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Oil and Natural Gas Reserve Prices 1982-2002: Implications for Depletion and Investment Cost

by
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Introduction

The main object of this research is to estimate a time series for the total and unit value of in-ground proved oil reserves and natural gas reserves in the United States. There are good official statistics of the physical quantities. Our task has been primarily to estimate the in-ground unit values. Total in-ground value equals quantity times unit value.

Such a series has several uses. First, it provides information about the national income and wealth, which includes mineral reserves. About 70 percent of mineral value-added in 1997 was oil and natural gas. [Census Bureau: Manufacturing & Mining] Some such proportion governs mineral wealth in the ground. The U.S. Government itself owns land that includes large reserves. The Bureau of Economic Analysis (BEA) has deplored the lack of reserve price data. They are estimated here.[2]

Second, there is much interest, when calculating national income and product, to make full allowance for current consumption of minerals. If the oil and gas reserve values are known, capital consumption of minerals is the difference in reserve value from the beginning to the end of the period. This difference can then be partitioned into the difference in physical amount held and the difference in the unit value.

Third, there is much interest in the condition of the oil and gas industries in the United States. The value of an in-ground unit (compared with its reproduction cost) is the crucial fact. Unfortunately, we can no longer make this comparison. Since 1991, there has been no compilation of capital expenditures for finding and developing hydrocarbons, formerly published (API 1983-1991; Census ASOG 1973-1982; see

[1] The authors are especially grateful to Jie Yang for her skillful and devoted research assistance. We thank Andre Plourde, James Smith and Ralph Kimball for valuable suggestions and comments on an earlier draft.
[2] This paper is in part a sequel to an earlier effort: Adelman & Watkins [1996].

Adelman [1992, pp. 19-20]). Information from the Department of Energy is not a substitute, since it is based on a partial and unrepresentative sample, omitting much of relevance.

Fourth, reserve values have important implications for the basic theory of mineral resources, with which we start.

Our report is organized in six main sections. Section I discusses mineral resource theory in the context of information reserve prices might provide. Section II reviews the basic data used to estimate reserve prices. The results of reserve price estimation – both from regression analysis and other sources – are presented and discussed in Section III. Section IV concerns the calculation of Hotelling Values, implicit price expectations embedded in reserve prices, and returns to holding reserves. Section V applies our estimates of in-ground reserve prices to value US oil and gas reserves. Concluding remarks are made in Section VI. Four Appendices provide full details.

I. Mineral Resource Theory – Pertinent Issues

Here we discuss salient theoretical issues relating to mineral resources on which reserve price data potentially shed some light. These include resource scarcity, past information on reserve values, the definition of reserves, and the notion of shifts in supply curves. In so doing we anticipate certain results that appear later on in the paper.

1. Mineral Values and Limited Resources

Minerals have long been considered as peculiar resources, being sooner or ultimately doomed to disappear. A bundle of quite recent books and articles foresee an end to oil production looming.[3] The President of the Institute of Petroleum in London sums up: oil and gas production is unsustainable. He thinks half the original endowment has already been produced, and in 10 years annual production "must" decline. (*Oil & Gas Journal*, March 3, 2003, p. 28) We have heard this refrain for over 100 years, starting in 1875, in Rockefeller's day [Chernow 1998, pp. 102, 197], during which time the production of oil has multiplied by a factor of over 1000. These kinds of forecasts are unaffected by factual evidence. From time to time the resource estimates are revised, but never the theory and predictions. There is no need to: since the Earth is finite, any subset is also finite. At any consumption rate the subset must in time disappear. The hydrocarbon stock is there from the start, and must finally be consumed. No economic process enters: no prices to govern supply and demand, or to guide investment.

The economic way of thinking appears in Jevons' pioneer if flawed 1865 study of British coal [Jevons 1865]. He repudiated the idea of a fixed underground stock, but forecast rising real marginal cost and ultimate decline. British coal production did indeed decline after 1913, and what little remains today is largely subsidized. But there was never any resource exhaustion. Untold billions of tons remain in the ground today,

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[3] Richard A. Kerr, "The Next Oil Crisis Looms Large—and Perhaps Close", *Science*, August 1998, pp. 1128-1130. See also J. J. MacKenzie, "Oil as a Finite Resource: When is Global Production Likely to Peak?" World Resources Institute (Washington, D. C.), March 1996. Petroconsultant writings: Colin J. Campbell and Jean H. Laherrere, "The End of Cheap Oil", *Scientific American*, March 1998, pp. 78-83; Colin J. Campbell, "Oil Price Leap in the Nineties", Noroil December 1989. Letter to *London Economist* August 6, 1994. On the Petroconsultant-predicted 2000 peak and price shock: *Oil & Gas Journal*, October 20, 1986, p. 22. Hence the European Union (and others) plan for renewables: *Oil & Gas Journal* May 17, 1999, p. 4. See also K. S. Deffeyes, Hubbert's Peak: the Impending World Oil Shortage, Princeton University Press 2001. See, however, the October 1 release by HIS (successor to Petroconsultants): "…the combination of reserve revisions and new discoveries has exceeded global oil demand over the past ten years."

untouched because current investment and extraction costs are too high compared with foreign coal, not to speak of oil, natural gas and nuclear power.

Economic analysis has always recognized that coming events cast their shadows before, through discounting. If the stock is limited¸ then even a low rate of its disappearance constantly reduces its amount and raises its price. The theory was worked out in the classic paper of Hotelling [1931]. He proved that if firms were competitive and profit-seeking, each unit of the fixed stock must at any moment have the same present value as any other, regardless of how soon any particular unit was to be produced. Arbitrage would erase any difference. Three testable hypotheses followed. (H1) At any moment, the value of a unit in-ground equals its net field price, i.e. its gross price less current outlays. (H2) Over time, the in-ground value must increase at a rate equal to the return on assets of comparable risk. (H3) At a given moment, the speed with which a given deposit is exhausted has no effect on its present value, because the price rises with the discount rate.

In 1931, little or no empirical data existed to confirm or refute the paradigm of constantly increasing net price and in-ground value (H2). Changes in *gross* spot prices, of the mineral emerging from the earth, were the first object of study. Potter and Christy [1962] showed that gross minerals prices had if anything decreased over the longer run. Many such studies later appeared. Tilton [2003, chapter 4] thought there had apparently been no general increase, but pointed to the difficulties of deflating the price series to get real price changes.

Gordon [1967] was one of the first to question the Hotelling paradigm of values and net prices rising. In his view, mineral industries were not behaving as they "should". Adelman [1970] doubted the distinction between mineral and non-mineral industries. But particularly after the price exploded in 1973-74 and in 1979, economic opinion ran strongly the other way. ([Solow 1974], [Stiglitz 1976], [DasGupta & Heal 1979], [Gately 1984], [Miller & Upton 1985], [Arrow 1987]). Many economists called the price increases the necessary effect of limited reserves, and some predicted field prices above $100 per barrel, arriving before the year 2000.

2. Earlier Data on North American Oil and Gas Reserve Values

There have long been many owners of producing properties, and many sales of in-ground reserves. The industry's working 'rule' or approximation has long been: gross field price is about three times the reserve value. Moreover, net field price was around two-thirds of gross, in a quite stable proportion (API 1983-1991; Census ASOG 1972-1982). Subtracting out one-third of the field price to allow for current outlays left the net price at double the reserve value, far above equality. Cairns and Davis [2001] found support for this rule.

Some engineering studies done in the 1950s confirmed the approximation of reserve values as one-third gross prices. They also showed that the more quickly the reserve was to be exhausted, the greater was its market value. [T.C. Frick and R.W. Taylor, eds, *Petroleum Production Handbook*, McGraw-Hill 1962, relevant sections in Bradley (ed) 1987, chs 40-41] Thus industry practice was in conflict with two Hotelling paradigms: H1 and H3. First, net in-ground values were about half (or the industry paradigm, one-third) of what they "should be". Second, present value depends partly on how near is the time when a barrel is scheduled to be drawn out of the earth. In theory, there should be no such relation. Watkins [1992] asked how the industry could thus ignore what seemed like a basic and favorable rule: that the net price had to rise at the current discount rate. Conversely, he asked, how could economists ignore what industry was actually doing?

Starting with 1946, per-barrel values of in-ground oil reserves were estimated, for many producing corporations, by the John S. Herold Company. Methods of estimation were not explained. However, the estimates continued to be updated and sold, a market test at least of their acceptability. One of the present authors participated in a study of these values for 1946-1986 (Adelman, DeSilva & Koehn [1991]). After eliminating 1946 and 1947 because of small samples (16 and 7 respectively), in every year the average field net price exceeded the annual average in-ground value plus at least one standard deviation. In 32 of the 39 years the net field price exceeded the average reserve value plus two or more standard deviations. Similar results were recorded in Adelman and Watkins [1996].

3. <u>The Meaning and Valuation of "Reserves"</u>

Reserves are defined and explained in the engineering handbooks [Frick, Bradley] as the end-product of development investment. The plan for any proposed well is that it will if drilled produce a given amount in the initial year, declining at a roughly constant percentage rate each following year, unless there were further investment in pressure maintenance, for example. The diminishing flow is reckoned as continuing as long as the net price is positive, i.e. as long as the value of the well's output at least exceeds its current costs. When net price goes to zero, the "economic limit" has been reached and production ceases. The oil or gas still left in the ground (usually much more than what has been produced) is not counted. But improved technology, making the previously uneconomic now profitable, in the same or other reservoirs, would increase reserves.

Oil in "non-producing reservoirs" is not in the US totals because these reservoirs are an interim or transitory class: "those waiting for well workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting…recompletion in reservoirs not currently open to production." (EIA Reserves, p. 24). *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2000 Annual Report*, December 2001, p. 24] These "reserves" are excluded from national totals, until the investment has been completed.

Whether a proposed well or production project will be undertaken, and reserves created, depends on estimated revenues versus costs, and therefore upon estimated present values. If the net present value of the proposed output, net of operating cost, is less than the required investment, the well is not drilled. If delay would increase present value, drilling will be delayed, and there is as yet no creation of new reserves.

Thus the reserve is the estimated cumulative production from capacity already in place, as calculated by engineers and accepted by investors. Let Q be initial output, continuing over time until point T. In a reservoir, or for all taken together, the reserve is the area under the curve, and the decline rate is current output divided by the reserve:

$$R = \int_0^T Qe^{-at}dt \qquad (1).$$

If T runs to infinity, we have:

$$a=Q/R \qquad (2)$$

i.e. the decline rate is initial output divided by the reserve. We list in Section III the following approximation:

$$V = Pa/(a+i-g) \qquad (3)$$

where: V is the reserve price

i is the discount rate on hydrocarbon reserves or production

g is the expected annual increase in the net price P embedded in the reserve price, V.[4]

This is a more general form of the basic Hotelling equality. That is, if net price rises at the discount rate, i, then g = i, and (3) collapses to V = P. Or, if we could establish by independent evidence that V=P, then it would follow that g = i. But the Hotelling equality V=P has thus far been refuted by the evidence, including evidence presented later in this paper.

Let us now assume that i>g, so that (i-g) is always positive. Then V/P should be an increasing function of 'a', at a decreasing rate. The engineering studies bear this out (Bradley¸ op cit). Moreover, since all variables but g are exogenous one can calculate g from them:

$$g = i + a\,[1- (P/V)] \qquad (4).$$

The variable g measures industry expectations of the future course of prices. As might be expected, annual g is highly variable and often negative. In Section IV we estimate the standard error of g.

But although Equation (3) contains some of the same variables as the Hotelling Paradigm, the reserve measure R may be different. In the Hotelling framework, R is exogenous, fixed by nature. In our usage, R measures only oil or gas created by exploration/development investment. The oil or gas is to be produced from defined facilities along some time gradient. R may be increased by later investment. Like many assets, R may be exploited or sold. These uses are substitutes, therefore so are their prices. We attempt to capture the average sales value of a reserve, which equals its average use value.[5]

National aggregate "proved reserves" in the USA or Western Europe are simply the national aggregate of R. (In most other areas, "proved reserves" are often not even updated, and are no longer useful. Canada has begun to count huge amounts of unhatched chickens – undeveloped reserves - from oil sands.) Such estimates imply little

[4] Expression (3) assumes a + i > g, as normally would hold.
[5] We acknowledge that sales values may include an element of option value.

about the amount of hydrocarbons to be ultimately produced within a given area. That amount cannot be known today, because it depends on future science and technology. "Probable reserves" are the amounts of oil and gas that would be economic to produce given current science and current technology, marked up by some estimate related to further development. "Probable reserves" may be a very useful ordinal measure, permitting one to rank areas where new oil is more likely or less likely to be found [Weeks 1969]. But adding "probable" reserves to current proved reserves adds apples to oranges. The total does not approximate ultimate production. Such a total minus consumption is not an estimate but more confusion. Yet every forecast of exhaustion assumes a total remaining reserve.

The crude oil and natural gas industries have diverged. US crude oil production decreased from 9.2 mmbd in 1973 to 5.9 million in 1999, since when it has been approximately constant. Its supply is becoming scarcer in the strict economic sense of the US supply curve moving leftward. (Bradley & Watkins [1994], Adelman [1998], Watkins & Streifel [1998]) This has not been true (perhaps we should say "not yet true") of natural gas, where North American production and proved reserves grew through the year 2001. For oil, value changes reflect worldwide oil price expectations. For gas, value changes reflect North America gas price expectations.[6] Hence, these are two different markets (also see below, section IV-2, "Oil and Gas Price Expectations").

The results of estimating reserve prices for 1982-2002 described in Section III of this paper differ from the earlier Herold series in that they are derived from observed sales of reserve-bearing properties. As with the other series, the current net field price is on average about 4 times the in-ground value for oil and 3 times for gas, and each year's net field price lies above the regression value plus at least one standard error. This data set cannot be reconciled with the Hotelling Paradigm any more than could the engineering studies or the 1949-1986 set of oil in-ground values. We discuss this further in Section IV.

To sum up: the Hotelling theory correctly draws out the implications of its basic assumption: that there exists "an exhaustible natural resource … a fixed stock of oil to divide between two [or more] periods." [Stiglitz 1976]. Since the implications are false, and the theory is sound, the premise must also be false.

[6] But the emerging international market for LNG, with participation by North America suggests that over time the market for natural gas will become a world market.

Having found little or no empirical support for the notion of a fixed stock and of the constant increase in reserve values, we can now face a lesser but real problem: what if anything is known about oil and gas becoming more or less scarce over time?

4. Values As Marginal Finding-Development Costs

In a competitive industry, the value of reserves of oil or natural gas in-ground is equal to the cost of the marginal reserve added (marginal cost). Even if oil or gas are produced and sold under imperfectly competitive conditions, the addition of reserves is competitive provided there is no public or private restriction upon the associated investment.

Restriction was strong in the creation of natural gas reserves before the 1980s, and it was not negligible for crude oil in 1946-1980. The prorationing system in Texas favored investment in high-cost "marginal" wells. Moreover, Federal maximum price-fixing in 1974-1980 favored investment in high-cost "new" oil. These imperfections in the 1948-1986 oil series should (we think) be considered as part of the larger scheme of fluctuations. Some will (not without reason) reject their use. But de-regulation of the oil and natural gas industries in the 1980s abolished constraints, and there are no such uncertainties for 1982-2002.

However, there are two principal difficulties in using these data sets to represent long-run cost trends. First, we need to deflate the observations. This would be necessary at any time, but particularly during a period of strong price inflation, as were much of the earlier series and some of 1982-2002. Second, these marginal costs are investment costs. We should not deflate them by a general index of goods bought to satisfy human needs; the appropriate index would be one specific to the particular investment vehicles (equipment and plant) employed. They are investments expected to enjoy a return comparable to investment in other industries, with similar degrees of risk. Indeed, the Hotelling Paradigm is that they should increase at the rate of return on other investments in oil and gas reserves. But if we drop the Paradigm assumption of a fixed hydrocarbon stock, the value of a reserve may vary up or down in any year. In Section IV we test for successive one-period returns from holding oil or gas reserves and find, again, no support for Hotelling patterns.

The value of oil reserves is set by competition in the worldwide market for hydrocarbon discovery and development. Part of this market is noncompetitive: in the

OPEC countries, investment and output are limited in order to support the price level. Resulting values bear little relation to marginal cost. But the non-OPEC world, which today comprises about 70 percent of world production, and more of worldwide investment, is competitive. It gives a competitive response to an exogenous fact: the fixed price at the field.

In non-OPEC areas, discovery and development comprise a sensing/selection network, constantly seeking the cheapest reserves of oil, gas, or both. As we have shown, the series of in-ground values also measures the marginal cost of increasing these reserves. But observed marginal costs are the outcome of a cost function and the position of a demand function. A constant level of observed North American marginal costs may be – and we think is – associated with the supply functions moving leftward – i.e., unfavorably. Therefore more of domestic consumption is supplied by imports. The results presented here are compatible with findings that rising marginal costs have made non-economic more North American deposits. (Bradley & Watkins [1994], Adelman [1998], Watkins & Streifel [1998]) It is the same case as British coal. But the results are not compatible with statements that worldwide discoveries have been declining since the early 1960s. This implies that both discovery and development costs have been increasing. If discovery is yielding smaller, deeper, and farther deposits, they cost more to develop. The IEA discussion is one of the more sober ones. (International Energy Agency, *World Energy Outlook 1998*, especially pp. 90-100). Yet it is at the least an anomaly that allegedly dwindling discoveries over 40 years have left little trace in in-ground values.

In actual fact: *there are no precise statistics of oil or gas discoveries*. Indeed, it is difficult even to state how to construct one. Merely counting the number of newly listed fields or pools is trivial. The contents of these new fields and pools will not be known until they are fully developed, which may be even as much as a hundred years away. One can at any time estimate those contents, given only the technology of the moment. It is useful comparing the guesses of one year with those of another. In the USA, "discoveries" are a sub-category of development: those reserves developed during the year in newly found fields. In the next year and in all later years, they will be "old" fields. In an area like the Persian Gulf the great bulk of new reserves are created in old fields. Far from indicating scarcity, the development of old fields has been sufficiently cheap as to deter seeking new fields.

II. Review of Transaction Data

We want to assemble information on the amounts paid for reserves of oil and natural gas to enable us to estimate reserve prices. For a period of twenty or more years, the Scotia Group has been collecting data on reserve related transactions in the US and has sought to identify the value of purchases and sales of reserve assets.[7] In what follows below, first we comment on the nature of the Scotia Group transaction data we employ. Second, we examine the Scotia data series, assembled on an annual basis.

1. The Scotia Group Database[8]

The information in the database is collected entirely from sources in the public domain. The version of the database used has nearly 6000 transactions of which 63 percent have transaction price data and 28 percent have both price and reserve information – the transactions on which we focus.

Some transactions involve non-reserve assets such as pipelines, plants and equipment, goodwill, strategic elements and the like. "Strategic" acquisitions, especially, may involve significant goodwill. Where values of tangible ancillary assets are known, they have been subtracted from the purchase price; where the purchaser assumes debt, its value is added. The resulting transaction values are referred to as 'adjusted prices' in the Scotia database.

Reserves are reported in millions of barrels of oil (mmbbls) and billions of cubic feet of gas (bcf). Producing rates, where available, are reported in thousands of barrels per day of oil (mb/d) and millions of cubic feet of gas per day (mmcf/d). Reserves are treated as proven, developed and on production – unless there were additional information (see below). Buyers and sellers may differ in their reserve assessments, even for proved reserves. However, no such discrepancies were disclosed in the transactions employed. There is no information on expected reserve appreciation that may underlie a given transaction.

International and Canadian transactions are excluded. So are transactions reported in terms of equivalent volumes of oil and gas, but with conversion factors

[7] The Scotia Group was founded in 1981 and specializes in the technical and economic analysis of projects, properties and companies.
[8] See Scotia Group Documentation "Description and Discussion of the Database" Mimeo, Jan 1995.

unknown, individual volumes cannot be derived. Data for some transactions are incomplete, and we exclude them. The database generally excludes stock transactions because reserves cannot be identified.[9]

Our working assumption, that the reserves changing hands are proved, developed, and producing, is not always true. A transaction could involve non-producing reserves. If so, it may well include reserves normally classified as proved undeveloped or prospective reserves (i.e. probable or possible) even though we have attempted to exclude transactions involving undeveloped reserves from our database.

Suppose parties have included in "reserves" some undeveloped oil or gas deposits. (Some companies will try to impress the financial community by reporting undeveloped reserves as developed. Some companies overpaying for undeveloped reserves will not be well regarded. We cannot say which event is more probable.) Then the observation we calculate, dollars per barrel-in-ground, will be too low as an estimate of the market value of a barrel of developed reserves. Support now the contrary, that the sellers have lumped undeveloped oil with any undeveloped acreage and other producing assets. Then the total value is too high, because it includes more than the value of developed reserves. We cannot identify either type of error, understatement and overstatement, and hence must consider both of them as contributing to chance variations, along with other sources of error. This would increase the error of estimate, and might make the intercept significant.

2. Description of Transaction Data

Information on those transactions that list reserve data is brought together in the 'A' series of Tables compiled in Appendix A, to which we refer the reader for full details.

Annual data on the number of observations selected are shown in Table A-1, columns 2, 3 and 4. The total number of transactions providing usable data is 1563, over the period 1982 to 2002 inclusive.[10] The bulk (77 percent) was from 1990 onwards. Of the overall total, 341 transactions identified only oil reserves as sold (22 percent); 416 transactions only identified gas reserves (26 percent). We call these 'pure' oil and 'pure'

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[9] Our earlier paper [Adelman and Watkins 1996] looked at various buyer and seller categories and at regional data. We do not pursue such breakdowns here.

[10] In Adelman and Watkins [1996] we showed data for 1979, 1980 and 1981. However, the sparseness of the observations and the unreliability of the results for these years led us to drop them this time around.

gas transactions, respectively. All the other 806 transactions (52 percent) involved the joint sale of oil and gas reserves; we term them 'mixed' transactions.

a) Outliers

Calculation of unit values of reserves (the in situ price per barrel or per mcf) for the 'pure' transactions by simply dividing the transaction value by the relevant oil or gas reserve showed that certain values were unusually high or low in relation to apparent market values. It is probable that such transactions reflected special terms of sale such as "goodwill," or lack of information on the nature of the property exchanged, or even erroneous data. Inclusion of these transactions in the sample would distort the market conditions we are trying to discern.

Accordingly we eliminated all 'pure' transactions where the calculated reserve price was more than two standard deviations from the mean value for the relevant year. We also excluded any 'pure' values that appeared unreasonably low in an absolute sense: below 10 cents per mcf or 55 cents per barrel of reserve. Similarly, we excluded unreasonably 'high' values, values where the apparent unit reserve value exceeded $5 per mcf or $27.5 per barrel of reserve.

The regression analysis embraces both 'pure' transactions and 'mixed' transactions – those including both oil and natural gas reserves. Our criterion for elimination here was where the actual transaction value was more than two standard errors away from the fitted value obtained from the regression equation (see Section III), plus any 'pure' observation identified as an outlier in the stand-alone analysis of 'pure' transactions even if not so identified using the spread between its value and the fitted value from the regression. We also excluded 'high' and 'low' unit value observations, irrespective of the two standard deviation criterion.[11] In this context, mixed transactions were converted to gas equivalence using the 5.5 mcf/bbl conversion rule.

Hence, the outliers in the regression analysis consist of all observations, 'pure' and 'mixed', defined as outliers using the fitted value criterion, plus any pure transaction defined as an outlier in the independent analysis of pure observations, irrespective of whether it is defined as an outlier in the regression analysis, plus any 'low' or 'high'

[11] Most of these observations were identified as outliers under the two standard deviation test. However, the lower two standard deviation boundary value could be negative, precluding identification as outliers what might be unreasonably low unit values. Hence the need at least for a lower absolute value test.

valued observations not already identified as outliers under the standard error rule. In almost all cases the 'pure' outliers in the 'pure' analysis were one and the same as 'pure' transaction outliers in the regression analysis. A further comment on outliers, in the context of robust regression techniques, is made in Section III.

The count of outliers is listed in Table A-1, columns 5, 6 and 7; they total 107 transactions. While the number of outliers is small – a mere seven percent of the total observation set – they are, as extreme values, influential. Hence their exclusion does materially affect the sample. The number of observations after exclusion of the outliers is shown in columns 8, 9 and 10, Table A-1.

We found our outlier procedure useful as a sensing device, leading us to subject outlying observations to additional scrutiny. In some instances this resulted in our eliminating an observation from the data set entirely, for example where the transaction was revealed as including overseas properties, did not have sufficient segregation of assets acquired, expressed reserve quantities in 'barrels equivalence', or was a mega merger. More generally, an observation identified as an outlier was only discarded from the data set if it were seen as invalid, not because it was simply so many standard deviations from a fitted value.

b) Summary Statistics

The summary statistics in Table A-2 for values of all transactions (including outliers) shows a considerable spread in annual mean values. There is a pattern, however, with higher values congregating at the beginning and the end of the sample period, while consistently lower mean transaction values prevailed over the interval 1989-1996, in part reflecting the larger number of observations in those years, which may better represent the skewness of the underlying population of reserves towards smaller volume (see below).

The distribution of transaction value observations for virtually all years is skewed to the left: smaller transaction values predominate. The medians are appreciably less than the means. Not surprisingly, Normality is strongly rejected for each year.[12] On the other

[12] The test used was Jarque-Bera.

hand, log Normality would not be rejected for any year.[13] The coefficients of variation are quite erratic before 1988, but are much more stable thereafter, except for 1998.

Table A-3 shows transaction value summary statistics after exclusion of outliers. Most of the outliers are large rather than small transactions. The means are substantially reduced, but the distributions remain skewed.

The next two tables (Tables A-4 and A-5) focus on the value of 'pure' transactions for both oil and gas, excluding outliers. The pattern of results pretty well parallels that for the total number of observations.

Tables A-6 and A-7 respectively deal with volumes of oil reserves and volumes of natural gas reserves, for all transactions. The distributions are heavily skewed to observations with relatively small reserves. This is in accord with the typical distribution of reserves in nature, suggesting that the sample of transactions has no apparent bias towards certain types of reserves, at least in terms of reserve size.

The final two tables in Appendix A concern transaction sizes in terms of reserve volumes of oil and gas aggregated on the basis of thermal content. Oil reserves were converted to trillion cubic feet (TCF) thermal equivalence at a conversion factor of 1 barrel equals 5.5 million BTUs.[14] Table A-8 relates to all transactions, Table A-9 excludes outliers. As would be expected, the reserve distributions are all slanted to the left and Normality is strongly rejected, while log Normality is not in all years for oil, in all but one year for natural gas.

We conclude that the statistical characteristics of the transaction data are in large measure stable across years. The distributions are typically skewed towards smaller transactions. Normality for the size distribution of transactions is rejected. This suggests that since the underlying size distribution of oil and gas reservoirs is heavily skewed – with log normality not rejected in virtually all years – the transaction data broadly represent the occurrence of the reserves in nature. To this extent, these data do not seem to constitute a biased sample from the underlying population.

[13]Although log Normality is not rejected, it does not follow that it is the best skewed distribution to represent the data. For example, in terms of North Sea data, Smith and Ward [1981] found that the log normal was not the preferred data generating process.
[14] That is 1 barrel = 5.5 mcf, where gas is measured at 1,000 btu/cubic feet.

III. Regression Results

In this section, we use the transaction data discussed in Section II to estimate the price of oil and gas reserves. We report both on values obtained from linear regressions of all types of transactions ('mixed' and 'pure') and on values obtained from the simple division of 'pure' transaction values by relevant individual reserve volumes. We also report on the results of some statistical tests and searches for relationships among possible transaction related variables. These include reserve-to-production ratios, reserves status (on production or not) and levels of field prices, all of which may have a systematic influence on reserve values. Finally, we illustrate how the estimates of reserve values can be used to measure company performance.

We estimate the unit reserve values for a given year from actual transactions – sales of oil and gas reserve properties – during that year. As with share valuations, we impute the sales value to all existing units. These values reflect all information, expectations, forecasts, hunches, and mistakes of buyers, sellers, operators and investors. Higher expected returns result in higher current reserve values in relation to current prices.

The basic statistical method is least squares regression. Fortunately, there are enough transactions relating solely to oil reserves or solely to gas reserves ("pure oil" or "pure gas") to provide a useful check on the regression results.

The set of tables relating to the various linear regressions run to estimate the in situ values of oil and gas reserves are located in Appendix B. Specifically, transaction values (in $millions) were regressed on the quantity of oil reserves (in millions of barrels) and on the quantity of natural gas reserves (in billions of cubic feet).

Conventional cash flow analysis indicates that a transaction value for the sale of oil and gas reserves would consist of the sum of the net present values of the expected flows of oil and gas production yielded by the property. This would suggest specifying value as a linear function of the respective reserves.[15] There is a question of whether the equation specification should include cross-product term. Reservoir engineering provides little evidence of a systematic relation between oil and gas reserves underlying various

[15] See Adelman and Watkins [1995, p. 666].

properties.[16] Our data are in agreement: the simple correlation coefficients among oil and gas reserve volumes for each year of our data set are typically low. Moreover, there is a basic logical objection: the insertion of a cross-product term in the equation specification would make the estimated reserve price of oil conditional on a given volume of oil reserves, and vice versa. This would thwart one of the main objectives of our investigation, namely to estimate as best we can an unambiguous price of oil and gas reserves. For these reasons we rejected inclusion of a cross-product term in the equation specification.

Hence our basic regression equation is:

$$V = b_0 + b_1 R_o + b_2 R_g \qquad (5)$$

where: V = transaction value

R_o = volume of oil reserves

R_g = volume of natural gas reserves.

The observation set used in the regressions is for all transactions, mixed and pure (those where only oil reserves or only gas reserves changed hands), with and without outliers (see Section II for discussion of outlier identification).[17]

Theoretically, a constant term in these regressions would be zero. No reserves sold, no value. We ran the regressions both suppressing and including a constant term. The latter may well attract noise in the data, detect systematic biases and indicate non-linearities. Also, a significant positive constant might be interpreted as affected by option values, fixed transaction costs, consistent goodwill and the like. However, we retain a preference for the no-constant specification. And as will be seen, the constant term was insignificant in most cases. The B-l series of tables reviewed immediately below include all the observations; the subsequent B-2 series of tables are for when outliers are excluded.

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[16] If it did, aggregation of oil and gas reserves would be simple – gas reserves would be a function of oil reserves and vice versa. Either oil or gas reserves could be expressed as a common numeraire.

[17] We ran Box-Cox tests on functional form. The results were inconclusive – no convincing evidence emerged favoring the linear or log linear forms; a reciprocal relationship was strongly rejected. Our preference remained for a straightforward linear function, for economic reasons: we wanted to estimate unit prices.

The regressions with outliers excluded were run with corrections for heteroscedasticity. This increased the standard errors of the coefficients in all but some of the earlier years. Hence, many of the 't' values fell, although still remaining highly significant.

1. <u>Results Before Exclusion of Outliers</u>

Table B-la shows the results for all 21 years with the constant term suppressed. Figures 1 and 2 plot the respective estimated reserve prices for oil and gas from 1982 to 2002. There is a great deal of variability in both the oil and gas reserve coefficients, representing the price of reserves in barrels or mcfs, respectively. As we shall see later, this in part reflects the impact of outliers.

The price of *oil* reserves shows no obvious pattern over time, and their fluctuations bear only scant relationship to shifts in field prices – as our later analysis shows. In all years, the oil reserve coefficients are statistically significant, usually strongly so.

The price of *natural gas* reserves represented by the regression coefficients also shows noticeable fluctuations year over year, fluctuations that again do not seem to be well correlated with changes in field prices (see later analysis). Except for 1982, all the gas reserve coefficients are strongly significant.

The results with inclusion of a constant term in the regression equation are shown in Table B-lb. As would be expected, given that the constant in only three years (1988, 1990, 1996) is significant, the results do not noticeably differ from those in the preceding Table.

We have one check on the OLS regression estimates, namely by making a comparison with the 'pure oil' and 'pure gas' transaction values.[18] The comparison for oil is made in Table B-lc, for the without intercept case. To derive aggregate 'pure' values, the pure oil value observations are weighted volumetrically by the barrels in each transaction for a given year. This is equivalent to summing the value of all pure transactions in a given year and dividing by the total volumes of oil or gas reserves sold, respectively. The ratios of the oil reserve coefficients from the regressions to the 'pure'

[18] Recall that the pure values are simply calculated by dividing the adjusted transaction value by the relevant volume of oil and gas reserves.

oil unit values differ markedly. There is no consistency, except that the regression coefficients are lower than the 'pure' oil transactions in about half the sample. Only in eight of the 21 years (1982, 1987, 1988, 1989, 1990, 1995, 1998, 2000) are the ratios within 10 percent of unity.[19]

Comparisons for natural gas are shown in Table B-ld. Again there is a large spread in the ratios of the regression values to the 'pure' values. And yet again in only eight years – 1986, 1987, 1989, 1998 through 2002 – were the ratios within 10 percent of unity. In contrast to oil, in the majority of years the regression coefficients exceeded the 'pure' values.

We conclude that the reserve values derived from the overall sample of transactions differ markedly in most years from the pure transaction sample. However, in many years the number of 'pure' observations is small, contributing to variability between the two sets of reserve values.

2. Results Excluding Outliers

The next set of Tables in Appendix B looks at what happens when we exclude the outliers. With the exception of 1985 and 2000, all the oil reserve coefficients are strongly significant (see Table B-2a, without constant). Their amplitude of variation, while large, is less than when the outliers are included, as would be expected. Much the same comment applies to the natural gas reserve coefficients, and no statistically insignificant values were recorded except for 1982. Overall, the gas coefficients were more stable over time than those for oil.

Results with an intercept are shown in Table B2-b, and show a similar pattern to those without it. The constant term was significant in seven years (1983, 1984, 1985, 1987, 1998, 2000, and 2001).

The oil coefficients are plotted in Figure 1; those for gas are plotted in Figure 2. The plots are shown both with and without outliers, for the without intercept case.

[19] These results are notwithstanding the fact that regression data include the 'pure' oil cases (see earlier).

Figure 1: Oil Reserve Prices for 1982-2002

Figure 2: Natural Gas Reserve Prices for 1982-2002

The next Table (B-2c) focuses specifically on the impact of the constant on the regression coefficients. For oil, only in three years (1982, 1998 and 2000) did the constant affect the regression coefficient by more than 10 percent. For natural gas, only in 1982 and 1985 did the impact of the constant on reserve values exceed 10 percent.

Table B-2d summarizes the impact of the exclusion of outliers on the reserve coefficients. The ratio of the oil and gas regression coefficients with and without the outliers is calculated in the no constant case. The impact of suppressing the outliers is considerable. And this holds in the case of both oil and gas (also see Figures 1 and 2).

Another approach to the issue of unusual observations is to apply robust regression techniques.[20] As an example, 'M Class' estimators and 'Least Trimmed Square' estimators were calculated for our total set of observations for the year 1996. The results both confirmed the presence of unusual, influential observations and yielded estimated coefficients similar to ours after we excluded outliers. While this analysis was only confined to one year, it suggests our 'ad hoc' rules for identifying outliers, described in Section II, are broadly congruent with those from a robust regression approach.

Table B-2e compares the oil regression values (no constant) with the weighted pure oil case values (outliers excluded in both instances). No clear pattern over time emerges. This is quite similar to the earlier corresponding comparison before adjustment for outliers, although the number of years when the ratio is within 10 percent of unity is 11, compared with eight years for all transactions (see Table B-1c). Much the same conclusion applies to natural gas. There was a considerably closer correspondence between the natural gas regression coefficient values and the 'pure' transaction values when the outliers were excluded. The amplitude of variation, while noticeable, is less than when outliers are included in the sample (Table B-2f). However, the number of years when the ratio is within 10 percent of unity remains at eight, the same as for the all transaction case (Table B-1d).

3. Influence of Reserves Status

Information was available for certain transactions that distinguished between those where reserves were on production and those where they were partly fallow. In the latter case the properties may include prospective reserves normally classified as proved

[20] We are grateful to Adonis Yatchew, University of Toronto, for this suggestion.

undeveloped, developed but not on production, probable or possible. Other things equal, the in situ reserve values for reserves on production would be expected to exceed those for dormant reserves. The theoretical margin between two identical properties, one on production, the other not developed, would be the development cost per unit of reserve, in the absence of any option value for the undeveloped reserve.

We tested the proposition of such differential values using our database of 1456 mixed transactions, of which 981 observations related to properties not on production.[21] We caution that the reason why so many observations are in this category may be lack of production information: that is, the numbers may well be exaggerated.

Specifically, we performed the following regression:

$$adjprice = [a_1^o + a_2^o D_o]R_o + [a_1^g + a_2^g D_g]R_g$$

where: adjprice is the transaction price (after elimination of non reserve assets)
the 'o' superscript denotes oil
the 'g' superscript denotes gas
a_1 and a_2 are the two coefficients for each reserve being tested
R denotes reserves sold
D denotes a dummy variable for reserves on production.

A priori, we expect both the a_1 and a_2 coefficients to be positive: reserves already producing would be expected to be worth more than those lying fallow.

The results are shown in Table C-2 (excluding outliers, no constant). For oil, the first coefficient is positive as expected (except for 1985). However, eleven of the second coefficients are negative, although only two of these are statistically significant. Of the nine positive second coefficient values, four are significant. For natural gas, all the first coefficients are positive, but 12 second coefficients are negative, of which five are statistically significant; only two of the positive coefficients are significant.

We treat these findings as broadly confirming that the sales value of oil reserves on production exceeds that where developed properties are either not producing, or are

[21] This set includes observations where oil reserves are not on production, observations where gas reserves are not on production, and where both are dormant.

only partly on production. The results for natural gas are murky.

4. Influence of the R/P Ratio

A factor which can be expected to influence reserve values is the rate at which reserves are produced. Evidence for such an effect is likely confined to cross section data. The shift in time series data for R/P ratios is too gradual to reveal impacts.

US (remaining) reserve to production ratios are shown for oil and gas in Table C-1, Appendix C. Those for oil are quite stable; those for gas show some tendency to fall.

The years during which we had an appreciable number of transactions containing R/P ratio information was confined to 1989, 1990 and 1992 to 2002, inclusive. To test whether the R/P ratio affects the transaction price we performed the following regression:

$$\text{adjprice} = [a_1^o + a_2^o H_o]R_o + [a_1^g + a_2^g H_g]R_g$$

where: adjprice is the transaction price (after elimination of non reserve assets)
the 'o' superscript denotes oil
the 'g' superscript denotes gas
a_1 and a_2 are the two coefficients for each reserve being tested
R denotes reserves sold
H denotes the R/P ratio.

The regression was run without a constant term.

The greater the R/P ratio, the lower the rate of production. The lower the rate of production, the lower the expected price of reserves, other things equal. Hence the expected sign of the a_2 coefficient attaching to the H variable (the R/P ratio) would be negative.

In the case of oil the a_2 coefficient is negative in 10 of the 13 years for which we had data; it was significant in four of the 10 cases. In these years, the coefficient shows a great degree of variation, from -\$1.64/bbl in 1989 to -\$0.01/bbl in 1996. In all three years in which the coefficient was positive, it was insignificant.

In the case of gas, a_2 is negative in all years but one (and here it was insignificant). And of the 12 years in which it is negative, it was significant in eight instances. The absolute value of the incremental coefficient is less than 10 cents/mcf in all years except 2001.

Our broad conclusion is that the transaction data do support the proposition that reserve prices would be inversely related to R/P ratios – and especially so for natural gas.

In summary: the impact on reserve prices of the two types or transactions discussed above – of whether production is taking place and of the rate of production – has the following implication. Unless the mix of transactions by these categories was reasonably constant, some of the variation in estimates of reserve prices among years will reflect compositional shifts in transaction types. Hence caution has to be exercised in any interpretation of temporal trends in estimated reserve prices. This seems to apply to a greater degree to natural gas than to oil reserve prices.[22]

5. Relationship Between Reserve Regression Coefficients and Field Prices

Expected field prices are an important determinant of reserve values, values that are influenced by current and previous field prices. We made some simple tests to see whether the annual estimates of oil and gas reserve prices calculated from the regressions displayed any obvious relationship with current and lagged field prices. We confined the tests to a simple linear regression of in-ground reserve prices, represented by our estimated oil and gas regression coefficients on field prices. We note that since reserve prices are influenced by field price expectations it is by no means clear in theory that a zero current or lagged field price would indicate zero reserve prices. Hence reserve prices could be positive even if field prices were zero. There is, then, a preference for including a constant term in the equation specification. The price series used are shown in Table C-4.

The regression results for both oil and natural gas are shown in the upper panel of Table C-5 for the two sets of regressions where the reserve price was regressed on each of contemporary field prices, prices lagged one year, and prices lagged two years. For all oil and gas equations the intercept is positive and significant. Oil reserve prices are positively (and significantly) related to field prices, whether contemporary or lagged one

[22] Our 1996 paper included some analysis of location (regions) reserve values. Change in regional mixes of transactions is another source of variation.

or two years; the results suggest about 12 to 15 percent of any increase in field prices would be reflected in reserve prices. But the degree of linear fit of the three oil equations is modest. Gas reserve prices are also positively related to field prices, but all coefficients are statistically insignificant; moreover, the degree of linear fit is trivial.

We also subjected the time series of reserve and field prices to stationarity tests. Stationarity was not rejected for the series of reserve prices, but was rejected for the field price series. Stationarity was not rejected for the residual terms of the equation results shown in the upper panel of Table C-5; nor was it rejected for the first differences of the respective series in field prices. Thus the regressions are of I(0) variables on I(1) variables and result in I(0) residual terms. The stationarity tests used a 5 percent level of significance throughout.

The fact that field prices were found to be I(1) while reserve prices were I(0) encouraged regressing reserve prices on the first differences field prices, since both variables then would be I(0). The results are shown in the lower panel of Table C-5. A fit is absent and coefficients for field price differences are insignificant, except for natural gas with a one period lag in field price first differences.[23] The constant term roughly picks up the average values of the respective reserve prices, which is consistent with what one anticipate for expected reserve prices when field prices are constant (first differences are zero). Overall, we find first differences in field prices do not have a material impact on reserve prices.

6. <u>Reserve Prices and Company Performance</u>

Differences between the actual expenditures incurred by a company and those implicit using the in situ prices generated from industry wide data will indicate the extent to which a company over or under performed in relation to the market. For example, suppose in year 2002 a company spent $500 million in acquiring 100 million barrels of oil and 100 billion cubic feet of natural gas. In situ prices for that year are $5.74 per barrel and $0.88 per mcf (see Table B-2a). At these prices, the estimated market value of the company's transaction would be $574 million for the oil and $88 million for the gas, a total of $662 million. In this example the company seemingly would have outperformed the market to the tune of $162 million, or about 32 percent.

[23] The sign of the coefficient is ambiguous. For example, a positive price change might indicate a peak, depressing price expectations embedded in reserve values, resulting in a negative coefficient; or it might indicate further price increases on the way, resulting in a positive coefficient.

The in situ prices are subject to uncertainty. Two standard deviations either side of the point estimates cited above yield a spread in values for oil of $4.58 to $6.80 per barrel, for gas $0.70 to $1.06 per mcf.[24] At the lower price bounds the imputed value of the transaction would be $528 million, and the company would still have outperformed the market by $28 million, or some 5 percent. At the upper bound, the corresponding figures would be $786 million, $286 million and 57 percent.

[24] For standard errors of the coefficients, see Table B-2a.

IV. Reserve Prices, Hotelling Values, Price Expectations and Returns to Holding

The Hotelling Valuation Principle states that the market value of a mineral in the ground at any point in time is equal to the prevailing net price per unit of production (Miller and Upton [1985]). In the first part of this section we relate the estimates of reserve prices discussed in Section III to estimates of Hotelling Values. We then examine what price expectations for oil and gas respectively may underlie our estimates of reserve prices. Finally, we look at one period returns to holding reserves in the ground, in the Hotelling context.

1. Reserve Prices and Hotelling Values - A Comparison

Hotelling Values are the net price, which we write as:

p-c

where: p is present price of oil or gas as produced at the field (wellhead)

c is unit extraction cost, plus non-cost outlays (non-income taxes, royalties).

The assumption here is that title to the reserve in the transaction passes at the field gate, and that the field is already developed. To the extent the transaction includes undeveloped reserves, the value of ‘c’ would need adjustment to add relevant development cost. The Hotelling Value, accordingly, would be smaller. However, results in our 1996 paper and in Section III of this paper indicate that transactions with some undeveloped reserves – reserves not on production – were not necessarily of lower value than those for just developed reserves, which obscures the picture.

We estimate national averages for the p-c values for the period 1982-2002. The oil and gas field prices (p) used are those shown in Table C-l, Appendix C. Operating costs (c) essentially consist of three components: a fixed element; one that varies with output; and royalties and taxes that are field price sensitive. A suitable historical series of operating costs was not available. Instead, reliance was placed on evidence that over a period of time when data were available on unit operating costs they approximated 35 percent of gross field values (Adelman [1992, Table 2]). The procedure we adopt of estimating operating costs as 35 percent of field prices treats them as *ad valorem*, whereas we know only a portion of them behave in this manner. Nevertheless, it remains the best approximation at hand. To the extent that operating costs are underestimated in a given year, estimated Hotelling Values would be inflated, and vice versa.

The annual Hotelling Values (HV) so estimated are shown in Tables D-1 through D-4 under the column headed "Net Field Price" (column 9). These Tables relate respectively to the oil values from all transactions, 'pure' oil values, natural gas values from all transactions, and 'pure' natural gas values.

a) <u>Oil Results</u>

The HVs for oil are graphed in Figure 3 for 1982 to 2002, along with the reserve prices estimated from the regressions in Table B-2a (excluding outliers, no intercept), Appendix B. Figure 3 shows that in all years the Hotelling Values comfortably and in most instances considerably exceed corresponding reserve prices. How significant is the spread between them?

The standard errors of the reserve prices are given by the regression results and reproduced in column 5 of Table D-1. This enables us to calculate by how many standard deviations the HVs are away from the reserve prices. The results are shown in Column 11. If we assume the estimated reserve price is Normally distributed within each year, as the Central Limit theorem would suggest, then 1.96 standard deviations would bracket 95 percent of them. It follows that the results in column 11 decisively reject the null hypothesis that the recorded differences between the HVs and reserve prices are not statistically significant. In only one year (1985) is the HV spread below 1.96.

The same analysis as undertaken for the oil values from the regression equation is pursued for the 'pure' oil reserve prices and is shown in Table D-2. In all years bar 1986 (the year of the OPEC price crash) the HVs exceed the reserve prices. And the null hypothesis that the differences are not statistically significant is rejected in all years except 1986, 1988 and 1994.

b) <u>Natural Gas Results</u>

The HVs for natural gas national averages are listed in Table D-3, Appendix D, in relation to reserve prices and displayed in Figure 4. In all years except two (1987, 1989) the HVs exceed the reserve prices by a statistically significant margin.

Figure 3: Estimates of Hotelling Values and Price Expectations, Oil

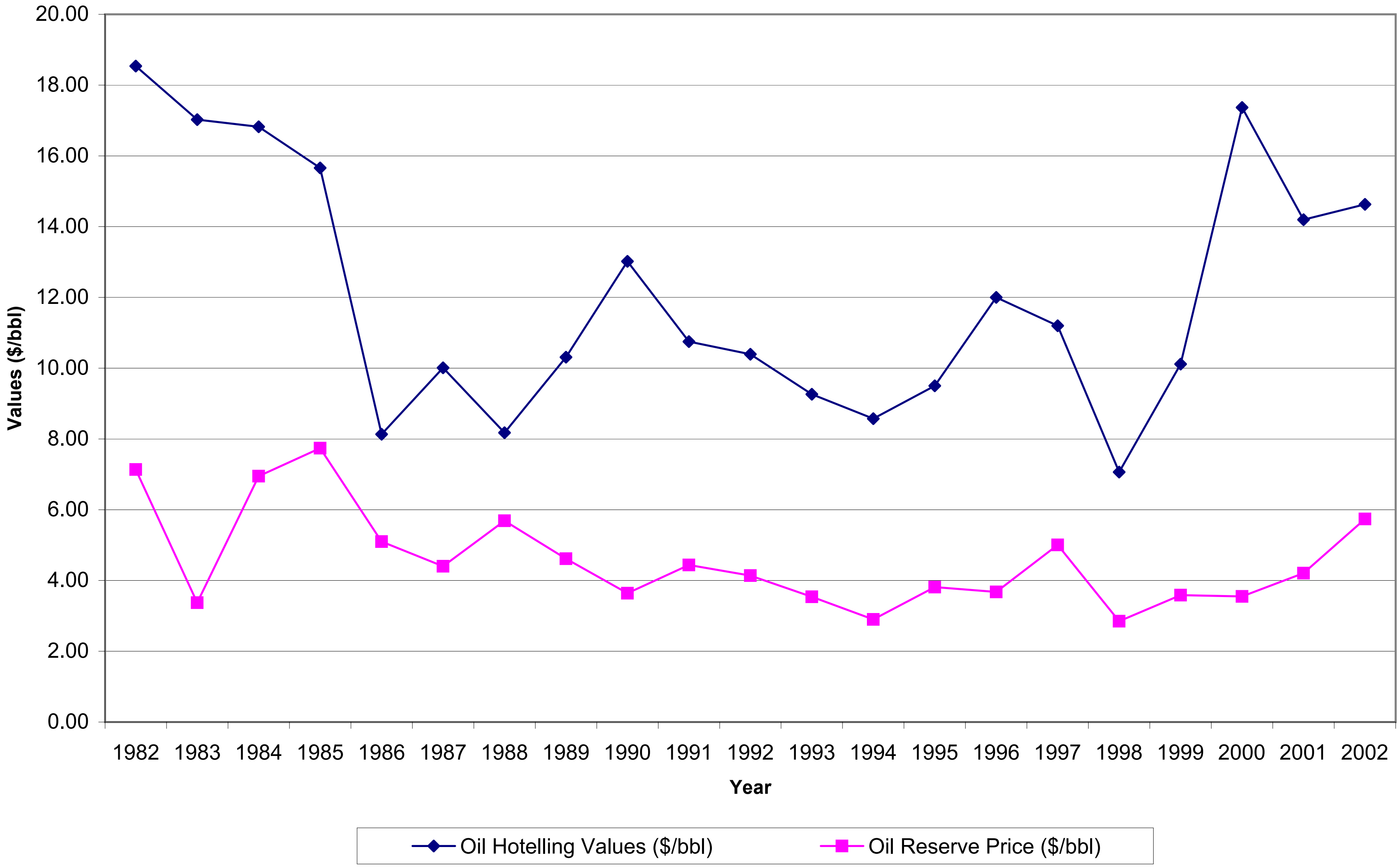
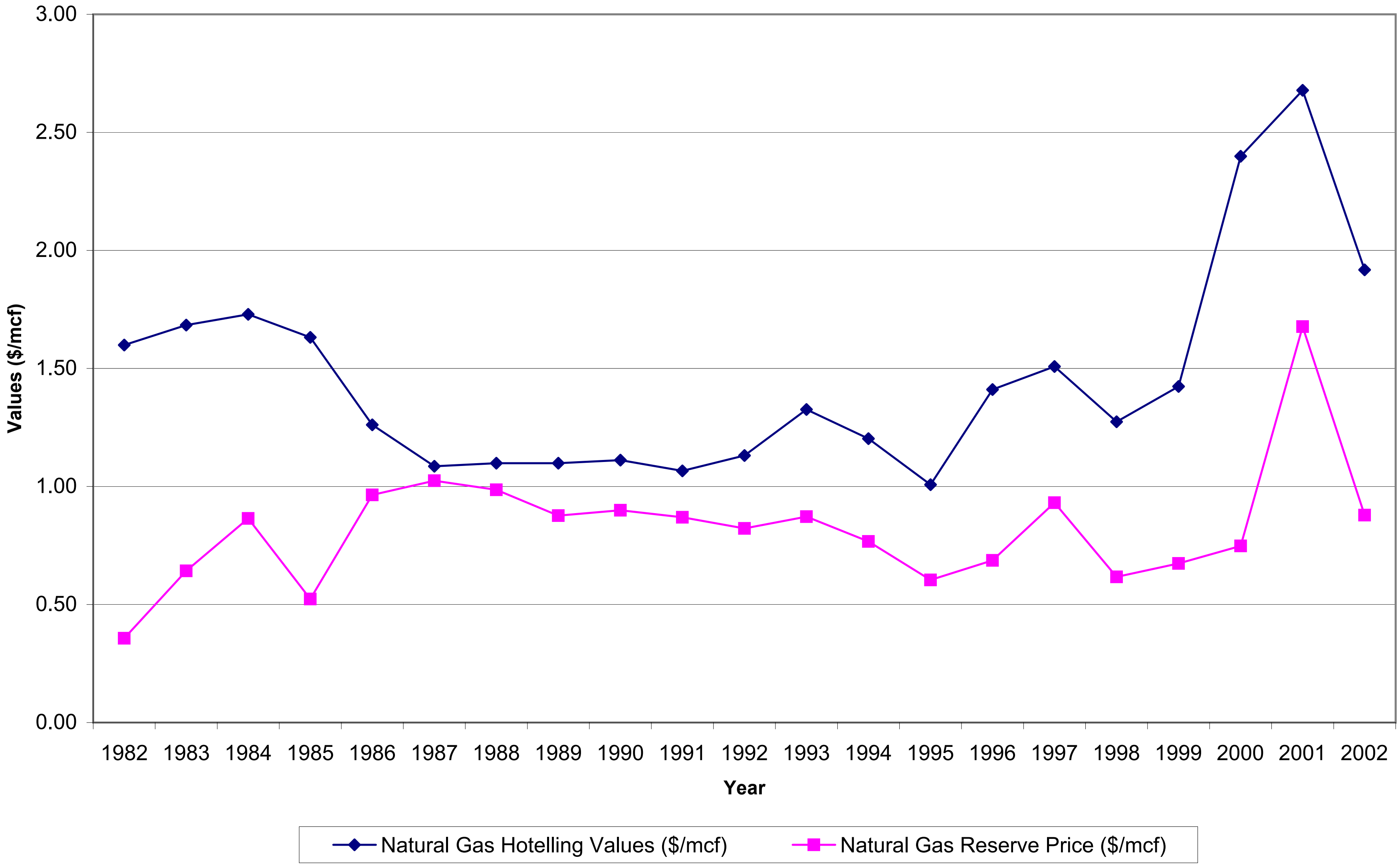


Figure 4: Estimates of Hotelling Values and Price Expectations, Natural Gas



With the exception of one year (1989) the 'pure' gas results (see Table D-4) show the HVs as exceeding the reserve values but the margins are statistically insignificant in ten years. This result mainly reflects the higher standard errors for 'pure' gas transactions compared with the regression coefficients.

2. <u>Oil and Gas Price Expectations</u>

Given information on field prices, production to reserve ratios and the discount rate it is possible to estimate the implicit growth rate in field prices that would be consistent with a given reserve price (Adelman and Watkins [1995, p.669]). Predicated on certain simplifying assumptions, the general expression for the growth rate in prices implicit in the reserve prices is given by:

$$g = i + a\{1- [(p-c)/V]\} \qquad (6)$$

where g = annual growth rate in prices
i = discount rate
a = production / reserve ratio
p = field price
c = extraction cost
V = reserve price.

For oil we need data on a_o, p_o, c_o, V_o; and for gas, a_g, p_g, c_g, V_g. In the case of both a_o and a_g (the production to reserves ratio), we make a refinement to correct for shorter than infinite reservoir life, and write 'a' in general terms as:

$$a = (P/R) - (P/R)^2$$

where P/R = production to reserve ratio.[25]

The values for field prices, p, are taken from the earlier tables (Table C-4); the P/R ratios are of course the inverse of the R/P ratios in Table C-1. The industry discount rate adopted was a nominal rate of twice the long-term bond rate (LTBR), as an approximation to a suitable rate of return on capital. This accommodates an assumed risk

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[25] When production life is infinite, $a = P/R$; see Section I.

premium equivalent to the LTBR. The LTBR itself has a range from about 13.0 percent in 1982 to 4.6 percent in 2002.[26]

The estimated implicit growth rates of field prices embedded in estimates of the value of reserves, V, are listed in column 8 in Tables D-l through D-4 for reserve prices derived from the regression without an intercept, after exclusion of outliers. The results are illustrated in Figure 5a (oil, all transactions), Figure 5b (natural gas, all transactions) and Figure 6 (just the 'pure' transactions).

Striking differences are revealed between oil and gas price expectations. Those for oil mirror perceived conditions in the world oil market. We suggest that the expectation of declining prices for the four years 1982-1985 reflect the weakening market after the price peak of 1981. Expectations of rising prices, 1986 to 1989, reflect anticipated recovery from the price nadir of 1986. Resumption of expected declines in prices, 1990 to 1997, express concern about OPEC discipline, concerns that seemed to end in 1998 and 1999. Anticipated declines in 2000, 2001 and 2002 reflect a supposition of continuing weakness on the OPEC front, in relation to prevailing prices. These trends in expectations also hold in much the same way for the 'pure' oil reserve values (see Table D-2, column 8).

In contrast to oil, price expectations for natural gas are persistently positive, with the main exception of year 2000 (year 2002 is also negative, but the estimated value is a trivial 1 percent). The anticipated sharp decline in gas prices for year 2000 probably reflects the peak price recorded at that time. The 'pure' gas results show much the same pattern as for all transactions (see Table D-4).

This pattern of variation between oil and gas price expectations is consistent with our knowledge of industry assessments and forecasts.

[26]Federal Reserve Board: Ten Year Treasury Rate.
(http://www.federalreserve.gov/releases/h15/data/a/tcm10y.txt).

Figure 5a: Implicit Annual Growth Rates for Oil Prices, All Transactions

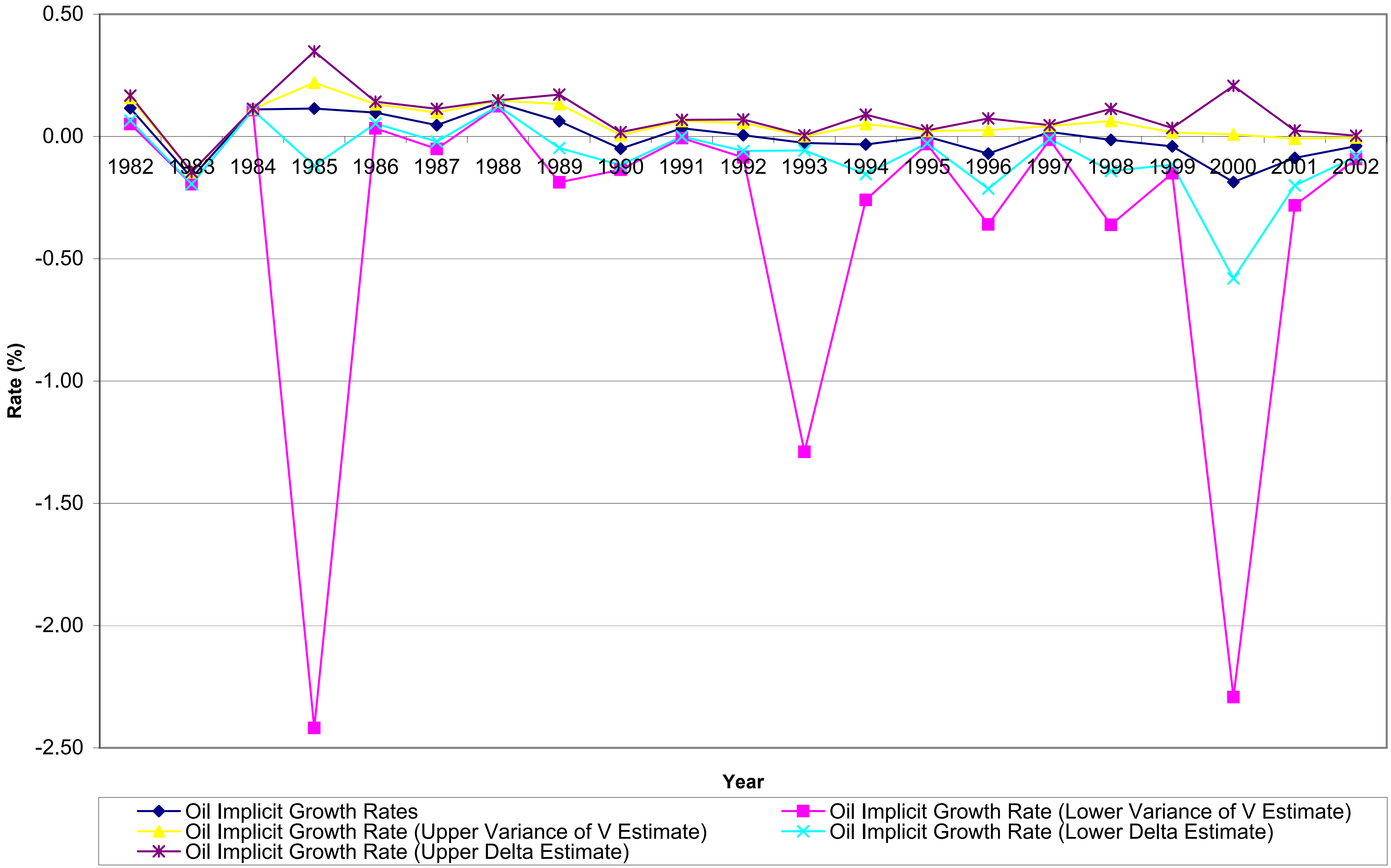


Figure 5b: Implicit Annual Growth Rates for Natural Gas Prices, All Transactions

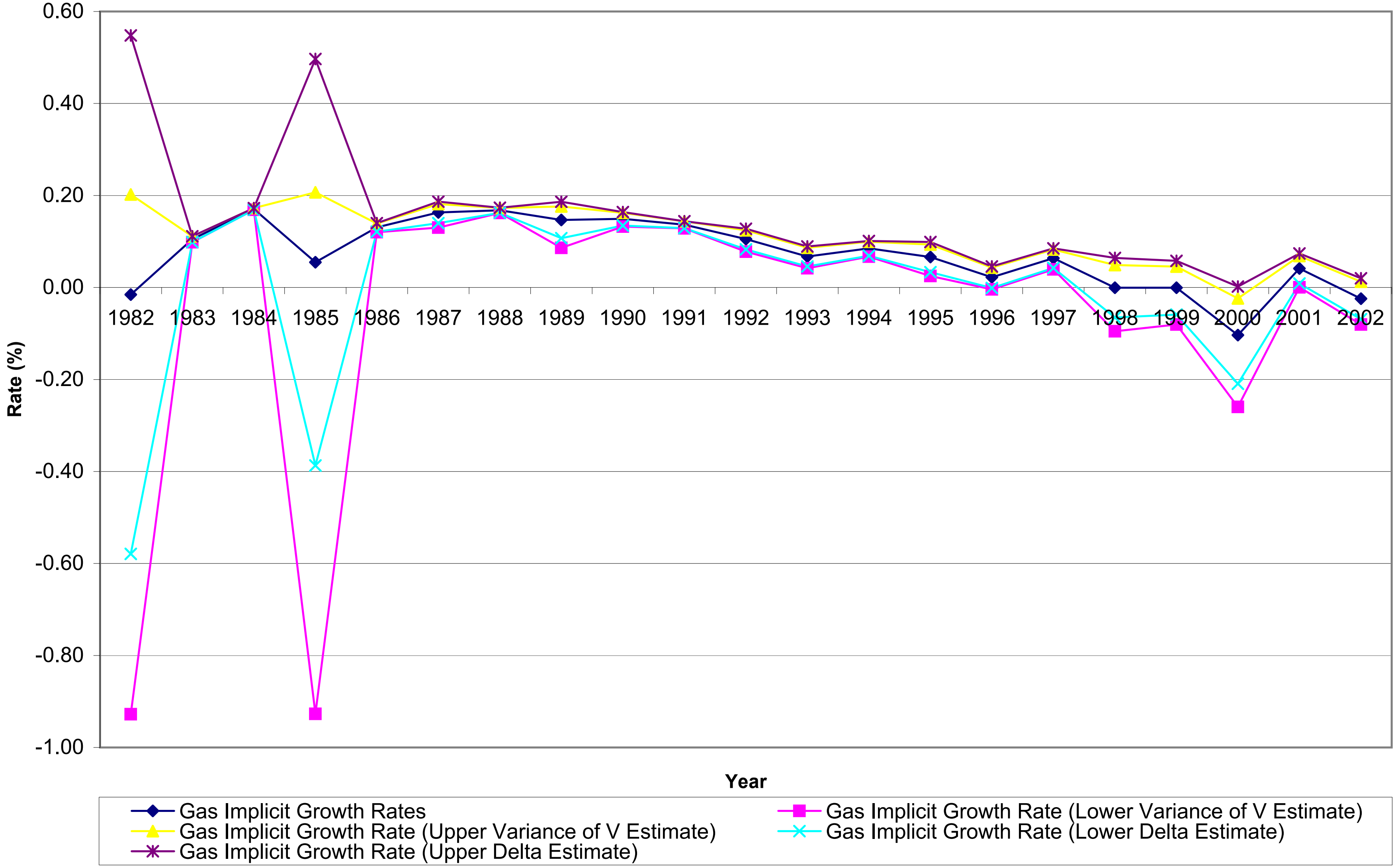
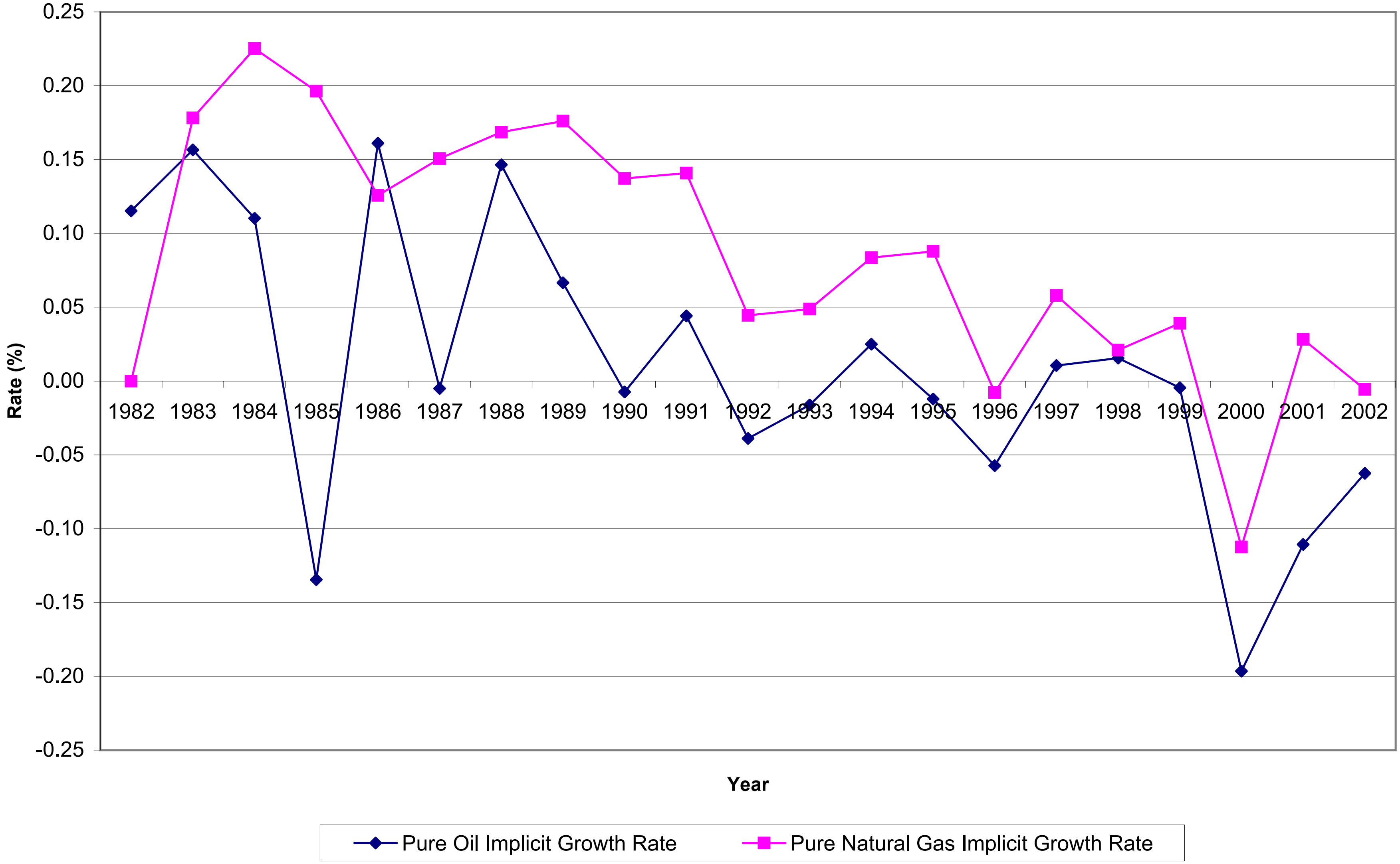


Figure 6: Implicit Annual Growth Rate for Oil and Natural Gas Prices, Pure Transactions



3. <u>Confidence Limits for Price Expectations</u>

What sort of confidence interval might bracket these estimates of implicit growth rates (g)? Sensitivities could be established by using different values for the exogenous variables i, a, p and c. However, we prefer to focus on the statistical variability in V, the reserve price, since we do have an estimate of its variance from the regression analysis. If we assume V does not co-vary with the exogenous variables, upper and lower bounds for g can be calculated numerically as a function of the variance of V.

In the 1996 paper, we took the two standard error spread either side of V and found the corresponding values of g from our formula, conditional on assumed values for i, a, p, and c. We assumed this spread represented the 95 percent confidence interval – (see Adelman and Watkins [1996, p28]), which is reasonable if we interpret g as a mean value, with an associated Normal distribution.

An alternative approach is a Monte Carlo simulation. But there are two problems here. First, we would have to assume all the variables were independent, a questionable assumption – for example consider V and i. Second, we have little information on what kind of distributions might reasonably characterize the relevant variables.

Another approach, one implicit in what we did in 1996, is to argue that variability in p,c,i and a is already embraced by the variability of V, since V essentially is the present value of the expected stream of net revenues from production of the reserve over time. That is, the variability in the components of V contributes to the variability in V itself. The implication is that we can simply look at the variability in V, and treat the other variables on the formula as constant. Hence we could write g as:

$$g = b - d/V \qquad (7)$$

where $b = i + a$

$d = a(p - c)$.

It is tempting to conclude that the variability in V embraces all the variability in its components. However, this is not so. It includes that part of the variability in p, c, a, or i correlated with V. It doesn't include all their inherent variability. The restriction, however, is not damaging because our formula for g is after all derived from the assumption that V is predicated on net present values incorporating p, c, a, and i. Nevertheless, it remains a conditional variance.

As already mentioned, the central limit theorem (CLT) suggests V is normally distributed. Thus there is no limit on the tails of the distribution of V: some of the probability distribution of V will be negative. However, V is essentially positive. Moreover, we have the inverse of the Normal distribution and values of V that are zero would be inadmissible, since they would yield values for g of infinity. In short, we have a restricted domain issue. Also note that quite apart from the sign of V issue, the spread of g values predicted on the confidence limits of V will not be symmetric.

An approach that offers some relief is to employ the 'delta' method.[27] Here, if we designate the number of observations on which V for a given year is based as n, then it can be shown that, in relation to equation (7), the expression $\sqrt{n}(b + d/\tilde{V} - (b + d/V))$ is approximately distributed Normally with mean zero and standard error of $(d/\tilde{V}^2)\sigma_V$ where $\tilde{V}$ is the estimated value of V and σ_V is its standard error.

Using this approach we multiply the standard error of V given by column 5 of our 'D' tables by the product of 'd' divided by V^2 to estimate the standard error (se) of g. The approximate 95 percent confidence interval would be given by the estimated value of g plus and minus two times its standard error calculated as above. If we interpret this as an approximation to the confidence interval for the mean of g, then again the CLT suggests a (symmetric) Normal distribution.

We use both approaches below: our 1996 method predicated on the standard errors of V, and the 'delta' method. Both approximations make a statement about the probability of the mean of g, not about the probability distribution of expected prices. That distribution may not be symmetric at all.

Upper and lower bounds for the implicit growth rates resulting from inserting in equation (6) values of plus and minus two standard errors from the estimated V and those resulting from the delta method are shown in Tables D-5 and D-6 respectively for oil and natural gas.[28] The intervals are also shown in Figures 5a and 5b (for all transactions).

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[27] We are indebted to Adonis Yatchew, University of Toronto, for this suggestion; also see W.Greene Econometric Analysis, Third Edition, 1997, p124.

[28] In the variance of V method, a floor boundary value for V was imposed of 55 cents per barrel and 10 cents per mcf.

a) <u>Variance of V Method</u>

As mentioned earlier, the implicit confidence intervals for g are not symmetric. Indeed the degree of asymmetry is noticeable: the upper confidence interval being much tighter than the lower level, with the spread from the mean usually in single digits, in terms of percentage points. And there is considerable variability among years.

In marked contrast to oil, the confidence intervals for natural gas are generally tight, at 1 to 2 percentage points, and with quite modest variability among years. This result reinforces our conclusion that price expectation behavior between oil and gas is quite different.

b) <u>Delta Method</u>

The spreads between the lower and upper limits are tighter than for the other method, and are symmetric. For oil, the four standard error spreads (difference between lower and upper bounds) vary between close to zero and a peak of 79 percentage points, but in most years the spread is less than 20 percentage points. The results for natural gas confirm the finding under the variance method of much tighter and consistent confidence intervals than for oil; in the great majority of years (16 out of 21), the four standard deviation spread is in the single digit range (percentage points).

It is also possible that the estimates of implicit growth rates in prices include expected cost reductions. But such technological and other improvements are more manifest at the exploration and development stage than at the production stage.

Expression (6) is derived on the assumption that the reserve price is a straightforward function of future net cash flows. Insofar as V includes an option value, the estimates of g, the implicit growth rate, are overstated. We are unable to measure the extent of any such bias. As long as it applies equally to oil and gas reserve values our finding of noticeable differences between oil and gas price expectations remains. We also note that option values are more important for undeveloped than for developed reserves already on production.

4. Mineral Holding Values

A corollary of the Hotelling Principle is that in-ground prices increase, one period over another, at the industry's discount rate. In Table D-7 we compare each year's value of a unit in-ground with the previous year's. The reserve prices in columns 3 and 6 are the regression values in Tables D-1 and D-3. The percentage increase or decrease in columns 4 and 7 measures the return to holding the reserve in the ground an additional year, rather than selling it at the year's price.[29] We subtract from that return the one-year risk-free discount rate, approximated by the one-year US Treasury bill rate, a rate which also reflects expected inflation. The apparent achieved rate premia for oil (column 5) and for gas (column 8) are therefore free of any distortion caused by the time value of money and by expected inflation, and are plotted in Figure 7.

For oil, in 12 out of the 20 years the achieved risk premia are negative, and indeed the mean achieved risk premium is a negative 1.7 percent, to boot. However, there is also a wide dispersion around the mean: its standard error is 8 percentage points. For natural gas, the risk premia are negative in 11 out of 20 years; however, the mean achieved risk premium is positive, at 5.3 percent, but with a high standard error of 9.5 percentage points. These high standard errors of the mean achieved risk premia undermine any precision in statistical testing of hypotheses about them. Instead, we make the simple comparisons below.

Specifically, we compare the achieved risk premia with suitable minimum risk premium for petroleum finding and development activities which the reserve assets represent. Earlier we approximated that risk premium as the LTBR.[30] We term this the required risk premium, and list it in column 9, Table D-7. It has a mean of 7.5 percent and a standard error of 0.5 percent. In the case of oil, this mean compares with a mean achieved risk premium of -1.7 percent, and in only seven of the 20 years does the achieved premium exceed the required level. For natural gas, parallel comparisons show a mean required premium of 7.5 percent and mean achieved levels of 5.3 percent; in just six of the 20 years do achieved premia exceed required premia. Overall, these comparisons offer scant support for the HVP of in-ground values increasing one period over another at the industry's discount rate.

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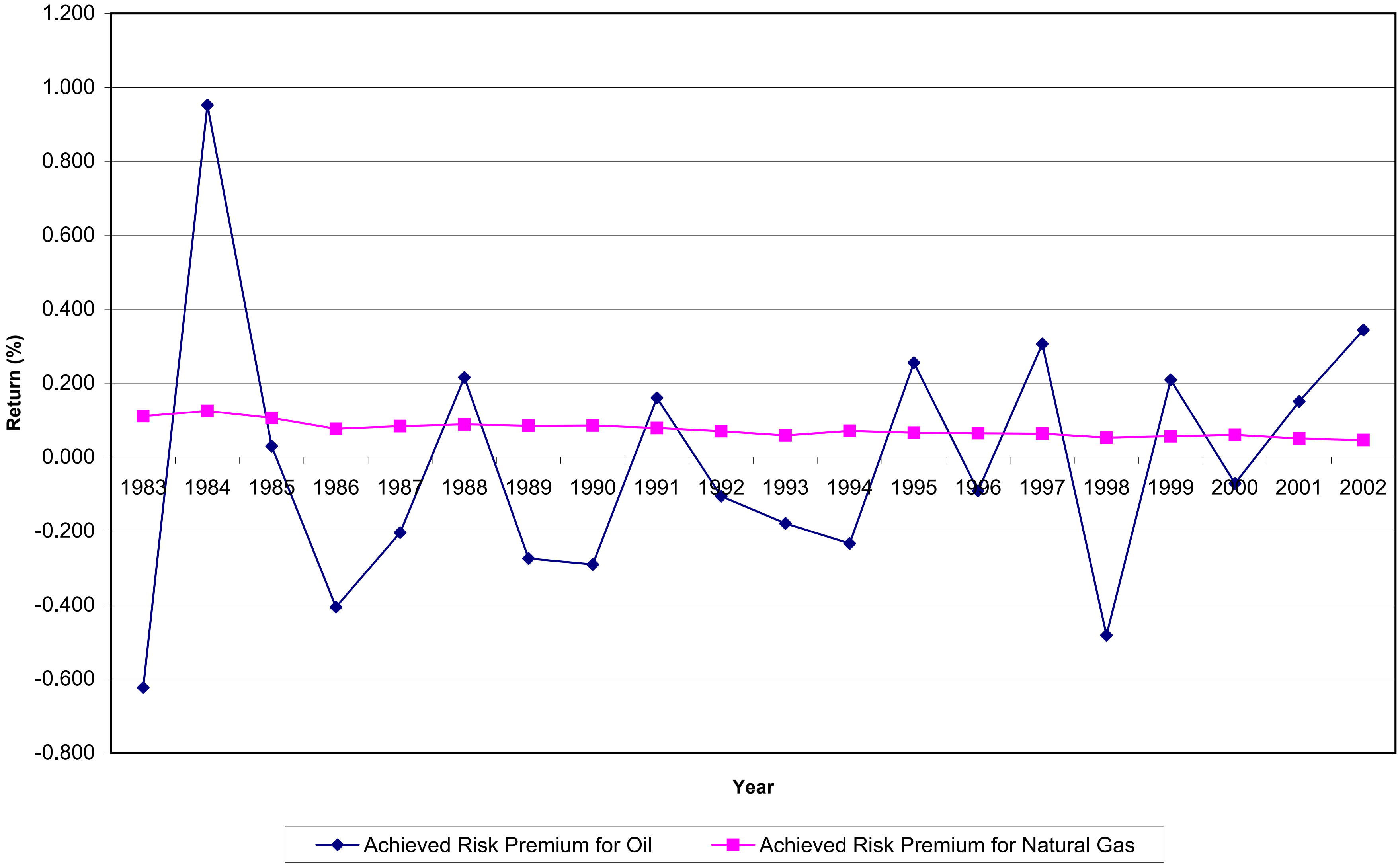
[29] For some results for oil, 1949-1986, see Adelman & Watkins [2003].
[30] See p32 above.

Figure 7: Returns to Holding Oil and Natural Gas Reserves



An operator can substitute for developing a barrel of oil in the USA, a barrel of oil anywhere in the world, and vice versa. (He cannot yet do this to develop natural gas.) Hence the data of Table D-7 permit a simulation, for the worldwide industry of exploration and development. Each year we borrow at the US (one year) riskless rate, to buy a reserve barrel of oil, at the year's price for oil in the ground. We hold it for a year, and then sell at the next year's price. In the 20 trials, we expect irregular fluctuation; such that we would win a few, lose a few. But if original oil in the ground worldwide were fixed, while its consumption continues and even grows, it must shrink over time. Correspondingly, the unit value of what remains in the ground must increase over time. Moreover, given the Hotelling corollary one would expect to earn enough to more than offset the year-to-year risks. But the table shows that even before considering any risk, we lose close to 2 percent per year on average. Any risk allowance will make the losses worse.

It is impossible to reconcile these data for the last 20 years with the belief in a fixed stock, nor in worldwide growing scarcity. But we do not extrapolate and argue that because oil and gas have not become more meager in the past 20 years, supply must always be plentiful. That is more than anyone can know.

V. Value of US Oil and Gas Reserves

Our estimates of reserve prices discussed in Section III can be applied to value US crude oil reserves in recent years. The results are shown in the following Table 1. The private values in the table should be multiplied by some 1.3 to approximate the social values (see below).

Table 1
Estimated Market Values of U.S. Oil and Natural Gas Reserves

	1999	2000	2001
End-of-year proved reserves			
Crude oil (B barrels)	21.8	22	22.4
Natural gas (T cu ft)	167.4	177.4	183.5
Market value per unit in situ			
Crude oil ($/barrel)	3.59	3.55	4.21
Natural gas ($/mcf)	0.67	0.75	1.68
Total market value ($ B)			
Crude oil	78.2	78.1	94.3
Natural gas	112.8	132.7	307.7
Total	191.0	210.9	402.0

		2000 wealth change ($ B)	2001 wealth change ($ B)
Value differences over previous year			
Crude oil	-----	-0.1	+16.2
Natural gas	-----	+19.9	+175.0
Weighted: 1999 prices			
Crude oil	-----	+0.7	+1.4
Natural gas	-----	+6.7	+4.1
Weighted: 2000 prices			
Crude oil	-----	+0.7	+1.4
Natural gas	-----	+7.5	+4.6
Weighted: 2001 prices			
Crude oil	-----	+0.8	+1.7
Natural gas	-----	+16.8	+10.2

The total value in current dollars of developed oil and gas reserves is in the neighborhood of $400 [$520] billion (bracketed figures are social values). Reserve quantities are from EIA publications; in situ values are from Table B-2a, Appendix B; weighted changes apply prices to reserve changes.

a) Excess of Social Over Private Values

There is a downward bias in our estimates. They show the value of the reserve to the private owner, which mainly depends on the price expected to be received, net of expected expenses. As mentioned earlier, the total of these expenses has long been quite constant around 0.35 of the gross field price. Operating costs and royalties payable to land owners (public and private) are each about 0.15 of the price. The 0.05 remainder is non-income taxes. The royalties are not costs but transfer payments, a share of profits. If we assume that half of the taxes are payment for services (police and fire protection, etc.), then about 0.175 of the gross field price is a transfer payment. Hence the true social value of the reserve is probably about 1.27 times, i.e. (0.650+0.175)/0.650, the private value which we record.

Our detailed calculations in Table 1 were aimed at calculating private values. For purposes of national income accounting, we need to add 27 percent. Note here we assume that the field price to cost ratios would hold equally for the in situ values of reserves.

b) U.S. Government Holdings

We can also calculate the approximate value of the U.S. Government interest. Current oil and gas production on Federal offshore and onshore lands is roughly one-fourth of the national totals (API, *Basic Petroleum Data Book*, vol. 23, no. 1, (February 2003, tables IV-6 and XI-18).

The Federal Government receives as royalty 0.155 of the gross field price for production from its lands. As noted above, the net to the owner has long been around 0.65 of the field price. Therefore the Federal interest per barrel is 0.155/0.65 = 0.2385 of the owners' interest. The value to the private owners of all oil and gas reserves was estimated as $402 billion at the end of 2001. The U.S. Government had a share in one-fourth of the reserves, in which portion its interest was worth 0.2385 of an owner's interest. Hence the total value of the Government's oil and gas holdings was $402 x 0.25 x 0.2385 = $24 billion. However, this total makes no allowance for additional income in the form of bonus payments that the Government receives related to the properties from which production is extracted.

Typically such properties attract bonuses through auctions when reserves are at an undeveloped or prospective stage. And the amounts are sizeable. During 1954-2001, bonus payments for permission to drill and explore in Federal waters totaled $61.4 billion, compared with royalties of $67.8 billion. But the ratio has fluctuated enormously. In 1974, bonuses were 9.4 times royalties; in the latest year of available data, bonuses were only a tenth (0.10) of royalties (API, *Basic Petroleum Data Book*, vol. 23, no. 1, Tables IV-6, XI-10). These data do not suggest a convenient yardstick with which to adjust royalties to reflect additional income accruing to the US Government from bonus payments. The implication, nevertheless, is that our estimated value of the US Government oil and gas holdings is appreciably underestimated.

VI. <u>Concluding Remarks</u>

The results of this research paper are of interest in several ways.

Reserve value embraces (net) price forecasts over the life of the reserve. This is because it mainly reflects the net present value of all the production expected. The appraisal is made by a team of engineers, geologists, bankers, economists, and investors. Their forecasts may be wrong, but the values at which reserves change hands merit serious attention.

The difference between the value of existing reserves on production and the cost of finding and developing additional reserves is the governor of investment. The value: cost comparison is a clue to whether oil or gas reserve additions are expected to increase or decrease.

Oil and gas reserve values must be separately calculated. Barrels of "oil equivalent" is an artifact. Our research broadly confirms price and production data, and industry opinion: the oil and gas industries have been on a different track.

Oil reserve values show no visible trend, 1982-2002, sometimes falling, sometimes rising, as they have recently – but to levels in 2002 no higher than those in the mid-1980s. These movements reflect changing perceptions about the world oil market, not the US domestic market. Natural gas reserve prices tended to fall gradually, from 1984 to 1995, as deregulation became pervasive; since then there has been an erratic tendency to rise, indicating nascent tighter supply conditions.

The Hotelling Valuation Principle (HVP) that the developed reserve value is equal to the field price net of extraction costs cannot be reconciled with the reserve values we have estimated. These show net prices averaging more than twice in-ground values, providing evidence more in favor of an old industry rule-of-thumb for reserve valuation, than for the HVP. The Hotelling theory, applied to actual data, does not support the notion of a fixed quantity of oil and gas "out there". Indeed, experience of the last 20 years repudiates the idea of prescribed stock and associated inevitable scarcity. But there is no presumption of perpetual abundance. Oil and gas reserve values will register changing conditions.

The national income needs to be adjusted for reserve accumulation or decumulation. Our measures are based on the premise that reserves are created and consumed like all other capital assets. There is little support for the theory that minerals are somehow unique, and that a unit produced today ineluctably means one less available in the future, except in a very elementary sense. Future reserves will be determined by future technology and costs on the one side, and future demands on the other.

Despite the defects in our estimates of income adjustments, they are more accurate than most other measures, which depend on arbitrary accounting rules to recapture original outlays over some assumed "service life." Our estimates are based on estimated market values. The value of the (developed) mineral holdings of the U.S. Government is in the neighborhood of $24 billion.

We believe our estimates of reserve values could be improved in several ways. First, as always it would be nice to have more reserve transaction observations, and better information to "clean out" non-reserve assets more precisely. Second, there seems to be significant variation in reserve values according to reserve/production ratios, whether reserves are fallow, and so forth. Normalization for these variations would improve the consistency of estimates over time. Third, more data on operating costs would improve estimates of net prices, for comparison with in-ground values. Fourth, we need information on the extent to which reserve values might incorporate option values, 'good will' and the like. Fifth, estimation of unit development costs would enable us to infer finding costs by deduction of development costs from prices of developed reserves.

Measuring the capital costs of newly created reserves is a problem we have barely touched. Depending on the state of knowledge, they could be rising, falling, or stable. So far as we can discern, North American natural gas reserve prices and marginal costs have been relatively stable, at least until recently, while North American oil production has been gradually undermined by its rising costs in the face of quite stable worldwide costs.

Finally, we suggest that less attention be paid to the narrow stage of the Hotelling theatre. More effort should be devoted to estimating aggregate supply functions to see whether they are moving outward with new plays and technology overcoming depletion effects, or inward as depletion effects dominate, or whether there is a saw-off. Reserve prices are useful leading indicators of shifts in supply functions.

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Appendix A:

Transaction Data

Table A-1: Number of Identified Transactions

1	2	3	4	5	6	7	8	9	10
		All Inclusive			*Number of Outliers*			*Excluding Outliers*	
Year	*All Types*	*Pure Oil*	*Pure Gas*	*All Types*	*Pure Oil*	*Pure Gas*	*All Types*	*Pure Oil*	*Pure Gas*
All Years	1563	341	416	107	33	29	1456	308	387
1982	14	1	0	1	0	0	13	1	0
1983	22	2	1	1	0	0	21	2	1
1984	34	8	1	3	1	0	31	7	1
1985	35	5	4	1	0	0	34	5	4
1986	27	3	3	2	0	0	25	3	3
1987	51	12	5	2	2	0	49	10	5
1988	66	14	9	2	1	0	64	13	9
1989	104	19	18	5	1	0	99	18	18
1990	160	38	29	9	3	2	151	35	27
1991	101	20	18	7	1	0	94	19	18
1992	92	20	20	6	2	2	86	18	18
1993	122	28	28	7	1	2	115	27	26
1994	98	17	33	6	2	2	92	15	31
1995	124	35	33	10	5	2	114	30	31
1996	100	31	31	6	1	2	94	30	29
1997	72	16	27	5	3	1	67	13	26
1998	91	19	45	8	3	3	83	16	42
1999	62	13	26	5	1	2	57	12	24
2000	70	15	28	4	1	2	66	14	26
2001	61	11	21	9	2	5	52	9	16
2002	57	14	36	8	3	4	49	11	32

Outliers are defined as follows:

For pure transactions, a reserve price more than two standard deviations for that year.
For mixed transactions, a transaction value more than two standard deviations away from the fitted value.
Transactions of value less than \$0.55 per barrel or \$0.10 per mcf, or greater than \$27.50 per barrel or \$5 per mcf.

Source: The Scotia Group M&A Database, January 2003

Table A-2: Summary Statistics for Transaction Values, All Transactions
[Millions of Nominal $, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	101.5	287.4	14.9	2.74	4.89	30.87	---	1563
1982	480.4	1569.7	38.0	3.27	3.32	12.04	Not Rejected	14
1983	103.7	224.3	14.4	2.16	2.37	7.13	Not Rejected	22
1984	979.0	2918.8	39.2	2.98	3.32	12.93	Not Rejected	34
1985	232.5	913.1	17.4	3.93	5.41	31.07	Not Rejected	35
1986	133.7	243.6	10.5	1.82	1.99	5.98	Not Rejected	27
1987	36.9	100.4	7.0	2.72	4.89	28.99	Not Rejected	51
1988	95.4	343.2	7.2	3.60	6.22	44.65	Not Rejected	66
1989	40.8	106.5	8.1	2.61	5.51	38.79	Not Rejected	104
1990	30.3	80.3	5.6	2.65	4.77	29.41	Not Rejected	160
1991	29.1	85.2	5.0	2.92	4.71	25.56	Not Rejected	101
1992	39.7	134.6	5.2	3.39	6.92	56.16	Not Rejected	92
1993	37.9	115.7	7.0	3.06	6.81	56.70	Not Rejected	122
1994	38.8	90.6	9.7	2.33	4.02	20.01	Not Rejected	98
1995	32.8	74.5	8.3	2.27	4.09	21.61	Not Rejected	124
1996	35.5	93.8	11.0	2.64	5.88	41.81	Not Rejected	100
1997	120.1	238.2	26.4	1.98	4.22	24.18	Not Rejected	72
1998	114.0	494.6	17.0	4.34	6.41	42.60	Not Rejected	91
1999	35.0	54.8	14.5	1.57	2.65	9.38	Not Rejected	62
2000	216.2	600.3	23.9	2.78	4.73	25.84	Not Rejected	70
2001	298.7	721.9	53.5	2.42	3.45	14.78	Not Rejected	61
2002	178.4	326.1	62.0	1.83	2.97	11.89	Not Rejected	57

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-3: Summary Statistics for Transaction Values, Excluding Outliers
[Millions of Nominal $, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	46.8	91.0	13.6	1.73	2.89	12.53	---	1456
1982	61.2	63.2	32.0	1.03	0.76	1.90	Not Rejected	13
1983	74.5	182.2	13.8	2.45	3.20	12.48	Not Rejected	21
1984	320.2	1047.2	33.7	3.27	4.66	24.10	Not Rejected	31
1985	80.5	161.2	16.8	2.00	2.97	11.02	Not Rejected	34
1986	78.2	143.2	10.1	1.83	1.86	4.89	Not Rejected	25
1987	19.8	35.8	6.0	1.81	2.81	10.23	Not Rejected	49
1988	56.3	142.9	6.7	2.54	3.66	15.73	Not Rejected	64
1989	28.3	59.7	8.0	2.11	4.99	34.37	Not Rejected	99
1990	16.8	32.3	5.0	1.93	3.12	12.33	Not Rejected	151
1991	13.5	22.6	5.0	1.67	2.82	11.39	Not Rejected	94
1992	19.0	33.6	4.4	1.77	2.85	11.85	Not Rejected	86
1993	20.4	31.8	7.0	1.56	2.77	11.32	Not Rejected	115
1994	20.0	29.6	8.2	1.48	2.59	9.95	Not Rejected	92
1995	19.1	31.2	8.0	1.64	2.89	11.29	Not Rejected	114
1996	20.7	28.2	10.5	1.36	2.90	13.11	Not Rejected	94
1997	85.5	120.8	25.1	1.41	1.72	5.39	Not Rejected	67
1998	42.3	55.5	17.0	1.31	1.82	5.63	Not Rejected	83
1999	22.4	24.0	13.7	1.07	1.61	5.16	Not Rejected	57
2000	116.0	209.3	22.0	1.80	2.42	8.05	Not Rejected	66
2001	127.2	234.2	46.4	1.84	3.58	18.11	Not Rejected	52
2002	106.7	141.9	60.0	1.33	2.63	10.44	Not Rejected	49

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-4: Summary Statistics for Pure Oil Transaction Values, Excluding Outliers
[Millions of Nominal $, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
1982	159.3	---	159.3	---	---	---	---	1
1983	14.0	17.6	14.0	1.26	0.00	1.00	Not Rejected	2
1984	263.4	633.7	18.7	2.41	2.04	5.16	Not Rejected	7
1985	8.3	10.4	4.2	1.25	1.34	3.01	Not Rejected	5
1986	32.9	43.9	15.0	1.33	0.62	1.50	Not Rejected	3
1987	4.2	6.6	1.7	1.56	2.43	7.34	Not Rejected	10
1988	79.6	189.3	2.9	2.38	2.48	7.80	Not Rejected	13
1989	21.3	47.5	3.5	2.23	3.15	12.06	Not Rejected	18
1990	10.1	27.6	1.3	2.72	4.72	25.64	Not Rejected	35
1991	14.6	24.1	2.9	1.65	1.70	4.19	Not Rejected	19
1992	12.3	28.4	2.4	2.30	2.95	10.56	Not Rejected	18
1993	13.8	15.1	7.8	1.09	1.55	4.89	Not Rejected	27
1994	19.7	29.7	6.2	1.51	2.00	6.07	Not Rejected	15
1995	18.4	39.4	2.6	2.14	2.95	10.61	Not Rejected	30
1996	19.5	33.5	8.7	1.72	3.44	15.44	Not Rejected	30
1997	93.2	122.0	18.7	1.31	1.08	2.46	Not Rejected	13
1998	48.9	51.4	36.3	1.05	1.46	4.78	Not Rejected	16
1999	15.1	21.4	7.5	1.42	1.79	4.71	Not Rejected	12
2000	57.5	106.6	11.6	1.85	2.32	7.51	Not Rejected	14
2001	21.3	35.0	4.0	1.64	1.62	4.19	Not Rejected	9
2002	157.0	213.3	58.0	1.36	1.98	5.94	Not Rejected	11

--- Insufficient data points.

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-5: Summary Statistics for Pure Natural Gas Transaction Values, Excluding Outliers
[Millions of Nominal $, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
1982	---	---	---	---	---	---	---	0
1983	7.5	---	7.5	---	---	---	---	1
1984	294.0	---	294.0	---	---	---	---	1
1985	72.0	54.9	64.8	0.76	0.43	1.97	Not Rejected	4
1986	137.6	231.6	4.3	1.68	0.71	1.50	Not Rejected	3
1987	9.2	7.9	7.3	0.86	1.10	2.77	Not Rejected	5
1988	83.1	237.0	3.2	2.85	2.47	7.12	Not Rejected	9
1989	25.0	40.8	5.7	1.63	2.22	6.74	Not Rejected	18
1990	18.1	31.1	4.3	1.72	2.25	7.01	Not Rejected	27
1991	26.5	38.5	9.4	1.45	1.57	3.97	Not Rejected	18
1992	9.5	14.5	3.1	1.52	2.02	6.46	Not Rejected	18
1993	28.2	41.1	6.6	1.38	2.08	7.12	Not Rejected	26
1994	20.3	34.1	7.4	1.68	2.82	11.00	Not Rejected	31
1995	24.9	31.2	11.4	1.25	1.94	5.80	Not Rejected	31
1996	24.5	29.8	12.1	1.22	2.20	7.34	Not Rejected	29
1997	58.6	95.3	22.6	1.55	2.26	6.80	Not Rejected	26
1998	42.5	49.8	19.8	1.17	1.71	5.55	Not Rejected	42
1999	26.6	26.7	18.2	1.35	1.34	4.25	Not Rejected	24
2000	146.8	227.6	44.3	1.55	2.11	6.55	Not Rejected	26
2001	130.7	220.9	36.4	1.69	1.87	5.17	Not Rejected	16
2002	92.5	123.0	56.8	1.33	2.18	7.21	Not Rejected	32

--- Insufficient data points.

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-6: Summary Statistics for Size of Oil Reserves, All Transactions
[Millions of Barrels, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	9.8	38.0	0.4	3.40	5.49	38.76	---	1563
1982	53.3	181.7	1.7	3.41	3.32	12.04	Not Rejected	14
1983	12.8	28.8	0.8	2.25	2.24	6.54	Not Rejected	22
1984	137.3	477.7	2.0	3.48	3.66	14.69	Rejected	34
1985	24.2	115.6	0.6	4.78	5.54	32.14	Not Rejected	35
1986	7.4	16.5	0.4	2.22	2.96	11.55	Not Rejected	27
1987	4.7	16.8	0.5	3.62	4.85	25.69	Not Rejected	51
1988	5.7	18.6	0.6	3.27	4.92	27.53	Not Rejected	66
1989	2.2	4.4	0.5	2.02	4.00	22.74	Not Rejected	104
1990	3.1	13.9	0.3	4.47	7.68	68.52	Not Rejected	160
1991	2.2	7.5	0.2	3.44	6.18	46.48	Not Rejected	101
1992	3.7	12.1	0.4	3.25	5.49	35.73	Not Rejected	92
1993	2.1	4.5	0.4	2.07	3.91	21.96	Not Rejected	122
1994	3.6	10.8	0.3	3.00	5.20	33.14	Not Rejected	98
1995	3.8	16.1	0.3	4.17	8.37	81.30	Not Rejected	124
1996	3.1	6.9	0.3	2.26	3.36	14.22	Not Rejected	100
1997	12.8	47.4	0.8	3.70	6.96	54.47	Not Rejected	72
1998	20.6	118.7	0.0	5.76	7.10	54.08	Not Rejected	91
1999	1.9	5.3	0.3	2.86	5.20	33.12	Not Rejected	62
2000	22.2	111.2	0.3	5.02	6.54	46.88	Not Rejected	70
2001	5.8	13.4	0.3	2.31	4.08	22.07	Not Rejected	61
2002	9.3	24.2	0.0	2.61	3.65	16.56	Not Rejected	57

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-7: Summary Statistics for Size of Natural Gas Reserves, All Transactions
[BCFs, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	58.3	159.0	7.6	2.69	4.70	29.91	---	1563
1982	178.3	564.7	9.9	3.17	3.27	11.82	Not Rejected	14
1983	59.9	181.0	3.6	3.02	3.78	16.34	Not Rejected	22
1984	414.1	1259.9	13.8	3.04	3.29	12.63	Not Rejected	34
1985	109.3	366.9	10.8	5.26	5.04	27.95	Not Rejected	35
1986	111.0	229.3	7.0	2.07	2.35	7.55	Not Rejected	27
1987	14.4	24.0	4.9	1.67	2.22	7.11	Not Rejected	51
1988	57.5	220.8	3.6	3.84	5.94	40.41	Not Rejected	66
1989	30.3	72.9	7.8	2.41	4.85	29.51	Not Rejected	104
1990	23.3	80.5	3.2	3.45	7.57	68.64	Not Rejected	160
1991	19.9	55.1	2.7	2.76	4.24	21.12	Not Rejected	101
1992	26.7	94.5	4.0	3.54	6.09	40.45	Not Rejected	92
1993	26.9	63.5	3.9	2.36	3.85	19.30	Not Rejected	122
1994	23.3	49.2	4.7	2.11	3.37	14.50	Not Rejected	98
1995	24.5	55.0	3.5	2.24	3.49	15.87	Not Rejected	124
1996	24.6	54.8	4.9	2.23	5.42	40.05	Rejected	100
1997	71.1	154.1	11.1	2.17	4.20	24.31	Not Rejected	72
1998	57.3	180.4	11.9	3.15	7.32	62.11	Rejected	91
1999	32.7	54.6	11.1	1.67	2.58	9.53	Not Rejected	62
2000	141.4	349.1	15.5	2.47	4.31	24.39	Not Rejected	70
2001	184.4	501.8	19.6	2.72	3.55	14.62	Not Rejected	61
2002	104.9	234.8	26.1	2.24	4.18	23.45	Not Rejected	57

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-8: Summary Statistics for Transaction Size in Thermal Equivalence, All Transactions
[Trillion BTUs, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	112.5	323.7	17.8	2.55	4.74	29.27	---	1563
1982	471.4	1562.3	27.0	3.31	3.31	12.01	Not Rejected	14
1983	130.5	305.8	11.5	2.34	2.72	9.63	Not Rejected	22
1984	1169.4	3746.3	28.6	3.20	3.50	14.06	Not Rejected	34
1985	242.3	998.4	18.0	4.12	5.41	31.05	Not Rejected	35
1986	151.8	291.3	11.0	1.92	2.26	7.27	Not Rejected	27
1987	39.9	95.0	9.4	2.38	4.12	20.55	Not Rejected	51
1988	88.8	288.2	10.7	3.25	5.71	38.84	Not Rejected	66
1989	42.4	83.2	13.3	1.96	4.24	24.40	Not Rejected	104
1990	40.4	119.9	8.1	2.97	5.55	37.44	Not Rejected	160
1991	31.9	88.8	5.7	2.78	5.01	29.96	Not Rejected	101
1992	47.1	144.4	8.1	3.07	6.23	45.98	Not Rejected	92
1993	38.7	79.1	11.6	2.04	3.94	19.44	Not Rejected	122
1994	43.2	89.3	13.3	2.07	4.45	27.45	Not Rejected	98
1995	45.7	103.8	10.6	2.27	5.33	39.92	Not Rejected	124
1996	41.4	78.4	17.5	1.89	5.57	41.67	Not Rejected	100
1997	141.6	315.5	31.4	2.23	4.80	27.92	Not Rejected	72
1998	170.6	747.5	24.0	4.38	6.43	43.14	Not Rejected	91
1999	42.9	58.2	21.1	1.36	2.20	7.30	Not Rejected	62
2000	263.3	778.9	31.5	2.96	4.93	27.34	Not Rejected	70
2001	216.2	507.0	42.8	2.34	3.33	13.30	Not Rejected	61
2002	155.9	250.0	66.0	1.60	3.27	16.21	Not Rejected	57

Trillion BTUs: 1 Trillion BTUs = 1 Billion Cubic Feet at 1,000 BTUs per cubic foot (TBTUs)
Thermal equivalence factor of 5.5 million BTUs per barrel used.

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Table A-9: Summary Statistics for Transaction Size in Thermal Equivalence, Excluding Outliers
[Trillion BTUs, where relevant]

1	2	3	4	5	6	7	8	9
Year	*Mean*	*Std. Dev.*	*Median*	*Coeff. Of Variation*	*Skewness*	*Kurtosis*	*Log Normality*	*# Obs.*
All Years	52.5	99.1	16.5	1.66	2.87	12.58	---	1456
1982	54.4	84.9	26.3	1.56	2.35	7.64	Not Rejected	13
1983	107.3	293.0	9.7	2.73	3.26	12.65	Not Rejected	21
1984	298.6	1060.8	28.5	3.55	4.87	25.87	Not Rejected	31
1985	76.1	177.1	17.3	2.33	4.11	20.45	Not Rejected	34
1986	81.9	148.9	10.8	1.82	1.87	4.94	Not Rejected	25
1987	22.5	34.6	8.1	1.54	2.29	7.13	Not Rejected	49
1988	57.9	139.8	9.8	2.41	3.66	15.84	Not Rejected	64
1989	33.8	60.0	12.5	1.78	4.32	27.64	Not Rejected	99
1990	20.9	39.7	7.3	1.89	3.65	18.07	Not Rejected	151
1991	16.2	25.6	5.5	1.58	2.72	10.99	Not Rejected	94
1992	24.6	39.3	7.4	1.59	2.55	9.60	Not Rejected	86
1993	25.8	36.3	11.0	1.41	2.36	8.75	Not Rejected	115
1994	28.3	42.1	12.6	1.49	2.47	8.72	Not Rejected	92
1995	28.6	47.8	10.2	1.67	2.94	11.96	Rejected	114
1996	30.9	36.3	17.1	1.17	1.92	6.41	Not Rejected	94
1997	94.4	121.5	30.0	1.29	1.70	5.90	Not Rejected	67
1998	61.0	87.5	23.8	1.43	2.61	11.00	Not Rejected	83
1999	31.0	34.1	21.0	1.10	1.89	6.48	Not Rejected	57
2000	137.5	243.7	23.9	1.77	2.71	10.57	Not Rejected	66
2001	99.7	165.9	44.8	1.66	4.00	22.68	Not Rejected	52
2002	110.9	144.8	59.9	1.31	2.04	6.52	Not Rejected	49

Trillion BTUs: 1 Trillion BTUs = 1 Billion Cubic Feet at 1,000 BTUs per cubic foot (TBTUs)
Thermal equivalence factor of 5.5 million BTUs per barrel used.

The normality test used is Jarque-Bera; reject indicates that normality of the log distribution was rejected at 95% confidence level.

Source: The Scotia Group M&A Database, January 2003

Appendix B:
Estimates of Reserve Prices

Table B-1a: Regression Results for All Transactions (No Constant)

1	2	3	4	5	6	7
Year	*# Obs*	*Oil Coeff ($/bbl)*	*t-stat*	*Gas Coeff ($/mcf)*	*t-stat*	*Adjusted R^2*
1982	14	7.59	11.03	0.35	1.58	0.99
1983	22	4.35	6.89	0.65	6.19	0.92
1984	34	3.71	31.85	1.02	23.36	0.99
1985	35	5.62	12.72	0.73	5.38	0.99
1986	27	2.12	3.26	0.97	21.16	0.97
1987	51	5.60	27.45	0.94	7.38	0.94
1988	66	6.07	22.13	1.20	51.47	0.99
1989	104	4.60	5.38	1.21	22.58	0.88
1990	160	4.18	21.33	0.48	14.49	0.84
1991	101	3.35	11.18	1.16	28.97	0.97
1992	92	6.34	28.07	0.75	25.82	0.98
1993	122	2.60	2.26	1.49	18.08	0.83
1994	98	5.59	13.28	0.74	8.36	0.81
1995	124	3.16	24.01	0.88	24.44	0.91
1996	100	6.98	14.71	0.95	15.92	0.90
1997	72	2.88	19.48	1.13	26.45	0.95
1998	91	3.53	100.81	0.76	34.03	0.99
1999	62	4.97	13.38	0.86	26.30	0.94
2000	70	4.21	30.18	0.75	17.90	0.96
2001	61	5.63	5.41	1.42	49.83	0.98
2002	57	6.49	10.92	1.21	20.15	0.90

Note: Transaction values are regressed on reserves of oil (in bbls) and natural gas (in mcf).

Source: The Scotia Group M&A Database, January 2003

Table B-1b: Regression Results for All Transactions (Constant Included)

1	2	3	4	5	6	7	8	9
Year	*# Obs*	*Constant*	*t-stat*	*Oil Coeff ($/bbl)*	*t-stat*	*Gas Coeff ($/mcf)*	*t-stat*	*Adjusted R^2*
1982	14	16.54	1.36	7.79	11.44	0.28	1.26	0.99
1983	22	10.91	0.67	4.22	6.33	0.64	6.05	0.91
1984	34	53.79	1.76	3.70	32.83	1.01	23.55	0.99
1985	35	21.18	1.86	5.96	12.85	0.61	4.21	0.99
1986	27	12.79	1.31	1.96	3.01	0.96	20.48	0.97
1987	51	-3.70	-0.87	5.64	26.77	1.00	6.79	0.94
1988	66	-9.20	-2.05	6.17	22.65	1.21	52.64	0.99
1989	104	-8.15	-1.85	5.17	5.75	1.24	22.59	0.87
1990	160	6.82	2.42	4.10	20.94	0.46	13.68	0.82
1991	101	-1.42	-0.82	3.37	11.19	1.16	28.45	0.96
1992	92	-4.29	-1.87	6.41	28.38	0.76	26.21	0.98
1993	122	-9.92	-1.96	3.23	2.73	1.52	18.35	0.82
1994	98	1.76	0.36	5.57	12.99	0.73	7.69	0.77
1995	124	-1.24	-0.51	3.18	23.48	0.89	22.53	0.90
1996	100	-11.88	-3.60	7.41	15.99	1.01	17.21	0.90
1997	72	3.25	0.41	2.87	18.88	1.13	24.04	0.94
1998	91	-2.37	-0.60	3.53	100.39	0.76	32.92	0.99
1999	62	-3.73	-1.46	5.17	13.15	0.89	23.31	0.91
2000	70	19.49	1.21	4.20	30.05	0.73	16.48	0.96
2001	61	6.45	0.37	5.47	4.83	1.41	46.70	0.97
2002	57	-11.82	-0.65	6.65	10.25	1.23	18.30	0.87

Note: Transaction values are regressed on reserves of oil (in bbls) and natural gas (in mcf).

Source: The Scotia Group M&A Database, January 2003

Table B-1c: Comparisons of Oil Regression Values with Pure Oil Values for All Transactions (No Constant)

1	2	3	4	5	6
Year	*Oil Coefficient ($/bbl)*	*# Obs*	*Weighted ppb from Pure Oil Transactions ($/bbl)*	*# Obs*	*Ratio of Estimated Oil Coefficient to Pure Transaction ppb*
1982	7.59	14	7.11	1	1.07
1983	4.35	22	10.15	2	0.43
1984	3.71	34	6.93	8	0.53
1985	5.62	35	3.39	5	1.66
1986	2.12	27	8.86	3	0.24
1987	5.60	51	5.27	12	1.06
1988	6.07	66	6.44	14	0.94
1989	4.60	104	4.72	19	0.97
1990	4.18	160	4.50	38	0.93
1991	3.35	101	4.69	20	0.71
1992	6.34	92	4.75	20	1.34
1993	2.60	122	3.90	28	0.67
1994	5.59	98	7.70	17	0.73
1995	3.16	124	3.36	35	0.94
1996	6.98	100	5.36	31	1.30
1997	2.88	72	3.67	16	0.79
1998	3.53	91	3.40	19	1.04
1999	4.97	62	4.23	13	1.18
2000	4.21	70	4.07	15	1.04
2001	5.63	61	4.09	11	1.38
2002	6.49	57	5.52	14	1.18

Source: The Scotia Group M&A Database, January 2003

Note: The pure oil value observations are weighted volumetrically by the barrels in each transaction for a given year. This is equivalent to summing the value of all pure transactions in a given year and dividing by the total volumes of oil reserves sold.

Table B-1d: Comparisons of Natural Gas Regression Values with Pure Gas Values for All Transactions (No Constant)

1	2	3	4	5	6
Year	*Gas Coefficient ($/mcf)*	*# Obs*	*Weighted ppmcf from Pure Gas Transactions ($/mcf)*	*# Obs*	*Ratio of Estimated Gas Coefficient to Pure Transaction ppmcf*
1982	0.35	14	---	0	---
1983	0.65	22	1.05	1	0.62
1984	1.02	34	1.32	1	0.77
1985	0.73	35	1.34	4	0.55
1986	0.97	27	0.92	3	1.06
1987	0.94	51	0.89	5	1.05
1988	1.20	66	1.00	9	1.21
1989	1.21	104	1.18	18	1.03
1990	0.48	160	0.83	29	0.58
1991	1.16	101	0.90	18	1.28
1992	0.75	92	0.66	20	1.14
1993	1.49	122	0.73	28	2.04
1994	0.74	98	0.88	33	0.84
1995	0.88	124	0.75	33	1.18
1996	0.95	100	0.63	31	1.51
1997	1.13	72	0.93	27	1.22
1998	0.76	91	0.69	45	1.09
1999	0.86	62	0.85	26	1.02
2000	0.75	70	0.79	28	0.95
2001	1.42	61	1.43	21	0.99
2002	1.21	57	1.13	36	1.07

--- Insufficient data points.

Source: The Scotia Group M&A Database, January 2003

Note: The pure gas value observations are weighted volumetrically by the cubic feet in each transaction for a given year. This is equivalent to summing the value of all pure transactions in a given year and dividing by the total volumes of gas reserves sold.

Table B-2a: Regression Results for All Transactions (No Constant), Excluding Outliers
(with Robust Standard Errors, rather than OLS Standard Errors)

1	2	3	4	5	6	7
Year	*# Obs*	*Oil Coeff ($/bbl)*	*t-stat*	*Gas Coeff ($/mcf)*	*t-stat*	*Adjusted R^2*
1982	13	7.13	9.18	0.36	1.26	0.76
1983	21	3.37	39.87	0.64	58.92	0.99
1984	31	6.95	177.40	0.86	173.62	0.90
1985	34	7.74	1.66	0.52	1.05	0.89
1986	25	5.10	6.66	0.96	20.63	0.99
1987	49	4.40	6.48	1.02	6.96	0.92
1988	64	5.69	22.87	0.99	32.97	0.98
1989	99	4.61	3.56	0.88	5.75	0.82
1990	151	3.64	9.07	0.90	15.61	0.94
1991	94	4.44	12.36	0.87	29.63	0.96
1992	86	4.14	6.95	0.82	11.43	0.89
1993	115	3.54	15.00	0.87	13.45	0.94
1994	92	2.90	4.32	0.77	19.58	0.91
1995	114	3.81	16.85	0.60	9.93	0.95
1996	94	3.67	3.98	0.69	17.76	0.86
1997	67	5.01	14.24	0.93	15.52	0.92
1998	83	2.85	3.15	0.62	6.33	0.81
1999	57	3.59	6.31	0.67	7.39	0.88
2000	66	3.55	1.96	0.75	6.17	0.74
2001	52	4.21	4.76	1.68	9.71	0.95
2002	49	5.74	10.20	0.88	9.69	0.95

Source: The Scotia Group M&A Database, January 2003

Table B-2b: Regression Results for All Transactions (Constant Included), Excluding Outliers (with Robust Standard Errors, rather than OLS Standard Errors)

1 *Year*	2 *# Obs*	3 *Constant*	4 *t-stat*	5 *Oil Coeff ($/bbl)*	6 *t-stat*	7 *Gas Coeff ($/mcf)*	8 *t-stat*	9 *Adjusted R^2*
1982	13	26.09	1.99	5.71	4.57	0.28	1.32	0.65
1983	21	8.37	2.84	3.28	55.43	0.64	75.33	0.99
1984	31	16.29	2.80	6.88	157.34	0.86	227.36	0.90
1985	34	21.87	2.13	8.22	1.85	0.39	0.77	0.88
1986	25	0.33	0.11	5.09	6.91	0.96	18.74	0.98
1987	49	-2.29	-2.11	4.61	6.05	1.05	6.69	0.90
1988	64	-2.36	-1.22	5.72	23.13	0.99	35.14	0.98
1989	99	-1.13	-0.40	4.69	3.42	0.88	5.40	0.77
1990	151	-0.25	-0.46	3.65	8.84	0.90	14.80	0.92
1991	94	-0.30	-0.76	4.47	11.85	0.87	31.11	0.95
1992	86	-0.70	-0.53	4.17	6.77	0.83	11.36	0.86
1993	115	-0.20	-0.34	3.56	14.60	0.87	12.86	0.92
1994	92	1.49	1.69	2.82	4.12	0.75	18.20	0.87
1995	114	1.17	1.40	3.76	15.86	0.59	9.03	0.93
1996	94	-0.46	-0.33	3.71	3.65	0.69	16.38	0.78
1997	67	-2.70	-0.91	5.08	14.78	0.94	16.34	0.89
1998	83	9.76	2.68	2.54	2.86	0.57	5.65	0.72
1999	57	3.12	1.43	3.24	4.48	0.63	5.58	0.79
2000	66	21.40	2.16	3.17	1.81	0.71	5.85	0.67
2001	52	-10.25	-2.16	4.32	4.88	1.71	10.02	0.94
2002	49	3.82	0.63	5.67	9.18	0.86	8.11	0.92

Source: The Scotia Group M&A Database, January 2003

Table B-2c: Effect of Including Constant on Regression Coeffcients
(Excluding Outliers)

1	2	3	4	5	6	7	8
	Oil Coefficient ($/bbl)			Gas Coefficient ($/mcf)			
Year	*Constant Included*	*No Constant*	*Ratio*	*Constant Included*	*No Constant*	*Ratio*	*# Obs*
1982	5.71	7.13	0.80	0.28	0.36	0.79	13
1983	3.28	3.37	0.97	0.64	0.64	0.99	21
1984	6.88	6.95	0.99	0.86	0.86	1.00	31
1985	8.22	7.74	1.06	0.39	0.52	0.74	34
1986	5.09	5.10	1.00	0.96	0.96	1.00	25
1987	4.61	4.40	1.05	1.05	1.02	1.03	49
1988	5.72	5.69	1.01	0.99	0.99	1.01	64
1989	4.69	4.61	1.02	0.88	0.88	1.01	99
1990	3.65	3.64	1.00	0.90	0.90	1.00	151
1991	4.47	4.44	1.01	0.87	0.87	1.01	94
1992	4.17	4.14	1.01	0.83	0.82	1.01	86
1993	3.56	3.54	1.01	0.87	0.87	1.00	115
1994	2.82	2.90	0.97	0.75	0.77	0.98	92
1995	3.76	3.81	0.99	0.59	0.60	0.98	114
1996	3.71	3.67	1.01	0.69	0.69	1.01	94
1997	5.08	5.01	1.01	0.94	0.93	1.01	67
1998	2.54	2.85	0.89	0.57	0.62	0.92	83
1999	3.24	3.59	0.90	0.63	0.67	0.94	57
2000	3.17	3.55	0.89	0.71	0.75	0.95	66
2001	4.32	4.21	1.03	1.71	1.68	1.02	52
2002	5.67	5.74	0.99	0.86	0.88	0.98	49

Source: The Scotia Group M&A Database, January 2003

Table B-2d: Effect of Outliers on Reserve Coefficients
(No Constant)

1	2	3	4	5	6	7
	Oil Coefficient ($/bbl)			Gas Coefficient ($/mcf)		
Year	*All Data*	*Excluding Outliers*	*Ratio 2/3*	*All Data*	*Excluding Outliers*	*Ratio 5/6*
1982	7.59	7.13	1.06	0.35	0.36	0.97
1983	4.35	3.37	1.29	0.65	0.64	1.01
1984	3.71	6.95	0.53	1.02	0.86	1.18
1985	5.62	7.74	0.73	0.73	0.52	1.40
1986	2.12	5.10	0.42	0.97	0.96	1.01
1987	5.60	4.40	1.27	0.94	1.02	0.91
1988	6.07	5.69	1.07	1.20	0.99	1.22
1989	4.60	4.61	1.00	1.21	0.88	1.38
1990	4.18	3.64	1.15	0.48	0.90	0.53
1991	3.35	4.44	0.76	1.16	0.87	1.33
1992	6.34	4.14	1.53	0.75	0.82	0.91
1993	2.60	3.54	0.73	1.49	0.87	1.71
1994	5.59	2.90	1.93	0.74	0.77	0.96
1995	3.16	3.81	0.83	0.88	0.60	1.46
1996	6.98	3.67	1.90	0.95	0.69	1.39
1997	2.88	5.01	0.58	1.13	0.93	1.22
1998	3.53	2.85	1.24	0.76	0.62	1.23
1999	4.97	3.59	1.39	0.86	0.67	1.28
2000	4.21	3.55	1.19	0.75	0.75	1.00
2001	5.63	4.21	1.34	1.42	1.68	0.84
2002	6.49	5.74	1.13	1.21	0.88	1.37

Source: The Scotia Group M&A Database, January 2003

Table B-2e: Comparisons of Oil Regression Values (No Constant) with Pure Oil Values, Excluding Outliers

1	2	3	4	5	6
Year	*Oil Coefficient ($/bbl)*	*# Obs*	*Weighted ppb from Pure Oil Transactions ($/bbl)*	*# Obs*	*Ratio of Estimated Oil Coefficient to Pure Transaction ppb*
1982	7.13	13	7.11	1	1.00
1983	3.37	21	10.15	2	0.33
1984	6.95	31	6.94	7	1.00
1985	7.74	34	3.39	5	2.28
1986	5.10	25	8.86	3	0.58
1987	4.40	49	3.56	10	1.24
1988	5.69	64	6.15	13	0.93
1989	4.61	99	4.72	18	0.98
1990	3.64	151	4.22	35	0.86
1991	4.44	94	4.66	19	0.95
1992	4.14	86	3.46	18	1.20
1993	3.54	115	3.70	27	0.96
1994	2.90	92	3.71	15	0.78
1995	3.81	114	3.63	30	1.05
1996	3.67	94	3.84	30	0.96
1997	5.01	67	4.81	13	1.04
1998	2.85	83	3.34	16	0.85
1999	3.59	57	4.22	12	0.85
2000	3.55	66	3.46	14	1.03
2001	4.21	52	3.88	9	1.09
2002	5.74	49	5.19	11	1.11

Source: The Scotia Group M&A Database, January 2003

Note: The pure oil value observations are weighted volumetrically by the barrels in each transaction for a given year. This is equivalent to summing the value of all pure transactions in a given year and dividing by the total volumes of oil reserves sold.

Table B-2f: Comparisons of Natural Gas Regression Values (No Constant) with Pure Gas Values, Excluding Outliers

1	2	3	4	5	6
Year	*Gas Coefficient ($/mcf)*	*# Obs*	*Weighted ppmcf from Pure Gas Transactions ($/mcf)*	*# Obs*	*Ratio of Estimated Gas Coefficient to Pure Transaction ppmcf*
1982	0.36	13	---	0	---
1983	0.64	21	1.05	1	0.61
1984	0.86	31	1.32	1	0.65
1985	0.52	34	1.34	4	0.39
1986	0.96	25	0.92	3	1.05
1987	1.02	49	0.89	5	1.15
1988	0.99	64	1.00	9	0.99
1989	0.88	99	1.18	18	0.74
1990	0.90	151	0.81	27	1.11
1991	0.87	94	0.90	18	0.96
1992	0.82	86	0.56	18	1.47
1993	0.87	115	0.77	26	1.13
1994	0.77	92	0.76	31	1.01
1995	0.60	114	0.70	31	0.87
1996	0.69	94	0.60	29	1.14
1997	0.93	67	0.90	26	1.03
1998	0.62	83	0.69	42	0.89
1999	0.67	57	0.83	24	0.82
2000	0.75	66	0.73	26	1.03
2001	1.68	52	1.55	16	1.08
2002	0.88	49	0.96	32	0.91

--- Insufficient data points.

Source: The Scotia Group M&A Database, January 2003

Note: The pure gas value observations are weighted volumetrically by the cubic feet in each transaction for a given year. This is equivalent to summing the value of all pure transactions in a given year and dividing by the total volumes of gas reserves sold.

Appendix C:
Auxiliary Data and Regressions

Table C-1: Proven Reserves to Production Ratios

1	2	3	4	5	6	7
	Crude Oil (millions of barrels)			Natural Gas (bcf)		
Year	*Beginning Year Reserves*	*Annual Production*	*Ratio 2/3*	*Beginning Year Reserves*	*Annual Production*	*Ratio 5/6*
1982	29426	2950	10.0	201730	17506	11.5
1983	27858	3020	9.2	201512	15788	12.8
1984	27735	3037	9.1	200247	17193	11.6
1985	28446	3052	9.3	197463	15985	12.4
1986	28416	2973	9.6	193369	15610	12.4
1987	26889	2873	9.4	191586	16114	11.9
1988	27256	2811	9.7	187211	16670	11.2
1989	26825	2586	10.4	168024	16983	9.9
1990	26501	2505	10.6	167116	17233	9.7
1991	26254	2512	10.5	169346	17202	9.8
1992	24682	2446	10.1	167062	17423	9.6
1993	23745	2339	10.2	165015	17789	9.3
1994	22957	2268	10.1	162415	18322	8.9
1995	22457	2213	10.1	163837	17966	9.1
1996	22351	2173	10.3	165146	18861	8.8
1997	22017	2138	10.3	166474	19211	8.7
1998	22546	1991	11.3	167233	18720	8.9
1999	21034	1952	10.8	164041	18928	8.7
2000	21765	1880	11.6	167406	19219	8.7
2001	22045	1915	11.5	177427	19779	9.0
2002	22446	2106	10.7	183460	20351	9.0

Note: Beginning reserves indicate remaining reserves at January 1.

Source: EIA/DOE "US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves"

Table C-2: Regression Results for Transactions with Information on Reserve Status (No Constant), Excluding Outliers

1	2	3	4	5	6	7	8	9	10	11	12	13	14
	Oil ($/bbl)				Natural Gas ($/mcf)								
Year	*a1*	*t-stat*	*a2*	*t-stat*	*a1*	*t-stat*	*a2*	*t-stat*	*Adj. R^2*	*Total Obs*	*No. of Obs: No Oil or Gas Prod*	*No. of Obs: No Oil Prod*	*No. of Obs: No Gas Prod*
1982	7.13	4.02	---	---	0.36	1.54	---	---	0.72	13	13	13	13
1983	5.84	0.10	-2.47	-0.04	0.64	25.51	---	---	0.99	21	20	20	21
1984	3.50	4.72	3.47	4.71	2.05	0.47	-0.94	-0.22	0.99	31	31	31	33
1985	-3.28	-0.04	12.46	0.16	1.38	2.51	-1.05	-1.76	0.89	34	32	32	32
1986	6.94	1.07	-1.82	-0.28	1.19	3.85	-0.24	-0.76	0.99	25	24	24	25
1987	4.44	1.06	-0.68	-0.16	0.80	3.83	0.33	1.42	0.92	49	41	41	44
1988	5.50	41.66	2.76	6.28	1.02	46.41	-0.25	-5.45	0.99	64	55	55	56
1989	5.15	2.94	-0.02	-0.01	1.02	16.29	-0.50	-4.62	0.85	99	85	87	89
1990	4.58	1.33	-0.96	-0.28	0.82	14.41	0.10	1.49	0.94	151	142	146	149
1991	4.33	18.84	0.47	1.09	0.79	7.22	0.08	0.70	0.96	94	80	81	89
1992	4.18	10.23	0.08	0.13	0.78	9.34	0.11	0.90	0.89	86	57	63	67
1993	3.57	12.15	-0.57	-0.97	0.81	29.57	0.19	3.91	0.95	115	74	84	81
1994	3.14	12.81	-0.64	-1.38	0.79	24.20	-0.26	-2.38	0.91	92	53	63	55
1995	3.93	28.77	-1.20	-2.63	0.66	22.35	-0.07	-1.76	0.95	114	78	90	85
1996	4.01	14.34	-1.58	-2.53	0.74	16.77	-0.15	-1.83	0.87	94	57	67	63
1997	3.56	4.45	1.86	2.09	0.90	11.46	0.07	0.70	0.93	67	46	53	53
1998	1.81	5.21	3.01	5.00	0.80	13.77	-0.27	-3.85	0.87	83	46	68	54
1999	3.79	8.19	-0.56	-0.30	0.58	13.11	0.25	3.50	0.90	57	26	43	30
2000	6.02	3.10	-3.32	-1.48	0.77	11.06	-0.10	-0.83	0.74	66	29	50	34
2001	4.42	4.77	1.75	1.09	1.76	18.68	-0.42	-2.07	0.95	52	28	45	36
2002	5.55	9.19	0.23	0.34	1.06	9.48	-0.21	-1.77	0.95	49	27	47	36

--- Insufficient data points.

Note: Reserve status - whether reserves are on production or not.

Equation Specification:

$$adjprice = [a_1^o + a_2^o D_o] R_o + [a_1^g + a_2^g D_g] R_g$$

where:

adjprice is transaction price (after elimination of non reserve assets)
the 'o' superscript denotes oil
the 'g' superscript denotes gas
a_1 and a_2 are the two coefficients for each reserve being tested
R denotes reserves sold
D denotes dummy variable for reserves on production

Table C-3: Regression Results for Transactions with Information on R/P Ratios (No Constant), Excluding Outliers

1	2	3	4	5	6	7	8	9	10	11
	Oil ($/bbl)				Natural Gas ($/mcf)					
Year	*a1*	*t-stat*	*a2*	*t-stat*	*a1*	*t-stat*	*a2*	*t-stat*	*Adjusted R^2*	*Obs*
1982	---	---	---	---	---	---	---	---	---	---
1983	---	---	---	---	---	---	---	---	---	---
1984	---	---	---	---	---	---	---	---	---	---
1985	---	---	---	---	---	---	---	---	---	---
1986	---	---	---	---	---	---	---	---	---	---
1987	---	---	---	---	---	---	---	---	---	---
1988	---	---	---	---	---	---	---	---	---	---
1989	11.00	3.35	-1.64	-2.00	0.80	4.30	0.03	1.17	0.97	17
1990	4.95	2.57	-0.39	-0.61	1.08	24.70	-0.04	-6.22	0.99	14
1991	---	---	---	---	---	---	---	---	---	---
1992	3.81	4.40	0.07	0.33	1.05	7.29	-0.08	-2.37	0.93	32
1993	3.85	10.11	-0.06	-1.15	1.21	20.16	-0.09	-7.22	0.97	46
1994	2.31	3.44	0.22	1.43	1.08	7.16	-0.07	-1.97	0.93	42
1995	5.00	7.57	-0.29	-1.66	0.72	8.49	-0.01	-0.77	0.97	42
1996	4.55	11.16	-0.01	-2.95	0.86	5.72	-0.02	-0.91	0.89	41
1997	5.00	5.35	-0.29	-1.73	0.93	25.56	0.00	-0.28	0.98	24
1998	5.68	8.14	-0.29	-5.62	1.06	13.96	-0.04	-2.97	0.95	42
1999	4.71	2.30	-0.16	-0.46	0.58	3.20	0.00	-0.03	0.86	32
2000	11.53	3.15	-0.66	-1.44	0.95	10.68	-0.03	-2.92	0.88	37
2001	3.22	1.49	0.16	0.36	2.47	17.12	-0.18	-5.76	0.96	32
2002	10.33	7.96	-0.99	-3.75	1.45	8.31	-0.08	-2.44	0.97	27

--- Insufficient data points.

R/P ratio is the ratio of remaining reserves to annual production.

Equation Specification:

$$adjprice = [a_1^o + a_2^o H_o] R_o + [a_1^g + a_2^g H_g] R_g$$

where:

adjprice is transaction price (after elimination of non reserve assets)
the 'o' superscript denotes oil
the 'g' superscript denotes gas
a_1 and a_2 are the two coefficients for each reserve being tested
R denotes reserves sold
H denotes the R/P ratio

Table C-4: Oil and Natural Gas Reserve and Field Prices

1	2	3	4	5	6	7
		Oil ($/bbl)			Natural Gas ($/mcf)	
Year	*Field Price*	*Reserve Price*	*Ratio 3/2*	*Field Price*	*Reserve Price*	*Ratio 6/5*
1982	28.52	7.13	0.250	2.46	0.36	0.145
1983	26.19	3.37	0.129	2.59	0.64	0.248
1984	25.88	6.95	0.268	2.66	0.86	0.325
1985	24.09	7.74	0.321	2.51	0.52	0.208
1986	12.51	5.10	0.408	1.94	0.96	0.497
1987	15.40	4.40	0.286	1.67	1.02	0.613
1988	12.58	5.69	0.452	1.69	0.99	0.583
1989	15.86	4.61	0.291	1.69	0.88	0.519
1990	20.03	3.64	0.182	1.71	0.90	0.526
1991	16.54	4.44	0.268	1.64	0.87	0.530
1992	15.99	4.14	0.259	1.74	0.82	0.473
1993	14.25	3.54	0.248	2.04	0.87	0.428
1994	13.19	2.90	0.220	1.85	0.77	0.415
1995	14.62	3.81	0.261	1.55	0.60	0.390
1996	18.46	3.67	0.199	2.17	0.69	0.317
1997	17.23	5.01	0.291	2.32	0.93	0.401
1998	10.87	2.85	0.262	1.96	0.62	0.315
1999	15.56	3.59	0.231	2.19	0.67	0.308
2000	26.72	3.55	0.133	3.69	0.75	0.203
2001	21.84	4.21	0.193	4.12	1.68	0.407
2002	22.51	5.74	0.255	2.95	0.88	0.298

Source: EIA/DOE "Monthly Energy Review" June 2003

Table C-5: Regression Results: Reserve Prices and Field Prices

Reserve Prices Against Field Prices

1	2 *Constant*	3 *t-stat*	4 *Coeff*	5 *t-stat*	6 *Adj.* R^2	7 *Obs*
Oil Contemporary Price ($/bbl)	2.34	2.31	0.12	2.31	0.18	21
Gas Contempory Price ($/mcf)	0.53	2.76	0.13	1.61	0.07	21
Oil 1 Period Lag Price ($/bbl)	2.35	2.50	0.11	2.33	0.19	20
Gas 1 Period Lag Price ($/mcf)	0.55	3.05	0.14	1.75	0.10	20
Oil 2 Period Lag Price ($/bbl)	1.77	2.12	0.15	3.41	0.37	19
Gas 2 Period Lag Price ($/mcf)	0.84	3.44	0.01	0.06	-0.06	19

Reserve Prices Against First Differences in Field Prices

Oil Contemporary Price ($/bbl)	4.43	15.24	-0.05	-0.79	-0.02	20
Gas Contempory Price ($/mcf)	0.85	15.27	0.03	0.25	-0.05	20
Oil 1 Period Lag Price ($/bbl)	4.50	14.71	-0.01	-0.23	-0.06	19
Gas 1 Period Lag Price ($/mcf)	0.83	18.08	0.34	3.28	0.35	19
Oil 2 Period Lag Price ($/bbl)	4.37	15.18	0.00	-0.01	-0.06	18
Gas 2 Period Lag Price ($/mcf)	0.86	14.03	-0.04	-0.28	-0.06	18

Appendix D:
Hotelling Values, Implicit Price Expectations and Returns to Holding

Table D-1: Estimates of Hotelling Values and Price Expectations, Oil

1	2	3	4	5	6	7	8	9	10	11
Year	*P/R Ratio*	*Adjusted Ratio (a)*	*Reserve Price (b) $/bbl*	*SE of Reserve Price $/bbl*	*Operating Cost (c) $/bbl*	*Field Price (p) $/bbl*	*Implicit Annual Growth Rate in Price*	*Net Field Price: HV $/bbl*	*Ratio of HV to Reserve Price*	*HV Spread SDs*
1982	0.10	0.09	7.13	0.78	9.98	28.52	0.12	18.54	2.60	14.7
1983	0.11	0.10	3.37	0.08	9.17	26.19	-0.17	17.02	5.05	161.4
1984	0.11	0.10	6.95	0.04	9.06	25.88	0.11	16.82	2.42	252.1
1985	0.11	0.10	7.74	4.66	8.43	24.09	0.11	15.66	2.02	1.7
1986	0.10	0.09	5.10	0.77	4.38	12.51	0.10	8.13	1.59	4.0
1987	0.11	0.10	4.40	0.68	5.39	15.40	0.05	10.01	2.27	8.3
1988	0.10	0.09	5.69	0.25	4.40	12.58	0.14	8.18	1.44	10.0
1989	0.10	0.09	4.61	1.30	5.55	15.86	0.06	10.31	2.23	4.4
1990	0.09	0.09	3.64	0.40	7.01	20.03	-0.05	13.02	3.58	23.4
1991	0.10	0.09	4.44	0.36	5.79	16.54	0.03	10.75	2.42	17.6
1992	0.10	0.09	4.14	0.60	5.60	15.99	0.01	10.39	2.51	10.5
1993	0.10	0.09	3.54	0.24	4.99	14.25	-0.03	9.26	2.62	24.3
1994	0.10	0.09	2.90	0.67	4.62	13.19	-0.03	8.57	2.96	8.5
1995	0.10	0.09	3.81	0.23	5.12	14.62	0.00	9.50	2.49	25.2
1996	0.10	0.09	3.67	0.92	6.46	18.46	-0.07	12.00	3.27	9.0
1997	0.10	0.09	5.01	0.35	6.03	17.23	0.02	11.20	2.24	17.6
1998	0.09	0.08	2.85	0.90	3.80	10.87	-0.01	7.07	2.48	4.7
1999	0.09	0.08	3.59	0.57	5.45	15.56	-0.04	10.11	2.82	11.5
2000	0.09	0.08	3.55	1.81	9.35	26.72	-0.19	17.37	4.89	7.6
2001	0.09	0.08	4.21	0.88	7.64	21.84	-0.09	14.20	3.37	11.3
2002	0.09	0.09	5.74	0.56	7.88	22.51	-0.04	14.63	2.55	15.8

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Production/Reserves Ratio, P/R, Table C-1.
(3) Adjusted Ratio (a), see text.
(4) Reserve Price (b), Table B-2a, Col 3.
(5) Regression Results.
(6) Operating Cost (c), 35% of field price.
(7) Field Price (p), Table C-4.
(8) Implicit Annual Growth Rate in Price, see text.
(9) Net Field Price, p-c, Column (7) - Column (6).
(10) HV to Reserve Price, Column (9) / Column (4).
(11) HV Spread: Standard Deviations, [Column (9) - Column (4)] / Column (5).

Table D-2: Estimates of Hotelling Values and Price Expectations, Pure Oil

.

1 Year	2 P/R Ratio	3 Adjusted Ratio (a)	4 Reserve Price (b) $/bbl	5 SE of Reserve Price $/bbl	6 Operating Cost (c) $/bbl	7 Field Price (p) $/bbl	8.00 Implicit Annual Growth Rate in Price	9 Net Field Price: HV $/bbl	10 Ratio of HV to Reserve Price	11 HV Spread SDs
1982	0.10	0.09	7.11	---	9.98	28.52	0.12	18.54	2.61	---
1983	0.11	0.10	10.15	3.38	9.17	26.19	0.16	17.02	1.68	2.0
1984	0.11	0.10	6.94	0.47	9.06	25.88	0.11	16.82	2.43	21.0
1985	0.11	0.10	3.39	2.24	8.43	24.09	-0.13	15.66	4.62	5.5
1986	0.10	0.09	8.86	1.95	4.38	12.51	0.16	8.13	0.92	-0.4
1987	0.11	0.10	3.56	2.03	5.39	15.40	-0.01	10.01	2.81	3.2
1988	0.10	0.09	6.15	1.62	4.40	12.58	0.15	8.18	1.33	1.3
1989	0.10	0.09	4.72	1.50	5.55	15.86	0.07	10.31	2.19	3.7
1990	0.09	0.09	4.22	1.71	7.01	20.03	-0.01	13.02	3.08	5.2
1991	0.10	0.09	4.66	1.89	5.79	16.54	0.04	10.75	2.31	3.2
1992	0.10	0.09	3.46	1.59	5.60	15.99	-0.04	10.39	3.01	4.4
1993	0.10	0.09	3.70	2.01	4.99	14.25	-0.02	9.26	2.50	2.8
1994	0.10	0.09	3.71	2.93	4.62	13.19	0.02	8.57	2.31	1.7
1995	0.10	0.09	3.63	1.45	5.12	14.62	-0.01	9.50	2.62	4.1
1996	0.10	0.09	3.84	2.09	6.46	18.46	-0.06	12.00	3.12	3.9
1997	0.10	0.09	4.81	2.60	6.03	17.23	0.01	11.20	2.33	2.5
1998	0.09	0.08	3.34	1.87	3.80	10.87	0.02	7.07	2.11	2.0
1999	0.09	0.08	4.22	1.71	5.45	15.56	0.00	10.11	2.40	3.4
2000	0.09	0.08	3.46	2.26	9.35	26.72	-0.20	17.37	5.02	6.1
2001	0.09	0.08	3.88	1.35	7.64	21.84	-0.11	14.20	3.66	7.6
2002	0.09	0.09	5.19	2.08	7.88	22.51	-0.06	14.63	2.82	4.5

--- Insufficient data points.

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Production/Reserves Ratio, P/R, Table C-1.
(3) Adjusted Ratio (a), see text.
(4) Reserve Price (b), Table B-2e, Col 4.
(5) Statistical Results.
(6) Operating Cost (c), 35% of field price.
(7) Field Price (p), Table C-4.
(8) Implicit Annual Growth Rate in Price, see text.
(9) Net Field Price, p-c, Column (7) - Column (6).
(10) HV to Reserve Price, Column (9) / Column (4).
(11) HV Spread: Standard Deviations, [Column (9) - Column (4)] / Column (5).

Table D-3: Estimates of Hotelling Values and Price Expectations, Natural Gas

1	2	3	4	5	6	7	8	9	10	11
Year	*P/R Ratio*	*Adjusted Ratio (a)*	*Reserve Price (b) $/mcf*	*SE of Reserve Price $/mcf*	*Operating Cost (c) $/mcf*	*Field Price (p) $/mcf*	*Implicit Annual Growth Rate in Price*	*Net Field Price: HV $/mcf*	*Ratio of HV to Reserve Price*	*HV Spread SDs*
1982	0.09	0.08	0.36	0.28	0.86	2.46	-0.02	1.60	4.48	4.4
1983	0.08	0.07	0.64	0.01	0.91	2.59	0.10	1.68	2.62	95.5
1984	0.09	0.08	0.86	0.00	0.93	2.66	0.17	1.73	2.00	173.7
1985	0.08	0.07	0.52	0.50	0.88	2.51	0.05	1.63	3.12	2.2
1986	0.08	0.07	0.96	0.05	0.68	1.94	0.13	1.26	1.31	6.3
1987	0.08	0.08	1.02	0.15	0.58	1.67	0.16	1.09	1.06	0.4
1988	0.09	0.08	0.99	0.03	0.59	1.69	0.17	1.10	1.11	3.8
1989	0.10	0.09	0.88	0.15	0.59	1.69	0.15	1.10	1.25	1.5
1990	0.10	0.09	0.90	0.06	0.60	1.71	0.15	1.11	1.24	3.7
1991	0.10	0.09	0.87	0.03	0.57	1.64	0.14	1.07	1.23	6.7
1992	0.10	0.09	0.82	0.07	0.61	1.74	0.11	1.13	1.37	4.3
1993	0.11	0.10	0.87	0.06	0.71	2.04	0.07	1.33	1.52	7.0
1994	0.11	0.10	0.77	0.04	0.65	1.85	0.08	1.20	1.57	11.1
1995	0.11	0.10	0.60	0.06	0.54	1.55	0.07	1.01	1.67	6.6
1996	0.11	0.10	0.69	0.04	0.76	2.17	0.02	1.41	2.05	18.7
1997	0.12	0.10	0.93	0.06	0.81	2.32	0.06	1.51	1.62	9.6
1998	0.11	0.10	0.62	0.10	0.69	1.96	0.00	1.27	2.06	6.7
1999	0.12	0.10	0.67	0.09	0.77	2.19	0.00	1.42	2.11	8.2
2000	0.11	0.10	0.75	0.12	1.29	3.69	-0.10	2.40	3.21	13.6
2001	0.11	0.10	1.68	0.17	1.44	4.12	0.04	2.68	1.60	5.8
2002	0.11	0.10	0.88	0.09	1.03	2.95	-0.02	1.92	2.18	11.5

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Production/Reserves Ratio, P/R, Table C-1.
(3) Adjusted Ratio (a), see text.
(4) Reserve Price (b), Table B-2a, Col 5.
(5) Regression Results.
(6) Operating Cost (c), 35% of field price.
(7) Field Price (p), Table C-4.
(8) Implicit Annual Growth Rate in Price, see text.
(9) Net Field Price, p-c, Column (7) - Column (6).
(10) HV to Reserve Price, Column (9) / Column (4).
(11) HV Spread: Standard Deviations, [Column (9) - Column (4)] / Column (5).

Table D-4: Estimates of Hotelling Values and Price Expectations, Pure Natural Gas

1 *Year*	2 *P/R Ratio*	3 *Adjusted Ratio (a)*	4 *Reserve Price (b) $/mcf*	5 *SE of Reserve Price $/mcf*	6 *Operating Cost (c) $/mcf*	7 *Field Price (p) $/mcf*	8 *Implicit Annual Growth Rate in Price*	9 *Net Field Price: HV $/mcf*	10 *Ratio of HV to Reserve Price*	11 *HV Spread SDs*
1982	0.09	0.08	---	---	0.86	2.46	---	1.60	---	---
1983	0.08	0.07	1.05	---	0.91	2.59	0.18	1.68	1.61	---
1984	0.09	0.08	1.32	---	0.93	2.66	0.23	1.73	1.31	---
1985	0.08	0.07	1.34	11.01	0.88	2.51	0.20	1.63	1.22	0.0
1986	0.08	0.07	0.92	0.18	0.68	1.94	0.13	1.26	1.37	1.9
1987	0.08	0.08	0.89	0.34	0.58	1.67	0.15	1.09	1.22	0.6
1988	0.09	0.08	1.00	0.27	0.59	1.69	0.17	1.10	1.10	0.4
1989	0.10	0.09	1.18	0.59	0.59	1.69	0.18	1.10	0.93	-0.1
1990	0.10	0.09	0.81	0.29	0.60	1.71	0.14	1.11	1.37	1.0
1991	0.10	0.09	0.90	0.35	0.57	1.64	0.14	1.07	1.18	0.5
1992	0.10	0.09	0.56	0.21	0.61	1.74	0.04	1.13	2.02	2.7
1993	0.11	0.10	0.77	0.28	0.71	2.04	0.05	1.33	1.71	2.0
1994	0.11	0.10	0.76	0.34	0.65	1.85	0.08	1.20	1.58	1.3
1995	0.11	0.10	0.70	0.24	0.54	1.55	0.09	1.01	1.45	1.3
1996	0.11	0.10	0.60	0.17	0.76	2.17	-0.01	1.41	2.35	4.6
1997	0.12	0.10	0.90	0.33	0.81	2.32	0.06	1.51	1.68	1.8
1998	0.11	0.10	0.69	0.29	0.69	1.96	0.02	1.27	1.85	2.0
1999	0.12	0.10	0.83	0.60	0.77	2.19	0.04	1.42	1.72	1.0
2000	0.11	0.10	0.73	0.48	1.29	3.69	-0.11	2.40	3.29	3.5
2001	0.11	0.10	1.55	0.56	1.44	4.12	0.03	2.68	1.73	2.0
2002	0.11	0.10	0.96	0.51	1.03	2.95	-0.01	1.92	1.99	1.9

--- Insufficient data points.

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Production/Reserves Ratio, P/R, Table C-1.
(3) Adjusted Ratio (a), see text.
(4) Reserve Price (b), Table B-2f, Col 4.
(5) Statistical Results.
(6) Operating Cost (c), 35% of field price.
(7) Field Price (p), Table C-4.
(8) Implicit Annual Growth Rate in Price, see text.
(9) Net Field Price, p-c, Column (7) - Column (6).
(10) HV to Reserve Price, Column (9) / Column (4).
(11) HV Spread: Standard Deviations, [Column (9) - Column (4)] / Column (5).

Table D-5: Confidence Limits for Implicit Growth Rate of Oil Prices

1	2	3	4	5	6
		Variance of V Method		*Delta Method*	
Year	*Implicit Annual Growth Rate in Price (g)*	*Lower Bound*	*Upper Bound*	*Lower Bound*	*Upper Bound*
1982	0.12	0.05	0.16	0.06	0.17
1983	-0.17	-0.20	-0.15	-0.19	-0.14
1984	0.11	0.11	0.11	0.11	0.11
1985	0.11	-2.42	0.22	-0.12	0.35
1986	0.10	0.03	0.13	0.05	0.14
1987	0.05	-0.05	0.10	-0.02	0.11
1988	0.14	0.12	0.15	0.12	0.15
1989	0.06	-0.19	0.13	-0.05	0.17
1990	-0.05	-0.14	0.01	-0.12	0.02
1991	0.03	-0.01	0.06	0.00	0.07
1992	0.01	-0.09	0.06	-0.06	0.07
1993	-0.03	-1.29	0.00	-0.06	0.00
1994	-0.03	-0.26	0.05	-0.15	0.09
1995	0.00	-0.03	0.02	-0.03	0.03
1996	-0.07	-0.36	0.03	-0.21	0.07
1997	0.02	-0.01	0.04	-0.01	0.05
1998	-0.01	-0.36	0.06	-0.14	0.11
1999	-0.04	-0.15	0.02	-0.12	0.04
2000	-0.19	-2.29	0.01	-0.58	0.21
2001	-0.09	-0.28	-0.01	-0.20	0.02
2002	-0.04	-0.09	0.00	-0.08	0.00

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Implicit Annual Growth Rate in Price, Table D-1, Col 8.
(3) See text.
(4) See text.
(5) See text.
(6) See text.

The Scotia Group M&A Database, January 2003

Table D-6: Confidence Limits for Implicit Growth Rate of Natural Gas Prices

1	2	3	4	5	6
		Variance of V Method		Delta Method	
Year	*Implicit Annual Growth Rate in Price (g)*	*Lower Bound*	*Upper Bound*	*Lower Bound*	*Upper Bound*
1982	-0.02	-0.93	0.20	-0.58	0.55
1983	0.10	0.10	0.11	0.10	0.11
1984	0.17	0.17	0.17	0.17	0.17
1985	0.05	-0.93	0.21	-0.39	0.50
1986	0.13	0.12	0.14	0.12	0.14
1987	0.16	0.13	0.18	0.14	0.19
1988	0.17	0.16	0.17	0.16	0.17
1989	0.15	0.09	0.18	0.11	0.19
1990	0.15	0.13	0.16	0.13	0.16
1991	0.14	0.13	0.14	0.13	0.14
1992	0.11	0.08	0.12	0.08	0.13
1993	0.07	0.04	0.09	0.05	0.09
1994	0.08	0.07	0.10	0.07	0.10
1995	0.07	0.03	0.09	0.03	0.10
1996	0.02	0.00	0.04	0.00	0.05
1997	0.06	0.04	0.08	0.04	0.09
1998	0.00	-0.10	0.05	-0.07	0.06
1999	0.00	-0.08	0.05	-0.06	0.06
2000	-0.10	-0.26	-0.02	-0.21	0.00
2001	0.04	0.00	0.07	0.01	0.07
2002	-0.02	-0.08	0.01	-0.07	0.02

Note: A value of 0.00 implies negligible growth rates.

Sources:

(2) Implicit Annual Growth Rate in Price, Table D-3, Col 8.
(3) See text.
(4) See text.
(5) See text.
(6) See text.

The Scotia Group M&A Database, January 2003

Table D-7: Return to Holding Oil and Natural Gas, 1982-2002

1	2	3	4	5	6	7	8	9
Year	*Riskless Rate (1-yr TB)*	*Oil Value ($/bbl)*	*Return to Holding*	*Oil Achieved Risk Premium*	*Gas Value ($/mcf)*	*Return to Holding*	*Natural Gas Achieved Risk Premium*	*Required Risk Premium*
1982		7.13			0.36			
1983	0.096	3.37	-0.527	-0.623	0.64	0.800	0.704	0.111
1984	0.109	6.95	1.061	0.952	0.86	0.345	0.236	0.125
1985	0.084	7.74	0.114	0.030	0.52	-0.395	-0.479	0.106
1986	0.065	5.10	-0.341	-0.406	0.96	0.843	0.779	0.077
1987	0.068	4.40	-0.136	-0.204	1.02	0.062	-0.005	0.084
1988	0.077	5.69	0.292	0.215	0.99	-0.038	-0.114	0.089
1989	0.085	4.61	-0.189	-0.274	0.88	-0.111	-0.196	0.085
1990	0.079	3.64	-0.211	-0.290	0.90	0.026	-0.053	0.086
1991	0.059	4.44	0.219	0.160	0.87	-0.033	-0.092	0.079
1992	0.039	4.14	-0.067	-0.106	0.82	-0.054	-0.093	0.070
1993	0.034	3.54	-0.145	-0.179	0.87	0.060	0.026	0.059
1994	0.053	2.90	-0.180	-0.234	0.77	-0.121	-0.174	0.071
1995	0.059	3.81	0.315	0.255	0.60	-0.213	-0.272	0.066
1996	0.055	3.67	-0.036	-0.091	0.69	0.138	0.082	0.064
1997	0.056	5.01	0.362	0.306	0.93	0.356	0.300	0.064
1998	0.051	2.85	-0.431	-0.482	0.62	-0.337	-0.388	0.053
1999	0.051	3.59	0.260	0.209	0.67	0.092	0.041	0.057
2000	0.061	3.55	-0.010	-0.071	0.75	0.110	0.049	0.060
2001	0.035	4.21	0.185	0.150	1.68	1.241	1.206	0.050
2002	0.020	5.74	0.364	0.344	0.88	-0.476	-0.496	0.046
Mean	0.062		0.045	-0.017		0.115	0.053	0.075
St.Dev.	0.022		0.358	0.356		0.429	0.427	0.021
St.Err.	0.005		0.080	0.080		0.096	0.095	0.005
Mn/Se	12.578		0.560	-0.213		1.197	0.556	15.975

Sources:

(2) Federal Reserve Board Historical Rates (http://www.federalreserve.gov/releases/h15/data/a/tcm1y.txt)
(3) Oil Reserve Price, Table B-2a, Col 3.
(4) Percentage Change, Col 3 (t)/Col 3 (t-1) - 1
(5) Oil Achieved Risk Premium, Col 4 - Col 2
(6) Natural Gas Reserve Price, Table B-2a, Col 5.
(7) Percentage Change, Col 8 (t)/Col 8 (t-1) - 1
(8) Natural Gas Achieved Risk Premium, Col 8 - Col 2
(9) Required Risk Premium, LTBR (http://www.federalreserve.gov/releases/h15/data/a/tcm10y.txt)