# Oil & Gas Valuation: Comparable Public Companies & Precedent Transactions

Picking a set of comparable companies or precedent transactions for an oil & gas company is very similar to how you would pick them for any other company – here are the differences:

1. Rather than cutting the set by revenue or EBITDA, you would instead select the set based on Proved Reserves or Daily Production (in addition to the normal geographic and industry criteria).
2. Instead of traditional metrics like revenue or EPS, you list the metrics and multiples that are relevant to an energy company: EBITDAX, Proved Reserves, Daily Production, the Oil Mix %, and so on.

Please see the previous handout in this course on Oil & Gas Key Metrics to see the full list and to learn how to calculate these metrics and multiples.

**Comparable Companies - North American Oil & Gas E&P Companies with Over 10 Tcfe Proved Reserves**
($ in Millions Except Per Share, Reserve, and Production Data)

| Operating Statistics | Capitalization | | EBITDAX[3] | | | Proved | Daily | | Proved | | R / P |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Equity | Enterprise | | | | Reserves | Production | Production | Developed | Oil | Ratio |
| Company Name | Value[1] | Value[1][2] | TTM | 12/31/2010 | 12/31/2011 | (Bcfe) | (MMcfe) | Areas | / Proved | Mix % [4] | (Years) |
| Chesapeake Energy Corporation | $ 15,489 | $ 29,710 | $ 4,509 | $ 4,571 | $ 4,949 | 14,254.0 | 2,480.8 | US Diversified | 58.4% | 7.8% | 15.7 |
| Anadarko Petroleum | 28,937 | 40,880 | 5,743 | 8,099 | 9,908 | 13,824.0 | 3,624.0 | International; US-Focused | 70.5% | 30.9% | 10.5 |
| Occidental Petroleum Corporation | 61,989 | 64,381 | 8,447 | 12,659 | 16,428 | 19,350.0 | 3,870.0 | International | 77.3% | 76.2% | 13.7 |
| Apache Corporation | 32,252 | 37,384 | 5,989 | 8,264 | 9,694 | 14,199.5 | 3,499.7 | International | 69.1% | 47.8% | 11.1 |
| Devon Energy Corporation | 28,999 | 37,353 | 4,797 | 6,364 | 5,613 | 16,398.0 | 3,830.1 | US & Canada | 70.3% | 18.0% | 11.7 |
| EOG Resources, Inc. | 22,289 | 24,882 | 1,761 | 4,375 | 5,507 | 10,776.1 | 2,118.0 | US, Canada & Trinidad | 54.4% | 15.6% | 13.9 |
| Maximum | $ 61,989 | $ 64,381 | $ 8,447 | $ 12,659 | $ 16,428 | 19,350.0 | 3,870.0 | | 77.3% | 76.2% | 15.7 |
| 75th Percentile | 31,439 | 40,006 | 5,927 | 8,223 | 9,855 | 15,862.0 | 3,778.6 | | 70.4% | 43.6% | 13.9 |
| **Median** | **$ 28,968** | **$ 37,368** | **$ 5,270** | **$ 7,232** | **$ 7,654** | **14,226.8** | **3,561.9** | | **69.7%** | **24.5%** | **12.7** |
| 25th Percentile | 23,951 | 31,620 | 4,581 | 5,019 | 5,534 | 13,917.9 | 2,735.5 | | 61.1% | 16.2% | 11.3 |
| Minimum | 15,489 | 24,882 | 1,761 | 4,375 | 4,949 | 10,776.1 | 2,118.0 | | 54.4% | 7.8% | 10.5 |
| **XTO Energy Inc.** | **$ 24,542** | **$ 34,686** | **$ 7,150** | **$ 6,818** | **$ 7,416** | **14,827.3** | **2,863.6** | **US Diversified** | **60.7%** | **13.9%** | **14.2** |

| Valuation Statistics | Capitalization | | Enterprise Value / EBITDAX[3] | | | Enterprise Value / | |
|---|---|---|---|---|---|---|---|
| | Equity | Enterprise | | | | Proved | Daily |
| Company Name | Value[1] | Value[1][2] | TTM | 12/31/2010 | 12/31/2011 | Reserves | Production |
| Chesapeake Energy Corporation | $ 15,489 | $ 29,710 | 6.6 x | 6.5 x | 6.0 x | $ 2.08 | $ 11.98 |
| Anadarko Petroleum | 28,937 | 40,880 | 7.1 x | 5.0 x | 4.1 x | 2.96 | 11.28 |
| Occidental Petroleum Corporation | 61,989 | 64,381 | 7.6 x | 5.1 x | 3.9 x | 3.33 | 16.64 |
| Apache Corporation | 32,252 | 37,384 | 6.2 x | 4.5 x | 3.9 x | 2.63 | 10.68 |
| Devon Energy Corporation | 28,999 | 37,353 | 7.8 x | 5.9 x | 6.7 x | 2.28 | 9.75 |
| EOG Resources, Inc. | 22,289 | 24,882 | 14.1 x | 5.7 x | 4.5 x | 2.31 | 11.75 |
| Maximum | $ 61,989 | $ 64,381 | 14.1 x | 6.5 x | 6.7 x | $ 3.33 | $ 16.64 |
| 75th Percentile | 31,439 | 40,006 | 7.7 x | 5.8 x | 5.6 x | 2.88 | 11.92 |
| **Median** | **$ 28,968** | **$ 37,368** | **7.4 x** | **5.4 x** | **4.3 x** | **$ 2.47** | **$ 11.51** |
| 25th Percentile | 23,951 | 31,620 | 6.7 x | 5.1 x | 4.0 x | 2.29 | 10.83 |
| Minimum | 15,489 | 24,882 | 6.2 x | 4.5 x | 3.9 x | 2.08 | 9.75 |
| **XTO Energy Inc.** | **$ 24,542** | **$ 34,686** | **4.9 x** | **5.1 x** | **4.7 x** | **$ 2.34** | **$ 12.11** |

(1) Valuation as of 12/11/2009.
(2) Enterprise Value defined as Equity Value less Cash & Cash Equivalents, less Net Value of Derivatives, less Investments in Equity Companies, plus Total Debt, plus Asset Retirement Obligation, plus Capital Leases, plus Unfunded Pension Obligations, plus Preferred Stock, plus Noncontrolling Interests.
(3) EBITDAX defined as Operating Income plus DD&A, plus Asset Retirement Accretion, plus Stock-Based Compensation, plus Non-Cash Derivative Losses, plus Impairment Charges, plus Other One-Time and Restructuring Charges, plus Exploration Expense.
(4) Oil Mix % Based on TTM Production Data rather than Reserves.

Precedent Transactions are similar as well – use geography, industry, transaction size, and possibly reserves / daily production to select the deals and then use the oil & gas-specific metrics and multiples.

## Common Add-Backs and Non-Recurring Charges

When calculating EBITDA or EBITDAX, there are a couple items specific to oil & gas to watch out for:

- Asset Retirement Accretion (a form of amortization)
- Non-Cash or Unrealized Derivative (Gains) / Losses (appears on the cash flow statement)
- Impairment Charges and PP&E Write-Downs (more common with full cost companies)
- (Gain) / Loss on Sale of Assets (appears on the cash flow statement)
- Environmental Remediation

**You need to read the footnotes carefully because sometimes these charges are already included in DD&A or are capitalized and don't hit the income statement at all**.

Here's an example of charges we would add back for Chesapeake Energy, one of XTO's comps:

| | Yea<br>2009<br>($ in mill |
|---|---|
| **REVENUES:** | |
| Natural gas and oil sales | $ 5,049 |
| Marketing, gathering and compression sales | 2,463 |
| Service operations revenue | 190 |
| Total Revenues | 7,702 |
| **OPERATING COSTS:** | |
| Production expenses | 876 |
| Production taxes | 107 |
| General and administrative expenses | 349 |
| Marketing, gathering and compression expenses | 2,316 |
| Service operations expense | 182 |
| Natural gas and oil depreciation, depletion and amortization | 1,371 |
| Depreciation and amortization of other assets | 244 |
| Impairment of natural gas and oil properties and other assets | 11,130 |
| Loss on sale of other property and equipment | 38 |
| Restructuring costs | 34 |
| Total Operating Costs | 16,647 |
| **INCOME (LOSS) FROM OPERATIONS** | (8,945) |

But there may be additional charges hidden in the cash flow statement and in the footnotes so we need look there as well:

| | 2009 |
|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | |
| **NET INCOME (LOSS)** | $ (5,805) |
| **ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:** | |
| Depreciation, depletion and amortization | 1,615 |
| Deferred income tax expense (benefit) | (3,487) |
| Unrealized (gains) losses on derivatives | 497 |
| Realized (gains) losses on financing derivatives | (154) |
| Stock−based compensation | 140 |
| Accretion of discount on contingent convertible notes | 79 |
| Restructuring costs | 12 |
| Loss on sale of other property and equipment | 38 |
| Gain on sale of investments | — |
| Loss from equity investments | 39 |
| Loss repurchases or exchanges of Chesapeake debt | 40 |
| Impairment of natural gas and oil properties and other fixed assets | 11,130 |
| Impairment of investments | 162 |
| Other | 27 |
| (Increase) decrease in accounts receivable | — |
| (Increase) decrease in inventory and other assets | (31) |
| Increase (decrease) in accounts payable, accrued liabilities and other | (105) |
| Increase (decrease) in current and non−current revenues and royalties due others | 159 |
| Cash provided by operating activities | 4,356 |

We're not adding the other charges on the cash flow statement either 1) because they're already included in the income statement add-backs (e.g. the loss on the sale of PP&E), or 2) because they do not hit the operating income (e.g. loss from equity investments) – **read the footnotes carefully**.

## Discounted Cash Flow Analysis

You can still build a DCF model for oil & gas companies and it's almost the same as what you see for normal companies:

- You start with Revenue and move down to EBIT, subtract taxes, and then add back non-cash charges.
- At the end you still subtract the increase or add the decrease in Working Capital and subtract CapEx to get to Unlevered FCF.
- You still discount the cash flows in the same way, applying a mid-year discount if you want.
- You still calculate the Terminal Value using multiples or long-term growth rates.
- You still calculate WACC just like you would for a normal company.

The key **differences** with an oil & gas DCF:

- You will have additional non-cash expenses in addition to the standard ones like DD&A and Stock-Based Compensation.
- You would use Daily Production, EBITDA, or EBITDAX for the terminal exit multiples rather than a Free Cash Flow-based multiple.

- For the Gordon Growth method usually you assume 0% long-term growth because oil & gas assets get depleted over time and there's only a finite amount in the ground.
- You could use the oil & gas industry standard 10% discount rate rather than calculating WACC.
- For the sensitivity tables you would look at commodity prices as one of the variables rather than revenue growth or EBITDA margins; other variables might be the discount rate and terminal growth rates or terminal multiples.

DCFs *generally* do not work well for oil & gas companies because:

- They have a high CapEx requirement, which reduces Free Cash Flow and may create declining or negative Free Cash Flow.
- As a result, they are even more dependent on the Terminal Value than normal companies – so the analysis doesn't tell you much.

An alternative is the **Net Asset Value (NAV) model**, which streamlines the traditional DCF and makes it more applicable to oil & gas companies.

## Net Asset Value (NAV) Models

A NAV model is an alternative to a DCF that gives more accurate results for oil & gas companies, especially for companies with an **upstream** or **exploration & production** focus (i.e. they focus on finding and producing energy rather than on refining energy or marketing it).

The major differences compared to a traditional DCF:

1. A NAV model assumes that the company **never increases its existing reserves, so there is no additional CapEx** in future years beyond what is required to develop *existing* reserves.
2. A DCF model is done at the corporate level, but you run a NAV model at the asset level. You value a company's assets separately and then add everything together at the end – whereas with a DCF you are valuing the entire company from the start.

With a DCF you're saying, "This company operates and keeps earning profit indefinitely into the future – how much is it worth right now?" but with a NAV you're saying, "This company stops operating once its reserves are depleted – how much profit can it generate between now and then, **assuming no future re-investment to find or acquire new reserves**?"

Here's how to create a Net Asset Value model:

**Step 1: Make Assumptions for Reserves, Production, Commodity Prices, Future Costs, and Discount Rates**

Most of these will flow in from other parts of your model or from the company's annual filing. In the example model here, we have projections for the first 5 years and then have to extrapolate beyond that in the NAV.

| **Proved Reserves as of 12/31/2009:** | | **Long-Term Production Decline:** | |
|---|---|---|---|
| Natural Gas (Bcf): | 12,502 | Natural Gas: | (5.0%) |
| Natural Gas Liquids (MBbls): | 93 | Natural Gas Liquids: | (5.0%) |
| Oil (MBbls): | 294 | Oil: | (5.0%) |
| Natural Gas Equivalents (Bcfe): | 14,827 | | |
| | | | |
| Future Estimated Development Costs: | $ 8,484 | Discount Rate: | 10.0% |
| Development Years | 5 | | |

The Proved Reserves numbers come directly from the filing. Future estimated development costs come from the PV-10 section of the company's filing, and we estimate that it will take 5 years to fully develop all their existing Proved Reserves:

***Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves***

| *(in millions)* | December 31 2009 | 2008 | 2007 |
|---|---|---|---|
| Future cash inflows | $ 57,792 | $ 65,608 | $ 86,080 |
| Future costs: | | | |
| Production | (21,114) | (22,239) | (22,066) |
| Development | (8,484) | (9,159) | (6,065) |
| Future income tax | (5,525) | (7,902) | (18,423) |
| Future net cash flows | 22,669 | 26,308 | 39,526 |
| 10% annual discount | (11,808) | (13,515) | (19,988) |
| Standardized measure | $ 10,861 | $ 12,793 | $ 19,538 |

The discount rate of 10% is the standard used in the oil & gas industry and what you always see in companies' filings.

We have the production numbers for the next 5 years, but past that we need to make our own assumptions as the reserves get depleted – so we are making a simple estimate here and assuming a 5% decline each year for natural gas, NGLs, and oil.

For commodity prices, you assume the same numbers for oil and NGLs and different numbers for natural gas and the hedging percentage; these numbers should flow through the rest of your model from the NAV and will give you averaged realized prices for the first 5 years.

| Resource Prices for NAV: | **Gas** | **Oil / NGL** | **Hedged** |
|---|---|---|---|
| | **$ per Mcf** | **$ per Bbl** | **Price %** |
| | $ 7.00 | $ 75.00 | 110.0% |
| | | | |
| Price Cased Used in NAV: | NAV | | |

**Step 2: Project Production and Realized Prices for Commodities**

For this one, let's take natural gas as an example and look at the first 5 years here:

| | | Natural Gas | | |
|---|---|---|---|---|
| | Year # | Beginning Reserves (Bcf) | Annual Production (Bcf) | Avg. Price $ / Mcf |
| 2010 | 1 | 12,502 | 941 | $ 6.84 |
| 2011 | 2 | 11,561 | 1,035 | 6.84 |
| 2012 | 3 | 10,527 | 1,141 | 6.84 |
| 2013 | 4 | 9,385 | 1,223 | 6.84 |
| 2014 | 5 | 8,162 | 1,315 | 6.84 |

| | Natural Gas | | |
|---|---|---|---|
| Year # | Beginning Reserves (Bcf) | Annual Production (Bcf) | Avg. Price $ / Mcf |
| 1 | 12,502 | 941 | $ 6.84 |
| 2 | 11,561 | 1,035 | 6.84 |
| 3 | 10,527 | =MIN(E22,'XTO-Prod'!L15) | |

The annual production is pulled directly from our production model, and we are assuming roughly a 10% production increase in the first 3 years followed by a 7-8% increase in years 4 and 5. The realized prices are also coming from our existing assumptions, flowed all the way through the model.

The beginning Proved Reserves balance declines by the annual production each year.

We are adding in a MIN formula to make sure that the annual production never drops below 0.

In the years beyond this initial 5-year period, you:

| Natural Gas | | | Natural Gas Liqu | |
|---|---|---|---|---|
| Beginning Reserves (Bcf) | Annual Production (Bcf) | Avg. Price $ / Mcf | Beginning Reserves (MBbls) | Annual Production (MBbls) |
| 12,502 | 941 | $ 6.84 | 93 | 8 |
| 11,561 | 1,035 | 6.84 | 85 | 9 |
| 10,527 | 1,141 | 6.84 | 76 | 10 |
| 9,385 | 1,223 | 6.84 | 66 | 11 |
| 8,162 | 1,315 | 6.84 | 55 | 12 |
| 6,847 | =MIN(E25,F24*(1+Natural_Gas_Production_Decline)) | | | |

- Continue to decrease the reserves balance by the annual production.
- Straight-line the average realized sale prices, i.e. assume a constant $6.84 for all future years here based on our price assumptions above.
- For the annual production, you take the MIN of the beginning reserves balance and the previous year's production multiplied by (1 + Long-Term Production Decline Rate) – that ensures that production declines over time but never drops below the reserves from the beginning of the year.

| Revenue ($ in Millions) | | |
|---|---|---|
| Natural Gas | Oil & NGL | Total Revenue |
| $ 6,438 | $ 2,390 | $ 8,828 |
| 7,081 | 2,629 | 9,711 |
| 7,811 | 2,844 | 10,655 |
| 8,374 | 3,049 | 11,422 |
| 9,002 | 3,277 | 12,279 |
| 8,552 | 3,113 | 11,665 |
| 8,124 | 2,958 | 11,082 |
| 7,718 | 2,810 | 10,528 |
| 7,332 | 2,669 | 10,001 |
| 6,965 | 776 | 7,742 |
| 6,617 | - | 6,617 |
| 1,558 | - | 1,558 |
| - | - | - |

You carry those formulas through the next 20 or 30 years (determine the period based on the Reserve Life Ratio).

Then you multiply the average realized price each year by the annual production each year for each commodity and sum up everything to get annual revenue.

**Step 3: Make Expense and Tax Assumptions and Calculate After-Tax Cash Flows**

Since the Net Asset Value model is done at an **asset level**, you do not include corporate overhead expenses such as G&A. For oil & gas you usually just include production and development expenses, and assume a tax rate based on the historical numbers:

| Production & Development Expenses: | | | | Cash Flows ($ in Millions) | | |
|---|---|---|---|---|---|---|
| Annual Bcfe | Production Per Mcfe | Total Production Expenses | Total Development Expenses | Pre-Tax Cash Flows | Cash Tax Rate | After-Tax Cash Flows |
| 1,150 | $ 0.95 | $ 1,092 | $ 1,697 | $ 6,039 | 11.8% | $ 5,327 |
| 1,265 | 0.95 | 1,201 | 1,697 | 6,812 | 11.8% | 6,009 |
| 1,391 | 1.00 | 1,391 | 1,697 | 7,567 | 11.8% | 6,675 |
| 1,491 | 1.00 | 1,491 | 1,697 | 8,235 | 11.8% | 7,264 |
| 1,603 | 1.00 | 1,603 | 1,697 | 8,980 | 11.8% | 7,921 |
| 1,522 | 1.00 | 1,522 | - | 10,143 | 11.8% | 8,947 |
| 1,446 | 1.00 | 1,446 | - | 9,636 | 11.8% | 8,499 |
| 1,374 | 1.00 | 1,374 | - | 9,154 | 11.8% | 8,075 |
| 1,305 | 1.00 | 1,305 | - | 8,696 | 11.8% | 7,671 |
| 1,086 | 1.00 | 1,086 | - | 6,655 | 11.8% | 5,871 |
| 967 | 1.00 | 967 | - | 5,650 | 11.8% | 4,984 |
| 228 | 1.00 | 228 | - | 1,331 | 11.8% | 1,174 |
| - | 1.00 | - | - | - | 11.8% | - |

The first 5 years of production expenses and tax rates flow in directly from our operating model; after that we assume constant expenses per Mcfe and a constant tax rate. For the annual development expenses, we take the total from the assumptions at the top and divide by the assumed development period, 5 years in this case.

At the end, we take revenue and subtract production, development, and taxes to calculate the after-tax cash flows.

**Step 4: Take the Net Present Value of the After-Tax Cash Flows**

This is just a simple NPV formula in Excel – apply it to the range that the After-Tax Cash Flows column covers:

| | |
|---|---|
| Present Value of Cash Flows from Proved Reserves: | =NPV(NAV_Discount_Rate,AB20:AB40) |

You should use the standard 10% oil & gas discount for the NAV_Discount_Rate variable here.

**Step 5: Value the Other Assets**

So far, we have included **only** the after-tax cash flows from oil & gas exploration and production activities.

But natural resource companies frequently have other business segments: **midstream** (transporting the energy), **refining & marketing** (turning it into usable gas / oil and selling it to customers), and **chemicals**.

They also have **undeveloped land** that has value even if it doesn't count as Proved Reserves or if nothing has been produced yet.

First, estimate the value for the undeveloped land (see Excel paste-in on the right).

You can get estimates for $ / Acre or total undeveloped land value from equity research or from industry sources like the Herold Database.

If XTO actually had other business segments, here's how we might estimate the value of each one:

| Undeveloped Acres (Property Values in $ Millions USD): | | | |
|---|---|---|---|
| Region: | Acres: | $ / Acre: | Value: |
| US - Texas: | 281,000 | $ 1,500 | $ 422 |
| US - Oklahoma: | 176,000 | 500 | 88 |
| US - New Mexico: | 21,000 | 300 | 6 |
| US - Arkansas: | 216,000 | 700 | 151 |
| US - Montana: | 92,000 | 500 | 46 |
| US - Utah: | 84,000 | 400 | 34 |
| US - Louisiana: | 39,000 | 700 | 27 |
| US - North Dakota: | 191,000 | 500 | 96 |
| US - Kansas: | - | 500 | - |
| US - West Virginia: | 58,000 | 600 | 35 |
| US - Pennsylvania: | 119,000 | 1,200 | 143 |
| US - Wyoming: | 13,000 | 400 | 5 |
| US - Colorado: | 2,000 | 500 | 1 |
| US - Other: | 76,000 | 300 | 23 |
| US - Offshore: | 45,000 | 400 | 18 |
| North Sea - Offshore: | 133,000 | 600 | 80 |
| **Total:** | **1,546,000** | **$ 759** | **$ 1,174** |

| Other Business Segments: | | | | | |
|---|---|---|---|---|---|
| **Chemicals** | | **Midstream** | | **Downstream** | |
| 12/31/2009 EBITDA: | $ 200 | 12/31/2009 EBITDA: | $ 100 | 12/31/2009 EBITDA: | $ 150 |
| EV/EBITDA Multiple: | 5.0 x | EV/EBITDA Multiple: | 3.0 x | EV/EBITDA Multiple: | 3.0 x |
| **Estimated EV:** | **$ 1,000** | **Estimated EV:** | **$ 300** | **Estimated EV:** | **$ 450** |

To do this more rigorously, you would select public comps for each segment and base the EBITDA multiple on those.

Once you have the value of the undeveloped land and the other business segments, you add up all of those and the Present Value of After-Tax Cash Flows from Proved Reserves to get the Enterprise Value:

| | |
|---|---|
| **Enterprise Value:** | =Proved_Reserves_Cash_Flow_PV+Undeveloped_Land_Value+Chemicals_Value+Midstream_Value+Downstream_Value |

### Step 6: Make Balance Sheet Adjustments and Calculate the Implied Per Share Price

| | | | |
|---|---|---|---|
| **Enterprise Value:** | | | **$ 48,444** |
| Balance Sheet Adjustments: | | | (10,144) |
| **Implied Equity Value:** | | | **$ 38,300** |
| | | | |
| Diluted Shares Outstanding: | | | 598.6 |
| **Implied Share Price:** | | | **$ 63.99** |
| | | Exercise | |
| **Type:** | **Number:** | **Price:** | **Dilution:** |
| Options | 18.366 | $ 38.39 | 7.347 |
| RSU | 5.493 | | 5.493 |
| Performance Shares A | 0.390 | 50.00 | 0.390 |
| Performance Shares B | 0.228 | 55.00 | 0.228 |
| Performance Shares C | 0.245 | 77.00 | - |
| Performance Shares D | 0.245 | 85.00 | - |
| Warrants | 2.600 | 20.78 | 1.756 |

Once you have the Enterprise Value, you work backwards (i.e. add cash, subtract debt, and so on) to get to Equity Value and calculate the implied per share price – just like you would for a normal company.

When you're finished and you have the per share price, you can then create sensitivity tables based on commodity prices and the other assumptions at the top of the model.

You would **not** use metrics like revenue growth or EBITDA margins because once again, they are not applicable to oil & gas companies.

## Mining, Footnotes, and More

You can also create NAV models for mining and other natural resource companies.

They're very similar – the main **difference** is that you make additional assumptions on the revenue side (e.g. you might assume that only a certain percentage of the tons mined have the metal you're looking for, or that a certain percentage are "wasted" in the mining process).

You don't have to create a NAV model exactly like the example we went through above – here are some variations you will see:

- We used Proved Reserves (1P) here but you can also use Proved + Probable Reserves (2P) or Proved + Probable + Possible Reserves (3P). You will see references to 1P NAV, 2P NAV, 3P NAV, and so on in equity research.
- You will see many variations on the expense and tax assumptions because they are company-dependent. The safest bet is to **follow what they do in the PV-10 calculation in their filings**.
- You could value the other business segments by using a segment-level DCF or other methods rather than just assuming a simple EBITDA multiple as we did here.

Finally, note that **NAV models are most applicable to exploration & production-focused natural resource companies**.

If a company is more focused on transporting energy or refining and selling it, they are not as dependent on assets as an E&P company so you would stick to the standard public comps, precedent transactions, and DCF there.