Taxes and U.S. Oil Production:
Evidence From California and the Windfall Profit Tax
Online Appendix

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March 2018

A Further Details on the Incentives to Shift Production

The model detailed in Section 2 shows how the extraction path of a producer with known reserves and prices is altered by the introduction of a permanent and temporary tax. Figure A.1 illustrates the original and tax altered extraction programs of a well with an original life of 40 years, cost parameters of $c = 0.0573$ and $f = 100$ facing a constant prices of \$25. The solid line describes the extraction path with no tax. The grey line shows how a permanent 15% excise tax introduced in year zero proportionally shifts the extraction path (also leading to longer well life). The dotted line shows how a temporary 15% excise tax levied for five years starting in year zero alters the production path. After a sharp reduction while the tax is in place, production rises once the tax expires to a rate slightly higher than the rate according to the extraction path without a tax and the well produces for a few months longer than it would have had there been no tax.

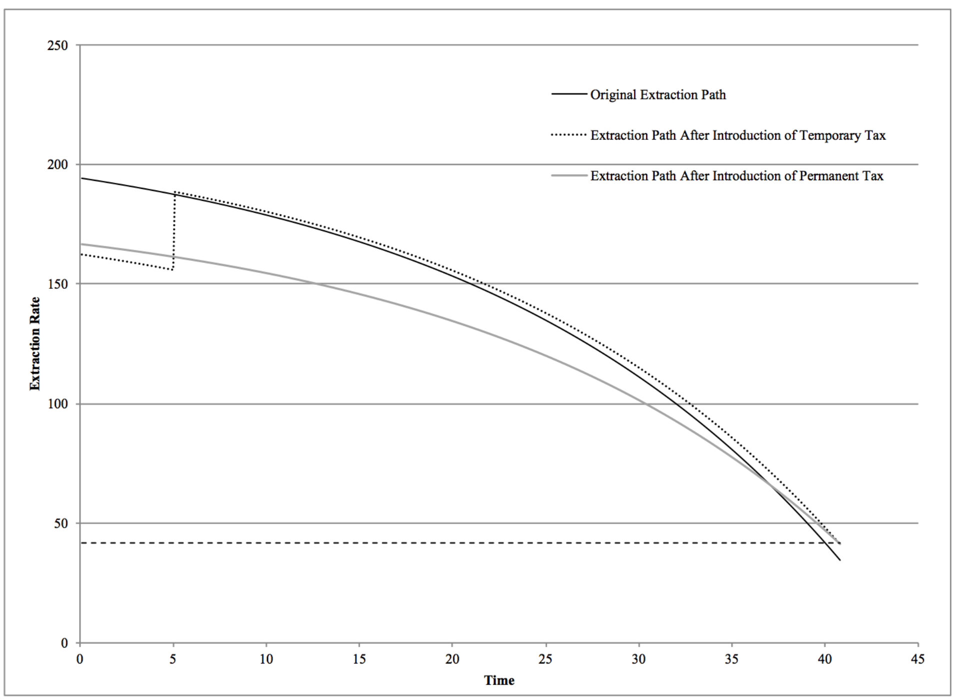

Figure A.1: Optimal Extraction Path Before and After the Introduction of a Permanent 15% Excise Tax and a Temporary 5-year 15% Excise Tax Well with 40-year original life, 5% interest rate, $c = 0.0573$

B Additional Context on U.S. and California Oil Production

The United States is the third largest oil producer[1], behind only Saudi Arabia and Russia; California is the third largest oil producing state in the U.S. Aggregate U.S. oil production comprised roughly 15 percent of total world production while price controls and windfall profit taxes were in place, a substantial but decidedly minority share. Domestic pre-tax prices are set by the global oil market. Unlike most other oil producing nations, oil extraction in the U.S. is a competitive market where large international oil firms operate alongside many smaller independent producers. Though the large international companies that operate in the U.S. also operate abroad, their market share was dramatically undercut by the establishment of the Organization of Petroleum Exporting Countries (OPEC) in 1960. By the mid-1970s, OPEC nations accounted for roughly half of world production and coordinated their production decisions in an effort to influence price. Though the evidence on OPEC's effectiveness as a cartel is mixed,[2] if any group of producers had the market share and coordination necessary to affect prices, it was and remains nationalized producers rather than the competitive fringe that operates in the U.S.[3]

California is divided into six oil and gas districts. Each month between 1977 and 1985, total California production ranged between 2.37 million barrels in February 1978 and 3.20 million barrels in August 1985. Roughly 16.1 percent of wells are shut-in on average; there is some variation in shut-in rates, with the smallest share of shut-in wells, 14.5 percent, during October 1978 and the largest share, 17.5 percent, in December 1985. Each of the top five producing wells accounts for less than 0.5 percent of total production.

C Longterm Effects of Temporary Taxes

Assessing the long-run impact of these temporary taxes can provide a sense of their ultimate welfare cost and help inform our view of their overall impact. Measuring the impact of differential treatment under price controls and the Windfall Profit Tax on long-term total production means comparing total output among wells that were exposed to higher and lower after-tax prices during the period of policy-induced price variation. The table below reports coefficients from estimates of:

$$TotalProd_i = \alpha + \beta\bar{(}ATP)_i + \gamma FirstProd_i + \epsilon_i$$

where the dependent variable is total production from well i between January 1977 and December 2007 (the end date of the data). The key independent variable of interest, ATP_i, is the mean after-tax price of well i over the period of policy variation on which the short-term analysis focuses, January 1977 to December 1985. To adjust for potentially large differences in well productivity, a control for production in the first period of production, $FirstProd_i$, is also included in the regression. If $\beta > 0$, then wells subject to lower tax rates and thus higher after-tax prices during the price control and Windfall Profit Tax period ultimately produced more oil over the 30-year period. In other words, wells subject to more price distortion produced less oil not just in the short-run but overall as well.

[1] The U.S. was the third largest producer in the 1970s and 1980s as well though U.S.S.R production totals were less accurately measured.

[2] Hamilton (2009) reviews recent production and quota discrepancies among OPEC nations and finds that OPEC members frequently cheat with respect to their quotas and there is little evidence of a clear enforcement mechanism. Also see Alhaji and Huettner (2000) for a review of 13 studies assessing the effectiveness of OPEC as a cartel.

[3] As the U.S., including California refiners, imports oil, within the range of transportation costs, domestic producers may have some pricing power. Given that transport costs comprise roughly 5 percent of oil prices, domestic producers have only a small scope of pricing power.

The challenge in this comparison stems from the fact that some well characteristics used to determine regulatory and tax treatment can also impact the cost of extraction. In nearly all of the regressions presented in Tables 4 through 8 of the paper, the analysis uses only within-well variation to avoid the bias of drawing comparisons in the pooled sample. When comparing aggregates, we are left comparing across wells and these underlying differences make it hard to isolate the impact of taxes.

Column 1 of the table below reports estimates of the above equation for the full sample. Underlying differences confound the impact of the policy treatment and yield a negative coefficient. This reflects the fact that taxes were lower and prices higher for some wells that may have faced higher costs (heavier oil and stripper wells). This specification includes a control for the amount the well produced in its first month of production, but this does not absorb the differences across wells. The second column excludes outliers, dropping the five percent most and least productive wells. Confounding differences among the remaining wells again result in a negative coefficient, although it is somewhat smaller and magnitude.

To facilitate an apples-to-apples comparison I limit the set of wells examined to more comparable wells (like in columns 3, 4 and 5 of Table 5). Column 2 limits the sample to wells that are of similar API gravities (13.0 to 19.0) like column 3 Table 5. Among these more similar wells, wells exposed to higher after-tax prices produced more oil. Column 4 drops wells that were ever classified as stripper wells. This limits the sample to many fewer but more comparable wells and yields a positive coefficient of greater magnitude. The estimate suggests that a 1% tax during the 1977 to 1985 period reduced total production from the well over the 30-year period by 0.33% or roughly 333 barrels of oil. For context, the average well produced roughly 100,000 barrels of oil over the 30 years.

The remaining columns further restrict the sample to even more comparable wells and find similar but larger estimates. Column 5, like column 5 of Table 5, drops wells that were not producing prior to 1980, excluding well drilled when different technologies may have been available. Column 6 also drops wells in the Naval Petroleum Reserve. Once the set of wells has been narrowed to these much more comparable wells the need to control for $FirstProd_i$ is diminished. Estimating the regression model without controlling for first period production yields a qualitatively similar estimate of 2,551.2 (826.1).

It should be noted that many of the wells assessed here were likely producing long before 1977 and continued producing after 2007 given the long lives of California's oil wells. These data do not let us compare total overall production from the well, just production during this 30-year period. Because these estimates are from a more comparable but much smaller sample, they are not considered a main result but are presented here as suggestive evidence.

D Shut-In Decisions Controlling for Prior Production

A well operator will choose to shut a well in when he no longer expects to be able to profitably extract the remaining reserves. Wells most likely to be shut-in when facing lower after-tax prices include those with higher production costs and those with the least reserves left. The table below reports how shut-in responses to differences in after-tax price vary by production history. These estimates examine shut-in decisions over the full sample period but condition on average production in 1977, the first year of the sample. The idea is to compare how shut-in responds to after-tax price among wells that produced more and less oil at the start of the sample period.

Column 1 reports marginal effects for the subsample of wells with average 1977 production below the median of average production in 1977 among producing wells. The marginal effect, -0.0123 (0.0049), trans-

Table C.1: Impact of Average After-Tax Price Between 1977 and 1985 on Total Production Between 1977 and 2007

	(1)	(2)	(3)	(4)	(5)	(6)
Mean ATP	-5,545.8***	-1,846.0***	492.0*	1,832.8**	3,370.0***	3,408.5***
	(328.6)	(147.1)	(269.1)	(729.7)	(773.1)	(774.4)
First Month Prod.	50.51***	14.88***	33.10***	21.04***	27.54***	27.74***
	(0.35)	(0.21)	(0.53)	(0.97)	(1.27)	(1.28)
Elasticity	-1.00***	-0.46***	0.13*	0.33**	0.61***	0.62***
	(0.06)	(0.04)	(0.07)	(0.13)	(0.14)	(0.14)
Number of Wells	68,756	61,879	30,130	5,327	3,363	3,350

Note: Columns 1 through 6 report estimates of $TotalProd_i = \alpha + \beta \bar{(ATP)}_i + \gamma FirstProd_i + \epsilon_i$ where $TotalProd_i$ is the aggregate production of well i between January 1977 and December 2007, $\bar{(ATP)}_i$ is the average after-tax price of well i between 1977 and 1985 and $FirstProd_i$ is production in the first month that a well produced. Column 1 includes all wells with non-zero total production. Column 2 excludes the 5% least and most productive wells. Column 3 limits the sample to wells with API Gravities between 13.0 and 19.0 while Column 4 limits the sample further to only wells that have never been stripper wells. Column 5 drops wells that began producing in 1980 or after. Column 6 excludes wells in the Naval Petroleum Reserve.

lates into a semi-elasticity of -0.2285 (0.0909), which is higher than the semi-elasticities reported for the full sample in Table 6. The implication of this higher semi-elasticity is that wells that produced less than most wells in 1977 were more likely to respond to lower after-tax prices by shutting in than other wells. Column 2 reports marginal effects for wells that averaged more production in 1977 than the median producing well. Here the marginal effect implies a semi-elasticity of -0.0852 (0.0286), which is below the semi-elasticities reported for the full sample in Table 6. Wells that produced more oil in 1977, were less likely to shut-in in reaction to lower after-tax prices. Interestingly in this higher-producing sample, older wells are less likely to shut-in while in all other specifications, older wells are more likely to shut-in. These estimates are consistent with the fact that California's oil production is dominated by large, long-producing wells, which would be unlikely to find shut-in economic strategic.

Table D.1: Shut-In Decisions and After-Tax Price, Controlling for Prior Production

	(1)	(2)
After-Tax Price	-0.0123	-0.0049
	(0.0049)	(0.0016)
Well Age	0.0070	-0.0260
	(0.0009)	(0.0054)
After-Tax Price	-0.2285	-0.0852
Semi-Elasticity	(0.0909)	(0.0286)
Observations	1,090,981	724,688
Number of Wells	10,676	6,991
Well FE	Y	Y
Time FE	Y	Y
API Gravity FE	Y	Y

Note: Columns 1 and report marginal effects from conditional logit regressions 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. Both specifications include well and time fixed effects as well as dummies for each API gravity decile. Column 1 limits the sample to wells with average oil production in 1977 that was below median production that year among producing wells. Column 2 examines the sample of wells with average oil production in 1977 that was above median production that year among producing wells.