Heterogeneous Oil Supply Elasticities: Indebtedness and Production Responses to the COVID-19 Shock*

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Abstract

Debt matters for oil supply elasticities. We document the resiliency of oil production to the COVID-19-related collapse in demand due to indebtedness. We use exogenous variation in the timing of debt-related payments to identify financially constrained operators. We show that more-financially-constrained firms cut production by less than less-constrained firms and were less likely to complete wells. To explore the mechanisms, we use borrowing limit cuts and credit line drawdowns to measure access to credit, and exploit failed hedging practices to identify additional cash pressures. The propagation of oil demand shocks depends crucially on the indebtedness of the oil sector.

Keywords: oil supply elasticities, debt, financial constraints, heterogeneous firms, well-level data, production distortions

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1 Introduction

The oil market has been repeatedly puzzled by the resilience of North American oil production to low oil prices. It took almost two years for oil production to adjust after the 2014 collapse in oil prices. During the COVID-19 crisis, the fear that significant supply cuts would not occur on their own led the regulators of the largest energy-producing state, Texas, to weigh in on the possibility of imposing state-wide production caps.[1] In January 2019, the government of Alberta, Canada actually implemented a production cap policy in response to a growing and prolonged price differential between the Western Canadian Select (WCS) price of oil and the West Texas Intermediate (WTI) benchmark price.[2]

In this paper, we provide the first large-scale evidence of oil production resilience driven by indebtedness. Intuitively, the oil industry is heavily indebted in general, and when oil prices fall, many producers struggle to service their debt and maintain high production levels to maintain sufficient cash flow. We use well-level monthly production data to document the effect of financial constraints on US oil production responses to the COVID-19 shock. Lockdowns and travel bans imposed by the government created the largest demand collapse in history. US oil prices tumbled to 20-year lows.[3] Oil producers responded to low oil prices by shutting down some of their wells in April and May of 2020. As oil prices improved, the firms started to return their wells back to full production.[4] For each well we calculate the decrease in production from March to May, when the oil market was hit the hardest.

Our results show that more financially constrained firms decreased production by about 10 percentage points less than less financially constrained firms - a large difference both economically and statistically. Financially constrained firms were also 3 pp less likely to completely shut in

[1] See "Texas' oil and gas regulators aren't ready to cut production yet. They're not even sure how it would work if they did" by Mitchell Ferman, in the Texas Tribune on April 15, 2020.

[2] By December 2018, the WCS price of oil fell to an astonishingly low \$6 per barrel, while the WTI benchmark was traded at \$50 per barrel. Following the intervention, oil production was reduced by 8.7% and the WCS-WTI price differential dropped to less than \$10/bbl in February 2019. The quota was lifted only in December 2020, when export capacity again reached sufficient levels. See Schaufele and Winter (2021) and Hallak et al. (2021).

[3] The WTI futures price for May delivery actually turned negative for the first time in history and settled at -\$37.63 per barrel on April 20, 2020.

[4] A shut-in well can be reopened, although not without some loss. 61% of respondents to the Dallas Fed Energy Survey Q2 2020 expected minor costs when putting wells back online, while 11% expected significant costs. Executives from 62 E&P firms answered this question.

wells. Our approach of using individual well-level production decisions rather than aggregating production cuts at the firm level allows us to include a rich set of controls and thus to capture differences in productivity and exposure to the COVID-19 shock across different firms. Specifically, we include granular geographical fixed effects and thereby capture local differences in the intensity of the pandemic, lockdown measures, refinery utilization rates, and availability of storage facilities, etc.

To identify more-financially-constrained oil firms, we identify operators that unluckily had upcoming debt-related payment deadlines right in the midst of the pandemic. To do this, we rely on synchronization of debt-related payments. We argue that a tendency of multiple forms of long-term debt to be co-issued and co-dependent creates conditions for various payments to be scheduled for the same time. Hence, we can use the available data on one type of long-term debt to reasonably predict the timing of other debt-related payments. We use Dealscan as our main source of information, because it is available for both public and private firms. We identify operators with credit facilities that were, at least once, set to mature in the four months from March to June of 2020. We provide evidence that such firms were likely to have other debt-related deadlines from March to June of 2020 due to synchronization. Using our measure, we show that financially constrained firms cut production by less. In contrast, we show that firms with credit facilities that were, at least once, set to mature from August to December of 2020 cut production by more. Assuming that payment deadlines that were set a number of years before the pandemic are orthogonal to the timing of the pandemic, as well as to the financial and operational decisions of the firms, our results provide strong confirmation that indebtedness distorts the production decisions of oil firms.

To further explore the mechanisms, we conduct two additional exercises. In the first exercise, we focus on secured asset-based lending and investigate firms' access to credit. We begin by showing that oil producers heavily utilize their revolving credit facilities. However, during the pandemic banks severely limited firms' ability to drawdown on their existing credit lines by significantly reducing borrowing limits, in line with the findings of Chodorow-Reich et al. (2021). We use borrowing base reductions and actual credit line drawdowns (defined as changes in credit utilization rates relative to pre-pandemic borrowing limits) to assess firms' ability to access credit. Our results imply that the firms that faced more favorable changes in credit conditions and were able to utilize their existing credit lines were cutting production by more, in line with our main results.

In our second additional exercise, we exploit a novel measure of failed hedging practices to identify more exposed firms with stronger cash needs. Our measure is based on whether a firm hedged using three-way collars. In contrast to traditional costless collars, three-way collars prescribe selling an additional, further out-of-the-money put option and thus maintain a substantial degree of risk. In 2020, three-ways collars failed to pay off and left producers who used them exposed to significant losses after oil prices plunged. We show that producers who used three-way collars also cut production by less.

To rule out alternative channels and provide evidence that immediate cash needs distorted production decisions, we also investigate well completions. Although a successful well completion can boost collateral value and facilitate refinancing, it is extremely costly and thus cannot alleviate immediate cash needs. We find that financially more constrained firms were less likely to complete their wells, thus supporting our mechanism.

We conduct extensive robustness checks to show that our results are not driven by any obvious confounding factor. In particular, our results are not driven by shale firms and cannot be explained by differences in hedging practices, physical delivery commitments, operating costs, ownership of downstream operations, or by differences in the types of credit facilities secured by the firms. We show that our results remain unchanged if we extend our analysis to vertical wells. Overall, our empirical design significantly raises the bar for alternative explanations that are completely unrelated to the economic mechanisms we test for.

For robustness, we exploit numerous alternative ways to identify financially weak operators. First, we exploit stock price responses to a collapse in the oil price following the sudden and unexpected failure of Russia-OPEC negotiations in March 2020. As a result of the failed negotiations, the oil price plunged by 24% or $10 per barrel on Monday, March 9, 2020. The price shock rattled the stock prices of oil producing firms. We identify financially weak firms as those that were devalued the most. Indeed, extensive corporate finance literature documents that the stock market rewarded firms with healthier balance sheets during the COVID-19 pandemic; see Acharya and Steffen (2020), Fahlenbrach et al. (2020), and Babenko et al. (2020). Our results confirm our previous findings that financially weaker firms cut production by less. Second, we use a battery of traditional measures of financial soundness and financial constraints. Overall, our results are consistent with financially constrained firms making suboptimal production decisions to maintain cash flows. In particular, our results show that firms that were less able to fund themselves without relying on external financing (as per the 2021 Huang and Ritter measure) also cut production by less.

The *main takeaway* of our paper is that debt matters for oil supply adjustments to low oil prices. We contribute to the literature by providing the first large-scale evidence of production resilience due to indebtedness. Domanski et al. (2015) was the first study to suggest that indebtedness could be a crucial factor in the lack of production response to low oil prices in 2014-15. Early evidence was provided by Lehn and Zhu (2016), who documented an inverse relation between capital expenditures and leverage and a positive relation between oil production and leverage, and found that these relationships became more pronounced in 2015. Gilje, Loutskina, and Murphy (2020) show that extremely high leveraged firms (those in the top quintile of leverage distribution) did not postpone investment decisions when they faced an upward-sloping futures curve in 2015. Our paper detects *widespread* and *significant production* distortions following the unprecedented cash flow shock due to the COVID-19 pandemic.

The idea that debt creates *investment* distortions has been studied extensively in the literature. Traditional distortions include debt-overhang-related underinvestment and asset substitution.[5] Myers (1977) argues that underinvestment is not limited to investment in physical capital; it can also affect other discretionary choices such as labor decisions, expenditures on R&D, marketing expenses, efficiency improvements etc. In contrast, our results highlight a novel debt-related distortion of *production* and in the direction of *overproduction* (not underproduction).

Our second contribution is to the literature on the estimation of oil supply elasticities. In contrast to existing studies, we document significant adjustments in oil production. We provide direct evidence that oil producers responded to low oil prices by shutting down some of their wells.

[5] See Gilje (2016) and Gilje, Loutskina, and Murphy (2020) for an overview as well as oil-market specific evidence.

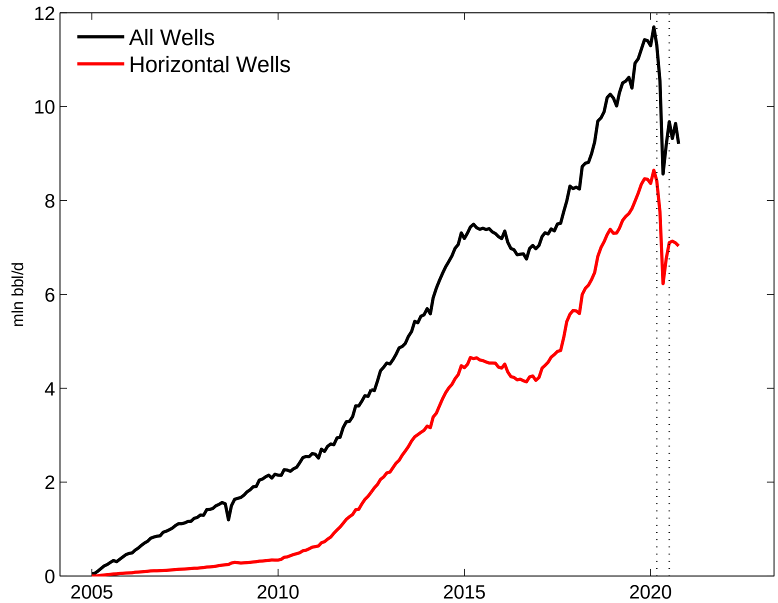
The existing empirical literature lacks consensus on the size of oil supply elasticities. Many papers find that short-run production responses (intensive margin) are close to zero, and only investment responses (extensive margin) can be detected, especially if one extends the response period; see, for example, Anderson et al. (2018) and Newell and Prest (2019); while other papers including Caldara et al. (2019) and Baumeister and Hamilton (2019) document a positive global oil supply elasticity. We are also the first to highlight heterogeneity in oil supply elasticities across different firms and to explain it by heterogeneous indebtedness using microdata. Our results imply that propagation of negative oil demand shocks depends crucially on the level of indebtedness of individual firms, which can vary over time. We discuss our contribution to the estimation of oil supply elasticities further in section 7.2.

Third, we contribute to the literature by exploring the effects of the unprecedented COVID-19 shock on the oil market. In a contemporaneous paper, Gilje, Ready, Roussanov, and Taillard (2020) investigate well shut-in decisions following the negative WTI price recorded on April 20, 2020. They argue that WTI benchmarking, which is prevalent in North Dakota, led to more shut-ins than in California and Alberta, Canada. In addition to asking a different question, our treatment occurs at the firm level and not at the state level, which allows us to incorporate geographical fixed effects and control for differences in fundamentals across locations.

Finally, from a methodological perspective we create a novel measure of cash flow pressure using variation in hedging practices. We also highlight the importance of distinguishing hedging practices by instrument type. This is not typical in the existing literature, which usually focuses on hedging ratio and maturity of hedging derivatives; see, for example, Babenko et al. (2020) and Doshi et al. (2018).

The paper proceeds as follows. In Section 2, we describe the aggregate state of the oil market following the coronavirus outbreak and provide necessary background information. We describe our methodology and data construction in Section 3. Section 4 presents our main results, as well as various robustness checks and placebo tests. In Section 5, we conduct an additional exercise to highlight and test our mechanism and rule out some alternative channels. Section 6.2 exploits alternative measures of financial constraints to provide additional evidence. Section 7 puts our

Figure 1: US Oil Production Response to the COVID-19 Shock



Notes: The figure uses monthly production data for all producing entities in the US with first production date recorded from January 2005 to December 2020. The black line corresponds to the total production from all wells in our sample. The red line corresponds to horizontal wells only (as labeled by Drillinginfo). The two vertical lines depict March 2020 and July 2020.

results into a wider perspective and describes our contribution to the literature on the estimation of oil supply elasticities. Finally, Section 8 concludes.

2 Background Information

We begin by describing the aggregate state of the oil market following the COVID-19 outbreak.

2.1 Aggregate Oil Production Response to the COVID-19 Shock

In 2020, the global oil industry faced the biggest consumption hit in its history, as governments imposed lockdowns and travel bans in response to the coronavirus outbreak. The resulting fall of the price of oil changed the economics of oil production and forced oil firms to adjust. A Kansas City Fed Energy Survey shows that over 62% of firms shut-in wells or curtailed production in the second quarter of 2020. In a similar survey, the Dallas Fed reports that 82% of firms cut production.[6] The production curtailment in both federal districts was primarily driven by low wellhead prices, as noted by 94% of respondents in the Dallas Fed's Energy Survey and by 60% of respondents in the Kansas City Fed's Energy Survey.

Figure 1 illustrates the drop in oil production in the US in response to the COVID-19 shock. The figure clearly indicates that production declines from March to May 2020 were unprecedented in magnitude. Indeed, unconventional oil production declined by an astonishing 26% from 8.42 mln bbl/d in March to 6.23 mln bbl/d in May.

Production responses were also quite heterogeneous geographically. While northern states including North Dakota, Montana, and Wyoming experienced more than 40% drops in production, other states including Colorado demonstrated a somewhat muted reaction to the shock with just a 9% cut in production (see Table 13 in Appendix). Of course, not all states were equally exposed and lockdown measures were not uniform. Other factors, such as availability of storage facilities, refinery utilization rates, productivity differences, and differences in sales practices (e.g., benchmarking to WTI or local trading, see Gilje, Ready, Roussanov, and Taillard (2020)) also were important in shaping production responses across locations. By conducting our analysis at the well-level rather than at firm level, we can control for geographical differences and focus on another source of heterogeneity related to the financial states of the firms.

2.2 Shut-ins of Horizontal Wells

In our analysis, we focus on horizontal oil wells. Figure 1 shows that horizontal wells currently dominate US oil production, accounting for more than 75% of total volume. Horizontal wells have a quickly deteriorating curve and a relatively short period of life. Thus, the tradeoff between selling oil today vs. tomorrow should be more acute for such wells. Horizontal wells are also quite expensive to drill and frack and shale producers are typically heavily indebted. Finally, the data on horizontal wells are recent and thus potentially more reliable (well design, coverage, first production date etc). For robustness, we repeat the main exercise for vertical wells as well.

Oil producers responded to low oil prices by completely shutting down some of their horizontal

[6] See Kansas City and the Dallas Fed Energy Surveys, Q2 2020.

wells.[7] A shut-in well can be reopened, although not without some loss. The Q2 2020 Dallas Fed Energy Survey reported that 27% of surveyed firms anticipated no costs at all, 61% expected minor costs, and only 11% of firms expected significant costs when placing shut-in and/or curtailed wells back online. Consistent with the survey evidence, the firms reported no significant costs associated with restoring production in their second quarter SEC reports.[8]

Technically, at any point in time a horizontal well can be either producing at its maximal capacity or it can be temporary or permanently shut-in. However, our production data only comes at monthly frequency. Thus, unless a decision to shut in a well comes before the first calendar day of a month, some production volumes are still recorded for this well.[9] Therefore, in the benchmark exercise, for each well we calculate the decrease in production from March to May, when the oil market was hit the hardest. For robustness, we investigate full shut-ins as well.

2.3 Firm-level Heterogeneity in Production Responses

To provide preliminary evidence on firm-level heterogeneity in production responses, we split the sample into financially constrained and unconstrained operators (see formal definition in Section 3.2) and investigate group-level responses.

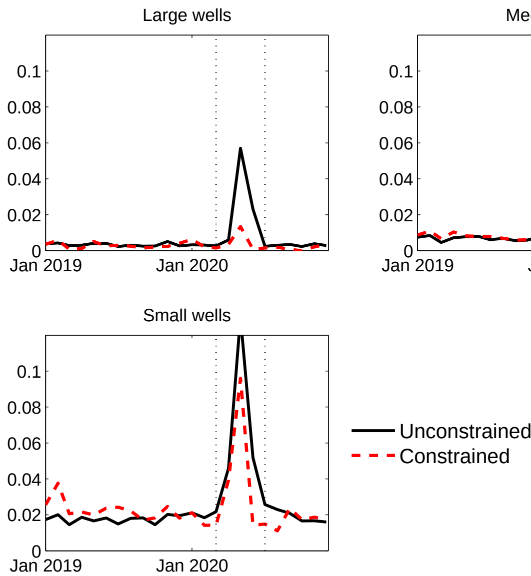
Figure 2 investigates complete shut-ins. A well is defined to be shut-in in month t, if it produces nothing in month t, but has strictly positive production in month $t-1$. Of course, well productivity

[7] This is based on the SEC filings, earnings call transcripts as well as our conversations with oil drillers and petroleum engineers. For example, Ring Energy: *"Starting the last week of April, the Company curtailed essentially all production, other than that associated with Ring's Delaware Basin property. The curtailments continued until early June, when, with commodity prices improving and price differentials decreasing, the Company began to ramp up production, returning to near April levels by the end of the quarter"*; Earthstone Energy: *"In late April 2020, WTI crude oil prices fell below $10/Bbl. In response, management began to voluntarily shut-in as much production as was feasible in an effort to conserve reserves in a market where cost exceeded the price".*Oasis Petroleum: *"..due to the current commodity price environment, we have reduced our planned E&P capital expenditures for 2020, curtailed flush production on newly completed wells and shut-in certain wells.".* Chesapeake Energy: " *Due to the significant drop in oil prices and midstream constraints in the Current Quarter, we shut-in wells and delayed turn-in-lines, which reduced our oil production by approximately 50% and 25% in May and June, respectively."*

[8] For example, Earthstone Energy Inc 10-k report as of June 30, 2020: *"In May, approximately 60% of our total production was shut-in. As oil prices improved considerably since then, we initiated a concentrated effort to return wells to full production in June. We are close to 100% of production capacity on our operated properties and very little of our non-operated production is curtailed. We have experienced no adverse effects from this short-term curtailment and have incurred no significant costs in restoring production".*

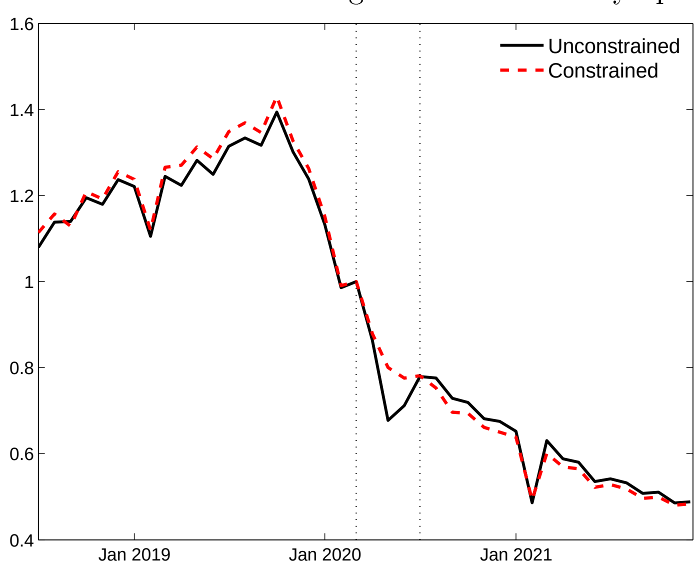
[9] See also Earthstone Energy Inc (ESTE) Q1 2020 Earnings Call Transcript: *"One thing is from the lease agreement standpoint, we're not shutting wells very long, and we're rotating wells throughout our different leases. So in general, wells will produce, at some point, a little bit during the month".*

Figure 2: Fraction of complete shut-ins by well type and operator type



Notes: The picture shows the fraction of wells in each category that were shut-in in each month from January 2019 to December 2020. A well is defined to be shut-in in month t, if it produces nothing in month t, but has strictly positive production in month $t-1$. For each month t we distinguish wells into three category based on observed production in the previous month $t-1$: large wells must produce more than 3000 barrels, medium wells must produce from 500 barrels to 3000, and small wells must have production from 100 to 500 barrels. Financially constrained (unconstrained) operators are depicted by a black solid line (red dashed line) and are identified by credit expiration dates as described in Section 3.2. The two vertical lines correspond to March 2020 and July 2020.

Figure 3: Production from existing horizontal wells by operator type



Notes: The picture shows normalized monthly production from a *fixed* set of horizontal wells from July 2018 to December 2021. For each group of operators we choose wells that were actively producing for at least 6 months in March 2020. The production is normalized to 1 in March 2020 (also depicted by the first vertical line). Financially constrained (unconstrained) operators are depicted by a black solid line (red dashed line) and are identified by credit expiration dates as described in Section 3.2. The second vertical line corresponds to July 2020.

is an important factor driving shut-in decisions. Therefore, for each month t we split wells into three categories based on the observed production in the previous month $t-1$: large wells produce3000 barrels or more, medium wells produce from 500 to 3000, and small wells produce from 100 to 500 barrels of oil a month.

Figure 2 illustrates three important observations. First, we can see a dramatic increase in shut-ins during the COVID-19 episode. For example, the probability to shut in a small well jumped from about 2% to more than 10%. Second, least productive wells were more likely to be shut in. Finally, there is a clearly seen difference in the shut-in behavior of financially unconstrained and constrained firms. In particular, constrained firms were less likely to shut in the most productive and medium wells. At the same time, we find that the shut-ins of the least productive wells were similar. As large wells account for more than 80% of the total production, we mostly focus on large wells in our formal analysis.

Because some wells could have been shut in for a fraction of month, we separately investigate production volumes. To focus on production decisions and abstract from new drills, we fix the set of wells that were actively producing for at least 6 months in March 2020 and trace their production before and after the pandemic. Figure 3 plots the results. For the sake of presentation, we normalize the total production volumes of financially constrained and unconstrained operators to 1 in March 2020. The figure shows that before and after the pandemic episode, constrained and unconstrained production volumes almost perfectly trace each other. Production volumes initially increased, as more wells got completed and started to produce. Once all wells were completed, production began to gradually decline. It is important to note, that we also observe the same drop in production for financially constrained and unconstrained operators in February 2021 *a year after* the pandemic episode when extremely cold weather in Texas and some other top producing states shut in some production.

In contrast, during the pandemic episode, unconstrained operators cut their production by substantially more than constrained operators. By May 2020 the difference in production responses reached 10 percentage points. Of course, this preliminary exercise does not account for any well- and firm-level characteristics. Hence, we proceed to formal analysis in the next section.

3 Methodology

In this paper, we aim to document heterogeneity in production responses due to indebtednes. In this section we outline our empirical setting and in the next section we describe how we identify financially constrained operators.

3.1 Empirical Model

We investigate oil production cuts in the US following the coronavirus outbreak. We perform our analysis at the well level and focus on horizontal wells drilled after 2005 and actively producing at the beginning of the pandemic.

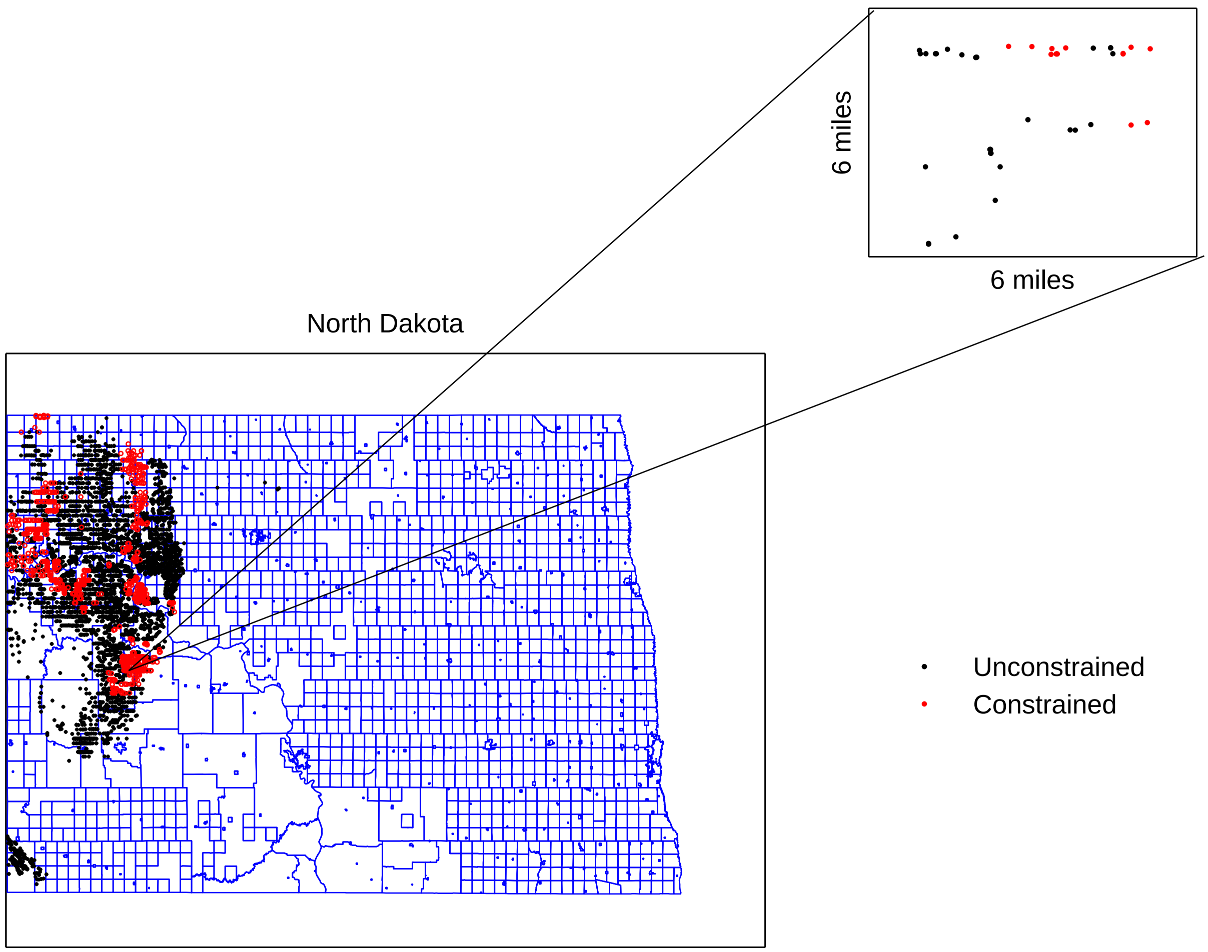
The main outcome variable is the well-level change in monthly oil production from March to May 2020. We investigate production cuts that occurred over April and May of 2020, because this was when the oil market was hit the hardest by the coronavirus outbreak and the demand collapse. We estimate the following cross-sectional model:

$$\Delta y_{j,i,s,k} = \delta_s + \gamma_k + \alpha \cdot Constrained_i + \beta_1' X_i + \beta_2' X_j + \varepsilon_j \tag{1}$$

where $\Delta y_{j,i,s,k}$ is one half[10] of the change in monthly oil production from March to May 2020 in well j operated by firm i, located in a geographical unit s, aged k. $Constrained_i$ is the operator-level variable that identifies financially constrained operators, as defined in the next section 3.2. The main coefficient of interest is α, which measures the extra cut in production that is made by more financially constrained operators relative to less constrained operators. The controls include X_i and X_j firm and well level controls, geographical unit s fixed effects δ_s and well age fixed effects γ_k, which we carefully discuss below in Section 3.3. The standard errors are clustered at the operator level.

[10] We divide the actual production cuts over the two months by two to facilitate the comparison of our results with existing estimates in the literature.

Figure 4: Illustration of our identification strategy



Notes: The figure depicts horizontal oil wells located in North Dakota. The black dots represent wells owned by unconstrained operators (as defined by credit expiry; see Section 3.2) and the red dots represent wells owned by constrained operators. The top figure zooms in on one 6 by 6 square mile geographical unit.

To provide further evidence, we separately explore complete well shut-ins. For each well in our sample, we create a ShutIn indicator which equals 1 if a well produced in March 2020, but had zero production either in April or May 2020. We then estimate the following linear probability equation model:

$$ShutIn_{j,i,s,k} = \delta_s + \gamma_k + \alpha \cdot Constrained_i + \beta_1' X_i + \beta_2' X_j + \varepsilon_j \tag{2}$$

where $ShutIn_{j,i,s,k}$ is the Shut-In indicator for well j, owned by operator i, located in geographical unit s and of age k. With the exception of the outcome variable, the model is exactly the same as given by equation 1.

3.2 Identifying Financially Constrained Operators

We use three different ways to identify financially more exposed firms and create a $Constrained_i$ variable for each operator i. Our first two measures characterize firms' indebtedness and access to credit. The third measure identifies firms with larger cash-flow pressure.

1. Credit Expiry

Long-term debt has a complex structure. Oil firms typically issue bonds and notes, take term loans and enter into revolving credit agreements, either secured or unsecured. Payment schedules vary for different bonds. Revolving credit agreements are frequently amended to reflect changes in loan conditions and maturity extensions.[11] To obtain a complete picture of a firm's payment deadlines and conditions it is necessary to manually-trace loan paths through multiple rounds of credit amendments, and to collect data on payment dates of various notes. This information needs to be hand-collected and often directly taken from the original documents, because annual and quarterly SEC filings do not always provide full information. The task becomes even more complicated for private firms.

[11] For example, from 2010 to 2019 Gulfport Energy Corp entered into 25 credit agreements and amendments of credit agreements. Only 2 out of 25 deals corresponded to new credit agreements. Maturity was extended 3 times, all these extenstions were recorded as credit amendments. Dealscan contains only 5 observations. From these 5 data entries, 1 corresponds to a new credit agreement and 4 to amendments; 2 out of 3 maturity extensions are not recorded.

We create a measure of financial constraints that exploits synchronization and periodicity of debt payments and relies only on standard Dealscan data. We argue that there is a tendency of multiple forms of long-term debt to be co-issued and co-dependent, which creates a synchronized/correlated pattern of payment deadlines. Hence, we can use the available data on one type of long-term debt to reasonably predict the timing of all other debt-related payment deadlines. We use Dealscan for the data on syndicated credit agreements, because it contains information for both public and private firms.[12] Formally, the indicator variable $Constrained_i$ equals 1 if the firm i has any data entries with an expiration date scheduled within 4 months from March to June 2020. The indicator equals 0 if the firm i has at least one data entry with an expiration date after January 2020, and does not have any data entries with an expiration date from March to June 2020. Although by December 31, 2019 most firms in our sample had extended their credit revolving facilities beyond 2020, the mere fact that at *some* point their credit facilities were set to expire from March to June 2020 increases the *probability* to observe other payment deadlines within the same time period. In particular, we argue that exposed firms (as per our measure) were *more likely* to have other forms of debt, such as senior unsecured bonds and notes or term loans that expired from March to June of 2020, and were *more likely* to have interest payments on other forms of debt scheduled for March to June of 2020.

One factor that tends to synchronize payments is the issuance of different forms of debt simulataneously to fund large investment projects, including mergers and property acquisitions. Another factor is issuance of new debt to repay outstanding borrowings under the other, especially as the maturity of the outstanding debt approaches. More generally, as any debt issuance typically triggers renegotiation of credit lines, the expiration and payment cycles of different forms of long-term debt often become aligned. In Appendix A.2 we discuss this further and provide evidence of synchronization of payments for the firms in our sample.

Using past credit expiration dates to identify financially constrained operators has certain advantages. Most importantly, it is safe to assume that the past expiration dates of credit agreements

[12] Dealscan contains both originations and renegotiations, many of which cannot be clearly distinguished. Moreover, many amendments are not recorded in Dealscan. Roberts (2015) finds that Dealscan observations do not correspond to any particular type of event; see also footnote 11. As a result, Dealscan provides only partial information about loan paths of our firms.

and payment deadlines that were set a number of years before the pandemic were exogenous to the timing of the COVID-19 outbreak, as well as to both the operational and financial performance of the firms. Hence, this approach provides exogenous variation in the *timing* of debt-related payments relative to the COVID-19 outbreak. Moreover, data on syndicated lending are available for both public and private firms and thus significantly extend and diversify our sample.

Of course, if the synchronization assumption was not correct, then using past credit lines expiration dates would randomly assign firms into treatment and control groups, and we would not be able to find any differences in production responses.[13] To provide additional evidence against finite sample flukes, we follow the same argument to identify the firms with delayed interest payments. Formally, we create an additional measure $Fall\,Expiration_i$ that equals 1 if the firm i has any credit data entries with an expiration date scheduled from August to December 2020 (and a start date before the pandemic), and equals 0 otherwise as long as the firm has any credit facilities in place at the beginning for the year. It should be noted that we can have all 4 possibilities in the data, that is, all 4 combinations of $\{Fall\,Expiration_i, Constrained_i\}$ are possible. We repeat our main production analysis using this second measure, but now expect to find the opposite responses.

2. Access to Credit

In the second exercise, we focus on the subsample of firms with secured credit facilities and assess firms' ability to draw on their existing credit lines.

Many oil and gas producing firms rely on asset-based lending. Each debt generally has a borrowing limit based on the firms' oil and gas reserves. The borrowing base amount is redetermined semiannually (in April-May and October-November), often by the lenders in their sole discretion. In addition, lenders typically have a right to make an interim redetermination of the firm's borrowing base at least one time in between regular redeterminations.[14] Lenders have substantial

[13] In section 3.4, we compare treated and control firms by a large number of observable characteristics. In particular, we compare typical loan maturities as of the previous 10 years as well as remaining maturities of credit facilities in place as of December 31, 2019. We find no differences in credit maturities, thus ruling out a concern that firms with shorter maturities were more likely to be assigned into the treatment group.

[14] For example, see Chaparral Energy Inc. 10-Q filing as of March 31, 2020: *"On April 1, 2020, we borrowed \$15,000, and on April 2, 2020, we provided notice to our lenders to borrow an additional \$90,000 (the latter herein referred to as the "Borrowing") which increased the total amount outstanding under the Credit Agreement to \$250,000. The Borrowing was made by the Company as a precautionary measure in order to increase*

flexibility to reduce the borrowing base due to subjective factors. Upon a redetermination, the firm could be required to repay a portion of the debt owed under its facility to the extent that its outstanding borrowings at such time exceeds the redetermined borrowing base.

We hand-collected the data on borrowing limits, borrowings outstanding and issued letters of credit as of December 31, 2019, March 31 and June 30, 2020 from SEC annual and quarterly filings. We make three important empirical observations.

First, oil producers heavily utilize their secured credit facilities. We define the credit utilization rate as the ratio of borrowings outstanding plus issued letters of credit over the borrowing limit. The borrowing limit is defined as the minimum between the borrowing base and elected commitments. We find that the median credit utilization rate as of December 31, 2019 was 45%, the first and third quantiles were 25% and 70%. The median credit utilization increased to 55% by the end of March, and to 77% by the end of June.

However, the increase in credit utilization rates was driven mostly by the severe cuts in the borrowing limits. Indeed, the median decrease in the borrowing base was 20%, the first and third quantiles were 11% and 35%.[15] Some firms experienced much larger cuts: Sandridge Energy saw its borrowing base cut by 67%, Oasis Petroleum was cut by 53%, Chaparral Energy Inc. by 46%, Contango Oil and Gas by 41%. Some companies saw their commitments cut below the actual amount drawn, requiring them to repay the deficit. Importantly, many borrowing redeterminations occurred before the scheduled dates, as lenders exercised their rights to make interim redeterminations (see footnote 14). Some lenders prevented extra borrowing until redetermination was complete.[16]

Finally, we find that the firms made very limited drawdowns on their credit lines during the pandemic. To assess the intensity of credit lines drawdowns, we calculate *actual drawdowns* defined

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its cash position and thereby provide for flexibility in the current challenging business environment and associated uncertainties. Subsequent to the Borrowing, we were notified that our lenders had exercised their right to make an interim redetermination of the Company's borrowing base. The lenders' redetermination notice stated that the Company's borrowing base was decreased from $325,000 to $175,000, effective April 3, 2020."

[15] Our findings are consistent with existing reports. For example, according to S&P Global Ratings, borrowing bases were reduced by an average of 23%.

[16] On March 11, 2020 Unit Corp entered into a standstill agreement with regards to the Unit credit facility which delayed the scheduled borrowing base redetermination from April 1, 2020 to April 15, 2020. Under the agreement, the company was prevented from withdrawing more than an additional $15.0 million between March 11, 2020 and the expiration of the agreement on April 15, 2020.

as the change in credit utilization *holding fixed* the borrowing limit at the pre-pandemic level as of December 31, 2019. We find that the median *actual drawdowns* were 6 pp only, with the first and third quantiles of 0 and 17.5 pp. We can see that actual drawdowns are significantly smaller than observed changes in credit utilization rates due to substantial cuts in the borrowing capacity.

Overall, we find that banks severely limited firms' ability to drawdown on their existing credit lines during the pandemic. Our findings are thus in line with the recent findings of Chodorow-Reich et al. (2021) who document that small firms were subject to greater lender discretion than large firms and thus could not fully utilize their open credit lines.

We use our findings to create two additional measures of financial constraints. First, we exploit *borrowing base cuts* as a measure of financial constraints. Second, we use *actual drawdowns* to identify operators that could access liquidity through their credit lines during the pandemic and thus were possibly less financially constrained.

3. Failed Hedging

In the third exercise, we approach the issue from the other side and identify the firms that had more acute immediate cash needs than others. To do that, we explore a novel variation in the hedging practices used by oil producing firms.

Although most firms use swaps and costless collars to manage oil price risks, some firms use three-way collars. A three-way collar is a typical collar (buying a put option and selling a call option), but in addition the producer sells a further out-of-the-money put option, which makes hedging cheaper, but at the same time the producer also takes on additional risk of significant declines in oil prices. Of course, when oil prices plunged in 2020, the three-way collars failed to pay off, and left producers exposed to significant losses.[17] The controversial hedging practice of using three-way collars, which failed to mitigate the decline in oil prices in 2020, offers another

[17] For example, Denbury Resources Inc. sold put options with the strike price of $48.25/bbl, purchased put options at the strike $56.95/bbl, ans sold call options at $62.83/bbl. Hence, at oil prices below $48.25/bbl the payoff of such a three-way collar equals $8.7/bbl, which is the difference between the strike prices of the put options (without the option premiums). Similarly, Ovintiv Inc. used the 43.44/53.44/61.68 three-way collars. The payoff of such an instrument for oil prices below $43.44/bbl equals $10/bbl (without the premiums). However, by mid March 2020, the WTI futures price for April delivery was below $30/bbl. On April 20, 2020 the WTI futures price for May delivery actually turned *negative* for the first time in history and settled at -$37.63/bbl. At such low prices three-way collars provided little to none compensation, while standard costless collars secured significant payoffs.

way to identify more financially constrained operators.[18]

We use the fraction of production volume hedged with the three-way collars instead of the $Constrained_i$ indicator.

3.3 Choice of Controls

Natural decline in well productivity In our analysis, we investigate production changes at the well level and focus on horizontal oil wells. Horizontal wells are characterized by a quickly deteriorating production curve. To accurately estimate *abnormal* production cuts, we need to carefully model the natural decline in monthly production that would normally be observed in a well of a particular age, design, and location even in the absence of the COVID-19 shock. We capture the natural decline in productivity by including a function of the age of a well, either using age fixed effects γ_k or a cubic function $f(k)$ of the number of production months k. To further capture individual differences in production declines, we include lagged changes in a well's production into the well-level controls X_j. We also include the logarithm of the cumulative oil production over the first 6 producing months and the horizontal wellbore length to capture productivity of the wells (in addition to geographical indicators as we discuss next). We expect that operators were more likely to shut in their least productive wells (as suggested by Figure 2).

Geographical location Second, we include indicators for each geographical unit s. Because we have data on a large number of wells, we can construct a very fine grid of unique geographical locations. Each geographical unit s is the size of a township and represents a 6 by 6 square mile unit.[19] To illustrate, Figure 4 depicts the locations of horizontal oil wells in North Dakota and zooms in on one of the constructed geographical units. We see that *within one unit*, there are wells owned by both constrained and unconstrained operators, and thus we can compare production

[18] In the existing literature, for example Babenko et al. (2020) and Doshi et al. (2018), it is common to focus on entering any hedging activity, hedging ratio, and maturity of hedging derivatives. Existing studies document significant heterogeneity across firms in hedging intensity. However, to the best of our knowledge none of the existing studies distinguishes three-way collars from standard hedging instruments.

[19] It is typical in the oil and gas industry to consider a 6-by-6 square mile unit as a separate drilling location. This choice can be partially driven by the fact that the Public Land Survey System (PLSS) splits the territory into such units for most of the states. However, some of the states do not use this system (for example, Texas). To make the analysis uniform, we divide the entire US territory into 6-by-6 square mile units, not trying to match the original land division.

cuts within the same location.

Overall, by including a fine grid of geographical fixed effects, we can capture i) differences in the productivity of wells across locations; ii) differences in the intensity of COVID-19 demand shocks, lockdown measures, refinery utilization, and etc.; iii) differences in the availability of storage facilities and access to a pipeline network; iv) differences in local sales practices (benchmarking to WTI or local trading, etc), and many other dimensions along which different locations may pose different incentives to cut production.

Operator-level controls In the benchmark exercise we only include the public status of the operator as an operator-level control, relying on the assumption of exogeneity in timing of debt-related payments. Under this assumption, our sample extends to both public and private operators.

However, to show that our results are not driven by any obvious confounding factor we run a large number of additional specifications and include a rich set of operator-level controls, both physical and financial. Physical controls include the fraction of oil production (as opposed to natural gas) and the fraction of shale oil production. One may be worried that primarily shale oil producers may run different balance sheets and be generally more indebted etc. Similarly, the companies which primarily extract and sell natural gas could be less affected by the demand collapse or could adjust differently to it. Information on these variables was hand-collected from the 10-k SEC filings and annual reports. Formal definitions are given in Section A.3.

One can also be worried that less efficient operators with larger operating costs would have higher shut-in rates at the same level of oil price. To address this concern, we collect the data on the average lease operating expenses (LOE), which are the costs incurred by an operator to keep production flowing. LOE include the costs associated with artificial lift and maintaining artificial lift, water disposal costs, costs associated with employees who regularly monitor and maintain wells etc. The data on operating costs was also hand-collected from SEC filings. Inclusion of LOE supplements geographical indicators that also pick up some variation in operating costs that is associated with differences in productivity, well design, well site accessibility etc.

Finally, we hand-collected data on hedging and physical delivery commitments in place as of December 31 2019 for the year of 2020 from the 10-k SEC filings. The existence of financial hedging contracts and/or physical delivery commitments can also have an influence on production adjustments.[20] If such contracts exist, the company might be more willing to continue producing either because the price is more favorable, or because there are fines for non delivering on its obligations. Moreover, it might be easier for such a firm to refinance or attract additional funding, thus improving its financial state. On the other hand, hedging and operating decisions are potentially independent, and thus a firm can simultaneously enjoy favorable pricing and optimally relocate production to the future.

In contrast to the previous literature, we argue that it is important to distinguish different hedging practices. Typically oil firms use swaps and costless collars to manage oil price risks, however some firms use three-way collars. A three-way collar is a typical collar (buying a put option and selling a call option), but in addition the producer sells a further out-of-the-money put option, which makes hedging cheaper, but at the same time the producer also takes on additional risk of significant declines in oil prices. Of course, when oil prices plunged in 2020, the three-way collars failed to pay off, and left producers exposed to significant losses. Hence, we separately calculate the percentage of firm's projected 2020 oil production that was hedged with standard instruments and with three-way collars. We use actual oil production in 2019 to forecast oil production in 2020. See Section A.3 for details.

Similarly, we hand-collect the data on physical delivery commitments to calculate the fraction of volume committed.[21]

We also include a battery of standard financial outcomes as of December 2019 such as profitability, leverage, fraction of short-term debt, cash holdings etc.

Finally, one might be worried that a subset of firms, defined by some observed or unobserved characteristics (for example riskier firms), tend to systematically rely on shorter term financing. Thus, we also include the number of days until the stated maturity date of the firm's revolving

[20] In a different setting, Doshi et al. (2018) show that hedging affects the sensitivity of capital expenditure to price uncertainty. Doshi et al. (2018) also document that large firms have significantly higher hedging intensity compared to small firms.

[21] Both the existence of physical delivery contracts and deficiencies are normal and customary in the oil E&P business. The deficiency fees on long term physical delivery commitments are paid when a firm fails to deliver the committed volumes. Such fees are typically around \$3-7 dollars per barrel and thus are relatively small compared to the fall in the oil price during the pandemic episode. See, for example, Whiting Petroleum Corporation, 10-k filing for the year ended December 31, 2019, page 24., or Ovinitiv Inc., 10-k filing for the year ended December 31, 2019, page 66.

credit facility as of December 31 2019 hand-collected from the annual SEC filings.

3.4 Data and Descriptive Statistics

Our main source of well-level data is Enverus (previously Drillinginfo). We consider all horizontal oil wells with first production date after 2005 in the US. In our benchmark exercise we focus on large oil wells, which we define as wells that produced at least 3k barrels of oil in March 2020. Our initial sample before we match it with financial data consists of 21,256 oil wells in total.

Our financial data comes from Compustat and DealScan. Data on hedging; physical delivery commitments; gross and net number of oil and gas wells; maturity of revolving credit facilities, borrowing limits, outstanding borrowings and issued letters of credit under firms' credit facilities; lease operating expenses; information about downstream operations were hand-collected from annual and quarterly SEC filings (see Variable Definition Section in Appendix A.3).

Our joint dataset on expiring credit facilities and well-level data contains 106 public and private operators accounting for 75% of total oil production from all horizontal wells in the US in March 2020 and for 74% of the total number of horizontal oil wells in the US that produced at least 3k barrels of oil in March 2020.[22] The final number of large horizontal wells in our dataset is 15,624. Out of 106 operators, we have 48 public firms accounting for 88% of production and 87.5% of large wells, and 58 private firms accounting for the remaining 12% of production and 12.5% of large wells.

Descriptive statistics and balance tables

Our main identification assumption is the exogeneity in the timing of debt-related payments which we capture using the past expiration dates of credit facilities. In what follows we compare well-level, loan-level, and firm-level characteristics of treated (constrained) and control (unconstrained) firms to provide evidence that no obvious characteristics can predict the expiry of credit agreements.

First of all, Figures 2 confirms no differences in shut-in behavior of treated and control firms before and after the pandemic episode. Similarly, Figure 3 shows no differences in the dynamics

[22] These estimates are based on our data from Drillinginfo.

of production (see Section 2.3).

Table 1 provides information about the portfolio of horizontal oil wells of constrained and unconstrained firms at the beginning of the pandemic. The table presents an average number of wells, average productivity, and location (as measured by the number of unique states, counties, and unique 6-by-6 square mile unites where the firms owned wells). We distinguish wells by productivity into large, medium, and small. The table shows no systematic difference in the composition of the wells of treated and control firms. Panel B further compares publicly traded firms only, and again finds no significant differences.

In our main exercise, we mainly focus on large wells that produced more than 3k barrels of oil in March 2020. Table 2 provides further information about the number, design, location, age, and initial and current productivity of large horizontal wells of constrained and unconstrained operators. The table again confirms that treated and control operators had almost indistinguishable wells. The wells had the same initial productivity and the same productivity at the beginning of the pandemic episode. The average productivity of large wells in March 2020 was about 8000 barrels a month. The average number of wells was 140 for unconstrained operators and 200 for constrained, however the difference was insignificant. The wells had produced for about 16 months on average by that time. Operators had large wells located on average in 1.5 states, 4-6 counties and 15-20 geographical squares, with a lot of variation in these variables. The only significant difference is that the wells of constrained operators were somewhat shorter. Overall, we do not find any evidence that treated operators had systematically more or less productive wells. Of course, in our empirical exercises we include granular geographical indicators and a large number of well-level characteristics to further control for any potential differences across wells of treated and control firms.

Next we compare firm-level characteristics of the treated and control firms starting with the loans characteristics. We begin by noticing that there are more publicly listed firms among constrained firms, as indicated by the last raw in Table 1. One potential explanation could be that data reporting on renegotiations is better for traded firms and thus the probability to capture an expiring loan at any given period is larger. Therefore, in our empirical analysis we always include

Table 1: Horizontal well portfolio of unconstrained and constrained operators at the beginning of the pandemic

Panel A: All Operators

	Unconstrained	Constrained	Difference
Number of Large Oil Wells	139.315	200.500	61.185
	(281.851)	(351.952)	(83.635)
Number of Medium Oil Wells	251.696	440.643	188.947
	(458.599)	(568.132)	(135.887)
Number of Small Oil Wells	127.109	231.714	104.606*
	(215.062)	(230.826)	(62.279)
Average Productivity of Large Wells	8,531.545	7,730.972	-800.574
	(3,010.421)	(1,715.058)	(826.358)
Average Productivity of Medium Wells	1,400.778	1,311.913	-88.865
	(339.707)	(172.270)	(92.862)
Average Productivity of Small Wells	293.648	284.985	-8.662
	(43.697)	(64.242)	(13.529)
Number of States	2.554	3.571	1.017
	(2.374)	(2.243)	(0.676)
Number of Counties	11.446	16.929	5.483
	(17.133)	(14.642)	(4.831)
Number of Geo Squares	46.630	76.286	29.655
	(78.062)	(59.704)	(21.806)
Public Status	0.402	0.786	0.384***
	(0.493)	(0.426)	(0.139)
Number of Operators	92	14	106

Panel B: Publicly Traded Operators

	Unconstrained	Constrained	Difference
Number of Large Oil Wells	293.838	253.455	-40.383
	(394.919)	(382.928)	(134.738)
Number of Medium Oil Wells	524.973	555.909	30.936
	(625.355)	(592.787)	(212.377)
Number of Small Oil Wells	252.351	288.455	36.103
	(281.091)	(229.536)	(92.970)
Average Productivity of Large Wells	8,464.278	7,990.046	-474.233
	(1,994.091)	(1,734.887)	(666.468)
Average Productivity of Medium Wells	1,371.285	1,277.779	-93.506
	(217.148)	(159.023)	(70.714)
Average Productivity of Small Wells	291.157	301.969	10.812
	(30.876)	(51.165)	(12.454)
Number of States	4.000	3.273	-0.727
	(3.118)	(1.902)	(0.995)
Number of Counties	21.081	15.818	-5.263
	(23.659)	(14.757)	(7.566)
Number of Geo Squares	89.541	76.455	-13.086
	(108.707)	(62.575)	(34.512)
Number of Operators	37	11	48

Notes: This tables compares the number, average productivity, and location of active horizontal US oil wells of unconstrained and constrained operators as of March 2020. We split wells into three categories: large wells produced more than 3000 barrels a month, medium wells produced from 500 barrels to 3000, and small wells produced from 100 to 500 barrels. Average productivity is calculated in barrels of oil per month. The number of states (counties) calculates the number of unique states (counties) where an operator i owns oil wells. Similarly, the number of geo squares calculates the number of 6-by-6 square mile units where the operator owns oil wells. Panel A contains information for all producers in our sample, Panel B provides information on publicly traded operators. All data were obtained from Drillinginfo. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 2: Large wells of unconstrained and constrained operators

	Unconstrained	Constrained	Difference
Number of Oil Wells in March 2020	139.315	200.500	61.185
	(281.851)	(351.952)	(83.635)
Production in March 2020	8,531.545	7,730.972	-800.574
	(3,010.421)	(1,715.058)	(826.358)
Fraction of Shut-ins April-May 2020	0.134	0.018	-0.116*
	(0.252)	(0.031)	(0.068)
Production Change from March to May 2020	-0.182	-0.109	0.073*
	(0.140)	(0.114)	(0.039)
Log Cumulative Production, T=6m	11.294	11.147	-0.148
	(0.354)	(0.393)	(0.103)
Log Cumulative Production, T=1y	11.818	11.723	-0.095
	(0.331)	(0.321)	(0.098)
Log Cumulative Production, T=2y	12.269	12.105	-0.164
	(0.302)	(0.437)	(0.100)
Log Cumulative Production, T=5y	12.569	12.721	0.152
	(0.454)	(0.507)	(0.179)
Horizontal Length	8,570.405	7,319.125	-1,251.280**
	(1,796.029)	(2,197.269)	(530.993)
Perforated Interval	8,160.927	6,872.766	-1,288.161**
	(1,902.830)	(2,341.458)	(563.720)
Number of Months Producing	16.567	15.487	-1.079
	(10.647)	(5.519)	(2.911)
Number of States	1.511	1.857	0.346
	(0.989)	(1.027)	(0.285)
Number of Counties	4.109	6.000	1.891
	(4.809)	(5.616)	(1.411)
Number of Geo Squares	14.859	20.643	5.784
	(21.979)	(27.108)	(6.507)
Number of Operators	92	14	106

Notes: This tables compares the number, average productivity, initial productivity, and location of large active horizontal US oil wells of unconstrained and constrained firms. A well is defined as large if it produced more than 3000 barrels a month in March 2020. Initial productivity is measured by the logarithm of the cumulative production over the firms 6 months, 1 year, 2 years, and 5 years of production. Production in March 2020 is measured in barrels of oil per month. The number of states (counties) calculates the number of unique states (counties) where an operator i owns wells. Similarly, the number of geo squares calculates the number of 6-by-6 square mile units where a firm owns wells. Panel A contains information for all producers in our sample, Panel B provides information on publicly traded operators. All data was obtained from Drillinginfo. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

an indicator variable for listing status of the firms. We also repeat the estimation within the subsample of traded firms only.

Next we investigate syndicated lending. It should be noted that Dealscan contains both originations and renegotiations, many of which cannot be clearly distinguished. Moreover, many amendments are not recorded in Dealscan (see Section A.1 and footnote 11). However, we still find it useful to compare existing data on loans of treated and control firms. Panel A in Table 3 summarizes information available in Dealscan about loans that were originated/amended within the last 10 years before the pandemic by the firms in our sample. In line with our previous argument, we see that constrained firms had on average two data entries more, and these facilities were typically larger. At the same time, Table 3 shows that average maturities of the loans of treated and control firms were the same. That is encouraging, because a shorter maturity loan could indicate larger perceived riskiness of a firm. Once we control for the listing status in Panel B, we find that the loans of treated and control public firms become indistinguishable.

Panel C compares revolving credit facilities active as of December 31, 2019 for public operators using SEC filings data. We find no significant differences in time to maturity (calculated as the number of days until expiration), fraction of secured vs unsecured facilities, and credit utilization. Interestingly, we find that constrained firms with secured facilities experienced somewhat larger borrowing base cuts, although the difference is not significant.

Overall, once we control for the listed status of the operators, we do not find any systematic differences in the types of credit agreements owned by the treated and control firms.

Next Table 4 compares standard financial outcomes of unconstrained and constrained firms. This information is only available for a subset of public firms. The table confirms that treated and control firms have similar size, leverage, profitability, Tobin's Q, tangibility, cash flow, and short term debt ratio (see also Table 18 in Appendix for further information). We also find that the firms have similar mixture of oil vs gas revenue and similar fraction of shale oil production.

We find that treated firms have larger average lease operating expenses and the difference is marginally significant. However, if anything, this should push our results in the opposite direction, as treated firms should have had more incentives to shut-down production once their costs exceeded

Table 3: Syndicated loans characteristics of unconstrained and constrained operators

Panel A: All Operators - All Facilities

	Unconstrained	Constrained	Difference
Maturity in Years	4.222	4.140	-0.082
	(0.894)	(0.532)	(0.246)
Amount in USD dollars	790.321	1,473.623	683.302**
	(1,060.284)	(1,698.238)	(333.107)
Number of Facilities	3.758	5.929	2.170**
	(3.045)	(2.814)	(0.866)
Number of Operators	92	14	106

Panel B: Publicly Traded Operators - All Facilities

	Unconstrained	Constrained	Difference
Maturity in Years	4.330	4.093	-0.237
	(0.884)	(0.507)	(0.281)
Amount in USD dollars	1,458.897	1,691.217	232.320
	(1,381.429)	(1,863.814)	(517.479)
Number of Facilities	5.278	6.364	1.086
	(3.058)	(2.976)	(1.047)
Number of Operators	37	11	48

Panel C: Publicly Traded Operators - Facilities as of December 31, 2019

	Unconstrained	Constrained	Difference
Days to Maturity	1,218.353	1,236.455	18.102
	(350.370)	(305.604)	(118.105)
Unsecured	0.324	0.455	0.131
	(0.475)	(0.522)	(0.169)
Credit Util Dec-19	0.298	0.259	-0.039
	(0.298)	(0.302)	(0.104)
Credit Util Mar-20	0.366	0.327	-0.039
	(0.327)	(0.300)	(0.111)
Credit Util Jun-20	0.533	0.508	-0.025
	(0.457)	(0.406)	(0.155)
Borrowing Base Reduction	-0.260	-0.339	-0.079
	(0.131)	(0.243)	(0.079)
Actual Drawdowns	0.090	0.093	0.003
	(0.141)	(0.149)	(0.050)
Number of Operators	37	11	48

Notes: This tables compares average maturity, size, and number syndicated loans of constrained and unconstrained operators. Panel A(B) uses Dealscan data to compare loans originated/amended within the last 10 years before the pandemic of all (public) constrained and unconstrained operators. Panel C uses SEC filings to compare open revolving credit facilities of public operators as of December 31, 2019. See Section A.3 for variable definitions.

* $p<0.1$, ** $p<0.05$, *** $p<0.01$

the price. We also directly control for operating costs in our regressions.

Finally, we compare hedging practices. We find that unconstrained firms tend to hedge more often and tend to hedge a larger fraction of their volume with standard instruments. In particular, 90% of unconstrained firms had any hedges in place and on average hedged 48% of their volume, while only 64% of constrained firms hedged with standard contracts and on average hedged 23% of volume. However, if anything, the difference in hedging coverage should drive the production responses in the opposite direction, as we discuss in Section 3.3.

At the same time, we do not find any significant difference in the fraction of volume hedged with three-way collars, both types of firms hedged exactly the same 15% of their volume on average with these controversial contracts. About a third of unconstrained firms and 45% of constrained firms had any three-way collars in place, even though the difference is not statistically significant. Thus, the hedging exercise can be expected to provide additional information into the firms behavior.

Overall, our findings in this section are consistent with the notion that the cross-sectional variation in credit expiry is not driven by any obvious firms' characteristics.

4 Main Results

4.1 Credit expiry

Production Responses

The main results are presented in Table 5. The first specification does not include any controls; the second specification adds geographic indicators, well age dummies, and basic well-level controls (horizontal length and lagged production changes). The third specification adds listing status of the operators and a measure of well productivity (the logarithm of the cumulative oil production over the first 6 producing months). The forth specification is the same as the third one, but replaces well age dummies with a cubic function to capture natural declines in well productivity due to age. Finally, columns (5) and (6) add operator-level data available for public firms only: specification (5) controls for hedging, and the last specification (6) controls for hedging, production characteristics, and future physical delivery commitments.

Table 4: Financial characteristics of unconstrained and constrained operators

	Unconstrained	Constrained	Difference
Volume Hedged with Standard Contracts	0.476	0.230	-0.246**
	(0.346)	(0.237)	(0.112)
Any Hedging with Standard Contracts	0.889	0.636	-0.253*
	(0.319)	(0.505)	(0.127)
Volume Hedged with Three-Way Collars	0.154	0.151	-0.003
	(0.286)	(0.231)	(0.095)
Any Hedging with Three-Way Collars	0.306	0.455	0.149
	(0.467)	(0.522)	(0.165)
Committed Volume	0.265	0.163	-0.102
	(0.473)	(0.285)	(0.151)
Fraction Oil	0.693	0.783	0.090
	(0.316)	(0.246)	(0.104)
Fraction Shale	0.497	0.457	-0.040
	(0.284)	(0.334)	(0.103)
Operating Costs	5.940	8.352	2.412*
	(4.007)	(2.617)	(1.292)
Log Total Assets	8.531	8.625	0.093
	(1.595)	(1.599)	(0.553)
Leverage	1.477	0.879	-0.598
	(2.688)	(0.681)	(0.825)
Tobin's Q	1.035	0.829	-0.206
	(0.403)	(0.235)	(0.129)
Profitability	0.054	0.036	-0.017
	(0.215)	(0.189)	(0.073)
Cash Flow	0.022	0.010	-0.012
	(0.227)	(0.180)	(0.075)
Tangibility	0.873	0.883	0.010
	(0.086)	(0.073)	(0.029)
Interest Coverage Ratio	7.305	-0.906	-8.211
	(11.928)	(21.156)	(5.066)
Short Term Debt	0.083	0.031	-0.053
	(0.196)	(0.044)	(0.060)
Number of Operators	37	11	48

Notes: This tables compares financial chacteristics of publically traded unconstrained and constrained operators. Standard financial data come from Compustat. Data on hedging volumes and physical delivery commitments was hand-collected from 10k froms and annual reports. Variable descriptions are provided in Section A.1.
* $p<0.1$, ** $p<0.05$, *** $p<0.01$.

Table 5: Production Responses and Financial Constraints: Credit Expiration Dates

	Oil Well Production Response					
	(1)	(2)	(3)	(4)	(5)	(6)
Constrained	0.046**	0.045***	0.041***	0.040***	0.048***	0.036***
	(0.023)	(0.011)	(0.010)	(0.010)	(0.012)	(0.012)
Log Cumulative Production, T=6m			0.008	0.007	0.008	0.008
			(0.005)	(0.005)	(0.005)	(0.006)
Public Status			0.020	0.021		
			(0.019)	(0.020)		
Hedged Volume					0.017	0.025
					(0.023)	(0.025)
Committed Volume						-0.014
						(0.015)
Fraction Oil						0.047
						(0.031)
Fraction Shale						-0.032
						(0.021)
Owns Refinery						-0.042*
						(0.022)
Mean Dep.Var	-0.115	-0.120	-0.116	-0.116	-0.112	-0.108
Number of Wells	14523	12488	11351	11362	10077	9591
Number of Operators	115	106	104	104	47	43
R^2	0.006	0.284	0.295	0.276	0.308	0.302
Geo FE		Y	Y	Y	Y	Y
Well Controls		Y	Y	Y	Y	Y
First Production FE		Y	Y		Y	Y
Well Age Function				Y		

Notes: The table displays the estimates of the following regression: $\Delta y_{j,i,s,k} = \delta_s + \gamma_k + \alpha Constrained_i + \beta_1' X_i + \beta_2' X_j + \varepsilon_j$, where $\Delta y_{j,i,s,k}$ is one half of the change in oil production over two months from March to May 2020 in well j operated by firm i, located in a geographical unit s, of age k. The indicator variable $Constrained_i$ equals 1 if firm i had any credit facilities recorded by the Dealscan that were set to expire in the 4 months from March to June of 2020, and 0 otherwise (as long as the firm i had any open credit facilities as of December 31, 2019). The main coefficient of interest is α that measures the extra cut in production that is done by more financially constrained operators relative to less financially constrained firms. The controls include geographical unit s fixed effects δ_s (6 by 6 square miles); well level controls X_j that include 3 lagged production changes, the horizontal length, and cumulative output over the first 6 months of production); and well age fixed effects γ_k or a cubic function of well age. Operator-level controls X_i include the public status of the firm, the fraction of oil production, fraction of shale production, fraction of volume hedged with standard instruments (swaps, futures, collars), and fraction of volume committed via future physical delivery commitments. The coefficients must be multiplied by 2 to obtain the total production response over the two months (April and May). St.err in parentheses are clustered at the firm level. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

We find that more financially constrained firms cut production by 4.5 percentage points *less* than less constrained firms (or by 9pp over the two months from the end of March to the end of May). The effect is both statistically and economically large. The effect is large relative to the sample mean of the dependent variable of 11.5 pp. The results are very stable and robust across different specifications. The exogeneity in the timing of debt-related deadlines and past expiration dates allows us to interpret this relationship as a causal effect of financial constraints on production responses.

It is important to emphasize that our results are not driven by any obvious firms' characteristics. In particular, specifications (5) and (6) control for hedging, fraction of oil production, fraction of unconventional production, and physical delivery commitments. Table 19 in Appendix includes operating expenses and the number of days until the stated maturity date of the credit facility. Tables 20 and 21 in Appendix further add a battery of standard firm-level financial controls (leverage, size, profitability, short term debt, interest coverage ratio etc). The tables further confirm that our results are not driven by any obvious firms' characteristics either physical or financial.

Shut-Ins

To provide further evidence we explore complete well shut in decisions. The shut-in results are reported in Table 6, which has the same structure as Table 5 before.

We find that financially constrained firms were about 3 percentage points *less* likely to fully shut-in wells than less constrained firms. The effect is large relative to the mean of 7 pp in the sample. The results are significant in all specifications with both private and public operators. When the sample is reduced to the subsample of public operators only, the size of the coefficient remains the same, however it becomes insignificant.

Overall, the shut-in results are consistent with our benchmark production results and confirm that financially constrained firms were *less* likely to decrease production in response to a negative demand shock and low oil prices.

Table 6: Well Shut-in Decisions and Financial Constraints

	Well Shut-In Indicator					
	(1)	(2)	(3)	(4)	(5)	(6)
Constrained	-0.060**	-0.044**	-0.033**	-0.033**	-0.028	-0.032
	(0.025)	(0.018)	(0.015)	(0.015)	(0.019)	(0.020)
Log Cumulative Production, T=6m			-0.028***	-0.026**	-0.022**	-0.021**
			(0.010)	(0.010)	(0.009)	(0.009)
Public Status			-0.109**	-0.112**		
			(0.047)	(0.048)		
Hedged Volume					-0.045	-0.045
					(0.038)	(0.046)
Committed Volume						0.003
						(0.018)
Fraction Oil						-0.092*
						(0.052)
Fraction Shale						-0.022
						(0.030)
Owns Refinery						-0.018
						(0.035)
Mean Dep.Var	0.073	0.071	0.071	0.071	0.060	0.061
Number of Wells	15647	13433	12215	12225	10722	10215
Number of Operators	117	108	106	106	47	43
R^2	0.008	0.375	0.389	0.377	0.386	0.390
Geo FE		Y	Y	Y	Y	Y
Well Controls		Y	Y	Y	Y	Y
First Production FE		Y	Y		Y	Y
Well Age Function				Y		

Notes: See Table 5 for details. In this exercise, the output variable is $ShutIn_{j,i,s,k}$ - the shut-in indicator for well j, owned by operator i, located in geographical unit s and aged k. The shut-in indicator equals 1 if a well produced in March 2020, but had zero production either in April or May 2020. The indicator variable $Constrained_i$ equals 1 if firm i had any credit facility recorded by the Dealscan that were set to expire in the 4 months from March to June of 2020, and 0 otherwise (as long as the firm had any open credit facilities as of December 31, 2019). * p<0.1, ** p<0.05, *** p<0.01

Fall Expiration

To provide additional evidence we identify firms with debt-related payments that were likely to be scheduled more towards the end of 2020. We create an indicator variable $Fall\,Expiration_i$ that equals 1 if the firm i has any credit data entries with an expiration date scheduled from August to December 2020 (and a start date before the pandemic), and equals 0 otherwise as long as the firm has any credit facilities in place at the beginning for the year(see Section 3.2). It should be noted that we can have all 4 possibilities in the data, that is, all 4 combinations of $\{Fall\,Expiration_i, Constrained_i\}$ are possible.

The results for both production responses and well shut-ins are presented in Table 7. We observe the opposite results. These firms were more likely to cut production and more likely to completely shut-in wells. The results provide additional evidence for our identification strategy and our main results.

Robustness

The results so far support the hypothesis that financially constrained firms cut oil production by less than less constrained firms. Next, we further explore the robustness of these findings.

Restricted set of geographical units To further strengthen an argument that differences in well locations between constrained and unconstrained operators do not drive our results, we repeat our main analysis on a subset of geographical units that have wells of both types of operators. Specifically, we drop all geographical units that have wells of constrained operators only and all units that have wells of unconstrained operators only. Table 14 in Appendix shows that our results remain unchanged.

Placebo test As an additional test to validate our empirical design, we conduct a placebo test. The basic identifying assumption is that, in the absence of the COVID-19 shock, the operators in the control and treatment groups would have exhibited similar production behavior. Thus, we repeat our analysis for the placebo period from the end of March to the end May of 2019, keeping the designations of the firms into more and less financially constrained (treatment and control

Table 7: Production Responses and Fall Expiration

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Fall Expiration	-0.044***	-0.064***	-0.057***	0.032*	0.043**	0.043*
	(0.016)	(0.013)	(0.012)	(0.019)	(0.018)	(0.022)
Log Cumulative Production, T=6m	0.007	0.007	0.007	-0.029***	-0.021**	-0.020**
	(0.005)	(0.005)	(0.006)	(0.011)	(0.009)	(0.009)
Hedged Volume		-0.017	-0.002		-0.023	-0.023
		(0.020)	(0.021)		(0.037)	(0.042)
Committed Volume			-0.027*			0.012
			(0.015)			(0.017)
Fraction Oil			0.029			-0.077
			(0.021)			(0.049)
Fraction Shale			-0.037*			-0.018
			(0.020)			(0.030)
Owns Refinery			-0.046**			-0.012
			(0.020)			(0.036)
Mean Dep.Var	-0.116	-0.112	-0.108	0.071	0.060	0.061
Number of Wells	11351	10077	9591	12215	10722	10215
Number of Operators	104	47	43	106	47	43
R^2	0.294	0.311	0.305	0.380	0.387	0.391
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise, we estimate the same cross-sectional regressions as in Tables 5 and 6, but we replace $Constrained_i$ with $Fall\,Expiration_i$. The indicator variable $Fall\,Expiration_i$ equals 1 if firm i had any credit facilities recorded by the Dealscan that were set to expire from August to December of 2020, and 0 otherwise (as long as the firm had any open credit facilities as of December 31, 2019).
See Table 5 and 6 for details.* $p<0.1$, ** $p<0.05$, *** $p<0.01$

groups, respectively) unchanged.

The results are presented in Table 15. The coefficients of interest are now small and insignificant in all specifications except one. In specification (2) for the production responses in the smaller subsample of public operators, the coefficient is barely significant at 10% level, but small and negative. If anything, the results are the opposite of our findings for the benchmark period. The mean fraction of shut-ins was just 0.007 in 2019, which is a magnitude smaller than during the pandemic episode in 2020 (the same result can be seen graphically in Figure 2).

Vertical wells In the benchmark case, we only consider horizontal wells. Our choice is discussed in Section 2.2. For robustness we repeat the main exercise for vertical wells. Vertical wells have worse productivity on average than horizontal wells, even thought the top vertical well produced 2.5 more than the top horizontal well in March 2020. In this exercise, we consider all vertical wells with more than 100 barrels of oil per month, although our results are robust to this choice. The results are shown in Table 16. We find that constrained operators decreased production by 4-5 pp less than less constrained firms (or by 9 pp over the two months of April and May).[23] Thus, our findings for vertical wells are consistent with our main results.

Overall, our empirical design significantly raises the bar for alternative explanations that are completely unrelated to the economic mechanisms we test for.

4.2 Access to credit

In the second exercise, we use observed borrowing base redeterminations and actual credit lines drawdowns (relative to initial borrowing capacity) to investigate the effects of access to credit on production responses.

The results are presented in Table 8. Panel A investigates the effects of borrowing base cuts. We find that the firms that faced larger reductions in borrowing capacity cut production by *less*. An interquartile range increase in borrowing base redetermination (more negative borrowing base reduction) is associated with a 3-4 pp smaller production cuts.

[23] The results become stronger, if we increase the threshold.

Table 8: Production Responses and Access to Credit

Panel A: Reduction in the Borrowing Base

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Borrowing Base Reduction	-0.168*	-0.211***	-0.184**	0.131	0.086	0.042
	(0.084)	(0.077)	(0.080)	(0.103)	(0.081)	(0.081)
Operating Costs		-0.015*	-0.022		-0.011	-0.004
		(0.008)	(0.014)		(0.012)	(0.013)
Hedged Volume		-0.081***	-0.056		0.035**	-0.083**
		(0.027)	(0.036)		(0.017)	(0.031)
Mean Dep.Var	-0.094	-0.094	-0.094	0.076	0.076	0.080
Number of Wells	7049	7049	6597	7628	7628	7169
Number of Operators	35	35	29	35	35	29
R^2	0.314	0.316	0.315	0.362	0.362	0.377
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y
Operator Controls			Y			Y

Panel B: Credit Line Drawdowns

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Credit Line Drawdowns	-0.208*	-0.194*	-0.344**	0.533**	0.509**	0.201
	(0.112)	(0.104)	(0.144)	(0.214)	(0.208)	(0.163)
Operating Costs		-0.006	-0.013		-0.008	-0.006
		(0.007)	(0.009)		(0.010)	(0.012)
Hedged Volume		-0.076**	-0.071*		0.022	-0.073*
		(0.031)	(0.038)		(0.023)	(0.036)
Mean Dep.Var	-0.094	-0.094	-0.094	0.076	0.076	0.080
Number of Wells	7049	7049	6597	7628	7628	7169
Number of Operators	35	35	29	35	35	29
R^2	0.314	0.315	0.316	0.366	0.367	0.377
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y
Operator Controls			Y			Y

Notes: In this exercise, we estimate the same cross-sectional regressions as in Tables 5 and 6 for the subsample of firms with secured reserves-based credit agreements. Panel A uses borrowing base reductions at the operator level as the main treatment variable. Panel B uses actual drawns defined as the change in credit utilization *holding fixed* the borrowing limit at the pre-pandemic level as of December 31, 2019. To enlarge the sample, we consider large and medium wells in this exercise. See Table 5 and 6 for further details.* $p<0.1$, ** $p<0.05$, *** $p<0.01$

Panel B explores actual credit line drawdowns. The results show that the firms that were able to draw more from their credit lines cut production by *more*. An interquartile range increase in actual drawdowns is associated with a 3-6 pp larger production cuts.

Our results imply that more financially flexible firms that faced more favorable changes in credit conditions and were able to utilize their existing credit lines were cutting production by more, in line with our main mechanism.

Of course, borrowing base redeterminations were driven by many factors including variation in production technology (by type and location of firms' assets), and not just financial state of the firms or lenders' discretion in lending. However, our outcome variable is a production cut in a horizontal well located in a certain geographical area. A non-trivial explanation would be required to explain the connection between borrowing base cuts and production responses in specific horizontal wells that is completely unrelated to access to credit and our mechanism in general. We also control for the most obvious firms' characteristics.

Similarly, the lack of drawdowns might reflect low demand for credit. However, we find it unlikely. The data show heavy utilization of credit lines even before the pandemic. An overwhelming wave of bankruptcies followed the pandemic and the worst cash flow shock in history. Our results are also consistent with the recent empirical evidence in Greenwald et al. (2021) and Chodorow-Reich et al. (2021).

4.3 Failed Hedging

The results are shown in Table 9. We find that firms which used three-way collars more extensively also cut production by less, thus further reinforcing our main conclusions.

Graphically, the results are also presented in Figure 5 in the Appendix. We see that production dynamics both before and after the pandemic episode is exactly the same for firms with and without three-way collars. However, the firms that had three-way collars in place, cut production by less and were less likely to shut down wells in line with the formal results in Table 9.

The failed hedging exercise suggests that the firms that we more exposed to cash flow shocks due to unfortunate choice of hedging instruments, were forced to maintain production. Note

Table 9: Production Responses and Failed Hedging

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Volume Hedged with Three-Way Collars	0.046***	0.061**	0.041	-0.042***	-0.073**	-0.092*
	(0.016)	(0.023)	(0.026)	(0.014)	(0.029)	(0.046)
Log Cumulative Production, T=6m	0.008	0.007	0.007	-0.022**	-0.021**	-0.020**
	(0.005)	(0.005)	(0.006)	(0.009)	(0.009)	(0.009)
Hedged Volume		0.028	0.029		-0.059	-0.066
		(0.024)	(0.026)		(0.042)	(0.051)
Committed Volume			0.017			-0.022
			(0.021)			(0.022)
Fraction Oil			0.027			-0.046
			(0.031)			(0.035)
Fraction Shale			-0.026			-0.025
			(0.026)			(0.032)
Owns Refinery			-0.032			-0.037
			(0.024)			(0.036)
Mean Dep.Var	-0.109	-0.109	-0.105	0.058	0.058	0.059
Number of Wells	11083	11083	10581	11758	11758	11235
Number of Operators	56	56	50	56	56	50
R^2	0.278	0.279	0.272	0.373	0.375	0.381
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise, we estimate the same cross-sectional regressions as in Tables 5 and 6, but we replace the main indicator $Constrained_i$ with a $Volume\,Hedged\,with\,Three-Way\,Collars_i$ variable, which is the percentage of firm $i's$ projected 2020 oil production that was hedged using three-way collars. See Table 5 and 6 for details.* $p<0.1$, ** $p<0.05$, *** $p<0.01$

also that the depth of hedging with three-way collars was exactly the same for constrained and unconstrained operators when defined by past credit expiration dates (see Table 4). Therefore, our failed hedging exercise provides additional independent evidence in support of our mechanism.

Of course, the choice of hedging instruments is hardly exogenous. However, jointly with our previous results, our findings paint a consistent picture of more-financially-constrained firms distorting their production decisions to preserve cash.

5 Testing the mechanism

5.1 Cash needs and well completions

We aim to highlight the importance of immediate cash needs during the pandemic episode. Another way to illustrate our mechanism is to explore well completion decisions. Both well drillings and well completions are costly and thus cannot alleviate immediate cash flow needs. Indeed, even completing an already drilled well costs a few million dollars that cannot be recovered over a few months. At the same time, new successful well completions can potentially improve the value of the land and thus the collateral value and facilitate refinancing, if a firm relies on collateral based lending common in the oil and gas sector (see Gilje, Loutskina, and Murphy (2020)). Thus, if immediate cash flow needs shaped firms decisions in 2020, we can expect to either see no difference in well completion decisions between financially constrained and unconstrained firms (suggesting that all firms similarly cut well completions), or we should even see that constrained firms were less likely to complete their wells.

To investigate the effect of financial constraints on new well completions, we focus on drilled but uncompleted wells, also known as DUCs. DUCs are oil wells that have been drilled but have not yet undergone various well completion activities, such as hydraulic fracturing. For our purposes, we identify all wells that were spud before March 1, 2020 but that were completed after that date. For each well we create a well completion indicator denoted by $WellCompletion_{j,i,s,k}$ equal to 1 if a well j owned by firm i, spud k months ago, and located in a geographical unit s was *completed* in March or April 2020, and equal to 0 if it was completed at a later date or if it has not been completed yet. Focusing on a well completion decision is easier, because the drilling location is already set before the start of the pandemic. Thus, we can maintain the same empirical setting as in our benchmark exercise, in particular, we can conduct the analysis at the well level and again include geographical indicators to capture various differences across locations.

Table 10 presents the results. Indeed, we find that financially constrained firms were less likely to complete wells in the midst of the pandemic thus supporting our mechanism of the immediate cash needs.

We find it useful to further highlight the difference of our results from those of Gilje, Loutskina, and Murphy (2020) who studied investment decisions of extremely high leveraged firms during the contango episode in 2015. At that time, the futures curve became extremely upward sloping suggesting that it could be optional to move production into the future. Gilje, Loutskina, and Murphy (2020) document that extremely high leverage firms (those in the top quintile of the leverage distribution) did not delay well completions in order to boost their collateral values and thus enhance their negotiation position during refinancing. In contrast, our results indicate that financially constrained firms were *less* likely to *complete* wells in the midst of the pandemic and maintained higher *production* from *existing* wells. Our channel is distinct from Gilje, Loutskina, and Murphy (2020). We also document *widespread* production distortions.

Speculating, the difference in findings could highlight a different nature of the pandemic episode. The cash flow shock in 2020 was large and sudden. As a result of failed OPEC-Russia negotiations, the oil price plunged 24% or $10 per barrel on Monday, March 9, 2020; see Section 6.1. On March 19, the State of California became the first to mandate a state-wide shelter-in-place order; by that time the oil price fell to $20/bbl. Lenders of reserves-based credit facilities quickly reacted by initiating redeterminations. Many lenders sped up this process by exercising their right for an interim redetermination; some lenders prevented extra borrowings until redetermination was complete (see Section 3.2 and footnotes 14 and 16). Oil producers had very limited time to make a decision and not enough time to manipulate their collateral values as in Gilje, Loutskina, and Murphy (2020). Moreover, most credit agreements require that a borrower prepares a Reserve Report or an Engineering Report evaluating its oil and gas properties as of December 31 (June

Table 10: Well Completions

	Well Completion Indicator			
	(1)	(2)	(3)	(4)
Constrained	-0.279***	-0.258***	-0.241***	-0.218**
	(0.067)	(0.077)	(0.083)	(0.106)
Public Status		-0.114		
		(0.127)		
Hedged Volume			0.070	0.128
			(0.066)	(0.103)
Committed Volume				-0.100
				(0.162)
Fraction Oil				0.254
				(0.192)
Fraction Shale				-0.211
				(0.225)
Owns Refinery				-0.165
				(0.106)
Mean Dep.Var	0.445	0.445	0.424	0.428
Number of Wells	2467	2467	2030	1686
Number of Operators	87	87	43	37
R^2	0.727	0.728	0.730	0.735
Geo FE	Y	Y	Y	Y
Spud Month FE	Y	Y	Y	Y

Notes: The table displays the estimates of the following regression: $WellCompletion_{j,i,s,k} = \delta_s + \gamma_k + \alpha Constrained_i + \beta_1' X_i + \varepsilon_j$, where $WellCompletion_{j,i,s}$ is the well completion indicator of well j owned by firm i, spud k months ago, and located in a geographical unit s. For this exercise, we only consider drilled but uncompleted (DUCs) wells that were spud before March 1 2020 and completed after that date. The well completion indicator equals 1 if the well j was completed during March and April of 2020, and zero if it was completed at a later date or if it has not been completed yet. The indicator variable $Constrained_i$ equals 1 if firm i had any credit facilities recorded by the Dealscan that were set to expire in the 4 months from March to June of 2020, and 0 otherwise (as long as the firm had any open credit facilities as of December 31, 2019). The controls include geographical unit s fixed effects δ_s (6 by 6 square miles) and the number of months since the spud date fixed effects γ_k. Operator-level controls X_i include the public status of the firm, the fraction of oil production, fraction of shale production, fraction of volume hedged with standard instruments (swaps, futures, collars), and fraction of volume committed via future physical delivery commitments. * p<0.1, ** p<0.05, *** p<0.01

30) to be submitted for the spring (fall) borrowing base redeterminations.[24] Hence, the firms could not make any changes to their reserves that would affect the 2020 spring borrowing base redeterminations.

We argue that facing a dramatic cash flow shock in 2020, it was not enough for the constrained firms to simply cut investment. The exposed firms had to distort *production* from *existing* wells in order to cover their immediate cash needs to remain solvent.

5.2 Covenant violations

A significant part of our sample consists of firms with secured credit facilities. Secured credit facilities typically contain a number of financial covenants, including restrictions on the debt-to-income ratio, current ratio, and interest coverage ratio. The covenant metrics typically rely on trailing 12-month EBITDAX numbers. Thus, short-term changes in operating activity cannot significantly affect a firm's financial covenant ratios.

The firms with unsecured credit facilities either have to maintain a low enough debt-to-capital ratio, or have no financial covenants at all. Moreover, our results remain to be true in the subsample of firms with unsecured facilities only (can be sent by request).

Overall, several specific contractual features make our findings inconsistent with the direct covenant channel.

6 Alternative Measures of Financial Constraints

In this section, we use a battery of alternative ways to identify financially weak firms. In particular, we use i) stock market reaction to the unexpected failure of OPEC-Russia negotiations; and ii) and a number of typical measures of financial constraints and financial distress.

[24] See, for example, PDC Eenergy Inc., credit agreement as dated as of May 23, 2018, Section 8.12 or Sandridge Energy Inc., credit agreement dated as of June 21, 2019, definition of the "Engineerign Report" on page 13 and section 2.05 .

6.1 Stock Market Reaction to OPEC's Announcement of the Price War with Russia

First, we use a natural experiment to identify financially weak operators. We investigate the stock market reaction to the unexpected announcement that OPEC-Russia negotiations had failed. We argue that financially weak operators can be identified as firms that were devalued the most following the announcement. Below we describe the details.

At a Friday, March 6 2020 meeting in Vienna, Russia rejected an agreement with OPEC on cuts in oil production to bolster oil prices. On Saturday, Saudi Arabia announced massive discounts to its official selling prices for April, thus initiating a price war with Russia. As a result of the failed negotiations, the oil price plunged 24% or $10 per barrel on Monday, March 9, 2020. It was the worst day for the oil market in decades, second only to the Gulf War shock on January 17, 1991.

The oil price shock surprised the stock market and rattled the stock prices of oil producing firms. Figure 6 zooms in to the time of the announcement and illustrates how large and abrupt devaluation was.

Figure 6 also suggests that price devaluations were quite heterogeneous across firms. Indeed, although some operators lost up to 70% of their value (such as Oasis Petroleum - 75%, Apache Corporation - 61%, and Continental Resources - 60%), some firms loss much less (Devon Energy lost 47%, Berry Corporation lost 31%, and Exxon Mobil - only 16%).

We argue that financially weak operators can also be identified as firms that were devalued the most. Intuitively, the financial market accounts for various factors, both operational and financial, when recalculating the value of a firm. For example, on average, large integrated firms and firms focused mainly on natural gas exploration lost less of their value. Similarly, financial factors such as hedging, unused debt capacity, debt maturity, and etc. shaped stock price sensitivity to the announcement. This argument is based on extensive CF literature documenting that the stock market rewarded firms with healthier balance sheets during the COVID-19 pandemic. Acharya and Steffen (2020) construct a measure of balance sheet liquidity of U.S. nonfinancial firms as the sum of undrawn credit lines and cash minus short-term liabilities over total assets. Using this measure, they show that the stock price performance of firms with liquidity buffers was better upon the onset of the pandemic. Individual measures of liquidity produce the same result: firms with lower initial cash holdings and short-term investments and higher initial levels of short-term debt (both scaled by total assets) experienced larger drops in returns in March 2020. Similar results are found by Fahlenbrach et al. (2020), who show that firms with greater financial flexibility (as measured by a large amount of cash, unused debt capacity, limited exposure to debt rollover risk, etc.) experienced smaller stock price drops in March 2020; similar results were found for CDS spreads. Babenko et al. (2020) show that U.S. oil and gas producers with contractual hedging commitments in their loan contracts performed better during the Covid-19 pandemic, showing that hedges are effective for reducing exposure to commodity prices.

Formally, to identify financially weak firms (as perceived by the market), for each operator i, we calculate the return over the period from Thursday, March 5 to Monday, March 9, 2020, which covers the escalation of the price war between OPEC and Russia. We use the calculated returns to create an indicator $BigStockLoss_i$ that equals 1 if the realized return is below the median and 0 otherwise (the median is taken over the oil producing firms in our sample).

The results are presented in Table 11. The estimates of the main coefficient are positive for production cuts, negative for well shut-ins, and statistically significant in all specifications. The results imply that financially weak firms cut oil production by about 5 percentage points *less* than less constrained firms (or by 10 pp over the two months of April and May). These firms were also 3.5-6 pp less likely to completely shut-in wells. The results are both statistically and economically large.

For robustness, Table 17 in Appendix repeats the estimation with the *realized returns* over the period of failed OPEC-Russia negotiations from Thursday, March 5 to Monday, March 9, 2020, instead of just a dummy variable as in Table 11. For the production cuts, the coefficients on realized returns are negative and significant across all specifications, in line with our main results that financially weaker firms (those with more negative realized returns) cut production by less. The results on complete shut-ins have the right sign, but are insignificant.

Overall, the results for stock devaluations are similar in magnitude with our main results and provide strong support for a relationship between financial constraints and production responses.

Table 11: Production Responses and Financial Constraints: Stock Price Devaluations

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Big Stock Loss	0.040***	0.054***	0.041**	-0.035**	-0.049***	-0.099**
	(0.012)	(0.015)	(0.017)	(0.014)	(0.016)	(0.039)
Log Cumulative Production, T=6m	0.006	0.006	0.006	-0.021**	-0.021**	-0.019**
	(0.006)	(0.006)	(0.006)	(0.009)	(0.009)	(0.009)
Hedged Volume		0.001	0.019		-0.036	-0.061
		(0.023)	(0.024)		(0.033)	(0.043)
Committed Volume			0.012			-0.016
			(0.023)			(0.019)
Fraction Oil			0.064*			-0.110***
			(0.036)			(0.039)
Fraction Shale			-0.053*			0.044
			(0.027)			(0.043)
Owns Refinery			-0.018			-0.079*
			(0.026)			(0.041)
Mean Dep.Var	-0.107	-0.109	-0.104	0.057	0.059	0.060
Number of Wells	11931	10969	10483	12641	11641	11134
Number of Operators	55	51	47	55	51	47
R^2	0.263	0.282	0.269	0.375	0.380	0.387
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise, the indicator variable $BigStockLoss_i$ equals 1 if the firm i is financially weak from the market point of view. To be labeled financially weak, the realized return of firm i over the period of OPEC-Russia failed negotiations from Thursday, March 5 to Monday, March 9, 2020 must be below the median. See Table 5 for details. See Table 17 for additional results. St.err in parentheses are clustered at the firm level. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

6.2 Standard Measures Of Financial Constraints

We use a battery of traditional measures of financing constraints that potentially capture different aspects of the financial state of oil firms: leverage, interest coverage ratio, profitability, ratio of short term debt, and cash holdings measures. Next, we use 2 traditional measures of financial constraints: the Kaplan-Zingales (KZ) index and the Whited-Wu (WW) index. We also use an additional measure recently put forward by Huang and Ritter (2021) (HR). Finally, we also use Altman's Z-score as a measure of financial distress. In total, this yields 9 different measures; see appendix A.3 for details. We repeat our main analysis for each of these measures.

The results are summarized in Table 6.2. We find that interest coverage ratio and short-term debt have strong explanatory power. The traditional measures of financial constraints show insignificant results. In contrast, the Huang-Ritter index shows a significant result in the same direction (more constrained firms have more negative HR index and thus decrease production by less). The HR measure is tailored to capture the ability of firms to fund their activity out of their existing cash holdings and thus, perhaps, better serves our purposes. Similar to us, Fahlenbrach et al. (2020) finds that traditional measures have no explanatory power for predicting which firms are more affected by the COVID-19 shock, while firms identified by the HR index as being at risk of running out of cash unless they access outside funds are more affected by the COVID-19 shock.

Finally, the z-score also shows a significant result in the same direction (more distressed firms have smaller z-score and cut production by less).

Overall, the results in this section support the view that cash flow problems were the likely drivers of firm's suboptimal decisions to maintain production despite catastrophically low oil prices.

7 Discussion

In this section we put our findings into perspective.

Table 12: Alternative Measures

	Oil Well Production Response								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Leverage	0.000								
	(0.006)								
Interest Coverage Ratio		-0.019**							
		(0.008)							
Profitability			-0.102						
			(0.086)						
Short Term Debt				-0.017**					
				(0.007)					
Almeida					0.007				
					(0.008)				
Kaplan-Zingales						-0.002			
						(0.007)			
Whited-Wu							-0.013		
							(0.010)		
Huang-Ritter								-0.010*	
								(0.006)	
Altman Z-score									-0.012*
									(0.007)
Mean Dep.Var	-0.104	-0.104	-0.104	-0.104	-0.104	-0.104	-0.104	-0.104	-0.104
Number of Wells	10483	10438	10483	10483	10483	10483	10483	10483	10483
Number of Operators	47	46	47	47	47	47	47	47	47
R^2	0.268	0.270	0.268	0.270	0.268	0.268	0.268	0.269	0.268
Geo FE	Y	Y	Y	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y	Y	Y	Y

Notes: In this exercise we reestimate the specification (6) in Table 5 but replace $Contrained_i$ indicator with other financial measures. All financial measures were **standardized**. The first five columns correspond to leverage, interest coverage ratio, profitability, and short term debt. The next 3 columns correspond to the 3 indices of financial constraints: Kaplan-Zingales, Whited-Wu, and Huang-Ritter. The last column uses the Altman's Z-score as a measure of financial distress. See appendix A.3 for variable definitions. All financial data are taken as of December 31, 2019. The firm-level controls include the fraction of oil production, fraction of shale production, fraction of production hedged with standard instruments, and fraction of volume committed using physical delivery commitments. See specification (6) in Table 5 for further details. * p<0.1, ** p<0.05, *** p<0.01

7.1 External Validity

In the paper, we investigate oil production responses to the COVID-19 outbreak. The demand collapse caused by the pandemic is useful for our purposes, as it was sudden, large, and unrelated to the oil market. However, one may argue that our findings are limited because COVID-19 represents a once-in-a-lifetime shock. We believe that although the shock itself is indeed quite unique, production distortions due to indebtedness represent a general pattern.

The oil market has repeatedly been puzzled by the resilience of North American oil production to low oil prices. Of all such episodes, the WCS-WTI divergence in 2018-19 is of particular importance. By December 2018 the WCS (Western Canadian Select) price of oil fell to an astonishingly low $6 per barrel, while the WTI (West Texas Intermediate) benchmark was trading at $50 per barrel. In response to a growing and prolonged price differential and the apparent impotence of market forces to adjust oil supplies, in January 2019, the government of Alberta, Canada decided to implement a production cap policy. Oil production was forcefully reduced by 8.7%; following the intervention, the WCS-WTI price differential dropped from more than $40/bbl in December 2018 to less than $10/bbl in February 2019; see Schaufele and Winter (2021) and Hallak et al. (2021). The nature of the WCS-WTI divergence has not been well studied or understood. Although not directly tested in our paper, indebtedness may have played a significant role in why local oil producers did not adjust production in the face of export bottlenecks and extremely low well-head oil prices. Interestingly, a relatively modest production cut was sufficient to significantly decrease the price differential.

Similarly, the resilience of US oil production in 2014-15 has raised a lot of questions. The oil price plunged in the second half of 2014 (although not as much as in 2020 or as WCS did in 2018), while fears of oversupply overwhelmed the market. Despite a general consensus that the oil market was extremely oversupplied, oil production only gradually leveled out, and only because completions of new oil wells nearly ceased. Production from existing wells was not adjusted and decreased only slowly, following a natural production decline. Our results complement Gilje, Loutskina, and Murphy (2020), who find that debt and credit frictions distorted investment decisions of *extremely* high leveraged firms to delay well completion during the brief contango episode in early 2015.

Jointly, our findings imply that indebtedness and credit market frictions can distort production outcomes, both by distorting production decisions on how much to extract from existing wells and/or by distorting investment decisions on whether to drill and complete new wells.

7.2 Relation to the Literature on Estimation of Oil Supply Elasticities

Our results contribute to the extensive literature on estimation of oil supply elasticities. Although we do not directly estimate oil supply elasticity, we do investigate oil production responses to the unprecedented demand shock triggered by the COVID-19 pandemic, which resulted in a huge negative oil price shock.

In contrast to existing studies, we document *significant* adjustments in oil production to low oil prices. We provide direct evidence that oil producers responded to low oil prices by shutting down some of their wells. The existing empirical literature lacks consensus on the size of oil supply elasticities. Many papers find that short-run production responses (intensive margin) are close to zero, and only investment responses (extensive margin) can be detected, especially if one extends the response period; see, for example, Anderson et al. (2018) and Newell and Prest (2019); while other papers including Caldara et al. (2019) and Baumeister and Hamilton (2019) document positive global oil production responses to oil prices. Of course, we focus on a huge negative demand shock. The COVID-19 shock is unique in both nature and magnitude. Typically, event study papers exploit smaller oil price fluctuations, while structural VARs are typically estimated over long periods and thus basically estimate a different elasticity; see Kilian (2020) and Baumeister and Hamilton (2021) for a recent literature review and discussion.

Importantly, we show that shut-in decisions were *not* driven solely by operating costs. Of course, not surprisingly we find that the least productive wells were shut in more frequently. However, we do find differences in production cuts made by different operators in wells drilled at the same location, that is within a 6 by 6 square mile unit. Keeping the location fixed allows us to control for many factors that could affect a well's operating costs and relevant local oil prices (and access to storage). We also carefully control for hedging, both physical and financial, and include a measure of average lease operating costs at the firm level.

We contribute to the literature by exploring heterogeneity in production responses using microdata. There are almost no prior studies using microdata: the rare exceptions are Newell and Prest (2019) and Bjornland et al. (2021); none of the studies explores heterogeneity in responses. We are the first to highlight heterogeneity in oil supply elasticities across different firms and to explain it by heterogeneous indebtedness. Overall, our results complement existing studies.

One may argue that our findings are limited because we focus on US regional production responses as opposed to global oil production, as is typical in this literature. Although oil shale production is still a relatively small fraction of global oil production, shale oil development with all of its frictions and bottlenecks undoubtedly affects the West Texas Intermediate benchmark. As long as benchmarking to the WTI is an everyday reality of the oil market and as long as price discovery at least partially occurs on the WTI futures market, any local fluctuations driven by the behavior of shale oil producers will be an important factor in global oil price dynamics.

8 Conclusion

Our results shed light on the puzzling production resilience observed repeatedly in the North American oil market throughout the last decade. We document significant heterogeneity in the production responses of individual oil producing firms to low oil prices and relate it to heterogeneity in financial constraints. Our results imply that propagation of negative oil demand shocks depends crucially on the level of indebtedness of individual firms, which can vary over time.

At the same time, we document significant adjustments in oil production to low oil prices, implying that oil supply elasticities can be much greater than zero even in the short run.[25] The literature has long argued that oil production is completely inelastic in the short-run, regardless of whether oil is extracted using conventional or unconventional production technologies (see Anderson et al. (2018), Newell and Prest (2019), and Kilian (2020)). Our results therefore suggest the presence of significant nonlinearities in production responses that need to be adequately captured in empirical work.

[25] This does not contradict the first finding, as we document large average adjustments and large heterogeneity in individual responses at the same time.

Going forward, our findings raise a question of the role of indebtedness in achieving US energy security. For years shale oil investors were eager to invest in the oil sector despite its relatively poor performance. However, the trend may have changed as U.S. producers remain reluctant to drill more oil despite sky-high gasoline prices and oil prices beyond $100/bbl in 2022 following the Russia–Ukraine crisis. Whether the reluctance to drill is driven by cautious expectations and labor/rigs shortages that occurred after the pandemic, or by the lack of financing either due to the poor recent financial performance or due to lenders' ESG commitments, remains an important open question for further research.

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A Appendix

A.1 Dealscan

Dealscan contains both originations and renegotiations, many of which cannot be clearly distinguished. Roberts (2015) finds that Dealscan observations do not correspond to any particular type of event. Using a 2010 extract of Thomson Reuters-Dealscan database and hand-collected SEC filings Roberts (2015) creates a sample of 501 loan paths for a randomly chosen 114 firms. For 817 unique Dealscan observations contained in the sample 59% correspond to an origination, 29% correspond to an amended and restated contract, and 13% correspond to an amendment. Covenant modifications are the plurality (45.91%) of renegotiation outcomes.

As Dealscan misses a substantial fraction of credit extensions, we cannot use it to accurately identify the state of credit facilities at the beginning of the pandemic. We also do not aim to hand-collect a comprehensive data on the loan paths of our oil producing firms, even public ones. In contrast, we create a measure that uses synchronization in long-term debt payment deadlines and relies only on the observable data from Dealscan. We discuss the details in the next section.

A.2 Path-dependence and synchronization of debt-related deadlines

We create a measure that exploits periodicity of debt-related deadlines and only relies on standard Dealscan data that are available for both public and private firms. We argue that a tendency of multiple forms of long-term debt to be co-issued and co-dependent creates conditions for various payments to be scheduled for the same time. Hence, we can use the available data on one type of debt to reasonably predict the timing of other debt-related payments.

In this section, we provide additional institution details and examples. We begin building our argument by providing evidence of periodicity and path-dependence of debt payments.

1. Periodicity and path-dependence of long-term debt

Long-term debt has a complex structure. However, issuance and service of long term debt has a certain degree of periodicity and path-dependence.

Credit lines are often extended *periodically* keeping the *same maturity month*. As an extreme example, SEC annual reportsCrescent Point Energy Corporation have had a syndicated credit facility renewed annually with maturity dates set sequentially to June 10, 2016, June 10, 2017, June 8, 2018, June 10, 2019, June 10, 2020, and June 10, 2021.[26] Similarly, PDC Energy entered into an amended credit agreement on May 21, 2013; the maturity of this credit facility was set to May 21, 2018; in 2015 the maturity credit facility was extended to May 21, 2020; in 2018 the maturity was further extended to May 23, 2023.[27] Although not all firms renegotiate their credit revolving facilities with such precision the general pattern exists. Periodicity in debt renegotiations

[26]See annual reports prepared by Crescent Point Energy Corp. and available at their website.

[27]See SEC annual reports filed by PDC Energy Inc.and Fourth Amended and Restated Credit Agreement dated as of May 23, 2018.

was also documented by Roberts (2015).

In addition, unsecured loans typically provide extension options. Usually the firms have a narrow window to apply for a credit line extension, which is typically set around the anniversary of the effective date. [28,29,30]

Payments associated with senior bonds and notes are also *periodic*. Interest payments are often made semiannually; on the maturity date, the bond nominal value is paid out together with the last interest payment.

Firms tend to issue debt securities in series that may have different maturity years but often the same maturity months. To illustrate, Pioneer Natural Resources tends to issue notes that mature in January and July and pay interest semiannually on January 15 and July 15. At the year end of 2019, Pioneer Natural Resources had 7.50% senior notes due January 15, 2020; 3.45% senior notes due January 15, 2021; 3.95% senior notes due July 15, 2022; 4.45% senior notes due January 15, 2026 - all with interest payments scheduled on January 15, 2020. The company's 7.50% senior notes matured on January 15, 2020 and the firm funded the payment of the $450 million principal balance with cash on hand.[31]

Large oil firms often sign indentures with large banks to issue debt securities from time to time.[32]

2. Synchronization of payments

In principle, periodic payments associated with different types of long-term debt do not need to be synchronized. However, a number of factors create conditions for synchronization. We discuss

[28]See EOG Resources, Inc., Revolving Credit Agreement dated as of July 21, 2015: *"Not earlier than 60 days prior to, nor later than 30 days prior to, each anniversary of the date hereof, the Borrower may, upon notice to the Administrative Agent (which shall promptly notify the Banks), request a one-year extension of the Termination Date provided that the Borrower may not exercise this right more than two times prior to the Termination Date."*

[29]See Pioneer Natural Resources Company, Credit Agreement dated as of October 24, 2018: *"The Borrower may, by delivery of a Maturity Date Extension Request to the Administrative Agent (which shall promptly deliver a copy to each of the Lenders) not less than 45 days and not more than 75 days prior to any anniversary of the Effective Date, request that the Lenders extend the Maturity Date for an additional period of one year; provided that, only two such extensions will be granted during the tenure of the credit facility".*

[30]See Ovintiv Inc. 10-K filing for the fiscal year ended December 31, 2019: *"At December 31, 2019, the Company had in place committed revolving U.S. dollar denominated bank credit facilities totaling $4.0 billion ... The facilities are extendible from time to time, but not more than once per year, for a period not longer than five years plus 90 days from the date of the extension request, at the option of the lenders and upon notice from the Company.".*

[31]See second supplemental indenture as of December 7, 2015; see also here.

[32]For example, see the indenture between Pioneer and Wells Fargo dates as of June 26, 2012.

them next.

Refinancing activity One of the reasons for synchronization is issuance of new debt to repay outstanding borrowings under the other. For example, on May 31, 2019 EQT borrowed $1.0 billion under a new term loan facility to repay the company's $700 million in aggregate principal amount of 8.125% senior notes maturing on June 1, 2019, and repay outstanding borrowings under the company's $2.5 billion revolving credit facility which expires in July 2022. During the first quarter of 2019, the maximum amounts of outstanding borrowings at any time under the credit facility were $1.1 billion. The term loan stated maturity was set on May 31, 2021.[33] On April 28, 2020, the company issued $500 million aggregate principal amount of 1.75% convertible senior notes due May 1, 2026 to repay $450 million of the term loan facility. In this case, we observe active refinancing activity and debt transformations, however, all payment and expiration dates are clustered around the same months of May, June, and July.

Financing of investment projects Different types of debt can also be synchronized by the necessity to fund a large investment project or an acquisition. For example, Occidental Petroleum Corporation issued $21.8 billion in debt in 2019 to fund its acquisition of Anadarko. In pariticular, on June 3, 2019, Occidental entered into a 364-day term loan agreement and a two-year term facility. On August 8, 2019, Occidental closed on its acquisition of Anadarko, hence the conditions to funding of the term loan facilities were satisfied and the loans thereunder were funded. On June 3, 2019, Occidental also entered into a new revolving facility which matures on January 31, 2023. Finally, on August 6, 2019, Occidental issued $13.0 billion of new senior unsecured notes. Out of 10 series of these notes, one matured in February 2021, and the rest were scheduled to mature in August of different years from 2021 to 2049. Interest on all fixed rate notes are payable semiannually in February and August; interest on floating rate notes are payable quarterly in February, May, August, and November. As a result, many different future payments were synchronized to occur in February and August of each year.[34]

[33] See EQT 8-k form as of May 31, 2019.

[34] Other recent examples of credit amendments following mergers and acquisitions: acquisition of SRC Energy Inc by PDC Energy, Inc. in 2019; acquisition Carrizo by Callon Petroleum Company in 2019; acquisition of White Star Petroleum by Contango Oil & Gas Company in 2019. Similarly, in connection with the closing of the sale

Similarly, on March 1, 2019, Cimarex Energy completed the acquisition of Resolute Energy Corporation. On February 5, 2019, Cimarex Energy amended its credit agreement and extended the maturity date to February 5, 2024. On March 8, 2019, Cimarex issued $500 million aggregate principal amount of 4.375% senior unsecured notes due March 15, 2029. The interest is payable semiannually on March 15 and September 15. Cimarex used the net proceeds to repay borrowings that were outstanding under the credit facility that were used to help fund the Resolute acquisition.[35] Again, many payments were synchronized to occur in March-February.

As another example, in June 2019, Murphy Oil Corporation announced the completion of a transaction with LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG). As of June 30, 2019, the company had a $1.6 billion revolving credit facility, which expires in November 2023. At June 30, 2019, the company had outstanding borrowings of $1.4 billion under the 2018 facility. On May 30, 2019, the Company entered into a $500 million term loan credit facility. The term credit facility was a senior unsecured guaranteed facility with an original maturity date of December 2, 2019. In 2019, the cash provided by financing activities was principally from borrowings on the revolver and short-term loan to fund the LLOG acquisition. In addition, in November 2019, the firm issued $550 million of new notes that bear interest at a rate of 5.875% and mature on December 1, 2027 and pay interest semi-annually on June 1 and December 1 of each year. The proceeds were used to repurchase and cancel $239.7 million of the Company's 4.00% notes due June 2022 and $281.6 million of the Company's 4.45% notes due December 2022. Again many payments occur in December-November and June of each year.

Other reasons More generally, issuance of notes and bonds as well as other commitments and liabilities often triggers renegotiations of revolving credit agreements. Among other things, issuance of new debt typically reduces the borrowing base.[36] Issuance of debt can also increase the debt-to-EBITDA ratio beyond its maximal value and thus require renegotiation; seeRoberts (2015). A

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of its Canadian business in 2019, Devon terminated its Canadian credit subfacility and entered into a new credit agreement.

[35] See Cimarex Energy Co. 10-Q filing as of March 31, 2019.

[36] For example, PDC Energy, credit agreement as of May 23, 2018, section Section 2.06 (e) Adjustment for Debt Incurrence. See also Oasis Petroleum, credit agreement as of September 3, 2013, section 2.2 (e) Reduction of Borrowing Base Upon Issuance of Senior Notes.

credit amendment can also be sometimes required to permit the firm to repurchase, refinance or repay the firm's outstanding senior notes.[37] As a result of triggered renegotiations, the maturity dates can be realigned.

An additional technical reason for synchronization is the maturity acceleration clause. The actual maturity date of the credit facility depends on the ability of the firm to repay or otherwise refinance its other liabilities in a timely manner. The maturity of the credit revolving facility can be accelerated forward and aligned with the maturity date of outstanding notes. For example, as of December 31, 2019 HighPoint Resources Corporation had a credit facility with stated maturity of September 14, 2023. However, the company also had more than $100 million of debt that matures prior to December 14, 2023, because it had outstanding 7.0% Senior Notes with maturity of October 15, 2022. As a result, the actual maturity date of the credit facility was July 16, 2022 (91 days prior to the maturity date of those notes) as the company reported in its 10-k filings.[38,39]

3. Exploiting synchronization

Overall, co-dependence of different types of long-term debt, co-issuance and refinancing activities create conditions for synchronization of debt-related payments. Of course, we do not argue that all firms necessarily have all of their payments perfectly synchronized. Instead, we argue that there is a *tendency for a certain degree of synchronization due to a certain degree of path-dependence.*

Synchronization of payments allows us to identify oil firms that were *more likely* to face various payment deadlines from March to June of 2020. To do this, we use Dealscan data and search for any data entries with an expiration date from March to June 2020. Although by December 31, 2019 all firms in our sample had extended their credit revolving facilities beyond 2020, the mere

[37] See Whiting Petroleum Corporation 10-k filing for the fiscal year ended December 31, 2019: *"On September 13, 2019, we amended the credit agreement to, among other things, permit the repurchase, redemption, prepayment or other acquisition or retirement for value of any senior notes (as defined in the credit agreement) ."* See also First Amendment to Seventh Amended and Restated Credit Agreement dated as of September 13, 2019.

[38] See HighPoint Resources Corporation 10-k filing for the fiscal year ended December 31, 2019.

[39] See Unit Corporation 10-K filing for the fiscal year ended December 31, 2019: *"The October 18, 2023 scheduled maturity date of the loans under the Unit credit agreement will accelerate to November 16, 2020 to the extent that, on or before that date, all the 2021 Senior Notes are not repurchased, redeemed, or refinanced with indebtedness having a maturity date at least six months following October 18, 2023 (the "Credit Agreement Extension Condition"). If we are not able to successfully restructure our indebtedness, doubt may arise about our ability to timely repay our outstanding senior subordinated notes".*

See also HighPoint Resources Corporation , Penn Virginia Corporation, SM Energy Company, Extraction Oil & Gas Inc., Denbury Resources Inc. and many others.

fact that at *some* point their credit facilities were set to expiry from March to June 2020 increases the probability to observe other payment deadlines within the same time period.

A.3 Variable Definitions

Well-level outcome variables created using Drillinginfo data and used in the main regressions:

- *Production Cut* is the one half of the change in monthly oil production from March to May 2020.[40]

- *Shut-in Indicator* equals 1 if a well produced in March 2020, but had zero production either in April or May 2020.

- *Well Completion Indicator* is defined only for wells that were spud before March 1 2020, but that were completed after that date. The indicator equals 1 if a was completed between March and April 2020, and equal to 0 if it was completed at a later date.

Treatment indicators were created using Dealscan:

- *Constrained* is an indicator variable that equals 1 if firm i had any credit facilities recorded by the Dealscan that were set to expire in the 4 months from March to June of 2020, and 0 otherwise (as long as the firm had any open credit facilities as of December 31, 2019).

- *Fall Expiration* is an indicator variable that equals 1 if firm i had any credit facilities recorded by the Dealscan that were set to expire from August to December of 2020, and 0 otherwise (as long as the firm had any open credit facilities as of December 31, 2019).

The following operator-level variables use data that was hand-collected from 10-k SEC filings and annual reports as of December 31 2019:

- *Gross Wells* means the wells in which a firm has a working interest.

- *Net Wells* is the sum of the fractional working interests owned in gross wells, as the case may be, expressed as whole numbers and fractions thereof.

[40] We divide the actual production cuts over the two months by two to facilitate the comparison of our results with existing estimates in the literature.

- *Fraction Oil* the ratio of the number of "net" oil producing wells to the total number of "net" oil and gas producing wells. This measure captures whether a firm primarily extracts oil or natural gas.

- *Fraction Shale* is the number of horizontal oil wells operated by firm i in December of 2019 (based on Drilliginfo data) to the "gross" number of producing oil wells (from 10-k filings). This measure captures a degree to which a firm is a conventional or unconventional/shale producer.[41]

- *Hedged Volume*(also called *Volume Hedged with Standard Contracts*) is the the percentage of firm's projected 2020 oil production that was hedged with standard instruments such as swaps, collars, and futures (as opposed to three-way collars, see below). We use production recorded in 2019 to estimate projected volume.

  Any Hedging with Standard Contracts is an indicator variable equal to 1 if the firm hedged any non zero volume with standard contracts.

- *Volume Hedged with Three-Way Collars* is the percentage of firm's projected 2020 oil production that was hedged using three-way collars. A three-way collar is a typical collar (buying a put option and selling a call option), but in addition the producer sells a further out-of-the-money put option, which makes hedging cheaper, but at the same time the producer also takes on additional risk of significant declines in oil prices. We use production recorded in 2019 to estimate projected volume.

  Any Hedging with Three-Way Collars is an indicator variable equal to1 if the firm hedged any non zero volume with three-way collars.

- *Committed Volume* is the fraction of projected for 2020 volume committed forward by physical delivery commitments. We use production recorded in 2019 to estimate projected volume. We use 10-k filings to identify physical delivery commitments that require delivery of a minimum amount of oil through 2020.

[41] We could have used total production instead of the number of wells. However, it would be harder to account for the wells that are owned by one firm, but are operated by the other. Although this problem is not completely solved by using the total number of wells, but at least we can distinguish gross and net number of wells owned by each firm.

- *Owns Refinery* is an indicator variable equal 1 if a firm runs any downstream operations in addition to oil and gas extractions and 0 otherwise.

- *Operating Costs* is the costs incurred by an operator to keep production flowing and typically reported as the lease operating expenses. LOE include the costs associated with artificial lift and maitaining artificial lift, water disposal costs, costs associated with employees who regularly monitor and maintain wells etc.

- *Days to Maturity* is the number of days until the stated maturity date of the firm's revolving credit facility as of December 31, 2019 (from annual SEC filings).

All financial variables are constructed as of the 2019 year end:

- *Leverage* is the ratio of long term debt and debt in current liabilities (Compustat items DLTT and DLC) to stockholders' equity (Compustat item SEQ).

- *Interest Coverage Ratio* (ICR) is the ratio of operating income before depreciation (Compustat item OIBDP) to interest expense (Compustat item XINT).

- *Profitability* is the ratio of operating income before depreciation (Compustat item OIBDP) to total assets (Compustat item AT).

- *Cash Flow* is the sum of income before extraordinary items (Compustat item IBC) and depreciation and amortization (Compustat item DP) to total assets (Compustat item AT).

- *Short Term Debt* is the ratio of debt in current liabilities (Compustat item DLC) to total debt (the sum of Compustat items DLTT and DLC).

- *Tobin's Q* is the ratio of total assets (Compustat item AT), the market value of equity as of the year end (multiplication of Compustat items $PRCC$ and $CSHO$), minus the book value of equity (Compustat item CEQ) to total assets.

- The Kaplan and Zingales (1997) index is constructed following Lamont et al. (2001) as

$$KZ = -1.002\frac{CF}{\text{lagged } PPENT} - 39.368\frac{Div}{\text{lagged } PPENT} - 1.315\frac{Cash}{\text{lagged } PPENT} + 3.139\frac{Lev}{Lev+1} + 0.283Q,$$

where cash flow (CF) is the sum of income before extraordinary items (Compustat item IB) and depreciation and amortization (Compustat item DP), dividends (Div) are measured as common and preferred dividends (Compustat items DVC and DVP), Cash is cash and short term investments (Compustat item CHE), leverage (Lev) is the ratio of long term debt and debt in current liabilities (Compustat items DLTT and DLC) to stockholders' equity (Compustat item SEQ), and Q is the ratio of total assets (Compustat item AT), the market value of equity as of the fiscal year end (multiplication of Compustat items $PRCC_f$ and $CSHO$), minus the book value of equity and deferred taxes (Compustat items CEQ and TXDB) to total assets. The first three variables are normalized by the lagged net value of property, plant, and equipment (Compustat item PPENT).

- The Huang and Ritter (2021) measure is the cash position at the end of the prior fiscal year, plus the net cash flow of the prior year (used as a projection for the current year's net cash flow):

$$Cash_{ex\,ante} = Cash + NCF$$

where Cash is cash and short term investments (Compustat item CHE) and the net cash flow is defined as $NCF = \Delta Cash - \Delta D - \Delta E$, where ΔD is the change in interest-bearing debt measured as long-term debt issuance (Compustat item DLTIS) minus long-term debt reduction (Compustat item DLTR) and plus current debt changes (Compustat item DL-CCH), and ΔE is the change in equity from the statements of cash flow measured as the sale of common and preferred stock (Compustat item SSTK) minus purchases of common and preferred stock (Compustat item PRSTKC). We set missing DLCCH2019 to DLC2019 – DLC2018, and we set missing SSTK, PRSTKC, DLTIS, and DLTR to zero.

- The Whited and Wu (2006) index is constructed according to the following formula:

$$WW = -0.091\frac{CF}{AT} - 0.062DIVPOS + 0.021\frac{DLTT}{AT} - 0.044\ln(AT) - 0.035SG$$

where cash flow (CF) is the sum of income before extraordinary items (Compustat item IB) and depreciation and amortization (Compustat item DP), DIVPOS is an indicator that takes the value of one if the firm pays cash dividends (Compustat item DVT is positive), DLTT is long term debt. Cash flow and long term debt are normalized by total assets (Compustat item AT). $\ln(AT)$ is the natural log of total assets and SG is the firm's sales growth (using compustat item SALE). We drop ISG which is the firm's three-digit SIC industry sales growth, because we consider firms from the same industry.

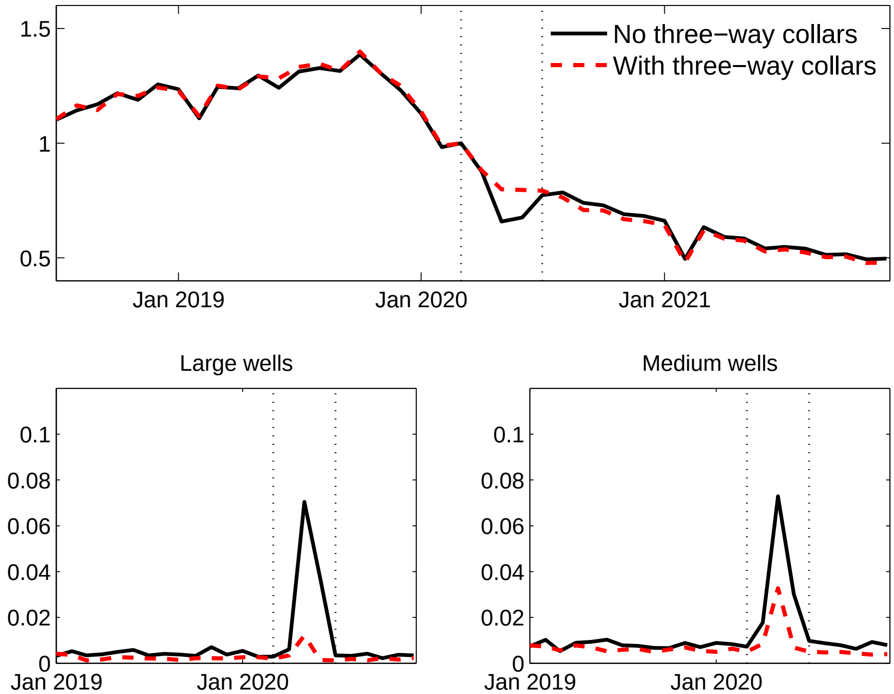
- The Altman Z-Score is calculated as

$$Z\text{-score} = 3.3\frac{EBIT}{AT} + 0.99\frac{SALE}{AT} + 0.6\frac{ME}{LT} + 1.2\frac{ACT}{AT} + 1.4\frac{RE}{AT}$$

in which the variable names correspond to the respective Compustat items. EBIT is earnings before interest and taxes, SALE measures sales or turnover net, ME is the market value of equity at year end calculated using Compustat item PRCC_C at the calendar year end and the number of shares outstanding (Compustat item CSHO), ACT is the total current assets or working capital, and RE stands for retained earnings. The market value of equity is normalized by total liabilities (LT), and all other variables are normalized by total assets (AT). We set missing retained earnings and missing current assets figures to zero.

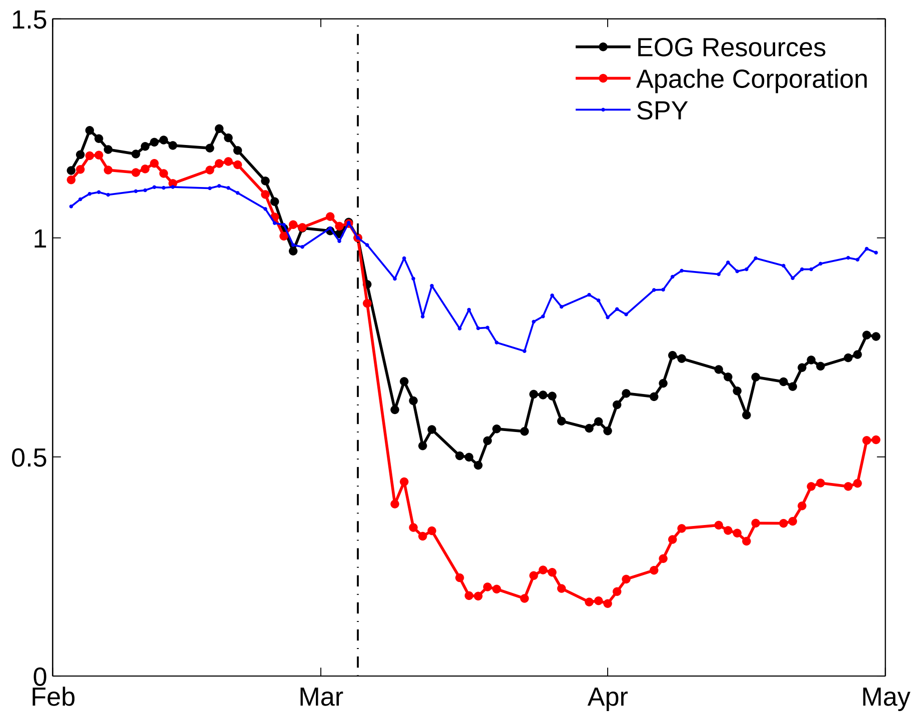
A.4 Additional Figures

Figure 5: Failed Hedging and Production Responses.



Notes: The top picture shows normalized monthly production from a *fixed* set of horizontal wells from July 2018 to December 2021. For each group of operators we choose wells that were actively producing for at least 6 months in March 2020. The production is normalized to 1 in March 2020 (also depicted by the first vertical line). Financially constrained (unconstrained) operators are depicted by a black solid line (red dashed line) and are identified by using any (none) three-way collars to hedge their projected production in 2020 (see Section 3.2). The second vertical line corresponds to July 2020.
The bottom pictures show the fraction of wells in each category that were shut-in in each month from January 2019 to December 2020. A well is defined to be shut-in in month t, if it produces nothing in month t, but has strictly positive production in month $t-1$. For each month t we distinguish wells into two categories based on observed production in the previous month $t-1$: large wells produce more than 3000 barrels and medium wells produce from 500 barrels to 3000.

Figure 6: Market performance of select oil producers in early 2020



Notes: The figure shows the market dynamics of select oil producers relative to the market in early 2020. The black line corresponds to EOG Resources (ticker EOG), the red line corresponds to Apache Corporation (ticker APA), and the blue line correponds to the SPDR S&P 500 ETF (SPY) for comparison. The vertical line depicts March 5, 2020, the last working day before the OPEC meeting in Vienna. The stock prices are normalized to 1 on March 5.

A.5 Additional Tables

Table 13: Production cuts in response to the COVID-19 shock across the top 10 oil producing states. Horizontal wells only.

	Oil Production in March 2020 (mln bbl per day)	Change from March to May 2020 (%)		Oil Production in March 2020 (mln bbl per day)	Change from March to May 2020 (%)
Texas	4.65	-22	Wyoming	0.19	-48
North Dakota	1.40	-40	Ohio	0.07	-13
New Mexico	1.02	-25	West Virginia	0.04	-11
Colorado	0.49	-9	Utah	0.04	-18
Oklahoma	0.44	-42	Montana	0.03	-42
			Total US	8.42	26

Table 14: Restricted Set of Geographical Units

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Constrained	0.038***	0.047***	0.032**	-0.023	-0.021	-0.012
	(0.011)	(0.012)	(0.013)	(0.014)	(0.016)	(0.013)
Log Cumulative Production, T=6m	0.003	0.001	0.001	-0.025***	-0.016**	-0.015**
	(0.005)	(0.005)	(0.005)	(0.008)	(0.007)	(0.007)
Public Status	0.032			-0.188***		
	(0.026)			(0.056)		
Hedged Volume		0.019	0.019		-0.004	0.015
		(0.022)	(0.025)		(0.020)	(0.019)
Committed Volume			-0.008			0.008
			(0.016)			(0.013)
Fraction Oil			0.058			-0.066
			(0.041)			(0.044)
Fraction Shale			-0.027			-0.035
			(0.025)			(0.027)
Owns Refinery			-0.051**			0.039*
			(0.021)			(0.022)
Mean Dep.Var	-0.111	-0.106	-0.104	0.066	0.055	0.056
Number of Wells	6491	6006	5857	6948	6356	6203
Number of Operators	81	42	41	83	42	41
R^2	0.285	0.289	0.290	0.372	0.371	0.375
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: To provide additional evidence that the composition of wells does not drive our results, we repeat our main analysis on a subset of geographical units that have wells of both types of operators. We drop all geographical units that have wells of only one type, that is, if $Constrained_i = 0$ or $Constrained_i = 1$ for all wells in unit s. Table 14 shows that our results remain unchanged. See Tables 5 and 6 for details. St.err in parentheses are clustered at the firm level. * p<0.1, ** p<0.05, *** p<0.01

Table 15: Placebo Test

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Constrained	-0.007	-0.011*	-0.010	-0.003	-0.004	-0.005
	(0.005)	(0.006)	(0.007)	(0.003)	(0.004)	(0.005)
Log Cumulative Production, T=6m	0.005	0.002	0.004	0.000	-0.002	-0.001
	(0.003)	(0.003)	(0.003)	(0.002)	(0.001)	(0.002)
Public Status	-0.009			-0.019**		
	(0.010)			(0.008)		
Hedged Volume		-0.015	-0.009		-0.004	-0.004
		(0.012)	(0.016)		(0.005)	(0.006)
Committed Volume			-0.014			-0.001
			(0.012)			(0.005)
Fraction Oil			0.031			-0.013
			(0.021)			(0.018)
Fraction Shale			-0.019			-0.005
			(0.023)			(0.009)
Owns Refinery			0.000			-0.005
			(0.015)			(0.008)
Mean Dep.Var	-0.078	-0.077	-0.076	0.007	0.007	0.007
Number of Wells	11214	9874	9370	12684	11093	10522
Number of Operators	107	47	43	109	47	43
R^2	0.143	0.134	0.130	0.138	0.126	0.127
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise, we run a placebo test by analyzing production cuts from the end of March to the end of May 2019. The grouping of the firms into more and less financially constrained categories remains unchanged. The results can be compared to Table 5 and 6. See those tables for details. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 16: Vertical Wells

	Oil Well Production Response					
	(1)	(2)	(3)	(4)	(5)	(6)
Constrained	0.038**	0.057***	0.042***	0.041***	0.051***	0.043***
	(0.018)	(0.014)	(0.014)	(0.014)	(0.013)	(0.012)
Log Cumulative Production, T=6m			0.007***	0.006***	0.008**	0.007**
			(0.002)	(0.002)	(0.003)	(0.003)
Public Status			0.076*	0.078*		
			(0.040)	(0.040)		
Hedged Volume					0.053**	-0.072
					(0.022)	(0.073)
Committed Volume						0.135**
						(0.051)
Fraction Oil						0.010
						(0.060)
Fraction Shale						0.032
						(0.058)
Mean Dep.Var	-0.103	-0.108	-0.108	-0.108	-0.096	-0.096
Number of Wells	11900	9696	9621	9623	7357	7324
Number of Operators	114	79	77	77	28	26
R^2	0.005	0.225	0.229	0.215	0.248	0.251
Geo FE		Y	Y	Y	Y	Y
Well Controls		Y	Y	Y	Y	Y
First Production FE		Y	Y		Y	Y
Well Age Function				Y		

Notes: In this exercise, we repeat the main estimation as in Table 5 but for *vertical wells*. Vertical wells have worse productivity on average than horizontal wells, even thought the top vertical well produced 2.5 more than the top horizontal well in March 2020. In this exercise, we consider all vertical wells with more than 100 barrels of oil per month. Well Controls now include the length of the perforated interval instead of the horizontal length.
We find that constrained operators decreased production by 4-5 pp less than less constrained firms (or by 9pp over the two months of April and May). Thus, our findings for vertical wells are consistent with out main results. The results become stronger, if we increase the threshold. The number of operators is smaller for specifications that rely on 10-k SEC filings, because we had not collected this information for firms operating vertical wells only. St.err in parentheses are clustered at the firm level. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 17: Realized Returns

	Oil Well Production Response			Well Shut-In Indicator		
	(1)	(2)	(3)	(1)	(2)	(3)
Realized Return	-0.040**	-0.052***	-0.028*	0.010	0.019	0.020
	(0.016)	(0.018)	(0.015)	(0.014)	(0.018)	(0.022)
Log Cumulative Production, T=6m	0.007	0.007	0.007	-0.021**	-0.021**	-0.020**
	(0.006)	(0.006)	(0.006)	(0.009)	(0.009)	(0.009)
Hedged Volume		0.004	0.014		-0.036	-0.040
		(0.018)	(0.022)		(0.034)	(0.044)
Committed Volume			0.000			0.007
			(0.019)			(0.015)
Fraction Oil			0.056			-0.085**
			(0.035)			(0.041)
Fraction Shale			-0.036			-0.002
			(0.026)			(0.032)
Owns Refinery			-0.036			-0.013
			(0.023)			(0.034)
Mean Dep.Var	-0.107	-0.109	-0.104	0.057	0.059	0.060
Number of Wells	11931	10969	10483	12641	11641	11134
Number of Operators	55	51	47	55	51	47
R^2	0.261	0.279	0.268	0.373	0.377	0.381
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise, we repeat the main estimation with the *realized returns* over the period of failed OPEC-Russia negotiations from Thursday, March 5 to Monday, March 9, 2020, instead of just a dummy variable as in Table 11. For the production cuts, the coefficients on realized returns are negative and significant across all specifications, in line with our main results that more financially constrained firms (those with more negative realized returns) cut production by less. The results on complete shut-ins have the right sign, but are insignificant. See Table 11 for details. St.err in parentheses are clustered at the firm level. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 18: (continues Table 4) Unconstrained and Constrained Firm Financial Characteristics

	Unconstrained	Constrained	Difference
Log Employment	-0.735	-0.326	0.409
	(1.646)	(1.572)	(0.565)
Market Value	15,566.836	6,145.866	-9,420.970
	(51,667.398)	(10,870.102)	(15,805.309)
Kaplan-Zingales	1.238	0.965	-0.272
	(0.930)	(1.065)	(0.334)
Altman Z-score	0.558	0.209	-0.348
	(1.875)	(1.352)	(0.613)
Almeida	0.019	0.014	-0.005
	(0.033)	(0.014)	(0.010)
Whited-Wu	-0.405	-0.401	0.004
	(0.100)	(0.105)	(0.035)
Huang-Ritter	497.599	-1,764.406	-2,262.005
	(3,025.714)	(6,538.885)	(1,428.905)
Market-to-Book Ratio	522.727	341.952	-180.775
	(1,175.998)	(487.886)	(366.865)
Capital Intesity	0.185	0.199	0.014
	(0.086)	(0.105)	(0.032)
Cost of Capital	9.567	6.068	-3.499
	(13.532)	(7.081)	(4.478)
Earnings per Share	-0.905	-3.020	-2.115
	(4.157)	(5.849)	(1.598)
Payout Ratio	-0.312	0.096	0.408
	(4.515)	(3.066)	(1.465)
Return on Assets	-0.098	-0.112	-0.014
	(0.240)	(0.233)	(0.083)
Return on Equity	-0.794	-1.638	-0.844
	(1.890)	(4.313)	(0.922)
Return on investment	-1.011	-0.145	0.866
	(5.356)	(0.305)	(1.628)
Number of Operators	37	11	48

Notes: This tables compares average financial chacteristics of publically traded unconstrained and constrained operators. Standard financial data are from Compustat. Variable descriptions are provided in Section A.1.
* $p<0.1$, ** $p<0.05$, *** $p<0.01$.

Table 19: Additional Operator-Level Controls

	Oil Well Production Response					
	(1)	(2)	(3)	(4)	(5)	(6)
Constrained	0.043***	0.048***	0.048***	0.044***	0.041***	0.018
	(0.010)	(0.012)	(0.014)	(0.011)	(0.013)	(0.017)
Log Cumulative Production, T=6m	0.008*	0.008	0.008	0.006	0.008	0.007
	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.005)
Hedged Volume		0.017	0.009	0.007	0.009	0.032
		(0.023)	(0.022)	(0.022)	(0.023)	(0.025)
Operating Costs			-0.001			0.007
			(0.004)			(0.005)
Log Days to Maturity				0.032***		0.024
				(0.006)		(0.017)
Owns Refinery					-0.037*	-0.059
					(0.021)	(0.035)
Committed Volume						-0.001
						(0.017)
Fraction Oil						0.030
						(0.031)
Fraction Shale						-0.038
						(0.023)
Mean Dep.Var	-0.116	-0.112	-0.111	-0.111	-0.112	-0.107
Number of Wells	11351	10077	10031	9996	10077	9510
Number of Operators	104	47	46	45	47	41
R^2	0.294	0.308	0.305	0.309	0.310	0.299
Geo FE	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y

Notes: In this exercise we reestimate the specification (6) in Table 5 but add additional operator-level physical controls. See appendix A.3 for variable definitions. All data are taken as of December 31, 2019. * p<0.1, ** p<0.05, *** p<0.01

Table 20: (continue) Additional Operator-Level Controls

	Oil Well Production Response									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Constrained	0.036***	0.033***	0.036***	0.035***	0.030**	0.039***	0.049***	0.035***	0.030**	0.033***
	(0.012)	(0.011)	(0.012)	(0.012)	(0.012)	(0.010)	(0.013)	(0.012)	(0.014)	(0.012)
Leverage	-0.002									
	(0.005)									
Interest Coverage Ratio		-0.018*								
		(0.009)								
Profitability			-0.242							
			(0.209)							
Cash Flow				-0.901						
				(1.086)						
Short Term Debt					-0.019**					
					(0.007)					
Almeida						0.013				
						(0.008)				
Kaplan-Zingales							0.015*			
							(0.009)			
Whited-Wu								-0.002		
								(0.016)		
Huang-Ritter									-0.004	
									(0.009)	
Altman Z-score										-0.008
										(0.009)
Mean Dep.Var	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107
Number of Wells	9510	9510	9510	9510	9510	9510	9510	9510	9510	9510
Number of Operators	41	41	41	41	41	41	41	41	41	41
R^2	0.298	0.299	0.298	0.298	0.300	0.299	0.299	0.298	0.298	0.298
Geo FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Operator Controls	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

Notes: In this exercise we reestimate the specification (6) in Table 5 but add additional financial measures. See appendix A.3 for variable definitions. All financial data are taken as of December 31, 2019. The operator-level controls include the fraction of oil production, fraction of shale production, fraction of production hedged with standard instruments, and fraction of volume committed using physical delivery commitments. See specification (6) in Table 5 for further details. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 21: (continue) Additional Operator-Level Controls

	Oil Well Production Response									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Constrained	0.035**	0.036***	0.032**	0.038***	0.038***	0.012	0.033***	0.045***	0.037***	0.035***
	(0.014)	(0.012)	(0.013)	(0.009)	(0.012)	(0.013)	(0.011)	(0.009)	(0.012)	(0.012)
Log Total Assets	0.002									
	(0.015)									
Market Value		-0.022								
		(0.013)								
Tobin's Q			-2.636							
			(2.173)							
Tangibility				-0.019						
				(0.012)						
Market-to-Book Ratio					-0.020					
					(0.014)					
Capital Intesity						-0.281***				
						(0.068)				
Cost of Capital							-0.004			
							(0.010)			
Payout Ratio								-0.014***		
								(0.004)		
Return on Assets									-0.838	
									(0.921)	
Return on Equity										0.160
										(0.224)
Mean Dep.Var	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107	-0.107
Number of Wells	9510	9510	9510	9510	9505	9510	9460	9510	9510	9510
Number of Operators	41	41	41	41	40	41	39	41	41	41
R^2	0.298	0.299	0.298	0.299	0.298	0.301	0.299	0.301	0.298	0.298
Geo FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Well Controls	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
First Production FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Operator Controls	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

Notes: In this exercise we reestimate the specification (6) in Table 5 but add additional financial measures. See appendix A.3 for variable definitions. All financial data are taken as of December 31, 2019. The operator-level controls include the fraction of oil production, fraction of shale production, fraction of production hedged with standard instruments, and fraction of volume committed using physical delivery commitments. See specification (6) in Table 5 for further details. * $p<0.1$, ** $p<0.05$, *** $p<0.01$