PRIVATE VS. GOVERNMENT OWNERSHIP OF NATURAL RESOURCES: EVIDENCE FROM THE BAKKEN[*]

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August 2018

Abstract:

Land ownership in the United States extends below ground, whereas most governments retain subsurface ownership. Which system generates greater resource use? We exploit a natural experiment to show the answer depends on land fragmentation. Historical policies created a mosaic of government, private, and co-owned parcels on the Ft. Berthold Indian reservation above the Bakken shale. Studying the 2005-2015 fracking boom, we find that private ownership generated more oil production than government ownership unless parcels were smaller than 5 acres (private) or 63 acres (co-owned). Scattered government holdings within private areas further reduced production. We estimate the implied gains from consolidation.

Key words: transaction costs, anticommons, land fragmentation, property rights, subsurface ownership, oil, resource booms

JEL Codes: O13, Q32, Q33, D23, H82, K11

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[*] For helpful comments we thank Michael Alexeev, Lee Alston, Terry Anderson, Fernando Aragón, Dan Benjamin, Christopher Costello, Olivier Deschênes, Christian Dippel, Donna Feir, Tim Fitzgerald, Jane Friesen, Gary Libecap, Dean Lueck, Kyle Meng, Paulina Oliva, Shawn Regan, Alex Rothenberg, Randy Rucker, Richard Startz, and seminar participants at Arizona State U., Stanford U. (Hoover Economic Policy Talk), U. of Illinois, U. of Hawaii, UC-Riverside, Indiana U., and the Property and Environment Research Center. We also thank attendees of conference and workshop sessions hosted by Simon Fraser U., SIOE, UC Santa Barbara, WEAI, AERE, and the Midwest International Development Conference. We are grateful to Matt Kelly, an attorney of Tarlow and Stonecipher PLLC for helpful discussions about oil and gas leasing on the Bakken and to Crow Tribal Chairman Alvin Not Afraid Jr. for sharing his insights about trusteeship and tenure on Native American Reservations.
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1. Introduction

Under the ancient *ad coelum* doctrine, ownership of land extends upwards infinitely and downwards to the center of the Earth. Ownership regimes do not adhere to this principle in modern times, but there is nevertheless a notable dichotomy across countries. In the United States, subsurface mineral rights are typically bundled with surface ownership. In most other countries, governments retain subsurface ownership even when the surface is privately owned.

Which ownership regime generates greater resource utilization and rents? Existing research has not answered this question in a quantitatively detailed manner, but points to tradeoffs between centralized and private control. Libecap (2018), for example, suggests that private ownership of mineral resources such as oil and gas has encouraged discovery, but suboptimal levels of output conditional on discovery due to uncoordinated competitive extraction.

We focus on two factors that affect relative utilization under private versus public ownership: the fragmentation of private surface ownership relative to the scale of mineral extraction, and the quality and structure of government. We hypothesize that these factors affect resource utilization by influencing the cost of mineral access and use. This framing follows Coase (1960, 1988), who argues that government performs comparatively well when a large number of people are involved because private contracting is costly.

When minerals are privately owned, the cost to a developer depends on N, the number of individuals who hold exclusion rights to minerals within the spatial scale of a project. Anticommons theory predicts the total costs will rise with N, reducing resource utilization relative to rent-maximization by a sole private owner (Heller 1998, Buchanan and Yoon 2000, Mitchell and Stratmann 2015).[1] Sole private ownership of minerals is rare because surface boundaries are often set before new extraction technologies and discoveries determine the optimal spatial scale of subsurface production.

This reasoning suggests that efficient mineral use may be stymied if the U.S. system of private subsurface ownership were applied to countries where small farms and fragmented ownership are prevalent. Globally, 84% of farms are smaller than 5 acres whereas over 90% of farms in the United States exceed 10 acres (Foster and Rosenzweig 2017, Lowder et al. 2016). Moreover, in many regions, multiple owners own fractional interests in individual farms because

[1] If exclusion rights are not enforceable, then the mineral deposit is common property as discussed in Section 2 and described by Libecap and Wiggins (1984) and Wiggins and Libecap (1985).

inheritance laws or customs allocate equal shares to descendants (see Baker and Miceli 2005, Palsson 2018, Hartvigsen 2014).

When government owns minerals, the cost of access and use includes two components. First, there is formal monetary compensation that developers must pay for leasing. Second, there are a variety of other costs including potential bribes to government officials, the expenditure of time and effort to navigate bureaucratic red tape and permitting processes, and the probability that drilling output will be expropriated ex post (see, e.g., Shleifer and Vishny 1993, Bohn and Deacon 2000, Stroebel and van Benthem 2013).

When will the cost of resource use be higher under government ownership compared to private ownership? One attempt to shed light on this question is provided by Kunce et al. (2002), who exploit random assignment of U.S. federal ownership in 1x1 square-mile railroad checkerboards in Wyoming. They argue that natural gas drilling was costlier on plots of U.S. federal land than on neighboring private parcels because of bureaucratic red tape.[2] Though useful, this approach misses the broader effect of fragmentation itself. Government ownership could be more conducive to resource utilization if it spanned a contiguous area greater than one square mile, especially compared to fragmented private ownership.

This paper exploits a natural experiment in subsurface ownership of the Bakken shale formation in North Dakota to compare mineral use under private versus government ownership under varying conditions of land fragmentation. The Bakken—one of the world's most productive oil plays—sits beneath the Fort Berthold Indian reservation, which was subdivided into parcels of various sizes as part of the U.S. government's program for "allotting" Native American land to promote agriculture over 1887-1934 (Carlson 1981). In 1951 some parcels were consolidated into tribal ownership as part of a federal water reclamation project, inadvertently conveying valuable mineral rights to a government with sovereign power to permit or exclude shale development.

The upshot is that shale ownership now occurs in three categories: blocks owned by the tribal government, small and large privatized parcels (fee simple), and small and large allotted trust parcels co-owned by multiple heirs of the original allottee. We use this variation to identify the causal effects of ownership patterns on drilling outcomes during the fracking boom of 2005-2015. Ownership was solidified before the discovery of oil and is exogenous to shale quality,

[2] The study was retracted due to data errors unrelated to the basic empirical design (Gerking and Morgan 2007).

unlike many settings where property rights are endogenous to resource quality (Demsetz 1967, Besley 1995, Alston et al. 1996, Kaffine 2009, Galiani and Schargrodsky 2012).

The degree of land fragmentation is important because oil extraction on the Bakken relies on horizontal drilling and hydraulic fracturing of shale. This modern technique involves drilling a “lateral” that extends about two miles from a vertical well pad deep beneath the surface. Oil leasing units are typically configured as 1 x 2 mile rectangles that span 1280 acres, which is roughly the technologically optimal scale of extraction under existing technology.

We describe the tradeoff of government versus private ownership in the context of oil leasing and test implications by comparing production and revenue from horizontal drilling across 12,000 private and governmental parcels on the reservation during the fracking boom. We find that production depends on the size and fractionation of landholdings, and on whether the minerals are privately or publicly owned. Holding constant shale quality and neighborhood fragmentation, fee simple parcels yield greater production and revenue per acre compared to tribally owned areas of equivalent size. When an area is subdivided into smaller private parcels, revenue and production from private ownership decrease.

Our results suggest a threshold parcel size of five acres below which oil production under government ownership exceeds production under private fee simple ownership. The private vs. tribal tradeoff is sharper for allotted trust lands, which have an average of fifteen owners per parcel. In this case, the threshold parcel size is 63 acres. We also find that scattered government holdings are especially influential in reducing output. Adding a single government parcel within a neighborhood of private parcels reduces expected oil production by 42%. In this case developers must pay the high fixed costs of dealing with government but do not avoid the costs of contracting with a large number of private owners.

We provide evidence that the private vs. government tradeoff in oil production is driven, at least in part, by royalty rates facing the developer. Holding constant neighborhood fragmentation, the royalty rates in allotted or fee simple leases are less than the royalty rates in tribal leases, consistent with an anticommons model in which contracting with the tribe entails satisfying a larger number of excluders relative to a single lease on a non-tribal parcel. Royalty rates increase as the number of fee and allotted parcels in a neighborhood grows, which is also consistent with the anticommons theory.

In a policy thought-experiment, we estimate the effects of a pre-boom consolidation of all allotted trust mineral ownership into tribal ownership. By reducing fragmentation, the consolidation would have increased expected royalty earnings during the boom by over $132 million. This amounts to roughly $26,702 for each fractional interest owner or $10,819 for each tribal member.[3] This policy experiment underscores the economic importance of ownership arrangements that encourage or discourage resource development.[4]

The paper proceeds with review of literature on commons and anticommons wherein we highlight the importance of scale when comparing private and public ownership. We then apply anticommons logic to shale drilling before describing the history behind our natural experiment. Next we describe the data and the empirical model, present empirical results, and discuss policy relevance and external validity (including supplementary tests of oil development on U.S. federal versus private lands). We also highlight the importance of anticommons for Native American reservation development beyond Ft. Berthold, where land rights are highly fragmented and an estimated $1.5 trillion worth of coal, oil, and gas remain untapped (U.S. Senate 2009).

2. Spatial Scale, Commons and Anticommons

A. Mismatch of Surface Ownership and the Scale of Subsurface Use

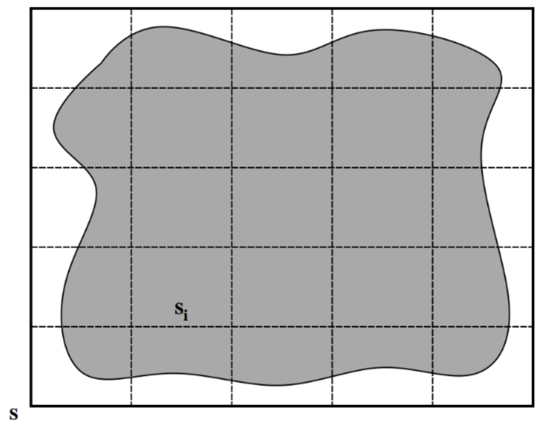
Figure 1 depicts a case typical throughout the world, where surface ownership is divided into parcel sizes smaller than a subsurface mineral deposit. In this figure, the entire square represents the spatial extent of a landscape of size S containing the deposit. The landscape contains surface parcels of size S_i, where $\sum_{i=1}^{N} S_i = S$. Under bundled ownership, the mineral deposit has a sole private owner only when $S_i = S$.

Subdivision has resulted from various policies: homesteading in the United States, Canada, and Australia during the 18th and 19th centuries (Allen 1991); titling and land redistribution programs in modern sub-Saharan Africa and post-Soviet Eastern Europe (e.g., Mwangi 2007, Ali et al. 2016, Hartvigsen 2014); and from the allotment of Native American lands during 1887-1934 (Carlson 1981). These programs sought to create private parcels that

[3] Corruption could reduce earnings to tribal citizens under government ownership, even if government ownership increases overall earnings (see Caselli and Michaels 2013). We discuss this issue in Section 7.
[4] The potential silver lining of fragmented ownership is that reduced fracking may have averted local environmental harms (e.g., Olmstead et al. 2013, Muehlenbachs et al. 2015, Bartik et al. 2017, Currie et al. 2017). We discuss this issue in greater detail in Section 7.

were large enough for viable farming, but small enough to allocate wealth to large numbers of citizens. In the case of U.S. homesteading and allotment, some parcels were never claimed and thereby retained by the government. As a result, scattered government holdings of mineral rights exist within mostly privatized landscapes (Hibbard 1939).

Figure 1: Surface Ownership over a Mineral Deposit



Notes: S represents the size (area) of the outer square demarcated by the solid line. The dark shape represents a mineral deposit, either a conventional oil reservoir or shale containing oil. Si represents an individual parcel of a particular size. The number of parcels, N, grows with decreases in parcel size because $\sum_{i=1}^{N} S_i = S$.

This history highlights why ownership boundaries are unlikely to match the technologically optimal scale of subsurface use. Even if political pressures and accidents of history did not result in *ad hoc* land fragmentation, there is still inevitable uncertainty about the existence, value, and scale of subsurface minerals. Given uncertainty about endowments *ex ante*, mismatch between surface ownership boundaries and optimal extraction scales is likely to be unavoidable *ex post*. This mismatch can cause rent dissipation under the U.S. system of private ownership due to either commons or anticommons incentive problems.

B. Common Property Problems

If the mineral deposit in Figure 1 represents a conventional oil reservoir, then surface subdivision into private parcels of size S_i creates $N = S/S_i$ use rights to the reservoir under bundled surface and subsurface ownership. Individual exclusion rights are difficult to enforce because conventional oil can migrate across property lines from high to low pressure areas. The result in the United States during much of the early 20th century was common property resource loss. A race to extract induced excessive oil rigs and rapid extraction that failed to fully drain reservoirs because pressure levels were not optimized, reducing production and increasing costs (Libecap and Wiggins 1984; Wiggins and Libecap 1985).

One solution to the commons is government subsurface ownership. Under this regime, the state maintains a monopoly on exclusion and grants use rights when, where, and to whom, it deems fit. Government assets remain *de facto* common property if the state cannot enforce its claimed exclusion rights (Ostrom 1990, Lueck and Miceli 2007, Iwanowsky 2018). If the state can enforce its claim, then government ownership can solve the common property problem but at the potential cost of creating an anticommons problem.[5]

C. Anticommons

Whereas common property problems are due to a lack of exclusion rights, anticommons are caused by too many exclusion rights. Citing examples in a variety of contexts including real estate markets in Manhattan, global pharmaceutical markets, and development in the wake of post-Soviet privatization, Heller (1998, 2008) argues that allocating exclusion rights to too many people creates contracting barriers to fuller resource use through two mechanisms. First, it can be costly to identify and contract with everyone with exclusion rights. Second, rational individuals fail to consider their impact on other owners when setting prices, leading to an aggregate price that can prevent Pareto improving resource use.

Buchanan and Yoon (2000) formalize Heller's reasoning with a model that demonstrates how the underuse of a fixed resource worsens with the number of owners holding exclusion rights. If multiple agents have the right to exclude others from the use of a required resource, each will fail to consider the effect on others when setting their own use fee. The resulting aggregate price exceeds the income-maximizing price, resulting in lower rents than sole private ownership.

Anticommons can arise under bundled ownership if the scale of profitable subsurface use exceeds the size of private parcels. To illustrate, imagine now that Figure 1 represents the economically profitable scale of a shale oil drilling project. Shale oil is tightly trapped within the rock, so it can only be profitably extracted with a well that extends horizontally through the shale, typically 2 miles. An anticommons may arise because the oil developer must get consent

[5] A second solution is to require coordination through oil field unitization. This approach is used widely throughout the United States. Regulatory agencies determine unit sizes, and a single oil developer is granted an access right when a majority of landowners within the unit consent to leasing terms. Royalty earnings from the drilled unit are apportioned based on mineral owner lease terms and parcel sizes.

from all (or the majority of) parcel owners overlaying the horizontal well before extraction commences.[6] The upshot is that conventional and shale oil pose symmetric problems—commons and anticommons—with the same solution: sole private ownership.

Contiguous government subsurface ownership solves the commons problem when the state restricts access, but does it create an anticommons problem? On one hand, contiguous government ownership mimics sole private ownership if a single public decision maker "holds the core bundle of property rights relatively intact" (Heller 1998, 682). A prospective oil developer, for example, can negotiate with the decision maker rather than multiple parcel owners, thereby circumventing coordination problems. However, the government typically requires approval of several agencies and officials who may be most interested in maximizing their individual rents rather than the aggregate value of perspective projects (Heller 1998, 655).

Shleifer and Vishny (1993) model inefficient government corruption in a way that could be characterized as an anticommons. This is because multiple officials "can deny a private agent the passport, access to a road, or an import license" (p. 601). They also note that "an important reason why many of these permits and regulations exist is probably to give officials the power to deny them and to collect bribes in return for providing the permits" (p. 601). This is similar to Heller's (1998) discussion of a regulatory anticommons, and the motivation for the Buchanan and Yoon (2000) model. Although their model is not explicitly about corruption, Buchanan and Yoon emphasize the difficulties of obtaining permits to develop natural resources in the U.S. because many regulatory agencies hold veto rights. They argue that this kind of bureaucratic red tape reduces resource use, although the "price" for each agent's approval is not modeled explicitly as a bribe.

3. Implications for Shale Use under Private vs. Government Ownership

A. Application of Anticommons to Horizontal Drilling

Although fracking and horizontal drilling were experimented with for several decades, their large-scale use did not emerge in the U.S. until about 2005 (Fitzgerald 2013). A well is first drilled vertically to the depth of the shale and then turned horizontally and driven for several thousand feet through the shale, which runs parallel to the surface and holds the trapped oil.

[6] This anticommons problem is similar to the one created by conventional oil unitization regulations in the U.S., but it is the physical characteristics of shale oil, rather than regulations, that create anticommons problems.

When hydraulic fracturing is added, a liquid solution is pumped at high pressure through the well, fracturing the shale and facilitating oil drainage from several feet in either direction of the lateral (the horizontal portion of the well). Horizontal wells can drain an area of over two square miles with little surface disruption for overlying landowners compared to conventional drilling.

In our empirical setting and elsewhere in the United States, regulations require oil developers to form a spacing unit prior to drilling. Spacing units range in size but are generally uniform within regulated production areas known as oil fields. On the Bakken shale formation, most units are 1280-acre, 1-by-2 mile rectangles. These units are the basis for mineral owner compensation: a lease is written with each owner in a unit, who then receives a bonus payment and, more importantly, a royalty on a share of the total project revenue that is proportional to his acreage in the unit.[7] The N mineral owners are excluders because their section of shale cannot be drained unless asking prices are paid to all (or the majority of) owners in the drilling unit.[8]

We show in the Mathematical Appendix that applying the Buchanan and Yoon (2000) model of the anticommons to this leasing framework yields the following predictions:[9]

P1) The aggregate (project-level) price to developers is increasing in N
P2) Oil production is decreasing in N
P3) Project-level surplus (net income) is decreasing in N
P4) Mineral owner compensation (rents) from drilling is decreasing in N

Following Heller (1998, 2008) , Buchanan and Yoon (2000), and Schleifer and Vishny (1993) we assume that the overall “price” of resource use rises with the number of excluders (N), whether they are government agents (e.g., bureaucrats, interest group lobbyists, local politicians), or individual private shale owners. Although this is a simple view of complex governmental decision-making, it generates implications that are testable in our empirical setting, where we

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[7] Fitzgerald and Rucker (2016) find that royalty payments typically comprise 85-90% of payments. Vissing (2016) finds that bonus payments are positively correlated with other aspects of the lease including royalty rates and terms that are favorable to the landowner.
[8] Forced pooling laws, passed by US states, compel minority mineral owners into horizontal drilling projects if a majority of neighboring acreage has already been leased. State-level forced pooling laws do not generally apply on sovereign Indian reservations (see Slade et al. 1996), but a 1998 federal law specific to Fort Berthold requires the consent of only a majority of owners of allotted trust lands before a mineral lease can be executed.
[9] The model applies the Buchanan and Yoon (2000) framework to a setting where N shale excluders set individual royalty rates by maximizing their individual expected royalty earnings, taking as given the royalty rates set by all other excluders. The oil driller, operating within a competitive industry, makes production decisions based on the aggregate royalty rate in a prospective drilling unit, which is the weighted mean of the individual royalty rates.

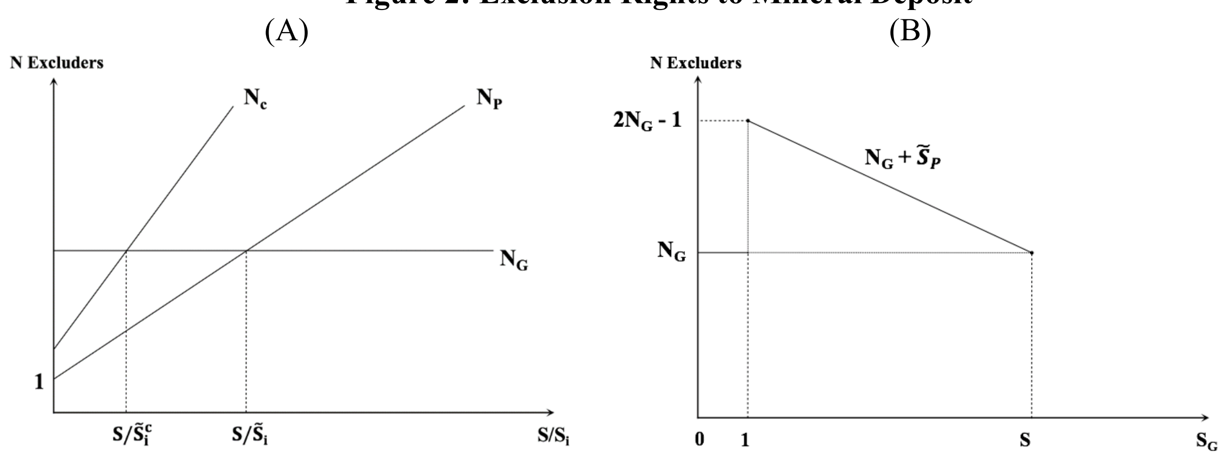
can observe oil production in different areas as well as royalty rates charged in government leases versus leases with private owners, in areas of shale with small and large parcels.

B. Ownership Regimes and the Number of Excluders

Panel A of Figure 2 illustrates how the number of excluders to a potential shale development project changes under private versus government ownership. The figure holds constant the scale of profitable extraction, as in area S of Figure 1. Moving left to right from the origin corresponds with further surface subdivision, or smaller parcels above the shale. Decreases in parcel size increase the number of excluders under private subsurface ownership, which is why the N_P line is positively sloped.[10]

The horizontal line N_G in Panel A represents the number of exclusion rights implicit in government ownership, which does not vary with the degree of surface subdivision. We assume that the height of the government line lies above one because administrative decision making in most governments involves multiple constituent groups, legislators, and committees (Weingast and Marshall 1988; Calvert et al. 1989). Decision making is also typically vetted through multiple agencies that must each be satisfied before consenting to a project as articulated in Schleifer and Vishny (1993), Heller (1998), Buchanan and Yoon (2000).

Figure 2: Exclusion Rights to Mineral Deposit



Notes: Panel A shows how the number of excluders to the shale deposit changes with surface subdivision under bundled private ownership (N_P and N_C) versus government ownership (N_G). The N_P line represents single-owned parcels and the N_C line represents co-owned parcels. S represents the size of landscape containing the deposit. $\tilde{S}i$ denotes the parcel size for which $N_P = N_G$ and $\tilde{S}_i^c$ denotes the parcel size for which $N_C = N_G$. Panel B sets $S_i = \tilde{S}i$ and shows how the number of excluders changes as parcels are converted from private, singular ownership ($\tilde{S}_P$) to government ownership ($\tilde{S}_G$). The number of excluders peaks with $\tilde{S}_G = 1$, and converges to N_G as the number of converted parcels approaches $\sum \tilde{S}_i$.

[10] A slope of one indicates a requirement of unanimous consent, whereas a slope less than one but greater than ½ indicates a requirement of majority consent.

Because the number of private excluders varies with parcel size but the number of government excluders does not, the N_P and N_G lines intersect at some threshold parcel size, $S/\tilde{S}_i$. Hence, there is some level of surface subdivision for which government ownership generates greater rents than private ownership. The threshold is conditioned by the structure of government, but it does not depend on how oil rents are distributed from government to civilians.

In addition to spatial variation in ownership, there may be multiple co-owners who hold fractional interests in each private parcel. Inheritance laws or local customs that prescribe equal shares to descendants (Baker and Miceli 2005) have led to severe co-ownership of parcels in many countries and regions, including Haiti (Palsson 2018), Eastern Europe (Hartvigsen 2014), and former share tenancy lands within the contiguous United States (Deaton 2012). On Native American reservations, millions of acres are jointly owned by descendants of families who received land allotment during 1887-1934 (Shoemaker 2003, Russ and Stratmann 2017. We represent this regime with the N_c line, which has a vertical intercept and a slope greater than 1 because each parcel overlying the mineral deposit has multiple owners holding exclusion rights.

Panel B of Figure 2 illustrates the effect of scattered government holdings in a mostly privately owned area of shale. To simplify the illustration, the figure ignores co-owned private parcels and holds constant the size of parcels at $S_i = \tilde{S}_i$, the threshold size for which $N_G = N_P$. The figure shows how the number of excluders changes as individual parcels are converted from private $(\tilde{S}_P)$ to government ownership $(\tilde{S}_G)$ when shale ownership follows surface boundaries. Moving from zero to one government parcel causes a discrete jump in the number of excluders of N_G -1 because this adds N_G excluders but eliminates only a single private excluder. As more of the surface parcels are converted from private to government ownership, the number of excluders converges back to N_G. Panel B demonstrates how the potential scale advantages of government ownership are undermined when ownership is scattered rather than consolidated.

4. Subdivision of Shale: Natural Experiment on the Bakken

The historical privatization of the Fort Berthold Indian Reservation created a useful natural experiment to assess the private versus government tradeoff under varying conditions of fragmentation. The patterns of parcel sizes and tenure types that existed when the fracking boom of 2005-2015 began were pre-determined with respect to the quality of the underlying Bakken shale that only recently became valuable via horizontal drilling.

A. *Land Allotment on American Indian Reservations*

The allotment of Fort Berthold during the late and early 19th centuries was governed by the U.S. Allotment Act of 1887, which authorized the allotment of communal Indian reservations into parcels for families and individuals (see Appendix Figure A1). Allotment was promoted to encourage agriculture, and the scale and timing of allotment across reservations was determined primarily by agricultural land quality (Carlson 1981, Anderson et al. 2017).

The rules of allotment created parcels of different sizes, which is useful for our empirical tests.[11] On reservations where total acreage exceeded that necessary for allotments, the surplus land was privatized and opened for white settlers, typically as 160-acre parcels. Allottees and settlers who acquired surplus lands generally also acquired subsurface rights to oil, even if it was not yet discovered.[12]

The Indian Reorganization Act (IRA) of 1934 halted further privatization, declaring those parcels not already alienated to be held in trust by the Bureau of Indian Affairs. Allotted lands not privatized prior to 1934 are held in trust to this day, and interests in the land are divided among the living heirs of the allottee each generation. The allotted trust parcels on Indian reservations today often have multiple owners with exclusion rights, sometimes more than 100 (Russ and Stratmann 2017, Dept. of Interior 2013).

B. *Shale Endowment and Ownership under Fort Berthold*

The Fort Berthold Indian reservation, depicted along with surrounding lands and the underlying shale endowment in Figure 3, was established in 1851 by treaty.[13] Congress approved Fort Berthold for allotment in 1894, and the northeastern section was opened for surplus homesteading settlement in 1910. The majority of Fort Berthold was allotted but not released from trust. Today there are approximately 91,707 divided ownership interests across 6,190 allotted trust parcels, resulting in an average of 15 owners per parcel (Dept. of Interior 2013).

[11] The distribution of arable land was as follows: 160 acres to each family head, 80 acres to each single person over 18 and orphans under 18, and 40 acres to each other single person under 18.

[12] After 1916, the Stock-Raising Homestead Act split oil ownership, reserving subsurface rights to the federal government on new homesteads. For reservations not yet allotted at this time, subsurface rights under future allotments were often reserved for tribal governments by specific laws (Ambler 1990).

[13] Though the treaty established a reservation of over 12 million acres for three tribes—the Arikara, Mandan, and Hidatsa—subsequent policies reduced the reservation to its contemporary size of slightly less than one million acres.

After the allotment era, 150,000 acres reverted back to tribal ownership when the Army Corp of Engineers flooded the reservation for a for a dam project in 1951. This Garrison Dam project was controversial and it forced the relocation of families off allotted trust land near the Missouri River and into other areas of the reservation. The episode explains why so much of the tribally owned shale today is by the river in contiguous holdings (Figure 4); much of the land is dry now but it was in the original flood basin. Today there are 385,699 acres of allotted mineral tenure, 367,972 acres of fee simple tenure, and 191,683 acres of tribal tenure. Some of this area sits above active oil fields as defined by the North Dakota Oil and Gas Commission (Appendix Figure A3). On active oil fields, there are 291,471 acres of allotted mineral tenure, 181,906 of fee simple tenure, and 112,665 acres of tribal tenure.

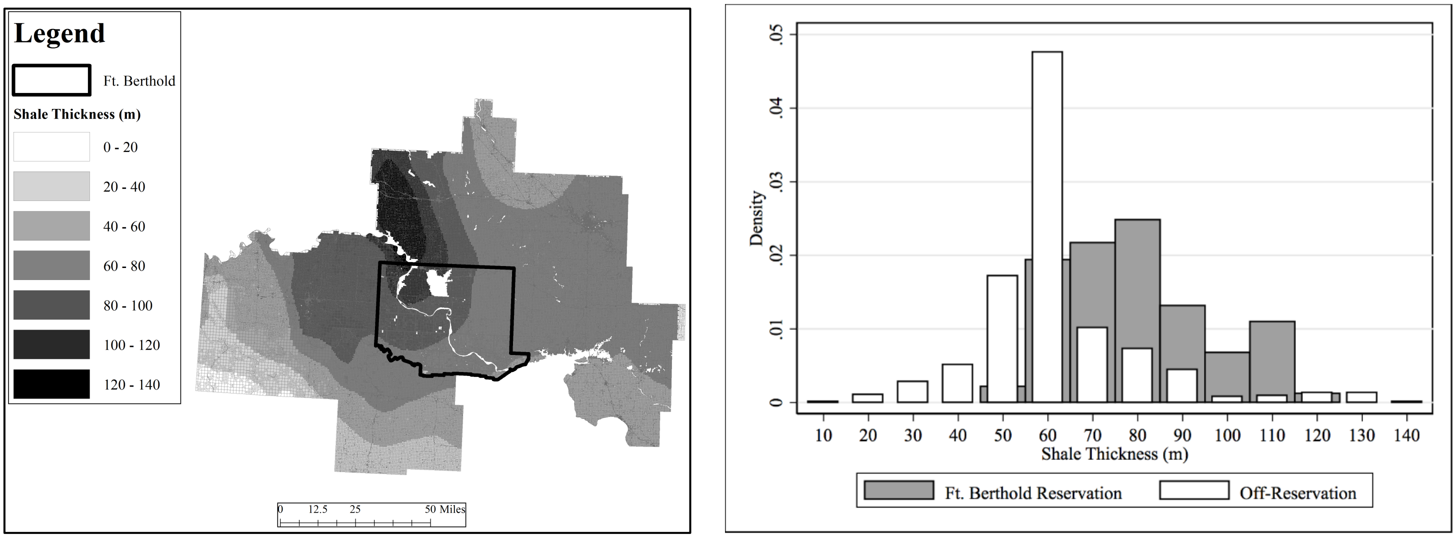
The variation in Fort Berthold tenure is plausibly exogenous to the quality of shale beneath because the reservation was established, allotted, and opened for settlement long before oil was discovered. As Ambler (1990, 42-43) notes: "When it surveyed [Fort Berthold] in the 1910s, the U.S. Geological Survey…found no oil and gas potential, which is not surprising because oil and gas was not discovered in the state until 1951." The Dam project was approved in 1947, also before the discovery of oil.

Figure 3 depicts the distribution of shale thickness for parcels on vs. off the reservation. Shale thickness is a typical measure of endowment quality used in other studies because it is a critical determinant of oil drilling productivity and profitability (Bartik et al. 2017). Panel B of Figure 3 makes it clear that the reservation has a relatively rich endowment. We take this as further evidence that reservation land designations were not selected on the quality of the underlying shale, given the federal government's propensity for gerrymandering reservation boundaries to avoid conveying high-value resources to Native Americans (Dippel 2014).

Figure 4 depicts the variation in tenure within the reservation across the distribution of shale quality that we exploit in our empirical tests. Panel A shows tenure on the reservation overlaid with shale thickness and depth contours and Panel B provides frequency distributions of shale thickness in each tenure category. Depth affects drilling costs, although this dimension of shale quality is less important than shale thickness (the frequency distribution for depth is presented in Appendix Figure A2).

Figure 3: Shale Endowment beneath Fort Berthold on Adjacent Counties

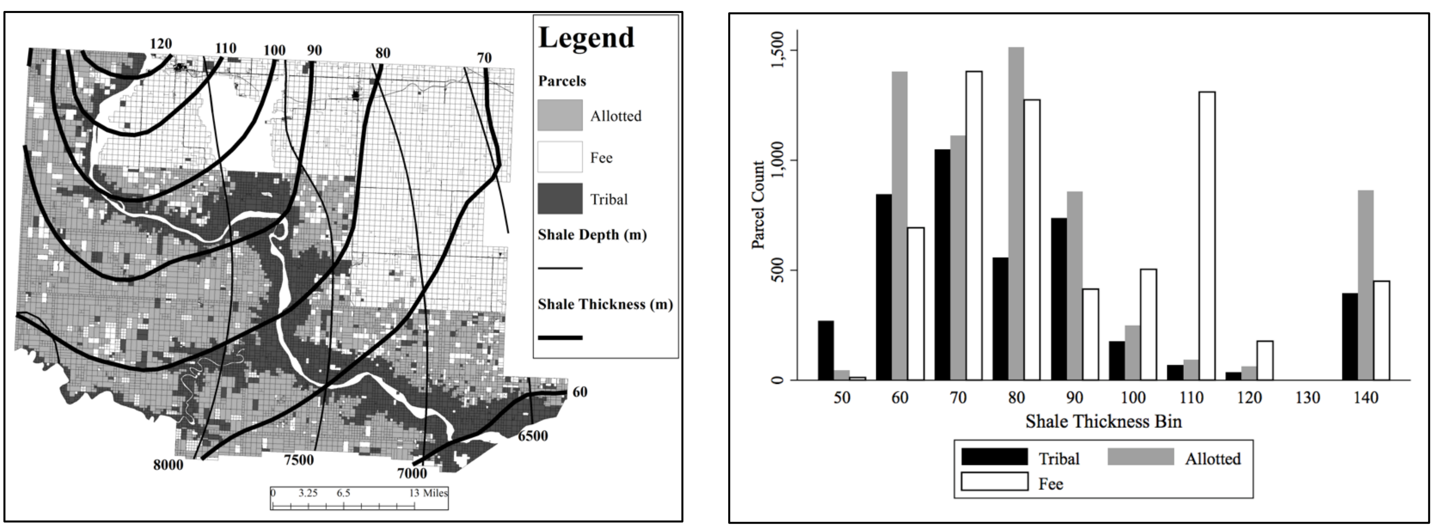
(A) Map of Ft. Berthold and Surrounding Counties **(B) Shale Distribution**



Notes: This figure depicts the spatial distribution of shale thickness underneath the Ft. Berthold Indian Reservation and surrounding counties. Shale thickness estimates were obtained from the North Dakota Oil and Gas Commission. Reservation parcels represent mineral ownership and were obtained from the Bureau of Indian Affairs. Off-reservation parcels represent surface ownership and were obtained from Dunn, McKenzie, McLean, Mountrail, and Ward Counties. Parcel data were not available for Mercer County, which lies to the southeast of the reservation. This area lacks fracking activity, however (see Appendix Figures A3 and A4).

Figure 4: Mineral Tenure and Shale Thickness on Ft. Berthold

(A) Map of Ft. Berthold **(B) Parcel Counts**



Notes: This figure depicts the distribution of shale thickness (and depth) across each tenure category on the Ft. Berthold Indian Reservation. In Panel A, thicker lines represent shale thickness contours and the thinner lines represent shale depth contours, both expressed in meters. Panel B plots the number of parcels from each tenure category in each shale thickness bin. Appendix Figure A2 provides an analogous plot for shale depth. Shale thickness and depth estimates obtained from the North Dakota Oil and Gas Commission. Reservation parcels represent mineral ownership and were obtained from the Bureau of Indian Affairs.

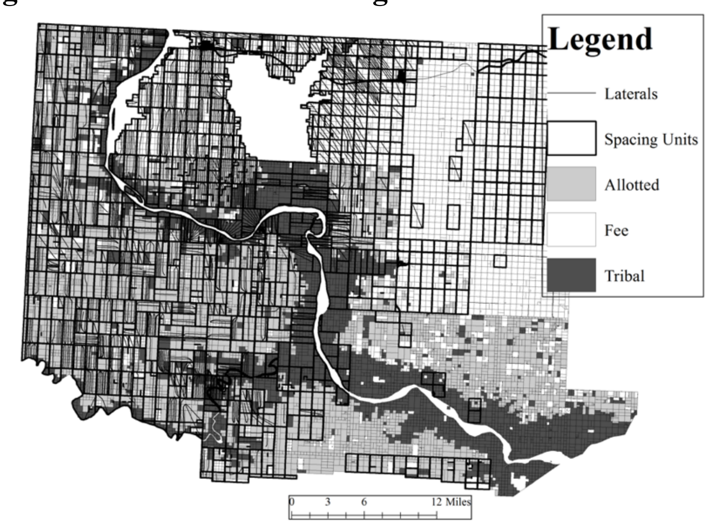
The crucial feature of the data depicted in Figure 4, Panel B is the common support across the distribution of shale thickness for each of the three tenure categories. This variation allows us to compare oil production, revenue, and investment outcomes across tenure regimes within multiple shale thickness bins, thereby holding endowment quality constant. This allows us to identify the average effect of tenure and subdivision across the distribution of shale quality, rather than focusing within a single neighborhood around some particular discontinuity.

5. Data for Empirical Tests

A. Overview

The source for data on drilling is the North Dakota Oil and Gas Commission website. It contains GIS data for every horizontal well bore and every lateral that has been drilled in the state. Our data set represents the accumulation of wells completed as of May 1, 2015, which corresponds with the beginning of a drilling 'bust.' Figure 5 shows the laterals and spacing units on the reservation and Appendix Figure A4 depicts drilling on vs. off the reservation. Note that some spacing units were formed but not drilled, presumably because drilling was not profitable.

Figure 5: Wells Drilled during 2005-2015 on Ft. Berthold



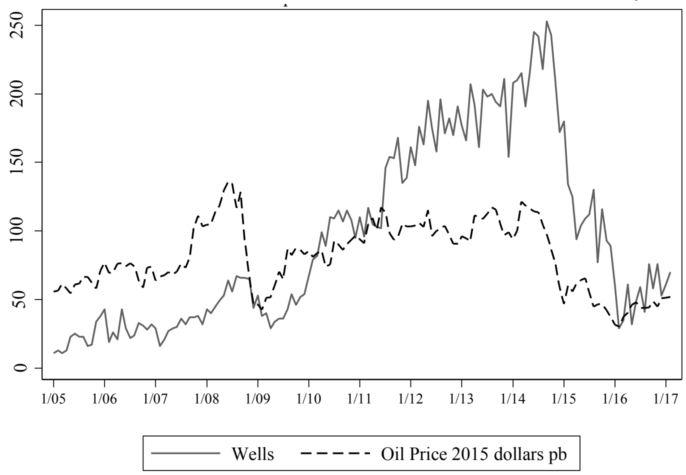
Notes: This map depicts the location all horizontal oil wells drilled on the reservation through May 2015. Bold rectangles represent spacing units, the basis for leasing and landowner compensation.

Figure 6 shows the new wells drilled in North Dakota during 2005-2017. The Bakken produced the vast majority of these wells and accounted for 1.56 billion barrels of oil.[14] To understand the potential magnitude of royalty payments, multiply the average price per barrel over 2005-2015, which was $85.5 in 2015 dollars, by the average royalty rate, which was 17.6

[14] https://www.dmr.nd.gov/oilgas/stats/2015CumulativeFormation.pdf

percent. This amount—$15 billion—does not account for the flow of royalty payments earned on oil extracted over the well's full lifetime of perhaps 25 years (MacPherson 2012).

Figure 6: New Wells in North Dakota and Global Oil Prices, 2005-2017



Notes: The source for drilling information in North Dakota is https://www.dmr.nd.gov/oilgas/. The oil price data come from the U.S. Energy Information Administration (West Texas intermediate) and are adjusted to 2015 U.S. dollars based on the U.S. CPI. Oil prices are per barrel. The source for oil drilling in our study area is the North Dakota's Oil and Gas Commission website.

B. Well-Level Production

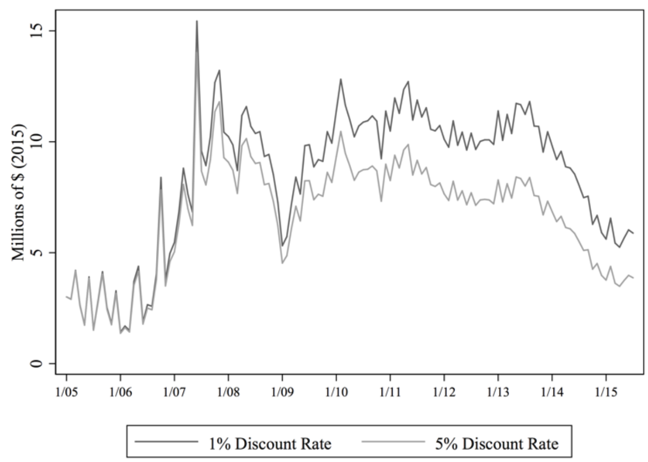
To measure production and revenue in different locations, we first estimate output from each well during its first 18 months of production. We focus on the first 18 months to normalize for differences in the timing of when wells were drilled. (Some wells were drilled near the end of our sample period, in May 2015, whereas others were drilled earlier, for example during 2011 or 2012). We choose an 18-month period because our data covers production through January 2017, spanning 18 months beyond May 2015.

We estimate the monthly flow of oil from a well by combining information on production starting month and cumulative production with data from a representative (baseline) oil decline curve on the Bakken. The oil decline calculations we use are based on the rate of monthly decline in productivity from the baseline well, as estimated by Hughes (2013, p. 57).[15] From the oil-decline curve, we estimate the lifetime oil-productivity of each sample well and then infer productivity over the first 18 months. We combine these estimates with monthly global price

[15] From the data we observe, $Q_T = \sum_{t=0}^{T} q_t$ where t = month, $T =$ number of months since production began, and Q_T is cumulative production as of early 2017. According to Hughes' estimates, the baseline well produces 127,785 barrels during the first 18 months and 213,488 barrels over the first 48 months. Production from the well declines rapidly at first, and then the rate of decline slows. We fit a hyperbolic decline-curve (Satter et al. 2008) to Hughes' figures to extend the estimates from 4 to 29 years, the predicted length of production (MacPherson 2012).

data to estimate the revenue earned by each well, discounting at annual rates of 1%, 3%, and 5% from Jan. 2005 through May 2015. Figure 7 graphs a summary of the results.

Figure 7: Estimated Revenue from Sample Oil Wells



Notes: We estimated oil production during the first 18 months in several steps. First, we match oil wells from the North Dakota Oil and Gas Commission with oil wells in DrillingInfo.com by API number. This provides well-specific data on (a) the first month of production and (b) cumulative oil production through the beginning of 2017. Second, we estimated the proportion of cumulative well production from a baseline oil decline curve by Hughes (2013, pg. 57). Third, we used the baseline oil decline curve to estimate cumulative production, and to back-out an estimate of production over 18 months. Fourth, we multiplied estimated monthly production by the monthly world oil price, deflated to $2015.

Well productivity was stable since early 2010, following an initial period of improvements in drilling technologies. Wells drilled after late 2013 earned lower revenue than wells drilled during 2010-2013. This is due to falling oil prices in mid-2014 (see Figure 6). At a five percent annual rate, the revenue disadvantage of being drilled later in time, relative to January 2005, is more significant than at a one percent discount rate.

C. Parcel-Level Production and Revenue

To assess the effects of subdivision and tenure on oil production, we must decide on a spatial unit of analysis. The options include a) rectangular cells created by imposing a grid sized at the scale of drilling projects; b) the actual oil drilling units assembled by developers during 2005-2015; or c) individual parcels defined by the Bureau of Indian Affairs as fee simple, tribal, or allotted trust. Options (b) and (c) are shown in Figure 5 whereas option (a) is not.

We use individual parcels as our unit of analysis, which has three main advantages. First, parcel sizes and tenure were predetermined with respect to oil-boom production decisions. By contrast, the drilling units are likely endogenous to parcel sizes and tenure types, and parcels are sometimes members of multiple units that have been drilled by different wells.[16] Second, analyzing parcels is more economically meaningful than analysis of arbitrary cells within a grid. Third, using parcels as a unit of observation enables us to separate an "own parcel" effect of size and tenure from the effects of neighbors' size and tenure.

We estimate each parcel's share of oil production and revenue in a two-stage process. First, we match wells to spacing units to obtain a unit-level measure of total revenue.[17] Second, we allocate unit revenue to each parcel in the unit based on a parcel's share of total unit acreage. This is how production and revenue are actually allocated to individual parcels. Figure 8 illustrates. Panel A depicts a representative set of laterals, units, and parcels and Panel B maps parcel-level total revenue across the reservation. Table 1 gives summary statistics.

Figure 8: Estimating Parcel-Level Oil Revenue

(A) Matching Laterals and Units **(B) Estimated Revenue**

Notes: This figure depicts our matching of lateral wells to spacing units (Panel A) and the spatial distribution of estimated parcel revenue (Panel B). Data on units, wells, and production come from the North Dakota Oil and Gas Commission. The variation in drilled vs. not drilled areas of the reservation align with the easternmost edge of active production off the reservation (Appendix Figure A3 and A4).

We regress parcel-level production and revenue on thickness and depth fixed effects both on and off the reservation and plot the coefficients for thickness in Figure 9. Four points are worth emphasizing. First, there is less production on reservation, which may be driven by

[16] Unit sizes are constrained by regulations, but drillers can affect their composition by deciding where to form units.
[17] The North Dakota Oil and Gas Commission provides shapefiles for spacing units but no administrative identifiers for matching wells to units. Our approach is to assign a well to the smallest spacing unit that contains all the laterals associated with the well. We begin with a restrictive criterion that only matches well to a unit that complete contain the laterals. In rare cases laterals cross unit boundaries and so wells are left unassigned. We use a less restrictive algorithm that assigns these residual wells to the smallest unit that contains the majority of the well.

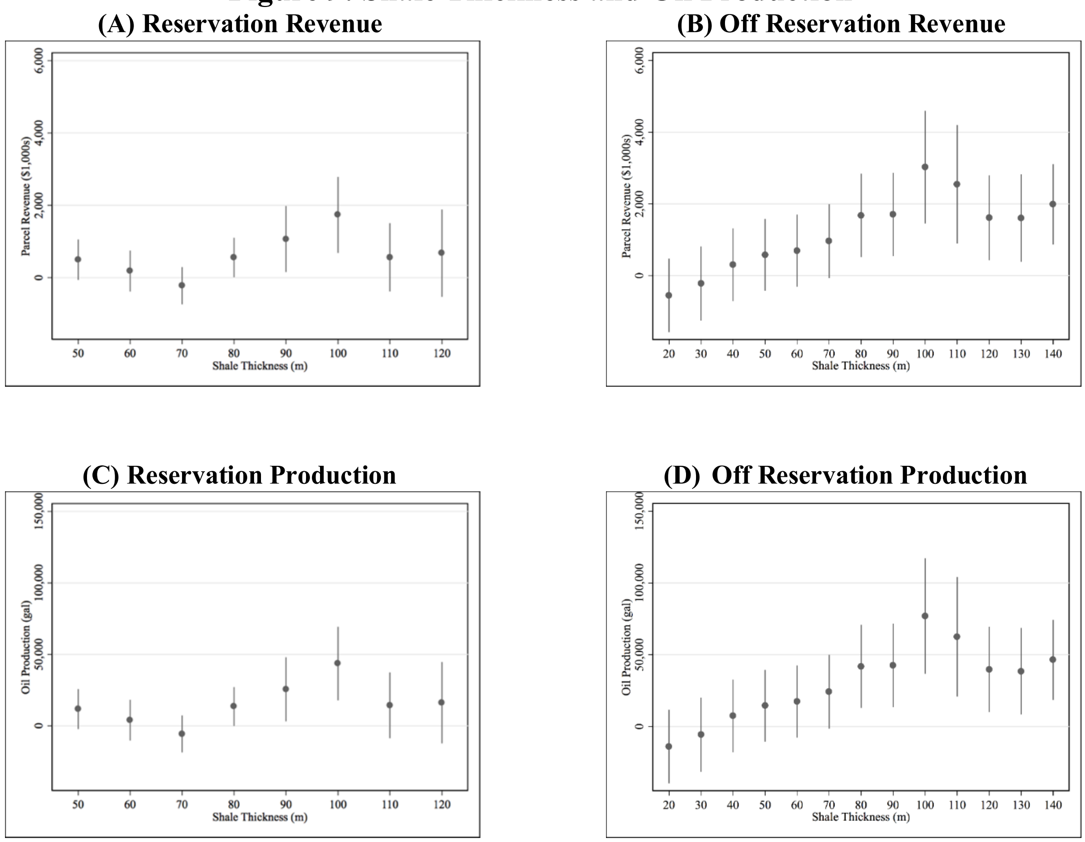
Table 1: Summary Statistics for Parcel Level Data Set

	Mean	*Std. Dev.*	*Min*	*Max*	*Description*
Outcome Variables					
Revenue, 1% dr[a,b,c,d,f]	897,430.2	2,621,519	0	5.79e+07	Total revenue from wells in the unit associated with a parcel as of May 1, 2015, discounted at 1%
Revenue, 3% dr[a,b,c,d,f]	773,697.8	2,253,393	0	5.02e+07	Total revenue from wells in the unit associated with a parcel as of May 1, 2015, discounted at 3%
Revenue, 5% dr[a,b,c,d,f]	667,903.6	1,940,377	0	4.36e+07	Total revenue from wells in the unit associated with a parcel as of May 1, 2015, discounted at 5%
Revenue per Acre[a,b,c,d,f]	11,804.86	20,803.55	0	399,534	Total revenue for the unit associated with a parcel as of May 1, 2015, discounted at 3%, divided by parcel acres
Production[a,b,c,f]	18,692.58	54,465.26	0	1,156,314	Total production from wells in the unit associated with a parcel as of May 1, 2015
Production per Acre	284.8554	493.751	0	9,199.286	Total production from wells in the unit associated with a parcel as of May 1, 2015, divided by parcel acres
Parcel Size, Shape, and Tenure					
Parcel Acres[b, c]	62.343	68.435	.00016	907.635	Area of the parcel, in acres
Fee Indicator[b]	0.393	0.488	0	1	=1 if the reservation parcel is fee simple, otherwise =0
Allotted Trust Indicator[b]	0.349	0.477	0	1	=1 if the reservation parcel is allotted trust, otherwise =0
Tribal Indicator[b]	0.257	0.437	0	1	=1 if the reservation parcel is tribally owned, otherwise =0
Neighbor Parcels (1/2 mile radius)					
Fee Neighbors[b, c]	73.845	181.853	0	819	Number of fee parcels within ½ mile radius around parcel
Allotted Trust Neighbors[b, c]	8.317	9.456	0	60	Number of fractionated parcels within ½ mile radius around parcel
Tribal Neighbor Indicator[b, c]	0.578	0.494	0	1	=1 if there are tribal parcels within a ½ mile radius around parcel
Neighbors Underwater [f]	6.057	8.925	0	53	Number of parcels under a body of water within ½ mile radius around parcel
Tribal Acres in Neighborhood[b, c]	355.925	494.406	0	2,984.028	Total acreage of tribally owned parcels within ½ mile radius around parcel
Other Covariates					
Topographic Roughness[e]	610.517	42.296	560.59	787.191	Standard deviation of elevation in the neighbourhood around a parcel, measured in centimeters
City Indicator[f]	0.099	0.298	0	1	= if the parcel is within a city boundary, otherwise = 0
Road density [f]	0.1592	0.353	0	2.875	Kilometres of roads touching parcel

Notes: This table summarizes data for all parcels in our estimation sample on the reservation. We exclude parcels with off-reservation neighbors. N = 12,780 for all variables except roughness, which is N = 12,769. Data sources are: a) North Dakota Oil and Gas Commission website, b) U.S. Bureau of Indian Affairs, c) Real Estate Portal, d) U.S. EIA website e) Authors calculations from National Elevation Dataset, and f) Authors calculations from North Dakota GIS Portal data.

fragmented ownership. Second, there is an increasing relationship between shale thickness and average oil production and revenue. Third, this relationship is notably less monotonic on the reservation, presumably because variation in oil ownership across shale categories is more prominent on the reservation (Figure 3). Fourth, the similarity between the plots for production and revenue suggest that cross-parcel differences in revenue are driven primarily by variation in production rather than by price volatility.

Figure 9: Shale Thickness and Oil Production



Notes: This figure depicts the estimated semi-parametric relationship between shale thickness bins and oil revenue (Panels A and B) and production (Panels C and D). The plotted coefficients represent the shale thickness fixed effects and are relative to the omitted thickness category and depth categories. Each regression uses a parcel as the unit of analysis and also controls for depth fixed effects.

D. Parcel Covariates

To measure the effects of subdivision and tenure mixes around a parcel, we focus on the neighborhood of parcels within a ½ mile radius of each parcel. This ½ mile radius includes the set of parcels surrounding parcel *i* that could potentially be included in the same unit and thus affect the aggregate royalty rate. Appendix Figure A5 illustrates our mapping from the spatial data to the variables. We choose the ½ mile radius because this yields an area close in size to the average spacing unit, but our results are robust to other distance choices.

The average area spanned by the ½ mile radius is 1550 acres, which is roughly the size of a the most common 1280-acre spacing unit.[21] Within the 1/2-mile radius, the number of neighboring fee simple parcels ranges from 0 to 819 and the number of neighboring allotted parcels ranges from 0 to 60. The average amount of tribal acreage in the radius is 355 acres; some ½ mile neighborhoods consist of fully contiguous tribal tracts, which are reported to us by the Bureau of Indian Affairs as "parcels." Some mineral parcels are under a body of water, based on the high flood lines of the Missouri River—we control for this to account for special rules governing drilling under water.

E. Lease-Level Data

To supplement the production data, we acquired lease data from DrillingInfo.com, which reports acreage, lease date, production status, approximate location, royalty rates, and the grantor for each lease. Leases are geo-referenced to the 1x1-mile Public Land Survey System (PLSS) section where production takes place, so we cannot directly match leases to our parcel-level dataset. Instead, we match leases to PLSS sections (1 square mile units in the land surveying system) and then calculate the total number of parcels in each section in addition to aggregating the other parcel-level covariates up to the PLSS section-level.

DrillingInfo's data do not allow us to separately identify leases signed with fee vs. allotted trust owners because they are aggregated up to the section level. However, we can identify leases for which the tribe was the grantor. The upshot is that these lease data have two important limitations. First, we can only measure covariates at the section level. Second, we cannot differentiate the own-tenure effect for allotted vs. fee leases. Table 2 reports the summary statistics for the lease data.

[21] There is some slight variation in the area within a ½ mile radius because we include any parcel that is touching the radius, and those perimeter parcel sizes vary.

Table 2: Summary Statistics from Well and Lease Level Data Sets

	Mean	*St. Dev.*	*Min*	*Max*	*Description*
Royalty[a]	0.176	0 .019	0.125	0.25	Royalty rate for lease *i*
Lease Term (Months)	50.393	14.127	0	120	Time until lease expires, in months
Non-tribal Lease Indicator	0.951	0.216	0	1	=1 if the grantor on the lease is not the tribe, otherwise 0
Acreage Under Lease	501.925	979.311	0	10,360	Area (in acres) of the land associated with a lease
Fee Parcels in Section	15.062	49.856	0	725	Number of fee simple parcels in PLSS section where lease is located
Allotted Parcels in Section	5.769	6.794	0	45	Number of allotted trust parcels in PLSS section where lease is located
Roughness	12.40	7.999	0	42.958	Std. dev. of elevation in the PLSS section where lease is located (m)
Road Density	1.769	1.346	0	6.002	Km of roads touching the PLSS section where lease is located
Underwater Indicator	0 .187	0 .389	0	1	=1 if the PLSS section where lease is located is partially underwater
City Indicator	0.037	0.188	0	1	=1 if the PLSS section where lease is located is in a city

Notes: N = 5,992 leases in our study area. The source is a) DrillingInfo.com data and b) author's calculations based on the PLSS section reported by DrillingInfo.com and land tenure variables and ownership data from U.S. Bureau of Indian Affairs and Real Estate Portal.

6. Empirical Estimates

We conduct two sets of empirical tests. First, we use the parcel data to estimate the effects of parcel acreage, neighborhood subdivision, and tenure patterns on production and revenue. Second, we use the lease data to estimate the effects of tenure and subdivision on royalty rates.

A. Regression Model of Parcel-Level Production

We estimate oil production per acre associated with parcel *i* during the boom using the following model:

$$Barrels\ per\ acre_{itd} = \alpha_t + \alpha_d + \phi Acres_{itd} + \lambda_F 1(Fee)_{itd} + \lambda_A 1(ATrust)_{itd} + \beta_F FeeNeigh_{itd} + \cdots$$
$$\ldots \beta_A ATrustNeigh_{itd} + \beta_T 1(TribalNeigh)_{itd} + \beta_{T1} 1(Tribal)_{itd} + \gamma X_{itd} + \varepsilon_{itd} \quad (1)$$

where i = parcel, t = thickness bin, and d = depth bin. The notation α_t and α_d represent the vector of shale thickness and depth bin fixed effects.

The key parameters are ϕ, the λ's, and β's. We expect parcel acres to positively affect production per acre ($\phi > 0$) because larger parcels reduce anticommons and transaction cost problems. While this relationship is mechanically true if the dependent variable was total production (because oil production is allocated to parcels within drilling units in proportion to size), it is not mechanically true for production *per acre*.

The λ coefficients measure the extent to which parcel i's own tenure influences drilling probabilities, conditional on the degree of neighborhood subdivision and tenure composition of neighbors. The omitted tenure type is a tribal parcel with zero fee or allotted neighbors, so the effects of fee and allotted ownership are relative to a large contiguous tribal tract. Theory predicts $\lambda_F > \lambda_A > 0$. This is the ordering of the vertical intercepts in Figure 2, Panel A, and these coefficients effectively compare the attractiveness of a single large parcel for drilling, based on whether that parcel is fee, allotted, or tribal.

The β's measure neighborhood subdivision effects by tenure type. We expect $0 > \beta_F > \beta_A$ because more finely subdividing a radius around a parcel into either form of private ownership will increase *N*, the number of potential excluders to a drilling project, thereby reducing production. The negative effect will be larger for allotted trust than fee simple because there are multiple excluders per allotted trust parcel, corresponding to the steeper slope of the N_c vs. N_p lines in Figure 2. β_T measures the effect of having *any* tribal parcels within the neighborhood of parcel i, which would add the fixed number N_G excluders. We predict that $\beta_T <$ 0. Finally, β_{T1} measures whether this effect of tribal neighbor presence is different when parcel i is tribal. We hypothesize that $\beta_T + \beta_{T1} = 0$, because adding tribal parcels does not alter N_G if parcel i is tribal (hence the zero slope of the N_G line in Figure 2).

Before proceeding, we emphasize how our approach contrasts to other studies that assess government versus private drilling outcomes by using checkboarded patterns of government versus private ownership (e.g., Kunce et al. 2002, Edwards et al. 2018). We exploit our data structure to study the tenure of both parcel i and its neighbors. In other words, we estimate not just the differences in intercepts (e.g., λ_F and λ_A), as previous studies have done, but we also estimate the marginal effect of changing the tenure composition of a neighborhood (e.g. β_F, β_A, and β_T). If our theory is correct, quantifying both effects is critical for understanding the aggregate effects of ownership on resource use.

B. Identification

Selection on resource quality is the primary identification challenge in most studies of property rights and resource use. More valuable resource endowments foster greater effort to define private property rights (Demsetz 1967), limiting the econometrician's ability to identify causal effects of property regimes on resource use (Besley 1995, Goldstein and Udry 2008, Galiani and Schargrodsky 2012). Our study avoids this challenge because the variation in shale ownership was determined before the shale endowment (or the technology to exploit it) was known, as outlined in Section 4. This section outlines our approach for addressing the remaining threat to identification, which is the possibility of incidental correlation between tenure and factors affecting either endowment quality or the cost of accessing shale.

Our identification strategy augments the natural experiment described in Section 4 with fixed effects for shale thickness and depth bins to identify the key parameters from Equation 1 using ownership variation within relatively homogenous bands of shale, depicted in Figure 4. Our focus on shale thickness and depth as measures of the shale endowment is consistent with other studies of both conventional and horizontal drilling that emphasize subsurface rather than surface characteristics as the primary drivers of production (Kellogg 2011; Bartik et al. 2017).

A remaining threat to identification is the possibility of unobserved geographic factors that are correlated with tenure and affect productivity *within* shale bins. We include various controls, denoted by X_{itd} in Equation 1, to directly account for the roughness of the terrain and the proximity of each parcel and its neighbors to water bodies (based on the high-water line of the Missouri River), which could affect the surface placement of well bores. We also control for surface development (e.g., road density and for the presence of urban areas).

Remaining omitted variables threaten identification only if they i) are systematically correlated with tenure, ii) are not captured by the controls in X_{itd}, and iii) affect shale productivity within thickness and depth bins. We think this threat is minor, particularly because one of the chief advantages of horizontal drilling is its ability to render surface characteristics less critical by enabling the extraction of oil under a large radius from any given point on the surface (Anderson et al. 2018). This is consistent with modelling assumptions in previous econometric work that treats surface characteristics as a relatively inconsequential component of drilling costs (Kellogg 2014).[22] Nevertheless, we conduct a series of robustness checks to further account for surface differences.

[22] Kellogg (2014) focuses on prices, rig rental rates, and subsurface endowments as the primary determinants of drillers' decisions. His analysis assumes non-rental drilling costs are constant across the sample.

C. Regression Estimates

Table 3 shows the estimation results. Column 1 employs the entire sample of parcels whereas columns 2-5 employ a subset of only those parcels that are on active oil fields as of May 2015 (see Figure A3 in the appendix). Thus, the estimates in Columns 2-5 focus on variation across parcels within areas where oil production is profitable, based on drillers' revealed behavior. Column 3 includes oil field fixed effects. The benefit of oil field fixed effects is that they control for heterogeneity in the regulatory rules governing production (e.g., spacing unit sizes), which can vary by oil field, but the drawback is that that these regulatory rules are likely endogenous to tenure and parcel configurations because oil fields are generally formed after leasing begins. Columns 4 and 5 employ only those parcels that were members of units drilled during the boom, thereby focusing on the intensive margin of drilling. In all models, the standard errors are calculated to allow for arbitrary spatial correlation in the error structures following Conley (2008) and Hsiang (2010).

The coefficients are robust to the inclusion or omission of off field parcels, to oil field fixed effects, and to conditioning the sample on positive drilling, but our preferred estimates are in Column 2. The Column 2 model focuses on the effects of subdivision and tenure on fields (i.e. the profitable areas of the reservation), but does not include the likely-endogenous field fixed effects. The Column 2 coefficients are based on linear estimation of a dependent variable that is zero in 28% of occurrences. The estimates in Columns 4 and 5, which are conditional on drilling, reveal the same patterns. The similar patterns imply that most of the subdivision and tenure effects occur on the intensive margin of drilling.[23]

The Column 2 coefficient on parcel acres implies that a one standard deviation increase above the mean (i.e., from 59 to 130 acres) is associated with 0.92 x 71 = 65.3 barrel increase in expected production per acre. This is a 15.4% percent increase relative to the mean per acre production, which is 421.6 barrels for sample parcels on oil fields. The point estimates on the tenure intercepts are $\hat{\lambda}_F = 300.6 > \hat{\lambda}_A = 141.5 > 0$, although the difference between $\hat{\lambda}_F$ and $\hat{\lambda}_A$ is not statistically significant. Because the omitted category is a tribal parcel, these findings suggest that a large privately owned parcel that spans the entire ½ mile radius will generate more

[23] This finding is consistent with additional results, not shown here, which indicate that the probability of parcel membership in a drilled unit is much less sensitive to ownership patterns when compared with production per acre.

revenue than a block of contiguous tribal ownership, especially if the parcel is owned in fee simple rather than allotted trust.

Table 3: Linear Estimates of Production per Acre

	(1)	(2)	(3)	(4)	(5)
Parcel Variables					
Parcel acres (ϕ)	0.537***	0.919***	0.775***	0.978***	0.853***
	(0.187)	(0.232)	(0.191)	(0.310)	(0.287)
Fee parcel indicator (λ_F)	188.9**	300.6***	259.8***	351.2***	327.4***
	(87.68)	(103.9)	(83.53)	(115.3)	(97.25)
Allotted trust parcel indicator (λ_A)	91.91	141.5*	157.8**	236.5**	230.2***
	(62.06)	(73.10)	(66.02)	(95.57)	(84.40)
Neighbor Variables					
Fee neighbors (β_F)	-0.763***	-0.893***	-0.880***	-1.079***	-0.996***
	(0.167)	(0.200)	(0.175)	(0.167)	(0.137)
Allotted trust neighbors (β_A)	-3.842**	-5.784**	-3.376	-8.231**	-5.963**
	(1.914)	(2.562)	(2.512)	(3.337)	(2.897)
Tribal Neighbor Indicator (β_T)	-128.9***	-179.4***	-183.3***	-215.4***	-209.8***
	(45.89)	(52.68)	(44.62)	(53.92)	(47.78)
Tribal Neighbor Indicator X	29.78	71.49	95.89	117.2	113.8
Tribal Indicator (β_{T1})	(64.09)	(76.75)	(65.67)	(101.4)	(83.83)
Covariate Controls					
Underwater indicator	-87.45***	-110.9**	-111.6**	-59.07	-66.19
Underwater neighbors	-5.803**	-11.53***	-10.00***	-8.004	-6.383
Topographic roughness	-1.721*	-2.042**	-2.049**	-2.629**	-2.593***
Road density	-25.24	-14.72	5.470	5.468	16.67
City indicator	68.67	72.89	42.69	50.19	29.51
Shale thickness & depth FE	x	x	x	x	x
Excludes parcels off fields		x	x	x	x
Oil field FE			x		x
Excludes parcels if revenue =0				x	x
Adjusted R-squared	0.523	0.552	0.584	0.651	0.670
Observations	12557	8524	8524	6204	6204

Notes: Conley (2008) spatial HAC standard errors shown in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * p<0.1, ** p<0.05, ***p<0.01. A parcel's neighborhood includes all parcels touching a half-mile radius from the parcel's boundary. All specifications control for the slight variation in the total area of the radius, due to variation in the size of parcels on the exterior of the radius. Column 1 employs all parcels, whether or not the parcels are on a designated oil field. Columns 2 and 3 use only parcels that are on a designated oil field. Columns 3 includes oil field fixed effects. Columns 4-5 exclude all parcels that were not drained of oil through May 2015.

The point estimates on the tenure slopes are $\hat{\beta}_A = -5.78 < \hat{\beta}_F = -0.89 < (\hat{\beta}_T + \hat{\beta}_{T1}) = 0$. This ordering follows our predictions, and the differences between coefficients are statistically significant. Adding an allotted trust neighbor reduces expected production by 5.8 barrels per parcel, which is 6.5 times the negative effect of adding a fee neighbor.[24] Holding all other variables constant, increasing the number of allotted trust neighbors by one standard deviation, which is 9.6, decreases expected production by 55.5 barrels. This is a 13.2% reduction relative to the mean. According to these estimates, converting the 9.6 parcels into fee simple would increase expected production by 9.6 x (5.784 – 0.893) = 46.9 barrels.

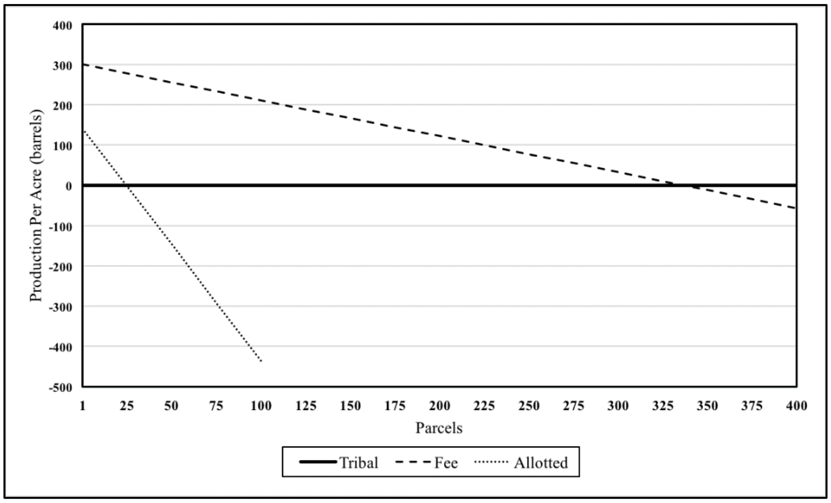
The point estimate of $\hat{\beta}_T$ = -179.4 means that adding a tribal parcel to the neighborhood causes a 42% reduction in parcel i's expected production relative to the conditional mean of 421.6 if parcel *i* is not tribally owned. If parcel *i* is tribally owned, the effect is $\hat{\beta}_T + \hat{\beta}_{T1}$, which is not statistically different from zero (p = 0.19). This pair of results is consistent with the theory that adding tribal land to the neighborhood does not add excluders if parcel *i* is tribal, but it adds a fixed number of excluders if parcel *i* is fee or allotted. We provide an additional test of this hypothesis in Appendix Table A1, where we test for an additional effect of tribal *acres* in a neighborhood of parcel *i.* We find that more tribal acreage is associated with less production and revenue if parcel *i* is allotted or fee, but has no marginal effect if parcel *i* is tribal.

The coefficients in Table 3 imply a subdivision threshold for fee and allotted tenure, after which contiguous government ownership generates more expected production. Figure 10—an inverse of the excluder graph in Panel A of Figure 2—depicts predicted production for areas of a single tenure type as a function of parcel size based on the coefficient estimates in Column 2 of Table 3. Predicted production is higher in fee and allotted areas, relative to tribal areas, unless parcels are too finely subdivided.

For fee simple parcels, the threshold is 300.6/0.893 = 336 parcels. Because the average half-mile radius spans 1,550 acres, this implies a threshold parcel size of 4.6 acres. In the estimating sample, the average fee parcel is 42 acres but, as discussed in the introduction, agricultural parcels in many areas of the world are smaller than 4.6 acres. For allotted trust, the threshold is 141.5/5.78 = 24.5 parcels, implying a threshold size of 63.3 acres. The average allotted trust parcel in the sample is 82.4 acres, but 58% of the allotted parcels are smaller than 63.3 acres.

[24] Recalling that the average Ft. Berthold allotted trust parcel is owned by 15 individuals (see Section 4), we note that the ratio of 6.5 is less than the average number of owners. This result implies that adding another trustee excluder has less of an effect on oil production when compared to adding another fee parcel. This is not surprising, because federal legislation allows a form of forced pooling on Ft. Berthold allotted trust land, so that super-majority rather than unanimous consent is necessary.

Figure 10: Predicted Difference in Tribal vs. Private Production



Notes: This figure plots the predicted effect of subdividing a 1,550-acre neighborhood into each tenure type, based on the coefficient estimates in Table 3. The vertical intercepts represent expected production on a single large parcel and are based on the $\hat{\lambda}$'s. The slope of each line is determined by the corresponding estimated neighbour coefficient (the $\hat{\beta}$'s).We omit standard error bars for the sake of clarity. Separate plots of fee vs. tribal and allotted vs tribal with 95% confidence intervals can be found in Appendix Figures A6 and A7.

Table 4 shows the results for revenue per acre over the first 18 months and provides robustness checks. In Columns 1-3, revenue is discounted at 1%, 3%, and 5% respectively, based on the number of months elapsed since January 2005. The specifications are identical to Column 2 in Table 3, and the point estimates follow the same pattern with $\hat{\phi}$ >0, $\hat{\lambda}_F$> $\hat{\lambda}_A$>0, and $\hat{\beta}_A$ < $\hat{\beta}_F$ < $(\hat{\beta}_T + \hat{\beta}_{T1})$ = 0. A comparison of the coefficients here in Columns 1-3 with those in Column 2 of Table 4 make it clear that patterns of revenue mimic patterns of production, in terms of the effects of parcel sizes and tenure.

Transaction costs could delay the timing of leasing and drilling, potentially leading to benefits for large-*N* projects if landowner bargaining power improved over time or if prices and drilling technology improve unexpectedly.[25] Though this is possible, the available evidence suggests the role of timing delays is minor. First, the finding that revenue patterns mimic production patterns implies that small parcels and parcels in neighborhoods with many excluders were not drilled when oil prices were systematically higher. Second, when we estimate the Table

[25] In these cases, the demand for oil shifts outward after royalties are set, leading to greater production and revenue at a higher royalty rate. If this happens, payouts to shale owners increase with *N* precisely because high-*N* projects end up being drilled under favorable price and technological conditions. However, if future changes in prices and costs are anticipated, then large *N* cannot benefit shale owners because the Buchanan and Yoon (2000) logic still applies and individually rational attempts to capture expected future surpluses will dissipate potential rents.

3 and 4 models of oil output and revenue and include well vintage fixed effects the main results are quite similar (see Table A2 and A3 in the appendix). The implication is that increases in N reduced revenue during the boom, even after accounting for the potentially complex interaction between transaction costs, delay, and dynamically changing prices and technology.

Table 4: Estimates of Revenue per Acre and Robustness

	1% discount	3% discount	5% discount	3% discount	3% discount	3% discount
	(1)	(2)	(3)	(4)	(5)	(6)
Parcel Variables						
Parcel acres (ϕ)	41.91***	35.81***	30.65***	35.22***	36.00***	38.75***
	(11.26)	(9.624)	(8.244)	(9.227)	(9.807)	(14.07)
Fee parcel indicator (λ_F)	13419.8***	11677.5***	10182.5***	11397.8**	12125.2***	12987.2***
	(5063.2)	(4426.1)	(3875.9)	(4433.9)	(4379.4)	(4655.9)
Allotted parcel indicator (λ_A)	6937.8*	5930.8*	5076.8**	5224.3*	6164.7*	5741.9
	(3609.9)	(3178.7)	(2802.1)	(3160.3)	(3177.9)	(3579.1)
Neighbor Variables						
Fee neighbors (β_F)	-42.01***	-36.00***	-30.93***	-34.91***	-45.45***	-30.36***
	(9.581)	(8.302)	(7.205)	(7.899)	(6.950)	(6.818)
Allotted trust neighbors (β_A)	-265.4**	-232.3**	-203.6**	-241.8**	-238.8**	-125.3**
	(124.0)	(105.3)	(89.57)	(100.7)	(99.47)	(58.65)
Tribal Neighbor Indicator (β_T)	-9070.4***	-7761.2***	-6649.5***	-7634.4***	-9296.1***	-6934.6***
	(2592.5)	(2245.3)	(1948.9)	(2206.7)	(2104.4)	(2258.3)
Tribal Neighbor Indicator	3023.3	2579.9	2208.3	1775.6	2187.5	3162.0
X Tribal Indicator (β_{T1})	(3744.7)	(3266.5)	(2855.1)	(3348.3)	(3132.1)	(3749.3))
Shale thick & depth FE	x	x	x	x	x	x
Covariate controls	x	x	x	x	x	x
Excludes parcels off fields	x	x	x	x	x	x
x & y coordinate controls				x		
Excludes parcels in cities					x	
One mile radius						x
Adjusted R-squared	0.537	0.535	0.575	0.538	0.538	0.547
Observations	8524	8524	8524	8524	7281	7630

Notes: Conley (2008) spatial HAC standard errors shown in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * p<0.1, ** p<0.05, ***p<0.01. Columns 1-3 discount revenue per acre at 1%. 3%, and 5%, respectively. The specifications in Columns 1-3 are identical to those in Column 2 of Table 3. Columns 4-6 are robustness checks, based on the revenue estimates discounted at 3%. Column 4 adds controls for the longitude and latitude of each parcel's centroid. Column 5 omits parcels in cities. Column 6 defines the neighborhood with a one-mile radius rather than a ½ mile radius.

Another possibility is that the parcel size estimates might reflect higher reservation prices from small parcel owners due to environmental damage concerns. This is possible if drilling through shale damages surfaces and smaller parcels have higher surface quality. We do not think this mechanism is driving the results for two reasons. First, the regressions control for surface quality, albeit imperfectly. Second, environmental damages from shale drilling—whether perceived or real—spill across neighboring parcels and are not generally contained to surface areas above a particular lateral (see, e.g., Olmstead et al. 2013, Muehlenbachs et al. 2015). This implies an owner of a small parcel cannot prevent exposure to external effects from drilling simply by trying to prevent drilling beneath her parcel.

Columns 4-6 of Table 4 check for robustness to this and other concerns. The dependent variable is revenue per acre, discounted at 3%. Column 4 adds controls for the longitude and latitude coordinates of a parcel's centroid to control for possible South-North and West-East patterns in drilling, and for potential unobserved spatial variation in shale quality or access costs. Column 5 drops the 1,243 parcels within the most urban area of the reservation because that area is an obvious outlier, with notably small parcel sizes. Column 6 measures all of the neighbor variables based on a 1-mile radius, rather than the ½ mile radius. In each of these columns, the pattern of estimates follows the baseline, indicating the results are robust to variations in estimating sample, control variables, and the measurement of neighborhoods. Appendix Tables A4 and A5 reproduce Tables 3 and 4 using a tobit rather than a linear estimator and demonstrate that accounting for censoring of revenue and production at zero does not change the results. We do not use a tobit as our main estimator because it does not readily account for spatially correlated standard errors or and is subject to incidental parameter problems with large numbers of fixed effects.

D. Royalty Rates

According to the anticommons model, the price that excluders charge developers for shale use is a mechanism that drives differences in oil production and revenue. Although the full price includes components that we cannot measure, such as leasing bonus payments, we do have data on royalty rates as summarized above. Royalty rates account for 85-90% of shale owner compensation in typical leases (Fitzgerald and Rucker 2016) and tend to positively correlate with bonus payments (see Vissing 2017), implying that higher royalty rates are unlikely to be offset by bonus payment reductions. Moreover, the results indicate that tenure and subdivision affect oil investment primarily on the intensive margin (e.g., drilling inputs per drained acres) rather than the extensive margin (whether or not to extract at all from a parcel). This suggests that royalty rates—rather than bonus payments borne at the time of leasing and sunk with respect to output—are likely a mechanism.

Here we provide tests of whether or not the royalty rate charged by excluder i increases with N, the total number of excluders in the neighborhood. Holding constant neighborhood characteristics, a relationship of $r_T > r_A > r_F$ would be consistent with anticommons predictions, where r_A is the average royalty rate requested by allotted owners, r_F is the average rate requested by fee owners, and r_T is the average rate requested by the tribe.

The lease data have two limitations: we can only measure lease covariates at the section level and we do not know if a lease is associated with allotted trust owner or a fee simple owner. Given these limitations, we estimate the following regression model:

$$royalty_{ltds} = \alpha_t + \alpha_d + \lambda_P(NonTribal)_{ltd} + \beta_A(AllotNeigh)_{tds} + \cdots \tag{2}$$
$$\ldots + \beta_F(FeeNeigh)_{tds} + \gamma X_{itd} + \varepsilon_{ltds}$$

where l = lease, t = thickness bin, d = depth bin, and s = PLSS section. As before, α_t and α_d represent the vector of shale thickness and depth bin fixed effects and X_{itd} represents controls for surface characterstics.

Table 5 shows the estimation results.[26] In Columns 1-2, the royalty rates are logged. In Columns 3-4, they are not. Columns 2 and 4 omit leases in the most urban sections of the reservation because these sections are outliers in terms of parcel size. In all models, the standard errors are calculated to allow for arbitrary spatial correlation in the error structures.

The Columns 1-2 estimates for the non-tribal indicator suggest that royalty rates for allotted or fee simple leases are 4.1% to 4.4% less than the royalty rates in tribal leases, after controlling for the neighborhood covariates. This corresponds to a 0.66 to 0.71 percentage point decrease in royalty rates, based on the Columns 3 and 4 estimates. This finding is consistent with

[26] The number of observations differs from out parcel-level regressions for several reasons. First, we are not able to directly match leases to parcels. Second, our parcel-level data treats individually-demarcated tribal parcels as unique observations. In reality, a tribe may lease collections of contiguous parcels with a single lease, reducing the number of leases relative to parcels. Third, a parcel may have been forced into a unit (with forced pooling) rather than by signing a lease.

the anticommons model if a single tribal lease entails satisfying a larger number of excluders relative to a single lease on a non-tribal parcel.

The estimated effects of adding fee and allotted parcels to a section support an anticommons explanation for the revenue and production results in Tables 3 and 4. The royalty rate increases by 0.015% for each additional fee parcel in a section and by 0.122% for each additional allotted parcel, which involves more excluders. These estimates imply that leases in areas with more finely subdivided fee and allotted mineral rights have higher royalty rates than leases in areas with larger parcels.

The limitations of the lease data prevent us from precisely identifying subdivision thresholds for fee or allotted vs. tribal leases as with production in Figure 10 because we cannot separately identify fee and allotted leases. Still, we note that the magnitudes are similar. A 640-acre section of purely fee land would have to be subdivided into 275 2.3-acre parcels to have a higher royalty rate than the average tribal lease. Similarly, a solely allotted trust section would have to be subdivided into 32 20-acre parcels to exceed the tribal royalty rate.

Table 5: Lease Level Estimates of Royalty Rates

	Ln(Royalty)		Royalty	
	(1)	(2)	(3)	(4)
Non-tribal indicator	-0.0413^{***}	-0.0441^{***}	-0.00660^{***}	-0.00711^{***}
	(0.0105)	(0.0109)	(0.00185)	(0.00191)
Fee parcels in section	0.000150^{***}	0.000683^{***}	0.0000255^{***}	0.000115^{***}
	(0.0000510)	(0.000224)	(0.00000873)	(0.0000394)
Allotted Trust parcels in section	0.00126^{*}	0.00152^{**}	0.000217^{*}	0.000259^{**}
	(0.000693)	(0.000710)	(0.000120)	(0.000122)
Topographic roughness	0.000371	0.000477	0.0000467	0.0000709
Road Density	-0.00445	-0.00531^{*}	-0.000764^{*}	-0.000899^{*}
City indicator	-0.0488^{**}		-0.00885^{**}	
Underwater indicator	-0.00356	-0.00681	-0.000400	-0.00106
Area under lease	-0.00000129	-0.000000695	-0.000000255	-0.000000152
Lease term (months)	-0.00303^{***}	-0.00306^{***}	-0.000539^{***}	-0.000548^{***}
Shale Thickness & Depth FE	x	x	x	x
Excludes Off Field Observations	x	x	x	x
Omits City Parcels		x		x
N	5882	5655	5882	5655
adj. R^2	0.997	0.997	0.992	0.992

Notes: Conley (2008) spatial HAC standard errors shown in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * p<0.1, ** p<0.05, ***p<0.01. The right-hand side variables are calculated at the section (640 acre) level.

Combining the royalty rate results with intensive margin estimates of oil production outside of cities (the specification of Column 5 of Table 3 but with cities dropped) implies that an additional fee parcel is associated with a -0.18% change in oil production, relative to the sample mean. Dividing by the 0.068% coefficient on fee parcels in Column 2 of Table 6 implies a -0.18/0.068 = -2.64 elasticity of output.[27] The large implied elasticities may suggest that factors additional to royalty rates are contributing to the lower production in finely subdivided areas of the reservation. On the other hand, output elasticities with respect to ad valorem taxes—which are conceptually equivalent to royalty rates—can be large compared to traditional price elasticities of output, suggesting the implied elasticities may be reasonable (see, e.g., Fagan and Jastram 1939 and Pritchard 1943).[28]

7. Policy Experiment, External Validity, and Welfare Interpretation

This section contextualizes our results in terms of their policy relevance, external validity, and welfare implications.

A. Policy Thought Experiment

A 2010 settlement of federal litigation (*Cobell vs. Salazar*) created a $1.9 billion "land consolidation fund" for Native American tribes to buy fractionated allotted trust interests and convert them into tribal ownership.[29] This settlement explicitly recognizes the potential drag that fractionated ownership has on productive resource use, and implicitly assumes that consolidated tribal ownership will be an improvement. On Ft. Berthold, $56,589,204 has been allocated for consolidation (Department of Interior 2013).

We apply the coefficients from Table 4, Column 2 to estimate the effect of replacing allotted parcels with tribal parcels on expected revenue from the fracking boom. Table 6 provides the results and the appendix provides details for our calculations. Consolidation from allotted trust to fee simple is not part of the Cobell settlement, but we include it here as part of

[27] This implied elasticity is about 2.5 times larger (in absolute value) if we try to adjust for differences in the size of a ½ mile radius versus a PLSS section or if we use a specification that includes city parcels.
[28] Anderson et al. (2018) estimate a drilling elasticity of -0.6 with respect to crude oil prices. Elasticities with respect to royalty rates are plausibly larger because of their ad valorem structure, and because drillers on the Bakken during the boom were deciding on where to allocate scarce drilling capital across units with different known aggregate royalty rates rather deciding whether or not to invest in a drilling rig based on uncertain future prices. Distinguishing output price elasticities from royalty rate elasticity is a topic for future research, outside the scope of this paper.
[29] See the Indian Trust Settlement website at www.indiantrust.com/prdoj.php.

the thought experiment for context. Assuming that the tribe collects its average royalty rate of 18%, the net increase in royalty income from the boom would have been $132,043,014.[30] This amounts to $20,824 per American Indian living on the reservation, $10,819 per tribal member, or $26,702 per fractionated interest owner. For context, the per capita income for American Indians living on Ft. Berthold in 2010 was $13,543. The calculations are similar for a conversion to fee simple ownership, suggesting that consolidating into either form of ownership would have increased income gains.

Table 6: Income Gains from Consolidating Allotted Trust

	Convert to Tribal Ownership	**Convert to Fee Simple Ownership**
Δ in Total Oil Revenue	$733,572,301	$806,838,105
Average Royalty Rate	18.0% (Tribal)	17.5 (Non-Tribal)
Δ in Oil Royalty Income	$132,043,014	$141,196,668
Fort Berthold Am. Indian Population (2010)[a]	6,341	6,341
Δ in Oil Royalty Income, per capita	$20,824	$22,267
Three Affiliated Tribes Enrollment (2011)	12,204	12,204
Δ in Oil Royalty Income, per member	$10,819	$11,570
Owners of Fractionated Interests (2012)	4,945	4,945
Δ in Oil Royalty Income, per owner	$26,702	$28,553

Sources: (a) 2010 U.S. Census; (b) http://indianaffairs.nd.gov/statistics/; (c) Dept. of Interior (2013)

The finding that fractionated allotted trust ownership is relatively unproductive is consistent with Russ and Stratmann (2017), who find that that higher degrees of fractionation across allotted trust lands reduce agricultural lease income. At the same time, our findings provide an interesting contrast with Anderson and Lueck (1992), who find that agricultural productivity was higher on fee simple land than on allotted trust land, which was higher than tribal land. Our results suggest that tribal land—if spatially contiguous—is more conducive than allotted trust land for natural resource production. Our results also contrast with Akee and Jorgensen (2015) in an interesting way. They compare business investment on neighboring fee versus trust parcels within the checkerboard of the Agua Caliente Indian Reservation (which was

30 In fact, the tribe rarely charges a royalty rate other than 18%: 449 of the 503 tribal leases in our sample charge exactly 18%.

subject to limited fractionation and allowed long-term leasing of trust lands) and find little evidence of differences. Our approach is complementary because we are interested in the effects of development across, rather than within, checkerboarded landscapes in a setting where fractionation is high.

Our findings extend the important literature on fractionation and allotted trust lands by highlighting a) how fractionation can impair the productivity of neighboring land and b) how the benefits and costs of tribal ownership depend on its spatial configuration. Our explanation for these findings focuses on how the costs of resource use vary with the number of excluders, which in turn varies based on ownership arrangements. This focus on transaction costs is supported by case studies of the barriers to resource development on fractioned trust lands that emphasize large-*N* problems.[31]

The calculations might overstate the per capita income gains to tribal members from consolidation into tribal ownership because there is no guarantee that tribal government revenues would be distributed to individual members.[32] Oil revenues accrued by governments are sometimes subject to corruption. In Brazil, for example, there is no evidence that windfall earnings from offshore oil accrued by municipal governments helped the average citizen (Caselli and Michaels 2013). In our empirical case, the former Tribal Chairman of the Three Affiliated Tribes was the subject of a "Tale of Oil, Corruption and Death" (Sontag and McDonald 2014). The narrative highlights, among other things, the tribal government's purchase of a 96-foot yacht costing $2.5 million. The new Tribal Chairman recently said that 85% of royalty earnings were distributed to each member, who also received added health insurance.[33]

Given concerns about environmental damages and other negative consequences of resource booms, we emphasize that our estimates reflect foregone earnings due to ownership

[31] Shoemaker (2003, 760) describes the problem of leasing on fractionated Indian reservation land and cites an example in which an oil company did not complete a lease "…after realizing how much work was involved in obtaining the necessary signatures from 101 heirs, of whom the BIA had no address for 21 and 6 were deceased with estates still pending agency probate."

[32] On the other hand, the calculations in Table 6 might understate foregone income because they focus on only the first 18 months of royalty payments. Estimates of oil decline curves from Hughes (2012) suggest that only 33 percent of oil from a typical Bakken well will be extracted within the first 18 months. In spite of this, the $132 million in estimated income gains from consolidation into tribal ownership exceeds the $57 million purchase ceiling that the Cobell Settlement has initially allocated to Ft. Berthold to purchase and consolidate fractionated interests (Dept. of Interior 2013, p. 13).

[33] See http://www.kfyrtv.com/content/news/Fort-Berthold-reservation-oil-and-gas-royalties-help-insure-tribal-members-480845371.html.

fragmentation rather than welfare impacts. The income benefits of more aggressive drilling likely overstate the associated welfare gains because of greater risk of local environmental harm (Bartik et al. 2017). We recognize this issue but point out that, on Fort Berthold and elsewhere, residents were exposed to drilling disamenities (e.g., noise, pollution, crime, congestion) regardless of the extent to which they were compensated for their shale ownership. The worst scenario, it seems, is to face institutional constraints on compensation while still being exposed to the disamenities of a resource boom.

B. External Validity

Our empirical estimates come from Ft. Berthold, which contains three ownership arrangements prevalent across the world: private, co-owned, and government. Because the setting is a Native American reservation, however, the reader might wonder if the results generalize to other settings where cultures and preferences towards drilling may differ. Our theoretical framing implies that transaction costs and coordination challenges should grow with N across contexts, albeit at potentially different rates. Just as with common pool problems studied by Ostrom (1990), variation in culture, preferences, and governance will affect the severity of the anticommons trade-offs we study.

While a thorough investigation of other settings is outside the scope of this paper, we can provide some evidence that our findings apply to broader comparisons of government versus subdivided private land. Table 7 replicates our approach from Table 4 but focuses on patterns of drilling on and around private vs. federal Bureau of Land Management and Forest Service land. Figure A3 in the appendix illustrates the off-reservation sample used for the estimation. We emphasize the data used here measure surface ownership rather than subsurface ownership. As a consequence, the Table 7 coefficients are less precisely estimated than those in Tables 3 and 4.

The results in Table 7 are similar to our comparisons of private versus tribal land on the reservation. The coefficients in Column 2 suggest a threshold parcel size of 1.75 acres, which is comparable to the 4.6-acre threshold for the fee vs. tribal comparison. The effect of parcel size and the number of neighbors may be smaller off the reservation due to forced pooling laws off the reservations that reduce the number of mineral owners whose consent is necessary to form a unit. Despite this difference, the results are qualitatively and quantitatively similar results to our fee versus tribal comparison: a private parcel large enough to comprise an entire drilling unit would earn more than an equivalently sized government parcel, but subdividing private land reduces expected revenue.

Table 7: Off Reservation Estimates of Per Acre Revenue from Drilling

	(1)	(2)	(3)	(4)	(5)
Parcel Variables					
Parcel acres	3.074	3.872	1.693	2.091	0.809
	(2.353)	(4.403)	(2.777)	(5.927)	(3.588)
Fee parcel indicator	5767.9**	7896.6***	5660.1**	6339.0**	6168.0**
	(2449.7)	(2701.7)	(2741.5)	(2724.6)	(3106.1)
Neighbor Variables					
Fee neighbors	-1.184*	-8.922*	-11.00**	-13.01***	-11.06***
	(0.678)	(4.806)	(5.132)	(4.810)	(4.243)
Govt. acres in neighborhood	-2.218***	-1.465	-0.528	-0.837	-0.626
	(0.719)	(0.977)	(0.772)	(1.238)	(0.976)
Govt. acres x Govt. parcel indic.	1.069	1.953	2.011	1.340	2.771
	(1.187)	(1.317)	(1.535)	(1.642)	(2.041)
Shale thickness & depth FE	x	x	x	x	x
Excludes parcels off fields		x	x	x	x
Oil field FE			x		x
Excludes parcels if revenue =0				x	x
Adjusted R-squared	0.484	0.501	0.645	0.549	0.678
Observations	94865	33354	33354	26654	26654

Notes: Conley (2008) spatial HAC standard errors shown in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * $p<0.1$, ** $p<0.05$, *** $p<0.01$. A parcel's neighborhood includes all parcels touching a half-mile radius from the parcel's boundary. All specifications control for the slight variation in the total area of the radius, due to variation in the size of parcels on the exterior of the radius. All specifications also control for topographical roughness, an indicator for whether or not the parcel is in a city, an indicator for whether or not the parcel is underwater, nearest distance to a road, and the number of mineral parcels within the radius that lie beneath the high water mark of the Missouri River. Columns 2 and 3 use only parcels that are on a designated oil field. Columns 3 includes oil field fixed effects. Columns 4-5 exclude all parcels that were not members of a drilled unit through May 2015.

We emphasize that the particular threshold parcel size at which government ownership dominates subdivided private ownership is a context-specific empirical question influenced by a variety of factors other than those we focus on including culture, individual preferences, and the structure of government. Despite this, the similarity of the on versus off reservation findings suggests that our primary results are not driven by idiosyncratic factors that are unique to Ft. Berthold (such as cultural differences across tenure types), but are reflective of broader trade-offs associated with private vs. public ownership. Future research should explore this trade-off in the context of other spatially expansive natural resources.[34]

[34] Lueck (1995) argues that the explanation for government versus private ownership of wildlife depends in part on the size of private landholdings.

8. Conclusion

Does private or government ownership lead to greater subsurface utilization? It depends. This paper studies a key tradeoff associated with government vs. private ownership. Under both forms of ownership, resource use depends on the cost of access, which in turn depends on the number of agents with authority to permit or preclude mineral use. The number of government-agent excluders varies with governance structure, but it is invariant to the spatial scale of resource extraction. The number of excluders under private ownership varies with parcel size, land fragmentation, and the spatial scale of resource extraction. Together these factors determine a threshold minimum size of private parcels below which government ownership yields greater resource use.

We find that tribal ownership outperforms private, fee simple ownership for shale oil extraction on the Fort Berthold Indian reservation if parcel sizes are less than five acres. Tribal ownership outperforms allotted trust (heirship ownership) if parcels sizes are less than 63 acres. For context, we note that 84% of the world's farms are smaller than five acres and a significant proportion of the world's land is held by heirs who share fractionated ownership interests. These findings suggest that government ownership may be the appropriate regime in most countries, in spite of the corruption, bureaucratic red tape, and mismanagement that often accompany governmental control.

Our policy thought experiment indicates significant gains from consolidating subsurface ownership and highlights another angle from which to view the legacy of Native American land allotment. Accounts written by sociologists, historians, and legal scholars characterize the injustices of allotment by documenting the large transfers of resource wealth from Native Americans that resulted (see, e.g., Banner 2005). We join other economists by emphasizing that allotment did more than transfer wealth; it also affected resource productivity by creating new systems and mixtures of tenure. Our contribution is to emphasize how fragmentation impaired development of a valuable, large-scale natural resource. Back-of-the envelop estimates suggest fragmentation reduced Fort Berthold's earnings from the fracking boom by an amount comparable to annual income from other sources. Moreover, we expect that fragmented ownership has reduced rents on other Native Americans lands that harbor large stocks of oil and natural gas shale, and hold other spatially expansive resources with value such as wind. [35]

Our findings quantify a barrier to the development of large-scale resources that matters beyond Indian reservations—checkerboarded private and public ownership. Projects spanning scattered government holdings within a mostly privatized landscape cannot avoid the fixed costs of negotiating with government agents, nor can they capitalize on the relative advantages of large, contiguous government ownership that avoid the marginal cost of contracting with additional private owners. This finding highlights the need for future research on resource development across, rather than just within, mosaics of private and public ownership such as the Wyoming checkerboard.

It is also worth emphasizing that land fragmentation may inhibit conservation as well as extraction. In the case of fracking, coordination challenges from ownership fragmentation can make it difficult for neighbors to act collectively to prevent oil drilling at a scale large enough to eliminate exposure to adverse effects. This is analogous to Hansen and Libecap (2004), who explain how high coordination costs among small landowners exacerbated environmental pollution during the U.S. dust bowl era. We note that some tribes such as the Turtle Mountain Band of Chippewa in North Dakota banned fracking entirely within reservation boundaries, a policy that would likely not be possible for reservations that are checkerboarded with fee simple and allotted trust parcels.[36]

Our study also raises questions for future research about how to mitigate the drawbacks of private ownership while still capitalizing on its advantages, particularly in the context of modern land reform and titling programs (see, e.g., Alston et al. 1996, de Soto 2000; de Janvry et al. 2015; Aragon and Kessler 2017). One approach might be for governments to retain default ownership to undiscovered resources and to resources that are inaccessible under present technologies. Rights to such resources (e.g., shale oil, wind) could be privatized only after the appropriate scale of resource use is revealed. This may benefit future generations because the

[35] The findings contribute to a literature on how historical policies toward indigenous people have affected modern economic outcomes. This literature includes Brown et al. (2017), Feir (2016), Feir et al. (2017), Akee et al. (2015), Dippel (2014), Dimitrova-Grajzl et al. (2014), Cookson (2010), Akee (2009), Anderson and Parker (2008), Cornell and Kalt (2000), Anderson and Lueck (1992), Carlson (1981), and Trosper (1978) among others.

[36] For details on the fracking ban, see www.huffingtonpost.com/sarah-van-gelder/in-north-dakotas-booming_b_9078378.html.

costs of reassembling rights once they have been subdivided generally exceed the costs of dividing large interests into smaller ones (Parisi et al. 2004).

Another alternative is to weaken the exclusion rights of private owners *ex-post*, through the use of eminent domain. In the context of oil development in the United States, this approach comes in the form of forced pooling rules that limit the power of individual landowners to hold up development (Libecap and Wiggins 1985; Vissing 2017). Our findings suggest that significant contracting problems persist in spite of these rules. Furthermore, such rules are politically difficult to impose ex-post, after property right entitlements have been assigned. The end result is that assigning property rights at a particular scale can create costly barriers to time-sensitive investment opportunities, such as those arising during resource booms.

9. References

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Mathematical Appendix

Most compensation to shale owners comes in the form of royalty payments that allocate a proportion of project revenue to mineral owners (Brown et al. 2016, Fitzgerald and Rucker 2016).[37] With royalty payments, the project-level expected profit for the oil developer is

$$\pi_D = Pq(1-R) - C(q). \tag{1}$$

Here, R denotes the project-level royalty rate which is $= \sum_i^N w_i r_i$. Each shale owner charges $r_i \in [0,1]$, where $w_i \in [0,1]$ are weights representing the proportion of owner *i's* mineral acreage in the project. We assume equal shares so that $R = \sum_i^N r_i / N$. Taking royalty rates as given, an oil developer maximizes profits by choosing oil extraction q that solves:

$$\max_q \pi_D = Pq(1-R) - C(q) \tag{2}$$

where P is the expected price of oil, q is the total oil extracted and $C(q)$ is the total cost function satisfying $C'(q) \geq 0$ and $C''(q) \geq 0$. Developers can increase q, the oil recovered from a project, by drilling additional laterals within a spacing unit or increasing their use of inputs such as silica and other ingredients in the fracking solution, and waste disposal after drilling commences. Hence, $C(q)$ reflects increased costs associated with the use of additional inputs for each lateral as well as the costs of drilling multiple laterals in a given area.[38]

Abstracting from uncertainty and discounting, π_D represents the expected present value of the well to the developer.[39] Changes in any parameter can change whether or not a project yields positive surplus in expectation, thereby influencing the probability of drilling. Kellogg (2014)

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[37] Fitzgerald and Rucker (2016) find that royalty payments typically comprise 85-90 percent of payments from a lease with bonus payments comprising 10 to 15 percent. Vissing (2016) finds that bonus payments are positively correlated with other aspects of the lease including royalty rates and terms that are favorable to the landowner.

[38] We model the cost function this way to be as general as possible. An alternative approach is to introduce a fixed cost per well drilled and model the decision of whether or not to drill an additional well. We solved this model in a previous draft and developed qualitatively identical testable predictions. This alternative model is available upon request.

[39] A more realistic expression is $\pi_D = \sum_{t=1}^T \rho^t [E(p_t, q_t) - C(q_t)]$, where T is the life of the well, which is projected to be about 25-30 years in our study area, q_t represents declining production over time, E(p_t) indicates expected prices over the life of the well, and ρ^t is a discount factor. We abstract away from uncertainty and dynamics because making these features explicit would add complexity to the theory without providing additional insights.

highlights the importance of volatility when analysing the effect of expected output price and other parameters on the drilling decision. We take those dynamics—and the interest rate—as given and focus on how changes in leasing behaviour alter the demand for oil.

B. The Landowner's Problem

We now develop the intuition for the anticommons in our setting, building on Buchanan and Yoon (2000), Schulz et al. (2002) and Parisi and Depoorter (2004). Each of *N* excluders to a resource charges an individual price for use. Permission to use the resource is not granted unless all excluders consent, and consent is granted only if each excluder's asking price is paid. The unique feature of our setting is that, rather than charging a fixed fee, each shale owner chooses a royalty rate r_i in an attempt to maximize his expected payout:

$$\max_{r_i} \pi_i = \frac{r_i}{N} Pq(P, R) \tag{3}$$

where N is the total number of excluders in the unit and $q(P, R)$ is the demand for oil, derived from the solution to the developer's problem. Each landowner chooses an individually optimal royalty rate, taking as given the royalty rates requested by the other excluders in the unit.

C. Equilibrium and Comparative Statics

Following Buchanan and Yoon (2000), we focus on the symmetric Nash equilibrium where r_i is the same for all landowners. We highlight several comparative statics associated with the equilibrium oil demand $q^*(P, R)$ and royalty rate $r_i^*(N)$:

P5) $\frac{\partial r_i^*(N)}{\partial N} = \frac{\partial R}{\partial N} > 0$ (The aggregate royalty rate is increasing in N)

P6) $\frac{\partial q^*(P,R)}{\partial N} < 0$ (Oil production is decreasing in N)

P7) $\frac{\partial \pi_D(P,N)}{\partial N} < 0$ (Project-level surplus is decreasing in N)

P8) $\frac{\partial \pi_i(P,N)}{\partial N} < 0$ (Landowner compensation is decreasing in N)

1. Proof that $\frac{\partial q^*(P,R)}{\partial R} < 0$

The oil driller's decision problem is:

$$\max_{q} \pi_D = Pq(1 - R) - C(q)$$

First-Order Necessary Condition:

$$\frac{\partial \pi_D}{\partial q} = P(1-R) - C'(q) = 0$$

Second-Order Sufficient Condition:

$$\frac{\partial^2 \pi_D}{\partial q^2} = -C''(q) \leq 0 \qquad \Leftrightarrow \qquad C''(q) \geq 0$$

When the second order condition holds, the first-order condition defines an implicit function:

$$q^* = q^*(P, R)$$

Plugging the optimal q^* back into the first-order condition yields the following identity:

$$P(1-R) - C'(q^*(P,R)) \equiv 0$$

Which can be differentiated with respect to R:

$$-P - C''(q^*(P,R))\frac{\partial q^*(P,R)}{\partial R} \equiv 0$$

Which implies:

$$\boldsymbol{\frac{\partial q^*(P,R)}{\partial R} \equiv \frac{-P}{C''\left(q^*(P,R)\right)} < 0}$$

This expression is less than zero by the second order condition. I.e. the demand for oil is decreasing in the royalty rate. QED.

2. Proof that $\boldsymbol{\frac{\partial r_i^*(N)}{\partial N} = \frac{\partial R}{\partial N} > 0}$

Recall the landowner's problem:

$$\max_{r_i} \pi_i = \frac{r_i}{N} Pq(P,R)$$

Where $R = \frac{\sum_{i=1}^{N} r_i}{N}$ and hence $\frac{\partial R}{\partial r_i} = \frac{1}{N}$

First-order condition:

$$\frac{\partial \pi_i}{\partial r_i} = \frac{Pq(P,R)}{N} + \frac{r_i}{N}\frac{\partial q(P,R)}{\partial R}\frac{\partial R}{\partial r_i} = 0$$

$$\frac{P}{N}\left[q(P,R)+\frac{r_i}{N}\frac{\partial q(P,R)}{\partial R}\right]=0$$

Which requires

$$q(P,R)+\frac{r_i}{N}\frac{\partial q(P,R)}{\partial R}=0$$

Second-order condition:

$$\frac{\partial q(P,R)}{\partial R}\frac{\partial R}{\partial r_i}+\frac{1}{N}\frac{\partial q(P,R)}{\partial R}+\frac{r_i}{N}\frac{\partial^2 q(P,R)}{\partial R^2}\frac{\partial R}{\partial r_i}\leq 0$$
$$\Leftrightarrow$$
$$\frac{\partial q(P,R)}{\partial R}\frac{1}{N}+\frac{1}{N}\frac{\partial q(P,R)}{\partial R}+\frac{r_i}{N}\frac{\partial^2 q(P,R)}{\partial R^2}\frac{1}{N}\leq 0$$
$$\Leftrightarrow$$
$$\frac{1}{N}\left[2\frac{\partial q(P,R)}{\partial R}+\frac{r_i}{N}\frac{\partial^2 q(P,R)}{\partial R^2}\right]\leq 0$$
$$\Leftrightarrow$$
$$2\frac{\partial q(P,R)}{\partial R}+\frac{r_i}{N}\frac{\partial^2 q(P,R)}{\partial R^2}\leq 0$$
$$\Leftrightarrow$$
$$2q'+\frac{r_i}{N}q''\leq 0$$

At landowner i's optimum the first-order condition defines an implicit function:

$$r_i^* = r_i^*(N, r_{-i})$$

Plugging back into the FOC yields the following identity

$$q\left(P,\frac{\sum_{i=1}^N r_i^*(N,r_{-i})}{N}\right)+\frac{r_i^*(N,r_{-i})}{N}\frac{\partial q(P,\frac{\sum_{i=1}^N r_i^*(N,r_{-i})}{N})}{\partial\frac{\sum_{i=1}^N r_i^*(N,r_{-i})}{N}}\equiv 0$$

And, in the symmetric Cournot-Nash equilibrium,

$$r_i^* = r_i^*(N) \quad \forall i$$

This implies

$$R=\frac{\sum_{i=1}^N r_i^*(N)}{N}=\frac{N r_i^*(N)}{N}=r_i^*(N)$$

Updating the identity:

$$q\big(P, r_i^*(N)\big) + \frac{r_i^*(N)}{N}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} \equiv 0$$

Differentiating with respect to N:

$$\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}\frac{\partial r_i^*(N)}{\partial N} + \frac{\partial r_i^*(N)}{\partial N}\frac{1}{N}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} + \frac{r_i^*(N)}{N}\frac{\partial^2 q(P, r_i^*(N))}{\partial r_i^*(N)^2}\frac{\partial r_i^*(N)}{\partial N} - \frac{r_i^*(N)}{N^2}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} \equiv 0$$

$$\Rightarrow$$

$$\frac{\partial r_i^*(N)}{\partial N}\left[\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} + \frac{1}{N}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} + \frac{r_i^*(N)}{N}\frac{\partial^2 q(P, r_i^*(N))}{\partial r_i^*(N)^2}\right] \equiv \frac{r_i^*(N)}{N^2}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}$$

$$\Rightarrow$$

$$\frac{\partial r_i^*(N)}{\partial N}\left[\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}\frac{N+1}{N} + \frac{r_i^*(N)}{N}\frac{\partial^2 q(P, r_i^*(N))}{\partial r_i^*(N)^2}\right] \equiv \frac{r_i^*(N)}{N^2}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}$$

$$\Rightarrow$$

$$\frac{\partial r_i^*(N)}{\partial N} \equiv \left. \frac{r_i^*(N)}{N^2}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} \middle/ \left[\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}\frac{N+1}{N} + \frac{r_i^*(N)}{N}\frac{\partial^2 q(P, r_i^*(N))}{\partial r_i^*(N)^2}\right]\right.$$

Note that the numerator, $\frac{r_i^*(N)}{N^2}\frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)} < 0$ (See Driller's Problem)

Therefore $\frac{\partial r_i^*(N)}{\partial N}$ is positive if and only if the denominator is negative:

$$\frac{\partial r_i^*(N)}{\partial N} > 0 \iff \frac{\partial q(P, r_i^*(N))}{\partial r_i^*(N)}\frac{N+1}{N} + \frac{r_i^*(N)}{N}\frac{\partial^2 q(P, r_i^*(N))}{\partial r_i^*(N)^2} < 0$$

$$\iff (N+1)q' + r_i^*(N)q'' < 0$$

$$\iff r_i^*(N)q'' < -(N+1)q'$$

By the second order condition,

$$2q' + \frac{r_i}{N}q'' \leq 0$$

$$\iff r_i q'' \leq -2Nq'$$

This implies that

$$\frac{\partial r_i^*(N)}{\partial N} > 0 \iff -(N+1)q' > -2Nq'$$

$$\iff 2Nq' > (N+1)q'$$

$$\Leftrightarrow 2N > (N+1)$$

$$\Leftrightarrow N > 1$$

Therefore,

$$\frac{\partial r_i^*(N)}{\partial N} = \frac{\partial R}{\partial N} > 0$$

Individual and aggregate royalty rates are increasing in N. QED.

3. Proof that $\frac{\partial q^*(P,R)}{\partial N} < 0$

This follows directly from results 1 and 2:

$$\frac{\partial q^*(P,R)}{\partial N} \equiv \underset{(-)}{\frac{\partial q^*(P,R)}{\partial R}} \times \underset{(+)}{\frac{\partial r_i^*(N)}{\partial N}} < 0$$

The demand for oil is decreasing in the number of exclusion right holders. QED.

4. Proof that $\frac{\partial \pi_D(P,N)}{\partial N} < 0$

The oil driller's optimized profit function is given by:

$$\pi_D(P,N) = Pq^*\big(P, r_i^*(N)\big)\big(1 - r_i^*(N)\big) - C\left(q^*\big(P, r_i^*(N)\big)\right)$$

Differentiating wrt N:

$$\frac{\partial \pi_D(P,N)}{\partial N} = P\frac{\partial q^*(P,R)}{\partial N} - Pr_i^*(N)\frac{\partial q^*(P,R)}{\partial N} - P\frac{\partial r_i^*(N)}{\partial N} q^*\big(P, r_i^*(N)\big) - C'\left(q^*\big(P, r_i^*(N)\big)\right)\frac{\partial q^*(P,R)}{\partial N}$$

$$= \frac{\partial q^*(P,R)}{\partial N}\left[P\big(1 - r_i^*(N)\big) - C'\left(q^*\big(P, r_i^*(N)\big)\right)\right] - Pq^*\big(P, r_i^*(N)\big)\frac{\partial r_i^*(N)}{\partial N}$$

$$= -Pq^*\big(P, r_i^*(N)\big)\frac{\partial r_i^*(N)}{\partial N} < 0$$

because the term in brackets is equal to zero by the FOC from the driller's problem. QED.

5. Proof that $\frac{\partial \pi_i(P,N)}{\partial N} < 0$

The landowner's optimized profit function is:

$$\pi_i(P,N) = \frac{r_i^*(N)}{N} P q^*\big(P, r_i^*(N)\big)$$

Differentiating wrt to N:

$$\frac{\partial \pi_i(P,N)}{\partial N} = P\left[\frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*}\frac{\partial r_i^*(N)}{\partial N} + \frac{\partial r_i^*(N)}{\partial N}\frac{q^*\big(P,r_i^*(N)\big)}{N} - \frac{r_i^*(N) q^*\big(P,r_i^*(N)\big)}{N^2}\right]$$

$$= P\left[\underset{(+)}{\frac{\partial r_i^*(N)}{\partial N}}\underset{(?)}{\left(\frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*} + \frac{q^*\big(P,r_i^*(N)\big)}{N}\right)} - \underset{(-)}{\frac{r_i^*(N) q^*\big(P,r_i^*(N)\big)}{N^2}}\right]$$

The first-order condition from the landowner's problem requires:

$$\frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*} + q^*(P,R) = 0$$

This implies

$$\frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*} + \frac{q^*\big(P,r_i^*(N)\big)}{N} < 0 = \frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*} + q^*(P,R)$$

Hence

$$\frac{\partial \pi_i(P,N)}{\partial N} = P\left[\underset{(+)}{\frac{\partial r_i^*(N)}{\partial N}}\underset{(-)}{\left(\frac{r_i^*(N)}{N}\frac{\partial q^*(P,R)}{\partial r_i^*} + \frac{q^*\big(P,r_i^*(N)\big)}{N}\right)} - \underset{(-)}{\frac{r_i^*(N) q^*\big(P,r_i^*(N)\big)}{N^2}}\right] < 0$$

QED.

These are the familiar outcomes of the anticommons model applied to a setting where excluders charge a royalty rate rather than a fixed fee for access. The intuition behind the results is that each landowner trades off the direct benefit of a higher royalty rate against the decrease in the driller's demand for oil. This reduction in demand affects all N landowners but each only considers the effect on his own profits, resulting in a suboptimally high royalty rate that reduces overall compensation.

D. Clarifications and Assumptions

Four clarifications are useful before proceeding. First, shale owners could inadvertently benefit from an anticommons if the price of oil unexpectedly increases after leasing but before drilling. In that case, the demand for oil increases and payouts to shale owners, conditional on drilling, increase because requested royalty rates are high. If future changes in prices and costs are all anticipated, however, then large *N* cannot benefit shale owners.

Second, the model does not consider institutional responses to contracting problems. Forced pooling laws, passed by US states, compel minority mineral owners into horizontal drilling projects if a majority of neighboring acreage has already been leased. State-level forced pooling laws do not generally apply on sovereign Indian reservations (see Slade et al. 1996), but a 1998 federal law specific to Fort Berthold requires the consent of only a majority of owners of allotted trust lands before a mineral lease can be executed. These institutional responses decrease but do not eliminate the problems modeled above.

Third, though the model focuses on a continuous demand function $q^*(P, R)$, the anticommons could affect both the intensive and extensive margin of the drilling decision. The result that $\frac{\partial q^*(P,R)}{\partial N} < 0$ may manifest itself as zero laterals drilled in certain areas.

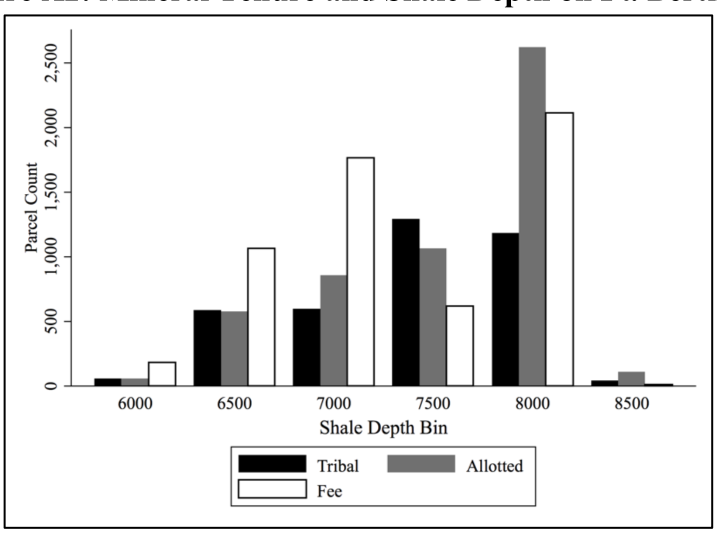
Fourth, the model does not explicitly differentiate government excluders from private individuals. This is abstraction—consistent with Buchanan and Yoon (2000) and Schleifer and Vishny (1993)—assumes the overall "price" of resource use rises with the number of excluders, whether they are government agents (e.g., bureaucrats, interest group lobbyists, local politicians), or individual private shale owners. Although this is a simple view of complex governmental decision-making, it is a framework that is testable in our empirical setting, where we can observe royalty rates charged in government leases versus leases with private owners, in areas of shale with small and large parcels.

Data Appendix

Figure A1: Allotment of American Indian Reservations

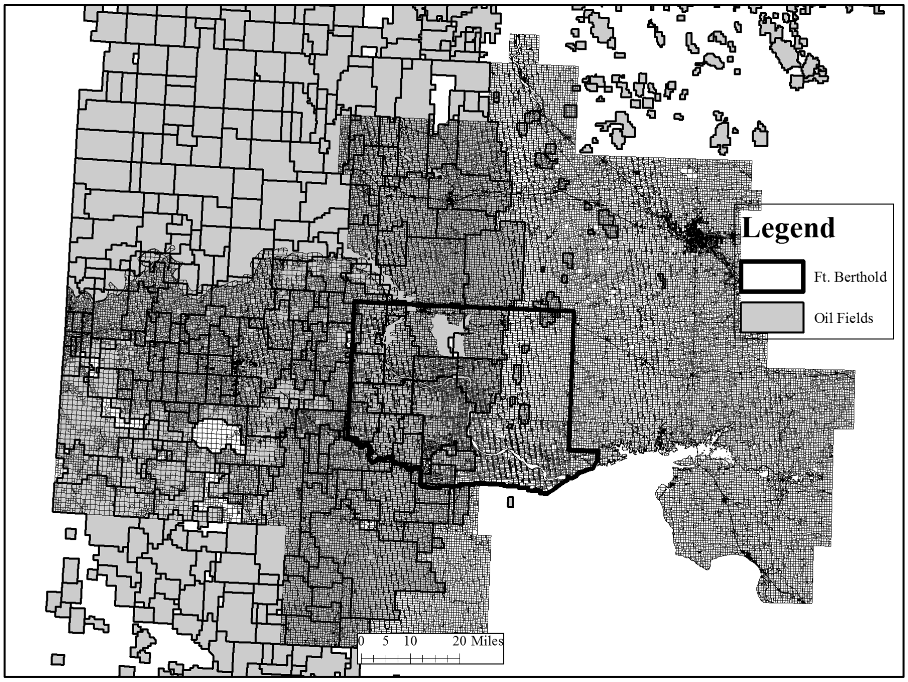
Notes: This map is based on our digitization of an 1890 Office of Indian Affairs map of 97 reservations that were west of the Mississippi River and clearly visible in the original map. With the exception of the Osage Reservation, we exclude Oklahoma because reservations in that state are no longer federally recognized. The data on surplus land and the timing of allotment come from *Indian Land Tenure, Economic Status, and Population Trends* prepared by the Office Indian Affairs of the U.S. Department of Interior in 1935. Based on that report, 68 of the reservations in our sample were allotted to some extent, and surplus land was given to white settlers in 21 reservations. Of the 68 reservations that were allotted, some land was alienated and sold out of trust on 56 reservations. The spatial definitions of shale basins and plays come from the U.S. Energy Information Administration.

Figure A2: Mineral Tenure and Shale Depth on Ft. Berthold



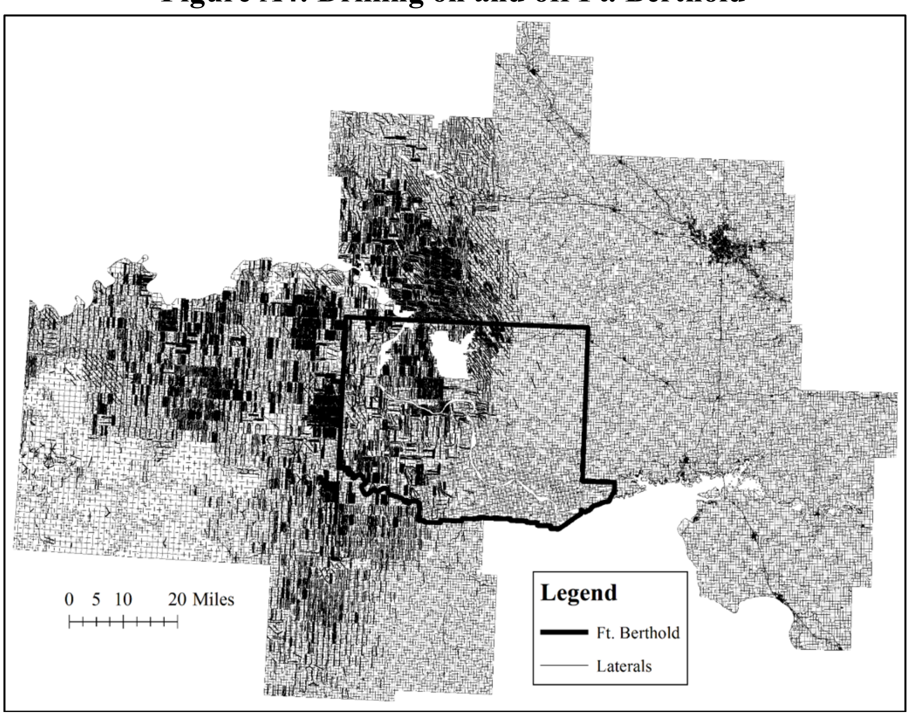
Notes: This figure depicts the number of parcels from each tenure category in each shale depth bin on the Ft. Berthold Indian Reservation. Shale thickness and depth estimates obtained from the North Dakota Oil and Gas Commission. Reservation parcels represent mineral ownership and were obtained from the Bureau of Indian Affairs.

Figure A3: Oil Fields in Study Area



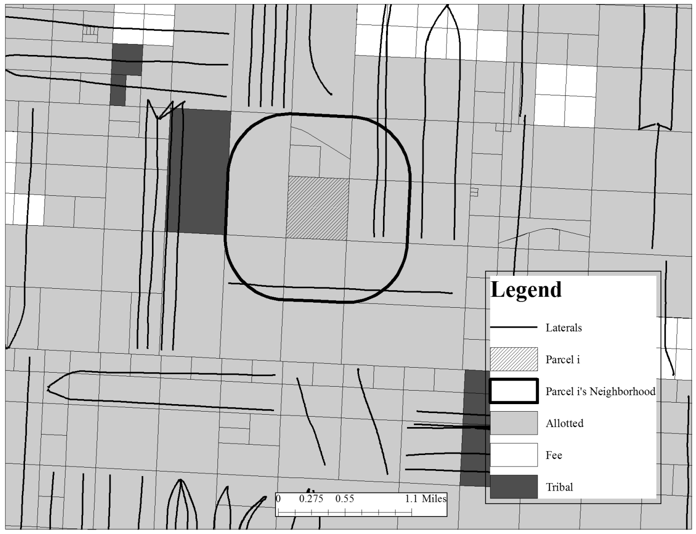
Notes: This figure depicts active oil fields on and around the Ft. Berthold Indian Reservation. Oil fields are administrative units that represent collection of drilling spacing units and are formed by the State. Areas not covered by an oil field had not experienced oil and gas development as of May, 2015. Data on oil fields were obtained from the North Dakota Oil and Gas Commission website.

Figure A4: Drilling on and off Ft. Berthold



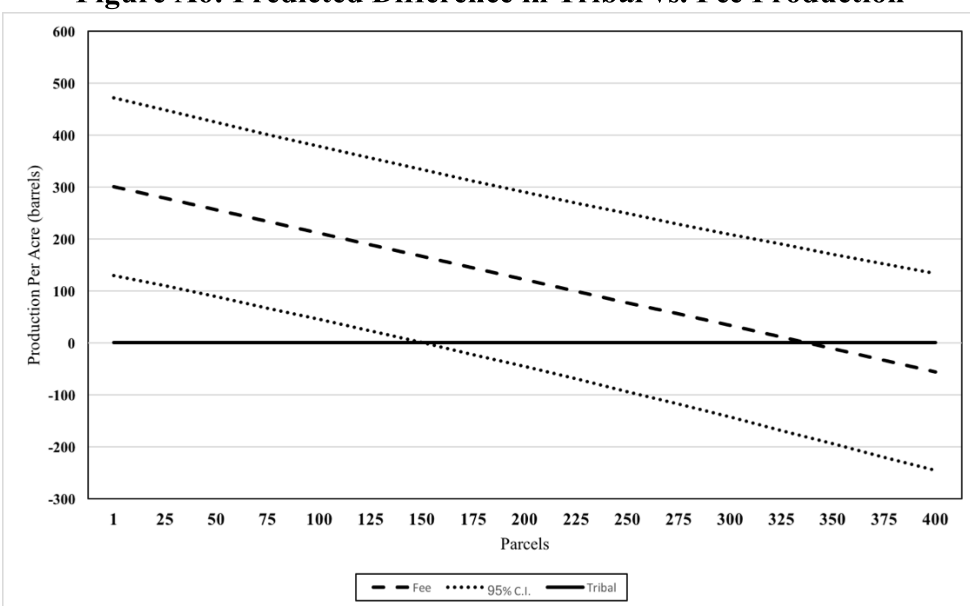
Notes: This figure depicts all lateral oil wells on and around the Ft. Berthold Indian Reservation as of May, 2015. Data were obtained from the North Dakota Oil and Gas Commission website.

Figure A5: Parcel i's Neighborhood



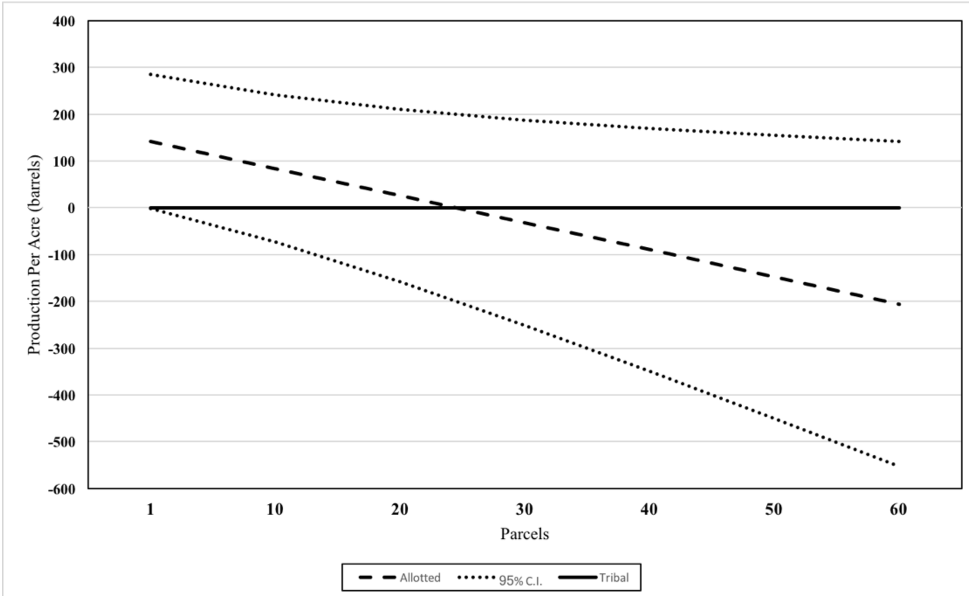
Notes: This figure illustrates our mapping from the spatial data to the variables. We determine the total number and acreage of parcels of each tenure within a ½-mile radius of each parcel.

Figure A6: Predicted Difference in Tribal vs. Fee Production



Notes: This figure plots the predicted effect of subdividing a 1,550-acre neighborhood into each fee vs. tribal ownership, based on the coefficient estimates in Table 3. The vertical intercept represents expected production on a single large fee parcel and is based on $\hat{\lambda}_F$. The slope of the line is determined by the estimated neighbor coefficient ($\hat{\beta}_F$).

Figure A7: Predicted Difference in Tribal vs. Allotted Trust Production



Notes: This figure plots the predicted effect of subdividing a 1,550-acre neighborhood into allotted trust vs. tribal ownership, based on the coefficient estimates in Table 3. The vertical intercept represents expected production on a single large allotted parcel and is based on $\hat{\lambda}_A$. The slope of the line is determined by the estimated neighbor coefficient ($\hat{\beta}_A$).

Table A1: Tests for Marginal Effect of Expanding Tribal Ownership

	Y= Production Per Acre			Y= Revenue Per Acre		
	(1)	(2)	(3)	(4)	(5)	(6)
Parcel Variables						
Parcel acres (ϕ)	0.919***	0.891***	0.913***	30.65***	34.64***	35.61***
	(0.232)	(0.240)	(0.234)	(8.244)	(9.981)	(9.691)
Fee parcel indicator (λ_F)	300.6***	350.7***	146.1**	10182.5***	14096.7***	6125.3*
	(103.9)	(106.4)	(73.28)	(3875.9)	(4437.0)	(3190.9)
Allotted parcel indicator (λ_A)	141.5*	198.8**	296.2***	5076.8**	8640.2**	11499.8***
	(73.10)	(85.95)	(104.2)	(2802.1)	(3672.4)	(4442.8)
Neighbor Variables						
Fee neighbors (β_F)	-0.893***	-0.886***	-0.897***	-30.93***	-35.67***	-36.15***
	(0.200)	(0.205)	(0.205)	(7.205)	(8.500)	(8.468)
Allotted trust neighbors (β_A)	-5.784**	-7.280***	-6.247**	-203.6**	-298.1***	-253.0**
	(2.562)	(2.547)	(2.599)	(89.57)	(103.4)	(106.2)
Tribal Neighbor Indicator (β_T)	-179.4***		-154.5***	-6649.5***		-6751.9***
	(52.68)		(54.01)	(1948.9)		(2334.1)
Tribal Neighbor Indicator X Tribal Indicator (β_{T1})	71.49		47.30	2208.3		1833.2
	(76.75)		(118.7)	(2855.1)		(5010.5)
Tribal Acreage (β_{TArea})		-0.341***	-0.122		-14.62***	-5.051
		(0.117)	(0.105)		(5.151)	(4.733)
Tribal Acreage X Tribal Indicator (β_{T1Area})		0.219*	0.0604		9.008*	2.106
		(0.115)	(0.109)		(4.899)	(4.690)
Shale thick & depth FE	x	x	x	x		x
Covariate controls	x	x	x	x		x
Excludes parcels off fields	x	x	x	x		x
Adjusted R-squared	0.552	0.547	0.552	0.575	0.532	0.538
Observations	8524	8524	8524	8524	8524	8524

Notes: Conley (2008) spatial HAC standard errors shown in parentheses. Following Hsiang (2010), these models are estimated using a GMM approach that allows for arbitrary forms of spatial correlation in the error term, as described in Conley (2008). * p<0.1, ** p<0.05, *** p<0.01. A parcel's neighborhood includes all parcels touching a half-mile radius from the parcel's boundary. All specifications control for the slight variation in the total area of the radius, due to variation in the size of parcels on the exterior of the radius. All specifications also control for topographical roughness, an indicator for whether or not the parcel is in a city, an indicator for whether or not the parcel is underwater, nearest distance to a road, and the number of mineral parcels within the radius that lie beneath the high water mark of the Missouri River. The specifications in each column mimics those of Column 2 in Table 3. Column 1 here is identical to Column 1 of Table 3, and Column 4 here is identical to Column 2 of Table 4.

Table A5 provides a more direct test of the theoretical proposition that adding *any amount* of tribal land to the neighborhood around a fee or allotted parcel will add a fixed number of excluders and hence reduce production, *ceteris paribus*. For reference, Column 1 mimics the baseline specification shown in Table 3 and Column 4 mimics the baseline from Table 4. In Columns 2 and 4, we include Tribal Acreage, rather than the single indicator for whether or not there is a tribal neighbor. Columns 3 and 6 include both measures—the indicator for a tribal neighbor and the tribal acreage variable—to explicitly test whether tribal acreage matters, conditional on having any tribal land in the neighborhood.

The $\hat{\beta}_{TArea}$ coefficients on Tribal Acreage in Columns 2 and 4 are negative, indicating that more tribal acreage is associated with less production and revenue for parcel *i*, as long as that parcel is allotted or fee. The combined coefficients ($\hat{\beta}_{TArea} + \hat{\beta}_{T1Area}$)are statistically indistinguishable from zero (p = 0.18 in Column 2 and p = 0.16 in Column 5), implying expanding tribal acreage has no marginal effect if parcel *i* is tribal. Similarly, the results in Columns 3 and 6 show that greater tribal acreage, conditional on a tribal presence, does not have a significant marginal effect. Joint tests reject the null hypothesis of $\hat{\beta}_T + \hat{\beta}_{T1} + \hat{\beta}_{TArea} + \hat{\beta}_{T1Area} = 0$ (p = 0.34 in Column 2 and p = 0.29 in Column 5). Considered together, these estimates suggest that adding a single government parcel decreases resource use to a greater extent than adding a single private parcel, and that this effect is invariant to the size of government holdings.

Table A2: Production Estimates with Year Fixed Effects

	(1)	(2)	(3)
Parcel Variables			
Parcel Acres (ϕ)	0.900***	0.894***	0.758***
	(0.304)	(0.305)	(0.284)
Fee parcel indicator (λ_F)	337.3***	337.2***	316.7***
	(119.0)	(119.0)	(99.30)
Allotted parcel indicator (λ_A)	232.2**	232.7**	224.4***
	(97.14)	(97.17)	(83.56)
Neighbor Variables			
Fee neighbors (β_F)	-0.988***	-0.988***	-0.908***
	(0.197)	(0.196)	(0.170)
Allotted trust neighbors (β_A)	-7.863***	-7.747**	-5.465**
	(3.001)	(3.050)	(2.420)
Tribal Neighbor Indicator (β_T)	-221.0***	-221.6***	-219.2***
	(56.66)	(56.85)	(49.80)
Tribal Neighbor Indicator	113.7	114.0	111.5
X Tribal Indicator (β_{T1})	(105.7)	(105.7)	(86.94)
Shale thick and depth FE	x	x	x
Covariate controls	x	x	x
Excludes parcels off fields		x	x
Oil Field FE			x
Exclude parcels if revenue =0	x	x	x
Drilling year FE	x	x	x
adj. R^2	0.654	0.654	0.675
N	6150	6140	6140

Notes: The standard errors, clustered by township, are shown in parentheses. * p<0.1, ** p<0.05, ***p<0.01. The specifications mimic columns 1-3 of Table 3. Columns 4 and 5 would be redundant because adding drilling year fixed effects automatically drops parcels that are never compensated. All columns add a fixed effect based on the year in which a unit associated with a parcel was first drilled.

Table A3: Revenue Estimates with Year Fixed Effects

	1% discount	3% discount	5% discount	3% discount	3% discount	3% discount
	(1)	(2)	(3)	(4)	(5)	(6)
Parcel Acres (ϕ)	40.74***	34.60***	29.44***	33.96***	35.53***	38.37**
	(14.91)	(12.76)	(10.95)	(12.60)	(13.05)	(16.60)
Fee parcel indicator (λ_F)	14788.9**	12944.3**	11349.7**	12587.3**	13706.9***	14234.6**
	(5868.4)	(5118.2)	(4470.9)	(5021.1)	(5125.3)	(5614.6)
Allotted parcel indicator (λ_A)	10746.0**	9324.3**	8103.6**	8330.4**	9449.4**	9281.1*
	(4759.8)	(4191.1)	(3693.3)	(3981.3)	(4204.2)	(4773.2)
Neighbor Variables						
Fee neighbors (β_F)	-49.10***	-41.69***	-35.45***	-39.66***	-49.53***	-30.20***
	(9.844)	(8.396)	(7.172)	(7.821)	(8.680)	(6.984)
Allotted neighbors (β_A)	-382.5**	-331.1**	-287.1***	-350.4***	-332.8***	-183.1***
	(152.1)	(128.7)	(109.2)	(123.7)	(124.6)	(66.06)
Tribal neighbor indicator (β_T)	-11101.1***	-9512.3***	-8161.0***	-9335.2***	-9549.0***	-8527.9***
	(2894.1)	(2478.4)	(2125.8)	(2346.5)	(2131.0)	(2244.7)
Tribal neighbor indicator	4467.8	3949.8	3499.7	2603.6	3198.3	4798.1
X Tribal indicator (β_{T1})	(5156.5)	(4503.5)	(3938.4)	(4369.8)	(4405.4)	(5313.3)
Shale thick and depth FE	x	x	x	x	x	x
Covariate controls	x	x	x	x	x	x
Excludes parcels off fields	x	x	x	x	x	x
x & y coordinate controls				x		
Excludes parcels in cities					x	
One mile radius						x
Drilling year fixed effects	x	x	x	x	x	x
adj. R^2	0.636	0.640	0.644	0.642	0.635	0.643
N	6140	6140	6140	6140	4985	5472

Notes: The standard errors, clustered by township, are shown in parentheses. * p<0.1, ** p<0.05, ***p<0.01. Columns 1-3 discount revenue per acre at 1%. 3%, and 5%, respectively. The specifications in Columns 1-3 are identical to those in Column 2 of Table 3. Columns 4-6 are robustness checks, based on the revenue estimates discounted at 3%. Column 4 adds controls for the longitude and latitude of each parcel's centroid. Column 5 omits parcels in cities. Column 6 defines the neighborhood with a one-mile radius rather than a ½ mile radius. All columns add a fixed effect based on the year in which a unit associated with a parcel was first drilled.

Table A4: Tobit Estimates of Production per Acre

	(1)	(2)	(3)
Parcel Variables			
Parcel acres (ϕ)	1.232***	1.269***	1.070***
	(0.289)	(0.290)	(0.262)
Fee parcel indicator (λ_F)	271.4*	311.9**	242.9**
	(146.5)	(146.6)	(103.6)
Allotted trust parcel indicator (λ_A)	105.4	132.4	142.6*
	(110.3)	(108.9)	(86.27)
Neighbor Variables			
Fee neighbors (β_F)	-0.885***	-0.937***	-0.888***
	(0.295)	(0.294)	(0.279)
Allotted trust neighbors (β_A)	-7.247**	-7.594**	-2.886
	(3.599)	(3.578)	(4.354)
Tribal Neighbor Indicator (β_T)	-152.4**	-179.9***	-189.1***
	(61.84)	(59.96)	(46.12)
Tribal Neighbor Indicator X	5.181	46.27	64.35
Tribal Indicator (β_{T1})	(119.4)	(115.6)	(89.42)
Covariate Controls			
Underwater indicator	-191.7***	-184.3***	-185.1***
Underwater neighbors	-21.21***	-20.64***	-16.53***
Topographic roughness	-2.199**	-2.250**	-2.129**
Road density	-35.51	-39.30	0.307
City indicator	191.2	145.4	92.32
Shale thickness & depth FE	x	x	x
Excludes parcels off fields		x	x
Oil field FE			x
Excludes parcels if revenue =0			
Pseudo R-squared	0.086	0.033	0.042
Observations	12557	8524	8524
Obs. Censored at Zero	6,343	2,320	2,320

Notes: The standard errors, clustered by township, are shown in parentheses. * p<0.1, ** p<0.05, ***p<0.01. A parcel's neighborhood includes all parcels touching a half-mile radius from the parcel's boundary. All specifications control for the slight variation in the total area of the radius, due to variation in the size of parcels on the exterior of the radius. Column 1 employs all parcels, whether or not the parcels are on a designated oil field. Columns 2 and 3 use only parcels that are on a designated oil field. Columns 3 includes oil field fixed effects. Columns 4-5 exclude all parcels that were not drained of oil through May 2015.

Table A5: Tobit Estimates of Revenue per Acre and Robustness

	1% discount	3% discount	5% discount	3% discount	3% discount	3% discount
	(1)	(2)	(3)	(4)	(5)	(6)
Parcel Variables						
Parcel acres (ϕ)	59.00***	50.48***	43.27***	48.98***	51.90***	55.08***
	(14.36)	(12.32)	(10.59)	(11.56)	(13.08)	(21.04)
Fee parcel indicator (λ_F)	13923.2**	12116.6*	10566.1*	11542.7*	12977.2**	14092.0**
	(7085.3)	(6187.0)	(5412.1)	(6096.0)	(6129.7)	(6055.4)
Allotted parcel indicator (λ_A)	6439.6	5514.7	4728.8	4286.8	6061.6	5517.8
	(5269.7)	(4603.8)	(4029.7)	(4677.7)	(4718.0)	(4877.0)
Neighbor Variables						
Fee neighbors (β_F)	-44.16***	-37.84***	-32.49***	-36.29***	-52.67***	-39.96***
	(14.24)	(12.29)	(10.62)	(11.58)	(9.141)	(12.29)
Allotted trust neighbors (β_A)	-354.1**	-309.3**	-270.5**	-328.6**	-336.3**	-137.6
	(178.1)	(151.1)	(128.5)	(144.0)	(149.8)	(85.31)
Tribal Neighbor Indicator (β_T)	-9108.1***	-7791.3***	-6673.5***	-7448.3***	-11395.7***	-6994.5***
	(2991.5)	(2604.8)	(2271.9)	(2597.4)	(2754.4)	(2589.8)
Tribal Neighbor Indicator X Tribal Indicator (β_{T1})	1662.5	1426.4	1229.5	78.20	1100.9	2434.5
	(5544.3)	(4805.6)	(4175.4)	(5135.2)	(4819.5)	(5262.3)
Shale thick & depth FE	x	x	x	x	x	x
Covariate controls	x	x	x	x	x	x
Excludes parcels off fields	x	x	x	x	x	x
x & y coordinate controls				x		
Excludes parcels in cities					x	
One mile radius						x
Pseudo R-squared	0.022	0.022	0.022	0.022	0.025	0.024
Observations	8524	8524	8524	8524	7281	7630
Obs. Censored at Zero	2,320	2,320	2,320	2,320	2,232	2,095

Notes: The standard errors, clustered by township, are shown in parentheses. * $p<0.1$, ** $p<0.05$, *** $p<0.01$. Columns 1-3 discount revenue per acre at 1%. 3%, and 5%, respectively. The specifications in Columns 1-3 are identical to those in Column 2 of Table 3. Columns 4-6 are robustness checks, based on the revenue estimates discounted at 3%. Column 4 adds controls for the longitude and latitude of each parcel's centroid. Column 5 omits parcels in cities. Column 6 defines the neighborhood with a one-mile radius rather than a ½ mile radius.

Table A6: Summary Statistics for Off-Reservation Parcel Level Data Set

	Mean	*Std. Dev.*	*Min*	*Max*	*Description*
Outcome Variables					
Revenue per Acre[a,b,c,d,f]	50,208.699	13,785.7	0	332,230.8	Total revenue for the unit associated with a parcel as of May 1, 2015, discounted at 3%, divided by parcel acres
Production per Acre	122.8522	349.424	0	4,468.5	Total production from wells in the unit associated with a parcel as of May 1, 2015, divided by parcel acres
Parcel Size, Shape, and Tenure					
Parcel Acres[b, c]	58.520	82.4277	0.0028	921.835	Area of the parcel, in acres
Fee Parcel Indicator[b]	0.969	0.174	0	1	=1 if the off-reservation parcel is fee simple, otherwise =0
Neighbor Parcels (1/2 mile radius)					
Fee Neighbors[b, c]	301.85	457.56	0	2651	Number of fee parcels within ½ mile radius around parcel
Government Neighbor Dummy[b, c]	0.179	0.383	0	1	=1 if BLM or US Forest Service own parcels within a ½ mile radius around parcel, otherwise =0
Neighbors Underwater[f]	3.134	8.903	0	83	Number of parcels under a body of water within ½ mile radius around parcel
Government Acres in Neighborhood[b, c]	145.72	533.36	0	5,348.37	Total acreage of parcels owned by BLM or US Forest Service within ½ mile radius around parcel
Other Covariates					
Topographic Roughness[e]	602.504	82.309	459.46	995.745	Standard deviation of elevation in the neighbourhood around a parcel, measured in centimeters
City Indicator[f]	0.312	0.463	0	1	= if the parcel is within a city boundary, otherwise = 0
Road density[f]	0.203	0.410	0	17.365	Kilometres of roads touching parcel

Notes: This table summarizes data for all parcels in our estimation sample off the reservation. We exclude government parcels and parcels with off-reservation neighbors. N = 94,865 for all variables. Data sources are: a) North Dakota Oil and Gas Commission website, b) U.S. Bureau of Indian Affairs, c) Real Estate Portal, d) U.S. EIA website e) Authors calculations from National Elevation Dataset, and f) Authors calculations from North Dakota GIS Portal data.

Policy Thought Experiment Appendix

We apply the estimates from Table 4, Column 2 to estimate the effect of replacing allotted parcels with tribal parcels separately for the average allotted, fee, and tribal parcel in the estimating sample. For the average allotted parcel, there are three effects. First, there is the direct reduction in revenue, which is $\hat{\lambda}_A$. Second, there is an increase in revenue associated with replacing the mean number of neighboring allotted parcels ($\hat{\beta}_A \; x \; \bar{N}_A$) with tribal parcels. Third, there is an expected increase in revenue associated with reducing the probability of the checkerboarding of tribal land interspersed among neighborhoods of allotted land: $\hat{\beta}_T$ x $(\bar{N}_T | Allotted = 1)$.

The calculation is similar for fee parcels, with the noted difference that the change in the probability of a tribal neighbor applies only to those fee parcels that had at least one allotted neighbor but no tribal neighbors (otherwise the marginal effect of converting allotted to tribal is zero). For tribal parcels, the benefit is an increase in expected revenue from removing $\bar{N}_A$ allotted neighbors.

Panel A of Table A6 gives the results. Converting all allotted tracts to tribal ownership would increase expected revenues for the average allotted and tribal parcel, but reduce expected revenue for the average fee parcel. Summing across the reservation, this back-of-the-envelope exercise suggests a $733,572,301 net increase in total revenue over first 18 months of each well. This increase in revenue is accrued by creating more contiguous blocks of tribal ownership (that eliminate checkerboarded neighborhoods of allotted and tribal ownership), and the negative marginal effect of allotted parcels on oil production.

Panel B shows that that the regression estimates from Table 4 imply a similar oil revenue increase if the allotted trust interests had been consolidated into fee simple parcels prior to the fracking boom. The calculations simply multiply the per parcel revenue gain from the tenure switch ($(\hat{\beta}_A - \hat{\beta}_F)$ by the average number of allotted neighbors, $\bar{N}_A$. (We ignore the differences between $\hat{\lambda}_A - \hat{\lambda}_F$ here because those differences are statistically insignificant). Consolidation from allotted to fee simple is not part of the Cobell settlement, but we include it here as part of the thought experiment for context.

Table A7: Increase in Oil Revenue from Consolidating Allotted Trust

Tenure	Calculation for Average Parcel Effect	Change in per acre revenue, for average parcel	Total change (per acre Δ x total acres)
Panel A: Conversion to Tribal			
Allotted Trust	$\hat{\beta}_A \times \bar{N}_A \mid (Allotted=1) - \hat{\beta}_T \times \bar{N}_T \mid (Allotted=1) - \hat{\lambda}_A$ $= 232.3 \times 17.8 + 7761 \times 0.52 - 5930$	\$2,252	\$578,296,732
Fee Simple	$\hat{\beta}_A \times \bar{N}_A \mid (Fee=1) - \hat{\beta}_T \times \Delta\bar{N}_T \mid (Fee=1)$ $= 232.3 \times 2.3 + 7761 \times (0.46 - 0.37)$	-\$120	-\$18,596,187
Tribal	$\hat{\beta}_A \times \bar{N}_A \mid (Tribal=1) = 232.3 \times 4.4$	\$1,017	\$173,871,756
All Parcels			**\$733,572,301**
Panel B: Conversion to Fee			
All Parcels	$(\hat{\beta}_A - \hat{\beta}_F) \times \bar{N}_A = (232.3 - 36.0) \times 8.05$	\$1,580	**\$806,838,105**