# Capturing Rents from Natural Resource Abundance: Private Royalties from U.S. Onshore Oil & Gas Production


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## Abstract

Innovation-spurred growth in oil and gas production from shale formations led the U.S. to become the global leader in producing oil and natural gas. Because most shale is on private lands, drilling companies must access the resource through private lease contracts that provide a share of the value of production – a royalty – to mineral owners. We investigate the competitiveness of leasing markets by estimating how much mineral owners capture geologically-driven advantages in well productivity through a higher royalty rate. We estimate that the six major shale plays generated $39 billion in private royalties in 2014, however, there is limited pass-through of resource abundance into royalty rates. A doubling of the ultimate recovery of the average well in a county increases the average royalty rate by 2 percentage points (an 11 percent increase). The low pass-through is consistent with firms exercising market power in private leasing markets, and with uncertainty over the value of resource endowments. The finding suggests that policies affecting the cost of extraction likely have little effect on the share of the value of production captured by mineral owners.

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## I. Introduction

During the 2000s, innovation in extracting oil and gas from shale formations caused the U.S. to become the global leader in producing oil and natural gas (EIA, 2013). Because shale formations lie primarily on private lands, drilling companies access the resource through private lease contracts that provide a share of the value of production – a royalty – to mineral owners. If mineral acreage is fixed, competition and free entry should ensure that mineral owners capture Ricardian rents – the additional revenues generated by a given parcel because it has more oil and gas than the marginal parcel. Mineral owners in resource-abundant areas would therefore capture a larger share of the value of production than owners in less abundant areas. Weyl and Fabinger (2013), however, note that most work on pass-through assumes perfect competition despite scant empirical evidence for many markets. This is especially true of the private oil and gas leasing market, which is surprisingly understudied given the hundreds of billions of revenue that private leases generate.

We address this large void in the literature by estimating the extent that resource abundance passes through to mineral owners via higher royalty rates. Aside from determining the distribution of the billions of dollars of rents from U.S. shale oil and gas, estimates of pass-through also provide insight into the incidence of a tax on the value of oil and gas extracted, commonly known as a severance tax. Severance taxes – and who really pays for them – have grown in importance as shale development has increased the revenues at stake in many states. In 2015 the governor of Pennsylvania proposed a 5 percent severance tax (the state does not have one currently) while the governor of Ohio proposed a several fold increase in his state's severance tax. By advancing the optimal time to stop extracting, from the perspective of mineral owners and firms the taxes are equivalent to reducing how much oil and gas is in the ground.

Some of the incidence of a severance tax will occur through changes to the extensive margin, but some may also occur by changing the royalty rate firms are willing to offer mineral owners.

To quantify the economic importance of a higher royalty rate, we also estimate and compare royalty income to what residents receive in government transfer income and total farm program payments. Pender et al. (2014) discuss the role that investment of royalty income in local economies may play in creating long-term wealth in rural areas. Gilje (2012), for example, found that bank deposits tripled in the Bakken region of North Dakota when oil production expanded, in part reflecting the royalty income of local mineral owners.

A proprietary dataset of nearly 1.8 million private leases located across 16 states provides royalty rates and the county of residence of the lessee, allowing us to calculate the magnitude and geographic distribution of royalty payments. Our empirical estimates indicate that in 2014 the six major U.S. shale plays generated a total of $39 billion in royalties. This is more than four times the royalty income received by the Federal government in the same year (Office of Natural Resources Revenue, 2015). In the more rural plays, private royalties rival government transfer income and swamp total farm program payments. We also observe that average royalty rates vary substantially across plays, from a low of 13.2 percent in the Marcellus to a high of 21.2 percent in the Permian, as does the share of ownership by county residents (12 to 55 percent).

Using spatial variation in royalty rates and resource abundance, we estimate that a doubling of the estimated ultimate recovery of the typical oil and gas well in the county increases the average royalty rate by 2 percentage points at most (an 11 percent increase). This is far less pass-through than what a model of perfect competition in leasing markets predicts and is consistent with a firms exercising power in a market with an upward sloping mineral acreage supply curve where Ricardian rents differ across acreage. It is also consistent with firms facing substantial uncertainty regarding the value of resource endowments. Although some pass-through may occur through signing (bonus) payments, accounting for such payments still leads to the conclusion that oil and gas abundance has a small effect on the share of production value captured by mineral owners.

## II. Leasing Markets

Acquisition of prospective acreage by extraction companies in the United States has historically occurred through two channels: auction of minerals owned by federal or state governments, and negotiation of private lease contracts with individual owners of mineral property (Ravagnani, 2008). Prior research on leasing focused on the first channel – namely the leasing of Federal lands and waters (e.g. Boskin et al. 1985, Hendricks and Porter 1996). We focus on the more economically important second channel.

Unlike most countries, private individuals own most of the subsurface resources in the United States (Williamson and Daum, 1959). However, mineral rights can be sold or conveyed separately from surface rights. For this reason, the ownership of most prospective oil and gas acreage has traditionally been fragmented among numerous private owners competing with one another in negotiating with companies (McKie, 1960). Oil and gas extraction historically has involved thousands of small "independent" companies, which yielded a high degree of competition in the leasing market (Davidson, 1963). More recently, some have credited the innovation in shale drilling to this competition and ease of accessing minerals through private leases (e.g. Hefner, 2014).

The majority of oil and gas production in the U.S. occurs via oil and gas leases as opposed to direct mineral ownership of the extracting firm (Fitzgerald and Rucker, 2014). There are two main types of ownership in oil and gas – working interests and royalty interests. Working interest owners incur all of the costs and liabilities of development, but must pay the royalty interest owner a share of the gross value of production as a royalty, with the share known as the royalty rate. Royalty and working interests share price and production risk, but the working interest carries all of the cost risk and environmental liabilities associated with production.

Leasing contracts are signed before drilling occurs and are generally structured as multi-year option contracts that provide the firm the right but not the obligation to explore for oil and gas. If the firm finds productive deposits and pursues extraction, the lease remains in effect so long as production continues.

Oil and gas resources are not uniformly distributed, which creates the possibility of larger Ricardian rents for richer deposits. Two factors affect the profitability of a prospective well: costs of development and the expected value of production. Resource abundance is commonly measured by estimates of ultimate resource recovery. Such measures vary substantially across space, even within similar formations (Ikonnikova et al. 2015). Because expected ultimate recovery varies across space, with some counties overlying "sweet spots" in the formation, some counties are potentially more profitable than others, with a given fixed investment providing access to more resource. An owner in a higher-profit area may be able to capture a larger share of the rents than an owner in a lower-profit county.

Yet, there are reasons why mineral owners may capture little of the geological richness associated with their rights. Equipped with teams of geologists and engineers, extraction firms have more information about resource abundance than the typical mineral owner. Moreover, the lease terms are set before production occurs. Most leases are written such that the lease remains in effect as long as production occurs, which prevents the mineral owner from using newly acquired information to hold up the lessee by negotiating a higher lease. On the other hand, mineral owners can share information with each other—informally or through formal landowners' groups. Most importantly, once extraction firms begin bidding against each other, information on offered royalty rates is likely to spread quickly amongst local mineral owners. Absentee mineral owners may lack some informal channels, but internet forums help keep information costs low for engaged owners.

The long life of most leases provides few opportunities for mineral owners to renegotiate new terms in response to new information. Comparatively, farmland rental leases provide more opportunities for renegotiation because the leases can be as short as one year. Yet, even with opportunities for renegotiation, there is evidence that farmland rental markets are far from perfectly competitive. Kirwan (2009) studies how much a guaranteed $1 more in farm revenue (through per acre subsidies) pass through to landowners in the form of higher rental rates. He finds that only 21 cents on the dollar passes to landowners, leaving the farmer with about three quarters of the subsidy. Hendricks et al. (2012) estimate a higher long-run pass-through (37 cents on the dollar), but still well below what is implied by perfect competition.

In our study, the extraction firm is in the same position as the farmer. We expect less pass-through to occur in oil and gas leasing markets. Agricultural landowners likely know more about the relative quality of their land than mineral owners know of the oil and gas in their ground. Moreover, farmland leases can typically be renegotiated every year (or every few years) while oil and gas leases remain effective for the life of a producing well, which can be decades. Moreover, uncertainty about the location and richness of deposits gives rise to potential rents for firms with superior information, as suggested by empirical evidence from Hendricks and Porter (1988, 1996).

Empirical academic research on private oil and gas leasing markets is quite limited. Vissing and Timmins (2014) address lease negotiations in a Coasian bargaining framework, with empirical results supporting the idea that mineral owners have heterogeneous reservation values due to different preferences to avoid risks associated with development. Vissing (2015) finds a negative correlation between the strength of lease terms and concentration of minority households, broadening the number of possible sources of heterogeneity in value.

## III. Model

We treat oil and gas as a single output. Define production in period $t$ as $q_t$, implying an ultimate recovery of $Q = \sum_{t=1}^{T} q_t$, where $T$ is the expected time horizon of production. If production is uncertain, the ultimate recovery is based on probability distributions of production common to all firms. Uncertainty surrounding $Q$ is why the industry refers to it as the estimated ultimate recovery, or simply EUR.

Ultimate recovery is a key consideration for a firm, but development costs also matter. For each unit of land indexed by $i$, the firm incurs a fixed cost of development $c_i$. Assuming zero marginal production costs, firms decide which parcels to develop by weighing fixed development costs against the estimated ultimate recovery, $Q_i$. This is consistent with Anderson et al. (2014), who find that once irreversible development costs have been made production is largely unresponsive to prices and instead is determined by geophysical decline. Alternatively, a positive marginal cost could be accommodated by considering the price a net price received.

Uncertainty over the ultimate recovery and future prices motivates the choice of a share contract, where the mineral owner is paid a share of the gross value of production, with the share known as the royalty rate ($\rho_i$). The gross revenue stream is price times the quantity produced and has a present value of $R_i = \sum_{t=1}^{T} \beta^t \widetilde{p_t} \cdot q_{it}$ where $\widetilde{p_t}$ is an expected price path and $\beta$ a discount factor, both of which are common to all firms. Based on the development costs and expected value of production, firms use backward induction to solve for the royalty rate they are willing to offer the parcel's owner.

To determine how many parcels are developed, assume that every firm has a periodic hurdle rate that is the risk-adjusted market rate *r*, and that $\beta = \frac{1}{1+r}$. Firms incur the fixed expenditure $c_i$ immediately and realize the present value of production revenues in the following periods. We assume that parcels are homogeneous but that mineral owners have different reservation values that must be met for them to sign a lease. Profit maximization requires that firms lease the optimal number of parcels as determined by:

$$\max_N \pi = N[(1-\rho)R - (1+r)c],$$

which is subject to a participation constraint by all leased mineral owners:

$$\rho R \geq g(N).$$

This constraint allows for an individual-specific reservation value expressed in present value when production begins. We assume $g(N)$ is a continuous and non-decreasing function, so the last lease will just satisfy an individual rationality constraint for the mineral owner.

Economic profit is driven to zero in a competitive market, so a zero-profit condition applies for the marginal lease:

$$(1 - \rho_i)R_i = (1 + r)c_i. \tag{1}$$

By rearranging the zero-profit condition, the competitive royalty rate ($\rho_i$) is defined as a function of the net expected profit from the marginal parcel.

$$\rho_i = 1 - \frac{(1+r)c_i}{R_i}. \tag{2}$$

This relates to the reservation value of the marginal mineral owner according to:

$$\rho_i = R_i - (1 + r)c_i = \frac{g(N)}{R_i}.$$

By taking logarithms, equation (2) can be linearized as

$$\ln(1-\rho_i) = -\ln(R_i) + \ln(1+r) + \ln(c_i), \tag{3}$$

which shows that in a competitive market a one percent increase in the present value of revenues is associated with a one percent decrease in the share of the value of production going to the firm, $(1-\rho_i)$. A mineral owner therefore captures the benefit of having more oil or gas in his property by receiving a larger share of the value of production compared to an owner whose lease grants access to less oil or gas.

Equation (2) shows that the competitive royalty rate depends on the revenues associated with development. Differentiating (2) with respect to $R_i$ yields $\frac{(1+r)c_i}{R_i^2} > 0$ , indicating pass-through of profitability in terms of a higher royalty rate and therefore a larger share of gross revenues. The asymmetry of revenues and costs is evident when we consider the impact of lower fixed development costs on the royalty rate: $\frac{(1+r)}{R_i} > 0$. This has important implications for mineral owners negotiating leases, in that having a lower-cost parcel is more advantageous than sitting on a more valuable resource when $c_i > R_i$. It naturally raises the issue of the correlation between costs and revenues, to which we return below.

Firms competing with each other for leases will increase the royalty rate such that equation (2) holds. The equation implies that development costs and ultimate recovery (embedded in $R_i$) explain differences in royalties across locations. To give a sense of how a firm would calculate royalty rates in a competitive market, consider a discount rate of 0.20. For each $1 million in development cost, a firm would be indifferent about a project yielding expected revenue of $1.37 million in exchange for a royalty share of 0.125, or $1.47 million in exchange for a royalty of 0.1875.

*A. Monopsony*

It is possible that oil and gas companies enjoy a measure of market power in the leasing market and thereby capture a larger share of the potential quasi-rents. First-mover advantages and spatial economies of scale in development may result in only one company acquiring a dominant acreage position in an area. Some development costs can be spread across nearby parcels. One access road, for example, can be used to access multiple parcels in an area. The average cost of development will then decline with the total acreage in a given region that the firm already controls. This provides an incentive for firms to consolidate acreage. For a given area, it also limits the ability of firms to compete with the firm with the dominant acreage position.

As a limiting case, consider the situation when only one firm leases minerals in an area. When acquiring parcels to develop, the monopsonist considers how many additional parcels can be leased if it offers a higher royalty rate. If the monopsonist cannot discriminate by offering individual royalty rates to different mineral owners, increasing the royalty rate for the marginal mineral owner means increasing it for all owners (see appendix A.3 for a discussion of the case with discrimination). It therefore offers a royalty rate different from the one in (2). The new optimal royalty rate is:

$$\rho_i^M = 1 - \rho'(N)N - \frac{(1+r)c_i}{R_i}, \tag{4}$$

where $N$ is the number of parcels leased. This rate is lower than the competitive rate by an amount determined by $\rho'(N)N$. The participation constraint binds for the marginal mineral owner so that $\rho(N)R_i = g(N)$. By substitution, $\rho'(N)N = \frac{g'(N)N}{R_i} = \gamma$. Note that $g'(N)$ is the slope of the mineral acreage supply curve, so $\rho_i^M$ approaches the competitive case as the (linear) supply curve becomes more elastic, flattening to a horizontal line. The lower bound of observable contracts is zero, but the formulation provides motivation for the state minimum royalty statutes in West Virginia and Pennsylvania. We would expect to see a clustering of leases at the minimum legal rate if the supply curve is vertical.

Greater dispersion of reservation rates reduces the elasticity of the mineral acreage supply curve, which in turn makes the firm less willing to increase the royalty rate. Lower elasticity means that an increase in the royalty rate allows the firm to acquire too little additional acreage to compensate for having to increase the market royalty rate for all inframarginal owners. Linearizing (3) and ignoring the zero lower bound for the sake of exposition yields

$$\ln(1-\rho_i^M-\gamma) = -\ln(R_i) + \ln(1+r) + \ln(c_i). \tag{5}$$

This formulation implies that a one percent increase in revenues causes a one percent decrease in the firm share $1-\rho_i^M-\gamma$. Because $1-\rho_i^M-\gamma$ is less than $1-\rho_i^M$ in all but the perfectly elastic case, the share of the value of production going to the firm is larger when $\gamma$ is larger. Thus, the steeper the mineral acreage supply curve, the less that resource abundance and revenues are passed to the mineral owner via a higher royalty rate.

Monopsony without price discrimination is an extreme case; market power is likely to take the form of a small number of firms offering to lease land in a particular area. The effect on royalty rates is similar, but attenuated as more firms enter the leasing market, until eventually there is sufficient entry to make the market competitive.

*B. Uncertainty*

We now consider an alternative distortion in the leasing market. Suppose that competitive firms are uncertain about the location and richness of oil and gas resources. The distribution of expected resources, *f(Q),* is shared by all firms. Each firms receives a signal of expected resources,$\hat{Q}$, from this common distribution. Expected revenues for each firm are then a multiple of $\hat{Q}$, and the expected revenue distribution is a transformation of *f(Q)*. The firm with the highest expectation offers the highest royalty. Given that it is higher than all other values, this highest expectation likely exceeds the true value, in which case the highest bidder has fallen under the "winner's curse" (Capen, Clapp, and Campbell 1971).

Firms will lower the offered royalty rate to avoid the winner's curse. This response is similar to the incentive to lower bids in common value auctions (Milgrom and Weber 1982)[1]. The incentive to reduce the offered royalty becomes larger the more firms there are competing for leases—the effect is represented as $\theta$ below. The royalty rate that is offered becomes:

$$\rho_i^I = 1 - \theta - \frac{(1+r)c_i}{R_i}. \tag{6}$$

The royalty in (6) is lower than the perfectly competitive royalty in (2). Whether it is larger or smaller than the offer in (4) is an empirical question.

Geologic uncertainty is only one reason why expected and actual revenues might differ. Expectations about uncertain energy prices might also lead to varying valuations of leases by firms. If price expectations are also drawn from a common distribution (such as futures markets), firms have a parallel incentive to shade their bids lower to avoid the winner's curse. Compound

[1] Haile (2001) extends the model to one that allows resale (like oil and gas leases), and demonstrates in a similar context that bids are higher in markets with resale. This corresponds to an incentive to offer slightly higher royalty rates than in the case with no resale.

uncertainty over EUR and prices is also possible. If these uncertainties are correlated, for example because unknown resources make it hard to anticipate the future path of prices, then the incentive to offer a lower royalty is even stronger.

Costs of development are also not known perfectly at the time of leasing. All else equal, the firm with the lowest expected costs would offer the highest royalty rate. If costs are drawn from a common distribution, then the firm would have a similar incentive to offer a slightly lower royalty than it otherwise might. Regardless of the source of uncertainty, the effect is the same as uncertainty over production or prices—firms will offer a lower royalty rate to mineral owners.

A final related issue is the correlation between costs and expected revenues. In (1), costs and revenues appear on opposite sides. If the two are perfectly positively correlated, then greater gross revenues from resource abundance will not be passed through to mineral owners because the revenues will be offset by higher costs. If the two are less than perfectly positively correlated, then some pass-through of resource abundance should occur, though less than the case where revenues and costs are uncorrelated.

## IV. Data

### *A. Proprietary Lease Data*

Private data provider DrillingInfo furnished data on leases of privately-owned oil and gas rights around the United States.[2] DrillingInfo collects data on various aspects of oil and gas development, especially in areas where there is interest in development. Leasing data are collected from courthouse records and include the legal description of the tract, the address of the mineral owner, the year the leased was signed, and the royalty rate.

[2] http://www.drillinginfo.com

In cases where a parcel was leased several times, we focus on the most recent lease. This reduces the potential for double-counting leases. Because acreage varies by parcel, we weight all lease statistics by the lease's share of leased acreage in the county. Fractionation of mineral ownership means that several people may have ownership of the same acre and can require multiple lease instruments to fully lease. We are limited in our ability to identify which leases pertain to the same acre as opposed to being near one another but not overlapping. We make a conservative measure of the number of acres leased by counting only a single lease for the smallest area we can identify from legal descriptions; in general that area is 40 acres, though in many cases we have specific parcel identifiers (e.g., lot numbers) that allow us to include more parcels.

The lease data in most states include information about the mineral owner, allowing us to determine if she has an address in the same county and state as the lease. For these states we use this information to estimate the extent of local ownership, which we define as the percent of oil and gas rights owned by county residents.

The full set of leases includes nearly 1.8 million private mineral lease observations from 558 counties located in 16 states (table 1). The 16 states include most of the major producers among the 32 oil and gas producing states, and many of the top-producing counties are represented.[3] The share of total oil and gas produced (in barrels of oil equivalent converting at 6Mcf/bbl) in the sample counties varies from 66 to 75 percent of total production over 2000-2011. Average acre-weighted royalty rates vary substantially across states ranging from 0.126 to 0.215. Local ownership also varies considerably, with the lowest rates in western states with a history of extensive oil and gas development.

[3] The states are: AR, CA, CO, KS, LA, MS, MT, ND, NM, OH, OK, PA, TX, UT, WV, WY. The largest producing states that are excluded are AK, which has very limited private mineral ownership, and AL, IL, IN, and MI. A total of 1,097 counties produced oil or natural gas in 2011.

<< Insert Table 1 >>

*B. Validating Royalty Rates from Leasing Data*

The DrillingInfo data have more observations in areas with recently active leasing markets, which are the areas most relevant for our analysis. Even in these areas, however, the data do not necessarily include the universe of leases. In particular, older leases are most likely to be excluded. In Pennsylvania, where we have a measure of total royalty income at the county level, we econometrically estimate the average royalty rate in the county by regressing total royalty income on the value of production (details and results table are provided in the appendix). We then compare the econometric-based average royalty rate with the rate calculated from the DrillingInfo lease data.

Our empirical estimate suggests a gross royalty rate similar to the one estimated from the lease data. The lease data indicate an average royalty rate of 13.2 percent for Pennsylvania counties. Econometrically, we find that each dollar in local production translates into 10.9 cents in local royalty income (s.e. of 1.4 cents) (table A1). Our royalty income measure reflects net rather than gross income. The difference between the two includes post-production costs, largely comprised of marketing deductions and transportation allowances. If expenses associated with the lease combined with post production costs account for roughly 2 percent of the value of production (or 20 percent of royalty share), our estimate of 10.9 would imply an average royalty rate of 12.9 percent, very close to the royalty rate indicated by the lease data.

## V. The Magnitude of Oil and Gas Royalties

Using the DrillingInfo leasing data, we estimate typical royalty rates for six major shale plays located around the country (figure 1). Play-specific royalty rates combined with production and price data from the Energy Information Administration allowed us to estimate total royalty income generated in 2014 from each shale play (see Appendix A.2 for data and estimation details). Using the share of leases owned by county residents, we also estimate the total and per capita royalty income going to residents of the county where production occurs. To put the estimates in perspective, we also report the per capita value of government transfer income and farm program payments for each play.

<< Insert Figure 1 >>

Oil and gas production and payments in 2014 were substantial, but varied considerably across shale plays (table 2). Together the six plays produced more than $211 billion in oil and gas in 2014, representing about 1.2 percent of U.S. GDP. The Permian accounted for the largest share, followed by the Eagle Ford and the Bakken, all of which primarily produce oil. Average royalty rates ranged from 13.2 (Marcellus) to 21.2 percent (Permian) while royalty income ranged from $2.5 billion (Niobrara) to $13 billion (Permian).

The share of local ownership sheds light on the royalty income captured by residents of the county where production occurs. Average local ownership shares ranged from 12 (Permian) to 55 percent (Marcellus), and local royalty income ranged from $0.54 (Haynesville) to $2.83 billion (Eagle Ford). This is an underestimate of the royalty income received by residents of each play because it does not capture the royalties of residents who hold mineral rights in other counties in the play, or as absentee owners in other plays.

To gain a sense of the economic importance of royalty income in the various regions, we normalize the estimates on a per capita basis. Much of the recent energy development has occurred in rural portions of the country (Brown et al., 2013). Particularly in sparsely populated areas, royalty income may account for a large share of personal income (though we do not observe the distribution of royalty income across local residents). Indeed, we find that in the Bakken and Eagle Ford plays, which cover sparsely populated areas, local royalty income per capita were between $2,900 and $4,200. In the more populated plays the measure ranged from $200 to $1,200 per capita.

Local royalty income is economically important when compared to government transfer income and federal farm payments per capita in 2012 for each play (table 2). The Bureau of Economic Analysis defines transfer payments as transfers to persons for which no services were performed. The measure, which we use, includes retirement and disability insurance benefits, medical payments, unemployment insurance benefits, grants, and other payments. Federal farm payments data came from the 2012 Census of Agriculture and include crop insurance subsidies, Conservation Reserve Program payments, and commodity support payments. For all plays, royalty exceeds farm payments but not transfer receipts. Total royalty income per capita, however, greatly exceeds transfer receipts in the Bakken and Eagle Ford.

Because the six plays produced an estimated $213 billion in oil and gas, a one percentage point increase in royalty rate corresponds to $2.13 billion dollars. Assuming that energy companies would not reduce production in response to a higher royalty rate, the royalty income of mineral owners would increase by this amount if they had negotiated a one percentage point higher royalty rate. A one percentage point lower royalty rate would reduce local royalty income per capita between \$20 and \$250 across the different plays. To put this number in perspective, the reduction is similar to eliminating all of the farm payments in most of the plays.

<< Insert Table 2 >>

## VI. Empirical Assessment of Pass-Through in the Leasing Market

We estimate pass-through in the leasing market by adapting the parcel-based theoretical predictions in (3) to county-level data on royalty rates and the ultimate recovery of the average county well. If parcels vary across counties but not within them, the arguments in equation (3) can be replaced with county-level analogues. We assume that the average expected revenues for the average parcel in the county are given by expected prices (common to all firms) multiplied by the estimated ultimate recovery of the average well: $\bar{R}_c = p_t \cdot \bar{Q}_c$, where the subscript $c$ refers to a specific county and $p_{c(t)}$ is the expected price of energy when the leases in county $c$ were negotiated. Replacing the terms in equation (3) with their county-level analogues yields

$$\ln(1 - \bar{\rho}_c) = -\ln(\bar{Q}_c) - \ln(p_t) + \ln(1 + r) + \ln(\bar{c}_c). \tag{7}$$

A perfectly competitive market scenario implies that a one percent increase in the estimated ultimate recovery should lead to a one percent decrease in the share of the value of production going to the firm. If the royalty rate is 15 percent, a one percent increase in $\bar{Q}_c$ would imply a .85 percentage point decrease in the share captured by the firm (0.85 percentage points (=0.01 x 85). The share captured by the mineral owner -- the royalty rate -- would increase to 15.85%.

Equation (7) provides the basis for our econometric model. We account for the time varying market return on capital ($r$) and the price of oil and gas by calculating the average interest rate, price of oil, and price of gas at the time of lease signing. This is done by averaging values across time, where the weight on each year is given by the acre-weighted share of leases signed in that year. Because the distribution of leases across time varies by county, so does the weighted expected price of energy.

Shale play fixed effects and measures of historic development control for county-specific development costs $c_c$, which we do not observe. Shale play fixed effects control for average cost differences across plays. The historic development measure, which is defined as the percent of the county that ever had an oil and gas well as of 1980, controls for county-level cost differences associated with prior development.[4] Presumably areas with greater development have more oil and gas infrastructure and lower costs than areas with less development. The measure also helps control for general knowledge that mineral owners have of the oil and gas industry and therefore their sophistication in negotiating leases. Our base econometric model then becomes:

$$\ln(1-\bar{\rho}_c) = \beta \ln(\bar{Q}_c) + \alpha PD_c + \boldsymbol{P_{c(t)}\delta} + \boldsymbol{Play_c}\gamma + \varepsilon_c, \tag{8}$$

where *PD* is the percent of the county that had oil or gas development by 1980, $\boldsymbol{P_{c(t)}}$ is a vector of two variables (interest rates, energy prices), and $\boldsymbol{Play_c}$ is a vector of shale play dummies. The price of energy is either the first purchase for crude oil (if an oil region) or the wellhead price of natural gas (if a natural gas region), both in terms of dollars per million British Thermal Units (MMbtu).

### *A. Estimating the Ultimate Recovery for the Typical County Well*

Various methods have been used to estimate the ultimate recovery of the typical well, ranging from the quadratic method (Hubbert, 1956) that fits a quadratic curve to the aggregate production

[4] We calculate this measure of historic development using the historic geo spatial data on oil and gas wells provided by the U.S. Geologic Survey: http://pubs.usgs.gov/dds/dds-069/dds-069-q/text/cover.htm.

of a field to more recent well-based methods that estimate a decline curve for the typical well (Kaiser, 2012; Cox, 2013). We take a county-based approach that follows the spirit of the well-based decline curve methods.

Using county-level data on production and the number of active wells in each age category, we estimate how much an additional well increases total production, where the increase depends on the well's age because production from a given well declines over time. Consider total production in a county *c* in year *t* as

$$Prod_{ct} = \sum_{a=1}^{A} \alpha_a (a\ yr\ wells_{\ ct} * thick_c) + \gamma_c + \eta_t + \varepsilon_{ct}, \tag{9}$$

where $a\ yr\ wells_{\ ct}$ is the number of active wells of age $a$ in county *c* in year *t*, and $\gamma_c$ and $\eta_t$ are county and year fixed effects. The coefficient $\alpha_a$ gives the average production of an $a$ year-old well from 1 meter of shale thickness. The county and year fixed effects help estimate the $\alpha_a$terms apart from additive time-invariant county characteristics or temporal shocks that affect the level of production.

We estimate (9) separately for each play, allowing an $a$ year-old well to give different production per each meter of shale in different plays. The majority of production from shale wells occurs in the first few years. As such we estimate the effect of wells of age 1, 2, 3, 4, and 5 year old well separately and lump wells 6 years and older into one category. We assume that wells 6 years and older produce for the equivalent of 4 more years. Thus, we estimate the ultimate recovery associated with 10 years of production. The estimated ultimate recovery of the typical well in the county is then calculated by summing the alpha coefficients multiplied by the county's shale thickness: $\widehat{\bar{Q}_c} = thick_c \cdot [(\sum_{a=1}^{5} \alpha_a) + (4 \cdot \alpha_{a>5})]$.

Estimation uses county-level production and well data from 2005 to 2013. For production data, we add the years 2012 and 2013 to extend the USDA County-Level Oil and Gas Production dataset (USDA-ERS, 2014); well data come from the provider of the leasing data, DrillingInfo. We focus on 2005-2013 because production growth in this period came almost entirely from shale wells. Shale thickness will therefore matter more for well productivity during this period than for prior periods. Moreover, our leasing data reflects leases signed in the 2000s, most of which occurred in areas with shale development and based on expectations about shale well ultimate recovery.

The coefficients on the shale thickness and well age interactions are shown in table A2, which we use to estimate ultimate recovery of the typical county well. The estimates of county-level EUR are shown in Figure 2. Our estimates of recovery compare well to those published by the Energy Information Administration (EIA). The EIA has published estimates of ultimate recovery for 106 of the 231 counties for which we have estimated the EUR (EIA, 2014b). It calculated county-level EURs using monthly well-level data to estimate parameters of a decline curve. The two sets of estimates are similar despite differences in methods. For the subset of counties where there is overlap, our average EUR is 1,485 BBtus compared to 1,419 for the EIA estimates (table 3). Moreover, the two sets of estimates move together. Regressing the EIA estimate on our estimate and a constant shows that on average a 1 unit increase in our EUR increases the EIA estimate by 0.89 units, with a standard error of just 0.12 (table A1).

<< Insert Figure 2 >>

<< Insert Table 3 >>

*B. Estimation*

Although our estimate of $\bar{Q}_c$ is based on exogenous geological characteristics (shale thickness), it is undoubtedly measured with error because of unobserved heterogeneity in well productivity across counties. If ignored, measurement error will cause us to underestimate pass through. We use the log of ultimate recovery in estimation (to match equation 10), which can be written as $\ln(thick_c) + \ln\left((\sum_{a=1}^{5} \alpha_a) + (4 \cdot \alpha_{a>5})\right)$. The log of shale thickness is perfectly correlated with and cannot be used to address measurement error. Instead, we use the log of the average shale depth in the county as an instrument for $\ln\left(\widehat{\bar{Q}_c}\right)$. It is a natural choice for an instrument as it is correlated with thickness and is uncorrelated with $\varepsilon_{ct}$ given that it is time invariant and fully accounted for in the regression by the county fixed effect $\gamma_c$. In addition, we use the log of the average well productivity as an alternative instrument for $\ln\left(\widehat{\bar{Q}_c}\right)$ because it should also be strongly correlated with ultimate recovery.

The equation estimated is then

$$\ln(1 - \bar{\rho}_c) = \beta \ln\left(\widehat{\bar{Q}_c}\right) + \alpha PD_c + \boldsymbol{P_{c(t)}\delta} + \boldsymbol{Play_c\gamma} + \varepsilon_c, \tag{10}$$

which we estimate using Two-Stage Least Squares (2SLS). First stage regressions of the form

$$\ln\left(\widehat{\bar{Q}_c}\right) = \pi_0 + \pi_1 \mathrm{z}_c + \pi_2 PD_c + \boldsymbol{P_{c(t)}\pi_3} + \boldsymbol{Play_c\pi_4} + \eta, \tag{11}$$

where $z_c$ is either the logarithm of shale depth or the log of average well productivity in the county, show that both instruments are strongly correlated with the estimated ultimate recovery (table 4). A one percent increase in depth and well productivity is associated with a 0.77 and 0.19 percent increase in the estimated ultimate recovery.

<< Insert Table 4 >>

*C. Pass-Through Estimates*

Turning to our second stage, our IV estimates suggested limited pass-through of oil and gas endowments into royalty rates in our 231 shale counties. As expected with attenuation bias, the OLS estimates are much smaller than the IV estimates, but even these are small. When using depth as an instrument, a 10 percent increase in ultimate recovery is associated with a 0.14% decrease in the share of the value of production going to the energy firm; when using the average well productivity, the effect is a 0.32% decrease (table 5).

Doubling the EUR is equivalent to increasing ln(Q) by 0.70 log points, which is associated with a roughly 1.0 and 2.2 percent decrease in the share of the value of production going to the firm (=0.70 x 1.4%, 0.70 x 3.2%). At the average royalty rate of 18 percent, this translates into a 0.8 and 1.8 percentage point decrease in the share going to the firm (and increase in the share going to the mineral owner, e.g., 0.8=0.01 x (1-0.18)).

Considering the other variables in the model, the coefficients on the price of energy and interest rates are as predicted -- negative for energy prices and positive for interest rates -- however, the coefficients are small and statistically insignificant. The same is true for our measure of historic oil and gas development. In contrast, there are large differences in average royalty rates across shale plays. All else constant, the largest share of production going to firms (and not to mineral owners) is in the Marcellus followed by the Fayetteville and Bakken plays.

<< Insert Table 5 >>

We re-estimate (9) using EIA estimates of $\bar{Q}_c$ to see if the pass-through estimates are sensitive to the measure of ultimate recovery. Because a different sample of counties is used, we also estimate the model with our estimate of $\bar{Q}_c$. In both cases we instrument for the EUR using the log of the average well productivity, which is strongly correlated with both measures of the EUR on this subset of counties, with an F-stat of 16.5 and 22.7.

Using a different EUR measure gives even smaller estimate of pass-through (table 6). The OLS results are nearly identical for both EUR measures, but our measure gives a larger IV estimate than the EIA measure, -0.020 compared to -0.007. The estimates nonetheless fit in the range of the previous estimates using the full set of counties and our measure of the EUR.

<< Insert Table 6 >>

*D. Implications for the Mineral Acreage Supply Curve*

Equation 5 showed that in a monopsonistic environment, a one percent increase in the EUR decreases $1 - \rho_i^M - \gamma$ by one percent. We empirically estimated that a one percent increase in the EUR decreases $1 - \rho_i^M$ by 0.032% at most. Combing the two expressions gives $1 - \rho_i^M - \gamma = .032 * (1 - \rho_i^M)$. Using the sample average royalty rate of 18%, we can solve for the implied slope of the (linear) mineral acreage supply, yielding $\gamma$=0.79 (=1-0.18-[0.032*(1-0.18)]). In a monopsonistic scenario with price discrimination (see appendix 3) $\gamma$ is the slope of the (linear) mineral acreage supply curve. Converting into an elasticity, a one percent increase in the royalty rate causes a 1.26% increase in the supply of mineral acreage (=1/0.79), indicating an elastic supply of private mineral acreage.

## VII. What Explains Such Low Pass-Through?

Our finding of little pass-through of oil and gas endowments to mineral owners is consistent with firms exercising market power in leasing markets and an upward sloping mineral acreage supply curve.  Yet, there may be other explanations for low pass-through such as sticky leases, well costs, and compensation through non-royalty payments.

*A. Sticky Leases*

Once signed, a mineral lease can remain in force for decades, with most leases written to remain in effect as long as production occurs. The long life of the lease prevents the mineral owner from renegotiating the terms in response to changes in prices, technology, or other factors. In areas where firms leased land prior to widespread adoption of horizontal drilling and hydraulic fracturing, average royalty rates would remain those negotiated when expectations about the EUR were much lower. We would therefore expect less pass-through in areas with more active leases in 2000, prior to the technological shift.

We calculate the share of actives leases signed in 2000 and estimate:

$$\ln(1-\bar{\rho}_c) = \beta_0 \ln\left(\widehat{\bar{Q}_c}\right) + \beta_1\left(SL_{c,2000}\cdot\ln\left(\widehat{\bar{Q}_c}\right)\right) + \alpha PD_c + \boldsymbol{P_{c(t)}\delta} + \boldsymbol{Play_c\gamma} + \varepsilon_c \qquad (12)$$

where $SL_{c,2000}$ is the share of active leases in 2000 normalized by the sample average. If sticky leases account for the limited pass-through, $\beta_1$should be greater than zero and in turn cause $\beta_0$, which is negative, to be larger in absolute terms. To address measurement error, we instrument the new interaction term with the $SL_c$ multiplied by the log of average well productivity. For the EUR and the interaction term, the Angrist-Pischke multivariate F-test is 11 and 270.

Much production occurring under the terms of old leases does not explain our findings of low pass-through. The estimate of $\beta_1$is positive as expected (0.06), but the coefficient $\beta_0$ is similar to what was estimated before (0.03) (see table A4).

*B. Deeper Wells Cost More to Drill*

Another potential explanation for low pass-through is that greater depth and well productivity are correlated with greater development costs. One parcel, for example, may have twice the EUR as another parcel yet differences in costs could be such that competitive firms offer both mineral owners the same royalty rate, in which case low pass-through is confounded with heterogeneity in development costs. Data limitations prevent a thorough assessment of how accounting for costs would affect our estimates of pass-through. Kaiser and Yu (2015), however, provide a detailed analysis of drilling costs for the Haynesville Shale. Looking over the 2008-2012 period, they find that each kilometer of well depth, which is roughly one standard deviation for our average county, increases drilling cost by roughly 20 percent.

The higher costs associated with deeper wells may explain why using depth as an instrument for ultimate recovery provides smaller estimates of pass-through than when using well productivity as an instrument. Because depth and well productivity are correlated, we estimate pass-through using well productivity as the instrument for ultimate recovery while controlling for depth. The estimate is in line with our prior estimates (coef. -0.021, s.e. 0.007) (results not shown). Still, we cannot dismiss the possibility that productivity advantages from sources other than depth may also be associated with higher drilling costs and in part explain low pass-through.

### *C. Compensation Through Non-Royalty Payments*

Although firms compensate mineral owners primarily through royalty payments, compensation can also occur through various fixed, per-acre payments, the most substantial of which is a signing bonus. The bonus is a one-time per-acre payment made to the mineral owner for signing a lease. Some of the pass-through of greater oil and gas endowments may therefore come through higher signing bonuses in addition to higher royalty rates.

It is plausible that incorporating bonus payments could double our estimate of royalty rate pass-through. Even so, only a small fraction of greater endowments would be going to the mineral owner. An example from Pennsylvania's Marcellus Shale is illustrative. Anecdotal evidence suggests that bonus payments can reach up to $5,000 per acre in the Marcellus. Suppose that a firm pays $2,500 more in per-acre bonus payments for a parcel with double the EUR of the average parcel in an area. At average spacing of 100 acres per well, the greater payment equals about 3% of the roughly $8 million in production from an average well (with an ultimate recovery of about 2,000 MMcf and a wellhead price of $4,000 MMcf). This is equivalent to the royalty rate pass-through that we estimated for a doubling of the EUR.

## VIII. Conclusion

The innovation-spurred growth in oil and gas production from shale formations resulted in the U.S. becoming the global leader in producing hydrocarbons. The six major U.S. shale plays produced more than $213 billion in oil and gas in 2014, generating $39 billion in private royalty payments. Although royalty rates vary widely, from 13.2 percent in the Marcellus to 21.2 percent in the Permian, greater ultimate recovery of the typical county well translates into very small increases in the average royalty rate. Thus, even though one mineral owner owns double the oil and gas compared to another owner, both will receive a similar share of the value of production.

Limited pass-through of oil and gas abundance is consistent with firms exercising market power as well as substantial uncertainty about the value of endowments. Both explanations may be pertinent to the case of unconventional resources, in which a relatively small number of firms took a lead in unlocking the unknown potential value using new techniques (Zuckerman 2013).

The finding suggests that policies affecting the cost of extraction likely have little effect on the share of the value of production received by mineral owners. For example, severance taxes on production could certainly affect owners of parcels on the extensive margin, but likely have small effects on the share of the value of production received by mineral owners. Our estimates indicate that a proposed 5 percent severance tax would reduce average royalty rates by 0.14 percentage points at most.[5] This of course does not mean that a severance tax would not affect the total value received by mineral owners – that would clearly decrease – but that owners would continue to capture a similar share of the value of production.

A perhaps further reaching implication of market power in leasing markets is that less acreage is leased and potentially developed than would be in a more competitive market, inadvertently leaving more oil and gas in the ground and raising prices in the present relative to the future. However, our data do not allow us to assess this extensive margin, which could be a rewarding area for future research.

[5] The average royalty rate in the Marcellus Shale is 13.2 percent. Our empirical estimates indicate that a 5 percent reduction would increase the average royalty rate by 0.14 percentage points, calculated as (1-.132) x 5 x 0.032.

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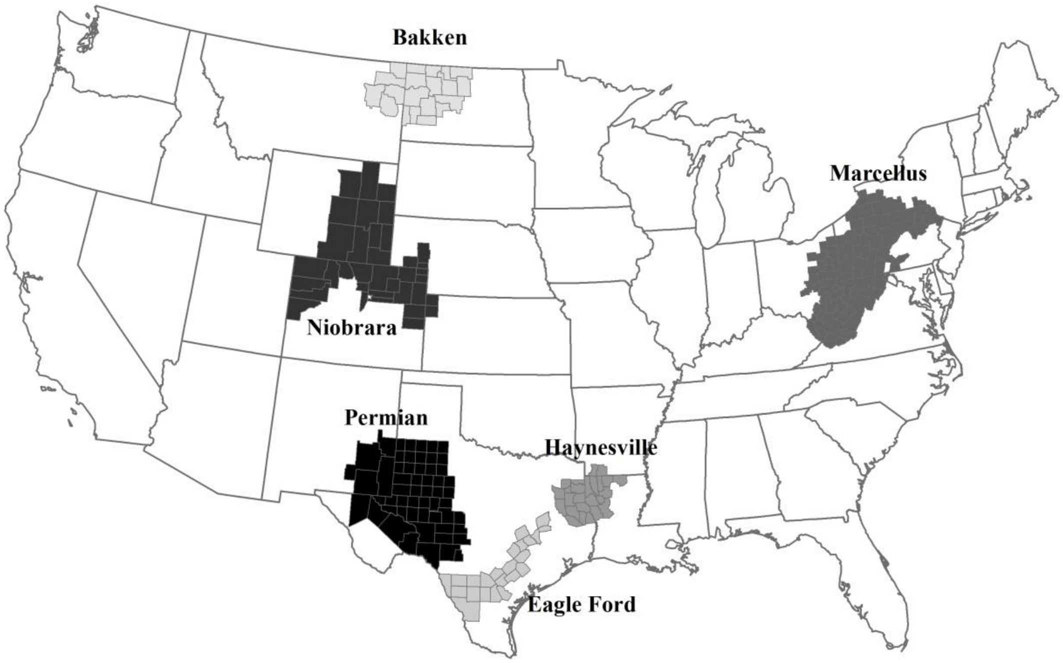


Figure 1. Major Shale Plays

Note: The major shale plays are those highlighted in the Energy Information Administration’s drilling productivity reports. The Marcellus and Utica Shales are combined due to collocation of those shales across much of their respective ranges.

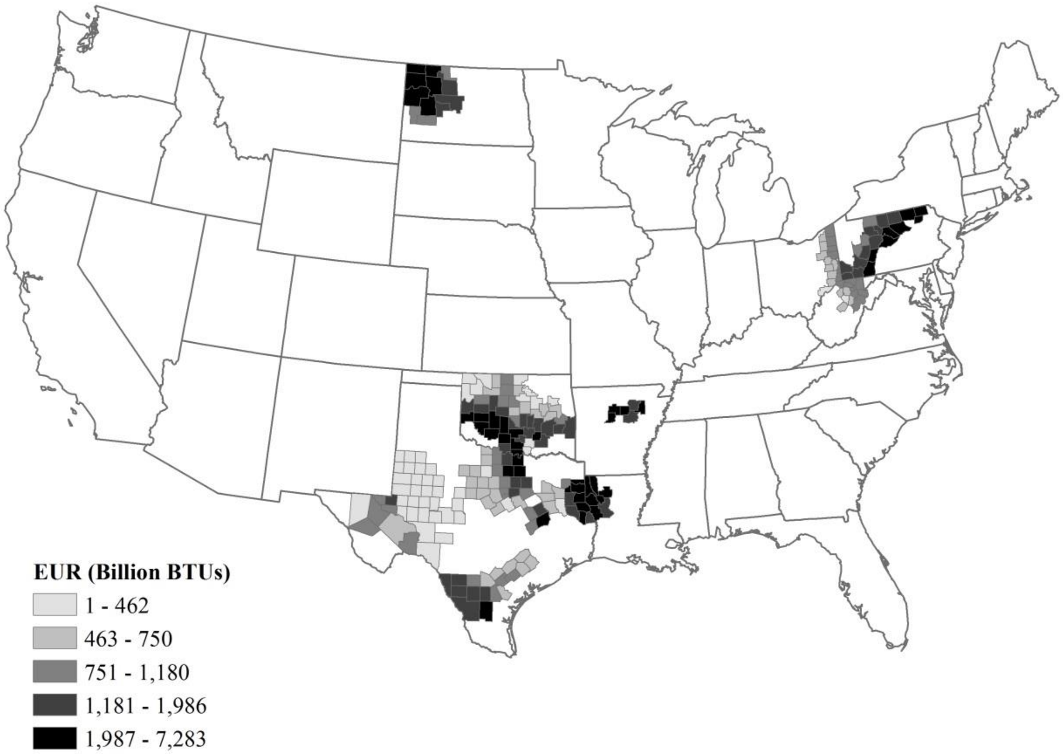


Figure 2. Estimates of Expected Ultimate Recovery of Oil and Natural Gas (in Billions of British Thermal Units)

Note: We do not have geologic data to estimate the EUR for counties in the Niobrara Shale shown in Figure 1. We do, however, have data to estimate EURs for the shale areas of Oklahoma (the Woodford Shale) as well as North Central Texas (the Barnett Shale), which are not shown in Figure 1 because they are not considered major shale plays by the Energy Information Administration.

Table 1. Summary of Oil and Gas Leases by State

| State | Leases | Counties | Avg. Royalty Rate | Avg. In-County Ownership |
|---|---|---|---|---|
| AR | 135,491 | 38 | 0.157 | -- |
| CA | 59 | 3 | 0.166 | -- |
| CO | 42,336 | 25 | 0.148 | 0.280 |
| KS | 81,972 | 38 | 0.137 | -- |
| LA | 99,541 | 54 | 0.215 | 0.328 |
| MS | 105,624 | 42 | 0.184 | -- |
| MT | 16,919 | 8 | 0.154 | 0.231 |
| NM | 20,177 | 3 | 0.211 | 0.217 |
| ND | 88,555 | 12 | 0.171 | 0.134 |
| OH | 31,175 | 32 | 0.126 | 0.670 |
| OK | 460,952 | 60 | 0.186 | 0.214 |
| PA | 50,094 | 26 | 0.135 | 0.576 |
| TX | 600,367 | 190 | 0.200 | 0.210 |
| UT | 1,574 | 1 | 0.166 | 0.109 |
| WV | 34,258 | 16 | 0.134 | 0.332 |
| WY | 6,733 | 10 | 0.153 | 0.219 |
| Total | 1,775,827 | 558 | 0.178 | 0.287 |

Note: In-county ownership can only be calculated for a subset of the states.

Table 2. Royalty Income Estimate, 2014

| | Shale Play | | | | | | |
|---|---|---|---|---|---|---|---|
| | Bakken | Eagle Ford | Haynesville | Marcellus | Niobrara | Permian | Total |
| Value of production ($ billion) | 36 | 57 | 12 | 30 | 17 | 61 | 213 |
| Royalty rate | 0.168 | 0.203 | 0.205 | 0.132 | 0.144 | 0.212 | |
| Royalty income ($ billion) | 5.97 | 11.54 | 2.45 | 3.94 | 2.51 | 13.03 | 39.45 |
| local ownership share | 0.151 | 0.245 | 0.22 | 0.547 | 0.303 | 0.119 | |
| Local royalty income ($ billion) | 0.90 | 2.83 | 0.54 | 2.15 | 0.76 | 1.55 | 8.73 |
| Population | 215,051 | 961,366 | 1,388,581 | 9,163,359 | 3,221,799 | 1,310,080 | 16,260,236 |
| Royalty income per capita | 27,770 | 12,008 | 1,764 | 429 | 780 | 9,946 | |
| Local royalty income per capita | 4,202 | 2,942 | 387 | 235 | 236 | 1,183 | |
| Govt. transfers per capita | 6,455 | 6,712 | 8,345 | 9,146 | 5,652 | 6,997 | |
| Federal farm payments per capita | 587 | 33 | 10 | 9 | 44 | 186 | |

Table 3. Average Estimated Ultimate Recovery By Shale Play, Billion BTUs

| | EUR_Q, All counties | EUR_Q, EIA Counties | EUR_EIA, EIA Counties |
|---|---|---|---|
| Barnett | 916 | 1,305 | 832 |
| Bakken | 2,124 | 2,218 | 976 |
| Eagle Ford | 1,077 | 1,020 | 932 |
| Fayette | 2,009 | 1,868 | 1,388 |
| Haynesville | 2,051 | 2,779 | 3,329 |
| Marcellus | 1,333 | 1,698 | 2,016 |
| Permian | 309 | 323 | 364 |
| Woodford | 1,482 | - | - |
| All | 1,276 | 1,485 | 1,419 |
| Counties | 231 | 106 | 106 |

Note: EUR_Q refers to our EUR estimates based on county level geologic, production, and well data. The EUR_EIA measure is based on published estimates of ultimate recovery for 106 counties of the 231 counties for which we have estimated the EUR (EIA, 2014b).

Table 4. Shale Depth, Well Productivity, and Estimated Ultimate Recovery (Y=ln(1-ρ))

| | ln(EUR_Q) coef/se | ln(EUR_Q) coef/se |
|---|---|---|
| Ln(depth) | 0.775*** | |
| | (0.147) | |
| Ln(Productivity) | | 0.194*** |
| | | (0.056) |
| Ln(Price of energy) | 0.134 | -0.208 |
| | (0.655) | (0.609) |
| Ln(Interest rate) | 0.379 | 0.725 |
| | (0.642) | (0.636) |
| Percent developed | -0.195 | 0.025 |
| | (0.215) | (0.291) |
| Barnett | -0.190 | -0.825 |
| | (0.911) | (0.849) |
| Eagle Ford | -0.581** | -0.410* |
| | (0.260) | (0.249) |
| Fayetteville | 1.009 | -0.590 |
| | (0.890) | (0.822) |
| Haynesville | -0.164 | -0.335 |
| | (0.902) | (0.845) |
| Marcellus | -0.042 | -0.588 |
| | (0.905) | (0.834) |
| Permian | -2.646*** | -2.193*** |
| | (0.348) | (0.331) |
| Woodford | -0.160 | -0.686 |
| | (0.931) | (0.886) |
| Intercept | 0.734 | 5.238*** |
| | (1.858) | (1.441) |
| | (2.774) | |
| Counties | 231 | 231 |
| Adjusted R2 | 0.454 | 0.436 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parenthesis. For the shale play dummy variables, the excluded play is the Bakken.

Table 5. Ultimate Recovery and the Log of the Share of Production Captured by the Firm ($Y=\ln(1-\rho)$)

| | OLS<br>coef/se | IV (Depth)<br>coef/se | IV (Productivity)<br>coef/se |
|---|---|---|---|
| Ln(EUR_Q) | -0.006*** | -0.014*** | -0.032*** |
| | (0.002) | (0.004) | (0.009) |
| Ln(Price of energy) | -0.008 | -0.008 | -0.006 |
| | (0.015) | (0.015) | (0.021) |
| Ln(Interest rate) | 0.011 | 0.015 | 0.025 |
| | (0.017) | (0.016) | (0.022) |
| Percent developed | -0.002 | -0.006 | -0.014 |
| | (0.005) | (0.005) | (0.009) |
| Barnett | -0.042* | -0.047** | -0.057* |
| | (0.022) | (0.021) | (0.030) |
| Eagle Ford | -0.048*** | -0.051*** | -0.058*** |
| | (0.006) | (0.006) | (0.008) |
| Fayetteville | 0.004 | 0.004 | 0.002 |
| | (0.022) | (0.022) | (0.029) |
| Haynesville | -0.050** | -0.049** | -0.046 |
| | (0.022) | (0.021) | (0.029) |
| Marcellus | 0.032 | 0.028 | 0.020 |
| | (0.022) | (0.021) | (0.029) |
| Permian | -0.072*** | -0.091*** | -0.133*** |
| | (0.006) | (0.009) | (0.022) |
| Woodford | -0.032 | -0.035 | -0.040 |
| | (0.022) | (0.021) | (0.030) |
| Intercept | -0.134*** | -0.077** | 0.047 |
| | (0.030) | (0.036) | (0.081) |
| Counties | 231 | 231 | 231 |
| Adjusted R2 | 0.840 | 0.803 | 0.466 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parenthesis. For the shale play dummy variables, the excluded play is the Bakken. The second column is from instrumenting the log of the EUR_Q with the log of shale depth; the third column is from using the log of average well productivity as the instrument.

Table 6. Pass-Through Estimates Using Different Measures of Ultimate Recovery (Y=ln(1-ρ))

| | OLS (EUR_Q) coef/se | OLS (EUR_EIA) coef/se | IV (EUR_Q) coef/se | IV (EUR_EIA) coef/se |
|---|---|---|---|---|
| Ln(EUR_Q) | -0.003 | | -0.018*** | |
| | (0.002) | | (0.006) | |
| Ln(EUR_EIA) | | -0.004*** | | -0.006*** |
| | | (0.001) | | (0.002) |
| Ln(Price of energy) | -0.011 | -0.011 | 0.001 | -0.010 |
| | (0.017) | (0.017) | (0.018) | (0.017) |
| Ln(Interest rate) | 0.017 | 0.014 | 0.024 | 0.013 |
| | (0.015) | (0.015) | (0.015) | (0.015) |
| Percent developed | 0.001 | -0.002 | -0.003 | -0.004 |
| | (0.006) | (0.006) | (0.007) | (0.006) |
| Barnett | -0.052** | -0.050* | -0.040 | -0.048* |
| | (0.026) | (0.027) | (0.025) | (0.026) |
| Eagle Ford | -0.042*** | -0.039*** | -0.051*** | -0.038*** |
| | (0.007) | (0.007) | (0.008) | (0.006) |
| Fayetteville | -0.001 | 0.003 | 0.011 | 0.006 |
| | (0.023) | (0.024) | (0.024) | (0.023) |
| Haynesville | -0.066*** | -0.061** | -0.043 | -0.055** |
| | (0.026) | (0.026) | (0.027) | (0.026) |
| Marcellus | 0.029 | 0.033 | 0.039* | 0.036 |
| | (0.023) | (0.024) | (0.023) | (0.023) |
| Permian | -0.077*** | -0.073*** | -0.108*** | -0.074*** |
| | (0.007) | (0.005) | (0.016) | (0.005) |
| Intercept | -0.153*** | -0.147*** | -0.081* | -0.135*** |
| | (0.044) | (0.045) | (0.049) | (0.043) |
| Counties | 106 | 106 | 106 | 106 |
| Adjusted R2 | 0.910 | 0.915 | 0.865 | 0.913 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parenthesis. For the shale play dummy variables, the excluded play is the Bakken. EUR_Q refers to our EUR estimates; EUR_EIA refers to those published by the Energy Information Administration. The results in the third and fourth columns column are from instrumenting the log of the EUR with the log of average well productivity.

## Appendix

*1. Econometrically Estimating Royalty Rates in Pennsylvania*

The Pennsylvania Department of Revenue provides county-level rent and royalty income as reported on state income tax returns from 2001 to 2012. Because this royalty income measure only captures income paid to county residents, we adjust the county's value of oil and gas production to reflect production occurring on locally-held leases. We assume that our estimate of local ownership is a reasonable proxy for the share of production occurring from leases held by county residents. Accordingly, aggregate royalty income to residents in county *c* in year *y* is

$$Royalty\ Income_{cy} = Royalty\ Rate_{c}\ \times\ Local\ VP_{cy}, \tag{A.1}$$

where the local value of production ($Local\ VP_{cy}$) is defined as the resident share of leases multiplied by the county's total value of oil and gas production. Because our royalty income measure includes other types of income (e.g. rental income), we put it in per capita terms. We do the same for the value of production.

By regressing per capita royalty income on the per capita value of production, we recover the average royalty rate: $\beta_1$ represents the cents in royalty income received for each dollar of production. Formally, we estimate

$$Royalty\ Income_{cy} = \beta_1 Local\ VP_{cy} + \beta_2\left(VP_{cy} \cdot PP\ \right) + \alpha_c + \gamma_y + \varepsilon_{cy}, \tag{A.2}$$

where individual county fixed effects ($\alpha_c$) control for unobserved differences across counties that are time invariant and year fixed effects ($\gamma_y$) control for temporal shocks affecting all counties similarly. The county fixed effect controls for average differences in rental income across counties, which the PA Department of Revenue also includes in our royalty income measure. We also control for the share of production that is potentially occurring on public land, which would not add to private royalty income. We do this by interacting the value of production with the share of public land where drilling may occur. Because we need lease information to calculate the local share of production, the leasing data limit the geographic scope of our estimation. But, they place no restriction on estimation of the average royalty rate, $\beta_1$.

The econometric approach arguably reflects the typical lease in the county, because it recovers the average relationship between the value of production and royalty income at the county level. Moreover, it most reflects the royalty rates from the leases where most production occurs. In an extreme case, imagine 100 leases in the county and all production happens under one lease. Only the lease with production will influence the estimate of the royalty rate because it alone governs the income generated from production in the county.

Table A1. Estimate of Royalty Rate in Pennsylvania Using Production and Income Data, 2001 to 2012. (Y=Royalty Income Per Capita)

| | Royalty Income Coeff/SE |
|---|---|
| *Local VP* | 0.109*** |
| | (0.014) |
| *VP × Pct. Public* | 0.032 |
| | (0.077) |
| $y_{2002}$ | 175.933*** |
| | (10.869) |
| $y_{2003}$ | 11.451 |
| | (5.956) |
| $y_{2004}$ | 8.900 |
| | (5.458) |
| $y_{2005}$ | 3.925 |
| | (5.500) |
| $y_{2006}$ | 34.935*** |
| | (9.470) |
| $y_{2007}$ | 57.347*** |
| | (7.273) |
| $y_{2008}$ | 729.148*** |
| | (255.142) |
| $y_{2009}$ | 537.272*** |
| | (199.952) |
| $y_{2010}$ | 765.858*** |
| | (211.030) |
| $y_{2011}$ | 377.800*** |
| | (81.577) |
| $y_{2012}$ | 203.831*** |
| | (55.456) |
| *constant* | 168.424*** |
| | (55.867) |
| Observations | 300 |
| Adjusted R2 | 0.374 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parenthesis. *Local VP* is the per capita value of production governed by leases signed by residents of the county.

*2. Data and Calculations for Royalty Income Estimates*

Price and production data by shale play comes from the Energy Information Administration's drilling productivity reports. We use average daily production in each month to calculate total production for the year (EIA 2014a). For oil prices, we use EIA's state-level first purchase price of oil (Jan. 14 to Dec. 14). Production-weighted averages of prices were used in cases where plays covered multiple states. EIA wellhead prices of natural gas by state were only available through 2010, so wellhead prices in 2014 were projected for each play by adjusting the Henry Hub spot price in 2014 by the average difference between it and state-level wellhead prices in 2009 and 2010. Value of production estimates were generated by summing the product of price and quantity of oil and gas in each play.

Table A2. Shale Thickness and Production

| | Bakken | Barnett | Eagle Ford | Fayetteville | Haynesville | Marcellus | Permian | Woodford |
|---|---|---|---|---|---|---|---|---|
| | coef/se | coef/se | coef/se | coef/se | coef/se | coef/se | coef/se | coef/se |
| Thick x 1 yr wells | 144*** | 110*** | 72*** | 270*** | 108*** | 151** | 8** | 206** |
| | (11) | (24) | (21) | (72) | (21) | (72) | (4) | (102) |
| Thick x 2 yr wells | 77*** | 136*** | 34 | 351* | 210*** | 102** | 22*** | -13 |
| | (28) | (14) | (83) | (194) | (64) | (50) | (5) | (60) |
| Thick x 3 yr wells | 142*** | 91*** | 60 | 78 | 168** | 34 | 25*** | 61 |
| | (18) | (25) | (90) | (60) | (83) | (25) | (8) | (37) |
| Thick x 4 yr wells | 15 | 70*** | 264 | 337*** | 73** | 22 | 24*** | 20 |
| | (29) | (4) | (181) | (117) | (34) | (18) | (6) | (41) |
| Thick x 5 yr wells | 141*** | 112*** | -116** | 7 | 135*** | 129** | 13 | 177* |
| | (26) | (31) | (55) | (232) | (41) | (56) | (11) | (106) |
| Thick x wells gt 5 yrs | 27 | 62*** | 50*** | 303** | 73*** | 33 | 8*** | 29** |
| | (34) | (11) | (14) | (136) | (26) | (22) | (3) | (15) |
| Observations | 120 | 328 | 192 | 48 | 216 | 712 | 296 | 406 |
| Adjusted R2 | 0.986 | 0.895 | 0.550 | 0.824 | 0.625 | 0.273 | 0.560 | 0.168 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors clustered by county are in parenthesis. The results are from estimating the county fixed effects model represented by equation (12) and using data from 2005 to 2013. Shale thickness is in meters.

Table A3. The EIA EUR Regressed on Our Estimate of the EUR

| | EUR_EIA<br>coef/se |
|---|---|
| EUR_Q | 0.895*** |
| | 0.123 |
| Intercept | 90 |
| | 133 |
| Counties | 106 |

Note: *** p<0.01, ** p<0.05, * p<0.1

Table A4. Sticky Leases and Pass Through

| | IV |
|---|---|
| | coef/se |
| Ln(EUR_Q) | -0.032*** |
| | (0.009) |
| ln(EUR_Q) x Share 2000 | 0.061* |
| | (0.032) |
| Ln(Price of energy) | -0.005 |
| | (0.021) |
| Ln(Interest rate) | 0.024 |
| | (0.022) |
| Percent developed | -0.014 |
| | (0.009) |
| Barnett | -0.056* |
| | (0.030) |
| Eagle Ford | -0.058*** |
| | (0.008) |
| Fayetteville | 0.003 |
| | (0.029) |
| Haynesville | -0.045 |
| | (0.029) |
| Marcellus | 0.021 |
| | (0.030) |
| Permian | -0.133*** |
| | (0.022) |
| Woodford | -0.039 |
| | (0.030) |
| Intercept | 0.044 |
| | (0.082) |
| Counties | 231 |
| Adjusted R2 | 0.468 |

Note: *** p<0.01, ** p<0.05, * p<0.1. Robust standard errors are in parenthesis. The *Share 2000* is the share of active leases signed in the year 2000. Ultimate recovery (EUR_Q) is instrumented by average well productivity. The interaction is instrumented by the interaction between well productivity and *Share 2000*.

*3. Sequential versus Simultaneous Leasing by a Monopsonist*

In the text we only consider the behavior of a monopsonist who simultaneously offers a uniform royalty rate to all mineral owners. Under this framework the monopsonist chooses the number of leases by maximizing the following expression:

$$\max_N \pi = N[(1-\rho(N))R-(1+r)c] \quad s.t.\, \rho(\mathrm{N})\mathrm{R} \geq g(N)\, \forall N$$

Derivation of the first order conditions gives the optimal royalty rate given by the firm:

$$\frac{\partial \pi}{\partial N} = -\rho'(N)R + [(1-\rho(N)R-(1+r)c] = 0$$

$$(1-(\rho(N))R - R\rho'(N)N = (1+r)c$$

$$R(1-\rho(N)-\rho'(N)N) = (1+r)c$$

$$1-\rho(N)-\rho'(N)N = \frac{(1+r)c}{R}$$

$$\rho(N) = 1-\rho'(N)N - \tfrac{(1+r)c}{R}. \qquad \text{(A.3)}$$

If the monopsonist can lease sequentially and perfectly discriminate between mineral owners, then it will capture additional rents. This is because inframarginal mineral owners will receive a royalty rate determined by their reservation rate, nothing higher. The $N^{th}$ royalty owner, with a reservation rate slightly higher than the *N-1*th owner, captures a slightly higher share of the value of production, as given by:

$$\rho_i^D = 1-\rho'(N) - \tfrac{(1+r)c_i}{R_i}, \qquad \text{(A.4)}$$

where parcels are homogeneous and$\rho'(N) \neq 0$, for $N$>1, $\rho_i^D > \rho_i^M$. The difference between A.3 and A.4 depends on the size of the leasing market, $N$. For larger $N$, the monopsonist faces a higher cost of acquiring more land because it will have to pay the higher royalty rate to many more parcels. In our empirical analysis, we focus on mean royalty rates. When the acreage supply function is linear, the firm pays a lower average royalty rate under sequential rather than simultaneous leasing, and the firm captures a greater surplus. If parcels vary in resource abundance or costs, and particularly if reservation royalty rates are less than perfectly correlated with potential returns, the firm can capture more rents through royalty rate discrimination.

Our modeling has avoided the possibility of differences in information between mineral owners and firms. Greater information could affect outcomes in the perfectly competitive scenario if the information affects reservation royalty rates of mineral owners. For example, if greater information increases reservation rates, Equation (1) will still hold with equality but it will do so at a lower N, thereby reducing the number of parcels that are developed. In the monopsonistic scenarios, greater information has a potentially counterintuitive effect. If information increases the dispersion of reservation royalty rates, it will increase the elasticity of the mineral acreage supply curve. In doing so, it increases the distortion introduced by imperfect competition. Asymmetric information may alternatively be considered the root cause of market power in the leasing market. In this interpretation, all oil and gas firms benefit from better information than mineral owners.