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7 Economic and Financial Determinants of Oil and Gas Exploration Activity

Peter C. Reiss

7.1 Introduction

In 1981, domestic oil companies spent a record $55.7 billion exploring for and developing oil and gas reserves in the United States. In 1986, they spent less than one-half that amount, a six-year low of $26.6 billion. This $29.1 billion drop in capital spending is impressive by any standard. It was more than one-half of domestic corporate R&D spending in 1986 and more than 10% of net corporate additions to new plant and equipment. Many factors contributed to this precipitous decline in exploration and development expenditures. From 1978 to 1981, world events such as the Iran-Iraq war and increased cooperation within OPEC caused the average domestic price of oil to jump from $8 to over $35 per barrel. As world oil prices rose, so did domestic exploration: large onshore and offshore projects were planned and undertaken; previously uneconomic leases became the object of renewed drilling efforts; and many firms began to experiment with expensive new drilling and completion techniques.

During the latter half of 1981 and early 1982, oil prices softened. While some oil companies cut back on their exploration and development efforts, most firms and analysts remained optimistic. Many firms, for example, continued to issue new shares and long-term debt to finance additional increases in their exploration and development activities. By 1986, however, spot prices for West Texas intermediate crude had fallen below $10 per barrel. As revenues fell and debt burdens increased, firms cut back on exploration and devel-

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opment. These cutbacks had a pronounced effect not only on the oil and gas industry but also on economic and financial activity in a number of oil-producing states. Hardest hit were Texas, Louisiana, Oklahoma, Kansas, Colorado, and Alaska.

Gyrations in natural gas prices also contributed to the dramatic swing in domestic exploration and development activity. From 1978 to 1983, prices for newly found gas rose from less than $1.00 to over $2.70 per mcf (thousand cubic feet). Part of this increase occurred because of natural gas price and pipeline deregulation; part occurred because of end-user substitution from oil to natural gas. A series of mild winters in the northern United States in the mid-1980s stopped the upward trend in gas prices. By December 1986, a severe gas glut had dropped the price of newly found natural gas from $2.70 to under $1.65 per mcf.

These unprecedented oscillations in energy prices provide economists with a unique opportunity to compare alternative models of investment. In particular, because investment costs and returns changed at different rates, one can assess separately the effects of each on investment spending. Further, because the escalation and decline in prices was so rapid, one can examine whether a firm's liquidity position affects its investment spending plans. Although several empirical studies have concluded that financial liquidity plays a role in firms' investment decisions, relatively few of these studies have had data covering periods in which the demand for external investment capital was known to have changed.[1]

The structure of the oil and gas industry also provides economists with a unique opportunity to study the inputs and outputs of investment projects. Accounting standards in this industry require firms to release detailed information on their capital structures and investment spending. These data contain not only different measures of the returns to investment but also detailed information on firms' finances. In addition, the oil and gas industry provides a useful reference industry for evaluating the predictions of theoretical investment models. It has price-taking firms, each producing a relatively homogeneous good. Most of these firms use the same exploration and production technologies. They also use the same input markets. Thus, in contrast to investment studies that have samples of diversified firms with different production technologies, here we can hold constant many technological differences that affect the returns to investment.

The next section provides background information on the oil and gas industry. It describes the exploration and development process. It also provides information on the costs of exploration and development projects. Section 7.3 builds a model of exploration and development. This model resembles conventional investment models, but also includes specific features of the oil and gas exploration process. The latter part of Section 7.3 estimates the parameters of this exploration model using annual data from 1978 to 1986 on the operations of 44 independent oil and gas firms. In addition to finding that firms face constant returns to scale in exploration, we find that liquidity variables explain some of the major changes in investment activity during this period. Section 7.4 considers ways in which firms' financial positions may affect their investment decisions by relating the structure of financial contracts to informational asymmetries between producers and outside equity or bond holders. It appears that when a firm's reserve collateral falls significantly (as was the case with the general deflation in oil and gas prices), financial contracts often limit discretionary investment spending. These contract provisions point to general difficulties that outside investors have in evaluating oil and gas firms' requests for, and uses of, external financial capital. Outside investors recognize that, as a firm's financial position deteriorates, the firm's opportunity cost of internal capital rises relative to that of external capital. In addition, as the probability of bankruptcy increases, the firm has incentives to take greater risks with outside capital. Investors recognize this problem and include clauses in their financial contracts that place restrictions on firms' discretionary investment. These contracts create a link between a firm's liquidity position and its investment decisions, but only during periods of firm or industry distress.

7.2 Background on Oil and Gas Exploration

7.1.1 Exploration versus Development

Oil and gas firms divide their exploration and development capital expenditures into three categories: exploration, development, and property acquisition. Of the $30 billion oil and gas firms spent on capital outlays in 1986, approximately 37% went for exploration and 59% went for development investment. Firms spent most of the remaining portion acquiring undeveloped oil and gas properties.

The division of oil and gas capital spending into exploration and development parallels the distinction drawn in manufacturing between "research" and "development." Exploratory, or "wildcat," drilling takes place on unexplored land or at unexplored depths. In addition to drilling expenses, exploration expenditures include those for basic and applied geologic research (e.g., seismic testing). For a typically exploratory well, firms spend anywhere from several hundred thousand to several million dollars. Table 7.1 summarizes trends in domestic exploratory drilling activity and expenses during the years 1978–86. In 1985, 12,208 exploratory wells were completed in the United States. Most of these wells were drilled in Texas (4,174) and Kansas (1,503). Of the roughly 12,000 exploratory wells drilled, very few uncovered large amounts of oil or gas. Indeed, from 1978 to 1986 only about one in four exploratory wells yielded commercial quantities of oil and gas.

Development takes place on properties proven to contain oil or gas. Development drilling usually involves locating a series of wells that "step out" from

Table 7.1 **U.S. Oil Industry Statistics, 1978–1986**

A. Prices

Year	Average U.S. Oil Price: $ per Barrel	Average U.S. Oil Price: 1967 $ per Barrel	Average U.S. Gas Price: $ per MCF	Average U.S. Gas Price: 1967 $ per MCF	U.S. Finding Cost ($ per BOE)
1978	8.96	4.28	.91	.43	6.64
1979	12.51	5.31	1.18	.50	11.74
1980	21.59	8.03	1.59	.59	10.66
1981	31.77	10.83	1.98	.68	12.17
1982	28.52	9.53	2.46	.82	11.57
1983	26.18	8.64	2.59	.86	9.24
1984	25.88	8.34	2.66	.86	6.61
1985	24.09	7.80	2.51	.81	8.76
1986	12.66	4.21	1.87	.62	6.96*

B. U.S. Exploration and Development

Year	Development Expenditures[a]	Exploration Expenditures[a]	Oil Reserve Revisions + Additions[b]	Exploratory Wells Completed	Exploratory Dry Holes	Success Rate (%)
1978	11.0	9.4	2.58	11,030	8,055	.270
1979	17.3	15.6	1.41	10,375	7,479	.303
1980	19.6	20.8	2.97	12,870	9,008	.300
1981	25.0	30.7	2.57	17,430	12,247	.297
1982	25.9	27.9	1.38	15,882	11,229	.293
1983	25.2	21.1	2.90	13,845	10,062	.273
1984	26.6	21.5	3.75	15,138	11,216	.259
1985	27.2	16.4	3.02	12,208	9,201	.246
1986	16.4*	8.5*	N.A.	7,192	5,469	.240

C. U.S. Drilling Statistics

Year	Total Drilling Costs[a]	Average Drilling Cost per Well[c]	Total U.S. Lease Acreage[d]	Active Drilling Rigs
1978	13.1	280	431	2,255
1979	16.1	331	449	2,176
1980	22.8	368	473	2,910
1981	36.7	454	513	3,970
1982	39.4	514	539	3,105
1983	25.1	372	586	2,229
1984	25.2	326	588	2,428
1985	23.7	417	N.A.	1,969
1986	13.6*	366*	N.A.	964

Sources: Oil and Gas Journal Database, Oil Industry Comparative Appraisals, Basic Petroleum Data Book, and *Oil and Gas Reserve Disclosures.*
Notes: A * denotes author's calculations. N.A. means not available.
[a]In billions of dollars.
[b]In billions of barrels.
[c]In thousands of dollars
[d]In millions of acres.

the initial exploratory play or find. Firms also drill development wells to improve the recovery of oil from nearby wells. Development expenditures include those for drilling and completion; they exclude expenses associated with the actual pumping or transportation of oil and gas. Development wells generally cost less than exploratory wells and have a much higher probability of success. During 1986, roughly 32,000 development wells were completed in the United States, about 4.5 development wells for each exploratory well. Table 7.1 also contains information on U.S. development spending.

7.1.2 Firms

Three types of firms explore for oil and gas: major, diversified, and independent companies. Major companies rank among the top 10–15 firms in the industry (e.g., Exxon, Texaco, and Mobil). These firms participate in all segments of the petroleum market: exploration, production, transportation, refining, and marketing. They usually conduct their exploration activities with large staffs of geologists and drilling experts. They also own their own drilling equipment. Diversified companies are somewhat smaller than the majors. They too participate in most segments of the petroleum industry; they, however, typically have a much smaller fraction of their operations in oil and gas (e.g., Pacific Lighting and Union Pacific). Independent oil and gas firms, or "operators," are smaller firms. They tend to concentrate their operations mainly in oil and gas exploration and production. These firms range in size from several-person "firms" (e.g., Willard Pease Oil Co. and Bronco Oil and Gas) to large producing firms (such as Adobe Oil and Gas and Dyco Petroleum). Independent operators mainly explore and develop onshore properties. They also tend to emphasize natural gas exploration over oil exploration (Arthur Andersen 1986).

7.1.3 The Exploration Process and Well Costs

U.S. oil companies currently explore for oil and gas in 41 states. While most companies have operations in several states, independent operators often concentrate their drilling in specific geologic horizons. Other than the major companies, relatively few domestic firms operate overseas; many diversified companies do, however, operate in Canada.

Exploration for oil and gas typically proceeds in one of two ways. Large firms use their in-house staff and public and private geologic data bases to identify prospects. Smaller firms typically rely on independent geologists and lease brokers. Most companies spend considerable amounts on research, seismic testing, and leases before drilling. Frequently, companies also lease large blocks of land surrounding potential prospects. This latter practice mitigates common pool problems and preempts other operators from free riding on a firm's success. Block leasing can, however, be costly. Roberts Oil and Gas provides a typical, although by no means unusual, example. In 1982, Roberts Oil and Gas earned $640,000 in oil and gas revenues from wells on

1,719 (net) acres of developed leasehold property. At the same time, Roberts held over 17,193 (net) acres of undeveloped leasehold property, much of which was never developed.

Oil and gas leases have quite elaborate and curious contractual provisions. These provisions respond to informational asymmetries and incentive problems between the lessee and the lessor. In general, private mineral leases grant the holder drilling and subterranean development rights for a fixed number of years.[2] In return, the landowner usually receives a per acre fee and a production bonus, termed a *royalty interest*. Operators commonly grant landowners a one-eighth (12.5%) royalty interest in the gross revenue generated by wells on their property. In some states, such as California, royalties may run as high as one-sixth. Some lease contracts also involve third parties who put together the deal, such as geologists or lease brokers. These dealmakers receive, without cost, an *override royalty*. Occasionally, an operator may also reserve an override royalty for its employees or shareholders. Override royalties may amount to between 1/32 and 1/16 of gross revenues.

In a standard lease agreement, the operator incurs all drilling and production costs—the so-called *working* or *operating interest* in the well.[3] In return for assuming all costs, the operator receives the remaining revenue streams from the well—that is, all gross revenues net of the front-end load from royalty payments. Operators term the remaining interest the *net revenue interest*.[4] To finance the working interest, the operator must often line up substantial financial capital in advance. This capital covers the front-end costs associated with drilling and completing a well. The operator's front-end costs differ by well type, location, and initial tests. All wells have substantial variable drilling and test costs; only successful wells incur completion costs. Accountants define drilling costs as all costs incurred to the "casing point"—the stage at which the operator lines the walls of the well with special pipe. Major drilling expenses consist of intangibles such as site preparation (5%–15%), drilling contract work (45%–55%), logging and testing (5%–10%), consultant fees (5%), and contingencies, damages, and survey work. Tangible costs include drilling mud, water, and chemicals (5%–15%), and permits, miscellaneous equipment, piping, and the casing head (1%–15%).[5]

Exploratory wells have greater sunk set-up costs. These sunk costs include those for lease inspection, drilling platforms, geophysical research, and site development. Development wells offer more opportunities for spreading costs, as suggested in their names: "offsets," "work-overs," "secondary extension," and "stepouts." Well costs differ across development wells for a variety of reasons, including depth, location, the availability of inputs (e.g., water and drilling mud), climate, and chance.[6] Table 7.1 summarizes average well costs. In 1984, the average well cost about $326,000 and the average cost per foot was about $75.

To complete a successful well, firms must test, line, perforate, and stimulate the well.[7] Depending on the drilling process used and the well test results, completion costs can double or triple the cost of a well. For example, according to a recent issue of the *Oil and Gas Investor,* Donald Slawson, an independent operator, recently developed several 8,000-foot wildcat wells in the Wyoming Powder River basin. Each well cost about $150,000 to drill. Completion costs on the successful wells were an additional $225,000 per well. In contrast, Foreland Company drilled similar 7,500–8,500-foot wildcat wells in tighter formations in eastern Nevada. Foreland's drilling costs averaged $700,000 per well. Completion costs were an additional $600,000 per well (Daviss 1987, 29–31).

The above examples of the capital required by an operator to drill and complete a successful well do not factor in an important element of cost—the probability of success. Dry holes account for a majority of all well expenditures. According to table 7.1, the average exploratory well is successful one out of four or five tries. If these attempts were independent, then the expected cost of a successful exploratory well would range from between one to $2 million. (This does not include the additional costs of abandoning wells or of complying with environmental regulations.) Thus, operators require substantial financial capital to obtain a successful well.

7.3 An Empirical Model of Exploration and Development Investment

Having described the costs associated with exploration and development, we now model the investment process. This investment model describes how the returns to exploration and development vary with changes in input and output prices. It provides a baseline investment specification against which we can assess the effect of financial variables on investment decisions.

To reduce the complexity of the model, we assume that firms explore for and produce a single, homogeneous product, oil. This assumption parallels an industry convention that quotes volumes of natural gas and condensate in oil "equivalent barrels."[8] Firms explore for oil each period by drilling w_t^e and w_t^d exploratory and development wells. Each well costs a constant amount, p_t^e or p_t^d.[9] Drilling adds to a firm's existing stock of reserves R_t according to the discovery function $A_t = A(w_t, L_t, R_t, X_t)$, where L_t denotes other inputs required to produce reserves, such as undeveloped leaseholdings, and X_t represents a firm's cumulative discoveries as of date t. We include both the reserve stock and cumulative discoveries in $A(\cdot)$ to allow for vintage and learning effects in the discovery process. Although in principle firms could sell newly discovered reserves and not extract them, almost all firms choose to hold reserves. In this model, firms hold reserves for three reasons. First, larger inventories reduce firms' extraction costs. We include this effect by assuming that total production (extraction) costs, $C(q_t, R_t)$, have the property that $C_{R_t} = \partial C(q_t, R_t)/\partial R_t < 0$. Second, larger inventories improve the chances of recovering significant reserves through secondary or tertiary drilling. Third, increases in the level of reserves increase the productivity of exploration and development through learning (here represented by X_t).

Given these technological specifications, we assume firms maximize profits by choosing their drilling and extraction policies over a finite lifetime T. Formally, firms maximize

$$\max_{\{q_t, w_t\}} \sum_{t=0}^{T} [P_t q_t - C(q_t, R_t) - D(w_t)]\rho^t,$$

subject to

$$X_{t+1} - X_t = A(w_t, L_t, R_t, X_t),$$
$$R_{t+1} - R_t = A(w_t, L_t, R_t, X_t) - q_t,$$

with R_0 and X_0 given, and R_t, q_t, w_t, and P_t greater than zero for all T periods. This formulation presumes firms discount profits at a constant rate ρ and it ignores uncertainty. Reiss (1989) has derived conditions on the functions $A(\cdot)$ and $C(\cdot)$ that relate the solutions of this problem to those in a model where discoveries occur randomly.

Solving this problem for the optimal production and exploration policies yields the following first-order necessary conditions for an interior optimum:

$$(1) \qquad P_t - C_{q_t}(q_t, R_t) = \rho\lambda_{t+1},$$

and

$$(2) \qquad -\frac{\partial D(w_t)}{\partial w_t} + \rho \frac{\partial A(w_t, L_t, R_t, X_t)}{\partial w_t} (\lambda_{t+1} + \theta_{t+1}) = 0.$$

In these equations, λ_t represents the shadow value of reserves and θ_t the shadow value of cumulative discoveries.[10] The first equation states that in equilibrium the net price of oil taken out of the ground must equal the shadow price of an additional unit of reserves. To interpret the second equation, we divide through by $A_{w_t} = \partial A(w_t)/\partial w_t$ and substitute for λ_{t+1}, giving

$$(3) \qquad \mathrm{MDC}(A) = \frac{D_{w_t}}{A_{w_t}} = P_t - C_{q_t} + \rho\theta_{t+1}.$$

This equation relates the marginal discovery cost of a barrel of oil to the shadow value of an additional unit of reserves. (Recall that reserves serve both to lower future production costs and to increase the productivity of exploration). To relate exploration and development expenditures per addition to the discovery function input elasticities and the shadow value of reserves, we multiply both sides of this equatioan by $\alpha_w = A_{w_t} w_t / A$, giving

$$(4) \qquad FC_t = \frac{p_{w_t} w_t}{A_t} = \alpha_w [P_t - C_{q_t} + \rho\theta_{t+1}].$$

Industry analysts commonly use the left-hand side of this equation, a firm's finding cost, to evaluate the performance of oil company exploration programs. The right side of equation (4) measures the production value of an additional unit of (capital) reserves. Thus, equation (4) relates the market value of an additional unit of reserves to their current replacement cost. In essence, the variables in this investment equation look much like those in a "q" investment specification: the higher the market value of current additions, the greater the firm's incentive to invest.

When cumulative discoveries and reserves do not affect the productivity of exploration programs, the shadow price of past discoveries, θ_t, does not vary through time. In this particular case, equation (4) states that capital spending increases proportionately to net increases in the price of oil (holding additions and the input elasticity of the discovery function constant). When cumulative discoveries and reserves affect the productivity of exploration, then θ varies with time. Solving for these shadow prices and substituting them back into equation (4) gives an autoregressive equation for finding costs

$$(5) \qquad FC_t = \gamma FC_{t-1} + \tilde{\alpha}_w(P_t - C_{q_t}) - \frac{\tilde{\alpha}_w}{\rho}(P_{t-1} - C_{q_{t-1}}),$$

where $\tilde{\alpha}_w = \alpha_w/(1 - A_{x_t})$ and $\gamma = 1/[\rho(1-A_{x_t})]$. This equation shows that capital spending has an autoregressive component when cumulative discoveries affect the productivity of exploration.

The finding-cost equations (4) and (5) characterize how oil and gas firms' investment policies change as a function of output prices and the technology of exploration (as embodied in the input elasticity α_w). Although the analysis was framed in terms of a single input, w_t, we can aggregate finding-cost equations across inputs to form a single finding-cost equation. Of the theoretical constructs in these equations, we observe or can estimate all but the marginal production cost of oil and the shadow value of cumulative discoveries. The absence of data on firm's *marginal* finding costs makes it impossible to estimate equations (4) or (5) directly. If we assume that average finding costs equal marginal finding costs, then we can estimate either (4) or (5) using accounting measures of firm's average production or "lifting" costs. When firms have constant unit production costs, however, the first-order conditions of the model do not uniquely determine their production rate, q_t. As an alternative to using only accounting cost data, I approximated the marginal costs with a rational function that varies with output and reserves. Specifically, I used

$$C_{q_t}(q_t, R_t) = \phi_0 + \frac{\phi_1}{R_t} + \frac{\phi_2 q_t}{R_t}.$$

In this cost specification, the ϕ_i are unknown, constant parameters. Because the last term in this equation involves firm output, I used instrumental variables for specifications that include this term.

To estimate equations (4) and (5) as linear regressions, I assume that the discovery function has constant input elasticities. Following the discussion of exploration in the previous section, I assume that w contains four inputs: exploratory wells drilled (w_e), development wells drilled (w_d), proved developed leaseholdings (L_p), and undeveloped leaseholdings (L_u). These inputs generate reserves according to the constant elasticity discovery function

$$A = \alpha_0 w_e^{\alpha_e} w_d^{\alpha_d} L_u^{\alpha_u} L_p^{\alpha_p} \psi. \tag{6}$$

The parameters α_e, α_d, α_p, and α_u represent the factor input elasticities. Constant returns to scale in discovery hold when $\alpha_e + \alpha_d + \alpha_p + \alpha_u = 1$. The variable ψ represents random factors in the discovery process. I assume that these factors follow an independently distributed, lognormal (ln) random process, with $\ln\psi$ having a mean of zero and with a standard deviation σ.

Using the discovery equation (6) and either (4) or (5), we can jointly estimate the parameters of the discovery process and characteristics of firms' costs. This model provides a simple description of how capital investment for oil and gas firms changes with swings in oil and gas prices. It does not, however, consider how a firm finances its exploration and development investments. In practice, independent oil and gas firms invest heavily up front to drill; only much later do the wells produce significant revenues. The lag between the initial expenditure of investment capital and the sale of reserves varies considerably, but many industry sources place the average payback period of a successful well at between 5 to 10 years. Unless the firm has internal capital from previous successes, it frequently must borrow or sell equity to finance additional exploration. In a world with perfect capital markets and perfect monitoring, asymmetries in information among borrowers and lenders should not affect firms' investment decisions. Indeed in the above model, one would model "finance" by simply adding interest payments to exploration costs. In practice, however, lenders do not have perfect information about the riskiness of a firms' projects and the firm itself. In such a world, one would expect that lenders and equity holders would insist on contingent contracts that limited their financial exposure to bad drilling projects. If such contracts were enforceable, they would most likely affect a firms' investment spending when the firm runs into financial trouble. We return to this point below after we have discussed the empirical results of the standard exploration model.

7.3.1 The Sample of Firms and Variable Definitions

To examine the investment process for oil and gas firms, capital spending, reserve, and financial data were assembled for a sample of 44 independent oil and gas firms. The data begin in 1978 because of a revision of oil and gas reporting requirements.[11] They end in 1986 because of reporting lags. The sample of firms was chosen at random from the *Oil and Gas Journal*'s 1983 list of the top 400 oil and gas firms. Major and diversified companies were automatically excluded because of the geographic diversity of their operations. Independent firms were selected as follows. From the initial list of 400 firms, 70 firms were selected at random. Twelve independents were eliminated from consideration because they had substantial foreign operations. Another 14 were subsequently eliminated because of insufficient or unreliable data (e.g., accounting convention changes or their oil and gas operations were not summarized in sufficient detail). It is not surprising that the eliminated firms tended to be very small or very large. The remaining 44 independents have mostly U.S. operations (an average of 95% or more of their production must be in the United States during the sample period).[12]

Information on the operations of these companies was gathered from a variety of public and private sources, including: SEC 10K filings, annual reports, the *Oil and Gas Investor,* the *Oil and Gas Journal, Moody's,* J. S. Herold, Inc., and conversations with several company officials. During the sample period, several firms were acquired or merged with other firms. If a sample firm acquired another large oil and gas firm (e.g., Discovery's acquisition of Texo Oil), the firms' data were pooled for prior years. When the acquired firm was small (e.g., Vanderbilt's 1978 purchase of Bell Western) or the acquired firm's assets were sold off, no adjustments were made to the data. Appendix A lists the firms in the sample, and Appendix B defines variables. Table 7.2 provides descriptive statistics on these firms and their operations by year. The average firm in the sample drilled between 15 and 30 net wells per year and in the process spent $10–$20 million on exploration and development. The average firm also divided their capital spending evenly between exploration and development.

7.3.2 Estimation Issues

Both the finding cost and discovery equations can contain endogenous variables on the right-hand side. Each model also implies a set of cross-equation restrictions among the coefficients and the error variance-covariance matrix. Finally, the discovery function contains nonlinearities. Below I report both ordinary least squares (OLS) and instrumental-variables estimates of the discovery function and finding-cost equations. Systems and least squares estimates of (5) did not produce dramatically different parameter estimates. Of more importance in the estimation was the issue of how to model firm heterogeneities in production and discovery. The theory of this section does not predict whether firms will have different discovery and cost functions. I allowed for productive heterogeneities by including additional regressors in the discovery specifications. In general, it was difficult to find geographic or firm-specific covariates that explained firm-level differences in investment. I therefore report firm and time fixed-effects specifications only when these specifications produced significantly different slope coefficients from the restricted specifications reported here.

Table 7.3 reports OLS and single equation instrumental-variables estimates of the discovery function.[13] The dependent variable is the natural logarithm of

Table 7.2 **Annual Averages of Sample Variables**

	A. Year							
	1979	1980	1981	1982	1983	1984	1985	1986
OIL PRICE	16.55	29.65	33.49	31.07	29.08	28.21	25.27	15.92
GAS PRICE	1.44	1.90	2.38	3.08	3.19	3.17	2.89	2.18
EWELLS	8.5	9.3	9.6	5.1	4.0	5.0	3.7	1.2
DWELLS	15.9	21.6	27.6	17.1	11.9	16.5	14.1	5.0
NRI PRD EWELLS	.29	.31	.32	.26	.24	.23	.22	.27
NRI DRY EWELLS	.31	.28	.29	.22	.22	.24	.27	.24
NRI PRD DWELLS	.31	.36	.37	.28	.27	.30	.27	.28
NRI DRY DWELLS	.31	.30	.34	.24	.26	.35	.27	.20
EWELL COST	.75	2.21	1.70	1.63	1.15	2.59	2.43	1.36
DWELL COST	1.47	1.55	.72	1.17	1.03	.87	.85	2.82
MBOE PRODUCTION	375.7	401.9	371.4	320.1	318.6	418.6	432.6	463.0
MBOE ADDITIONS	508.0	561.9	593.2	424.1	501.3	512.2	409.3	238.4
LONG-TERM DEBT	27.9	30.0	46.4	52.2	50.0	54.0	65.8	70.8
O&G REVENUE	21.9	30.9	31.4	29.8	27.8	31.1	21.6	22.0
EXPLORATION	4.06	7.32	11.5	8.27	4.23	4.93	7.28	1.57
DEVELOPMENT	4.71	9.92	13.1	8.58	6.64	7.78	3.13	3.39
Observations	26	27	34	38	35	32	27	23

	B. Production Size Class		
	Less than 250 MBOE	Less than 250 MBOE and Greater than 500 MBOE	Greater than 500 MBOE
EWELLS	3.04	3.04	11.10
DWELLS	6.57	10.80	31.19
EWELL COST	1.64	.84	2.01
DWELL COST	1.55	1.35	.79
MBOE PRODUCTION	82.6	397.6	2673.5
MBOE ADDITIONS	558.4	950.1	3684.1
LONG-TERM DEBT	5.4	13.3	116.9
O&G REVENUE	6.4	9.0	53.0
EXPLORATION EXPENDITURES	1.53	2.13	12.60
DEVELOPMENT EXPENDITURES	1.42	3.74	17.30

Notes: The first part of the table omits the 1978 observations. The oil and gas prices are January to December averages. Because not all firms have fiscal years that end in December, prices and revenue figures were adjusted so as to represent end-of-year averages. O&G stands for oil and gas.

Table 7.3 **Discovery Function Estimates**
$A = G(w) = \alpha_0 \, w_e^{\alpha_e} \, w_d^{\alpha_d} \, L_p^{\alpha_p} \, L_u^{\alpha_u} \, \psi$

	OLS (1)	OLS (2)	IV (3)	IV (4)	IV (5)
CONSTANT	4.56	4.60	3.54	4.63	4.35
	(28.04)	(15.25)	(12.52)	(6.84)	(10.15)
ln EWELLS	.11	.12	.54	.75	.69
	(1.64)	(1.62)	(1.48)	(2.17)	(3.59)
ln DWELLS	.44	.44	.42	.38	.26
	(6.64)	(6.62)	(1.32)	(2.80)	(2.81)
ln DEVELOPED LAND	.35	.36	.36	.07	.15
	(5.37)	(5.08)	(1.41)	(.21)	(1.94)
ln UNDEVELOPED LAND	. . .	−.01	. . .	. . .	. . .
		(−.16)			
SIZE1	. . .	. . .	. . .	−2.26	−.52
				(−5.31)	(−1.23)
SIZE2	. . .	. . .	. . .	.28	.10
				(.75)	(.97)
SIZE3	. . .	. . .	. . .	−.12	.34
				(−.30)	(.01)
SEE	1.19	1.18	1.84[a]	1.61[a]	.82[a,b]

Note: [a] indicates unadjusted IV estimate; [b] includes firm effects. Asymptotic t-statistics are in parentheses. The label OLS stands for ordinary least squares and IV stands for instrumental variables. The standard errors of estimate (SEE) have been adjusted for possible heteroscedasticity. $N = 215$.

the firm's annual oil equivalent discoveries, denominated in thousands of barrels. ("Oil equivalent" means that gas reserves have been converted into oil reserves.) Table 7.2 defines most of the independent variables and gives their units. The size dummies categorize each firm's average level of production during the sample period. The dummy variable SIZE1 equals one if the firm produces fewer than 100 MBOE per year; SIZE2 equals one for firms that produce more than 100 but fewer than 250 MBOE per year; and SIZE3 equals one for firms who produce more than 250 but less than 500 MBOE per year. The omitted category contains all firms producing more than 500 MBOE per year. These production cutoff levels were chosen to divide the firms into four roughly even size classes.

The OLS estimates in table 7.3 suggest that the discovery function exhibits slight decreasing returns to scale, while the instrumental-variable estimates suggest increasing returns to scale. In both cases, hypothesis tests do not reject the null hypothesis that exploration and development exhibit constant returns to scale. It is somewhat surprising that the two sets of estimates produce dramatically different estimates of the value of exploratory and development drilling. The OLS estimates suggest that a 1% increase in the number of exploratory wells drilled will increase reserves by .12%, while a 1% increase in development drilling will increase reserves by about four times that amount. The two-stage least squares estimates lead to a different conclusion. In particular, they indicate a high return to exploratory wells. I tested whether the differences in these two sets of estimates reflected a bias caused by the endogeneity of the discovery function inputs. Wu-Hausman tests indicate that each of the inputs should be treated as variable factors. Thus, more weight should probably be placed on the instrumental-variable estimates.

The last two columns of table 7.3 examine the issue of whether size plays a role in the productivity of firms. Column 4 provides some evidence of a size effect in discovery; namely, very small firms have lower productivities. The inclusion of nonredundant individual firm effects (col. 5) reduces the statistical significance of this result. Further analysis of the individual firm effects also suggests that only the smallest firms (less than 75 MBOE) have low productivities.

Estimates of the investment or finding-cost equation (4) appear in table 7.4. The first three columns of table 7.4 examine how closely investment follows energy prices (assuming no unit production cost effects). While the parameter estimates are plausible, only the estimates that use firm gas prices have estimated input elasticities comparable to those in table 7.3. Consider, for example, the coefficient on the per barrel equivalent oil price (BOE). It indicates

Table 7.4 **Finding-Cost Function Estimates**

$$\frac{D(w)}{A(w)} = \alpha_A P + \phi(q_t, R_t)$$

	OLS	OLS	OLS	IV	OLS	OLS
CONSTANT				10.31	9.02	12.73
				(3.12)	(5.06)	(3.21)
OIL PRICE	.39					
	(15.89)					
GAS PRICE		.65				
		(14.65)				
BOE PRICE			.26	.12	.30	.37
			(15.20)	(1.97)	(3.37)	(1.71)
$1/R_t$				.18		
				(1.31)		
q_t/R_t				−.11		
				(−1.20)		
CF_{t-1}/R_t					.21	
					(3.12)	
CM_{t-1}/R_t						−.08
						(−2.51)
SEE	9.62	10.06	9.86			

Note: Asymptotic t-statistics are in parentheses. The standard errors have been adjusted for possible heteroscedasticity. When an estimate of lifting costs (including windfall profits and severance taxes) is subtracted from prices in the first three columns, the elasticity estimates (t-statistics) are, respectively, .44 (16.17), .83 (14.36), and .28 (15.45).

that an increase (decrease) in the price of oil by $1 during this period would increase (decrease) capital spending per barrel of oil found by 26¢.

The third column allows unit production costs to vary with (beginning of the period) firm reserves and production. These estimates imply that reserves and output do not affect production costs. In other words, production costs were relatively constant over the range of outputs observed during the sample period. The estimated price effect falls from 26¢ to 12¢, suggesting that the cost terms only marginally affect the estimated productivity effects. Experimentation with firm and time effects failed to change these conclusions.

Several studies of investment have found that financial variables such as cash flow affect investment spending.[14] Following this earlier work, I included each firm's cash flow from the previous year (divided by its reserves) in the finding-cost regression. Under the null hypothesis that the neoclassical model is correctly specified, a firm's liquidity position should not affect investment, nor explain the apparently low price effects. Including cash flow improves the overall fit of the model and increases the estimated effect of price on capital spending. The estimated coefficient implies that a decrease in cash flow last period of $1 will reduce overall capital spending by 21¢, holding price and the relevant bases constant. Various specifications that introduced linear splines in cash flow were also tried. For example, the cash-flow effect was allowed to differ by firm size, year, and net income class. None of these specifications revealed significant nonlinear cash flow effects.

During the deflationary period from 1982 to 1986 the liquidity of oil and gas firms also was affected by increased debt service. (Table 7.2 documents the increase in long-term debt.) As oil prices declined, bank loans and other medium-term debt contracts placed increased demands on firms' internal funds. To explore whether falling oil and gas revenues, combined with increased debt service payments, may have affected investment, current maturities of debt were included in the investment equation. Only lagged current maturities (CM[−1]) had a significant effect on capital spending. Estimates of this relationship appear as the last column of table 7.4. The negative coefficient suggests that an increase in current maturities due last period significantly diminished investment spending in the subsequent period.

7.4 Financing Arrangements in Oil and Gas

The previous section showed that after controlling for investment opportunities, financial variables explained additional variation in oil and gas investment spending. Other empirical investment studies have found similar so-called liquidity effects.[15] How one interprets the presence of significant liquidity effects depends upon a variety of economic and econometric issues. Some researchers interpret the significance of these variables as evidence of liquidity constraints. Others interpret them as evidence of serious flaws in conventional investment specifications. Previous studies have had difficulty discriminating between these alternative interpretations of the evidence, largely because they do not test explicit liquidity theories. Recent empirical research on liquidity has sought instead to confirm liquidity hypotheses by choosing statistical designs that isolate firms experiencing liquidity problems. (See, e.g., the Hoshi, Kashyap, and Scharfstein, and Meyer and Strong papers in this volume.) Unfortunately, not much is known about the mechanisms by which these problems arise or how liquidity problems actually affect investment plans. The remainder of this paper discusses how financial contracts in this industry may create a link between a firm's liquidity position and its investment spending plans. It appears that financial contracts in this industry can have real consequences for managements' control over funds during deflations in oil and gas prices. This section starts by describing various ways in which firms finance oil wells. It concludes with some observations on incentive and contracting problems in this, and possibly other, research-intensive industries.

7.4.1 Shared Financing

One of the most curious features of oil and gas exploration is that few small- and medium-size oil companies chose to drill "heads up"; instead, most firms drill wells with the financial backing of outside investors. This has been true in good times and in bad, when companies have had ready internal finance and when they have not. It is surprising that many of the major companies also rarely finance wells on their own. Outside investors range everywhere from other oil and gas firms, banks, financial service companies, pipeline companies, and refiners to individual investors. When the outside investors are other oil and gas firms, these outside firms typically have an active interest in the operator and the operator's wells. For example, oil and gas firms sometimes combine their resources to manage common pool problems. Companies with complementary assets (e.g., drilling equipment, transmission lines, and input supplies) also choose to pool their resources so as to reduce transactions costs. "Farm outs" constitute another common form of joint venture. In a farm out, a leaseholder allows another firm to drill wells on its leases in return for an override or revenue interest. Typically the leaseholder uses this arrangement when it needs extra drilling rig capacity or when it wishes to purchase expertise in drilling a particular geologic horizon.

While technological complementarities and common pool problems provide partial explanations for the joint participation of firms in drilling projects, they do not completely explain why oil and gas firms regularly sell equity interests in their projects. Some industry experts believe that bankruptcy risks provide firms with incentives to form joint ventures. While the pooling of projects can provide insurance, why should firms with asymmetric information pool risks? Firms can self-insure by diversifying their geographical operations. Moreover, they can cheaply diversify by buying equity in other firms (as opposed to specific investment projects). Some industry analysts have argued that tax advantages cause firms to pool their funds. By supplying up-front capital, outside investors purchase immediate tax offsets. They then defer taxable income streams to later (presumably lower) tax years.[16] Oil companies find it profitable to sell their tax benefits whenever they know that they will have little income against which they can deduct drilling expenses.

7.4.2 Financial Terms

Although capacity constraints, common pool problems, bankruptcy risk, and tax incentives may explain why firms seek external funds to finance exploration and development, they do not explain the idiosyncrasies of equity participation contracts. Equity contracts in this industry incorporate many provisions that address asymmetric information and adverse selection problems. These problems occur because the operator has private information about the prospects of joint exploration and development projects. Thus, even though a project may contain substantial tax advantages, these gains may go unrealized because the operator cannot credibly transfer all of them to investors. Although the theoretical contracting literature suggests that the firm and its investors could commit to complete contingent contracts to overcome these incentive problems, firms and investors face two major problems when writing contracts. First, in many instances the operator has private information about *what* contingencies might arise. The operator need not have any incentive to reveal these contingencies at the time the parties contract. Second, lenders face substantial monitoring and verification costs when trying to enforce contracts. For example, while investors in this industry can file due diligence suits against operators, they frequently have a hard time proving that management contributed to a bad outcome. Statements indicating the difficulty of assessing a project's risks regularly appear in public prospectuses. For example, one operator warns investors, "With new investors what I try to do is make them clearly understand that if they can't afford to take their money and flush it down the toilet, they can't afford to be in the oil business, because chances are that is what they are doing" (Treibitz 1985, 47). Given the difficulty outside investors face in writing complete contingent contracts and in verifying investment outcomes ex post, one might expect to see few inexperienced investors in the oil and gas industry. Curiously, this is not the case. Thus, there must be other mechanisms by which outside investors affect an operator's drilling plans.

The terms on which outside equity investors participate in drilling projects differ across deals for a variety of reasons. Most equity deals, however, have the following structure. The outside investor agrees to pay some fraction of the working interest in a series of wells. The investor receives in return a net revenue interest in each well. Occasionally large outside investors receive the same terms as the operator: the investor pays 1% of the costs and receives 1% of the net revenue. The typical outside investor purchases a *carried interest* in a series of oil and gas wells. A common carried interest is stated as "one-third buys one-quarter." Under these terms, the outside investor receives .75 percent of the net revenue for each percentage point of the project's costs he has assumed.[17] The outside investor thus "carries" one-quarter of the operator's costs. In return for carrying the operator, outside investors often require the operator to own a significant interest in the project, typically at least a one-eighth interest. Industry analysts claim that this capital requirement insures that operators will complete wells with due diligence. Although operators do not always require outside investors to commit minimum sums, it appears that operators prefer for investors to purchase at least a one-sixteenth share in a series of wells.

When an outside investor purchases a working interest in a well, the investor assumes some of the liability for the operation of the well. Should the operator go bankrupt, those with the remaining working interest are liable for completing or abandoning the well. Should the well have a blow out, they are also responsible for additional costs (or the insurance deductible). Thus, a working interest in the well carries with it large potential liabilities. These liabilities may not be completely insurable at a reasonable cost (Fraser 1986). During the 1970s, alternative financing arrangements arose to reduce operators' incentives to expose outside investors to large legal liabilities (such as those associated with deep offshore wells). Most of these arrangements reduce agency problems by shifting risks onto the operator. The most common of these arrangements was the oil and gas limited partnership. Under this arrangement, outside investors (the "limited partners") contributed money to a partnership in return for tax benefits. The general partner (typically the well operator) drilled its own prospects with these funds and bore most of the partnership's operating liabilities. While these partnerships limited the legal exposure of participants, they raised their own set of incentive problems. In order to remove the partners from legal liabilities, the partners typically had to engage in "arm's length" transactions with the general partner. While some oil and gas partnerships were dedicated to drilling specific projects or areas, many partners simply funded vague portfolios of drilling projects or even "blind pools." Thus, these partnerships often allowed the general partner wide discretion in drilling and completion decisions. Although some industry experts believe that when general partners repeatedly seek funds they have sufficient incentives to offer good projects to outsiders, some argue that reputations matter little in this business.

In all of the aforementioned financing arrangements, the lender has a very difficult time mitigating agency problems that arise when the operator has better information. Over time, outside investors have designed several new financing arrangements to deal with these informational asymmetries. These new arrangements typically place constraints on the operator's discretionary investment spending, particularly when the operator has bad luck or runs into financial trouble. One common way in which outside investors control operators' incentives is through *"back-in"* or *revisionary interest* contracts. These contracts give the operator an interest (or an additional interest) in a well when the well reaches a certain stage. Typically the operator "backs in" after production begins or after production has covered all of the well's costs. Once the operator has backed in a revenue interest, the operator assumes a fraction of the remaining costs and revenues just as the other investors do. In essence, this arrangement mitigates agency and information problems by only allowing the operator into a deal after the well pays off. This makes the operator less likely to under-complete profitable wells.[18] On the other hand, these contracts may provide the operator with an incentive to over-complete marginal wells.

7.4.3 Empirical Evidence

The previous subsections underscored two important features of the exploration process: the amount of capital required before production can occur and the inability of investors to write complete contingent contracts that resolve investment incentive problems. If capital markets were perfect, and lenders could perfectly evaluate projects and costlessly monitor the performance of operators, then these costs should not affect the real investment activities of oil and gas firms. Moreover, one would expect to see few differences across firms in their capital structures or the terms on which they obtained their investment financing. Risk-neutral firms requiring external finance would simply borrow at risk-adjusted rates of return or offer equity. Bad luck, or a string of dry holes, would not affect the ability of firms to raise capital for future projects, except insofar as it changed general perceptions of risk. Risk-averse firms would also face few constraints in raising capital, since they could easily diversify risk across other firms.

In practice, it appears that there are systematic differences in the ways oil and gas firms finance their exploration activities. Table 7.5 provides some evidence on how firms' net revenue interests in wells vary with their financial position. The table reports regression results for equations that explain a firm's average net revenue interest in their exploratory (EWELL) and development (DWELL) wells. To control for possible size effects, production size dummies were included on the right-hand side. (The intercept term reflects the mean effect for the largest size class.) Also included were lagged cash flow and a second variable that was zero when cash flow was positive, and cash flow when cash flow was negative. These results show that smaller firms in the sample maintain significantly smaller average net revenue interests in the wells they drill. More important, even after controlling for size effects, it appears that the cash flow position of the firm during the previous year significantly affects the firm's net revenue interest in exploratory wells. This same effect appears, but is somewhat weaker, in the final development-well interest equation. Specifications that include firm or time effects do not change these basic conclusions.

7.4.4 Bonds and Other Debt Contracts

Debt contracts in this industry also recognize agency problems and attempt to control them by limiting operator discretion. Just as outside equity holders have problems controlling the quality of an operator's drilling projects, so too

Table 7.5 **Net Revenue Interest (NRI) Equations**

	EWELL NRI	EWELL NRI	EWELL NRI	DWELL NRI	DWELL NRI	DWELL NRI
CONSTANT	.36	.36	.36	.44	.44	.44
	(16.76)	(16.79)	(16.75)	(15.69)	(15.66)	(15.64)
SIZE1	−.17	−.18	−.18	−.21	−.18	−.21
	(−5.52)	(−5.67)	(−5.59)	(−5.37)	(−5.68)	(−5.08)
SIZE2	−.08	−.08	−.08	−.11	−.08	−.11
	(−2.97)	(−2.98)	(−2.97)	(−3.21)	(−2.98)	(−3.20)
SIZE3	−.06	−.06	−.06	−.12	−.06	−.12
	(−2.26)	(−2.27)	(−2.26)	(−3.25)	(2.27)	(−3.23)
$CF(-1)/R_t$		.05	.04		−.01	−.02
		(1.97)	(1.83)		(−.35)	(−.49)
$CF(-1)/R_t < 0$			.02			.12
			(2.03)			(1.89)
SEE	.17	.16	.16	.14	.14	.13

Note: Asymptotic t-statistics are in parentheses. The standard errors have been adjusted for possible heteroscedasticity.

do debt holders. Debt holders also have a difficult time securing their loans with firms' assets. While they can formally attach a firm's primary source of collateral, its reserves, outsiders have a hard time determining the market value of a firm's reserves and, hence, its total net worth.

Banks and insurance companies provide most of oil companies' debt capital. These institutions rarely make loans for specific drilling projects; instead, they issue lump sum amounts of credit or revolving lines of credit. To mitigate incentive problems, they often place covenants and penalties in their debt contracts. These debt covenants require specified repayments and penalize the firm when it gets into financial trouble. (Contracts usually define trouble as the failure to maintain certain financial ratios.) Typically, the debt covenants limit the flexibility of both the lender and the borrower should the firm encounter financial troubles. The debt covenants for Arapaho Petroleum provide a good example of these limitations: "The loan is collateralized by United States proved oil and gas properties, gas gathering systems, and certain partnership interests. Agreements issued in conjunction with this debt specify among other things that Arapaho maintain certain operating and financial ratios, limit payment of cash dividends, prohibit redemption of its common stock, and under certain circumstances incurring additional indebtedness, merging with another entity, and entering into a new business" (Moody's *OTC Industrial Manual* 1986).

These provisions clearly limit what Arapaho could do in response to changes in its financial position. For instance, the contract may force the company to curtail capital spending on good projects in order to meet its financial obligations on others. This contract also prohibits it from borrowing additional funds or from other joint venture arrangements. Banks claim that they must include these provisions to deter firms from taking unacceptable risks. In practice, however, banks cannot credibly commit to enforcing these provisions should the firm run into financial trouble. This insistence on constraining the discretion of firms in bad times appears in even relatively flexible loan arrangements. For example, consider the terms of Hadson Oil's revolving credit agreement: "Long-term debt consists of a secured note payable to a bank under a revolving credit agreement which provides for a total line of credit of $25 million. The amount which the company may borrow is limited to a loan base amount which is based on an analysis of oil and gas reserves. . . . The note is secured by these reserves" (Hadson Oil Annual Report 1986). In this agreement, the bank attaches the firm's oil and gas reserves as collateral to the loan. Notice, however, the loan's provisions do not distinguish between events within Hadson's control and events outside their control. Thus, while the amount of credit available depends on the market value of recoverable assets, the contract does not distinguish between fluctuations in firm value caused by market conditions versus changes due to management's actions. Thus, these contracts potentially limit the ability of capable managers to respond to downturns in energy prices. When energy prices fell in 1985 and 1986, for example, Hadson's access to capital was limited.

Although the use of reserves as collateral may seem like a very practical way of aligning the firm's incentives with the lender's, these contracts introduce their own incentive and moral-hazard problems. Reserve estimates are subjective. Even with outside appraisals, lenders rarely have a complete picture of firms' reserve collateral. Geologists, for instance, define reserves based upon what they estimate a firm can "economically" recover. Sometimes a firm's reserve base may double or fall in half simply because the firm declares certain reserves may no longer be recoverable. This discretion introduces the possibility of moral hazard in firms' operating decisions. Consider the position of Discovery Oil and Gas in 1984. "The Company's continuation as a going concern appears to be dependent on its ability to generate sufficient [internal] cash flow from operations or the sale of assets, or make arrangements for alternative sources of capital [as may be permitted by the debt covenants] . . . in order to reduce its outstanding bank indebtedness and to return to profitable operations" (Discovery Oil Annual Report 1986).

That some firms actually had difficulty in meeting their obligations in these contracts is apparent in Alamco's 1986 Auditor Report: "The Company's liquidity has been impaired due to significant decreases in its revenues and the debt service associated with its long term debt and capital lease obligations. Although the company has continued to meet its obligations as they mature, it is in technical default on a substantial portion of its long term debt and capital lease obligations" (Moody's *OTC Industrial Manual* 1986, 1473–74). During 1986 Alamco stopped doing any significant exploration and development at the insistence of its creditors. Less than five months after the above report appeared, Alamco filed for bankruptcy and the company proceeded to liquidate its assets. While this is perhaps one of the most dramatic cases of outside investors affecting the investment decisions of an independent operator, it does illustrate that outside investors can place real constraints on investment activity.

7.5 Conclusions

This paper considered what effects liquidity and other financial factors may have on the exploration and development activities of oil and gas firms. It started by noting that there were dramatic changes in the oil and gas industry between 1978 and 1986 that affected both firms' investment opportunities and their financial viability. Using an investment model that controlled for firm's investment opportunities, we found that financial factors such as cash flow and current maturities of long-term debt explained some variation in investment spending.

In the latter half of the paper, descriptive evidence on the financial terms used in the financing of wells was considered, and the role of debt contracts in placing constraints on the firm was noted. In particular, the use of oil and gas reserves as collateral was seen to have potentially important implications for how much firms could borrow during deflationary periods. Additional regression evidence suggested that firms' ownership positions in wells are affected by the availability of internal finance. Much remains to be done to convincingly tie this descriptive evidence to more formal theories and tests of liquidity theories of investment. The detail of the oil and gas industry, however, provides a useful starting point for further theoretical and empirical work. In particular, future research might consider how much control firms have over their liquidity positions. Clearly, the availability of finance depends not just on the availability and cost of external finance, but also on the internal conditions that determine how a firm allocates its own resources.

Appendix A
Firms in the Sample

Adams Resources and Energy
 (formerly ADA Resources)
Alamco, Inc.
Alta Energy Corporation
Arapaho Petroleum
Argo Petroleum
Argonaut Energy Corporation
Aztec Resources
Century Oil and Gas
Chaparral Resources
Conquest Exploration
Damson Oil
Diablo Oil Corporation
Discovery Oil
Double Eagle Petroleum and Mining Company
Dyco Petroleum
Galaxy Oil
Hadson Corporation
 (formerly Hadson Ohio Oil)
Mitchell Energy

Roberts Oil and Gas
Royal Resources Corporation
Sabine Corporation
Seneca Oil Company
Statex Petroleum
Striker Petroleum
Summit Energy
Target Oil and Gas
Templeton Energy
Texas International
Tipperary Corporation
Towner Petroleum
Unit Drilling
Usenco
Valex Petroleum, Inc.
Vanderbilt Energy
Wainoco Oil
Western Energy Development
Whiting Petroleum
Wichita Industries
Wiser Oil Company
Woodbine Petroleum
Woods Petroleum
Worldwide Energy

Appendix B
Variable Definitions

OIL PRICE	=	dollars per barrel;
GAS PRICE	=	dollars per mcf (thousand cubic feet);
EWELLS	=	exploratory wells;
DWELLS	=	development wells;
MBOE	=	thousand barrels of oil equivalent;
ADDITIONS	=	discoveries in thousands of barrels (MBOE);
EXPLORATION	=	exploration expenditures ($ million);
DEVELOPMENT	=	development expenditures ($ million);
EWELL COST	=	exploration expenditures per exploratory well ($ million);
DWELL COST	=	development expenditures per exploratory well ($ million);
NRI	=	net revenue interest;
PRD	=	producing wells.

Notes

1. In related work, Bernanke (1983) studied the effects of the Great Depression deflation on bank capital. Much earlier, Meyer and Kuh (1957) emphasized that small firms' investment programs were sensitive to large downturns in demand.

2. A private landowner owns both surface rights and (unassigned) subsurface rights. These rights are transferred whenever the property is sold. The landowner may choose to sell all mineral rights to the property separately at any time. The landowner may also restrict the depth of the mineral rights. Federal leases involve somewhat different allocations of rights. Federal royalty contracts, however, do not typically differ from those in private contracts.

3. The term "operator" usually identifies the firm drilling the well. The term "operator of record" identifies the entity responsible for well logs and drilling liabilities. The operator may or may not own an operating interest in any particular well.

4. Consider the following example. An operator signs a lease promising the landowner a 12.5% royalty. In addition, the operator pays a 2.5% override royalty to a

lease broker. Upon completion, the operator pays 15% of any revenues to these parties. The operator receives in return 85% of the revenues but pays 100% of the costs.

5. These figures come from sample well budgets reported in issues of the *Oil and Gas Investor.*

6. The American Petroleum Institute and the Independent Petroleum Association publish annual survey estimates of drilling costs by date, location, type, and depth of well. Academic studies of these drilling costs include those by Fisher (1964), Epple (1975) and others.

7. To perforate a well, the operator fires metal bullets or pressurized gas into the walls of the well. These "shots" increase the flow of oil and gas into the drill hole. Stimulation includes additional measures to increase the flow of oil and gas, such as injecting water into the ground surrounding the well or pump.

8. Firms convert the two using the BTU equivalence: 6,000 cubic feet of gas equals one barrel of oil. A barrel of oil contains 42 gallons.

9. I assume that the price of a well does not depend on individual firms' drilling decisions. The price can change over time, however, because of movements in the aggregate supply curve of drilling services.

10. For related exploration models see Pindyck (1978), Uhler (1978), and Livernois and Uhler (1987).

11. In December 1977, the Financial Accounting Standards Board (FASB) issued statement 19. This statement established uniform accounting conventions for oil and gas firms. Statement 19 was later amended by Securities and Exchange Commission Accounting Series Releases 253, 257, and 269. These releases added requirements or amendments affecting reserve reporting and the definitions of exploration and development expenditures. See, e.g., Moore and Grier (1982) and Magliolo (1986).

12. The initial subsample was limited to 70 firms because of data collection costs. I focus on independents with limited foreign operations to reduce variation in firms' investment opportunities. Fewer than 2% of the sample firms had significant foreign operations.

13. The instrument list included fixed effects, annual price indexes for the inputs (from the *Basic Petroleum Data Book*), oil and gas prices, beginning of period reserves, and geographic and geologic dummy variables. The dummy variables include variables summarizing the presence of offshore, Alaskan, Gulf Coast, and California operations.

14. In addition to the empirical chapters in this volume, see Fazzari, Hubbard, and Petersen (1988) and the references therein.

15. For a review of aggregate and disaggregate studies on U.S. data see Fazzari, Hubbard and Petersen (1988). Meyer and Strong's paper in this volume provides another industry study. The Hoshi, Kashyap, and Scharfstein paper provides evidence from Japan.

16. Special oil and gas investment offsets also attract individual investors. Until the recent tax reform act, most intangible drilling costs were fully deductible. Under functional allocation programs, the firm sold these deductions to individual investors. Recent revisions in the tax code reduce the incentives for individuals to use these shelters. For example, individuals must now assume part of the working interest in order to take tax deductions. The new tax law also limits the types of income individuals may offset with oil and gas revenue.

17. Under "one-third buys one-quarter," if the outside investor paid 50% of the costs of the well, the investor would receive $50 \times .75 = 37.5\%$ of the net revenue interest in the well. If the well operator pays 15% in front-end royalties, then the investor receives $31.875 = 85 \times .5 \times .75\%$ of the well's gross revenues.

18. Wolfson (1985) notes that because exploratory well results provide information

externalities for other wells, operators may choose not to complete successful wells. Part of the monitoring problem investors face is one of cost—it is extremely expensive to verify that the operator has correctly reported the costs and results of a well. In many cases, there is always residual uncertainty about outcomes. In the words of one operator, "I can think of three wells that I have drilled that I can hardly wait until I get to Heaven [so that I can] see what was really down there, to look down and see where that oil was" (Treibitz 1985, p. 49).

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