The 7 Top Ways to Measure Oil & Gas Finding & Development Costs
Why Finding & Development (F&D) Costs are Important

The true cost of finding and developing oil and gas reserves is one of the key drivers of the success or failure of an oil and gas company in the long term. However, the true cost of finding and developing reserves is rarely adequately reflected in the financial accounting of an oil and gas company.

In the oil industry DD&A (depreciation, depletion and amortization) is typically based on either a straight line method which devalues property plant & equipment over its useful life or on a unit of production method where depreciation is weighted towards when there will be the most depletion of oil reserves via production. Plant Property & Equipment, which will always be the base of depreciation regardless of a company’s accounting policy is measured at historical cost and is not altered materially for any subsequent revaluations. When inflation is low this accounting method will not have a large adverse effect on analysing a company’s accounts. However, in the past 10 the oil industry has had dramatic industry specific changes to its costs and real asset values (since 2003 the WTI price has risen by 230% which equates to an annual rise far in excess of 10%). These changes in values will eventually feed through to the accounts of oil companies but with a typical field having a reserve life of 20 years, in the oil and gas industry this will take a long time. Therefore the DD&A in a given year will reflect the necessary investment required to sustain reserves based on a mixture of present and potentially very historic costs and therefore serves as a poor benchmark for changes in the real asset value.

In order to generate more realistic estimates of the cost of replacing reserves, the industry adopts various measures for estimating the costs of finding and replacing reserves.

It’s worth noting that some companies will report their own version of their finding and development costs without spelling out the components of the calculation. The need to understand and standardize these measures is one of the key drivers for Evaluate Energy to present its data in a clear, transparent format.

In this paper, Evaluate Energy

- Identifies 7 key ways in which the industry typically measures these costs.
- Discusses the limitations of these calculations
- Gives some examples of finding and development cost performance for the Majors

For further information on finding and development costs in global oil and gas, please contact us or book a demo of our service.
Overview of F&D Cost Calculations

In this paper we identify 7 ways to measure finding and development costs. Although this might sound like a lot, in fact there are, in theory if not in practice, many more ways of measuring F&D costs.

The reason for this multiplicity of possible calculations is that “reserves” can be defined in a variety of ways. Briefly, companies can present their finding and development costs on a per barrel basis based on

- 1P reserves: so-called “proved” reserves, discovered and considered to have a greater than 90% certainty of being commercially extractable.
- 2P reserves: so-called “probable” reserves, discovered and considered to have a 50% certainty of extraction.
- 3P reserves: so called “possible reserves, discovered and considered to have a 10% certainty of being commercially extractable.
- Marginal “Contingent” resources, with less than a 10% chance of being commercially extractable.
- 1C reserves: low estimate of “Contingent” resources, discovered but currently sub-commercial
- 2C reserves: Best estimate of “Contingent” resources, discovered but currently sub-commercial
- 3C reserves: High estimate of “Contingent” resources, discovered but currently sub-commercial
- Prospective resources – Low estimate, undiscovered
- Prospective resources – Best estimate, undiscovered
- Prospective resources – High estimate, undiscovered

For further discussion of reserve definitions, please see our blog about various definitions of oil and gas reserves, including details of 3P reserves that Evaluate Energy has recently released.
### Summary of & Typical Finding & Development Costs in Oil & Gas

<table>
<thead>
<tr>
<th>Name</th>
<th>Numerator</th>
<th>Denominator</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>F&amp;D Costs (Organic)</td>
<td>Exploration cost + cost of acquiring unproved property + development costs</td>
<td>Extensions, discoveries, revisions, improved recovery</td>
<td>One of the most common definitions of finding and development costs. Excludes acquisition cost of proved reserves.</td>
</tr>
<tr>
<td>F&amp;D costs (All Sources)</td>
<td>Exploration costs + proved and unproved property acquisition cost + Development cost</td>
<td>Extensions, discoveries, revisions, improved recovery, acquisitions</td>
<td>Gives a fuller picture of full cycle F&amp;D costs for an IOC because includes proved property acquisitions.</td>
</tr>
<tr>
<td>F&amp;D costs (Technical)</td>
<td>Exploration costs (excluding property acquisition cost) + development cost</td>
<td>Extensions, discoveries, revisions, improved recovery</td>
<td>Measures technical, (rather than commercial) efficiency of F&amp;D and excludes acquisitions of any kind.</td>
</tr>
<tr>
<td>Finding Cost (Technical)</td>
<td>Exploration cost</td>
<td>Extensions &amp; discoveries</td>
<td>Measures technical efficiency of IOC to find oil and gas.</td>
</tr>
<tr>
<td>Finding Cost (Inc Acquisitions)</td>
<td>Exploration cost + acquisition costs of proved and unproved properties</td>
<td>Extensions, discoveries, acquisitions</td>
<td>Takes account of cost and impact of acquisitions on IOC finding costs.</td>
</tr>
<tr>
<td>Development Costs</td>
<td>Development costs</td>
<td>Extensions, discoveries, revisions, improved recovery</td>
<td>Standard industry definition. Not usually separated as appears as part of F&amp;D cost calculation.</td>
</tr>
<tr>
<td>Development Costs (Developed reserves &amp; Acquisitions)</td>
<td>Development costs current year + 2 future years</td>
<td>Change in Developed reserves (end of year minus start of year) + Production - 60% of net acquisitions/divestitures</td>
<td>Evaluate Energy forward-looking definition designed to more accurately reflect current development costs for an IOC. Tends to be higher than standard industry definitions</td>
</tr>
</tbody>
</table>
The 7 Definitions of Finding and Development Costs

1. F&D Costs (Organic)
This is one of the most commonly used definitions of finding and development costs used in the industry.

The numerator in this F&D cost calculation is:

- exploration costs plus
- the cost of purchasing unproved properties plus
- development costs as defined above

The denominator in this F&D cost calculation is:

- Extensions and discoveries
- Revisions: although revisions to reserves may cause short term fluctuations in reserve replacement, over time they are a real component of proved reserves.
- Improved recovery

The definition does not include any allowance for the cost or impact of acquisitions of proved properties.

2. F&D Cost (All Sources)
F&D Costs (Organic), defined in 1) above, excludes acquisitions of proved properties from the numerator and the costs of these acquisitions from the denominator. However, from the point of view of an IOC or an investor, acquisition of reserves and the cost of those acquisitions may be considered to be a real and ongoing cost of doing business. In order to measure the cost of finding the marginal barrel Evaluate Energy suggests using a definition that captures all of the costs from all sources, as this may prove a more complete indicator of reserve replacement.

3. F&D Cost (Technical)
As in 2) above but excluding acquisitions so that the measure refers purely to replacement of reserves through drilling. The exploration department of a company might be interested in this measure.

4. Finding Costs (Technical)
We include a supplementary definition of finding cost that excludes the costs of acquiring proved properties and its associated reserves. This is a measure of a company’s technical ability to find oil and gas.

5. Finding Costs (inc Acquisitions)
This measure recognizes the importance of acquisitions in the long-term development of an oil and gas company.

6. Development Costs
This measure focuses on development costs only and excludes finding costs. The numerator is development cost and denominator extensions discoveries, revisions and improved recovery.
7. Development Costs (Developed Reserves & Acquisitions)

Standard industry definitions of development costs relate development costs to current year reserves and exclude the acquisition of proved reserves as part of development. The aim of this measure, designed by Evaluate Energy, is to relate development expenditure just to developed reserves and also acknowledge that acquisition of proved reserves is a viable option for expanding developed reserves.

**Numerator:** Development cost in the current year as per the Costs Incurred statement.

**Denominator:** 3 year average for current and 2 future years (to take into account lag time) of the following: Change in Developed reserves (end of year minus start of year) + Production - 60% of net acquisitions/divestitures.

The denominator shows the estimated change in developed reserves which should always be a positive figure as long as the company is spending money on reserve development. Calculated via the end of year developed reserves minus the start of year developed reserve position, plus production (as these will come from the start of year developed reserve pool), minus 60% of net acquisitions/divestitures. This assumes that 60% of any reserves bought or sold will be 60% developed\(^1\), therefore an acquisition of a million barrels of reserve would have added 600,000 barrels of developed reserve (which we subtract as this isn’t accounted for by the development costs in the costs incurred) and vice versa for divestitures.

We adjust the change in developed reserves for the effects of acquisition or divestiture of reserves during the year. Acquisitions of reserves are subtracted from reserves at end year as their addition has not been the result of development expenditure. In contrast, divestitures are added back to end of year reserves to reflect the fact that the development expenditure was not directed at these reserves.

---

\(^1\) Based on historic trends in the global M&A market, about 60% of reserve purchases are developed reserves and we net this off to adjust the reserve change so that it only reflects organic changes due to development expenditure. For example, an acquisition of a million barrels of reserves would typically have added 600,000 bbls of developed reserves (which we net off as this isn’t accounted for by the development costs in the costs incurred). The opposite is true in the case of divestitures – we would add 60% of the amount of divestitures back to the end of year reserve position.
Limitations of F&D Cost Calculations

Short term fluctuations
An inherent challenge of measuring finding and development costs is that the expenditures and the reserve additions recognized in a particular period do not usually correspond exactly with each other. In the reported data, expenditures are usually recognized in the period in which the payment actually occurs while proved reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must occur in the same time period, so that some expenditures may not be recognized in the same time period in which their corresponding reserves are recognized.

In addition, revisions to reserves may take place from time to time based on new knowledge of the performance and size of the reservoir or due to the application of SEC pricing rules on whether or not reserves are considered “producible” at year end. Such revisions may take place in one year but actually refer to an initial discovery that occurred a few years previously.

In an ideal world we would be comparing money spent in each year with reserves found in the same year based on that expenditure. However, data is not available publicly to be able to use this definition. We must therefore work around it.

In order to iron out short term distortions caused by the nature of the data reporting, we can increase the length of the time period over which finding costs are measured. We suggest taking a 3 year average. It should be recognized however that the longer the time period over which finding costs are measured, the more out of date they become, because they include increasingly older expenditures and reserves, and costs and technology are constantly changing. For this reason, while we suggest using a 3 year average as the core metric, we may also refer to the metric for the latest available year(s) to assess whether the numbers are on a rising or falling annual trend.

Whichever F&D cost measure we take, it is worth remembering that estimates based on reported company data are a proxy for estimated finding and development cost.

Inflation/Deflation of per barrel F&D Costs due to Impairments
Per barrel finding and development costs can be distorted from year to year because of an SEC rule that

“economic producibility of a reservoir must be based on existing economic conditions. It specifies that, in calculating economic producibility, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions”.

As a direct result of this rule, companies may report large revisions to their natural gas reserves at the end of 2012.

---

2 SECURITIES AND EXCHANGE COMMISSION, 17 CFR Parts 210, 211, 229, and 249, [Release Nos. 33-8995; 34-59192; FR-78; File No. S7-15-08]
The average for revisions of both oil and gas for the 2002-2013 period is just over +3 billion boe for a 52 company group taken from the Evaluate Energy database. In 2012 net revisions were under 1 billion boe. This was due to a massive 3.7 billion boe negative revision to natural gas reserves for a 52 company group taken from Evaluate Energy’s company database. With relatively strong crude oil prices during 2012, oil revisions were strongly positive.

Large negative natural gas reserve revisions in 2012 inflated per barrel F&D costs and its associated 3 year average in that year.

The above trends are mainly related to the slump in natural gas prices in the United States as shown in the graph below.
Finding & Development Cost Performance of the Major Oil Companies

The graph above shows the 3 year average trend in some selected oil and gas finding and development costs 2002-2012 for the Major oil companies (BP, Chevron, ExxonMobil, Shell and Total). Data is taken from the Evaluate Energy database. For contrast we have included the DD&A line to show how much lower it is compared with the more realistic level of costs being incurred by the industry to replace and develop its reserves.

F&D costs have soared in recent years as a result of a variety of factors but note that the bulk of the increase in reserve replacement and development costs relates to the higher cost of development. The cost of just finding and booking oil and gas has risen over the last decade but not as quickly as the cost of development.

For further information on finding and development costs in global oil and gas, please contact us or book a demo of our service.
Comparative F&D costs for the Majors

The graph above shows the relative performance of different Major oil companies on one F&D cost measure. Figures are 3 year averages taken from the Evaluate Energy database.

At the beginning of the last decade, costs were bunched fairly close together with Shell showing the highest costs and BP the lowest. During the middle years of the decade, costs diverged widely with Chevron and Total manifesting much higher per boe finding and development costs than their rivals. Both Chevron and Total managed to reduce their costs between 2007-10. By 2012 costs for most companies came together again, albeit at much higher levels than 10 years previously.

For further information on finding and development costs in global oil and gas, please contact us or book a demo of our service.
Appendix 1

Glossary of Terms

This glossary is designed to clarify the definitions of common components of finding and development costs.

Most of the data quoted in the oil and gas industry is based on data sourced from company filings submitted to the US Securities and Exchange Commission (SEC). The glossary below uses the definitions of exploration costs and reserves set out in the statement of financial accounting standards SFAS69.

1. Reserve Definitions used in F&D Calculations based on US SEC Data

Extensions and discoveries: Under SFAS 69, extensions and discoveries are additions to proved reserves that result from

- extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and
- discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Improved Recovery is the extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes water-flooding, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes.

Proved developed oil and gas reserves: According to SEC definitions, proved reserves are those that

- in projects that extract oil and gas through wells, can be expected to be recovered through existing wells with existing equipment and operating methods; and
- in projects that extract oil and gas in other ways, can be expected to be recovered through extraction technology installed and operational at the time of the reserves estimate.
- Reserves are also considered developed if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped oil and gas reserves: Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using

reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Revisions: Under SFAS 69, revisions represent changes in previous estimates of proved reserves, either upward or downward, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors. Evaluate Energy considers revisions to be an authentic source of reserve additions in the long run although they can cause sharp fluctuations in per barrel cost calculations in the short run.

2. Cost Definitions used in F&D Calculations based on US SEC Data

Exploration costs: According to the SEC, exploration costs include the costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting or G&G costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or G&G costs.
- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- Dry hole contributions and bottom hole contributions.
- Costs of drilling and equipping exploratory wells.
- Costs of drilling exploratory-type stratigraphic test wells.

Development Costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

- Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and well equipment such as casing, tubing, pumping equipment, and wellhead assembly.

- Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

- Provide improved recovery systems.

**Property Acquisition costs – proved and unproved** According to the SEC, Property Acquisition costs – proved and unproved are the costs of acquiring proved (those properties that contain proved reserves) and unproved properties (those properties that contain no proved reserves). These purchases may be considered to be an ongoing and necessary cost of being in the exploration business. However, including the acquisition of unproved properties may cause sharp fluctuations in finding costs in a year in which a major acquisition has been made which is why we use 3 year averages to smooth out such fluctuations.

3. **Other Terms used in F&D Calculations based on US SEC Data**

**Development project**: According to the SEC, a development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

**Development well**: According to the SEC, a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.