

# Oil and Gas Company Valuations

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*This article provides a primer on the analysis and valuation of exploration and production companies and related reserve engineering reports.*

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## Introduction

Based in Houston, Texas, our firm is particularly active in oil and gas company valuations, now primarily known as exploration and production (E&P) companies. Like most appraisal firms, we are generalists, but we have found that the skill set necessary to perform an E&P valuation is highly specialized. The valuation tools we feel comfortable applying in almost any other industry are not usually appropriate or adequate for the valuation of an E&P company. Significant scientific and technical issues are involved in the evaluation of information, due diligence, and nomenclature. There are very few, if any, other industries that require training to interpret a press release. The purpose of this article is to provide an overview of the special issues involved in this industry and to educate appraisers unfamiliar with these types of companies on the basics of E&P valuation.

## An Overview of E&P Firms

E&P firms represent the “upstream” aspect of the energy industry. Pipeline and marketing firms are known as “midstream” companies, and refiners and petrochemical companies are considered “downstream” participants.

The primary assets of an E&P company are its oil and gas reserves, that is, hydrocarbons below the surface that have not yet been produced and are economically viable to extract. E&P firms are unique in that their primary asset base is depleting and therefore must be continually replaced through either drilling activities or acquisition.

Ownership interests related to reserves can be held in a variety of forms including working interests, royalty (or mineral) interests, and overriding royalty interests. Working interest owners share in the profits after the royalty interest payment, lease operating expenses, severance and ad valorem taxes, and capital expenditures associated with a property (lease/well) as well as the risks associated

with drilling. The working interest must pay all of the costs of exploring for, developing, and producing oil and gas. Working interests can be further classified as “operating” or “nonoperating” working interests. The operating working interest influences day-to-day operations of the well or lease. Operating interests can be more valuable than nonoperating interests in fields where significant development activities are required (since the operator has the exclusive right to control the exploration activities and pace). Operating interests are basically controlling interests, and nonoperating interests are like minority and noncontrolling interests. The operator also has the right to collect standard overhead charges (known as COPAS charges) from other working interest holders that can be beneficial to the operator. Royalty interests are created when the mineral interest owner leases a property and are passive in nature not requiring the owner to share in drilling or monthly operating expenses. A royalty takes preference over all other payments from lease revenue. They represent payments to mineral owners to drill on their property and typically represent a one-fourth to one-eighth interest in gross revenues after taxes. Royalties are similar to a triple-net lease. Overriding royalty interests (ORRI) are like royalty interests except these expire once the lease has become uneconomic.

## Methods of Accounting: Successful Efforts versus Full Cost

Financial statements of E&P firms prepared in accordance with generally accepted accounting principles (GAAP) may utilize either successful efforts or full cost accounting for oil and gas reserves. These methods differ in the treatment of specific operating expenses relating to *exploration* costs (as opposed to *acquisition* or *development* costs, which are capitalized in both methods). Exploration costs are costs relating to carrying and retaining undeveloped properties, costs of the collection and analysis of geophysical and seismic data, and costs incurred with drilling an exploratory well. The successful efforts method capitalizes only those exploration costs associated with successfully locating new reserves. For unsuccessful (or dry hole) results, the associated exploration costs are immediately expensed. The full cost method

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capitalizes all exploration spending regardless of the outcome.

**Analyzing Financial Statements**

When analyzing historical financial statements, it is useful to include historical production volumes as well as the average hydrocarbon prices received for the periods in question. Since hydrocarbons are a commodity, the physical volumes indicate whether the company is producing more or less, regardless of revenue increases resulting from price increases. Production volumes are typically expressed as barrels of oil equivalent (boe) or thousands of cubic feet equivalent (mcf) for gas. Conversion of gas to oil equivalent is typically based on 6,000 cubic feet (mcf) of gas per one barrel of oil, roughly equivalent to the British thermal unit (BTU) conversion.

Also various analytical ratios can be calculated such as lifting costs (lease operating expenses per boe or mcf produced during a period) and finding costs (costs associated with increasing reserves during a particular period). As opposed to industrial companies, the quantitative measures of E&P performance are based primarily on the ability to replace and grow resources at a favorable cost. This is in contrast to profit margins and growth.

Rather than EBITDA (earnings before depreciation, interest, taxes, and depreciation and amortization), analysts usually consider EBITDAX a primary pricing metric for E&P companies. EBITDAX represents EBITDA before *exploration costs* for successful efforts companies. For full cost firms, exploration costs are embedded in depreciation and depletion, so EBITDAX equalizes both accounting types. Exploration costs in successful efforts companies are typically labeled or referred to in the financial statements as exploration, abandonment, and dry hole costs. In addition, other noncash expenses such as impairments, accretion of asset retirement obligation, and deferred taxes should be added back in calculating EBITDAX. See Table 1. Free cash flow could also be

considered where cash income taxes and capital expenditures are deducted from EBITDAX.

**Reserves and Reserve Categories**

Reserves are classified as either (1) proved or (2) unproved.

**Proved Reserves**

Proved reserves are quantities (volumes) of oil or natural gas that are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves are classified into three categories:

- 1) Proved Developed Producing (PDP) reserves are expected to be recovered from completion intervals (oil- and gas-producing sands or zones) that are open and producing at the time of the estimate. PDPs are the only reserve class generating current cash flow or EBITDAX, and PDPs are the least risky and therefore most valuable reserve class.
- 2) Proved Developed Non-producing (PDNP) reserves include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from completion intervals (zones) that were open at the time of the reserve estimate but are not producing. Behind pipe reserves are expected to be recovered from completion intervals not yet open but still behind casing in existing wells. Such wells are usually producing, but from another completion interval. Additional completion work is needed before these reserves are produced.
- 3) Proved undeveloped (PUD) reserves are expected to be recovered from (1) new wells on undrilled acreage or (2) existing wells requiring major expenditure. PUDs are typically not counted (or booked) until it is clear the well or major expenditure will be funded and completed in the near term.

**Table 1**  
General Framework for Calculating Comparable Earnings Before Income Tax, Depreciation, Depletion, Amortization, and Exploration Costs (EBITDAX)

Full Cost	Successful Efforts
Operating Income	Operating income
Plus: Depreciation, Depletion and Amortization	Plus: Depreciation, depletion, and amortization
Plus: Accretion of Asset Retirement Obligation	Plus: Exploration expenses
Plus: Deferred Taxes	Plus: Dry hole, abandonment, and/or impairment expenses
	Plus: Accretion of asset retirement obligation
	Plus: Deferred taxes
= EBITDAX	= EBITDAX

### **Nonproved Reserves**

Probable reserves (referred to as 2P reserves when aggregated with proved reserves) have a 50% chance that reserves quantities will be higher than estimated and a 50% chance that the reserves will be smaller in accordance with the engineering definition of the American Petroleum Institute. Possible reserves (referred to as 3P reserves when aggregated with proved and probable reserves) reserves have a 10% chance that reserves are greater than estimated and a 90% chance that reserves will be smaller. These nonproved categories are highly speculative and generally given little weight.

### **How to Read Reserve Reports**

The Pension Protection Act of 2006 reinforces and provides penalties for appraisers who, among other factors, accept information provided by management of a company or other experts hired by the company without adequate due diligence. Therefore, when valuing E&P companies the appraiser must have the basic knowledge to converse with petroleum engineers in order to understand the basis for their conclusions. This section seeks to provide some basic understanding of the reserve report.

Unlike third-party appraisal reports, many petroleum (or reservoir) engineers do not determine the fair market value of reserves. Rather, they provide gross quantities expected to be produced from wells, net such quantities to the subject company's ownership interest, and make estimates of future prices, operating expenses, and capital expenditures. Essentially the reserve report is a discounted cash flow (DCF) model for the subject company's reserves, on a pre-income tax basis. Appendix I presents a typical summary data table from a reserve report prepared by Netherland, Sewell & Associates, Inc. (NSAI), a highly regarded worldwide petroleum engineering firm based in Texas, who provided permission to reproduce their sample report in this article. Using this table of data, the analyst can calculate total proved reserves (33,969 bbls of oil and 8,772,300 mcf of gas or total proved reserves of 8,976,114 mcfe) of about 9 bcfe and the percent gas at 98%. Firms such as NSAI are engaged to conduct reserve studies for various reasons including the following: (1) year-end reserve studies for GAAP or Securities and Exchange Commission (SEC) purposes, (2) bank or other financing purposes, and (3) merger and acquisition (M&A) and related valuation activity. The purpose of the study can influence the inputs into the DCF model. For example, SEC reserve reporting requires the petroleum engineer to develop the DCF model using oil and gas prices in effect at the evaluation date (typically at 31 December) and hold such prices constant throughout the long-term projection period (certain changes with respect to SEC reserve reporting go into effect beginning

in late 2009). When the pretax cash flows in the SEC case are discounted to the present at a 10% discount rate, the result is referred to as the "SEC 10" value of the reserves. If the purpose of the reserve study is for M&A activity, a different "price deck" may be considered such as futures pricing for oil and gas (i.e., the New York Mercantile Exchange (NYMEX) strip pricing).

Below is a listing of key items that we believe are important to bear in mind in reviewing a reserve report and its underlying assumptions:

- 1) What price deck (commodity price forecast) was used for reserve report? Note that engineers do not typically build the effect of hedges or other derivatives into their DCF model. The projections may be overly conservative if the NYMEX strip pricing is significantly higher than the oil and gas prices used in the reserve report.
- 2) How do the projected volumes compare with historical production volumes? If materially different, ask why.
- 3) Are PUDs included in the analysis? Are probable and possibles (3P) included in the projections? What drilling and capital expenditure assumptions were utilized in developing the projections associated with the PUDs?
- 4) How concentrated is the production by well, by field, and by region? Generally, the more concentrated the production, the higher the risk. If one or only a few wells represent a significant portion of the projected cash flow, a risk adjustment is warranted.
- 5) How did the engineer consider plug and abandonment costs? GAAP balance sheets refer to this liability as the asset retirement obligation.
- 6) If the engineer is not providing an opinion of fair market value, we often question the engineer as to what discounts to the PV-10 value would reflect market value. In the industry, such discounts are referred to as "haircuts."

### **Typical Valuation Approaches and Methodology**

E&P companies are commodity businesses which have no control over the prices they receive. They may vary their production and capital expenditures based on current and future price expectations and can hedge their reserves by utilizing the futures market. The primary method we use to value E&P firms is the Market Approach because of the availability of reliable pricing and operating data.

We do not typically use the Income Approach directly since the reserve report is in fact a form of the Income

**Table 2**  
Sample Publicly Traded Guideline Company Method (E&P Companies) in Millions \$

Company	Primary Areas of Production	Projected (Current Year) EBITDAX	Lifting Cost LOE/Bbl <sup>a</sup>	All-in Finding Cost per Bbl <sup>b</sup>	Debt/Total Cap	Proved Reserves Oil Equivalent (MM boe) <sup>c</sup>	Mix Oil %	Proved Developed Reserves/Total Reserves	R/P Ratio (Years)	Market Value of Equity	Enterprise Value (EV)	EV/Projected EBITDAX	EV/Proved Reserves (boe)	EV/Daily Production (boe/day)
Comparable no. 1	Diversified U.S.A. and international	\$3,217	\$8.05	\$14.60	25%	880	37%	74%	12.0	\$6,500	\$7,400	2.3x	\$8.40	\$32,000
Comparable no. 2	Diversified U.S.A. and international	\$1,926	\$12.60	\$16.00	45%	970	48%	61%	23.5	\$2,600	\$5,200	2.7x	\$5.40	\$43,000
Comparable no. 3	Diversified U.S.A. and Canada	\$1,364	\$9.20	\$16.30	49%	372	25%	69%	15.0	\$2,000	\$4,500	3.3x	\$10.40	\$45,000
Comparable no. 4	Diversified U.S.A. and international	\$1,870	\$13.60	\$18.50	37%	425	27%	63%	10.0	\$2,500	\$4,300	2.3x	\$10.50	\$37,000
Comparable no. 5	Diversified U.S.A.	\$893	\$21.50	\$15.00	41%	250	78%	67%	17.0	\$1,400	\$2,500	2.8x	\$9.20	\$50,000
Subject Company	Rocky Mountain	\$90	\$13.50	\$15.00	15%	19	56%	25%	25.0					

Bbl = barrel, boe = barrels of oil equivalent, MM = million.

<sup>a</sup> Lease operating expenses per barrel.

<sup>b</sup> Three-year average all-in finding costs: costs incurred for acquisitions, exploration, and development divided by sum of reserve extensions, additions, and revisions. Stated on a \$/boe basis.

<sup>c</sup> Oil-to-gas conversion ratio: 6 mcf = 1 bbl.

**Table 3**  
Guideline Company Method Application of Pricing Metrics

	Subject Company	Guideline Company Pricing metrics	Resulting Value (MM) <sup>a</sup>	
Projected EBITDAX (MM)	\$90.0	2.5× to 3.0×	\$225	\$270
Proved Reserves (MMboe)	9.0	10× to 12×	190	228
Daily Production (Boe/d)	2,100.0	45,000× to 60,000×	95	126
Enterprise value			200	230
Plus: mark to market hedge value			10	10
Plus: other assets (mid-stream, acreage)			20	20
Less debt, including asset retirement obligation			(35)	(35)
Equity value			\$195	\$225

<sup>a</sup> As if publicly traded.  
MM: million.

Approach and due to the difficulty of modeling corporate level income taxes for E&P firms. In the Asset Approach, the E&P firm’s balance sheet is marked to market (the Net Asset Value Method) using the reserve report.

This article is focused on independent E&P companies that are not highly diversified/integrated, with midstream and downstream activities such as integrated majors (i.e., Exxon Mobile Corporation). Likewise, royalty trusts and master limited partnerships (MLPs) are yield oriented securities and not the focus of this article.

The first step in working with a market approach is selecting appropriate guideline companies. We use the John H. Herold database (energy industry specific) to identify comparable publicly traded companies. We believe some of the most important screening criteria include (1) size (in market capitalization or reserve volumes), (2) gas/oil mix (the percentage of reserves or production represented by natural gas verses oil), (3) reserve life (proved reserves divided by last or current year’s production and known as the r/p ratio), (4) the PUD to total proved reserve ratio (this indicates how much of the reserve base is currently generating EBITDAX), and (5) areas/basins of operation (i.e., onshore versus offshore activities).

**Key Pricing Metrics**

Once guideline companies are selected, the appraiser should consider the following pricing metrics:

- Enterprise Value (EV)/proved reserve quantities (i.e., EV/boe)
- EV/daily production
- EV/EBITDAX.

A forward or current year indication of reserves, production, and EBIDAX should be utilized because of the

frequency of reserve acquisitions and divestitures among the publicly traded E&P companies that could distort valuation indications. Developing forward or current-year metrics often requires a time-consuming review of press releases and other sources of information. An example of the information collected in the Guideline Company Method is presented in Table 2, and the application of that data to the subject company is presented in Table 3.

Table 2 shows that relative to the Guideline Companies, the subject company is small and has average finding and lifting costs. The subject company is less leveraged, and its proved reserves are mostly undeveloped, which means there are significant capital requirements related to converting the subject company’s reserves to cash flow–generating assets. However, the growth potential is strong: the subject company’s reserves have been found and need only to be developed. The subject company’s r/p ratio (reserve life) is high, meaning that current production levels can be maintained for a long duration—longer than any of the other Guideline Companies.

The Guideline Companies were priced (on an enterprise value basis) at 2.3× to 3.3× EBITDA, \$5.40 to \$10.50 per proved boe, and \$32,000 to \$50,000 boe of production per day. Historically there has tended to be a strong correlation between the r/p ratio and the EV/EBITDAX multiple. Excluding Comparable no. 3, there is some noticeable correlation between EV/EBITDAX and the r/p ratio. This correlation is intuitive, since reserves are depleting assets, so perhaps the correlation will return in time.

Although the subject company is small and less diversified, which points to greater risk, its low debt ratio coupled with a long r/p ratio and high undeveloped ratio result in favorable risk and growth comparisons. Accordingly, we believe the subject company would trade at

multiples at the high end of the group and have applied those multiples in Table 3. Other considerations in the valuation should include the potential value of undeveloped leasehold acreage or other assets (pipelines/gathering systems and seismic data) held by the subject company. Table 3 also shows that the mark to market value of the hedges as of the valuation date should be considered in the valuation. Note also that the asset retirement obligation should be treated as debt and subtracted from EV to calculate equity value.

Summary

Investments in E&P companies are essentially commodity plays. Their market prices are highly correlated to the price expectations of the commodities they sell. The analysis therefore is based heavily on reserve life and the ability to replace production. PUDs are the reserves that will fuel future reserve replacement.

These companies are analyzed and valued on an industry-specific metric that this article has described.

Appendix 1



SUMMARY PROJECTION OF RESERVES AND REVENUE AS OF 12-31- 7

BIG STRIKE OIL CORPORATION INTEREST

TOTAL PROVED RESERVES

SUMMARY - ALL WELLS FIELDS LOCATED IN KS, IA, OK, AND TX

PERIOD ENDING	GROSS OIL/COND		NET OIL/COND		GROSS GAS		NET GAS		GROSS REVENUE			PROD+AV	NET CAP COST	OPERATING EXPENSE	NET REVENUE	CUM P.W. 10.000%
	MMBBL	MMBBL	MMBBL	MMBBL	MMCF	MMCF	OIL	PROD+ADVAL GAS	TAXES TOTAL	MS	MS					
12-31- 8	7.015		2.188		2247.746		1477.614		49.5	4431.1	4480.6	351.8	4472.8	257.3	-601.3	-604.4
12 31 9	6.010		1.628		1691.354		1044.801		73.3	6530.0	6603.3	533.9	0.0	266.9	5802.5	4440.3
12-31-10	5.441		1.393		1346.396		792.026		55.7	4554.2	4609.9	385.4	0.0	274.8	3949.7	7560.1
12 31 11	4.993		1.240		1115.925		630.986		51.1	3737.1	3788.2	326.3	0.0	282.9	3179.0	9842.3
12-31-12	7.229		2.422		1132.135		592.209		102.7	3612.7	3715.4	325.3	417.3	259.2	2713.6	11603.7
12-31-13	13.072		5.386		1446.933		719.338		235.4	4519.7	4755.1	398.5	0.0	257.8	4098.8	14035.7
12-31-14	10.636		4.244		1193.612		587.794		191.1	3803.9	3995.0	339.8	0.0	265.6	3389.6	15864.1
12-31-15	8.734		3.363		990.338		484.306		156.0	3228.3	3384.3	291.4	0.0	272.1	2820.8	17247.0
12-31-16	7.242		2.683		800.580		391.503		128.0	2681.8	2815.8	245.8	0.0	263.9	2306.1	18275.4
12-31-17	6.066		2.151		665.186		317.960		105.8	2248.7	2354.5	208.6	0.0	251.8	1894.1	19042.5
12 31 18	5.131		1.740		567.856		270.837		87.0	1972.8	2059.8	184.3	0.0	258.6	1616.9	19637.8
12-31-19	4.386		1.419		485.771		231.765		70.9	1738.8	1809.7	164.0	0.0	264.3	1381.4	20100.2
12 31 20	3.784		1.165		422.277		200.519		58.4	1549.6	1608.0	147.9	0.0	272.1	1188.0	20461.9
12-31-21	3.297		0.967		369.522		174.609		48.3	1389.6	1437.9	133.4	0.0	280.2	1024.3	20745.5
12-31-22	2.872		0.790		302.247		132.788		39.4	1088.4	1127.8	109.6	0.0	252.2	766.0	20938.5
SUBTOTAL	95.908		32.779		14777.878		8049.035		1452.6	47092.7	48545.3	4146.0	4890.1	3979.7	35529.5	20938.5
REMAING	6.868		1.190		1624.445		723.295		59.4	6412.5	6471.9	683.8	12.5	2619.6	3156.0	21510.6
TOTAL OF 40.0 YRS	102.776		33.969		16402.323		8772.330		1512.0	53505.2	55017.2	4829.8	4902.6	6599.3	38685.5	21510.6
CUM PROD	858.692				111549.946											
ULTIMATE	961.468				127952.269											

BASED ON ESCALATED PRICES AND COSTS

PRESENT WORTH PROFILE	
FOR 8.00 PCT, PRESENT WORTH \$	23793.1
FOR 12.00 PCT, PRESENT WORTH \$	19573.3
FOR 15.00 PCT, PRESENT WORTH \$	17169.7
FOR 20.00 PCT, PRESENT WORTH \$	14132.1
FOR 30.00 PCT, PRESENT WORTH \$	10217.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.