

EOG Resources - Where Should the Next Well Go?

Internal ID: S&F-STR-215

Topic: Capital Allocation, Corporate Strategy, Risk Management

Industry: Oil & Gas Exploration & Production

Source: Strategy & Finance

Publication date: 5 October 2026

License: Not specified

Decision information cutoff: 22 February 2024

Case convention: The review exercise and alternatives below are author-created and hypothetical. EOG's reported results, policies and announced plan are historical facts. No private company deliberation or pending management review is represented.

The assignment

On 22 February 2024, EOG Resources reported 2023 results and its 2024 capital plan. The plan called for \$6.0-\$6.4 billion of capital expenditures, with management expecting crude-oil production to rise 3% and total production to rise 7% from 2023. EOG also said that, beginning in 2024, it would return at least 70% of a defined annual cash amount—operating cash before certain balance-sheet changes, less total capital expenditures—to shareholders through dividends and share repurchases. (S1, Item 7, “Capital”; S1, “Cash Return Framework”; S2, release summary.)

For this classroom exercise, assume a hypothetical capital-allocation committee asks you to assess the announced plan and propose decision rules for any marginal, uncommitted capital during the year. The committee and assignment are fictional. EOG did not disclose a plan to reconsider its 2024 budget.

Your task: Recommend one of three approaches:

1. **Execute the announced program:** maintain the 2024 plan and use EOG's stated internal return discipline to steer operations.
2. **Stage selected newer-play and infrastructure spending:** continue the core plan while setting technical and commercial gates for incremental spending in plays such as Utica or Dorado.
3. **Pace or reallocate marginal capital:** defer or reduce selected activity where uncertainty or expected returns warrant it, while preserving contractual commitments and the 70% post-capex return floor.

Support your choice with evidence available by 22 February 2024. Identify what you would monitor, what evidence could change your decision, and how the 70% commitment works under your recommendation. Do not assume that the full announced budget is freely reassignable: the 10-K lists substantial lease, transportation, storage, purchase and service commitments.

A return-focused producer

EOG explores for, develops and produces crude oil, natural gas liquids (NGLs) and natural gas, primarily in the United States and Trinidad. At year-end 2023 it reported 4,498 million barrels of oil equivalent (MMBoe) in proved reserves; 99% on a crude-oil-equivalent basis were in the United States. Its disclosed proved-reserve mix was 39% crude oil and condensate, 28% NGLs and 33% natural gas. The company said it evaluates each prospective drilling location by estimated return, focuses on internally generated prospects and aims to develop low-cost reserves. (S1, Item 1, “Business.”)

Those statements describe EOG's approach, not an external ranking of each project. EOG did not publish a comparable risk-adjusted return table for its planned 2024 wells. The company's characterization of certain plays as highest-return areas is management's own assessment.

Exhibit 1. U.S. operating footprint and well plans

Company-reported figures. Net acres in thousands; production volumes are 2023 average daily volumes; planned completions are 2024 guidance.

Area	Oil (MBbl/d)	NGLs (MBbl/d)	Gas (MMcf/d)	Net acres	2023 net wells completed	2024 expected net completions
Delaware Basin	301.9	164.0	890	395	370	360
South Texas	126.0	32.4	436	1,155	200	170
Rocky Mountain	39.4	15.3	149	801	54	40
Other Areas	7.9	12.1	76	1,015	16	30
Total	475.2	223.8	1,551	3,366	640	600

Source: S1, Item 1, U.S. operations table. “Net” wells and acreage reflect EOG's working interest; production volumes are reported as MBbl/d or MMcf/d.

Delaware was the largest planned program: EOG expected approximately 360 net completions, compared with 370 in 2023. Within the basin, it completed 188 Wolfcamp, 140 Bone Spring and 42 Leonard wells in 2023. The company described roughly 4,800 feet of oil-rich stacked pay over its 395,000-net-acre Delaware position and said it would continue co-development. These are company descriptions; they do not show how returns vary across zones or remaining inventory. (S1, Item 1, Delaware discussion.)

In South Texas, EOG reported 172 Eagle Ford and 28 Dorado completions in 2023, and expected 145 and 25 respectively in 2024. The company planned major infrastructure to connect Dorado gas to the Agua Dulce market near Corpus Christi. In the newer Utica play, it reported 435,000 net acres, including 135,000 net mineral acres; after completing six wells in 2023, it expected about 20 in 2024. EOG described Utica testing and Dorado delineation positively, but did not provide in these disclosures a project-level return comparison or a quantified range of geological outcomes. (S1, Item 1, South Texas and Other Areas discussions.)

The 2024 capital and cash-return policies

EOG's Form 10-K estimated 2024 capex at \$6.0-\$6.4 billion, including drilling, facilities, acreage, capitalized interest, dry-hole costs and other property, plant and equipment, but excluding specified categories such as property acquisitions and noncash exchanges. The company's results release summarized the plan at \$6.2 billion; that amount is the midpoint of the 10-K range. The release forecast 3% oil production growth and 7% total-volume growth. These were forecasts, not results. (S1, Item 7, "Capital"; S2.)

EOG said it would focus U.S. drilling on Delaware, Eagle Ford, Dorado and Utica, which it described as its highest-return areas. It expected efficiency gains and some service-cost lock-ins. It also expected to spend on leasing, evaluating prospects, gathering and processing, transportation infrastructure and environmental projects. (S1, Item 7, "Capital.")

Beginning in fiscal 2024, EOG committed to return a minimum of 70% of its annual operating cash before certain balance-sheet changes, less total capital expenditures, through quarterly dividends, special dividends and share repurchases. The threshold had been 60% for 2022 and 2023. The 70% is a floor on the company's stated post-capex cash measure; it is not 70% of revenue or net income and does not prescribe a fixed dividend-versus-buyback split. As capex changes, the cash base used for the commitment changes too. (S1, "Cash Return Framework.")

Exhibit 2. Cash, spending and financial capacity

USD billions unless stated otherwise; fiscal years ended 31 December.

Measure	2022 actual	2023 actual	2024 plan or year-end position
Cash flow from operations before working-capital changes (non-GAAP)	12.252	11.149	-
Total capital expenditures (non-GAAP)	4.607	6.041	6.0-6.4
Free cash flow as defined by EOG (non-GAAP)	7.645	5.108	Depends on actual operating cash and capex
Dividends paid (cash flow statement)	5.148	3.386	Policy: at least 70% of defined annual post-capex cash returned
Treasury stock purchased (cash flow statement)	0.118	1.038	Buybacks are one permitted return method
Cash and cash equivalents at 31 Dec	5.972	5.278	-
Available revolving-credit capacity at 31 Dec 2023	-	-	1.9
Debt / total capitalization at 31 Dec	17%	12%	-

Sources: S1, Item 7, liquidity and cash-return discussion; S2, cash-flow and FCF reconciliation; S2 defines EOG non-GAAP free cash flow as cash flow from operations before working-capital changes less total capex. Cash and revolver values reflect 31 December 2023, not cash

available after 2024 commitments. Values are rounded.

EOG's listed 2024 cash requirements under minimum commitments totaled \$2.206 billion, including \$878 million in transportation and storage commitments, \$873 million in purchase and service obligations and lease items. These are not all capital expenditures, but they limit the assumption that spending can be moved immediately without cost. (S1, Item 7, "Cash Requirements.")

Exhibit 3. Price risk and cash-flow exposure

EOG said it uses swaps, options, swaptions, collars and basis swaps to manage crude, NGL and natural-gas price risk. During 2023, it recorded \$818 million of net mark-to-market gains on financial commodity derivatives, while cash settlements for crude, NGL and natural-gas contracts were net payments of \$112 million. At year-end, the 10-K listed gas price swaps and basis swaps extending into 2024 and 2025. Mark-to-market accounting and cash settlements measure different things. (S1, Note 12, "Risk Management Activities.")

The company's disclosures permit analysis of specific contracts, volumes, indices and maturities; they do not justify treating all production as fully hedged or unhedged. Regional basis, product mix and price realizations remain relevant.

A peer's different allocation

Coterra Energy's 22 February 2024 results release described a different response to commodity fundamentals. Coterra planned \$1.75-\$1.95 billion of 2024 incurred capex, down 12% at the midpoint, with total BOE production expected to decline about 2%, oil up about 6% and natural gas down about 6%. It said it was lowering gas-directed activity and modestly increasing investment in liquids-rich basins, while preserving flexibility to pivot spending. It reported 2023 shareholder returns of 77% of its own non-GAAP free cash flow and a 50%+ return commitment. (S3, release highlights and 2024 outlook.)

Coterra's asset mix, scale, capital program and non-GAAP cash measures differ from EOG's. Its announcement demonstrates one peer's willingness to change basin and product mix; it does not establish a superior choice for EOG.

Investment under uncertainty: evidence students may use

Three academic studies illustrate mechanisms relevant to drilling and inventory, without supplying a coefficient or forecast for EOG:

- **Kellogg (2014)** estimates a dynamic investment model with Texas oil-drilling data and futures-options-implied oil-price volatility. Drilling responses were consistent in magnitude with the model's optimal response to volatility; the paper also finds that ignoring volatility shocks can be costly. This is evidence on investment timing in Texas, not an EOG basin allocation rule.
- **Doshi, Kumar and Yerramilli (2018)** analyze quarterly data for 197 U.S. upstream firms from 1990-2013 and hand-collected hedging for 126 of them. Higher oil-price uncertainty is associated with lower capital spending in the pooled sample, but the largest firm-size quartile increases hedging intensity without lowering capex; the negative association is concentrated among smaller firms and is weaker for firms that hedge. EOG's own size, financing and hedging details therefore matter.

- **Smith (2018)** estimates a remaining economic supply curve using 12,376 North Dakota Bakken horizontal fractured wells drilled during 2006-2015. The model accounts for resource depletion, selective drilling and assumed efficiency gains; under its assumptions it estimates roughly 8 billion barrels could be economic near \$50 per barrel. That is a Bakken result, not an estimate of EOG's inventory. Its assumptions about site selection and fracking efficiency show why acreage and raw well productivity alone can mislead.

Full citations, publication details, links and precise source versions appear in the sources below. These summaries report the studies' methods and findings; they do not resolve how EOG should allocate marginal capital.

Decision questions

1. Which option would you recommend, and what is the strongest argument against it?
2. Which activity should be protected first if expected cash flow weakens: core wells, appraisal wells, infrastructure, or the stated shareholder-return floor? Explain any contractual limits.
3. What technical and commercial gates would you set for the Utica step-up or Dorado connection? What evidence would trigger a stop, continue or scale decision?
4. How should the 70% commitment affect capital allocation? Distinguish the policy's post-capex cash base from a payout of revenue or earnings.
5. What two or three operating, market-access, financial or learning indicators should the committee monitor? State when each would cause you to revise the recommendation.

Sources

Company and competitor filings

- **S1.** EOG Resources, Inc., *2023 Form 10-K*, filed 22 February 2024, year ended 31 December 2023, SEC accession 0000821189-24-000011. [Full filing](#). Key locators: Item 1, “Business,” HTML lines 136-178; Item 7, “Capital” and “Cash Requirements,” lines 1344-1372; liquidity and cash-return framework, lines 1084-1099; Note 12, derivative contracts, lines 2520-2557.
- **S2.** EOG Resources, Inc., *Fourth Quarter 2023 Results and 2024 Forecast*, Exhibit 99.1 to Form 8-K, filed 22 February 2024, SEC accession 0000821189-24-000009. [Release](#); [8-K](#). Key locators: opening summary graphic; release page 18 financing cash flows; page 35 cash-flow from operations and free-cash-flow reconciliation.
- **S3.** Coterra Energy Inc., *Fourth-Quarter and Full-Year 2023 Results, Provides 2024 Outlook, and Announces Dividend Increase*, Exhibit 99.1, 22 February 2024, SEC accession 0000858470-24-000006. [Release](#). Key locators: release pp. 1-3 / HTML lines 5-23 and 57-74.

Academic studies

- **A1.** Ryan Kellogg, “The Effect of Uncertainty on Investment: Evidence from Texas Oil Drilling,” *American Economic Review* 104, no. 6 (June 2014): 1698-1734. [Article and full text](#); [author-hosted PDF](#). Relevant sections: dynamic investment model, data and empirical results.
- **A2.** Hitesh Doshi, Praveen Kumar, and Vijay Yerramilli, “Uncertainty, Capital Investment, and Risk Management,” *Management Science* 64, no. 12 (2018): 5769-5786. DOI [10.1287/mnsc.2017.2815](#). [Article](#); [authors' full-text PDF](#). Relevant sections: sample/methods, capex and size heterogeneity, hedging and conclusion.
- **A3.** James L. Smith, “Estimating the Future Supply of Shale Oil: A Bakken Case Study,” *Energy Economics* 69 (2018): 395-403. DOI [10.1016/j.eneco.2017.11.026](#). [Published article page](#); [full CEEPR working paper](#). Relevant sections: model and assumptions, 2006-2015 North Dakota sample, estimates, sensitivity and limitations.