THE JOURNAL OF FINANCE • VOL. LV, NO. 1 • FEBRUARY 2000

Financing Policy, Basis Risk, and Corporate Hedging: Evidence from Oil and Gas Producers

G. DAVID HAUSHALTER*

ABSTRACT

This paper studies the hedging policies of oil and gas producers between 1992 and 1994. My evidence shows that the extent of hedging is related to financing costs. In particular, companies with greater financial leverage manage price risks more extensively. My evidence also shows that the likelihood of hedging is related to economies of scale in hedging costs and to the basis risk associated with hedging instruments. Larger companies and companies whose production is located primarily in regions where prices have a high correlation with the prices on which exchange-traded derivatives are based are more likely to manage risks.

DESPITE THE PREVALENCE OF CORPORATE RISK MANAGEMENT and the effort that has been devoted to developing theoretical rationales for hedging, there are no widely accepted explanations for risk management as a corporate policy. Important questions remain regarding the determinants of the extent to which a company hedges, the impact of risk management on a firm's value, and the interaction between a firm's hedging policy and its other policy decisions. To address some of these questions, I examine the risk management activities of 100 oil and gas producers for 1992 to 1994. In particular, I investigate whether the fraction of production an oil and gas producer hedges against price fluctuations is related to its financing policy, tax status, compensation policy, ownership structure, and operating characteristics.

I document a wide variation in hedging policies among oil and gas producers. My tests find that this variation is associated with several differences in the firms' characteristics. The fraction of production hedged is positively related to the differences in financial leverage, measured as the ratio of total debt to total assets, and it is greater for oil and gas producers

* University of Oregon. I thank John McConnell (my thesis advisor), Wayne Mikkelson, René Stulz (the editor), and an anonymous referee for their many detailed comments. I have also greatly benefited from the comments of John Chalmers, Diane Del Guercio, Larry Dann, David Denis, Diane Denis, George Fenn, Jarrad Harford, Randy Heron, Tim Kruse, Erik Lie, Peter MacKay, Patrick McCarthy, Megan Partch, Mitchell Petersen, Gordon Phillips, and Sunil Wahal. This paper is adapted from my dissertation at the Krannert School of Management, Purdue University. An earlier version of this paper entitled "The role of corporate hedging: Evidence from oil and gas producers" was presented at the 1997 meeting of the Western Finance Association.

classified as having little financial flexibility, defined as firms with a debt ratio above the sample median and a current ratio below the sample median. These tests also document a negative correlation between the fraction of production hedged and the basis risk associated with hedging instruments.[1] Specifically, companies that have production located primarily in regions where oil and gas prices tend to have a low correlation with the prices on which exchange-traded derivatives are based hedge less extensively than other companies.

I also conduct tests in which the determinants of a company's decision to hedge are estimated separately from the determinants of the extent of hedging by companies that do hedge. These tests find substantial differences between the determinants of these decisions. The likelihood of hedging is greater for firms with more total assets and for firms expected to face less basis risk when using exchange-traded derivatives to hedge. In contrast, among oil and gas producers that hedge, the extent of hedging is related to proxies for financing costs. Conditional on a company hedging, the fraction of production hedged is increasing in the debt ratio, is greater for companies that pay out a smaller fraction of income in dividends, and is less for those that do have a debt rating. Though there is little evidence that this decision is affected by total assets, like the decision to hedge, this decision is associated with the basis risks a firm would be expected to face in using exchange-traded derivatives.

Results from this study support several explanations for corporate risk management. First, the positive correlation between the extent of hedging and financial leverage supports theories that corporate risk management is used to alleviate financial contracting costs. For example, Froot, Scharfstein, and Stein (1993) argue that corporate risk management allows companies to take on more attractive investment opportunities, and Smith and Stulz (1985) and Bessembinder (1991) contend that risk management reduces the expected costs of bankruptcy and underinvestment.

Second, the positive correlation between the decision to hedge and total assets is consistent with the notion that companies can face significant economies of scale in hedging, particularly in setting up a hedging program. This result is consistent with that from a stream of empirical literature on the determinants of the decision to hedge—for example, Mian (1996) and Géczy, Minton, and Schrand (1997).

Finally, the association between basis risk and both the decision to hedge and the decision of the extent to hedge supports the view that the extent to which a firm should hedge to reduce risks is decreasing in the basis risk it faces in using instruments available for hedging (e.g., see Ederington (1979)). Moreover, this result indicates that even within industries the ability to hedge can differ among firms.

[1]Basis risk refers to the correlation between the price of the underlying asset being hedged and the price of the asset underlying the hedging instrument. The lower this correlation, the greater the basis risk a firm faces in using this instrument.

Because of data constraints, most empirical examinations of corporate risk management have concentrated on factors related to a firm's decision to hedge or use derivatives.[2] One exception is Tufano (1996) who examines risk management in the gold mining industry. Like my study, Tufano examines the determinants of the *extent* to which a firm hedges. My paper has two important distinctions from this literature. First, the results are quite different. Consistent with theories for corporate hedging, I find a firm's hedging policy is associated with its financial leverage. In general, neither Tufano nor papers focusing on the decision to hedge find evidence of this association. I also document an association between hedging policies and a firm's ability to hedge effectively, which has not been examined in other studies.

A second distinction is that, unlike these other studies, this study uses a method that separately examines the determinants of the decision to hedge and the determinants of how much to hedge. This approach reveals significant differences between the determinants of these decisions. These differences can explain the discrepancies between corporate risk management theory and the results of previous empirical studies that only address the decision to hedge. The differences also suggest that the conflicts between the results of this study and the results of studies focusing on the decision to hedge can be explained by the choice of metric for hedging policies.

The following section presents the hypotheses for corporate hedging. Section II describes the database of oil and gas producers' risk management activities and presents descriptive statistics. Section III discusses regression analyses of the fraction of production hedged. Section IV presents my conclusions.

I. Hypotheses

Risk management is a purely financial transaction. It therefore follows from Miller and Modigliani (1958) that, in perfect financial markets, hedging is fruitless. However, when markets are imperfect, hedging can alter a firm's value by influencing its investment decisions, expected costs of financial distress, or expected taxes.

I examine three motives for corporate hedging: (1) to alleviate financial contracting costs, (2) to reduce expected taxes, and (3) to reduce the manager's personal risk exposure. The first two motives attribute risk management to attempts by managers to maximize shareholder wealth, and the third implies that managers hedge to maximize their personal utility. This section discusses the theories related to these arguments and their empirical implications.

[2] For example, see Nance, Smith, and Smithson (1993), Dolde (1993), Mian (1996), or Géczy et al. (1997). For an extensive review of work in this area, see Fenn, Post, and Sharpe (1997).

A. Financial Contracting Costs

Two types of hypotheses consider the role of hedging in alleviating financial contracting costs. The first, developed by Froot et al. (1993), contends that hedging helps ensure that a corporation has sufficient internal funds available to take advantage of investment opportunities. This argument presumes that capital market imperfections make external sources of funds costly. Accordingly, low cash flow forces a company either to bypass profitable investment opportunities or to increase its use of costly external financing. By reducing the likelihood that a company faces a shortage in cash flow, hedging reduces the influence that external sources of financing have on a company's investment decisions. Differences in the costs of external financing can influence the value of hedging.[3] All else equal, the more difficulty a company has in obtaining outside financing, the more costly a shortfall in cash flow will be and the greater is the value hedging provides.[4]

A second line of literature considers the role of hedging in reducing the magnitude of a company's funding costs. Smith and Stulz (1985) and Mayers and Smith (1990) argue that hedging reduces expected bankruptcy costs by reducing the variability of cash flows. These costs include direct bankruptcy costs, the loss of tax shields, and the loss of valuable growth options. Similarly, Bessembinder (1991) demonstrates that by reducing the probability of default, hedging can reduce the incentives for equity holders to underinvest, which improves contracting terms with creditors.

B. Tax Structure

Smith and Stulz (1985) and Graham and Smith (1999) contend that characteristics of the tax code enable corporations to potentially increase their value by hedging. Under present U.S. tax laws, the marginal corporate tax rate is progressively increasing from 15 percent to 34 percent for taxable income between $0 and $100,000, fluctuating between 34 percent and 39 percent for taxable income between $100,000 and $18.3 million, and 35 percent on taxable income above $18.3 million. If a corporation's taxable income falls in this progressive region, its expected tax liability is a convex function of its taxable income. Based on this theory, a corporation facing an increasing marginal tax rate can reduce its expected tax liability by reducing the variability of its taxable income.[5]

[3] Differences in the costs of external finance can be attributed to asymmetric information problems (Myers and Majluf (1984)) or contracting problems (Myers (1977), Jensen and Meckling (1976), Jensen (1986)).

[4] See Whited (1992), Hoshi, Kashyap, and Scharfstein (1991), and Fazzari, Hubbard, and Peterson (1988) for further discussion of the relation between the costs of external financing and investment behavior.

[5] Initially, one might expect that corporations face a convex tax function only under unusual circumstances. However, provisions of the tax code, such as tax-loss carrybacks, tax-loss carryforwards, and investment tax credits, can have a significant impact on a firm's taxable income. For example, Graham and Smith (1999) use data from COMPUSTAT to estimate the tax status

C. Managerial Risk Aversion

Stulz (1984) and Smith and Stulz (1985) argue that managers are often unable to diversify firm-specific risks. For this reason, risk averse managers often choose to take actions that reduce the variability of the firm's returns. These arguments imply that, all else equal, managers with more wealth invested in a firm's equity will have greater incentives to manage the firm's risks.

Smith and Stulz (1985) contend that managers' compensation plans can influence their hedging choices. Specifically, the incorporation of option-like provisions in managers' compensation increases the incentives for managers to take risks. Consequently, the more option-like features there are in the compensation plans, the less managers will hedge.

II. Price Risk Management by Oil and Gas Producers

Although focusing on oil and gas producers raises concerns regarding the generality of the results, several features of this industry make it particularly well suited for an analysis of risk management policies. First, oil and gas producers are exposed to a common risk: The volatility of oil and gas prices has a substantial impact on cash flow variability. Second, methods are available for these companies to hedge against this risk. Futures and options for both crude oil and natural gas are traded on the New York Mercantile Exchange (NYMEX), and forward and swap contracts are traded in the over-the-counter market. Third, as I discuss later in Section II.C, there is a large dispersion in risk management policies among oil and gas producers. For example, in 1993 the fraction of annual production hedged by these firms varies from zero to 97.5 percent.

In this section, I first discuss the construction of the database of oil and gas producers' risk management practices. Then I describe the independent variables. Finally, I discuss the characteristics of the firms in the sample.

A. Dependent Variable: Fraction of Production Hedged

To construct a database of hedging by oil and gas producers, I use *Ward's 1994 Business Directory* to identify 177 independent public companies that have a primary SIC code of 1311 (i.e., Crude Petroleum and Natural Gas Extraction).[6] In February 1995, I sent a letter to the chief financial officer or treasurer of each firm requesting that he or she report the percentage of the annual oil and gas production hedged for the years from 1992 to 1994. In the Appendix, I provide a description of the responses, a copy of the survey I sent with this letter (Figure A1), and a list of the 100 companies that responded (Table AI).

of more than 10,000 firms for the years from 1980 to 1994. They find that in approximately 50 percent of the cases, corporations face a convex effective tax function.

[6] The 177 firms exclude approximately 28 firms that were contacted but found to be either holding companies, companies not covered by COMPUSTAT, no longer active in oil and gas production, or moved with no forwarding information.

For production to be considered hedged, either the selling price for production is fixed or it is insured from dropping below some fixed level. Oil and gas producers can lock in the sales price of production using forward agreements, fixed price contracts, volumetric production payments, forwards contracts, or swaps.[7] They can ensure a minimum sales price by purchasing a put option. The extent of hedging is defined as the fraction of the firm's production for the year that is hedged against price fluctuations. The companies that completed the survey directly provided the fraction of oil production and gas production hedged for 1992, 1993, and 1994, and the fraction of total revenues from oil production and gas production. However, for those firms that supplied only their financial statements, production hedged is reported several different ways. The procedure used to translate the data provided in financial statements to the fraction of production hedged is described in the Appendix.[8]

B. Independent Variables

B.1. Financial Contracting Costs

There is no widely accepted measure of financial contracting costs. Therefore, to examine the relation between financial contracting costs and hedging, I characterize the relative costs of a corporation's external financing using several proxies that consider a firm's dividend policy, bond ratings, size, and capital structure.

[7] A volumetric production payment is a contract in which producers are provided financing that they agree to repay with a specified volume of future production of oil or gas. Therefore, this agreement is similar to a future or forward contract. The obligation to repay this financing is generally accounted for as deferred revenue, which is considered a liability but is not included as part of current or long-term debt.

[8] In calculating the fraction of production hedged, I assume that the fraction of production hedged using options is equivalent to that hedged with forward agreements. A key difference, however, between forward agreements and put contracts is their sensitivity to changes in the prices of an underlying asset. As the price of an asset changes, the value of a forward agreement changes by an equal amount, while the value of an option can change by less. For example, if oil prices drop by \$1, the value of a forward agreement to deliver oil and the value of a deep in-the-money put on oil increases by \$1, but the value of an out-of-the-money put on oil increases by less than \$1. Though I know the fraction of production or the number of barrels of oil or cubic feet of gas each company has hedged against price fluctuations using options, I do not have sufficient information to calculate the sensitivity of each firm's option holdings to a change in oil and gas prices (i.e., the delta of their option holdings). Therefore, I count a barrel of oil hedged with a put option the same as if it were hedged with a forward agreement. Two attributes of the sample firms help mitigate any bias this approach introduces. First, as I discuss in Section II.C, of the sample firms that hedge, less than 11 percent use options and no firm's option holdings account for more than 40 percent of its total production hedged. Second, to offset the cost of put options, these companies regularly sell call options with the same expiration date and a slightly higher strike price. This creates what is termed *a collar position*. The payoff from a collar position is similar to that from forward agreements.

The company's dividend payout ratio is included in the regressions as a proxy for dividend policy. This variable is defined as annual dividends paid to common stockholders as a fraction of income before extraordinary items—adjusted for common stock equivalents. I assume that companies facing liquidity constraints pay small or no dividends. The coefficient on this variable is predicted to be negative.

A binary variable is used to indicate if a firm's debt is rated by Standard & Poor's. All else equal, firms with rated debt have probably undergone more capital market scrutiny and are thus assumed to face fewer informational asymmetries than ones with no rated debt. Moreover, because companies typically get bond ratings only if they issue public debt, those that have a bond rating are the ones most likely to have access to the public debt market (Barclay and Smith (1995)). Firms with a debt rating are predicted to hedge less extensively.

The size of a company is measured as the market value of assets, defined as the market value of equity plus total liabilities minus the book value of equity. All else equal, companies with fewer total assets are likely to have greater informational asymmetries with potential public investors. Additionally, the direct costs of bankruptcy are proportionally greater for companies with fewer assets (Weiss (1990) and Ang, Chua, and McConnell (1982)). The degree of hedging is predicted to be negatively correlated with this variable.

I construct two measures for the degree of a firm's financial leverage. First, I define financial leverage as the ratio of the book value of short-term and long-term debt to the market value of assets.[9] Several studies, including Whited (1992), argue that firms with higher leverage are more likely to face binding financial constraints. Others, however, find this relation only holds for firms or industries with low Tobin's q ratios (e.g., see Lang, Ofek, and Stulz (1996)). Based on this argument, using leverage as a proxy for financial constraint requires the condition that when oil and gas prices decrease, the industry's Tobin's q will also decrease. Under this condition, the ability of a highly financially levered firm to finance investment opportunities is more sensitive to price fluctuations than its less levered industry counterparts. A second measure for financial leverage is a binary variable (debt constraint) that is set equal to one if a firm's debt ratio is above the sample median and its current ratio is below the sample median and zero otherwise. As discussed by Pulvino (1998), although a highly levered company may have little unused debt capacity, as long as it has a large cash balance, it will still be able to finance value-increasing projects. Therefore, a company faces the greatest degree of capital constraints when it is both highly levered and it has little cash on hand. The coefficients on these variables are predicted to be positive.

[9] I examine several other proxies for a firm's size and its financial leverage beyond those presented here. Size is also measured as the book value of total assets and the quantity of company reserves. Leverage is also measured as the ratio of the book value of short-term and long-term debt to the book value of assets. The analysis results are qualitatively similar when I use these alternative proxies.

Two additional variables related to financial contracting costs are operating leverage and investment opportunities. I measure operating leverage as production cost per barrel of oil equivalent. I assume the greater a company's per barrel production cost, the more sensitive its cash flows are to changes in oil and gas prices; all else equal, companies with higher production costs are more likely to encounter financial distress. The coefficient on this variable is predicted to be positive. I measure investment opportunities as the ratio of investment expenditures to the market value of assets. Myers (1977) and Myers (1984) suggest that expected bankruptcy costs and underinvestment costs are increasing in the value of a firm's investment opportunities. Based on this argument, the extent to which a firm hedges is predicted to be positively correlated with this ratio.

B.2. Tax Structure

To examine the relation between taxes and hedging policy, I estimate each firm's marginal tax rate using a tax rate obtained from Graham's database of simulated corporate marginal tax rates.[10] The simulated tax rate considers a firm's investment tax credits and the alternative minimum tax, as well as the firm's ability to carry losses and tax credits forward and backward. All of these are important features of the tax code for oil and gas producers.[11]

The likelihood that a firm's income will fall in the progressive region of the tax function is estimated two ways. First, I use the estimate of the firm's marginal tax rate for the year. I assume that firms with lower marginal tax rates in the current period are more likely to face nonconstant marginal tax rates in future years and, hence, are expected to hedge more extensively. Second, I use a binary variable that is set equal to one if the firm's tax rate for the year is in the progressive region of the tax structure (i.e., it is less than 34 percent). The extent to which a firm hedges is predicted to be positively correlated with this variable.

B.3. Compensation Policy and Ownership Structure

To examine the relation between hedging policy and managerial risk aversion, I use data from 1993 proxy statements regarding the ownership of the firms' equity and the managers' compensation packages. The level of a manager's firm-specific wealth is represented in two ways: (1) by the log of the market value of the firm's equity owned by officers and directors and (2) by

[10] This database, which can be accessed from the *Journal of Finance* home page, contains simulated corporate marginal tax rates spanning 1980 to 1995 for all COMPUSTAT observations with valid data. Graham (1996b) describes the methodology used to estimate the simulated tax rate and shows that it provides a better approximation of a corporation's marginal tax rate than measures that focus solely on net loss carry forwards, investment tax credits, or pretax income. Throughout this study, I use the before-interest-expense simulated rate. The results are qualitatively similar when I use the after-interest-expense simulated marginal tax rate.

[11] I thank Bob Palmquist at Arthur Andersen for his assistance in clarifying issues regarding taxation in the oil and gas industry.

the fraction of the firm's outstanding shares held by officers and directors. The incentives for managers to hedge should be increasing in both these variables.

I control for the presence of outside blockholders using the number of outside blockholders, defined as the number of investors other than officers and directors who own at least five percent of the common shares outstanding. Tufano (1996) argues that outside blockholders are primarily well-diversified institutional investors and, therefore, they are less likely to act like risk-averse poorly diversified investors. The coefficient on this variable is predicted to be negative.

The extent to which options are used in managers' compensation is gauged using four variables. All the proxies are predicted to be negatively correlated with the extent of hedging. The first variable is the number of options held by officers and directors that are exercisable within 60 days, as reported in the 1993 proxy statement. The second measure is the number of options held by officers and directors that are exercisable within 60 days divided by the number of officers and directors. A third proxy for managerial compensation is the ratio of the sum of exercisable and unexercisable options, or what I refer to as *total option holdings*, to the number of officers for whom this information is provided. The fourth variable is the ratio of the value of stock options awarded to the CEO in 1993 to the CEO's 1993 salary plus bonuses.

B.4. Basis Risk

The risk a company encounters when the settlement price of the hedging instrument is different from the price of the underlying asset being hedged is termed *basis risk*. As shown by Ederington (1979) the degree of basis risk a firm faces in using a hedging instrument can have a substantial effect on the usefulness of the instrument in reducing risk.[12] This risk can be measured as the correlation between the change in the price of the asset being hedged and the change in the price of the asset underlying the financial instruments available for hedging: The lower this correlation, the greater the basis risk from hedging. Ederington shows that the lower this correlation, the less effective hedging is in reducing risk, and consequently the less extensively a firm should hedge to minimize risks.

For an oil and gas producer the location of production can have a significant impact on the basis risk it faces in hedging production.[13] The spot prices of oil and gas can vary substantially between regions. For example, over the period November 1993 to May 1994, the correlation coefficient between the spot prices of natural gas sold at the Wheeling Ridge Hub, located in California, and that sold at Henry Hub, located in Louisiana, is slightly less than 0.30; spot prices between Kern River, located in the Rocky Moun-

[12] Much of the theoretical discussion in Ederington (1979) draws on earlier work by Stein (1961) and Johnson (1960).

[13] I thank the referee for pointing this out.

tains, and Henry Hub has a correlation coefficient of 0.33.[14] During the 1992 to 1994 period, the future contracts on natural gas traded on NYMEX, the only exchange offering this product, were based on the price at the Henry Hub. The most liquid futures contracts on crude oil were based on the price of West Texas intermediate crude. Companies with production in regions where prices have a lower correlation with prices at Henry Hub and the price of West Texas intermediate crude likely face greater basis risk in using these exchange-traded derivatives. Although companies facing greater basis risk when using exchange-traded derivatives can hedge using alternative means (e.g., fixed price contracts or forward agreements), the markets for these alternative means may not be considered as liquid or accessible.[15]

To control for the basis risk associated with hedging, I include a variable indicating the location of production. This variable is defined as the amount of the company's total production located in the regions where the spot price of oil and gas is most highly correlated with the price at Henry Hub and the price of West Texas intermediate crude as a fraction of the company's total production. These "highly correlated" locations include Louisiana, Texas, Kansas, Oklahoma, Arkansas, and the Gulf Coast. The amount of basis risk a firm faces in using exchange-traded derivatives is assumed to be inversely related to this variable. If basis risk reduces the effectiveness of hedging in reducing risk, the extent of hedging should be positively related to this variable.

B.5. Other Control Variables

Table I summarizes the definitions of the independent variables, the predicted signs on the coefficients of each variable, and the data sources. In addition to the independent variables discussed above, variables are included to control for several other attributes that may affect the hedging policies of oil and gas producers.

The degree of diversification of the firms' assets is accounted for using the fraction of the firms' total revenues from oil and gas production. The method the company uses to account for drilling and exploration expenditures (i.e., dry holes, expired leases, and delay rentals) is controlled for using a binary variable that is set equal to one if the company uses the successful efforts method, and equal to zero if the firm uses the full cost method. As discussed in Malmquist (1990), these methods usually produce different results in the

[14] These figures are from the Energy Information Administration, "Natural Gas 1996: Issues and Trends."

[15] In more recent years, at least partially in response to concerns over basis risks, several financial instruments have been introduced that should help alleviate the location basis risks companies face in hedging. For example, in 1995 the Kansas City Board of Trade established a future contract (for delivery of natural gas at Waha Hub) that is more highly correlated with the natural gas prices in the western United States. Additionally, an active over-the-counter market now exists for companies to hedge basis risks.

financial statements. For example, relative to successful efforts, full cost yields a higher book value of assets and reduces the sensitivity of net income to drilling and exploration expenditures.

The level of cash holdings is accounted for using the ratio of cash and marketable securities to the market value of total assets as a proxy for the level of cash reserves. Similar to Pulvino (1998), mentioned above, Harford (1999) and Opler et al. (1999) discuss that cash reserves can provide a valuable source of funds for investments when current internally generated funds fall short and external financing is costly.

Finally, differences between firms operating primarily in the oil industry versus those operating primarily in the gas industry are controlled for using the ratio of revenues from oil production to total revenues from oil and gas production.

C. Data Characteristics

C.1. Descriptive Statistics—Dependent Variable

Table II contains descriptive statistics for the firms in the sample. Although all of these companies are in the same industry, there is substantial variation in the fraction of production hedged. The distribution for the entire sample is shown in Figure 1. The fraction of production hedged appears to be relatively constant over this period. On average, firms hedged 13.8 percent of production in 1992, 14.4 percent in 1993, and 16.8 percent in 1994.

In Table III, I break hedging down by year. In 1992, more than half of the sample (54 firms) did not hedge any production, the other 43 firms hedged an average of 32.2 percent of production and a median of 24.1 percent. In 1994, 57 companies hedged production. The extent of hedging by these 57 firms is an average of 28.4 percent of 1994 production and a median of 23.3 percent. Therefore, although risk management activities appear to become more widespread over this period, of those companies hedging, there is a slight drop in the fraction of production they hedge.

The prices of oil and gas during the period 1992 to 1994 are mixed. The price of oil decreases over this period and the price of natural gas increases. In 1992, the average price per barrel of West Texas intermediate crude oil was \$20.54, in 1993 it was \$18.48, and in 1994 it was \$17.18. The average price of gas at Henry Hub per thousand cubic feet (mcf) increased from \$1.73 in 1992 to \$2.11 in 1993. The average price per mcf of gas in 1994 was \$1.94.

The use of risk management by oil and gas producers is not particularly unusual relative to risk management practices in other industries. For example, Tufano (1996) reports that, for a sample of 48 companies in the gold mining industry, a little more than 84 percent hedged a fraction of their production over the period 1990 to 1993. Risk management activities by these 48 gold mining companies cover an average of 25.6 percent of their production and a median of 22.9 percent. In a study of 372 Fortune 500 companies that have foreign exchange rate exposure, Géczy et al. (1997) report that 41.4 percent use currency derivatives.

Table I

Variable Definitions and Summary of Hypotheses

This table presents the independent variables for the analysis of hedging of oil and gas producers. It provides the variable's definition, the source of data for the variable, and the correlation between the variable and the fraction of production that oil and gas producers hedge as predicted by each hypothesis. In addition to the debt rating variable presented in the table, an additional variable that considers the rating given by S&P is described in Table VII. Production expenses include those costs incurred to operate and maintain productive wells and related equipment. For example, these costs include labor, repairs, maintenance, materials, supplies, fuel consumed, and production taxes. Gas is converted to barrels produced at a rate of 6,000 cubic feet (mcf) per barrel. The simulated marginal tax rates are the before-interest-expense simulated marginal tax rates from the database of simulated marginal tax rates described by Graham (1996b). For observations when the simulated marginal tax rate is not available, I use a trichotomous variable as suggested by Graham (1996b). The marginal rate is estimated as: 34 percent if the firm has no tax loss carryforwards for the year and net income is positive, 17 percent if net income is negative or the firm has tax loss carryforwards, and zero if the firm has tax loss carryforwards and negative net income. Bonuses include cash bonuses plus the market value of any stock bonuses. The Black–Scholes pricing formula is used to estimate the value of options awarded. Parameters for the Black–Scholes model are estimated using the assumptions discussed in Yermack (1995). Insider ownership excludes options held by officers and directors.

		Hypothesis				
		Financial Contracting Costs				
Independent Variables	Specification [Source]	Investment Coordination	Financial Distress	Underinvestment	Tax	Risk Aversion
External financing costs						
Dividend payout	(Dividends paid to common stockholders)/(Net income after taxes before extraordinary items) [COMPUSTAT]	−				
Bond rating	Indicator variable, if the firm's debt is rated by S&P (1) or not (0) [COMPUSTAT]	−				
Market value of assets	(Number of common shares outstanding * End-of-year price per share) + (Book value of total assets − Book value of equity) [COMPUSTAT]	−				
Debt ratio	(Long term debt + Current debt)/(Market value of total assets) [COMPUSTAT]	+	+	+		
Debt constraint	Indicator variable = 1 if debt ratio > median for the sample and current ratio < median of the sample	+				

Investment opportunities						
Investment expenditure	(Total costs incurred in oil and gas property acquisition, exploration, and development)/Market value of assets [10k and Annual Report]	+	+	+		
Operating characteristics						
Production costs	(Total production costs excluding depreciation, depletion, and amortization)/Number of barrels produced [10k and Annual Report]	+				
Convexity of tax function						
Marginal tax rate	The simulated marginal tax rate				−	
Tax rate indicator	Indicator variable = 1 if the firm's marginal tax rate is <34 percent				+	
Compensation structure						
Exercisable options owned by insiders	The number of options held by officers and directors that are exercisable within 60 days [1993 Proxy Statement and 10k]					−
Exercisable options per insider	Exercisable options owned by insiders/Number of officers and directors [1993 Proxy Statement and 10k]					−
Total options per officer	The number of exercisable and unexercisable options held by officers/Number of officers for which information is available [1993 Proxy Statement and 10k]					−
CEO compensation	Value of option awarded to the CEO/Salary + Bonus compensation [1993 Proxy Statement and 10k]					−
Ownership structure						
Insider ownership	Log of: Number of shares owned by officers and directors * Year-end market price per share [1993 Proxy Statement, 10k, and Compustat]					+
Fraction of shares owned by insiders	Percentage of total outstanding common shares owned by officers and directors [1993 Proxy Statement and 10k]					+
Five percent blockholders	Number of beneficial owners of more than five percent of outstanding shares of common stock, excluding officers and directors [1993 Proxy Statement and 10k]					−

continued

Table I—*Continued*

Independent Variables	Specification [Source]	Hypothesis: Financial Contracting Costs: Investment Coordination	Financial Distress	Underinvestment	Tax	Risk Aversion
Basis risk						
Location	Production in Louisiana, Texas, the Gulf of Mexico, Oklahoma, Kansas, and Arkansas/Total production [10k and Annual Report]					
Other control variables						
Diversification	Revenues from oil and gas production/Total revenues [10k and Annual Report]					
Accounting method	Indicator variable: = 1 if the firm uses successful efforts to account for exploration and development; Indicator variable: = 0 if the firm uses full cost [Compustat]					
Cash ratio	Cash and cash equivalents/Market value of assets [Compustat]					
Production mix	Revenues from oil production/Total revenues from oil and gas production [10k and Annual Report]					

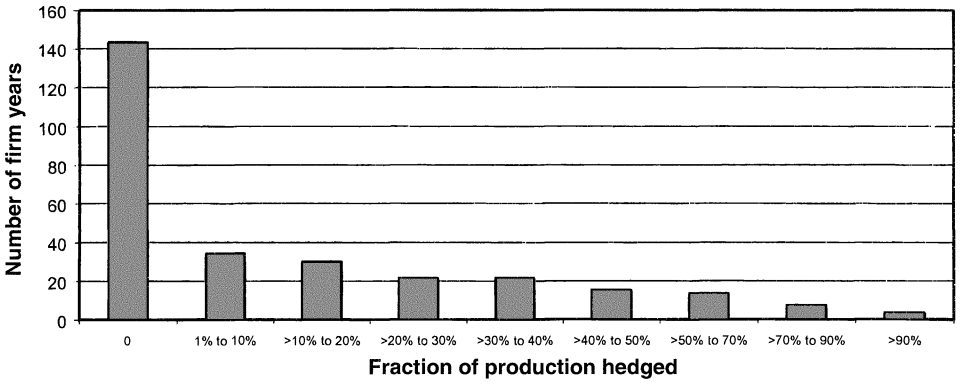

Figure 1. Fraction of annual production hedged by oil and gas producers, 1992 to 1994. The fraction of production hedged is defined as the fraction of annual production of oil and gas—expressed as barrel of oil equivalents (BOE)—hedged against price fluctuations. Barrels hedged included those protected from price fluctuations using derivatives, fixed price contracts, and volumetric production payments. This figure is based on data for 100 oil and gas producers (SIC code 1311).

In Table IV I present a breakdown of the frequency of different types of instruments used to manage price risks. The most commonly used instrument is a swap contract, used by slightly less than 51 percent of the firms that hedged production in 1994. The other frequently used instruments include fixed price contracts, used by 40.4 percent of hedgers, and futures or forwards, used by 37 percent of those hedging.[16] As discussed above, because of data limitations, I assume that barrels hedged by put options are equivalent to those covered by forward sales. This assumption may overstate the fraction of production hedged by those using out-of-the-money or at-the-money put options. The extent to which options are used by these firms, however, should help limit any bias this assumption introduces to my analysis. Options were used by approximately 10.5 percent of those hedging in 1994. Further, when these firms are removed from the sample, the results are comparable to those presented here.

These data are comparable to the results from other studies examining specific aspects of derivative usage in the oil and gas industry. In the "Wharton Survey of Derivative Usage among U.S. Non-Financial Firms" for 1994, nine of the 19 companies (47 percent) with a primary SIC code 13 or 29 who responded reported that they use derivatives. In 1995, 11 of the 24 companies (45.8 percent) with a two-digit SIC code of 13 or 29 who responded

[16] Fixed price contracts are almost exclusively entered into as part of marketing natural gas production. As discussed in "Natural Gas 1996: Issues and Trends" by the Energy Information Administration, natural gas contracts that specified volumes and pricing were initially used by producers in response to regulations by the Federal Energy Regulatory Commission. Although these regulations were eliminated in the mid-1980s and market-sensitive contracts became available, many gas producers continue to use fixed price agreements.

Table II

Oil and Gas Producer Sample Characteristics

This table presents descriptive statistics for 100 oil and gas producers (SIC code 1311) for the years 1992 to 1994. Companies included in the sample provided data on the fraction of production hedged for this period. The fraction of production hedged is defined as the fraction of annual production—expressed as barrel of oil equivalents (BOE)—protected from price fluctuations using derivatives, fixed price agreements, and volumetric production payments. The other variables in the table are defined in Table I.

Variable	Number of Observations	First Quartile	Mean	Median	Third Quartile	Minimum	Maximum	Standard Deviation
Hedging policy								
Fraction of production hedged, 1994	97	0	0.164	0.068	0.283	0	0.975	0.215
Fraction of production hedged, 1993	98	0	0.144	0.002	0.24	0	0.975	0.221
Fraction of production hedged, 1992	97	0	0.138	0	0.211	0	0.83	0.219
External financing costs								
Dividend payout	295	0	0.178	0	0.101	0	1	0.343
Bond rating	300	0	0.261	0	0	0	1	0.439
Debt ratio	295	0.081	0.226	0.209	0.319	0	0.793	0.176
Debt constraint	291	0	0.285	0	1	0	1	0.452
Market value of total assets ($MM)	295	35.26	1454.05	134.25	632.34	1.36	48316.43	5290.09
Investment opportunities								
Investment expenditure	290	0.053	0.149	0.105	0.198	0	0.146	10.04
Acquisition expenditures	295	0.004	0.072	0.025	0.091	0	0	0.752
Exploration and development expenditures	290	0.027	0.074	0.056	0.093	0	0.639	0.076

Operating characteristics							
Production costs	291	3.42	4.85	4.58	5.98	1.18	9.47	1.86
Convexity of tax function							
Marginal tax rate	286	0.115	0.222	0.268	0.34	0	0.393	0.007
Compensation structure							
Exercisable options per insider (in 100,000)	300	0.035	0.426	0.190	0.542	0	4.347	0.649
Total options per officer (in 100,000)	297	0.200	1.192	0.702	1.595	0	10.948	1.482
CEO compensation	294	0	0.531	0.217	0.927	0	2.31	0.670
Ownership structure							
Fraction of shares owned by insiders	300	0.03	0.226	0.15	0.380	0.010	0.78	0.214
Insider ownership ($ MM)	297	1.98	24.77	5.52	17.44	0.175	360.0	57.13
Five percent blockholders	291	0	1.498	1	2	0	6	1.500
Basis risk							
Location	291	0	0.592	0.700	1	0	1	0.425
Other characteristics							
Revenues oil and gas production/ Total revenues	300	0.703	0.810	1	1	0.020	1.100	0.295
Accounting method	300	0	0.570	1	1	0	1	0.500
Cash ratio	299	0.011	0.069	0.033	0.086	<0.001	0.821	0.097
Production mix	300	0.238	0.425	0.380	0.600	0.022	1	0.247

Table III

Fraction of Production Hedged by Year

This table presents the fraction of production hedged for each of the years 1992 to 1994 by 100 oil and gas producers (SIC code 1311). The entire sample includes all companies providing data on the fraction of production hedged for the year. Hedgers include only those companies in the sample that hedge a portion of the year's production. The fraction of production hedged is defined as the fraction of annual production—expressed as barrel of oil equivalents (BOE)—protected from price fluctuations using derivatives, fixed price agreements, and volumetric production payments.

	Entire Sample			Hedgers		
	No. of Firms	Mean Percentage of Production Hedged	Median Percentage of Production Hedged	No. of firms	Mean Percentage of Production Hedged	Median Percentage of Production Hedged
1992	97	13.8	0	43	32.2	24.1
1993	98	14.4	0.2	49	29.6	24
1994	97	16.8	6.8	57	28.4	23.3

reported using derivatives.[17] In a 1996 survey by Arthur Andersen of 92 oil and gas companies regarding the types of tools they use to manage price risk, 53 percent reported using futures, 49 percent used swaps, 41 percent used options, 32.6 percent used forwards, and 14 percent used volumetric production payments.[18] The results from the Arthur Andersen survey suggest that the use of price risk management tools by companies in this industry has continued to grow into 1995 and 1996.

C.2. Descriptive Statistics—Independent Variables

Descriptive statistics of the independent variables are presented in Table II. There is substantial variation in many of these variables so I present quartiles as well as the averages for each variable. This table shows a wide variation in financing policies and size within the sample. The ratio of total debt to the market value of total assets ranges from zero percent to more than 79 percent. One-fourth of these companies' debt ratios are less than nine percent, and another fourth of firms' total leverage ratios are greater than 31 percent. The median market value of total assets for the sample is slightly more than $134 million, with one-fourth having less than $36 million in assets and another fourth having more than $632 million in total assets.

More than half the companies in the sample do not pay out dividends, and almost 75 percent have an annual dividend payout less than 10 percent of net income. Because the bond rating variable is an indicator variable, its

[17] I appreciate Gordon Bodnar's help in obtaining this information.

[18] These data are obtained from Arthur Andersen's "1996 U.S. Oil & Gas Industry Outlook Survey Results" and Jim Petrie at Arthur Andersen.

Table IV

Instruments Oil and Gas Producers Use to Manage Price Risk

This table presents the different types of financial instruments used by companies in the sample that hedge their production in 1994 (57 companies). Companies can use more than one type of instrument during the year. The values for each instrument refer to the fraction of firms hedging in 1994 that report using the instrument. The sample consists of 100 oil and gas producers and is described in Table II.

Financial Instrument	Fraction Indicating Use
Options	10.5%
Swaps	50.8%
Fixed price contracts	40.4%
Futures or forwards	37.0%
Volumetric production payments	9.8%

mean value (26.1 percent) is equal to the proportion of firms that have debt rated by Standard & Poor's. Both of these values are comparable to the findings of studies examining a large cross section of industries. For example, Sharpe and Nguyen (1995) report that 59 percent of the 2,024 companies they examined from the COMPUSTAT files do not pay dividends and 21 percent have debt rated by Standard & Poor's.

The estimated marginal tax rate for these companies ranges from zero percent to 39.3 percent with more than half of these companies having a marginal tax rate less than 34 percent. The median marginal tax rate is 26.8 percent, and the mean is 22.2 percent. Thus, a considerable proportion of the firms face a marginal tax rate that falls in the progressive region of the tax code.[19] By comparison, Graham (1996a) reports that for all firms on COMPUSTAT the average simulated marginal tax rate in 1992 was 20.0 percent.

The ownership structure and compensation policies of these firms vary substantially. The median percentage of shares owned by officers and directors is 15 percent of the shares outstanding and varies from three percent for the 25th percentile to 38 percent for the 75th percentile. Based on the structure of the CEO's 1993 compensation, the median ratio of the value of stock options awarded to salary and bonuses is 21.7 percent. For a quarter of the firms, this ratio is more than 92 percent.

C.3. Comparison of Firms in the Sample to Nonrespondent Firms

To examine the extent to which the 100 respondents are representative of the 177 oil and gas producers contacted for this study, I compare the companies in the sample to the oil and gas producers who did not provide hedg-

[19] The simulated tax rate is not available for slightly less than 12 percent of the firm-year observations. In these cases, I follow Graham's suggestion and estimate the marginal tax rate based on a trichotomous variable that I calculate using the procedure described in Graham (1996b).

ing data. The mean market value of assets of the 77 oil and gas producers that did not respond is a little more than $818 million and the median is $47.03 million. The average of the ratio of debt to total assets for the 77 nonrespondents is 25.4 percent and the median is 20.8 percent. Compared to the firms in the sample, the companies that did not respond appear to have similar debt ratios and fewer assets. I do not have information on the operating characteristics of the nonrespondents, but the operating characteristics of the firms in the sample are similar to industry averages. For example, in 1992, the average production cost per barrel of oil equivalent (BOE) for the oil and gas industry was $4.50, for the firms in the sample it was $4.85.[20] Overall, these operating and financial characteristics, along with the results of the Wharton Survey of derivative usage and the survey by Arthur Andersen on the types of risk management tools used, suggest that the companies in the sample are representative of the oil and gas production industry.

C.4. Univariate Analysis

Table V shows the correlation between my measure of hedging and the independent variables. The correlations indicate that there is fairly substantial time series variation in hedging. For example, the correlation coefficient between the fraction of production hedged in 1992 and that hedged in 1994 is 0.582. In all three years, the fraction of production hedged is positively correlated with the debt ratio and the location variable. The fraction of production hedged is negatively correlated with the production mix variable, defined as the ratio of oil production revenues to total production revenues.

Table VI presents the results comparing the characteristics of companies I classify as extensive hedgers (observations where at least 25 percent of the year's production is hedged) to those not hedging and to those I classify as minor hedgers (observations where hedging covered between one percent and 25 percent of the years' production). A Wilcoxon test for difference in medians identifies a considerable number of differences between the firms classified as hedging extensively and those in the other two groups. For example, firms hedging more than 25 percent of production tend to have a greater debt ratio and fewer total assets than either of the other groups. Also, both the dividend payout and the fraction of firms with rated debt are less for extensive hedgers than those classified as minor hedgers. All of these variables are proxies for financing costs, and all of these relations are consistent with theories suggesting that financial contracting costs affect hedging policies. Other differences between these groups include the production mix and the location of reserves. The extensive hedgers focus more on gas

[20] The industry data are from Salomon Brothers, Independent Oil and Gas Producers-Performance Review and Outlook, February 1994.

Table V
Pearson Correlation Coefficients

This table presents correlation coefficients for selected variables. The sample and the variables are defined in Table II. Coefficients with an asterisk (*) are significantly different from zero at the 1 percent level. The variables are defined in Table I.

	Fraction Hedged, 1992	Fraction Hedged, 1993	Fraction Hedged, 1994	Dividend Payout	Bond Rating	Debt Ratio	Market Value of Assets	Investment Expenditure	Production Costs	Marginal Tax Rate	Exercisable Options	CEO Compensation	Percentage Owned by Insiders	Insider $ Ownership	Cash Ratio	Location	Production Mix
Fraction hedged, 1992	1	0.811*	0.582*	−0.110	−0.026	0.266*	−0.087	−0.003	−0.027	0.167	0.041	0.155	−0.078	0.019	−0.076	0.375*	−0.309*
Fraction hedged, 1993		1	0.735*	−0.109	−0.058	0.220*	−0.106	0.004	0.013	0.131	0.022	0.107	−0.067	0.005	−0.065	0.273*	−0.231*
Fraction hedged, 1994			1	0.001	0.037	0.274*	−0.094	−0.032	0.054	0.096	0.002	0.073	−0.175*	0.009	−0.077	0.233*	−0.157*
Dividend payout				1	−0.401*	−0.021	0.377*	−0.148	−0.063	0.222*	−0.035	−0.038	−0.288*	0.237*	−0.228*	0.037	−0.159*
Bond rating					1	0.180	0.389*	−0.065	−0.258*	0.321*	0.092	0.295*	−0.382*	0.170	−0.207*	0.153*	0.056
Debt ratio						1	−0.026	0.179	−0.040	0.155	−0.025	0.118	−0.047	−0.098	−0.233*	0.028	−0.195*
Market value of assets							1	−0.151	−0.075	0.220*	0.115	0.127	−0.234*	0.073	−0.104	0.068	0.188
Investment expenditure								1	0.092	−0.102	−0.109	−0.047	0.090	−0.109	−0.123	0.314*	−0.006
Production costs									1	−0.222*	−0.102	−0.080	0.189*	−0.147	0.073	0.088	0.328
Marginal tax rate										1	−0.078	0.023	−0.129	0.173	−0.151	0.011	−0.136
Exercisable options											1	0.055	−0.211*	−0.084	0.016	0.165*	−0.013
CEO compensation												1	−0.301*	−0.068	−0.058	0.078	−0.141
Percentage owned by insiders													1	0.235*	0.112	0.083	−0.002
Insider $ ownership														1	0.013	0.003	0.032
Cash ratio															1	0.183	0.135
Location																1	−0.313*
Production mix																	1

Table VI

Characteristics of Sample Companies by the Fraction of Annual Production Hedged

This table presents the mean and median values according to the fraction of production that companies hedge for the year. For each year between 1992 and 1994, a company is classified as a zero hedger if it does not hedge production during the year, a minor hedger if it hedges between zero and 25 percent of the year's production, and an extensive hedger if it hedges 25 percent or more of annual production. The table also reports p-values from Wilcoxon rank sums test for the differences in the median of each characteristic between zero hedgers and extensive hedgers and between minor hedgers and extensive hedgers. p-values that are less than 10 percent are in bold. The sample and variables are defined in Table II.

	Zero Hedgers	Minor Hedgers	Extensive Hedgers	p-Values Difference in Median	
Variable	Median	Median	Median	Zero Hedgers vs. Extensive Hedgers	Minor Hedgers vs. Extensive Hedgers
Fraction of production hedged	0	13.2%	41.3%	**(0.001)**	**(0.001)**
Dividend payout	0	0	0	(0.612)	**(0.006)**
Bond rating	0	0	0	(0.635)	**(0.001)**
Debt ratio	0.161	0.218	0.282	**(0.002)**	**(0.080)**
Debt constraint	0	0	0	(0.121)	(0.622)
Market value assets ($ MM)	56.85	351.90	223.02	**(0.001)**	**(0.016)**
Investment expense	0.106	0.118	0.099	(0.427)	(0.203)
Production costs	$4.93	$3.98	$4.31	**(0.009)**	(0.669)
Marginal tax rate	0.192	0.303	0.276	**(0.015)**	(0.741)
CEO compensation	0	0.577	0.378	**(0.053)**	(0.168)
Exercisable options (in 100,000)	2.000	3.106	1.602	(0.811)	**(0.079)**
Exercisable options per insider (in 100,000)	0.207	0.239	0.138	(0.735)	(0.259)
Total options per insider (in 100,000)	0.643	10.559	0.790	**(0.026)**	(0.862)
Fraction of shares owned by insiders	0.235	0.104	0.137	**(0.024)**	**(0.090)**
Insider ownership ($ MM)	4.420	8.625	5.438	(0.633)	**(0.005)**
Five percent blockholders	1	1	1	(0.843)	**(0.011)**
Oil and gas sales/Total revenues	1	0.95	1	(0.735)	(0.161)
Accounting method	1	1	0	**(0.047)**	**(0.011)**
Cash ratio	0.045	0.027	0.026	(0.101)	(0.887)
Location	0.375	0.698	1	**(0.001)**	**(0.001)**
Production mix	0.360	0.496	0.250	**(0.001)**	**(0.001)**

production and are more likely to operate in regions where oil and gas prices are most highly correlated with prices on which exchange-traded derivatives are based.

III. Multivariate Analysis

A. Tobit Model and Model Specifications

To investigate the characteristics of a firm related to its hedging policy, I estimate cross-sectional regressions using a tobit model. In these regressions, the fraction of production hedged is regressed on variables that measure external financing costs, tax structure, compensation policy, and ownership structure, as well as control variables for diversification, accounting method, the location of production, and the source of the production revenues.

The tobit model is used because there are a significant number of zero observations for the fraction of production hedged, as can be seen in Figure 1. This model implies that the observed value of the dependent variable is censored at zero. There are at least two reasons why the fraction of production hedged could be censored. First, if there are costs associated with initiating a hedging program that prohibit some companies from hedging production, the dependent variable will be censored. Second, if managers anticipate that the price of oil and gas will increase and thus increase the exposure of the company's cash flow to oil and gas prices, the fraction of production hedged will be censored. (I cannot observe negative hedging.)

For each of the independent variables, I examine the assumption of homoskedasticity of the error terms from these regressions using a chi-square test. This assumption is rejected for the log of total assets. So, the regressions in Tables VII and VIII are estimated using a tobit model that corrects for heteroskedasticity induced by the log of total assets. However, the significance of the coefficients using adjusted standard errors does not differ materially from those not adjusted for heteroskedasticity.

Regressions on a pooled sample of oil and gas producers for 1992 through 1994 are reported in Table VII. Because a pooled time-series cross-sectional regression can violate the assumption of independent errors so that t-statistics may be overstated, I reestimate the regressions using annual data. The results for regressions on annual data are presented in Table VIII. The sample size for the regressions using annual data ranges between 90 and 98 observations. Therefore, although the magnitude of the estimated coefficients is comparable to those using the pooled sample, the standard error of these estimates tends to be greater, and the significance of the coefficients is generally less.

B. Results—Tobit Model

B.1. Financial Contracting

The results in Tables VII and VIII are generally consistent with hypotheses linking hedging to financing decisions. In particular, in most of these regressions, the fraction of production hedged is positively related to the ratio of debt to total assets. As discussed above, prior work reports that companies' financing costs are linked to their debt ratios. For example, Whited

Table VII

Tobit Regression Results—Analysis of Hedging-Pooled Data

The dependent variable is the fraction of the firm's annual oil and gas production that is hedged. The coefficients are marginal effects using a tobit model with censoring at zero. The *p*-values are based on heteroskedastically consistent *t*-statistics. The pooled sample consists of hedging by 100 oil and gas producers during the period 1992 to 1994. AAA (CCC) is an indicator variable that is set equal to one if S&P rates the firms debt BBB or higher (BBB− to D); the omitted category contains unrated firms. The other variables are defined in Table I. The data are presented as marginal effects with *p*-values in parentheses. Variables significant at the 10 percent level or less are in bold.

Independent Variables	(1)	(2)	(3)	(4)
Intercept	−0.165 (0.144)	**−0.209** **(0.016)**	**−0.239** **(0.007)**	−0.126 (0.307)
Dividend payout	−0.031 (0.348)	−0.013 (0.697)	−0.017 (0.641)	−0.26 (0.458)
Bond rating	**−0.054** **(0.057)**		**−0.065** **(0.048)**	**−0.081** **(0.013)**
AAA		**−0.106** **(0.008)**		
CCC		−0.020 (0.537)		
Debt ratio	**0.252** **(0.001)**	**0.175** **(0.016)**	**0.213** **(0.002)**	
Debt constraint				**0.047** **(0.024)**
Log of total assets	0.039 (0.667)	0.029 (0.761)	−0.035 (0.719)	0.075 (0.453)
Investment expenditures	0.075 (0.146)	0.071 (0.242)		**0.105** **(0.040)**
Acquire/Explore			0.084(0.259)/ −0.187(0.392)	
Production costs	0.017 (0.804)	0.109 (0.159)	−0.045 (0.555)	0.007 (0.922)
Marginal tax rate	**0.178** **(0.052)**		**0.205** **(0.036)**	
Tax indicator		0.033 (0.178)		0.017 (0.463)
Fraction of shares owned by insiders		**−0.146** **(0.040)**	−0.112 (0.104)	
Insider ownership	−0.103 (0.112)			**−0.131** **(0.056)**
Number of exercisable options held by insiders	−0.004 (0.111)			
Exercisable options per insider		**−0.060** **(0.034)**		

continued

Table VII—*Continued*

Independent Variables	(1)	(2)	(3)	(4)
Total options per officer			−0.004	
			(0.782)	
CEO compensation				**0.023**
				(0.025)
Number of blockholders		−0.003		−0.001
		(0.621)		(0.953)
Oil and gas production sales/	0.021	0.012	0.049	0.018
Total revenues	(0.576)	(0.778)	(0.243)	(0.656)
Cash ratio		0.062	0.020	
		(0.682)	(0.877)	
Location of production	**0.162**	**0.152**	**0.143**	**0.204**
	(0.001)	**(0.001)**	**(0.001)**	**(0.001)**
Accounting method	−0.036	−0.033		−0.016
	(0.121)	(0.143)		(0.470)
Production mix		**−0.132**	**−0.112**	
		(0.016)	**(0.051)**	
Number of observations	285	288	282	282
Log likelihood	−110.15	−102.99	−105.22	−115.12
Adj. R^2 (from OLS regressions)	0.166	0.206	0.188	0.133

(1992) argues that highly levered firms face high premiums for external funds. Similarly, Kaplan and Zingales (1997) report that the likelihood of a firm being financially constrained increases with its leverage.

The results for the variables pertaining to bond ratings are consistent with the predictions of the hypotheses linking corporate hedging to financial contracting costs. The fraction of production hedged is lower among companies that have obtained a debt rating—companies that I assume have undergone more capital market scrutiny and are most likely to have access to the public debt market—than among those that have not. However, these bond rating variables are only significant in the regressions using the pooled sample and for 1992.

I find no significant or consistent association between the fraction of production hedged and the log of the market value of total assets. In general, hypotheses linking hedging to financial contracting costs predict that firms with fewer assets will hedge more extensively. One possible explanation for this result, or lack thereof, is the choice of model. The tobit model does not accommodate the possibility that the extent of hedging depends on two decisions: First, a firm must decide if it is going to hedge. Then, if a firm decides to hedge, it must determine how much it will hedge. Because a tobit

Table VIII

Tobit Regression Results—Analysis of Hedging Policy, Annual Data

The dependent variable is the fraction of the firm's annual oil and gas production that is hedged. The coefficients are marginal effects using a tobit model with censoring at zero. The *p*-values are based on heteroskedastically consistent *t*-statistics. The pooled sample consists of hedging by 100 oil and gas producers during the period 1992–1994. AAA (CCC) is an indicator variable that is set equal to one if S&P rates the firms debt BBB or higher (BBB− to D); the omitted category contains unrated firms. The other variables are defined in Table I. The data are presented as marginal effects with *p*-values in parentheses. Variables significant at the 10 percent level or less are in bold.

	1992				1993				1994			
Independent Variables	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
Intercept	**−0.417** **(0.037)**	**−0.265** **(0.086)**	**−0.354** **(0.006)**	−0.167 (0.393)	−0.015 (0.948))	−0.205 (0.165)	−0.221 (0.160)	0.077 (0.743)	0.410 (0.153)	0.031 (0.877)	0.116 (0.563)	0.142 (0.621)
Dividend payout	0.072 (0.222)	0.042 (0.561)	−0.057 (0.336)	0.049 (0.432)	−0.006 (0.918)	−0.011 (0.832)	0.029 (0.613)	−0.005 (0.939)	−0.023 (0.761)	−0.015 (0.873)	−0.030 (0.743)	0.011 (0.898)
Bond rating	−0.066 (0.129)		−0.071 (0.116)	−0.062 (0.200)	−0.068 (0.135)		**−0.093** **(0.097)**	−0.070 (0.230)	−0.021 (0.761)		−0.037 (0.654)	−0.069 (0.311)
AAA		−0.091 (0.183)				**−0.111** **(0.088)**				−0.059 (0.471)		
CCC		−0.001 (0.995)				−0.052 (0.432)				−0.018 (0.824)		
Debt ratio	**0.302** **(0.009)**	0.123 (0.375)	**0.206** **(0.067)**		**0.223** **(0.085)**	0.155 (0.297)	0.181 (0.174)		**0.383** **(0.015)**	**0.279** **(0.084)**	**0.352** **(0.026)**	
Debt constraint				0.031 (0.324)				0.058 (0.110)				0.075 (0.135)
Log of total assets	−0.274 (0.133)	−0.132 (0.544)	−0.143 (0.469)	−0.107 (0.597)	−0.142 (0.449)	−0.082 (0.711)	−0.244 (0.292)	−0.156 (0.538)	−0.020 (0.922)	0.015 (0.932)	−0.093 (0.637)	0.055 (0.782)
Investment expenditures	**0.116** **(0.050)**	**0.139** **(0.074)**		**0.177** **(0.008)**	0.224 (0.175)	0.231 (0.143)		0.190 (0.322)	−0.392 (0.118)	−0.317 (0.142)		−0.244 (0.267)
Acquire/Explore			0.108(0.113)/ −0.433(0.339)				**0.294(0.096)/** −0.103(0.824)				−0.47(0.179)/ −0.33(0.492)	
Production costs	−0.128 (0.292)	−0.038 (0.821)	−0.037 (0.786)	−0.226 (0.119)	−0.011 (0.922)	0.049 (0.721)	0.021 (0.873)	−0.063 (0.641)	−0.058 (0.715)	0.112 (0.554)	0.038 (0.816)	0.043 (0.808)

Marginal tax rate	**0.387**		**0.493**		**0.387**		**0.435**		0.233		−0.288	
	(0.074)		**(0.022)**		**(0.071)**		**(0.032)**		(0.266)		(0.226)	
Tax indicator		0.022		−0.019		0.060		0.065		−0.064		−0.068
		(0.646)		(0.567)		(0.131)		(0.178)		(0.265)		(0.249)
Fraction of shares		−0.064	−0.038			−0.133	−0.118			−0.225	−0.197	
owned by insiders		(0.542)	(0.711)			(0.217)	(0.296)			(0.145)	(0.216)	
Log of market value	0.224			0.064	**−0.226**			**−0.225**	**−0.277**			−0.235
of insider ownership	(0.833)			(0.613)	**(0.056)**			**(0.072)**	**(0.059)**			(0.116)
Total exercisable options	−0.001				−0.005				**−0.010**			
held by insiders	(0.799)				(0.254)				**(0.092)**			
Exercisable options		0.003				−0.057				**−0.125**		
per insider		(0.961)				(0.248)				**(0.019)**		
Total options per officer			0.020				−0.003				−0.035	
			(0.327)				(0.877)				(0.233)	
CEO compensation				**0.032**				−0.002				0.031
				(0.055)				(0.952)				(0.123)
Number of blockholders		−0.011		−0.013		−0.002		0.004		−0.002		0.003
		(0.488)		(0.296)		(0.931)		(0.979)		(0.900)		(0.855)
Oil and gas production	**0.115**	0.095	**0.137**	0.099	−0.002	0.008	0.036	−0.026	−0.051	−0.052	−0.038	−0.036
sales/Total revenues	**(0.047)**	(0.215)	**(0.030)**	(0.106)	(0.977)	(0.929)	(0.611)	(0.819)	(0.475)	(0.488)	(0.596)	(0.645)
Cash ratio		0.178	0.185			−0.011	−0.112			−0.025	−0.075	
		(0.595)	(0.465)			(0.963)	(0.629)			(0.914)	(0.762)	
Location of production	**0.195**	**0.195**	**0.154**	**0.241**	**0.063**	**0.129**	**0.123**	**0.194**	**0.154**	**0.145**	**0.133**	**0.219**
	(0.001)	**(0.001)**	**(0.003)**	**(0.001)**	**(0.002)**	**(0.012)**	**(0.039)**	**(0.001)**	**(0.016)**	**(0.011)**	**(0.035)**	**(0.001)**
Accounting method	−0.013	−0.023		−0.155	−0.051	−0.034		−0.024	−0.022	−0.027		−0.002
	(0.683)	(0.558)		(0.643)	(0.261)	(0.445)		(0.568)	(0.646)	(0.582)		(0.967)
Production mix		−0.142	−0.125			−0.144	−0.122			−0.132	−0.158	
		(0.223)	(0.216)			(0.129)	(0.218)			(0.278)	(0.200)	
Number of observations	96	96	95	94	98	98	97	96	91	94	90	92
Log likelihood	−35.44	−32.89	−29.67	−33.98	−32.58	−34.79	−34.79	−36.18	−24.44	−22.32	−23.17	−30.15
Adj. R^2 (from OLS regressions)	0.157	0.195	0.250	0.159	0.104	0.109	0.080	0.061	0.143	0.200	0.122	0.046

model estimates one value for each coefficient, the tobit model cannot identify if firms' characteristics (e.g., total assets or location) affect these two decisions differently. As I discuss below, when I examine these decisions separately the probability that a firm hedges is increasing with the value of total assets while the extent of hedging among companies hedging tends to be decreasing in the value of total assets.

B.2. Managerial Risk Aversion and Compensation

The regression results in Tables VII and VIII provide some indication of a negative correlation between the extent of hedging and the compensation of officers and directors. In particular, for the pooled data and the annual data for 1994, the fraction of production hedged is negatively associated with the number of exercisable options held per officer and director. This result is consistent with the Smith and Stulz (1985) conjecture that stock options awarded to managers reduce their incentive to hedge, as well as with empirical evidence documented in Tufano (1996) and Schrand and Unal (1998).

However, two issues make it difficult to draw strong conclusions about the effect of options holdings on hedging. First, when executive compensation is measured as the fraction of the CEO's 1993 compensation comprised of option awards, I find a *positive* relation between the fraction of production hedged and executive compensation, opposite that predicted by theory. Second, because of data limitations, I am unable to calculate the delta of a manager's exercisable options (their sensitivity to a change in the price of the underlying stock), or these options' vega (their sensitivity to a change in the standard deviation of the underlying stock). As discussed by Guay (1999), these sensitivities determine the effect stock options have on convexity of the relation between the managers' wealth and a company's value. For example, all else equal, the wealth of a manager whose options holdings are deep in the money is not as sensitive to a change in the underlying risk of a company's equity as one whose options holdings are slightly out of the money. Smith and Stulz's (1985) prediction that executive stock option awards reduce managers' incentives to reduce a company's risks is based on the degree of convexity in the managers' incentive schemes provided by stock options. In this analysis, I assume that all stock options held by managers provide the same incentive effects.

There is no evidence that the extent of hedging is increasing in the degree of managerial stock ownership.[21] The fraction of production hedged is not positively related to the fraction of shares held by insiders or the market value of the common shares held by insiders. This result is inconsistent with the notion that managerial risk aversion affects corporate risk management

[21] I consider alternative specifications for ownership structure, including the fraction of shares owned by outside blockholders, the level of CEO ownership, the level of ownership by insiders other than the CEO, and nonlinear specifications for the level of insider ownership. The results using these alternative specifications are qualitatively similar to those presented here.

policy. The apparent negative correlation between hedging and managerial ownership, however, should be interpreted with some caution. In these regressions, one company—Louis-Dreyfus Natural Gas—has a significant impact on these results. This company follows a policy of hedging extensively. It hedged more than 90 percent of production in 1993 and 1994, the highest in the industry. This company also has relatively low managerial ownership.[22] In regressions not presented in the paper, the coefficient on the ownership variables is no longer significant when Louis-Dreyfus is excluded from the sample. The results for the other independent variables are qualitatively similar when this observation is excluded.

B.3. Tax Structure

Estimates of the company's marginal tax rate provide little support for a tax-based explanation for hedging. The coefficient on the marginal tax rate variable tends to be significantly positive, implying that companies facing a lower marginal rate hedge less extensively than those facing a higher marginal rate. I assume companies that face a lower marginal rate are more likely to face a convex tax function and, consequently, benefit from reducing the variability of taxable income. Further, the binary variable indicating whether a firm's estimated marginal tax rate falls in the convex region of the tax structure is not significant in any of the regressions.

B.4. Basis Risk

In virtually every regression, the coefficient on the variable indicating the location of production is positive and statistically significant (p–values < 0.05). This result suggests that basis risk is an important determinant of oil and gas producers' risk management policies. I find more extensive hedging by companies whose production is mainly in regions where spot prices are most highly correlated with the price on which exchange-traded derivatives are based.

B.5. Other Variables

A couple of other results from these regressions are also noteworthy. First, the results point to a negative association between hedging and the ratio of revenues from oil production to total revenues from production. In general, companies that are primarily gas producers hedge production more exten-

[22] In 1993, the officers and directors of Louis-Dreyfus Natural Gas owned less than 1.5 percent of the total shares outstanding. Slightly less than 72 percent of the shares outstanding are owned by S. A. Louis-Dreyfus et Cie, a company privately owned by members of the Louis-Dreyfus family. The chairman of the Board of Louis-Dreyfus Natural Gas is also the president and chairman of the board of S. A. Louis-Dreyfus et Cie. When the ownership of S. A. Louis-Dreyfus et Cie is included as part of the shareholding by Louis-Dreyfus Natural Gas' officers and directors, the coefficient on the ownership variables is statistically insignificant.

sively than their oil-based counterparts. This may be somewhat surprising given that exchange-traded contracts on oil have been available since 1983 and exchange-traded derivatives on gas prices have only been available since 1990.

There are several differences between the oil industry and the gas industry that might help explain this behavior. In particular, the price of natural gas was regulated until 1985. Therefore, many natural gas companies matured in an environment in which price risk was not a significant concern. In recent years, however, the price of natural gas has been relatively volatile. For example, over the period from January 1991 to January 1995, the coefficient of variation of monthly oil prices was 0.116 while the coefficient of variation of monthly gas prices was 0.205. Additionally, even during periods of gas price regulation, other federal regulations resulted in gas producers entering into fixed-price contracts, which are less common in the oil industry. Many of these companies continued to use these contracts after these regulations ceased and market-sensitive contracts became available.

Second, these results provide little indication of a link between hedging policy and accounting policy, at least with respect to the method used to account for investment expenditures. The variable indicating whether a firm uses full cost or successful efforts to account for investment expenditures is not statistically significant in any of these regressions.

C. Cragg Model—Separating the Decision to Hedge from the Extent of Hedging

Though the decision to hedge can be a function of the benefits the company expects to realize from hedging (e.g., a reduction in expected bankruptcy costs), there are other factors that affect this decision. There are at least three different reasons why a company's managers decide not to hedge, even if they recognize the benefits of hedging: (1) they believe the company's shareholders are using the company to gain exposure to commodity price risk (for a further discussion of this argument, see Hu (1995)), (2) there are no suitable financial products to hedge the company's exposure, and (3) managers feel that initiating a risk management program is too costly. The issue of costs is particularly relevant for the relation between hedging policy and firm size. Several previous empirical studies (e.g., Nance et al. (1993), Mian (1996), and Géczy et al. (1997)) find that firms with more assets are more likely to hedge. These studies contend that the positive correlation between size and hedging can be attributed to significant economies of scale in information and transaction costs of hedging. Based on this argument, a firm's size should be positively related to the probability that the firm hedges. However, theories linking risk management to financing costs suggest that hedging can benefit firms with fewer assets more than it can those with greater assets. Therefore, the extent to which a firm hedges, once it decides to hedge, is predicted to be negatively correlated with size.

As noted in the preceding discussion, the tobit model does not accommodate the possibility that a firm's hedging policy depends on two decisions which could have different determinants. In an effort to disentangle these relations, I use a variant of the tobit model proposed by Cragg (1971). The Cragg model applies when the probability of a nonlimit outcome (e.g., the decision to hedge production) is determined separately from the level of the nonlimit outcome (e.g., the fraction of production to hedge). Therefore, this model is a combination of a binomial probit (i.e., the decision equation) and a conditional regression (i.e., the regression equation for nonzero outcomes). I reestimate the model specifications from Tables VII and VIII using Cragg's model. The results from these regressions are presented in Table IX for the pooled data and in Table X for the annual data.

C.1. Probit Model Results—The Decision to Hedge

Regressions 1 to 4 in Table IX and all of the regressions in Table X, Panel A, are binomial probits. These regressions consider the factors related to a firm's decision to hedge and are of particular interest because they are comparable to studies using a binary variable to classify a company as a hedger or nonhedger (e.g., Nance et al. (1993), Dolde (1993), Mian (1996), and Géczy et al. (1997)). Consequently, these binomial probit regressions shed light on the additional information provided by a continuous measure of hedging.

The results from the probit regressions identify several variables as significantly related to a company's decision to hedge production. In particular, the coefficients on the log of total assets and the location variable are both positive. The result for total assets supports the notion that significant economies of scale in the costs of hedging discourage companies with fewer assets from initiating a risk management program. As discussed above, Nance et al. (1993), Mian (1996), and Géczy et al. (1997) also document a positive correlation between total assets and the likelihood that a firm will hedge. The result for the location variable implies that companies whose output prices are most highly correlated with the price of exchange-traded derivatives are more likely to hedge. One interpretation of this result is that some companies do not hedge because the risk management instruments available are not suitable for their exposures and therefore they may not be able to hedge price risks effectively.

The regressions provide some evidence that the likelihood that a company hedges is negatively correlated with the fraction of shares owned by managers, opposite that predicted by theory. This negative relation is statistically significant for the pooled sample and for 1994, and it remains significant when Louis-Dreyfus Natural Gas is taken out of the sample. As I discuss below, this negative correlation may be attributed to "self-selection" by the managers. In other words, the more positive a manager's outlook is toward future oil and gas prices, the more likely she is to increase her shareholdings and the less likely she is to hedge.

Table IX
Cragg's Model—Pooled Data

The dependent variable is the fraction of production that oil and gas producers hedge. The pooled sample consists of hedging by 100 oil and gas producers during the period 1992 to 1994. Regressions 1 to 4 use a binary probit model to estimate the likelihood that a firm hedges. Regressions 5 to 8 use a truncated model to estimate the relation between the independent variables and the level of hedging (given that a firm hedges). The variables are defined in Tables I and VIII. The data are presented as marginal effects with *p*-values in parentheses. Variables significant at the 10 percent level or less are in bold.

	Binomial Probit *(hedge or don't hedge)*				Truncated Model *(extent firms hedge)*			
Independent Variables	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Intercept	**−0.954 (0.010)**	**−0.445 (0.064)**	**−0.622 (0.015)**	**−0.965 (0.008)**	**0.362 (0.054)**	0.026 (0.817)	0.102 (0.396)	**0.494 (0.012)**
Dividend payout	0.099 (0.391)	0.116 (0.342)	0.115 (0.323)	0.096 (0.410)	**−0.197 (0.001)**	**−0.123 (0.021)**	**−0.143 (0.007)**	**−0.169 (0.005)**
Bond rating	−0.077 (0.427)		−0.131 (0.194)	−0.112 (0.263)	**−0.068 (0.099)**		−0.059 (0.123)	**−0.084 (0.067)**
AAA		**−0.248 (0.057)**				−0.022 (0.692)		
CCC		0.059 (0.616)				−0.045 (0.354)		
Debt ratio	0.328 (0.107)	0.213 (0.299)	0.311 (0.115)		**0.369 (0.001)**	**0.397 (0.001)**	**0.347 (0.001)**	
Debt constraint				0.001 (0.985)				**0.086 (0.009)**
Log of total assets	**0.546 (0.020)**	**0.625 (0.012)**	0.302 (0.231)	**0.790 (0.001)**	0.059 (0.622)	−0.141 (0.216)	−0.180 (0.121)	−0.032 (0.791)
Investment expenditures	0.105 (0.485)	0.107 (0.488)		0.201 (0.188)	0.022 (0.627)	0.010 (0.819)		0.053 (0.264)
Acquire/Explore			0.119(0.464) 0.067(0.883)				0.021(0.633) **−0.707(0.022)**	
Production costs	−0.036 (0.857)	0.053 (0.819)	−0.097 (0.678)	−0.127 (0.539)	0.112 (0.256)	**0.366 (0.001)**	**0.204 (0.047)**	**0.213 (0.046)**

Marginal tax rate	0.412 (0.169)		**0.642** **(0.036)**		**0.407** **(0.006)**		0.242 (0.111)	
Tax indicator		−0.035 (0.658)		−0.056 (0.475)		**0.115** **(0.001)**		**0.119** **(0.001)**
Fraction of shares owned by insiders		**−0.461** **(0.019)**	**−0.446** **(0.025)**			−0.027 (0.760)	−0.056 (0.541)	
Insider ownership	0.155 (0.492)			0.148 (0.486)	**−0.329** **(0.003)**			**−0.369** **(0.001)**
Total exercisable options held by insiders	−0.001 (0.934)				**−0.010** **(0.006)**			
Exercisable options owned per insider		−0.122 (0.103)				**−0.088** **(0.028)**		
Total options owned per top insider			**0.055** **(0.095)**				**−0.033** **(0.035)**	
CEO compensation				0.023 (0.414)				**0.036** **(0.048)**
Number of blockholders		0.008 (0.752)		0.029 (0.213)		**−0.021** **(0.052)**		−0.019 (0.116)
Oil and gas production sales/Total revenues	0.144 (0.215)	0.015 (0.898)	0.124 (0.293)	0.117 (0.331)	−0.007 (0.887)	**0.124** **(0.024)**	0.075 (0.166)	−0.034 (0.574)
Cash ratio		0.189 (0.596)	0.172 (0.633)			0.001 (0.997)	0.016 (0.918)	
Location of production	**0.334** **(0.001)**	**0.390** **(0.001)**	**0.377** **(0.001)**	**0.406** **(0.001)**	**0.135** **(0.004)**	**0.077** **(0.082)**	**0.102** **(0.025)**	**0.189** **(0.001)**
Accounting method	−0.052 (0.456)	−0.051 (0.477)		−0.021 (0.765)	−0.036 (0.239)	−0.056 (0.070)		−0.011 (0.730)
Production mix		−0.074 (0.651)	−0.025 (0.879)			**−0.359** **(0.001)**	**−0.298** **(0.001)**	
Number of observations	292	295	289	289	145	146	145	141
Log likelihood	−173.99	−170.17	−168.37	−168.97	77.60	91.36	83.26	75.52
Adj. R^2 (from OLS)	0.146	0.165	0.159	0.161	0.342	0.464	0.383	0.354

Table X
Cragg's Model—Annual Data

The dependent variable is the fraction of production that oil and gas producers hedged. The sample consists of annual data for 100 oil and gas producers for the period 1992 to 1994. The regressions in Panel A use a binary probit model to estimate the likelihood that a firm hedges. The regressions in Panel B use a truncated model to estimate the relation between the independent variables and the level of hedging, given that a firm hedges. The coefficients are the marginal effects. The variables are defined in Table I and VIII. The data are presented as marginal effects with *p*-values in parentheses. Variables significant at the 10 percent level or less are in bold.

	1992				1993				1994			
Independent Variables	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
					Panel A: Binomial Probit Model							
Intercept	−0.969 (0.157)	−0.743 (0.093)	**−0.760** **(0.096)**	**−10.13** **(0.085)**	−0.833 (0.204)	−0.578 (0.191)	**−0.804** **(0.093)**	0.581 (0.362)	−0.867 (0.168)	−0.249 (0.567)	−0.529 (0.257)	−0.790 (0.216)
Dividend payout	0.136 (0.496)	0.216 (0.297)	−0.223 (0.227)	0.217 (0.288)	0.149 (0.480)	0.109 (0.617)	0.100 (0.627)	0.013 (0.949)	0.196 (0.402)	0.295 (0.292)	0.211 (0.382)	0.256 (0.299)
Bond rating	0.022 (0.887)		0.032 (0.851)	−0.050 (0.761)	−0.284 (0.133)		**−0.351** **(0.074)**	−0.243 (0.193)	−0.078 (0.667)		−0.206 (0.306)	−0.061 (0.755)
AAA		−0.246 (0.264)				−0.308 (0.199)				−0.290 (0.244)		
CCC		0.198 (0.325)				−0.292 (0.192)				0.243 (0.357)		
Debt ratio	0.191 (0.612)	0.018 (0.960)	0.118 (0.746)		0.482 (0.208)	0.500 (0.189)	0.459 (0.227)		0.516 (0.133)	0.397 (0.283)	0.574 (0.095)	
Debt constraint				−0.056 (0.663)				0.013 (0.929)				0.051 (0.708)
Log of total assets	−0.128 (0.749)	0.300 (0.477)	−0.303 (0.486)	0.279 (0.446)	**10.09** **(0.022)**	**10.03** **(0.051)**	0.776 (0.144)	**10.257** **(0.010)**	**0.777** **(0.084)**	0.710 (0.125)	0.473 (0.312)	**10.04** **(0.022)**
Investment expenditures	0.152 (0.373)	0.186 (0.313)		0.264 (0.108)	0.378 (0.385)	0.350 (0.435)		0.375 (0.378)	0.105 (0.838)	0.008 (0.987)		0.338 (0.505)
Acquire/Explore			0.289(0.164)/ −1.25(0.255)				0.271(0.624)/ 0.573(0.513)				−0.54(0.527)/ 0.556(0.482)	
Production costs	−0.149 (0.680)	0.233 (0.597)	−0.226 (0.627)	−0.288 (0.466)	−0.164 (0.650)	−0.144 (0.717)	−0.221 (0.594)	−0.231 (0.512)	0.029 (0.933)	0.098 (0.812)	−0.022 (0.955)	−0.004 (0.991)

Marginal tax rate	**10.22**		**10.47**		0.611		0.794		−0.430		0.119	
	(0.038)		**(0.019)**		(0.233)		(0.132)		(0.456)		(0.847)	
Tax indicator		0.155		0.064		−0.004		0.001		**−0.325**		**−0.327**
		(0.276)		(0.638)		(0.975)		(0.911)		**(0.066)**		**(0.049)**
Fraction of shares owned by insiders		−0.511	−0.339			−0.355	−0.519			**−0.694**	−0.585	
		(0.135)	(0.266)			(0.321)	(0.156)			**(0.050)**	(0.101)	
Insider ownership	0.139			0.209	−0.054			0.098	0.198			−0.037
	(0.736)			(0.584)	(0.893)			(0.798)	(0.602)			(0.922)
Total exercisable options held by insiders	0.006				0.001				−0.008			
	(0.653)				(0.944)				(0.583)			
Exercisable options per insider		−0.067				−0.071				−0.194		
		(0.592)				(0.602)				(0.169)		
Total options per officer			0.089				0.048				0.030	
			(0.125)				(0.415)				(0.610)	
CEO compensation				0.044				0.038				−0.017
				(0.358)				(0.482)				(0.734)
Number of blockholders		0.036		0.037		0.037		0.049		−0.028		0.016
		(0.444)		(0.369)		(0.425)		(0.256)		(0.556)		(0.688)
Oil and gas production sales/Total revenues	0.218	0.135	0.319	0.292	0.157	0.046	0.176	0.036	0.009	−0.155	−0.026	−0.031
	(0.244)	(0.521)	(0.138)	(0.165)	(0.473)	(0.844)	(0.432)	(0.870)	(0.961)	(0.470)	(0.899)	(0.884)
Cash ratio		**10.61**	**10.51**			−0.044	−0.110			−0.265	−0.062	
		(0.041)	**(0.066)**			(0.945)	(0.861)			(0.658)	(0.918)	
Location of production	**0.389**	**0.546**	**0.479**	**0.531**	**0.258**	**0.295**	**0.299**	**0.293**	**0.348**	**0.415**	**0.420**	**0.400**
	(0.005)	**(0.001)**	**(0.002)**	**(0.001)**	**(0.072)**	**(0.051)**	**(0.055)**	**(0.047)**	**(0.011)**	**(0.005)**	**(0.005)**	**(0.006)**
Accounting method	−0.035	−0.030		−0.015	−0.167	−0.155		−0.085	0.026	0.003		0.026
	(0.764)	(0.805)		(0.895)	(0.182)	(0.229)		(0.507)	(0.835)	(0.981)		(0.835)
Production mix		−0.379	−0.277			−0.124	−0.003			0.109	0.258	
		(0.212)	(0.379)			(0.669)	(0.992)			(0.721)	(0.383)	
Number of observations	98	98	97	96	98	98	97	96	94	97	93	95
Log likelihood	−56.36	−53.72	−49.93	−53.24	−55.37	−54.76	−54.21	−55.64	−53.21	−48.51	−51.31	−51.30
Adj. R^2 (from OLS regressions)	0.081	0.085	0.160	0.095	0.144	0.110	0.130	0.107	0.095	0.179	0.095	0.147

Table X—*Continued*

Independent Variables	1992 (1)	1992 (2)	1992 (3)	1992 (4)	1993 (1)	1993 (2)	1993 (3)	1993 (4)	1994 (1)	1994 (2)	1994 (3)	1994 (4)
Panel B: Truncated Model												
Intercept	−0.008 (0.983)	0.285 (0.188)	−0.068 (0.749)	**0.688** **(0.079)**	**0.647** **(0.041)**	0.556 (0.437)	0.174 (0.405)	**0.865** **(0.006)**	**0.729** **(0.020)**	0.094 (0.619)	0.333 (0.122)	0.539 (0.148)
Dividend payout	−0.175 (0.113)	−0.126 (0.143)	−0.118 (0.201)	**−0.086** (0.382)	**−0.181** **(0.085)**	−0.105 (0.304)	−0.118 (0.241)	0.163 (0.107)	**−0.151** **(0.063)**	**−0.155** **(0.057)**	−0.102 (0.195)	−0.109 (0.211)
Bond rating	**−0.186** **(0.017)**		**−0.147** **(0.033)**	−0.089 (0.247)	−0.061 (0.425)		−0.031 (0.687)	0.001 (0.988)	−0.037 (0.533)		0.011 (0.866)	−0.113 (0.133)
AAA		−0.089 (0.407)				0.079 (0.420)				0.011 (0.898)		
CCC		−0.028 (0.737)				−0.017 (0.859)				−0.058 (0.415)		
Total debt/total assets	**0.640** **(0.001)**	**0.522** **(0.005)**	**0.558** **(0.001)**		**0.332** **(0.039)**	0.286 (0.121)	0.274 (0.108)		**0.338** **(0.013)**	**0.425** **(0.003)**	**0.346** **(0.016)**	
Debt constraint				**0.173** **(0.003)**				**0.113** **(0.037)**				0.074 (0.179)
Log of total assets	−0.129 (0.588)	−0.213 (0.278)	−0.257 (0.207)	**−0.302** **(0.001)**	−0.048 (0.816)	−0.381 (0.107)	**−0.411** **(0.095)**	−0.232 (0.319)	0.129 (0.508)	−0.185 (0.335)	−0.227 (0.295)	0.027 (0.898)
Investment expenditures	**0.122** **(0.089)**	**0.163** **(0.012)**		**0.293** **(0.001)**	0.040 (0.838)	−0.172 (0.435)		−0.069 (0.715)	**−0.673** **(0.021)**	**−0.446** **(0.086)**		**−0.601** **(0.077)**
Acquire/Explore			**0.122(0.065)/** **1.35(0.085)**				0.128(0.567)/ −0.662(0.159)				−0.11(0.784)/ **−1.08(0.068)**	
Production costs	−0.323 (0.146)	−0.141 (0.572)	−0.069 (0.765)	**−0.466** (0.061)	0.194 (0.233)	**0.423** **(0.018)**	**0.289** **(0.094)**	0.191 (0.223)	0.135 (0.367)	**0.400** **(0.016)**	0.233 (0.143)	0.279 (0.122)
Marginal tax rate	**0.609** **(0.085)**		**0.855** **(0.013)**		**0.476** **(0.062)**		0.373 (0.175)		0.211 (0.357)		−0.119 (0.641)	

Tax indicator		0.092 (0.185)		0.024 (0.711)		**0.121** **(0.039)**		**0.154** **(0.006)**		0.109 (0.161)		0.077 (0.286)
Fraction of shares owned by insiders		0.034 (0.826)	0.022 (0.884)			0.057 (0.757)	0.016 (0.931)			−0.129 (0.378)	−0.191 (0.212)	
Insider ownership	−0.047 (0.817)			−0.277 (0.103)	**−0.488** **(0.011)**			**−0.491** **(0.008)**	**−0.490** **(0.005)**			**−0.429** **(0.035)**
Total exercisable options held by insiders	−0.004 (0.517)				−0.009 (0.144)				**−0.017** **(0.009)**			
Exercisable options per insider		0.013 (0.836)				−0.041 (0.554)				**−0.209** **(0.005)**		
Total options per officer			0.001 (0.992)				−0.022 (0.427)				**−0.071** **(0.019)**	
CEO compensation				**0.064** **(0.061)**				−0.005 (0.869)				0.037 (0.218)
Number of blockholders		**−0.068** **(0.002)**		**−0.068** **(0.003)**		**−0.032** **(0.076)**		**−0.037** **(0.055)**		−0.010 (0.537)		0.007 (0.686)
Oil and gas production sales/Total revenues	**0.167** **(0.150)**	**0.233** **(0.017)**	**0.295** **(0.005)**	0.092 (0.408)	−0.074 (0.473)	0.129 (0.238)	0.043 (0.670)	−0.018 (0.867)	0.013 (0.865)	0.097 (0.262)	0.002 (0.976)	0.009 (0.939)
Cash ratio		**−0.681** **(0.069)**	−0.151 (0.654)			−0.489 (0.246)	−0.426 (0.314)			0.175 (0.352)	0.113 (0.546)	
Location of production	0.114 (0.183)	0.065 (0.386)	0.122 (0.133)	**0.368** **(0.001)**	**0.148** **(0.064)**	0.069 (0.380)	0.092 (0.244)	0.114 (0.165)	**0.123** **(0.080)**	0.119 (0.115)	0.109 (0.146)	**0.185** **(0.062)**
Accounting method	0.010 (0.858)	−0.034 (0.555)		−0.019 (0.720)	−0.014 (0.782)	−0.056 (0.307)		−0.009 (0.858)	−0.038 (0.417)	−0.095 (0.237)		−0.002 (0.965)
Production mix		**−0.253** **(0.080)**	**−0.346** **(0.034)**			**−0.267** **(0.025)**	**−0.265** **(0.026)**			**−0.298** **(0.010)**	**−0.317** **(0.013)**	
Number of observations	42	42	42	40	49	49	49	48	54	55	54	53
Log likelihood	26.35	37.02	32.94	33.55	29.77	32.58	30.27	31.33	33.56	37.88	33.45	28.51
Adj. R^2 (from OLS regressions)	0.343	0.524	0.481	0.548	0.322	0.380	0.295	0.354	0.265	0.333	0.225	0.106

These regressions also suggest that several variables related to the extent of hedging are not significantly associated with the decision to hedge. For example, although the debt ratio has a strong correlation with hedging when we use the continuous measure of hedging, it is not statistically significant in any of the probit regressions. The costs of hedging and the basis risk of instruments available for hedging appear to be more important determinants of this decision.

The differences in these results from the tobit regressions show that a test using a binary measure as proxy for hedging may not detect variables associated with the extent of hedging. Indeed, previous empirical studies that use only binary measures (e.g., Nance et al. (1993), Dolde (1993), Mian (1996), and Géczy et al. (1997)) find little or no evidence that hedging is significantly related to financial leverage. Moreover, the differences in the probit regression results from the tobit regressions suggest that differences in results between this study and previous empirical studies can at least partially be attributed to differences in the measure of hedging.

C.2. Conditional Regressions' Results— The Extent of Hedging, among Hedgers

Regressions 5 to 8 in Table IX and all the regressions in Table X, Panel B, use a truncated model that estimates the determinants of the extent of hedging, conditional on a company hedging. The explanatory power of these regressions is substantially greater than it is using the probit or the tobit models. The adjusted R^2 for the conditional regressions is generally 0.3 or greater, at least twice the adjusted R^2 for the regressions using the tobit and probit model. Additionally, several variables that are not statistically significant using the tobit or probit models are significant in the conditional regressions. The differences between the results from the conditional regressions and those using the probit model suggest that there are substantial differences between the determinants of the decision to hedge and the decision of how much to hedge. Because the tobit model considers the combined effect of these decisions, it likely does not reveal all of the determinants of a firm's hedging policy.

An important difference between the conditional regressions and the probit regressions relates to total assets. The probit model indicates that firms with more assets are more likely to hedge. However, the conditional regressions, which only consider the companies that hedge, indicate an insignificant or negative relation between total assets and the extent of hedging. This difference implies that the economies of scale in hedging are particularly relevant for initiating or maintaining a hedging program and that the costs associated with these activities can be substantial. However, there do not appear to be significant economies of scale in the marginal costs of increasing the extent of hedging.

Because the conditional regressions only consider the group of firms able to bear the costs of hedging, many of the other characteristics associated with the extent to which a firm hedges become more apparent. In particular,

these conditional regressions show a strong relation between hedging and proxies for financial contracting costs, supporting the argument that corporations use risk management as a means of alleviating these costs. In all of these regressions, the leverage variables (debt ratio and debt constraint) are positive and significant. This relation is substantially stronger than that for the tobit models. For example, for truncated regressions, the coefficient on the ratio of debt to total assets ranges from 0.27 to 0.64, indicating that, all else equal, a 25 percent increase in this ratio is associated with a 6.7–16 percent increase in the fraction of production hedged. For the tobit model, this increase in leverage is associated with approximately a five percent increase in hedging. The regressions also indicate that, of the companies hedging, the extent of hedging is greater among those paying out a smaller fraction of income in the form of dividends, those that do not have a debt rating, and those with fewer assets.

Like the results from the regressions using the tobit and probit model, the location variable is positive. The significance of this relation, however, is not as great in the regressions using the truncated model as it is using the probit model. One interpretation of this result is that although basis risk is an important determinant of the extent a firm hedges, it has a more important impact on the decision to hedge.

These regressions do not offer a clear picture of the relation between a firm's risk management policy and its tax function. The coefficient on the tax indicator variable, which is set equal to one when a firm's tax rate is in the progressive region of the tax code, is positive and statistically significant in several of these regressions. The direction of this relation is opposite that in the tobit or probit models, but consistent with that predicted by theory. The marginal tax rate variable is positive and is also statistically significant; the opposite of that predicted by theory.

The results for the compensation and ownership variables are comparable to those using the tobit model and offer mixed support for the argument linking corporate hedging to managerial risk aversion. Consistent with this argument, the fraction of production hedged is negatively correlated with the number of options held per officer and director. Inconsistent with this argument, the fraction of production hedged is negatively correlated with the log of the market value of insider ownership. This result conflicts with the empirical evidence documented by Tufano (1996).[23] Unlike the tobit model, this correlation also holds when Louis-Dreyfus is taken out of the sample.

A possible explanation for the negative correlation between hedging and managerial shareholdings is that a firm's ownership structure, like its hedging policy, is determined endogenously. That is, the manager's shareholdings and a company's choice of a corporate hedging policy can reflect other—possibly unobservable—exogenous characteristics, such as the manager's

[23] Tufano (1996) uses a tobit model and finds the extent of hedging by gold mining firms is positively associated with the dollar value of the shares owned by officers other than the CEO and insignificantly associated with the dollar value of the shares owned by the CEO.

forecast of future oil and gas prices. In this case, managers with a more optimistic view of oil and gas prices hold larger ownership stakes and hedge less production than managers with a more pessimistic view of future prices.

Finally, for all the sample specifications, the production mix variable is negative and significant. This variable is insignificant in the probit model. In other words, among the companies hedging, those focusing on gas production tend to hedge more extensively than their oil production based counterparts, but they are not any more likely to hedge.

IV. Summary and Implications

A. Summary

This study examines the determinants of corporate risk management policies using data on the hedging practices of 100 oil and gas producers from 1992 through 1994. I document a positive relation between the extent to which a firm hedges and its financial leverage. More specifically, the fraction of production that oil and gas producers hedge against price risk is positively related to the ratio of total debt to total assets and is greater for companies having little financial flexibility, measured by the relative amount of debt outstanding and cash holdings. This relation is consistent with the argument that risk management reduces financing costs.

I also document a positive relation between hedging and a proxy for firms' ability to hedge. The fraction of production hedged and the likelihood a firm will hedge is related to the basis risk associated with exchange-traded derivative instruments, measured by the fraction of production located in regions where prices are highly correlated with the prices on which exchange-traded derivative instruments are based.

B. Implications

There are several important implications from these findings. First, the link between hedging and financial leverage supports the notion that hedging can reduce financing costs (e.g., see Froot et al. (1993)), and it is also consistent with the predictions of Stulz (1996) who argues that corporate hedging can be viewed as a technique that allows managers to substitute debt for equity. As a result, a company's risk management policy should be made jointly with its financing policy.

If hedging and financing policies are made jointly, my evidence indicates that studies of corporate financing decisions need to consider corporate hedging policies. In particular, a company facing relatively high costs of financing that hedges may choose the same capital structure as a firm with lower costs of financing that does not hedge. Without controlling for hedging, the relation between capital structure and the determinants of the costs of financing will be missed.

Second, it is also important to note that although firms facing binding financial constraints can benefit from hedging, reducing firms' dependence on the capital markets does not automatically translate to an increase in shareholder wealth. In fact, Tufano (1998) points out that hedging can lead to overinvestment. If hedging enables managers to take on projects without facing scrutiny from the capital markets, it can enable managers to finance projects that benefit managers but reduce shareholders' wealth. So although firms facing financial constraints hedge more extensively, this relation does not imply that hedging increases shareholder value.

Finally, these findings suggest that basis risk might help explain the variation of hedging policies within other industries. Though the market for risk management tools has grown since the period I examine in this study, basis risk likely remains an important concern for hedging many different types of exposures. For example, currency markets for Asian Pacific countries other than Japan are virtually nonexistent. Largely because of this, few portfolio managers of Asian Pacific funds investing outside of Japan hedge their currency exposures.[24] Therefore, empirical studies of corporate hedging policies should not only consider a firm's need to hedge but also its ability to do so.

Appendix

A.1. Corporate Risk Management Data

The survey used to gather information for this study is reproduced here as Figure A1. The list of companies providing data is given in Table AI.

Corporations provided hedging information for the years 1992 to 1994 in several different ways. Fifty-nine companies completed the survey. Although the companies did not identify who completed the survey, it was generally signed by either the chief financial officer, the treasurer or controller, the manager of energy risk management, the manager of natural gas and oil marketing, or the director of investor relations. Nineteen companies supplied their annual report or 10K in which the extent of their risk management activities is discussed, either as a percentage of production or as the number of barrels of oil equivalent (BOE) hedged.[25] The other 22 respondents supplied their 10K or annual report, but their financial statements did not discuss the extent of hedging. I contacted these firms by phone for further information. Nineteen of these firms do not hedge, so minimal specific information was required from them. The other three companies reported hedging and provided the percentage of production hedged. My sample consists of 292 observations for 100 firms over three years. The eight missing observations are: two companies that did not go public until after 1992,

[24] See "Funds Generally Don't Hedge Asian Bets," *The Wall Street Journal*, December 22, 1997, Section C-25.

[25] Oil and gas companies generally quote the volume of natural gas and oil in "barrel of oil equivalent" or BOE. Gas is converted to a barrel of oil equivalent as: 6 thousand cubic feet (mcf) of gas = 1 BOE, 1 barrel of oil = 1 BOE.

SURVEY OF RISK MANAGEMENT ACTIVITIES
ALL INFORMATION IS TO BE USED SOLELY FOR RESEARCH PURPOSES AND WILL BE KEPT FULLY CONFIDENTIAL

Company: _____

What was the fraction of production hedged against price fluctuations (using fixed price contracts, derivatives, or volumetric production payments) in the years 1992-1994?
(enter NA if you did not hedge any production for the year)

Oil: 1992_____ 1993_____ 1994_____
Gas: 1992_____ 1993_____ 1994_____

Give a breakdown (by the percentage of your hedging activity) of the types of instruments used to hedge.

Swaps _____
Put Options _____
Collars _____
Futures _____
Forwards _____
Fixed Price Contracts _____
Volumetric Production Payments _____
Others (please list): _____
100% of Hedging Activity

Do you hedge operations other than production (e.g., refining)?
Yes_____ No_____
If yes, list the operation you hedged and the fraction of the operation's revenues hedged:

Type of Operation:_____ Fraction of Revenues Hedged:_____

_____ I would like a copy of the final report. (please check if yes)

Name:_____ Title: _____

Figure A1. Survey mailed to oil and gas producers. Oil and gas producers include 177 companies have a primary SIC code of 1311 according to Ward's 1994 Business Directory. The survey was first sent in February, 1995.

three companies that sold their oil and gas properties after 1992, and two companies that only provided hedging data for two of the years between 1992 and 1994.

Table AI

Oil and Gas Producers Providing Data on Risk Management Activities.

Oil and gas producers are companies that have a primary SIC code of 1311 according to *Ward's 1994 Business Directory*. The company names are as of 1993.

ABRAXAS PETROLEUM CORP	LOUIS DREYFUS NATURAL GAS
ADAMS RESOURCES & ENERGY	LOUISIANA LAND & EXPLORATION
ALAMCO INC	MALLON RESOURCES CORP
ALEXANDER ENERGY CORP	MAXUS ENERGY CORP
AMOCO CORP	MCFARLAND ENERGY INC
ANADARKO PETROLEUM CORP	MESA INC
APACHE CORP	MIDLAND RESOURCES INC
BARNWELL INDUSTRIES	MITCHELL ENERGY & DEVELOPMENT
BELDEN & BLAKE CORP	MURPHY OIL CORP
BERRY PETROLEUM	NEWFIELD EXPLORATION CO
BOUNTY GROUP INC	NOBLE AFFILIATES INC
BOX ENERGY CORP	NUEVO ENERGY CO
BROCK EXPLORATION	OAKRIDGE ENERGY INC
TOM BROWN INC	OCCIDENTAL PETROLEUM CO
CABOT OIL & GAS CORP	ORYX ENERGY CO
CAIRN ENERGY USA INC	PARTNERS OIL CO
CASTLE ENERGY CORP	WILLARD PEASE OIL & GAS
CHAPARRAL RESOURCES INC	PETROLEUM DEVELOPMENT
CHESAPEAKE ENERGY	PHILLIPS PETROLEUM CO
CLAYTON WILLIAMS ENERGY	PHOENIX RESOURCE CO
CLINTON GAS SYSTEMS INC	PLAINS PETROLEUM CO
CODA ENERGY INC	POGO PRODUCING CO
COLUMBUS ENERGY CORP	PRIMA ENERGY CORP
COMSTOCK RESOURCES INC	PRIMEENERGY CORP
CONVEST ENERGY CORP	QUESTA OIL & GAS CO
CROSS TIMBERS OIL CO	QUESTAR CORP
CRYSTAL OIL CO	RESOURCE AMERICA INC
DELTA PETROLEUM CORP	SAMSON ENERGY CO
DEVON ENERGY CORP	SANTA FE ENERGY RESOURCES
DOUBLE EAGLE PETROLEUM & MINING	SEAGULL ENERGY
ENSERCH CORP	SEARCH EXPLORATION INC
EQUITY OIL CO	SHEFFIELD EXPLORATION INC
ESPERO ENERGY CORP	SNYDER OIL CORP
EVERGREEN RESOURCES	SONAT INC
EXPLORATION CO	SOUTHWESTERN ENERGY CORP
FM PROPERTIES INC	ST MARY LAND & EXPLORATION
FOREST OIL CORP	STONE ENERGY CORP
GARNET RESOURCES CORP	SUNLITE INC
GENERAL RESOURCES INC.	SWIFT ENERGY CO
GEORESOURCES INC	TEXAS MERIDIAN RESOURCES
GERRITY OIL & GAS CORP	TGX CORP
GREAT EASTERN ENERGY	TIPPERARY CORP
HALLWOOD ENERGY PARTNERS	TRITON ENERGY CORP
HARKEN ENERGY CORP	UNION TEXAS PETRO HLDGS
HONDO OIL & GAS CO	VAALCO ENERGY INC
HUNTER RESOURCE INC	VINTAGE PETROLEUM INC
KCS ENERGY	WAINOCO OIL CORP
KELLEY OIL & GAS PTRS	WISER OIL CO
KERR-MCGEE CORP	WOLVERINE EXPLORATION
KEY PRODUCTION CO	XCL LTD

A.2. Determination of the Extent of Hedging from Financial Statements

Companies that supplied only their financial statements generally report their hedging either as the number of barrels of oil and cubic feet of natural gas hedged or as the percentage of production hedged. For example, Coda Energy's 1992 Annual Report states:

> The Company's open hedge positions as of December 31, 1992, were as follows. The Company has effectively collared its oil price between $17.00 and $20.50 per barrel on 40,000 barrels per month through April 1993. The Company has hedged its gas price through April 1993 on 120,000 mcf per month at an average price of $1.50 through the use of a commodity swap.

Alternatively, Forest Oil's 1993 Annual Report discloses the percent of production hedged:

> As a result of volumetric production payments, energy swaps, and fixed contracts, the Company currently estimates that approximately 62 percent of its natural gas production and 15 percent of its oil production will not be subject to price fluctuations from January 1994 through December 1994.

If the firms completed the survey or reported hedging activities in their financial statements as a percentage of production hedged (as Forest Oil did), the process to calculate the fraction of total production hedged is straightforward. The percentage of sales coming from oil production is multiplied by the percentage of oil hedged, and the percentage of the firm's sales coming from the gas production is multiplied by the percentage of gas hedged. The total production hedged is simply the sum of these two values. Referring to Forest Oil, if 50 percent of Forest Oil's sales are from oil production and 50 percent of sales are from gas production, 38.5 percent (i.e., $0.50 * 0.62 + 0.50 * 0.15$) of its total production is hedged in 1994.[26]

If a company only reports the number of barrels of oil and the cubic feet of gas hedged, these data are converted to the percentage of total production hedged using a two-step process. First, the percentage of oil hedged is computed by dividing the barrels of oil hedged in a year by the barrels of oil

[26] For these examples, I use the companies' end of year financial statements to calculate the fraction of production hedged in the following year; thus, for Coda Energy, I use its 1992 financial statements to calculate the fraction of its 1993 production hedged. Companies tend to give more detailed information about their open hedge positions than historical hedging. However, in constructing my database, I also checked the company's financial statements the following year for transactions that affect the fraction of the year's production hedged and adjust the fraction of production hedged accordingly. For the Coda example, I also checked its 1993 financial statements to see if it entered into any further agreements or if it repurchased contracts in 1993 that affected its hedge position for the year.

produced that year. Likewise, the percentage of gas hedged is found by dividing the cubic feet of gas hedged in a year by the cubic feet of gas produced that year. Using the above example for Coda, if Coda's total oil production in 1993 is 500,000 barrels, then 32 percent (i.e., 160,000/500,000) of its oil production is hedged. Once the percentage of oil production and gas production hedged is determined, the percentage of total production hedged is computed using the procedure discussed in the example for Forest Oil.

REFERENCES

Ang, James S., Jess H. Chua, and John J. McConnell, 1982, The administrative costs of corporate bankruptcy: A note, *Journal of Finance* 37, 219–226.

Barclay, Michael, and Clifford Smith, 1995, The maturity structure of debt, *Journal of Finance* 50, 609–631.

Bessembinder, Hendrick, 1991, Forward contracts and firm value: Incentives and contracting effects, *Journal of Financial and Quantitative Analysis* 26, 491–532.

Cragg, John G., 1971, Some statistical models for limited dependent variables with application to the demand for durable goods, *Econometrica* 39, 829–844.

Dolde, Walter, 1993, The trajectory of corporate financial risk management, *Journal of Applied Corporate Finance* 6, 33–41.

Ederington, Louis H., 1979, The hedging performance of the new futures markets, *Journal of Finance* 34, 157–170.

Fazzari, Steven R., Glen Hubbard, and Bruce Peterson, 1988, Financing constraints and corporate investment, *Brookings Papers on Economic Activities* 19, 141–195.

Fenn, George W., Mitch Post, and Steven A. Sharpe, 1997, Does corporate risk management create shareholder value? A survey of economic theory and evidence, *Financial Risk and the Corporate Treasury* (Risk Publications).

Froot, Kenneth, David Scharfstein, and Jeremy Stein, 1993, Risk management: Coordinating corporate investment and financing policies, *Journal of Finance* 48, 1629–1658.

Géczy, Christopher, Bernadette A. Minton, and Catherine Schrand, 1997, Why firms use currency derivatives, *Journal of Finance* 52, 132–1354.

Graham, John R., 1996a, Debt and the marginal tax rate, *Journal of Financial Economics* 41, 41–74.

Graham, John R., 1996b, Proxies for the marginal tax rate, *Journal of Financial Economics* 42, 187–222.

Graham, John R., and Clifford W. Smith, 1999, Tax incentives to hedge, *Journal of Finance* 54, 2241–2262.

Guay, Wayne, 1999, Compensation, convexity, and the incentives to manage risk: An empirical analysis, *Journal of Financial Economics* 53, 43–71.

Harford, Jarrad, 1999, Corporate cash reserves and acquisitions, *Journal of Finance* 54, 1969–1997.

Hoshi, Takeo, Anil Kashyap, and David Scharfstein, 1991, Corporate structure and liquidity and investment: Evidence from Japanese panel data, *Quarterly Journal of Economics* CVI, 33–60.

Hu, Henry T. C., 1995, Hedging expectations: Derivatives reality and the law and finance of corporate objective, *Texas Law Review* 73, 985–1040.

Jensen, Michael, 1986, Agency costs of free cash flow, corporate finance, and takeovers, *The American Economic Review* 76, 323–329.

Jensen, Michael, and William Meckling, 1976, Theory of the firm: Managerial behavior, agency cost, and ownership structure, *Journal of Finance* 33, 383–392.

Johnson, Leland L., 1960, The theory of hedging and speculation in commodity futures, *Review of Economic Studies* 27, 139–151.

Kaplan, Steven, and Luigi Zingales, 1997, Do investment sensitivities provide useful measures of financing constraints, *Quarterly Journal of Economics* 112, 169–215.

Lang, Larry, Eli Ofek, and René Stulz, 1996, Leverage, investment, and firm growth, *Journal of Financial Economics* 40, 3–29.

Malmquist, David H., 1990, Efficient contracting and the choice of accounting method in the oil and gas industry, *Journal of Accounting and Economics* 12, 173–205.

Mayers, David, and Clifford Smith, 1990, On the corporate demand for insurance: Evidence from the reinsurance market, *Journal of Business* 63, 19–40.

Mian, Shezad L., 1996, Evidence on corporate hedging policy, *Journal of Financial and Quantitative Analysis* 31, 419–439.

Miller, Merton, and Franco Modigliani, 1958, The cost of capital, corporation finance and the theory of investment, *American Economic Review* 53, 261–267.

Myers, Stewart, 1977, The determinants of corporate borrowing, *Journal of Financial Economics* 5, 147–175.

Myers, Stewart, 1984, The capital structure puzzle, *Journal of Finance* 49, 575–592.

Myers, Stewart, and Nicholas Majluf, 1984, Corporate financing and investment decisions when firms have information that investors do not have, *Journal of Financial Economics* 13, 187–202.

Nance, Deana, Clifford Smith, and Charles Smithson, 1993, On the determinants of corporate hedging, *Journal of Finance* 48, 267–284.

Opler, Tim, Lee Pinkowitz, René Stulz, and Rohan Williamson, 1999, The determinants of implications of corporate cash holdings, *Journal of Financial Economics* 52, 3–46.

Pulvino, Todd, 1998, Do asset fire-sales exist?: An empirical investigation of commercial aircraft transactions, *Journal of Finance* 53, 939–978.

Schrand, Catherine, and Haluk Unal, 1998, Hedging and coordinated risk management: Evidence from thrift conversions, *Journal of Finance* 53, 979–1014.

Sharpe, Steven A., and Hien H. Nguyen, 1995, Capital market imperfections and the incentive to lease, *Journal of Financial Economics* 39, 271–294.

Smith, Clifford, and René Stulz, 1985, The determinants of firms' hedging policies, *Journal of Financial and Quantitative Analysis* 20, 391–405.

Stein, Joseph L., 1961, The simultaneous determination of spot and future prices, *American Economic Review* 51, 1012–1025.

Stulz, René, 1984, Optimal hedging policies, *Journal of Financial and Quantitative Analysis* 19, 127–140.

Stulz, René, 1996, Rethinking risk management, *Journal of Applied Corporate Finance* 9, 8–24.

Tufano, Peter, 1996, Who manages risk? An empirical analysis of risk management practices in the gold mining industry, *Journal of Finance* 51, 1097–1137.

Tufano, Peter, 1998, Agency costs of corporate risk management, *Financial Management* 27, 67–77.

Weiss, Lawrence A., 1990, Bankruptcy resolution: Direct costs and violation of priority of claims, *Journal of Financial Economics* 27, 285–314.

Whited, Toni M., 1992, Debt, liquidity, and corporate investment: Evidence from panel data, *Journal of Finance* 47, 1425–1460.

Yermack, David, 1995, Do corporations award CEO stock options effectively? *Journal of Financial Economics* 39, 237–270.