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Capturing rents from natural resource abundance: Private royalties from U.S. onshore oil & gas production☆

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ABSTRACT

We study how much private mineral owners capture geologically-driven advantages in well productivity through a higher royalty rate. Using proprietary data from nearly 1.8 million leases, we estimate that the six major shale plays generated $39 billion in private royalties in 2014. 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 1–2 percentage points (a 6–11 percent increase). Thus, mineral owners benefit from resource abundance primarily through a quantity effect, not through negotiating better lease terms from extraction firms. The low pass-through likely reflects a combination of firms exercising market power in private leasing markets and uncertainty over the value of resource endowments.

1. 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. Using a proprietary dataset of nearly 1.8 million oil and gas leases, we make two contributions to the understanding of royalties and royalty rates in the United States. First, we quantify the economic importance of royalties to various regions by estimating royalty income flows and comparing them to what residents receive in other income transfers—government

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transfer income and total farm program payments. We are aware of no published studies quantifying royalty income to different regions despite its potentially large effect on local income and wealth (Gilje, 2012; Pender et al., 2014).[1]

The second contribution is an estimate of the extent that resource abundance passes through to mineral owners via higher royalty rates. 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 via a greater endowment of oil and gas. 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) note that most work on pass-through assumes perfect competition despite scant empirical evidence in many markets. This is potentially 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 estimate 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 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 (12–55 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 1–2 percentage points at most (a 6–11 percent increase). This is far less pass-through than what a model of perfect competition in leasing markets predicts. It likely reflects a combination of market power in leasing markets and uncertainty. 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. Thus, mineral owners benefit from resource abundance primarily through greater production, not by negotiating better lease terms from extraction firms.

2. Leasing markets

We provide a brief overview of oil and gas leasing markets to give a foundation for our theoretical model and for interpreting our empirical results. 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).

The majority of oil and gas production in the U.S. occurs via oil and gas leases as opposed to direct mineral ownership by the extracting firm (Fitzgerald and Rucker, 2016). 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. Resource abundance, commonly measured by estimates of ultimate resource recovery, varies 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. This creates a potential information asymmetry for the 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.

[1] Hardy and Kelsey (2015) show that local ownership of land varies across Pennsylvania counties in the Marcellus shale and thus the potential for varying local ownership of lease and royalty payments. However, patterns in surface and mineral right ownership need not be the same in a given area.