The Role of Split Estates in Coalbed Methane Production*

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PRELIMINARY DRAFT

Abstract

Divided ownership has been shown to dilute economic incentives in a variety of contexts. Severed mineral rights are a widely-held form of divided ownership. Split estates have been a topic of recent policy interest. Using well-level production data from coalbed methane (CBM) wells in Wyoming during the years 1987-2006, wells on federal minerals with private surface are compared to those on federal minerals with federal surface. Federal minerals are studied to avoid the endogeneity problems found on private minerals. Delays in development on split estate are found; maximum production is somewhat lower but cumulative production is higher. Some support is found for strategic incentives firms face regarding property rights. The role of the accommodation doctrine in preventing holdup is discussed.

Keywords: coalbed methane, split estate, transaction costs, property rights
JEL classification: D23, L71, Q41

1 Introduction

In the past decade technological advances and rising energy prices have brought formerly subeconomic energy resources into the limelight. North America has substantial reserves of natural gas trapped in coal, shale, and other geologic formations. Initial exploitation of these resources during the past decade has spurred a development boom that has run up against changing attitudes about energy development in the general population. One

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nexus of sometimes fierce conflict has been between owners of severed mineral and surface rights–so-called "split estate." This paper examines how the potential for conflict between surface and subsurface owners affects production from coalbed methane (CBM) wells in Wyoming. Since split estate adds to development costs by requiring some accommodation between surface and subsurface owners, we expect that divided tenures are marginally less attractive to developers. It is unclear what, if any, effect this cost difference has on the use of the resource. Wells on divided and undivided tenures are compared by taking advantage of property rights that are effectively randomized with respect to underground resources. Differences are interpreted as an average effect attributable to the structure of incentives and costs that vary between split and unified estate.

Which form of ownership prevails on a parcel is determined by when agricultural land claims were made in the late 19th and early 20th centuries. The factors affecting this decision are effectively independent of the extensive sedimentary coal deposits in Wyoming that constitute the reservoirs for CBM. Developers have a choice of surface tenures to access what are largely undifferentiated reservoirs within a particular coal formation. Presumably location choice is guided by expecte profitability. Split estate affects costs, and since expected revenues from similar resources are likely comparable, also profits. Previous work has shown that developers consistently bid less for federal mineral leases that have a split estate as opposed to those with unified federal ownership, likely in anticipation of higher transaction costs. This work tests that result in part: finding lower production on split estate implies that either tenure randomization fails or that differences in tenure lead to lower recovery; finding higher production suggests that either randomization is imperfect or that incentives on split estate favor recovery. Production may also differ in when it occurs, even if the quantities are the same, and tests are conducted to determine if differences in optimal investment timing exist.

While correctly identifying the location and richness of deposits remains the central challenge of energy production, systematic differences across ownerships are an important internal margin. Well sites are not random, being chosen by firms after consulting professional geologists and engineers who aim to identify the most valuable reserves and exploit them in the most profitable manner. Since tenures are scattered across the landscape over a range of deposits, the primary concern is that tenures might coincidentally be correlated with the amount of recoverable resource in place, which would bias an estimate of the impact of ownership. The extent to which the randomization of resources holds is important. In a world of perfect information, the selection mechanism would eliminate differences in the value of wells across tenures. However, information about the location and extent of resources, future paths of prices, and actual costs of development is imperfect. Importantly, the developer is uncertain about the type of surface owner that may be encountered on split estate, and what costs that might entail.[13]

This research marks an initial attempt at using micro-level production data to evaluate efficiency impacts of property rights allocation on energy production. Divided ownership is ubiquitous in energy production, and while effects of ownership structures have been explored in other contexts, only scant attention has been paid in energy production,[2] with none at a micro level. The individual level avoids problems of aggregation bias and allows a direct assessment of the effects of tenure on resource use. The implications of property rights for efficient resource use are important as continued development promises to disrupt additional and increasingly valuable surface acreage in coming years. Much of the energy literature glosses over the effects discussed here. While both severed and fractional ownerships have attracted attention in the legal literature (Hill and Rippley (2004), Micheli (2006), Anderson and Smith (1999)), the economic impacts have yet to be explored and quantified. Split estate has also been a policy issue at both the state and federal level in recent years.[3]

This research draws on the extensive literature on property rights. Oil and gas wells represent iconic specific investments. Coupled with the likelihood of incomplete contracts, the importance of variation in transaction costs in economic activity–in this case the development of natural resources–is a key insight drawn from transaction cost economics [27]. Significant investments are required in order to develop unconventional resources. The property rights literature ([22] [24]) demonstrates that ownership may affect investment outcomes.

The paper proceeds as follows. First, the pertinent background of split estates is related, then the next section expands on how the costs of development differ across tenures. A section explaining the data on CBM wells in Wyoming that are analyzed precedes a discussion of peculiarities of defining ownership are discussed with an eye towards spotting strategic

[2]E.g., Bohn and Deacon (2000) consider the role of expropriation risk on petroleum development.

[3]Wyoming, Colorado, and New Mexico, three states with substantial natural gas reserves and federal ownership, have all recently passed legislation that addresses the obligations of mineral developers to surface owners in cases where there is a split estate (Wyoming Surface Owner Accommodation Act of 2005 (W.S. 30-5-401); New Mexico Surface Owners Protection Act of 2007 (N.M.S.A. 70-12); Colorado Surface Owner Protection Act of 2007 (C.S. 34-60-127)). Similar legislation has been considered in other energy-producing states: Montana, North Dakota, and Utah. The impetus for reform in all states has been widespread sentiment that historic provisions protecting the surface owner are insufficient in the face of expanded drilling programs employing new technologies. In addition, at the federal level, Section 1835 of the Federal Energy Policy Act of 2005 mandated that the BLM review its split estate policies. The review was completed in 2007, with the revisions reflected in the latest edition of Onshore Oil and Gas Order No. 1, known as the "Gold Book."

misreporting by firms in the fifth section. This is followed by a discussion of the empirical strategy. Results are presented in the seventh section before a brief discussion concludes.

2 Background

2.1 Split Estates

Split estates arise in several common variations. The simplest case is when a private, fee simple landowner elects to separate the mineral rights from the surface.[16] Several reasons might motivate the private owner, but severance is unlikely unless there is some prospect of mineral value. This raises the concern of non-random tenure for alternative well locations, where split estate might indicate higher expected mineral value and thus productivity in the event a well is drilled.

A split between two private owners is not by any means the only common permutation of ownership. Various levels of government–federal, state, tribal–all end up in split estates with private landowners and each other. A private split estate and private surface over federal minerals are the most common situations: while no statistics for private split estates are available, the federal government recognizes 57.2 million acres of the West where it holds mineral rights beneath private surface (Public Land Statistics, 2007). This paper analyzes the impacts of this particular ownership combination.

Three facts suggest that federal split estates offer a suitable basis for analyzing the economic role of divided ownership in energy production. First, split and unified ownerships were assigned as a result of homesteading practices during the late 19th and early 20th centuries, long before the unconventional resources that are being extracted today were known to be valuable. The existence of coal was known, but its current use as a gas reservoir was implausible; the ownerships defined at the time make this clear. The U.S. Supreme Court had to clarify the ownership of coalbed methane gas in 1998 because under some homesteading provisions the federal government retained only the coal, but not the gas trapped in the coal.[4] Based on the assumption that agricultural potential was the primary criterion of homesteaders, and the further assumption that agricultural productivity is unrelated to mineral potential, a perfect instrumental variable for tenure would be the agricultural productivity of land (on a per acre basis) circa 1900.

Second, since homesteading in the continental U.S. ended in 1934, the federal government

[4]See *Amoco Production Company v. Southern Ute Tribe.*

has made very few adjustments to its ownership of surface and subsurface. These holdings are now mandated to be perpetual by statute. Especially as extracting unconventional resources has become economic, the long-term nature of government holdings is useful since it has not been adjusted in light of changing resource values.

Third, the terms under which the government leases resources are uniform across different reserves and all operators. This includes such important features of the contract as the royalty payment, which can affect production decisions on the margin (Deacon (1993), Black (2002), Kunce and Morgan (2005)). Examining federal split and federal unified isolates the institutional aspects of split estate as cleanly as is possible.

2.2 Accommodation Doctrine

One concern is that the surface owner can effectively hold-up the subsurface developer– that is, manipulate the contract for surface access in such a way as to capture the rents from the subsurface. An alternative but related concern is that the surface owner might hold out and refuse to negotiate with the mineral owner, again devaluing the mineral estate. Fortunately for mineral developers, Wyoming is among the several states that subscribe to a legal principle known as the accommodation doctrine.[5] This prevents contractual problems by guaranteeing the mineral owner reasonable access to the surface. By posting a performance bond covering damages to planted crops or structures, a developer is able to access the surface as necessary to produce. Exercising this option is commonly-known as "bonding-on."[6]

The accommodation doctrine has two primary effects. First, it places a ceiling on the amount a developer is willing to pay for surface access by providing a low-cost substitute for a surface-use agreement in the form of a bond. Second, it clarifies the precedence of property rights and therefore should make negotiations more transparent and less costly.[7] While giving the subsurface owner the dominant right transfers rents to the subsurface owner, this may be efficient since surface production can often continue in the presence of energy development, but prohibiting surface access is apt to make mineral extraction at best unprofitable and at worst impossible.

[5]See Hill and Rippley [25] for a discussion of how Wyoming and other states have come to adopt the accommodation doctrine.

[6]The baseline amount for a bond is $ 2000, with the burden on the landowner to prove the need for a higher amount. The bond covers only damage to planted crops or structures.

[7]This does not mean that bargaining will necessarily be efficient, or that limiting bargaining would offer an efficiency improvement. See Haddock and McChesney (1991).

A negotiated agreement for access is known as a surface-use agreement (SUA) and stipulates when, where, and how the operator will occupy the surface. Surface owners are affected by construction of well pads, roads, pipelines, and power lines. In some cases these improvements may be beneficial to the landowner by enhancing real estate value, but typically surface use is diminished. It is common for a developer to make a one-time cash payment to the surface landowner to offset the disturbance of roads, wells pads, and so forth. A surface owner who welcomes development without owning the underlying minerals is atypical; a more common reaction is to try to capture some of the resource rents in exchange for access. The accommodation doctrine makes this objective more difficult, since developers always have a low-cost outside option in the form of a bond.

However, operators seem to be loath to bond-on, preferring instead to reach negotiated settlements. Before March 2008, only 55 bonds were posted on federal minerals in Wyoming, with 9 returned after an agreement was subsequently reached. Two possible explanations for this strong preference for surface-use agreements are that firms prefer to have amicable relationships with surface owners because they find their long-term costs are lower, or that there are negative reputational effects that result from bonding-on to the surface that hurt prospects for future (low-cost) landowner relationships. Regardless, enough bonding-on occurs to make it a credible threat, and the accommodation doctrine effectively strengthens operators' negotiating position.

2.3 Production Technology

Even after deposits are located, producing oil and gas is a complicated process involving high levels of technical sophistication and specific investments. Typically, a well has a high initial production rate that gradually diminishes over time–this is usually modeled as a constant rate of depletion. However, by increasing either subsurface pressure (drive) or permeability it may be possible to increase production later in a well's life. Injecting either gas or liquid into the subsurface can increase geophysical drive and reduce lifting costs. Hydraulically fracturing rock increases permeability. One advantage of focusing on coalbed methane is that the technology is relatively simple–typified by shallow, vertical wells. Furthermore, the technology differs little across firms or among wells in similar geologic formations (coals). Little if any variation in the timing or amount of gas produced is attributable to differences in production technology, allowing direct comparison across tenures.

Production varies in two basic ways: when gas comes out of the ground and how much gas comes out of the ground. In order to compare across both of these dimensions multiple dependent variables are used: time of entry, time to production, maximum rate of production, and cumulative production. Those measures are discussed further below in Section 4.2.

3 Comparison of Development Costs across Tenures

Many factors affect expected profits for any particular drilling site, including cost differences across tenures. Exploration and development costs are subject to myriad definitions and this section describes how costs vary across tenures at the well level.[8] The model developed here is used to motivate the empirical study rather than make a contribution to the theory of extraction investment; Chermak and Patrick (1995) have previously estimated a well-level cost function, although their model does not address tenure.

Production costs are incurred sequentially in three stages: acquisition, development, and operation. A prospect must first be secured by lease or purchase; each acquisition may permit one or more wells. Firms use private and common information about the location, extent, and richness of deposits, in addition to firm-specific cost factors, to assess the expected value of prospects. A competitive market for prospects exists, incorporating a range of tenure options.

Once prospects are acquired, a firm determines the most profitable site (if any) for a well. Assuming expected profits are still positive, development costs are incurred after acquisition until a completed well is ready to begin production. Additional wells are constructed if expected profits are still positive.

After a well is constructed, a firm has improved information about the nature of deposits. If the well is completed into a geological horizon with paying quantities of hydrocarbon (i.e., expected profits remain positive), then the firm will incur the operational costs of actual production, along with reclamation costs. Alternatively, the firm may also choose to delay production, or to plug and abandon the well, permanently reclaiming the surface in the process.

Development costs depend on the physical characteristics of a drilling location: pertinent characteristics include the type, depth, and thickness of target formations, distance to pipelines and service facilities, and other physical characteristics such as elevation and

[8] In an effort to be consistent with Adelman (1992), which addresses the redundancies in cost nomenclature, I use "development costs" in a very specific sense of costs incurred after initial property acquisition and until completion of a well. This usage is analogous to Paddock et al.'s (1988) definition. I use "drilling cost" in a more restrictive sense that entails the costs of physically creating a well. This usage differs from Adelman's insofar that it does not take into account reserve additions. The data do not include reserve additions. Instead, elements of individual well production paths are compared.

terrain. Represent these characteristics with the vector $\mathbf{X}$. All of these factors affect how expensive a given well will be to construct and how fast it is likely to be completed. A large portion of the costs of creating a well is apt to be in the drilling of a wellbore. These costs are strongly dependent on the depth drilled, but may also vary by geologic complexity. The balance of the costs of development is consumed by overhead and other infrastructure such as roads, power lines, collection pipelines, or water disposal systems. Let $C^D(\mathbf{X})$ represent development costs for a well with given characteristics.

The expertise of geologists and engineers in identifying profitable locations is a critical input in the development process. Once a firm's experts make decisions about when and where to drill, much of the physical construction is contracted to specialists (earthmovers, drillers, welders, etc.). In developing a well, a firm will choose the optimal time of completion that maximizes expected profits. A well will be completed at the time that minimizes costs given expectations about the paths of output prices and available resource. Denote this optimal time of completion as T^*. Choosing costs implies a choice of T^* and vice versa; for example, a firm might elect to spend more (increase C^D) in an effort to complete a well earlier. Technological improvements may outpace rising costs over time, so the time path of development costs is indeterminate.[9]

Construction costs are unlikely to vary across tenures with similar observable characteristics, but the contracting costs incurred in obtaining access from a surface owner are hypothesized to be higher on split estate versus unified. These include the cost of a bond or the payment made in a surface use agreement as well as the costs of reaching an agreement. Let the parameter γ represent the difference in contracting or transaction costs incurred during the drilling process on split estate, but not unified. These costs are expected to be positive, implying that split estate is a more costly tenure to develop, all else equal.

Alternatively, operators may be able to differentially externalize environmental costs on unified versus split estates. Regulations are nominally the same but firms recognize that probabilities of detection and enforcement are low and so may choose to save costs by altering performance. Represent the difference in environmental compliance costs across tenures with a parameter ε. The expectation is that unified rights give a stronger incentive to internalize external effects because the owner controls access to the valuable minerals as well. However, the possibility of closer monitoring by the surface owner prevents signing

[9]This has been the subject on the literature of the relationship of drilling costs and technological progress over time. Because drilling costs are strongly correlated with depth, and new technology often allows deeper wells, it appears that technological progress leads to an increase in drilling costs. For further discussion, see Copp (1974), Farnsworth and Norgaard (1976), and Copp (1976).

the parameter. Combining these two parameters, the difference in development cost on split estate (designated by 1) and unified (0) is expressed as follows.

$$C^D(\mathbf{X}, 1) - C^D(\mathbf{X}, 0) = \Delta C^D = \gamma + \varepsilon \tag{1}$$

The combined effect of γ and ε is the basis of the tests performed here.[10]

Because tenure potentially affects the costs firms incur in constructing wells at physically-similar sites, we expect that the timing of development may also differ. Negotiating surface access with private landowners takes time that a firm might otherwise spend constructing another well. We expect there to be differences in the optimal timing of entry and completion of wells on split and unified tenures precisely because there are cost differences. Differences in completion times can be captured in a parameter τ, which is tested below.

$$T^*(\mathbf{X}, 1) - T^*(\mathbf{X}, 0) = \tau \tag{2}$$

After a well is completed and production begins, firms incur costs in operating a producing well. These costs depend on the physical characteristics of the wellsite, the amount of production, and the amount of resource in place. Let $C^O(\mathbf{X}, q(t), Q(t))$ represent these operating costs, where $q(t)$ represents production and $Q(t)$ represents the amount of resource in the ground.[11] Operating costs are incurred over time and firms attempt to maximize profits over time by choosing the optimal time path of extraction, $q^*(t)$. Operating costs range from mundane maintenance costs, to costs of increasing reservoir pressure or otherwise lifting the resource to the surface, to additional fracturing procedures that increase well production.

Operating costs potentially differ across tenures. For example, concessions made in a surface use agreement may raise variable costs during operation (e.g., more expensive water disposal methods). On the other hand, a developer may reduce operating costs by imposing hard-to-verify environmental impacts on the surface owner. It is reasonable to posit different operating costs, but is not possible to sign the differences. We can express the absolute

[10]Note that this differs from the test in Kunce et al. (2002), which also included initial acquisition costs.

[11]This quantity is estimable but probably unknown. If the total amount of resource in place is fixed at $\bar{Q}$, then $Q(t) = \bar{(Q)} - \int_{T^*}^{t} q(s)ds$, where s is simply the variable of integration. The assumption that tenures are exogenous to resources implies that is equal (on average) across tenures. The integral represents total production, and $Q(t)$ therefore represents the amount of resource remaining in ground. Because optimal production paths potentially differ due to cost differences, the amount of resource remaining at any given t also potentially differs. In general, more gas in the ground reduces costs, or $\frac{\partial C^O}{\partial Q} < 0$.

difference in costs with a parameter η.

$$\Delta C^O = C^O(\mathbf{X}, 1, q, Q) - C^O(\mathbf{X}, 0, q, Q) = \eta \tag{3}$$

Cost differences enter the marginal production conditions. Because the price of gas does not depend on where it was produced, differences in revenues are attributable only to varying production paths. Profits are likely to differ as a result. We can observe differences in the optimal production path q^*. Tests for differences in this optimal production path are conducted below, which also test for differences in marginal production costs.

In a landscape with heterogeneous property rights we might expect the exogenous tenures to affect resource, and thus revenue, potential beyond cost differences. This is true in any formation with significant transmissivity and further motivates the focus of this study on relatively impermeable coal formations with exogenously-determined property rights.

In order to close the model of costs, the third type of costs is the initial acquisition of rights to a well site. Firms have several options for acquiring rights: purchase of whole estate, purchase of mineral rights, leasing of whole estate or minerals, or leasing of operating (majority) interest in minerals. On federal minerals, only leasing is an option. Competition for acquisition of prospects in expected to exhaust supernormal profits. Arbitrage implies that acquisition costs will be higher for more valuable sites. The highest bidder for a lease is the firm with the lowest expected development and operating costs, or the most productive firm.

4 Data

4.1 Provenance

Oil and gas wells in Wyoming are permitted by the state Oil and Gas Conservation Commission (WOGCC). The state maintains records for all CBM wells and the data used here are drawn from those records. The physical characteristics, including location, formation, depth, and so forth, are drawn from the initial permit application. This initial application includes a report of the tenure on which the well is located. A condition of operation is that a monthly report (Form 2) be filed with the state for any well that is producing. These reports include the amount of oil and or gas produced, the volume of water produced, and the number of days a well operated in each month. These data are self-reported and potentially subject to reporting bias; missing and miscoded data is a pervasive problem requiring attention. Monthly production reports form a detailed picture of the history of each well.

All CBM wells on record before August 2006 are included in the sample. Table 1 summarizes the wells in the dataset. The earliest permit was granted in 1987, but not until 1996 were more than 100 permits granted in one year. Before that time the technology was still very prospective and experimental.[12] Some earlier petroleum wells were retrofitted or completed into coal horizons during the early stages of CBM exploration. These 10 wells are omitted.

A well appears in the data when its permit application is approved (or in some rare cases, rejected). Regulations require that a well be spudded (drilling started) within 180 days of the application approval. A substantial number of permits expire without ever being spudded, either because firms elect not to drill the well or because they cannot get a drill into the ground within 6 months. The last six months of data also include a large number of wells for which applications have been processed but drilling has not yet started. Actual production typically follows initial drilling by a lag of 1 or more months, time that is spent constructing and completing the well. However, the time to production can be longer than the six months within which firms must spud the well. This is because a well may be drilled but not completed until a later date.

Because the latitude and longitude of each well are reported with 3-digit accuracy (on the order of 100 yards), well tenures can also be classified by mapped location. The Bureau of Land Management (BLM) maintains regularly-updated and highly accurate electronic maps of their holdings, which include both surface tenures and mineral ownerships throughout the state. Since reported and mapped tenures are not always the same, the question of strategic misreporting of tenure is addressed in Section 5. Tables 1.1 and 1.2 report descriptive statistics for the entire sample according to each of the respective definitions of tenure.

Only wells in northeastern Wyoming have been included. The rule that was used is to select wells located north of township 37 and east of range 85. This corresponds to Campbell, Crook, Johnson, Sheridan, and Weston Counties in their entirety, as wells as small portions of Converse, Natrona, and Niobrara Counties. Figure 1 shows the wells that are analyzed.[13] The Powder River Basin is the main watershed in this region that has been one of the leading CBM exploration and production areas in the world during the last decade. Wells in the

[12]Tenure insecurity is another plausible explanation since the *Amoco v. Southern Ute* decision, which clarified ownership of CBM gas, was not finally decided until 1998.

[13]None of the sample wells are located in Crook, Weston, or Niobrara Counties even though they were included in the possible area.

southwestern part of the state were excluded because there are no CBM wells on split estate there. Although there are many oil or shale gas wells on split estate, the technologies used for those deposits are sufficiently different from those used in coalbeds as to make direct comparisons invalid.

4.2 Dependent Variables

Well productivity can be measured in several ways. In the case of common-pool resources claimed by capture, we expect to see a "race to exploit" that rewards firms able to produce faster. An alternative motivation is given by the capital intensity of energy production, under which time may be a costly input for developers using borrowed money. Four measures are used to assess differences in productivity of wells across tenures. Each of these variables is connected to the expected profits and amount of underlying natural gas–because property rights are randomly assigned with respect to these resources, we expect that observed differences are due to the treatment of split estate rather than random differences in endowments. Table 2 presents differences in means of some pertinent physical parameters across tenures.

The first measure is the date of application for the permit to drill (APD—a permit to drill). If firms exploit their most profitable opportunities first, we expect to see later access to comparable resources with higher costs, or later entry on split estate.[14] Delayed application is taken as a sign of lower expected profit associated with a site. All potential well sites are made available by federal mineral auction, and since split estate is not systematically leased earlier or later, there is no expectation of bias introduced by the unavailability of split estate locations as compared to unified locations.

The second measure is the time delay between the application and production (TTFP—time to first production). This measure is available only for wells that have produced gas: a few wells are dry holes, some permits expire, and many of the later wells in the dataset have not yet produced any gas. Given comparable physical characteristics such as depth, hardness, and location, we expect there to be no difference in construction costs or time. One explanation for a difference in this measure is delays encountered in negotiating for surface access from the surface owner. While it is possible that a surface use agreement is signed without specifying well numbers and locations, it is more common that firms must reach terms with the surface owner after deciding where wells will be located, which occurs after application for the drilling permit. Longer delays between application and production

[14] Holland (2003) shows that even in a partial equilibrium setting with limited extraction capacity, the "Herfindahl principle," or extraction in strict order of extraction costs does not necessarily hold.

are interpreted to be costly and indicative of higher transaction costs. If firms apply for wells before securing access to the surface, we expect to see a delay while access is negotiated. A significant delay should work in the opposite direction of the time of application variable. Anticipating a longer delay from permit to production, firms might apply for permits earlier in order to ensure timely access to resources.

Wells typically produce at their maximum rate within a month or two of first production, then decline through the life of the well. Two measures are important in comparing production profiles across wellsthe height of the peak, or maximum rate of production, and the sum of all months, or cumulative production. We expect maximum withdrawal rates to be equal, provided that gas is intransient and firms do not risk losing gas to nearby wells by delaying entry. While coals are generally considered tight formations, there is uncertainty about the movement of gas below the surface. Significant differences in maximum production rates are interpreted as a potentially high cost of the delay imposed by additional transaction costs. Maximum monthly production is measured in thousand cubic feet (Mcf), a standard measure of natural gas equivalent to 1,020,000 British thermal units (Btu).

Cumulative production is the ultimate arbiter of value of a natural gas well–how much gas is produced over the lifetime of the well. At modest discount rates production timing differences are likely small provided that the gas is there. In assessing cumulative production, it is important to control for the length of time that a well has been in production. Higher production from longer-producing wells does not necessarily imply higher value. Cumulative production is also measured in Mcf. Results derived using production levels can be transformed into dollars by using a time series of prices.[15]

5 Misreporting

One potential problem presented by the data is that the classification of a well varies depending on how ownership is defined. Thirteen different tenures are reported in the data–unified private, federal, state, and Indian as well as split estates between those parties. The far right column of Table 3 details these reports. In rough terms, half of the wells are on private tenures (split or unified), a further quarter on federal unified, and the balance approximately equally divided between federal split and state land.

[15]The actual prices received by firms are not actually observed. Collected wellhead prices are an average constructed from actual prices paid. Some firms sell at the wellhead, others at the hub. The variation in marketing arrangements makes it hard to pin down the exact value of a particular well. This issue is discussed further in Section 7.2.1

Given that the federal government owns just over 42% of all surface acreage in Wyoming, these proportions suggest selection of private ownership by developers. Selection could occur at two different points. On one hand, it could be that land claims were made in large part on the mineral value so more valuable deposits ended up in private hands and the government retained the remainder. Alternatively, it might be that the resources are similar but developers chose to locate disproportionately on private land because of lower costs. The novel nature of CBM as a natural gas technology strongly suggests that land claims made a century ago were not predicated on future mineral value for natural gas. This leaves selection of well sites by developers as the more plausible mechanism. These data do not support tests of hypotheses parsing which of these explanations dominates, although the topic of cost differences between private and federal land has been addressed in previous research (Kunce et al. (2002)), and the indication of this data is that it corroborates the authors central result.[16]

An alternative way of identifying tenures is to overlay well locations, which are reported with three-digit GPS accuracy (on the order of a football field) in the permit application, on electronic cadastral maps available from the state BLM office in Cheyenne. These maps are electronic renderings of BLM ownership maps. Official plat maps are held at county courthouses, but the accuracy of the digitized plat maps appears to be high since few errors were encountered with the same cadastral data and oil and gas leases. The cadastral maps only identify 6 different tenures because no data about specific private owners is included. This method is unable to identify divided private ownerships: it is not possible to identify any split estates unless one party is the federal government. Since the maps are continuously updated, it is possible that changes in ownership after the construction of a well would account for error in the mapped tenure. However, since the federal government makes few, if any, adjustments to landholdings, this is unlikely to be a large source of error for wells on federal minerals. Changes of ownership are common amongst private owners, but these are not changes in type of tenure. The bottom row of Table 3 reports the mapped well locations. Private tenures again account for roughly half of all wells while federal split is slightly more than a quarter, with the balance divided between federal unified and state ownership. The disparity between reported and mapped tenures entails switching the approximate proportions of federal split and unified wells.

In a perfect world we would expect that the reported tenure for each well location is the same as indicated by the cadastral GIS data. This is not the case, as Table 3 details across

[16]Gerking and Morgan (2007) make a thorough explanation of the results obtained in Kunce et al. (2002).

all possible combinations of reported and mapped tenures. The main diagonal shows wells that are mapped and reported on the same tenure. For these "correct" wells there is no ambiguity about the tenure. The off-diagonal elements represent cases in which there is a difference between the tenure of a well as indicated by the operator and as mapped given the location provided by the operator. Private tenures include both divided and whole private interests. Unified wells are located where the federal government owns both surface and subsurface. Split refers to the case in which federal minerals are overlain by private surface. State ownership is indicated and sundry ownerships are included in the final category.

Measurement error introduced in recording well locations (usually with handheld GPS units) likely explains some of the off-diagonal activity. Since tenures are interspersed, sometimes on the scale of 40-acre parcels and often in 640-acre tracts, errors on the order of 200 yards (well within the scale of error of handheld units over the time investigated here) in measurement are sufficient to misrepresent a well location. A 200-yard error moves a well from the center of a 40-acre tract to its edge, which potentially abuts a different tenure. That is, a well could be reported correctly but the reported coordinates are subject to error, introducing confusion when the misrepresented coordinates are mapped. Private wells are the most-reliably reported. Less than 2% of wells reported on private ground turn out to be elsewhere and only 3.6% of wells mapped on private ownership are reported elsewhere. Given the fragmentation of state holdings, the associated errors are somewhat larger, but still within plausible bounds for measurement error. Sundry other holdings also exhibit a higher percentage of misreporting, attributable to the imperfect alignment of reported and mapped tenure types.

Well locations that are mapped as federal unified are only reported otherwise 3.1% of the time. Wells that are reported as being on federal split also usually are–only 2.4% of such wells appear on other tenures when mapped. These figures are commensurate with the background measurement error of 2-4% that was observed on private ground. However, two-thirds of all wells that are mapped on split estate are reported as being on unified federal ownership. Given a presumed background error rate on the order of 2-4%, this anomaly is substantial enough to suggest possible strategic behavior.

Table 3 raises the question: why do firms appear to overwhelmingly misreport wells that are in fact on split estate as being on unified federal tenure? Three possible explanations present themselves. First, this could simply be a magnification of measurement error across all tenures that we suspect in Table 3. While we cannot reject the presence of measurement error across unified and split federal tenures, the disparity between the misreporting of split and unified wells and the background levels of apparent measurement error is striking.

A second possible explanation is that paperwork for well applications is often filled out by office personnel unfamiliar with the actual situation on the ground. It is possible that office personnel are not even located in the same state and may be ignorant of the importance of split estate. This explanation dismisses misreported wells as random errors by uninformed office staff. Severed ownerships are pervasive in energy development and no office staff in any energy company could long exist without developing a nuanced understanding of split estates. Some evidence that misreporting may be due to lack of understanding is presented in Table 4, which shows when well applications were made. The first and fourth columns are correctly reported wells on unified and split tenure, respectively. The second column is wells reported on unified but mapped on split–the third column is the converse.

Before 1999 every well that was drilled on split estate was reported as being on federal unified. After that time the incidence of misreporting dropped precipitously, as shown in the final column, which reports the percentage of mapped split wells reported as unified. During the debate leading up to passage of a state law (W.S. 30-5-401) over obligations of energy developers to split estate surface owners, it is clear that firms were much more careful in recording tenures accurately. The act was passed in 2005, and in 2006 the level of misreporting of wells that are mapped on split estate (4.0%) was more commensurate with measurement error. So while it is clear that the reporting has become more accurate over time, it is does not explain why firms disproportionately tried to misreport split tenures as unified but not vice versa. This leads to a third line of inquiry.

The third plausible explanation is that we are observing strategic behavior by firms. Misreporting is subject to fines if it is detected and punished. If misreporting is strategic, it must be done in cases in which the firm expects benefits to exceed the costs of penalty. What incentive could a firm possibly have to misreport the tenure of a well site? Firms typically apply for well permits as they are planning whole developments of CBM wells. At times they may concurrently be negotiating terms of surface access with private split estate owners since development plans are fluid and commonly change given information that is revealed during the initial drilling process. In order to be granted a drilling permit, firms must show evidence of a surface use agreement or obtain a waiver from the landowner. In an effort to expedite the process of well permitting and construction, a firm might neglect to inform the state of the true tenure of the site. This increases the chance of a fast permit approval and hopefully a quick completion. This explanation implies that firms selectively choose to "accidentally" misreport the tenure that a well lies on.

6 Empirical Strategy

Two characteristics of the development process require special econometric consideration. For wells to appear in the dataset, a firm must choose to file a permit; for wells to have a production history, firms must choose to carry development through to production. The sample of observed wells is nonrandom, and almost certainly biased towards those that are most productive—those that will produce the most gas in the shortest time. If tenure affects productivity, estimates ignoring selection are biased. The second feature is that we expect nearby wells to have similar production characteristics. This similarity has two causes: first, coalbeds are extensive and broad swathes of land are likely to have very similar resource endowments (across a variety of tenures); second, the geophysics of extraction suggest that there may be correlations between observed production from wells in proximity to one another. Since the physical and geological relationships between wells are not perfectly understood even by engineers in the field the structural assumptions necessary for parameterized spatial correlations are quite strong. Furthermore, the dual problems of selection and spatial correlation pose difficult problems for implementation.

One option to deal with these problems is to use a matching estimator that calculates an individual-specific counterfactual for each observation. In this context that would be the production outcome of a specific well were it located on the alternative tenure, conditional on the observable covariates that firms can use to make their development decisions. Averaging these individual-specific effects we can calculate an average treatment effect associated with a particular tenure.

Paramteric estimation of models exhibiting spatial correlation in addition to selection is not straightforward. If spatial correlations are important only in the selection but not the outcome, then the spatial probit estimator outlined by Pinske and Slade (1998) is adequate to account for the appearance of data. However, in the more likely event of spatial correlation in both stages, the variance-covariance structure is more complicated. Flores-Lagunes and Schnier (2008) have proposed a "spatial heckit" estimator based on Heckman's familiar selection correction. Maximum likelihood estimates are feasible using conditional likelihoods ([30], [32]), but [5] warns about the complications imposed by spatial correlations in both selection and outcome.

Limiting the analysis to only wells on federal minerals does not eliminate spatial correlations to other surrounding tenures. The spatial error structure must take into account the neighboring wells. The large number of wells makes the problem computationally-intensive, especially since a wells neighbors potentially change in each time period. At this point no adequate solution to this problem has been found, and the estimates presented here do not incorporate spatial error structures in either the duration models for transition between states or in the linear models for levels outcomes. However, a strong argument can be made that spatial attributes that are important in selection are not in production, since the same firm often owns neighboring wells. At that point the spatial problem is on a different scale (i.e., units vs. wells) that often span tenures. The correlation of the two spatial error structures is unknown.

A final complication with these data is that collinearity between explanatory variables is a pervasive problem. This was one motivation for using reservoir-specific fixed effects, discussed in Section 6.2 below.

6.1 Measuring Timing

One set of dependent variables pertains to the text *timing* of development. Time of application, time of first production, and the delay from application to production are all functions of time. For these variables, the transition from one state to another (e.g., the approval of a drilling permit, or production from an approved well) can be modeled using a duration model. Since the data are collected at the monthly level, it is not possible to discern when within a month the transition occurred. Therefore a discrete time model is used.

Following Cameron and Trivedi (2005), the discrete probability of transition (T) for period j is given by a probability density function and can be represented as:

$$\rho_j = Pr[T = t_j | T \geq t_j] = \frac{f^d(t_j)}{S^d(t_j)} \tag{4}$$

which simply expresses the probability that a transition occurs in period j conditional on it surviving until then, or the hazard rate.

Ignoring the interval censoring issues of intra-month decisions and using the continuous Weibull distribution to model the underlying probability distribution, we can parameterize Equation 4 as

$$\rho(t) = \theta\alpha t^{\alpha-1} = exp(\mathbf{x}'\beta)\alpha t^{\alpha-1} \tag{5}$$

where $\alpha > 0$ and $\mathbf{x}'$ is a vector of explanatory variables. Given this specification, the vector

β can be obtained by finding the parameter values that optimize the likelihood function.

$$lnL = \sum_i [\mathbf{x}_i'\beta + ln\alpha + (\alpha - 1)lnt_i - exp(\mathbf{x}_i'\beta)t_i^\alpha] \tag{6}$$

Since time-variant factors like expectations of future natural gas prices potentially affect the speed with which firms develop, the unit of observation is a well-month. The four-month NYMEX natural gas future price is included as a proxy for expectations.

6.2 Measuring Levels

While timing of production is important, the ultimate goal of oil and gas production is to find and extract hydrocarbons. Levels of production matter. Measuring *levels* of production, be they initial, maximum, or cumulative, is a straightforward exercise. In the simplest sense, a set of well-specific factors explain the production levels. Some of these factors vary over time while others do not. Considering the case of levels that vary by well (i) over time (t), we can write the basic specification as follows.

$$q_{it} = \mathbf{X}_{it}'\beta + \varepsilon_{it} \tag{7}$$

As mentioned above, many of the descriptive variables that would otherwise be included in $\mathbf{X}_{it}'$ present collinearity problems. For this reason fixed effects for reservoir characteristics are included. Indexing reservoirs by k, we can rewrite Equation 7

$$q_{ikt} = \mathbf{X}_{it}'\beta + \beta_k + \varepsilon_{ikt} \tag{8}$$

where β_k is the reservoir-specific intercept term.

7 Results

7.1 Development Timing

The results of duration models explaining the transition from permit to producing well and initial to peak production are presented in Table 5. The estimates are reported as hazard rates, as developed in Equation 4. An increase in the hazard rate implies a greater probability of transition given survival to the current stage, and therefore a shorter spell in either the permit or initial production phase. A permitted but uncompleted well is at the stage where the expected difference between tenures is greatest: while the developer must obtain access from a potentially reluctant surface owner. Without access, which can always be obtained by bonding-on, the value of split estate minerals cannot be fully realized. Initial production represents a period during which the firm has made a substantial specific investment—drilling and completing a well—that has yet to yield a return on invested capital.

Column 1 reports the results from a model of initial production. Permits issued in later years have lower hazard rates, or longer duration before initial production. Deeper wells also have longer spell, although the effect of an additional foot of depth is small, as we might expect. Higher prices reduce the hazard rate, or extend the delay from permit to production. This result is contrary to the expectation, although there is no guarantee that the NYMEX 4-month future is an appropriate proxy for firms long-term expectations.[17] The average lifetime of a CBM well is 12-15 years, so short-term fluctuations in prices may not affect firms' expectations.

The primary variable of interest, reported split estate, is associated with a reduction in the hazard rate, implying longer spells before production for wells on split estate. This supports the hypothesis that split estate can lead to longer delays in production. If a developer chances to encounter a surface owner who is unwilling to take the firm's offer for a surface-use agreement, the delay to getting a producing well may increase.

Column 3 reports the effect on duration from initial to peak production, or how long it takes for a firm to realize a return from a well. Reported split estate again reduces the hazard rate. While time-consuming interaction with the surface owner is unlikely to be the proximate cause at this stage, the longer delay does represent a foregone benefit to a developer.

Column 2 uses the mapped definition of split estate as an explanatory variable instead of the reports. Mapped split estate *increases* the hazard rate, implying a *faster* conversion of a permit into a developing well. This result is contrary to the hypothesized effect of split estate, but consistent with results found using a matching estimator. Similar results for the time to peak production are presented in Column 4.

[17]Retail natural gas prices, like the NYMEX price, show a strong seasonality that producers may be able to mitigate via contracting with midstream (distribution) firms.

7.2 Development Levels

Table 6 reports results of reservoir fixed-effects regressions for the maximum monthly gas production, allowing for well-invariant differences in production levels across reservoirs.[18] The peak monthly production Column 1 reports the effect of reported split tenure, while Column 2 reports the effect of mapped tenure. Across both specifications, the explanatory variables take on expected signs and plausible magnitudes. Wells that take longer to reach their peak production have lower maximum production rates, a result that is likely a function of the geophysics of extraction. Wells that produce for the first time in later years have lower peak production. Since production rate is generally a function of the richness of the subsurface resource, this result implies that the "Herfindahl Principle," or exploitation of the richest deposits first, holds despite theoretical results to the contrary. Wells that produce for more days during the peak month have higher maximum production rates. Longer delays from permit to production lead to slightly higher peak production rates.

The primary variable of interest, split estate, is associated with lower peak production rates. This result holds regardless of whether the reported or mapped definition is used, although the magnitudes are quite different. Reported split estate wells have maximum production levels about 1340 Mcf lower than wells reported on federal unified. When these same wells are mapped, those that appear on split estate average 4216 Mcf lower, about a three times larger reduction in peak production.

Differences in maximum production rates might not matter if the cumulative production is the same across tenures, since the value of a well depends on its lifetime production. Table 7 presents results of reservoir fixed-effects regressions for cumulative gas production. A total of 65 reservoir fixed-effects are included. Column 1 reports the effect for reported split estate. It has a negative but insignificant effect on the cumulative production level. Column 2 reports a similar specification for mapped split estate. The effect of split estate is large, negative, and significant.

7.2.1 Valuing Production

While cumulative production is a primary concern for developers, it is also interesting to consider the value of that production as product prices vary over time. Various contractual

[18] For comparison, random-effects models were also performed to ensure that the fixed-effects estimator is the most efficient consistent estimator. A Hausman test was performed to assess whether regressors are correlated with the random-effects. The result of this test was a rejection of the null hypothesis of no correlation for both the maximum gas and cumulative gas variables. Results of the Hausman tests and the random-effects specifications are available on request.

arrangements for the sale of natural gas are used: both spot and forward contracts are used, and the place of delivery varies depending on the arrangements producers have with pipeline owners. For CBM, prices also may vary due to the cost of compression for transport. Two stages of compression are often needed as opposed to the usual one because CBM is produced at relatively low pressure. However, an estimate of the generated revenue is useful.

Average monthly wellhead and city gate prices are maintained by the Energy Information Administration. Unfortunately, the wellhead series is not specific to Wyoming, where prices are often lower than the national average due to higher transport costs. Two measures of value are constructed, one using the average U.S. wellhead price, and the other using the average Wyoming city gate price. Both price series are likely to be slightly higher than the actual prices received by most operators. Table 8 reports the results of these regressions.

The first production year variable can be interpreted as the average annual production value of a well, and the revenues are considerable. Given the relatively low costs of constructing CBM wells, these data suggest that the mean well is earning a healthy return on its investment. It is also striking that the annual value far exceeds any typical payment to surface owners. Like the cumulative production regressions discussed above, the reported split estate variable is negative but insignificant while the mapped split estate variable is large, negative, and significant. These estimates suggest that wells actually located on split estate are worth \$ 210,437- \$ 222,534 less than their counterparts on federal unified estate.

8 Discussion

Developers pay less for split estate leases than for unified leases, a result that has been attributed to higher transaction costs on split estate. While the higher contracting costs inherent in dealing with an additional (surface) landowner are easily recognizable, these results suggest that there are additional effects of split estate on the production of wells. Namely, the hazard rates for conversion from permitted to producing well and from producing to peaked well are negatively affected by reported split estate. Mapped split estate has the opposite effect. While both classifications of split estate have a negative effect on the maximum monthly gas production, wells that are mapped on split estate have significantly lower production and value than those on unified estate. Wells that are reported on split estate are not significantly different from unified wells in this regard.

Taken together, these results paint an uncertain picture about the effect of split estates on CBM production. However, the strategic incentives inherent in the reporting decision and the significant differences in outcomes between mapped and reported tenures deserve further investigations. A more rigorous econometric framework that accounts for potential spatial correlations in both the well selection phase and during production is also required.

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1 Table 1

1.1 Table 1A: Well Description by Reported Tenure

	Federal Unified	Federal Split	**Federal Minerals**	Private Unified	Private Split	State	Other	**Total**
Denied	71	33	104	331	3	66	8	512
Expired	2678	449	3127	5045	18	1105	111	9406
Waiting	51	70	121	51	32	9	2	215
APD	1075	2095	3170	625	700	281	101	4877
Not Drilled	3875	2647	6522	6052	753	1461	222	15010
Spud	405	343	748	290	152	141	29	1360
Dry Hole	20	0	20	14	0	4	0	38
Shut In	857	284	1141	2309	157	575	35	4217
Abandoned	333	11	344	1135	7	175	0	1661
Producing	4878	763	5641	10448	62	1792	43	18148
Drilled	6493	1401	7894	14196	378	2687	107	25424
No Data	6	1	7	22	0	1	0	30
TOTAL	10374	4049	14423	20270	1131	4149	329	40464

1.2 Table 1B: Well Description by Mapped Tenure

	Federal Unified	Federal Split	**Federal Minerals**	Private	State	Other	**Total**
Denied	20	99	119	327	64	1	511
Expired	675	2596	3271	5053	1063	18	9405
Waiting	32	91	123	83	9	0	215
APD	994	2207	3201	1352	276	48	4877
Not Drilled	1721	4993	6714	6815	1412	67	15008
Spud	304	442	746	449	124	4	1323
Dry Hole	6	14	20	15	3	0	38
Shut In	391	771	1162	2551	474	5	4192
Abandoned	32	323	355	1149	157	0	1661
Producing	970	4102	5072	8175	1437	31	14715
Drilled	1703	5652	7355	12339	2195	40	21929
No Data	1	5	6	23	1	0	30
TOTAL	3476	11212	14688	21772	3889	151	40460

2 Table 2: Physical Descriptive Statistics for Producing CBM Wells in Northeastern Wyoming

Mean	Reported		Mapped		All Tenures
(s.d.)	Unified	Split	Unified	Split	
Permit Year	2002	2004	2003	2002	2001
	(2.4)	(1.5)	(2.2)	(2.4)	(2.5)
Elevation (feet)	4596	4571	4387	4632	4456
	(376.6)	(534.1)	(287.6)	(416.8)	(467.3)
Depth (feet)	1082.5	1087.0	1319.9	1027.7	998.7
	(439.6)	(450.2)	(512.8)	(405.6)	(474.5)
Months to First	13.6	12.5	17.1	12.8	12.6
	(10.7)	(8.4)	(11.6)	(13.4)	(10.9)
Months to Max	10.9	6.4	11.7	10.1	14.6
	(12.0)	(6.6)	(11.8)	(11.4)	(14.8)
Maximum Gas (Mcf)	5930	3899	6155	5513	5272
	(9053)	(6786)	(13039)	(7543)	(7745)
Cumulative Gas (Mcf)	87137	45030	65803	84854	87848
	(127989)	(76766)	(143758)	(119373)	(127224)
Total Days Produced	906	411	450	920	1042
	(727)	(419)	(584)	(711)	(787)
Observations	5804	1024	1260	5619	23195

Some variables may have fewer than maximum number of observations due to missing data.

3 Table 3: Reported vs. Mapped Tenure of All CBM Wells in Wyoming

	Mapped					
	Private	Unified	Split	State	Other	Total
Private	20979	24	312	82	0	21397
Unified	79	3367	6927	7	20	10400
Split	28	69	3951	1	0	4049
State	476	16	13	3634	10	4149
Other	210	0	9	165	81	465
	21772	3476	11212	3889	111	40460

4 Table 4: History of Well Reporting

Rep-Map	U-U	U-S	S-U	S-S	Total	% Split Misreported
1987	0	4	0	0	4	100.0
1988	1	7	0	0	8	100.0
1989	1	5	0	0	6	100.0
1990	0	10	0	0	10	100.0
1991	1	3	0	0	4	100.0
1992	2	11	0	0	13	100.0
1993	0	1	0	0	1	100.0
1994	1	8	0	0	9	100.0
1995	1	18	0	0	19	100.0
1996	4	121	0	0	125	100.0
1997	19	96	0	0	115	100.0
1998	30	206	0	0	236	100.0
1999	189	1107	2	25	1323	97.8
2000	102	735	0	6	843	99.2
2001	158	1601	5	121	1885	93.0
2002	135	652	1	162	950	80.1
2003	474	602	2	248	1326	70.8
2004	600	898	12	766	2276	54.0
2005	770	613	10	1335	2737	31.5
2006	702	47	30	1140	1919	4.0
Total	3199	6745	62	3803	13809	63.9

5 Table 5: Duration Models

	(1)	(2)	(3)	(4)
Failure	Produced	Produced	Peaked	Peaked
Permit Year	-0.2804**	-0.2873**	-0.2561**	-0.2615**
	(0.03697)	(0.03613)	(0.02630)	(0.02569)
Depth	-8.831e-04**	-7.329e-04**	-0.001360**	-0.001242**
	(4.466e-05)	(4.642e-05)	(4.690e-05)	(4.826e-05)
Reported Split	-0.3731**		-0.2536**	
	(0.03955)		(0.04416)	
Mapped Split		0.3794**		0.3959**
		(0.03657)		(0.03714)
NG Futures Price	-0.1831**	-0.1968**	-0.1509**	-0.1582**
	(0.01811)	(0.01800)	(0.01671)	(0.01665)
Observations	82965	83865	149310	150907

Robust standard errors in parentheses
** p<0.01, * p<0.05

6 Table 6: Peak Gas Production

	(1)	(2)
Year First Produced	410174**	457550**
	(59836)	(60977)
Year First Produced Squared	-102.69**	-114.56**
	(14.948)	(15.233)
Reported Split	-1339.5**	
	(343.42)	
Mapped Split		-4216.0**
		(578.76)
Months to Max Production	-107.56**	-115.54**
	(9.9360)	(9.8686)
Months to First Production	47.855**	36.141*
	(14.867)	(14.199)
Days Produced in Max Month	241.31**	262.38**
	(32.618)	(33.682)
Observations	5263	5263
R^2	0.453	0.465

Robust standard errors in parentheses
** p<0.01, * p<0.05

7 Table 7: Cumulative Gas Production

	(1)	(2)
Year First Produced	1.4746e+06	1.7693e+06
	(1.0840e+06)	(1.1016e+06)
Year First Produced Squared	-366.99	-440.84
	(270.82)	(275.21)
Reported Split	-4052.1	
	(3600.7)	
Mapped Split		-33040**
		(6041.8)
Months to Max Production	-1535.3**	-1603.7**
	(147.83)	(145.91)
Months to First Production	449.35*	349.07*
	(175.06)	(169.20)
Total Days Produced	128.89**	128.91**
	(4.4285)	(4.4377)
Observations	5274	5274
R^2	0.569	0.573

Robust standard errors in parentheses
** $p<0.01$, * $p<0.05$

8 Table 8: Cumulative Well Value

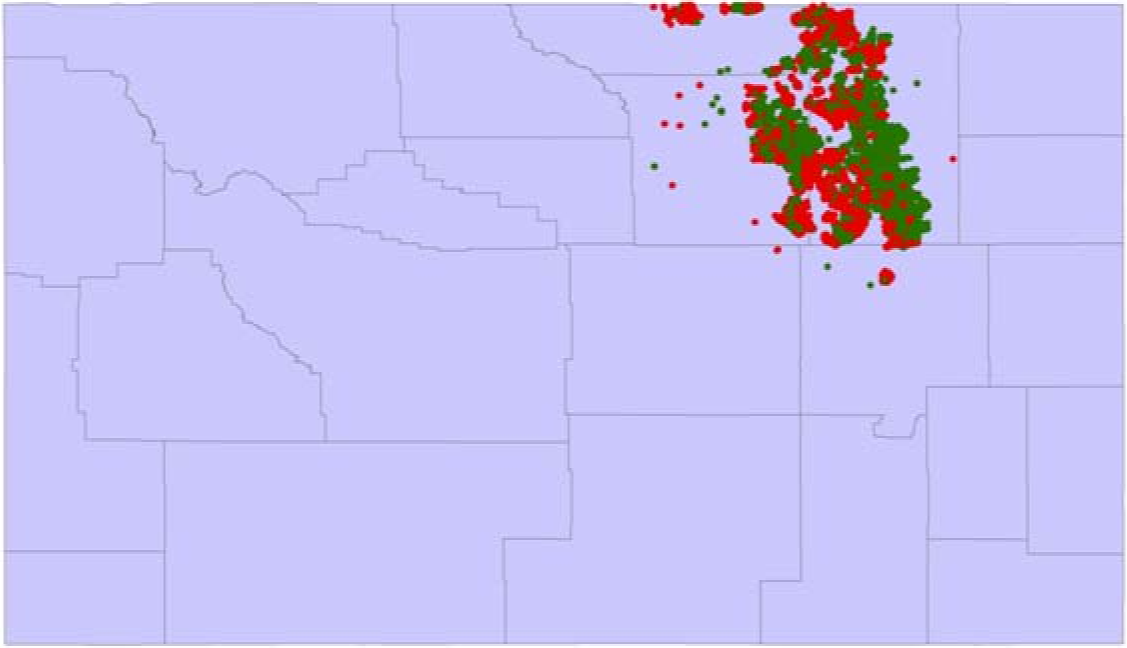
	(1) US Wellhead	(2) City Gate	(3) US Wellhead	(4) City Gate
Year First Produced	2.5991e+07**	1.8646e+07**	2.7849e+07**	2.0664e+07**
	(6.2024e+06)	(5.3337e+06)	(6.3634e+06)	(5.4888e+06)
Year First Produced Squared	-6480.4**	-4646.8**	-6946.1**	-5152.4**
	(1549.0)	(1332.6)	(1589.1)	(1371.2)
Reported Split	-24494	-29690		
	(23494)	(24945)		
Mapped Split			-210437**	-222534**
			(39787)	(42292)
Months to Max Production	-4658.3**	-5007.4**	-5095.9**	-5465.3**
	(788.03)	(846.94)	(767.97)	(825.33)
Months to First Production	2703.1*	2653.6*	2062.5*	1981.6
	(1049.5)	(1081.9)	(1015.5)	(1052.2)
Total Days Produced	567.48**	585.88**	567.63**	586.02**
	(19.655)	(21.674)	(19.731)	(21.724)
Observations	5274	5274	5274	5274
R^2	0.483	0.476	0.489	0.481

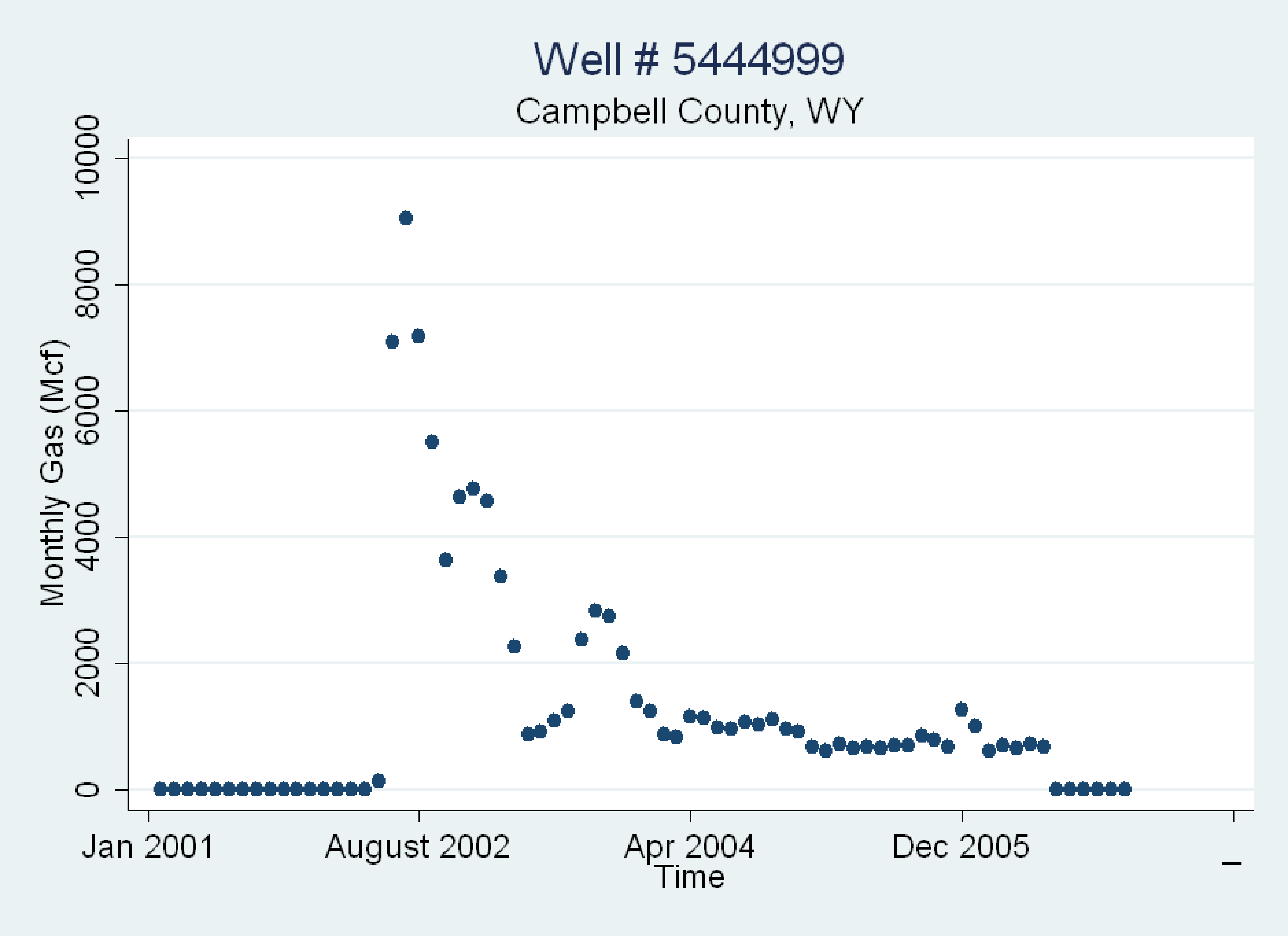
Robust standard errors in parentheses
** p<0.01, * p<0.05

Figures

Figure 1

Figure 2




Well # 5444999
Campbell County, WY
Monthly Gas (Mcf)
0
2000
4000
6000
8000
10000
Jan 2001
August 2002
Apr 2004
Dec 2005
Time