CHAPTER 9

Oil & Gas Financial Modeling with Claude

النمذجة المالية لقطاع النفط والغاز

Level: Advanced

Learning Objectives

- Understand the financial characteristics that distinguish oil and gas from other industries, including commodity-driven revenue, depletion accounting, reserve-based lending, and the upstream/midstream/downstream value chain
- Calculate and interpret the six core oil and gas KPIs: Netback, Finding & Development (F&D) Cost, Reserve Replacement Ratio (RRR), Production per BOE, Break-even Price, and Depletion, Depreciation & Amortization (DD&A)
- Build a complete upstream E&P financial model using Claude, from production decline curves through netback analysis, break-even pricing, and Net Asset Value (NAV) estimation
- Apply exponential and hyperbolic decline curve analysis to forecast future production, and calculate full-cycle and half-cycle break-even prices for investment decision-making
- Use the DARE framework to structure oil and gas prompts and deploy targeted Claude prompts for reserve valuation, commodity hedging analysis, and peer NAV comparison

9.1 Oil & Gas Industry Overview

The oil and gas industry is the world's largest sector by revenue, with the top five international oil companies alone generating combined annual revenues that exceed $1.5 trillion. Financial modeling in this sector requires a fundamentally different analytical framework than corporate finance or even other capital-intensive industries. Four defining characteristics shape every oil and gas financial model: commodity-driven revenue, extreme capital intensity, pronounced cyclicality, and a unique accounting treatment centered on depletion rather than depreciation.

Unlike manufacturing or service companies that can influence pricing through branding, differentiation, or market positioning, oil and gas producers are price takers. Revenue is determined by the interaction of two variables: production volume (measured in barrels of oil equivalent, or BOE) and the realized commodity price. This price-taker dynamic means that cost management, capital allocation, and reserve replacement are the primary levers through which management creates shareholder value. The financial modeler's task is to capture these dynamics while accounting for the geological uncertainty inherent in subsurface assets.

Source: Damodaran, A. (2012). Investment Valuation, 3rd ed. John Wiley & Sons. Chapter on commodity and natural resource companies.

Key Financial Characteristics

Commodity-Driven Revenue: Oil and gas companies sell fungible commodities whose prices are set by global or regional markets. West Texas Intermediate (WTI) and Brent crude benchmarks for oil, and Henry Hub for natural gas, determine realized revenue. This means revenue forecasting in an E&P model is fundamentally a commodity price and production volume exercise. Price assumptions are the single largest driver of model output, and sensitivity analysis around commodity prices is essential to every oil and gas valuation.

Capital Intensive: The upstream oil and gas business requires enormous capital expenditure before any revenue is generated. Exploration and development costs can range from $5 million for a conventional onshore well to over $200 million for a deepwater subsea completion. Capital efficiency—measured by metrics like Finding & Development cost per BOE—is a critical performance differentiator. The industry typically reinvests 60–80% of operating cash flow back into capital programs.

Cyclical: Oil and gas is among the most cyclical industries in the global economy. Commodity price cycles can span 5–15 years, with peak-to-trough price swings of 50–75% not uncommon. Brent crude, for example, traded above $110/bbl in mid-2014, fell below $30/bbl in early 2016, recovered to over $80/bbl by 2018, and collapsed again in 2020. This cyclicality demands that financial models incorporate scenario analysis and stress testing across multiple commodity price environments.

Depletion Accounting: Unlike most industries where assets are depreciated over their useful life, oil and gas assets are depleted based on production relative to total estimated reserves. Under the successful efforts method (US GAAP and IFRS), only costs associated with successful exploration are capitalized, while dry hole costs are expensed immediately. Under the full cost method, all exploration costs—including dry holes—are capitalized into a single cost pool and depleted as a unit. This distinction materially affects reported earnings and asset values.

Source: IFRS 6 — Exploration for and Evaluation of Mineral Resources. International Accounting Standards Board.

The Oil & Gas Value Chain

The oil and gas industry is organized into three segments, each with distinct financial characteristics, risk profiles, and modeling requirements:

Upstream (Exploration & Production): The upstream segment encompasses the exploration for and production of crude oil and natural gas. This is the highest-risk, highest-reward segment of the value chain. Upstream companies bear geological risk (the uncertainty of finding hydrocarbons), commodity price risk (revenue fluctuates with market prices), and operational risk (drilling and completion challenges). Financial models for upstream companies center on reserve estimation, production decline curves, and netback analysis. Key metrics include F&D cost, reserve replacement ratio, and production per BOE. Upstream valuations rely heavily on Net Asset Value (NAV) models that discount future production cash flows at risk-adjusted rates.

Midstream (Transportation & Processing): The midstream segment includes pipelines, gathering systems, processing plants, storage facilities, and marine terminals that connect production sites to end markets. Midstream businesses often operate under long-term, fee-based contracts that provide more stable and predictable cash flows than upstream operations. Financial models focus on contracted capacity, throughput volumes, fee escalation mechanisms, and distributable cash flow. Many midstream companies are structured as Master Limited Partnerships (MLPs) or C-corporations with high distribution yields.

Downstream (Refining & Marketing): The downstream segment converts crude oil into refined products (gasoline, diesel, jet fuel, petrochemicals) and markets them to end consumers. Downstream profitability depends on the crack spread—the difference between crude oil input costs and refined product output prices. Financial models for refiners emphasize capacity utilization, Nelson Complexity Index, feedstock flexibility, and product yield optimization. Downstream businesses tend to be less cyclical than upstream operations because refining margins can partially offset crude price movements.

Source: Society of Petroleum Engineers (SPE). Petroleum Resources Management System (SPE-PRMS), 2018 revision.

Core KPIs and Metrics

Oil and gas financial models are built around a set of industry-specific KPIs that differ significantly from standard corporate finance metrics. The six essential KPIs for upstream E&P analysis are presented below.

Netback ($/BOE)

Formula: *Revenue − Royalties − Transportation − Operating Costs) / Production*

The single most important measure of E&P profitability. Netback represents the cash margin earned per unit of production after deducting field-level costs. A higher netback indicates superior asset quality or cost discipline. Industry benchmarks range from $15–45/BOE depending on basin, commodity mix, and fiscal regime.

F&D Cost ($/BOE)

Formula: *Total Finding & Development CapEx / Reserves Added (BOE)*

Measures the capital efficiency of reserve replacement. F&D cost captures how much a company spends to find and develop each barrel of new reserves. Three-year rolling averages smooth annual volatility. Industry benchmarks typically range from $8–25/BOE, with lower values indicating superior exploration and development efficiency.

Reserve Replacement Ratio

Formula: *Reserves Added / Production (in BOE)*

Indicates whether a company is replacing the reserves it produces. An RRR above 100% means the company is growing its reserve base; below 100% signals depletion without adequate replacement. Three-year averages smooth acquisition effects. Sustained RRR below 100% raises going-concern questions for E&P companies.

Production per BOE

Formula: *Total Production (BOE) / Weighted Average Shares or per Asset Basis*

Measures production efficiency and scale. This metric is used for peer comparison and to evaluate per-share production growth. Analysts track production per share to assess whether growth is accretive or dilutive. Production growth of 3–7% annually is considered healthy for mid-cap E&P companies.

Break-even Price ($/bbl)

Formula: *Total Costs (including CapEx, OpEx, G&A, Taxes, Interest) / Total Production*

The commodity price at which a company generates zero free cash flow. Full-cycle break-even includes all costs from exploration through production. Half-cycle break-even excludes sunk exploration and development costs, representing the price needed to continue operating existing wells profitably. Permian Basin operators have achieved full-cycle break-evens of $40–55/bbl.

DD&A ($/BOE)

Formula: *Depletion, Depreciation & Amortization / Total Production (BOE)*

Represents the non-cash charge for depleting the capitalized cost of proved reserves and depreciating production equipment. DD&A is calculated using the unit-of-production method: (Net Capitalized Cost × Period Production) / Total Proved Reserves. DD&A per BOE typically ranges from $8–20/BOE depending on asset vintage and acquisition price.

Source: U.S. Energy Information Administration (EIA). Annual Energy Outlook and company 10-K filings for benchmark data.

Revenue Drivers

Oil and gas revenue is the product of two variables: production volume and realized price. Revenue = Production Volume (BOE) × Realized Price ($/BOE). Production volume is determined by the number of producing wells, the decline rate of each well, and any new wells brought online. Realized price equals the benchmark commodity price adjusted for quality differentials (API gravity, sulfur content), transportation discounts (basis differentials), and any hedging gains or losses. Understanding this revenue decomposition is essential because each component is modeled differently: production is a geological and engineering input, while price is a market and contractual input.

Cost Structure

Lifting Costs (LOE): Direct operating costs to extract hydrocarbons from the reservoir, including labor, power, chemicals, workovers, and artificial lift. Typically $5–15/BOE for conventional onshore operations and $10–25/BOE for offshore or unconventional plays.

Royalties: Payments to mineral rights owners, typically 12.5–25% of wellhead revenue. In many jurisdictions, royalties are the first deduction from gross revenue before any other costs. Crown royalties (government) and overriding royalties (third-party) reduce the operator's net revenue interest.

Transportation & Processing: Costs to move produced hydrocarbons from the wellhead to market hubs, including pipeline tariffs, trucking costs, and gas processing fees. These costs vary significantly by basin and infrastructure availability, ranging from $1–8/BOE.

DD&A: Non-cash depletion charge calculated using the unit-of-production method. This is the largest non-cash cost for most E&P companies and is driven by the capitalized cost base and remaining proved reserves.

Exploration Expense: Under successful efforts accounting, dry hole costs and expired leases are expensed immediately. Seismic acquisition and geological/geophysical (G&G) costs may be capitalized or expensed depending on the company's accounting policy.

Reserve Categories (SPE-PRMS)

The Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS) provides the global standard for classifying hydrocarbon reserves. Reserve estimates are central to oil and gas valuation because they determine the denominator in DD&A calculations, the basis for reserve-based lending, and the foundation for NAV models.

Proved Reserves (1P): Quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward. Proved reserves are subdivided into Proved Developed (PD) and Proved Undeveloped (PUD). Under SEC rules, proved reserves must have at least a 90% probability of being recovered. 1P reserves form the basis for DD&A calculations and reserve-based lending.

Proved + Probable (2P): The sum of proved and probable reserves. Probable reserves are those additional quantities estimated to be less certain than proved but more likely than not to be recovered (at least 50% probability). 2P reserves are the most common basis for international reserve reporting and asset valuations in acquisition transactions.

Proved + Probable + Possible (3P): The sum of proved, probable, and possible reserves. Possible reserves are those additional quantities estimated to be less certain than probable (at least 10% probability). 3P reserves represent the high case in resource estimates and are rarely used as the primary basis for valuation, though they inform exploration upside potential.

Source: Society of Petroleum Engineers (SPE). Petroleum Resources Management System (SPE-PRMS), 2018 revision.

Source: SEC Regulation S-X, Rule 4-10, and Regulation S-K, Item 1202 — Oil and Gas Reserve Disclosure Requirements.

Key Takeaways

- Oil and gas revenue is commodity-price-driven: Revenue = Production Volume x Realized Price, making price assumptions the single largest model driver.
- Netback (cash margin per BOE after field-level costs) is the most important upstream profitability metric, with benchmarks of $15–45/BOE depending on basin and fiscal regime.
- F&D cost and reserve replacement ratio measure the long-term sustainability of an E&P business—sustained RRR below 100% signals reserve base erosion.
- The SPE-PRMS framework (1P, 2P, 3P) provides the global standard for reserve classification, with 1P reserves driving DD&A calculations and reserve-based lending.

- Depletion accounting (unit-of-production method) fundamentally differs from standard depreciation and directly links non-cash charges to production activity.

9.2 Deep-Dive: Upstream E&P Financial Model

[Demonstration Example — Hypothetical Data]

In this section, we construct a comprehensive upstream Exploration & Production (E&P) financial model using Claude. The model covers production decline curve forecasting, netback analysis, break-even price calculation, F&D cost and reserve replacement analysis, and a Net Asset Value (NAV) model that estimates the present value of reserves. This model follows the DARE framework (Define, Ask, Refine, Extract) to demonstrate how structured prompting produces institutional-quality financial analysis.

DARE Framework: Define the role, Ask the question, Refine the output, Extract structured results.

Model Overview: HorizonX Energy Corp.

For this demonstration, we model HorizonX Energy Corp., a hypothetical mid-cap E&P company operating in the Permian Basin (West Texas/New Mexico). All data presented is illustrative and does not represent any real company. The model parameters are designed to reflect realistic industry benchmarks for a Permian Basin operator.

Model Assumptions

Parameter	Value	Source / Basis
Current Production	45,000 BOE/day (65% oil, 25% gas, 10% NGL)	Typical mid-cap Permian E&P
Proved Reserves (1P)	380 million BOE	SEC-compliant proved reserves
Proved + Probable (2P)	520 million BOE	Independent reserve engineer report
WTI Oil Price Assumption	$72/bbl (base case)	EIA Short-Term Energy Outlook
Henry Hub Gas Price	$3.25/mcf (base case)	EIA reference case
NGL Price	35% of WTI ($25.20/bbl)	Historical NGL-to-WTI ratio
Royalty Rate	18.5% of gross revenue	Average Permian royalty burden

Lease Operating Expense (LOE)	$8.50/BOE	Permian Basin peer median
Transportation & Processing	$3.75/BOE	Permian midstream market rates
Cash G&A	$2.25/BOE	Mid-cap E&P peer benchmark
Development CapEx (2024E)	$1.2 billion	Maintaining production + modest growth
Initial Decline Rate (Year 1)	65% for new horizontal wells	Permian horizontal well type curve
Terminal Decline Rate	8% per year	Conventional terminal decline
Hyperbolic Exponent (b-factor)	1.2	Typical Permian unconventional
Discount Rate (WACC)	10%	E&P sector risk-adjusted rate

Note: All values are hypothetical and designed to reflect typical Permian Basin operating parameters. Based on EIA, SPE, and peer company disclosures.

Step 1: Production Decline Curve Modeling

Production decline curve analysis is the foundation of every upstream financial model. Once a well begins producing, its output declines over time as reservoir pressure drops and the natural drive mechanism weakens. Modeling this decline accurately is critical because production forecasts drive revenue, operating costs, and ultimately asset value.

Two primary decline curve models are used in industry practice. The exponential decline model assumes a constant percentage decline rate: q(t) = q_i x e^(-D x t), where q_i is the initial production rate, D is the nominal decline rate, and t is time. The hyperbolic decline model allows the decline rate to decrease over time: q(t) = q_i / (1 + b x D_i x t)^(1/b), where b is the hyperbolic exponent (0 < b < 2) and D_i is the initial decline rate. For Permian Basin unconventional wells, b-factors typically range from 1.0 to 1.4, reflecting the steep initial decline that gradually moderates as the well transitions from transient to boundary-dominated flow.

Source: Arps, J.J. (1945). Analysis of Decline Curves. Transactions of the AIME, 160(01), 228–247.

Applying the DARE framework (Define), we establish Claude's role as a petroleum engineering and financial modeling expert to generate the production forecast.

[Chat Prompt]

```
You are a senior petroleum engineer and E&P financial analyst. I need you
to build a production decline curve forecast for a Permian Basin
horizontal well program.

Well Type Curve Parameters:
- Initial Production (IP30): 1,200 BOE/day (780 bbl oil, 300 bbl NGL, 720
mcf gas = 120 BOE)
- Year 1 decline rate: 65%
- Hyperbolic exponent (b-factor): 1.2
- Terminal decline rate: 8% per year
- Switch from hyperbolic to exponential decline at 8% annual rate
- Economic limit: 10 BOE/day

Please provide:
1. Monthly production forecast for Years 1-3, then annual for Years 4-20
```

```
2. Cumulative production (EUR) calculation
3. A production schedule showing the transition from hyperbolic to
exponential decline
4. Calculate the time at which the hyperbolic decline rate reaches the
terminal rate

Format the output as a structured table with columns: Period, Rate
(BOE/d), Cumulative (MBOE), Decline Rate.
```

Expected Output: *A detailed production forecast table showing steep initial decline (65% in Year 1) moderating to terminal decline (8%), with EUR of approximately 750–900 MBOE per well over a 20-year economic life.*

Refinement: *Add a second well type curve for a lower-productivity zone with IP30 of 800 BOE/day and b-factor of 1.0, and compare the EUR and capital efficiency of both type curves.*

[API Prompt]

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hyperbolic decline curve forecast for a Permian Basin horizontal well
with the following parameters: IP30 = 1,200 BOE/day, initial decline rate
= 65%, b-factor = 1.2, terminal decline = 8%. Calculate monthly
production for months 1-36, then annual for years 4-20. Include
cumulative production and identify the hyperbolic-to-exponential switch
point. Return the result as a JSON object with keys: monthly_forecast
(array of {month, rate_boed, cumulative_mboe, decline_pct}),
annual_forecast (array of {year, avg_rate_boed, annual_mboe,
cumulative_mboe}), eur_mboe (number), switch_point_months (number)."
    }
  ]
}
```

Expected Output: *A JSON-structured production forecast with monthly granularity for the first three years and annual thereafter, including EUR calculation and the month at which the decline switches from hyperbolic to exponential.*

Step 2: Netback Analysis

Netback analysis is the core profitability metric for upstream E&P companies. It measures the cash margin earned per barrel of oil equivalent after deducting all field-level costs. The netback waterfall follows a specific sequence: Gross Revenue → Less Royalties → Less Transportation & Processing → Less Lifting Costs (LOE) → Operating Netback. An extended netback may further deduct cash G&A and interest expense to arrive at a corporate netback.

For HorizonX Energy, we calculate the netback using our hypothetical operating parameters. This analysis follows the DARE framework (Ask) by structuring the question to produce a complete netback waterfall with sensitivity analysis.

[Chat Prompt]

```
You are a senior E&P financial analyst. Calculate a detailed netback
analysis for an upstream oil and gas company with the following operating
profile:

Production Mix: 45,000 BOE/day (65% oil at $72/bbl WTI, 25% gas at
$3.25/mcf, 10% NGL at $25.20/bbl)
Revenue Adjustments: Quality differential of -$2.50/bbl on oil, basis
differential of -$0.15/mcf on gas
Cost Structure per BOE:
- Royalties: 18.5% of gross revenue
- Lease Operating Expense: $8.50/BOE
- Transportation & Processing: $3.75/BOE
- Cash G&A: $2.25/BOE

Please provide:
1. Blended realized price per BOE across all commodity streams
2. Operating netback per BOE (before G&A)
3. Corporate netback per BOE (after G&A)
4. Netback margin percentage
5. Annualized operating cash flow from the netback
6. Sensitivity table showing netback at WTI prices of $55, $65, $72, $80,
and $90/bbl
```

Expected Output: *A comprehensive netback waterfall showing blended realized revenue of approximately $48–55/BOE, operating netback of $25–35/BOE, and a sensitivity table demonstrating cash flow leverage to oil price.*

Refinement: *Add a comparison column showing how the netback changes if the production mix shifts to 55% oil / 30% gas / 15% NGL, and calculate the gas-oil ratio (GOR) impact on corporate economics.*

[API Prompt]

```
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      "content": "Role: Senior E&P financial analyst. Calculate a netback waterfall for an upstream E&P company producing 45,000 BOE/day (65% oil at $72/bbl WTI with -$2.50 quality diff, 25% gas at $3.25/mcf with -$0.15 basis diff, 10% NGL at $25.20/bbl). Cost structure per BOE: royalties 18.5% of revenue, LOE $8.50, transport $3.75, G&A $2.25. Return JSON with: blended_realized_price_boe, royalty_per_boe, loe_per_boe, transport_per_boe, ga_per_boe, operating_netback, corporate_netback, netback_margin_pct, annual_operating_cashflow, price_sensitivity [{wti_price, operating_netback, annual_cashflow}] for WTI at $55/$65/$72/$80/$90."
    }
  ]
}
```

Expected Output: *A JSON-structured netback analysis with per-BOE waterfall components, margin percentages, annualized cash flow, and a five-scenario price sensitivity matrix.*

Step 3: Break-Even Price Calculation

Break-even analysis determines the minimum commodity price at which an E&P company generates zero free cash flow. This is arguably the most important metric for investment decision-making because it directly answers the question: at what price does this asset stop making money? Two types of break-even are calculated in industry practice:

Full-Cycle Break-Even: Includes all costs from exploration through production: finding & development capital, lease operating expense, royalties, transportation, G&A, interest expense, and production taxes. This represents the price needed to generate an adequate return on total invested capital. Full-cycle break-evens for Permian Basin operators typically range from $40–55/bbl.

Half-Cycle Break-Even: Excludes sunk exploration and development costs, including only operating costs (LOE, royalties, transportation, G&A) and sustaining capital. This represents the price below which it is uneconomic to continue producing from existing wells. Half-cycle break-evens are typically $15–30/bbl lower than full-cycle break-evens.

Applying the DARE framework (Refine), we iterate on the break-even analysis to incorporate both full-cycle and half-cycle perspectives with tax effects.

[Chat Prompt]

```
You are a senior E&P financial analyst specializing in break-even
analysis. Calculate the full-cycle and half-cycle break-even oil prices
for the following upstream company:

Production: 45,000 BOE/day (65% oil, 25% gas, 10% NGL)
Annual Development CapEx: $1.2 billion
Lease Operating Expense: $8.50/BOE
Royalty Rate: 18.5% of revenue
Transportation & Processing: $3.75/BOE
Cash G&A: $2.25/BOE
Annual Interest Expense: $95 million
Production/Severance Tax Rate: 4.6% of revenue (Texas rate)
Effective Income Tax Rate: 21%
Sustaining CapEx (maintenance only): $450 million
Gas price held constant at $3.25/mcf, NGL at 35% of WTI
```

```
Calculate:
1. Full-cycle break-even WTI price (covering all costs + minimum 10% return)
2. Half-cycle break-even WTI price (existing wells, operating costs + sustaining capex only)
3. Cash flow at WTI prices of $50, $60, $72, $80, $90
4. Show the cost stack waterfall for both break-even scenarios
5. Margin of safety at current $72/bbl WTI
```

Expected Output: *A detailed break-even analysis showing full-cycle break-even of approximately $48–55/bbl and half-cycle break-even of approximately $28–35/bbl, with a cost-stack waterfall and cash flow sensitivity table.*

Refinement: *Add a scenario where gas prices increase to $4.50/mcf and NGL prices to 40% of WTI, and recalculate the break-even price to show how product mix diversification lowers the oil price break-even.*

Step 4: F&D Cost and Reserve Replacement Analysis

Finding and Development (F&D) cost measures the capital efficiency of reserve replacement—how much a company spends to find and develop each barrel of new reserves. Reserve Replacement Ratio (RRR) indicates whether a company is maintaining or growing its resource base. Together, these metrics provide a forward-looking assessment of E&P sustainability that complements the backward-looking netback analysis.

F&D Cost = Total F&D Capital Expenditure / Net Reserves Additions (BOE). This metric should be evaluated on a three-year rolling average basis to smooth the effects of lumpy capital programs and reserve revisions. The calculation should separate organic F&D (drilling and completion only) from all-in F&D (including acquisitions and revisions) to provide clearer insight into operational capital efficiency.

[Chat Prompt]

```
You are a reserve engineer and E&P financial analyst. Perform an F&D cost
and reserve replacement analysis for a Permian Basin E&P company with the
following three-year history:

Year 1:
- Development CapEx: $1,050 million
- Exploration CapEx: $120 million
- Extensions & Discoveries: 85 million BOE
- Revisions: +12 million BOE
- Production: 14.6 million BOE (40,000 BOE/d)

Year 2:
- Development CapEx: $1,150 million
- Exploration CapEx: $95 million
- Extensions & Discoveries: 78 million BOE
- Revisions: -8 million BOE
- Production: 15.3 million BOE (42,000 BOE/d)

Year 3:
- Development CapEx: $1,200 million
```

```
- Exploration CapEx: $85 million
- Extensions & Discoveries: 92 million BOE
- Revisions: +15 million BOE
- Production: 16.4 million BOE (45,000 BOE/d)

Calculate:
1. Annual and three-year average organic F&D cost (development +
exploration only)
2. Annual and three-year average all-in F&D cost (including revisions)
3. Annual and three-year average reserve replacement ratio
4. Recycle ratio (netback / F&D cost) using operating netback of $32/BOE
5. Assessment of reserve base sustainability
6. Implied reserve life (1P reserves / current annual production)
```

Expected Output: *A three-year F&D analysis showing organic F&D costs trending around $12–18/BOE, all-in F&D adjusted for revisions, reserve replacement ratios above 100%, and a recycle ratio indicating capital efficiency.*

Step 5: Net Asset Value (NAV) Model

The Net Asset Value model is the primary valuation methodology for upstream E&P companies. Unlike DCF models for operating companies that project earnings or free cash flow, the NAV model values the company's reserves by discounting the after-tax cash flows from future production at a risk-adjusted discount rate. The NAV model reflects the fundamental reality that an E&P company's value is ultimately derived from its subsurface hydrocarbon reserves.

The standard NAV framework values reserves in layers, applying different risk factors to each reserve category: Proved Developed Producing (PDP) reserves at 100% (no risk adjustment, these wells are already producing), Proved Developed Non-Producing (PDNP) at 85–90%, Proved Undeveloped (PUD) at 60–70%, Probable at 40–50%, and Possible at 15–25%. The total NAV also adds the value of undeveloped acreage, hedging book mark-to-market, and net debt to arrive at equity NAV.

This step applies the DARE framework (Extract) to generate a structured NAV model output that can be directly used for investment analysis and peer comparison.

[Chat Prompt]

```
You are a senior E&P equity research analyst. Build a Net Asset Value
(NAV) model for an upstream E&P company with the following reserve
profile:

Reserve Categories:
- PDP (Proved Developed Producing): 210 million BOE
- PDNP (Proved Developed Non-Producing): 45 million BOE
- PUD (Proved Undeveloped): 125 million BOE
- Probable: 140 million BOE
- Possible: 110 million BOE

Valuation Parameters:
- WTI strip price: $72/bbl declining 2% annually in real terms
- Gas price: $3.25/mcf escalating at 1% annually
- Operating cost: $8.50/BOE escalating at 2% annually
- Development cost for PUD: $18/BOE
```

```
- Corporate tax rate: 21%
- Discount rate: 10% (WACC)
- Risk factors: PDP 100%, PDNP 90%, PUD 65%, Probable 45%, Possible 20%

Additional Items:
- Undeveloped acreage: 85,000 net acres at estimated $8,000/acre
- Hedge book MTM value: +$145 million
- Net debt: $1.8 billion
- Shares outstanding: 250 million

Calculate:
1. PV of each reserve category (PDP, PDNP, PUD, Probable, Possible)
2. Risk-adjusted PV for each category
3. Core NAV (1P reserves only)
4. Total NAV including 2P and risked upside
5. NAV per share for Core, 2P, and Total scenarios
6. Implied valuation multiples (NAV/share vs. assumed current price of
$42/share)
```

Expected Output: *A comprehensive NAV model showing Core NAV per share of approximately $35–50, 2P NAV per share of $50–70, and Total NAV including risked upside, with the implied discount/premium to current trading price.*

Refinement: *Add a price sensitivity showing NAV per share at WTI prices of $55, $65, $72, $80, and $90, and calculate the implied WTI price embedded in the current share price.*

[API Prompt]


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      "content": "Role: Senior E&P equity research analyst. Build a Net
Asset Value model for an upstream E&P company. Reserve categories
(million BOE): PDP 210, PDNP 45, PUD 125, Probable 140, Possible 110.
Risk factors: PDP 100%, PDNP 90%, PUD 65%, Probable 45%, Possible 20%.
WTI base $72/bbl (-2% real annual), gas $3.25/mcf (+1% annual), OpEx
$8.50/BOE (+2% annual), PUD dev cost $18/BOE, tax 21%, WACC 10%. Add:
```

```
acreage 85,000 acres x $8,000, hedge MTM +$145M, net debt -$1.8B, shares
250M. Return JSON: {reserve_pv: [{category, gross_pv, risk_factor,
risked_pv}], core_nav, nav_2p, total_nav, nav_per_share: {core, two_p,
total}, current_price: 42, premium_discount_pct, price_sensitivity:
[{wti, core_nav_ps, total_nav_ps}] for WTI $55/$65/$72/$80/$90}"
    }
  ]
}
```

Expected Output: *A JSON-structured NAV model with granular reserve-level PV calculations, risk-adjusted NAV per share across three scenarios, and a price sensitivity matrix.*

Key Takeaways

- Production decline curve modeling is the foundation of every upstream financial model—hyperbolic decline with b-factors of 1.0–1.4 is standard for unconventional Permian wells.
- Netback analysis (revenue minus field-level costs per BOE) provides the clearest picture of asset-level profitability and enables direct peer comparison across different basins and operators.
- Break-even analysis should always distinguish full-cycle (including all CapEx) from half-cycle (operating costs only) to properly inform both investment and shut-in decisions.
- The NAV model values reserves in risk-adjusted layers (PDP at 100% down to Possible at 20%), reflecting the geological uncertainty inherent in each reserve category.
- The DARE framework ensures structured, institutional-quality prompts: Define the role, Ask the specific question, Refine with follow-up scenarios, Extract in JSON or tabular format.

9.3 Quick-Reference Oil & Gas Prompts

This section provides a library of ready-to-use prompts for common oil and gas financial analysis tasks. Each prompt is labeled for Chat or API use and includes expected output descriptions. These prompts can be adapted to specific companies, basins, or analytical contexts by modifying the input parameters.

Prompt 1: Netback Analysis

[Chat Prompt]

```
Act as a senior E&P analyst. Calculate the operating and corporate
netback for an oil and gas producer with the following profile: [Insert
production volume, commodity mix, realized prices, royalty rate, LOE,
transport costs, G&A]. Present the netback waterfall showing each
deduction from gross revenue to final netback per BOE. Include a netback
margin percentage and annualized cash flow. Provide a sensitivity table
at five different oil price assumptions.
```

Expected Output: *Complete netback waterfall with per-BOE cost breakdown, margin percentage, annualized cash flow, and a five-scenario price sensitivity table.*

Prompt 2: Production Decline Curve Forecasting

[Chat Prompt]

```
You are a reservoir engineer. Build a production decline curve forecast
for a [basin name] horizontal well with the following type curve
parameters: IP30 of [X] BOE/day, initial decline rate of [Y]%, hyperbolic
b-factor of [Z], terminal decline rate of [W]%. Forecast monthly
production for the first 36 months, then annual for years 4–20. Calculate
the Estimated Ultimate Recovery (EUR) and identify the transition point
from hyperbolic to exponential decline. Present results in a structured
table format.
```

Expected Output: *A detailed production forecast with monthly and annual granularity, EUR in MBOE, and the identified switch point from hyperbolic to exponential decline.*

Prompt 3: Break-Even Price Analysis

[API Prompt]

```
{
  "model": "claude-sonnet-4-20250514",
  "max_tokens": 3000,
  "messages": [{"role": "user", "content": "Role: E&P break-even analyst.
Calculate full-cycle and half-cycle break-even WTI oil prices for a
company producing [X] BOE/day ([Y]% oil, [Z]% gas, [W]% NGL). Costs:
development capex $[A]M, LOE $[B]/BOE, royalties [C]% of revenue,
transport $[D]/BOE, G&A $[E]/BOE, interest $[F]M, production tax [G]%,
income tax [H]%. Gas at $[I]/mcf held constant. Return JSON with
full_cycle_breakeven, half_cycle_breakeven, cost_stack_waterfall,
cashflow_sensitivity at 5 WTI prices,
margin_of_safety_at_current_price."}]
}
```

Expected Output: *JSON with full-cycle and half-cycle break-even prices, cost-stack decomposition, and cash flow sensitivity matrix.*

Prompt 4: Reserve Valuation (NAV Model)

[Chat Prompt]

```
You are a senior E&P equity research analyst. Build a Net Asset Value
(NAV) model for [Company Name] using the following reserve data: PDP [X]
million BOE, PDNP [Y] million BOE, PUD [Z] million BOE, Probable [W]
million BOE. Apply risk factors of 100% for PDP, 90% for PDNP, 65% for
PUD, and 45% for Probable. Use a WTI strip price of $[A]/bbl, operating
cost of $[B]/BOE, PUD development cost of $[C]/BOE, WACC of [D]%, and tax
rate of [E]%. Add net debt of $[F] and shares outstanding of [G] million.
Calculate Core NAV (1P), 2P NAV, and NAV per share. Compare to the
current share price of $[H] and calculate the implied premium or
discount.
```

Expected Output: *A layered NAV model with risk-adjusted PV per reserve category, NAV per share for Core and 2P scenarios, and implied premium/discount to market price.*

Refinement: *Add a price sensitivity showing NAV per share at five WTI prices and calculate the implied oil price embedded in the current stock price.*

Prompt 5: DD&A Calculation (Unit-of-Production Method)

[Chat Prompt]

```
You are an oil and gas accountant specializing in depletion accounting.
Calculate the DD&A expense using the unit-of-production method for the
following E&P company:

- Net capitalized costs (PP&E, net of accumulated DD&A): $[X] billion
- Estimated future development costs: $[Y] million
- Total proved reserves (beginning of period): [Z] million BOE
- Period production: [W] million BOE
- Salvage value: $[V] million

Calculate: (1) DD&A rate per BOE, (2) Total DD&A expense for the period,
(3) DD&A as percentage of revenue assuming [A] average realized price per
BOE, (4) Sensitivity to reserve revisions of +/- 10% and 20%. Compare the
result under both successful efforts and full cost methods if the company
had $[B] million in dry hole costs during the period.
```

Expected Output: *DD&A per BOE calculation with the unit-of-production formula, total expense, percentage of revenue, reserve revision sensitivity, and comparison between successful efforts and full cost methods.*

Prompt 6: Commodity Hedging Analysis

[API Prompt]

```
{
  "model": "claude-sonnet-4-20250514",
  "max_tokens": 3000,
  "messages": [{"role": "user", "content": "Role: Commodity risk
management analyst. Analyze the hedging program for an E&P company
producing [X] BOE/day of oil. Current hedge book: [Y]% of next 12 months
production hedged via [swap/collar/put] at $[Z]/bbl floor and $[W]/bbl
ceiling. Evaluate: 1) Hedged vs unhedged revenue at WTI prices of
$50/$60/$72/$80/$90, 2) Mark-to-market value of hedge book at current
strip, 3) Effective realized price per barrel after hedging gains/losses,
4) Hedge ratio adequacy assessment relative to debt covenants requiring
[A]x DSCR, 5) Recommended hedge strategy adjustments. Return as
```

```
structured JSON with revenue_comparison, mtm_value,
effective_realized_prices, dscr_coverage, and recommendations."}]
}
```

Expected Output: *JSON-structured hedging analysis with hedged vs. unhedged revenue comparison, MTM valuation, effective realized prices, DSCR coverage assessment, and strategic recommendations.*

Prompt 7: Peer NAV Comparison

[Chat Prompt]

```
You are a senior E&P equity research analyst. Create a peer NAV
comparison table for [Company] versus its Permian Basin peer group. For
each company, show: (1) 1P reserves (million BOE), (2) 2P reserves
(million BOE), (3) Current production (BOE/day), (4) Reserve life
(1P/production), (5) Core NAV per share, (6) Current share price, (7)
Price/NAV ratio, (8) EV/2P reserves ($/BOE), (9) EV/daily production
($/BOE/d), (10) F&D cost (3-year average $/BOE). Rank the peer group by
Price/NAV ratio and identify which companies trade at the largest
discount to NAV. Provide an investment thesis for the most undervalued
company based on the NAV analysis.
```

Expected Output: *A comprehensive peer comparison table with NAV-based valuation metrics, rankings by discount to NAV, and an investment thesis for the most attractively valued peer.*

Refinement: *Add a scatter plot description showing Price/NAV vs. F&D cost efficiency to identify companies with both cheap valuations and superior capital efficiency.*

Prompt 8: Well-Level Type Curve Economics

[Chat Prompt]

```
You are a petroleum engineer and financial analyst. Build a single-well
type curve economic model for a Permian Basin horizontal well with the
following parameters:
- Drilling & Completion cost: $[X] million per well
- IP30: [Y] BOE/day ([Z]% oil)
- Decline parameters: initial decline [A]%, b-factor [B], terminal
decline [C]%
- Realized prices: oil $[D]/bbl, gas $[E]/mcf, NGL $[F]/bbl
- LOE: $[G]/BOE, royalties [H]%, transport $[I]/BOE
```

```
Calculate: (1) EUR per well (MBOE), (2) Payout period in months, (3)
Single-well IRR at base case prices, (4) Single-well NPV10, (5) Capital
efficiency (NPV/CapEx ratio), (6) IRR sensitivity at five different oil
prices. Present in a summary table suitable for a capital allocation
committee.
```

Expected Output: *A single-well economic model with EUR, payout, IRR, NPV10, capital efficiency ratio, and price sensitivity suitable for investment committee presentation.*

Key Takeaways

- These eight prompts cover the essential analytical tasks in oil and gas financial modeling: netback, decline curves, break-even, NAV, DD&A, hedging, peer comparison, and well economics.
- Chat prompts are ideal for exploratory analysis and narrative output; API prompts with JSON structure enable automated workflows and data pipeline integration.
- Always adapt the template parameters ([X], [Y], etc.) to the specific company, basin, or scenario being analyzed.
- Combining multiple prompts in sequence (e.g., decline curve into netback into NAV) creates a complete valuation workflow.

9.4 Oil & Gas Financial Modeling Cheat Sheet

This cheat sheet provides a quick reference for the essential formulas, benchmarks, and unit conversions used in oil and gas financial modeling. Keep this section as a reference when building models or reviewing E&P company disclosures.

Key Formulas and Benchmarks

Metric	Formula	Benchmark Range
Netback ($/BOE)	(Revenue − Royalties − Transport − LOE) / Production	$15–45/BOE
F&D Cost ($/BOE)	F&D CapEx / Net Reserves Added	$8–25/BOE (3-yr avg)
Reserve Replacement Ratio	Reserves Added / Production	>100% sustainable
Recycle Ratio	Operating Netback / F&D Cost	>1.5x value-creating
DD&A ($/BOE)	(Net Capitalized Cost − Salvage) × Production / Reserves	$8–20/BOE
Full-Cycle Break-Even	(All Costs + Min Return) / Production	$40–70/bbl (basin-dependent)
Half-Cycle Break-Even	(OpEx + Sustaining CapEx) / Production	$20–40/bbl
Reserve Life Index	1P Reserves / Annual Production	8–15 years
NAV per Share	(Risked PV of Reserves + Other Assets − Net Debt) / Shares	Company-specific
EV/2P Reserves	Enterprise Value / 2P Reserves (BOE)	$8–18/BOE
EV/Daily Production	Enterprise Value / Daily Production (BOE/d)	$30,000–80,000/BOE/d
Production Decline (Arps)	q(t) = q_i / (1 + b·D_i·t)^(1/b)	b = 1.0–1.4 (unconventional)

Unit Conversions

Oil and gas production is measured in different units depending on the hydrocarbon type. The Barrel of Oil Equivalent (BOE) is the standard unit for aggregating production across different commodity streams on an energy-equivalent basis.

Conversion	Value	Notes
1 barrel (bbl) of oil	= 1.0 BOE	Reference unit
1,000 cubic feet (mcf) of gas	= 1/6 BOE (0.167 BOE)	Based on energy equivalence (6:1 ratio)
1 million cubic feet (mmcf)	= 166.7 BOE	1,000 mcf × 0.167
1 billion cubic feet (bcf)	= 166,667 BOE	Common for reserve reporting
1 barrel of NGL	= 1.0 BOE (approximately)	Varies by NGL composition
1 barrel of oil	= 42 US gallons	Standard petroleum barrel
1 metric tonne of oil	= 7.33 barrels (approximately)	Varies by API gravity
1 BOE	≈ 5.8 million BTU	Energy equivalence basis
1 mcf	≈ 1.0 million BTU (MMBTU)	Approximate thermal content
bbl/d to bbl/year	× 365 days	Annual production conversion

Common Abbreviations

Abbreviation	Full Term	Context
BOE	Barrel of Oil Equivalent	Standard production/reserve unit
WTI	West Texas Intermediate	US oil price benchmark
HH	Henry Hub	US natural gas price benchmark
LOE	Lease Operating Expense	Direct production costs
DD&A	Depletion, Depreciation & Amortization	Non-cash charge

F&D	Finding & Development	Capital efficiency metric
RRR	Reserve Replacement Ratio	Reserve sustainability
PDP	Proved Developed Producing	Highest-confidence reserves
PUD	Proved Undeveloped	Booked but undeveloped reserves
NAV	Net Asset Value	Primary E&P valuation method
EUR	Estimated Ultimate Recovery	Total well lifetime production
IP30	Initial Production (30-day average)	Well productivity measure
GOR	Gas-to-Oil Ratio	Production mix indicator
NRI	Net Revenue Interest	Operator's share after royalties
WI	Working Interest	Operator's cost-bearing share
SPE-PRMS	Society of Petroleum Engineers – Petroleum Resources Management System	Reserve classification standard

Key Takeaways

- Netback, F&D cost, and reserve replacement ratio are the three metrics that best summarize E&P operational and financial performance.
- The 6:1 energy equivalence ratio (6 mcf of gas = 1 BOE) is the industry standard for aggregating multi-product production, but does not reflect price equivalence.
- Break-even analysis should always distinguish full-cycle (investment decision) from half-cycle (shut-in decision) perspectives.
- Three-year rolling averages for F&D cost and RRR smooth annual volatility from lumpy capital programs and reserve revisions.

9.5 References and Further Reading

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النمذجة المالية لقطاع النفط والغاز

Oil & Gas — النفط والغاز

Upstream (Exploration & Production) — المنبع (الاستكشاف والإنتاج)

Midstream — القطاع الوسيط

Downstream — القطاع النهائي

Netback — صافي العائد

Reserves — الاحتياطيات

Proved Reserves (1P) — الاحتياطيات المؤكدة

Probable Reserves (2P) — الاحتياطيات المحتملة

Barrel of Oil Equivalent (BOE) — برميل مكافئ نفط

Production Decline Curve — منحنى انخفاض الإنتاج

Finding & Development Cost — تكلفة الاكتشاف والتطوير

Reserve Replacement Ratio — نسبة تعويض الاحتياطي

Break-even Price — سعر التعادل

Depletion — النضوب / الاستنفاد

Royalties — الإتاوات

Lease Operating Expense — مصاريف تشغيل العقد

Net Asset Value (NAV) — صافي قيمة الأصول

Commodity Price — سعر السلعة

Hedging — التحوط

Well Completion — إكمال البئر