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Choices Among Alternative Risk Management Strategies: Evidence from the Natural Gas Industry

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Choices Among Alternative Risk Management Strategies:
Evidence from the Natural Gas Industry

Abstract

This paper examines the substitutability and complementarity of a variety of risk management strategies that firms can use to reduce price risk exposure. Time-series analysis over a period of significant regulatory changes indicates that natural gas companies increased diversification and started using derivatives as price risk increased following price deregulation and the regulated unbundling of sale and transmission activities. The use of derivatives is a substitute both for holding internal cash and for storing gas underground. The latter two activities are complements. In choosing between derivatives and storage or cash holdings, less profitable and more financially distressed firms are more likely to manage risk using derivatives. Accounting earnings management strategies, however, are not complements to activities that have a "real" effect on cash flow volatility and diversification is not related to financial hedging activities. Market-based estimates of wellhead gas price sensitivities are negative prior to deregulation and become significantly positive following price deregulation. The change in exposure is consistent with the changing role of pipelines from buyers of gas for transport to only transporters of gas resulting from deregulation. Cross-sectional variation in price sensitivities is related to firms' use of combinations of operational (non-accounting) and financial hedging activities. Firms that pursue these activities have smaller and less variable risk-adjusted wellhead gas return exposures than firms that do not, especially post-deregulation.

Choices Among Alternative Risk Management Strategies:

Evidence from the Natural Gas Industry

This paper examines firms' choices among various risk management strategies that can be used to reduce price risk exposure. Unlike most recent empirical research on risk management that focuses primarily on derivatives use as a risk management tool (exceptions are Tufano, 1996 and Petersen and Thiagarajan, 1999), the tests in this paper examine a wide variety of activities that contribute to a firm's overall exposure to price risk. In particular, in addition to financial risks this analysis considers non-financial risk management strategies, including accounting earnings management, diversification, physical storage, and operational hedging. Since part of the sample period is prior to the development of an active spot market and exchange-traded derivatives market for natural gas futures and options, we consider risk management activities in the absence of alternatives for financial hedging. This feature of the sample period makes the results more generalizable to industries where financial risks (e.g., price risks) that are more typically managed with financial products are a relatively small component of the total risks that the firms are managing.

The paper focuses on the natural gas industry to take advantage of a unique series of regulatory events that changed pipelines' price risk exposures. Beginning in 1978, regulators took a number of steps to deregulate various aspects of the natural gas industry including natural gas prices. As a result, natural gas pipelines became increasingly exposed to gas price risk. These regulatory events provide a powerful setting to examine *changes* in risk-related activities unlike cross-sectional tests of the determinants of risk management based on *levels* of firm characteristics and proxies for the levels of risk management (e.g., Géczy, Minton, and Schrand, 1997; Tufano, 1996; Mian, 1996; and Dolde, 1993).[1]

During the early part of the sample period prior to price deregulation, natural gas pipeline companies used over-the-counter long-term contracts containing "take-or-pay" and "minimum-bill" contracts to manage exposure to price changes. As deregulation adversely affected the risk exposures of pipelines in the early 1980s, the sample pipelines increased diversification. This trend toward diversification is opposite the trend away from diversification that was occurring during this time period for U.S. firms in general. Pipelines achieved diversification both by making acquisitions outside the natural gas industry and by divesting of subsidiaries engaged in natural gas related businesses. Finally, the pipeline firms turned to exchange-traded natural gas derivative products in the early 1990s as they became available. At fiscal year-end 1991, only five firms disclose using energy-based derivatives. However, by 1995, all but two firms report using energy-based derivatives to manage commodity price risk.

Univariate and factor analysis of the relations among risk-related activities over the sample period indicate that the use of financial derivatives as a risk management tool is a substitute for two alternative activities related to price risk exposure: holding a buffer of internal cash and storing gas underground. Moreover, these latter two activities are complements to each other. Consistent with the evidence that storing gas and holding cash are complementary activities, the firms that pursue these "hedging" activities are similar to each other and significantly different from the "non-hedgers" in these categories. In particular, the cash "hedgers" and the storage "hedgers" are more profitable and less financially distressed than the non-hedgers. In contrast, the firms that extensively use derivatives to manage price risk are less profitable and more financially distressed. Finally, accounting earnings management strategies are not complements to activities that have a "real" effect on cash flow volatility and diversification is not related to financial hedging activities.

Over the entire sample period, the stock returns of the sample pipelines are significantly sensitive to natural gas price changes. Risk adjusted market-based estimates of wellhead gas price sensitivities are negative in the first several years of the sample period and become significantly positive for the pipelines following price deregulation, particularly after the Decontrol Act of 1989 when natural gas futures became the most volatile exchange-traded futures contract from 1992 to 1994 (Fitzgerald and Pokalsky, 1995). The negative natural gas price betas prior to deregulation reflect the role of the pipeline as a consumer of gas, when the pipelines purchased significant quantities of gas for transportation and resale. The positive betas post-deregulation are consistent with the unbundling of the sale and transportation of gas. The pipeline's post-deregulation

[1] Guay (1999) exploits a setting of changing exposures by examining first-time derivatives users.

exposure is similar to that of a producer, rather than a consumer, in that the value of the firm's services rises and falls with the demand for gas.

The stock price sensitivities vary cross-sectionally as function of the use of hedging techniques and activities predicted to be associated with natural gas price risk. Firms that use derivatives have smaller and less variable stock price sensitivities to natural gas returns than do natural gas firms in general. In addition, users of non-derivative hedging activities such as holding cash buffers or storing gas also have smaller and less variable sensitivities to natural gas price fluctuations than the entire sample of natural gas firms at large.

The paper proceeds as follows. Section II describes the sample. Section III summarizes regulatory changes in the natural gas industry from 1978 to 1995 and shows the corresponding time-series pattern of price risk during this period. In Section IV, we discuss various activities of pipeline firms that affect their exposure to price risk and review the time-series changes in these activities. In addition, we examine whether these activities are used as substitutes or complements and the firm characteristics that are associated with cross-sectional variation in the use of these activities. Finally, in Section V we analyze how different risk-related activities are associated with market-based measures of price risk exposure. Section VI concludes.

II. Sample

The sample represents publicly traded natural gas companies that are major interstate natural gas pipelines or that have subsidiaries that are major interstate natural gas pipelines during the period 1978 to 1995. We identify major pipelines using Form 2 filings, “Annual Report of Natural Gas Companies” to the Energy Information Agency. These filings, which are required by the Federal Energy Regulatory Commission (FERC, the industry regulatory agency), provide comprehensive data on pipelines’ annual financial and operating conditions.[2] In almost all years,

[2] The reports contain financial and operating information for both Class A (Major) and Class B (Minor) interstate pipeline companies in the United States. Major interstate natural gas pipeline companies are defined as “those firms that have combined gas sales for resale and gas transported (interstate) or stored for a fee that exceeded 50 billion cubic feet during the preceding calendar year or those firms that filed FERC Form 11, Natural Gas Pipeline Company Monthly Statement. Class A (B) pipeline companies have annual gas revenues of at least $2.5 million (at least one million dollars but less than $2.5 million). These dollar figures are not deflated over time. Form 2 filings are included in annual volumes of *Statistics of Interstate Natural Gas Companies*.

these major interstate pipelines account for over 80 percent of the total gas receipts, total assets, total sales, and gas operating revenues in the industry. Thus, the sample is very comprehensive of the natural gas transmission market. Table I lists the pipelines with available FERC data that are in the final sample and the minimum and maximum number of pipelines owned by each firm during its tenure in the sample.

While a few pipelines are publicly-traded entities, almost all pipelines that were identified in FERC Form 2 filings are subsidiaries of natural gas companies or holding companies that also own other energy subsidiaries or transportation subsidiaries (i.e., railroad and trucking operations). Subsidiary pipelines are matched to publicly-traded entities on the CRSP (Center for Research in Security Prices) database based on reviews of annual reports of natural gas companies, selected discussions in the annual *Statistics of Interstate Natural Gas Companies,* and LEXIS/NEXIS searches. Joint ownership of some pipelines complicates the process of combining the FERC data (which is reported at the pipeline level) with Compustat or CRSP data (which is reported for the entity that owns the pipeline). For jointly owned pipelines, the pipeline data are divided among the sample firms that own the pipeline according to the entities' ownership percentages. Thus, a sample firm's natural gas data are the weighted average of the data for each FERC pipeline that it owns.[3] Over 95% of the major interstate pipelines are matched with one or more publicly-traded firms. After restricting the sample to firms with available data on Compustat, the final annual samples contain a minimum of 21 firms (1978) and a maximum of 25 firms (1985).

[INSERT TABLE I HERE.]

As expected, various measures of accounting earnings changes for the sample firms are significantly correlated with changes in natural gas prices during the sample period. For each firm i, we estimate the following time-series regression for each of eight proxies for accounting

[3] Note that the sum of the natural gas data across pipelines does not necessarily equal the segment data reported by firms in their annual reports or on Compustat. The aggregated annual report/Compustat data include other pipelines which are not classified as major interstate pipelines, gas segments other than transmission, and sometimes oil segments.

earnings changes (referred to collectively as ACCTGNUM) on natural gas price changes using annual data from 1978 to 1995:

$$\Delta \text{ACCTG NUM}_i = \alpha_0 + \alpha_1 (\text{WH}_{i,t} - \text{WH}_{i,t-1}) / \text{WH}_{i,t-1} + \varepsilon_i \qquad (1)$$

where WH is the wellhead natural gas price, which is the price that pipelines pay to producers to purchase gas. The wellhead price was regulated at the beginning of the sample period and deregulated during the sample period. The wellhead price for year t is the average of the twelve month-end prices for the year obtained from *The Monthly Energy Review*.

Table II reports the mean, standard deviation, minimum, and maximum of the coefficient estimates from the firm-specific regressions. The table also reports the number of regressions estimated and the number of coefficient estimates that are significant at better than the 10% significance level. Regressions are estimated for all firms with at least seven annual observations.

[INSERT TABLE II HERE.]

Annual percentage changes in total sales revenues for the parent company are statistically and positively related to annual percentage changes in natural gas prices for 14 of the 25 sample firms. Changes in natural gas transmission and distribution segment revenues as reported on FERC Form 2 filings (Compustat) are statistically positively related to changes in wellhead prices for eleven (four) of 22 (21) firms. These segment revenues are related only to the transmission and distribution of gas in contrast to total sales revenues that include revenues related to natural gas exploration and production. The smaller number of statistically significant coefficient estimates potentially reflects the regulation of transmission prices to various degrees during the sample period. The quantities and prices that generate the segment revenues are not necessarily the current spot price or current quantities of gas because of prices and quantities established in long-term contracts with take-or-pay or minimum bill clauses. The nature of these agreements and their impact on price risk is discussed further in Section III.[4]

Changes in the proxies for net earnings (total firm operating income, total firm net income, operating income reported on Form 2, and net income reported on Form 2) are only statistically related to changes in wellhead prices for a small number of the sample firms. One explanation for the lack of sensitivity of net income to natural gas prices, despite the sensitivity of revenues, is that earnings contain income and costs that are unrelated to gas activities including restructuring charges, litigation settlements, and non-operating income or expenses. With respect to operating income, however, the lack of sensitivity provides a preliminary indication that the sample firms are undertaking risk management activities that match gas-price sensitive costs to gas-price sensitive revenues.

These regressions show that the sample firms are exposed to changes in gas prices over the entire sample period, but the estimations do not attempt to document changes in exposure. It is difficult to document changes in accounting-based natural gas price sensitivities through time because of the small sample of firms and the limited frequency of accounting observations during the period. We use higher frequency stock return data in Section III to illustrate changes in exposure.

III. The effects of regulation

Section A summarizes the operations and regulation of the natural gas industry that are salient to this study by focusing on regulation that affected the risks faced by pipelines. This limited discussion of the effects of regulation on the industry is based on more extensive analyses from the following sources: American Gas Association (1987), Castaneda and Smith (1996), Fitzgerald and Pokalsky (1995), and the New York Mercantile Exchange (undated). Section B illustrates the corresponding effects of the changes in regulation on changes in characteristics of the sample firms and their stock-price sensitivity to gas returns.

[4] We also use annual percentage changes in the quantities of total natural gas sales and deliveries as a dependent variable in equation (1) (results not reported). None of the natural gas price coefficient estimates is statistically different from zero. This result is not surprising during the period 1978-1995. Both regulation and underground storage of natural gas combine to disrupt the normal price-quantity relation observed in a competitive market.

We recognize that regulation is endogenous and do not claim that the observed changes in risk management practices and gas price sensitivities were necessarily a response to the regulatory changes. The observed changes also potentially represent a response to the same factors that inspired the regulation. Moreover, the effects of regulation do not typically occur on the date that the regulation is enacted. Clearly, firms can anticipate the potential regulation prior to its enactment and can react to its potential effects. The complex relations among regulation, firms' reactions to regulation, and the underlying factors that affect both are considered in the following analysis.

A. Overview of regulation

Two central features of the natural gas industry between the mid-1950s and late 1970s were regulated pricing and the bundling of the sale and transportation of gas. Pipeline companies purchased gas from producers at regulated wellhead prices. Pipelines transported purchased gas (and their own production) to the "city gate" for resale to local distribution companies (such as gas utilities) and other end users at regulated city-gate prices. The spread between the city-gate price and the wellhead price covered the pipeline's cost of transportation. Throughout this period, a formal spot market or futures market for the purchase of natural gas did not exist.

From the mid-1930s through 1978, pipeline companies commonly entered into long-term contracting arrangements to purchase gas from producers (take-or-pay contracts) and to sell gas to end users (contracts containing minimum bill provisions) to guard against gas shortages and mitigate price risk (Masten and Crocker, 1985). A take-or-pay contract required that the pipeline pay for a minimum quantity of gas during the contract period at a preset regulated wellhead price (plus tariffs and other transaction fees). The producer and pipeline negotiated the quantity. A minimum bill provision similarly required that the end user pay the pipeline for a minimum quantity of gas during the contract period at the regulated city-gate price. Under both contracts, the gas-receiving party did not have to take delivery of all purchased gas. Because the pipelines had the opportunity to use both types of long-term contracts, price risk associated with take-or-pay contracts existed only if the firm did not have offsetting contracts with minimum bill provisions.[5]

The first major regulatory change that increased natural gas price risk for pipelines occurred in the late 1970s following the enactment of the Energy Reorganization Act in 1977. This act abolished the Federal Power Commission (FPC) and established the Federal Energy Regulatory Commission (FERC). The regulations that followed were designed to increase the flow of gas into the interstate market and deregulate wellhead natural gas prices. In particular, the Natural Gas Policy Act (NGPA) of 1978 removed controls over market entry and wellhead gas sales and established partial deregulation of prices.[6] Briefly, the NGPA established "categories" of gas based on age. The prices of the various categories were deregulated in stages over time. The act, first discussed in April 1977, also discussed the establishment of a spot market for gas and allowed end users, including local distribution companies, to buy gas directly from producers and contract for transportation services separately with the pipelines (Section 311). Subsequent to the NGPA, the newly established FERC issued additional orders meant as gradual steps toward the ultimate goal of deregulation of the wellhead price of natural gas. For the pipeline companies, price risk was generally increasing with each new FERC order.

FERC Order 380 (1984, first discussed in late 1983) was the first to have a significant impact on price risk. At the time of the order, the deregulated wellhead prices were decreasing because of an increased supply of natural gas in the early 1980s, attributed to energy conservation and the end of the OPEC embargo. However, city-gate prices remained regulated at levels above wellhead prices. For example, at the end of December 1983 the city-gate price was $1.30 per mcf greater than the wellhead price of $2.58. The lower demand for natural gas triggered minimum bill clauses in contracts between end users and pipelines which was costly to end users (Henderson, Guldmann, Hemphill, and Lee, 1986). FERC responded to this situation by issuing Order 380. This order freed pipeline customers from their obligations under minimum bill provisions with the pipelines. However, the pipelines were not freed from their take-or-pay

[5] See Parsons (1989) for a discussion of the effects of take-or-pay provisions in contracts and a method for pricing their option value.

obligations with producers.[7] The result was huge losses for the pipeline companies that led to significant industry-wide financial distress (Castaneda and Smith, 1996). As a result of this order, the hedge that the firms thought they had created by matching these two types of long-term contracts was disrupted by the regulators, and the firms faced an increase in price risk. Given prices at this time, the increased price risk meant increased payments by the pipelines.

In the following year, FERC Order 436 (October 1985, first discussed in December 1984) made three significant changes that increased the exposure of pipelines to natural gas prices. First, it required pipelines that elected to transport gas under the order to provide open access transportation services. This requirement was the first major step in the unbundling of the sale and transportation of natural gas such that end users could buy gas directly from gas merchants at the wellhead and transport the gas via the pipelines. Second, Order 436 required pipelines to allow customers to convert their firm *purchase* obligations to firm *transportation* services over a five-year period. Third, Order 436 instituted some controls over city-gate prices.[8] FERC Order 500 (1987), which replaced Order 436 in 1987, reduced the pipelines' costs associated with take-or-pay contracts. Order 500 allowed gas quantities sold directly by a producer to an end-user but transported through the pipeline to count towards the pipeline's take-or-pay obligation with the producer (Williams and Parent, 1988). This provision mitigated the increase in price risk and related financial burden that occurred when FERC freed end-users from their obligations under minimum bill provisions without freeing the pipelines from their take-or-pay obligations.

FERC Order 451 (1986) further provided for the sharing of costs related to take-or-pay contracts between producers and pipelines that had begun with FERC Orders 436/500. It required that producers and pipelines enter into "good faith" renegotiations of existing take-or-pay contracts. The order also brought vintage gas prices (one of the many categories of gas classified under

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[6] Descriptions of natural gas regulation during this time period do not discuss quantity controls or quantity rationing. The focus of regulation during this time period was price regulation.

[7] Following the NGPA of 1978, pipelines and producers entered into special marketing programs (SMPs) in which the producer sold gas to the end user at a discounted price and specified which pipeline would transport the gas. This arrangement provided some take-or-pay relief for the pipelines because gas transmitted under the SMPs was counted towards the take-or-pay obligation. The courts terminated SMPs in 1985 claiming that they were discriminatory against LDCs because they were offered only to industrial end users.

[8] Specifically, Order 436 required pipelines to set maximum rates designed to ration capacity during peak periods and maximize the flow of gas (throughput) for firm services during off peak periods and for interruptible services during all periods.

NGPA) to market levels thus continuing the deregulation of wellhead natural prices that had started with the NGPA of 1978. FERC Order 500 affected pipelines' risks differently as a function of their inventory of gas and the extent of their take-or-pay contracts with producers.

Finally, FERC Order 636 (1992, first discussed in early 1991), which completed the series of FERC mandates, resulted in a reorganization of the natural gas industry.[9] Order 636 mandated that all pipelines unbundle the sale and transportation of natural gas (unlike Order 436 which allowed the pipeline firms to *elect* open-access). It also required that pipelines provide for the issuance of blanket "sales for resale" certificates for gas sales at market-based prices and nondiscriminatory open-access transportation and storage services.[10] The implementation of FERC Order No. 636 was completed by the end of 1994.

B. Time-series illustrations of the effects of regulation

Table III reports yearly averages for selected financial characteristics for the sample natural gas firms for 1979, 1984, 1987, 1990, 1992, and 1995. These periods represent the first-year after the start of deregulation (1979), four years in which major regulatory events occurred, and the end of the sample period. Figure 1 graphs the monthly wellhead price of natural gas over the entire sample period and marks the dates of significant regulatory events.

[INSERT FIGURE 1 HERE.]

Panel A of Table III shows a steady increase in the numbers of sample firms during the period of price deregulation. In 1979, the sample contains 22 natural gas companies that own 33 major interstate natural gas pipelines. The number of firms increases to a maximum of 25 in 1985 (not reported) and declines to 21 in 1995. The number of pipelines and total pipeline transmission

[9] Prior to Order 636, Congress enacted the Decontrol Act (1989) that amended the NGPA of 1978. The 1989 act eliminated the remaining price controls on some of the aging categories of natural gas sold at the wellhead.

[10] In addition to the components of Order 636 that directly and significantly affected price risk, Order 636 also made some significant changes to operating activities in the industry that have no direct impact on price risk. For example, Order 636 required that pipelines adopt a generic capacity release program, changed transportation rate design methodology from modified fixed-variable to a straight fixed-variable (SFV) rate design, and established policies for the recovery of all transition costs for implementing Order 636 (http://www.ferc.fed.us).

miles follow similar increasing trends. The initial increases in the numbers of sample firms, pipelines, and transmission miles correspond to entry following increases in natural gas prices associated with the NGPA in 1978.

[INSERT TABLE III HERE.]

After 1984, the number of pipelines and firms decline. The decreases result both from mergers and acquisitions within the industry as well as from exit from the industry due, in part, to bankruptcies. By 1984, natural gas prices were at an all time high. Table III, Panel B, reports that prices ranged from $0.91 per mcf in 1979 to $2.57 in 1984 and $1.84 at the end of the sample period. Also in 1984, take-or-pay contracts between pipelines and producers were being triggered while FERC Order 380 was allowing end users and local distribution companies to renege on minimum bill provisions with the pipelines. Together, these events resulted in financial losses for the pipelines.

Table III also reports the time-series patterns in selected gas account statistics for FERC Form 2 pipelines (see Panel C) over the years of changes in regulation described in the previous section. The ratio of gas purchased to total gas receipts declines from 60.99% in 1979 to only 6.60% in 1995. The unbundling of transportation and merchant functions forced firms to transport more gas purchased by others and transport a smaller percentage of gas purchased by the pipeline for resale. Total gas sales declined from 59.99% of total sales and deliveries in 1979 to 28.55% in 1987 and then to only 7.92% in 1995. During the same period, gas deliveries increased from 40.01% of total sales and deliveries to 92.07%.

Customer composition also changed during the period of deregulation. Gas sales for resale declined almost monotonically from 56.25% of total sales and deliveries in 1979 to 3.00% in 1995. In contrast, gas received from others for transportation increased from 18.21% of total gas receipts to 82.62% during the period from 1979 to 1995. Given the regulatory changes taking place during the sample period, gas transported for others was most likely purchased in the spot market (Fitzgerald and Pokalsky, 1995).

Table III (Panel D) also shows the time-series trends in some key financial indicators for the pipeline parent companies. The profit margins of the sample firms, as measured by the ratio of operating income to total sales, increased from about 16% to over 20% during the sample period.[11] However, the ratio of net income to sales did not change significantly during the sample period. After eliminating one firm with extreme ratios of net income to sales in years 1993 through 1995 and another firm with an extreme ratio in 1995, the ratio of net income to sales is approximately 0.04 from 1987 through 1992 and then increases to over 0.06 for the remainder of the sample period. [12] The increases from 1990 to 1992 or 1995 are not significant. One explanation for the increase in operating profit margins without a corresponding increase in net profit margins is the increase in special items (such as litigation and restructuring charges), extraordinary items, and discontinued items that affect net income but not operating income. In particular, total special items, extraordinary items, and discontinued items as a percentage of sales are -0.001 in 1979 (primarily discontinued operations), -0.005 in 1984 (primarily special items), 0.000 in 1987, -0.019 in 1990 (primarily special items), -0.015 in 1992 (special and extraordinary items), and 0.024 in 1995 (primarily discontinued operations). Compared to the early years of the sample, the amounts in the 1990s are a significant component of net profit margins.

Consistent with the claims of increasing financial distress in the industry following the regulatory changes in 1984, Panel D shows that the sample firms were less able to service their long-term obligations. Average interest coverage ratios declined from 5.122 in 1979 to 3.899 in 1995. However, during the same period firms' market-to-book ratios increased from 2.440 in 1979 to 3.163 in 1995. If the market-to-book ratio is a proxy for a firm's growth opportunities, one interpretation of the increasing market-to-book ratios is that firms had higher growth

[11] These figures are consistent with trends for the pipelines. Pipeline profit margins, as measured by the ratio of operating income to revenues using FERC Form 2 data, increased during the sample period from 14.7% to over 30% in the 1990s.

[12] The ratio of net income to sales for Leviathan partners is approximately 1.1 in 1993-1995. Eighty-two percent of Leviathan's net income in 1995 represents income from Leviathan's interest in pipeline partnerships. Because the partnerships are accounted for by the equity method, the partnership income is included in Leviathan's net income, but the partnership revenues are not included in Leviathan's revenues. The ratio of net income to sales for Williams Cos. is 0.46 in 1995. Williams Companies recorded a significant gain (77% of net income) related to the discontinuation of network service operations. Excluding these observations, the 1995 ratio of net income to sales is 0.067.

opportunities in 1995, post-deregulation, than in 1978. As a benchmark, the average market-to-book ratio (of equity) for all Compustat firms (excluding financial institutions) in 1995 was 2.589.

Changes in the sensitivities of stock returns to natural gas price returns also illustrate the effects of regulation during the period from 1979 to 1995. Natural gas price exposure is measured using an extended market model that regresses returns for an equal-weighted portfolio of the sample natural gas firms (R_P) in excess of the rate of return on the 3-month Treasury Bills (R_{TB}) on the equal-weighted market return (R_M) in excess of R_{TB} and the excess return of average wellhead prices ($R_{NG} - R_{TB}$). The equal-weighted market return is used in place of the value-weighted market return since the sample firms are quite small. The results are qualitatively robust to the choice of market measure.

$$R_P - R_{TB} = \alpha + \beta_M \left(R_M - R_{TB}\right) + \beta_{NG}\left(R_{NG} - R_{TB}\right) + \varepsilon \qquad (2)$$

The model is estimated using monthly data and rolling 48-month windows from 1978 to 1995 (i.e., the first observation is estimated for the 48-month period ending December 31, 1981).[13] These regressions provide 169 estimates of natural gas price sensitivities using data from the overlapping windows. Motivated by the caveats in Tufano (1998) regarding potential problems related to using monthly data, we use weekly spot price and market data to verify the robustness of the beta estimates over the period since the early 1990s during which weekly data are available. The natural gas betas using weekly data during this limited period are qualitatively similar to the monthly results that we present.

[INSERT TABLE IV HERE.]

Table IV presents summary statistics for β_{NG} and β_M for the full sample of natural gas firms. The mean estimate of β_{NG} is -0.05, and the time-series standard deviation of β_{NG} is 0.16,

[13] 60-month windows tend to span the time-periods during which the beta point estimates cross zero while 24 and 12-month windows tend to estimate betas with great imprecision. The 48-month window offers a reasonable compromise. Results for the 48-month window are presented; results for the 36-month window are similar.

with a maximum estimate of 0.21 and a minimum of -0.35. Twenty-one percent of the estimated wellhead-return betas are significantly different from zero. In addition, the market betas are less variable over time than the wellhead return sensitivities and 83% of the market betas are significantly different from zero. The average market beta is 0.65 with a standard deviation of 0.08 and a range from 0.42 to 0.88. The use of overlapping observations likely understates the true volatilities of the coefficient estimates (Hansen and Hodrick, 1980). However, corrected t-statistics confirm that β_{NG} is significantly negatively on average. The research on natural gas price sensitivity, in particular, is limited but related papers on commodity price sensitivities provide perspective on the statistics presented in Table IV. The natural gas betas are similar to those reported by Thorton and Welker (1999) and to oil price betas reported by Rajgopal and Venkatachalam (1998). Note, however, that both the mean oil and natural gas betas are approximately half the average gold price beta reported by Tufano (1998).

The parameter values reported in Table IV demonstrate the volatility of natural gas price sensitivities over the entire sample period, but the means hide the time-series patterns of changes in wellhead price sensitivities. Figure 2a illustrates the time-series of β_{NG} for the period following establishment of the Natural Gas Policy Act (1978) to 1995 for the full sample of firms. Each plotted observation represents the β_{WH} calculated using the preceding four years of data. Thus, the beta corresponds to the changes in regulation that occurred during the four years preceding the stated beta date. Between the time of the NGPA (1978) and the issuance of FERC Order 380 (1984) and continuing with Orders 436 and 500 (1985 and 1987, respectively), approximately half of the sensitivities to changes in wellhead prices were negative, with an overall pattern of decrease. Also during this first part of the sample period, the volatility of the β_{NG} estimates is higher than in subsequent years.

As deregulation progressed in the 1980s and 1990s and wellhead price volatility increased, the estimated gas sensitivities become positive around the effective date of the 1989 Decontrol Act, which was first discussed in March 1989. Following the initiation of NYMEX natural gas futures contract trading in 1990, the average natural gas return sensitivity for the portfolio of sample firms is approximately 0.15 from 1993 through 1995. In addition, the sensitivities are relatively less volatile than in the periods prior to the initiation of these contracts.

Figure 2b presents the OLS t-statistics for the wellhead sensitivities and demonstrates that the majority of statistically significant positive sensitivities occur after price deregulation, particularly after the Decontrol Act of 1989 with values averaging approximately 2.0. In contrast, significantly negative natural gas exposures emerge in the first several years of the sample. The negative betas prior to deregulation reflect the role of the pipeline as a consumer of gas, when the pipelines purchased significant quantities of gas for transportation and resale. The positive betas post-deregulation are consistent with the unbundling of the sale and transportation of gas. The pipelines' exposures are similar to those of a producer, rather than a consumer, in that the value of the firms' services rise and fall with the demand for gas. Market betas (not graphed) exhibit a pattern similar to that of the β_{NG}'s with variable sensitivities in the first half of the sample period and more stable estimates in the post-regulation period.

[INSERT FIGURE 2a and 2b HERE.]

Because the two-factor model above may not adequately explain stock returns in general, we use an extended Fama-French (1993) five-factor model in addition to the extended market model presented above:

$$\begin{aligned} R_P - R_{TB} &= \alpha + \beta_M(R_M - R_{TB}) + \beta_{NG}(R_{NG} - R_{TB}) \\ &\quad + \beta_{HML}R_{HML} + \beta_{SMB}R_{SMB} + \beta_{TERM}R_{TERM} + \beta_{DEF}R_{DEF} + \varepsilon \end{aligned} \tag{3}$$

This model includes a control for the potential impact of interest rates on the estimates of natural gas price sensitivities. The early part of the sample period coincides with a period of high and volatile interest rates. Three-month treasury bill rates exceeded 16% in August 1981 and interest rate volatility was high following the change in monetary policy in 1979. T-bill rates hit a low of approximately 5.5% in late 1986 and remained at this level for a year before climbing again through 1988 and 1989. Rates fell through early 1994 before a slight increase at the end of the sample period.

The extended Fama-French model regresses the excess return of the entire sample portfolio on six factors. The factors are: (1) the value-weighted market return (R_M) in excess of R_{TB}; (2) the excess return of average wellhead prices ($R_{NG} - R_{TB}$); (3) the return on a zero-investment portfolio (R_{HML}) which is constructed by subtracting the return on low book-to-market ratio firms from high book-to-market firms (from Fama and French, 1993); (4) the return on a zero-investment portfolio (R_{SMB}) which is constructed by subtracting the return on a portfolio of large firms from the return on small firms (from Fama and French, 1993); (5) the return difference between the 30-year Treasury bond and the 3-month Treasury bill (R_{TERM}); and (6) the return difference between BAA corporate debt and AAA-rated corporate debt (R_{DEF}).[14] Fama and French (1993) argue that R_{HML} captures the value and growth effects apparent in average returns, R_{SMB} captures the size effect in average returns, R_{TERM} models the slope of the term structure, and R_{DEF} models the corporate "default spread." Market and Treasury bill returns are from CRSP. Wellhead returns are calculated using monthly wellhead prices as described previously. R_{TERM} and R_{DEF} are constructed using data from the Standard and Poor's DRI macroeconomic database.

The second panel in Table IV reports summary statistics from rolling regressions similar to those in the first panel. The five-factor model regressions produce wellhead return betas that have a mean value of –0.02 and volatility of 0.15, which is similar to the volatility of β_{NG} estimated using the two-factor model. The Hansen and Hodrick (1980) corrected t-statistics also show a marginally significant and negative average natural gas beta estimate. The minimum β_{NG} from the five-factor model is lower than that from the extended market model (-0.35 vs. -0.44) while the maximum is about the same (0.21 vs. 0.19). Eighteen percent of the β_{NG} estimates are different from zero at the 10% level. The β_{NG} estimates that are reliably different from zero are negative at the beginning of the sample period and positive near the end of the sample period.

Figures 3a and 3b show the time-series patterns of the β_{NG} s estimated using the five-factor model and the associated OLS t-statistics. The patterns roughly match those for the estimates from

[14] Gene Fama kindly provided the market, HML and SMB time series that we use in the regression.

the two-factor model in Figures 2a and 2b. In general, the β_{NG} estimates are negative in the first part of the sample and increase in value as deregulation proceeds. The increasing trend coincides with the advent of FERC Orders 436 and 500 and the Decontrol Act and with the increase in wellhead price volatility that accompanied deregulation. The estimates remain positive and less volatile even as wellhead price variability increased in the early to mid-1990s. The parameter estimates are relatively more stable in the last three years of the investigation period, 1993-1995.[15] By the end of the sample period, the β_{NG} s shown in Figure 3a are significantly positive at the 10% level, as illustrated in Figure 3b.

[INSERT FIGURE 3a and 3b HERE.]

IV. Activities that affect natural gas price risk

This section describes financial and operational activities that affect the price exposure of pipelines. We analyze the time-series patterns in these activities, the associations among these activities, and the firm characteristics associated with particular activity choices. Cross-sectional variation in these activities is potentially related to cross-sectional variation in the wellhead return exposures of the pipelines' stock returns. The aggregated analysis in the previous section obscures these potentially significant differences across firms, if any. In Section V, we investigate the association between the wellhead return sensitivities and the activities that can affect price risk. This analysis shows the relative contribution of each activity to price risk exposure using a setting that covers a period of significant increases in price risk due to deregulation.

We examine eight activities that can potentially affect a natural gas pipeline's price risk exposure. Extant empirical evidence on "hedging" generally focuses on the use of derivative instruments or insurance products (Tufano, 1996, and Petersen and Thiagarajan, 1999, are notable exceptions). This analysis considers a more comprehensive set of activities than the use of derivatives. Section A describes the activities and the proxies for each activity. The discussion in

[15] The estimates in Figures 3a and 3b use fewer observations per parameter than those graphed in Figures 2a and 2b. Specifically, the regressions supporting Figure 2a use 48/3 = 16 observations per coefficient while the regressions underlying Figure 3a use 48/7 = 6.9 observations per coefficient. The parameter estimates displayed in Figure 3 may be intrinsically more unreliable, *ceteris paribus.*

Section A focuses on the time-series patterns in these activities over the sample period as regulation changed price risk exposures. The variables that are used as proxies for these activities are all scaled, thus inflation adjusting is not necessary. Section B examines whether the sample firms use the eight activities as complements or substitutes. In addition, Section B examines the characteristics of firms that make different activity choices.

[INSERT TABLE V HERE.]

A. Summary of strategies for managing risk

A.1 Financial derivative instruments

Firms can use exchange-traded or over-the-counter derivative instruments to manage natural gas price risk. We measure a firm's use of financial derivative instruments using an indicator variable (DERIV). For each sample year, DERIV is equal to one if the firm reports having outstanding commodity derivatives at fiscal year-end or reports using commodity derivatives during the year, and equal to zero otherwise. We use an indicator variable because measures of the magnitude of off-balance sheet activities are inconsistent or missing due to limited disclosure requirements during the sample period. Although notional amounts or market values are available for some sample firms, the sample size would be greatly reduced by using a continuous measure of derivatives activities. Data on the use of derivatives are obtained from 10-K filings and annual reports and are available from 1990 through 1995.

All commodity derivatives users are considered "hedgers" even though the use of derivatives can imply speculation rather than risk reduction (Géczy, Minton and Schrand [1997]). Several firms (i.e., El Paso Natural Gas, Questar, and Enron) report that derivatives are used both for risk management and trading. The use of natural gas derivatives for trading is consistent with the claim that trading in derivatives can be a positive NPV activity for a firm that believes it has “insider” knowledge of prices.[16] Although the use of derivatives can reflect speculation, the data do not allow a better specification of hedgers because firms have been required to report if

[16] For example, Stulz (1996) discusses the trading of interest-rate based derivatives by Banc One.

derivative instruments are used for trading (SFAS No. 119) only for fiscal years ending after December 15, 1994.

Table V reports an increasing trend in the use of commodity derivatives. In 1990, 19% of the sample firms used commodity instruments. By 1995, 85% of the sample firms used commodity derivatives (all but two firms). The increase from 1990 to 1995 is statistically significant based on a t-test of the differences in the cross-sectional means across years. Similarly, Haushalter (1999) reports that 58% of his sample of oil and gas producers use commodity derivatives in 1994. As Table V reports, the use of interest rate and currency derivatives also increases from 1990 to 1995 and the increase in the use of interest rate derivatives from 1990 to 1995 is statistically significant.

The increase in commodity derivatives activity is consistent with the increased risk exposures of pipelines related to deregulation and with an increase in expertise related to using these instruments. Exchange-traded natural gas price derivatives are a relatively recent innovation. The first natural gas futures contract began trading on the New York Mercantile Exchange in April 1990. In October 1992, the exchange launched options on natural gas futures. Prior to the 1990s, firms could cross-hedge using exchange-traded products based on oil prices to manage gas price risk. Although the spot price changes of oil and natural gas are highly correlated, there is basis risk associated with this hedging strategy. Haushalter (1999) notes that the coefficient of variation of monthly natural gas prices from January 1991 to January 1995 was 0.205 while that of monthly oil prices was 0.116. Of course, the introduction of exchange-traded natural gas derivatives is not exogenous but is an outcome that is likely related to the deregulation that created a demand for these instruments.[17]

[17] Petzel (1989) indicates five criteria for a successful futures contract, the first of which is that "there is a sizeable pool of assets or income at risk" (p. 3). Although there was a large pool of natural gas-related assets and income prior to price deregulation, it was not "at risk" of market price movements until deregulation.

A.2 Contracting (OTC price fixing)

Long-term contracts are another tool to manage cash flow volatility related to input and output prices in the natural gas industry (Masten and Crocker, 1985).[18] Natural gas pipeline companies used two types of long-term contracts prior to 1978 (the start of our sample period) and through the mid-1980s. Together, the take-or-pay contracts with producers and the corresponding contracts with consumers that contained minimum bill clauses mitigate price and quantity risk. The intuition that long-term contracting can be used as a risk management tool is supported by theoretical arguments in Hubbard and Weiner (1986) which analyzes markets with both regulation and bargaining possibilities.

Time-series predictions about the use of contracting to manage risk are not unambiguous. The increasing exposure of pipelines to price risk over the sample period suggests that the use of long-term contracts as a risk management tool will increase. However, changes in the regulation of these contracts during the sample period potentially had a countervailing effect. FERC Order 380 (1984) which allowed end users to renege on minimum bill provisions but did not allow pipelines to renege on take-or-pay obligations showed pipelines first-hand the regulatory risk associated with these contracts. As a result, natural gas pipelines and producers were involved in numerous lawsuits as industry profitability declined in the late 1980s and the related acrimony between the potential contracting parties decreased the use of such privately negotiated contracts in favor of exchange-traded instruments.[19] In summary, we predict that the regulatory unbundling of sale and transmission services led to a decrease in the use of long-term contracting.

Our proxy for the use of take-or-pay contracts (TOP) is the cost associated with gas purchases that are covered by take-or-pay contracts, scaled by revenues from gas activities (as reported in the FERC 2 annual report). For the period from 1978 to 1989, data on the costs associated with take-or-pay related gas purchases are reported annually in the *Statistics of Interstate*

[18] Certain end users also had access to short-term spot contracts beginning in 1978 with section 311 of the NGPA. Unlike long-term contracts that were common in the 1970s, spot market transactions did not contain take-or-pay or minimum bill clauses. Hence, these contracts alleviated concerns about contract risk and credit risk (Fitzgerald and Pokalsky, 1995). However, firms using these contracts have greater exposure to changes in wellhead natural gas prices than firms using long-term contracts. Data on the firm-specific use of short-term contracts are not available. Data on the industry-wide use of short-term contracts indicates that these contracts accounted for 70 to 80% of the market by 1989.

[19] We thank Charles Smithson for noting this dimension of the contracting process.

Natural Gas Companies. After 1989, these data are available only if the firm voluntarily reports take-or-pay costs in the annual report. The cost of gas purchased under take-or-pay obligations is an imperfect measure of the use of such contracts. However, data on quantities under contract are not consistently available.

Table V reports that the costs related to gas purchased under take-or-pay contracts increased as regulation changed price risk exposure during the 1980s. The mean (median) take-or-pay costs as a percent of sales increases from 0.8% (0.2%) in 1979 to 3.7% (2.9%) in 1987 and is statistically significant. The increase is consistent with anecdotal claims of increased use of these contracts related to natural gas shortages and price deregulation described in Section III in the early 1980s.[20] The increase, however, is not consistent with the use of take-or-pay contracts as a risk management tool. During this period, end users did not have to comply with the minimum bill provisions with the pipelines (FERC Order 380). Consequently, pipeline firms with significant take-or-pay arrangements faced greater risk than firms that had decreased the use of these contracts. Footnotes to firms' annual reports and anecdotal evidence suggest that the higher take-or-pay costs resulted because take-or-pay provisions contained in contracts initiated in the early 1980s (specifically, large quantities of gas at newly deregulated higher prices) were being triggered as the demand for natural gas declined. Firms, however, were not initiating new contracts with take-or-pay provisions because customers were increasingly using short-term contracts to purchase gas directly from producers in the spot market.[21]

A.3 Operational changes

Firms also can change operating activities in response to changes in price risk exposure. Natural gas pipelines have the flexibility to alter production or transmission prices and quantities. Such changes in production plans to manage price risk are consistent with the findings of Tufano (1996) that gold firms adjust their extraction plans, at least partially, to changes in gold prices.

[20] The increase in the medians is also statistically significant.
[21] Castaneda and Smith (1996) note this change in the industry using Panhandle Eastern as an example: "When large utility customers discarded their long-term contracts with minimum bill provisions in favor of short-term contracts in the spot market, Panhandle Eastern had no choice but to scale back its own long-term gas supply programs during the last half of 1982." (Castaneda and Smith, 1996, page 221.)

Multi-segment holding companies also have the option to shift resources across activities within the gas industry (e.g., from transmission to exploration and production), or to other industries (e.g., from gas to oil or railroad). The risk management effects of diversification are described in Sections A.4 and A.5. Clearly, because operational strategies involve investment and financing, these strategies affect more than just a firm's exposure to price changes. Firms presumably consider both the price risk effects and other risk/return effects when evaluating operational changes (Schrand and Unal, 1998).

Gas storage is one operating activity that significantly affects a firm's exposure to risk in the natural gas industry. Storage of gas underground is the physical equivalent of using gas futures to purchase gas quantities for future delivery in terms of its impact on price risk exposure. Consistent with the use of long positions in derivatives, storage reduces the volatility of cash flows by mitigating a pipeline's exposure to fluctuating prices or demand (Susmel and Thompson, 1997).[22] Thus, higher storage implies greater hedging. We measure storage (STORAGE) as the billions of cubic feet (bcf) of gas in underground storage at fiscal year end scaled by the total quantity of gas sales and deliveries (in bcfs) for the year. The gas in underground storage includes the amounts in both the current and non-current sections of the FERC 2 balance sheet.

The storage data in Table V illustrate no obvious trend in underground storage activities during the sample period. None of the changes in average or median storage levels for the reported years are statistically different from zero, and the standard deviations of storage levels are high. One explanation for the lack of significance is the required unbundling of transportation and marketing activities. Because of this unbundling, there was less uncertainty for pipelines about demand for gas. Thus, while price risk was increasing following deregulation and storage is predicted to increase to mitigate this risk, precautionary demand risk was decreasing. We cannot disentangle these effects. In addition, the benefits of storage as a risk management tool depend on the level and volatility of gas prices which affect the implicit net cost of storage (Williams, 1986).

[22] See Williams (1986) and the writings of Working (1977) for the theory of storage. As a speculator, if a natural gas firm expects prices to increase (decrease), one would expect the firm to store more (less) gas. In addition to expected prices affecting the storage decision, the level of the price also matters. The higher the price level, the more costly it is for the firm to store the gas. We are currently working on incorporating the effects of price levels and price expectations into our measure of storage.

A.4 Line-of-business diversification

The exposure of cash flows to fluctuations in natural gas prices will be lower for firms that engage in lines of business other than natural gas transmission or production assuming that the risk exposures of a firm's non-gas segments are not positively correlated with gas prices.[23] We consider two measures of diversification. NUMSEG is the number of separate business segments for each firm-year observation. We summarize the segments defined by four-digit SIC codes on Compustat into nine categories: (1) natural gas transmission and distribution; (2) natural gas and oil production and processing; (3) refining and marketing; (4) coal and minerals; (5) electric; (6) rail, trucking, and transportation; (7) real estate and properties; (8) services; and (9) other.[24] NUMSEG has a minimum of one and a maximum of nine. Firms with more segments are assumed to have greater diversification and be more hedged, all else equal.

The second proxy for diversification reflects the concentration of the firm-year observations in particular segments. CONC is a revenue-based Herfindahl index defined by Comment and Jarrell (1995) as:

$$CONC_{j,t} = \sum_{i=1}^{Njt} \left(REVS_{ijt} / \sum_{i=1}^{Njt} REVS_{ijt} \right)^2$$

where $REVS_{ijt}$ is the revenue from segment i for firm j in period t and N is the number of segments reported by firm i in period t. The maximum CONC is one for a firm with a single segment. A lower concentration ratio implies that the firm is more diversified and is thus more hedged.

[23] This benefit of diversification seems to contrast with results in the existing literature that diversification decreases firm value (e.g., Berger and Ofek, 1995, Comment and Jarrell, 1995, Lang and Stulz, 1994, and Rajan, Servaes, and Zingales, 1998). However, these pooled results do not consider whether diversification of price risk across the individual entities within the diversified firm is associated with cross-sectional differences in the value-enhancement or value-destruction of diversification. We are not aware of any empirical evidence either supporting or refuting this claim. However, anecdotal evidence suggests that natural gas companies diversified in the 1970s in an attempt to provide alternative energy sources and supplemental gas supplies, and, perhaps, to allay increases in price risk (Castaneda and Smith, 1996).

[24] The primary SIC codes of the segments in each category are: (1) includes 4922, 4923, and 4924; (2) is 1311; (3) is 2911; (4) includes 1429 and 1222; (5) is 4911; (6) includes 4011, 4213, 4449, and 4581; (7) includes 6500 through 6600; (8) includes 7000 and higher, and (9) is all other SIC codes.

Changes in CONC shown in Table V clearly indicate that firms increased diversification over the sample period as deregulation increased natural gas price risk. Although the number of segments does not change significantly during the sample period, the mean (and median) concentration of the sample firms' segments exhibit statistically significant decreases from 0.722 (0.706) in 1979 to 0.598 (0.522) in 1995. This trend toward diversification is opposite the trend away from diversification that was occurring during this time period for American firms in general. Comment and Jarrell (1995) show that the average level of focus across all exchange-listed firms on Compustat increased steadily from 0.683 in 1978 to 0.840 in 1989.

A.5 Mergers, takeovers, acquisitions and divestitures

As stated in section A.3, asset acquisitions and divestitures can be related to changes in a firm's concentration. For example, acquisitions of non-gas related segments or divestitures of gas-related segments will result in a more diversified firm. Acquisitions and divestitures, however, also can affect a firm's price risk exposure without necessarily leading to diversification. Thus, we consider mergers, takeovers, acquisitions and divestitures as a separate risk-related activity from diversification. Mitchell and Mulherin (1996) argue that takeovers (mergers) represent a "cheap and quick" alternative to internal expansion in the face of *positive* demand shocks. Conversely, Dutz (1989) suggests that industry-wide *negative* demand shocks provide firms with incentives to combine the best parts of each other's assets in order to rationalize existing capacity.[25] As demand falls, firms first stop investing in new productive assets, all else equal, and then allow certain assets to become idle.

In addition, consistent with the theoretical arguments about the effects of acquisitions and divestitures, empirical evidence suggests that deregulation and merger activities are correlated. Mitchell and Mulherin (1996) note that takeovers during the 1980's were clustered in time and that the time-clustering differed across industries. In particular, they note that over 67% of firms in the natural gas industry are the subjects of some form of takeover bid, more of which were hostile (38% of bids were hostile, and 29% were friendly). Similarly, Comment and Schwert (1995)

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[25] See Mitchell and Mulherin (1996) for a brief discussion of Dutz (1989) as it relates to takeovers.

suggest that the decline in takeovers in the late 1980s was motivated by economic factors rather than firm-specific anti-takeover measures or legal prohibitions against takeover activity.

We use two measures of pipeline acquisition and divestiture activity during the sample period. CHPIPE represents the *net* increase or decrease in the number of natural gas pipelines owned by the sample firms. CHMILES represents the percentage change in the number of transmission miles for the sample firms. Both CHPIPE and CHMILES are calculated using year-end data reported in FERC 2 filings. The proxies measure changes that occurred because of both construction and acquisition/divestiture. The relation between changes in the number and miles of pipelines and risk exposure is not clear. Decreases can be a direct attempt to decrease gas price risk exposure. However, increases in pipeline holdings also can decrease risk if they increase geographic diversification.

We also analyze the number and dollar magnitude of the acquisitions and divestitures made by the sample firms during the years 1978 to 1995. Data on acquisitions and divestitures were obtained from annual report footnote descriptions of significant activities and Mergerstat reports available on Lexis/Nexis. The transactions are classified as either gas-related or non-gas (NG) related based on the same criteria used to classify segments. For each group, we separately measure the number of acquisitions and divestitures for each firm-year observation and the mean deal value (as reported by Mergerstat or by the firm in its annual report) scaled by sales for the year in which the deal was closed. Data availability leads to a potential sample bias in the measurement of acquisition and divestiture activities. Mergerstat reports appear to be more comprehensive after the mid-1980s, but annual reports were likely equally comprehensive during the sample period. Since footnotes report only "significant" deals, the change in Mergerstat reporting implies that the number of acquisitions and divestitures is likely to be understated in the earlier sample years relative to the later sample years. However, the mean deal values are likely overstated in the earlier years when only the deals reported in the annual report are included for the sample.

Table V reports more frequent activity in the early 1980s as measured by CHPIPE but the actual miles are increasing more in the 1990s. The differences between the medians for CHMILES in 1979 versus 1987, 1984 versus 1987, and 1987 versus 1990 are significantly different from zero. The increase in CHMILES in 1979 is due to the reclassification of pipelines from minor in 1978 to major in 1979 for Texas Eastern Corporation. Without this firm, the average percentage change in pipeline miles is 1.10% in 1979. The large CHPIPE observation of 0.217 in 1984 is the result of three pipeline acquisitions by Midcon. If Midcon is excluded from the sample for 1984, the average CHPIPE is 0.091.

The increases in miles without corresponding increases in the number of pipelines reflects the nature of growth in the natural gas industry. By the late 1970s, firms had a basic infrastructure of pipelines in place. Growth resulted from the extension of existing lines rather than the development of new pipelines.[26] The trend of increasing miles also corresponds to the increase in natural gas usage documented in Table III. However, the increases in miles, achieved both through construction and through acquisitions in the natural gas industry, do not increase focus as measured by CONC. Rather, CONC is decreasing. At the same time that the firms are increasing their natural gas holdings, firms are increasing acquisitions outside the natural gas industry and are also increasing divestitures of natural gas entities.

A.6 Cash buffers

Natural gas companies can manage cash flow volatility associated with gas price risk by holding internal buffers of liquid assets. We measure internal cash holdings (CASH) as the ratio of cash to total assets minus cash consistent with Opler, Pinkowitz, Stulz, and Williamson (1999).[27] This variable is measured for the gas subsidiary alone using FERC Form 2 data and for the pipeline holding company based on COMPUSTAT. We predict that larger cash holdings represent a hedge of cash flow risk, consistent with the findings of Opler et al (1999) that cash buffers are positively associated with the industry-level cash flow volatility.[28] The results do not reveal a clear time-series pattern in the trend of cash holdings. However, using the cash balance

[26] For example, in its 1992 annual report, PG&E describes an expansion project as follows: "The Company is constructing an expansion of its natural gas transmission system from the Canadian border into California. The 840 miles long pipeline will provide an additional 148 MMcf/d of firm capacity to the Pacific Northwest and an additional 755 MMcf/d of firm capacity to California."
[27] Measuring cash holdings on the last day of the year produces a noisy proxy for average cash holdings which is the variable of interest. We also use the average quarterly cash holdings for the parent company. The results are similar.
[28]Opler et al (1999) test a variety of theories about the determinants of cash holdings in addition to the theory that cash reserves reduce the costs of cash flow volatility. The results indicate that cash holdings are positively associated with growth opportunities, firm size, and credit ratings.

only at year-end likely measures the concept of "cash holdings" with error.[29] The cross-sectional relations between cash holdings and other activities in Section C are more revealing.

A.7 Regulatory rate adjustments

In the absence of long-term contracts, changes in input gas prices (to either the producer or the pipeline) can be passed through to customers (either the pipeline or the end user). Thus, the sample firms potentially have a natural hedge of cash flow volatility associated with gas price changes. The effectiveness of this hedge depends on the elasticity of prices. The delivery end of the business to large industrial consumers like electric utilities was and is competitive after price deregulation and competition moderates the pass through of price changes. Even for rate-regulated activities, the effectiveness of this hedging strategy is limited. Regulated entities are forced to appeal to their governing regulatory bodies to obtain higher delivery prices based on effective rates of return. The rate adjustments on the output side occur after the firm has incurred costs on the input side because historical costs rather than anticipated costs are used to justify the need for rate increases, and the appeals process is not timely. The timing of rate adjustments reduces the effectiveness of this activity as a hedge of internal *cash flow* volatility, even though the regulated firms are subject to less *earnings* volatility. However, access to regulatory rate adjustments will reduce overall cash flow volatility if external capital markets understand the rate-making process, anticipate recoveries, and fund internal cash shortfalls.

We identify firms that are able to use regulatory rate adjustments to mitigate price risk as those that follow Statement of Financial Accounting Standards (SFAS) 71 to account for their gas operations. SFAS 71, "Accounting for the Effects of Certain Types of Regulation," allows for specialized accounting treatment for costs that a firm expects to recover through rate regulation. Specifically, certain firms are permitted to defer recoverable costs and report the costs only when the offsetting revenue is recorded. The deferral of costs is allowed only for firms that meet the standard's criteria to qualify as a "regulated enterprise." The criteria are designed to identify firms

[29] We also measured cash holdings at the parent level using quarterly data; the results are similar.

that are likely to be able to recover costs through rate regulation.[30] Thus, the fact that a firm follows SFAS 71 indicates that it has regulatory rate adjustments available as a cash flow hedging tool.[31]

Approximately one half of the sample firms meet (or have a subsidiary that meets) the criteria to follow SFAS No. 71. Firms that meet the criteria generally meet the criteria in all years. However, there are a few cases when one pipeline within the parent's holdings becomes compliant or falls out of compliance with the criteria but other holdings remain compliant. Thus, this variable does not change over time for a given firm and it is not reported in Table V. In Section C, we examine the correlation between other risk-related activities and access to regulatory rate adjustments.

A.8 Accounting earnings management

We consider two earnings management activities that affect the volatility of reported earnings. Some of these activities also are considered by Petersen and Thiagarajan (1999) for two firms in the gold industry.

First, we examine the reporting of special items. Under generally accepted accounting principles (GAAP), a special item is any income or cost that is either extraordinary or infrequent but not both.[32] Common examples of special items include litigation and restructuring charges, reserves, losses due to a permanent impairment in the value of an asset, and gains or losses on sales of assets (including subsidiaries). Because of the conservatism principle of GAAP, special items are more likely to be charges than income. Not all special items are discretionary. However, prior literature has argued that firms can exercise discretion in the timing of reporting special items (e.g., Pourciau, 1993) or in the timing of engaging in the events that create special items (e.g., Bartov, 1993).

[30] In summary the three criteria require that (1) there is a regulator with the authority to set rates, (2) the rates are linked to specific costs, and (3) collection based on set is reasonable and likely.
[31] SFAS 71 was effective for fiscal years beginning after December 31, 1983; earlier application was encouraged. The standard was preceded by a discussion memorandum issued December 31, 1979 and an exposure draft issued March 4, 1982. Although the actual accounting was not in place during the entire sample period, the use of this variable to classify firms is reasonable.
[32] If an item is both unusual and infrequent, then the income or cost is classified as extraordinary. As the name implies, these items do not occur regularly and there were too few in our sample to draw any conclusions.

We use annual report data to categorize total special items from Compustat into three types: restructuring charges, oil and gas-related (O&G) reserves, and other. Restructuring charges and O&G reserves are measured as the amount of the annual charge scaled by sales revenue and these amounts are always negative. Other special items are measured as the absolute value of other special items scaled by sales. The major contributors to "other" special items are reserves for potential litigation settlements or environmental remediation costs, pension/retirement-related settlements, and take-or-pay contract settlement costs.

Table V indicates that restructuring charges increased on average over the sample period which is consistent with the increase in restructuring charges across all industries as documented by Elliott and Hanna (1996). However, none of the average increases are statistically significant due to the small number of firms taking these charges. Although the median charge is zero, when taken, the charges can be large. For example, in 1986, including the firms that take zero charges, the average charge is -0.225. The largest restructuring charge was $2.169 billion (10% of sales) by Occidental Petroleum in 1990. While taking a restructuring charge is not an earnings management activity, per se, firms can manage the timing of the charge. In addition, the SEC has accused firms of including regular operating expenses for future periods in restructuring charges to improve future operating earnings (Elliott and Hanna, 1996). Thus, documenting these charges provides insights about the nature of the other proxy variables that measure risk-related activities. For example, divestitures can occur alone or as part of a significant restructuring and the charges help identify which situation occurs.

Oil and gas reserves and other special items also increase over the sample period. The increase in oil and gas reserves is consistent with the poor economic conditions in the natural gas markets and decrease in oil and gas prices that reduced the estimated market value of oil and gas inventories and properties. The increases in special items are due to higher litigation and environmental costs and increases in acquisition and divestiture activity that generate significant gains/losses. The increase in litigation charges is at least partially related to lawsuits over take-or-pay settlements based on our review of footnotes to financial statements about the nature of special items.

The second earnings management activity that we consider is a firm's choice of accounting policies. In particular, we consider the accounting policy choices related to inventory costing and business combinations.[33] Related to oil and gas inventory, GAAP (SFAS 19) allows firms to follow one of two methods for accounting for acquisition, exploration and production costs associated with oil and/or gas reserves: the full cost (FC) method and the successful efforts (SE) method. Basically, the two methods differ on when the costs of unsuccessful production are reported as part of income.[34] Under the SE method, costs related to unsuccessful exploration, development or property acquisition are expensed when incurred. Under the FC method, all costs associated with acquisition, discovery and development of oil/gas -- successful or unsuccessful -- are capitalized as an asset and amortized into expense as part of the cost of inventory when the related revenues on gas sales are recognized.

We consider firms that use the FC method to be hedgers based on the results of Collins, Rozeff, and Dhaliwal (CRD, 1981). First, CRD show that the full cost method generally leads to a smoother earnings stream as unsuccessful costs are allocated across time. Second, CRD document that abnormal stock returns calculated over a two-week period surrounding the Wall Street Journal's report of the FASB's Exposure draft for SFAS 19 in July 1977 are negatively related to proxies measuring the increased contracting costs and estimation risk associated with the elimination (for some firms) of FC accounting.

However, one part of the FC calculations can lead to more volatile earnings. Under the FC method, ceiling tests require write-downs of gas inventories if the market value of the asset (capitalized costs) is less than the book value because prices have fallen. These write-downs, which occur all in one period, can substantially reduce earnings and create volatility.[35]

[33] For a discussion of this earnings management tool and evidence that firms strategically time the adoption of accounting standards, see Amir and Ziv, 1997, and Amir and Livnat, 1996.

[34] The SEC allows firms to use the successful efforts method as stated in SFAS 19 or to use a "modified" full cost method (Regulation S-X, Rule 4-10). The SEC's full cost method limits the costs that can be capitalized by requiring that firms form cost centers on a country-by-country basis and only capitalize costs that can be directly ascribed to one of the cost centers (i.e., general corporate overhead cannot be capitalized). The SEC also more clearly specifies how the capitalized costs are to be amortized. Finally, the SEC rule includes a ceiling test. If the total capitalized costs exceed a ceiling based on expected future revenues from gas sales, the capitalized costs must be charged to expense immediately. The SEC rules were proposed in ASR 253 (8-31-78) which stated that the SEC would develop its own full cost method. The SEC's full cost method was finalized in a 12-19-78 release. Therefore, the GAAP and SEC rules were in effect for our entire sample period.

[35] Note that the write-downs that are related to the ceiling test are included in special items.

Table V shows that most firms used the full cost method at the beginning of the sample period. However, during the sample period, nine firms changed from FC to SE (eight voluntarily) and two firms changed from SE to FC (one voluntarily). By 1995, half of the sample firms used the successful efforts method.[36] The first group is considered less hedged as a result of the switch from the FC to SE method. Overall, firms' discussions of these changes suggests that switches were undertaken to manage the current period level of earnings, but not necessarily the volatility of earnings. Three of the nine voluntary changes increased net income in the change year from a negative amount to a positive amount. Four of the nine switchers experienced credit downgrades in the year of the change and none experienced upgrades. In addition, four of the eight voluntary changes from the FC method to the SE method occurred in 1985.[37] Prices had been increasing during the sample period from 1979 through 1984 but then dropped from a high of $2.71 in February 1985 to $2.31 in December 1985. This price decrease would have triggered a write-down under the FC method so the change to the SE method increased income in the year of the change. For these firms, net income changed from negative to positive in the year of the change.

The second accounting method choice that we consider is the choice between pooling and purchasing when a firm is engaging in a business combination. This "choice" differs from the inventory method choice in two important ways. First, the choice of accounting for business combinations is transaction-based. The structure of the transaction dictates the accounting method, but firms "choose" the structure of the transaction. In very general terms, the purchase method is used for cash deals and the pooling method is used for stock deals. Thus, this “choice” has an impact on (or is a result of) the firm's cash holdings. Second, the main effect of the choice is on current period earnings, not on volatility of current and future-period earnings.

Considering only the accounting implications of structuring a deal, firms will prefer poolings for two reasons. First, in a pooling, consolidated earnings are reported as if the combination occurred at the beginning of the reporting period even if the acquisition takes place on December 31. In a purchase, only the earnings of the acquired firm that occurred after the

[36] Non-voluntary switches result from mergers with other entities that are following a different policy or corporate reorganizations.
[37] Although the timing of the changes is consistent with an attempt to avoid the ceiling limits under the FC method, these firms stated that the FASB had expressed a preference for the SE method.

acquisition date are included in consolidated earnings. Thus, as long as earnings of the acquired entity are positive, pooling leads to higher reported income for the acquirer. Second, in a purchase, the acquirer records an asset, goodwill, that represents the difference between the purchase price and the market value of all identifiable assets of the acquired firm. Because there is no goodwill in a pooling, there is no drain on future-period earnings when this asset is expensed.[38] For these reasons, although the impact on "volatility" per se is not clear, we consider the pooling method of accounting for acquisitions to be a hedging activity.

While we would like to examine whether firms that need the earnings increase that a pooling can provide (e.g., financially distressed firms) are more likely to engage in pooling transactions, the data do not allow such an analysis. For both the 47 non-gas (NG) related firm observations (more acquisitions as some had multiple acquisitions but never mixed methods) and the 41 firm-year observations of non-NG acquisitions for which we know the accounting method, approximately 85% used the purchase method. The thirteen poolings that are done by eight firms are uniformly distributed across the years. For eight of the thirteen poolings, the firms disclose that the transaction had an immaterial impact on earnings. Thus, these firms do not disclose "as if" earnings without the pooling and we cannot assess the pre-pooling financial condition of the firm.

C. Hedging activities as substitutes and complements

In this section, we use two separate analysis techniques to examine the relations among the activities discussed in the previous section. The goal is to show which activities are substitutes or complements. In the first exercise, firms are classified as "hedgers" and "non-hedgers" based on each separate activity defined in the previous section. Within each classification of "hedgers" and "non-hedgers", we examine the means of the other proxy variables. This approach provides the most direct illustration of the relations among each activity. A disadvantage of this approach is that the results are univariate. Another disadvantage is that it requires that we define a "hedger" for each of the activities discussed in the previous section. This task is ad hoc, especially for the

[38] See Vincent (1997) for a discussion of the benefits of pooling accounting over purchase accounting that are hypothesized to lead to a share price premium for pooling firms.

activities for which we have a continuous measure. There is no clear definition of the levels of these variables that constitutes "hedging."

The second exercise is factor analysis to determine which of the activities associated with gas price risk load up on unobserved common or unique factors. The factor analysis explicitly indicates the activities that are related in the sense that a common factor contributes to the variance of the observed proxies. A disadvantage of the factor analysis in this particular study is data constraints. Because observations included in the analysis must have data available for all input activities, we face a trade-off between the number of activities included in the analysis and the number of observations available to estimate the factors. As we discuss below, we use several combinations of input variables and interpolation of the final factor scores to mitigate the problems created by our small sample size. Although there are benefits and disadvantages of both the univariate analysis and the factor analysis, together the results of the two analyses lead to similar conclusions.

C.1 Univariate Analysis

The results of the univariate analysis in which we classify firms as hedgers and non-hedgers on the basis of each risk-related activity are reported in Table VI. A firm's classification as a hedger or non-hedger can change by year. For strategies that are measured by dichotomous variables, such as users and non-users of derivatives, the table indicates which group is defined as hedgers. For strategies that are measured by continuous variables, firms are ranked into triciles (thirds) annually based on the proxy variable and designated as high (HI) or low (LOW) if the firm is in the highest or lowest tricile, respectively. The table indicates whether the HI or LOW firms are hedgers. The data on the means of the other proxy variables are pooled for the firms within each group across all sample years.

[INSERT TABLE VI HERE.]

Three main results emerge from Table VI. First, the use of financial derivatives as a risk management tool is a substitute for holding a cash buffer and for storing gas underground. Moreover, the latter two activities are complements to each other. Second, accounting earnings management strategies are not complements to activities that have a "real" effect on cash flow volatility. Finally, diversification is not related to financial hedging activities. The analysis shows that more diversified firms are less likely to be rate-regulated, and that greater diversification is related to lower storage and the use of successful efforts accounting. However, these documented associations likely represent fundamental differences between the underlying operations of the more diversified firms and less diversified firms rather than a risk-management phenomenon.

The first panel of Table VI, which classifies firms as hedgers and non-hedgers based on their use of commodity derivatives, shows that hedgers hold significantly less cash (measured at the pipeline level) and store lower quantities of gas underground. Likewise, firms that are in the lower-third of the sample with respect to gas storage are significantly more likely to use commodity derivatives and hold significantly lower cash buffers than hedgers. Firms that hold more cash are less likely to use derivatives (this difference is not statistically different from zero) and hold significantly higher quantities of storage. Thus, cash holdings and gas storage are complements to each other and substitutes for derivatives use.

There are no clear trends between the use of accounting earnings management and either diversification or the use of financial derivatives. There is a positive relation between special items and storage. However, this relation appears to be driven by the accounting for storage. Several of the special charges are write-downs based on the ceiling tests required by the full cost method of accounting for reserves. Thus, firms with more gas in storage are more likely to have special items (write-downs) of this type.

Finally, the last panel of Table VI, which presents the results for firms classified as hedgers or non-hedgers based on whether the firm meets the definition of a rate-regulated entity under SFAS 71, suggests that the rate-regulated firms are significantly different than the non-regulated firms. The results show associations between the variables, not causality. Clearly, some of the proxy variables are determinants of rate regulation. For example, firms that are rate-regulated store higher levels of gas and are significantly more likely to use the full cost method of accounting, and this accounting choice is likely related to the nature of the operating activities of these firms. However, other variables are likely the effects of regulation or the firm characteristics associated with being a rate-regulated entity. Although the endogeneity issues related to this variable preclude us from making statements about rate-making as a risk management activity, the documented associations among the risk-related activities are still interesting. For example, rate-regulated firms hold significantly less cash as a buffer and are significantly less likely to use commodity derivatives. In addition to the lack of financial hedging by the rate-regulated firms, the firms are significantly less diversified as measured by the concentration ratio.[39]

C.2. Factor Analysis

The results of the factor analysis are presented in Table VII. The factor analysis identifies six factors that have eigenvalues greater than one. Together these factors retain approximately 70% of the variation in the input variables. The table presents the factor scores after oblique rotation.[40] These scores are used to calculate firm and year-specific proxies for the combinations of hedging activities identified in this factor analysis. The details of the calculation of the proxy variables are described following the discussion of the factors.

The input variables to the factor analysis represent thirteen of the proxies identified as activities that affect gas price risk. These thirteen proxies were chosen to maximize data availability. When there are two proxies that measure the same economic construct, such as NUMSEG and CONC that measure diversification, only one of the two variables was included in the analysis. The analysis is done using panel data for the period 1990-1995 so that the derivatives variables can be included. We also perform the same analysis for the entire sample period with the exception that the derivatives variables are excluded. The factor loadings are similar for the five

[39] These results related to the concentration ratio are not driven by the rate regulation criteria. Firms can follow SFAS 71 for segments within the firm as long as the segment meets the accounting criteria. It is not necessary for the entire firm to meet the criteria of SFAS 71. Thus, it is not the case that less diversified firms are more likely to meet the criteria, *ceteris paribus*.

[40] We use the Promax oblique transformation method in SAS.

non-derivative factors. Thus, the availability of derivatives does not significantly alter the correlations among the use of other risk management strategies.

[INSERT TABLE VII HERE.]

The six factors have intuitive economic interpretations. The variables with significant loadings for the first factor, which we label the “operating activities factor,” are cash buffers, storage, and diversification. The signs indicate that holding more cash, greater storage, and less concentration (i.e., more diversification), all of which reduce price risk exposure, are related. The variables with significant loadings for the second factor, which is denoted the “financial hedging factor,” are the use of commodity and other derivatives (foreign exchange rate or interest rate). The loadings are positive for both of these variables.

The third factor, the "restructuring factor", has significant loadings on the two variables that measure the extent of divestitures by the firm related to both natural gas and other segments and on the variable that measures the restructuring charges taken by the firm (a component of special items). Note that the signs indicate that firms are concurrently engaging in extensive divestitures and taking significant restructuring charges (a negative special item). As noted previously, the time-series pattern of the use of restructuring charges does not suggest that these charges were used to manage earnings volatility. However, including this variable in the factor analysis is useful for better understanding the role of divestitures as a risk management activity.

As evidenced by the common loading of divestitures with restructuring charges, the divestitures generally represent significant changes in the nature of firm's asset holdings. There are a total of 135 divestitures by the sample firms: 22 energy, 53 natural gas, and 60 other. The mean level of restructuring charges (as a percent of sales) equals -0.0045 for the 53 natural gas divestitures, -0.0031 for the 60 other divestitures, and -0.0012 for the 22 energy-related divestitures. Restructuring charges scaled by sales has a correlation of -11% (statistically significant) with the number of other divestitures and of -20% (statistically significant) with the number of natural gas divestitures (recall that the charges are negative). Combined with the evidence that the sample firms are decreasing focus through time as measured by the concentration ratio, these results suggest that the natural gas divestitures, which lead to less focus, are associated with significant restructuring plans.

The fourth "gas" factor represents two activities of the firm that are related to gas prices: the percentage change in pipeline miles (CHMILES), which is the proxy for the acquisition and divestiture activity, and the component of special items that represents write-offs due to decreasing oil and gas prices (ceiling test write-offs and provisions for losses due to permanent asset impairment). The special item related to oil and gas reserves does not measure "hedging" per se, but provides confirmation about the interpretation of the other proxy, CHMILES. A decrease in the percentage of pipeline miles owned is related to an increase in the oil and gas charges. Thus, the firms that are decreasing pipeline miles are doing so at the time that oil and gas prices are falling.[41]

The loadings on the fifth and sixth factors represent the variables that measure acquisitions within and outside the natural gas industry, respectively. Finally, other special items does not load as a separate factor.

C.3. Firm characteristics and risk management activities

Table VIII reports characteristics of the firms that use the various risk management strategies. There are significant differences between the "hedgers" and the "non-hedgers" based on the panel data reported in Table VIII, however, separate annual tests reveal less statistical significance.

The results related to storage, cash holdings, and derivatives are interpreted in light of the results in Table VI that the use of financial derivatives is a substitute for holding a cash buffer and for storing gas underground, and that the latter two activities are complements. Consistent with this result, the firms that hold high cash buffers and store large quantities of gas are similar to each

[41] One explanation for the association between changes in pipeline miles and the ceiling test write-downs is that the falling oil and gas prices drive both variables. However, the charges can also be taken as a means of managing future period earnings. In this case, the common factor indicates that the firms that are changing pipeline miles represent firms that benefit from earnings management, such as firms in financial distress. We cannot distinguish these explanations for the common loading.

other and significantly different from the "non-hedgers" in these categories. In particular, the cash "hedgers" (panel six) and the storage "hedgers" (panel two) are more profitable (higher operating income ratios) and less financially distressed (higher interest coverage ratios, lower long-term debt ratios, better S&P bond ratings, and higher dividend yields). The hedgers also have lower market-to-book ratios. Thus, the same kinds of firms use storage and cash buffers, consistent with the evidence that these two activities are complements.

By contrast, users of financial derivatives are unlike the storage and cash hedgers, consistent with the evidence that derivatives are substitutes for the use of storage and cash. Derivatives users (panel one) have lower profit margins and are more financially distressed as evidenced by their worse S&P bond ratings, lower dividend yields, and higher market-to-book ratios than non-hedgers.

The results in Table VI also indicated that there are no clear trends between the use of accounting earnings management and either derivatives use or diversification. In Table VIII, firms that are classified as hedgers based on their use of full cost accounting have higher profit margins, are larger and have lower long-term debt ratios than non-hedgers (firms which use successful efforts accounting). These characteristics are not shared by hedgers based on derivatives use, measures of diversification, or storage.

Finally, as in Table VI, firms that follow SFAS 71 accounting (regulated firms) are statistically different from firms that do not follow SFAS 71. Regulated firms have higher profit margins, better S&P bond ratings, higher interest coverage ratios, are smaller and have lower market-to-book ratios. The characteristics of the regulated firms are similar to those of the cash and storage hedgers and unlike those of the derivative hedgers. This result is consistent with the result in Table VI that 69.5% of unregulated firms use derivatives while only 46% of regulated use derivatives to hedge. Mian (1996) also suggests that regulated firms are less likely to use derivatives. Although our results suggest differences between regulated firms and unregulated firms with respect to hedging activities, the results obviously do not suggest causality.

[INSERT TABLE VIII HERE.]

We also use the factor scores to classify firms as hedgers and non-hedgers. This classification has the advantage that it considers that firms use multiple activities together and does not classify firms based on the choice of a single activity as in the univariate analysis. Using the factor analysis as a means of defining hedgers and non-hedgers assumes that activities that load up together are complements and both are used because of their relation to risk.

We create a proxy for operating-activity hedgers based on the first factor and a proxy for financial hedgers based on the second factor. To compute these firm and year-specific proxies, we use the factor scores (after oblique rotation) from the previous section and the standardized input variables. The rotation provides scores that are easier to interpret economically but can potentially produce correlated factors. However, the rotation does not induce significant correlation in the factors in this case based on an analysis of the correlations and semi-partial correlations between the common factors and the input variables.

We create the factors by equally weighting only the input variables with significant factor scores in the initial analysis (after rotation). This procedure reduces measurement error associated with inputs that have little impact on the factors.[42] In addition, we are able to create factors for a greater number of firm-year observations. The factor analysis is based on the 81 observations with complete data to estimate the factors. However, there are 125 observations during the post-1989 period. The equally weighted factor scores are applied not only to the observations that are included in the factor analysis but also to the observations that are excluded from the factor analysis because they are missing data for at least one of the input variables.

Using factor two (financial hedging factor) to define hedgers and non-hedgers confirms the previously stated univariate differences between commodity derivatives users and non-users (results not tabulated). Using factor one (operating activities factor) indicates further the relation between hedging by holding cash, storing gas, and diversifying. When the firms are classified as hedgers and non-hedgers based on this factor, there are no significant differences between the two

[42] The correlations between the factors that are based on all input variables and the equally-weighted factors for the 81 observations are between 92% and 97% for the first five factors. For the sixth factor that represents other special items, the correlation is 78%.

groups. This result occurs because diversification loads negatively on this factor while storage and cash buffers load positively. Further, the characteristics of firms that hedge through diversification are generally opposite those of the firms that are defined as hedgers on the basis of cash buffers and storage.

V. Equity price risk and hedging activities

This section links the natural gas price sensitivities perceived by the market to firm-specific risk management activities. We examine the relation between firms' return sensitivities to changes in wellhead prices from equation (2) and the various proxies for risk-management activities including the financial risk management strategies as well as the non-derivative strategies and the factor scores that attempt to create a measure of multiple hedging activities.

Table IX shows the results of annual cross-sectional regressions of wellhead betas (β_{NG}) and the absolute value of wellhead betas ($|\beta_{NG}|$) on an intercept and each of the proxies for a risk-related activity. The table presents the mean of the annual cross-sectional coefficient estimates on the risk-related proxies; results for the intercept are not presented. The results indicate that gas price betas are positively associated with gas storage and the use of successful efforts accounting. However, the *absolute* magnitude of a firm's gas price sensitivity, which is a better proxy for net exposure regardless of its sign, is not associated with a firm's accounting choice (i.e., full cost v. successful efforts accounting). Thus, we focus the discussion on the results of the regressions using $|\beta_{NG}|$ as a dependent variable.

[INSERT TABLE IX HERE.]

The absolute value of β_{NG}, or a firm's net gas price exposure, is associated with the use of take-or-pay contracts, net cash, concentration, factor 1 (operational hedges), and factor 2 (derivative hedges). Table IX shows negative relations between $|\beta_{NG}|$ and take-or-pay costs as a percent of sales and cash holdings. These results indicate that more extensive use of long-term contracts, as evidenced by a higher cost incurred on these contracts, and holding a greater buffer stock of cash, both of which are designated as hedging activities, are associated with a lower overall exposure to gas price risk. The relations between both of these risk proxies and the raw gas price beta are not significantly different from zero. Concentration ratios are positively associated with $|\beta_{NG}|$ which suggests that more focused firms (less diversified and less well hedged) have higher gas price sensitivities, on average.

The analysis of the relation between $|\beta_{NG}|$ and the factor scores indicates that combinations of operating risk-related strategies are associated with gas price sensitivity. On average firms with higher cash, higher storage and greater diversification (factor 1) have lower gas price sensitivities (in absolute value). However, there is a positive association between $|\beta_{NG}|$ and the factor score associated with using financial hedging of all types (commodity, interest rate, and foreign exchange). This unpredicted result is based on only six annual observations from 1990 through 1995. In addition, the factor represents a summary of all financial hedging; the relation between the use of commodity derivatives and $|\beta_{NG}|$, which is also based on a small number of observations, is insignificant.

The univariate analysis ignores the potential for combinations of risk management activities to affect gas price betas and also masks the time-series pattern of rolling exposures. Table X provides an analysis of the rolling betas for portfolios of "hedgers" and "non-hedgers" that attempts to correct these deficiencies, although the analysis is still constrained by the small sample size. First, we examine differences in the sensitivities of firms that use commodity derivatives (denoted derivatives users) and firms that do not use commodity derivatives (non-users). Second, we consider differences in the sensitivities of firms that are defined as hedgers using the non-derivatives strategies. If a firm uses two or more of the other non-redundant available strategies besides the use of derivatives, it is considered a "non-derivative hedger". Third, we consider differences in the sensitivities of firms based on factor scores. A firm is assigned to the factor hedger portfolio in a given month if it has two or more factor values in the upper third of the equally weighted factor score values discussed in the previous section. The equally weighted factor score values utilize data from all firms in the sample. This imputation effectively avoids discarding information for the majority of factor scores for a given firm if it is missing data in a given time period for one of the underlying characteristics that loads on a different factor. Assigning firms as hedgers and non-hedgers on the basis of two or more of the six factors should reduce noise relative to simply observing actual non-derivative hedging activities without further analysis. Finally Figures 4 and 5 illustrate the time-series pattern of wellhead price sensitivities for "non-derivative hedgers" and hedgers classified based on factor values.

[INSERT TABLE X HERE.]

[INSERT FIGURES 4 AND 5 HERE.]

Table X, Panel A, indicates that firms that disclose using commodity derivatives have significantly smaller and less variable stock-price sensitivities to wellhead price changes than non-hedgers. The mean of the estimated β_{NG}s for each 48-month period (the time series begins in 1990) for the portfolio of derivative hedgers is -0.005 and the estimates vary between -0.05 and 0.05. In contrast, non-users of derivatives have an average exposure to wellhead price changes of 0.02 with a range of -0.04 to 0.80. The similarity in the means and standard deviations of the market betas, however, indicates that the two groups are not fundamentally different with respect to systematic risk as specified in equation (2). Rather, the difference between the groups is evident only in their exposures to wellhead price returns. Finally, only 2.7% of the sample of derivatives hedgers have exposures that are statistically different from zero –- either negatively or positively –- at the 10% level. However, the fraction of the β_{NG}s of non-hedgers that are different from zero is 12.8%.

Similarly, Panel B reports that the "other hedgers" have appreciably smaller gas price sensitivities than non-hedgers. The average natural gas price sensitivity of the hedger and non-hedger portfolio is -0.0049 and 0.13, respectively, and ranges from -0.04 to 0.091. The range of estimates is narrower for firms comprised of other hedgers (-0.04 to 0.091) than for non-hedgers (0.38 to 0.40). The volatility of the rolling natural gas betas for other hedgers is 0.08 while that for the non-hedger portfolio is 0.14. In addition, the average market exposure of hedgers in Panel

B is smaller than the non-hedgers average market exposure, a somewhat surprising finding because hedgers by any method are typically larger in size than non-hedgers.

Figure 4a demonstrates that the time-series of rolling natural gas return betas for "non-derivative hedgers" exhibits a pattern qualitatively similar to the time-series of rolling betas for the entire sample. Exposures are negative in the first part of the sample until the mid-1980's when they cross the zero line. Exposures then become negative again (but not significantly different from zero) in the late 1980's. In the early 1990's, after the genesis of both a futures market and the final steps of market deregulation, exposures are positive for the remainder of the sample period.

A key difference between the results for the entire sample (Figure 2a) and those for non-derivative hedger portfolio (Figure 4a) is that the absolute values of the hedger-portfolio gas exposures are smaller. In the mid-1980's when exposures turn positive, the overall sample portfolio gas exposure climbs above 0.20, while the hedger portfolio exposure reaches its sample maximum of only 0.09. Figure 4b, which plots the time-series of t-statistics corresponding to the exposure estimates in Figures 4a, shows that for non-derivative hedgers, the significance levels of the rolling exposure estimates are mostly below one in absolute value except near the end of the sample. In summary, the returns of firms that engage in non-derivative hedging strategies have economically smaller and less variable sensitivities to natural gas price fluctuations during the period of deregulation.[43]

Panel C of Table X reports gas and market sensitivities for portfolios of hedgers and non-hedgers classified using the factor analysis of the previous section. The results suggest that "factor hedgers", like both the non-derivative hedgers in Panel B and financial hedgers in Panel A, have smaller, slightly negative average natural gas exposures with lower volatilities and a narrower range of variation than the corresponding non-hedgers. The mean average exposure of factor hedgers is -0.018 while the factor non-hedger portfolio has a mean exposure of 0.11. The hedger β_{NG} volatility over time is 0.028 while for non-hedgers it is 0.12. The hedger range is -0.07 to 0.089 while the non-hedger range is -0.32 to 0.44. Finally, only 1.7% of the hedger wellhead

[43]This conclusion is based on the reported statistics that are not adjusted for serial correlation in the estimates from the rolling regressions (e.g., Hansen and Hodrick, 1980).

return exposures is different statistically from zero while 12.3% of the non-hedger factor exposures is different from zero. Figure 5a illustrates that factor hedger exposures are small in comparison to full sample exposures. Figure 5b shows that the estimated exposures of factor hedgers are never reliably different from zero.

In addition, factor hedgers appear to be less exposed to market variability. Their average market beta is 0.37 while the non-hedgers have an average beta of 0.66, a pattern very similar to the non-derivatives case in Panel B. This difference is somewhat unexpected because hedgers by both derivatives-based classifications as well as factor and financial derivatives explanations are generally larger in size and therefore might be expected to have betas nearer to one. However, as discussed in Géczy, Minton and Schrand (1997), a possible motive for derivatives use is financial distress. Firms in distress might have higher idiosyncratic variability that emerges in estimates of overall market exposures.

Overall, in each of the cases presented, the exposures of the hedgers are lower, less variable, and less frequently unconditionally statistically significant than those of the non-hedgers. While *ex ante* hedger portfolio assignments are arbitrary, the results of this section demonstrate that there are measurable differences in exposures between the two types of firms, regardless of a possibly noisy classification procedure and the time-varying nature of the exposures through deregulation changes. In addition, controlling for complements and substitutes among hedging choices and extracting common factors present in hedging activity variables clarifies the classification. The evidence that this clustering of firms' activities improves our ability to distinguish between firms with high exposures and low exposures suggests that the factor analysis explains the complementary nature of the relations among the derivative and non-derivative risk-related activities.

VI. Conclusion

We utilize a unique string of events associated with the deregulation of the natural gas industry to examine how natural gas pipeline firms choose among alternative risk management activities. The significant regulatory changes were the deregulation of natural gas prices and the required unbundling of sale and transportation services. These regulatory changes are predicted *ex ante* to increase the price risk exposures of pipeline firms before consideration of the firms' responses to these changes.

Prior to the regulatory changes during the early part of our sample period, natural gas pipeline companies used long-term contracts with both producers and customers to mitigate exposure to natural gas prices. As regulatory changes adversely affected pipelines, firms increased diversification through acquisitions outside the natural gas industry and divestitures of subsidiaries engaged in natural gas related business. Firms also turned to exchange-traded derivative instruments to manage exposures in the early 1990s when natural gas derivatives first became available. By the end of our sample period in 1995, all but two firms disclosed using derivatives for risk management.

Derivatives are a substitute for holding large cash buffers and storing gas underground. Univariate and factor analyses indicate that the latter two activities are complements. Consistent with this complementary relation, the financial characteristics of firms that hold high cash buffers and store large quantities of gas ("hedgers") are similar to each other and are significantly different from the characteristics of “non-hedgers” in these categories. In addition, the users of financial derivatives differ from the pipelines that use cash buffers and storage to hedge price risk. The derivative users have lower profit margins and are more financially distressed as evidenced by worse S&P bond ratings, lower dividend yields, and higher market-to-book ratios. Finally, accounting earnings management strategies are not complements to activities that have a “real” effect on cash flow volatility and diversification is not related to financial hedging activities.

Over the entire period from 1978 to 1995, the pipeline firms are generally sensitive to wellhead gas prices but the exposures change through time. Risk-adjusted market-based estimates of wellhead gas price sensitivities are negative in the first several years of the sample and become significantly positive following price deregulation, especially after the Decontrol Act of 1989. The change in sign of the natural gas price sensitivities is consistent with the changing nature of the natural gas firm during this period of deregulation from that of a consumer of natural gas to that of producer and transporter of natural gas.

Cross-sectional variation in price sensitivities is related to firms' use of combinations of operational and financial activities. Finally, firms that pursue operational and financial risk management strategies have smaller and less variable risk-adjusted wellhead gas return exposures than firms that do not.

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Table I
Sample firms and their tenure in the sample from 1978 to 1995

List of publicly-traded natural gas firms that are major interstate natural gas pipelines or wholly or partially own major interstate natural gas pipelines from 1978 to 1995.

	FERC Form-2 Data Availability		Major Interstate Pipelines wholly or partially owned during the sample period			
Company	First Year	Last Year	Min No.	Max No.	Min. Miles	Max. Miles
Burlington Northern	1978	1987	1	1	9,330	10,924
Burlington Resources	1988	1991	1	1	10,129	10,765
Central Louisiana Electric	1980	1980	1	1	392	392
Coastal	1978	1995	4	7	6,986	15,568
Columbia Gas Systems	1978	1990	1	3	9,946	11,288
Commonwealth Energy Systems	1978	1985	1	1	314	324
Consolidated Natural Gas	1978	1995	1	1	3,515	4,678
Consumers Power/CMS Energy	1978	1995	1	1	543	570
CSX	1983	1987	1	2	5,574	5,787
Eastern Enterprises	1978	1985	1	1	335	345
El Paso Natural Gas	1992	1995	2	2	5,303	10,540
Enron	1978	1995	1	6	9,386	33,064
Equitable Resources	1989	1995	1	1	478	530
Florida Gas	1978	1979	1	1	4,279	4,286
Iowa-Illinois Gas & Electric	1990	1992	1	1	NA	NA
K N Energy	1978	1995	1	2	6,053	18,332
LaSalle Energy	1988	1989	6	7	15,261	15,441
Leviathan Gas	1991	1995	1	3	138	239
MDU Resources	1985	1995	1	1	3,071	3,224
Midamerican Energy Company	1995	1995	1	1	NA	NA
MidCon	1980	1985	2	7	10,232	13,220
National Fuel Gas	1978	1995	1	2	1,369	3,256
Noram Energy	1982	1995	1	2	1,964	8,644
Northern States Power	1993	1995	1	1	549	549
Northwest Energy	1979	1982	2	4	433	5,835
Occidental Petroleum	1986	1995	1	9	10,403	15,162
Pacific Gas & Electric	1978	1995	1	1	637	1,336
Panenergy	1978	1995	3	6	10,646	21,982
Primark	1982	1988	1	1	2,186	2,295
Questar	1984	1995	1	3	1,517	2,204
Sonat	1978	1995	2	3	7,048	10,575
Tenneco	1978	1995	2	5	14,246	17,181
Texaco	1978	1980	1	1	174	174
Texas Eastern	1978	1989	1	3	3,746	14,360
Texas Gas Transmission	1978	1982	1	1	5,575	5,672
Transcanada Pipelines	1978	1995	1	2	247	1,287
Transco Energy	1978	1994	1	6	9,051	16,499
United Energy Resources	1978	1985	2	6	7,473	7,726
Williams Company	1983	1995	3	5	103	6,215

Table II
Summary of sensitivities of revenues and income to natural gas wellhead prices

Regression estimates of the sensitivity of annual changes in eight earnings metrics to changes in annual average natural gas wellhead prices. Regressions are estimated for firms with at least seven observations. The earnings metrics are total firm revenues, operating income, and net income; total natural gas transmission and distribution revenues, segment revenues, and operating income reported on Compustat; and gas transmission and distribution revenues, operating income, and net income reported FERC Form 2 filings. # significant denotes numbers of estimates that are significant at the 10% (or better) significance level.

Earnings Metric	Statistic	Intercept	Coefficient on well-head price change	Range of Adj. R^2
Total firm revenue	Mean	0.0274	0.5893	
(N = 25)	Std Dev	0.0876	0.4574	
	Minimum	-0.2245	-0.4579	-18.14
	Maximum	0.2084	1.936	70.04
	# significant	8	14	
Segment revenue	Mean	56.2104	-52.3693	
(N = 21)	Std Dev	200.6785	472.8736	
	Minimum	-13.6243	-1,760.84	-14.29
	Maximum	927.3887	1,157.84	55.76
	# significant	12	4	
FERC 2 segment	Mean	1.1927	2.5353	
revenue	Std Dev	3.5533	11.620	
(N = 22)	Minimum	-0.2300	-19.2830	-10.95
	Maximum	12.1680	48.0216	89.51
	# significant	4	11	
Total firm operating	Mean	0.0667	0.3738	
income	Std Dev	0.1240	0.6727	
(N = 25)	Minimum	-0.2358	-1.7119	-11.58
	Maximum	0.2957	1.7760	78.91
	# significant	5	7	
Segment operating	Mean	4.4044	-17.2427	
income	Std Dev	13.5213	68.5259	
(N = 21)	Minimum	-22.9176	-261.3736	-14.08
	Maximum	49.2350	71.4033	91.75
	# significant	8	9	
FERC 2	Mean	1.3183	0.0997	
segment	Std Dev	4.0094	4.0592	
operating	Minimum	-0.5836	-11.1407	-13.79
income	Maximum	18.4626	13.9614	72.78
(N = 22)	# significant	1	2	
Total firm	Mean	0.2115	6.6569	
net income	Std Dev	12.5307	22.4894	
(N = 25)	Minimum	-8.7335	-45.1990	-19.34
	Maximum	60.7187	77.8693	51.39
	# significant	7	8	
FERC segment	Mean	-0.8142	1.1986	
net income	Std Dev	4.0938	13.976	
(N=22)	Minimum	-15.5021	-34.6849	-13.99
	Maximum	7.2297	45.5191	26.22
	# significant	0	1	

Table III
Average selected gas account statistics for 1979, 1984, 1987, 1990, 1992, and 1995

Average selected gas account statistics for fiscal year-end 1979, 1984, 1987, 1990, 1992, and 1995. t-statistics for tests of the difference between the annual mean and 1979 are reported in parentheses.

	1979	1984	1987	1990[a]	1992	1995
Panel A: Sample						
Number of firms	22	24	22	21	21	21
Number of pipelines	33	58	57	53	52	54
Total pipeline miles	147,630	157,137	165,061	158,124	142,867	137,592
Panel B: Natural gas wellhead prices (dollars/mcf)						
Average annual price	0.91	2.66	1.67	1.71	1.74	1.55
Year-end price	0.91	2.57	1.70	2.04	2.21	1.84
Panel C: Selected gas account data for FERC 2 pipelines						
Gas receipts (in bcfs)	1,135	1,326	1,185	1,688	1,316	1,583
		(-0.59)	(-0.16)	(-1.30)	(-0.49)	(-1.00)
As a percent of total gas receipts:						
Gas produced	2.38%	2.45%	1.09%	0.96%	1.16%	1.72%
		(-0.04)	(0.96)	(1.06)	(0.88)	(0.30)
Gas purchased	60.99	48.17	29.28	23.61	17.48	6.60
		(1.98)*	(5.31)***	(6.15)***	(7.72)***	(9.04)***
Gas from storage	7.56	5.94	6.26	4.86	6.19	5.02
		(0.65)	(0.47)	(1.08)	(0.49)	(0.86)
Gas of other received for transmission	18.21	18.79	39.41	46.36	62.10	82.62
		(-0.09)	(-2.98)***	(-4.02)***	(-5.93)***	(-8.74)***
Gas sales and deliveries (in bcfs)	1,312	1,322	1,178	1,684	1,312	1,576
		(-0.58)	(-0.15)	(-1.30)	(-0.49)	(-0.99)
As a percent of total gas sales and deliveries:						
Gas sales	59.99%	42.82%	28.55%	23.65%	17.39%	7.92%
		(1.88)*	(5.23)***	(5.47)***	(7.47)***	(7.86)***
Sales to main line industrials	5.27	4.99	2.13	1.11	0.53	0.03
		(0.08)	(1.43)	(2.07*)	(2.47)**	(1.73)
Sales for resale	56.25	39.73	23.10	16.45	14.16	3.00
		(2.43)*	(5.55)***	(6.73)***	(7.45)***	(11.62)***
Sales to LDCs	2.22	16.35	15.37	15.32	11.92	28.93
		(-1.46)	(-1.57)	(-1.48)	(-1.07)	(-0.92)
Delivered to storage	6.71	5.81	6.63	5.58	4.68	4.64
		(0.34)	(0.03)	(0.48)	(0.92)	(0.79)
Total deliveries	40.01	52.18	71.45	76.35	82.61	92.07
		(-1.88)*	(-5.23)***	(-5.47)***	(-7.47)***	(-7.86)***
Gas profit margins:						
Gas operating income/ gas revenues	0.147	0.214	0.283	0.174	0.330	0.497
		(-1.33)	(-2.30**	(-0.47)	(-3.49)***	(-10.28)***
Gas net income/ gas revenues	0.067	0.054	0.012	0.074	0.101	0.119
		(0.96)	(0.68)	(-0.21)	(-1.91)*	(-0.66)

Table III, continued

Panel D: Selected Income Statement and Balance Sheet Data for Parent Company						
Operating Income/Sales	0.163	0.165 (-0.14)	0.204 (-1.97)*	0.219 (-2.46)**	0.227 (-2.78)***	0.241 (-2.91)***
Net Income/Sales	0.056	0.048 (1.01)	0.043 (1.46)	0.043 (0.79)	0.042 (0.80)	0.133 (-1.51)
Interest Coverage Ratio	5.122	4.230 (1.47)	3.189 (3.28)	3.288 (3.14)***	3.378 (2.87)***	3.899 (2.14)**
Firm Size ($ Millions)	2,814	3,454 (-0.63)	4,848 (-1.72)*	5,471 (-1.98)*	5,474 (-1.81)*	6,493 (-2.65)**
Quick Ratio	0.099	0.145 (-1.27)	0.091 (-0.83)	0.104 (-0.09)	0.104 (-0.14)	0.084 (0.62)
Long-term debt ratio	0.465	0.476 (-1.55)	0.528 (-1.87)*	0.471 (-0.17)	0.470 (-0.14)	0.393 (2.21)**
Change in S&P Bond rating[b]	NA	NA	-0.05 (NA)	0.167 (NA)	0.555 (NA)	0.000 (NA)
Dividend Yield	0.057	0.067 (-0.92)	0.064 (-0.76)	0.054 (0.38)	0.043 (1.88)*	0.043 (1.88)*
Market-Book Ratio	2.440	2.176 (1.16)	2.795 (-1.16)	3.211 (-2.63)**	3.853 (-2.82)***	3.163 (-2.68)**
P-E Ratio	7.440	9.711 (-1.55)	18.093 (-1.08)	15.002 (-2.58)	-31.704 (0.91)	59.604 (-1.41)

[a]1990 numbers are calculated excluding firm observations for which gas receipts and total gas sales and deliveries are negative.

[b]A negative number denotes a credit downgrade.

Table IV
Summary of statistics for natural gas wellhead price betas and stock market betas

Regression estimates for an extended market model regression of equal-weighted portfolios of natural gas company returns on equal-weighted market return (R_M) in excess of the Treasury Bill 3-month rate (R_{TB}) and the excess return of average wellhead prices ($R_{NG} - R_{TB}$). Market and Treasury Bill returns are from the Center for Research in Security Prices (CRSP) and wellhead returns are calculated using monthly wellhead prices.

$$R_P - R_{TB} = \alpha + \beta_M (R_M - R_{TB}) + \beta_{NG} (R_{NG} - R_{TB}) + \varepsilon$$

	β_{NG}	β_M
Mean	-0.05	0.65
Standard deviation	0.16	0.08
Hansen-Hodrick t-statistic	-3.85	36.31
Minimum	-0.35	0.42
Maximum	0.21	0.88
% significant at the 10% level	21%	83%

Regression estimates for an extended Fama-French (1993) five-factor model of equal-weighted portfolios of natural gas company returns on the value-weighted market return (R_M) in excess of the Treasury Bill 3-month rate (R_{TB}), the excess return of average wellhead prices ($R_{NG} - R_{TB}$), the return on a size factor-mimicking portfolio (R_{SMB}), the return on a value effect factor-mimicking portfolio (R_{HML}), the return on a portfolio capturing the slope of the term structure of interest rates (R_{TERM}), and the return on a portfolio that is long low-grade corporate bonds and short high-grade corporate bonds (R_{DEF}). Wellhead returns are calculated using monthly wellhead prices.

$$\begin{aligned} R_P - R_{TB} = \alpha + \beta_M(R_M - R_{TB}) + \beta_{NG}(R_{NG} - R_{TB}) \\ + \beta_{HML}R_{HML} + \beta_{SMB}R_{SMB} + \beta_{TERM}R_{TERM} + \beta_{DEF}R_{DEF} + \varepsilon \end{aligned}$$

	β_{NG}	β_M
Mean	-0.02	1.02
Standard deviation	0.15	0.14
Hansen-Hodrick t-statistic	-1.82	18.03
Minimum	-0.44	0.71
Maximum	0.19	1.43
% significant at the 10% level	18%	92%

Table V
Descriptive statistics of proxies for hedging activities for selected years

Descriptive statistics for hedging activity variables for fiscal year-ends 1979, 1984, 1987, 1990, 1992, and 1995. Means are presented in the first row. Standard deviations {in curly brackets} and medians [in square brackets] are presented for some continuous variables. Concentration (CONC) is the measure of segment focus from Comment and Jarrell (1995) such that larger amounts represent greater focus (less diversification). Acquisitions and divestitures are segregated for natural gas (NG) and entities not related to natural gas (non-NG). Special items - other consists primarily of litigation reserves, reserves for environmental remediation costs, gains and losses on sales of assets including investment securities, PPE, and subsidiaries, and miscellaneous amounts. O&G reserves represent provisions for losses on oil and gas inventories or oil and gas-related properties that are created because of permanent impairments in value or inventory accounting ceiling tests.

		1979	1984	1987	1990	1992	1995
Derivative Instruments:	% using commodity	-	-	-	0.190	0.300	0.850
	% using interest rate	-	-	-	0.190	0.300	0.750
	% using currency	-	-	-	0.238	0.300	0.350
Contracting:	Take-or-pay costs/Sales	0.008	0.017	0.037	0.015	-	-
		{0.010}	{0.017}	{0.035}	{0.018}		
		[0.002]	[0.020]	[0.029]	[0.005]	-	-
Operating activities:	Gas in storage/Total gas	0.143	0.167	0.220	0.195	0.162	0.173
		{0.166}	{0.170}	{0.248}	{0.289}	{0.263}	{0.275}
		[0.066]	[0.091]	[0.103]	[0.075]	[0.069]	[0.071]
Focus:	No. of segments (0-9)	2.524	2.917	3.136	2.571	2.500	2.905
		[3.000]	[3.000]	[3.000]	[3.000]	[2.000]	[3.000]
	Concentration (CONC)	0.722	0.708	0.698	0.694	0.665	0.598
		{0.228}	{0.226}	{0.226}	{0.199}	{0.216}	{0.206}
		[0.706]	[0.719]	[0.737]	[0.618]	[0.585]	[0.522]
Acquisitions/ Divestitures	Number of net pipeline acquisitions/(sales)	0.091	0.217	0.045	(0.100)	0.050	0.050
		[0.000]	[0.000]	[0.000]	[0.000]	[0.000]	[0.000]
	Percentage change in owned pipeline miles	12.28%	1.08%	-1.41%	5.73%	7.56%	0.81%
		[0.21%]	[0.33%]	[0.00%]	[1.15%]	[0.95%]	[0.00%]
	No. of acquisitions-NG	1	5	10	11	12	8
	Mean deal value/Sales	0.001	0.013	0.018	0.032	0.007	0.017
	No. of non-NG acquis.	1	6	12	9	5	14
	Mean deal value/Sales	0.004	0.009	0.001	0.004	0.002	0.012
	No. of divestitures-NG	0	2	4	6	13	5
	Mean deal value/Sales	0.000	0.017	0.003	0.004	0.028	0.003
	No. of non-NG divests.	0	5	19	6	9	10
	Mean deal value/Sales	0.000	0.006	0.026	0.004	0.001	0.013
Cash Buffers:	Cash/(Total assets-cash)						
	Gas subsidiary only	0.024	0.033	0.041	0.011	0.033	0.024
		{0.023}	{0.040}	{0.080}	{0.019}	{0.061}	{0.058}
		[0.017]	[0.021]	[0.006]	[0.007]	[0.005]	[0.003]
	Parent company	0.028	0.035	0.027	0.018	0.020	0.015
		{0.032}	{0.038}	{0.034}	{0.029}	{0.022}	{0.011}
		[0.012]	[0.020]	[0.011]	[0.009]	[0.011]	[0.009]

Table V, continued

Earnings Mgmt:	Restructuring charges/ Sales	0.000	0.000	-0.002	-0.005	-0.004	-0.001
		{0.000}	{0.000}	{0.008}	{0.022}	{0.016}	{0.003}
		[0.000]	[0.000]	[0.000]	[0.000]	[0.000]	[0.000]
	O&G reserves/Sales	0.000	-0.003	-0.001	-0.005	0.000	-0.0001
		{0.000}	{0.007}	{0.006}	{0.023}	{0.000}	{0.000}
		[0.000]	[0.000]	[0.000]	[0.000]	[0.000]	[0.000]
	|Other special items|/ Sales	0.000	0.003	0.002	0.006	0.015	0.014
		{0.000}	{0.007}	{0.007}	{0.011}	{0.038}	{0.028}
		[0.000]	[0.000]	[0.000]	[0.000]	[0.000]	[0.002]
	% using SE	0.222	0.095	0.444	0.375	0.500	0.500

Table VI
Comparison of hedging activities across categories of hedgers

Univariate comparisons of hedging activities by the sample firms categorized as hedgers (H) and non-hedgers (NH) based on various definitions of hedging activities. For activities measured using dichotomous variables, the table indicates which group is defined as hedgers. For activities measured using continuous variables, firms are ranked into triciles based on the level of the activity and designated as high (HI) or low (LOW) if the firm is in the upper or lower tricile, respectively. The table indicates whether the HI-firms or LOW-firms are hedgers. For each activity, means of the proxies for the other hedging activities are presented. The data are pooled across all years. Derivatives data are available only for 1990 through 1995. The second column indicates the prediction about whether a firm that hedges (H) using the strategy indicated by the proxy variable in that row will have a higher or lower mean value of that proxy variable than a non-hedger (NH).

		Hedgers	Non-hedgers	t-value
Hedging activity: Financial derivatives		DERIV = 1	DERIV = 0	
Take-or-pay costs/Sales	H>NH	0.010	0.012	0.28
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.118	0.252	2.19**
No. of segments (0-9)	H>NH	2.683	2.667	-0.08
Concentration	H<NH	0.659	0.653	-0.16
Percentage change in pipeline miles	?	0.016	0.041	0.49
Restructuring charges/Sales	NA	-0.002	-0.002	-0.03
O&G valuation reserves/Sales	NA	-0.00004	-0.002	-0.98
|Other special items|/Sales	NA	0.008	0.007	-0.25
% using successful efforts	H<NH	0.552	0.458	-0.79
Cash/(Total assets-cash) - Parent company	H>NH	0.015	0.016	0.47
Gas subsidiary	H>NH	0.007	0.022	1.93*
Hedging activity: Operating activities - storage		HI STORAGE	LOW STORAGE	
% using commodity derivatives	H>NH	0.433	0.800	2.98***
Take-or-pay costs/Sales	H>NH	0.023	0.024	0.27
No. of segments (0-9)	H>NH	2.562	3.314	4.60***
Concentration	H<NH	0.764	0.610	-4.94***
Percentage change in pipeline miles	?	0.029	0.043	2.03**
Restructuring charges/Sales	NA	0.000	-0.002	-1.61
O&G valuation reserves/Sales	NA	0.000	-0.003	-2.03**
|Other special items|/Sales	NA	0.004	0.006	0.61
% using successful efforts	H<NH	0.232	0.358	1.77
Cash/(Total assets-cash) - Parent company	H>NH	0.018	0.018	-0.01
Gas subsidiary	H>NH	0.033	0.016	-1.94*
Hedging activity: Focus - Concentration (CONC)		LOW CONC	HI CONC	
% using commodity derivatives	H>NH	0.405	0.485	0.69
Take-or-pay costs/Sales	H>NH	0.026	0.032	0.62
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.238	0.218	-0.53
No. of segments (0-9)	H>NH	3.511	1.641	-16.44***
Percentage change in pipeline miles	?	0.031	0.022	-0.24
Restructuring charges/Sales	NA	-0.001	-0.0001	1.43
O&G valuation reserves/Sales	NA	-0.001	-0.001	0.14
|Other special items|/Sales	NA	0.007	0.010	0.66
% using successful efforts	H<NH	0.364	0.188	-2.87***
Cash/(Total assets-cash) - Parent company	H>NH	0.020	0.025	1.38
Gas subsidiary	H>NH	0.043	0.026	-1.65*

Table VI, continued

	H v. NH	Hedgers	Non-hedgers	t-value
Hedging activity: Focus - No. of segments (NSEG)		HI NSEG	LOW NSEG	
% using commodity derivatives	H>NH	0.493	0.455	-0.31
Take-or-pay costs/Sales	H>NH	0.020	0.036	1.13
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.187	0.196	0.35
Concentration	H<NH	0.591	0.955	20.99***
Percentage change in pipeline miles	?	0.036	0.021	-0.48
Restructuring charges/Sales	NA	-0.001	0.000	2.04**
O&G valuation reserves/Sales	NA	-0.002	-0.001	0.99
|Other special items|/Sales	NA	0.006	0.012	0.57
% using successful efforts	H<NH	0.299	0.172	-2.13**
Cash/(Total assets-cash) - Parent company	H>NH	0.021	0.029	1.67*
Gas subsidiary	H>NH	0.030	0.042	1.12
Hedging activity: Pipeline acquisitions		HI CHMILES	LOW CHMILES	
% using commodity derivatives	H>NH	0.486	0.529	0.36
Take-or-pay costs/Sales	H>NH	0.023	0.026	0.30
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.155	0.202	1.40
No. of segments (0-9)	H>NH	2.675	2.765	0.58
Concentration	H<NH	0.722	0.681	-1.33
Restructuring charges/Sales	NA	-0.0009	-0.0002	1.43
O&G valuation reserves/Sales	NA	-0.006	-0.0003	2.15**
|Other special items|/Sales	NA	0.006	0.010	0.79
% using successful efforts	H<NH	0.287	0.405	1.65*
Cash/(Total assets-cash) - Parent company	H>NH	0.024	0.021	-0.54
- Gas subsidiary	H>NH	0.031	0.020	-1.15
Hedging activity: Earnings management - FC v. SE		FC	SE	
% using commodity derivatives	H>NH	0.333	0.421	-0.79
Take-or-pay costs/Sales	H>NH	0.022	0.024	-0.43
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.216	0.167	1.64
No. of segments (0-9)	H>NH	2.892	2.926	-0.27
Concentration	H<NH	0.704	0.621	3.28***
Percentage change in pipeline miles	?	0.033	0.009	0.76
Restructuring charges/Sales	NA	-0.0002	-0.002	1.35
O&G valuation reserves/Sales	NA	-0.002	-0.002	-0.29
|Other special items|/Sales	NA	0.004	0.011	-2.64***
Cash/(Total assets-cash) - Parent company	H>NH	0.023	0.018	1.60
- Gas subsidiary	H>NH	0.033	0.033	-0.06
Hedging activity: Gas subsidiary cash buffers		HI CASH	LOW CASH	
% using commodity derivatives	H>NH	0.291	0.522	1.62
Take-or-pay costs/Sales	H>NH	0.013	0.025	1.94*
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.235	0.082	-3.10***
No. of segments (0-9)	H>NH	2.871	3.211	1.83*
Concentration	H<NH	0.650	0.696	1.34
Percentage change in pipeline miles	?	0.009	0.020	0.41
Restructuring charges/Sales	NA	-0.0002	-0.0006	-1.21
O&G valuation reserves/Sales	NA	-0.001	-0.002	-0.03
|Other special items|/Sales	NA	0.006	0.003	-1.01
% using successful efforts	H<NH	0.242	0.250	0.10
Cash/(Total assets-cash) - Parent company	H>NH	0.038	0.012	-6.68***

Table VI, continued

	H v. NH	Hedgers	Non-hedgers	t-value
Hedging activity: Regulatory rate adjustments		SFAS 71 - Yes	SFAS 71 - No	
% using commodity derivatives	H>NH	0.462	0.695	2.35**
Take-or-pay costs/Sales	H>NH	0.032	0.021	-0.77
Gas in storage/Gas sales and deliveries (bcfs)	H>NH	0.352	0.097	-4.58***
No. of segments (0-9)	H>NH	2.372	2.861	2.72***
Concentration	H<NH	0.735	0.653	-2.42**
Percentage change in pipeline miles	?	0.034	0.006	-1.05
Restructuring charges/Sales	NA	-0.0002	-0.002	-2.17**
O&G valuation reserves/Sales	NA	-0.002	-0.005	-1.23
|Other special items|/Sales	NA	0.008	0.006	-0.63
% using successful efforts	H<NH	0.217	0.511	3.76***
Cash/(Total assets-cash) - Parent company	H>NH	0.017	0.027	2.82***

Table VII
Summary of Factor Analysis

Summary of explanatory power and rotated factor pattern for six factors related to hedging activities. The first row of the table specifies the names of the hypothetical factors which are based on the variables that load on the factor. For each factor, the eignenvalue and percentage of variation explained by the factor are presented. The factor pattern presented is the pattern after oblique rotation. These tabulated rotated factor loadings are converted to standardized scores and multiplied by the standardized variables to create definitions of hedgers and non-hedgers. Loadings designated in bold are for the variables with significant loadings on the factor in that column. Factors are estimated using data from 1990-1995. Factor loadings estimated for the earlier sample period (that exclude derivatives use variables) have similar loadings on factor 1 and factors 3-6.

	Factor Name					
	Operating activities factor	Financial Hedging factor	Restruct-uring factor	Gas factor	NG acquisition factor	Non-NG acquisition factor
Measures of explained variance:						
Eigenvalue	2.55129	1.72887	1.44116	1.25240	1.16073	1.00630
% of variation explained by the factor	19.63%	13.30%	11.09%	9.63%	8.93%	7.74%
Cumulative	19.63%	32.92%	44.01%	53.64%	62.57%	70.31%
Rotated factor pattern:						
Cash/(Total assets-cash) Parent company	0.79846	-0.13318	0.09751	-0.08096	-0.23014	0.24990
STORAGE (in bcfs)	0.75634	-0.41757	-0.14903	-0.08564	-0.10128	0.05296
Concentration (CONC)	-0.73832	-0.25611	0.04219	0.00183	-0.26977	0.29459
% using commodity derivs.	-0.10932	0.75060	0.13587	-0.02367	-0.10038	0.17962
% using other derivatives	-0.06969	0.79627	0.12184	-0.00925	0.08906	0.08052
Number of NG divestitures	-0.10735	0.10675	0.72850	0.10350	0.24987	0.41563
No. of non-NG divestitures	0.05353	0.21837	0.73276	0.10485	-0.23013	0.05501
Restructuring charges	0.03425	-0.01885	-0.69838	0.13697	-0.18970	0.25841
Provisions for O&G losses	0.14534	0.35691	-0.18174	-0.68755	0.08853	-0.15787
% change in pipeline miles	-0.04404	0.10219	-0.08996	0.77311	0.37375	0.08323
Number of NG acquisitions	-0.06502	0.01113	0.09144	0.04809	0.86097	0.07450
No. of non-NG acquisitions	0.07347	0.27936	-0.00824	0.03984	0.08675	0.80631
Special items - other	0.01582	0.14606	-0.02487	0.50553	-0.31904	-0.29533

Table VIII
Comparison of selected firm characteristics by categories of hedgers

Univariate comparisons of selected firm characteristics by their hedging activities. Firms are categorized as hedgers (H) and non-hedgers (NH) based on each activity. The averages of the annual means are reported for each category of firms in columns two and three. The last column reports the number of years for which the difference in the means of each groups are different from zero at the 10% significance level or better. Derivatives data are available only for 1990 through 1995.

	Mean of annual means			
Strategies and firm characteristics:	Hedgers	Non-hedgers	Test for difference in means	# sig. in annual tests
Use of derivatives	DERIV = 1	DERIV = 0	t-statistic	90 – 95
Operating Income/Sales	0.179	0.268	3.66***	3
Net Income/Sales	0.045	0.064	-0.35	0
Interest Coverage Ratio	2.949	4.109	1.44	3
Firm Size ($ Millions)	6,381	6,831	-0.27	0
Long-term debt ratio	0.482	0.445	0.01	1
S&P bond rating	8.779	7.430	-2.62**	1
Dividend Yield	0.044	0.050	2.34**	1
Market-Book Ratio	4.127	3.176	-2.61**	2
Operating activities - storage	HI STORAGE	LOW STORAGE	t-statistic	78 – 95
Operating Income/Sales	0.189	0.174	-1.38	3
Net Income/Sales	0.058	0.053	-0.78	1
Interest Coverage Ratio	4.267	3.682	-2.58**	1
Firm Size ($ Millions)	2,220	5,779	7.33***	0
Long-term debt ratio	0.456	0.477	1.32	2
S&P Bond rating	6.613	9.140	5.78***	2
Dividend Yield	0.064	0.041	-5.05***	4
Market-Book Ratio	2.522	3.096	3.45***	2
Operating activities - Diversification	LOW CONC	HI CONC	t-statistic	78 – 95
Operating Income/Sales	0.195	0.181	-1.36	4
Net Income/Sales	0.054	0.071	0.91	4
Interest Coverage Ratio	3.664	4.204	1.71*	0
Firm Size ($ Millions)	5,329	2,924	-5.61***	5
Long-term debt ratio	0.489	0.472	-1.04	4
S&P Bond rating	8.344	7.587	-1.68*	1
Dividend Yield	0.057	0.061	0.82	1
Market-Book Ratio	2.893	2.809	-0.45	1
Operating activities - Diversification	HI SEG	LOW SEG	t-statistic	78 – 95
Operating Income/Sales	0.188	0.204	1.04	1
Net Income/Sales	0.048	0.090	1.72*	3
Interest Coverage Ratio	3.861	4.329	1.03	0
Firm Size ($ Millions)	4,332	4,097	0.04	0
Long-term debt ratio	0.474	0.478	0.08	3
S&P Bond rating	8.594	7.173	-2.72***	2
Dividend Yield	0.051	0.064	3.24***	2
Market-Book Ratio	2.867	2.843	-0.01	1

Table VIII, continued

Strategies and firm characteristics:	Mean of annual means Hedgers	 Non-Hedgers	Test for difference in means	# sig in annual tests
Pipeline mile acquisitions	HI CHMILES	LOW CHMILES	t-statistic	78 – 95
Operating Income/Sales	0.198	0.181	-1.21	0
Net Income/Sales	0.064	0.051	-0.75	0
Interest Coverage Ratio	3.922	3.848	-0.31	0
Firm Size ($ Millions)	4,605	4,466	-0.12	0
Long-term debt ratio	0.452	0.471	0.95	1
S&P Bond rating	7.982	7.964	0.26	0
Dividend Yield	0.052	0.055	1.19	4
Market-Book Ratio	2.912	2.740	-1.21	4
Gas subsidiary Cash Holdings	HI CASH	LOW CASH	t-statistic	78 – 95
Operating Income/Sales	0.222	0.175	-2.95***	2
Net Income/Sales	0.090	0.044	-1.85*	2
Interest Coverage Ratio	4.313	3.296	-2.54**	3
Firm Size ($ Millions)	3,481	4,813	1.97*	0
Long-term debt ratio	0.464	0.522	3.16***	5
S&P Bond rating	7.823	9.256	3.36***	1
Dividend Yield	0.052	0.045	-1.23	1
Market-Book Ratio	2.889	3.127	1.54	1
Earnings management - FC v. SE	FC	SE	t-statistic	78 – 95
Operating Income/Sales	0.204	0.188	-2.39***	1
Net Income/Sales	0.075	0.045	-1.67*	2
Interest Coverage Ratio	3.884	3.901	0.90	0
Firm Size ($ Millions)	6,849	3,378	-5.72***	0
Long-term debt ratio	0.449	0.478	2.00**	2
S&P Bond rating	7.623	7.867	0.59	0
Dividend Yield	0.060	0.052	-0.55	0
Market-Book Ratio	2.671	2.975	0.22	1
Regulatory accounting	SFAS71 –Yes	SFAS71 - No	t-statistic	
Operating Income/Sales	0.226	0.188	-3.30***	2
Net Income/Sales	0.075	0.459	-2.00**	3
Interest Coverage Ratio	4.231	3.643	-2.69***	2
Firm Size ($ Millions)	3,891	5,245	2.64***	0
Long-term debt ratio	0.434	0.461	1.82*	2
S&P Bond rating	6.530	8.672	-5.40***	4
Dividend Yield	0.050	0.051	-2.57**	3
Market-Book Ratio	2.839	3.056	2.29**	4

Table IX
Cross-sectional variation in natural gas wellhead betas as a function of risk-related activities

Summary of regressions of natural gas wellhead betas derived from the two-factor model described in table IV on an intercept and proxies for risk-related activities. The regressions are estimated yearly; the means of the annual intercepts and the annual coefficients on the risk proxies are presented. t-statistics and Z-statistics are presented in parentheses below the estimates. The Z-statistic is calculated as $Z = \bar{t} / \left[\sigma(t) / \sqrt{(N-1)}\right]$ where $\bar{t}$ and $\sigma(t)$ are the average and standard deviation of the annual t-statistics, respectively, and N is the number of annual observations.[a] The last column reports the number of annual estimations for which the hedger coefficient is statistically significant at better than the 15% significance level (# sig years).

Risk-related activity:	Dependent variable: β_{NG} Mean coeff. on risk proxy (t-stat) {z-stat}	# sig years	Dependent variable: $\lvert\beta_{NG}\rvert$ Mean coeff. on risk proxy (t-stat) {z-stat}	# sig years
Derivatives use (COMDER=1)[b]	-0.067 (-0.79) {-0.68}	1	0.009 (0.28) {0.42}	0
Successful efforts = 1, full cost = 0	0.293 (2.37) {1.81}	3	0.085 (0.66) {0.67}	2
Take-or-pay costs/Sales	2.845 (0.86) {0.76}	0	-1.156 (-1.76) {-0.95}	4
Percentage change in owned pipeline miles	-0.421 (-0.50) {-0.97}	2	-0.338 (-0.52) {-0.90}	2
Cash/(Total assets-cash)	0.380 (0.23) {-0.13}	2	-1.577 (-2.07) {-1.49}	1
Concentration (CONC)	-0.116 (-0.62) {-0.75}	1	0.313 (2.07) {2.57}	2
Gas in storage/gas sales & deliveries (bcfs)	0.540 (3.31) {2.66}	2	-0.030 (-0.18) {-0.01}	1
Factor 1: Operating activities factor	0.028 (0.60) {0.41}	1	-0.040 (-2.33) {-2.12}	1
Factor 2: Financial hedging factor	-0.021 (-0.76) {-0.62}	0	0.021 (1.44) {1.55}	0
Factor 3: Restructuring factor	-0.017 (-0.93) {-0.49}	0	-0.004 (-0.14) {0.86}	0
Factor 4: Gas factor	-0.129 (-1.28) {-0.56}	1	-0.172 (-1.39) {-0.30}	1
Factor 5: NG acquisition factor	-0.016 (-1.39) {-1.20}	1	-0.015 (-0.74) {-1.22}	0
Factor 6: Non-NG acquisition factor	0.079 (1.44) {0.69}	1	-0.012 (-1.14) {-1.38}	0

[a] An alternative test statistic is $Z' = 1/\sqrt{T} \sum_{t=1}^{N} t_i \Big/ \sqrt{k_i/(k_i - 2)}$ where t_i is the t-statistic for year i and k_i is the degrees of freedom. Z' assumes the annual parameter estimates are independent and is likely overstated; Z corrects for the potential lack of independence. (See Healy, Kang and Palepu, 1987.)

[b] This sample is based on six annual coefficient estimates from 1990-1995 (when derivatives data are available).

Table X
Summary of natural gas wellhead return betas and stock market betas across for hedgers and non-hedgers

Regression estimates for an extended market model regression of equal-weighted portfolios of the returns of natural gas company defined as financial or operational hedgers on equal-weighted market return (R_M) in excess of the Treasury Bill 3-month rate (R_{TB}) and the excess return of average wellhead prices ($R_{NG} - R_{TB}$). Market and Treasury bill returns are from the Center for Research in Security Prices (CRSP) and wellhead returns are calculated using monthly wellhead prices. A firm is defined as an operational hedger if it uses two or more possible operational hedging methods. Firms thus identified are assigned to the hedger portfolio monthly; the 48-month window precedes this point. A firm is defined to be a financial hedger if it used commodity derivatives in the year preceding portfolio assignation. The two-factor model is described in Table IV. Derivatives data are available only for 1990 through 1995. Descriptive statistics are presented for β_{NG} which is the sensitivity of the natural gas portfolio returns to the wellhead return factor, and β_M which is the market beta.

Panel A: Hedging defined based on the use of commodity derivatives

	Hedgers		Non-hedgers	
	β_{NG}	β_M	β_{NG}	β_M
Mean	-0.005	0.29	0.02	0.33
Standard deviation	0.020	0.36	0.03	0.28
Hansen-Hodrick t-statistic	-2.860	9.57	10.21	7.62
Minimum	-0.050	0.14	-0.04	0.13
Maximum	0.050	1.08	0.80	1.64
% significant at the 10% level	2.7%	71%	12.8%	67%

Panel B: Hedging defined based on the use of non-derivative strategies

	Hedgers		Non-hedgers	
	β_{NG}	β_M	β_{NG}	β_M
Mean	-0.0049	0.57	0.13	1.02
Standard deviation	0.080	0.23	0.14	0.24
Hansen-Hodrick t-statistic	-1.370	12.29	18.90	10.49
Minimum	-0.040	0.12	-0.38	0.68
Maximum	0.091	0.84	0.40	1.59
% significant at the 10% level	4.8%	84%	10.9%	88%

Panel C: Hedging defined based on the factor classifications

	Hedgers		Non-hedgers	
	β_{NG}	β_M	β_{NG}	β_M
Mean	-0.018	0.37	0.11	0.66
Standard deviation	0.028	0.27	0.12	0.42
Hansen-Hodrick t-statistic	-0.300	8.25	5.76	8.57
Minimum	-0.070	0.17	-0.32	-0.13
Maximum	0.089	1.48	0.44	1.81
% significant at the 10% level	1.7%	76%	12.3%	84%

Figure 1: Monthly wellhead prices and significant regulatory events
(December 1977 - December 1995)

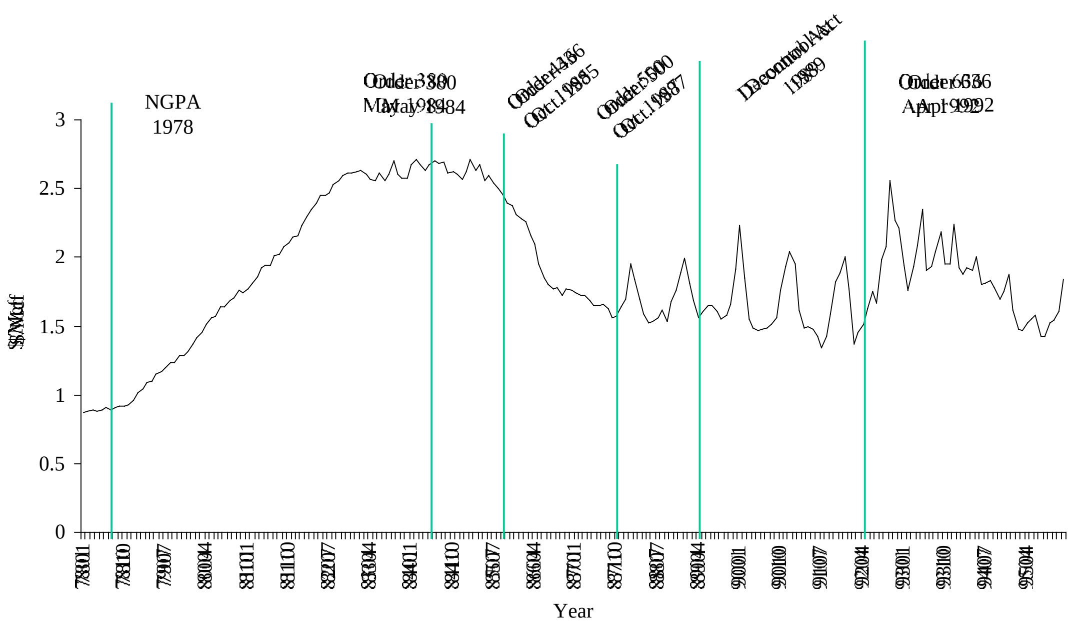


Figure2a: Full-Sample Wellhead Return Betas 2-Factor Market Model, 48-Month Window

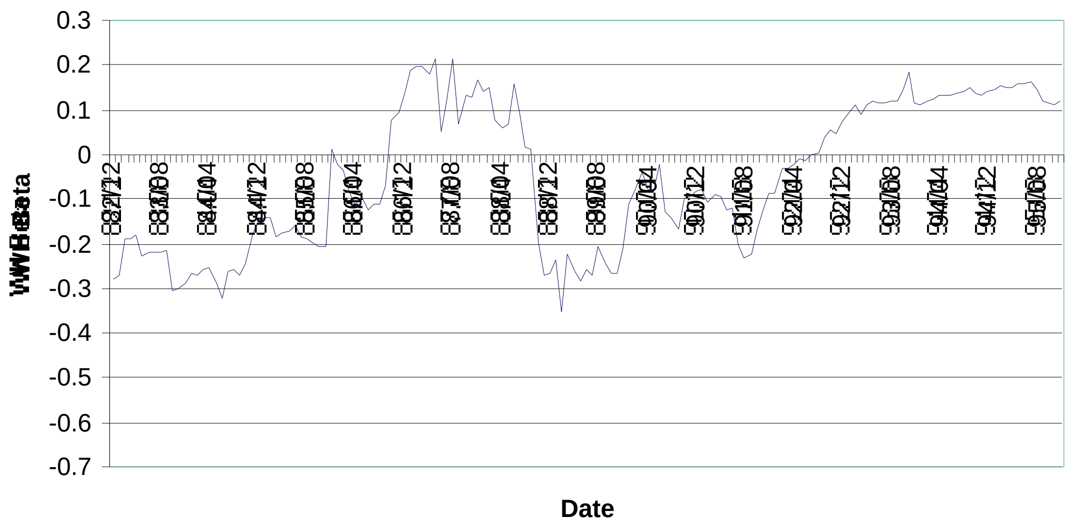


Figure2b: T-Statistics for Natural Gas Betas 2-Factor Market Model

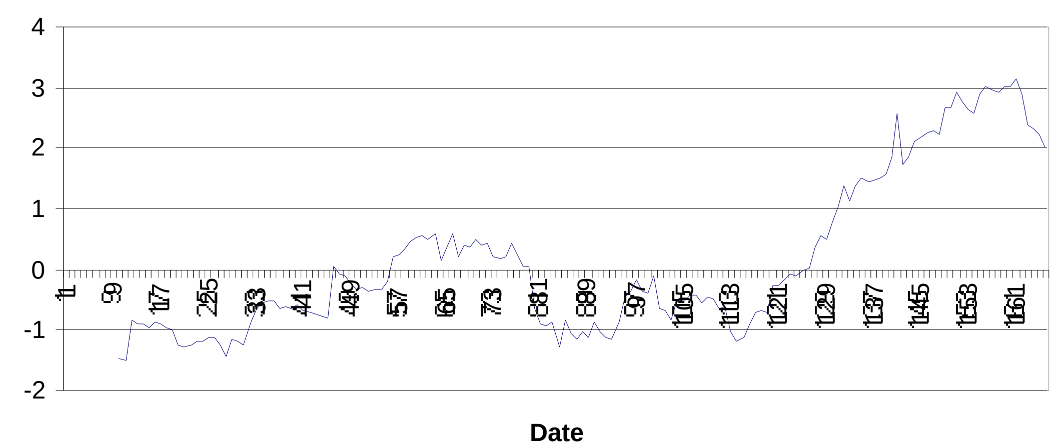


Figure3a: Full-Sample Wellhead Return Betas Fama-French 5-Factor Model, 48-Month Window

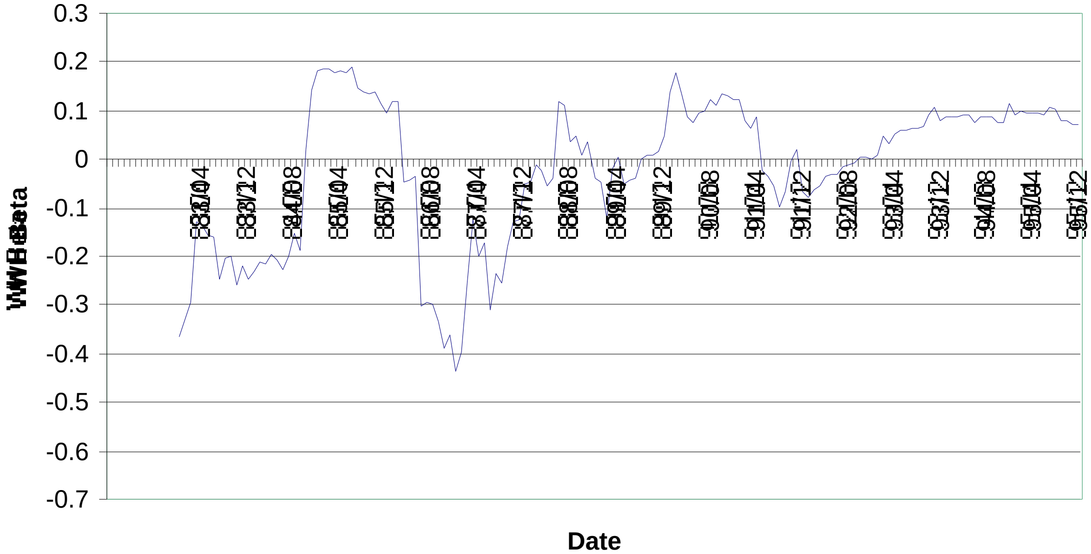


Figure3b: T-Statistics for Natural Gas Betas Fama-French 5-Factor Model

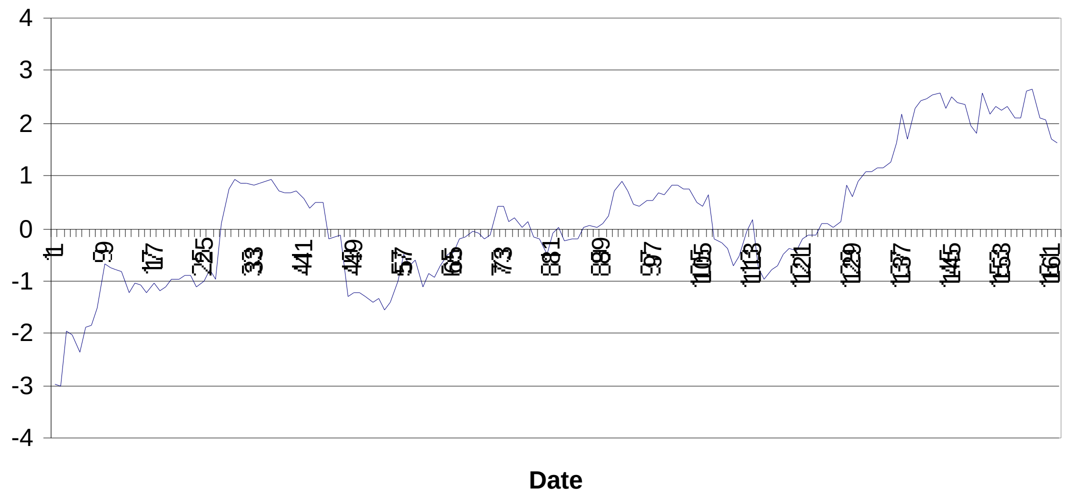


Figure4a: Non-derivative Hedger Wellhead Return Betas
2-Factor Market Model, 48-Month Window

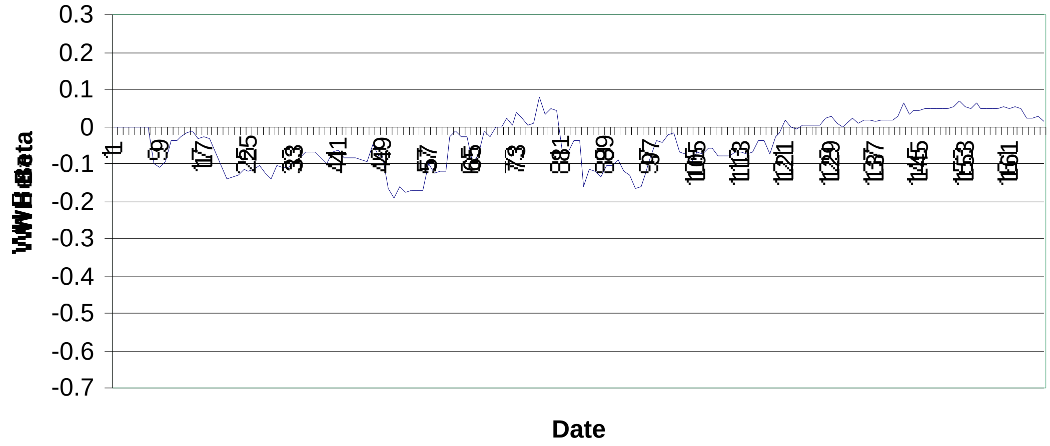
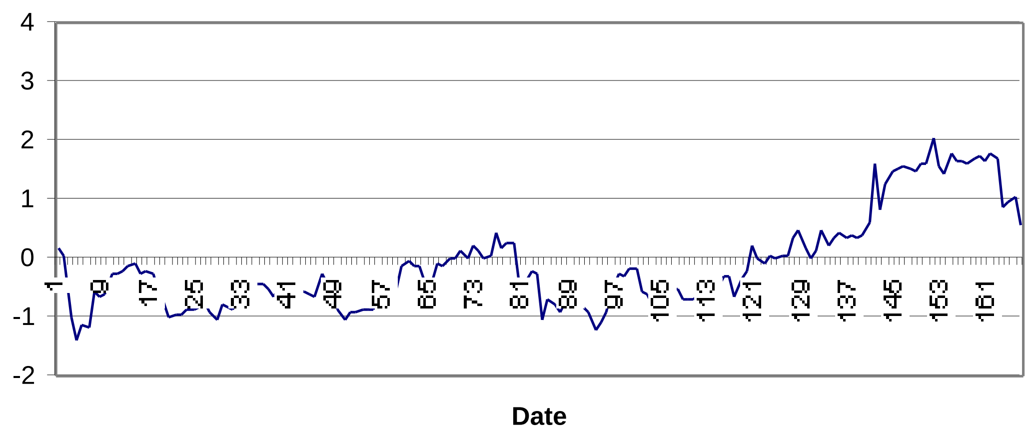


Figure4b: T-Statistics for Natural Gas Betas 2-Factor Market Model, 48-Month Window: Non-derivative Hedgers



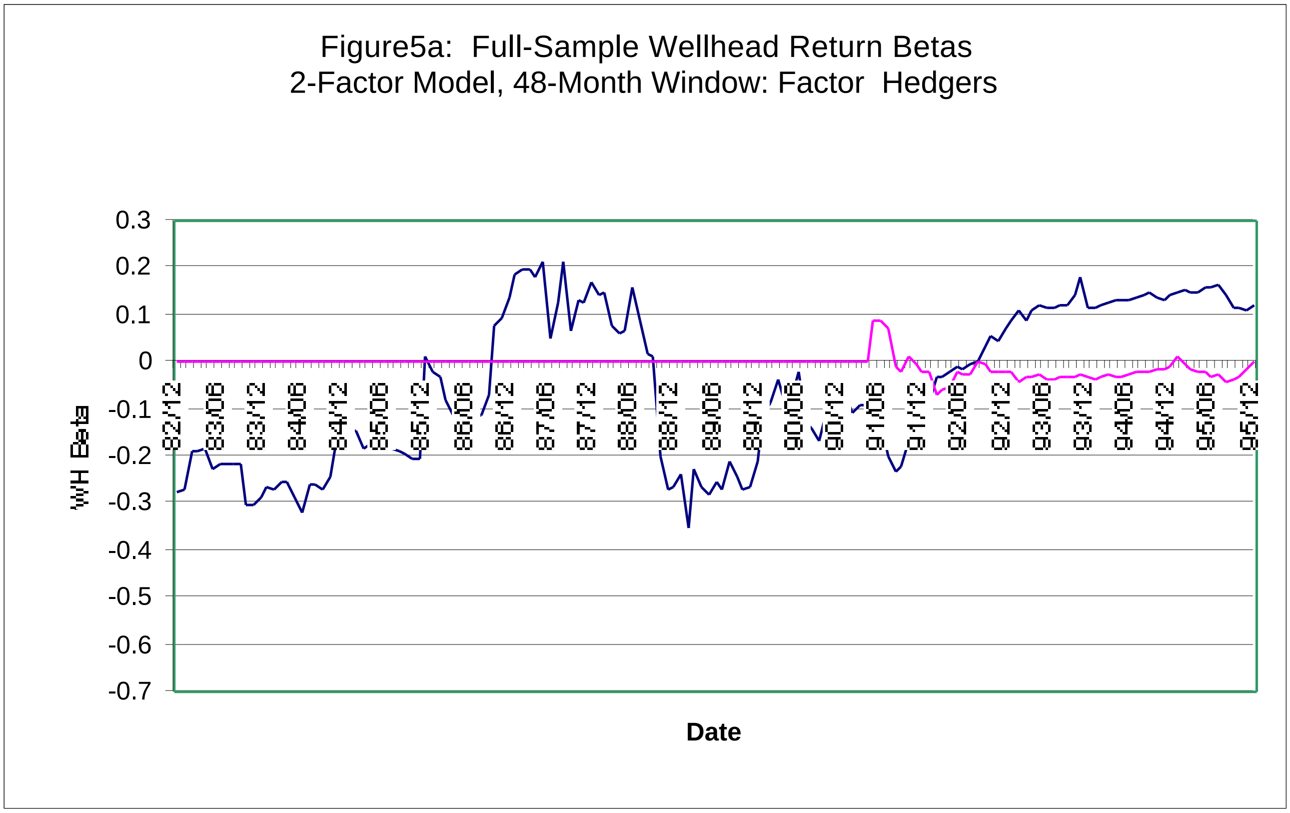


Figure5a: Full-Sample Wellhead Return Betas
2-Factor Model, 48-Month Window: Factor Hedgers
WH Beta
Date

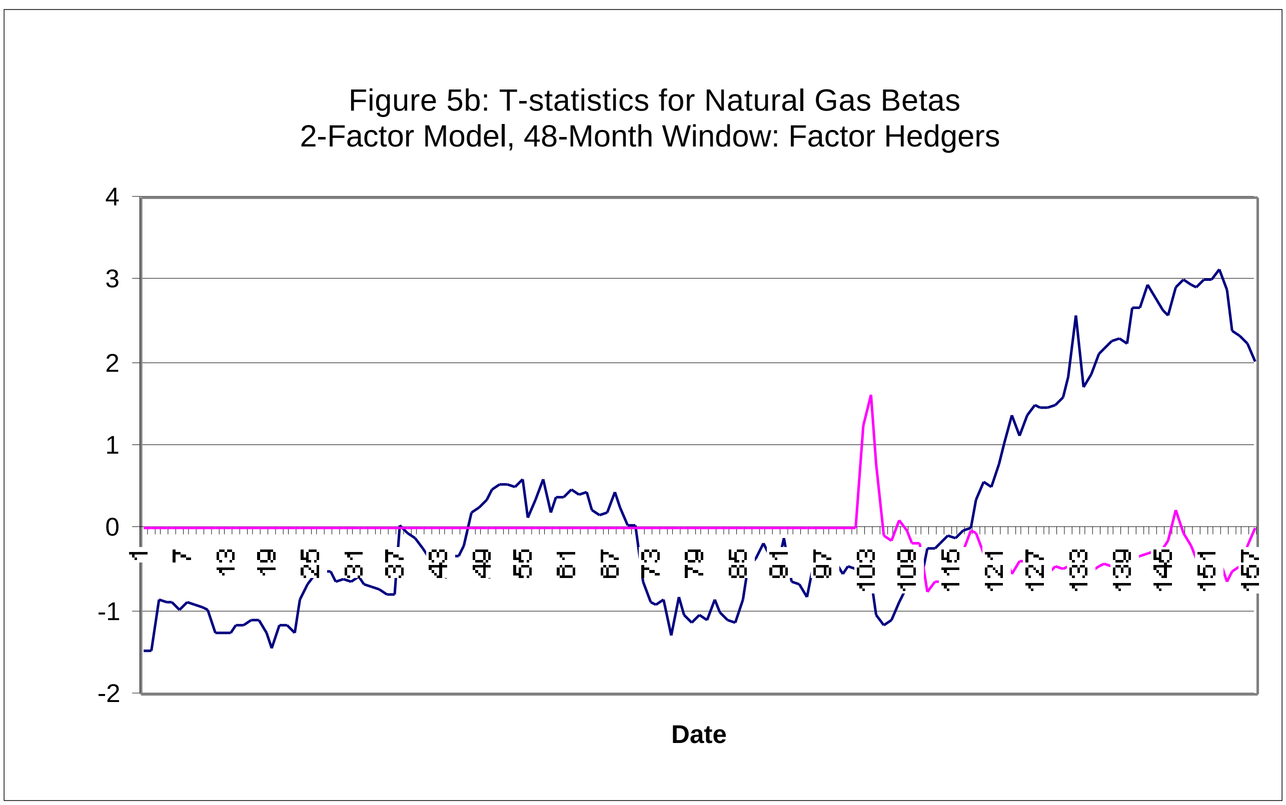


Figure 5b: T-statistics for Natural Gas Betas
2-Factor Model, 48-Month Window: Factor Hedgers
Date