ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

149 SCOMM 9: HOUSE SPEC. COMM. ON PERMANENT FUND 1977-78

White, Weld & Co. Incorporated

Basic Report

Philip L. Dodge
(212) 285-2043

March 28, 1977

BRITISH PETROLEUM (BP)

Price (NYSE)		Dividend		EPS (Dec.)		P/E
Current	14	Rate:	$0.34	1978E:	$2.90	4.8X
Range (1976-77):	16-9	Yield:	2.5%	1977E:	$1.60	8.8X
				1976:	$0.79	17.7X

Average Shares Outstanding:	386 million	Return on Average 1976 Equity:	5.6%
Market Value:	$5,400 million	Book Value Per Share (12/31/76):	$14.45

OPINION

British Petroleum has entered a period of sharply rising crude oil production in the North Sea and Alaska, a most successful transition from former dependence on the Middle East. As a result, earnings per share should move up to $1.50-1.75 in 1977 and about $3.00 in 1978-1979 from $0.79 last year. Dividends are presently regulated by the government, limiting increases to a maximum of 10% annually. These controls might be relaxed in the future, and U.S. shareholders of BP could also receive a refund for the 35% British advance corporation tax on dividends if a preliminary intergovernmental treaty is ratified. Thus, the effective dividend to U.S. owners may increase by about 50% although it is more difficult to say whether in 1977.

The British Government owns 48% of BP directly and another 20% indirectly through the Bank of England. Despite concentration of government ownership, BP has historically operated as an independent commercial enterprise. The government is currently considering the sale of about 66 million shares of BP to reduce ownership by 17 percentage points to a still controlling 51%. However, Burmah Oil, which was forced to sell BP shares at a much lower price to the Bank of England in 1975, has instituted legal proceedings which may delay the contemplated sale. In addition, the government could be having second thoughts because of its own clearly improving finances. With rising North Sea production, impact of oil on the U.K. trade account should be moderately favorable by 1979-1980 compared with a deficit of $7 billion last year.

On balance, BP common stock looks attractive. At the current price, purchase of BP provides about 1 barrel of U.S. and North Sea crude oil per $1.00 of market value. The prospective 1978 earnings level should support a higher price within the next twelve months. However, near-term performance could be less favorable if the secondary offering materializes.

NORTH SEA OIL DEVELOPMENT

BP began to produce from the North Sea in late 1975, and it should raise output over a period extending at least into the early 1980s. During this interval, BP should consistently rank as the largest producer of North Sea oil. Several fields are involved.

Forties

Among the major North Sea fields, Forties contains an estimated 1.8 billion barrels of recoverable oil, some 96% of which is under BP acreage. Gross production is currently about 375,000 barrels a day, and a rate of 500,000 barrels a day should be reached by the end of this year. Output should be sustainable at 500,000 barrels a day until about 1982, followed by a possible 10% annual decline.

Quarterly production and sales statistics for Forties crude are shown below, including estimates for 1977 and 1978. Sales generally lag production by 30 days.

FORTIES FIELD STATISTICS
(Thousand Barrels Daily)

		Estimated	
	1976	1977	1978
Production			
1Q	78	360	500
2Q	132	410	500
3Q	182	460	500
4Q	307	490	500
Year	175	430	500
Sales			
1Q	65	355	500
2Q	115	400	500
3Q	165	450	500
4Q	255	490	500
Year	150	425	500

Brought onshore, Forties oil currently has a value of $14.20 a barrel, up from about $12.90 a barrel last year, this advance reflecting the higher end of the 5-10% OPEC price increase on January 1. The pipeline tariff is roughly $0.15, leaving $14.05 at the wellhead. The government assesses a 12½% royalty on the wellhead price, about $1.75 a barrel at the moment but lower in 1976 due to temporary credits. Individual wells produce as much as 20,000 barrels a day, and we estimate that 1977 lifting costs will be a relatively low $0.50 a barrel. Depreciation of the production investment at Forties is approximately $0.85 a barrel.

Income is subject to a 45% Petroleum Revenue Tax (PRT) which in turn is deductible before the 52% Corporation Tax. For PRT purposes, a major portion of depreciation can be "uplifted" by 75% to a resulting figure at Forties of approximately $1.25 a barrel. The effective rate of PRT is also reduced by exemption of about 75 million barrels over a ten year period. Moreover, PRT cannot be applied to reduce pretax return on investment below 30%. This provision will tend to stabilize profitability after production begins to decline. Interest cannot be subtracted before assessment of PRT.

Unit earnings estimates for Forties in 1976 and 1977 are shown below. BP also makes a modest profit on the pipeline itself. Cash flow this year should be as high as $9.50 a barrel due to accelerated deductions for U.K. tax purposes. Forecasting future years is more complicated because world oil prices will probably continue to rise. For this reason, we believe that pretax profitability will tend to increase over time even if taxation becomes more onerous.

	1976		1977	
	Financial Reporting	PRT Purposes	Financial Reporting	PRT Purposes
	($ per Barrel)			
Per Barrel				
Landed Price	$12.90	$12.90	$14.20	$14.20
Pipeline Tariff	0.20	0.20	0.15	0.15
Wellhead Price	$12.70	$12.70	$14.05	$14.05
Royalty	1.15	1.15	1.74	1.74
Lifting Costs	0.80	0.80	0.50	0.50
Depreciation	0.85	1.25	0.85	1.25
PRT Allowance		0.60		0.25
Income for PRT		$ 8.90		$10.31
PRT (45%)	4.00	4.00	4.64	
Interest	1.50	–	0.50	–
Pretax Income	$ 4.40	–	$ 5.82	–
Corporation Tax (52%)	2.29	–	3.03	–
Net Income	$ 2.11	–	$ 2.79	–
Total				
Sales (mil. bbl.)	54	–	155	–
BP's 96% Share	51	–	149	–
Net Income (mil.)	$107	–	$416	–
Earnings Per Share	$0.28	–	$1.08	–

Other North Sea Properties

British Petroleum holds interests in several other North Sea discoveries, as follows.

United Kingdom

Field	Interest
Ninian	15%
Magnus	100
Andrew	45

Norway

Field	Interest
7/12	57½%

Of these four finds, Ninian is the most extensively delineated, and production is scheduled to begin in 1978. Recoverable reserves are estimated at 1,100 million barrels, and peak production should reach 375,000-380,000 barrels a day by 1981 before commencing an approximate 15% annual decline. Budgeted Ninian development costs are 1,425 million pounds sterling, or $2,450 million at the present exchange rate of $1.72. On this basis, amortization of investment will be about $1.75 a barrel, excluding the pipeline. Lifting costs are likely to be about

$0.75 a barrel once full potential is reached. Assuming the present North Sea oil landed price of $14.00-14.25 a barrel, unit profitability in early years should be in a $2.50-2.60 range, somewhat below Forties due to the more sizable investment. When full flow is reached in 1981, Ninian should make an annual profit contribution to BP of about $0.10-0.15 a share at current prices.

Magnus is the most northerly North Sea discovery. Although areal extent is large, development plans are complicated by faulting and by water depth of over 600 feet. In addition, the north-south length of the productive area itself poses logistical problems. BP is currently drilling the seventh well at Magnus, and a decision whether to proceed should be possible following completion of this test. If development is opted, BP will probably consider installing production platforms despite the water depth. At one time, Magnus was felt to hold about 800 million barrels, a figure which would justify a major outlay. The company has recently announced plans to spend $2.6 billion on U.K. exploration and development over the next five years. Although details have not been disclosed, we believe the major portion of this budget is for Magnus.

The Norwegian discovery on Quadrant 7, Block 12 is on a farmin from Continental Oil under which BP earned a 70% interest subject to a 12½ percentage point government option. BP completed this find last September at a location which had been drilled unsuccessfully to a shallower depth in 1968. The September 1976 well tested 7,100 barrels a day of crude oil and 4.2 million cubic feet a day of natural gas from a Jurassic sandstone below 10,900 feet. These flows suggest a sizable reservoir. A delineation well will be drilled shortly.

BP's North Sea production and earnings prospects over several years are estimated below. We have separated individual properties into the two categories of probable and speculative. Present North Sea margins are assumed, almost certainly a conservative influence. On estimated 1980 production, for example, a price of $1.00 per barrel higher would add $0.15 a share to earnings. Participation of 51% by the British government will not affect profitability, only flexibility in selling the crude.

	1977	1978	1979	1980	1981	1982
	(Millions)					
Annual Production						
Probable						
Forties	149	175	175	175	175	160
Ninian	–	7	13	17	21	18
Subtotal	149	182	188	192	196	178
Speculative						
Andrew	–	–	–	3	5	7
Magnus	–	–	–	25	50	70
July 12	–	–	–	–	15	25
Subtotal	–	–	–	28	70	102
Total	149	182	188	220	266	280
Net Income						
Forties ($2.81/bbl.)	$416	$492	$492	$492	$492	$450
Ninian ($2.55/bbl.)	–	18	33	43	54	46
Others ($2.50/bbl.)	–	–	–	70	175	255
Total	$416	$510	$525	$605	$721	$751
Per Common Share	$1.08	$1.32	$1.36	$1.57	$1.87	$1.95

Fifth Round Licenses

British Petroleum was the largest participant in the fifth round of offshore licenses awarded by the U.K. government on February 9. Of 46 blocks licensed, BP received 49% interests in 11 and 25% in 2. The British National Oil Company (BNOC) holds a 51% share of all the new licenses and will pay a commensurate portion of expenses. Five of the new BP tracts are in the vicinity of discoveries east of the Shetland Islands, and the others are in new prospective areas. Considerable difference of opinion exists on the potential of the fifth round. Clearly, the largest U.K. prospects have already been licensed and tested. In fact, much of the acreage in the recent awards includes earlier relinquishments. Even so, exploration possibilities remain.

BP is also seeking to acquire interests in the Bruce and Crawford fields from the Hamilton Ground and in the Buchan field from the Transworld Group. These properties appear to be relatively small by North Sea standards and would have only modest potential for a company the size of British Petroleum.

SOHIO AND OTHER U.S. INTERESTS

In 1969, British Petroleum merged most of its U.S. interests into Standard Oil of Ohio in exchange for Sohio common stock, ultimately a controlling interest. By taking this step, BP has been able to facilitate financing of Alaskan North Slope oil development through access to U.S. capital markets. Total Sohio-BP outlays for North Slope development and transportation are currently estimated at about $7.5 billion, of which BP's direct share is some $1.5 billion, mostly financed by pipeline debt which has already been arranged.

Prospects for Standard Oil of Ohio were covered at length in a Basic Report which we issued on March 4, 1977. Our main assumptions involving Alaskan oil are as follows.

1. Gross production will begin at 600,000 barrels a day in July and reach 1,200,000 barrels a day by December.

2. Production will increase to 1,500,000 barrels a day in 1980.

3. Sohio—BP will have 53-54% of the oil.

4. During early years, about one-third of the Sohio-BP oil will be sold on the West Coast and the balance at longer haul destinations.

5. The wellhead price of North Slope oil will initially be $5.75-7.50, equivalent to imported crude less transportation and treated as imported crude for entitlements purposes.

6. The Trans Alaska Pipeline will be allowed a 6-7% return on Interstate Commerce Commission valuation including capitalized interest in the rate base but flowing through tax benefits from accelerated depreciation and investment credit.

7. The state of Alaska will raise the severance tax to about 12% from 8%, and the income tax to 9% from a presently effective 5% or less, but earlier "excess profit" tax proposals will be deferred indefinitely.

8. Prudhoe Bay natural gas production will not begin until 1982.

If these general expectations are borne out, Sohio net income should rise several fold over the next year and move moderately further upward between 1978 and 1981. In this assessment, we have allowed for world crude oil prices to rise 10-15% by 1980, probably a low assumption. Our present Sohio net income estimate along with BP's equity are shown below.

	Actual 1976	1977	1978	1979	1980	1981
			(Millions)			
Alaskan Production	–	60	410	410	625	625
Trans Alaska Pipeline	–	5	135	135	165	165
Other Operations	101	105	100	120	120	135
Investment Tax Credit	36	75	200	75	25	50
Net Income	137	245	845	740	935	975
BP's Sohio Stock Ownership	26%	34%	52%	52%	54%	54%
BP's Equity in Sohio Net Income	36	83	439	385	505	527
Per BP Share	$0.09	$0.22	$1.14	$1.00	$1.31	$1.37

In addition to its equity in Sohio, BP will also obtain earnings from 15.8% ownership of the Trans Alaska Pipeline (TAPS) and a 75% net profits interest in gross Sohio-BP Prudhoe Bay production above 686,000 barrels a day. BP's annual profits from TAPS should be $65-70 million, or $0.15-0.20 a share, assuming a 6-7% return and flow through of tax benefits from the investment credit and accelerated depreciation as currently prescribed by the Interstate Commerce Commission. In addition, BP will book an investment tax credit of about $120 million ($0.30 a share), probably spread over a period of two or three years due to the 50% of tax liability limitation.

British Petroleum also has a royalty interest in Prudhoe Bay production. If total Prudhoe Bay production reaches 1,500,000 barrels a day in 1980, as appears likely, Sohio's share would be an estimated 803,000 BD. The BP royalty interest is equal to 75% of net income from *gross* production between 686,000 BD and 1,200,000 BD. Such net income on production of 117,000 BD (803,000 BD minus 686,000 BD) would be an estimated $90-125 million in 1980, the higher end of the range if all the oil can be sold on the West Coast. BP's 75% share then is $70-90 million, or about $0.20 a share.

INTEGRATED EASTERN HEMISPHERE OPERATIONS

Historically a large merchant producer of crude oil in the Persian Gulf and Africa, British Petroleum has evolved like other international oil companies into primarily a marketer of OPEC oil. This business has been, and may for some time be, one of chronically narrow margins. The following analysis estimates 1976 profitability by major sources.

Upstream *—Iran, Kuwait, Nigeria and Abu Dhabi*

Iran

British Petroleum obtains roughly half of its crude oil supply from Iran through a 40%

interest in the Consortium. Although the precise number has not been disclosed, we believe that BP purchased about 1,700,000 barrels a day in Iran last year. Offtake by Consortium members is geared to provide a discount from world crude prices of about $0.22 a barrel. On this basis, BP would have received Iranian crude in 1976 for a profit of $135-140 million or $0.35 a share.

Kuwait

Under the 1975 takeover agreement with the government, retroactive to March 5, BP is entitled to lift 450,000 barrels a day of Kuwait crude through March 31, 1980 and 400,000 barrels a day for a five-year period thereafter. This crude is available at a discount of $0.15 a barrel with 60 days of credit. The annual discount is equivalent to $25 million, or $0.06 per BP share.

Nigeria

BP's equity interest in Nigerian production during 1976 was roughly 275,000 barrels a day. In addition, the government sells about 150,000 barrels a day to BP at the buy-back price, i.e, usually on a nonprofit basis. Nigeria's buy-back price averaged about $13.00 a barrel last year, or $1.49 a barrel above the Arabian Light marker crude. The tax-paid cost of equity crude in 1976 was an estimated $12.60 a barrel, or $2.75 of royalty, $0.75 of operating costs, and $9.10 of income taxes. On this basis, BP would have netted about $40 million, or $0.10 a share, in Nigeria last year.

Abu Dhabi

BP has equity interests of 15% in Abu Dhabi Marine Areas and 10% in Abu Dhabi Petroleum, equivalent to production in 1976 of about 165,000 barrels a day. An additional 120,000-125,000 barrels a day is obtained on a buy-back basis. We estimated that an equity profit of approximately $0.35 a barrel is still available in Abu Dhabi, indicating that BP made about $20 million, or $0.05 a share there last year.

Derivation of Estimated 1976 Downstream Results

The table on the following page summarizes estimates of profitability from principal streams of crude oil as discussed earlier, assumed chemical earnings including dividends from Erdolchemie and other European affiliates which lag operating results by one year and were therefore modest in 1976, equity in Sohio and BP Canada, and financial income. It should be noted that 1976 profits also benefited from a U.K. tax credit of $121 million for advance corporation tax that had previously been written off. An undisclosed portion of the contribution from other financial income reflected favorable translations into sterling of net current assets in other countries.

	Estimated 1976 Net Income	
	$ Millions	Per Share
Production		
OPEC Area		
Iran	$135	$0.30
Kuwait	25	0.06
Nigeria	40	0.10
Abu Dhabi	20	0.05
Subtotal	$220	$0.57
North Sea		
Crude Oil	$105	$0.28
Natural Gas	10	0.02
Subtotal	$115	$0.30
Chemicals	65	$0.17
Equity in Sohio	34	$0.09
BP Canada	21	$0.05
Interest Income	50	$0.13
Other Financial Income	45	$0.12
Non-Operating Expenses		
Interest Expense (ex Forties)	$(110)	$(0.28)
Exploration Expenses	(50)	(0.13)
Corporate Overhead	(60)	(0.16)
ACT Previously Written Off	121	0.31
Total	$451	$1.17
Less Net Income	309	0.79
Indicated Downstream Loss	$(142)	$(0.38)

Despite efforts to reduce surplus capacity, BP's tanker operations apparently remain in the red, although to a lesser extent than in 1975. Two years ago, the company accelerated the retirement of 20 older vessels having a total capacity of one million tons, and last year, five tankers aggregating 700,000 tons were sold for $60 million to a joint venture with the Iranian government. These steps, along with gradually declining long-term charter commitments, should serve to eliminate the tanker deficit over the next several years, but a suddenly favorable comparison is unlikely.

About 70% of BP's product sales are in Europe, and close to half in the U.K., West Germany, and France alone. Marketing operations in the U.K. were moderately profitable during the first half of 1976, but after mid-year, pound sterling product price increases were not commensurate with rising dollar crude oil costs, due to both market factors and deteriorating exchange rates. Several government authorized price increases, most recently on December 20, 1976, have not stuck. In West Germany, pricing has been extremely competitive, and losses are believed to be the largest of any single country. France was probably closer to break even, partly because price competition has been minimal below government imposed ceilings. Deutsche BP lost $106 million and 70% owned Societe Francaise des Petroles BP $24 million ($17 million after minority) in 1975, and deficits of these subsidiaries were comparable in 1976. However, some further deterioration occurred in other continental European markets.

Since January 1, British Petroleum has been at a cost disadvantage under the OPEC two-tier crude oil price structure. A full 90% of BP's crude oil supply comes from Iran and others which have raised prices 10%, compared with about 65% for the industry as a whole. Product price flexibility is limited in Europe by surplus refining capacity approaching 30%. In addition, France has thus far imposed a 5% ceiling on product price increases. Although OPEC crude pricing may be rationalized by July 1, we expect BP's downstream margins to remain under pressure during 1977. On the other hand, North Sea oil profits are benefiting from a 10% price increase, as noted earlier.

EARNINGS AND DIVIDENDS

Our five-year profit forecast is shown below. We have allowed for the OPEC price level to be 10–15% higher in 1980–1981 than now, probably a conservative assumption.

	Estimated Earnings Per Share					
	1976	1977	1978	1979	1980	1981
OPEC Area	$0.57	$0.55	$0.50	$0.50	$0.50	$0.50
North Sea	0.30	1.10	1.35	1.40	1.60	1.90
United States	0.09	0.20	1.40	1.25	1.60	1.65
Canada	0.05	0.05	0.05	0.10	0.10	0.10
Eastern Hemisphere Downstream	(0.38)	(0.40)	(0.40)	(0.35)	(0.25)	(0.15)
Other, Net	0.16	0.10	–	–	–	–
Total	$0.79	$1.60	$2.90	$2.90	$3.55	$4.00

The handling of Eastern Hemisphere downstream results is somewhat arbitrary. In the actual event, experience is likely to be more volatile. It is also possible that capacity surpluses can be largely eliminated by 1981, allowing some profitability. Presently, however, the burden of proof is on "transferring profits downstream."

Dividend payments by U.K. corporations are regulated by the government, recently to a maximum 10% annual increase. In addition, BP shareholders in the United States receive no tax credit for the 35% advance corporation tax (ACT) on dividends as do their counterparts in Britain. U.S. stockholders of BP were paid $0.34 a share in 1976, equivalent to $0.52 before noncreditable ACT.

If dividend increases remain limited to 10% annually, we believe BP will pay the full amount allowed. Or, if controls are relaxed, BP could pay as much as $0.75 a share by 1978 (before 35% ACT), or about 40% of earnings excluding equity in Sohio. Under a December 31, 1975 preliminary tax treaty between Great Britain and the United States, U.S. shareholders of U.K. corporations would receive a refund for ACT. This treaty requires ratification by legislative bodies in both countries. Such approval would raise the effective dividend received by U.S. taxpaying shareholders by 54%.

FINANCES

Capital expenditures were $1,660 million in 1976, and outlays this year could drop slightly to about $1,500 million reflecting approaching completion of both Forties field development and the Trans Alaska Pipeline. BP plans to spend $4,600 million in the United Kingdom during 1977–1981, including $2,600 million for further North Sea development. Consequently, we believe that total spending will average $1,750 million annually for several years after 1977. In addition, BP's share of Sohio's spending could be on the order of $400 million a year.

With cash flow likely to rise sharply over the next several years, BP should be able to readily finance this prospective level of spending from internal sources, as indicated below. High deferred income taxes result from favorable capital recovery provisions of the U.K. Petroleum Revenue Tax.

	Actual	Estimated			
	1976	1977	1978	1979	1980
		($ Millions)			
Capital Expenditures	1,660	1,500	1,600	1,700	1,800
Net Income*	275	535	735	990	960
Dividends from Sohio	14	25	85	125	165
BP Dividend	(131)	(144)	(170)	(200)	(225)
Retained Earnings	158	416	650	915	900
Depreciation	452	550	650	725	800
Deferred Income Taxes	375	1,000	500	300	300
Cash Flow	985	1,966	1,800	1,940	2,000
(Deficiency) Surplus	(675)	466	200	240	200

*Excluding estimated equity in Sohio as follows: 1976, $34 million; 1977, $80 million; 1978, $440 million; 1979, $385 million; 1980, $505 million.

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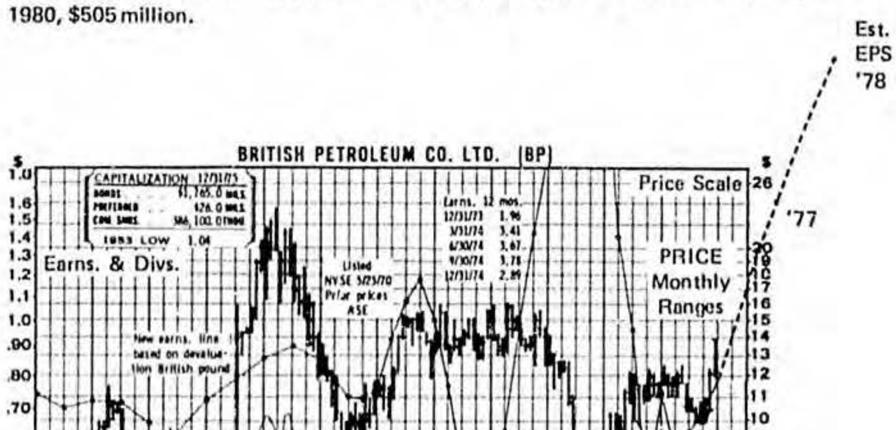

Chart courtesy of Securities Research Company.

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White, Weld & Co.
Incorporated

Thomas C. Pryor *Executive Vice President* (212) 285-2666	**Harold W. Janeway** *Director of Investment Policy* (212) 285-2060
Jerome P. Kenney *Director of Research* (212) 285-2020	**Richard A. Kimball** *Director of Marketing* (212) 285-2374
Frank J. Ritger *Senior Vice President* (212) 285-2120	**A. Gary Shilling** *Chief Economist* (212) 285-2670

Basic Industries		
George H. Cleaver	Metals & Mining	(212) 285-2012
Frederic S. Coffman, Jr.	Forest Products, Paper	(212) 285-2748
Betty M. Fagan	Pollution, Publishing, Capital Goods	(212) 285-2054
F. Robert Mayforth	Chemicals, Environmental Controls	(302) 656-7741
William N. Walling, Jr.	Coal	(212) 285-2438
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Energy		
A. Hager Bryant, 3rd	Gas Pipelines and Distribution	(212) 285-2696
Philip L. Dodge	Oil, Gas	(212) 285-2043
John H. Hayward, Jr.	Oil Services & Related	(212) 285-2032
John L. Kalmbach	Natural Gas, Resources, Diversified	(212) 285-2065
Richard L. Davisson, Jr.	Oil Consultant	(617) 482-7767
Financial Services		
A. James Donohue	Banks, S&L's, REIT's, Mortgage Insurers, Misc. Real Estate	(212) 285-2010
Gerald E. Lewinsohn	Insurance	(212) 285-2000
Health Care		
Michael M. Harshbarger	Drugs	(212) 285-2698
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Market Analysis		
H. Carroll Mackin	Computer Support—Performance Monitor	(212) 285-2056
Peter J. Canelo	Computer Support—Performance Monitor	(212) 285-2256
John A. Mendelson	Technical Analyst	(212) 285-3753
Technology		
Stover L. Babcock, Jr.	Special Situations	(212) 285-2026
James C. Blair	Computers, Office Equipment	(212) 285-2045
Craig W. Fanning	Electrical Equipment	(212) 285-2030
Anthony G. Langham	Instrumentation, Semiconductors	(212) 285-2047
Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
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White, Weld & Co.
Incorporated

Progress Report

MANAGEMENT CONTACT

Philip L. Dodge
(212) 285-2043

December 20, 1976

CONTINENTAL OIL COMPANY (CLL)

Price (NYSE)		Dividend		EPS (Dec.)		P/E
Current:	37	Rate:	$1.20	1977E:	$5.00	7.4X
Range (1976):	41-33	Yield:	[illegible]%	1976E:	$4.60	8.0X
				1975:	$3.25	11.4X

Average Shares Outstanding:	106,910,000	Return on Average 1975 Equity:	16.4%
Market Value	$3,955 Million	Book Value Per Share (9/30/76):	$24.02

1. We have recently visited Continental Oil. The company has an excellent position in coal, one that other firms are trying to emulate, and favorable North Sea oil prospects. Coal margins are currently under pressure due to excess mining capacity and ample inventories. Immediate investment appeal may also be limited by the probability that horizontal divestiture, or dividing companies like Continental into basic energy sectors like oil or coal, will be debated in the 95th Congress. Divestiture is a rather drastic, unlikely step, in our opinion, and one that would not reduce the investment value of Continental. The company's earnings per share have increased in each of the past five years, jumping about 40% in 1976. We anticipate further significant improvement. Longer term prospects are enhanced by meaningful contributions from North Sea oil to begin in 1978. Consequently, despite near term uncertainty in coal, we recommend that present holdings be maintained and further stock be accumulated on possible weakness.

2. The company's **U.S. crude oil production** will average about 170,000 barrels a day in 1976, down 4% from 178,000 barrels a day in 1975. Lower tier is about 63% of total, upper tier 28%, and stripper 9%. The average wellhead price for the year should be about $7.65 a barrel and about $8.35 in 1977, compared with $7.26 a barrel in 1975. A further production decline of 8,000 barrels a day, or 4-5%, is likely next year, but price improvement should more than offset this negative influence.

3. Continental's **U.S. natural gas production** has risen this year, and a further increase is likely in 1977. The indicated volume trend in daily MCF is: 1975, 860,000; 1976, 900,000; 1977, 925,000-930,000; 1978, 950,000. Recent improvement primarily reflects a 95,000 MCF a day benefit from liquidation of the Delhi Taylor production payment. New production from the West Cameron area in the Gulf of Mexico should contribute about 25,000 MCF daily next year and 65,000 MCF

QUARTERLY EARNINGS PER SHARE

	1975					1976					
	1Q	2Q	3Q	4Q	Year	1Q	2Q	3Q	4Q(e)	Year(e)	1977(e)
Petroleum Exploration & Production											
United States	$0.45	$0.30*	$0.37	$0.40	$1.52	$0.41	$0.41	$0.38	$0.40	$1.60	$2.05
International	(0.03)	(0.10)	(0.07)	(0.14)	(0.34)	0.05	0.00	0.01	0.10	0.16	0.20
Hudson's Bay Oil and Gas	0.09	0.09	0.09	0.08	0.35	0.11	0.08	0.08	0.08	0.35	0.40
Subtotal	$0.51	$0.29	$0.39	$0.34	$1.53	$0.57	$0.49	$0.47	$0.58	$2.11	$2.65
Petroleum Refining, Marketing and Transportation											
United States	$(0.06)	$0.08	$0.11	$(0.04)	$0.09	$0.01	$0.07	$0.07	$0.05	$0.20	$0.20
International	0.14	0.11	0.03	(0.16)	0.12	0.15	0.03	0.11***	0.05	0.34	0.30
Subtotal	$0.08	$0.19	$0.14	$(0.20)	$0.21	$0.16	$0.10	$0.18	$0.10	$0.54	$0.50
Worldwide Petroleum	$0.59	$0.48	$0.53	$0.14	$1.74	$0.73	$0.59	$0.65	$0.68	$2.65	$3.15
Coal											
Operating	$0.23	$0.25	$0.16	$0.47	$1.11	$0.39	$0.40	$0.28	$0.30	$1.37	$1.45
Capital Gains	–	0.12	–	0.17	0.29	0.20	–	–	–	0.20	0.10
Subtotal	$0.23	$0.37	$0.16	$0.64	$1.40	$0.59	$0.40	$0.28	$0.30	$1.57	$1.55
Chemicals	$0.11	$0.07	$0.08	$0.05**	$0.31	$0.12	$0.16	$0.15	$0.20	$0.63	$0.75
Minerals	(0.02)	(0.03)	(0.03)	(0.04)	(0.12)	(0.03)	(0.03)	(0.03)	(0.05)	(0.14)	(0.15)
Foreign Exchange	(0.10)	0.03	0.23	0.06	0.22	0.17	0.02	0.02	0.02	0.23	–
Other Corporate	(0.01)	(0.06)	(0.16)	(0.07)	(0.30)	(0.18)	(0.06)	(0.06)	(0.10)	(0.40)	(0.25)
Earnings Per Share	$0.80	$0.87	$0.81	$0.77	$3.25	$1.40	$1.08	$1.00	$1.05	$4.54	$5.05

*After $(0.15) for settlement of Olin litigation.

**After $(0.05) writeoff.

***Includes $0.06 from sales of petroleum coke that applied to earlier quarters.

daily in 1978. The company has reserves on High Island Block 110 offshore Texas which could add 45,000 MCR daily in 1978-79 and a recent 33.3% interest discovery on Mustang Island Block A-85. We believe that the company's gas production will at least hold even for several years beyond 1978.

Continental's average wellhead price (thousand cubic feet) should average 45-47¢ in 1976 and 60¢ in 1977, up from 34¢ last year. Approximately 45% of deliveries are intrastate, 30-35% interstate pre-1973, and the balance of the newer $0.93 and $1.43 vintages. On these assumptions, domestic natural gas revenues should average about $155 million in 1976 and $205 million in 1977, up from $107 million last year. After royalties and income taxes, the 1977 benefit to earnings should be about $20 million or $0.18-0.19 a share.

4. The company's **Libyan crude oil production** should average about 230,000 barrels a day in 1976, up from 165,000 barrels a day in 1975. Profitability has improved since midyear in a buoyant crude market, and we estimate that 1976 net income from Libya will reach $30 million or $0.28 per Continental share. Output from Dubai is also up and should average 95,000 barrels a day for the year compared with 77,000 barrels a day in 1975. The Dubai operation is contributing $0.10-0.15 a share annually, and we expect this level to continue.

5. Continental has interests in four commercial **North Sea** oil discoveries. Production will begin in 1977 and rise significantly over the following eight years, as shown below.

ESTIMATED CONTINENTAL NORTH SEA PRODUCTION
(Barrels per Day)

	Thistle	Dublin	Statfjord	Murchison	Total
1977	1,000	–	–	–	1,000
1978	3,000	5,000	–	–	8,000
1979	5,000	10,000	15,000	–	30,000
1980	5,000	15,000	39,000	15,000	74,000
1981	5,000	15,000	39,000	35,000	94,000
1982	4,000	15,000	39,000	35,000	93,000
1983	4,000	14,000	78,000	35,000	131,000
1984	4,000	13,000	117,000	33,000	167,000
1985	4,000	12,000	117,000	31,000	164,000

We believe that world crude oil prices will be rising over the next decade, and profitability of North Sea production will accordingly move up from the present range of $2.25-2.75 a barrel. In estimating future Continental North Sea earnings, we are assuming a $3.00 a barrel profit level, probably conservative considering North Sea producers will net about 30% of future OPEC price increases. Considering the prospect for rising world crude prices, a $3.00 unit profit could hold up even if the United Kingdom or Norway later raises taxes again. Using the $3.00 figure, Continental's North Sea earnings per share should reach $0.75 in 1980 and $1.70 in 1984.

6. Consistent with a general industry pattern, Continental has experienced some recovery in **U.S. refining and marketing** profits in the first half of 1976, reflecting both recovery of earlier costs and better refinery utilization. Unlike most others, it has also registered modest **downstream improvement in the Eastern Hemisphere,** mainly due to a swing from red to black in Italy and better results in Sweden. Profits per barrel of oil refined are shown below. Continental's **tanker operations** remain about on a break-even basis, as they were in 1975. The Humber (U.K.) refinery which has a 30% gasoline yield and important petroleum coke output, accounts for Continental's relatively high overseas margin.

DOWNSTREAM COMPARISONS
(Millions)

	United States			Overseas		
	Net Income	Barrels Refined	Per Barrel	Net Income	Barrels Refined	Per Barrel
1975						
1Q	$ (5.7)	28.2	$(0.20)	$13.8	10.4	$1.33
2Q	8.0	28.8	0.28	11.7	14.6	0.80
3Q	11.1	30.5	0.36	3.5	13.0	0.27
9 Mos.	$13.4	87.5	$0.15	$29.0	38.0	$0.76
1976						
1Q	$ 1.1	30.5	$0.04	$15.2	9.3	$1.63
2Q	7.3	30.9	0.24	3.6	9.7	0.37
3Q	7.9	32.5	0.24	11.4*	10.6	1.08
9 Mos.	$16.3	93.9	$0.17	$30.2	29.6	$1.02

*Includes about $7 million applicable to prior periods.

7. Coal earnings per share are likely to increase 10-15% this year to $1.55-1.60 from $1.40 in 1975. Liquidation of the Consol production loan added an estimated $0.40 a share, but this benefit has been partially offset by a decline of $0.10 a share in property sales and margin pressure resulting from ample inventories in the hands of electric utilities. Productivity in deep mines continues to average 10 tons per man day. Quarterly profit spreads (excluding capital gains) have been as follows.

COAL MARGIN COMPARISONS
(Millions)

	Net Income	Tonnage	Per Ton Profit
1975			
1Q	$ 23.2	12.1	$1.92
2Q	25.5	12.6	2.02
3Q	16.5	11.0	1.50
4Q	47.6	13.5	3.53
Year	$112.8	49.2	$2.29
1976			
1Q	$ 39.9	13.7	$2.91
2Q	41.1	12.9	3.19
3Q	29.9	10.9	2.74
4Q	35.0	13.0	2.69
Year	$145.9	50.5	$2.89
1977E	$156.0	52.0	$3.00

Bolstered by an estimated increase of 7-8% in utility markets, U.S. coal consumption should rise 4-5% in 1976. However, earlier excessive inventory accumulations have not been worked off, and supply of high sulphur coal exceeds demand. We presently estimate that U.S. coal consumption will rise 3-5% in 1977, reflecting higher kilowatt hour sales, further shifts to coal as boiler fuel, and benefits to steel demand from higher economic activity. This forecast allows for a 3-4 week United Mine Workers strike upon expiration of the current three-year contract next December, assuming that utilities will stock up further in anticipation of this shutdown. Although Continental sells all of its coal under long-term contracts, cost passthroughs are more easily facilitated when supply is tight. We believe there is a better-than-even chance of of a sellers' market by the fall of 1977 and are therefore assuming full year margin improvement to about $3.00 a ton after taxes. Without a strike, Continental should mine about 55 million tons next year. A 3-4 week strike would reduce this potential to 52 million tons.

Continental plans to raise mining capacity to 91 million tons by 1985, of which steam coal would be 78 million tons versus 49 million currently and metallurgical 13 million (versus 6 million). We consider this objective realistic in view of both economic and political incentives which favor coal for boiler fuel over residual oil. Political incentives must include the matter of high sulphur content, and we understand the Carter Administration will address this problem early. Assuming modest margin improvement from both a generally escalating price structure and rollovers of presently low priced contracts, Continental's coal earnings should rise at about a 10% annual rate over the next five years.

8. **Chemical** profits have risen significantly this year, reflecting better polyvinyl chloride volume and prices, and improved realizations on vinyl chloride monomer exports. We presently look for about a 10% chemical profit increase in 1977.

9. The **corporate** account, which can fluctuate widely from year to year, should aggregate a loss of about $20 million this year comparable with a deficit of $8 million in 1975. Negative items in this composite are: 1) net interest expense, which should approximate $35 million this year, and 2) corporate administrative expense, about $50 million in 1976. Offsets are the investment tax credit, estimated at about $25 million this year compared with $18 million in 1975, and equity in earnings of affiliates in a 1976 range of $10-15 million. Foreign exchange results are also included, a positive $21 million in the first nine months.

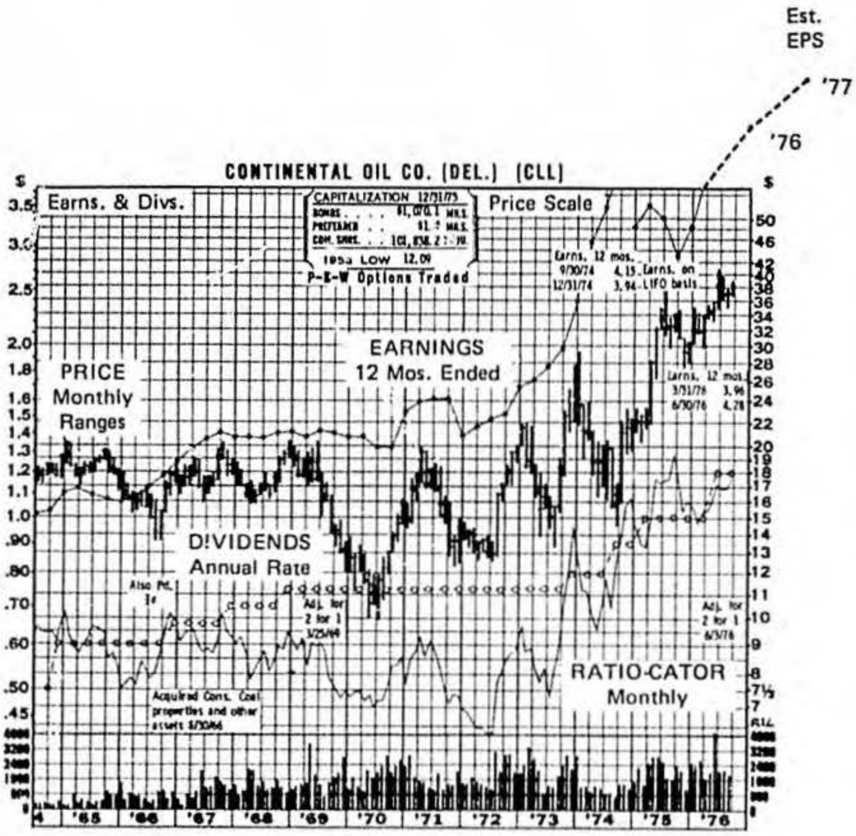
10. Capital **expenditures** should total about $730 million in 1976, up on a comparable basis from $703 million in 1975. The $703 million 1975 figure excludes $98 million for the purchase of Sulpetro of Canada Ltd. Outlays in 1976 were partially financed by sales in May of $200 million of 8 7/8% 25-year debentures and 4,500,000 shares of common stock (proceeds $149 million).

Spending of $975 million is budgeted for 1977. Although this level will probably exceed funds provided internally (see below), further outside financing is unlikely in 1977 due to ample cash hol... s, currently about $950 million. This strong financial position also allows flexibility ... raising the $0.30 a share quarterly dividend in 1977.

	1975	1976E	1977E
		$ Millions	
Total Capital Outlays	801	730	975
Retained Earnings	217	350	395
Non-Cash Charges	394	370	425
Funds Provided by Operations	611	720	820
Deficiency	190	10	155

11. Continental has recently made management changes in connection with earlier political contributions. Although disruptive, these moves do not undermine future growth prospects, in our opinion.

RR-76-184 —Research Department—



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Thomas C. Pryor *Executive Vice President* (212) 285-2666	**Harold W. Janeway** *Director of Investment Policy* (212) 285-2060
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Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Rieser	Assistant to Director of Research	(212) 285-2020
Ann T. Stott	Institutional Marketing	(212) 285-2064

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White, Weld & Co.
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Basic Report

Philip L. Dodge
(212) 285-2043

January 12, 1977

SOUTHLAND ROYALTY COMPANY (SRO)

Price (NYSE)		Dividend		EPS		P/E
Current:	40	Rate:	$0.68	1977E:	$2.85	14.0X
Range (1976-1977):	43-20	Yield:	1.7%	1976E:	$2.25	17.8X
				1975:	$1.76	22.7X

Average Shares Outstanding:	12 million	Return on Average 1975 Equity:	35%
Market Value:	$480 million	Book Value Per Share (9/30/76):	$6.85

OPINION

Southland Royalty is a U.S. petroleum exploration-production company and, we believe, an attractive long-term investment. However, the stock has moved up sharply in recent weeks along with most of the producing company group, and it may now be selling about in the middle of a probable 1977 range, assuming a 12-18 P/E ratio.

Over the next three years, Southland should experience crude oil and natural gas price increases of 10-15% annually. Moreover, it is one among few companies which can raise natural gas production through development drilling rather than requiring successful exploration. The company attained this preferable position through the February 1976 purchase of Aztec Oil & Gas, a firm holding 850 billion cubic feet of gas reserves in the San Juan Basin of New Mexico, or 30 years of production at the current rate. Through a combination of increasing prices and rising natural gas production, Southland's earnings per share should reach $4.25-4.50 by 1979, roughly double the 1976 level.

We believe the recent FPC decision to price new intrastate gas at $1.42 per thousand cubic feet plus $0.01 quarterly escalation will ultimately prevail in court, although the process may be lengthy. Of further significance, the energy program of President-elect Carter will probably include a proposal to remove price controls from future new production either indefinitely or for a period of five years. In this event, prices would probably move to parity with imported oil, or to $2.25-2.50 per thousand cubic feet. The importance of this repricing to producers bears further emphasis. Last July, the FPC raised the new gas price 175% from the previous level of $0.52. Decontrol would add an additional 65%. From another perspective, a new well depleting one billion cubic feet of reserves would previously have generated revenues of $520,000 (excluding escalation). Under the FPC decision, this figure would rise to $1,420,000, and decontrol would result in $2,350,000. Exploration efforts obviously promise far greater rewards.

In our opinion, the stock market is already recognizing a portion of the higher value of natural gas reserves. Southland Royalty, for example, roughly doubled in 1976, and it is now selling to about 32¢ per MCF of natural gas and equivalent reserves in the ground. However, producing companies with active exploration efforts, particularly ones like Southland with long life reserves, should continue to be above-average investment vehicles over a 12-month or longer period.

BACKGROUND

Southland Royalty is a U.S. petroleum exploration and production company. Historically, income was obtained primarily from royalty interests in the Waddell Ranch of West Texas, but operations have been transformed by two major events in the past 18 months. On July 14, 1975, the company regained full mineral interests in Waddell Ranch, those having been leased to Gulf Oil for the previous fifty years. In early 1976, Southland acquired Aztec Oil & Gas for a cash payment of about $180 million. Revenues and production rose dramatically after each of these additions, as shown below.

	1975		1976
	2Q	4Q	2Q
Revenues (Thous.)			
Oil	$9,448	$12,787	$16,985
% over Previous		35%	33%
Natural Gas	$1,988	$ 9,084	$14,811
% over Previous		357%	63%
Daily Production			
Oil (Bbls.)	12,400	24,000	25,900
% over Previous		93%	8%
Natural Gas (MMF)	55	115	184
% over Previous		109%	60%

The addition of Waddell Ranch natural gas was particularly significant because previously Southland had been receiving only 4¢ per MCF on casing-head gas and $200 per well on gas well gas.

Southland's estimated reserves were last reported as of January 1, 1975. These figures plus estimates available more recently for Aztec properties are shown in the table on the following page.

	Crude Oil (mil. bbl.)	Natural Gas (bil. CF)
Southland ex Waddell Ranch	42	154
Waddell Ranch	70	192
Aztec Oil & Gas	10	928
Total (Year's Life)	122 (13)	1,274 (19)
Conversion of Oil to Gas at BTU Equivalent of 6 MCF (Per Barrel)		732
Total Gas Equivalent		2,006 (1)
		– – millions – –
Current Market Value		$480
Long-Term Debt		168
Total		$648 (2)
Value per MCF (2) ÷ (1)		32¢

This calculation indicates that Southland is currently selling at the equivalent of natural gas in the ground at 32¢ per MCF. This valuation appears reasonable in relation to the company's present average selling price for natural gas of $1.00, with prospects for rapid increases over the next several years.

PRICING OUTLOOK

Like other domestic producers, Southland is receiving significant benefits from rising crude oil and natural gas prices. Quarterly price and volume trends during 1975 and 1976 were as follows.

	Crude Oil			Natural Gas			
	Thousand Barrels (000)	Revenues in $000	Average Oil Price	Thousand MCF (000)	Revenues in $000	Average Natural Gas Price	Total Revenues in $000
1975							
1Q	1,107	$ 8,991	$8.13	4,612	$ 1,938	$0.42	$10,929
2Q	1,132	9,448	8.35	5,042	1,988	0.39	11,436
3Q	1,889	13,407	7.10	8,482	9,666	1.14	23,073
4Q	2,205	12,787	5.80	10,616	9,084	0.86	21,871
Year	6,333	$44,633	$7.05	28,751	$22,676	$0.79	$67,309
1976							
1Q	2,237	$15,792	$7.06	15,691	$14,750	$0.94	$30,542
2Q	2,358	16,985	7.20	16,780	14,811	0.88	31,796
3Q	2,360	16,798	7.12	16,731	15,290	0.91	32,088
4Q (Est.)	2,350	17,155	7.30	16,798	16,739	0.99	33,894
Year (Est.)	9,305	$66,730	$7.17	66,000	$61,590	$0.93	$128,320
1977 (Est.)	9,125	$70,720	$7.75	73,000	$83,950	$1.15	$154,670

Southland's crude oil mix is about 70% lower tier and 30% upper tier including a modest amount of stripper. As evident above, the average crude price fell in the second half of 1975 when working interests at Waddell Ranch were included for the first time. On the other hand, the purchase of Aztec Oil & Gas in early 1976 raised the percentage of upper tier crude. Prices should benefit in 1977 from new crude out of the South Pumpkin Creek and Teton areas of Wyoming, and later in the year from the rising Federal Energy Administration schedule.

Southland's annual natural gas production is presently divided about as follows:

	Billion Cubic Feet
San Juan Basin	28
Waddell Ranch	17
Other	25
	69

Southern Union Company is the principal gas buyer in the San Juan Basin. About 55% of Southland's production moves to interstate markets, with the balance remaining within New Mexico. The interstate price, which is established by the Federal Power Commission, currently averages 37¢ per thousand cubic feet including liquids value (29.5¢ per million BTU). San Juan gas has an unusually high BTU content. The price for intrastate gas rose to $1.30 per MCF from $0.85 as of July 27, 1976, and an additional penny on January 1, 1977. There will be a further escalation to $1.41 per thousand cubic feet on April 1, 1977.

The agreement with Southern Union is subject to further annual price redeterminations on April 1, 1978 and April 1, 1979. On those dates, intrastate prices will be calculated as an average of the highest in the San Juan Basin and the rest of New Mexico, with a 50% weighting for the San Juan Basin in 1978 and 25% in 1979. If new natural gas is decontrolled by then, we believe that interstate buying competition will raise the intrastate price to $2.50 per thousand cubic feet.

About 70% of Waddell Ranch production goes to Houston Natural Gas under a contract terminating in 1996 at a price of $2.40 a thousand cubic feet ($2.00 per million BTU), escalating 2½¢ on July 1 and 2½¢ every six months thereafter. The balance has recently been sold under an old contract to El Paso Natural Gas at $0.81 ($0.68 per million BTU). If a December 1976 court decision prevails, Southland will henceforth deliver this gas to an intrastate buyer at the $2.40 price.

PRODUCTION TREND

Natural Gas

Southland has recently completed a 17 well (15 net) development drilling program in the Mesa Verde formation of the San Juan Basin. These new wells will add about 4.2 billion cubic feet to annual production beginning this month. Thirteen of them will receive the 1975-1976 vintage new gas price of about $1.70-1.75 per thousand cubic feet ($1.44 per million BTU). Annual revenues will benefit by about $6.5 million.

San Juan Basin reserves are equal to 30 years of production at the current rate, and further infill drilling is feasible for some time in the future. Southland plans a 50 well program in 1977 with annual production expected to benefit by about 10 billion cubic feet. The estimated cost of this program is $10 million, or $200,000 per well. Present intentions are to maintain drilling activity at this level in 1978 and 1979. On this basis, Southland's San Juan Basin production should rise approximately as shown on the following page. We have arbitrarily assumed lower productivity from infill wells in later years.

	Estimated Billion Cubic Feet				
	1976	1977	1978	1979	1980
Existing Wells	25*	26	24	22	20
Infill Wells	–	4	14	22	28
Total	25	30	38	44	48

* Aztec purchased in February.

Southland has interests in two offshore natural gas discoveries–Vermilion 22 (6¼%) and East Cameron 231 (10%)–where production is scheduled to begin by mid-1977. Combined annual output net to Southland should be on the order of 4 billion cubic feet, or 10 million cubic feet a day. Minor reserves will also be developed later on South Marsh Island 249-250, obtained in the Aztec purchase. Onshore, Southland is developing a 50% interest 1975 discovery called Bayou Boullion in St. Martin Parish, Louisiana which should add annual production of about 2 billion cubic feet.

Oil development is presently limited mainly to the Powder River Basin of Wyoming where a new discovery was made in the Heldt Draw field during 1975. Several wells are producing from the Shannon sand of the South Pumpkin Creek area at a rate net to Southland approaching 1,000 barrels a day, and delineation drilling is continuing to the southeast at three locations. Last year, Southland made a similar discovery nearby called Teton, and a confirmation well called Streeter was recently completed at a rate of 390 barrels a day. At least two other development wells will be drilled.

EXPLORATION

Southland has about 2,500,000 net acres of undeveloped properties. Approximately $12 million was spent on exploration last year, and a budget of $17 million has been authorized for 1977. In addition, the company plans to acquire Westhoma Properties as of April 1, 1977 for $4½ million. Involved in this transaction are about 90,000 acres in the Oklahoma Panhandle which are prospective for natural gas in the Morrow sand.

Exploration efforts are focused onshore east of the Rocky Mountains in all major basins. Spending is anticipated to rise in line with available cash flow.

OUTLOOK

Southland should benefit over the next several years from rising natural gas production, and higher natural gas and crude oil prices. As estimated below, revenues and profits are likely to continue a strong upward trend. The company follows the "successful efforts" practice of accounting under which dry holes are charged against current income. Offshore leases are capitalized until evaluation is completed. The company currently carries about $7½ million in the capitalized category.

1977-1979 OUTLOOK
(millions)

		Estimated			
	1975	1976	1977	1978	1979
Production					
Crude Oil (mil. bbl.)	6.3	9.3	9.1	8.9	8.7
Natural Gas (bil. CF)	28.8	66.0	73.0	81.0	90.0
Average Price					
Crude Oil (bbl.)	$7.05	$7.17	$7.75	$8.50	$9.35
Natural Gas (MCF)	0.79	0.93	1.15	1.35	1.50
Revenues					
Crude Oil	$44	$67	$ 71	$ 76	$ 81
Natural Gas	23	61	84	109	135
Other	1	1	1	1	1
Total Revenues	$68	$129	$156	$186	$217
Production Expenses	$ 6	$15	$17	$ 19	$ 21
Exploration Expenses	10	12	17	21	25
General and Administration	4	6	7	7	8
Operating Taxes	1	9	11	13	16
Abandonments	1	3	3	4	5
Depreciation, Depletion	6	19	21	23	26
Interest Expense	1	15	17	19	21
Total Expenses	$29	$79	$93	$106	$122
Earnings Pretax	$39	$50	$63	$80	$95
Income Tax	18	23	29	37	44
Net Income	$21	$27	$34	$43	$51
Earnings Per Share	$1.76	$2.25	$2.85	$3.60	$4.30

FINANCING

In conjunction with the Aztec Oil & Gas purchase, Southland arranged a $200 million loan through Morgan Guaranty Trust. The loan was to be repaid in 24 quarterly installments beginning March 31, 1977, but arrangements are currently being made to refinance the original borrowing. Under the modified proposal, annual debt service would be cut about 50% to $15 million.

Total drilling is budgeted at $35-40 million in 1977, including $17 million estimated to be charged against current income. Property acquisitions might amount to an additional $15-20 million. Actual and estimated cash flow figures for 1975-1977 are furnished below.

		Estimated	
	1975	1976	1977
	———— ($ Millions) ————		
Net Income	$20.8	$27.0	$34.0
Dividends	5.7	7.0	8.0
Retained Earnings	$15.1	$20.0	$26.0
Non-Cash Charges	11.4	24.0	26.0
Funds Provided by Operations	$26.5	$44.0	$52.0
Expenditures*	$38.2	$45.0	$55.0
Debt Service	5.7	18.0	15.0
Total Requirements	$43.9	$63.0	$70.0
Deficiency	(17.4)	(19.0)	(18.0)

* Excluding about $180 million for purchase of Aztec.

Southland appears to need additional funds in 1977, probably in the form of bank loans at the outset. Arrangements with prospective natural gas buyers are still possible, despite the price penalty that must be incurred on interest-free loans from pipelines under FPC Opinion 770-A. There is also some flexibility in the budget if funds prove difficult to obtain.

RR-77-10 —Research Department—

OPERATING SUMMARY
($ Millions)

	1971	1972	1973	1974	1975	1976E
Operating Data						
Revenues	$17.9	$17.9	$22.5	$37.8	$68.3	$128.0
Depreciation	3.5	3.3	3.2	3.3	6.4	19.0
Pretax Income	7.2	6.4	9.6	21.1	38.7	50.0
Income Taxes	2.1	1.7	2.6	6.6	17.9	23.0
Net Income	5.1	4.6	7.0	14.4	20.8	27.0
Operating Ratios						
Pretax Margin	40%	36%	43%	56%	57%	39%
Tax Rate	29	27	27	31	46	46
Net Margin	28	26	31	38	30	21
Equity Turnover	0.5X	0.5X	0.5X	0.7X	1.0X	1.5X
Return on Equity	14%	12%	18%	29%	35%	36%
Per Share Data						
Earnings Per Share	$0.44	$0.40	$0.60	$1.22	$1.76	$2.25
Dividends	0.30	0.30	0.30	0.37	0.48	0.62
Price Range	12-9	16-9	23-11	25-13	31-20	43-20
Book Value	$3.09	$3.20	$3.53	$4.43	$5.61	$7.25
P/E Range	27-20	39-22	38-18	20-11	18-11	19-9
Average P/E	23.5	25.5	28.0	15.5	14.5	14.0
P/E Relative to S&P500	137%	148%	215%	174%	137%	139%
Shares Outstanding (mil.)	11.8	11.8	11.8	11.8	11.8	12.0

BALANCE SHEET SUMMARY
($ Millions)

	12/31/71	12/31/75	9/30/76
Current Items			
Assets:			
Cash and Equivalent	$ 9.1	$ 1.4	
Receivables	1.8	14.9	
Total Current Assets	$10.9	$16.3	$25.3
Liabilities:			
Short-Term Debt	$ –	$ 3.1	
Other Current Liabilities	1.9	15.7	
Total Current Liabilities	$ 1.9	$18.8	$45.1
Current Ratio	5.7-1	(neg.)	(neg.)
Net Assets			
Net Working Capital	$ 9.9	$ (2.5)	$(19.8)
Net Plant	25.7	81.2	278.2
Investments	2.4	2.0	1.6
Total	$38.0	$80.7	$260.0
Capitalization			
Long-Term Debt	$ –	$ 7.2	$168.4
Deferred Taxes	1.7	7.0	9.4
Stockholders Equity	36.3	66.5	82.2
Total Capitalization	$38.0	$80.7	$260.0
Long-Term Debt % Capital	0%	9%	65%

White, Weld & Co. Incorporated

Basic Report

Philip L. Dodge
(212) 285-2043

January 19, 1977

MESA PETROLEUM CO. (MSA)

Price (NYSE)		Dividend		EPS (Dec.)		P/E
Current:	37	Rate:	$0.10	1977E:	$2.35	15.7X
Range (1976-1977):	38-25	Yield:	0.3%	1976E:	$1.75	21.1X
				1975:	$1.25	29.6X

Average Shares Outstanding:	13 million	Return on Average 1975 Equity:	8.2%
Market Value:	$480 million	Book Value Per Share (9/30/76):	$22.54

OPINION

Mesa obtains about 62% of total revenues from natural gas production, and it has an above-average gas reserve life of 19 years. With prospective deliveries from several Gulf of Mexico tracts, natural gas output should rise some 35-40% by 1980. Most of the new gas will sell for $1.44 plus escalation per thousand cubic feet, helping future annual gas revenues by more than $50 million, compared with total company gross income of about $95 million in 1976. Mesa also has 25% of a significant oil discovery in the Moray Firth off the coast of Scotland. Production there should begin by 1980, but an estimate of size would be premature.

Earnings per share should rise to $3.75-4.00 a share in 1979 and a good bit higher in the early 1980s as the Moray Firth contributes. Nevertheless, the stock has moved up sharply from the 1976 low of 25, and less conservative full cost accounting may limit further multiple expansion. Accordingly, we advocate a twelve month or longer investment strategy, believing the stock to be midway in a probable 1977 trading range.

PRODUCTION AND PRICES

Mesa experienced strong growth in oil and gas revenues during the past three years, primarily because of price increases but partly due to increasing oil production. On most recently available reserve data as of July 1, 1975, gas production had a 19-year life and liquids 11 years, both above industry averages.

				Estimated	
	1973	1974	1975	1976	1977
Average Daily Production					
Natural Gas (MMCF)	271	261	253	270	290
Gas Liquids (bbls.)	3,688	3,450	3,670	4,320	4,300
Crude Oil (bbls.)	4,197	5,716	6,523	6,800	8,000
Average Price					
Natural Gas (MCF)	23¢	27¢	37¢	62¢	80¢
Gas Liquids (bbl.)	$ 3.50	$ 7.18	$ 4.53	$ 5.70	$ 6.50
Crude Oil	3.77	7.92	9.86	10.05	10.50
Revenues (000)					
Natural Gas	$22,873	$25,564	$33,956	$61,000	$85,000
Gas Liquids	4,705	9,048	6,056	8,975	10,000
Crude Oil	5,776	16,515	23,414	24,950	30,700

Natural gas production last year benefited primarily from completion of a 17-well infill drilling program in the San Juan Basin. Further increases in 1977 are coming mainly from the Gulf of Mexico and Canada. In the Gulf, deliveries from 52% owned East Cameron 322/323 began in mid-1976 at a net rate of 5 million cubic feet a day. Later this year, initial gas production is scheduled from 43.3% owned Vermilion 228 at about 15 million net cubic feet a day and from Eugene Island 333/312 at 6-7 million net feet a day. Fairly modest new production is also commencing at the Myette Point field in St. Mary's Parish, Louisiana. Output from the Hugoton field, which accounts for close to half of total company gas output, is expected to decline again in 1977 as a further adjustment to earlier over-production.

Natural gas prices during 1977 will benefit from (1) May 1, 1976 renegotiation with Kansas Power and Light for Hugoton gas under which the average price went to 53¢ from 25¢, (2) FPC Order 770-A, which added about 10¢ to the company's average price as of July 27, 1976, (3) an increase in Alberta to $1.23 on January from an average of about $0.85 in 1976 (Alberta does not vintage gas), and (4) new Gulf of Mexico gas at $1.44 with $0.01 quarterly escalations. (We have assumed $1.44 even in cases where Mesa applied for higher optional pricing.) The weighted average price for the full year should move up to about 80¢ per thousand cubic feet from approximately 60¢ in 1976.

Oil production benefited moderately last year from initial output on East Cameron 322/323, and Vermilion 228 and Eugene Island 333/312 should together contribute about 1,500 barrels a day by this coming summer. Natural gas liquids output will probably remain even in 1977, after having risen last year following completion of new facilities at Garrington in Alberta.

OFFSHORE TEXAS

Mesa has interests ranging from 5% to 50% in 29 Federal tracts offshore Texas on which 9 platforms are installed or planned. Production of natural gas is scheduled to begin in early 1978 following completion of the High Island Offshore pipeline system. At the outset, deliveries will be from 18.4-20% owned High Island 330/349, 25% owned High Island 339/340, and 15% owned High Island 474/489. We expect that combined production net to Mesa from these three fields will be 55-60 million cubic feet a day, contributing annual revenues of at least $30 million. A platform on 5.7% owned High Island 563 collapsed late last year, and development will be delayed. At least three other tracts—High Island 279 (15%), 313 (30.7%), and 492 (10%)—appear commercial, and will probably be developed. Assuming satisfactory experience on these additional properties, Mesa's net production offshore Texas could reach 75-100 million cubic feet a day by 1979 or 1980.

MORAY FIRTH

In September 1976, Mesa announced an oil discovery on Block 11/30 in the Moray Firth area of the North Sea. A successful confirmation was completed 2-1/4 miles southwest in December. Both wells tested slightly over 6,000 barrels a day of 37° API gravity crude. The wells are about 15 miles from shore in water of 135-150 feet, fortuitous cost circumstances compared with many less accessible North Sea fields. A third well is under way 1-1/4 miles northeast of the discovery. Mesa has a 25% interest in Block 11/30 along with Kerr-McGee (25%), Hunt Oil (15%), P&O Petroleum (15%), Cresslenn Chelsea (15%), and Exploration Holding (5%).

On the basis of results to date, commercial reserves appear to be present on 11/30. Two wells 2-1/4 miles apart suggest an areal extent of at least 1,500 acres. The discovery had 300 feet of oil pay and the confirmation 140 feet. Assuming an average section of 220 feet, reserves in place might typically be 500 million barrels on 1,500 acres. Premising further a 30% recovery factor, recoverable reserves proven thus far would be roughly 150 million barrels. A successful well to the north might raise this possibility by 75% to 260 million barrels. Further delineation could enlarge this figure, perhaps substantially. Each 100 million barrels of reserves would probably support a daily production rate of 30,000 barrels, or 11 million barrels annually.

Considering the handy locations, costs should be relatively low. Total development outlays might be no more than $300 million, including $40-50 million for pipeline and onshore facilities, and $50-60 million for two steel platforms. Some of the platform slots would probably be used for repressuring because the reservoir has a low gas-low oil ratio. Profitability should be in the upper bracket of typical North Sea experience, perhaps $3.00 a barrel on a current landed price of about $13.50. If development proceeds, production is likely by 1979 or 1980. On assumptions discussed above, Mesa should earn $0.60-0.65 a share for each 100 million barrels of recoverable reserves. Ultimate size will depend of course on further delineation, in part moving across a fault to the southeast.

EXPLORATION

Mesa spent $60 million on drilling last year, and a similar outlay is anticipated in 1977. About 40% of this budget is earmarked for exploration. Activity is currently focusing in three areas, but also includes a number of other locations.

1. **Gulf of Mexico.** Drilling continues offshore Louisiana on several tracts where platforms are planned, including South Marsh Island 146 (16% owned), Eugene Island 327 (11.5%), and South Pass 78 (25%). In addition, Mesa recently paid $15 million for 5% interests in East Cameron 336, Vermilion 25 and 310, Eugene Island 310, and West Delta 34. This transaction also included 10% interests in East Cameron 263 and High Island 492 (discussed earlier). Both of these blocks have productive wells.

2. **Texas State Offshore.** In October 1976, Mesa purchased 18 tracts encompassing 22,000 acres in Texas state waters for $9,370,000. About 8,000 acres are near the large Shipwreck natural gas field, currently under development by Houston Oil & Mineral. Mesa plans to drill this prospect in the immediate future.

3. **West Texas.** Mesa is farming in on acreage which has relatively low risk and thus far successful gas prospects.

REVENUE AND EARNINGS PROSPECTS

Mesa should continue to experience good growth over the next three years, as estimated below. Beyond 1979, Moray Firth production should make a sizable contribution, but a precise forecast would be premature.

	1975		1976		Estimated 1977		Estimated 1978		Estimated 1979	
	(Millions)									
Revenues										
Natural Gas	$ 34		$ 61		$ 85		$ 115		$ 145	
Gas Liquids	6		9		10		11		12	
Crude Oil	23		25		31		35		38	
Other	1		1		1		1		1	
Total	$ 64		$ 96		$ 127		$ 162		$ 196	
Cost and Expenses										
Operating	$ 8		$ 11		$ 14		$ 18		$ 22	
Gen. & Admin.	6		7		8		9		10	
Operating Taxes	1		2		3		3		4	
Depre. & Amort.	16		24		32		40		48	
Interest	4		3		5		7		9	
Total Costs	$ 35		$ 47		$ 62		$ 77		$ 93	
Pretax Earnings	$ 28		$ 49		$ 65		$ 85		$ 103	
Income Tax (Tax Rate)	9	(33%)	21	(42%)	29	(45%)	38	(45%)	46	(45%)
Net Income	$ 19		$ 28		$ 36		$ 47		$ 57	
Preferred Dividend	3		5		5		5		5	
Available for Common	$ 16		$ 23		$ 31		$ 42		$ 52	
Earnings Per Share	$1.25		$1.78		$2.38		$3.23		$4.00	

We have assumed the following:

1. Production increases in 1977 of 7% for natural gas and 18% for oil; in 1978 of 14% for gas, 6% for oil; and 1979 of 9% for gas and zero for oil.

2. Average prices for gas of $0.80 per MCF in 1977, $0.95 in 1978, and $1.10 in 1979; for oil $10.50 a barrel in 1977, $11.50 in 1978, and $12.50 in 1979.

3. An $8 million annual increase in depreciation and amortization upon inclusion of additional offshore tracts in the depletable property base. In addition to using full cost accounting, Mesa follows the rather liberal practice of excluding unevaluated offshore leases from unit-of-production write-offs. However, probable reserves on these leases are also excluded, at least partly mitigating the favorable profit impact. About $205 million of properties were in the unevaluated category at the end of 1975.

4. Interest expense will probably begin to rise this year due to the lesser appeal of interest-free loans from natural gas pipelines under FPC Order 770-A.

5. With all percentage depletion eliminated as of July 1, 1976, the tax accrual rate should rise to about 45% in the future.

FINANCING

Actual 1974–1975 and estimated 1976–1977 cash flow items are shown below.

			Estimated	
	1974	1975	1976	1977
	($ in Millions)			
Funds Provided by Operations				
Retained Earnings	24	15	22	30
Depreciation and Amortization	13	17	24	32
Deferred Taxes	-	9	21	29
Subtotal	37	41	67	91
Funds Expended				
Capital Outlays	119	101	145	110
Deficiency	82	60	78	19

Principal outside financing has been in the form of non-interest bearing notes from pipelines (Mich Wisc, Tenneco, and Transco) to be repaid out of future natural gas production. These obligations presently total about $[illegible].0 million. In addition, Mesa raised $71 million from the sale of convertible preferred stock in 1975.

As part of Order 770-A dealing with post-1972 interstate natural gas prices, the FPC required that prices be reduced from the new national rates to reflect the economic benefit from interest-free advances after November 5, 1976 if the advance is included in the pipeline rate base. As normal loans appear to involve a lower carrying charge than the stipulated price concession (about $0.80 per MCF), Mesa henceforth may accept such advances only if they are not given rate base treatment by the pipeline. As a consequence, the company will probably use some conventional borrowings in 1977. The indicated capital deficiency is considerably less than in the past three years.

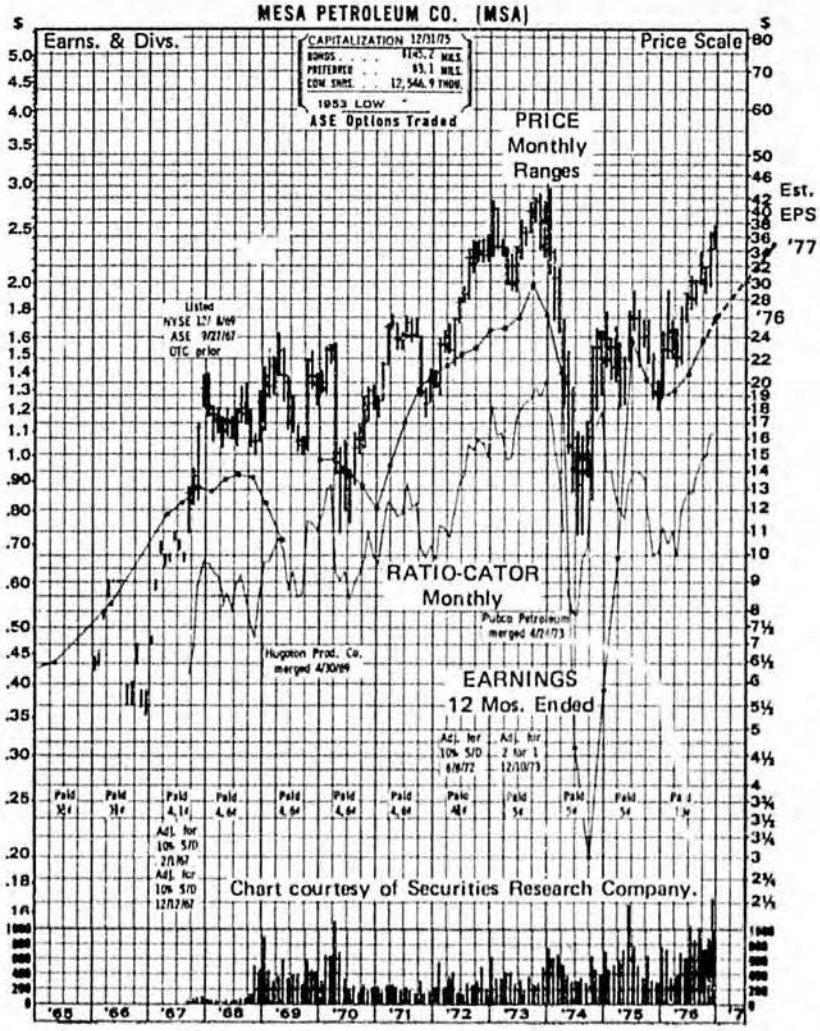
About $32 million of the $145 million outlay in 1976 was for purchase of 495,717 shares (7.4% of the outstanding stock) of General American Oil, a medium sized domestic oil and gas production company. Mesa may ultimately try to acquire General American, but no immediate effort is likely. If General American is acquired by another firm, the price would probably be higher than the $64 a share paid by Mesa.

BALANCE SHEET SUMMARY

(Millions)

	12/31/71	12/31/75	9/30/76
Current Items			
Assets:			
Cash & Equivalent	$ 4	$ 10	
Receivables	7	15	
Inventories	13	11	
Total Current Assets	$24	$ 36	$39
Liabilities:			
Short-Term Debt	$ 3	$ 6	
Other Current Liabilities	15	27	
Total Current Liabilities	$18	$ 33	$35
Current Ratio	1.3X	1.1X	1.1X
Net Assets			
Net Working Capital	$ 6	$ 3	$ 4
Net Plant	70	455	483
Investments	2	3	4
Other Assets–Net	9	3	3
Total	$87	$464	$494
Capitalization			
Long-Term Debt	$34	$145	$149
Deferred Items	3	43	27
Reserves	–	–	25
Stockholders' Equity	50	276	293
Total	$87	$464	$494
LT Debt % of Capital	39%	31%	30%

RR-77-14 —Research Department—


MESA PETROLEUM CO. (MSA)
Earns. & Divs.
Price Scale
CAPITALIZATION 12/31/75
BONDS . . . $145.2 MILS.
PREFERRED . . $3.1 MILS.
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1953 LOW
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Chart courtesy of Securities Research Company.
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Thomas C. Pryor
Executive Vice President (212) 285-2666

Harold W. Janeway
Director of Investment Policy (212) 285-2060

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Craig W. Fanning	Electrical Equipment	(212) 285-2030
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Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Riesar	Assistant to Director of Research	(212) 285-2020
Ann T. Stott	Institutional Marketing	(212) 285-2064

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White, Weld & Co.
Incorporated

Basic Report

Philip L. Dodge
(212) 285-2043

February 10, 1977

STANDARD OIL OF INDIANA (SN)

Price (NYSE)		Dividend		EPS (December)		P/E
Current:	55	Rate:	$2.60	1977E:	$7.15	7.7X
Range (1976-77):	60-41	Yield:	4.7%	1976:	$6.09	9.0X
				1975:	$5.36	10.3X

Average Shares Outstanding:	147 million	Return on Average 1976 Equity:	15.4%
Market Value:	$8,085 million	Book Value Per Share (12/31/76):	$41.91

OPINION

We believe that Standard Oil of Indiana has above average appe ı in a generally attractive domestic oil group.

1. Through unusually active onshore exploration and development, the company should be able to at least maintain U.S. production (about two-thirds of earnings) over the next several years, compared with a generally declining industry trend.
2. As a result, annual production revenues will benefit fully from future U.S. crude oil and natural gas price increases, a probable contribution of some $300 million ex cost increases, or about $0.95 a share after taxes.
3. Rising production in Egypt, Iran, and the North Sea (overseas production about 13% of earnings) should add profits of $1.00 a share by 1980.
4. Expansion of chemical operations (8% of 1976 earnings) has been strategically executed, and this segment should earn about $1.00 a share by 1980 under normal economic conditions, compared with $0.51 a share in 1976.
5. In an equally important but less tangible vein, Standard Oil of Indiana is extremely well managed, as attested to by average annual earnings per share growth of 13% over the past ten years.
6. We estimate that earnings per share will rise to about $9.60 by 1980, or 12% annually, and dividend increases should at least match this pace, considering that the payout is currently at the lower end of the 35-45% stated policy.
7. We believe the price-earnings ratio will be in a probable future 7-11 range.

Considering these positive aspects, purchase of Standard Oil of Indiana should provide an annual Investment return of 15-20% over the next several years.

1976 EARNINGS

Earnings per share of $6.09 in 1976 were about 2½ times the $2.41 level of 1971 but under the record $6.55 set in 1974. Quarterly 1975–1976 comparisons by major lines of business are tabulated below (EPS in $).

	Petroleum					
	U.S.	Canada	Overseas	Chemicals	Other	Net Income
1975						
1Q	$0.83	$0.07	$0.16	$(0.09)	$0.00	$0.97
2Q	0.99	0.08	0.37	0.18	(0.01)	1.61
3Q	1.06	0.16	0.29	0.06	0.00	1.57
4Q	0.85	0.18	0.13	0.11	(0.06)	1.21
Year	$3.73	$0.49	$0.95	$ 0.26	$(0.07)	$5.36
1976						
1Q	$1.21	$0.14	$0.33	$0.15	$(0.38)	$1.45
2Q	1.20	0.21	0.13	0.27	(0.05)	1.76
3Q	1.38	0.14	0.16	0.09	(0.04)	1.73
4Q	0.98	0.07	0.14	0.00	(0.04)	1.15
Year	$4.77	$0.56	$0.76	$0.51	$(0.51)	$6.09
% of Total						
1975	69%	9%	18%	5%	(1%)	100%
1976	78	9	13	8	(8)	100

The company benefitted particularly in 1976 from (1) an increase in the average U.S. natural gas wellhead price to 65¢ per MCF from 48¢ per MCF, (2) higher U.S. refined product prices, particularly in the summer, and (3) a sharp increase in chemical volumes. Overseas petroleum earnings per share declined to $0.76 from $0.95. The comparison was actually more negative than reported because the first quarter of 1976 included a reversal of unnecessary expenses for fourth quarter drilling in Egypt.

Results were hurt last year by a $0.39 a share first quarter nonrecurring expense for estimated costs of termination of a copper project in Zaire. In addition, revisions of North American oil and gas reserve estimates required a charge of $0.18 a share in the fourth quarter, of which $0.11 was additional amortization and $0.07 was a writedown in value. The fourth quarter was also penalized by a number of negative operating factors. U.S. downstream results suffered from a buildup in inventories in anticipation of the OPEC price increase and a $30 million jump in the quarterly rate of entitlements purchases. Chemical margins narrowed because demand was insufficient to maintain cost pass-throughs, and results were also hurt by startup costs of four new plants. Foreign currency translations penalized the fourth quarter 1976 earnings per share comparison by $0.12 and the full year by $0.20.

NORTH AMERICAN PRODUCTION

Standard of Indiana's U.S. production record over the past five years is shown below. On the basis of exploration and development discussed below, we believe the company can hold U.S. crude oil and natural gas output essentially even through 1980.

	1972	1973	1974	1975	1976	1977E
Crude Oil						
Thousand Barrels Daily	420	459	471	459	449	445
Million Barrels Annually	154	167	172	168	164	162
Average Price Per Barrel	\$3.46	\$4.12	\$7.04	\$7.95	\$8.23	\$8.75
Natural Gas						
Million Feet Daily	3,118	3,124	2,893	2,631	2,556	2,600
Billion Feet Annually	1,141	1,140	1,056	960	935	949
Average Price Per Thousand Feet *	20¢	24¢	35¢	48¢	65¢	80¢

*Includes Canada which accounts for about 10% of total North American natural gas sales.

U.S. Crude Oil

About 60% of the company's U.S. crude oil production is from the state of Texas where many reservoirs respond effectively to waterflooding and other forms of secondary recovery. Over 400 waterflood projects are operated with combined output of some 200,000 barrels a day, or roughly double the level of ten years ago. Mainly as a result of incremental output from waterflooding, Standard of Indiana has a ratio of 45% upper tier crude oil, unusually high for a major company. However, crude oil from stripper wells (ten barrels a day or less) not subject to price controls is only 2% of total, reflecting earlier sales of then uneconomic properties. Except for 1974 when \$578 million was spent on lease acquisitions, the company has not participated as heavily as most in Federal offshore lease sales.

Instead, efforts have been particularly aggressive onshore. Total undeveloped U.S. land holdings are about 25 million net acres, compared with 12.6 million net acres at the end of 1970. Oil exploration has been most successful at Pineview and Ryckman Creek in the Thrust Belt of Utah–Wyoming, the Silurian Reef trend of northern Michigan, South Marsh Island Block 128 offshore Louisiana, and deeper in the established Abo Reef trend of West Texas. In addition, some 16,000 barrels a day of crude output were added in south central Wyoming through the December 1975 purchase of Pasco, Inc. for a \$135 million production payment plus \$89 million in cash. The production loan is paid down out of 85% of production and should be retired by the early 1980s.

U.S. Natural Gas

After declining about 18% since 1973, the company's domestic natural gas production should commence a gradual recovery this year reflecting development in several areas including Wamsutter and Moxa Arch in Wyoming, the Ozona-Sonora area of southwest Texas, and Wattenberg in eastern Colorado. The Wyoming program includes up to 89 wells being drilled by Cities Service in return for a call on most of the gas. Production offshore Texas, where interests are held in 11 platforms, will begin in 1978 following completion of the High Island Offshore pipeline system. Deliveries net to Standard of Indiana should exceed 100 million cubic feet a day by 1979 or 1980, and oil production of 8,000-10,000 barrels a day will begin following completion of a pipeline.

Drilling will continue to be particularly active this year on 3,690,000 acres in Wyoming and Utah under a land grant option from Union Pacific Railroad which expires on November 1. Ryckman Creek, where Standard of Indiana has a 37½% interest, had a 120 foot oil column and and a 300 foot gas cap in the discovery well. It is being developed at several locations, and several exploration wells are planned or under way in this attractive area.

Rising Prices

Like other oil companies, Standard Oil of Indiana is benefitting significantly from rising U.S. crude oil and natural gas prices. The company's average domestic crude realization should rise about $0.50 a barrel in 1977 and close to $1.00 a barrel in each of several following years. Using $1.00 as a yardstick, annual revenues would rise by about $160 million after royalties. Additional severance taxes would be about $10 million, and annual production costs might rise by $40 million ($0.25 a barrel). After income tax, net profit would benefit by $57 million, or $0.40 a share. The company also sells about 30 million barrels of natural gas liquids annually in the United States. Under present Federal Energy Administration controls, significant near-term price improvement is unlikely.

Somewhat more than 40% of the company's natural gas 1976 sales are to uncontrolled intrastate markets, a sharp increase over 1975, as shown by the following statistics.

	Million Feet a Day					
	1971	1972	1973	1974	1975	1976E
Intrastate	1,048	1,145	1,272	1,045	869	1,100
Interstate						
Onshore	1,633	1,565	1,387	1,376	1,309	1,060
Offshore	377	444	432	443	423	400
Total	3,058	3,154	3,091	2,864	2,601	2,560

About 400 million feet a day, or 15% of total gas production, is in the post-1972 vintage category which benefits from price increases to $0.93-1.42 plus escalation price increases under FPC Order 770-A. Reflecting both 770-A and the higher proportion of uncontrolled intrastate sales, the company's average U.S. natural gas price rose to 65¢ per MCF in 1976 from 48¢ a year earlier, and a further 15-20¢ improvement is likely in 1977. On this basis, revenues will benefit by $140-190 million, and net income should rise by $55-75 million, or $0.35-0.50 a share. With prospects for a price of at least $1.44 per MCF on all new gas and considerably higher if the Carter Administration implements decontrol, we believe Standard of Indiana's U.S. natural gas revenues and profits will rise a similar rate for several years in the future.

Reserves

Standard of Indiana has recently reduced North American petroleum reserve estimates. This revision resulted in a charge against fourth quarter 1976 earnings of $0.18 a share. U.S. changes are shown below.

ESTIMATED U.S. RESERVES (12/31/75)

	Original	Revisions: SEC Guidelines	Revisions: Other	Revised
Liquids (mil. bbl.)	2,242	32	11	2,199
% Decrease	–	1.4%	0.5%	1.9%
Natural Gas (bil. CF)	10,680	429	692	9,559
% Decrease	–	4.0%	6.4%	10.4%

Although reserve revisions are a frequent occurrence, the 1976 study was a particularly intensive one because of new SEC reporting requirements. Natural gas reserves were particularly affected by unexpectedly rapid pressure declines at the Old Ocean and Gomez fields in Texas, and Blanco Mesa Verde in New Mexico. U.S. reserve lives are about 10 years for natural gas and 11 for oil, comparable to the industry as a whole.

Canada

About 10% of total net income is obtained from oil and gas output in Canada. Net production has fallen since 1973, partly reflecting higher provincial royalties. However, profits have roughly tripled during that period as a result of higher prices. We estimate that the company's Canadian earnings per share will rise $0.05-0.10 annually over the next several years as prices move up further.

OVERSEAS PRODUCTION

Standard Oil of Indiana re-entered overseas oil operations in 1958 in what since has come to be considered as a watershed joint venture with the Iranian government. This departure from the venerable concession system was followed by a similar agreement with Egypt in the Gulf of Suez. Exploration under both ventures has yielded significant reserves and rising production. Statistics on overseas oil production are shown below, including estimates for the next several years.

NET OVERSEAS LIQUIDS OUTPUT
(000 Barrels a Day)

	1973	1974	1975	Estimated 1976	Estimated 1977	Estimated 1979	Estimated 1981
Trinidad	49	71	109	95	100	100	55
Iran	64	66	88	100	130	160	155
Egypt	50	42	67	80	105	150	115
Argentina	54	55	49	45	45	45	40
Venezuela	34	29	28	–	–	–	–
United Kingdom	–	–	–	–	5	15	15
Other	7	6	8	3	2	20	50
Total	258	269	349	323	387	490	430

Note: Venezuela was nationalized on December 31, 1975. Growth in "other" primarily reflects Norway. Egypt includes cost recovery barrels.

Trinidad

Production from three fields has reached an aggregate level of about 100,000 barrels a day. Samaan, the largest of the three, has API gravity of 36.8 degrees. Reservoirs characteristically have rather rapid declines from peak flows. With further development, however, production should hold at the present rate for three more years, following which considerable slippage is likely unless there are further discoveries. In 1976, producing operations in Trinidad involved a royalty of $2.18 a barrel, producing costs of an estimated $2.00, and income taxes of an estimated $7.62, or a total tax paid cost of $11.80 a barrel. Allowing for an average export price of $12.60 last year, the company made $0.80 a barrel last year on production in Trinidad, equal to net income of $30 million, or $0.20 a share. We expect this contribution to be essentially maintained through 1979 although the government might tighten fiscal terms to something more in line with OPEC.

Iran

The company's Iranian production should rise to about 160,000 barrels a day from 100,000 BD over the next three years as the two newer fields—Ardeshir and Fereidoon—develop to peak flow rates. However, Iranian fiscal terms are harsh, limiting profitability to $0.20-0.25 a barrel. On this basis, earnings per share from Iran would move up to only $0.08 a share in 1979 from $0.05 in 1976.

Egypt

Operations in Egypt are under a production sharing agreement with the government whereby the company receives up to 20% of the oil for recovery of costs and an additional 17% of the remaining 80% as profits. The 17% share will drop to 15% in 1978. As indicated below, equity production should more than double in the next three years, benefiting from waterflooding of the Morgan and July fields and further development of Ramadan. Two discoveries made during 1976 should add to this potential. A profile of these properties is shown below.

			Estimated Production (BD)			
	API	Sulphur	Gross		Indiana's Equity Share	
Field	Gravity	Content	1976	1979	1976	1979
Morgan	31°	1.7%	100,000	160,000	14,000	19,000
July	32	1.1	50,000	80,000	7,000	10,000
Ramadan	34	1.1	85,000	250,000	12,000	30,000
Block 382	34	1.1	–	120,000	–	14,000
Block 300	26	2.8	–	20,000	–	2,000
Total			235,000	630,000	33,000	75,000

Assuming an average wellhead price of $11.25 a barrel, the company's revenues on equity production in 1976 were $135 million (33,000 BD X 365 days X $11.25 a barrel). Hypothesizing costs above and beyond cost recovery at $50-75 million, net earnings would have been $60-85 million, or $0.40-0.55 a share. At a probable price in the vicinity of $13.00 a barrel by 1979, revenues from equity production would be about $355 million, or $2.65 a share.

However, we believe that continuing costs above cost recovery or harsher terms will reduce this contribution to $1.00-1.50.

Argentina

Argentine production ranges between 45,000 and 50,000 barrels a day under a long-term contract with the government. This agreement appears to allow a unit profit of about $1.00 a barrel (basic fee plus adjustments), equivalent to net income of $17 million ($0.12 a share).

North Sea

Standard of Indiana has relatively small interests in North Sea oil reserves compared with most major oil companies. Production from the Montrose field (30.77% owned) began during 1976, with peak output estimated to reach 50,000 barrels a day, or about 15,000 BD net to the company. Two discoveries, Hutton and Northwest Hutton, have been made in the "golden" quadrant 211 area east of the Shetland Islands, but they as yet remain uncommercial in size. On the Norwegian side, initial production is anticipated from the 7.2% interest Tor unit this year, and Tor should reach a gross rate of 75,000 BD (5,000 BD net to Indiana) in 1978. Delineation of the nearby Valhall field (28 1/3% owned) is continuing, and gross potential appears to be 100,000-150,000 BD. The company has a tiny 1.04% interest in the giant Stratfjord field, which should contribute net production of about 3,000 BD in 1979 and 8,000-9,000 BD by the mid-1980s.

DOWNSTREAM

United States

The company has operable U.S. refinery capacity of 1,150,000 barrels a day including large plants at Whiting, Indiana (360,000 BD) and Texas City, Texas (333,000 BD). Utilization is over 90% and should remain so in the near future because no grass roots expansion is contemplated. With annual U.S. oil product sales of about 17 billion gallons, Standard of Indiana has material price leverage. Each 1¢ a gallon price change over the course of a year is equivalent to net income of about $90 million, or $0.60 a share. Industry operating rates should remain at about 90% over at least the next three years, reflecting only moderate capacity additions, and gasoline price structures should accordingly allow generally consistent cost pass-through or even some margin improvement. In this regard, the Federal Energy Administration entitlements program has had the inadvertent effect of encouraging crude oil rather than refined product imports, tempering downward price pressures which often result from excess refining capacity. Domestic downstream profits improved in 1976, probably representing some 10% of company total.

Overseas

Principal overseas refineries are located at Milford Haven, Wales (102,000 BD) and Cremona, Italy (80,000 BD). As elsewhere in Europe, these plants have operated at uneconomical rates over the past three years because of depressed demand, but the impact on overall results has been modest.

CHEMICALS

Standard of Indiana is one of several major oil companies which has placed considerable emphasis on chemical expansion over the past few years. Revenue and profit trends are shown below.

	1973	1974	1975	1976E
Revenues (millions)				
Fibers and films	$197	$272	$293	$375
Industrial	68	130	195	270
Fertilizers	89	133	187	175
Synthetic fabrics	153	165	166	185
Polymers	96	143	110	150
Petroleum additives	35	65	78	100
Fabricated plastic products	71	101	75	80
Other	62	80	86	101
Total	$771	$1,089	$1,190	$1,436
Net Income	$ 48	$ 95	$ 37	$ 74
% of Total Net Income	9%	10%	5%	8%
Average Net Investment	$506	$584	$776	$1,000
Return on Average Net Investment	9.5%	16.3%	4.8%	7.4%

Results have been highly sensitive to broad trends in business activity and also to mini-cycles within the economic expansion of the last year and a half. Quarterly profits moved in a volatile pattern during 1975 and 1976. The second quarter is seasonally higher because of fertilizer.

	1Q	2Q	3Q	4Q
	millions			
1975	$(13)	$27	$ 9	$16
1976	22	39	13	0

About one-fourth of Standard of Indiana's chemical revenues come from the sale of purified terephthalic acid (PTA), and, to a lesser extent, dimethyl terephthalate (DMT), both raw materials in the production of polyester films and fibers. The company has concentrated on PTA because it has a 12-15% cost advantage over DMT. Second in importance as a category is the manufacture of ethlyene, styrene, and other basic "industrial" chemicals. Fertilizers have diminished in significance as a result of price weakness since mid-1975. Roughly one-sixth of total chemical revenues are from overseas.

Five chemical plants were completed in 1976, and eight more are scheduled between now and the end of 1979. Among the largest to be completed over the next three years are a second billion pound per year olefins (ethylene, etc.) facility at Chocolate Bayou, Texas in 1977 and a billion pound per year PTA unit at Charleston, South Carolina. Chemical results should benefit during 1977 from full year operations of a 200 million pound per year high density polyethylene plant at Chocolate Bayou, a 500 million pound per year polypropylene facility at Geel, Belgium, all of which had a negative impact in 1976 due to start-up costs. Current year revenue contributions from these three new expansions (and two smaller ones) should total $250-300 million at present price levels, and additional profits should be in the range of $15-20 million. And, ongoing chemical operations should add $5-10 million, or a total increase in net income of $20-30 million ($0.15-0.20 a share) from chemicals in 1977. Facilities starting up during the next three years should add about $500 million in annual revenues, or equivalent cost reductions, at current price levels. Assuming a 6% after-tax margin, the profit increment would be $30 million by 1980. Allowing for moderate further growth from existing chemical activities, we estimate that total chemical profits will rise to about $150 million ($1.02 a share) by 1980 from $74 million ($0.51) last year.

1977-1980 EARNINGS PROSPECTS

Our profit expectations through 1980 by major line of business are as follows:

		Estimated			
	1976	1977	1978	1979	1980
	($ millions)				
Petroleum					
U.S.	700	760	840	920	980
Canada	82	92	100	110	120
Overseas	111	120	145	170	195
Total	893	972	1,085	1,200	1,295
Chemicals	74	100	115	130	150
Other	(74)	(20)	(25)	(30)	(30)
Net Income	893	1,052	1,175	1,300	1,415
Earnings Per Share	$6.09	$7.15	$8.00	$8.85	$9.60

As discussed earlier, earnings per share should benefit particularly over the next several years from rising crude oil and natural gas prices in North America, moderate improvement in U.S. refining margins, new crude production in Egypt, and chemical expansion. In addition, current year results will be helped by absence of the $0.39 a share 1976 writeoff in Zaire. During an economic downturn in any individual year, chemical results would slip, thereby affecting the reasonably even progression developed above. Moreover, we have not attempted the precarious effort of estimating annual swings in foreign currency translations.

FINANCES

Capital expenditures roughly doubled between 1972 and 1974, and outlays have remained in the $1½ billion area during each of the past three years.

	1972	1973	1974	1975	1976	1977E
	($ millions)					
Net Income	$372	$511	$958	$789	$893	$1,052
Dividends	167	180	234	294	337	382
Retained Earnings	$205	$331	$724	$495	$556	$ 670
Non-Cash Charges	422	462	580	695	725	800
Funds Provided From Operations	$627	$793	$1,304	$1,190	$1,281	$1,470
Capital Expenditures	749	901	1,511	1,525	1,340	1,700
(Deficiency)	(112)	(108)	(207)	(335)	(59)	(230)

The deficiency has been financed primarily by long-term debt under a financial strategy that has held the debt ratio to less than 25%. The common dividend was recently raised to a quarterly rate of $0.65 from $0.575. Stated policy is to pay out 35-45% of earnings, suggesting that the dividend could be increased again during the next twelve months and further in the years ahead.

RR-77-24 — Research Department—

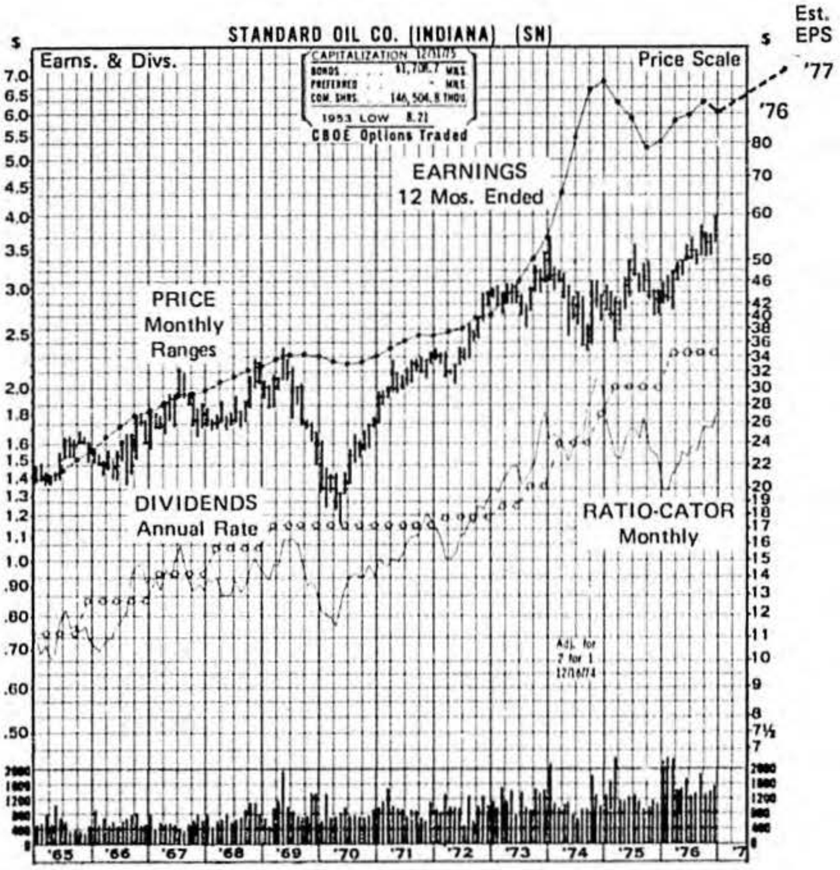

Chart courtesy of Securities Research Company.

FINANCIAL SUMMARY
($ millions)

	1971	1972	1973	1974	1975	1976
Operating Data						
Revenues	$4,965	$5,477	$6,468	$10,156	$11,147	$12,672
Depreciation, etc.	344	384	448	562	610	640E
Pretax Income	448	496	781	1,694	1,966	2,243E
Income Taxes	107	124	270	736	1,179	1,350E
Net Income	$ 341	$ 372	$ 511	$ 958	$ 787	$ 893
Operating Ratios						
Pretax Margin	9.0%	9.1%	12.1%	16.7%	17.6%	17.7%
Tax Rate	23.9	25.0	34.6	43.4	60.0	60.2
Net Margin	6.9	6.8	7.9	9.4	7.1	7.0
Equity Turnover	1.4X	1.5X	1.6X	2.2X	2.1X	2.2X
Return on Equity	9.9%	10.1%	12.9%	20.7%	14.7%	15.4%
Per Share Data						
Earnings Per Share	$2.41	$2.59	$3.54	$6.55	$5.36	$6.09
Dividends	1.15	1.20	1.29	1.65	2.00	2.30
Price Range	35-26	44-31	52-38	55-35	53-36	60-41
Book Value	$25.70	$27.20	$29.54	$34.78	$38.12	$41.91
P/E Range	14-11	17-11	14-10	8-5	10-7	10-7
Average P/E	12.5	14.0	12.0	6.5	8.5	8.5
P/E Relative to S&P 500	73%	81%	92%	73%	80%	85%
Shares Outstanding	138	140	140	147	147	147

BALANCE SHEET SUMMARY
($ millions)

	1971	1975	9/30/76	Percent Change 1970 to Latest
Current Items				
Assets:				
Cash and Equivalents	$ 288	$ 772	$ 819	184%
Receivables	712	1,506	—	—
Inventories	466	923	—	—
Total Current Assets	$1,466	$3,201	$3,616	147%
Liabilities:				
Short-Term Debt	$ 49	$ 112	—	—
Other Current Liabilities	719	2,057	—	—
Total Current Liabilities	$768	$2,169	$2,475	222%
Current Ratio	1.9X	1.5X	1.5X	—
Net Assets				
Net Working Capital	$ 698	$1,032	$1,141	63%
Net Plant	3,964	6,413	6,808	71
Investments	211	240	317	50
Total	$4,873	$7,685	$8,266	70%
Capitalization				
Long-Term Debt	$1,027	$1,709	$1,741	70%
Deferred Items	281	391	458	63%
Minority Interests	15	—	—	—
Stockholders' Equity	3,550	5,585	6,067	71%
Total Capitalization	$4,873	$7,685	$8,266	70%
Long-Term Debt % Capital	21%	22%	21%	—

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Thomas C. Pryor
Executive Vice President (212) 285-2666

Harold W. Janeway
Director of Investment Policy (212) 285-2060

Jerome P. Kenney
Director of Research (212) 285-2020

Richard A. Kimball
Director of Marketing (212) 285-2374

Frank J. Ritger
Senior Vice President (212) 285-2120

A. Gary Shilling
Chief Economist (212) 285-2670

Basic Industries		
George H. Cleaver	Metals & Mining	(212) 285-2012
Frederic S. Coffman, Jr.	Forest Products, Paper	(212) 285-2748
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William N. Walling, Jr.	Coal	(212) 285-2438
Consumer Products & Services		
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A. Hager Bryant, 3rd	Gas Pipelines and Distribution	(212) 285-2696
Philip L. Dodge	Oil, Gas	(212) 285-2043
John H. Hayward, Jr.	Oil Services & Related	(212) 285-2032
John L. Kalmbach	Natural Gas, Resources, Diversified	(212) 285-2065
Richard L. Davisson, Jr.	Oil Consultant	(617) 482-7767
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Michael M. Harshbarger	Drugs	(212) 285-2698
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Market Analysis		
H. Carroll Mackin	Computer Support—Performance Monitor	(212) 285-2056
Peter J. Canelo	Computer Support—Performance Monitor	(212) 285-2256
John A. Mendelson	Technical Analyst	(212) 285-3753
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Stover L. Babcock, Jr.	Special Situations	(212) 285-2026
James C. Blair	Computers, Office Equipment	(212) 285-2045
Craig W. Fanning	Electrical Equipment	(212) 285-2030
Anthony G. Langham	Instrumentation, Semiconductors	(212) 285-2047
Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Rieser	Assistant to Director of Research	(212) 285-2020
Ann T. Stott	Institutional Marketing	(212) 285-2064

ONE LIBERTY PLAZA, NEW YORK, N.Y. 10006

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Summary Report

Philip L. Dodge
(212) 285-2043

February 28, 1977

CITIES SERVICE COMPANY (CS)

Price (NYSE)		Dividend		EPS (December)		P/E
Current:	59	Rate:	$3.00	1977E:	$8.75	6.7X
Range (1976-1977):	61-39	Yield:	5.1%	1976:	$7.98	7.4X
				1975:	$5.12	11.5X

Average Shares Outstanding:	27.3 million	Return on Average Equity:	12.7%
Market Value:	$1,611 million	Book Value Per Share (12/31/76):	$65.63

SUMMARY

Cities Service should experience moderate profit improvement over the next several years as a result of rising U.S. natural gas and crude oil prices, and a possible turnaround in chemical-metal operations at Copperhill, Tennessee. The company would also benefit differentially if government price controls were removed from all natural gas liquids, although timing of such a step is unclear. On the other hand, Cities is among the majority of U.S. crude oil producers facing a decline in production, and efforts to reverse this trend thus far appear futile. While the entire domestic oil group continues to appear attractive, we prefer companies with visible sources of rising energy production.

PRODUCTION OUTLOOK

Both crude oil and natural gas production declined 4-5% in 1976, but natural gas liquids output stabilized at 90,000 barrels a day, reflecting expansion of the Odessa (Texas) and Paddle River (Alberta) plants, a new facility in Campbell County, Wyoming, and deeper cuts at several other facilities. Crude production will probably drop a further 5% in 1977, natural gas is likely to fall by a lesser 1-2%, and NGL should again remain about even. The natural gas decline is being tempered by broad efforts in older domestic onshore basins and by new offshore Louisiana production.

Most important exploration success has been experienced during recent years on Federal tracts in the Gulf of Mexico. Cities' daily production from the Gulf currently averages about 23,000 barrels of oil (about 22% of U.S. total) and 300 million cubic feet of gas (30%). Since November 1971, the company has spent over $225 million on Gulf lease bonuses, and it subsequently has established commercial reserves on 25-30 tracts, only 2 of which (East Cameron 33 and South Marsh Island 261) are already producing. Offshore Texas production has been delayed by earlier Federal Power Commission transportation deliberations, but the High Island Offshore pipeline system is now under construction. Assuming completion of HIOS early next year, Cities' offshore Texas gas production should make a significant contribution in 1978. Initial connections will be to Blocks 110-111 (20% owned), A 322-323 (19%), and A 520 (25%). The A 327-332 field (10% owned) will be tied in shortly thereafter. All in all, the Gulf of Mexico should add net new gas production of 150-200 million cubic feet a day by 1979, more than offsetting decreases in older fields. The increase in total gas production will probably be on the order of 3-5% in both 1978 and 1979. Gulf of Mexico natural gas reservoirs are typically meager in associated liquids, and additional NGL output may be no more than 3,000-4,000 barrels a day. Nevertheless, these and other expansions should be adequate to offset other declines, and aggregate company natural gas liquids output should hold about even over the next few years. Barring some unpredictable and perhaps unlikely significant discovery, the downward trend in crude oil output will continue.

Cities' natural gas production probably contributes 25% of total profits, and the company has unusually high leverage on rising natural gas prices. FPC Order 770-A, which raised post-1972 gas prices substantially, initially adds about $13 million to company net income on an annual basis. Partly because of 770-A, Cities' average wellhead gas price rose to 43¢ per thousand cubic feet in 1976 from 33¢ in the previous year. A comparable increase appears likely in 1977, or the equivalent of about $35 million in pretax earnings ($0.70 a share net after taxes). By 1980, when new Federal offshore tracts are in production, the company's average price should reach 80¢ per MCF, or higher if new gas is decontrolled.

Cities' U.S. crude oil price averaged $7.55 a barrel in 1976. About 61% of production is lower tier (industry norm 52%), 25% upper tier (35%), and 14% stripper (13%). Although domestic crude oil prices are technically *frozen* by the Federal Energy Administration, stripper crude postings, which are not regulated, rose at the first of the year along with OPEC increases, and higher priced upper tier is also rising as a percent of total. Moreover, monthly allowable increases in both upper tier and lower tier prices will probably resume by the middle of 1977. On this basis, Cities should realize an average U.S. crude oil price of about $8.25 a barrel this year, up $0.70 from 1976. Allowing for a 5% drop in volume, domestic crude oil production revenues after royalties should rise to about $303 million from $290 million, and earnings per share by $0.20 after severance taxes, moderate cost increases and income taxes. This favorable comparison should be typical of general experience in each of the next several years.

Overseas exploration efforts have met with only modest success over the years, currently involving production in Argentina, Indonesia, and Sharjah, but on the whole unprofitable because of exploration costs. First half 1976 results were penalized by write-downs of $12 million ($0.45 a share) in Indonesia and Peru.

In Canada, Cities Service is making a substantial investment to develop synthetic oil production in the Athabasca tar sands. Cities' 22% share of the Syncrude project is presently estimated at $475 million, of which the Alberta government is loaning $100 million. Alberta has the option of converting this loan into a 5% equity interest. Moreover, Alberta Energy Company may purchase a 20% interest in the entire Syncrude project. Depending on whether and when these options are exercised, Cities' interest could decline to 12.6–13.6%.

Construction is essentially on schedule, and synthetic crude oil extraction and processing is likely to begin in 1978. Initial design capacity of the plant is 109,000 barrels a day, and Cities' 22% share of daily output is expected to average 5,000 barrels in 1978, 16,000 in 1979, and 24,000 barrels in 1980. With debottlenecking, capacity can later be raised about 15-20% at a relatively nominal expense. Operating costs are estimated at $10.25 a barrel in constant dollars over the 25-year estimated life of the project, but the figure will probably be higher in early years of below-design utilization. Syncrude will not be subject to Canadian price controls, and it would currently fetch about $12.00-13.00 a barrel at the plant. Barring an unlikely reversal in trend, oil prices should move up 5-10% annually over the next several years. On this basis, Syncrude would realize close to $15.00-16.00 a barrel in 1980, a figure which should be moderately profitable. The Province of Alberta is to receive 50% of profits, this amount deductible for Federal Canadian tax purposes. Assuming a 1980 price of $16.00 and costs of $11.00, Cities would net about $1.25 a barrel or $11 million net ($0.40 a share). Better results are contingent on higher prices and scaling up to greater output, both certainly future possibilities.

NATURAL GAS TRANSMISSION

Cities operates a primarily interstate transmission system in the central U.S. This activity accounts for about 20% of company profits. Although volume has declined over the past several years due to supply limitations, the spread between price and cost has risen to about 30¢ per thousand cubic feet from 10¢, and profits have improved sharply. Results last year benefited particularly from rate case adjustments. With regulatory limits now being approached, earnings are likely to increase by a lesser 5-10% in 1977, again reflecting a wider spread. This rate of growth is also a realistic expectation over the next several years.

METALLURGICAL CHEMICAL AND COPPER

Copperhill

Cities continues to lose money on sulfide ore processing operations at Copperhill, Tennessee, although we estimate that the pretax deficit was reduced last year to about $10-15 million from approximately $25-30 million in 1975. Principal products are copper, iron oxide pellets, sulfuric acid, and zinc concentrate. Copperhill was expanded in 1973 and has been plagued with problems since. Major modifications were required in four iron roasters which heat iron concentrate to remove sulphur dioxide, and this segment is now functioning satisfactorily. However, difficulties continue in the critical iron pelletizing system, and production has been running below levels that could readily be supplied to Republic Steel and other available markets. Results were also hurt in 1976 by reduced demand for sulphuric acid related to fertilizer industry over-supply of phosphates. Cities was able to temper the impact of this downturn by closing sulphuric acid facilities at Atlanta, thereby maintaining better utilization at Copperhill. Expectations are that the Copperhill deficit can be reduced or eliminated in 1977.

Arizona Copper

Cities operates a copper mine with design capacity of 125 million pounds annually at Pinto Valley near Miami, Arizona. Pinto Valley produced about 120 million pounds in 1976, and an additional 30 million was obtained from processing at Copperhill (and additional small quantities elsewhere). Revenues from copper last year were about $100 million at an average price of 68¢ a pound, and profits were probably on the order of $8-10 million, or $0.30-0.40 a share. Contingent on demand from Inspiration Copper, which operates nearby smelting facilities, Pinto Valley output may rise 10 million pounds this year. Prices are not likely to improve significantly in the near term, despite some recent strengthening. Each 1¢ change on an annual basis equals about 3¢ a share in Cities' earnings.

EARNINGS

Cities registered outstanding profit improvement last year to $7.98 a share, up 56% from $5.12 in 1975. Each quarter showed a strong gain.

	1Q.	2Q.	3Q.	4Q.	Year
1975	$1.00	$0.90	$1.49	$1.73	$5.12
1976	1.82	1.89	2.09	2.18	7.98
% Increase	82%	110%	40%	26%	56%

Earnings in 1976 were favorably influenced by several factors. On a pretax basis, higher U.S. natural gas prices added about $1.25 a share and higher U.S. crude prices about $0.65 a share. Natural gas transmission earnings rose by about $10 million, or $0.35 a share. Utilization of the 275,000 barrel a day Lake Charles (Louisiana) refinery rose to 95% from 93% in 1975, and, more importantly, product prices were strong, allowing considerable cost recovery under Federal Energy Administration price controls. Pretax petrochemical profits increased by an estimated $10-15 million, or roughly $0.40-0.50 a share, benefiting from expanded low-density polyethylene facilities at Lake Charles. Copper sales jumped more than 50% as a result of new output at Pinto Valley. The year-to-year comparison also was helped by a $7 million decline in exploration and lease amortization expenses, even though first half 1976 results included writedowns in Indonesia and Peru totaling $12 million ($0.44 a share).

We estimate that 1977 earnings per share will rise to an $8.50-9.00 range. Anticipated improvement will particularly reflect a full year of higher natural gas price under Federal Power Commission Order 770-A. Overall, Cities' average natural gas price should move up about 10¢ per thousand cubic feet this year, adding $0.70 a share to net income before cost increases. If producing costs are 10% higher this year, probably more than an adequate allowance, the additional profits would be about $0.40 a share after taxes. As noted earlier, Cities also has considerable leverage on U.S. crude oil prices, and a probable increase of approximately $0.70 a barrel this year should more than offset the negative impact of lower production and cost inflation. Gains in other segments are likely to be more moderate this year than last, although most should be up. Downstream operations should continue to benefit from a firm price structure, with gasoline recently showing contraseasonal improvement, although a recent strike at Lake Charles clouds the first quarter outlook. Further corrective efforts at Copperhill could eliminate deficits of recent years, adding about $0.25 to earnings per share. On the negative side, international results may be depressed again by higher exploration costs or further writedowns of unsuccessful efforts.

Profits beyond 1977 are somewhat uncertain pending clarification of national energy policy. If price controls are removed from new natural gas and natural gas liquids, five-year growth could be in the upper end of a 5-10% annual range. About 80% of Cities' NGL is subject to price controls. On the other hand, a restrictive approach would probably hold average yearly improvement to a more moderate 5-7%. Cities is not among companies that have more assured prospects from development of major new sources of crude oil or natural gas, and it has no coal. Only in the long term could tar sands make a significant contribution to total profits. Year-to-year variations in earnings may be considerable as a result of fluctuations in copper prices or the impact of general industrial activity on Copperhill.

FINANCES

Capital outlays rose to $525 million last year from $439 million in 1975, and $575 million is budgeted for 1977. These increases primarily reflect large capital requirements of the Athabasca tar sands. The company raised $150 million through sale of 9 3/4% twenty-five year debentures in October 1975. Recent year cash flow-expenditure relationships are shown below.

($ in Millions)

	1974	1975	1976	1977E
Net Income	204	138	217	240
Dividends	61	65	71	82
Retained Earnings	143	73	146	158
Noncash Charges	239	269	310E	350
Funds Provided Internally	382	342	456E	508
Capital Expenditures	447	439	525	575
(Deficiency)	(65)	(97)	(69)	(67)

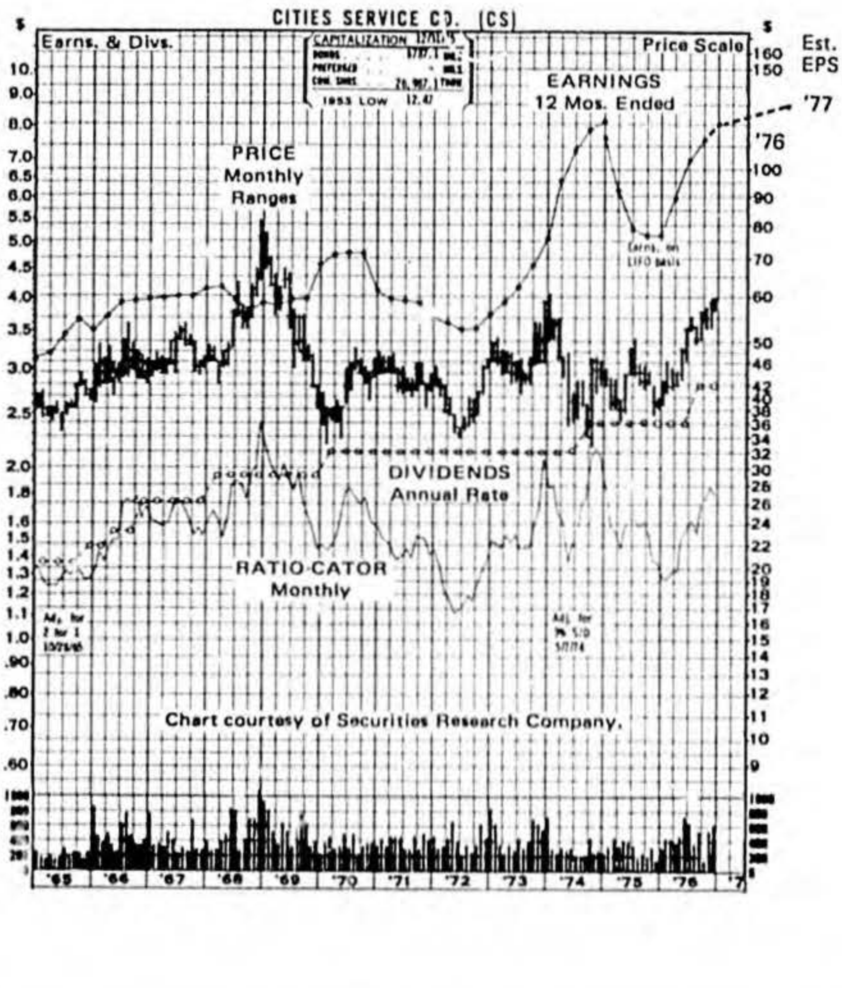
Cities maintains over $200 million in cash holdings, and the indicated current year deficit could be met from working capital. The quarterly dividend was recently raised to $0.75 a share, the second increase in six months. At about 35% of estimated 1977 earnings, the payout is comfortably low and could be raised again before the year is over. The stock currently yields 5 .% on the $3.00 dividend.

RR-77-33 —Research Department—

FINANCIAL SUMMARY

(Millions)

	1972	1973	1974	1975	1976
Operating Data					
Revenues	$1,870	$2,066	$2,847	$3,238	$4,006
Depreciation, etc.	115	114	128	130	148
Pretax Income	122	193	298	245	394
Income Taxes	22	55	89	99	170
Net Income	99	136	204	138	217
Operating Ratios					
Pretax Margin	6.5%	9.3%	10.5%	7.6%	9.8%
Tax Rate	18.0	28.5	29.9	40.4	43.1
Net Margin	5.3	6.6	7.2	4.3	5.4
Equity Turnover	1.3X	1.4X	1.8X	2.0X	2.3X
Return on Equity	7.1%	9.2%	12.7%	8.6%	12.7%
Per Share Data					
Earnings Per Share	$ 3.73	$ 5.06	$ 7.58	$ 5.12	$ 7.98
Dividends	2.14	2.14	2.27	2.40	2.60
Price Range	47-34	59-40	61-33	51-36	60-39
P/E Range	13- 9	12- 8	8- 4	10- 7	7- 5
Average P/E	11.0	10.0	6.0	8.5	6.0
P/E Relative to S&P 500	64%	77%	67%	80%	59%
Shares Outstanding	26.6	26.8	26.9	26.9	27.2



BALANCE SHEET SUMMARY

($ in Millions)

	1971	1975	9/30/76	% Change 1971 to Latest
Current Items				
Assets:				
Cash and Equivalents	$ 98	$ 217	$ 262	167%
Receivables	260	408	397	52
Other	226	366	437	93
Total Current Assets	$ 584	$ 991	$1,096	88%
Liabilities:				
Short-Term Debt	$ 102	$ 56	$ 61	(40%)
Other	237	462	507	114
Total Current Liabilities	$ 339	$ 518	$ 568	68%
Current Ratio	1.7X	1.9X	1.9X	–
Net Assets				
Net Working Capital	$ 245	$ 473	$ 528	116%
Net Plant	1,642	2,087	2,210	35
Investments	87	140	93	7
Other Assets – Net	86	16	69	(20)
Total	$2,060	$2,716	$2,900	41%
Capitalization				
Long-Term Debt	$ 564	$ 768	$ 833	48%
Deferred Items	55	309	307	458
Minority Interests	7	7	8	14
Stockholders' Equity	1,434	1,632	1,752	22
Total Capitalization	$2,060	$2,716	$2,900	41%
Long Term Debt % Capital	27%	28%	29%	–

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Thomas C. Pryor *Executive Vice President* (212) 285-2666	**Harold W. Janeway** *Director of Investment Policy* (212) 285-2060
Jerome P. Kenney *Director of Research* (212) 285-2020	**Richard A. Kimball** *Director of Marketing* (212) 285-2374
Frank J. Ritger *Senior Vice President* (212) 285-2120	**A. Gary Shilling** *Chief Economist* (212) 285-2670

Basic Industries		
George H. Cleaver	Metals & Mining	(212) 285-2012
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A. Hager Bryant, 3rd	Gas Pipelines and Distribution	(212) 285-2696
Philip L. Dodge	Oil, Gas	(212) 285-2043
John H. Hayward, Jr.	Oil Services & Related	(212) 285-2032
John L. Kalmbach	Natural Gas, Resources, Diversified	(212) 285-2065
Richard L. Davisson, Jr.	Oil Consultant	(617) 482-7767
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A. James Donohue	Banks, S&L's, REIT's, Mortgage Insurers, Misc. Real Estate	(212) 285-2010
Gerald E. Lewinsohn	Insurance	(212) 285-2000
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Michael M. Harshbarger	Drugs	(212) 285-2698
L. John Wilkerson	Hospital Products	(212) 285-2695
Market Analysis		
H. Carroll Mackin	Computer Support–Performance Monitor	(212) 285-2056
Peter J. Canelo	Computer Support–Performance Monitor	(212) 285-2256
John A. Mendelson	Technical Analyst	(212) 285-3753
Technology		
Stover L. Babcock, Jr.	Special Situations	(212) 285-2026
James C. Blair	Computers, Office Equipment	(212) 285-2045
Craig W. Fanning	Electrical Equipment	(212) 285-2030
Anthony G. Langham	Instrumentation, Semiconductors	(212) 285-2047
Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Rieser	Assistant to Director of Research	(212) 285-2020
Ann T. Stott	Institutional Marketing	(212) 285-2064

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White, Weld & Co.
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Summary Report

John Kalmbach
(212) 285-2065

March 2, 1977

TEXAS OIL AND GAS (TXO)

Price (NYSE)		Dividend		EPS (August)		P/E
Current:	27	Rate:	$0.20	1977E:	$2.90-3.10	9.0X
1976-77 Range:	33-13	Yield:	0.7%	1976:	$2.46	11.0X
				1975:	$2.05	13.2X

Shares Outstanding:	19,593,861	Return on Avg. 1976 Equity:	23.9%
Market Value:	$529 Million	Book Value Per Share (11/30/76):	$12.06

SUMMARY & CONCLUSION

Texas Oil and Gas has compiled one of the outstanding records of earnings growth and stability in recent U.S. history. Over the past 19 years, net income has grown uninterruptedly at a rate of 37% per year and at a rate of 40% over the past five years. Current and expected future price trends for natural gas point to continued strong future growth for TXO and we believe it is one of the more attractive equities for long term participation in the domestic oil and gas industry.

Many investors have viewed TXO as a quasi-public utility, gas gathering company. In our opinion, the company is more accurately a highly integrated natural gas producer with a strong gas exploration and development bias. Upwards of 65% of capital outlays have been devoted to exploration and development and acreage acquisitions in recent years. The company does not break out the earnings contribution from its oil and gas production, preferring to regard these activities as part of an integrated whole with its gas gathering and gas liquid extraction operations. Nevertheless, we estimate that the $71.1 million in revenues generated by oil and gas production in FY 1976 produced 40% or more of TXO's earnings before interest and taxes (EBIT) and 50% or more of its cash flow. Further, 62.4% of TXO's net investment in long term assets is represented by oil and gas properties. We fully expect the relative importance of oil and gas production to increase in the future as the company develops more of its substantial inventory of 3.5 million unproven net acres. Most of this inventory is trend acreage in proximity to established production. Drilling locations are chosen to maximize near term return on investment thus, wild-catting is pretty much avoided. Instead TXO participates in a large number of relatively low reserve potential/low risk wells (394 in 1976) and realizes a high success ratio (60% to 70% in recent years). TXO's concentration on development and field extension drilling virtually precludes major discoveries but has resulted in solid reserve additions on an overall basis.

TXO continues to build its gas gathering and processing facilities at a strong pace so that this important part of operations is positioned for good future growth as well. In addition to expanding several of its existing 31 gathering systems, where possible, TXO continues to follow its long standing tactic of building gathering systems in gas prospective areas where there are good prospects for considerable exploration and development activity. This approach to the gathering business dovetails with TXO's drilling activities since much of its undeveloped acreage is adjacent to its gathering systems in Texas and Oklahoma.

It should also be noted that, although nearly all of TXO's current gathering and production revenues come from sales in the Texas and Oklahoma intrastate markets, the company is positioned to enter the interstate gas market in a major way should de-regulation of new gas or court confirmation of the $1.44 interstate price for new gas take place. TXO holds significant, largely unexplored leases in Southern Wyoming, Kansas, Southeast New Mexico, Colorado and Arkansas, areas which lack large intrastate markets. In addition, TXO purchased a small interstate gathering system in Wyoming last year. Thus, the creation of viable interstate prices for new gas will probably lead to major investments by TXO in these markets.

Texas Oil and Gas, with a large base of reserves and production, a major acreage inventory, considerable financial strength and an outstanding record of growth is a low risk vehicle for participation in the domestic oil and gas industry. Selling at about 10X estimated EPS for the year ending August 31, 1977, TXO has 19.6 million shares outstanding with a market value of $529 million. TXO common shares appear to be one of the best values among publicly owned independent oil and gas equities and are suitable for all types of investors.

VALUATION / MARKET DATA

Bank Holdings (Spectrum) 9/30/76:	22	13.7%
Mutual Funds (Spectrum) 9/30/76:	15	8.0
Insurance Companies 12/31/75:	30	4.0
Total Institutional:		25.7%

1976 Average Daily Trading Volume: 25,700 shares

As indicated by the six year history of TXO's average P/E and P/E relative presented in the Financial Summary, TXO has been priced over a wide multiple range in recent years. TXO commanded a P/E as high as 40X to 60X during much of 1971, 1972 and 1973, even though reported earnings were untaxed in those years. Since 1973, as a result of the nationwide natural gas shortage, P/E's for all companies associated with the transportation and distribution of gas have come down sharply until recently. TXO's market fortunes were further impacted by the severe financial and supply problems of Coastal States Gas, another large gas gathering company, even though TXO has consistently maintained a strong financial and supply position. Thus, TXO's P/E has been as low as 6X earnings in each of the past three years. TXO has never contracted to deliver gas in amounts in excess of the quantities it has dedicated to it. In fact, TXO employs dedication contracts i.e., its suppliers dedicate gas to TXO for the life of the field and its buyers buy reserves in place, what ever they may prove to be, as opposed to a specified quantity.

In our opinion the past offers little aid in formulating a proper current and future P/E for TXO, however, the following factors should be key determinants of where TXO will sell:

1. Earnings growth—TXO's past record has been outstanding. For 1977, we are projecting an earnings gain of 22%. Beyond 1977, given TXO's strong gas supply position and excellent exploration potential, we envision EPS growth of 15% or more in fiscal 1978-79.
2. The whole economic and political climate surrounding natural gas has improved dramatically over the past two years and gas de-control would considerably further enhance the group's investor image. Hence, the oil and gas group may well be gaining a higher relative multiple.
3. Within the domestic independent oil and gas group, TXO is one of the few equities that offers both investment grade quality and good marketability.
4. The low dividend payout provides no yeild support.

The above factors suggest to us that, in the present yield conscious investment environment, a P/E at a 10% to 20% discount to TXO's expected growth rate may well be appropriate, or 12 to 14X earnings. Stocks seldom trade in such a narrow range for very long so that a spread of 10X to 16X may prove to be TXO's typical trading range over the next eighteen months, assuming no significant change in overall market multiples. If the above suggested range proves to be reasonably accurate, TXO offers considerable appreciation potential since it would sell in the range of 29 to 50 based on our 1977 estimate. In any case, TXO does seem to offer investors an attractive risk/reward ratio and it is for this reason that we favor it for participation in the domestic oil and gas industry.

DISCUSSION OF OPERATIONS

Through 26 wholly owned and 5 partly owned systems, TXO gathers large amounts of natural gas for distribution via intrastate pipeline systems or directly to industrial users in Texas and Oklahoma. These 31 systems have an aggregate maximum daily capacity of 1.37 billion cubic feet net to the company's interest. A second, important part of operations is company owned hydrocarbon production and gas liquids production. Company production in FY 1976 averaged about 139,000 mcf/d of gas, 3,270 b/d of oil and condensate plus 11,553 b/d of gas liquids. The gathering system had 13 years of reserves at 1976 delivery rates and about 19% of these reserves are company owned.

Although not significant from an earnings standpoint, the wholly owned FWA Drilling Company is an important adjunct to TXO's operations. FWA provides onshore contract drilling services in Texas and Oklahoma. Most of FWA's revenues are generated outside of TXO, however, with 25 drilling rigs, FWA provides TXO with strong protection against possible future rig shortages.

GAS GATHERING AND PROCESSING

Gas gathering is a business of collecting gas from a number of individual wells, often owned by a number of different producers, in a localized producing area. Thus, a sizeable block of gas production/reserves is made available for marketing to buyers of large quantities of gas - usually a gas pipeline company or other large user. Gas gathering is a vital function in the process of getting the gas production of individual wells to the ultimate consumer of gas. Traditionally, large buyers of gas have been unwilling to go to the expense of hooking up relatively small reserves of gas. Similarly, individual producers usually prefer to avoid the cost of installing gathering lines to connect their wells to a transmission system. As a middleman, the gas gatherer makes the investment necessary to assemble a large block of gas from a number of wells for sale to large buyers through the construction of a gas gathering system. Natural gas often contains condensate and other gas liquids such as butane, ethane, and propane. These liquids have economic value and can be stripped from the gas stream by processing plants so that gas liquids production is an important corollary aspect of the gas gathering business.

TXO is one of the largest intrastate gas gatherers in the U.S. and it processes its systems' gas through-put for liquids. Hence gas liquids production is a meaningful source of revenues. TXO owns all or part of 30 intrastate systems located primarily in Texas and Oklahoma with the Texas systems providing most of TXO's gas gathering/processing revenues. In addition, TXO acquired a small interstate system in Southern Wyoming last year.

A six year summary of gathering results is presented on the following table.

	1976	1975	1974	1973	1972	1971
Revenues from Gas						
Gathering/Processing (000)	$298,611	$197,984	$129,597	$ 62,740	$ 43,948	$ 29,007
Cost of Purchased Gas (000)	224,134	133,515	92,572	42,442	29,444	18,053
Gross Profit (000)	74,477	64,469	37,025	20,298	14,504	10,954
Volume Delivered (mcf 000)	210,055	217,688	203,204	175,252	146,032	107,430
% Company Owned	16.3	12.0	13.7	15.4	12.2	14.4
Dedicated Reserves (mmcf)	2,722.0	2,706.9	2,687.0	2,504.3	2,221.8	1,844.2
% Company Owned	18.9	19.0	20.0	18.8	16.9	14.2
System Reserve Life (years)	13.0	12.4	13.2	14.3	15.2	17.2

Although recent volume/reserve trends reflect the growing national shortage of natural gas, TXO's reserve position remains strong and is one of the best in the nation among major interstate or intrastate gas systems (nationally, the reserve life index is under 10 years of supply). Importantly, TXO's gross profit or gross gathering differential has improved both steadily and rapidly over the past four years, increasing from $14.5 million to $74.5 million since 1972.

Volume growth has slowed over the past two years reflecting the recession of 1974-1975, mild weather patterns in Texas and Oklahoma, a shift by some industrial users from gas to fuel oil and coal and conservation efforts by users in the face of rapidly escalating gas prices in TXO's marketing areas. Continued economic recovery and the severe cold weather thus far in fiscal 1977 is resulting in a resumption of volume growth this year and we suspect that deliveries will increase by 10% to 15%, partially as a result of new contracts signed in fiscal 1976. Gas liquids output should increase also, reflecting the increased processing capacity on-stream this month at Woodward, Oklahoma and increased gas deliveries. The gross gathering spread will be up again in 1977 and we look for another strong earnings gain from gas gathering this year.

Longer term and weather patterns aside, we expect at least moderate growth in demand for TXO's gas and gas liquids reflecting continued economic growth and population influx in Texas and Oklahoma. New intrastate markets in certain southern and southwestern gas producing states where TXO does not presently operate may become attractive as increasing exploration activity proves up new gas reserves. Decontrol of new gas prices nationally would probably lead to significant expansion by TXO in the interstate gas gathering market. To that end, TXO's 1976 purchase of a small profitable Wyoming gathering system will give it experience in dealing with the regulatory climate of the interstate market. Interestingly, the prospect of a $1.44+ price per mcf for new interstate gas has touched off a rather feverish level of gas exploration in the Rocky Mountain Region and S.E. New Mexico, even though this price level has been subjected to legal challenge. Hence, TXO appears to have ample room for substantial growth in the gas gathering field. Our worst case assumption, based on TXO confining its gathering activities to its present markets, envisions volume growth of 5% to 10% per year with earnings increasing at a rate of 7% to 13% per year. It is worth noting that TXO's present maximum daily gathering capacity of 1,366,000 mcf/d is well above 1976 average throughput of 573,920 mcf/d and the recent estimated peak of 825,000 mcf/d indicating that the systems have substantial unused capacity. Gas gathering is a capital intensive, largely fixed cost business and expected increases in exploration activities in areas adjacent to TXO's gathering systems along with its strong reserve position should lead to higher utilization and positive operating leverage for TXO's existing investment in gathering and processing facilities.

Beyond the next two to three years, however, there must be some concern over TXO's ability to show good volume growth. It remains to be seen whether or not increased exploration by TXO and others will produce new reserves sufficient to allow volume growth for an extended period. However, for the intermediate term, in view of TXO's strong reserve position, given the demand conditions, deliveries can expand.

PRODUCTION AND EXPLORATION

TXO holds substantial producing and undeveloped oil and gas leases in the major producing areas of Texas and the Mid-Continent region. In addition, significant acreage is under lease in S.E. New Mexico, Colorado and Southern Wyoming. A five year summary of operating results and acreage holdings is presented on the following page.

	1976	1975	1974	1973	1972
Oil and Gas Revenues (000)	$71,150	$36,282	$24,041	$15,252	$11,858
Volumes Produced Annually:					
Natural gas (mmcf)	50,875	40,454	44,733	45,985	41,165
Oil & Condensate (BBLS 000)	1,193.5	938.6	932.7	1,027.2	853.5
Proved Reserves:					
Natural Gas (BCF)	*799.1	721.3	708.2	697.2	731.6
Oil & Condensate (BBLS 000)	*9,564	8,945	8,716	8,240	12,279
Reserve Life					
Natural Gas	15.7	17.8	15.8	15.2	17.8
Oil & Condensate	8.0	9.5	9.2	8.5	14.4
Undeveloped Acreage (000)	3,529	2,925	2,639	1,535	613

*1976 data includes proved undeveloped reserves, 1972-1975 data do not include proved undeveloped reserves.

It should be noted that the above reserve and production data is for those amounts owned by the company except for gas liquids a fraction of which is attributable to company owned leases. Similarly, the revenue figures include the amount generated by oil, condensate and gas production only. Revenue from gas liquids are included in gathering revenues.

Two significant factors emerge from the above data. TXO's production and reserve trends have been superior to that of the domestic industry where declining production and reserves have been the rule. Secondly, TXO has built its undeveloped acreage inventory from a modest level in 1972 to 3.5 million acres, one of the larger positions among domestic independent oil and gas producers. In addition, although its reserve life indices are down, TXO still enjoys a good reserve position in natural gas, the most important source of production revenues and earnings for TXO. Average realizations for company owned gas production came to $1.11 in 1976 up from 61¢ the year before. Similarly, average prices for crude production were $11.08 per barrel vs. $9.54, indicating a high proportion of upper tier and stripper production in the mix.

Earlier we mentioned TXO's bias toward exploration and development based on recent capital spending trends and book investment. Thus, of total capital spending in fiscal 1975 and 1976 of $111.5 million and $106.3 million, respectively, $70.6 million and $81.4 million was spent on oil and gas for the two years. In 1977, the company expects to apportion about 2/3 of its anticipated $150 million capital budget to oil and gas.

Some comments on TXO's approach to exploration are appropriate here:

1. Drilling prospects are heavily natural gas oriented.

2. Most of the exploration activity is in areas near TXO's gathering systems.

3. For the most part, the company drills low risk/low potential wells.

4. Consistent with the above, the company has avoided true wild-cat drilling which sharply reduces the odds of a major discovery.

5. The company participates in a large number of wells each year (394 gross wells and 231 net wells in 1976) and enjoys a high success ratio due to the semi-proven nature of the prospects drilled. Since 1971, the company's success ratio has ranged between 62% and 80%.

6. Finding costs are relatively high at around 64¢/mcf recently.

The company's approach has resulted in annual net reserve additions over the past few years and this is likely to continue. Further, TXO's drilling has been heavily concentrated in areas with access to well developed, high priced intrastate markets. As a result TXO's substantial 2,120,000 acres of undeveloped leases in Colorado, Wyoming, Kansas, Oklahoma, Arkansas and New Mexico are largely unexplored and may hold great future potential. We feel that sufficiently high prices for interstate gas (the current $1.44 interstate price may be enough) may lead to much enlarged activity on this part of TXO's acreage. Indeed, TXO recently formed a joint drilling agreement with a unit of Northern Natural Gas covering about 190,000 acres of TXO's leases in Kansas and another joint-venture with Columbia Gas for a 5 to 10 well program in New Mexico. Recognizing that predicting future exploration results for any company is problematical, TXO appears well positioned for good future exploration results.

Finally, production is clearly an important source of earnings for TXO and, although it does not report the earnings contribution from its production, we feel it necessary to make an independent estimate of its contribution. First let us present what is known and our other operative assumptions as they relate to fiscal 1976 results and expected 1977 results.

1. We know production volumes for oil, condensate and gas production and revenues for oil, gas and condensate.

2. We know average oil and gas prices for 1976 as well.

3. Management has forecast a gas volume increase of at least 10% in 1977.

4. We know that total 1976 DD&A amounted to $30.6 million and that depletion alone came to $17.7 million.

5. A 40%-50% pre-tax profit margin is often attained by pure oil and gas producers.

6. By deducting revenues from oil and gas obtained from the volume and price figures given, we can derive revenues from condensate and drilling arrangements from company owned leases.

The above factors form the basis for the estimates presented on the following page.

Revenues: (000,000)	1976	1977
Gas (1976, 50.9 BCF @ $1.11/MCF; 1977, 57.9 BCF @ $1.35)	$56.5	$78.2
Oil (1976, 863,229 BBLS @ $11.08; 1977, 800,000 BBLS @ $11.75)	9.6	9.4
Condensate (1976, 330,553 BBLS @ $10.50E; 1977, 350,000 BBLS @ $11.20)	3.5	3.9
Other	1.5	2.0
	71.1	93.5
Depletion, Depreciation, etc.	20.0	28.0
Operating Expenses	14.0	16.0
Earnings Before Interest & Taxes (EBIT)	$37.1	$48.5
Oil & Gas % of Total EBIT	43.8%	45.8%
Oil & Gas % of Total Cash Flow Before Interest & Taxes	50.3%	52.5%

The above indicated cash flow and EBIT estimates are imprecise and should be viewed as a rough approximation of the real situation. Nevertheless, it seems clear that TXO's production is an important source of earnings and cash flow.

CONTRACT DRILLING

The wholly owned FWA Drilling owns and operates 25 shallow and medium depth drilling rigs. FWA is used captively to a considerable extent but generated $19 million of revenues in 1976 and produced 3% to 5% of earnings in recent years. FWA may prove invaluable to TXO's exploration and development program over the next few years. Signs of a widely anticipated future rig shortage are already appearing in some areas and TXO could use FWA 100% if need be (the previous peak use of FWA by TXO was 38% in FY 1975). Furthermore the rig availability represented by FWA may create a number of attractive farm-out opportunities to TXO.

RECENT OPERATING TRENDS AND OUTLOOK

Fiscal 1976 was another in a long string of strong earnings years. Reflecting rapidly rising energy prices and strong growth in company owned production, total revenue advanced 55% to $389.3 million. Strong profit margin expansion in oil and gas production allowed pretax earnings to increase about 47% and, after accruing federal income taxes at a 32.3% rate versus 17.3% in 1975, net income and EPS were each up approximately 20%.

During the first quarter of the current fiscal year earnings accelerated largely because of very strong gains in production profits. First quarter results are summarized on the following page.

SUMMARY FOR THE QUARTER ENDED NOV. 30

	1976	1975	% Change
Revenues (000):			
Gas gathering	$103,640	$55,834	+85.6%
Oil & gas	23,079	13,090	+76.3
Drilling	5,832	4,690	+24.3
Total	$132,733	$73,782	+79.9
Expenses			
Costs of Gas	83,727	39,039	+114.5
Other expenses	27,878	21.012	+ 32.7
Total Costs	111,604	60,051	+ 85.8
Income Before F.I. Taxes	21,128	13,731	+ 53.8
Federal Income Taxes (rate)	7,246 (34.3%)	3,059 (22.3%)	+136.9%
Net Income	$13,882	$10,672	+ 30.1
EPS	$0.71	$0.54	+ 31.4

The first quarter results did demonstrate the temporizing effects on TXO's gathering business of the ample supply situation in its markets. While gathering revenues increased by nearly $48 million or 86%, cost of gas rose by a faster rate of 115% or about $45 million. As a result, although deliveries were up 29.9% from the depressed year ago level, the gross gathering differential increased a more modest, but still healthy, 18.5%. After the dramatic increase in TXO's gross gathering differential (GGD) in recent years, which reflected gas shortage and rapidly rising well head prices; a slowdown in growth is to be expected. High prices for gas led to increased drilling and reserves available to the Texas and Oklahoma intrastate markets eliminating for the time being the "sellers market" of 1973 to 1975. While national decontrol of new gas prices may well create a new "sellers market" f . XO, in the absence of decontrol TXO's gathering business figures to grow more in line with volume growth than it has in recent years. Traditionally, the gas gathering business has been a fixed spread (or differential), rate of return type of business. The character of the business is reflected in TXO's gathering contracts which, with some variation, allow the company to recover the cost of gas and other costs plus enough additional revenues to provide it with a return on investment. Indeed, 33% of 1976 deliveries were made under straight "cost of service" contracts permitting TXO a rate of return on investment of not less than 8%. New reserves dedicated to TXO from wells contiguous to its gathering system are, for the most part, not obligated to existing purchasers so that TXO was able to substantially improve its GGD and rate of return on new contracts during the recent period of rapidly rising gas prices. Most likely, TXO was able to upgrade some older contracts in return for additional supplies as well.

The foregoing discussion of gathering trends notwithstanding, TXO should be able to maintain a respectable rate of growth in its gathering business in the future. Population and industrial growth in Texas and Oklahoma should be well above average leading to continued growth in demand for natural gas in TXO's markets. TXO has the reserve position to satisfy increased demand and considerable unused capacity to leverage its volume growth.

OPERATING FORECAST
(000)

Revenues	1976A	1977E	% Change
Gathering	$298,611	$433,600	+45.2%
Oil & Gas	71,150	93,000	+30.7
Drilling	18,757	22,500	+20.0
Miscellaneous	781	800	----
Total	$389,300	$549,900	+41.3%
Expenses			
Cost of Gas	224,134	354,120	+57.9%
Operating & General	28,125	37,970	+35.0
Operating Taxes	7,647	12,000	+60.1
Depreciation, Depletion, etc.	28,857	40,000	+38.6
Drilling	15,818	20,500	+29.6
Interest Charges (net)	13,510	14,500	+ 7.3
Earnings Before Taxes	71,208	91,310	+28.2
Federal Income Taxes	23,000	31,960	+39.0
Net Income	48,208	59,350	+23.1
EPS	$2.46	+3.03	+23.2

FINANACIAL AND ACCOUNTING

At November 30, 1976, TXO's capitalization was:

CAPITALIZATION: NOVEMBER 30, 1976
(000)

Long Term Debt	$201,901.6	42.8%
Deferred Credits	33,437.0	7.1%
Common Equity	236,357.9	50.1%
Total	$471,696.5	100.0%

Given the character of TXO's business, the company is strongly capitalized. The first quarter annualized return on capital was 11.8% and a healthy 23.5% on equity. Further, interest charge coverage came to a solid 6.2X on a pretax basis - worthy of the company's "A/A+" rated debt. Though capital spending in fiscal 1977 is targeted to rise sharply to $150 million from $106 million last year, net internal cash generation should be in the range of $125-$130 million including deferred taxes, or some 32% greater than last year. Nevertheless, bank loans under the company's long term line of credit were up to $64 million recently. Hence, and partially because of relatively attractive long term interest rates, TXO recently sold $75 million 8¼% First Mortgage Bonds. Capital ratios will remain strong, however, since retained earnings will come to about $53 million this year and we expect TXO to apply a significant portion of the proceeds from the bond offering to retirement of bank borrowings.

Longer term, whether or not capital ratios will strengthen further will be determined by management's perception of the attractive investment opportunities available to TXO, and the strong desire to maintain an "A" rating on the company's debt. More to the point, we strongly suspect that firmly established high interstate prices for natural gas would lead to an acceleration of capital investment by TXO with some attendant increase in financial leverage.

The principal accounting methods employed by TXO include:

1. "Full Cost" method for oil and gas properties.

2. Straight-line depreciation.

3. Interest is capitalized for all major investments and improvements.

4. Flow through of the investment tax credit.

5. Deferred Taxes are charged to earnings to reflect the difference in taxes paid between tax and book accounting.

FINANCIAL SUMMARY

	1977E	1976	1975	1974	1973	1972	1971
Operating Data (000)							
Revenues	$549,900	$389,300	$250,514	$167,104	$88,731	$65,717	$43,869
Pre-Tax Earnings	91,310	71,208	48,512	25,881	16,501	12,520	8,945
Income Taxes	31,960	23,000	8,400	—	—	—	—
Net Income	59,350	48,208	40,112	25,881	16,501	12,520	8,945
Operating Ratios							
Pre-Tax Margins	16.6%	18.3%	19.4%	15.5%	18.6%	19.1%	20.4%
Tax Rate	35.0	32.3	17.3	—	—	—	—
Net Margins	10.8	12.4	16.0	15.5	18.6	19.1	20.4
Return on Equity	23.6	23.9	25.2	20.5	15.7	14.9	14.8
Per Share Data							
EPS	$3.03	$2.46	$2.05	$1.32	$0.84	$0.65	$0.51
Dividends	0.20	0.20	0.0125	0.0125	0.0125	0.0125	0.0125
Shares Outstd. (000)	19,600	19,601	19,599	19,593	19,601	19,137	17,617
Price Range		28-13	22-12	21- 8	39-14	39-24	26-14
P/E Range		11- 5	11- 6	16- 6	46-17	60-37	51-27
P/E Relative		0.84	0.80	1.21	1.65	2.82	2.28

RR-77-40

—Research Department—

White, Weld & Co.
Incorporated

Thomas C. Pryor
Executive Vice President (212) 285-2666

Harold W. Janeway
Director of Investment Policy (212) 285-2060

Jerome P. Kenney
Director of Research (212) 285-2020

Richard A. Kimball
Director of Marketing (212) 285-2374

Frank J. Ritger
Senior Vice President (212) 285-2120

A. Gary Shilling
Chief Economist (212) 28 2670

Basic Industries		
George H. Cleaver	Metals & Mining	(212) 285-2012
Frederic S. Coffman, Jr.	Forest Products, Paper	(212) 285-2748
Betty M. Fagan	Pollution, Publishing, Capital Goods	(212) 285-2054
F. Robert Mayforth	Chemicals, Environmental Controls	(302) 656-7741
William N. Walling, Jr.	Coal	(212) 285-2438
Consumer Products & Services		
William R. Gill, Jr.	Retail Trade	(212) 285-2070
John A. Jensen, Jr.	Consumer Products, Household Products	(212) 285-2074
Brenda Lee Landry	Photography, Cosmetics, Household Products	(212) 285-2080
Milton Schlackman	Consumer Electronics, Air Conditioning, Appliances	(212) 285-2024
Daniel E. Somers	Beverages, Fast Food, Lodging	(212) 285-2076
Energy		
A. Hager Bryant, 3rd	Gas Pipelines and Distribution	(212) 285-2696
Philip L. Dodge	Oil, Gas	(212) 285-2043
John H. Hayward, Jr.	Oil Services & Related	(212) 285-2032
John L. Kalmbach	Natural Gas, Resources, Diversified	(212) 285-2065
Richard L. Davisson, Jr.	Oil Consultant	(617) 482-7767
Financial Services		
A. James Donohue	Banks, S&L's, REIT's, Mortgage Insurers, Misc. Real Estate	(212) 285-2010
Gerald E. Lewinsohn	Insurance	(212) 285-2000
Health Care		
Michael M. Harshbarger	Drugs	(212) 285-2698
L. John Wilkerson	Hospital Products	(212) 285-2695
Market Analysis		
H. Carroll Mackin	Computer Support—Performance Monitor	(212) 285-2056
Peter J. Canelo	Computer Support—Performance Monitor	(212) 285-2256
John A. Mendelson	Technical Analyst	(212) 285-3753
Technology		
Stover L. Babcock, Jr.	Special Situations	(212) 285-2026
James C. Blair	Computers, Office Equipment	(212) 285-2045
Craig W. Fanning	Electrical Equipment	(212) 285-2030
Anthony G. Langham	Instrumentation, Semiconductors	(212) 285-2047
Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Rieser	Assistant to Director of Research	(212) 285-2020
Ann T. Stott	Institutional Marketing	(212) 285-2064

ONE LIBERTY PLAZA, NEW YORK, N.Y. 10006

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White, Weld & Co. Incorporated

Progress Report

MANAGEMENT CONTACT

Philip L. Dodge
(212) 285-2043

April 4, 1977

GULF OIL (GO)

Price (NYSE)		Dividend		EPS (December)		P/E
Current:	28	Rate:	$1.80	1977E:	$4.50	6.3X
1977 Range:	31-27	Yield:	6.3%	1976:	$4.19	6.8X
				1975:	$3.60	7.9X

Market Value:	$5,530 million	Return on Average 1976 Equity:	12.2%
Average Shares Outstanding:	195 million	Book Value Per Share (12/31/76):	$35.64

OPINION

We have been generally avoiding international oil stocks for new investment, and would continue to. Relative multiples have moved up about 30 percentage points over the past 2½ years to levels which are historically above average, and overseas operations appear to face chronic margin pressure. In our opinion, Gulf will moderately underperform the market over the next year and is attractive only for its generous and well-covered yield. We expect the dividend to be raised modestly in 1977.

FIRST QUARTER

Gulf Oil expects to report lower first quarter earnings per share. We are currently estimating $0.80 versus $1.02 a year ago. However, we continue to look for an increase to $4.50 for the full year. By line of business, we believe the comparisons will be roughly as follows:

	First Quarter			Year		
Earnings Per Share	1976	1977E	Incr./ (Decr.)	1976	1977E	Incr./ (Decr.)
United States						
Petroleum	$ 0.57	$ 0.40	$(0.17)	$ 1.88	$ 2.25	$ 0.37
Chemicals	0.14	0.08	(0.06)	0.48	0.50	0.02
Nuclear	(0.01)	(0.01)	-	(0.05)	(0.05)	-
Minerals	(0.01)	(0.01)	-	(0.05)	(0.03)	0.02
Subtotal	$ 0.69	$ 0.46	$(0.23)	$ 2.26	$ 2.67	$ 0.41
Canada						
Petroleum	$ 0.17	$ 0.15	$(0.02)	$ 0.52	$ 0.60	$ 0.08
Chemicals	0.01	0.01	-	0.04	0.05	0.01
Minerals	-	0.02	0.02	0.02	0.07	0.05
Subtotal	$ 0.18	$ 0.18	$ 0.00	$ 0.58	$ 0.72	$ 0.14
Overseas						
Petroleum	$ 0.06	$ 0.12	$ 0.06	$ 1.11	$ 0.87	$(0.24)
Chemicals	0.09	0.05	(0.04)	0.24	0.25	0.01
Nuclear	-	-	-	(0.01)	(0.01)	-
Other	-	-	-	0.01	-	(0.01)
Subtotal	$ 0.15	$ 0.17	$ 0.02	$ 1.35	$ 1.11	$(0.24)
Total	$ 1.02	$ 0.81	$(0.21)	$ 4.19	$ 4.50	$ 0.31

U.S. petroleum (45% of 1976 profits) has been hurt in the first quarter by narrower refining and marketing margins. This negative comparison has been aggravated by an artificial element of product price controls. Under Federal Energy Administration rules, cost changes cannot initially be reflected in price adjustments until the month following incurrence. In early 1976, the $2.00 a barrel crude oil import duty had been removed, and profits were temporarily inflated for as much as a month until appropriate price alterations (or reductions in banked costs) were necessary. This year, however, the cost of imported oil has been rising sharply because (1) quantities are higher, (2) spot prices were already moving up toward the end of 1976, and (3) OPEC increased official prices 5–10% on January 1, 1977. Gulf imported about 36 million barrels of crude during the first quarter of this year, up 8 million barrels from 28 million barrels in the same period of 1976, and import costs probably rose $145 million on a year-to-year basis, or $0.35 a share after income tax offset. Although product prices rose, full cost recovery has not yet been possible.

Domestic refining profitability has also been impaired by product market shifts during the recent frigid winter which required maximizing fuel oil yields. In the "distillate mode", refineries manufacture a combination of products having a lower aggregate value, and this seasonal dip was magnified by the greater need for heating fuels last winter. In January–February, Gulf's U.S. distillate sale rose 5% compared with a 2% increase in total product volume.

On the production side, domestic petroleum trends have been better thus far in 1977. The company's U.S. crude oil price averaged about $7.90 a barrel in the first quarter, up from $7.08 a barrel a year ago. This comparison was helped considerably by a decline in lower-price "old" oil to 67% from 75% offtotal crude output. Oil production itself dropped to about 330,000 BD from 337,000 BD, but revenues rose by an indicated $18 million, or about $0.05 a share after taxes.

	Estimated First Quarter U.S. Crude Production	
	1976	1977
	(barrels daily)	
Lower-Tier	253,000	221,000
Upper-Tier	84,000	109,000*
Total	337,000	330,000

*Includes 26,000 barrels a day of stripper crude.

Gulf's U.S. natural gas production during the first quarter of this year averaged an estimated 1,750 million cubic feet a day, equal to last year. The average wellhead price was roughly 52¢, up from 39¢. On this basis, domestic natural gas revenues rose by about $19 million, or $0.05 a share allowing for the tax offset. About 15% of the company's natural gas sales are covered by Federal Power Commission Order 770-A, suggesting an annual revenue benefit of about $40 million. Thus far, Gulf has reserved roughly half of this amount, pending the outcome of court proceedings. Although production commences from four new

Gulf of Mexico natural gas fields during 1977, much of the additional volume, ultimately 240 million cubic feet a day, is contractually committed to Texas Eastern Transmission at a fixed price of 21¢ per MCF, or a marginally profitable level. (Even so, Gulf's 1977 U.S. wellhead price of natural gas should average about 55¢, up from 45¢.)

The first quarter U.S. petroleum comparison will be helped moderately by absence of a March 1976 $11 million ($0.06 a share) after tax expense for the Rio Blanco oil shale project.

In overseas petroleum (26% of 1976 earnings), Gulf has been particularly squeezed by the January 1, 1977 OPEC price increase. All of the company's OPEC crude stream comes from countries which have raised prices approximately 10%. About two-thirds of total OPEC crude is from ten percenters. Purchases, including modest equity liftings by Gulf from OPEC countries, total about 1,100,000 barrels a day, of which about 400,000 barrels a day moved to the U.S. On this basis, the overseas cost increase during the first quarter would be about $75 million (90 days X 700,000 barrels a day X $1.19 a barrel). The company's European oil product realizations averaged about $17.00 a barrel in the first quarter of 1977, up $0.77 from $16.23 a barrel in the fourth quarter of 1976. If European experience was representative, overseas operations absorbed about $25 million ($0.13 a share) of unrecovered crude oil cost increases during the first quarter. Nevertheless, the first quarter overseas comparison should be modestly favorable, partly because early 1976 was so weak.

Chemical operations (18% of 1976 earnings) have been hurt by volume declines of 10-15% from levels of a year ago. In addition, start up costs at the new Cedar Bayou, Texas olefins plant have had a negative influence.

FULL YEAR

Despite the lower first quarter, we continue to estimate that Gulf will earn about $4.50 a share in 1977, up from $4.19 last year. U.S. natural gas production should rise 7-8% and average prices by 20-25%. Domestic crude oil prices are likely to be up about 10%, and volume down only modestly. Refining-marketing margins in the United States may show significant recovery as early as the second quarter. U.S. petroleum product supply is snug in a background of rising demand, and refinery utilization east of the Rocky Mountains is stretched at the seams. On the whole we expect Gulf's U.S. petroleum operations to show year-to-year improvement during the final nine months of 1977. Our current year U.S. petroleum estimate allows for exploration expenses to rise $30 million.

The slip in chemical volumes also appears to be temporary, particularly in the United States where economic expansion should continue at least into next year. Later in 1977, Gulf should benefit from greater use of new olefins facilities at Cedar Bayou, Texas. This plant has annual capacity for 1,200 million pounds of ethylene and 800 million pounds of polypropylene and other olefins. However, full year U.S. chemical comparisons will be hurt by the absence of a $40 million ($0.21 a share) investment tax credit recorded in 1976. The chemical segment should account for the total estimated decline in i.t.c. to about $50 million from $92 million in 1976.

Although overseas operations have become less important in recent years, Gulf may continue to experience margins pressure over the balance of 1977, and we presently expect a negative twelve month comparison. Quarterly variations from this pattern are of course possible. For example, if a further OPEC price increase is anticipated on January 1, 1978, the final months of 1977 may again benefit from abnormally high volumes. Overseas exploration expenses are estimated to rise by about $40 million in 1977.

Gulf has an excellent position in uranium. However, production from the Mt. Taylor (New Mexico) mine, which has estimated reserves of more than 100 million pounds, is not likely to begin until 1981. Minerals operations as a whole are not likely to have a major impact on 1976-1977 comparisons.

CAPITAL EXPENDITURES

Budgeted 1977 outlays in relation to actual 1976 spending are shown below:

	1976	1977E
	($ Millions)	
Exploration and Development	744	1,000
Refining, Marketing, Transporation	306	250
Chemicals	150	240
Minerals	70	100
Other	92	110
Total Capital Expenditures	1,362	1,700
Exploration Charged Against Income	364	450
Total Outlays	1,726	2,150

Retained cash flow should approximate $1,400 million in 1977, indicating a $300 million drawdown in cash holdings during the year. This reduction should be entirely tolerable. Gulf held cash and marketable securities totaling $1,989 million ($10.20 a share) at the end of 1976, compared with current liabilities of $1,562 million. We also expect an increase in the quarterly dividend to $0.47½ or $0.50 a share from the current $0.45 during 1977.

RR-77-59 —Research Department—

White, Weld & Co.
Incorporated

Progress Report

A. Hager Bryant, 3rd
(212) 285-2696

December 15, 1976

UNITED ENERGY RESOURCES (UER)

Price (NYSE)		Dividend		EPS (Dec.)*		P/E
Current:	25 1/4	Rate:	$1.32	1977E:	$5.10	5.0X
Range (1976):	25-14	Yield:	5.2%	1976E:	$4.70	5.4X
				1975A:	$3.48	

Shares Outstanding:	11.5 million*	Return on June 1976 Equity:	21.8%*
Market Value:	$286 million	Book Value Per Share 6/30/76:	$21.11*

*Pro-forma for Cotton Merger

SUMMARY

United Energy Resources, formerly United Gas Pipe Line, has just acquired Cotton Petroleum through the issuance of 0.75 shares of United for each share of Cotton, an acquisition value of $36.6 million. The earnings, shares, ROE and book value above reflect the pro-forma results. Cotton, which will now operate as a subsidiary of United Energy, is engaged in oil and gas exploration, development and production. In addition, it operates or owns interest in 600 oil and gas wells, owns interest in 62,000 net undeveloped acres and also organizes and manages oil and gas drilling programs. Another subsidiary, United Gas Pipe Line, is an interstate transmission system which owns 100% of United Texas Transmission, an intrastate pipeline in southeast Texas, and a 50% interest in Sea Robin Pipeline, an offshore pipeline system in the Gulf of Mexico.

United's pipeline operations are projected to have a large positive cash flow over the next few years that would tend to reduce its leverage significantly, barring acquisitions. The acquisition of Cotton, however, will bring to United a full exploration staff and opportunities to better utilize the cash flow. Cotton, in turn, will benefit from its affiliation with United by gaining access to a solid future cash flow at a time when tax law changes are reducing the appeal of drilling programs, formerly Cotton's primary source of funds. On a pro-forma basis 8% of earnings will come from Cotton's operations in 1976. This portion should increase to 10% in 1977 and grow further in the years beyond.

Currently, natural gas transmission companies are selling at 8.5 times earnings and yielding about 5.1%. United, at only 5.0 times 1977 estimated earnings, is selling on a 5.2% yield basis, but on a dividend that represents a payout of only 29% versus an average pipeline industry payout ratio of 41%. The uncertainties associated with pending litigation resulting from gas delivery curtailments beginning several years ago and the interstate

W/01/31/51

pipeline systems' low inventory of gas reserves are largely responsible for UER's low P/E. We believe UER, at 5.0 times our 1977 estimate, is adequately discounting the legal contingencies and the low reserves/production ratio and consider it attractive for investors seeking reasonable yie' '5.2%) together with the possibility of above average dividend increases as more suitable payout ratios are achieved and modest earnings growth materializes.

THE COMPANY

United Gas Pipe Line (50% of pro-forma earnings), which was spun off to Pennzoil shareholders in 1974, is an interstate pipeline that transports gas gathered in the Texas and Louisiana Gulf Coast areas for resale to distributors in the Gulf South, to other pipelines or direct to users. In 1975, United sold 872 Billion Cubic Feet of gas and transported 51 BCF for others. Of these gas sales, 541 BCF (62%) were to other pipelines, 192 BCF (22%) were to distribution systems for resale to the public and the balance were direct sales to industry for use. United Gas Pipe Line purchases its entire gas supply from independent producers. Reserves dedicated to the system at the beginning of 1976 amounted to 4.3 Trillion Cubic Feet which represented a reserve life index of only 4.9 years. United Gas Pipe Line is attempting to rebuild the reserves and appears to have three major prospects for near-term success. First, advance payments have been made to producers in return for the right to purchase their gas production; second, as part of the divestiture agreement from Pennzoil, United has the right to purchase most new ga, developed by Pennzoil and/or its affiliates; and, third, United has a 20% interest in the HIOS line which, when completed in late 1977, will provide access to gas being developed in offshore Texas areas. United is also exploring possibilities of purchasing Alaskan Gas or importing LNG for use in the system in the 1980's. Earnings improvement over the near-term, however, will be limited to those produced by the company's ability to obtain rate increases from the F.P.C. to maintain earnings on level or declining sales volumes and the ability to maintain direct sales volumes. A $21 million rate increase became effective October 9, 1976.

The intrastate system, **United Texas Transmission** (32% of pro-forma earnings), gathers and resells gas wholly within Texas. In 1975, 251 BCF of gas was sold and 79 BCF was transported for others. Of 1975 gas sales, 113 BCF was to Houston Lighting & Power for electric generation and 73 BCF was to Entex for resale to high priority gas consumers; the remaining 26% was sold to industrial customers in the Gulf Coast for their own use. United Texas sales volumes have continued to rise (since intrastate gas supplies are in surplus) and the system's reserves/production ratio is about 10.4 years based on 1975 year-end reserves of 2.6 TCF. Earnings of the intrastate system have improved over the past two years as a result of upgrading direct sales contracts from fixed price to price plus cost of gas; however, since almost all contracts have now been renegotiated, earnings may flatten out beyond 1976 unless additional sales or transportation contracts can be negotiated.

Offshore Pipelines: (11% of pro-forma earnings) Sea Robin, which is 50% owned with Southern Natural Gas, operates an interstate pipeline system in the Gulf of Mexico offshore Louisiana. Sea Robin has a capacity of 1.2 BCF per day and, in the first half of 1976, operated at 792 Million Cubic Feet per day (66% of capacity). Sea Robin provided 16% of United's interstate system supply in 1975. Sea Robin, in conjunction with the HIOS and UTOS systems to be completed late in 1977, will give the interstate system access to those several leases on which United has made advance payments and to those blocks being developed by Pennzoil and its affiliates. Sea Robin earnings will hold about level but earnings from HIOS and UTOS will boost offshore pipeline EPS in 1976 ($3 million tax credit) and in 1977 ($6 million tax credit).

Cotton Petroleum: (7% of pro-forma earnings) is engaged in oil and gas exploration, development and production and is also in the business of organizing and managing oil and gas drilling programs. Most recently, oil and gas sales contributed 83% of revenues while management fees, service charges and other income sources provided the balance. Daily average production rates for the first half of 1976 were 1,464 barrels of oil and 15.7 MMCF of gas, the prices for which were $10.56 per barrel and $0.86 per MCF, respectively, at mid-year. At August 1, 1976, oil and condensate reserves amounted to 3.34 million barrels of oil and condensate and 56.1 BCF of gas. At a valuation of $3.50 per barrel and $0.50 per MCF, these reserves equal about $40 million. Cotton's earnings have improved recently owing primarily to increased oil and gas production (and somewhat to higher prices) deriving from growing success of the exploration activities related to its drilling programs. Cotton's revenues and income for the past five years are summarized below.

COTTON PETROLEUM

OPERATING RESULTS

	1971	1972	1973	1974	1975	6 Months 1976
Average Daily Production:						
Crude Oil & Condensate (Bbls.)	380	785	825	1,010	1,349	1,464
Natural Gas (Mils. Cubic Feet)	3.2	8.7	11.1	12.9	15.0	15.7
Revenues (Mil.)						
Oil & Gas Sales	$0.62	$1.48	$2.50	$4.61	$7.15	$4.43
Other	0.41	0.44	0.62	1.18	1.75	0.93
Total	$1.03	$1.92	$3.12	$5.79	$8.90	$5.36
Income from continuing operations before extraordinary items (mil.)	$0.11	$0.35	$0.73	$1.58	$2.77	$1.75

EARNINGS

Following is a summary of the earnings of each division as derived from the Cotton/United merger prospectus for the 12 month results through September 30, 1976 together with our estimates of 1976 and 1977 earnings.

COMBINED PRO-FORMA EARNINGS RESULTS

	12 Months September 30, 1976		Estimated Earns. Per Share	
	Net Income (mil.)	Earns. Per Share	1976	1977
United Gas Pipeline	$26.64	$2.32	$2.35	$2.35
United Texas Transmission	16.80	1.46	1.45	1.50
Offshore Pipeline Systems	5.66	0.49	0.50	0.75
Cotton Petroleum	3.71	0.32	0.40	0.50
Total	$52.81	$4.59	$4.70	$5.10

FINANCES

Capital spending by the United system will probably amount to $40 million in 1976 compared with internal generation of $82 million consisting of $40 million from retained earnings, $35 million of depreciation and $7 million of deferred taxes. Rather than reduce leverage, United will now have a staff of highly competent geologists and exploration experts to profitably invest the cash flow in the exploration for new oil and gas reserves and thus help diversify UER's operations.

CAPITALIZATION 6/30/76

Pro forma for Merger

	Amount (Mil.)	Ratio
Short-Term Obligation	$ 12.4	2.7%
Long-Term Debt	199.4	43.9
Preferred Stock	None	–
Common Equity	242.1	53.3
Total	$453.9	100.0%

DIVIDENDS

After being spun-off from Pennzoil in March 1974, United paid its initial dividend of $0.15 on July 1, 1974, an annual rate of $0.60. The payment was boosted 20% to $0.72 on July 1, 1975 and 83% to $1.32 on April 1, 1976. The present rate represents a payout of 29% of current EPS of $4.59 per share; the average pipeline industry payout is 41%. We see no reason why UER should not, eventually, payout about the same percentage of earnings as other gas pipelines with their own production and look for another dividend increase in 1977.

LITIGATION

United is a defendent in several lawsuits alleging damages resulting from forced curtailments of natural gas deliveries and alleged violations of antitrust laws. United's counsel believes that applicable judicial decisions, F.P.C. orders, tariffs and contracts, and industry practices should furnish adequate defenses to the claims for damages. However, the ultimate outcome cannot be determined and investors in UER should be cognizant of the uncertainties created by the lawsuits which, together, request damages aggregating $1.15 billion.

RR-76-181 —Research Department—

Within the last three years we managed offerings of 50 million debentures.

White, Weld & Co. Incorporated

Progress Report

A. Hager Bryant, 3rd
(212) 285-2696

January 10, 1977

TEXAS GAS TRANSMISSION (TXG)

Price (NYSE)		Dividend		EPS (Dec.)		P/E
Current:	47	Rate:	$2.00	1977E:	$6.50	7.2X
Range (1976-77):	49-29	Yield:	4.3%	1976E:	$5.65	8.3X
				1975:	$4.39	–

Shares Outstanding:	10.3 Million	Return on Avg. 1975 Equity:	14.2%
Market Value:	$484 Million	Book Value Per Share (9/30/76):	$37.34

SUMMARY

Based on a recent review of the company's operations with management, we are raising our earnings estimates for Texas Gas from $5.45 to $5.65 for 1976 and from $5.70 to $6.50 for 1977. The principal areas of change are in the gas pipeline division (to reflect the tax credit and allowance for funds related to HIOS) and the trucking division (to reflect the acquisition of All-American Transport on October 1, 1976).

Natural gas pipelines in general are currently selling about 7.5 times estimated 1977 earnings; however, natural gas producers sell at higher P/E's than the general market while major trucking companies are priced at 8-9 times current EPS with higher earnings expected in 1977. On the basis of the trucking (TXG is now one of the ten largest truckers in the U.S.) and pipeline operations, together about 54% of earnings, TXG appears appropriately priced. There are no valid market comparisons for TXG's inland waterways division. However, in comparison with gas producers, TXG appears slightly behind the market. Accordingly, we rate TXG a strong hold in growth oriented accounts and suitable for purchase by investors seeking some yield and good dividend growth.

NATURAL GAS TRANSMISSION (41% of 1976 earnings)

TXG sold or transported 672 billion cubic feet of gas in 1975, down 15.7% from peak deliveries in 1972. For 1976, the available gas supply is projected at 624 BCF of which 6% will be system produced gas, 35% purchased from onshore fields, 35% from offshore producers and the remaining 24% from other pipelines. For 1977, the addition of new gas supplies from several offshore blocks should help offset delivery curtailments from onshore sources and from other pipelines resulting in level volumes for the first time since 1972. Volumes are projected to hold at 1976 levels or slightly above through the remainder of the 1970's, especially after the HIOS line connects additional offshore Texas production in late 1977 or early 1978.

An F.P.C. rate increase collected since April 1, 1976 has been settled with a 13% return on a $174 million equity base which equates to $22.7 million earnings or $2.20 per share. Additional earnings in the pipeline division will be generated by the 10% investment tax credit on TXG's $70 million share of the $353 million High Island Offshore System (HIOS) scheduled for completion by early 1978 and by the allowance for funds used during the construction of HIOS; together these two items are expected to add close to $0.20 per share to earnings in 1976, $0.85 in 1977 and $0.10 in 1978. HIOS will be accounted for on an equity basis.

OIL & GAS EXPLORATION AND PRODUCTION (22% of 1976 earnings)

At the end of 1975, Texas Gas Exploration's reserves amounted to 280 BCF of gas and 9.7 million barrels of condensate and crude oil; assigning a conservative valuation to these reserves of $0.35 per MCF and $3.00 per barrel, the asset value equates to about $12 per share. In 1975, Exploration sold 36.7 BCF of gas (mostly old gas), 1.1 million barrels of oil and 175 million gallons of liquids (at F.E.A. controlled prices). Commencement of deliveries of gas from Ship Shoal Blocks 247 and 271 in the second quarter 1976, from Vermilion Block 256 in the third quarter 1976 and from Eugene Island Block 292 sometime around mid-1977 should boost gas production to over 40 BCF in 1976, between 45-50 BCF in 1977, and over 55 BCF by 1978. Oil production should be about level in 1976, but the addition of Eugene Island Block 292's oil output of 1,000 BPD in November, 1976 will hike 1977 oil production by over 25%. The higher production of oil and gas coupled with higher gas prices of $1.44 per MCF authorized by F.P.C. Order 770-A should help boost earnings significantly.

INLAND WATERWAYS (24% of 1976 earnings)

Coal remains the major commodity carried by the barging operation followed by grains downriver and liquids upriver. Earnings in the first half 1976 benefitted from the absence of flooding conditions although second half earnings were depressed owing to shallow water levels and narrow channels (a result of dry weather in the upper midwest) which reduced the size of the tows. For 1977, barging earnings could be up modestly given a return to normal river conditions although Jeffboat, the shipbuilding affiliate, may show some weakness as less of its output will be sold to other barge operations.

TRUCKING (12% of 1976 earnings)

The addition of All-American Transport on October 1, 1976 makes Texas Gas one of the ten largest trucking concerns in the U.S. The AAT acquisition will be treated as a pooling of interest and its contribution to earnings should amount to about $0.40 per share. The acquisition is antidilutive in that net income for the first nine months of 1976 equated to $4.77 for each of the 650,000 TXG shares issued versus $3.88 for TXG for the same period.

Terminal Transport earnings are sharply ahead of last year because of the recovering economy and new management techniques established earlier this year. Further improvement is foreseen in 1977 assuming an up economy. Commercial Carriers is also up sharply in line with the stronger auto output versus last year; however, in view of the recent slowing of the growth in auto sales, we are expecting only level earnings through 1977.

CAPITAL SPENDING

Outlined below are capital outlays by division through 1976 together with our estimated spending for 1977 and 1978:

CAPITAL SPENDING
(Millions)

	1974	1975	1976E	1977E	1978E
Pipeline	$21.1	$19.9	$14	$ 15	$ 15
Waterways	21.7	17.9	32	35	30
Trucking	15.2	3.1	10	12	10
Expl. & Prod.	23.6	22.7	35	45	50
Total	$81.6	$63.5	$91	$107	$105

The HIOS line will be built and financed as an independent pipeline and therefore does not appear in the capital expenditures forecast. The barging operation's terminal for coal to be received from Burlington Northern starting in 1979 will cost about $26 million and is spread $7 million in 1976, about $10 million in 1977 and the rest in 1978.

FINANCING

Texas Gas accomplished the following financings in 1976:

a. $28.5 million private placement loan agreement with insurance companies to finance advance payments.

b. $37.8 million U.S. Gov't Guaranteed Ship Financing Bonds to finance barges and towboats.

c. $50.0 million Debentures for the acquisition of additional gas supplies and repayment of short-term obligations.

For 1977 we project retained earnings at $35 million, depreciation at $63 million and deferred taxes of $25 million for total internal generation of $123 million excluding cash on hand from the 1976 financings. The $107 million capital outlays plus $25 million sinking fund and debt maturity needs will about match the internal funds. No major external financing is anticipated other than another ship financing issue of about $40 million to further reduce short-term borrowings.

CAPITALIZATION
(9/30/76)

	Amount (mil.)	%
Short Term Obligations	$ 26.7	3.8%
Long Term Debt	323.7	46.0
Preferred Stock	10.5	1.5
Common Equity*	342.2	48.7
Total	$703.1	100.0%

* Includes $2.7 million Convertible Preference Stock

EARNINGS

Outlined in the following table is our forecast of TXG earnings by division. For 1977 the two main sources of the estimated $0.85 EPS increase are in the gas pipeline area ($0.46 per share) and oil and gas production ($0.45 per share). The gas pipeline earnings increase is based on the investment tax credit and AFUDC associated with HIOS and are not *true* earnings entitled to a full P/E multiple valuation. For 1978, only a modest 3% earnings improvement is forecast since the disappearance of a portion of the HIOS items will offset gains in oil & gas production and waterways. Over the longer term, pipeline earnings growth will be modest, trucking earnings about in line with the economy, waterways should grow faster than the economy owing the incremental growth of coal hauling and the appeal of this inexpensive shipping mode, and oil & gas production growth should continue well above average as long as the energy shortages persist.

QUARTERLY EARNINGS PER SHARE BY DIVISION

	Gas Pipe-line	Oil & Gas	Water-ways	Trucking Division: Comm'l Carriers	Trucking Division: Terminal Transp.	Trucking Division: AAT	Total Company
1974							
1Q	$ .51	$ .39	$ .20	$ .03	$ .05	–	$1.18
2Q	.47	.39	.39	.03	.10	–	1.3
3Q	.44	.34	.21	–	(.01)	–	.99
4Q	.62	(.06) [a]	.32	–	.02	–	.93
Yr.	$2.05	$1.03	$1.13	$ .08	$ .16	–	$4.45
1975							
1Q	$ .63	$ .21	$ .31	$ (.03)	$ (.03)	–	$1.09
2Q	.33	.25	.34	.01	.01	–	.94
3Q	.32	.30	.31	(.02)	.01	–	.93
4Q	.73	.35	.32	.08	–	–	1.48
Yr.	$2.02	$1.06	$1.28	$ .03	–	–	$4.39
1976[c]							
1Q	$ .75	$ .27	$ .38	$ .03	$ .02	$ .08	$1.53
2Q	.56	.26	.48	.06	.05	.09	1.50
3Q	.18[b]	.32	.26	–	–	.14	.90
4Q E	.85	.40	.25	.07	.05	.10	1.72
Yr.	$2.34	$1.25	$1.37	$ .16	$ .12	$ .41	$5.65
1977E							
1Q	$ .80	$ .40	$ .35	$ .05	$ .05	$ .10	$1.75
2Q	.65	.40	.40	.05	.05	.10	1.65
3Q	.45	.45	.25	–	.05	.10	1.30
4Q	.90	.45	.25	.05	.05	.10	1.80
Yr.	$2.80	$1.70	$1.25	$ .15	$ .20	$ .40	$6.50
1978E							
1Q	$ .85	$ .45	$ .40	$ .05	$ .05	$ .10	$1.90
2Q	.65	.45	.40	.05	.05	.10	1.70
3Q	.35	.50	.30	–	.05	.10	1.30
4Q	.80	.50	.30	.05	.05	.10	1.80
Yr.	$2.65	$1.90	$1.40	$ .15	$ .20	$ .40	$6.70

[a] Includes ($0.42) non-recurring year-end adjustment.

[b] Includes ($0.15) non-recurring reserve set up for possible coal gasification plant write-off.

[c] Based on 10.3 million shares outstanding throughout the year.

DIVIDENDS

During the five years 1971 to 1975 the payout ratio averaged 43% and the dividend was raised annually effective with the June 15th payment. The present $2.00 rate represents a payout of only 35% of our estimated 1976 earnings and 31% of our 1977 estimate. We believe the payout ratio may trend back toward 40% gradually and that an increase to $2.20-2.36 effective in June, 1977 is possible.

VALUATION

Assigning a P/E multiple to Texas Gas is difficult because there are few comparable barging companies; however, we have outlined possible multiple values in the following formula:

TEXAS GAS VALUATION

Division	Est. 1977 EPS		P/E Value		Worth
Pipeline	$2.80	x	6.5	=	$18.20
Oil & Gas	1.70	x	11.0	=	18.70
Waterways	1.25	x	8.0	=	10.00
Trucking	0.75	x	7.0	=	5.25
Total	$6.50	x	8.0	=	$52.15

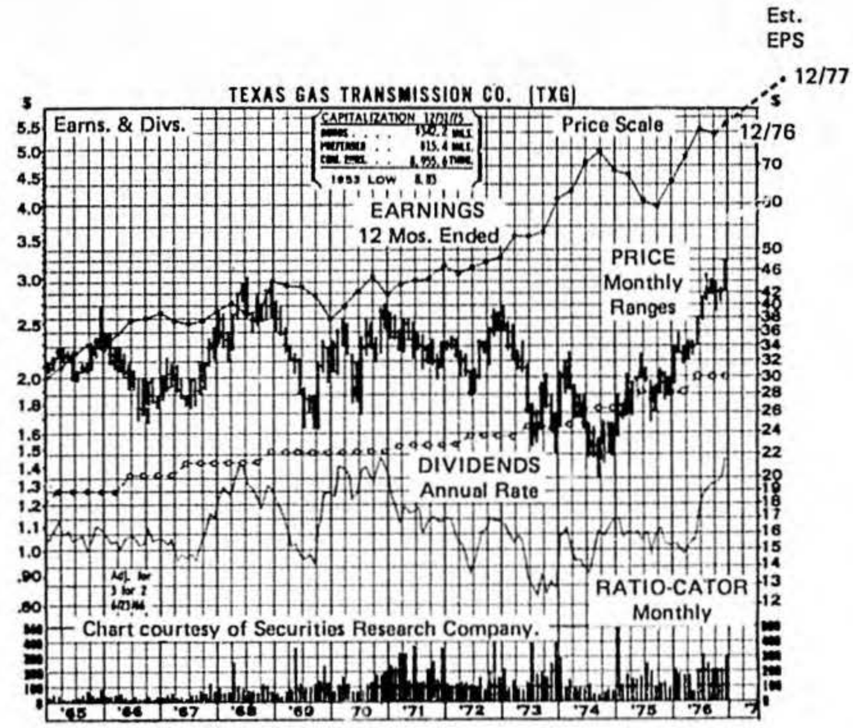
Despite the recent move in the price of TXG we feel the company remains a hold at current levels for growth oriented investors and is suitable for purchase if some yield and good dividend growth is desired.

TEXAS GAS INSTITUTIONAL OWNERSHIP

Category	Number	Shares Held	% Outst. Shares
Banks*	21	1,035,647	10.1%
Investment Cos.*	16	817,200	7.9%
Insurance Cos.**	33	482,260	4.9%
Total	70	2,335,107	22.7%

Source: *Spectrum
**A.M. Best

RR-77-9 —Research Department—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Thomas C. Pryor
Executive Vice President (212) 285-2666

Harold W. Janeway
Director of Investment Policy (212) 285-2060

Jerome P. Kenney
Director of Research (212) 285-2020

Richard A. Kimball
Director of Marketing (212) 285-2374

Frank J. Ritger
Senior Vice President (212) 285-2120

A. Gary Shilling
Chief Economist (212) 285-2670

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Richard L. Davisson, Jr.	Oil Consultant	(617) 482-7767
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L. John Wilkerson	Hospital Products	(212) 285-2695
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John A. Mendelson	Technical Analyst	(212) 285-3753
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Jack K. Smith	Computers	(302) 656-7741
Utilities		
Marjorie M. Jones	Electric, Telephone	(212) 285-2040
Edward A. Pescatello	Electric, Telephone	(212) 285-2066

Support Services		
Emily K. Baldt	Research Assistant	(302) 656-7741
Jeanne M. Gallagher	Editor	(212) 285-2075
Robert Margolis	Art Director	(212) 285-2319
Ellen L. Miller	Librarian	(212) 285-2085
Mary M. Rieser	Assistant to Director of Research	(212) 285-2020
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CENTURY CITY	HOUSTON	NEW YORK	SEATTLE		MONTREAL
CHICAGO	KANSAS CITY	OMAHA	TULSA	*INTERNATIONAL*	PARIS
CLAYTON, MO	LOS ANGELES	PHILADELPHIA	TROY, MI	CARACAS	ZURICH

White, Weld & Co.
Incorporated

Basic Report

BUY RECOMMENDATION

A. Hager Bryant, 3rd
(212) 285-2696

January 10, 1977

FLORIDA GAS COMPANY (FLG)

Price (NYSE)		Dividend		EPS* (Dec.)		P/E
Current:	20 3/8	Rate:	$1.00	1977E:	$2.75	7.4X
Range (1976-77):	21-14	Yield:	4.9%	1976E:	$2.50	8.2X
				1975:	$2.31	–
Shares Outstanding:			6.37 Million	Return on Avg. 1975 Equity:		11.1%
Market Value:			$130 Million	Book Value Per Share (9/30/76):		$24.40

*Fully Diluted

SUMMARY

Florida Gas is gradually changing from a pure natural gas pipeline and distribution company into an oil and gas producer with land operations and, possibly, a petroleum products pipeline. The success of an early diversification move into land development was hampered by the collapse of the Florida land market, although the market value of the properties still exceeds their cost; the Florida real estate market is finally beginning to recover, and proceeds from land sales can be used to develop future oil and gas production prospects. The company's oil and gas exploration program has been uncommonly successful in its early phases both offshore and onshore and production is just becoming a major earnings factor. Earnings declined 15% from the first quarter 1975 to the first quarter 1976 as a result of lower volumes of wet gas passing through the hydrocarbon extraction plant and a foreign exploration write-off. This contraction is now fully reflected in results and per-share earnings growth has resumed. Furthermore, the dividend is likely to be raised (probably 10% to a $1.10 rate), effective with the June, 1977 payment.

At current prices, FLG is yielding 4.9% and selling at 7.4 times 1977 estimated EPS based on a market price of only 84% of book value. Other gas pipeline companies typically offer similar yields and sell about the same multiple but are priced at 25-30% over book value. Despite the recent strength of FLG and the rest of the natural gas pipelines we believe Florida Gas is an attractive purchase for growth oriented investors for the following reasons:

a) the company's base is a solid natural gas pipeline whose volume deliveries will be turning up again starting in 1977;

b) a recovering real estate market for Florida land holdings should allay fears of possible writedowns and help boost the market-to-book ratio closer to industry norms;

c) continued success in the oil and gas exploration and production area could gradually move the P/E valuation toward the multiples generally accorded oil and gas producers;

d) a major oil or gas discovery could be more significant to FLG than to most other pipelines owing to the leverage of a small number of shares;

e) longer term earnings growth should average at least 10% annually; and

f) consistent annual dividend increases are expected in line with or faster than earnings growth.

THE COMPANY

Florida Gas' principal earnings source is Florida Gas Transmission, a natural gas pipeline stretching from the Rio Grande Valley of South Texas to Miami, Florida. Also, retail natural gas distribution systems are operated in Miami, Jacksonville, Orlando-Winter Park, St. Petersburg and Daytona.

Diversification activities are concentrated in three principal areas; extraction of liquid hydrocarbons from the pipeline stream; land development in Central Florida; and oil and gas exploration, development, and production. An additional proposal calls for conversion of a portion of the existing gas transmission line into a petroleum products pipeline. Outlined in Table 1 is a breakdown of 1975 divisional results.

Table 1

DIVISIONAL BREAKDOWNS

	1975		Earnings Before Interest & Taxes 1975			
	Revenues (mil.)	Margins	Total (mil.)	% of Total	1976E (mil.)	1977E (mil.)
Pipeline	$101.5	36.7%	$37.2	79%	$39.0	$40.5
Distribution	27.4	13.6	3.7	8	4.5	5.0
Hydrocarbons	13.8	42.5	5.8	12	2.0	1.0
Land	0.9	N.M.	(0.9)	(2)	(0.5)	–
Oil & Gas	4.7	28.5	1.3	3	3.0	5.0
Other	(20.8)*	N.M.	(0.1)	–	(0.5)	(0.5)
Total	$127.5	36.9%	$47.0	100%	$47.5	$51.0

* Includes intercompany eliminations

N.M. – Not meaningful