunity cost of extraction. For this quadratic cost function the shadow value, λ, is given by

$$\lambda \;=\; e^{-rT}\left(p_T - 2\sqrt{fc}\right). \tag{3}$$

The shadow value of reserves will be higher if the life of the well, T, is shorter, meaning that the incremental addition will be pumped sooner and thus worth more in present value. Additional reserves are also worth more if the price of oil in the last period the well will produce, p_T, is higher, or the fixed, f, or variable cost, c, of production, is lower.

Given the quadratic cost function, the optimal extraction at time t is

$$q_t^* \;=\; \frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c}, \tag{4}$$

where again T is the economic life of the well.[17] Extraction will rise with price and will be inversely proportional to the slope of the marginal cost function—oil will be extracted more slowly from wells with more steeply convex costs of extraction.

[17] $T(\mathbf{p})$ is implicitly defined by the exhaustibility constraint $\int_0^T \left[\frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c}\right] dt \;\leq\; R_0$. Under the assumption of constant price, $p_t \;=\; p_T \;=\; p$, in the final period the extraction rate will be $q_T \;=\; \frac{p}{2c} - \frac{e^{-r(T-T)}\left(p - 2\sqrt{fc}\right)}{2c} \;=\; \sqrt{\frac{f}{c}}$. The extraction rate equates the marginal and average cost of extraction: if more oil was produced, the marginal cost would be too high to justify the marginal production sold at price p; if less oil was produced, the average cost would be higher than marginal profit and the well would shut down.

The well will not produce under two scenarios. First, when marginal profit cannot possibly exceed the rising scarcity rent, that is, when $p_t - 0 < \lambda e^{rt}$. Second, production will cease when the optimal production quantity according to the first-order condition above does not generate sufficient revenue to cover the total costs of production, that is, even when $q_t^* > 0$ but $p_t q_t^* < c q_t^{*2} + f$. Both of these zero production scenarios could arise when prices drop or taxes rise such that after-tax price is too low to justify production.

Permanent and temporary excise taxes will alter extraction differently. Assuming constant prices for notational simplicity, the introduction of a permanent *ad valorem* excise tax at rate τ will reduce after-tax price to $p_1 = (1-\tau)p$. The permanent excise tax reduces prices in all periods, including the final period T, which determines the opportunity cost of extraction. As equation (3) shows, a permanent tax will directly reduce the opportunity cost of extraction by reducing the price received in the final period of extraction from p to p_1.[18] Following the introduction of a permanent excise tax, extraction rates will follow:

$$q_t^* = \frac{p_1}{2c} - \frac{e^{-r(T(p_1,p)-t)}\left(p_1 - 2\sqrt{fc}\right)}{2c}. \tag{5}$$

A permanent tax shifts the extraction path downward without altering its general shape. A temporary tax in place from time 0 to time t_1 will effectively be a permanent tax for wells with lives shorter than t_1. For longer lived wells, a temporary tax will alter the general shape of the production path. For a well that produces longer than the temporary tax is in place, a temporary tax like the WPT reduces the near-term after-tax price received by producers but does not directly change the after-tax price received for production after the tax has expired.[19] Extraction will decline sharply while the tax is in place and then rise again once it expires.

While the tax is in place between 0 and t_1, the operator's optimal extraction quantity will be

$$q_t^* = \frac{p_1}{2c} - \frac{e^{-r(T(p_1,p)-t)}\left(p - 2\sqrt{fc}\right)}{2c}. \tag{6}$$

Assuming zero fixed costs for expositional clarity, the impact of a change in after-tax price p_1 on extraction while the tax is in place is

[18] A permanent tax will also indirectly reduce the opportunity cost of extraction by extending the life of the well; less oil is pumped each period, but the well will be profitably pumped for slightly longer. After the introduction of a permanent tax, the life of the well with $f = 0$ is defined by $\frac{p_1 T(p_1)}{2c} - \frac{p_1\left(1-e^{-rT(p_1)}\right)}{2cr} \leq R_0$. Higher permanent taxes that reduce p_1 lead to longer well life as $\frac{dT}{dp_1} = \frac{T}{p_1\left(e^{-rT}-1\right)} + \frac{1}{p_1 r}$ is negative. The last barrel is pumped later, making it worth less.

[19] A temporary tax will have a small indirect effect on the opportunity cost of production. By slowing production prior to t_1, higher temporary taxes leave more oil to be pumped in the posttax period and lengthen the life of the well. With a temporary tax and $f = 0$, the life of the well is defined by $\frac{p_1 t_1 + p(T(p_1)-t_1)}{2c} - \frac{p\left(1-e^{-rT}\right)}{2cr} \leq R_0$ with $\frac{dT}{dp_1} \leq \frac{-t_1}{p\left(1-e^{-rT}\right)}$.

$$\frac{dq_t^*}{dp_1} = \frac{1}{2c} - \frac{e^{-r(T(p_1,p)-t)}}{1+e^{-r(T(p_1,p)-t)}}\frac{rt_1}{2c} \tag{7}$$

again, where $p_1 = (1-\tau)p$—higher tax rates lead to lower extraction. The first term of equation (7) describes the direct impact of a tax change on extraction: a higher after-tax price accelerates extraction. The second term captures the mitigating impact of the exhaustibility constraint: higher price before t_1 reduces the life of the well, increasing the opportunity cost of extraction since the last barrel is pumped sooner. Similarly, higher prices after the tax period increase the opportunity cost of production and reduce extraction while the tax is in place. Temporary taxes like the WPT create strong incentives to temporally shift production. Producers, though, trade-off avoiding the tax against higher extraction costs and delayed revenues when they shift production to the posttax period.[20] As equation (7) shows, this incentive will be strongest for wells that have smaller cost parameters, as the added cost of shifting production will be lower when c is lower.

Of course extraction often does involve fixed costs, for pumping and monitoring equipment, for example. These fixed costs can induce shut-in, even in reaction to a temporary tax, if the oil remaining in the well cannot be profitably extracted. That is, a producer may decide to shut-in if

$$\int_0^{t_1}\left(p_1 q_t - cq_t^2 - f\right)dt + \int_{t_1}^{T(p_1,p)}\left(pq_t - cq_t^2 - f\right)dt < 0. \tag{8}$$

Shut-in will be most likely for wells with high fixed or operating costs and little remaining reserves.

Price uncertainty, of course, complicates matters.[21] Different forms of price uncertainty have differing implications (see Weinstein and Zeckhauser 1975 and Lewis 1977) but in general, greater uncertainty, all else equal, enhances the option value of holding the reserves *in situ*.[22]

For some wells it may be true that extraction is not a choice variable for the operator. For example, the leaseholder of a flowing well that produces with its own natural pressure and is not pumped has little incentive to adjust production, and incur the related costs, in reaction to changes in after-tax price. The degree to which California's oil wells during this period were operating at a constrained level of production will limit the price responses estimated here.

The temporary nature of the WPT meant that operators had much stronger incentives to reduce production in reaction to contemporaneous taxes than they would under a permanent excise tax. Thus, the elasticities estimated here can be considered an upper bound on the response of supply to permanently levied taxes. The WPT, nonetheless, offers a unique opportunity to estimate the impact of taxes on oil production. Typically, all wells producing similar crude face a common price

[20] For more detail on how permanent and temporary taxes alter the extraction path, please see the online Appendix.

[21] Investigation of the statistical behavior of crude prices have found differing patterns with work by Pindyck (1999) finding strong evidence of mean-reversion, while more recent work by Hamilton (2009) concluded that crude prices follow a random-walk without drift.

[22] Kellogg (2014) shows that uncertainty also affects drilling decisions. In particular, when the expected volatility of futures prices increases, drilling activity decreases by a magnitude consistent with the real options model.

and are subject to a single tax rate. Thus, regressions of production on after-tax price preclude flexible time controls and will yield coefficients biased by time-varying factors, such as the confounding effect of changing price expectations. The WPT taxed otherwise similar wells very differently, allowing for time fixed effects that net out the effect of evolving price expectations. As long as producers held common expectations for future price—which given the economic importance of the question and research budgets of oil producers seems reasonable—the cross-sectional tax variation of the WPT should afford the opportunity to isolate the impact of contemporaneous after-tax prices on production. Further, any taxes on oil that are viewed as ultimately temporary in light of potential policy changes will have similar incentives.

The spatial layout of oil extraction informs the empirics as well. Most operators do not pump their reserves with a single well. Instead, a leaseholder typically taps his reserves using multiple wells. Wells on the same lease operated by the same firm can be subject to differential WPT treatment due to differences in well and oil characteristics. If production from well i on lease l at time t is denoted with q_{ilt}, then well-level regressions of production on after-tax price will yield the mean response of well production to contemporaneous price, dq_{ilt}/dp_{ilt}. The production of wells on the same lease, however, may be related; namely, a leaseholder could strategically reallocate production from high- to low-tax wells, leaving total lease production unaffected, or less affected, while minimizing tax liabilities. This type of shifting will lead to lease-level production responses that are smaller than suggested by well-by-well regressions, that is, dq_{ilt}/dp_{ilt} would exceed average lease production, $d\overline{q_{lt}}/d\overline{p_{lt}}$. If there is no spatial shifting, the supply elasticity estimated from well-level regressions of production on after-tax price should be equivalent to the response of average production of all the wells on a lease to average after-tax price, weighted by production. Any lack of well-level metering only raises the potential for leaseholders to allocate production across wells to minimize tax burdens without actually shifting real production to tax-advantaged wells.

III. Data and Empirical Design

The decontrol of oil prices and the introduction of federal excise taxes created substantial variation in after-tax price over time and across wells. These policies classified wells into different regulatory and tax tiers by the characteristics of the well and the oil it produced. Thus, well-level data are necessary to account for and make use of this substantial variation. Wells within a field could be assigned very different after-tax producer prices depending on whether they produce the same kind of oil, share the same stripper status, or produced in 1978. To use this well-level variation, I assembled a new database of well-level production and after-tax producer prices that describes every onshore well in California starting in 1977, which encompasses the regulatory and tax periods. These data have not been used in previous studies.

A. *Data*

California remains the third highest oil producing state in the nation despite the recent surge in production elsewhere. Onshore producers account for roughly 92.5 percent of state production, with offshore wells pumping the rest.[23] California crude is generally of lower quality than more prominent benchmark crudes such as WTI. California oil was more than 60 percent heavy crude during the 1977–1985 period. Heavy oil is generally more expensive to extract and refine.[24]

The data used in this study cover all potentially active onshore oil wells in California, beginning in 1977. The main analysis regarding the impact of price regulation and excise taxes makes use of data describing the more than 75,000 oil wells that were capable of producing at some point during the 1977 to 1985 period. The State of California Department Conservation Division of Oil, Gas, and Geothermal Resources requires operators to report monthly production and characteristics for all completed wells. Each month the data report the barrels of oil, thousands of cubic feet of natural gas, and barrels of water produced from each well in addition to the status of the well (abandoned, producing, shut-in, etc.). The oil production that is the key quantity of interest in the analysis is well-level crude oil production, separated from any water or gas that the well produces that month. On some leases, production is not metered for each well individually. Instead, all of the wells on a lease are flowed to a separating facility, where production is metered at the lease-level. This aggregate lease production is then allocated back to the lease's wells based on periodic "well tests," in which each well is flowed into a small test separator to measure its production rate.[25]

The data are particularly well suited for the analysis since they provide monthly information that allows more precision in the timing of price and tax changes relative to the annual or quarterly data used in other studies. Most importantly, the data report the characteristics necessary to determine the timing of decontrol and WPT tax treatment for each well. Characteristics reported each month include the date of well completion, API gravity of the oil produced, the field and pool being tapped, operator name, and the status of the well.

Some adjustments to the data were necessary. In months where oil production is zero either because the well is not yet complete or is shut-in, no API gravity data are reported; I assign these well-month observations the soonest future API gravity in the case of uncompleted wells and the most recent previous API gravity in the case of shut-in wells.

All oil does not trade at a single price; different grades, in terms of API gravity and sulfur content, trade at their own prices. The price data are from Platt's "Oil Price Handbook and Oilmanac," which provides monthly field-by-field posted

[23] Mauritzen (2014) examined Norwegian offshore fields and found no significant evidence of a concurrent reaction of field production to oil price, but found a lagged effect of roughly a 2 to 4 percent production increase for a $10 per barrel real price increase.

[24] Higher API gravity oil is lighter with a lower specific gravity and sells for a premium. During the 1977–1985 period, 61.4 percent of California crude had an API gravity of 20 or less, while 49.8 percent had an API gravity of 16 or less.

[25] For more information regarding the oil production process, please consult the thorough and accessible non-technical volume by Hyne (2001).

prices by API gravity for controlled and decontrolled oil. Fields for which price data are not available are assigned the average price for oil of the same API gravity for wells in California that month. Because the prices of different grades do not track the world price in parallel, using these more precise prices could potentially be important. Crude is globally traded and priced based on API gravity and location. Location provides information on the sulfur content of the oil since sulfur content is largely constant across the wells in a field.[26] Oil with low sulfur content, known as "sweet" crude, can be refined into light petroleum products such as gasoline or kerosene more cost effectively than high-sulfur, "sour" crude, which is typically processed into diesel or fuel oil.[27] For refining purposes, oil of the same API gravity and sulfur content is viewed as perfectly substitutable regardless of origin.

While various congressional acts created the systems of regulation, decontrol, and excise taxation that provide the identifying variation in producer prices, the detailed implementation rules of these legislative acts are found in the Code of Federal Regulations for each year. The details of price control assignment and WPT tax treatment are drawn from "Title 10: Energy" of the Code of Federal Regulations for each year, 1976–1980, and "Title 26: Internal Revenue" of the Code of Federal Regulations for each year, 1981–1985.

Table 3 presents summary statistics for the full sample of 75,342 wells used to assess the impact of the regulatory and tax regimes of the late 1970s and 1980s. The average well produces 476.4 barrels of oil per month; conditioning on nonzero production raises the average roughly 40 percent. Approximately 28 percent of well-month observations report zero oil production; these wells could potentially be shut-in or not yet been completed. The production data are right skewed. The median well produces 113 barrels of oil per month, the seventy-fifth percentile well-month observation produces 428 barrels per month, and the ninety-ninth percentile observation produces 5,325 barrels per month. The within-well production variation, 868.5, is comparable to the overall standard deviation, 1,473.8. The average producer price during the period, \$18.3, is only 45 percent of the mean purchaser's price, with part of this difference attributable to the corporate income tax and part to the WPT. Producers for whom price controls were gradually phased out as they faced excise taxes under the WPT received the lowest—less than \$12.30—after-tax prices. Producers of lighter oil received the highest prices in the sample—exceeding \$32.00—at the end of 1979 and the beginning of 1980 prior to the introduction of the WPT. The within-well deviation in average after-tax price is 15 percent smaller than the overall variation in after-tax price, while the within-well and overall variation in pretax price is comparable. This discrepancy is driven by the differential regulatory and tax treatment of wells over the period. The average and median API gravities are 18.2 and 15.0, respectively, illustrating the heaviness of California oil. Finally, note that although there is considerable variability in API gravity in the

[26] Refiners with the lowest transportation costs, typically those with the closest refineries, will purchase from a given field. As individual purchase and production decisions are too small to move transport costs, the difference between price at the wellhead and price at the refiner is taken to be independent of the decisions of individual firms.

[27] When oil prices are referred to in the popular media, the price frequently quoted is that of WTI, or UK Brent, both of which are light and sweet. The OPEC basket, which is a weighted average of crudes produced by OPEC nations, is a third benchmark, and is both heavier and sourer than WTI or Brent.

Table 3—Summary Statistics

	Mean	Standard deviation	
		Overall	Within-well
Oil production (barrels)	476.4	1,473.8	868.5
Oil production if producing	663.2	1,702.9	869.3
After-tax price ($)	18.3	4.1	3.5
WPT tax rate	0.21	0.24	0.19
Purchase price ($)	41.0	10.1	9.76
API gravity (degrees)	18.2	6.8	1.1
Number of wells	75,342		
Observations	6,517,139		

Notes: This table presents summary statistics describing the well-month observations that comprise the sample for the main regression analysis leaving out one observation where production exceeds 10,000 barrels in a month. Not all 75,342 wells report 108 observations since new wells are drilled and old wells are abandoned during the sample period.

sample (standard deviation of 6.8), each individual well has little variation in the API gravity of the oil it produces (standard deviation of 1.1).

B. *Estimation Strategy*

The way in which oil prices were decontrolled and oil production was taxed provide an unusual degree of variation in net-of-tax prices for often identical commodities across producers and over time. The decontrol of oil prices and the introduction of the WPT were policy changes implemented in tandem; oil prices were decontrolled by executive order while legislation enacting the excise tax was in committee in Congress. Figure 1 illustrates the timing of decontrol for different types of oil over the 1979 to 1981 period, starting with new oil and ending with old oil. These different categories of oil were also subject to different WPT tax rates and corresponding tax bases. Taken together, these policy changes provide substantial deviations from the world market price. This policy-induced variation in after-tax price identifies the supply response estimated here.

The policy-driven incentives to shift production described above in Section II suggest a simple empirical framework. The second term of equation (6) will be very small for long-lived wells like those in California and to first-order a natural model that would yield estimates of dq_{it}/dp_{it} is a simple linear regression model of the form

$$(9) \quad q_{it} = \beta\left(1-\tau_t^{Corp}\right)\left(B_{it}+\left(1-\tau_t^{W}\right)\left(P_{it}-B_{it}\right)\right)+X_{it}\gamma+\chi_t+u_i+\eta_{it},$$

where q_{it} is extraction per month, τ_t^{Corp} is the prevailing corporate tax rate, B_{it} is the real base price, τ_t^{W} is the WPT tax rate, P_{it} is the real selling price for oil pumped at well i at time t, X_{it} is a set of controls, and $u_i+\eta_{it}$ is the error term.[28]

[28] The after-tax price here, $\left(1-\tau_t^{Corp}\right)\left(B_{it}+\left(1-\tau_t^{W}\right)\left(P_{it}-B_{it}\right)\right)$, captures the producer price under both price controls and the WPT. Producers bore the full incidence of both. Price controls and the WPT can both be described

Estimates of β from equation (9) capture the average well response to changes in after-tax price, including both the extensive and intensive margin. For wells near the end of their economic life, the posttax profit from remaining reserves may not offset the losses they will incur during the tax period. Thus, some well operators may choose to exit by shutting-in their wells. In fact, there was notable concern regarding response along this extensive margin at the time the tax was introduced.[29] To assess the degree of extensive response, we want to estimate the impact of variation in after-tax price on the decision to shut-in a well. That is, a model of the form:

$$(10)\quad S_{it} = \delta\left(1 - \tau_t^{Corp}\right)\left(B_{it} + \left(1 - \tau_t^{W}\right)\left(P_{it} - B_{it}\right)\right) + X_{it}\gamma + \chi_t + u_i + \eta_{it},$$

where S_{it} is a dummy variable equal to one if the well is shut-in, and the regressors are as described above. The coefficient on after-tax price, δ, measures the percentage change in the probability of shut-in caused by a \$1 after-tax price increase.

If the price ceilings and WPT tax rates were uncorrelated with the error term, the policy-based variation in after-tax price would yield an unbiased estimate of the tax response for both equations (9) and (10). But if after-tax price is correlated with an underlying well-specific component of the error term, u_i, then pooled ordinary least-squares estimation will yield biased estimates. The bias of the estimate will depend on the correlation between the omitted well-specific effect and the tax rate or price ceiling. Price ceilings and excise tax rates were not randomly assigned to wells by price controls and the WPT. Well characteristics (e.g., well age and stripper status) and oil characteristics (i.e., specific gravity), which can be factors in the cost of extraction, were used to determine regulatory and tax treatment. Regulatory and tax treatment varied along these dimensions, in part in an effort to favorably treat operators who would be most adversely impacted by the tax. Thus, pooled ordinary least squares (OLS) estimates of equation (9) or (10) would be inappropriate.

Because extraction costs vary across wells even within tier, controls for the factors that determine tax treatment may not be sufficient to fully address heterogeneity in extraction costs. Instead, to isolate variation in the after-tax price not related to underlying differences in extraction costs, the analysis uses only within-well variation. Because of the considerable across-time variation in after-tax price generated by the decontrol of oil prices and the levying of the WPT, there remains sufficient variation for each well over time to identify the supply response.

C. *Residual Variation in After-Tax Price*

Price variation generated by taxes is likely to be perceived as having a persistence that differs from that generated by movements in price. If producers perceive price changes as having less persistence than even temporary tax-driven changes, then supply elasticities generated by price changes would understate the supply response

as taxes on a price basis, where the basis is the difference between the selling price of a barrel of oil and a statutory base price. In the case of price controls, the tax rate is 100 percent.

[29] For example, two months before the enactment of the tax, the *Wall Street Journal* ran a critical editorial about the proposed WPT titled "The Close-the-Wells Tax" (January 22, 1980).

to temporary taxes. Thus, within-well variation in after-tax price, which retains both price- and tax-driven changes in after-tax price may not be the appropriate price measure to understand the impact of taxes. To isolate price differences due only to differential decontrol and tax treatment, the data are purged of time-series variation in price. Figure 2 plots different price measures for two wells. The real posted price line reports the real purchase price of the oil. The upper plot describes a relatively tax-disadvantaged well, and the lower plot describes a relatively tax-favored well. The plot for each well tracks this process of isolating relative within-well variation in after-tax price.

The upper plot tracks an initially non-stripper well in the Livermore field that was decontrolled gradually beginning in January 1980, then fully decontrolled in January 1981. The gradual decontrol can be seen in the nearly linear upward slope of the Real Posted Price line starting in January 1980 and continuing until January 1981, when the price discontinuously jumps with full decontrol. This well was initially subject to a 70 percent WPT excise tax. The onset of the tax is the sudden downward jump in the after-tax price in March 1980. In October 1982, the well qualified as a stripper well and thus shifted to the slightly more tax-favored Tier II with a 60 percent excise tax rate; hence, the uptick in the after-tax price. The decrease in posted price in January 1983 led to decreases in all price measures.

The estimation strategy removes well and time fixed effects. Purging the after-tax price measure of well fixed effects amounts to subtracting the well's average price over all periods from the price each period. Thus, the Residual–Well FE line is the after-tax price line shifted downward by the well mean price. Further purging the post-well fixed effect residuals of time fixed effects amounts to then subtracting the average price each period over all wells. This two-way residual isolates relative within-well price variation, where relative means relative to all other wells in the sample that period. Thus, this well's two-way residual declines beginning in June 1979 as Tier III oil is fully decontrolled and market oil prices rise. The Residual–Well, Time FE line slopes upward between January 1980 and March of 1980 as the well began gradual decontrol, while already decontrolled wells faced less rapidly increasing prices. When the WPT is levied in March 1980, the two-way residual continues its upward trend because the increases in after-tax price due to continued decontrol more than offset the tax. Even after full decontrol in January 1981, the relative within-well after-tax price remains negative because this well faces the highest tax rate of all wells. The disadvantage narrows as posted prices in the Livermore field increased relatively faster than other fields. When the well is reclassified as a stripper well, there is a final uptick in the two-way residual as its WPT tax rate has fallen by 10 percentage points, which is short-lived as the Livermore price premium fades a few months later. From that point on, the two-way residual is near zero since declines in the posted price result in after-tax prices nearly equal to the average after-tax price for each well.

The lower plot tracks a relatively tax-favored well. The well did not produce oil in 1978 and is classified as a new well. The after-tax price line jumps upward in June 1979 when new oil was decontrolled and again several months later as posted

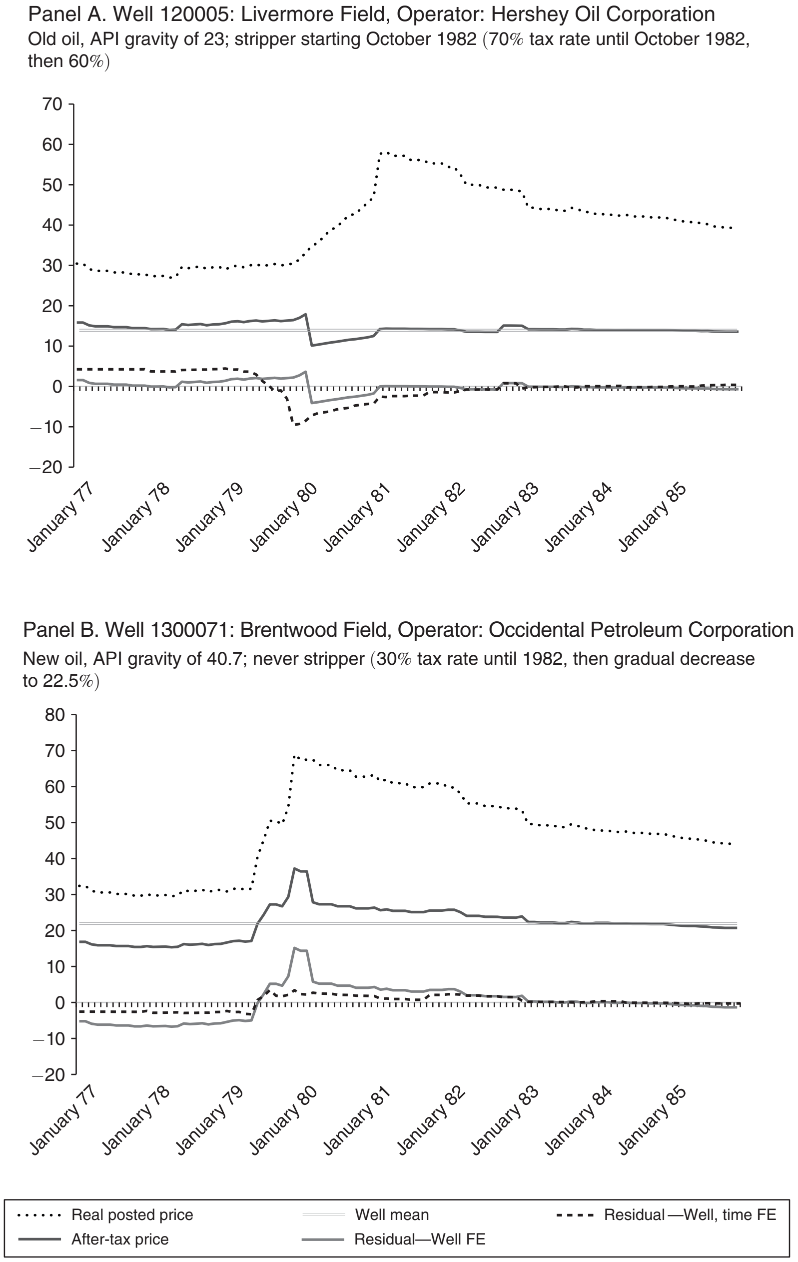

Figure 2. Timeline of Price Decontrol and Enactment of 1980 Windfall Profit Tax

Notes: This figure presents price measures for two wells that are plotted above. The upper plot tracks a relatively tax disadvantaged well that was decontrolled gradually beginning in January 1980, then fully decontrolled in January 1981. The lower plot tracks a relatively tax-favored well that did not produce oil in 1978 and is classified as a new well. In each plot, the dotted line signifies real posted price at the well head, the solid line is real after-tax price, the double line is the average price for the well, the gray line is the real after-tax price less the well mean, and the dashed line is the real after-tax price less the well mean and the month-year mean over all wells.

prices reflected higher world prices. This Tier III well was initially subject to a 30 percent WPT tax rate, which was decreased by 2.5 percentage points each year starting in 1982 until the rate was 22.5 percent in 1984. Focusing on the two-way residual line, Residual–Well, Time FE, the fact that this well was tax-advantaged can be seen at several points. When this well was decontrolled in June 1979, the two-way residual is large and positive. The strong upward movement of posted prices beginning in 1980 is mitigated in the two-way residual since other wells were beginning decontrol and receiving higher after-tax prices during this time—the residuals do, however, remain above zero since this well was fully decontrolled. The residuals remain positive even after the introduction of the WPT because it was tax-favored.

The key exclusion restriction of an identification strategy that purges after-tax prices of well and time averages is that, outside a time-invariant fixed factor, wells respond identically over time to changes in relative after-tax price. In other words, there are no time-varying well-specific factors, besides after-tax price, affecting well production.

Although well and time fixed effects control for unobservable differences across wells and control flexibly for the general evolution of oil production in California, there are several potential threats to identification. For example, differential production declines across wells that are correlated with after-tax prices could bias the elasticity estimates. In particular, if production from wells that enjoyed higher after-tax prices—that is, wells that did not produce in 1978, stripper wells, or wells that produced heavy oil—declined less steeply than production from other wells, then the estimate of the after-tax price elasticity would be downwardly biased. The robustness tests reported in columns 3 through 5 of Table 5 try to address this concern by comparing more similar sets of wells, dropping stripper wells, wells outside of a narrow range of heaviness and newer wells in turn, and yield similar price elasticity estimates. While differences within these narrower subsets of wells could potentially bias the results, the robustness of the positive impact of after-tax price on production using different sources of variation and isolating more similar sets of wells suggests that unobservable differences across wells are not driving the main results. One reason to think differential decline may be less of an issue here is that California's production is dominated by large, decades old wells that may all be well past their periods of sharply changing production.

The development of extraction technologies that have differing impacts on different wells could also threaten identification if these advancements particularly benefit wells with characteristics that also determine regulatory and tax treatment. For example, if technologies to improve extraction from stripper wells or wells that produce heavy oil were adopted during the sample period, then we may be misattributing technological impacts to the higher after-tax prices of these wells. While comparing more similar wells, as in columns 3 through 5 of Table 5, narrows the scope for these kinds of gravity- or productivity-biased technologies, it doesn't eliminate it and technological innovation that has disparate impacts that are correlated with changes in after-tax price remain a threat to identification. The short time frame of the study—just nine years—also reduces the potential for this type of technology adoption but does not eliminate the threat to identification.

IV. Results

A. *Main Results*

Table 4 presents OLS estimates of equation (9) using the full sample of California oil wells. The dependent variable is quantity of oil produced by well i in month t. All specifications include well-level fixed effects to absorb level differences across wells in operator responses to changes in after-tax price—namely, production cost heterogeneity. The sample includes all wells, whether or not they are shut-in. Month-by-year dummies absorb mean production and price variation each month. The tax-price elasticity is identified by within-well variation in after-tax price relative to the within-well variation of other wells. As wells age, their productivity may decline, so additional controls for the age of the well, measured from its date of completion, are also included.

Column 1 of Table 4 reports results from a model employing only time and well fixed effects. The estimated coefficient on the after-tax price term, β, implies that a \$1 increase in the after-tax price leads the average well to produce 8.73 (1.082) additional barrels of oil, a price elasticity of 0.335 (0.042). Because well age is considered an important determinant of well productivity, column 2 adds a quadratic function of well age. The insignificant increase in the elasticity to 0.336 and the unchanged precision suggest that the well fixed effect provides sufficient controls and age does not matter very much within a well. Although over the course of a well's life there is little change in the API gravity of the oil extracted—the within-well standard deviation is only 1.1 degrees, less than 20 percent of the overall variation—changes in API gravity could lead to changes in lifting costs if the changes are concentrated and thus large for wells that do experience changing API gravity. Column 3 of Table 4 employs dummies and quadratic time trends for each decile of API gravity. The after-tax price coefficient is reduced by these time-varying controls for oil quality, but the change, a reduction of the elasticity to 0.295, is statistically insignificant and economically minor.

Although the vast majority of wells in California are pumped in any given month, 33,198 wells produce oil based on their natural subsurface reservoir pressure for at least part of their lives. These flowing wells have low operating costs if they produce their natural flowing quantity, but it is very costly to adjust their production either upward or downward. Adjustment involves the installation of pumping equipment. In other words, very high costs of extraction rate adjustment make the operators of flowing wells unlikely to adjust their production in response to temporary changes in after-tax price. Columns 4 and 5 of Table 4 present estimates of equation (9) separately for pumped and flowing wells, respectively.[30] Pumped wells—those for which production levels are more of a choice variable—are more price responsive than the average well. A 10 percent increase in after-tax price leads to a 3.71 percent

[30] Because some wells may initially flow but then need to be pumped, the number of wells in the flowing and pumped regressions exceeds the total number of wells.

TABLE 4—REGRESSIONS OF QUANTITY PRODUCED ON AFTER-TAX PRICE

	(1)	(2)	(3)	(4)	(5)
After-tax price	8.730	8.741	7.673	9.287	−8.606
	(1.082)	(1.082)	(0.977)	(0.621)	(9.116)
Well age		−1.228	−1.335	−2.248	−1.047
		(0.0809)	(0.441)	(0.471)	(1.165)
Well age squared		−3.09e-04	−1.98e-04	1.25e-04	7.50e-05
		(2.29e-04)	(2.28e-04)	(2.88e-04)	(3.98e-04)
After-tax price elasticity	0.335	0.336	0.295	0.371	−0.262
	(0.042)	(0.042)	(0.038)	(0.025)	(0.278)
Observations	6,517,140	6,517,140	6,517,140	5,698,198	818,942
Number of wells	75,342	75,342	75,342	72,797	33,198
Well fixed effects	Yes	Yes	Yes	Yes	Yes
Time fixed effects	Yes	Yes	Yes	Yes	Yes
API gravity time trends			Yes	Yes	Yes

Notes: This table presents estimates from OLS regressions where the dependent variable is the quantity of oil produced by well i in month t. After-tax price is the posted price at which oil from well i sold during month t, net of corporate and Windfall Profit Taxes. The coefficient on after-tax price, β in equation (9), reports the supply response of well operators to net price. Column 1 is the baseline specification; it includes time and well fixed effects. Column 2 adds a quadratic function of well age. Column 3 includes separate quadratic time trends, slopes, and coefficients, by API gravity decile. Column 4 restricts the sample to only pumped wells. Column 5 restricts the sample to only flowing wells, which do not require mechanical lift to produce oil. The elasticities for all specifications are the product of the coefficient estimate and the ratio of after-tax price to average quantity for the estimation sample of producing wells. Heteroskedasticity robust standard errors are clustered at the individual well level and reported in parentheses.

increase in production.[31] The higher point estimate, however, is not statistically significantly different from the specification of column 3, which includes both flowing and pumped wells. Flowing wells, however, do not show a statistically significant production response to changes in after-tax price.[32] The strong response of pumped wells and nonresponse of flowing wells means that the tax responses estimated in columns 1 through 3 are driven by the types of wells that could in fact respond to changes in after-tax price.

B. *Robustness*

Table 5 examines the robustness of the baseline estimates. All specifications include well and time fixed effects as well as quadratic time trends by API gravity decile. To assess the role of outlier observations, column 1 drops wells that produce

[31] As equation (7) shows that wells with lower marginal costs of extraction should be more responsive to changes in after-tax price, wells that produce oil of higher API gravity should have lower lifting costs and thus higher elasticities. Estimates of the supply response of wells in the top quartile of API gravities are consistent with this prediction as the estimated elasticity for these wells, 0.545 (0.032), is substantively higher than the overall elasticity.

[32] Using company-level aggregate data on reserves, Thompson (2001) found that many firms are operating at a corner solution given by capacity constraints. Here we only see this in the case of flowing wells.

Table 5—Regressions of Quantity Produced on After-Tax Price, Robustness

	(1)	(2)	(3)	(4)	(5)
After-tax price	7.629 (0.975)	8.745 (0.622)	13.69 (1.484)	3.456 (1.128)	6.648 (0.968)
Well age	−1.618 (0.348)	−1.377 (0.429)	−2.727 (0.573)	−0.550 (0.299)	−0.840 (0.515)
Well age squared	−2.64e-04 (2.18e-04)	−1.52e-04 (1.98e-04)	−3.22e-04 (4.32e-04)	−6.83e-04 (2.96e-04)	3.14e-04 (3.28e-04)
After-tax price elasticity	0.294 (0.038)	0.385 (0.027)	0.375 (0.041)	0.152 (0.050)	0.229 (0.033)
Observations	6,517,137	6,350,820	4,170,688	3,079,546	5,030,913
Number of wells	75,342	73,548	75,220	41,630	49,388
Well fixed effects	Yes	Yes	Yes	Yes	Yes
Time fixed effects	Yes	Yes	Yes	Yes	Yes
API gravity time trends	Yes	Yes	Yes	Yes	Yes

Notes: This table presents estimates from OLS regressions where the dependent variable is the quantity of oil produced by well i in month t. After-tax price is the posted price at which oil from well i sold during month t, net of corporate and Windfall Profit Taxes. The coefficient on after-tax price, β in equation (9), reports the supply response of well operators to net price. All specifications include well and time fixed effects as well as quadratic time trends by API gravity decile. Column 1 drops wells that produce more than 100,000 barrels of oil per month. Column 2 drops observations from the federal Naval Petroleum Reserve. Column 3 drops stripper wells. Column 4 includes only observations with an API gravity between 13.0 and 19.0. Column 5 includes only wells producing before 1980. Heteroskedasticity robust standard errors are clustered at the individual well level and reported in parentheses.

an excess of 100,000 barrels of oil per month. The elasticity estimate, 0.294 (0.038), is virtually identical to column 3 of Table 4.[33]

The data cover all wells in the state of California, including wells located in the federally-owned and privately-leased NPR. The extracting firm in the NPR made production decisions, but received less than the observable after-tax price for each barrel. Furthermore, as the firm only leased the reserves, it may not have taken the exhaustibility of the reserves into account in the same way that a reserve owner would. Thus, the production response of these NPR wells to changes in after-tax price may be smaller than the response for privately owned wells.[34] Column 2 presents estimates of a model identical to that of column 3 of Table 4, but drops the NPR wells from the sample. The point estimate is larger, 0.385 (0.027), which is consistent with the idea that the operator of the NPR wells was less price sensitive than other

[33] We may also be concerned that if well production mechanically declines exponentially over the life of the well, specifying the dependent variable in levels may lead to spurious correlation between changes in the after-tax price and well production over time that may be further compounded by the unbalanced nature of the panel. Alternative specifications where the dependent variable is specified in logs rather than levels also show that production is higher where and when taxes are lower, with an estimated semi-elasticity of 0.00798 (0.000575), which translates into an elasticity of 0.1442 (0.0104). Balancing the panel by restricting the sample to wells that produce in all 108 months of the sample period also yields a positive and statistically significant price-elasticity, 0.0989 (0.0148), meaning that even among wells that always produce and after accounting for the potential for exponential production declines, production responds positively to lower WPT rates.

[34] The federal government opened the NPR to drilling in 1976. From 1976 until 1998, a private firm leased access to the field and extracted oil from the reserves. The oil was sold to private refiners at the after-tax price with the proceeds divided between the extracting firm and the federal government.

well operators.[35] Though the estimated after-tax price response is larger in terms of the point estimate, the difference is statistically insignificant. The NPR wells, in other words, were not significantly biasing the overall estimate of column 1.[36]

Part of the variation in after-tax price comes from the Tier II tax rates applied to wells that qualify as stripper wells—a status that could be endogenously determined. That is, by producing an average of 10 barrels per day for 12 consecutive months a well could qualify for classification as a stripper well and be subject to a lower tax rate. Since the incentive to reduce production to gain a lower tax rate yields a negative correlation between production and after-tax prices, we may be concerned that the estimates reported above are biased away from zero. Stripper status is the only mutable characteristic that affords tax advantages. To investigate the impact of this potential source of bias, column 3 of Table 5 drops all stripper well observations, reducing the sample by 2,346,452 observations. The elasticity, 0.375 (0.041), is similar to the non-NPR estimate of column 2 and is not statistically distinguishable from the main results. Non-stripper wells do exhibit a stronger per dollar response—a $1 increase in after-tax price leads to a nearly 14 barrel production increase—but because these wells are by definition more productive than the marginally productive stripper wells, the elasticity is roughly the same. The results from column 3 suggest that endogenously determined stripper status does not significantly affect the estimates. There are two plausible reasons why this potential source of bias is empirically innocuous. First, the tax advantage of stripper status is small—only 10 percentage points—relative to the tax benefit of new or heavy oil. Second, stripper status requires a substantial period of low production—only a limited set of producers may have been willing to curtail production to roughly 300 barrels a month for a year to gain the minor tax advantage.

Much of the identifying variation comes from wells that are tax advantaged because the oil they pump is new rather than old, or pump heavy rather than non-heavy oil. The full set of wells have a broad range of heaviness—API gravities range from 10.0 to 41.9. Wells also vary greatly in age with some well completions dating back to 1901. Columns 4 and 5 of Table 5 narrow the range of wells examined. Column 4 limits the sample to wells with API gravities between 13.0 and 19.0 degrees, inclusive; that is, three degrees above and below the API gravity, 16.0, which defines heavy oil. Limiting the sample to wells of more similar API gravities, yields a smaller elasticity, 0.152 (0.050), that is statistically different from the main specification. Nonetheless, higher tax rates do lead to lower production. Column 5 limits the sample to wells capable of producing prior to 1980. These wells were drilled and completed prior to the WPT legislation and thus their development could not have been motivated by the specifics of the WPT definition of old versus new oil. Again, in this subsample of more comparable wells, the estimated elasticity, 0.229

[35] The supply elasticity of the NPR wells, 0.268 (0.088) (not in table), is roughly 30 percent smaller than the non-NPR elasticity, but statistically indistinguishable from the overall or non-NPR elasticities.

[36] Alternative specifications that cluster at the lease level instead of the well level yield similar, statistically significant estimates. Because nearly a third of well-month observations are missing lease name information, these regressions were estimated in a smaller sample of 4,484,531 observations describing 51,153 wells. The coefficients on after-tax price in these models that correspond to the specifications of columns 1 through 3 of Table 4 are in order: 7.820 (3.093), 7.818 (3.092), and 6.274 (2.483).

(0.033), is smaller, but significant. Taken together, the results of Table 5 show that the estimated elasticity may be as low as 0.152 (0.050) or as high as 0.385 (0.027), but that in all cases well production responds positively to increases in after-tax price where the identifying variation comes from within-well and after time fixed effects.

C. *Well Closure Decisions*

Oil taxes can motivate some producers to simply shut their wells if the cost of extracting remaining reserves exceeds expected after-tax revenue. If taxes motivate well operators to close their wells, then the temporary tax could translate into a permanent reduction in oil production as the reserves remaining in the shut wells are effectively lost. As the WPT was a temporary tax, it is reasonable to think that fewer operators chose to close their wells than would under a permanent tax. The estimates of equation (10) reported in Table 6 can thus be considered lower bounds of the effect of a permanent tax on well closures.

Columns 1 through 4 and 8 of Table 6 report marginal effects and semi-elasticities from conditional logit models. For comparison purposes, columns 5 and 6 report results from fixed effect OLS models. All of these regression models include well and time fixed effects to partial-out cost heterogeneity at the well level and time-varying factors that affect production for all wells. Results from a hazard model that precludes well fixed effects are reported in column 7.

As the predicted values of conditional logit models must lie between one and zero, the conditional logit model excludes wells that experience no variation in shut-in status. Of the 75,342 wells observed in the data between 1977 and 1985, 43,256 are never shut-in and 2,789 are always shut-in. The remaining 38.9 percent of wells that experience variation in shut-in status comprise the sample of 2,694,267 observations used in the conditional logit models. Approximately 27 percent of these well-month observations are shut-in.[37] Identification again comes from relative within-well changes in after-tax price and the exclusion restriction requires that no time-varying well-specific factors correlated with after-tax price affect the shut-in decision. The after-tax price marginal probability effect reported in column 1 of Table 6 suggests that a 10 percent increase in the after-tax price only reduces the rate of shut-in by 0.96 percentage points. This small estimated response suggests that the WPT has a negligible impact on firms' shut-in decisions. This could be because the fixed costs of operating are small relative to profit from production or because few wells are near enough to the end of their economic life. Of the wells producing in 1977, 69 percent are still produced in 1987, 44 percent were still producing in 1997, and 34 percent still produced in 2007.

Column 2 adds a quadratic term in well age to better adjust for any potential decline in productivity that occurs over the life of the well. The estimates are virtually

[37] The data report a well as shut-in if it is ever shut during the month in question, even if it was only shut for a day for routine repairs. To distinguish between very short (days long) periods of shut-in and meaningful shut-in where the operator truly takes the well offline, I define shut-in as a well in shut-in status for at least two months. Using single month shut-in as the dependent variable has a negligible impact on the magnitude of the estimates, which remain statistically significant though less precise, as we would expect given the more random nature of very short-term shut-in.

Table 6—Shut-in Decisions and After-Tax Price

	Conditional logit (1)	Conditional logit (2)	Conditional logit (3)	Conditional logit (4)	OLS (5)	OLS (6)	Hazard (7)	Conditional logit (8)
After-tax price	−0.0052	−0.0052	−0.0059	−0.0079	−0.0044	−0.0015	0.9928	−0.0090
	(0.0008)	(0.0008)	(0.001)	(0.0013)	(0.0004)	(0.0002)	(0.0015)	(0.0029)
Well age	0.0126	0.0126	0.0141	0.0155	0.0013	0.0049	0.9928	0.0287
	(0.0007)	(0.0007)	(0.0013)	(0.0014)	(0.0007)	(0.0003)	(0.0005)	(0.0037)
Well age squared		−3.97e-08					1.0000	−7.99e-07
		(0.0000)					(4.80e-07)	(0.0000)
After-tax price semi-elasticity	−0.096	−0.096	−0.109	−0.147	−0.081	−0.028	−0.130	−0.167
	(0.015)	(0.015)	(0.018)	(0.023)	(0.008)	(0.003)	(0.027)	(0.053)
Observations	2,694,267	2,694,267	2,694,267	2,571,746	2,694,267	6,517,140	1,186,696	356,760
Number of wells	29,297	29,297	29,297	27,989	29,297	75,342	22,178	4,490
Well fixed effects	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Time fixed effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
API gravity fixed effects	No	No	Yes	Yes	Yes	Yes	Yes	Yes

Notes: This table presents marginal effects from conditional logit regressions and OLS estimates where the binary dependent variable is one if well i is shut-in in month t and zero if it is not. After-tax price is the posted price at which oil from well i sold during month t, net of corporate and Windfall Profit Taxes. The coefficient on after-tax price, δ of equation (10), describes the extensive response of operators to net price. Column 1 includes a full set of month by year and well fixed effects and a linear control for well age. Column 2 adds a quadratic term in well age. Column 3 adds dummies for each API gravity decile. Column 4 excludes observations from the federally owned NPR. Column 5 estimates an OLS model with well and time fixed effects using the same sample of wells that experience variation in shut-in status. Column 6 estimates the fixed effect OLS model using the full sample of wells. The semi-elasticity for all specifications is the product of the marginal effect estimate and average after-tax price. Column 7 reports estimates from a Cox proportional hazards model on a restricted sample of more similar wells that are neither stripper nor new and produce oil with API gravities between 13.0 and 19.0. Column 8 reports marginal effects from a conditional logit model using a sample with the same restrictions as column 7. Heteroskedasticity robust standard errors are clustered at the individual well level and reported in parentheses.

identical, suggesting that a linear control for well age is sufficient. Adding API gravity decile fixed effects increases the semi-elasticity to −0.109 (0.018), though the increase is statistically insignificant and economically minor. Column 4 excludes wells from the NPR field. Dropping wells from the NPR field increases the point estimate of price response along the extensive margin, suggesting again that firms that lease government reserves are less price responsive than other operators, though again the difference is statistically insignificant.[38]

The conditional logit model requires variation in the dependent variable for each well in the sample. To assess the impact of limiting the sample this way, shut-in semi-elasticity estimates from fixed effect OLS models are also reported. For comparison, column 5 of Table 6 reports OLS estimates for the sample of wells used to estimate the conditional logit model; column 6 reports OLS estimates from the full sample of wells. The estimate using the smaller sample is nearly three times as large as the estimate from the full sample and is similar to the conditional logit estimates. The estimates of columns 5 and 6 imply that, among operators that have meaningful discretion over the shut-in status of their wells, the effect of after-tax

[38] In fact, the after-tax price semi-elasticity of shut-in among NPR wells is only −0.0002 (0.0002) and statistically insignificant.

price on the shut-in decision is significantly larger. This suggests that the sample restrictions of the conditional logit model may be partly responsible for the higher semi-elasticity estimates of columns 1 through 4 relative to column 6. Nonetheless, though the conditional logit marginal effects are multiple times the magnitude of the full sample OLS estimates, they are small in economic terms.

Many wells that are shut-in tend to remain shut-in for several months; other wells come back online. Of the 58,460 shut-in spells of at least two months in length in the data, a substantive share are quite short with 25 percent lasting three months or less and 50 percent lasting 8 months or less. The seventy-fifth percentile of shut-in durations is 39 months, or 3.25 years, while the ninetieth percentile is 133 months, or slightly longer than 11 years. Because shut-in status is persistent for at least a subset of wells, survival analysis may better assess the impact of after-tax price on shut-in decisions. Column 7 presents estimates from a Cox proportional hazards model. Since the hazard model cannot include well fixed effects, which are key to identifying the after-tax price response, only a subset of similar wells are used in the hazard analysis. Specifically, the sample consists of wells that are neither new nor stripper wells, and produce oil with API gravities between 13.0 and 19.0 (restrictions similar to columns 3, 4, and 5 of Table 5). As the coefficient on after-tax price in the hazard model is less than one, higher after-tax prices reduce the likelihood of shut-in. Specifically, a one-dollar increase in after-tax price reduces the probability of shut-in by 0.72 percentage points. This translates into a semi-elasticity of 0.130 (0.027), which is higher but not substantively different from the other semi-elasticities reported in columns 1 through 4. For better comparability, a conditional logit model is also estimated using the same restricted sample. These results are reported in column 8. The marginal effect of after-tax price, −0.0090 (0.0029), translates into a semi-elasticity of 0.167 (0.053), which is slightly larger than the hazard estimate but not dissimilar. Although the shut-in status signifies that a well is mechanically shut-in, the substantive amount of churn in shut-in status leads to similar hazard and panel data estimates. Taken together, the estimates presented in Table 6 suggest that taxes did not lead to economically important rates of shut-in.

D. *Spatial Shifting*

Tables 4 and 5 establish that wells facing higher tax rates produced less oil. These models estimate the mean response of well production to after-tax price. If producers strategically reallocate production from high- to low-tax wells on their lease, these estimated responses may overstate the overall response to variation in after-tax price. Specifically, if producers are strategically shifting production spatially, then responses at the lease level should be smaller than the responses suggested by the well-level regressions. Table 7 examines the degree of spatial shifting. Odd-numbered columns report estimates from well-level regressions while even-numbered columns report estimates from lease-level regressions.[39] Column 1

[39] For the lease-level regressions, oil production data is summed for wells on the same lease that share the same operator. After-tax price is the production-weighted average of after-tax price of wells on the lease with the same

Table 7—Spatial Shifting: Well and Field-Level Regressions of Quantity Produced on Price

	Well (1)	Lease (2)	Well (3)	Lease (4)	Well (5)	Lease (6)	Well (7)	Lease (8)
After-tax price	6.274	5.066	9.171	7.325	11.37	12.41	6.563	5.225
	(0.744)	(1.550)	(0.850)	(3.348)	(1.033)	(6.861)	(0.814)	(2.633)
Well age	−0.770	−3.229	−2.383	−3.204	−2.145	−4.470	−0.692	−2.657
	(0.553)	(0.940)	(0.891)	(0.767)	(1.049)	(1.942)	(0.577)	(0.520)
Well age squared	0.000193	0.0031	0.000802	0.00409	0.000717	0.00855	0.000126	0.00376
	(0.000242)	(0.000660)	(0.000295)	(0.00104)	(0.000648)	(0.00371)	(0.000258)	(0.000834)
After-tax price elasticity	0.295	0.245	0.405	0.307	0.441	0.359	0.307	0.229
	(0.035)	(0.075)	(0.038)	(0.140)	(0.040)	(0.199)	(0.038)	(0.115)
Observations	4,484,531	391,002	2,238,017	136,855	1,763,386	71,325	4,226,585	188,246
Number of wells/leases	51,153	4,804	23,812	1,373	18,766	706	50,497	2,267
Well fixed effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Time fixed effects	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
API gravity time trends	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Notes: This table presents OLS regressions where the dependent variable is either the quantity of oil produced by well *i* in month *t* or the average well production on lease *l* in month *t*. After-tax price is either the posted price at which oil from well *i* sold during month *t*, net of corporate and Windfall Profit Taxes, or the average of such prices for all wells on a lease *l*, weighted by oil production. The coefficient on the after-tax price variable is the coefficient of interest and describes the supply response of well operators to changes in net price. All specifications include time fixed effects and either well or lease fixed effects as well as quadratic time trends by API gravity decile; wells from the National Petroleum Reserve are dropped. Odd columns are well-level regressions and even columns are lease-level regressions. Columns 1 and 2 drop all wells with missing lease names. Columns 3 and 4 restrict the sample to leases that have wells that are classified into at least two different Windfall Profit Tax tiers. Columns 5 and 6 require that the leases included in the sample include both Tier I and Tier III wells—wells with the greatest tax rate disparity and thus the strongest incentives for spatial shifting. Columns 7 and 8 limit the sample to leases with at least three wells to ensure there is meaningful scope for spatial shifting. Heteroskedasticity robust standard errors are clustered at the individual well or lease level and reported in parentheses.

is the same specification as column 3 of Table 4 but omits wells with missing lease names. Dropping these wells does not affect the estimated elasticity, which is within rounding of the baseline in Table 4. Column 2 of Table 7 reports estimates from the lease-level model. The estimated elasticity is slightly smaller, 0.245 (0.075) versus 0.295 (0.035) and of lower precision though still significant at the 1 percent level. The difference between the well-level and lease-level elasticites, however, is not statistically or economically significant. The comparability of the estimates suggests that producers are not engaging in significant production reallocation and that such reallocation is not driving the estimates reported in Tables 4 and 5.

Columns 3 and 4 of Table 7 restrict the sample to leases that have wells that are classified into at least two different WPT tiers; this restricts the sample to only leases where strategic spatial shifting opportunities exist.[40] The well-level

operator. Aggregating purely to the lease-level rather than the operator-lease level does not substantively affect the results.

[40] Of the 1,337 leases analyzed here, 812 contain both Tier I and Tier II wells, meaning that they have stripper and non-stripper wells (that produced in 1978 and are not heavy); 706 contain both Tier I and Tier III wells, meaning that they have non-stripper, non-new wells that produce non-heavy oil and wells that are either new or produce

estimate, column 3, suggests that this sample is somewhat more elastic than the full sample of column 1. The lease-level estimate, column 4, is also higher than the full sample estimate reported in column 2, but the difference is not as large as between columns 1 and 3. Comparing the point estimates suggests that wells in this restricted sample exhibit a slightly higher elasticity not fully mirrored by aggregate lease-level estimates. The difference, however, is not statistically significant. Columns 5 and 6 further require that the leases included in the sample feature both Tier I and Tier III wells—wells with the greatest rate disparity and thus the strongest incentives for spatial shifting. While the well-level and lease-level point estimates are somewhat higher, 0.441 (0.04) and 0.359 (0.199) respectively, their difference is again statistically insignificant.

In addition to different tax rates among wells on a lease, having more wells on a lease may facilitate strategic spatial production shifting. Columns 7 and 8 of Table 7 limit the sample to leases with at least three wells to ensure there is meaningful scope for spatial shifting. Once again the point estimate from the well-level regression, 0.307 (0.038), is larger than the lease-level estimate, 0.229 (0.115). Although both estimates are significant, at least at the 5 percent level their difference is too small to be statistically significant.

Taken together, the regressions presented in Table 7 show a consistent pattern of lease-level point estimates that are smaller than the well-level estimates, but the differences are not large enough to be statistically significant. All of the estimates show that higher taxes lead to less production, and the response is not primarily driven by strategic spatial shifting of production from tax-disadvantaged to tax-advantaged wells.

E. *Other Events*

Apart from reducing production or shutting-in, operators can make other adjustments. For example, operators at some point must make the decision to pump a previously flowing well, perform maintenance on a well, or potentially even alter their well's production to qualify for stripper status. Table 8 reports estimates describing the effect of after-tax price on these decisions, which given their impact on future production, can have an investment-like interpretation. Each column of Table 8 reports the marginal effects of a conditional logit specification that accounts for the potential nonlinearity of the impact of after-tax price on these events and contols for six-month time fixed effects, a quadratic in well age and quadratic time trends by API gravity decile.[41]

heavy oil; and 963 contain both Tier II and Tier III wells, meaning that they have both stripper wells and wells that are either new or produce heavy oil.

[41] Because conditional logit models restrict the sample to wells with varying shut-in status, to assess the effect of this sample restriction, linear models with the same controls were also estimated using both the limited conditional logit sample and the full sample of wells. Results from these linear models (not reported in Table 8) are broadly consistent with the results from the conditional logit models, though often yielding smaller estimates, and are referenced where relevant. For each regression model, early months prior to the first observed event are excluded from sample. The first month, first three months, and first 13 months of data is dropped for the flow-to-pump, improvement, and stripper specifications, respectively.

Table 8—Other Events and After-Tax Price

	Flow-to-pump (1)	Improvement (2)	Stripper eligibility (3)	Stripper eligibility (4)
After-tax price	2.27e-06	1.84e-03		
	(0.00e-00)	(7.90e-04)		
Lag after-tax price			−4.05e-04	
			(2.10e-04)	
Change in after-tax price				2.86e-03
				(1.66e-03)
Age	−7.97e-05	1.06e-03	−1.92e-04	−1.09e-03
	(3.00e-05)	(1.70e-04)	(8.00e-05)	(5.00e-04)
Age squared	2.82e-08	2.93e-06	−6.52e-08	−9.84e-07
	(0.00e+00)	(0.00e+00)	(0.00e+00)	(0.00e+00)
After-tax price semi-elasticity	0.0000	0.0340	−0.0076	0.0541
	(0.0000)	(0.0146)	(0.0040)	(0.0314)
Observations	1,905,232	1,197,837	1,673,691	1,141,818
Wells	23,544	13,934	19,492	13,999
Well fixed effects	Yes	Yes	Yes	Yes
Six-month fixed effects	Yes	Yes	Yes	Yes
API decile time trends	Yes	Yes	Yes	Yes

Notes: This table presents marginal effects from conditional logit regressions where all specifications include time and well fixed effects, a quadratic control for well age and dummies for each API gravity decile. After-tax price is the posted price at which oil from well i sold during month t, net of corporate and Windfall Profit Taxes. The binary dependent variable in column 1 is equal to one if a well that flowed in period $t-1$ is pumped in period t. In column 2, the dependent variable is equal to one if it is undergoing an "improvement" where an improvement is proxied by a one-month shut-in after which average production over the subsequent three months is higher than average production during the three months preceding shut-in. For both columns 3 and 4, the binary dependent variable is equal to one if a well was not eligible for stripper well status in time $t-1$ but was eligible in time t. Each specification includes six-month time dummies and quadratic time trends by API gravity decile. The semi-elasticity for all specifications is the product of the marginal effect estimate and average after-tax price. Heteroskedasticity robust standard errors are clustered at the well level and reported in parentheses.

Although many wells are not initially pumped, at some point in their lives the operator decides to make the investments necessary to switch to artificial lift. As artificial lift presumably increases production above what natural flow would produce, after-tax price could potentially influence the flow-to-pump transition decision. As the first column of Table 8 shows, after-tax price has no statistically discernible impact on the probability a formerly flowing well is pumped, suggesting that not only do taxes not affect production from flowing wells but that they do not impact the decision to pump either.[42]

Not all shut-ins are long in duration. Wells are also shut-in for short periods of time. The well closure analysis reported in Table 6 examines shut-ins of at least

[42] Estimates from the linear fixed effects model using the same sample shows a small but statistically significant effect with the coefficient on after-tax price, 1.35e-04 (5.67e-05), implying that a $1 increase in oil price leads to roughly a 0.01 percent increase the probability a flowing well is pumped. In the full sample, the linear model yields an even more economically modest estimate of 4.61e-05 (1.63e-05). Taken together the results from the conditional logit and linear models show that the decision to pump is not strongly affected by variation after-tax price.

two months with similar results for shut-ins of at least six months; maintenance of a well may involve temporary shut-in, including maintenance activities to improve oil output. These types of improvements may be influenced by after-tax prices. Although the data do not specifically identify such improvements, we can assess the impact of after-tax price on proxies for such events. I define an "improvement" as a one-month shut-in after which average production over the subsequent three months is higher than average production during the three months preceding shut-in.[43] Column 2 of Table 8 reports marginal effects from a conditional logit model where the dependent variable is equal to one if well i undergoes such an improvement in month t and zero otherwise. The marginal effect of after-tax price suggests that wells exposed to higher after-tax prices are more likely to undergo short-term shut-ins that lead to increased production, but the effect is very small with a \$1 increase in after-tax price corresponding to just a 0.18 percentage point increase in likelihood of an improvement or a semi-elasticity of 3.4 percent.

A well's stripper status is in part an operator's decision. Operators could potentially withhold production from a marginally productive well in order for it to qualify for stripper status and be eligible for higher after-tax prices due to considerations offered for stripper wells. Columns 3 and 4 of Table 8 examine the impact of after-tax prices on a dependent variable equal to one if a well was not eligible for stripper well status in time $t-1$ but was eligible in time t. Column 3 examines the impact of lagged after-tax price on stripper eligibility and the reported marginal effects show that wells with higher after-tax prices in the prior month are slightly less likely to become newly eligible stripper wells, though the estimate is only significant at the 90 percent confidence level. An additional dollar of after-tax price in the prior month makes a well 0.04 percent less likely to be newly eligible for stripper status. Column 4 examines the effect of expected changes in after-tax price on stripper well transitions where $\textit{Change in After-Tax Price}_{it}$ is the mean after-tax price received by stripper wells on the field and lease of well i at time t less the after-tax price received by well i at time $t-1$. The sample here is limited to wells on leases with stripper wells. The marginal effects from this model show that wells that would see relatively larger price increases if they became stripper wells are indeed more likely to become stripper wells; a \$1 increase in after-tax price leads to more than a 5 percent increase in the likelihood of stripper eligibility, a statistically and economically meaningful effect. While the two specifications find effects of very different magnitudes, both sets of results imply that where stripper wells received higher prices, wells were more likely to experience the production patterns that lead to stripper eligibility.

Although the empirical estimates reported in this paper describe only existing wells and do not bear on decisions to drill new wells, these results regarding other events can help shed light on the impact of taxes on decisions that can have an investment-like interpretation.

[43] Comparing productions six months before and after a one-month shut-in yields similar results.

V. Conclusion and Policy Implications

This paper uses new detailed data on the quantity and price of oil produced by wells in California to estimate the effect of tax- and price control-induced variation in oil prices on production decisions. The unusual cross-sectional variation in after-tax price afforded by these government interventions allows for flexible controls for time-varying factors, like price expectations and underlying changes in technology, that may affect oil production. The main results show an elasticity ranging between 0.295 (0.038) and 0.371 (0.025), meaning that a 10 percent excise tax would lead to a roughly 3 to 4 percent change in domestic oil production.

The results show that while oil production from existing wells is responsive to the after-tax price, after-tax price has no appreciable impact on wells that flow in accordance with their natural subsurface pressure. Only pumped wells alter production in light of taxes. The analysis finds no evidence of significant spatial shifting of production from tax disadvantaged wells to tax advantaged wells on the same lease, meaning that the estimated elasticity is largely a real reduction in production. Because these estimates imply that producers alter their behavior in response to tax changes, they suggest that the incidence of an oil excise tax cannot be modeled simply as a tax on the rents of oil producers. State taxes legislated today effectively raise the marginal cost of production, potentially reducing extraction and leading to deadweight loss. The elasticities estimated, however, are much below unity, suggesting the WPT and potentially more recent state taxes discourage production but not to a self-defeating extent. The results also show that while operators are more likely to shut-in wells when facing lower after-tax prices, the extensive response is modest.

The main empirical findings bear on short-run production decisions,[44] and it is important to keep in mind several cautions about their broader interpretation. First, taxes are likely to delay or curtail exploration and development activities by reducing the near-term returns to such activities. This response margin is not captured by the analysis presented above. Second, the estimates reported here are generated by variation from the 1980s using data from only California where extraction costs are higher than average. Technological innovations like hydraulic fracturing have made extraction more cost-effective, and it is not clear that production from these newer sources is as sensitive to tax-driven changes in after-tax price as production from the wells studied here. Further, these policy changes came on the heels of binding price controls that may have impacted the degree to which the wells studied here were producing below their geological constraint, potentially affecting the ability of operators to adjust production. Finally, the taxes studied here were temporary. More recent state taxes on oil production have been levied on a permanent basis.

[44] Using additional data that tracks production for each well through 2007, I also examined whether wells subject to higher or lower after-tax prices during the period of policy-driven price variation ultimately produced more or less oil over the 30-year period between 1977 and 2007. Estimates from a subsample of comparable wells suggest that a 1 percent higher tax during the 1977 to 1985 period reduced production over the long-term by 0.13 percent to 0.62 percent, though these estimates should be interpreted with caution as the set of comparable wells is at most about 10 percent of all wells. For more detail, please see online Appendix C.

Nonetheless, the elasticities estimated here, with caveats, can help inform current policy. Alaska's 2013 reversal of a prior tax increase and more recent attempts in Oklahoma to reverse severance tax increases, suggest that even oil taxes that are designed to be permanent are in fact subject to meaningful policy uncertainty. More broadly, the estimates here suggest that domestic oil production is not fixed but is in fact responsive to after-tax price. State and local governments considering oil taxes should view the revenues resulting from higher taxes as likely to also entail the cost of reduced production, though the reduction is unlikely to come from producers shutting in wells. Much like the WPT, many state oil taxes attempt to tax different types of wells at differential rates. The limited spatial shifting seen under the WPT, despite considerable variation in after-tax price, suggests that these differential rates may not spur tax avoidance, and could help keep marginal wells in production.

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