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Expectation Models and Potential Information Content of Oil and Gas Reserve Value Disclosures

Bala G. Dharan

ABSTRACT: This study examines the potential information content of oil and gas reserve value disclosure requirements mandated by the SEC in 1979 by examining whether the reserve value disclosures based on Reserve Recognition Accounting (RRA) are obtainable from transformation of other concurrently available non-RRA data. This can be interpreted as a "necessary condition" approach to studying potential information content in general. Three increasingly complex specifications of an expectation model were developed. All identifiable RRA signals were excluded from their information sets. Association between the resulting model estimates based on non-RRA data and reported reserve values based on RRA was studied using a sample of about 160 firms. The strong linear relationships uncovered imply that RRA signals may have potentially low incremental information content in the sense that they may not have much incremental impact on observed security prices. Prediction errors at the firm level were often large, implying usefulness of RRA data in other contexts.

1. Introduction

In 1978, the Securities and Exchange Commission (SEC) issued Accounting Series Release 253 [SEC, 1978], requiring oil and gas firms to compute and report reserve values based on estimated future cash flows rather than past incurred costs of finding and developing the reserves. The SEC reasoned that its proposed Reserve Recognition Accounting (RRA) procedure was superior to the historical cost methods in measuring the success of oil and gas firms in adding new reserves. RRA was intended to provide a better measure of earnings that reflected accurately the risks borne by firms in exploration. In 1982, the Financial Accounting Standards Board (FASB) issued Statement No. 69 [FASB, 1982], which essentially adopted the RRA procedure for supplementary disclosure of reserve values, though an earnings measure based on the procedure was not required. Since then, the SEC has withdrawn its own rules in favor of the new FASB standard.

The issue of information content of RRA disclosures has not been studied so far in the accounting literature. This paper examines the potential incremental information content of the RRA *reserve*

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Bala G. Dharan is Assistant Professor of Accounting, Rice University.

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value disclosures by examining whether the disclosed reserve values are obtainable from a transformation of other *concurrently* available non-RRA data. Three alternative specifications of an expectation model, whose increasingly complex information sets exclude all RRA signals, are first formed. The association between model expectations and actual reserve value data for a sample of 162 firms is then used to draw inferences on the potential information content of RRA signals excluded from the expectation models.

Implicit in this approach is the assumption that a *necessary* condition for a new disclosure such as the RRA reserve value to have incremental information content (i.e., to affect stock return distribution incrementally) is that the new disclosure is *not* obtainable by a costless known transformation of other previously released or concurrently released signals. If this "necessary condition" is not satisfied by a new disclosure, then market participants with a need for the reserve value information would clearly have access to it even without the new disclosure; hence, the stock return would reflect that information even before the disclosure. If the condition *is* satisfied, then the new disclosure adds something new to the information set of the market participants which *may* or *may not* affect stock returns; hence it is said to have *potential* information content. Since perfect transformations are seldom possible, this paper assumes that the degree of association between expectations based on the non-RRA signals and the actual RRA reserve values nevertheless provides an inverse measure of the potential information content of the RRA signals.

The above approach of examining potential information content differs from the approach used by most information content studies. In the traditional approach (e.g., Ball and Brown [1968]), forecast errors from an expectations model are used to form portfolios, and differential behavior of the portfolios' abnormal (residual) security returns is interpreted as the information content of the forecast errors.[1] The approach used in this study is *complementary* to the traditional approach in two ways. First, the traditional approach often relies critically on the appropriateness of an expectation model. As Beaver, Christie, and Griffin [1980] note, if the expectation model is poorly specified, the empirical study would understate the association between the signal and the security returns, and hence understate the information content of the signal. This paper emphasizes appropriate design of the information set of expectation models. The procedure is first to identify the signals unique to the disclosure under study and then to exclude them from the information set of the expectation model. This procedure is relevant to analyzing many other new disclosure requirements apart from the RRA disclosures, and it is clearly preferable to using ad-hoc expectation models, such as "expected value of a signal equals its previous realization."

Second, the approach used here can potentially explain *null* results obtained in a security return-based study. As Beaver, Griffin and Landsman [1982, p. 16] note, lack of association between residual returns and the signal of interest (assuming it is a relevant signal) may mean 1) "security prices already 'reflected' such information because of the prior availability of substitute data," 2) the signal is so "garbled" that it provides no information, or 3) the market has yet to learn how to use the information. Conditional on null results from a security

[1] Many variations of this method have been used. See Beaver [1981] for a formal discussion of the information content research methodology.

return study, the first two hypotheses can be differentiated using this paper's approach, which allows an expectation model to use concurrent as well as past financial data so long as they are a complement to the signal of interest. High association between forecasts from such an expectation model and actual signals would then point to the validity of Hypothesis (1). By contrast, a low correlation would imply that the signal is computed nonuniformly and thus is garbled.[2]

This method is somewhat related to the approach taken by Falkenstein and Weil [1977], who constructed estimates of replacement cost data for 1975 for 31 companies, using the data in their historical cost-based financial statements of the same year. The main difference is that the expectation models developed here explicitly test for potential information content by recognizing and avoiding signals specific to RRA from their information sets. Fabozzi and Shiffrin [1979] tested the Falkenstein-Weil procedure on the 1976 replacement cost disclosures of 17 pharmaceutical firms. However, they did not address the issue of potential information content of the replacement cost disclosures. They seemed more concerned with the usefulness of the Falkenstein-Weil procedure for estimating *pre-1976* replacement cost data. Finally, Easman, Falkenstein and Weil [1979] evaluated the correlations between estimates obtained from the Falkenstein-Weil procedure, historical cost income, and stock returns. Here again, the testing of potential incremental information content of the new disclosures was not an objective.[3] Nevertheless, the present study should be considered a generalization of Falkenstein and Weil [1977] to constructing expectation models and studying potential incremental information.

The rest of the paper is organized as follows. In the next section, ASR-253/FASB-69 disclosure requirements are analyzed to identify signals present in those disclosures that are not present in other non-RRA disclosures. Using this analysis as a basis, Section 3 presents the development of three alternative specifications of a reserve value expectation model. The three models can be described as naive, industry-based, and company-specific, based on the level of detail in their information sets. Section 4 describes sample selection and results of association and predictability tests between model expectations and actual reserve value data of 162 large and small oil and gas firms. Results are summarized in the concluding section.

2. RRA Disclosure Signals

2.1 Background

From the beginning, there have been questions raised about the potential information content of RRA disclosures. One line of argument has focused on the fact that the reserve value estimates are based on reserve quantity estimates which can be highly variable (e.g., Connor [1979]) and subjective [Porter, 1980]. Responses from financial analysts to the disclosures have been mixed. For example, in a questionnaire survey of 190 financial analysts, Deakin and Deitrick [1982] found that 92.8 percent of the respondents said "yes" when asked whether companies' estimates of reserve value should be disclosed to investors, and 90.5 percent said that the reserve value data were useful for their investment decision. But it is clear that the analysts were referring to *supplementary* RRA disclosures. When asked if RRA should replace historical cost in primary financial statements, only 7.7 percent

[2] An alternative interpretation would be that the expectations model is misspecified, or garbled.

[3] See Beaver, Griffin and Landsman [1982] for a discussion of the Easman, Falkenstein and Weil [1979] study.

agreed. As for the potential information content of the supplementary disclosures, Avard [1982, p. 74] summarizes the feelings of 25 petroleum industry analysts whom he interviewed as follows: "There is almost complete agreement that the measure of value currently required by the SEC under RRA accounting is neither realistic nor meaningful." In February 1981, the SEC itself declared in ASR-289 that it "no longer considers [RRA] to be a potential method" because "RRA does not presently possess the requisite degree of certainty."

Bell, Boatsman and Dhaliwal [1983] question the line of argument that criticizes RRA for its subjectivity. They point out that similar arguments can be made against historical cost disclosures as well. In fact, it can be seen that apart from the use of subjective reserve quantity estimates, which are separately disclosed as well, the RRA method of ASR-253 and the similar method of FASB-69[4] are characterized by uniform, explicit steps and assumptions for the computation of reserve value, and the subjectivity argument may thus be unrealistic. The major steps in the procedure are as follows:

i) Estimate reserve quantities. Firms must estimate both proved developed and proved undeveloped reserve quantities at year-end. Proved reserves are those that can be profitably recovered given current prices and technologies.
ii) Estimate future production. Firms must decide how much oil and gas will be produced from each field or well in all future periods until reserves are exhausted.[5]
iii) Estimate future cash flows. Firms must assume that current year-end prices and costs will prevail in future.[6] Then cash flow for a year is obtained by deducting estimated production cost (based on current year experience) from the product of estimated production for that year and current year-end prices.[7]
iv) Compute present value. Firms must use a ten percent discount rate, regardless of their risk characteristics, to discount estimated future cash flows.

2.2 Signals

There are two possible rationales for the reserve value data computed by the ASR-253 procedure to have potential information content for investors. First, the procedure itself may cause the reserve value data to have information content. Second, some of the input variables (or signals) to the procedure may have information value to investors, and these may not have been disclosed separately (outside RRA) to investors. Both rationales can also hold together. Each will be considered separately in this paper.

Empirical studies on capital market efficiency (e.g., Foster [1979]) have addressed the question of whether a computational procedure, *per se*, can have value. Let a disclosure, X, be given by a costless transformation, T, performed by the firm on the information set Y. If Y is completely disclosed by the firm to investors, and if the firm's transformation procedure, T, is also public knowledge, then the semi-strong form of efficient market hypothesis holds that X cannot affect expected security returns over and

[4] Though the FASB does not use the term RRA, its disclosure rules are very similar to those of ASR-253.

[5] For this, firms usually determine physically optimal "natural" production rates, but have flexibility in altering them. Also, since reserve estimates affect planned production and vice versa, firms usually carry out steps (i) and (ii) together.

[6] Increases due to anticipated inflation cannot be assumed. Firms can, however, allow for price escalations in their computations if they are provided for in existing contracts.

[7] In the case of proved undeveloped fields, firms must also deduct estimated development costs for each year.

above the impact of Y.[8] Failure for this result to hold implies market inefficiency in processing public information, since the public can also carry out the costless T.[9] Still, transformation procedures used by firms may be expected to have informational value if they aggregate a large amount of data to produce a small set of desired measures and if the transformation is costly (to the investors). A firm's choice of transformation procedures (within GAAP) may also have information value. Additionally, firms' transformation procedures may be preferred to investors' transformation procedures for reasons of temporal consistency and cross-sectional comparability. For example, earnings are computed using the historical cost methods by transforming cash flow data. Yet, earnings are claimed to convey more information than cash flows [FASB, 1979]. Evidence from Foster [1979] also supports the view that experts' financial analysis (transformation) of publicly available information sometimes can affect security returns.

Consider, next, whether the reserve value data contain signals not disclosed elsewhere. Step (i) of the RRA procedure deals with reserve quantities. As noted, firms must disclose these separately under FASB Statement No. 19 [FASB, 1977]. Step (iv) uses an assumed discount rate, disclosed separately, and hence does not convey new signals. Steps (ii) and (iii), however, can be shown to contain unique signals. Step (iii) is primarily based on year-end prices and costs applicable to each field or well. These *field-specific* data are not disclosed by firms elsewhere. Firms do disclose average selling prices and aggregate costs of exploration, production, etc. under FASB-19 and other SEC requirements. However, the average and aggregate data cannot be used in step (iii). The windfall profit tax on oil and federal controls on natural gas result in dozens of applicable prices to oil and gas depending on their location and time of discovery. Similarly, development and production costs can vary greatly depending on a reservoir's location. Additionally, step (ii) requires firms to estimate future production quantities for every field. These data can span ten or more years, depending on the existing reserve quantities. The forecasted production quantities are not disclosed by firms, either in the aggregate or on a field-by-field basis under existing disclosure rules.[10] Thus, the use of undisclosed field-specific data on prices, costs, and planned production may make the RRA procedure valuable and the resulting RRA reserve value have potential information content.

In summary, there are *a priori* reasons to expect that RRA value data may have information content to investors. The rest of the paper will ignore the possibility that the value of RRA data comes from computational procedure itself. Instead, it will focus on the question of whether the unique signals used in the RRA procedure have potential information content. These signals are field-specific data on prices, costs, and planned future production.

2.3 Model Design and Selection

The method used to examine the potential information content of RRA signals is to develop transformation functions or expectation models based on non-RRA data, and to examine the association between the predictions from

[8] This is the basis for the "necessary condition" (for potential information content) noted earlier.

[9] Accounting changes with no cash flow effects are transformations of the above type. As Kaplan [1978] concludes, evidence from the market is consistent with the statement that the market does not respond to such transformations.

[10] Some states do require firms to file production plans with state regulatory bodies. These are publicly available.

TABLE 1

SUMMARY OF VARIABLES

p_t	Current-year production of oil and gas in year t.
q_t	Current year-end proved developed reserves in year t.
Q_t	Current year-end total proved reserves in year t.
D_t	Addition to proved reserves in year t.
d_t	Production in year t from a given prior year's addition.
i	Discount rate; for RRA, $i=(1.1)^{-1}$.
h	Industry average rate of decline in production.
g	$1-h$.
H	Company-specific rate of decline in production.
G	$1=H$.
S_t	Net revenue from the sale of oil and gas in year t.
a_t	Price-adjustment index for S in year t.
S'_t	Price-adjusted net revenue in year t.
$\hat{S}_t$	Forecasted net revenue for year t.
r_0, R_0	Reported reserve values for q_0 and Q_0.
$\hat{r}_j$, $\hat{R}_j$	Computed reserve values for q_0 and Q_0, from model j, $j=1, 2, 3$.
N	Reserve life for proved developed reserves.
N'	Reserve life for total proved reserves.

these models and actual reserve value data. The association is an inverse measure of the potential information content of the RRA signals that were not utilized by the expectation models but are present in the actual RRA disclosures. Thus, the model design in the next section will exclude contemporaneous RRA data from the expectation models. On the other hand, to prevent poor specification, the model design will allow contemporaneous *non-RRA* data in a model's information set.[11] To test the richness of the contemporaneous data, three different expectation models are developed. The three models use increasing levels of non-RRA data, with model 1 being least detailed, model 2 using industry-wide data, and model 3 using company-specific data. These are presented next.

3. RRA EXPECTATION MODELS

3.1 *Naive Expectation Model (Model 1)*

The first expectation model will estimate the RRA reserve value by making the naive assumption that a firm's future production of oil and gas will equal its current year production, which is a non-RRA datum in the model's information set. Similar random-walk expectation models have been used in past studies of earnings, dividends, and stock prices.

Table 1 summarizes the definitions of variables used in this and subsequent models. Let p_0 be the current-year production and q_0 and Q_0 be the current-year-end quantity of proved developed reserves and total proved reserves, respectively. Given this model's assumption on future production, the reserve life for proved developed reserves is $N_1=q_0/p_0$ and for total proved (developed *and* undeveloped) reserves is $N'_1=Q_0/p_0$. Let n_1 and n'_1 be the integer portions of N_1 and N'_1, respectively.

Since RRA requires freezing future prices and costs at current year levels to compute future cash flows, and since production is assumed constant, future net revenues (assuming production equals sales) will equal the current year's net revenue from oil and gas operations. This quantity, S_0, is a non-RRA datum avail-

[11] Not doing so would make the model's information set too lean, and hence poorly specified in the sense of Beaver, Christie and Griffin [1980].

able to this model. Then, using a ten percent discount rate as required by ASR-253 and FASB-69, the present value of future cash flows from proved developed reserves is given by

$$\hat{r}_1 = S_0 i + S_0 i^2 + \ldots S_0 i^{n_1} + S_0(N_1 - n_1) i^{n_1+1} \quad (1)$$

where $i=(1.1)^{-1}$ is the discount factor. The last term in (1) denotes the revenue from residual production in the year n_1+1. Similarly, the present value of cash flows from total proved reserves, denoted by $\hat{R}_1$, is given by (1) when N_1 and n_1 are replaced by N_1' and n_1', respectively. The values $\hat{r}_1$ and $\hat{R}_1$ are the estimates from this model for the reported reserve values r_0 and R_0.

3.2 Industry-Based Expectation Model (Model 2)

It will be seen in the next section that model 1 generally overestimates r_0 and R_0 values. There are at least two reasons why this occurs. First, the naive production plan of model 1 is usually violated in practice since most firms have declining production rates. Second, the model equation for total proved reserves does not make an allowance for the future cost of developing undeveloped reserves. Mitigating these two factors somewhat, model 1 implicitly uses average prices instead of the usually higher year-end prices, thus underestimating r_0 and R_0. Each of these factors, to be discussed below, will be adjusted for in model 2 using various non-RRA data available from industry statistics.

Consider a correction to model 1 to adjust for price changes during a year. Given the large price increases for oil and gas in the period 1979–81, this adjustment may be significant for many firms. As noted, firms are expected to use year-end prices and costs to compute r_0 and R_0. However, the reported net revenue, S_0, used in (1), is based on various prices and costs prevailing throughout the year. Since the expectation model does not have access to these data, industry-wide price data will be used to adjust S_0 to reflect year-end prices and costs.

Table 2 presents the industry-wide average domestic wellhead price of oil and gas for the years 1979–82.[12] The price adjustment index, a, will be defined as

$$X_e/X_m \quad (2)$$

where X_e is (oil production x year-end oil price)+(gas production x year-end gas price), X_m is (oil production x mid-year oil price)+(gas production x mid-year gas price) and the production figures are firm-specific. Then the adjusted net revenue[13] using year-end industry prices is given by $S_0' = S_0 a$. The adjustment will vary from firm to firm since it depends on i) a firm's production mix, and ii) a firm's fiscal year-ending month.

Model 1 assumed a naive production plan of constant production. In this model, it is assumed that investors use the industry-wide average production decline rate as an estimate for a firm's production decline rate. RRA requires firms to estimate future production based only on existing fields and not on assumed future discoveries. Hence, the decline rate used in this model is the average decline rate of existing fields, which is likely to be different from the decline rate one observes in the annual industry production data. This model will

[12] The data were obtained from *Monthly Energy Review*, a publication of the U.S. Energy Department, which also provides price data for imports. The domestic prices were used because they were more relevant to the majority of firms in the empirical study described in Section 4.

[13] This adjustment assumes that the denominator of (2) represents the weighted average of prices actually experienced by a firm. A more accurate adjustment is possible if firms disclose monthly production data.

TABLE 2

U.S. OIL & GAS PRICES

Crude Oil: Average domestic wellhead price per barrel, in dollars.
Gas: Average domestic wellhead price per thousand cubic feet, in dollars.

	CRUDE OIL				GAS			
Month	*1979*	*1980*	*1981*	*1982*	*1979*	*1980*	*1981*	*1982*
January	$ 9.46	17.86	28.85	30.87	$0.995	1.382	1.785	2.164
February	9.69	18.81	34.14	29.76	1.018	1.435	1.834	2.234
March	9.83	19.34	34.70	28.31	1.063	1.488	1.865	2.236
April	10.33	20.29	34.05	27.65	1.070	1.553	1.917	2.271
May	10.71	21.01	32.71	27.65	1.116	1.573	1.952	2.295
June	11.70	21.53	31.71	28.14	1.129	1.578	1.995	2.300
July	13.39	22.26	31.13		1.164	1.655	2.012	
August	14.00	22.63	31.13		1.190	1.655	2.012	
September	14.57	22.59	31.13		1.206	1.705	2.115	
October	15.11	23.23	31.00		1.240	1.723	2.140	
November	15.52	23.92	30.98		1.256	1.770	2.178	
December	17.03	25.80	30.72		1.289	1.750	2.131	
Average	$12.64	21.59	31.77		$1.178	1.603	1.995	

Source: Monthly Energy Review

assume that the field decline rate is described by an exponential curve of production vs. time, which is commonly observed in many oil and gas fields. Maddox [1982], Hobson and Tiratsoo [1981] and Uren [1953] describe oil and gas production mechanisms that justify the use of this assumption.

Let $0<g<1$ be the average field decline rate and $h=1-g$ such that, for every field, production in year $t+1$ is given by g times production in year t. Let D_t be the reserve addition in year t, which equals the sum of revisions to beginning reserves, new discoveries, and purchases of reserves. Every addition, D_t, results in future productions d_{t+1}, gd_{t+1}, $\ldots$, $g^{n-1}d_{t+1}$, where n is the field life.[14] Summing these and rearranging terms, we get $d_{t+1}=kD_t$, where $k=h/(1-g^n)$. The current-year production, p_0, comes from all prior year additions. Hence

$$p_{t+1}=kD_t+kgD_{t-1}+\ldots kg^{n-1}D_{t-n+1},$$

which can be rewritten as

$$p_{t+1}-gp_t=kD_t-kg^nD_{t-n}. \quad (3)$$

Given $g<1$, g^n can be assumed negligible and k assumed equal to h for large n. Then,[15]

$$p_{t+1}-gp_t=hD_t.$$

Substitution of this equation into the material balance equation for proved reserves, $Q_t=Q_{t-1}+D_t-p_t$, and some simplifying yields:

$$(p_t-p_{t-1})=h(Q_{t-1}-Q_{t-2}). \quad (4)$$

Table 3 presents the data on U.S. domestic oil and gas production and year-end reserves for 1969 to 1979. These data and equation (4) can be used to obtain an estimate of g for use in model 2.

[14] That D_t will result in production in year $t+1$ is a reasonable assumption for many firms since D_t often comes from revisions to existing developed reserves or from new discoveries of fields near producing fields.

[15] It is seen here that g is different from the decline rate in observed production, of p_{t+1}/p_t. The rates are equal only when discoveries and reserve purchases are zero.

TABLE 3

U.S. OIL AND GAS RESERVES AND PRODUCTION[a]

(1) Year	(2) Oil reserve[b]	(3) Gas reserve[c]	(4) Oil and Gas reserve[d] (Q_t)	(5) Oil production[e]	(6) Gas production[f]	(7) Oil and Gas production[d]	(8) Non-Alaskan production[d] (P_t)	(9) Change in Q_t	(10) Change in P_t	(11) g[g]
1969	29,632	275.11	75,484	3,195.3	20.70	6,645.3	6,571.3			
1970	39,001	290.75	87,459	3,319.4	21.92	6,972.7	6,889.1	11,975		
1971	38,063	278.80	84,530	3,256.1	22.49	7,004.4	6,924.9	−2,929	35.8	0.9970
1972	36,339	266.08	80,686	3,281.4	22.53	7,036.4	6,963.5	−3,844	38.6	1.0132
1973	35,300	249.95	76,958	3,185.4	22.65	6,960.4	6,888.1	−3,728	−75.4	0.9804
1974	34,250	237.13	73,772	3,043.5	21.60	6,643.5	6,572.9	−3,186	−315.2	0.9155
1975	32,682	228.20	70,715	2,886.3	20.11	6,238.0	6,168.2	−3,057	−404.7	0.8730
1976	30,942	216.03	66,947	2,825.3	19.95	6,150.3	5,986.9	−3,768	−181.3	0.9407
1977	29,486	208.88	64,299	2,859.5	20.03	6,197.8	6,028.6	−2,648	41.7	1.0111
1978	27,804	200.30	61,187	3,029.9	19.97	6,358.2	5,909.6	−3,112	−119.0	0.9551
1979	27,051	194.92	59,538	2,958.1	20.47	6,369.8	5,858.5	−1,649	−51.1	0.9836

Mean g = 0.9633
Standard dev. = 0.0470

Notes

[a] Data taken from DeGolyer and MacNaughton [1981].
[b] In millions of barrels, end of year.
[c] In trillions of cubic feet, end of year.
[d] In equivalent millions of barrels. Gas converted to oil using 6 thousand cubic feet = 1 barrel.
[e] In millions of barrels.
[f] In trillions of cubic feet.
[g] See equation (4).

Given the exceptional nature of the Alaskan oil discovery and its delayed impact on output, the non-Alaskan production (column 8) will be denoted p_t. The computed g values (column 11) range from 0.873 to 1.013, with a mean of 0.9633. The actual average rate is likely to be smaller than this since (4) was derived by making approximations to some terms in (3). Hence, for model 2, I will assume $g = 0.95$.

Cost of development was ignored in model 1 when defining the estimate, R, for proved reserve value. In practice, development costs can be significant. For example, from a survey of the 1979 financial reports of 147 oil and gas firms, Arthur Andersen & Co. [1981] found that the cost of exploration and development was, on the average, 62.5 percent of the present value of reserves added. Model 2 will use this industry-based, non-RRA information. I examined the development and exploration costs reported in 1979 by about 160 firms, and found that about 40 percent of the above total represents development cost.[16] Hence, the proportion of development cost to reserve value is $0.4 \times .625 = .25$, and so model 2 will assume that the present value of net cash flows from proved *undeveloped* reserves equals 0.75 times the present value based on cash flows that exclude development cost.

With the adjustments for price changes, production decline, and development cost, the model 2 equations for reserve value can now be derived. Consider the developed reserves, q_0, first. Let the integer n_2 be the reserve life. If p_0 is the current year production, then

$$q_0 = p_0 g + p_0 g^2 + \dots p_0 g^{n_2} + u_2,$$
$$0 < u_2 < p_0 g^{n_2+1}, \quad (5)$$

where u_2 is the residual production in year $n_2 + 1$. The constraint in (5) is useful in computing n_2 and u_2 given p_0 and q_0. Using the price-adjusted net revenue, the estimate for proved developed reserves is given by

[16] The empirical study is described in the next section. King [1982] obtains almost the same results on cost behavior from a survey of 128 companies.

$$\hat{r}_2 = S'_0 gi + S'_0 g^2 i^2 + \ldots S'_0 g^{n_2} i^{n_2} + S'_0 u_2 p^{-1} i^{n_2+1}. \quad (6)$$

Equations similar to (5) and (6) are used to obtain the estimate, $\hat{R}_2$, for the total proved reserve value. With proved reserves Q_0 used in (5) instead of q_0, one gets proved reserve life n'_2 and proved reserve residual production u'_2. Substituting these in (6) for n_2 and u_2, one gets an estimate for proved reserve value that excludes development cost. Denote this as $\hat{R}_{2u}$. As discussed above, the estimate, $\hat{R}_2$, adjusted for development cost, is then given by $\hat{R}_2 = 0.75(\hat{R}_{2u} - \hat{r}_2) + \hat{r}_2 = 0.75\hat{R}_{2u} + 0.25\hat{r}_2$.

3.3 Firm-based Expectation Model (Model 3)

The three adjustments for price changes, production decline, and development cost were made in model 2 using industry statistics. In this model the first two factors will be adjusted using additional non-RRA data available in a firm's financial disclosure. Primary use will be made of the three-year net revenue forecasts issued by firms as part of ASR-253 and FASB-69 requirements. These aggregate revenue forecasts do not give any direct information on field-specific prices, costs, or production and hence are not RRA signals as defined in Section 2.2.

Consider first an adjustment for price. Since the revenue forecasts are based on current year-end prices and costs, given current reserves, they can be used to obtain a firm-specific adjustment for price. Let $\hat{S}_1$, $\hat{S}_2$, and $\hat{S}_3$ be the revenue forecasts based on proved developed reserves. In this model, each $S'_0 g$ term of (6) will be replaced by the firm-specific datum, $\hat{S}_1$.

The revenue forecasts can also be used to estimate the decline rate applicable to the company's reserves. Since $\hat{S}_1$, $\hat{S}_2$, and $\hat{S}_3$ are based on the same prices and costs, the arithmetic average of the ratios $\hat{S}_1/S'_0$, $\hat{S}_2/\hat{S}_1$, and $\hat{S}_3/\hat{S}_2$ should give an estimate of the firm's projected aggregate production decline rate.[17] Denote this firm-specific decline rate as G. Correspondingly, $H = 1 - G$. The industry-wide decline rate, g, of model 2 will be replaced by G in this model.[18]

The exponential decline assumption will be generally maintained in this model. However, an examination of sales forecasts of a few firms revealed that when the computed G was much smaller than 1 and when the firms also had a small current production, the exponential decline assumption led to the possibility that the firms' production would decay to zero before their reserves were exhausted. This would happen whenever $qH > Gp$. In practice, firms do not allow production to decay to zero, and usually institute secondary and tertiary recovery techniques to increase or maintain the production rate at an economical level. In this model, I will assume that firms switch to constant production techniques when the production level declines to 20 percent of current-year level.[19] Let the integer, n_3, be the total reserve life of developed reserves, made of n_{3a} years of exponentially declining production and n_{3b} years of constant production, and u_3 be the residual production in the year $n_3 + 1$. The term n_{3a} can be estimated from the relationship[20] $p_0 G^{n_{3a}+1} < 0.2p_0 < p_0 G^{n_{3a}}$. After n_{3a} years, the firm is left with developed reserves of $[q_0 - (p_0 G(1 - G^{n_{3a}})/H)]$. Dividing this by $p_0 G^{n_{3a}+1}$ and taking the integer component gives

[17] Alternatively, the geometric mean could be used.

[18] When a firm's revenue forecasts estimate $G > 1$, this model will assume $G = 1$.

[19] The association results reported later are not sensitive to this assumption. See also the next footnote.

[20] Some of the firms reported in the next section have G as low as 0.81. For this G, n_{3a} is seen to be approximately log 0.2/log 0.81, or 7 years. For $G = .95$, n_{3a} is about 31 years. Thus a switch to straight-line production is usually not an imminent event.

n_{3b}. The reserve life, n'_3, for total reserves is similarly obtained.

With the firm-specific adjustments for prices and production, an estimate, $\hat{r}_3$, for the value of developed reserves is given by

$$\hat{r}_3 = (\hat{S}_1 i + \hat{S}_1 G i^2 \ldots + \hat{S}_1 G^{n_{3a}-1} i^{n_{3a}}) + [\hat{S}_1 G^{n_{3a}} i^{n_{3a}+1}(1-i^{n_{3b}})/(1-i)] + \hat{S}_1 u_3 p_0{}^{-1} G^{-1} i^{n_3+1}. \quad (7)$$

To compute the estimate, $\hat{R}_3$, for total reserve value, an estimate unadjusted for development cost, $\hat{R}_{3u}$, is first obtained using (7) with proved reserve data on sales and reserve life substituting for proved developed reserve data. Then the estimate, $\hat{R}_3$, adjusted for development cost, is given by $0.75\hat{R}_{3u} + 0.25\hat{r}_3$.

4. Empirical Study

This section describes an empirical study of the association between the estimates from the three expectation models and actual RRA reserve values. The objective is to evaluate the potential information content of the RRA signals by examining the sufficiency of non-RRA model estimates as proxies for RRA data. In addition, this section evaluates the predictive ability of the three models since this may indicate potential RRA information about firm-specific risk characteristics.

4.1 Sample Selection and Data Collection

Moody's Industrial and OTC manuals were used to identify publicly held oil and gas firms. All firms listed in the 1982 Moody's manuals under the section "Petroleum producing, refining, transporting and distributing" were examined. The following criteria were then applied:

i) The firm must have existed since 1979.
ii) It must have sales during fiscal 1980 of at least $1 million.
iii) Its business description in the Moody's entry must specify exploration and/or production as an activity.
iv) Its annual report for 1981 and 10-Ks for 1980 and 1979 must be available.

Criteria (i) and (ii) were imposed mainly to eliminate small public firms with little or no expected data availability. Six firms which were not listed in the Moody's indices under "Petroleum . . . " but which satisfied criteria (i) to (iv) were included in the sample. Finally, Canadian firms were excluded even if they satisfied (i) to (iv) since past studies have found that they could bias empirical results on American oil and gas accounting issues.

The final sample contained 162 firms, of which 100 are listed in one of the exchanges and 62 are traded over-the-counter (OTC).[21] The following is a break-down based on sales size:

Sales (1980)	*Listed*	*OTC*	*Total*
$10 billion or more	16	—	16
$1 billion to $10 billion	21	—	21
$100 million to $1 billion	28	6	34
$10 million to $100 million	29	26	55
$1 million to $10 million	6	30	36
Total	100	62	162

This sample is larger than that of Collins, Rozeff and Salatka [1982] or King [1982]. It is also larger than the one used in the survey by Arthur Andersen & Co. [1981], but more recent surveys by this firm have included more firms in the sample.

Historical cost data such as sales, total assets, and net income, and oil and gas-related data such as production and reserve quantities were collected for the sample firms for the fiscal years 1979,

[21] The list of firm names is available from the author upon request.

TABLE 4

SUMMARY OF ESTIMATED AND REPORTED RESERVE VALUES

	Reported R_0	Model 1 $\hat{R}_1$	Model 2 $\hat{R}_2$	Model 3 $\hat{R}_3$	Reported r_0	Model 1 $\hat{r}_1$	Model 2 $\hat{r}_2$	Model 3 $\hat{r}_3$	Company decline rate G	Price adjustment Index, a
					Panel A: 1981 Fiscal Year					
Firms with data	156	156	156	156	156.	156	156	156	156	156
Mean	$2,655.68	$3,414.41	$2,883.06	$2,520.56	$2,164.28	$2,948.28	$2,682.42	$2,397.45	1.0018	0.9968
10 Percentile	13.10	12.95	10.26	16.30	10.58	11.04	8.67	15.82	0.8436	0.9520
30 Percentile	45.45	45.96	39.52	55.68	39.85	37.19	35.47	52.95	0.9056	0.9843
Median	134.10	125.29	118.49	140.88	109.76	116.24	114.36	136.90	0.9482	0.9964
70 Percentile	548.00	569.88	531.00	516.62	508.00	550.49	504.61	513.00	1.0208	1.0097
90 Percentile	9,458.00	10,030.11	8,310.12	8,441.04	8,062.00	9,224.33	7,901.06	7,667.62	1.2382	1.0311
					Panel B: 1980 Fiscal Year					
Firms with data	161	158	157	150	161	159	159	152	152	159
Mean	$2,557.16	$3,020.15	$3,070.42	$2,406.71	$2,031.25	$2,592.96	$2,818.52	$2,301.51	0.9569	1.1843
10 Percentile	7.78	8.14	8.85	10.74	6.41	7.20	8.06	9.02	0.7859	1.1382
30 Percentile	33.95	31.07	32.47	35.87	26.38	23.49	26.93	31.78	0.8664	1.1589
Median	108.37	100.53	99.78	121.01	87.24	89.05	92.63	107.34	0.9084	1.1724
70 Percentile	[illegible]3.42	429.55	445.24	508.76	279.04	408.77	440.91	497.23	0.9734	1.1854
90 Percentile	7,832.00	10,052.89	10,589.16	9,402.35	6,381.00	8,185.66	9,063.08	6,771.16	1.1693	1.2234

Notes

1) All values in the first eight columns except "Firms with data" are in millions of dollars.
2) $\hat{R}_j$ refers to value of proved reserves and $\hat{r}_j$ refers to value of proved developed reserves, for models $j = 1, 2, 3$. $R_{\bullet}$ and $r_{\bullet}$ are reported reserve values.

1980, and 1981.[22] In addition, disclosures on RRA reserve value, expected future cash flows based on RRA, income based on RRA, and costs of exploration and development were also collected. Most of the data were unavailable in computer-readable form and had to be manually collected from 10-Ks and Annual Reports. Complete, usable sets of data were available for 156 firms for fiscal 1981, and 150 firms for fiscal 1980 and 1979.

RRA disclosures were begun by companies in the year 1979. During that first year of disclosure, most firms relied on their own techniques and formats to report the RRA data, since the SEC had given little guidance on these. Reporting procedures have become more uniform in subsequent years. Since an objective of this study is to examine the association results for potential information content, the focus of the following analysis is primarily on the more uniform 1980 and 1981 years' data.[23] The reserve values for proved reserves and proved developed reserves were estimated for these two years using the three models of Section 3 for the sample firms. Table 4 presents descriptive statistics for the six estimates as well as for the two reported reserve values for each year. Model 2 requires estimation of a price adjustment index for sales and model 3 requires estimation of company-specific decline rates. Statistics for these are also described in Table 4. The statistical association between the estimates and actual values is examined next.

4.2 Association Results

Two association statistics, the Pearson product-moment correlation coefficient and Kendall's tau, were computed for various subgroups of the sample to measure statistically the level of association between predicted and actual reserve value data. Both statistics assume that each individual occurrence of a model

[22] Fiscal year was defined as year $x-1$ if the ending month in year x was 1 to 6, and as year x for ending months 7 to 12.

[23] With a different objective, Bell [1983] examined primarily 1979 RRA disclosures.

estimate and actual reserve value is a joint numerical random event and test the strength of the statistical relation between the variables. They also test the possible predictive ability of the relation. Neither statistic requires any assumption on causality. Association measures were computed for the full sample as well as for various subgroups. The latter was done to investigate whether the performance of the three models as expectation models differed between large and small firms. Proponents of RRA disclosures have in the past suggested that the disclosures are likely to be more valuable to investors of smaller oil and gas firms. Association measures for subgroups were expected to shed light on this possibility.

In the absence of a uniformly agreeable proxy for size in the literature, five different variables were used to form subgroups. Three of them were: total sales, net revenue from oil and gas operations, and proved reserve quantity. The first of these has been used often in the past as a proxy for firm size. The oil and gas net revenue measure probably is a preferred proxy for size in this study since RRA disclosures depend more on this variable than on total sales. For the same reason, reserve quantities were also considered as a size proxy. Firms were formed into five equal subgroups under each size variable using the 20, 40, 60, and 80 percentile values of the variables, with group 1 having the largest 20 percent and group 5 having the smallest 20 percent of the firms. In addition, two subgroups based on exchange listing (listed vs. OTC) were also formed. Differences in expectation models for listed and OTC stocks have not been studied in the past. Finally, firms were broken into full cost (FC) and successful efforts (SE) method groups. It has been suggested that information production costs for RRA disclosures could be different for FC and SE firms since the former tend to be more aggressive in exploration and hold greater reserves in relation to total assets (see Collins, Rozeff and Salatka [1982]). These possible differences in information costs may imply differences in information value as well. In summary, a total of 19 subgroups were analyzed together with the full sample.

Table 5 presents the squared correlation coefficients, or coefficients of determination, using the 1981 data for the twenty groups. The three models give rise to two pairs of variables each: predicted proved reserve values vs. actual proved reserve values, and predicted proved developed reserve values vs. actual proved developed reserve values. In addition to these six pairs, the association between proved reserve *quantities* and reported proved reserve values was also examined. In the absence of the predictions from the three models, reserve quantities might be considered the best available proxy for reserve values. Hence the association metrics for this pair should serve as benchmarks to evaluate the three models.

Considering the full sample first, the correlation coefficients indicate a high degree of association between model predictions and reported values for both proved and proved developed reserves. For 1981 data and model 3, about 94 percent of the variability in R_0 and r_0 is accounted for by a linear univariate rule between actual data and model predictions. Only six percent is due to omitted RRA information signals. The strength of the association is about equal for models 1 and 2 at 83 to 84 percent, but higher for model 3. This means that a naive model of constant production plan is not improved by addition of industry-wide variables, but is considerably improved by addition of company-specific decline rate data. All three models per-

TABLE 5

COEFFICIENTS OF DETERMINATION FOR RESERVE VALUE ESTIMATES ASSOCIATION PAIRS

Year	*Grouping*	$R_0-\hat{R}_1$	$R_0-\hat{R}_2$	$R_0-\hat{R}_3$	$r_0-\hat{r}_1$	$r_0-\hat{r}_2$	$r_0-\hat{r}_3$	R_0-Q_0	*Sample size*
1981	Full Sample	.8293	.8305	.9431	.8420	.8390	.9364	.7786	156
1981	Sales 1	.7114	.7088	.8955	.7248	.7186	.8803	.6534	32
1981	Sales 2	.9527	.9592	.8728	.9214	.9550	.9104	.8902	32
1981	Sales 3	.9109	.9021	.9661	.9176	.9171	.9558	.9574	31
1981	Sales 4	.7778	.7061	.7938	.8030	.7175	.8725	.7822	31
1981	Sales 5	.8642	.7833	.9125	.9256	.8953	.9620	.8950	30
1981	O&G Sales 1	.7049	.7014	.8925	.7184	.7115	.8768	.6490	32
1981	O&G Sales 2	.9213	.9330	.8592	.9036	.9283	.9199	.8914	31
1981	O&G Sales 3	.6247	.4977	.6945	.7005	.5694	.8258	.6780	32
1981	O&G Sales 4	.5284	.5247	.8689	.6085	.6280	.8820	.5348	31
1981	O&G Sales 5	.6474	.4380	.8782	.6079	.5307	.9080	.9505	30
1981	Reserves 1	.7054	.7023	.8924	.7183	.7119	.8764	.6480	32
1981	Reserves 2	.8999	.9104	.7765	.8775	.8834	.8287	.7590	30
1981	Reserves 3	.5489	.5264	.5527	.7605	.7898	.8450	.2520	32
1981	Reserves 4	.5578	.4704	.7392	.7960	.7492	.7950	.6439	31
1981	Reserves 5	.1271	.1790	.8095	.1891	.2495	.8826	.7105	31
1981	Full Cost	.9922	.9929	.9846	.9915	.9939	.9909	.9832	69
1981	Succ. Effort	.8145	.8153	.9380	.8277	.8243	.9300	.7621	87
1981	Listed	.8168	.8177	.9384	.8299	.8266	.9308	.7648	99
1981	OTC	.9185	.8801	.8842	.9730	.9710	.9685	.8326	57
1980	Full Sample	.8495	.8570	.8884	.8347	.8333	.8916	.7761	150

Notes

1) $\hat{R}_j$ refers to value of proved reserves and $\hat{r}_j$ refers to value of proved developed reserves, for models $j=1, 2, 3$. R_0 and r_0 are reported reserve values.
2) Q_0 is the proved reserve quantity.
3) Sample sizes for subgroups are not equal because of missing or non-estimable data.

form better than the benchmark model of R_0 vs. Q_0. Results are similar for 1980 fiscal year data, which are given in Table 5 for the full sample only.

The strength of the relationship between predicted and actual values varies considerably among the subgroups. For the five groups based on sales, the coefficients are largest for group 2 and smallest for group 4. Surprisingly, group 1 firms do not have the best coefficients.[24] The subgroups based on oil and gas net revenues and reserve quantity show a similar pattern. They also point to the superiority of model 3 over the other two.

The FC-SE method classification produced surprisingly significant differences in the coefficient values. For the 1981 data, the three models, as well as the reserve quantity, explained 98 to 99 percent or more of the variation in the reported reserve values of FC firms. Coefficients for the SE firms were much smaller. The 1980 data showed a similar difference. It is not clear why the two groups should have this difference. As noted, FC firms are likely to have higher information preparation costs. The above results imply that their RRA reserve values have lower potential information content as well.

Models 1 and 2 have low association metrics for the large exchange-listed firms

[24] This is perhaps because some of the largest firms did not include their significant interests in the Middle Eastern fields in computing their reserve values. The R_0-Q_0 correlation is also low for group 1 firms.

TABLE 6

KENDALL'S TAU STATISTICS FOR RESERVE VALUE ESTIMATES ASSOCIATION PAIRS

Year	*Grouping*	$R_0-\hat{R}_1$	$R_0-\hat{R}_2$	$R_0-\hat{R}_3$	$r_0-\hat{r}_1$	$r_0-\hat{r}_2$	$r_0-\hat{r}_3$	R_0-Q	*Sample size*
1980	Full Sample	.8907	.8717	.9025	.9064	.8973	.9213	.9231	150
1980	Sales 1	.8826	.8788	.8485	.8561	.8523	.8902	.8636	33
1980	Sales 2	.8836	.9048	.8413	.8889	.8889	.8889	.8677	28
1980	Sales 3	.8769	.8128	.8374	.8867	.8621	.8522	.8670	29
1980	Sales 4	.6452	.5524	.7419	.6492	.6169	.7540	.8819	32
1980	Sales 5	.7672	.6931	.7852	.8148	.7831	.8677	.8609	28
1980	O&G Sales 1	.8629	.8508	.8347	.8307	.8266	.8669	.8266	32
1980	O&G Sales 2	.7677	.7936	.7677	.7763	.7763	.8409	.7449	31
1980	O&G Sales 3	.6690	.5494	.6690	.7563	.6828	.7977	.7871	30
1980	O&G Sales 4	.5527	.3979	.6645	.5097	.4280	.6860	.7333	31
1980	O&G Sales 5	.7046	.6000	.7870	.7169	.6923	.7723	.8179	26
1980	Reserves 1	.8548	.8508	.8186	.8186	.8145	.8670	.8468	32
1980	Reserves 2	.6782	.6828	.7563	.7655	.7609	.7977	.7043	30
1980	Reserves 3	.6699	.5813	.6158	.7586	.7143	.7291	.5961	29
1980	Reserves 4	.5011	.3936	.5785	.6215	.5828	.6860	.5912	31
1980	Reserves 5	.3915	.3545	.6207	.5079	.5027	.6349	.7835	28
1980	Full Cost	.8424	.8183	.8626	.8732	.8583	.8909	.8979	66
1980	Succ. Effort	.9053	.8927	.9235	.9134	.9088	.9398	.9331	84
1980	Listed	.9015	.8921	.9050	.9153	.9095	.9265	.9141	95
1980	OTC	.8088	.7643	.8457	.8357	.8141	.8626	.9944	55
1981	Full Sample	.9137	.9026	.9233	.9288	.9245	.9378	.9047	156

Notes

1) $\hat{R}_j$ refers to value of proved reserves and $\hat{r}_j$ refers to value of proved developed reserves, for models $j=1, 2, 3$. R_0 and r_0 are reported reserve values.
2) Q is the proved reserve quantity.
3) Sample sizes for subgroups are not equal because of missing or non-estimable data.

and higher coefficients for the OTC firms. This somewhat surprising result parallels the above result on FC-SE classification though for this sample, FC firms are as likely to be listed as traded over the counter. For the full sample, 47 percent of the OTC firms and 43 percent of the listed firms followed the FC method.

In summary, the coefficients of determination indicate that model 3 predictions are highly and most closely associated with reported reserve values, with models 1 and 2 having somewhat lower and equal levels of association. Within subgroups, the models are as satisfactory for the smallest firms as for the largest firms. The accounting method used by firms for exploration seems to have a significant effect on the association results, with the models performing extremely well with the full cost firms and less well with the successful effort firms.

The statistics in Table 5 measure association between sets of data by assuming a *linear relationship* between the underlying variables. However, it is not clear from the model development in Section 3 that a linear relationship between model expectations and actual data *should* exist. Association can be defined more generally in terms of *monotonicity*, rather than its subset linearity, in the underlying relationship between two sets of data. Monotonicity can be measured by either the Spearman rank correlation coefficient or the Kendall's tau statistic. Of these, the latter has several desirable advantages and will be used here.[25]

Table 6 presents the values of the Kendall's tau statistics for the sample for 1981 and 1980. Since Table 5 focused mostly on 1981, Table 6 presents the 1980 data for the various subgroups. The statistics, which tell us the strength of the monotonicity relationship, with +1 or −1 denoting perfect monotonicity and 0 denoting independence, are similar in many respects to the Table 5 data on coefficients of determination. An important difference is that all three models have comparable values for monotonicity, while model 3 had better coefficients of determination. Another important difference is that the SE firms have comparable or slightly superior Kendall statistics compared to the FC firms, while the FC firms had better statistics on coefficients of determination. Overall, though, the conclusion that the three models are extremely satisfactory expectation models for both large and small oil and gas firms is supported by both sets of statistics.

The main implication of these results is that the non-RRA information sets shared by the three models (and the firms preparing RRA data) explain much of the variability in the RRA data. The variability attributable to the unique RRA signals on field-specific costs, prices, and production, which are known only to the firms and not to the investors, is minimal when the full sample is considered. This is consistent with the view that the RRA signals potentially convey little information over and above that provided by related non-RRA data. Yet, at least for certain groups of companies (such as size groups 1 and 4) and for firms following the successful effort method, RRA signals do seem to provide incremental information. More importantly, Tables 5 and 6 data only tell us that predictable associations exist for *portfolios* of firms and do not address the issue of the magnitude of prediction errors for *individual* firms. If the three models are found to have large firm-specific prediction errors, then RRA signals can be potentially valuable to users (such as lenders) concerned with a firm's unsystematic risk. Such analysis is reported next.

4.3 Predictability Results

Prediction errors from the models for individual firms were computed using assumed linear relationships of the form $R_0 = a_j + b_j\hat{R}_j$, where $\hat{R}_j$ is the proved reserve value from model j ($j = 1, 2, 3$) and R_0 is the reported reserve value. The proved reserve quantity, Q_0, was also considered as a proxy for reserve value in a fourth model.

Table 7 presents the estimated a_j and b_j coefficients for the four models using the 1980 and 1981 data. For models 1–3, the expected values of a_j and b_j are zero and one, respectively, given the model development in Section 4. From Table 7, the null hypothesis $a_j = 0$ cannot be rejected at the 0.05 level for models 1–3. Thus, the intercept terms for models 1–3 appear insignificant as expected. However, adjusted t-ratios for b_j indicate that the b_j coefficients are significantly different from 1 for models 1 and 2. The two models significantly and consistently overestimate reserve values. By contrast, model 3 computes reserve value estimates only two to three percent below the reported values. While the slope coefficients are nonunity for models 1 and 2, the high R^2 values mean that the overestimations from the two models are *consistent*, and thus predictable. Hence, an investor wanting to use the models for

[25] See Hays [1973], pp. 796–797.

TABLE 7

ESTIMATES OF LINEAR FUNCTION COEFFICIENTS

Model: $R_0 = a_j + b_j\hat{R}_j, j = 1, \ldots 4$
where R_0 is the actual reserve value and $\hat{R}_j, j = 1, \ldots 3$ is the value from model j. R_4 is the proved reserve quantity.

	1981 Data (156 Firms)			*1980 Data (150 Firms)*		
Model	*a*	*b*	R^2	*a*	*b*	R^2
1	402.10 (1.62)	0.6600 (27.35)	0.8293	377.37 (1.56)	0.7427 (28.91)	0.8495
2	358.21 (1.45)	0.7969 (27.46)	0.8305	331.39 (1.40)	0.7493 (29.78)	0.8570
3	44.51 (0.31)	1.0359 (50.53)	0.9431	272.72 (1.30)	1.0202 (34.32)	0.8884
4	636.52 (2.27)	4.7926 (23.27)	0.7786	664.11 (2.27)	4.6349 (22.65)	0.7761

Notes
1. R^2 is the coefficient of determination.
2. The numbers in parentheses under the coefficients are the t-ratios.

forming reserve value expectations would be expected to adjust the computed values using the coefficients in Table 7. In other words, an expected value from models 1–3 is obtained by computing the value $\hat{R}_j$ from Section 3 and then computing the expectation $a_j + b_j\hat{R}_j$ using Table 7 coefficients.

The expectation errors from the three models were computed when the above procedure was used to form model expectations. First, the linear equations for all models were reestimated by suppressing the intercept terms. The reestimated slope coefficients for the 1980 data were 0.7562, 0.7613, 1.0335, and 4.7793 for the four models. Next, to measure forecast errors more accurately, the 1981 model values were multiplied by the slope coefficients estimated from the *1980* data, and the resulting expectations were compared with the actual 1981 reserve values. The following error measures were then computed for every model and every firm:

Squared Percentage Error (SPE)

$$= \left(\frac{b_j\hat{R}_j - R_0}{R_o}\right)^2 \times 100,$$

Absolute Percentage Error (APE)

$$= \left|\frac{b_j\hat{R}_j - R_0}{R_0}\right| \times 100.$$

These two measures are similar to the mean square percentage error (MSPE) and mean absolute percentage error (MAPE) studied in Dharan [1983].

The computed error measures for the 1981 data showed that, despite the high coefficients of determination and despite the use of reestimated b_j values, SPE and APE were large for many firms. The median APEs were 24%, 29.8%, 19.4% and 50.1% and SPEs were 5.8%, 8.9%, 3.8% and 25.2% for the four models respectively. For model 3, which seemed to have the lowest errors, the APE measure ranged from a 10th-percentile value of 3.7 percent to a 90th-percentile value of 54.6 percent. These high prediction errors imply that the RRA reserve value disclosures may have potential information content with respect to firm-specific risk characteristics.

5. Conclusion

This study examined the potential information content of RRA reserve values using three expectation models of RRA disclosure. The model design was characacterized by the fact that all RRA signals, identified in Section 2 as comprised of field-specific data on costs, prices, and planned production, were excluded from the information sets of the models. Expectations of RRA reserve value disclosures were formed using non-RRA signals concurrently released with RRA data. Given this design, association between model estimates and actual reserve value data was expected to provide a measure of the incremental potential information content of RRA signals.

The results from the empirical study of about 160 small and large oil and gas firms showed that, at the full sample level, all three model estimates were highly associated with the reported reserve value data. Model 3, in particular, was able to explain 94 percent of the observed variation in 1981 reserve values. The strength of the association varied somewhat among five subgroups based on size, but was comparable for the largest and smallest firms. Some surprising differences in linear association were found when the firms were classified based on accounting methods and exchange listing. Except for the latter, the results were similar when the association was measured nonparametrically.

Overall, the results were consistent with the view that the RRA signals may have low information content when considered incrementally over the model information sets. An implication of this is that incremental security return effects due to RRA disclosures are likely to be minimal, and may even be unnoticeable when the sample is dominated by large to medium firms. In two recent studies of the security return behavior around an RRA disclosure event, Bell [1983] and Bell, Boatsman and Dhaliwal [1983] found that i) the stock market did react significantly to the 1979 RRA disclosures and ii) the reaction was more pronounced than that accompanying 1979 earnings disclosure. These two studies, however, did not employ any expectation model for RRA disclosure and consequently it is hard to interpret the market reaction they observed as signifying information content. It is hoped that a subsequent study will use the models developed here as expectation models to examine security return effects.

The three models do have significant prediction errors at the company level. For certain types of financial statement users such as lenders, reserve values of specific firms, rather than portfolios, are likely to be of value to determine various risk characteristics. Such users cannot be satisfied with the expectation models developed here and will likely find incremental information content in the RRA disclosures of the firms they are interested in. An examination of the development of the RRA methodology confirms that the latter class of users has demanded and obtained RRA-type data even prior to ASR-253. For many years, banks lending to oil and gas firms have required the firms to provide a measure of the present value of future cash flows from reserves, using procedures similar to RRA. The SEC in ASR-253, and consequently the FASB in Statement 69, essentially standardized these procedures and made the data more widely available.

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