ABSTRACT

Title of dissertation: INTERNALIZING PRODUCTION EXTERNALITIES: A STRUCTURAL ESTIMATION OF REAL OPTIONS IN THE UPSTREAM OIL AND GAS INDUSTRY

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There are hundreds of thousands of crude oil and natural gas wells across North America that are currently not producing oil or gas. Many of these wells have not been permanently decommissioned to meet environmental standards for permanent closure, but are in an inactive state that enables them to be more easily reactivated. Some of these wells have been in this inactive state for more than sixty years which begs the question of whether they will ever contribute to our energy supply, or whether they are being left inactive because the environmental remediation costs are prohibitively high. I estimate a structural model of optimal well operations over time and under uncertainty to determine what conditions or policies might push any of the inactive wells out of the hysteresis in which they reside. The model is further used to forecast production from existing wells and recoverable reserves from

existing pools. The estimation uses data on production decisions from 84 thousand conventional oil and gas wells and estimates of the remaining reserves of 47 thousand pools. As the producer's decision depends on their subjective belief for how prices and recoverable reserves change over time, I also estimate the probability of changes in prices and recovery technology. I model increases and decreases in the estimated recoverable reserves to depend on price, and predict that natural gas reserves are more responsive to changes in price than conventional oil reserves. Under high prices there is potential for large increases in gas reserves, however this is not the case for oil reserves when the oil price is high. And likewise, under low prices, gas reserves decrease more than oil reserves.

The dynamic programming model predicts that with only a drastic, arguably implausible, increase in prices and recovery rates will there be a significant increase in the number of inactive wells that are reactivated. If ideal conditions are not enough to induce well reactivation then this implies that typically wells are left inactive not because of the option to reactivate, but rather because the cost of environmental cleanup is too high. Should there be externalities from idling the wells (such as continued contamination of groundwater) that are not accounted for in the decision, then this behavior may not be socially optimal. The model predicts that a Pigouvian tax on inactive wells would have the added benefit of inciting the reactivation of oil and gas wells, however in the case of oil, a tax would incite more wells to be decommissioned than reactivated.

INTERNALIZING PRODUCTION EXTERNALITIES: A STRUCTURAL ESTIMATION OF REAL OPTIONS IN THE UPSTREAM OIL AND GAS INDUSTRY

by

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Dedication

To my mom and dad

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Contents

List of Tables

List of Figures

List of Abbreviations

1	Active state
2	Inactive state
3	Permanently decommissioned state
$\alpha_{0,A}$	Intercept in production, for age group A
$\alpha_{1,A}$	Coefficient on reserve size in production
A	Age interval (takes the value of the lowest age in the interval)
b	Scale parameter of ϵ
σ_P^2	Variance of error in price path
β	Discount factor
C	Cost of per unit extraction (lifting costs)
d	Decision (policy) for choice of operating state, o
ϵ_o	Unobserved cost in operating state o
E	Expectation operator
E^3m^3	Thousand cubic meters (used as the unit for volume of natural gas)
E^6m^3	Million cubic meters (used as the unit for volume of natural gas)
f_q	Probability density function of the amount of oil extracted
F_q	Cumulative distribution function of the amount of oil extracted
f_Q	Probability density function of an exogenous change in reserves
F_Q	Cumulative distribution function of an exogenous change in reserves
f_p	Probability density function of the price process
F_p	Cumulative distribution function of price process
g	Well type (group)
κ	multiplied by $\overline{Q}$ gives the upper limit on how much can be extracted
M_1	Annual maintenance costs of leaving a well active
M_2	Annual maintenance costs of leaving a well inactive
o	Operating state (active, inactive, decommissioned)
p_{HL}	Probability of switching from high price regime to low
p_{LH}	Probability of switching from low price regime to high
P	Price of hydrocarbon (subscript g for gas, o for oil)
P'	Price of hydrocarbon in the following period
$\overline{P}$	Mean price
$\phi_{0,i}$	Intercept in reserve growth (i=U) or decrease (i=D)
$\phi_{1,i}$	Parameter on price in reserve growth (i=U) or decrease (i=D)
r	Price regime (L=low price, H=high price)
π	Profit of firm
σ_A	Variance in distribution of production for wells in age group A
$\theta_{1^{st}}$	First stage parameters (transition probability density functions)
$\theta_{2^{nd}}$	Second stage parameters (cost parameters)
q	Quantity of hydrocarbon extracted in a month
Q	Estimated Remaining Reserves in Pool
Q'	Estimated Remaining Reserves Next Period
$\overline{Q}$	Per Well Remaining Reserves (Q/no. of wells in a pool)

ρ	Probability transition density for ϵ
s	State variable (includes A, P, Q and o)
$SC_{(1\to 2)}$	Fixed cost of temporarily deactivating an active well
$SC_{(2\to 1)}$	Fixed cost of reactivating an inactive well
$SC_{(1,2\to 3)}$	Fixed cost of permanently decommissioning a well (irreversible)
ϑ_r	Coefficient in price process of regime r
ς_r	Variance in price process of regime r
V	Value function
V_d	Value function evaluated at policy decision d
w	Subscript for well
W_g	The number of wells in a group, g

AS	Additively Separable
CI	Conditional Independence
ERCB	Energy Resources and Conservation Board
IER	Initial Established Reserves (remaining reserves+cumulative production)
PSAC	Petroleum Services Association of Canada

1 Introduction

Currently, there are hundreds of thousands of oil and gas wells scattered across North America that are inactive. Some of these wells have not produced any oil or gas in the last 60 years, but they also have not been permanently decommissioned[1] under the claim that they will be reactivated some day. Different jurisdictions across the United States and Canada have different ways of ensuring wells are decommissioned at the end of their productive lives so that environmental damage is remediated and avoided. Unlike jurisdictions that limit the time that a well can be left inactive before it is decommissioned, in Alberta, Canada, the decision of *when* to declare that a well has reached the end of its productive life is left up to the operator and there is no limit to the length of time that a well can be left inactive. By allowing the producer to decide when to decommission its wells, the option for future production is preserved so that the wells can be readily reactivated should prices or technology improve. However preserving the option to reactivate comes with a social cost. Leaving a well inactive without proper decommissioning increases the risk of contamination of the atmosphere, drinking water, vegetation and soil, lost productivity of other wells in the same pool and even explosions [Kubichek et al., 1997, Williams et al., 2000]. There is also the risk that the producer will declare bankruptcy before undertaking the expense of the environmental cleanup. Texas, for example, has roughly 10,000 orphaned wells for this reason[RRC, 2006]. The cleanup costs associated with decommissioning in Alberta range from $20,000

[1]Here, to permanently decommission a well is to plug and abandon it, and to reclaim the surrounding land.

to several million dollars per well[Orphan], whereas the cost that a producer must pay to keep a well inactive is usually only a payment to the owner of the surface rights (typically around $1500 per year [Marriott, 2001]). In 2009 the Government of Alberta announced plans to spend $30 million dollars in the cleanup of 600 orphaned wells [ABGovt, 2009]. As there are over 225,000 conventional oil and gas wells in Alberta that will eventually need to be decommissioned, examining the factors that influence this decision is a worthwhile endeavor. This dissertation examines the probability that wells will be reactivated or decommissioned as well as the resulting production of oil and natural gas should they be reactivated. This examination sheds light not only on the extent of the liability that has accumulated by not decommissioning inactive wells, but also on the future oil and gas supply from existing conventional wells.

To determine how likely it is that the inactive wells will ever be productive or not, I propose the following three steps: (1) model the producer's decision for the optimal operating state of a well (active, inactive or decommissioned) over time and under uncertainty, (2) estimate the structural parameters in the model, (3) use the model to simulate a producer's reaction to counterfactual scenarios, to see what conditions would result in wells being reactivated. I model the producer's decision in a dynamic programming framework and recover the parameters in the model with data on the decisions made for 84 thousand Albertan oil and gas wells from 2000 to 2007. The decision depends on observable and unobservable states of nature, as well as a producer's perception of what the future state of nature will be. One such state is the recoverable reserves that a well taps into, for which I exploit a previously unused dataset of the official reserve estimates of 47 thousand oil and gas pools in Alberta from 2000 to 2007. As this dataset comes from a panel I am able to estimate the change in recoverable reserves, by technological improvements, discoveries or reevaluations, depending on the price of oil or gas. The model predicts that with a high natural gas price there is potential for large increases in the quantity of recoverable reserves, however in the case of oil, a high price does not significantly increase recoverable reserves.

After recovering the model primitives the model predicts that very little of the oil and gas supply is forfeited under policies that induce decommissioning. The model also predicts that only with a significant increase in prices or the efficiency of recovery is there a notable decrease in the percentage of inactive wells, and that the additional contribution to the oil and gas supply from these reactivated wells is only marginal. This implies that typically wells are left inactive not because of the option to reactivate, but rather because the cost of environmental cleanup is too high.

1.1 Literature Review

In this dissertation, I estimate the structural parameters of a real options model, and am thereby able to test the goodness-of-fit of a real options model to actual firm behavior. Real options extends the Black and Scholes [1973] and Merton [1973] theory for financial options to that of irreversible real investments. Real option models put value on investment flexibility; having the option to wait before investing will add value to the project. Much of the literature on real options relies on examples from the natural resource industry so that models of many different discrete decisions in the industry have been developed. The same three choices presented in this paper (to activate, inactivate or decommission a project) have already been modeled by Brennan and Schwartz [1985][2], Dixit and Pindyck [1994], Gamba and Tesser [2009]. However, none of these authors applied their models to real data.

Unlike the case of financial derivative models, empirical investigations to test the fit of real option models to data are rare. Gamba and Tesser [2009] note that this is due to two factors: the value of the state variables is often not observed; and because of the existence of non-price or quantity uncertainty. The empirical examination of real options has been limited to comparing stylized facts from the predictions of real options models to the data. Many of these papers have relied on having data for the cost parameters rather than estimating these parameters structurally, restricting their investigations to small sample sizes. Moel and Tufano [2002] compare stylized facts from real options theory to estimates from a probit analysis of 285 gold mines, but without data on opening and closing costs. Paddock et al. [1988] apply real options to value offshore petroleum leases using data on 21 offshore petroleum tracts. Slade [2001] determines the value of mine opening and closings using panel data for 21 mines. The opening, closing and maintenance costs were "rough" estimates obtained from interviewing people in the industry. With

[2]There have also been many extensions to Brennan and Schwartz [1985]'s numerical example of opening, closing and decommissioning a hypothetical copper mine (for example, Castillo-Ramirez [1999], Cortazar and Casassus [1998],Cortazar et al. [2001] and Stensland and Tjostheim [1989]).

60 observations from copper mines Harchaoui and Lasserre [2001] test if there are trigger prices as predicted by theory. Hurn and Wright [1994] use data on 108 oil wells to estimate a hazard model to examine the time to develop a field to test predictions for irreversible investment decisions. While the literature on real options in the natural resources industry is large, to the best of my knowledge, this is the first time that there has been a structural estimation of the primitives of this type of model with real data.

Generally data on production are more readily available than data on costs (production reporting is usually mandatory, whereas cost data are proprietary) and therefore the gains of not relying on cost data are immense. For this paper, relative costs are estimated using the data on production decisions via Rust [1987]'s Nested Fixed Point Algorithm allowing for a powerful way to take advantage of the extensive production datasets available. This technique will not identify all costs, but only relative costs[3]. Aided by this technique to estimate the costs, this is the first time that a dataset so large has been combined with a real options model.

Furthermore, throughout the real options literature the permanent closure option is often downplayed. Decommissioning costs are treated as negligible or null [Brennan and Schwartz, 1985, Dixit and Pindyck, 1994], or the option of decommissioning is completely left out of the choice set [Moel and Tufano, 2002, Slade, 2001, Mason, 2001, Paddock et al., 1988]. By assuming away decommissioning costs, the previous literature has overlooked the case of firms that continue to maintain the

[3]To identify the absolute costs external information of actual well sale prices would be needed. For the time being I refrain from interpreting parameter values.

option to reactivate a project, even when they have no intention to reactivate.

If the costs from mothballing a project are small enough relative to the decommissioning costs, this behavior would be privately optimal. This is especially the case in the natural resources industry where the large imprint that is typically left on the environment make decommissioning costs high. Should there be externalities from mothballing a project (such as continued contamination of groundwater) that are not accounted for in the decision, then this behavior may not be socially optimal. If a firm "temporarily" closes a hazardous site, when in fact there is no potential or intention to reactivate, regulators have reason to implement policies to ensure that environmental obligations are met.

In future work I will use the model developed here to investigate financial bonding mechanisms to ensure environmental remediation. One of the main reasons for a policy to induce prompt environmental cleanup is the risk that the firm will declare bankruptcy. The concern that oil and gas companies may walk away from their environmental obligations has been brought up by Boyd [2001], Parente et al. [2006], Ferreira et al. [2003]. While these authors discuss bonding mechanisms, the model here can be used to quantify the effect of a bond on production as well as the choice to undertake cleanup.

2 Background

Oil and gas activity in the Western Canada Sedimentary Basin began at the turn of the last century and thus the conventional oil and gas reserves are mature and the vast number of oil and gas wells present is not indicative of the remaining reserves that they tap into. Alberta's conventional oil production (that which is pumped out of the ground from a well) contributed 0.52 million barrels a day [ERCB, 2008], or .6% of the world's oil supply in 2007 [EIA2009, 2009]. Alberta's natural gas production contributed .135 trillion m^3 [ERCB, 2008], or 4.6% of the world's gas supply in 2006 [EIA2008]. The reserves of conventional oil, estimated at 1.5 billion barrels in 2007, is eclipsed by the estimated reserves of non-conventional oil from the oil sands, estimated at 173 billion barrels [ERCB, 2008].

Producers leaving a well inactive commonly claim that they are waiting for the price to increase to a point at which the well will become profitable. While a well might be drilled in a pool with a high estimated amount of oil in place, the current recovery factor, or fraction of the oil in place that can be recovered is likely to be low. Therefore, a producer might want to hold on to a well that taps into a massive reserve, even if it is not currently profitable to produce oil or gas, in the hopes that prices or technology improve. However many of the inactive wells are in a state of hysteresis because the cost to either retrofit the well for production or finally decommission the well is high. The preceding reasons for leaving wells inactive are directly modeled in this paper. The following are some reasons for inactivity that are not explicitly entered into the model (but only enter via an error term that compensates for unobservable states): (1) technical difficulties (for example, blockage in the wellbore, a leak caused by corrosion or erosion, an external fire, or a temperature change causing mechanical failure), (2) pipeline failure or pipeline capacity reached, (3) gas plant capacity reached or (4) a mandated suspension for exceeding the maximum rate limit[4] assigned to the well by the regulator.

The development of enhanced recovery methods has brought wells back into production after many years of inactivity. These extraction methods have improved over the last century, with the introduction of horizontal wells, progressive cavity pumps, cyclic steam stimulation, and coiled tubing [Beliveau and Baker, 2003]. Today most operators use enhanced recovery methods, most commonly by injecting water or gas into the well or a nearby well. There are many other techniques to increase the production rate, such as generating carbon dioxide in-situ, dissolving minerals with acid, injecting hot fluid or steam, or creating in-situ combustion. There are also various pumps that provide mechanical energy such as sucker rod pumping, electrical submersible pumping, hydraulic piston pumping, hydraulic jet pumping, progressive cavity pumping, and plunger lift systems.

With the introduction of these methods, recoverable reserves have been seen to increase, rather than decrease with time. For example from 1978 to 1993 the decrease in U.S. natural gas reserves by production was approximately the same as the increase in reserves, where 87% of the increase came from existing fields [Beliveau and Baker, 2003]. And within the last ten years, the development of hy-

[4] Various wells must conform to maximum rate limitations set by the industry regulator. These limits are to ensure that the cumulative amount of oil or gas extracted is maximized. In our model we will not truncate by maximum rate limit because only about 10 percent of the wells have limits placed on them, and for only a portion of those wells is the rate limit binding.

draulic fracturing[5] and horizontal drilling has made natural gas from shale accessible and thereby dramatically increased the recoverable reserves of natural gas. Reserve growth was first examined by Arrington [1960] using his own company's reservoir data. And since then reserve growth has been studied using state or state subdivision estimates of initial established reserves from the American Petroleum Institute [Morehouse, 1997], or a small number of pools [Verma and Henry, 2004]. This is the first time that such a large dataset on reserves has been used to study reserve growth.

2.1 Environmental Impacts

The fact that recoverable reserves can increase over time, gives credence to the claim that wells should not be decommissioned immediately. On the other hand, without proper decommissioning (and in some cases, even after proper decommissioning) a well poses a risk to vegetation, soil, surface water, and underground aquifers. Many wellbores extend thousands of meters underground, and it is often only a steel casing or cement that isolates the different formations. The casing might rust out or crack (especially when there is much sand or saltwater lifted along with the hydrocarbons) and contaminants such as uranium, lead, salt, iron, selenium, sulfates, and radon [Kubichek et al., 1997] may enter into formations that contain freshwater. The likelihood of this occurring increases when injection from disposal or enhanced recovery builds pressure [Canter et al., 1987].

[5] Hydraulic fracturing is the injection of fluids (many of which are hazardous and carcinogenic[6]) at high pressure to fracture the formation, releasing the gas.

The most prevalent contaminant from oil and gas wells into freshwater aquifers has been methane gas[7]. Methane is the second largest contributor to radiative forcing from anthropogenic greenhouse gases (second to carbon dioxide) [Reilly et al., 2006]. The second largest source of methane emissions is from the energy industry, where the majority of those methane emissions can be attributed to the production and processing of natural gas and oil, including due to the fugitive release from leaking gas wells [EPA, Katzenstein et al., 2003]. Another concern surrounding methane migration is that high concentrations can lead to explosions (there are instances of homes and windmills exploding). The presence of methane also foreshadows worse events to come. Methane indicates that a leak exists, meaning that other contaminants that are in lower concentrations, and slower moving than methane, follow shortly behind. Those more hazardous contaminants are the carcinogens uranium and radon, the probable carcinogen selenium, and the neurotoxin lead. Decommissioning a well does not guarantee that there will be no leaks, and often improperly decommissioned wells cause problems, however nonetheless, the risk is reduced as compared to when the well is active or inactive.

2.2 Various Regulations in the United States

In the U.S., minimum standards and regulations for well decommissioning (plugging, abandoning and reclamation) vary within and across states, depending on the regulatory authority and characteristics of the well. For example, the Bureau

[7] It is possible that methane may enter groundwater through shallow reservoirs that a water well penetrates, swamps or landfills, which has averted liability away from oil and gas producers. To determine the source of the methane gas isotopes are used.

of Land Management oversees the abandonment of wells drilled on Federal Land, a state's Department of Environmental Quality, Department of Conservation, or Oil and Gas Commission oversees oil and gas wells, and the Environmental Protection Agency oversees underground injection wells. Most require that cement plugs be placed across any open hydrocarbon-bearing formations, freshwater aquifers, and perhaps several other areas near the surface, including the top of the wellbore. However, stringency in granting permits for temporary inactivity, standards for materials used, and bonding requirements for abandonment vary by jurisdiction.

Many states require that wells that have not produced (for 30 days to a year, depending on the state) must be plugged and abandoned unless permission is granted to leave the well in "Temporary Abandonment" (TA) status. It is hard for the regulator to get a handle on the legitimacy of the request, and TA status is granted easily. Furthermore, the fine for leaving a well inactive, without permission, is usually small, for example in Kansas, the fine is only $100[8]. In Indiana it was found that many of the "active" were sitting idle with essential operating units removed[9].

In California, an operator does not need permission to leave a well inactive, but must do one of the following: pay an annual fee based on the length of time a well has been idle ($100 for 5 years, $250 for 10 years, or $500 for 15 years or more), establish an escrow account of $5,000 for each idle well, funded at the rate of $500 per year, file a bond of $5,000 per idle well, or file an Idle-Well Management/Elimination Plan to commit to plugging or returning the well to production[10]. However, in California,

[8] http://www.kcc.state.ks.us/conservation/cons_rr_0704.pdf

[9] http://www.in.gov/dnr/dnroil/pdf/inactivewells.pdf

[10] State of California, Department of Conservation, Division of Oil, Gas and Geothermal Resources: http://www.conservation.ca.gov/dog/idle_well/Pages/idle_well.aspx)

there is also the option to file a blanket bond of 1 million dollars that will cover all wells (including idle wells). In New Mexico[11] and Montana[12], that blanket bond is only $50,000. And the Bureau of Land Management requires a blanket bond of at least $25,000 to cover all wells drilled in a State, or $150,000 to cover all wells nationwide[13]. In Michigan, there are blanket bonds of up to 100 wells, but also, abandoning without properly plugging a well is a misdemeanor punishable by imprisonment[14].

2.3 Regulations in Alberta

2.3.1 Regulations for Decommissioning

In Alberta, it is required that all wells eventually be decommissioned however it is left up to the firm to decide when to decommission[15]. Decommissioning a well entails abandonment and reclamation. To abandon a well is to leave downhole or subsurface structures in a permanently safe and stable condition so that it can be left indefinitely without damaging the environment. It is required that all non-saline water formations are shut-off with cement. All porous zones must be isolated with cement plugs to prevent any crossflow. The cement between the casing and the

[11] New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division: http://www.emnrd.state.nm.us/ocd/documents/formcbbsample.pdf

[12] Montana Code Annotated, Title 82, Chapter 11: http://leg.mt.gov/content/lepo/2005_2006/subcommittees/hb790/minutes/eqchb79003162006_ex01.pdf

[13] Code of Federal Regulations (CFR Oil & Gas Bonding). 43 CFR 3104.1-3104.8 (2007)

[14] Michigan Department of Environmental Quality, Oil and Gas Regulations: http://www.deq.state.mi.us/documents/deq-ogs-land-fuelsmineral-oilandgas-regs.pdf

[15] The Energy Resources Conservation Board does have the authority to order that a wellsite be decommissioned, however this is not a common occurrence and the order is often rescinded or amended. For example, in 2007 there were only 6 well abandonment orders and in 2006 there were 19 well abandonment orders, but as of June 2009 only 2 of these wells have been abandoned.[AbndOrder, 2009]

formation must be checked to ensure that there are no flows of water or gas between formations. The operator must cap the well and test that there is no buildup of gas below the cap. Any detected leaks must be reported and repaired [ERCB020, 2007]. Reclamation includes the removal of any structures, decontamination of land or water, and “stabilization, contouring, maintenance, conditioning or reconstruction of the surface of the land” [EPEA, 2000]. Abandonment is under the jurisdiction of the Alberta Energy Resources Conservation Board (ERCB), and reclamation is under the jurisdiction of Alberta Environment. The duty to abandon inactive wells is put forth in the *Oil and Gas Conservation Act* [OGCA, 2000], and reclamation in the *Environmental Protection and Enhancement Act* [EPEA, 2000].

It can be very inexpensive to sustain an idle well–often only costing the compensation to the surface rights owners. As the province owns most of the minerals in Alberta, they auction off the rights by parcels of land without giving notice to the surface owners or occupiers. The holder of the mineral rights will then have the right to enter and use the surface of the land. Outlined in the *Surface Rights Act* [SRA, 2000], the operator can either reach an agreement with the surface owner privately or can go to the Surface Rights Board to receive a right of entry order and to determine the compensation necessary. The annual payment for a wellsite is based on “loss of use” and “adverse effects” only (not land value or entry fee which is paid one time in the first year). The compensation must be paid until the operator has received a reclamation certificate. Of 4069 well leases, the average loss of land use payment was $184/acre and $1146 for general disturbance [Marriott, 2001].

2.3.2 Consistency of Regulations over the Sample Period

The estimation in this paper relies on the assumption that the regulatory regime was constant during the sample period. Fortunately the royalty regime has remained the same from 1993 until 2009 [MineralAct], coinciding with the study period. The royalty structure in Alberta adjusts according to price, when the pool was discovered, and productivity, all accounted for in the estimation. There were, however, two regulations that increased the cost of leaving a well inactive issued during the study period. In 2004 the ERCB increased requirements for inactive wells [ERCB013, 2007], whereby low risk wells (or those wells that have non critical levels of sour gas ($H_2S < 5\%$), and gas wells with an open flow potential of less than 28 thousand m^3/day) are to be inspected every 1 to 5 years. Medium and high risk wells (non-flowing oil wells with sour gas) must either place a packer and a tubing plug, or a bridge plug in the wellbore and high risk wells with a critical level of sour gas, must cap the bridge plug with 8 meters of cement.

The second regulation that increased the cost of inactivity was a bonding scheme introduced in 2002. Firms with liabilities that exceed their assets must post a bond for the difference. The liability is calculated as the sum of the decommissioning costs of the firm's inactive wells and 75% of the decommissioning costs of their active wells. The decommissioning costs used in the calculation for the bond are voluntarily reported amounts paid. The firms that want to ensure that the bond remains low would report instances of low decommissioning expenditures, and the firms that fear other firms are accumulating liability recklessly would report instances of high decommissioning expenditures. The former appears to abandonment costs used in the calculation range from \$7,200 to \$90,000 and land reclamation costs vary by location from \$13,200 (grasslands area east) to \$33,700 (alpine area). However, abandonment and reclamation costs often dramatically surpass these figures. For example, the Orphan Well Association spent over \$2 million to re-enter and repair one orphan well [Orphan]. Not all firms post a bond because it is only posted when the firm's liability exceeds their assets, where assets are calculated using the firms reported production of oil and gas from the preceding year. If the bond is less than the cost to decommission, there is not sufficient incentive to decommission. If a company becomes defunct, the Orphan Well Association will collect the required abandonment and reclamation costs from the remaining firms in the industry based on each firms share of industry liability. This levy is roughly \$280 per inactive well, and can be assumed not to influence the decision to leave a well inactive.

I model the well as if the well were a stand-alone entity, and I do not consider the portfolio of wells that the firm has a working interest in when determining the optimal operating state. The number of wells on a mineral lease might especially influence the decision to decommission. Once all of the wells on a mineral lease are decommissioned, the mineral rights are reverted to the Crown, and therefore if there is only one non-decommissioned well on the lease there is likely a lower probability to decommission. Fortunately, most of the leases are for one quarter section, or 160 acres, and only one oil well can be drilled on one quarter section (and for gas wells, only one gas well can be drilled per section, so a firm must obtain the mineral leases for all four quarters of the same section in order to drill a gas well).

3 Data

The data collected on the oil and gas industry in Alberta is unrivaled by data collected in other oil producing areas in its comprehensiveness and accessibility. Here, five datasets of the Albertan oil and gas industry are used. The first dataset is a panel of production from the universe of oil and gas wells in Alberta. Obtained through IHS Incorporated (that distribute the records collected by the Alberta Energy Resources Conservation Board (ERCB)), this dataset contains monthly oil and gas production dating back to 1924, with complete records starting after 1961. There is information on the location (latitude and longitude as well as the name of the field and pool that the well is on), depth, licence date, spud date (when the drill hit the ground), on production date, name of the current operator and name of the original operator (unfortunately there is no information on whether the well switched hands between the original and current operators).

The second dataset is a panel of official reserve estimates of all nonconfidential pools[16] in Alberta from both the ERCB and the National Energy Board of Canada. The dataset was obtained from the ERCB and spans 2000 to 2007 and contains 67,142 oil and gas pools although not observed in every year. The year that the estimate was last reviewed is listed and therefore the data can be extended to years prior to 2000 if the last review date of the pool was before 2000. This dataset contains: (1) initial oil or gas in place, which is the estimated volume of oil or gas in place before any extraction, and can be updated every year[17], (2) recovery factor,

[16] All pools eventually lose their confidential status (usually after 1 year), and so this dataset contains nearly all pools in Alberta.

[17] "Initial" is a misleading term because it refers to the estimate before extraction and can be

which is the fraction of the oil or gas in place that can be extracted "under current technology and present and anticipated economic conditions"[ERCB, 2008], (3) initial established reserves, which is equal to the initial oil or gas in place multiplied by the recovery factor, and (4) remaining established reserves, which is the initial established reserves minus the cumulative production and surface loss. Each pool contains information on characteristics of the pools and hydrocarbons in those pools such as porosity, initial pressure, area, density, temperature, and water saturation amongst others.

The third dataset is a list of all wells that were permanently decommissioned. To decommission a well entails that the well has met abandonment standards set by the ERCB [ERCB020, 2007], reclamation standards set by Alberta Environment [ABEnvironment, 1995] and received a reclamation certificate from Alberta Environment or Alberta Sustainable Resource Development, or were exempted from certification. The dataset contains wells that were abandoned along with the date of abandonment, and the wells that received a reclamation certificate or were reclamation exempt.

The fourth dataset consists of GIS shape files that designate areas that according to the Petroleum Services Association of Canada (PSAC) have similar costs in production and drilling. The PSAC areas were entered into ArcView GIS to assign a PSAC area to each well to account for heterogeneity in costs across Alberta. The seven areas are depicted in Figure 1 and described in Table 1.

The final dataset is the average wellhead price of crude oil and natural gas

updated every year–it does not refer to the operator's initial guess of reserve size.

Table 1: Characteristics of PSAC Areas

PSAC Area	Surface	Hydrocarbon	Characteristics
1	Rocky Mountains	Deep gas	Strict environmental regulations
2	Ranching, farming and forest	Oil and gas	Easily accessed
3	Agricultural prairie grassland	Gas and medium/heavy oil	Easily accessed
4	Prairie and woodland	Gas and heavy oil	Easily accessed
5	Agricultural	Oil and gas	Most densely populated area
6	Prairie and woodland	Shallow gas	Only winter drilling
7	Agricultural and logging	Oil and gas	Often no road access

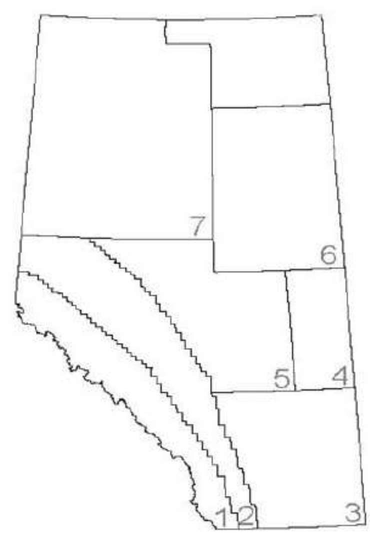


Figure 1: PSAC Areas

in Alberta, obtained from the Canadian Association of Petroleum Producers' Statistical Handbook [CAPP, 2009]. The wellhead price is inflated to 2007 dollars using Statistics Canada's quarterly machinery and equipment price index for mining, quarries and oil wells. The wellhead price paths for crude oil and natural gas prices are illustrated in Figure 2.

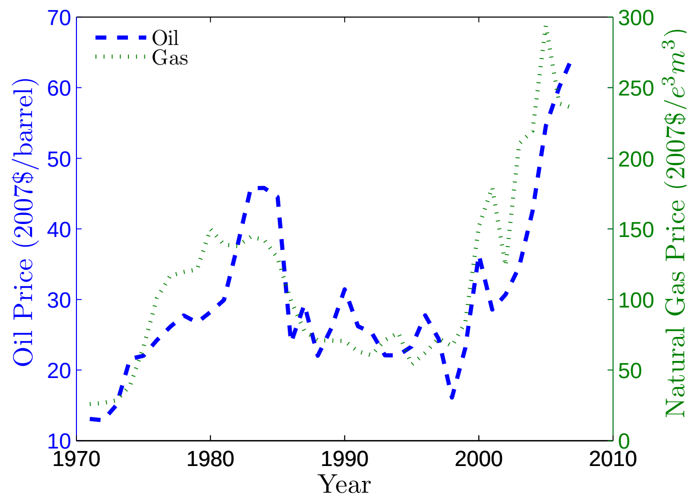


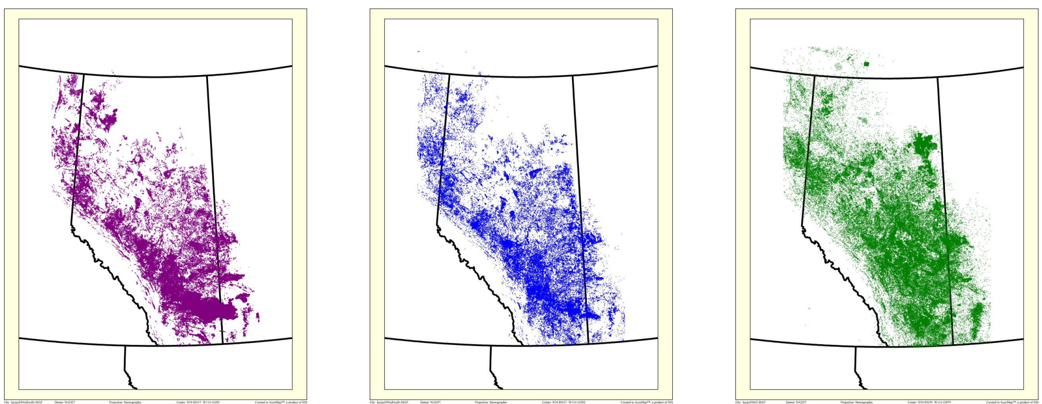
Figure 2: Annual Crude Oil and Natural Gas Wellhead Prices in Alberta

3.1 Description of the subsample

The full dataset of the universe of wells in Alberta is pared down into a subsample that is used for the estimation. Excluding coalbed methane, heavy oil, injection and water wells there are 350,457 wells in the production dataset. As the model here depends on the well's remaining reserves, the full sample is restricted to only those wells that have a reserve estimate. Of the 350,457 wells, 105,207 are in a pool that is listed in the reserves dataset, and these are used in the subsample. The subsample is further reduced by deleting wells that traverse both oil and gas pools. Doing so does not significantly reduce the size of the subsample, but does significantly reduce the computational complexity because modeling the choice to producing oil or gas is avoided without losing much insight into the decision of operating state. After deleting all wells that produce oil and gas from different pools, the final subsample contains 94,009 wells distinguished as either oil wells or gas wells.

A panel is created where each well is classified as either active, inactive, or decommissioned for each year starting with the year the well was drilled until 2007. A well is classified as active if it produced any amount of gas or oil within that year, classified as inactive if it did not produce oil or gas in twelve months or more, and classified as decommissioned if it appeared in the dataset of decommissioned wells. A snapshot of all oil and gas wells in different operating states in 2007 is shown in Figure 3.

The distribution of different operating states according to age groups for the full sample of all wells in Alberta is compared to that of the subsample (Table 2).



(a) Active Wells (150,997)

(b) Inactive Wells (95,575)

(c) Decommissioned Wells (103,885)

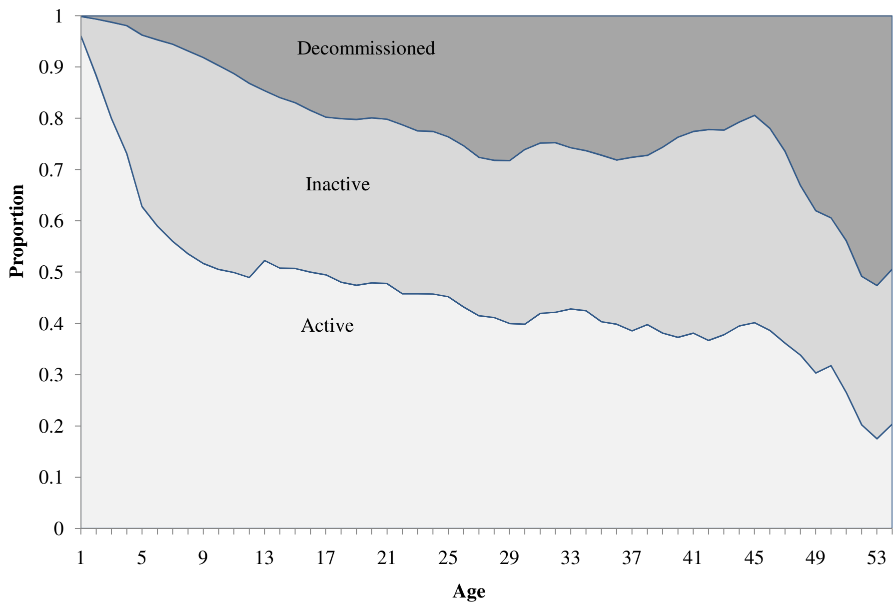
Figure 3: Oil and Gas wells in Alberta in 2007

There is a higher proportion of wells that are active in the subsample than in the full sample. The subsample does not contain as large a proportion of young wells that have been decommissioned as the full sample. This is because more than 45% of the wells that are decommissioned in Alberta are decommissioned immediately after being drilled (Figure 5(a)). Upon drilling the well, if the operator realizes that the well will not be productive, then it is worthwhile to decommission immediately because the necessary equipment is present, and it can be decommissioned before investing in the completion of the well for production. The wells that do not tap into an oil or gas pool are more likely to be immediately decommissioned, and they will also not show up in the subsample (that contains only wells with pool information). Therefore this paper examines the decision of decommissioning wells that are or once were deemed producible. The distribution of the age that wells are decommissioned in the full sample when omitting any well that had zero production hours (Figure 5(b)) is very similar to the distribution of the age that wells are decommissioned in the subsample (Figure 5(c)). The decision of whether to complete the well or not is a separate decision from whether to produce from an already completed well or not. And indeed it is more challenging to determine the future of wells that have or once had a potential for production as opposed to those for which there is no question that they cannot produce.

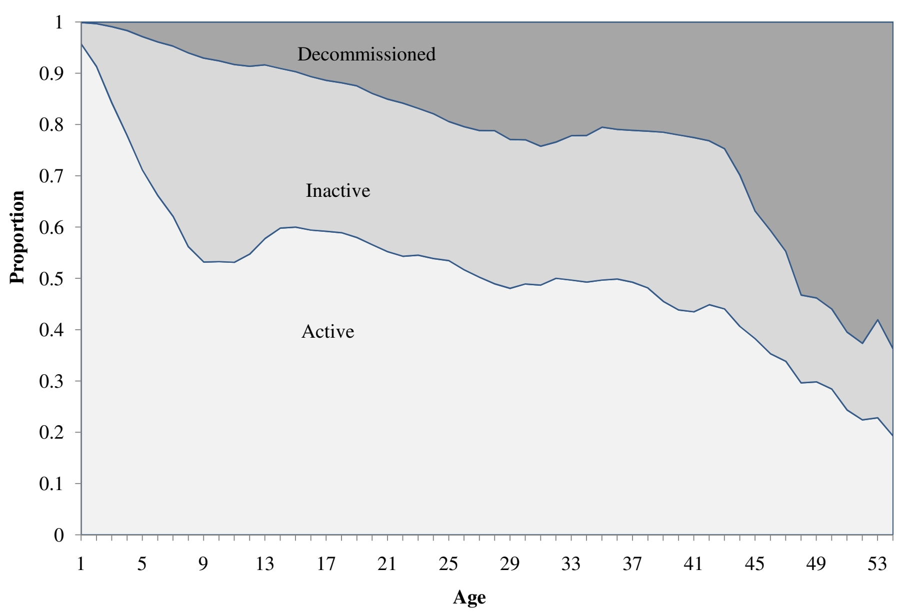
Table 2: Distribution of wells according to status within age groups

Age (in years)	Number of Observations		Proportion Active		Proportion Inactive		Proportion Decommissioned	
	(Subsample)	(Full)	(Subsample)	(Full)	(Subsample)	(Full)	(Subsample)	(Full)
$age = 0$	0	130791	N/A	0.476	N/A	0.427	N/A	0.097
$1 \leq age < 10$	162162	823205	0.719	0.566	0.249	0.269	0.032	0.164
$10 \leq age < 20$	105269	445136	0.532	0.356	0.339	0.241	0.128	0.403
$20 \leq age < 30$	64462	436830	0.504	0.369	0.298	0.200	0.198	0.430
$30 \leq age < 40$	23848	192081	0.469	0.260	0.298	0.213	0.233	0.527
$40 \leq age < 50$	18391	150170	0.395	0.220	0.287	0.341	0.319	0.438
$50 \leq age < 60$	9095	124015	0.223	0.093	0.238	0.539	0.539	0.368
$60 \leq age < 70$	1717	7541	0.378	0.120	0.378	0.457	0.244	0.423
$age \geq 70$	973	5365	0.337	0.132	0.217	0.470	0.446	0.398

Notes: Data from 2000-2007. The full sample comprises all wells in Alberta. The subsample contains only the wells that have pool information and produce from only one pool.



(a) Oil Wells



(b) Gas Wells

Figure 4: Proportion of Operating State by Age

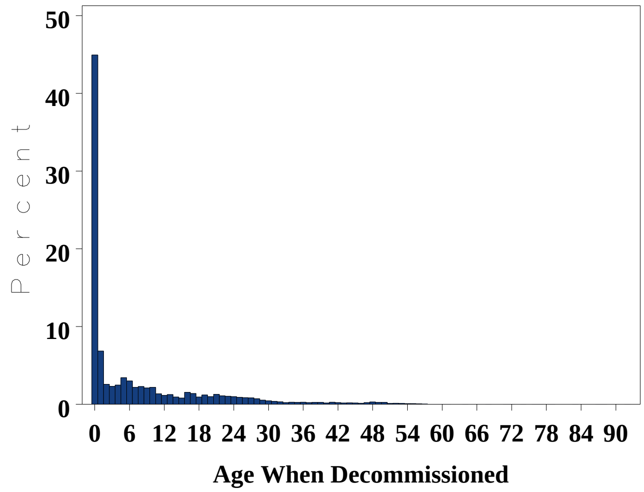
Table 3: Distribution of operating choice for inactive wells by age groups

Age (in years)	Number of Observations (Oil)	Number of Observations (Gas)	Proportion Reactivated (Oil)	Proportion Reactivated (Gas)	Proportion Stay Inactive (Oil)	Proportion Stay Inactive (Gas)	Proportion Decommissioned (Oil)	Proportion Decommissioned (Gas)
$1 \leq age < 10$	18963	21091	0.110	0.194	0.874	0.790	0.016	0.015
$10 \leq age < 20$	19892	14965	0.056	0.066	0.922	0.915	0.022	0.019
$20 \leq age < 30$	7997	11234	0.057	0.075	0.914	0.897	0.029	0.028
$30 \leq age < 40$	2340	4791	0.046	0.054	0.928	0.913	0.026	0.033
$40 \leq age < 50$	2176	3135	0.030	0.042	0.945	0.929	0.025	0.030
$50 \leq age < 60$	704	1461	0.024	0.027	0.953	0.955	0.023	0.018
$60 \leq age < 70$	131	503	0	0.010	1	0.990	0	0
$age \geq 70$	50	157	0	0	1	0.987	0	0.013

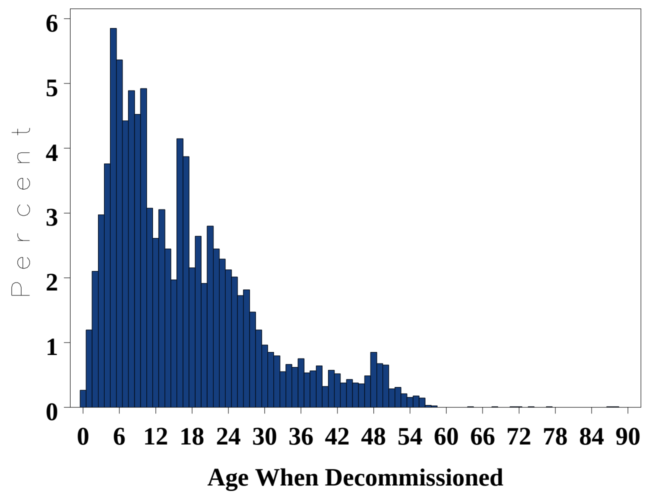
Notes: Data from 2000-2007 subsample.

Table 3 shows the proportion of inactive oil and gas wells that have been reactivated, left inactive, or decommissioned by different age intervals. To determine whether the well is an “oil” or a “gas” well I depend on whether the well is drilled in an oil pool or a gas pool, these proportions are of wells in the subsample. As expected the proportion of inactive wells that get reactivated decreases with the age of the well. The proportion of inactive wells that are decommissioned is low for very young wells and for very old wells. An explanation could be that very young wells are more likely to be reactivated and hence decommissioning is lower, and very old wells are more costly to decommission and so they are not decommissioned as readily (but there are far fewer observations of inactive wells older than 50 years to make this inference). The table reiterates that the hysteresis of inactivity increases as wells age.

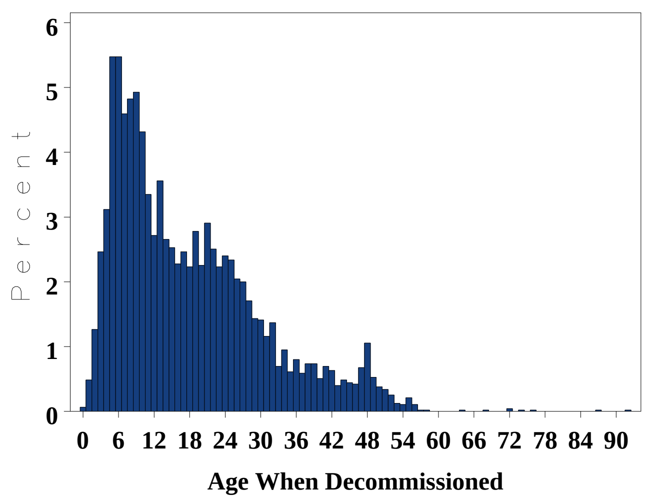
The majority of the wells have small reserves and only a few have large reserves, some being extremely large–for example, the largest gas reserve is 1,500 times larger than the mean gas reserve (Table 4). The pools with large reserves have more than one well–as many as 4151 wells in a gas pool, and 711 in an oil pool. In the estimation



(a) Full Sample



(b) Wells in Full Sample that Produced



(c) Subsample

Figure 5: Histogram of Age when Decommissioned

per well reserves, $\overline{Q} = Q/n$ are used as a state variable[18]. Depth, porosity, density, initial pressure, temperature, water saturation and the year the pool was discovered are all constant over time and are used in grouping the wells into types. Temperature and water saturation in reality would not be time invariant, but it is still valuable to use these in forming groups of similar types of wells. The summary statistics also show the number of different firms that are in the same pool. In the majority of the pools only one firm has access to the pool. In future research it will be interesting to model the interaction between different firms on the same pool[19]. In this paper, wells that are in single-well pools are put into different groups from wells in multi-well pools. The average number of wells in a gas pool is 3.5 (and 4.4 for oil pools), but the majority of the time there is only 1 well per pool (the median and mode are 1 for both oil and gas).

[18]Livernois [1987] also incorporates the concept of reserves per well.

[19]There has been extensive theoretical research on this issue, but the empirical remains scarce (see Libecap [2003] for an overview of the literature.

Table 4: Summary Statistics

Variable	No. of Obs.	Mean	Std. Dev.	Min	Max	Unit
$\overline{Q}_g$	118187	15.233	62.948	0	8800	E^6m^3
$\overline{Q}_o$	54523	27.087	237.073	0	43871.42872	$E^3Barrels$
Wellhead Price$_{\mathrm{g}}$	37	111.901	64.761	25.892	293.905	2007C\$ $/E^3m^3$
Wellhead Price$_{\mathrm{o}}$	37	30.160	12.116	12.881	64.448	2007C\$ $/Barrel$
Age$_{\mathrm{g}}$	61876	19.861	15.757	1	104	Years
Age$_{\mathrm{o}}$	31430	16.581	12.145	1	94	Years
Q_g	118187	32.973	297.793	0	51271	E^6m^3
Q_o	54523	135.644	1026.834	0	104866.4698	E^3Barrels
No. of wells in Pool$_{\mathrm{g}}$	118187	3.589	47.018	1	4117	Wells
No. of wells in Pool$_{\mathrm{o}}$	54523	4.442	17.905	1	699	Wells
No. of firms in Pool	169841	1.279	1.317	1	91	Firms
q_g (Full)	1241677	1.777	7.947	0.0001	930.388	E^6m^3
q_g (Subsample)	322907	1.679	8.266	0.0001	568.394	E^6m^3
q_o (Full)	505749	9.746	20.366	.001	1389.129	$E^3Barrels$
q_o (Subsample)	155773	7.267	14.507	.001	822.946	$E^3Barrels$
Depth	93239	1197.528	690.357	90.9	6552	m
Porosity$_{\mathrm{g}}$	22452	.200	.075	0.01	0.4	Fraction
Porosity$_{\mathrm{o}}$	25894	.161	.074	0.01	0.36	Fraction
Density$_{\mathrm{g}}$	22452	.643	.076	0.54	2.03	Fraction
Density$_{\mathrm{o}}$	25894	868.644	48.012	708	999	kg/m^3
Initial Pressure$_{\mathrm{g}}$	22452	9038.083	7564.568	130	99625	kPa
Initial Pressure$_{\mathrm{o}}$	25894	12568.804	5688.370	1442	61097	kPa
Temperature$_{\mathrm{o}}$	25894	50.144	20.342	9	350	C°
Water Saturation$_{\mathrm{o}}$	25894	.314	.115	0.06	0.82	Fraction
Wells per Firm (Sub)	1196	281.927	2015.260	1	44095	Wells
Wells per Firm (Full)	2818	124.364	1319.684	1	44095	Wells
Pool Discovery Year$_{\mathrm{g}}$	22452	1989.667	13.898	1904	2007	Year
Pool Discovery Year$_{\mathrm{o}}$	25894	1988.305	12.401	1910	2006	Year
Duration Inactive$_{\mathrm{o}}$	9556	8.39	8.33	0	73	Years
Duration Inactive$_{\mathrm{g}}$	12298	9.58	10.23	0	78	Years
Duration Active$_{\mathrm{o}}$	14472	10.11	9.11	0	46	Years
Duration Active$_{\mathrm{g}}$	34047	11.35	11.85	0	46	Years

Notes: The full sample encompasses all oil (o) and gas (g) wells in Alberta and the subsample encompasses only wells that have pool information. Data on remaining reserves (Q) is listed for pools 1993-2007. Extraction (q) is listed for wells, 1993-2007. The pool specific variables, depth, porosity, density, initial pressure, temperature, water saturation, area of pool and discovery year are time invariant in the data. Data on the number of wells held by a firm, age of the wells, and duration active and inactive is a snapshot of 2007. Price data are the wellhead price from 1971-2007. E^3=1000.

In a reduced-form multinomial logit regression for the discrete choice to activate, inactivate or abandon, as expected, the older the well the more likely it is to be abandoned, and the more likely it is to be inactive than active (Table 5). Also, when there are large remaining reserves, the wells are less likely to be abandoned, and more likely to be active than inactive. Also as expected, with higher prices wells are less likely to be abandoned, and gas wells are more likely active than inactive, but not as expected, oil wells are slightly more likely to be inactive than active. There could be some unobserved variable that is correlated with price and propensity to be inactive. Pool and well characteristics such as porosity, initial pressure, depth and density are included to determine which time invariants to cluster the data on. Gas wells are clustered on depth, initial pressure and density. Deeper gas wells with higher initial pressure and density are less likely to be decommissioned (Table 5). The wells are not clustered on porosity because the sign in the reduced-form multinomial logit regression (Table 5) for gas wells and the regressions of quantity extracted (Table 6) are not as expected. More porous rock is easier and cheaper to extract from, but higher porosity makes gas wells less likely to be active than inactive or decommissioned. This could also be a result of more wells being drilled in more porous rock, and more wells results in less extraction. The questionable result that wells with higher porosity extract less oil and gas makes porosity an unreliable variable to cluster the data on.

The wells are divided into groups of well type, g, depending on, (1) whether the well is an oil or gas well, (2) whether the well is in a single-well pool or a multi-well pool, (3) the royalty regime applicable, (4) PSAC area, and within these groups, (4)

Table 5: Mulitnomial Logit Estimates

	Oil Wells			Gas Wells	
	Activate vs. Decommission	Inactivate vs. Decommission		Activate vs. Decommission	Inactivate vs. Decommission
Intercept	1.2027 **	-0.4852 **	Intercept	0.9294 **	-0.8543 **
	(0.2151)	(0.2209)		(0.1158)	(0.1210)
$\overline{Q}_o$	0.1831 **	0.1712 **	$\overline{Q}_g$	0.0156 **	0.0151 **
	(0.0030)	(0.0030)		(0.0006)	(0.0006)
Price_o	0.0030 **	0.0071 **	Price_g	3.126E-06 **	1.237E-06 **
	(0.0005)	(0.0005)		(1.507E-07)	(1.587E-07)
Age_o	-0.0677 **	-0.0432 **	Age_g	-0.0802 **	-0.0495 **
	(0.0006)	(0.0006)		(0.0005)	(0.0006)
Porosity_o	1.8737 **	1.4764 **	Porosity_g	-1.4537 **	1.6757 **
	(0.1658)	(0.1696)		(0.1485)	(0.1587)
Initial Pressure_o	2.994E-05**	2.865E-06	Initial Pressure_g	8.782E-06 **	1.102E-05 **
	(2.853E-06)	(2.920E-06)		(2.844E-06)	(2.956E-06)
Depth_o	-0.0002**	-1.779E-05	Depth_g	0.0003 **	0.0003 **
	(3.331E-05)	(3.297E-05)		(2.519E-05)	(2.633E-05)
Density_o	-0.0006 **	0.0007 **	Density_g	1.2688 **	2.0219 **
	(0.0002)	(0.0002)		(0.1735)	(0.1795)
No. Wells in Pool_o	0.0022 **	0.0006 **	No. Wells in Pool_g	0.0033 **	0.0017 **
	(6.280E-05)	(6.787E-05)		(0.0001)	(0.0001)
Water Saturation_o	-0.8337 **	-1.8483 **			
	(0.0740)	(0.0768)			
Gas to Oil Ratio	0.0063 **	0.0034 **			
	(0.0002)	(0.0003)			
Temperature_o	0.0049 **	0.0113 **			
	(0.0009)	(0.0009)			
Log Likelihood	-164358			-161065	
No. of Observations	171834			183757	
R^2	0.1423			0.1484	

To decommission is the reference choice in the logit. ** parameter estimates are significantly different from zero at the 2.5% level. Standard errors are in parentheses.

two clusters based on time invariants (for gas: initial pressure, density and depth of well). The clustering only occurs if the likelihood ratio test confirms that clustering improves the fit. This results in 88 types of wells. The royalty regime depends on when the pool was discovered: "old" for oil from pools discovered before 1974, "new" for oil from pools discovered between 1974 and 1992, and "third tier" for oil from pools discovered after 1992. The royalty for gas refers to: "old" for gas from pools discovered after 1974 and "new" for gas from pools discovered after 1974.

The reserve and production datasets can be credited for being comprehensive but perhaps not for being accurate. The estimation assumes that the data on estimated reserves are the same as the well operator's estimated reserves. The reserve estimates however are made by the ERCB using data on production decline combined with the volumetric estimate of the reserves in place. Estimation based on material balance methods is often omitted because of unreliable pressure, volume and temperature data[ERCB, 2008]. The operator no doubt has a better estimate of recoverable reserves.

The production dataset contains firm reported volumes to which the accuracy is difficult to attest. The ERCB identifies cases when there is *any* difference in the reported production of oil from a production company and a pipeline company. In the case of natural gas, the ERCB identifies differences in reported production of 20% or more for volumes greater than 15,000 m^3 . When the difference is 5% to 20% of reported gas volumes the penalty is only a warning message. Non-compliance results in a fee of $100 if a well does not report in a given month, and upon persistent noncompliance the firm might be subject to increased audits or inspections, or partial or full suspension [ERCB019, 2007]. Nonetheless, to the best of my knowledge this is the largest dataset of a natural resource industry to be applied in the literature on real options. And it is with these data that the composition of active, inactive and decommissioned wells can be replicated to match reality closely.

4 Model

Dynamic programming lends itself to the modeling of the optimal operating state of an oil or gas well–it is a dynamic decision made under much uncertainty. The choice of an operating state depends on the expected future stream of profits from that choice which depends on uncertain prices, technology and reserves. The producer's problem is modeled as an infinite time Markov Decision Process, which as explained in [Rust, 1994], includes a decision variable, d, that is here to extract, 1; temporarily stop extraction, 2; or to permanently decommission and remediate environmental damages, 3. It is assumed that the producer is rational, and follows a decision rule $d_t = \delta_t(s_t)_{t=0}^{\infty}$ that dictates the optimal choice under all possible states of nature, s_t. The decision rule maximizes the expected discounted sum of profits, $V(s) = \max_{\delta} \mathrm{E}_{\delta} \left[\sum_{t=0}^{\infty} \beta^t \pi(s_t, d_t | s_0 = s)\right]$, where $V_t(s_t)$ is the value function for the well when choosing the optimal choice, β is the discount factor, $0 \leq \beta \leq 1$, and $\pi(\cdot)$ is the instantaneous profit from the well. The vector of state variables, s, include the age of the well, A, the wellhead price of the hydrocarbon, P, the per well remaining reserves, $\overline{Q}$, and the current operating state, o. The current operating state (o= active, 1, inactive, 2, or decommissioned, 3) is endogenous to the decision, and the remaining reserves per well is both endogenous (by extraction) and exogenous (upon technology change or by there being another well in the same pool).

If the producer decides to extract, they will receive the current wellhead price, P, per quantity extracted, q, less corporate income tax, τ, royalties, R, lifting costs, C, and a fixed operating cost, M_1. Leaving the well inactive also entails an annual fixed cost, M_2. If the producer decides to permanently decommission the well, they must pay switching cost $SC_{(1,2\to3)}$ and then they do not have to pay the annual fixed costs, although they will forgo any future extraction.

The firm also pays switching costs when reactivating or inactivating the well. The producer pays $SC_{(1\to2)}$ to temporarily inactivate an active well, $SC_{(2\to1)}$ to reactivate an inactive well and $SC_{(1,2\to3)}$, to decommission a well (assumed to be the same for active and inactive wells). Leaving the well in its current state entails no switching costs, $SC_{(1\to1)} = 0$, $SC_{(2\to2)} = 0$, and $SC_{(3\to3)} = 0$. To decommission the well is to enter an absorbing state (in the sample there are only 261 observations of a switch from decommissioned to active, whereas there were 22,308 observed deactivations, 15,369 reactivations of inactive wells, 1,917 active wells decommissioned, and 3,664 inactive wells decommissioned).

The profit from a single period is:

$$\pi(s,d) = \begin{cases} ((1-R)P - C)\,q - M_1 & \text{if d=1, active} \\ \qquad -\tau \max\{((1-R)P - C)\,q - M_1, 0\} - SC_{(s\to1)} & \\ -M_2 - SC_{(s\to2)} & \text{if d=2, inactive} \\ -SC_{(s\to3)} & \text{if d=3, decommission} \end{cases} \tag{1}$$

The per unit lifting cost $C(\overline{Q}, A, g)$ is increasing in age, A, and decreasing in per well reserves, $\overline{Q}$[20]. As costs will also depend on other factors such as well

[20]Chermak and Patrick [1995] and Foss et al. [2002] show how the lifting cost of natural gas depends on quantity extracted, and remaining reserves. Chermak and Patrick [1995] use data from 29 gas wells in Wyoming and Texas from 1988 to 1990, and Foss et al. [2002] use data from 22 gas wells in Alberta for roughly 3 years. They both find that operating costs increase with quantity extracted, and decrease with remaining reserves. It is expected that extraction costs rise

depth, porosity, location, etc., the estimation will be repeated for clusters of well types, g, based on these time invariant states. The royalty rate $R(P, q, A)$ adjusts according to price, date that the pool was discovered, and quantity produced. τ is the corporate income tax and is assumed flat for all wells.

The expected present discounted value of the well can be expressed as the unique solution[21] to the Bellman equation:

$$V(s) = \max_{d}[\pi(s, d) + \beta \int_{s'} V(s')h(s'|s, d)\mathrm{d}s']$$

The Bellman equation contains the conditional expectation of the value function in the future state, s'. The transition of s to s' is assumed to be a Markov process with a transition probability density function $h(s'|s, d)$. Specifically, price is assumed to follow the exogenous process $f_P(P'|P, \varsigma)$, characterized by parameters ς. Recoverable reserves decrease from extraction but also increase or decrease from new discoveries, revisions, or technological change. The quantity extracted, q, is modeled as a random draw from a density, $f_q(q|\overline{Q}, A, \alpha)$, that depends on the reservoir size, $\overline{Q}$, the age of the well, A, and unknown parameters to be estimated, α. The transition of recoverable reserves from extraction depends on whether the well is the only well in the pool or not. For wells on single-well pools, the transition probability of reserves depends on the probability of how much can be extracted,

as reserves are depleted, however, Livernois and Uhler [1987] explain that the discovery of new reserves can increase the reserves by more than what is extracted, but these new reserves are more costly to extract. This is how Livernois and Uhler [1987] explain a positive relationship between extraction costs and reserves using aggregate data from the Albertan oil industry. However, upon disaggregation, they find the typical results of extraction costs increasing with reserve depletion, and quantity extracted.

[21] Following Blackwell's theorem (outlined in [Rust, 1994] Theorem 2.3)

$f_q(\overline{Q} - \overline{Q}'|\overline{Q}, A, \alpha, d)$, only when the decision, d, is to extract, while for wells on multi-well pools, reserves transition according to this probability whether the operator extracts or not. Exogenous to the decision, recoverable reserves also follow another process, $f_{\overline{Q}}(\overline{Q}'|\overline{Q}, P, \phi)$, that accounts for the probability of change from improved technology, discoveries, reassessment, and additions. $\overline{Q}$ also decreases whenever another well is drilled in the pool. A simplification for the time being is that the probability of a decrease from more wells being drilled is incorporated into the exogenous change dictated by the transition probability density $f_{\overline{Q}}$.

I assume that the producers act as atomistic agents and do not consider gaining market power when making a choice for the operating state of a well. This is realistic because the conventional oil and gas wells are owned by over 1,200 different firms and are mostly on mature fields where the producible quantity, from even from the most productive wells, is not large enough to have an effect on the price. I also assume that the well is owned and operated by a single entity, however often many different firms have working interest in a well (starting from as little as 1% working interest). Given that operating decisions might need to be negotiated by different parties, the more firms that have an interest in the well, the slower it might be to decide on an operating state. Unfortunately, the data do not contain information on the number of different firms that have working interest in a well, but rather only a single licensee, and so this assumption is unavoidable, but perhaps not very grave because most interests are likely aligned.

4.1 Estimation Strategy: Introduction of Unobservables

The decision rule that maximizes the Bellman equation as specified above dictates exactly what the producer should do under any given age, price, remaining reserves and current operating state. However there is no *one* decision rule with which the data would perfectly coincide because in reality there are many other factors that will determine the producer's decision. Therefore, following Rust [1987] I add an component, ϵ_d, to the profit from each alternative that is observed by the producer but not by the econometrician. This unobserved component can account for unobserved heterogeneity in the firms or wells, or more specific characteristics that influence costs such as pressure, condition of the casing, etc. For example there are added costs of operating a well when there is excess water that needs disposal, a blowout, or a worker injured; added costs of leaving a well inactive if the owner of the surface rights takes the producer to court, or if there is gas is migrating out of the casing; added costs of proper abandonment if there is the toxic gas hydrogen sulfide (H_2S) present, or if the well traverses potable water. I use Rust's assumptions on ϵ_d in order to facilitate estimation. First, ϵ_d enters the profit in an additively separable (AS) way so that the expected profit is:

$$\pi(s,d) = \begin{cases} ((1-R)P - C)\,\mathrm{E}q - M_1 & \text{if d=1} \\ \qquad -\tau \max\{((1-R)P - C)\,\mathrm{E}q - M_1, 0\} - SC_{(s\to 1)} + \epsilon_1 & \\ -M_2 - SC_{(s\to 2)} + \epsilon_2 & \text{if d=2} \\ -SC_{(s\to 3)} + \epsilon_3 & \text{if d=3} \end{cases} \tag{2}$$

where $\mathrm{E}q = \int_0^Q q f_q(y|\overline{Q}, A, \alpha)dy$. Also following Rust [1987, 1988], the transition probabilities of the state variables can be factored as:

$$h(s', \epsilon'|s, \epsilon, d) = f(s'|s, d)\rho(\epsilon'|s')$$

where $\rho(\cdot)$ is the transition probability density function of ϵ, the unobserved state variable. Specifically in the case of this model the state transition probability density function is:

$$h(\overline{Q}', P', \epsilon'|\overline{Q}, P, \epsilon, d) = f_q(\overline{Q} - \overline{Q}'|\overline{Q}, d) f_{\overline{Q}}(\overline{Q}'|\overline{Q}) f_P(P'|P)\rho(\epsilon'|\overline{Q}', P')$$

This factorization is the Conditional Independence (CI) assumption which implies that ϵ' depends entirely on the observed variables, and not on ϵ, while the transition of the observed state variables entirely depends on the current observed states and not on ϵ. For example, if a well starts to leak hydrogen sulfide (a highly poisonous gas), there is the additional cost ϵ, where the age of the well increases the probability of a leak, but the leak will not change the age of the well.

Under the additional assumption that ϵ is independent and identically distributed with a type I extreme value distribution, the Bellman equation becomes:

$$V_\theta(s, \epsilon) = \max_d [v_\theta(s, d) + b\epsilon(d)]$$

where v_θ is the fixed point of $v_\theta = \Gamma(v_\theta)$, where Γ_θ is a contraction mapping[Rust, 1988]:

$$\Gamma_\theta(v)(s,d) = \pi(s,d,\theta) + \beta \int_{s'} b \log \sum_{d'=1}^{3} \left[\exp\left\{ \frac{v_\theta(s',d')}{b} \right\} \right] f(s'|s,d) \mathrm{d}s' \qquad (3)$$

with scale parameter, b, from the extreme value distribution of ϵ. Here, I normalize b to 1 (equivalent to \$1 million dollars); if b approaches zero, $V_\theta(s,\epsilon)$ converges to the ordinary Bellman equation. With the CI assumption, computing the fixed point of Γ_θ is far easier than without because I would have had to solve for the fixed point, V_θ, of the Bellman equation:

$$V_\theta(s,\epsilon) = \max_d [\pi(s,d,\theta) + b\epsilon(d) + \beta \int_{s'} \int_{\epsilon'} V(s') h(s',\epsilon'|s,\epsilon,d) \mathrm{d}\epsilon' \mathrm{d}s']$$

Because of the CI assumption, the expected value is not a function of ϵ and therefore I do not have to integrate out the ϵ distribution to obtain the choice probabilities for the likelihood function. The assumption of the extreme value distribution allows for a closed form solution of the choice probabilities–that of the multinomial logit:

$$p(d|s,\theta) = \frac{\exp \frac{v_\theta(s,d)}{b}}{\sum_{d'} \exp \frac{v_\theta(s,d')}{b}} \qquad (4)$$

Dagsvik [1995] showed that the generalized extreme value class is dense; choice probabilities from any distribution can be approximated arbitrarily closely by choice probabilities from the generalized extreme value class. Therefore this framework can be applied under various settings of correlation between the error terms. It is possible to estimate a more general discrete choice model than the multinomial logit, by including unobservables with other distributions, using a mixed logit model. McFadden and Train [2000] show that mixed logits can be used to approximate any choice probability under mild regularity conditions. Therefore it is possible to include a distribution for serially correlated unobservables in the mixed logit and then integrate over this distribution using Monte Carlo methods.

If it is less expensive to access the same reserves by drilling a new well than reactivating an old well, then the likelihood that a well will be reactivated is lower. As the model does not include the option to drill a new well, the reduced probability of reactivation is accounted for by a decrease in the cost of leaving a well inactive relative to the cost of reactivating. Because the estimates are obtained from data on decisions that might have been influenced by an option to drill, then incorporated in any prediction from the model using these estimates is this reduced probability of reactivation and the model predictions should still conform to reality.

The full likelihood of observing the operating decisions and state variable transitions is:

$$L_f(\theta) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} p(d_t^i | s_t^i \theta) f(s_{t+1}^i | s_t^i, \theta) \tag{5}$$

Which can be broken down into a first stage estimation of the parameters in the transition probability density of the state variables:

$$L_1(\theta_{1^{st}}) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} f(s_{t+1}^i | s_t^i, \theta_{1^{st}}) \tag{6}$$

which are then used in the second stage estimation of the structural parameters in the choice probability:

$$L_2(\theta_{2^{nd}}) = \prod_{i=1}^{N_i} \prod_{t=1}^{T_i} p(d_t^i | s_t^i, \theta_{2^{nd}}, \hat{\theta}_{1^{st}}) \qquad (7)$$

I use the Nested Fixed Point Algorithm[22] [Rust, 1987] to estimate the parameters, where nested within the algorithm to maximize the likelihood function there is an inner algorithm to compute the fixed point, v_θ, of equation 3. The estimation is explained in more detail in the following section.

[22]The same code reformulated as a mathematical program with equilibrium constraints, MPEC [Su, 2008], runs out of memory when using the solver KNITRO called from TOMLAB.

5 Estimation

The estimation consists of three stages:

1. First Stage:

   This stage consists of estimating the parameters of the operator's subjective beliefs for the progression of the state variables over time. This stage is a standard parametric estimation of the parameters that maximize the first stage partial likelihood function (equation 6) and does not involve solving the fixed point. The parameters in this stage are those of the:

   - the transition probability density of the price process: ϑ_r, ς_r
   - the probability density of the quantity extracted: α_{0a}, α_{1a}, σ_a
   - the transition probability density of remaining reserves: ϕ_0, ϕ_1

2. Second Stage:

   In this stage the parameter estimates from the first stage are taken as given and the remaining parameters of the Bellman equation are estimated by maximizing the partial likelihood function that contains the choice probabilities (equation 7). The parameters estimated in this stage are those of the:

   - profit function: C, M_1, M_2, $SC_{(1\to2)}$ and $SC_{(2\to1)}$

   The choice probabilities contain the Bellman equation, and therefore each time that the likelihood iterates over different trial parameter values, the fixed point to the Bellman equation is solved [Rust, 1987]. The outerloop of the algorithm, maximizing the likelihood, was submitted to the solver KNITRO [Byrd et al.]. The inner loop, that solves the fixed point of equation 3, consists of successive approximations followed by Newton-Kantorovich iterations Rust [1988].

3. Third Stage

   Third, I obtain consistent standard errors from the full likelihood function (equation 5). The parameter values from the first stage contain a measurement error, but they are treated as the true parameters in the second stage, and so the standard errors are inconsistent. I obtain a consistent estimate of the covariance matrix by using the consistent parameter values from the first and second stage as starting points for one Newton step on the full likelihood function [Rust, 1994].

Well-level heterogeneity is accounted for only to the extent that the dynamic programming model is estimated separately for each well type, g. All wells of the same type are treated as homogeneous and a well of the same type that also has the same reserve size and age is assumed identical. The total number of different types of wells varies across time periods with the drilling of new wells. It is assumed that the number of new wells drilled is exogenously specified[23].

[23] For a model of where to drill for oil and gas see Levitt [2009].

5.1 First Stage Estimates

The first stage involves estimating the operator's beliefs about future prices and recoverable reserves. These beliefs are unobservable and subjective, but here I assume that the operator's beliefs are recoverable from objective probability measures estimated from the data (quasi-rational expectations). In estimating the first stage transition probabilities there is no need to solve for the fixed point of the Bellman equation. This first stage consists of the estimation for the transition probabilities for price and recoverable reserves. To save computing time the age variable is discretized into the intervals, $A = 1 \leq age < 5$, $5 \leq age < 15$, $15 \leq age < 30$ and $age \geq 30$, under the assumption that wells within these age intervals are similar. The transition probability of entering the next interval is $1/n_{years}$ where n_{years} is the number of years in the current interval.

5.1.1 Transition in Remaining Reserves from Extraction

Reserve changes due to extraction are such that when the well is active, the quantity extracted is modeled as a random draw from a distribution that depends on the per well remaining reserves, $\overline{Q}$. It implies that the operator only chooses whether to extract and does not have control over the quantity extracted, even though operators may be controlling the quantity extracted to maximize total recovery, or investing in enhanced recovery to increase extraction. I could attempt to model the quantity extracted as a continuous choice model however I do not have data on expenditures for enhanced recovery methods and it would not be clear how to identify the various technologies used. Therefore here I assume that the extraction is mainly driven by a technologically and geologically determined rate. To defend this assumption, a regression of the quantity extracted shows that variables that the operator has no control over (such as depth, density and initial pressure) are very important in determining extraction (Table 6). Price, on the other hand, gives the surprising result that there is slightly less extraction with higher prices in specifications I, II, and IV, and 1 percent increase in price leads to only .076 percent increase in extraction in specification III.

The equation that describes the actual production in any given year when the producer is assumed to be producing is:

$$\log q_{wt} = \alpha_0 + \alpha_1 \log \overline{Q}_{wt} + \sigma\varepsilon_{wt} \tag{8}$$

assuming an independent and identically distributed $N(0,1)$ error, ε. The regression is estimated for each well type g[24] and age group a. If there are less than 30 observations of production within a given type's age group, then observations from the age group of the type without clustering. Extraction from a well is truncated to fall in the interval $[q^L, q^U]$ where the lower bound, q^L, is 10^{-8} (not zero because of the subsequent logarithm), and the upper bound, q^U, is equal to the well's per well remaining reserves, $\overline{Q}$, multiplied by a factor, κ_m, which depends on whether the well is in a single-well pool $m = 0$ or a multi-well pool $m = 1$. In the dataset

[24]Groups depend on depth, initial pressure and density for gas and initial pressure water saturation, temperature and depth for oil. There are many other factors that will influence the extraction that are not accounted for in this regression, such as type of enhanced recovery method, gas to oil ratio, current pressure, viscosity.

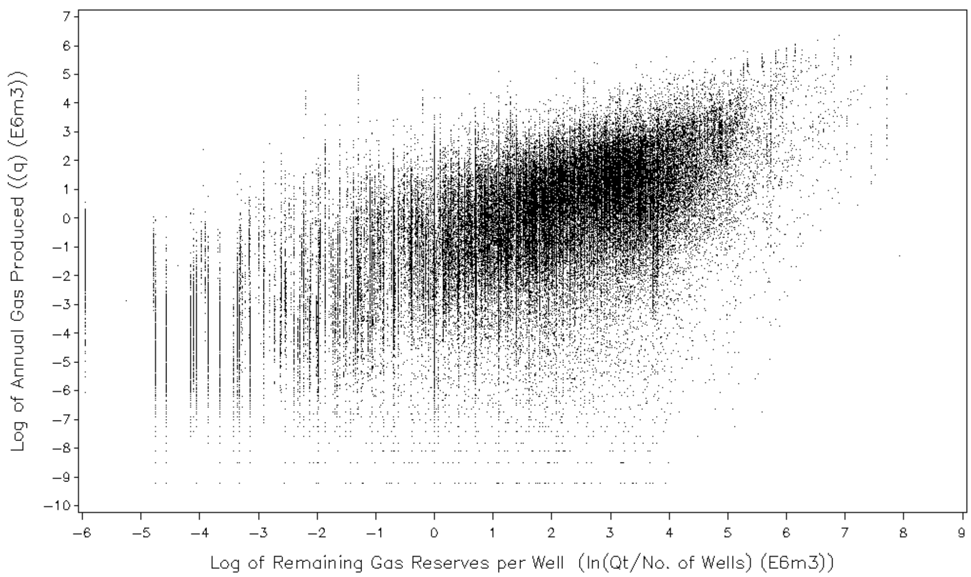
there are a few observations where the amount produced in a year is greater than the per well remaining reserves. This is more defensible in cases that the well is on a multi-well pool because the well taps into the full reserve Q, not only the per well reserve Q/n. But there are also observations from wells that are on their own pools producing more than $\overline{Q}$ (6% of the production data would be classified as such), giving evidence that the reserve size is on occasion an underestimate. Therefore, the factor κ_m is equal to the 99^{th} percentile of the observed fractions $q_w/\overline{Q}_w$ (different for single-well pools and multi-well pools). The 99^{th} percentile is used, because there are a few outliers where q_w dramatically exceeds $\overline{Q}_w$. (That is, the 99^{th} percentile of $q_w/\overline{Q}_w$ for gas wells on single-well pools, k_0, is 2.9 compared to a maximum of 66 and for gas wells on multi-well pools k_1 is 25.2 compared to a maximum of 807.)

The reserves are estimated reserves and prone to revisions. This implies that the quantity extracted depends on what is believed to be in place, not what is actually in place. This would mean that, for example, if the estimate of reserves are revised to half of what was believed, then extraction would decrease correspondingly, which is not realistic. To defend this choice for the model, many of the reserve estimates increase due to an upward revision in the recovery factor, and therefore an increase in recovery factor should increase the quantity recovered. And finally, Figure 6 illustrates that there is a strong relationship between extraction and estimated reserves, as does Table 6, which shows that a 1% increase in reserves leads to a 32 to 56% increase in quantity extracted.

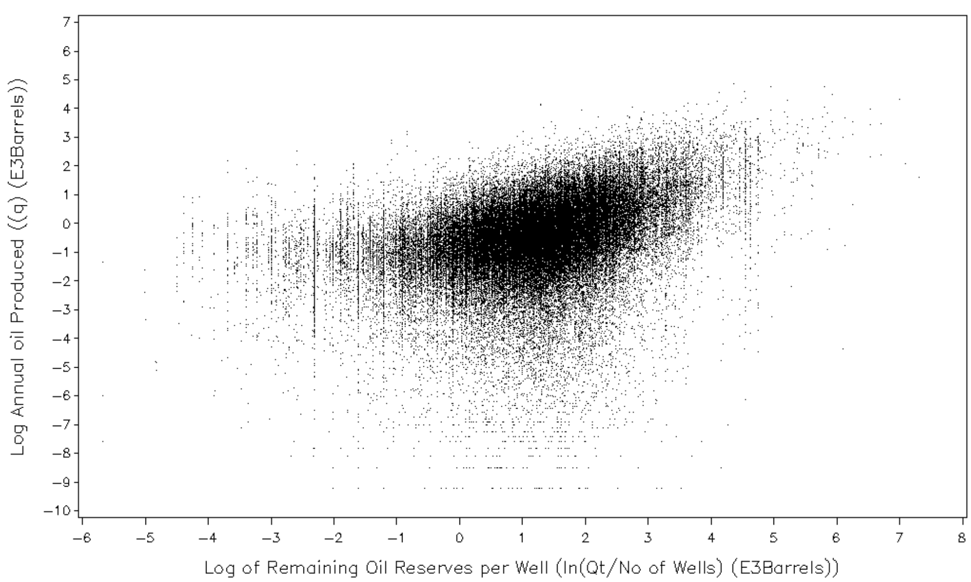
Table 6: Maximum Likelihood Estimates for Quantity Extracted

	ln(Oil Production)			ln(Gas Production)	
	I	II		III	IV
Intercept	3.6696**	-0.0182	Intercept	-1.541**	0.2485
	(0.0674)	(1.0347)		(0.1637)	(0.2038)
$\ln(\overline{Q}_o)$	0.3819**	0.323**	$\ln(\overline{Q}_g)$	0.5579**	0.3564**
	(0.0038)	(0.0045)		(0.0023)	(0.0034)
$\ln(\text{Price}_o)$	-0.0992**	-0.0997**	$\ln(\text{Price}_g)$	0.0763**	-0.1565**
	(0.0146)	(0.0164)		(0.0133)	(0.0142)
$\ln(\text{Age}_o)$	-0.156**	-0.223**	$\ln(\text{Age}_g)$	-0.1786**	-0.1721**
	(0.0046)	(0.0056)		(0.0044)	(0.0049)
$\ln(\text{Porosity}_o)$		-0.0403*	$\ln(\text{Porosity}_g)$		-0.2441**
		(0.0182)			(0.0181)
$\ln(\text{Init. Pressure}_o)$		0.4744**	$\ln(\text{Init. Pressure}_g)$		0.0322*
		(0.0240)			(0.0154)
$\ln(\text{Depth}_o)$		-0.4447**	$\ln(\text{Depth}_g)$		0.1522**
		(0.0475)			(0.0215)
$\ln(\text{Density}_o)$		0.3247	$\ln(\text{Density}_g)$		0.5269**
		(0.1408)			(0.0671)
$\ln(\text{No. Wells}_o)$		0.0426**	$\ln(\text{No. Wells}_g)$		-0.046**
		(0.0033)			(0.0033)
$\ln(\text{Oil to Water}_o)$		-0.2725**			
		(0.0146)			
$\ln(\text{Temperature}_o)$		0.077*			
		(0.0349)			
No. of Observations	89300	73329	No. of Observations	114961	92223
Log Likelihood	-151456.1	-122952.9	Log Likelihood	-218913.8	-172645.6

Dependent variable: natural logarithm of annual quantity produced. $**$ parameter estimates are significantly different from zero at the 2.5% level (and $*$ at the 5% level). Standard errors are in parentheses.



(a) Gas



(b) Oil

Figure 6: Scatterplot of Log Annual Production by Log Remaining Reserves for Individual Wells

5.1.2 Exogenous Transition in Reserves

The reserve estimates can increase or decrease by events other than production. The recoverable reserves is an estimate of the oil or gas in place multiplied by the recovery factor (the fraction of the oil or gas in place that is recoverable under current technology and prices). The estimates of the oil or gas in place can increase or decrease from new discoveries or revisions of the estimate, while the recoverable reserves change with the same factors but also with technology and prices. In the model, I use per well recoverable reserves $\overline{Q}$, and therefore when a new well is drilled the reserves also decrease. For the time being, I am estimating a single probability density function for the exogenous decrease in reserves that includes decreases from more wells being drilled as well as a decreases from reassessments of the estimate. To measure the changes in reserves from all else other than production, the observations on per well initial established reserves $\overline{Q}^{IER}$ (IER=remaining reserves + cumulative production) are used and not the observations on remaining reserves.

In the vast majority of the reserve data there is no change in per well initial established reserves , that is $\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER}$ equals one 78% of the time. The distribution of the natural logarithm of changes that occurred is illustrated in Figure 7. I approximate the distribution as two exponentials spliced together. When the price of oil or gas is high, there is more exploration, more investments into enhanced recovery and therefore, changes are also modeled to depend on price. Here I assume that with higher prices the reserves grow more and decrease less, and with low prices they grow less and decrease more. This is not necessarily the case because with higher prices there are more wells being drilled into the same pool, and the per well reserves will decrease more[25]. When there is an increase in reserves, $\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})$ can be approximated by an exponential distribution that depends on the price, as when there is a decrease in reserves, and $-\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})$ can be approximated by a different exponential distribution. That is, when there is an increase (or decrease), $\Delta = \left|\ln(\overline{Q}_{t+1}^{IER}/\overline{Q}_{t}^{IER})\right|$ follows an exponential distribution with density function:

$$f_{\overline{Q}}\left(\Delta|\lambda\right) = \lambda \exp\left(-\lambda\Delta\right)$$

where λ is a function of price:

$$\lambda = \begin{cases} (\phi_{0U} + \phi_{1U}P)^{-1} & \text{when increase,} \\ \\ (\phi_{0D} + \phi_{1D}/P)^{-1} & \text{if decrease.} \end{cases}$$

The likelihood:

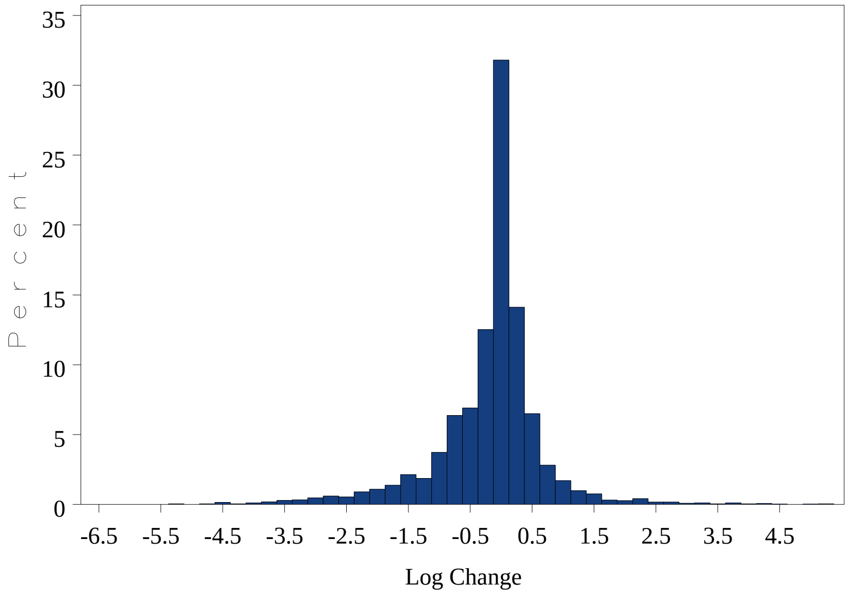
$$L(\phi_{\mathbf{U}}) = \prod_i \prod_t \frac{1}{(\phi_{U0} + \phi_{U1}P_{t-1})} \exp\left(-\frac{\left|\ln(\overline{Q}_{it}^{IER}/\overline{Q}_{it-1}^{IER})\right|}{(\phi_{U0} + \phi_{U1}P_{t-1})}\right)$$

is maximized anytime that $\overline{Q}_{it}^{IER} > \overline{Q}_{it-1}^{IER}$. As well as:

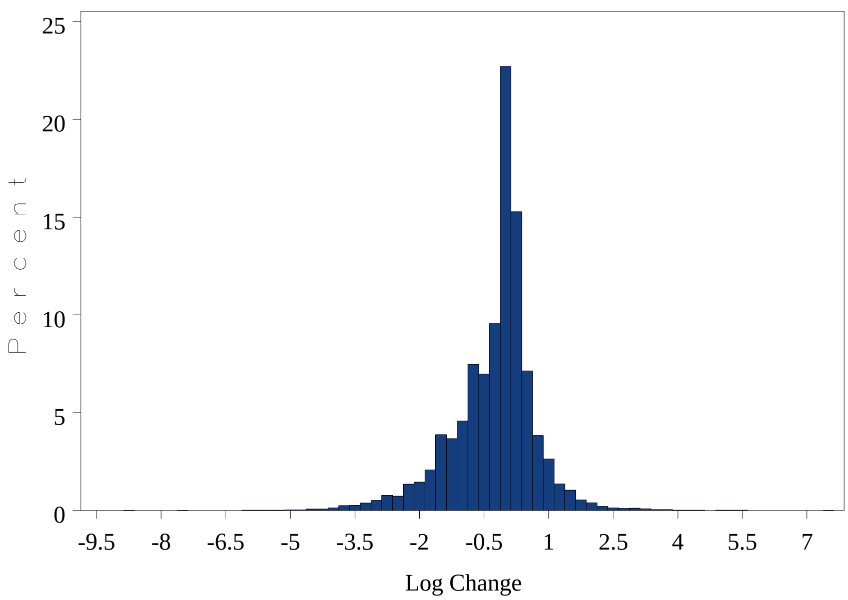
$$L(\phi_{\mathbf{D}}) = \prod_i \prod_t \frac{1}{(\phi_{D0} + \phi_{D1}/P_{t-1})} \exp\left(-\frac{\left|\ln(\overline{Q}_{it}^{IER}/\overline{Q}_{it-1}^{IER})\right|}{(\phi_{D0} + \phi_{D1}/P_{t-1})}\right)$$

[25]The contradicting influence of price is one reason the coefficient on price for oil reserve increases and decreases and gas reserve decreases is small and insignificant. Future research entails estimating the change in reserves due to more wells separately from revisions in the estimates.

anytime that $\overline{Q}_{it}^{IER} < \overline{Q}_{it-1}^{IER}$.



(a) $\log\left(\frac{\overline{Q}^{IER\prime}}{\overline{Q}^{IER}}\right)$ for Oil Pools



(b) $\log\left(\frac{\overline{Q}^{IER\prime}}{\overline{Q}^{IER}}\right)$ for Gas Pools

Figure 7: Histograms of the Natural Logarithm of Annual Change in Initial Established Reserves (not including occurrences of no change)

5.1.3 Transition in Price

Analysis of the price of oil is a well researched area, although there is little consensus for the best fitting model. Models differ by allowing for mean-reversion [Hammoudeh], unit roots [Perron, 1989], underlying market fundamentals [Yang et al., 2002] or unexpected jumps [Gronwald, 2009, Tvedt] for example. I chose a process that would fit easily into the Bellman equation. Specifically a price process that follows an exogenous first order Markov process with only one state variable. I am also able to incorporate a switching process between a high price and low price regime without introducing "price regime" as a state variable in the model. The regimes are determined depending on whether the price is above or below the average price observed from 1971 to 2007. As soon as we know the price, we know which regime we are in simply by knowing whether the price is above or below the average price and there is no need to include the state variable for the regime. That is, the final matrix of transition probability weights for price depends only on the current price. The transition probability of switching from regime H to L is simply the number of times that regime H was followed by regime L divided by the number of times the process was in regime H.

$$\hat{p}_{HL} = \frac{\sum_{t=1}^{T} I\{r_t = L, r_{t-1} = H\}}{\sum_{t=1}^{T} I\{r_{t-1} = H\}}$$

And vice versa for switching from L to H. For each regime, the parameters from a regression with deviations from the mean logarithm of price, $\wp_{t,r} = \log P_t - \mu_r$, are estimated:

$$\wp_{t,r} = \vartheta_r \wp_{t-1,r} + \varsigma_r \varepsilon_t \tag{9}$$

where ε is independent and identically distributed $N(0,1)$. The process is truncated so that price does not fall below $\underline{P} = 1E-6$ (and not zero because of the subsequent logarithm). The transition probability of price in regime r is:

$$F_P(P_t|P_{t-1}, r) = \frac{\Phi\left(\left(\wp_{t,r} - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right) - \Phi\left(\left(\underline{\wp}_r - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right)}{1 - \Phi\left(\left(\underline{\wp}_r - \vartheta_r \wp_{t-1,r}\right)/\varsigma_r\right)}$$

where Φ is the standard normal cumulative distribution function and $\underline{\wp}_r = \ln(\underline{P}) - \mu_r$.

The transition probability matrix is derived from a mixture of the distributions under high and low price regimes, including the transition probabilities between the two regimes:

$$F_P(P_t|P) = \begin{cases} p_{HH} F_P(P_t|P_{t-1}, r = H) + p_{HL} F_P(P_t|P_{t-1}, r = L) & \text{if } P > \overline{P}, \\ p_{LH} F_P(P_t|P_{t-1}, r = H) + p_{LL} F_P(P_t|P_{t-1}, r = L) & \text{if } P \leq \overline{P}. \end{cases}$$

.

5.2 Second Stage Estimation

For each different well type, g, a different set of structural parameters, $\theta_{2^{nd}}$ = $(C,\ M_1,\ M_2,\ SC_{(1\to 2)},\ SC_{(2\to 1)})$ is estimated. The likelihood of observing the decisions d that were made for each well ($w = 1...W_g$) in the well group is maximized:

$$L(\theta_{2^{nd}}) = \prod_{t=1}^{T} \prod_{w=1}^{W_g} p(d_t^w | P_t, Q_t^w, A_t^w, \theta_{2^{nd}}, \hat{\theta}_{1^{st}})$$

where p is the multinomial logit given in equation 4 for the probability that well w at time t chooses decision d. For each iteration of the likelihood there is a nested subroutine to find the fixed point to the Bellman equation 3. The model is in discrete time and the operator chooses the operating mode on a yearly basis. In reality this decision is in continuous time however, a well is classified as an inactive well by the ERCB if it has not reported any volumetric activity (production, injection, or disposal) within the last 12 months. Therefore, the data are assigned as follows: for an oil well in 2000, the current operating state, o, is the operating state in 1999, where the decision, d, is the operating state in 2000, given the average wellhead price of oil (or gas for gas wells) in 2000, the reserve size in 2000, and the age of the well in 2000.

The royalty rate is calculated using formulas specified by the Alberta Department of Energy[Fiscal, 2006]. The rates range from 5% to 35% depending on the price of oil (or gas), when the reserve was discovered, and the volume of oil (or gas) produced. As this model is based on the expected production, and not the actual production, the royalty rate is the expected royalty rate. The government issues a price threshold above which the royalty rate is price sensitive[26] . This price is slightly different every year, however in the estimation, the price threshold of 2006-

[26] Formulas can be found in [Fiscal, 2006]

2007 is used for all years–which is reasonable as the past wellhead prices are inflated to 2007 prices anyway.

The Alberta corporate income tax rate is 10% of taxable income while the federal corporate income tax rate is 22.12%. The combined federal and provincial tax rate on corporate income, τ, is set at 32.12%[Corporate, 2007].

Estimating the discount factor, β, along with the cost parameters is difficult. For example, both a high reactivation cost and a low discount factor will prolong reactivation. Therefore, I fixed the discount factor at .80. Deciding upon .80 was through estimating the model at various fixed discount factors. When the discount factor is set low, the parameter values for the fixed costs compensate by being extremely low, and when the discount factor is very high, the parameter values for the fixed cost and reactivation costs in exchange are very high. Discount factors in the range of .75 and .95 result in the most evenly distributed parameter estimates. Summing the log likelihoods of all well groups for different fixed discount factors, a discount factor between .80 and .90 gives the highest likelihood (Figure 19). I choose the discount factor to be .80, corresponding to an annualized discount rate of 22.31% ($\beta = \exp(-r)$). This is consistent with Farzin [1985] who estimated a before tax discount rate in the oil and gas industry to be 25.4% and the Texas Comptroller's Property Tax Division that uses a range of discount rates from 17.29% to 22.52% for oil and gas properties[Texas, 2007].

The model was estimated for many different specifications of the cost function (Tables 7 and 8). A parsimonious specification that leads to timely convergence and high likelihood values is specification 7 where the lifting cost depends on the reserve size and age, and the operating cost and reactivation cost depends on age.

Table 7: Specification of Cost Functions

Cost Spec	Lifting Costs (C)	Fixed Operating (M_1)	Fixed Idle (M_2)	Deactivation ($SC_{1\to 2}$)	Reactivation ($SC_{2\to 1}$)
1	θ_1	θ_2	θ_3	θ_4	θ_5
2	$\theta_1+\theta_2/\overline{Q}^2$	θ_3	θ_4	θ_5	θ_6
3	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A$	θ_4	θ_5	θ_6	θ_7
4	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A+\theta_4 P$	θ_5	θ_6	θ_7	θ_8
5	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A+\theta_4 P$	θ_5	θ_6	θ_7	$\theta_8 P$
6	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A+\theta_4 P$	θ_5	θ_6	θ_7	$\theta_8 P+\theta_9/\overline{Q}^{.5}$
7	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A$	$\theta_4(1+\theta_5)^A$	θ_6	θ_7	$\theta_8(1+\theta_9)^A$
8	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A+\theta_4 P$	$\theta_5(1+\theta_6)^A$	θ_7	θ_8	$\theta_9(1+\theta_{10})^A$
9	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A$	$\theta_4(1+\theta_5)^A$	$\theta_6(1+\theta_7)^A$	θ_8	$\theta_9(1+\theta_{10})^A$
10	$\theta_1+\theta_2/\overline{Q}^{1.5}$	$\theta_3+\theta_4 P$	$\theta_5+\theta_6 P$	$\theta_7+\theta_8 P$	$\theta_9+\theta_{10} P$
11	$\theta_1/\overline{Q}^{1.5}+\theta_2 P$	$\theta_3(1+\theta_4)^A$	θ_5	$\theta_6(1+\theta_7)^A$	$\theta_8(1+\theta_9)^A$
12	$\theta_1/\overline{Q}^{1.5}+\theta_2 P$	θ_3	θ_4	$\theta_5(1+\theta_6)^A$	$\theta_7(1+\theta_8)^A$
13	$\theta_1/\overline{Q}^{1.5}+\theta_2 P$	θ_3	θ_4	θ_5	θ_6
14	$\theta_1/\overline{Q}^{1.5}+\theta_2(1+\theta_3)^A+\theta_4 P$	$\theta_5(1+\theta_6)^A$	$\theta_7(1+\theta_8)^A$	θ_9	$\theta_{10}(1+\theta_{11})^A$

Notes: In all specifications the abandonment cost ($SC_{1,2\to 3}$) is held fixed (at $75,000).

Table 8: Specification Search: Log-Likelihoods from PSAC Area 3 Gas Wells

Cost Spec	Gas			
	Single-Well Pool		Multi-Well Pool	
	Old	New	Old	New
1	-272.581	-3388.393	-3380.876	-4140.893
2	-272.581	-3388.392	-3336.074	-4145.124
3	-272.625	-3386.624†	-3336.095	-4134.379
4	-272.776	-3584.931	-3358.012	-4165.348
5	-290.097	-3438.452	-3546.267	-4261.963
6	-282.194	-3411.877	-3435.400	-4220.655
7	-276.818	-3384.944	-3150.003*	-3913.233*
8	-301.671†	-3386.947	-3165.950	-3930.887
9	-280.258†	-3411.778	-3221.193	-4027.607†
10	-709.548	-3363.691*	-3343.370	-4576.699
11	-279.939	-3551.243	-3201.951†	-3921.884†
12	-295.257†	-3412.283†	-3573.341†	-4236.784†
13	-273.345†	-3393.152†	-3360.022	-4150.901†
14	-270.669*	-3411.784	-3205.862	-4071.837
No. Obs.	961	12167	13647	14364

Notes: Old refers to wells drilled on pools discovered in 1974 or earlier, and new to wells on pools discovered after 1973. $\beta = .95$ and $b = 1$. † indicates that the iteration limit was met. The iteration limit was set at 1000 and although this is low, the specifications that converged did so in 20 to 198 iterations.

5.3 Third Stage Estimation: Maximizing the Full Likelihood

The parameter estimates from the partial likelihood estimation are used as starting values in the full likelihood. I make one Newton step on the full likelihood in order to determine a consistent estimate of the asymptotic covariance matrix for the estimates. The weighted average of the estimated cost parameters and their standard errors is calculated across all oil and gas well groups (Table 9) and for groups of wells depending on whether they are in single-well pools or multi-well pools and what royalty regime is applicable (Tables 11 and 12). The annual fixed cost of leaving the well inactive, M_2, and operating, M_1, are negative because they are interpreted relative to the decommissioning cost that for identification was fixed at \$75,000, $SC_{(1,2\to 3)} = .075$. By construction of the multinomial logit (equation 4), identifying all fixed costs of the model is not possible (for example, both π and $a\pi+b$ will return the same decision rule). The location and scale of the profit function is unidentifiable.

The standard errors are calculated using the misspecification consistent information matrix, $C(\hat{\theta}) = A(\hat{\theta})^{-1}B(\hat{\theta})A(\hat{\theta})^{-1}$ where A is the information matrix calculated via the Hessian, $A(\hat{\theta}) = E\left(\partial^2 \ln L(\hat{\theta})/\partial\hat{\theta}\partial\hat{\theta}'\right)$, and B is the information matrix calculated via the outer product of the gradient, $B(\hat{\theta}) = E\left(\partial \ln L(\hat{\theta})/\partial\hat{\theta} \cdot \partial \ln L(\hat{\theta})/\partial\hat{\theta}'\right)$ [White, 1982]. The standard errors obtained by the Hessian, bootstrapping, and the misspecification consistent information matrix are not very different. In an example well-group, (Table 13) estimating the partial likelihood and calculating the standard errors via the Hessians for each partial likelihood results in the highest standard errors for the first stage parameters, and second highest for the second stage. Bootstrapping was only performed on the second stage of the partial likelihood (again using the parameters from the first stage). The bootstrapped standard errors for the majority of the parameters are smaller than the asymptotic standard errors from both the full and partial likelihood estimation. The estimated covariance matrix for the second stage of the partial likelihood is not necessarily consistent because the first stage parameters are taken to be the true parameters–and so the standard errors from the full likelihood are also calculated. The asymptotic standard errors in the full estimation are highest (roughly 70% of the time) when calculated via the misspecification consistent form of the information matrix. However the difference is not very large; the misspecification consistent standard errors are usually around two times as large as the standard errors calculated from the Hessian, but still smaller than the standard errors calculated from the Hessians of the partial likelihood.

In most cases the standard errors are much smaller than the parameter estimates, however this is not the case of the parameter estimates of exogenous reserve changes in oil reserves. This is perhaps one reason why the model does not match the data as closely for oil as it does for gas (section 5.4). The standard errors are extremely large for oil wells on multi-well "new" pools. Upon closer inspection, this is driven by one well group (PSAC 3 cluster 3 with 18677 observations).

Table 9: Weighted Average Parameter Estimates from the Full Likelihood

Parameter	Oil		Gas	
	Estimate	Std.Err.	Estimate	Std.Err.
Reserves				
$\alpha_{0,1}$	0.3113	(0.2825)	3.3777	(1.2456)
$\alpha_{0,5}$	0.2748	(0.4845)	2.3709	(0.2833)
$\alpha_{0,15}$	0.0824	(0.2217)	2.1707	(0.7497)
$\alpha_{0,30}$	-0.2245	(0.2535)	2.8161	(0.8220)
$\alpha_{1,1}$	0.4163	(0.0790)	0.4280	(0.1408)
$\alpha_{1,5}$	0.2841	(0.1475)	0.4840	(0.0320)
$\alpha_{1,15}$	0.3022	(0.0699)	0.5218	(0.0809)
$\alpha_{1,30}$	0.4288	(0.1075)	0.4444	(0.2436)
σ_1	1.2958	(0.0222)	1.4891	(0.0504)
σ_5	1.2833	(0.0319)	1.5246	(0.0831)
σ_{15}	1.2687	(0.0233)	1.5241	(0.0990)
σ_{30}	1.1835	(0.0997)	1.3777	(1.2539)
$\phi_{0,U}$	0.3728	(0.0350)	0.2681	(0.0249)
$\phi_{1,U}$	2.042e-7	(0.8019)	573.5992	(130.2248)
$\phi_{0,D}$	0.6911	(0.1574)	0.4358	(0.4249)
$\phi_{1,D}$	5.151e-9	(0.0062)	6.450e-5	(7.485e-5)
Price				
ϑ_L	0.4380	(1.4361)	0.7076	(0.7005)
ς_L	0.1555	(0.7744)	0.1697	(0.2973)
ϑ_H	0.6195	(0.1136)	0.5958	(0.3084)
ς_H	0.1449	(0.0505)	0.2133	(0.0562)
Cost Parameters				
θ_1 (C)	0.0097	(0.0436)	0.0729	(0.4800)
θ_2 (C)	0.0117	(0.0214)	0.0001	(3.3169e-5)
θ_3 (C)	0.1562	(0.1569)	0.0824	(0.0307)
θ_4 (M_1)	-0.9883	(0.8389)	-1.6392	(0.4028)
θ_5 (M_1)	-0.1077	(0.0317)	-0.0096	(0.0993)
θ_6 (M_2)	-1.0387	(0.0174)	-0.7405	(0.0976)
θ_7 $(SC_{(1\to2)})$	3.7367	(1.1268)	1.7304	(0.7120)
θ_8 $(SC_{(2\to1)})$	0.1641	(3.9543)	2.0714	(1.4891)
θ_9 $(SC_{(2\to1)})$	-0.5551	(0.3703)	-0.0299	(0.0188)

Notes: Parameters of cost specification 7. These are the weighted average of the estimates across well groups.

Table 10: Parameters Not Estimated in the Full Likelihood

	Oil	Gas
p_{HL}	0.272	0.062
p_{LH}	0.160	0.100
$\overline{P}$	0.031	1.1429e-4
μ_H	-3.2034	-8.7838
μ_L	-3.7723	-9.7263
$SC_{(1,2\rightarrow 3)}$	.075	.075
β	.80	.80
b	1	1

Notes: P is measured in millions of dollars per thousand m^3 of gas and millions of dollars per thousand barrels of oil

Table 11: Weighted Average of Full Likelihood Parameter Estimates for Different Types of Oil Wells

Parameter	Oil					
	Single-Well Pool			Multi-Well Pool		
	Old	New	Third	Old	New	Third
Reserves						
$\alpha_{0,1}$	-0.012(0.250)	0.679(0.250)	0.310(0.250)	-0.881(0.250)	-0.113(0.250)	0.798(0.250)
$\alpha_{0,5}$	0.104(0.427)	0.187(0.427)	0.525(0.427)	-0.232(0.427)	-0.242(0.427)	0.549(0.427)
$\alpha_{0,15}$	0.130(0.194)	0.280(0.194)	-0.008(0.194)	-0.307(0.194)	-0.365(0.194)	0.649(0.194)
$\alpha_{0,30}$	-0.039(0.223)	-0.173(0.223)	0.017(0.223)	-0.764(0.223)	-0.613(0.223)	-0.403(0.223)
$\alpha_{1,1}$	0.481(0.070)	0.297(0.070)	0.489(0.070)	0.598(0.070)	0.490(0.070)	0.331(0.070)
$\alpha_{1,5}$	0.314(0.130)	0.301(0.130)	0.244(0.130)	0.360(0.130)	0.427(0.130)	0.308(0.130)
$\alpha_{1,15}$	0.320(0.061)	0.223(0.061)	0.359(0.061)	0.369(0.061)	0.385(0.061)	0.212(0.061)
$\alpha_{1,30}$	0.420(0.094)	0.383(0.094)	0.395(0.094)	0.559(0.094)	0.496(0.094)	0.484(0.094)
σ_1	1.304(0.020)	1.301(0.020)	1.267(0.020)	1.290(0.020)	1.362(0.020)	1.173(0.020)
σ_5	1.345(0.028)	1.266(0.028)	1.277(0.028)	1.267(0.028)	1.121(0.028)	1.331(0.028)
σ_{15}	1.303(0.021)	1.274(0.021)	1.273(0.021)	1.228(0.021)	1.230(0.021)	1.142(0.021)
σ_{30}	1.201(0.090)	1.130(0.090)	1.177(0.090)	1.305(0.090)	1.278(0.090)	1.317(0.090)
$\phi_{0,U}$	0.373(0.031)	0.373(0.031)	0.373(0.031)	0.373(0.031)	0.373(0.031)	0.373(0.031)
$\phi_{1,U}$	2e-7(0.717)	2e-7(0.717)	2e-7(0.717)	2e-7(0.717)	2e-7(0.717)	2e-7(0.717)
$\phi_{0,D}$	0.691(0.141)	0.691(0.141)	0.691(0.141)	0.691(0.141)	0.691(0.141)	0.691(0.141)
$\phi_{1,D}$	5e-9(0.006)	5e-9(0.006)	5e-9(0.006)	5e-9(0.006)	5e-9(0.006)	5e-9(0.006)
Price						
ϑ_L	0.438(1.266)	0.438(1.266)	0.438(1.266)	0.438(1.266)	0.438(1.266)	0.438(1.266)
ς_L	0.155(0.702)	0.155(0.702)	0.155(0.702)	0.155(0.702)	0.155(0.702)	0.155(0.702)
ϑ_H	0.620(0.101)	0.620(0.101)	0.619(0.101)	0.619(0.101)	0.619(0.101)	0.619(0.101)
ς_H	0.145(0.044)	0.145(0.044)	0.145(0.044)	0.145(0.044)	0.145(0.044)	0.145(0.044)
Cost Param.						
θ_1 (C)	0.033(0.038)	0.000(0.038)	0.005(0.038)	0.028(0.038)	0.007(0.038)	0.010(0.038)
θ_2 (C)	0.012(0.019)	0.004(0.019)	0.019(0.019)	0.003(0.019)	0.002(0.019)	0.012(0.019)
θ_3 (C)	0.354(0.138)	0.077(0.138)	0.042(0.138)	0.644(0.138)	0.514(0.138)	0.037(0.138)
θ_4 (M_1)	-1.771(0.735)	-0.291(0.735)	-1.078(0.735)	-3.512(0.735)	-2.411(0.735)	-1.062(0.735)
θ_5 (M_1)	-0.103(0.028)	-0.128(0.028)	-0.035(0.028)	-0.194(0.028)	-0.154(0.028)	-0.052(0.028)
θ_6 (M_2)	-1.073(0.015)	-0.792(0.015)	-1.147(0.015)	-1.020(0.015)	-1.430(0.015)	-2.414(0.015)
θ_7 $(SC_{(1\to2)})$	4.011(0.991)	2.341(0.991)	4.417(0.991)	4.827(0.991)	1.330(0.991)	5.399(0.991)
θ_8 $(SC_{(2\to1)})$	-5.734(3.818)	1.093(3.818)	3.445(3.818)	-4.772(3.818)	3.088(3.818)	-5.784(3.818)
θ_9 $(SC_{(2\to1)})$	-0.459(0.337)	-0.262(0.337)	-0.761(0.337)	-0.429(0.337)	-0.289(0.337)	-0.625(0.337)

Notes: Parameters of cost specification 7. These are the weighted average of the estimates across PSAC areas and clusters. In parenthesis are the weighted average of the standard errors calculated by the misspecification consistent version of the information matrix.

Table 12: Weighted Average of Full Likelihood Parameter Estimates for Different Types of Gas Wells

Parameter	Gas			
	Single-Well Pool		Multi-Well Pool	
	Old	New	Old	New
Reserves				
$\alpha_{0,1}$	3.2222 (0.0735)	3.5797 (0.0778)	3.1326 (0.4116)	3.4648 (3.0257)
$\alpha_{0,5}$	1.8686 (0.0383)	2.9016 (0.0481)	1.7393 (0.4192)	2.5924 (0.3488)
$\alpha_{0,15}$	1.8459 (0.0819)	2.7575 (0.0556)	1.4052 (0.1241)	2.4687 (1.9315)
$\alpha_{0,30}$	2.2226 (0.0611)	3.3901 (0.2310)	1.8580 (0.4209)	3.3240 (1.7113)
$\alpha_{1,1}$	0.4133 (0.0084)	0.4177 (0.0086)	0.4324 (0.0462)	0.4326 (0.3425)
$\alpha_{1,5}$	0.5073 (0.0053)	0.4375 (0.0076)	0.5274 (0.0491)	0.4772 (0.0358)
$\alpha_{1,15}$	0.5436 (0.0105)	0.4636 (0.0066)	0.5926 (0.0155)	0.4979 (0.2058)
$\alpha_{1,30}$	0.5082 (0.0077)	0.3758 (0.0308)	0.5512 (0.0545)	0.3914 (0.6050)
σ_1	1.5116 (0.0016)	1.4743 (0.0028)	1.4987 (0.0132)	1.4902 (0.1260)
σ_5	1.5083 (0.0015)	1.5171 (0.0047)	1.5073 (0.0100)	1.5481 (0.2195)
σ_{15}	1.5777 (0.0022)	1.4787 (0.0084)	1.5750 (0.0121)	1.5077 (0.2587)
σ_{30}	1.5270 (0.0010)	1.2959 (0.0437)	1.5017 (0.0086)	1.3139 (3.4687)
$\phi_{0,U}$	0.2291 (0.0049)	0.2904 (0.0076)	0.2291 (0.0245)	0.2904 (0.0397)
$\phi_{1,U}$	346.3773 (24.2742)	703.4817 (38.3561)	346.3773 (128.5903)	703.4817 (209.1606)
$\phi_{0,D}$	1.4e-5 (0.0630)	0.6860 (0.0309)	1.4e-5 (0.0552)	0.6838 (1.1583)
$\phi_{1,D}$	1.0e-5 (1.265e-5)	4.5e-5 (5.7e-6)	9.5e-5 (1.1e-5)	4.5e-5 (6.3e-6)
Price				
ϑ_L	0.7076 (0.8605)	0.7076 (0.1456)	0.7076 (0.3925)	0.7076 (1.4235)
ς_L	0.1697 (0.6758)	0.1697 (0.0686)	0.1697 (0.0107)	0.1697 (0.7332)
ϑ_H	0.5958 (0.0291)	0.5956 (0.0669)	0.5959 (0.2178)	0.5958 (0.5995)
ς_H	0.2133 (0.0053)	0.2133 (0.0529)	0.2133 (0.0308)	0.2133 (0.0859)
Cost Parameters				
θ_1 (C)	0.2890 (0.5415)	0.1324 (0.1198)	0.0880 (0.1801)	0.0004 (1.0482)
θ_2 (C)	7.2e-5 (3.7e-5)	1.6e-4 (2.1e-5)	2.0e-4 (3.0e-5)	9.3e-5 (1.1e-5)
θ_3 (C)	0.1368 (0.0190)	0.0189 (0.0100)	0.0086 (0.0129)	0.2006 (0.0646)
θ_4 (M_1)	-1.5761 (0.8891)	-1.6003 (0.1449)	-1.7024 (0.1828)	-1.6118 (0.7917)
θ_5 (M_1)	-0.0294 (0.1413)	-0.0044 (0.0039)	-0.0019 (0.0050)	-0.0202 (0.2628)
θ_6 (M_2)	-0.6956 (0.0782)	-0.7463 (0.0443)	-0.8102 (0.0188)	-0.6710 (0.2165)
θ_7 $(SC_{(1\to2)})$	0.8997 (0.7921)	1.5201 (0.2393)	2.3127 (0.2868)	1.3755 (1.4883)
θ_8 $(SC_{(2\to1)})$	3.9745 (2.0169)	2.5734 (0.1688)	0.4862 (0.3893)	3.1112 (3.5563)
θ_9 $(SC_{(2\to1)})$	-0.0005 (0.0150)	0.0156 (0.0014)	-0.1282 (0.0026)	0.0279 (0.0482)

Notes: Parameters of cost specification 7. These are the weighted average of the estimates across PSAC areas and clusters. In parenthesis are the weighted average standard errors.

Table 13: Example of Different Standard Errors from Partial and Full Likelihood

Parameter	Partial Likelihood			Full Likelihood		
	Estimate	Std.Err. (hessian)	Std.Err. (boot)	Estimate	Std.Err. (hessian)	Std.Err. (White)
Reserves						
$\alpha_{0,1}$	3.0830	(0.1475)		3.0807	(0.0554)	(0.0780)
$\alpha_{0,5}$	2.1399	(0.1610)		2.1422	(0.0286)	(0.1601)
$\alpha_{0,15}$	2.7343	(0.1957)		2.7379	(0.0324)	(0.0180)
$\alpha_{0,30}$	3.2357	(0.1955)		3.2327	(0.2107)	(0.5245)
$\alpha_{1,1}$	0.3351	(0.0184)		0.3334	(0.0064)	(0.0087)
$\alpha_{1,5}$	0.4295	(0.0203)		0.4319	(0.0016)	(0.0177)
$\alpha_{1,15}$	0.4172	(0.0246)		0.4227	(0.0054)	(0.0020)
$\alpha_{1,30}$	0.3787	(0.0251)		0.3747	(0.0277)	(0.0655)
σ_1	1.2094	(0.0139)		1.2100	(0.0136)	(0.0010)
σ_5	1.2671	(0.0166)		1.2677	(0.0171)	(0.0018)
σ_{15}	1.5194	(0.0256)		1.5202	(0.0211)	(0.0432)
σ_{30}	1.4141	(0.0245)		1.4141	(0.0214)	(0.0244)
$\phi_{0,U}$	0.2291	(0.0244)		0.2291	(0.0078)	(0.0072)
$\phi_{1,U}$	346.3773	(120.0978)		346.3773	(12.2214)	(28.7837)
$\phi_{0,D}$	1.44e-5	(0.0670)		1.37e-5	(0.0211)	(0.1232)
$\phi_{1,D}$	1.02e-4	(1.34e-5)		9.93e-5	(2.76e-6)	(2.16e-5)
Price						
ϑ_L	0.7076	(0.1045)		0.7076	(0.0519)	(0.1249)
ς_L	0.1697	(0.0291)		0.1697	(0.0398)	(0.0758)
ϑ_H	0.5959	(0.1373)		0.5957	(0.0172)	(0.0079)
ς_H	0.2133	(0.0346)		0.2133	(0.0239)	(0.0890)
Cost Param.						
θ_1 (C)	0.0817	(0.0306)	(0.0151)	0.0817	(0.0207)	(0.0467)
θ_2 (C)	2.45e-4	(1.11e-4)	(3.01e-5)	2.45e-4	(5.57e-5)	(1.52e-4)
θ_3 (C)	0.0036	(0.0140)	(0.0014)	0.0036	(0.0103)	(0.0154)
θ_4 (M_1)	-1.9647	(0.0627)	(0.0058)	-1.9634	(0.0395)	(0.0751)
θ_5 (M_1)	-0.0087	(0.0019)	(0.0016)	-0.0087	(0.0012)	(0.0024)
θ_6 (M_2)	-0.6089	(0.0235)	(0.0134)	-0.6085	(0.0193)	(0.0041)
θ_7 $(SC_{(1\to2)})$	1.5024	(0.0256)	(0.0030)	1.5026	(0.0526)	(0.0786)
θ_8 $(SC_{(2\to1)})$	3.1373	(0.0912)	(0.0018)	3.1377	(0.0473)	(0.0659)
θ_9 $(SC_{(2\to1)})$	0.0173	(0.0021)	(0.0018)	0.0173	(0.0017)	(0.0004)
LL	20346.6481			20353.9227		

Notes: Example from PSAC area 3 cluster 1 well on single-well "old" pool. "hessian" are the standard errors calculated from the information matrix via the Hessian; "boot" are the standard errors from bootstrapping the data with replacement 30 times; "White" are the standard errors derived from the misspecification consistent information matrix.

5.4 Goodness-of-Fit Tests

To test the dynamic programming model's ability to fit the data, the choice probabilities from the estimated dynamic programming model $p(d|s,\hat{\theta})$, are compared to the observed (nonparametric) estimates of the conditional choice probability function $\hat{p}(d|s)$. The nonparametric estimate $\hat{p}$ is the sample histogram of choices made in the subsample of wells with state s. Following Rust and Phelan [1997] and Rothwell and Rust [1997], by sample enumeration, if S is a collection of s cells, the nonparametric estimate of the choice probability is computed as:

$$\begin{aligned}\hat{p}(d|S) &= \int_{s\in S}\hat{p}(d|s)\hat{F}(\mathrm{d}s|S)\\ &= \frac{1}{N_S}\sum_{i=1}^{N} I\{d_i = d, s_i \in S\}\end{aligned}$$

Where $\hat{F}(\mathrm{d}s|S)$ is the nonparametric estimate of the conditional probability distribution of s given S, equal to the number of observations in cell $\mathrm{d}s$ divided by the total number of observations in all cells that comprise S. This is compared to the estimates of the choice probability from the dynamic programming model:

$$\begin{aligned}p(d|S,\hat{\theta}) &= \int_{s\in S} p(d|s,\hat{\theta})\hat{F}(\mathrm{d}s|S)\\ &= \frac{1}{G}\sum_{g=1}^{G}\frac{1}{N_g}\sum_{i=1}^{N_g} p(d|s,\hat{\theta}_g)I\{s_{ig}\in S\}\end{aligned}$$

Where $p(d|s,\hat{\theta}_g)$ is the probability given by equation 4 and $\hat{\theta}_g$ are the estimates of the structural parameters for group g.

Table 14 shows the observed (non-parametric) choice probabilities along side the expected choice probabilities from dynamic programming model for oil and gas wells. The three panels in Table 14 show: the case that S is a collection of all possible s cells, S is a collection of wells that are active, and S is a collection of wells that are inactive. The dynamic programming model does a very good job in predicting the overall observed choice probabilities (Table 14 and by group (Table 19 in the Appendix). For the operating state of gas wells, the chi-squared test cannot reject the dynamic programming model at the 70% significance level. The chi-squared test rejects the model for oil wells, however, it still does a very good job in predicting the choice probabilities (it is not off by more than a percentage point).

The model is able to predict the very small probability of decommissioning a well. For example, the observed proportion of active gas wells in the subsample that are decommissioned is .0046, and the expected probability from the dynamic programming model for that sample of wells to be decommissioned is .0043.

Table 14: Actual versus Predicted Choice Probabilities

	Oil		**Gas**	
Current State: Active or Inactive	Observed	Expected	Observed	Expected
Pr(Active)	0.6207	0.6277	0.6878	0.6884
Pr(Inactivate)	0.3683	0.3621	0.3026	0.3021
Pr(Decommission)	0.0110	0.0102	0.0096	0.0094
No. Obs.		150078		186274
χ^2		37.3242		0.6341
Marg.Sig.		0		0.7283
Active				
Pr(Active)	0.9253	0.9310	0.9421	0.9428
Pr(Inactivate)	0.0691	0.0630	0.0534	0.0528
Pr(Decommission)	0.0056	0.0060	0.0046	0.0043
No. Obs.		96880		129322
χ^2		64.0670		2.0164
Marg.Sig.		0		0.3649
Inactive				
Pr(Activate)	0.0660	0.0750	0.1105	0.1108
Pr(Inactive)	0.9132	0.9071	0.8685	0.8682
Pr(Decommission)	0.0209	0.0179	0.0210	0.0210
No. Obs.		53198		56952
χ^2		85.9339		0.0636
Marg.Sig.		0		0.9687

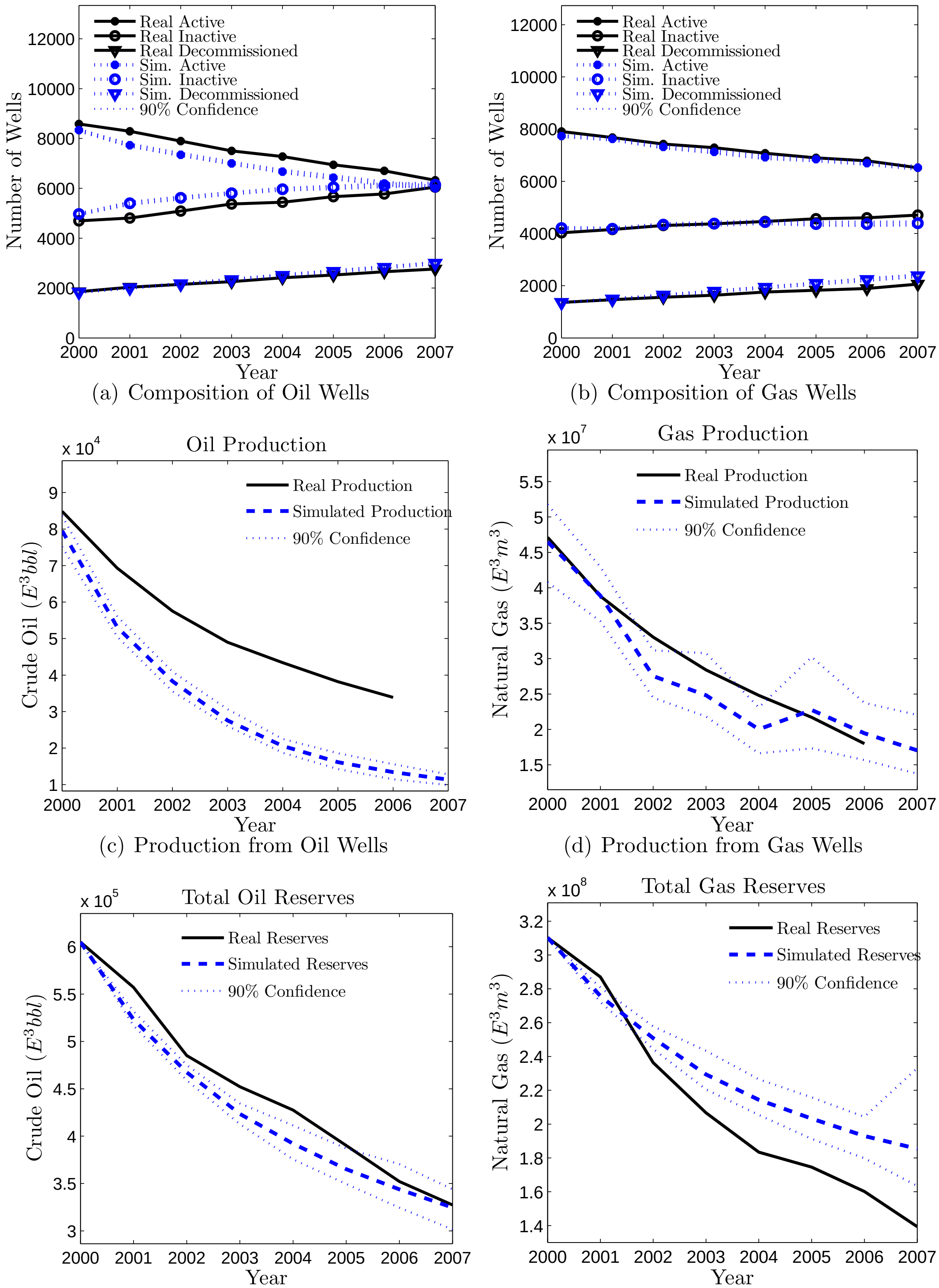
Notes: The chi-square test statistic was calculated as
$\chi^2 = N \sum_{d=1}^{3} (\text{Obs}_{Pr(d)} - \text{Exp}_{Pr(d)})^2/\text{Exp}_{Pr(d)}$, where N is the number of observations.

6 Simulation

Having estimated the structural parameters in the model of the operating choice, the model can be used to simulate the choices made by operators if any of the parameters or state variables are changed. The structural estimation can predict the industry's reaction to counterfactual scenarios that have not been previously observed. Before performing counterfactual simulations, I first validate the model by simulating the industry in 2000 to 2007 to see how well it matches reality. I then simulate the industry from 1993 to 1999, a period that was not used in the estimation, to see how well the model matches the data. After these descriptive measures, the model is used as a prescriptive tool to see the effect of taxing inactive wells.

6.1 Validation: In-Sample Simulation

Figure 8 illustrates the in-sample predictions from the dynamic programming model. The simulation begins with the state of the industry in 2000 as the starting point. Each year each well becomes a year older, and the current operating state and reserve size evolve according to the state dependent choice probabilities for the well type. The choice is determined from a pseudorandom draw from the probability density of the choice. To determine whether there is an exogenous increase or decrease to the reserve estimates I take a pseudorandom draw from the probability denstiy of an increase or a decrease. The magnitude of the increase or decrease is determined by a draw from the exponential distribution that depends on the price and reserve size. If the decision is to activate, and the well is the only well in the pool, the remaining reserves decrease by a random draw from $f_q(\cdot|Q, A)$. If there is more than one well in the pool then the reserves decrease by this amount under any operating choice. The price of the hydrocarbon is not simulated and each year the real wellhead price is used. In order to make the simulated number of wells comparable to the actual number of wells, I only include wells that are observed in every year from 2000 to 2007; there being any intermittent missing years is due to missing information on some pools in some years. Figure 8 depicts the 90% confidence interval around the average prediction from 30 simulations for oil and gas wells. The model is able to match the data closely for the first year of the simulation for both oil and gas wells, but over time gas wells continue to match the data while the oil wells deviate. The simulation of oil wells over-predicts the number of inactive wells and under-predicts the number of active wells. The prediction for the number of wells decommissioned matches the data for both oil and gas wells. There is a dip in the simulated quantity of gas extracted in 2002, as that year had the lowest in-sample price (of $\$123.77/E^3m^3$ compared to a high of $\$293.90/E^3m^3$ in 2005) and the model proves to be overly sensitive to low prices.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

(c) Production from Oil Wells

(d) Production from Gas Wells

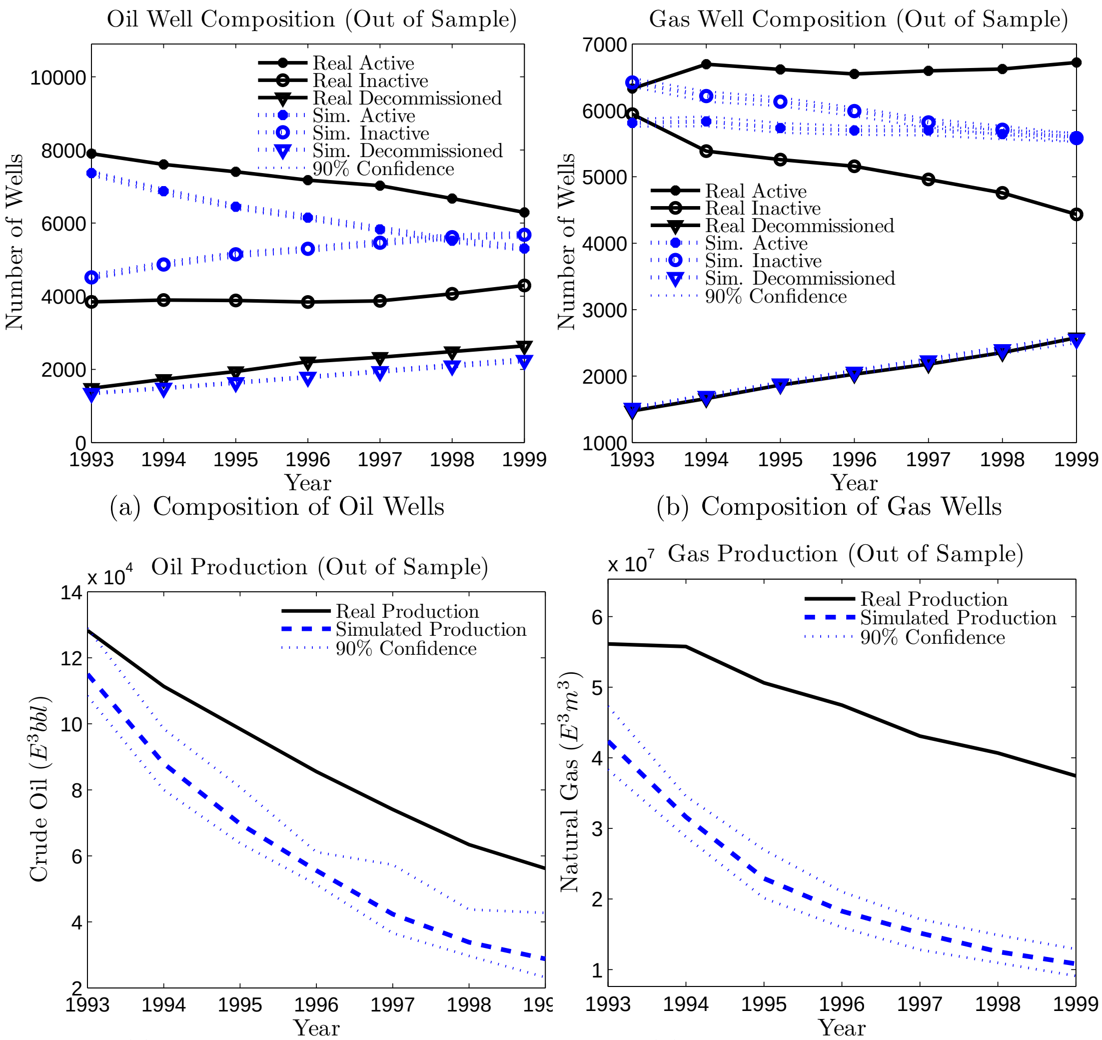
(e) Reserves for Oil Wells

(f) Reserves for Gas Wells

Figure 8: In-Sample Real and Simulated Data

6.2 Validation: Out-of-sample simulations

Another test is to see how the model predicts out-of-sample decisions that were not used to estimate the parameters. The parameters estimated using observations from 2000 to 2007 are used to predict the decisions from 1993 to 1999. The out-of-sample predictions for the number of wells decommissioned match the data closely (Figure 9); the predictions for the number of active and inactive wells match the data only somewhat closely in the first year (for example, the number of active oil wells is under-predicted by 7% and for gas wells, 9%) only to diverge with time (by the end of the simulation the number of active oil wells is under-predicted by 18% and by 20% for gas wells). The simulation under predicts the number of active wells, and therefore under predicts production. There are two reasons that recreating the out-of-sample data is a difficult task. The first is due to the quality of the out-of-sample data on reserves, and the second is that the range of hydrocarbon prices substantially differ from the in-sample. In order to obtain reserve information for the years 1993 to 1999 the pools that were last reviewed before 2000 are used. The remaining reserves are created by subtracting the cumulative production up to the review year from the estimate of initial established reserves of that year. This allows for a starting point of the last reviewed year for simulating the path of a well. The out-of-sample differs from the in-sample in a fundamental way: the pools in the out-of-sample are not reviewed as frequently as the majority of the pools used in the estimation. Furthermore, the price range is quite different: the in-sample prices range from \$120 to \$294 per e^3m^3 of natural gas, but the out-of-sample prices range from \$53 to \$83 per e^3m^3. And as can be seen in the in-sample simulation as well, the model tends to overestimate the industry's reaction to low prices.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

(c) Production from Oil Wells

(d) Production from Gas Wells

Figure 9: Out of Sample Prediction 1993-1999

6.3 Counterfactual Simulations

The reason that operators are allowed to postpone decommissioning their wells is to facilitate the reactivation of their wells should operating conditions become more favorable. However, if a well is not going to be brought back into production, then decommissioning should not be postponed because the sooner a well is decommissioned, the sooner that the land might be reused, and the less chance there is for contaminants to enter drinking water, surface or the atmosphere. The laissez-faire regulations for decommissioning wells in Alberta only pay off if the conditions that producers claim to be waiting for materialize and wells are brought back into production. The model here is used to simulate the industry under different scenarios that should be ideal for production, such as high prices and improved recovery technology, just what operators are waiting for, to see if wells will be reactivated.

Table 15: Outline of Counterfactual Simulations

Scenarios	Effect on Activity
Ideal Scenarios	
High recovery factors (1 year in-sample)	100% recovery, 3%-point higher reactivation
High prices (1 year in-sample)	1.5× EIA high price, 6%-point higher reactivation
High recovery factors (12 year forecast)	100% recovery, 1-5% more active wells
High prices (12 year forecast)	2.1-3.3×baseline price, 6-21% more active wells
Low reactivation costs (12 year forecast)	25% lower, 15-25% more active wells
Non-ideal Scenarios	
Low prices (12 year forecast)	2.3×less than baseline, 6-9% less active wells
High royalty rate (12 year forecast)	50% royalty, 3.7-8.5% less active wells
Tax on inactivity (12 year forecast)	$3000 inactivity tax, <1% more active wells

First I predict the choice probabilities in the subsample after changing the state variables price and reserve size from what was observed. I also simulate a 12 year forecast to 2020 using 2007 as a starting point. I do this for a baseline case of what is expected of the industry should states progress as they have in the past and then compare the baseline to various counterfactuals. If the number of inactive wells does not decrease when prices or recovery rates increase (to unrealistical levels), then this implies that operators are not waiting for high prices or increased recovery. However it could be that the operators are waiting for an improvement in technology that would come in the form of reduced reactivation costs, and as soon as it becomes cheaper to reactivate, the inactive wells will be brought back into production. The model predicts that a probable increase in the profit from extracting is not enough to incite operators to reactivate wells, and so relying on increases in prices or recovery rates to spur reactivations is not warranted. Relying on technology improvements to reduce the reactivation costs might be warranted because the model predicts that lowering the reactivation cost will substantially increase reactivations. However, it is more difficult to say what a probable reduction in reactivation costs might be because I do not observe the impact of past technological improvements in reactivation as I do in the case of recovery rates.

6.3.1 Overall Choice Probability Under Increased Recoverable Reserves

In a first scenario a hypothetical technology change increases the recovery rate of all pools to 100%. According to the reserve data, recovery rates range from 15% to 95% with an average of 67% for gas and from .01% to 90% with an average of 12% for oil[27]. Changing the recovery rate to 100% moves the mean average reserve size, $\overline{Q}$, from 14,696e^3m^3 to 51,782e^3m^3. The expected average production would increase to 5,116e^3m^3 as compared to the observed average of 2,560e^3m^3. The model's predicted choice probabilities match the observed choice probabilities before applying the hypothetical scenarios (the first two columns of Table 16). The average reserve size and age listed in Table 16 (as well as price) are the state variables that the choice probabilities are based on, and therefore are the same. The average quantity extracted is the predicted quantity given the reserve size and age of the wells. The third column shows that increasing recovery rates to 100% only increases the overall probability of activity by a little less than 2 percentage points, and increases the probability of inactive wells to be activated by 6 percentage points, indicating the extent of the hysteresis of inactivity. Upon first glance this seems to be an implausible prediction, and so to justify it, the observed probability of activity for wells on hydrocarbon rich and poor reserves is compared (Table 17).

The wells that have less than 5,000e^{3}m^3 are only 2.6 percentage points less likely to be active as those with reserves greater than 10,000e^{3}m^3. This might lead

[27]For gas, the average recovery rate calculated from the data on gas pools matches the average recovery rate in the ERCB's publication on Alberta's energy reserves [ERCB, 2008]. However, for oil my calculated average recovery rate differs from the ERCB's, where recovery rates for oil are said to range from 5% to over 50%, with an average of 26%

Table 16: Actual versus Predicted Choice Probabilities Under Different Scenarios

Current State:	**Observed**	**Expected**	**100% Recovery**	P_{high}
Active or Inactive				
Pr(Activate)	0.6878	0.6884	0.7051	0.7183
Pr(Inactivate)	0.3026	0.3021	0.2865	0.2735
Pr(Abandon)	0.0096	0.0094	0.0084	0.0082
No. Obs.	186274	186274	186274	186274
Mean $\overline{Q}$	14696.3049	14696.3049	51782.4453	14696.3049
Mean Age	15.0276	15.0276	15.0276	15.0276
Mean q	3272.4195	2560.1683	5116.5363	2509.6345
Active				
Pr(Active)	0.9421	0.9428	0.9526	0.9578
Pr(Inactivate)	0.0534	0.0528	0.0439	0.0391
Pr(Abandon)	0.0046	0.0043	0.0035	0.0031
Inactive				
Pr(Activate)	0.1105	0.1108	0.1430	0.1745
Pr(Inactive)	0.8685	0.8682	0.8375	0.8059
Pr(Abandon)	0.0210	0.0210	0.0196	0.0196

one to question the relation between reserves and productivity, but as shown in the row indicating the average quantity produced (9th row of Table 17), wells with higher reserves are indeed more productive. The expected quantity produced is calculated for all wells depending on their well type, age, and reserve size and the parameterized probability density function for extraction, $f_q(q|\overline{Q}, A, \alpha)$. The model slightly underpredicts the quantity produced from a well. However, the chi-squared goodness of fit shows that the model closely matches the observed choice probabilities for both the large and small reserves, and cannot be rejected at the 1% significance level. The small-reserve wells and large-reserve wells differ slightly by their age, and may differ by geographic location, so in an experiment, the remaining reserves in

Table 17: Influence of Reserve Size

Current State: Active or Inactive	$\overline{Q}_{Small}$ Observed	$\overline{Q}_{Small}$ Expected	$\overline{Q}_{Large}$ Observed	$\overline{Q}_{Large}$ Expected	$\overline{Q}_{Small} \Rightarrow \overline{Q}_{Large}$ Experiment
Pr(Activate)	0.6785	0.6782	0.7040	0.7061	0.6946
Pr(Inactivate)	0.3108	0.3114	0.2882	0.2865	0.2959
Pr(Abandon)	0.0106	0.0104	0.0078	0.0075	0.0095
No. Obs.	102024	102024	56527	56527	102024
χ^2	0.5549		1.8576		
Marg. Sig.	0.7577		0.3950		
Mean $\overline{Q}$	1797.8571	1797.8571	41642.0035	41642.0035	41859.7134
Mean Age	16.3845	16.3845	13.4828	13.4828	16.3845
Mean q	1141.0560	713.2404	7362.3941	5287.9515	4915.5162
Active					
Pr(Active)	0.9399	0.9393	0.9474	0.9500	0.9492
Pr(Inactivate)	0.0555	0.0559	0.0482	0.0463	0.0468
Pr(Abandon)	0.0046	0.0047	0.0044	0.0036	0.0039
No. Obs.	70440	70440	39547	39547	70440
χ^2	0.4664		10.1006		
Marg. Sig.	0.7920		0.0064		
Inactive					
Pr(Activate)	0.0957	0.0958	0.1370	0.1378	0.1267
Pr(Inactive)	0.8802	0.8811	0.8472	0.8458	0.8516
Pr(Abandon)	0.0241	0.0231	0.0157	0.0164	0.0218
No. Obs.	31584	31584	16980	16980	31584
χ^2	1.3412		0.6127		
Marg. Sig.	0.5114		0.7361		

Notes: The "$\overline{Q}_{Small}$" subsample includes any observation where $\overline{Q} \leq 5,000\text{e}^3\text{m}^3$, and the "$\overline{Q}_{Large}$" subsample includes any observation where $\overline{Q} \geq 10,000\text{e}^3\text{m}^3$. The mean q is the average expected production from a given well in one year. The expected production depends on the well's age, $\overline{Q}$ and the parameters of $f_q(q|\overline{Q}, A, \alpha)$ that were estimated in the first stage.

the subsample with small reserves are increased to be of the same distribution as the reserves in the subsample with large reserves. This will show how much of the difference in the choice probabilities comes from the reserve size. As seen, the probability to be active and the average expected quantity extracted increases when the reserves are increased. That the probability to be active and the quantity produced is smaller in the wells with increased reserves than the large-reserve wells is due to a difference in the proportion of different well types and age of the two groups.

6.3.2 Overall Choice Probability Under Increased Price

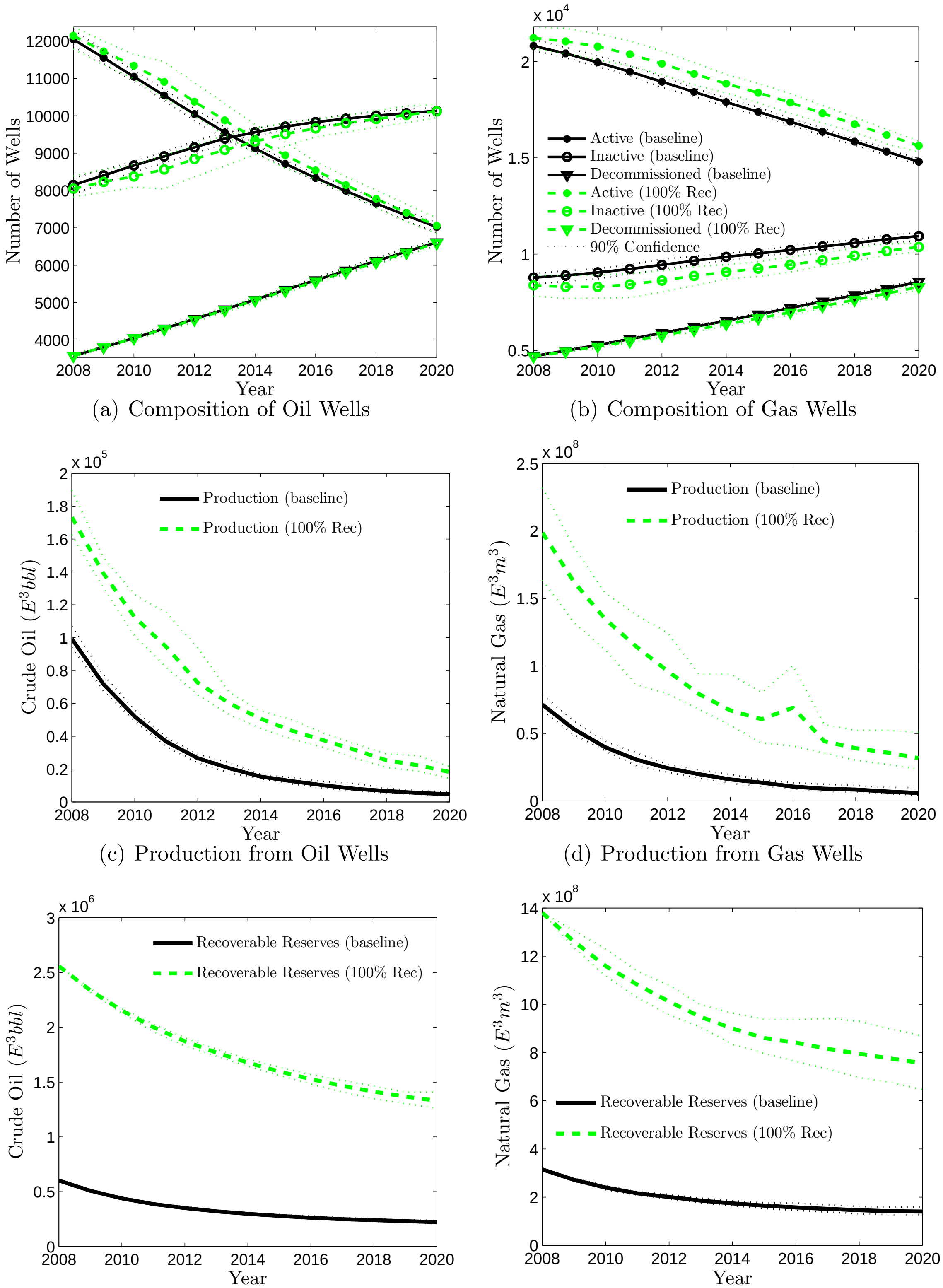
A second scenario examines the choice probabilities when there is a high gas price. In the U.S. Energy Information Administration's Annual Energy Outlook of 2009 the "high price" case for 2030 is $\$308.29/e^3m^3$ for natural gas at the wellhead[28] [EIAproj]. This is only slightly more than the wellhead price in Alberta in 2005 ($\$293.90/e^3m^3$ (2007 dollars)), and so I use 1.5 times their high price as the high price scenario. This results in 3 percentage point increase in the probability of activating an inactive well.

Table 16 shows that exposing the industry to an extreme scenario for one year has only a very small effect on the operating decisions. It is also worthwhile to explore the effect that many years of an extreme hypothetical scenario has on the industry. Therefore, a forecast of the industry from 2007 through to 2020 is made under a baseline for the most likely case to be compared to different extreme cases for both oil and gas wells. The baseline forecast takes the state in 2007 of all wells in the sample as an initial state and allows the state variables to change according to the probability densities estimated from the 2000-2007 data. Figures 11 to 14 depict the baseline scenario forecast (solid lines) superimposed on the forecasts of different extreme scenarios (dotted lines).

[28]converted from Mcf to e^3m^3 using 35.314 Mcf/e^3m^3

6.3.3 12 Year Forecast Under High Recovery Rates

Figure 10 demonstrates the unrealistic scenario of increasing the recovery factor so that all of the gas or oil in-place is recoverable (currently 67% of the gas-in-place and 12% of oil-in-place is recoverable). In the case of gas, production from producing wells increases, however this increased profitability is not incentive enough to reactivate many inactive gas wells (there are only 5.6% more active wells). In the case of oil, the increased recovery rates does not change the number of active wells by the end of the period (there are only 1% more active wells). This reiterates that an increase in recovery that is realistic is not enough to induce the reactivation of inactive wells.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

(c) Production from Oil Wells

(d) Production from Gas Wells

(e) Reserves for Oil Wells

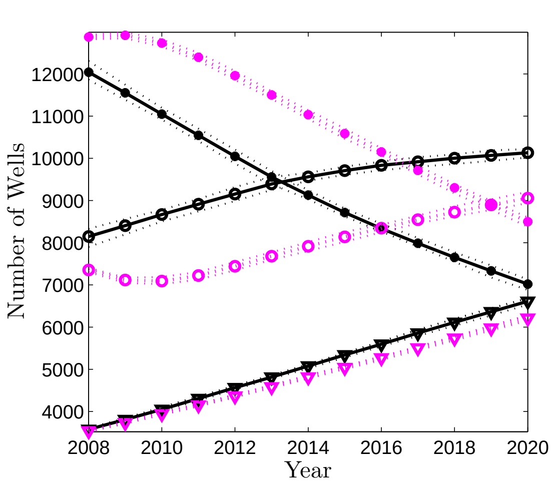
(f) Reserves for Gas Wells

Figure 10: Forecast under Baseline and 100% Recoverable Reserves

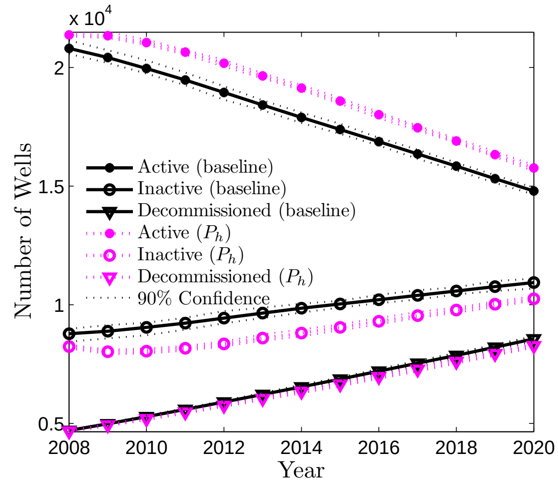
6.3.4 12 Year Forecast Under High Prices

Figure 11 shows the forecast when operators receive a constant "high price" of \$197.72/bbl for oil and \$462.44/e^3m^3 for gas[29]. In reality the operator would notice that they are receiving a constant high price and then update their beliefs for the price process, however in this simulation the transition probability density for the future price stays the same as that estimated from the price path from 1971 to 2007. On average over the 50 simulations, by 2020 there are only 6.6% more gas wells that are active under the high price scenario as compared to the baseline prediction, where the high price for gas is 2.1 times the average forecasted price of the baseline in 2020. For oil, the high price is 3.3 times the average forecasted price of the baseline in 2020, and this leads to 21% more wells that are active. Oil wells are reactivated more readily under high prices than gas wells, however, a high price does not spur as much reserve growth in oil reserves as it does for gas reserves. In the case of oil, the growth in reserves does not compensate for the increased production, so that after 12 years there are fewer oil reserves than in the baseline case. For gas reserves, the high price results in more reserve growth showing that the expected returns from investments in exploration or enhancing production are greater for gas than oil. By 2020 under the high price there are 133% more reserves and 104% more production than in the baseline case. The gas wells that are active result in producing more, however these conditions of increased reserves and increased prices are not sufficient to induce many inactive gas wells to be reactivated.

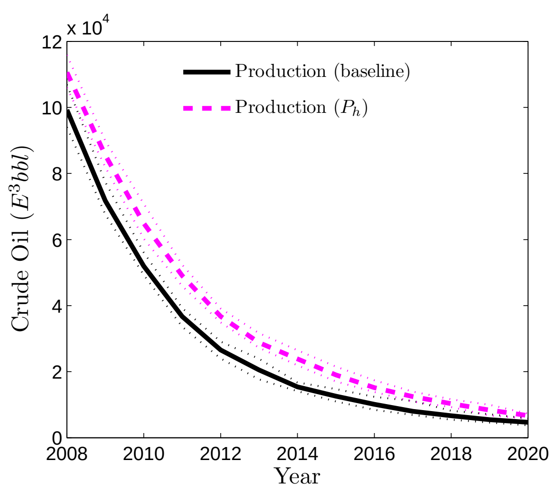
[29]This is equal to the U.S. Energy Information Administration's Annual Energy Outlook of 2009 "high price" case in 2030 for oil, and 1.5 times the "high price" for gas



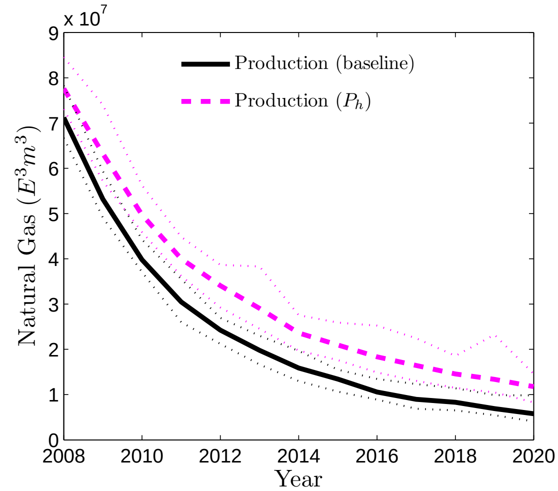
(a) Composition of Oil Wells



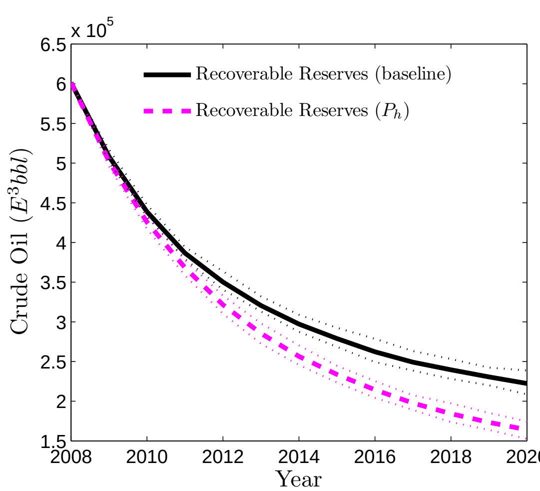
(b) Composition of Gas Wells



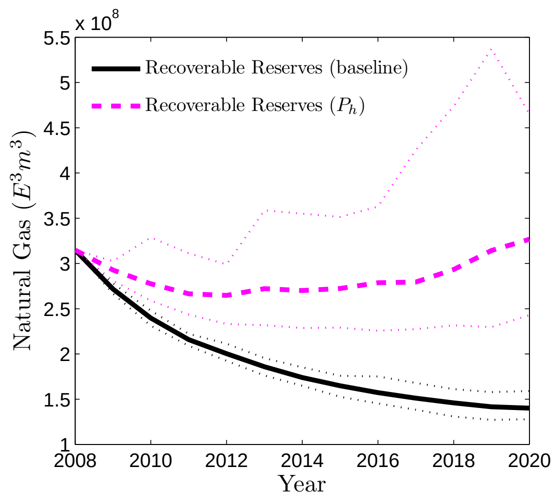
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells

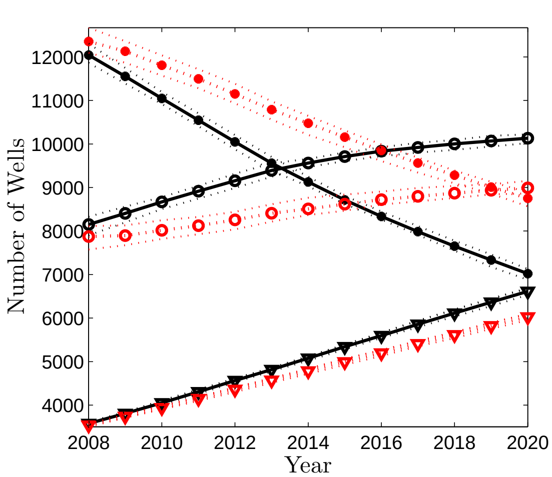


(f) Reserves for Gas Wells

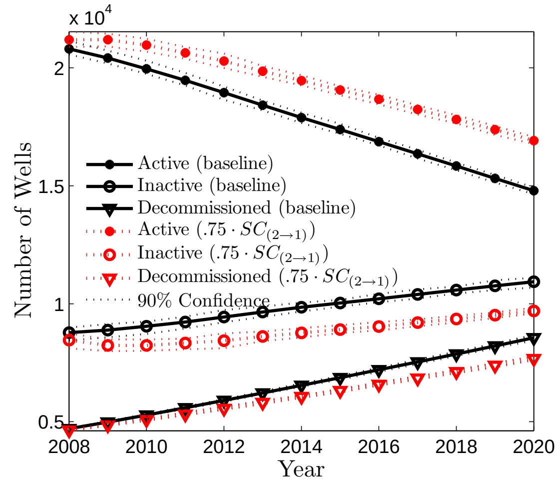
Figure 11: Forecast under Baseline and High Price Scenarios

6.3.5 12 Year Forecast Under Reduced Reactivation Costs

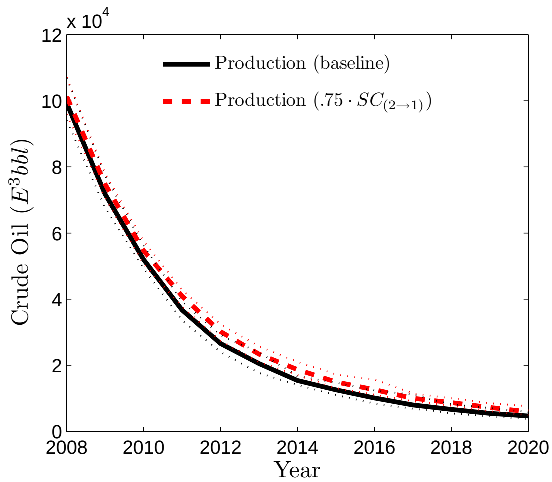
If technology changed in a way that reactivating inactive wells became cheaper, then there should be more wells reactivated and more total production. Figure 12 shows a forecast of the industry when there is a 25% reduction in the cost to reactivate, $SC_{(2\to1)}$. For both oil and gas wells, as expected, more wells are reactivated. Each year there are still more wells that are deactivated than reactivated, however the pace at which this occurs is slowed. In the case of gas, by 2020 there are 14% more active wells, 12% more production and 11% less remaining reserves. In the case of oil, the simulation ends with 25% more active wells, 27% more production, and 10% less reserves.



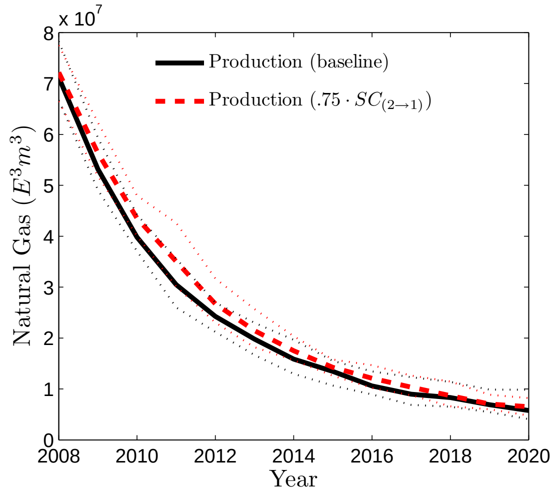
(a) Composition of Oil Wells



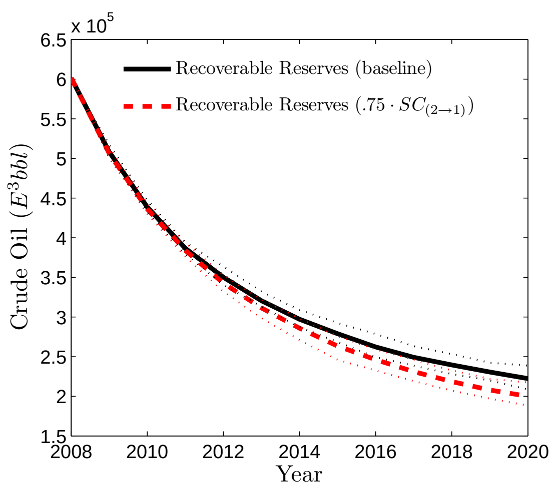
(b) Composition of Gas Wells



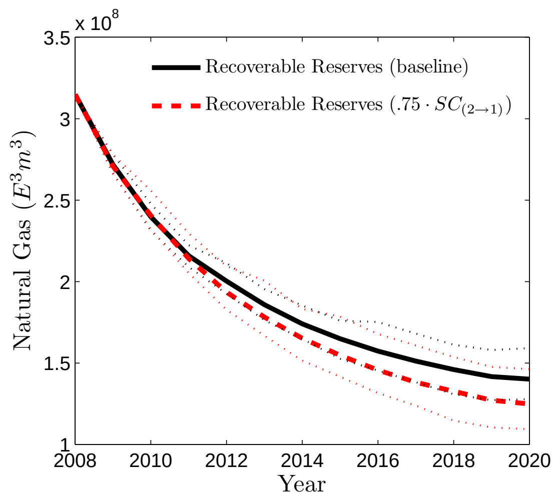
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells

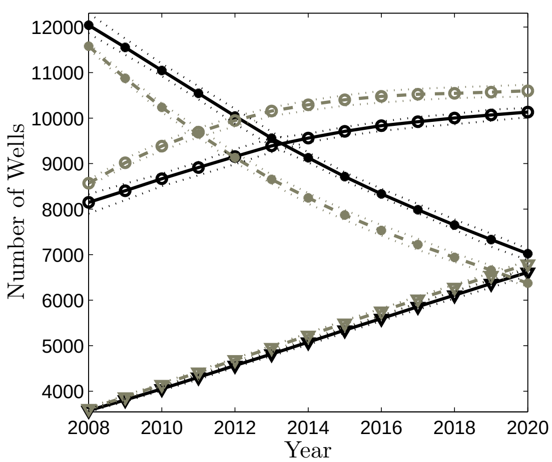


(f) Reserves for Gas Wells

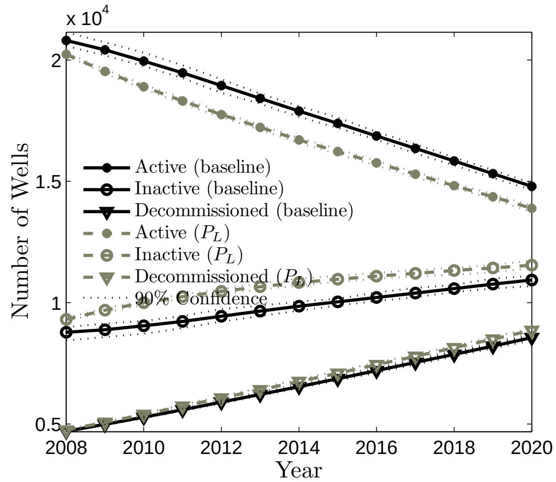
Figure 12: Forecast under Baseline and $SC_{(2\to1)}$ 75% Cheaper

6.3.6 12 Year Forecast Under Low Prices

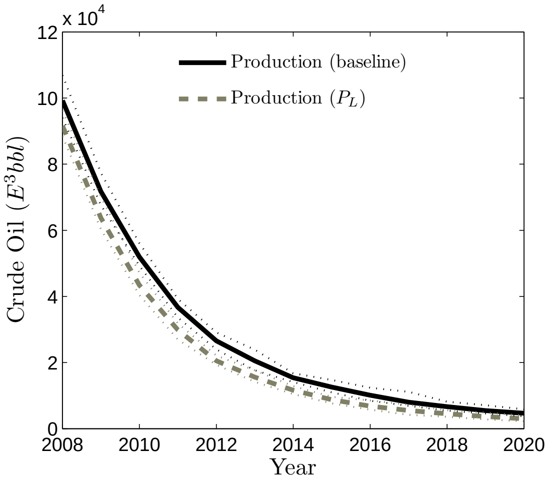
Recently the price of natural gas hit its seven year low, mainly due to increased production of natural gas from shale gas and inventories reaching record high levels. The September 2009 wellhead price, \$103.12/E^3m^3, is almost two times lower than the EIA's "low" price scenario for natural gas. I examine what the conventional natural gas and oil production would look like after 12 years of sustained low prices (Figure 13), using wellhead prices of \$91/E^3m^3 for natural gas and \$25/bbl. Recoverable gas reserves are more price sensitive and after 12 years, there are 10% less remaining recoverable gas reserves than the baseline. In the case of oil, there is less extraction and reserve growth does not change, so there are 18% more remaining recoverable oil reserves than the baseline. The number of wells that are abandoned does not significantly increase when there are low prices. Most of the switching between states is comes from active wells becoming inactive resulting in less production. Under low prices the model predicts that there are 6% less active gas wells, 62% less gas production, 9% less active oil wells and 35% less oil production than in the baseline.



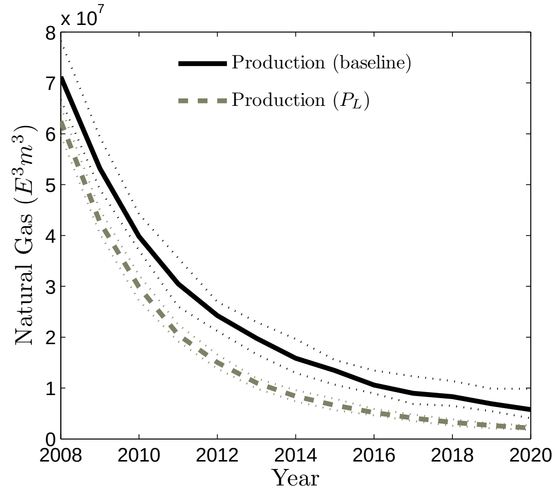
(a) Composition of Oil Wells



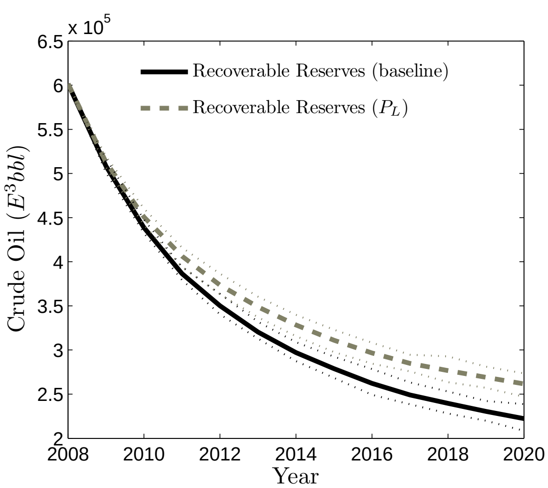
(b) Composition of Gas Wells



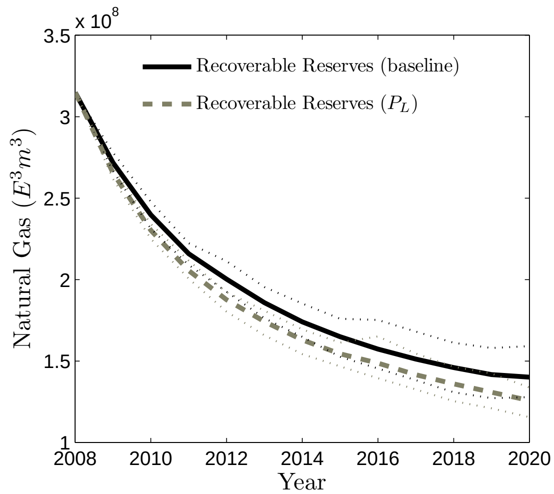
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells

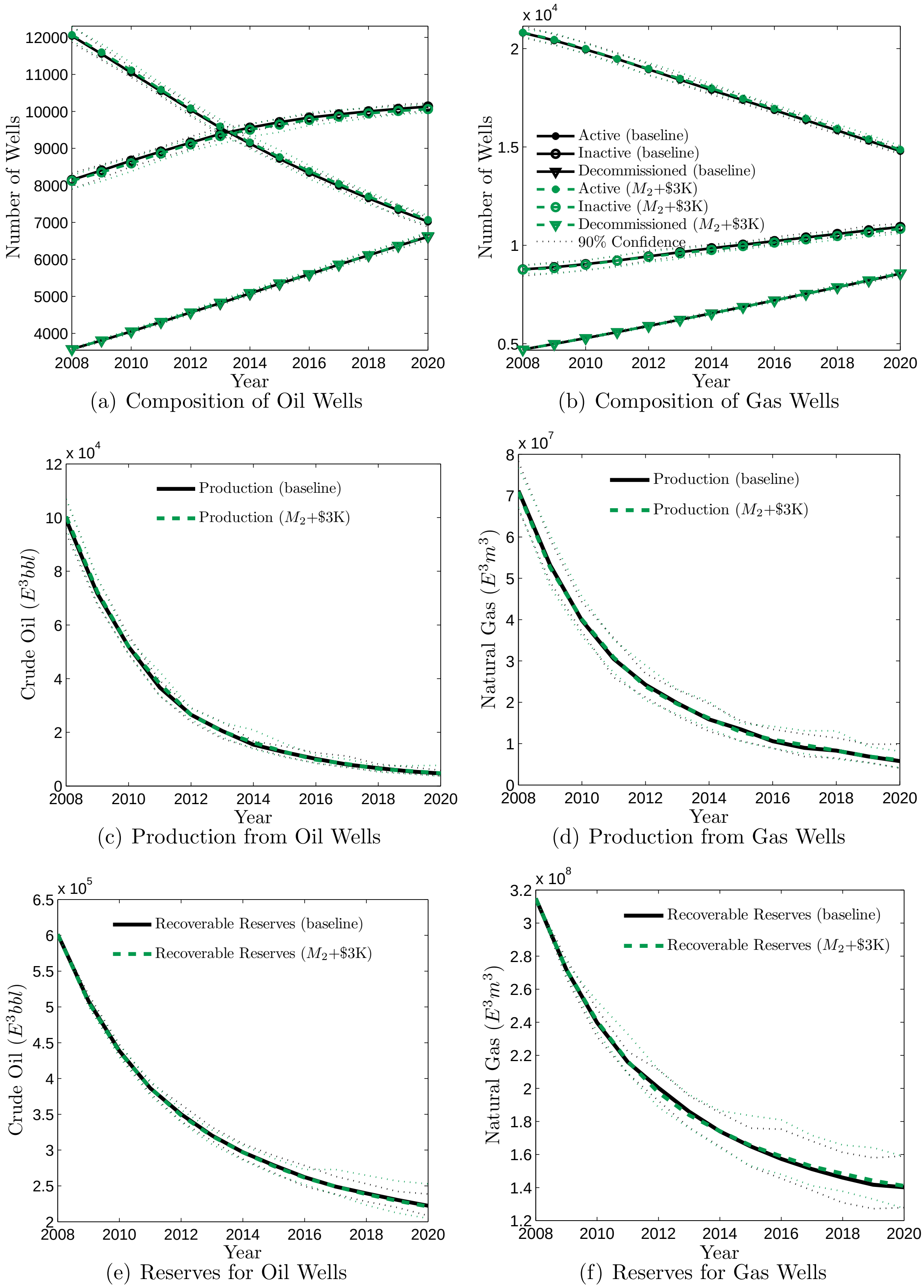


(f) Reserves for Gas Wells

Figure 13: Forecast under Baseline and Low Price Scenarios

6.3.7 12 Year Forecast with Tax on Inactive Wells

Implementing a \$3,000 tax each year that a well is left inactive has the least repercussions out of the scenarios. There is less than a percent increase in the number of active gas wells, 4% increase in gas production, and less than a percent increase in reserves (a decrease would have been expected). For the case of oil, there is 0.7% increase in active wells, 2% decrease in production and 0.4% increase in reserves. A tax on inactive wells makes the options of reactivating or decommissioning more favorable, but it is not immediately obvious which of these states becomes more preferred. Therefore, I simulate the industry up to 2020 under different levels of the tax (Figure 15), and it becomes immediately apparent that a tax results in more gas wells being reactivated than decommissioned. In the case of oil, a tax results in wells being decommissioned and reactivated. There is a threshold at which nearly all inactive wells are either decommissioned or reactivated, and the fraction that are decommissioned or reactivated does not change with an increase in the tax. The second panel of Figure 15 shows that the cumulative production by 2020 increases with a higher inactivity tax, but levels out as higher taxes no longer increase the number of wells reactivated.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

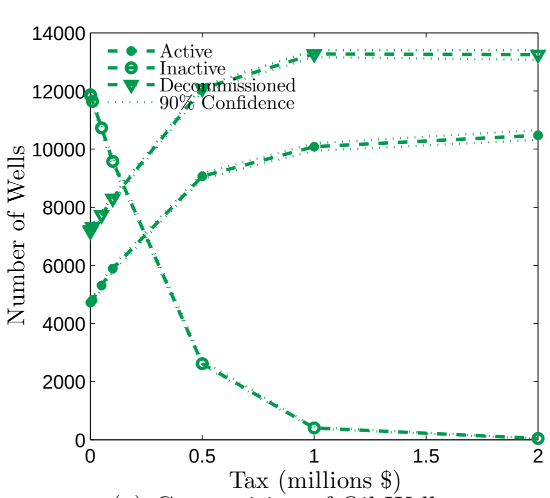
(c) Production from Oil Wells

(d) Production from Gas Wells

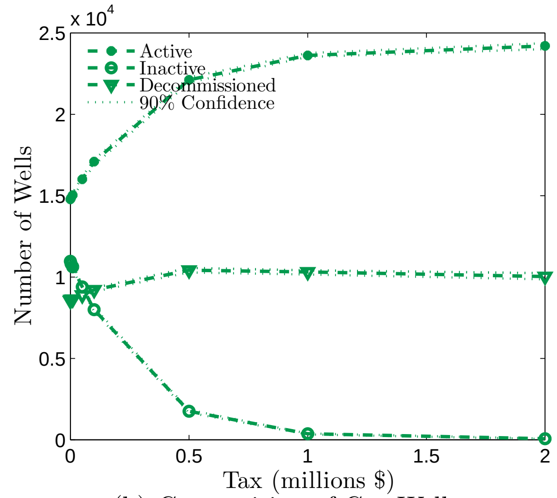
(e) Reserves for Oil Wells

(f) Reserves for Gas Wells

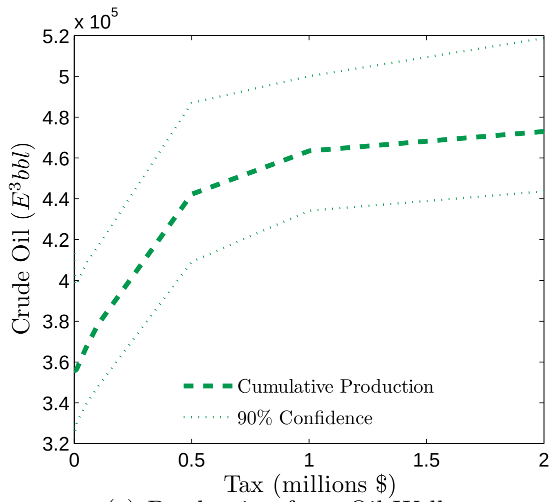
Figure 14: Forecast under Baseline and with $3000 Annual Inactivity Fee



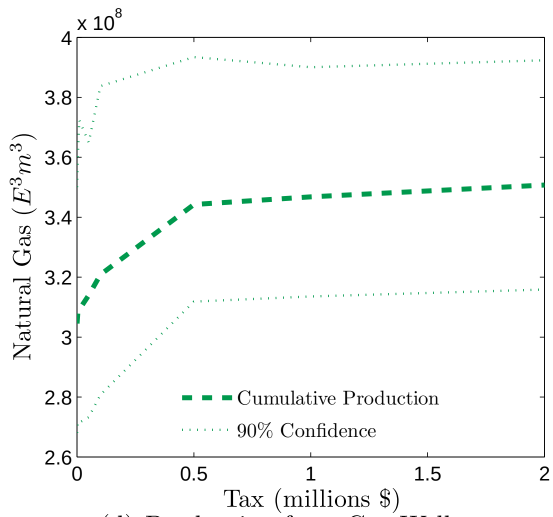
(a) Composition of Oil Wells



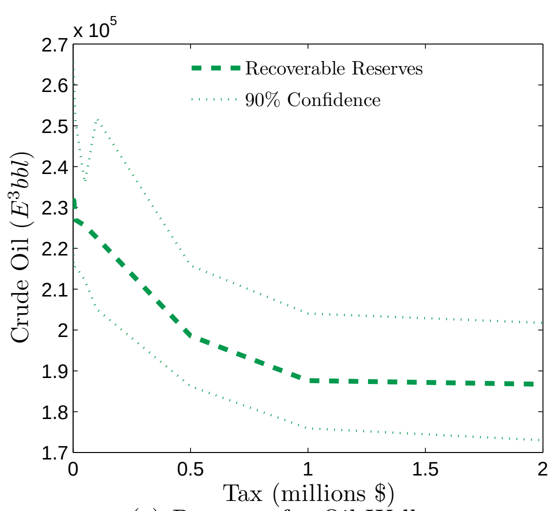
(b) Composition of Gas Wells



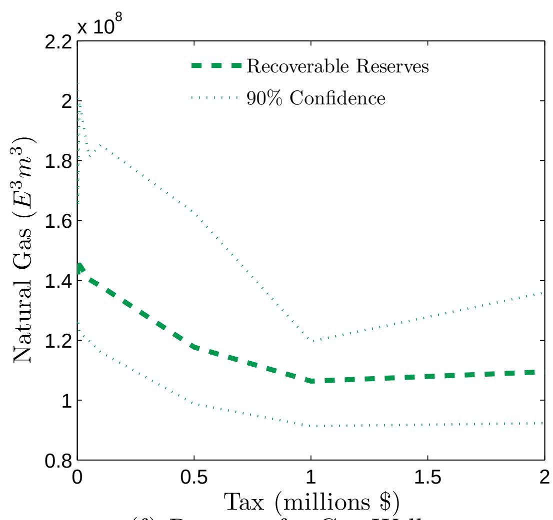
(c) Production from Oil Wells



(d) Production from Gas Wells



(e) Reserves for Oil Wells

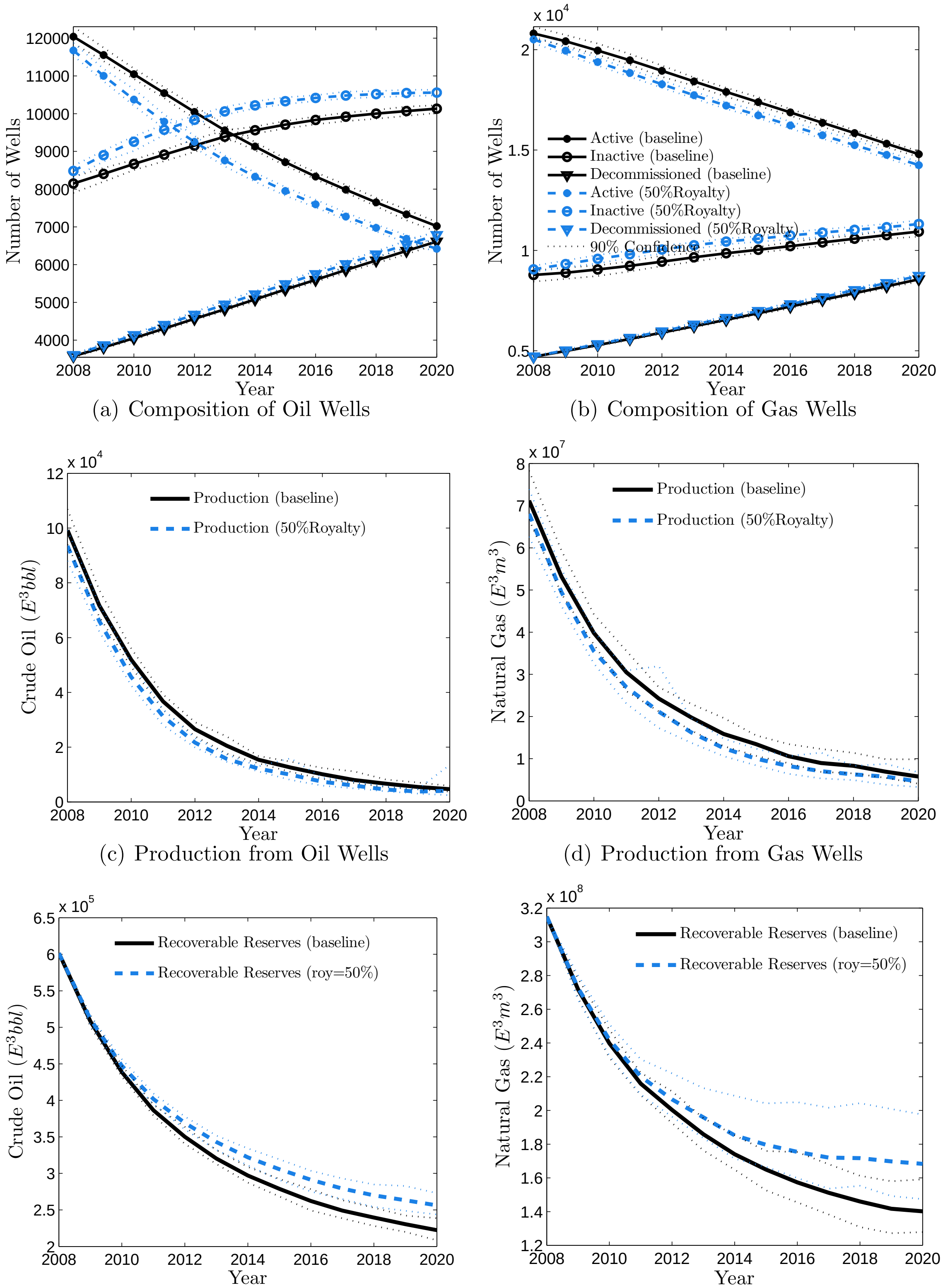


(f) Reserves for Gas Wells

Figure 15: Effect of Tax on Inactivity

6.3.8 12 Year Forecast with Increased Royalty Rates

Hysteresis in the operating state implies that changes in royalty rates have a muffled influence on the operating state of already drilled wells. This is not to say that an increase in the royalty rates would not have a dramatic effect on the industry, but that effect would likely come from changing the decision to drill or not rather than the operating state of already drilled wells. Increasing royalty rates that currently range from 5% to 35% (depending on the price, when the reserve was discovered, and quantity produced) to 50% results in 3.7% less active wells, 20% less production, and 20% more reserves in the case of gas after 12 years; and 8.5% less active wells, 13% less production, and 15% more remaining reserves in the case of oil.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

(c) Production from Oil Wells

(d) Production from Gas Wells

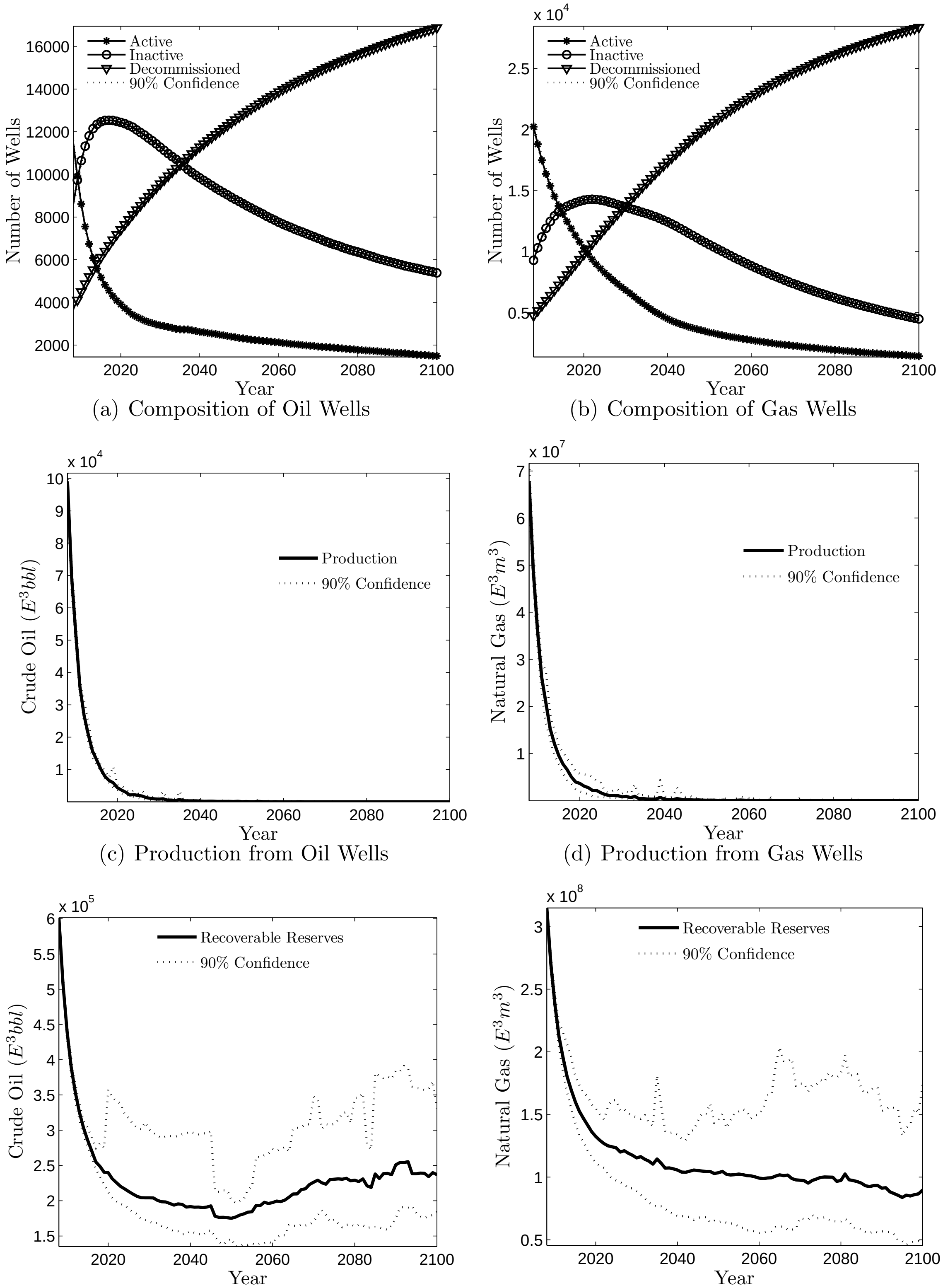
(e) Reserves for Oil Wells

(f) Reserves for Gas Wells

Figure 16: Forecast under Baseline and 50% Royalty Rate

6.3.9 Long Term Forecast

As can be seen in all of the forecasts, the trend over time is that the number of wells that have been decommissioned increases. Extending the simulation out to the next century illustrates that according to this trend, eventually all wells will be decommissioned (Figure 17). This prediction comes with a large grain of salt that the economy and regulatory regime is to remain as it has in the last eight years. However this simulation also illustrates that by virtue of the dynamics themselves, the industry will not remain as it has in the last eight years. Currently the industry as a whole has more assets than liabilities, however the simulation shows that there is a risk of not always having more active wells than inactive wells. The simulation predicts that in less than 20 years, of the wells present in 2007, there will be more inactive than active. The simulation does not include a prediction for new wells drilled and so the change in the proportion of inactive to active wells will not be as dramatic as the simulation suggests. The trend that results in all wells eventually being decommissioned depends on funds for decommissioning to be available. Firms not setting aside sufficient funds becomes an even more severe problem when the stream of income from producing wells is no longer present. Nonetheless, assuming that the parameters and transition probabilities remain the same, it would take over 100 years to have all of the wells present in 2007 decommissioned; the majority of the inactive wells are never reactivated, and so it was not necessary for them to remain inactive, potentially be polluting, only to be later decommissioned.



(a) Composition of Oil Wells

(b) Composition of Gas Wells

(c) Production from Oil Wells

(d) Production from Gas Wells

(e) Reserves for Oil Wells

(f) Reserves for Gas Wells

Figure 17: Long-run Forecast for Wells in Subsample

7 Conclusion

The decision that oil and natural gas producers make for the operating state of their wells can be categorized as a classic example of an irreversible investment under uncertainty. Restarting production or finally decommissioning a well is an expensive endeavor and is made with uncertainty in future recovery technology and prices. I show that this decision can be modeled by a real options formulation. The operating decisions taken for a subsample of wells in Alberta can be replicated by modeling well operators as dynamic optimizers with an annual discount rate of about 22%. Within-sample goodness of fit tests show that the model is able to closely predict actual operating choices. The model is further validated using an out-of-sample prediction of decisions from data not used in the estimation of the parameters.

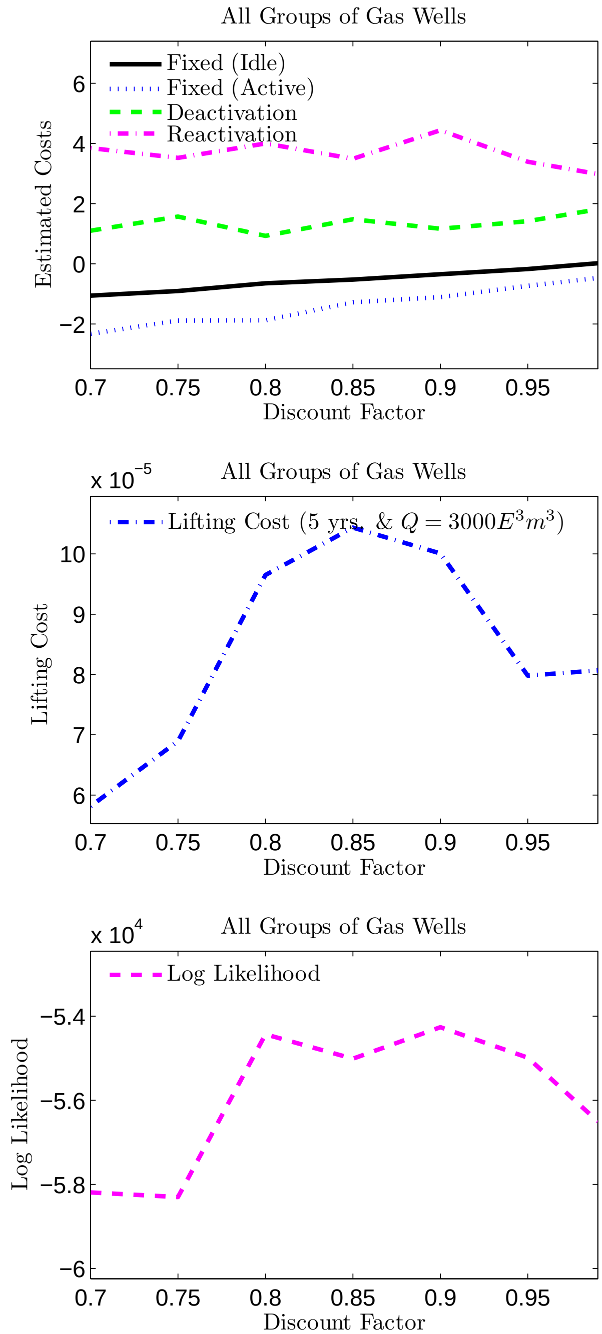
The motivation of this dissertation was to determine the fate of inactive wells; they could be either a blessing, if they are to be reactivated and contribute to our energy supply, or they could be a curse, if they are never reactivated but must undergo costly decommissioning. By having estimated the structural parameters of a model for the optimal operating state, I predict how operating choices might change under different conditions. The model predicts that a probable increase in the profit from extracting is not enough to incite operators to reactivate wells, and so it is not justified for the regulator to rely on increases in prices or recovery rates to spur reactivation. Relying on technology improvements to reduce the reactivation costs might be justified because the model predicts that lowering the reactivation cost will substantially increase reactivation. However, what a probable reduction in reactivation costs might be is difficult to say because I do not observe the impact of past technological improvements in reactivation as I do in the case of recovery rates.

The socially optimal solution would be to account for the externalities associated with leaving a well inactive, such as by implementing a Pigouvian tax on inactive wells equal to the marginal damages to groundwater. The model predicts that a tax on inactive wells would have the added benefit of increasing the number of reactivated wells. In the case of oil the number of decommissioned wells is greater than the number of reactivated wells after a Pigouvian tax. Setting the optimal tax is difficult because unfortunately there is no study that I am aware of that puts a price tag on damages from inactive wells.

8 Appendix

8.1 Choice of Discount Factor

There was not a discount factor that resulted in the highest likelihood for all groups. I choose a constant discount factor across all of the different well types. I choose a discount factor of .80. Summing the log likelihoods of all well groups for different fixed discount factors, a discount factor between .80 and .90 gives the highest likelihood (Figure 18). Not all of the well group optimizations reached an optimum before the iteration limit (of 1200) was met, and therefore to create the Figures 19 to 20, if the iteration limit was reached and the log likelihood was more than 4 times the average of the other log likelihoods, then I interpolated a log likelihood from the results from the two closest discount factors. This had to be done for 5 out of 259 of the optimizations.



(a)

Figure 18: Effect of Using Different Discount Factors on Results from All Gas Wells

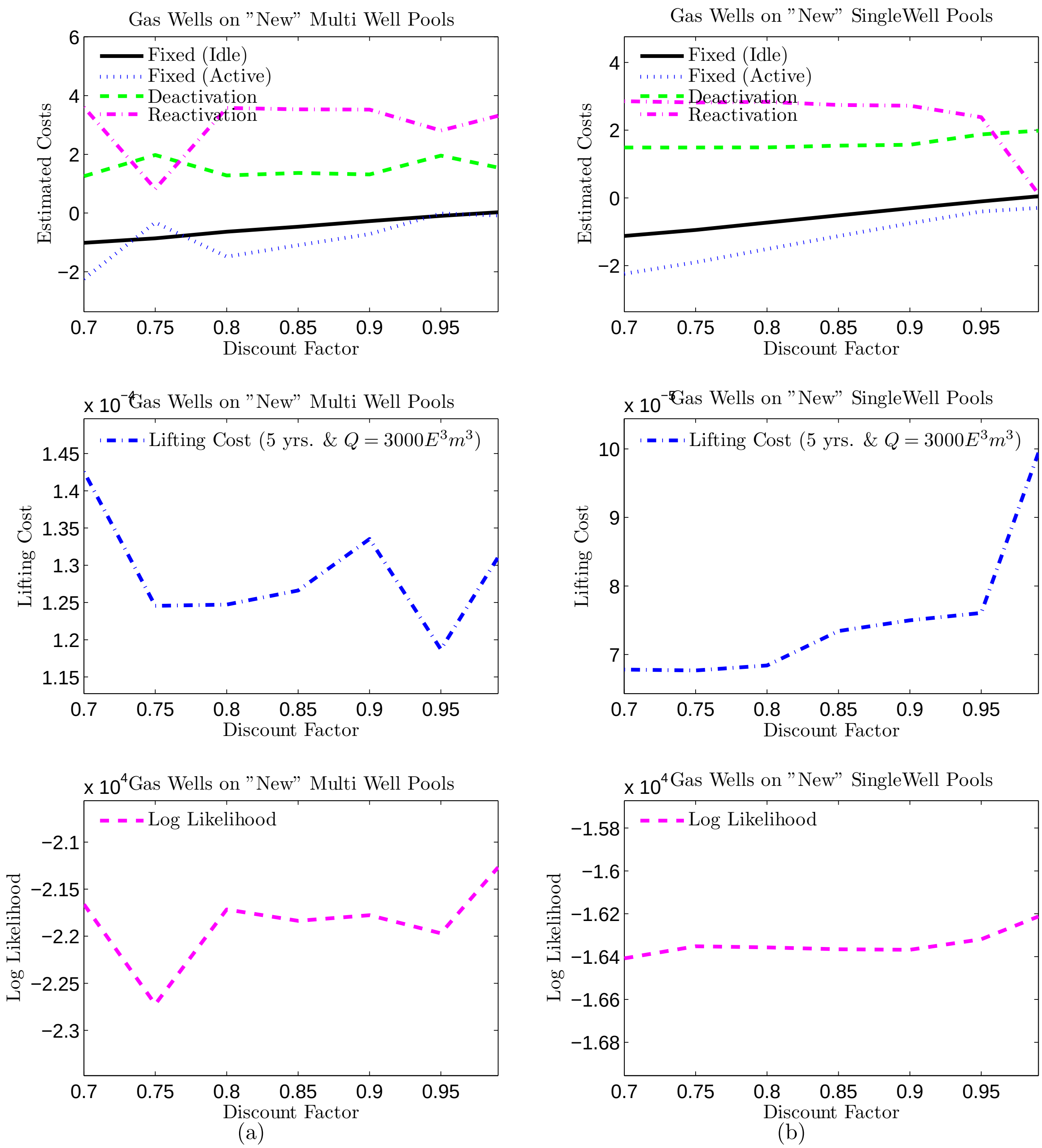


Figure 19: Effect of Using Different Discount Factors on Results from Gas Wells in "New" Pools

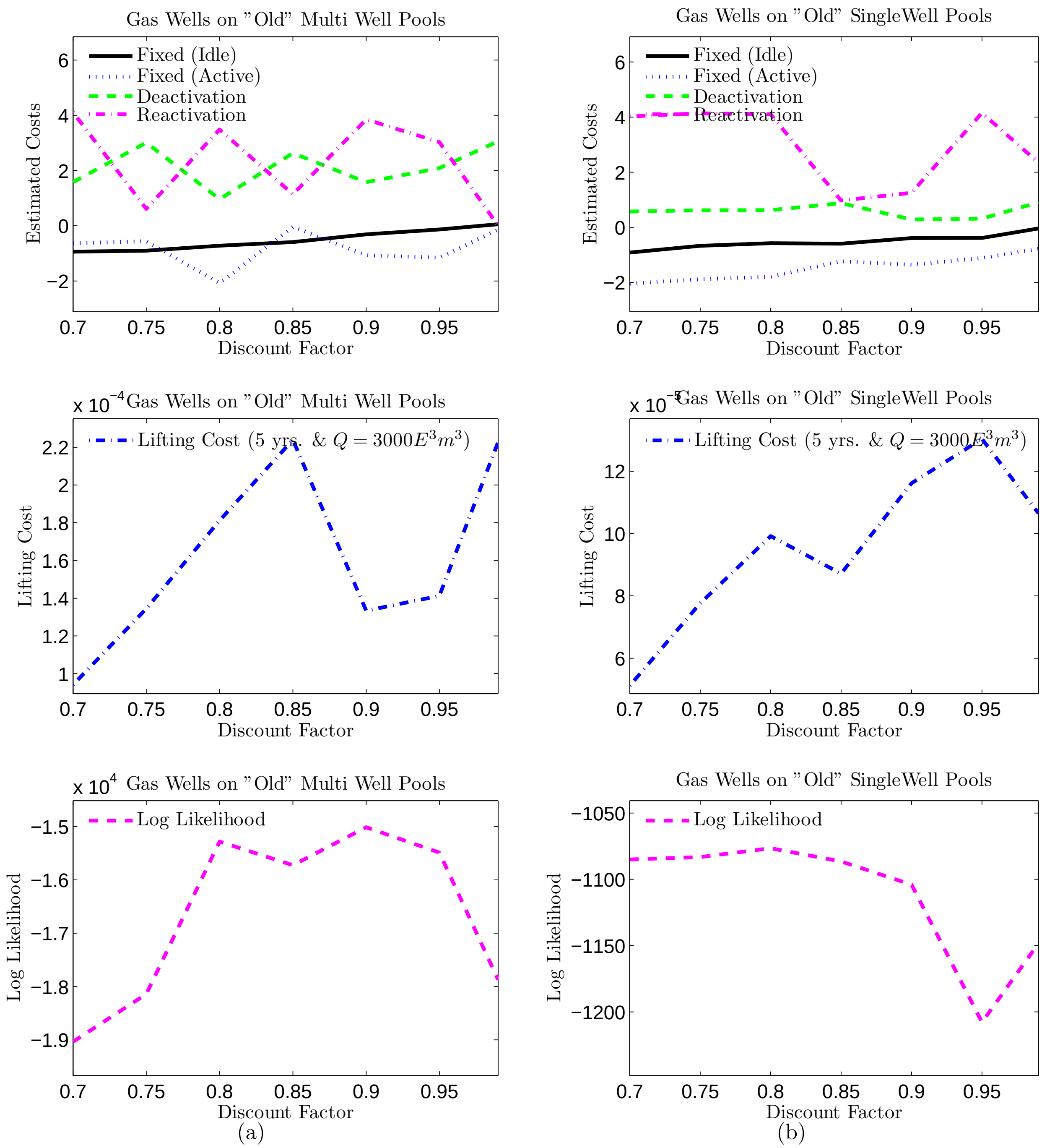


Figure 20: Effect of Using Different Discount Factors on Results from Gas Wells in "Old" Pools

8.1.1 Example of Resulting Value Function

Figures 21 and 22 depict how the value of different decisions changes with price and reserve size for four different well types of inactive wells in PSAC area 3. The value of continuing to idle an inactive well is displayed next to the value of reactivating it. As expected, the value of each decision for each well increases with prices and reserves. This is the case for both wells drilled in pools discovered before 1974 ("old") and wells drilled in pools discovered in 1974 or after ("new"), wells drilled in pools with other wells, and wells in pools of their own. In this example, the value of a well in an "old" pool is greater than the value of a well in a "new" pool in the case of single-well pools (Figures 21). It is not a surprise that wells in "old" pools would be more valuable than wells in "new" pools, because pools that are easier to extract from are also easier to find and hence were discovered earlier. The royalty regime tries to account for this by requiring that a higher royalty is paid for gas extracted from "old" pools. However, in this example, the value of a well in an "old" pool is not greater than the value of a well in a "new" pool in the case of wells in multi-well pools (Figures 22). Perhaps this is due to "old" pools having been around longer and therefore have had more wells drilled in them. For example, the average number of wells on a multi-well "old" gas pool in PSAC area 3 is 41.27 (26.21 for the whole province) compared to an average of 6.6 wells on a multi-well "new" gas pool (4.96 for the whole province) on a multi-well "new" gas pool. The model does not distinguish between a pool with 4000 wells and a pool with 2 wells, but as there are more wells drilled on older pools this is perhaps

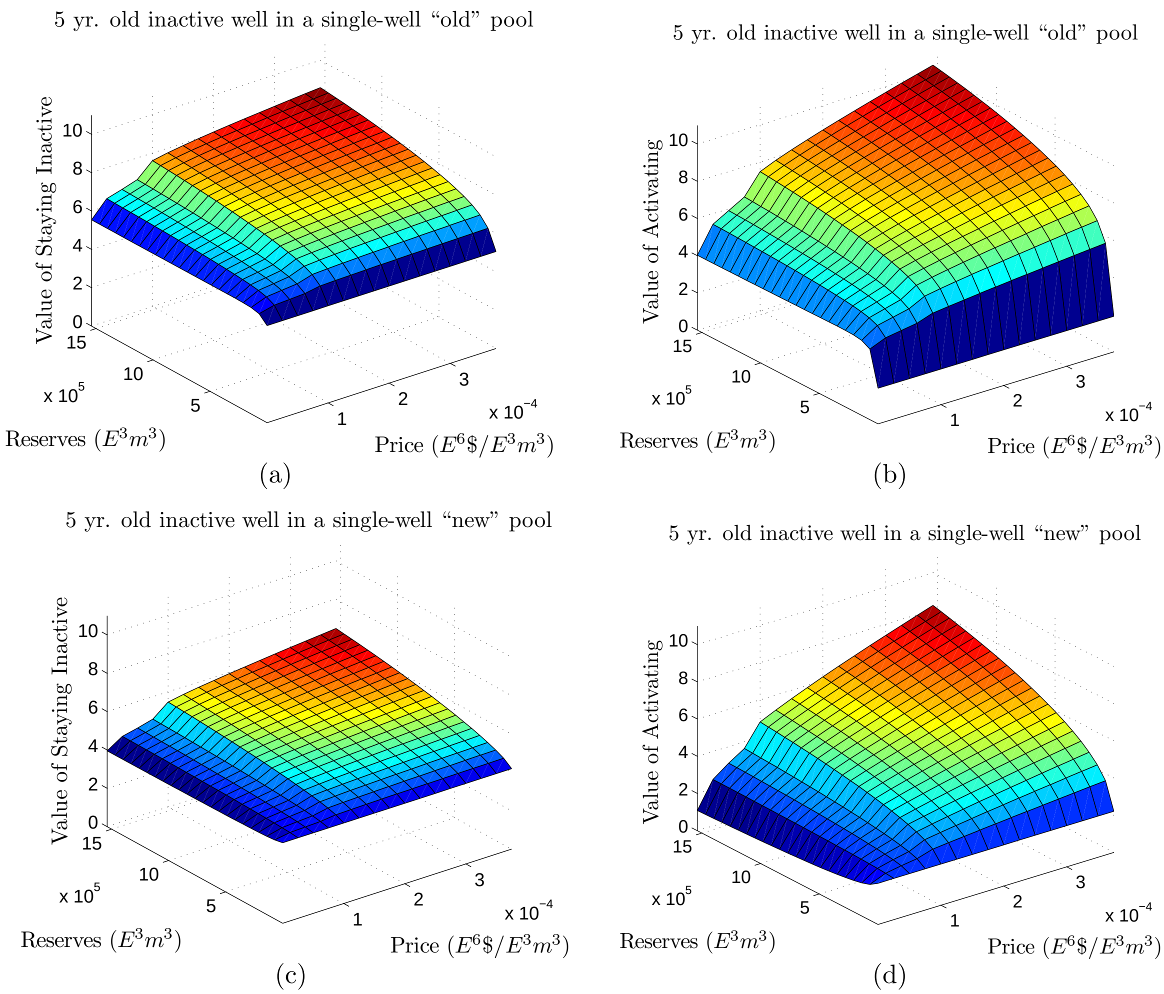


Figure 21: Value of leaving inactive and activating a 5 year old inactive gas well in PSAC area 3 (in single-well “new”(post-1974) pools and “old”(pre-1974) pools)

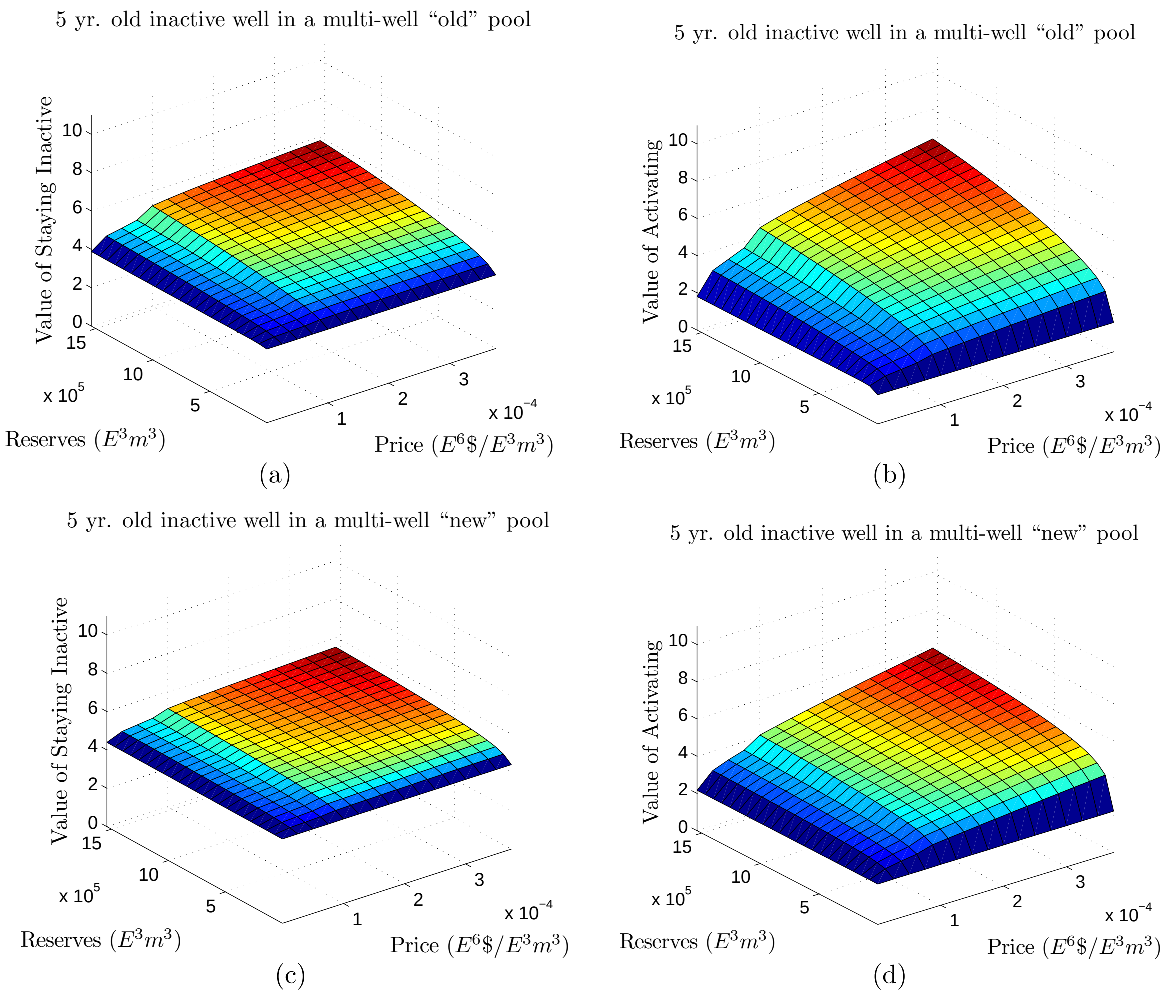


Figure 22: Value of leaving inactive and activating a 5 year old inactive gas well in PSAC area 3 cluster 2 (in multi-well "new"(post-1974) pools and "old"(pre-1974) pools)

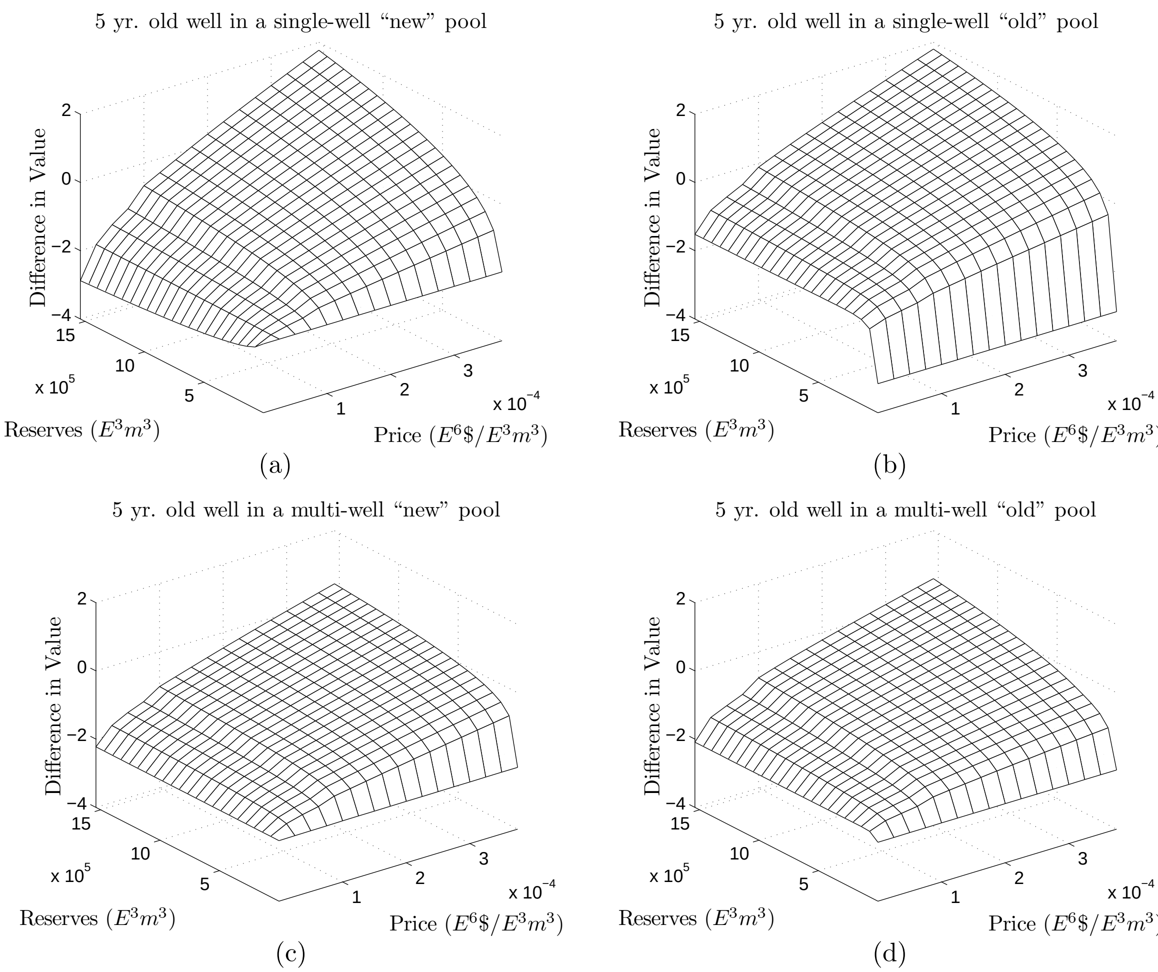


Figure 23: Difference between value of activating and leaving inactive a 5 year old inactive gas well in PSAC area 3 cluster 2 (in multi-well "new"(post-1974) pools and "old"(pre-1974) pools)

why multi-well "old" pools are valued less. At a certain price, the value of the well increases more than at other prices. This nonuniform increase is not present when the producer is myopic and the discount factor β is equal to zero. The value of the well under any choice includes the probability of the making the choice and the expected discounted profit from this choice. And so even the value of leaving the well inactive includes the probability of reactivation in the next period. Then at a price that it is profitable to extract, the probability of reactivation is higher and the increase in the value of the well is larger. This also explains why the value function of leaving the well idle is flatter than reactivating it. If left idle then the only reason that higher prices and higher reserves will increase the value of the well is because of the probability of reactivating in the future.

Each of the well groups has a threshold price and reserve size that above which the value of reactivating the well is greater than leaving it idle, and below which is less than leaving it idle. The difference in the value of reactivating the well and leaving the well inactive is presented in Figures 23. The threshold price is higher for multi-well pools than single-well pools which is expected.

There is an unknown location parameter that could be shifting the value of a well up or down without changing the choice probabilities. Therefore the estimated value of a given well cannot be interpreted immediately as the true value. However, the shape of the value function and the relationship between the values of different states remains the same.

8.2 Determining When to Cluster

The well groups are broken down into clusters depending on the time invariants (for gas: depth, initial pressure and density and for oil: initial pressure water saturation, temperature and depth [30]). The model was estimated with and without clustering so that a likelihood ratio test could be used to determine whether they should be clustered or not. This was done for each well group and the results for whether the groups were clustered or not can be found in the Appendix Table 19. A more detailed look is shown for PSAC Area 3 gas wells, where clustering improves the likelihood such that the null hypothesis that the group is homogenous and should not be clustered is rejected (Table 18).

Table 18: To Cluster or Not to Cluster: Example Using PSAC Area 3 Gas Wells

Parameter	Cluster 1	Cluster 2	Cluster 1 & 2	Likelihood Ratio	Marg. Sig.
θ_1 (C)	0.0816 (0.0305)	0.1590 (0.0772)	0.0559 (0.0194)		
θ_2 (C)	0.0002 (0.0001)	1.656e-7(9.259e-10)	8.358e-6(1.213e-5)		
θ_3 (C)	0.0035 (0.0139)	0.2686 (0.0015)	0.1042 (0.0514)		
θ_4 (M_1)	-1.9646 (0.0627)	-1.6408 (0.2787)	-1.4412 (0.0377)		
θ_5 (M_1)	-0.0086 (0.0019)	-0.0004 (0.0064)	-0.0100 (0.0025)		
θ_6 (M_2)	-0.6089 (0.0235)	-0.6454 (0.0941)	-1.2805 (0.0236)		
θ_7 $(SC_{(1\to 2)})$	1.5024 (0.0255)	1.8260 (0.8382)	6.0158 (0.0721)		
θ_8 $(SC_{(2\to 1)})$	3.1372 (0.0911)	3.2001 (0.9059)	-8.2566 (0.1919)		
θ_9 $(SC_{(2\to 1)})$	0.0172 (0.0020)	0.0143 (0.0080)	-0.6414 (0.0126)		
No. Obs.	12944	703	13647		
LL_2	3110.9449	162.3341	3306.1562	65.7541	5.551e-16

Notes: These results are for determining whether wells in a multi-well "old" pool in PSAC area 3 should be further broken down into clusters. Standard errors are in parentheses (asymptotic standard errors from the partial likelihood). The likelihood ratio test is performed for all well groups. Parameters refer to cost specification 7.

[30] PSAC area 3 oil wells' best results came when clustering was only done on water saturation, and PSAC 4 only clustering was on initial pressure

Table 19: Actual versus Predicted Choice Probabilities for All Well Types

Fluid	PSAC Area	Single Well	Royalty Regime	Cluster	No. Obs.	Obsv. Pr(Act)	Exp. Pr(Act)	Obsv. Pr(Inact)	Exp. Pr(Inact)
Oil	3	No	Third	1	737	0.6825	0.6833	0.3080	0.3071
Oil	3	No	Third	2	7537	0.7080	0.7081	0.2858	0.2856
Oil	5	No	Third	1	1686	0.6489	0.6474	0.3422	0.3432
Oil	5	No	Third	2	801	0.6417	0.6416	0.3483	0.3484
Oil	4	No	New	1	7550	0.5234	0.5228	0.4581	0.4586
Oil	4	No	New	2	14219	0.5580	0.5578	0.4281	0.4283
Oil	3	No	Old	1	15065	0.6188	0.6188	0.3708	0.3708
Oil	3	No	Old	2	1765	0.5904	0.5901	0.4045	0.4048
Oil	4	No	Old	1	14358	0.6502	0.6495	0.3375	0.3382
Oil	4	No	Old	2	5327	0.5016	0.4618	0.4701	0.4820
Oil	5	No	Old	1	6668	0.5195	0.5195	0.4741	0.4740
Oil	5	No	Old	2	3817	0.5512	0.4839	0.4299	0.4443
Oil	7	No	Old	1	1606	0.6239	0.6235	0.3667	0.3672
Oil	7	No	Old	2	1847	0.5116	0.5111	0.4808	0.4814
Oil	4	Yes	Third	1	175	0.6571	0.6631	0.3257	0.3204
Oil	4	Yes	Third	2	529	0.6200	0.6198	0.3743	0.3745
Oil	5	Yes	Third	1	611	0.7185	0.7176	0.2717	0.2725
Oil	5	Yes	Third	2	390	0.7487	0.7496	0.2462	0.2453
Oil	2	Yes	New	1	408	0.8358	0.8354	0.1642	0.1646
Oil	2	Yes	New	2	564	0.8085	0.8016	0.1897	0.1894
Oil	3	Yes	New	1	528	0.8163	0.8157	0.1837	0.1843
Oil	3	Yes	New	2	349	0.8768	0.8748	0.1146	0.1165
Oil	4	Yes	New	1	77	0.6494	0.6241	0.3506	0.3733
Oil	4	Yes	New	2	123	0.6341	0.6351	0.3659	0.3649
Oil	3	Yes	Old	1	53	0.6792	0.5533	0.3208	0.3724
Oil	3	Yes	Old	2	52	0.6538	0.6552	0.3462	0.3448
Oil	5	Yes	Old	1	59	0.9322	0.9352	0.0678	0.0648
Oil	5	Yes	Old	2	87	0.6667	0.5679	0.3333	0.3509
Oil	1	No	Third	No	48	0.8125	0.8105	0.1875	0.1895
Oil	2	No	Third	No	1965	0.7746	0.7732	0.2178	0.2185
Oil	4	No	Third	No	6102	0.6188	0.6187	0.3704	0.3705
Oil	6	No	Third	No	15	0.4000	0.3982	0.6000	0.6018
Oil	7	No	Third	No	3395	0.7137	0.7138	0.2786	0.2785
Oil	2	No	New	No	3107	0.6112	0.6102	0.3833	0.3843
Oil	3	No	New	No	18677	0.6510	0.6509	0.3399	0.3400
Oil	5	No	New	No	6847	0.5772	0.5770	0.4082	0.4084
Oil	6	No	New	No	17	0.6471	0.6471	0.2941	0.2941
Oil	7	No	New	No	9057	0.6226	0.6223	0.3646	0.3647
Oil	1	No	Old	No	36	0	0	1	1
Oil	2	No	Old	No	4152	0.6197	0.6195	0.3719	0.3720
Oil	1	Yes	Third	No	30	0.6000	0.6088	0.4000	0.3910
Oil	2	Yes	Third	No	1292	0.7763	0.7714	0.2206	0.2236
Oil	3	Yes	Third	No	2068	0.7742	0.7739	0.2200	0.2203
Oil	6	Yes	Third	No	6	0.5000	0.5070	0.5000	0.4930
Oil	7	Yes	Third	No	3025	0.6846	0.6842	0.3107	0.3112
Oil	1	Yes	New	No	8	1	0.8750	0	0.1250
Oil	5	Yes	New	No	695	0.7698	0.7697	0.2273	0.2274
Oil	7	Yes	New	No	1608	0.7009	0.5969	0.2954	0.3256

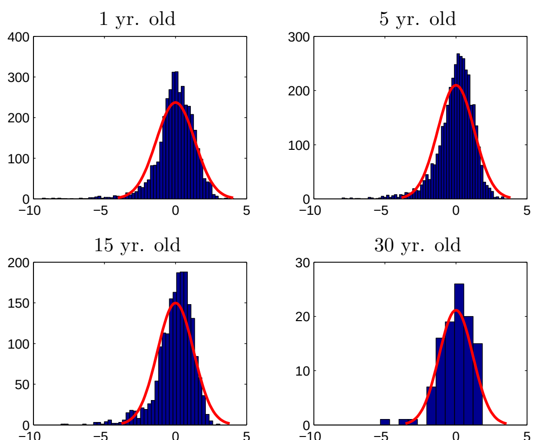
Continued on Next Page. . .

Table 19 – Continued

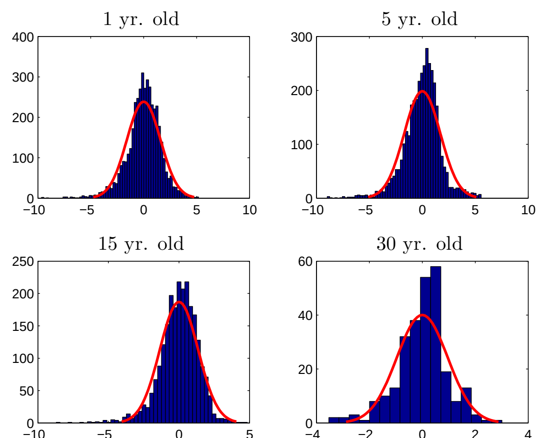
Fluid	PSAC	Single Well	Royalty	Cluster	No. Obs.	Obsv. Pr(Act)	Exp. Pr(Act)	Obsv. Pr(Inact)	Exp. Pr(Inact)
Oil	2	Yes	Old	No	177	0.6893	0.6897	0.3107	0.3103
Oil	4	Yes	Old	No	36	0.5278	0.4315	0.4722	0.5047
Oil	7	Yes	Old	No	543	0.5285	0.5282	0.4696	0.4701
Gas	3	No	New	1	13842	0.7586	0.7575	0.2331	0.2340
Gas	3	No	New	2	522	0.7759	0.7754	0.2222	0.2227
Gas	4	No	New	1	5445	0.6505	0.6518	0.3412	0.3400
Gas	4	No	New	2	1286	0.5086	0.5086	0.4798	0.4797
Gas	5	No	New	1	414	0.6739	0.6748	0.3116	0.3109
Gas	5	No	New	2	9440	0.6238	0.6249	0.3603	0.3594
Gas	7	No	New	1	13704	0.6822	0.6826	0.3049	0.3046
Gas	7	No	New	2	3492	0.7033	0.7082	0.2878	0.2836
Gas	2	No	Old	1	4254	0.6718	0.6749	0.3209	0.3182
Gas	2	No	Old	2	5424	0.7000	0.7035	0.2933	0.2908
Gas	3	No	Old	1	12944	0.7451	0.7440	0.2458	0.2467
Gas	3	No	Old	2	703	0.6714	0.6731	0.3186	0.3177
Gas	5	No	Old	1	5649	0.4780	0.4783	0.5151	0.5148
Gas	5	No	Old	2	6353	0.5649	0.5657	0.4140	0.4133
Gas	7	No	Old	1	3605	0.6413	0.6419	0.3420	0.3415
Gas	7	No	Old	2	5964	0.5867	0.5864	0.4079	0.4083
Gas	7	Yes	New	1	5997	0.6797	0.6805	0.3148	0.3141
Gas	7	Yes	New	2	1042	0.6727	0.6734	0.3225	0.3217
Gas	1	No	New	No	432	0.7824	0.7819	0.2106	0.2111
Gas	2	No	New	No	9569	0.7452	0.7451	0.2512	0.2515
Gas	6	No	New	No	11595	0.6091	0.6097	0.3746	0.3740
Gas	1	No	Old	No	3095	0.6847	0.6876	0.3073	0.3052
Gas	4	No	Old	No	10870	0.7454	0.7456	0.2468	0.2466
Gas	6	No	Old	No	3111	0.5188	0.5205	0.4455	0.4442
Gas	1	Yes	New	No	491	0.8921	0.8876	0.1079	0.1123
Gas	2	Yes	New	No	8527	0.8335	0.8342	0.1637	0.1631
Gas	3	Yes	New	No	12167	0.7805	0.7810	0.2145	0.2141
Gas	4	Yes	New	No	5539	0.7111	0.7116	0.2827	0.2824
Gas	5	Yes	New	No	11848	0.7091	0.7102	0.2830	0.2821
Gas	6	Yes	New	No	5717	0.6411	0.6414	0.3490	0.3488
Gas	1	Yes	Old	No	31	0.8387	0.8384	0.1613	0.1561
Gas	2	Yes	Old	No	371	0.7197	0.7167	0.2803	0.2822
Gas	3	Yes	Old	No	961	0.6691	0.6734	0.3247	0.3241
Gas	4	Yes	Old	No	302	0.6755	0.6768	0.3013	0.3009
Gas	5	Yes	Old	No	973	0.6023	0.6051	0.3864	0.3839
Gas	6	Yes	Old	No	187	0.5668	0.5677	0.4171	0.4165
Gas	7	Yes	Old	No	408	0.3873	0.3885	0.6005	0.5994

8.3 Regression of Production

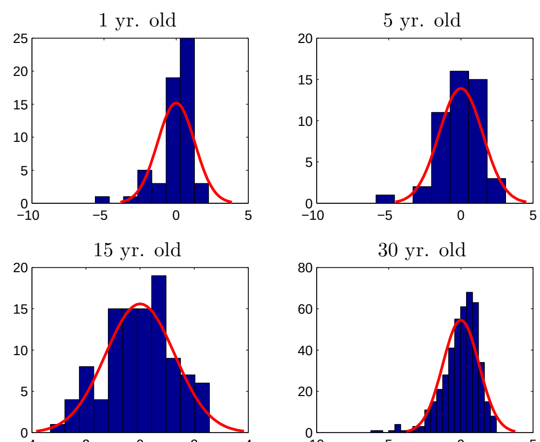
The Kolmogorov-Smirnov test rejects the null hypothesis that the residuals from equation (8) have a standard normal distribution 66% of the time (there were 352 of these regressions, and an example of 16 are found in Figure 24).



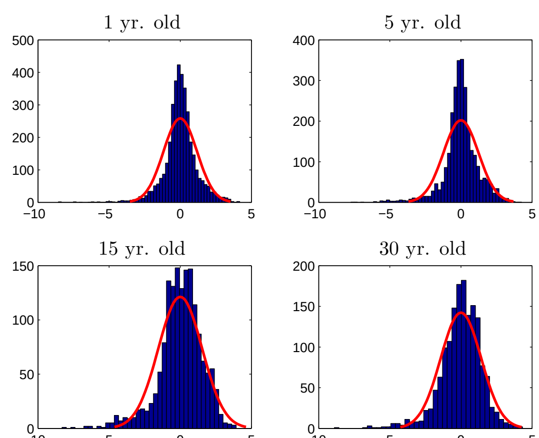
(a) "new" gas PSAC 3 single-well



(b) "new" gas PSAC 3 multi-well



(c) "old" gas PSAC 3 single-well



(d) "new" gas PSAC 3 multi-well

Figure 24: Examples of the Distribution of the Residuals from Equation (8)

8.4 Monte Carlo Experiment

A Monte Carlo experiment is used in order to test whether the program will be able to estimate the structural parameters. This is an important test to determine whether the program can indeed find the parameters that it is designed to. I only test the ability of the program to estimate the parameters in the second stage of the partial likelihood. The parameters from the first stage are set at estimates from a well group (specifically, well group PSAC area 3 cluster 1 on a multi-well "new" pool). I choose a value for each of the costs to be the "real" costs that I want to recover. Using the "real" parameters, an artificial dataset is generated that contains no more information than what we are faced with (that is, a dataset that only contains information on the decision made and the current state). An observation consists of price, remaining reserves, age, the endogenous state variable (current operating state), and what decision was made for the future operating state. To generate the Monte Carlo sample for a given well three state variables (price, reserve size, age and current operating state) are randomly drawn from a distribution similar to that of the real data. The observation of the decision is created by first solving the inner fixed point for $v_\theta(P, Q, s, d)$, given the "real" parameters. Then the probability of choosing an action is obtained by equation (4). A uniformly distributed pseudo-random number is drawn and depending on where it falls in intervals dictated by the probabilities calculated from equation (4) I assign a decision to the data point. This is done for a dataset of 10,000 observations. The nested fixed point algorithm is able to back out the "real" parameters from the simulated dataset closely, even

Table 20: Estimates from the Monte Carlo Experiment

Variable	"Real" Parameter	Estimated Parameter	Standard Error	Starting Value	Lower Bound	Upper Bound
θ_1 (C)	0.012	0.0135	(0.0018)	0.001	0	1
θ_2 (C)	1.2e-4	1.1641e-4	(5.3e-006)	1e-007	0	0.01
θ_3 (C)	0.12	0.1209	(0.0044)	0.01	0	1
θ_4 (M_1)	0.12	0.1288	(0.0286)	0.01	-16	16
θ_5 (M_1)	0.12	0.1137	(0.0109)	0.01	-1	1
θ_6 (M_2)	0.12	0.1093	(0.0158)	0.01	-16	16
θ_7 $(SC_{(1\to 2)})$	0.12	0.1120	(0.0395)	0.01	-16	16
θ_8 $(SC_{(2\to 1)})$	1.2	1.0435	(0.0747)	0.01	-16	16
θ_9 $(SC_{(2\to 1)})$	0.12	0.1539	(0.0189)	0.01	-1	1

Notes: Parameters refer to cost specification 7. A sample size of 10,000. Stopping tolerance for the Newton-Kantorovich iteration in the inner loop was set at 10^{-14}.

when the starting point is far from the solution (Table 20).

8.5 Glossary of Industry Terms

Bridge Plug A downhole tool that is located and set to isolate the lower part of the wellbore. Bridge plugs may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone.[a]

Cap a well installing and closing a valve on the wellhead.[a]

Casing Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluid, and providing a means of maintaining control of formation fluids and pressure as the well is drilled.[a]

Cement plug A portion of cement placed at some point in the wellbore to seal it. [d]

Coiled Tubing Coiled tubing enables fluids to be pumped at any time regardless of the position or direction of travel. This is a significant advantage in many applications. Installing an electrical conductor or hydraulic conduit further enhances the capability of a coiled tubing string and enables relatively complex intervention techniques to be applied safely.[a]

Crude Oil (Conventional) A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds and is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen.[b]

Crude Oil (Heavy) Crude oil is deemed to be heavy crude oil if it has a density of 900 kg/m3 or greater. [b]

Crossflow A condition that exists when two production zones with dissimilar pressure characteristics are allowed to communicate during production. Reservoir fluid from the high-pressure zone will flow preferentially to the low-pressure zone rather than up the production conduit unless the production parameters are closely controlled.[a]

Cumulative Production The sum of production volumes from all prior years.[b]

Cyclic Steam Stimulation A method of thermal recovery in which a well is injected with steam and then subsequently put back on production. A cyclic steam-injection process includes three stages. The first stage is injection, during which a slug of steam is introduced into the reservoir. The second stage, or soak phase, requires that the well be shut in for several days to allow uniform heat distribution to thin the oil. Finally, during the third stage, the thinned oil is produced through the same well. The cycle is repeated as long as oil production is profitable.[a]

Density The mass or amount of matter per unit volume.[b]

Discovery Year The year when drilling was completed of the well in which the oil or gas pool was discovered.[b]

Enhanced Recovery Method The third stage of hydrocarbon production during which sophisticated techniques that alter the original properties of the oil are used. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.[a]

Established Reserves Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.[b]

Extraction The process of liberating hydrocarbons (propane, bitumen) from their source (raw gas, mined oil sands).[b]

Field The geographically defined area on which wells are drilled.[b]

Formations The fundamental unit of lithostratigraphy. A body of rock that is sufficiently distinctive and continuous that it can be mapped.[a]

Gas Raw gas, marketable gas, or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and is gaseous at the conditions under which its volume is measured or estimated.[b]

Horizontal Well A subset of the more general term "directional drilling", used where the departure of the wellbore from vertical exceeds about 80 degrees. Because a horizontal well typically penetrates a greater length of the reservoir, it can offer significant production improvement over a vertical well.[a]

Hydraulic Pumping An artificial-lift system that operates using a downhole pump. A surface hydraulic pump pressurizes crude oil called power oil, which drives the bottom pump.[a]

Initial Established Reserves Established reserves prior to the deduction of any production.[b]

Initial Oil or Gas in Place Estimated volume of oil or gas in place before any extraction, and can be updated every year.[b]

Initial Pressure The reservoir pressure at the reference elevation of a pool upon discovery.[b]

Non-confidential pool when the one-year confidential status of the initial well has expired; 5 or more wells are cased for production; in the case of a gas pool, gas has been produced, gathered and marketed; or the ERCB has designated it non-confidential on application by the licensees.[c]

Packer A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. Packers employ flexible, elastomeric elements that expand.[a]

Plunger Lift An artificial-lift method principally used in gas wells to unload relatively small volumes of liquid. An automated system mounted on the wellhead controls the well on an intermittent flow regime. When the well is shut-in, a plunger is dropped down the production string. When the control system opens the well for production, the plunger and a column of fluid are carried up the tubing string. The surface receiving mechanism detects the plunger when it arrives at surface and, through the control system, prepares for the next cycle.[a]

Pool A subsurface oil accumulation. An oil field can consist of one or more oil pools or distinct reservoirs within a single large trap.[a] A pool is the porous and permeable rock formation that contains hydrocarbon, confined within impermeable rock or water.[b]

Porosity The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.[b]

Progressive Cavity Pump A type of a sucker rod-pumping unit that uses a rotor and a stator. The rotation of the rods by means of an electric motor at the surface causes the fluid contained in a cavity to flow upward.[a]

Recovery Factor The fraction of the oil or gas in place that can be extracted under current technology and present and anticipated economic conditions.[b]

Remaining Established Reserves The initial established reserves less cumulative production and surface loss.[b]

Saturation (Water) The fraction of pore space in the reservoir rock occupied by water upon discovery.[b]

Sour Gas A gas containing hydrogen sulfide, carbon dioxide or mercaptans, all of which are extremely harmful.[a]

Sucker Rod Pumping An artificial-lift pumping system using a surface power source to drive a downhole pump assembly. A beam and crank assembly creates reciprocating motion in a sucker-rod string that connects to the downhole pump assembly. The pump contains a plunger and valve assembly to convert the reciprocating motion to vertical fluid movement. [a]

Surface Loss A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons and is used as lease or plant fuel or is flared.[b]

Temperature The initial reservoir temperature upon discovery at the reference elevation of a pool.[b]

Wellbore The borehole, including the openhole or uncased portion of the well.[a]

Zone Any stratum or sequence of strata that is designated by the ERCB as a zone.[b]

Source:

[a] Schlumberger Oilfield Glossary (online), 2009 Schlumberger Limited (http://www.glossary.oilfield.slb.com/default.cfm)

[b] Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008-2017, ERCB [2008]

[c] Oil and Gas Conservation Regulations, Part 12.150(1) OGCR [2000]

[d] U.S. Department of Labor Occupational Safety & Health Administration Oil and Gas Well Drilling and Servicing eTool Glossary of Terms.

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