# EOG Earnings Call Transcript

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## Quarter: 2

Operator: Good day, everyone, and welcome to EOG Resources Second Quarter 2025 Earnings Results Conference Call. As a reminder, this call is being recorded. For opening remarks and introductions, I will turn the call over to EOG Resources Vice President of Investor Relations, Mr. Pearce Hammond. Please go ahead, sir.
Pearce Wheless Hammond: Good morning, and thank you for joining us for the EOG Resources Second Quarter 2025 Earnings Conference Call. I'm Pearce Hammond, Vice President, Investor Relations. An updated investor presentation has been posted to the Investor Relations section of our website, and we will reference certain slides during today's discussion. A replay of this call will be available on our website beginning later today. As a reminder, this conference call includes forward-looking statements. Factors that could cause our actual results to differ materially from those in our forward-looking statements have been outlined in the earnings release and EOG's SEC filings. This conference call may also contain certain historical and forward-looking non-GAAP financial measures. Definitions and reconciliation schedules for these non-GAAP measures and related discussion can be found on the Investor Relations section of EOG's website. In addition, some of the reserve estimates on this conference call may include estimated potential reserves as well as estimated resource potential not necessarily calculated in accordance with the SEC's reserve reporting guidelines. Participating on the call this morning are Ezra Yacob, Chairman and Chief Executive Officer; Jeff Leitzell, Chief Operating Officer; Ann Janssen, Chief Financial Officer; and Keith Trasko, Senior Vice President, Exploration and Production. Here's Ezra.
Ezra Y. Yacob: Thanks, Pearce. Good morning, and thank you for joining us. EOG delivered another quarter of outstanding results, reflecting the focused execution of our employees across our multi-basin portfolio. In the second quarter, oil, natural gas and NGL volumes came in above the midpoint of our guidance. At the same time, we drove our capital expenditures, cash operating costs and DD&A; below guidance midpoints, demonstrating the efficiency and operational excellence that is a hallmark of EOG. Our teams continue to find ways to optimize operations, improve well performance and safely deliver volumes while maintaining capital discipline. Strong operational performance once again translated directly into impressive financial results. We generated nearly $1 billion of free cash flow during the quarter. And between our regular dividend and $600 million of opportunistic share repurchases, we returned more than $1.1 billion to our shareholders. Consistent with our long-standing cash return commitment, we have committed to return at least $3.5 billion in cash during 2025, inclusive of our regular dividend and nearly $1.4 billion of year-to- date share repurchases, reflecting our confidence in the growing value of our business. Our confidence in the future of the company is also reflected in the 5% increase in our regular dividend, which we announced in connection with the Encino acquisition in May. This marks another step forward in our remarkable dividend growth track record. Over the past decade, we have increased our regular dividend at a 19% compound annual growth rate, far outpacing the peer group average. More importantly, we have never cut nor suspended the dividend in 27 years. This sustained record of dividend growth highlights both the durability of our business and our unwavering focus on delivering shareholder value. Last week, we closed the accretive Encino acquisition, marking a major milestone for EOG. With a total core acreage position of 1.1 million net acres and associated resource potential net to the company of 2-plus billion barrels of oil equivalent,

the Utica has become a foundational EOG asset alongside the Delaware Basin and Eagle Ford. In aggregate, EOG is net resource potential totaling over 12 billion barrels of oil equivalent across our multi-basin portfolio. This top-tier resource base generates a greater than 55% average direct after-tax rate of return at bottom cycle prices and over 200% after-tax rate of return at mid-cycle prices, providing our investors one of the deepest and highest quality inventory positions. We are focused on the safe and rapid integration of the Encino assets into our portfolio. We remain highly confident in the value creation opportunity before us in the Utica and believe that through effective integration and the application of EOG's operating model and proprietary technology, the Utica will be a major contributor to both growth and returns. We look forward to sharing more as we capitalize on the advantages this transaction brings to shareholders. On the international front, in the second quarter, we were awarded an onshore concession to explore and appraise an approximately 900,000-acre unconventional oil exploration prospect in the UAE. We are very excited about this new opportunity that will allow us to leverage our technical expertise and extensive data set from drilling thousands of unconventional wells across a wide variety of plays. The UAE and our Bapco joint venture in Bahrain form an exciting long-term business opportunity for EOG in the Gulf States. Our results through the first half of 2025 serve as a powerful affirmation of EOG's enduring value proposition. We're committed to being among the highest return, lowest cost producers, recognized for leading environmental performance and a steadfast role in meeting the world's long-term energy needs. Four pillars underpin our differentiated strategy, capital discipline, operational excellence, sustainability and culture. As we look at new opportunities in our portfolio from the Encino acquisition to the expansion in the Gulf States, we believe operational excellence will be a key differentiator to enhance returns as we utilize our in-house technical expertise, proprietary information technology and self-sourced materials to drive superior well performance and reduce costs. Turning now to supply and demand fundamentals. While first quarter oil demand was stronger than forecast and second quarter oil demand also benefited from delays in the implementation of tariffs, growth in demand for the second half of 2025 is expected to moderate before beginning to increase throughout 2026. On the supply side, we expect spare capacity returning to the market to allow inventory levels to build from historically low levels. This reduction in spare capacity, coupled with current demand forecasts, paves the way for pricing to strengthen on the back of a more fundamentally driven market. On natural gas, 2025 is an inflection year, driven by an uptick in U.S. LNG feed gas demand. We expect a 4% to 6% compound annual growth rate for U.S. natural gas demand through 2030, driven primarily by LNG and power demand. Our investment in Dorado to develop a stand-alone gas asset that complements our oil assets as EOG prime to deliver supply into these growing markets. EOG is better positioned than ever before to create value for our shareholders. Our portfolio expansion, including Encino, the UAE, Bahrain and additional exploration opportunities is adding significant new resource potential for our shareholders, while we simultaneously continue to improve and expand our existing resource through applying technology to reduce costs, improve well performance and unlock additional well locations. And at the same time, delivering robust cash return to our shareholders and maintaining a pristine balance sheet, allowing for continued investment in high-return projects, generating strong current and future free cash flow. Now here's Ann with a detailed review of our financial performance.

Ann D. Janssen: Thanks, Ezra. We delivered another strong quarter with adjusted earnings per share of $2.32 and adjusted cash flow per share of $4.57. Second quarter free cash flow was $973 million. We provided robust cash returns to our shareholders in the second quarter, anchored by our sustainable regular dividend of over $500 million and complemented by share buybacks of $600 million. In the second quarter, in connection with our Encino acquisition announcement, we declared a 5% increase in our regular dividend. The new indicated annual dividend rate is $4.08 per share, which is a 3.5% dividend yield at our current share price, far in excess of the average dividend yield for the S&P; 500. Regarding future cash returns, we expect to return a similar level of free cash flow as we have the last couple of years. We continue to favor buybacks as a source of additional cash return beyond our regular dividend, and we'll monitor the market for opportunities to step in and repurchase shares. Since initiating buybacks in 2023, we have repurchased over 46 million shares, which is approximately 8% of shares outstanding or a total of $5.5 billion. We have $4.5 billion remaining on our buyback authorization. In May, we announced the $5.6 billion acquisition of Encino, which was funded at closing on August 1 with cash on hand and debt. On July 1, we issued $3.5 billion of senior notes with proceeds directed towards the Encino acquisition. This issuance consisted of 4 tranches: $500 million due in 3 years, $1.25 billion due in 7 years, $1.25 billion due in 10.5 years and $500 million due in 30 years. The weighted average maturity of the senior notes is approximately 11 years with a weighted average coupon of 5.175%. We were extremely pleased with the investor response to the notes offering as it demonstrates their confidence in EOG's long-term outlook. Our updated guidance reflects ownership of Encino for the 5 remaining months of 2025. At assumed prices of $65 WTI and $3.50 Henry Hub, we expect to generate $4.3 billion in free cash flow in 2025, which adjusted for commodity price changes is 10% higher than our forecast last quarter. This higher free cash flow reflects not only the Encino acquisition, but also modest efficiency gains and lower cash taxes due to recent tax legislation. The last few months have been transformational for EOG, and the company is exceptionally well positioned from a balance sheet and cash generation standpoint to further reward shareholders in the future. Now here's Jeff to review operating results.

Jeffrey R. Leitzell: Thanks, Ann. Let me begin by thanking every member of our team for the outstanding execution across the organization this quarter. Your dedication and diligence were especially evident both in our core operations and in preparing for the successful acquisition and the work on integrating Encino. This marks another quarter where our operational excellence was a driving force, positioning us to capture new opportunities and deliver meaningful results for our shareholders. Our performance in the second quarter stands out across nearly every operational metric. Once again, we outperformed both our production and cost expectations. Oil, gas and NGL volumes exceeded forecast, powered by continued momentum across our foundational assets. Additionally, we saw better-than-expected gas and NGL volumes in the Powder River Basin. Cash costs were below the midpoint of guidance. Lease operating expense was the largest contributor with beats across all basins. This was a direct result of enhanced efficiencies in workover execution and overall lease and well maintenance. The incremental barrels associated with our volume beat further supports lower unit costs, underscoring our operational leverage and the collective impact of strong execution throughout the organization. On capital spending, we delivered lower-than-expected capital CapEx this quarter, primarily driven by efficiency gains across our operating areas as well as the deferral of some indirect spending into the back half of the year. We're seeing the benefit of careful planning, disciplined execution and real-time efficiency measures that are translating directly into tangible savings. With the closing of the Encino acquisition just a week ago, we have updated our 2025 CapEx and production guidance to include Encino's planned activity for the last 5 months of 2025 and the underlying improvements in our business. Our new full year 2025 CapEx guidance is $6.3 billion with forecasted full year average oil production of 521,000 barrels of oil per day and average total production of 1,224,000 barrels of oil equivalent per day. Relative to the midpoint of our guidance last quarter, full year 2025 CapEx is increasing by 5%, while full year 2025 average daily total production is increasing by 9%. Our operating teams are working swiftly and efficiently to fold the Encino team into the EOG organization. The initial transition is progressing better than anticipated, and we're highly encouraged by the early collaboration between teams and the utilization of technology to increase data integration, both in the office and across the field. Looking at our pro forma Utica activity, we are layering Encino's activity on top of our existing program, and we plan to run 5 rigs and 3 completion crews in the basin through the remainder of the year. This tempo will maximize value for Encino's high-quality acreage while leveraging the best practices and technical expertise from both companies. We expect at least $150 million in annual run rate synergies within the first year post close. These savings are largely attributed to well cost with a smaller contribution from targeted G&A; reductions. For context, EOG's average well cost in the Utica are less than $650 per foot compared to Encino's $750 per foot. We see clear line of sight to bring well costs in line with EOG's leading-edge D&C; cost quickly and efficiently. We're optimistic about the upside potential as our teams begin to work on the Encino assets and apply EOG's operational model. We see incremental opportunities from further optimizing location construction costs, enhancing infrastructure utilization, optimizing marketing agreements and deploying innovations from in-basin sand to advanced water recycling and evaporation technologies as well as employing our optimizer technology on the combined production base. We are confident in our ability to unlock additional synergies and drive sustained value creation. In our investor deck, on Slide 8, we highlight just how attractive the Utica is and why we are excited to add this play to our current foundational assets, the Delaware Basin and Eagle Ford. With just 50-plus net wells developed in the Utica, we are already realizing payback periods less than a year, driven by low total well costs and highly productive results. While it's too early to discuss specifics on 2026 plans, the Utica is now part of our foundational operating areas, and we will continue to invest at a pace to improve the asset. Turning to Dorado. Our high-intensity completion designs are continuing to deliver superior results with individual well production outpacing our forecast. The team is also continuing to drive efficiencies through success with the EOG drilling motor program and most recently by eliminating a string of casing in many of our Austin Chalk targets. This has helped to increase drilled feet per day by more than 20% in the first half of the year versus 2024 and reinforces our view of Dorado as the lowest cost dry gas asset in the U.S. We expect our Dorado production on a gross basis to reach approximately 750 million cubic feet per day exiting 2025. With our Verde Pipeline in service, which has a 1 Bcf per day capacity and is easily expandable to 1.5 Bcf per day, our Dorado asset is well positioned to capture incremental gas demand in 2026 and beyond. Focusing on the Eagle Ford and Permian, our teams continue to push extended laterals and are realizing the benefit in both efficiencies and well cost. In the Eagle Ford, we drilled the longest lateral in Texas history in the second quarter. The Whistler E #5H had 24,128 feet of treatable lateral or nearly 4.6 miles. In the Permian, we have increased our average lateral length by over 20% year-over-year, and this has helped us realize a 10% increase in drilled footage per day versus 2024. These are just a few examples of how our teams are focused on driving sustainable efficiencies to lower well costs, further enhancing returns. With regards to well costs, as activity levels have moderated across the industry, we're now seeing some softening in the service cost environment, more so for lower quality equipment. As a reminder, we focus on contracting high-quality crews and equipment where pricing has been more stable. As we turn to the back half of the year, we will look for opportunities within our current services to take advantage of any potential softening in the market with a focus on retaining top-tier high-spec services to continue to drive operational efficiencies. We continue to advance our business through technology, and I'm excited to discuss 2 new proprietary technology platforms for EOG. The first platform uses high-frequency sensors that captures and processes subsurface data while drilling wells. These sensors allow us to calculate geomechanical rock properties, identifying faulting, local stresses and also monitor downhole equipment performance to minimize downtime. Also, we are able to improve our completion designs through fracture identification, minimising our -- maximizing our frac efficiency within the zone of interest. By integrating this high-resolution data with our traditional data sets, we've achieved improvements in well performance and cost efficiency. This year, over 50 wells have already benefited from this higher resolution data, and we will look to expand its use across our portfolio. The second platform centers on our enhanced AI capabilities. Building on years of utilizing machine learning for production optimization and cost savings, we have now deployed our proprietary generative AI system. This platform is already enabling field and division staff to collaborate more efficiently, automate and capture data more easily and gain operational insights across all operations. After a strong first half of the year, EOG is well positioned to execute on its full year plan, and we're excited about the opportunities in front of us. Now I'll hand it back to Ezra to wrap it up.

Ezra Y. Yacob: Thanks, Jeff. Let me highlight a few key points from the second quarter. First, our team delivered outstanding execution with operational results exceeding expectations. Second, our strong operational performance translated directly into impressive financial results and strong cash returns. Through the first half of the year, we have committed to return more than $3.5 billion of free cash flow to investors through our regular dividend, which we have increased by 5% and through share buybacks. Third, with the Encino transaction now closed, we are updating our 2025 guidance to reflect both the expanded portfolio and momentum across the basins. We are confident in the transformative impact of the Utica, which we believe will serve as a foundational asset for years to come. In addition, we are excited about our ongoing exploration efforts, both domestic and especially in the new international concessions we have captured this year. Fourth, looking ahead, our performance in the first half of 2025 reflects the enduring strength of EOG's value proposition, capital discipline, operational excellence, sustainability and a high-performing culture. Our business is better positioned than ever to create value for our shareholders. Thanks for listening. We'll now go to Q&A.;

Operator: [Operator Instructions] The first question is from Arun Jayaram with JPMorgan.
Arun Jayaram: My first question is on the Utica. Ezra, when you provided the acquisition deck, you highlighted, call it, pro forma production at 275 MBoe per day for both EOG and Encino. My question is if you could talk about the sustaining capital requirements to sustain that level of production from a capital or activity standpoint? And would you expect a, call it, a 5-rig, 3 completion crew cadence to deliver growth from the Utica?
Ezra Y. Yacob: Yes. Arun, thanks for the question. So you're right. We are very excited that we were able to close a little bit earlier than anticipated. As you mentioned, we closed last week. And so with regard to pro forma sustaining capital, for the rest of this year, we are layering on top of our activity levels, the ongoing Encino plan. But to be honest, I think it's going to be just a little bit early for us to kind of lean in on what the activity looks like. We do have lower well costs than Encino. And dominantly, that's not necessarily contracts, that's dominantly from operational efficiency gains. And so there should be a little bit of incremental synergies and savings with regard to that. But ultimately, when it comes to our sustaining CapEx, we'd like to get in there and operate the asset for just a little bit longer than a week. In the first rollout, we've already seen as we brought the asset in-house, and we've started to roll out some of our technologies, things like our production optimizers, as a matter of fact, we've actually already started to see a lot of upside that we can capture in the field. And so I'd hate to speak a little bit too early. What I will point out is last November, we released our sustaining capital for what I guess now would be kind of legacy EOG. And that capital range was about $4.3 billion to $4.9 billion. And that range is something important to think about because it -- for a multi- basin company like ours that has not only oil and associated gas, but also stand-alone gas assets, maintenance capital is a little bit difficult to pin down. And what I mean is, are we talking about just keeping oil volumes flat or natural gas volumes flat? Are we still investing in exploration and things of that nature. And the new Utica asset falls right into that. As you know, we're very focused on the volatile oil window, which really drives the returns for us. But that asset does come with a very attractive dry gas position. which gives us a great option as the demand increases there. And so really thinking through where our investments are, what the macro environment looks like, that's going to be kind of the more important thing that we will contemplate how much we invest and what the activity levels would be.
Arun Jayaram: Great. My follow-up is, Ezra, I was wondering if you could give us a sense of your geological concept and potential path to commercial development in the UAE. And do you view the risk here more on the geological front, cost front or a little both?
Ezra Y. Yacob: Yes. Fantastic, Arun. We couldn't be more excited about this concession in the UAE. This is actually a reservoir that we've been working on for a number of years really. And the path to getting commercial contract terms that kind of work for everybody and getting stakeholder alignment really came together here in the last 12 months. So it's a shale play. It's a carbonate shale, maybe similar geologically in some regards to the Eagle Ford play. It has been drilled and delineated both vertically and horizontally throughout the basin, not throughout the entire basin, but throughout a portion of the basin where our concession is. And so we've got good geological data on it. We don't have significant production data. They have tested oil to the surface. But that is something that we think we can improve upon with the combination of our data set from the North American unconventional plays, our petrophysical models, our combination of log and core data. But then also combining that with our understanding of geomechanical properties and how horizontal completions really match up with the landing zones that we target. I would say the challenge that we have in front of us is not necessarily on the geologic side. It's going to be more on bringing an international unconventional play up to scale. I think everyone has seen that what really makes these plays attractive and what makes them work is having your infrastructure, your supply chain, your logistics worked out. That's really -- scale is important in each of these plays, and we certainly have the exposure to scale here. But as an initial large-scale unconventional resource play in the UAE, that's the one that we'll be focused on is how quickly can we get the production uplift that we think from our -- applying our techniques, but then also how quickly can we drive down those costs.
Operator: The next question is from Steve Richardson with Evercore ISI.
Stephen I. Richardson: I was wondering if you could talk a little bit about how you think about the gas

market, Ezra and your marketing strategy. I mean we're seeing counterparties willing to sign what seems to be multiyear contracts. You seem to be accepting of where the market is on the demand outlook being really robust here. So how does that play into how you're thinking about your marketing strategy? Are we likely to see EOG enter into those types of contracts now that you've got the Utica dry gas volumes that you just mentioned in-house? Like are you likely to do that? Or are we likely to see more of the same of you just being really thoughtful about what markets you want to get your gas to and continue to realize really high realizations?

Ezra Y. Yacob: Yes, Steve, it's a great question. It's very topical right now because I think everyone is seeing the increased demand for natural gas coming not only from power, which is maybe a little bit more of what you're referencing, but also just LNG in general. And like I said in the opening remarks, and we've been saying for a while, 2025 is kind of the inflection point on that. So I like that you pointed out, we have 2 kind of dedicated gas assets, and that's where some of these agreements begin with, whether it's LNG or power demand. Because when you're making these long-term commitments, I think what we've seen in discussions with LNG and discussions with hyperscalers is sometimes it's a little bit difficult to get comfortable with a 10- or 15- or 20-year agreement if you're only talking about associated gas. And so right off the bat, this tremendous gas business, if you will, that we've built internal to EOG and alongside our oil business is very well positioned to service that out of Dorado and the Utica. I do think we'll continue to be thoughtful. I appreciate how you phrased that. I think what we look for with any marketing agreement is we start with good partners. We look for agreements that align all the parties involved, so good stakeholder alignment. And then we're always focused on getting exposure to premium pricing. Just signing up a takeaway for essentially a differential based or a pricing mechanism that includes a differential. There's some value there to have diverse markets. But really, when we -- what we think we've captured is assets that can deliver low cost consistently to these projects. And so I think we deserve to be paid at least a bit of a premium to that. As we've done with our LNG terms, we like the diversity of different pricing mechanisms, and we can get creative with that. But yes, Steve, as we look at some of these opportunities, whether it's hyperscalers or increased LNG, we think we're very well positioned to capture the upside with either of our 2 assets.

Stephen I. Richardson: Great. And then maybe just staying on midstream strategy, Utica, now you have more curious on the oil side and the liquids side. But can you maybe talk about the opportunity to come up with a better solution for those barrels, improve pricing and maybe what we should expect from a time line of when you might have one of those solutions in place?

Jeffrey R. Leitzell: Yes, Steve, this is Jeff. Yes, we really -- we're excited to get our marketing team up there because I think that's really where we're going to make the most headway so they can start working on the asset and that Utica production. We have a superb track record of improving the realizations over time in all of our assets, and that's going to be our primary focus when we get up there. So I think one of the big things that we need to look at is the differentials in the area. Obviously, they are slightly more narrow than what EOG consolidated are, the Encino was. So what that really just reflects is the wider Utica oil dips versus kind of our legacy stuff. I mean, when you look at the Eagle Ford and the Delaware where we've been operating for quite a while. A really good example of how we can improve that is, I mean, take a look at the Delaware. I mean, over the last decade, I think we've improved our oil differentials close to $6. So we've definitely got a track record of being able to do that. And then with any play, I think with time and maturity, we'll be able to improve those differentials, especially with the scale that we get from this acquisition. And then one last thing that I'd just point out, I talked about a new slide in our deck in our opening remarks, Slide 8. And what that shows is it shows the Utica payout period, and it's about 9.3 months, which is right with the Permian. And what I'd say is that all of this is actually built into that, all of the diffs and the other operating expenses. So that's in the metrics, and it's obviously extremely competitive within the portfolio and other conventional plays. I'd say another place that we can really move the needle is going to be on the GP&T; side. Obviously, primarily, we'll work with our midstream providers up there. We'll make sure we're capturing better rates, both in the Utica as well as we'll utilize our position in our multi-basin portfolio. The Utica, we've got fantastic long-term relationships with the midstream companies that are up there. So ultimately, our goal will be to really seek for win-win deals for both parties. And over the last handful of years, just the 50 wells or so that we've drilled there in the Utica, we've had great success in lowering the GP&T; cost in a short period of time. So as I said, same with the Dips with this kind of scale and the larger footprint, we really think that's going to help out a lot. Another few notes just to kind of take into account. I mean, with the increased GP&T; that we have with the asset, it's offset really by the LOE, the G&A; and the DD&A;, if you look at it, they're actually quite a big reduction across the board there. And then also, just keep in mind that some of the increases in GP&T; really reflects the firm gas transportation that we got from Encino, which that firm transport moves Utica gas to premium markets really resulting in much higher price realizations. And then lastly, just Ohio as a whole, they're an outstanding place to do business and very, very friendly from that aspect. And the Utica taxes other than income, we call it TOTI, they're actually lower than the average of EOG's multi-basin portfolio. And that right off the bat really helps offset some of those higher dips in GP&T.; So I think we've got a long runway, and we'll have a lot of improvement when it comes to the marketing strategy up there in the Utica.

Operator: The next question is from Neil Mehta with Goldman Sachs & Company.

Neil Singhvi Mehta: I just want to start off on cash tax benefits with changes in legislation. You indicated that it's supporting the free cash flow, but can you help us quantify the impact over the next couple of years?

Ann D. Janssen: Yes. Thanks, Neil. This is Ann. The recent tax legislation is going to help us out. The one big, beautiful bill has some positive impact for EOG. The bill restores 100% of the bonus depreciation permanently and additionally, restores 100% deductibility of the research and experimental cost, again, permanently. For 2025, the impact of the one big, beautiful bill for EOG is approximately $200 million, and we expect that amount to be a recurring benefit in future years. So penciling $200 million is reasonable. Always keep in mind that there are numerous variables that can impact our tax rates and our profiles in any given period. But we expect that kind of a $200 million is kind of going to be a run rate for the next couple of years.

Neil Singhvi Mehta: And then Ezra, just -- I always value your views on the oil macro, and you guys have been rightly cautious here. Just your perspective about the -- how the balances build through the balance -- the back end of the year and into 2026 on the crude side, in particular, a lot of moving pieces, particularly around Russia right now. But your perspective from your Market Intelligence group would be great.

Ezra Y. Yacob: Yes, Neil. Yes, it's very topical right now. There are a lot of moving parts, as you discussed. And I'm not sure with regards to Russia or India. I'm not sure if anyone knows exactly how that's going to play out. But the data that we do have in front of us shows that if I start on the demand side, as I said in the opening remarks, demand in Q1, which is typically a little bit seasonally softer, was really pretty strong. And then demand too, while it was volatile with some of the announcements on potential tariffs and how those would implement, where they would exactly land, just like any change in policy, you saw a little bit of volatility in there. But ultimately, the implementation, not only was it delayed, but I think it was at levels that were somewhat more priced in. And so you saw even demand in Q2 was a bit strong. And you started to see demand revisions throughout the year for 2025 and some of that coming out of China as well. So indications that you've got China doing a bit better year-over-year. We still have modest decline based on -- or I'm sorry, demand growth based on historical levels for year-over-year growth in '25. And then we continue to see the demand growth increasing into '26. So a little bit stronger demand growth in '26 than over '25. So the demand side looks -- the back half maybe flattening out, maybe not as much demand growth, but still strong demand. And then that brings us to the supply side, which there's been a lot of speculation on how and when and how is the spare capacity going to hit. And I think the most important thing to touch on is where we're at with inventory levels, historically, very, very low. And so we think the first thing for that spare capacity is obviously, it's going to fill into the inventory levels and bring those up back to more of in line along the 5-year average or slightly above the 5-year average since we've been running at a deficit the last couple of years with the spare capacity being higher than usual. But ultimately, once we get through the next quarter or 2, maybe seasonally demand weakness in Q1, we actually find ourselves looking at a potentially balanced market going forward. And what we see is less non-OPEC supply growth coming on in the next couple of years than what we've seen. And so it really sets up. That's why I said in the opening remarks that we start to see in 2026, you arrive at a spot where pricing is likely more driven by fundamentals without as much spare capacity offline and a market in general that looks more balanced in '26 than it does today.

Operator: The next question is from Douglas Leggate with Wolfe Research.

Douglas George Blyth Leggate: Ezra, I sometimes have trouble recognizing my name, but there you go. I wonder if I could come back to the Utica and just ask the question a little differently. Arun already hit the maintenance capital question or sustaining capital question. My question is, when you lay out the synergies the way you talked about it, the $100 per foot, obviously, you're going to manage the midstream differently. My question is, what is your objective for the Utica? And what are the constraints around that? In other words, what would it grow if you kept the 5 rigs in place? Do you have the midstream takeaway to make that happen? And I guess I'm really trying to get to -- it sounds like you can do a lot more with less and still grow the business on lower spending. Am I thinking about that right?

Ezra Y. Yacob: Yes, Doug Leggate, this is Ezra. It's good to hear from you. Yes, thanks for the question. I think you're right. The Utica in general, we consider it to be a growth asset for the company going forward and one that can grow for years to come. We have -- the midstream is there. Just like any of our plays, we'll need to continue to build out in-basin gathering and continue to look at midstream agreements, the same as any other play. But no, there are no large bottlenecks or anything like that. The legacy rig or frac contracts or anything else that might be there, those are really in line with ours. Encino, as we've talked about, I think I talked about in May, Encino did a good job with the asset. They had some of the same focuses that we had as far as focusing on high-quality rigs and high-quality people. It's just the fact of the matter that we're bringing a little bit more of our supply chain knowledge, our own technical abilities in-house really stems from the data that we have from drilling so many horizontal wells across the U.S. that we can drive down those costs. And so when we look at the first year kind of synergies that we talked about, that $150 million, I think there's a lot of upside to that number. Now as far as do we turn that thing immediately into growth, Doug, I think you know better than anyone that output really does need to be -- the growth needs to be incremental markets are being driven by spare capacity offline and things like that. So part of what will contemplate how much we invest in the activity levels in the Utica comes back to what does the macro environment look like. Right now, as I just finished up talking about so much spare capacity coming back online and demand looking solid. I'm not sure quite yet even if maybe in the next year, if it's going to be the right opportunity to really hammer the gas and invest pretty aggressively in growth. But it's a dynamic market, and we'll see.

Douglas George Blyth Leggate: That's a great answer. And my follow-up is I want to -- it's a philosophical question. I just want to -- maybe it's for you or for Ann. But look, your dividend yield, as you pointed out, is 3.5%. Most everybody on this call asking questions today is an E&P; analyst. You have the balance sheet of a major, you have the scale of a major, you have the asset depth of a major and now you've got the dividend policy of a major. So my question is, how should we think about translating that free cash flow from Encino and from the portfolio generally towards your priorities for free cash, specifically your policy on dividend growth per share? And I'll leave it there.

Ezra Y. Yacob: Doug, that's a good question. When we look at growing the regular dividend, I appreciate the metrics you just put out there. Because it is something that we focus on is making it not only competitive across our peer group, competitive with the majors in our peer group, but we also look at it competitive with the broad market. We do think that EOG is quickly turning into just about one of the only pure upstream E&Ps; that can really act like a blue-chip stock. And so our commitment to that regular dividend and growing it in a disciplined manner is the #1 priority. And we support that, obviously, with a pristine balance sheet, which even after this acquisition, we still maintain. We maintain our total debt levels versus EBITDA at roughly 1x at $45 oil and $2.50 natural gas, so at the bottom of the cycle. What that means for our excess cash return is which we've developed a pretty solid track record now of returning that excess cash return through special dividends or more recently through buybacks is that we can continue down that same policy. And I think we see opportunities for that in our stock right now and opportunities not only in ours, but really across the industry. I'm not sure if the earnings or the profitability of the industry, especially through this earnings season is being really reflected in Energy's weighting in the S&P; 500. But especially with respect to EOG, our inventory quality and depth that supports high returns and free cash flow generation, both in the short and long term, our strong balance sheet, our competitive regular dividend, our track record on excess cash return, some of our new exciting exploration potential, both domestically and internationally. And then these 2 new transformative items for the company that we've talked about today in the Utica, especially with the acquisition of Encino. And then really, the coming out party here for our gas business in Dorado and the Utica dry gas, I'm not sure if we -- those things are being correctly valued in the current valuation of the company. And so those are the things that provide us the opportunities when we look at buy back stock, such confidence to step in and buy back those shares.

Operator: The next question is from Scott Hanold with RBC Capital Markets.

Scott Michael Hanold: Can I touch on the Utica real quick? And it sounds like based on your conversations, you all layered on Encino's plans for the -- effectively the second half of the year in terms of how you guided. I'm curious, are there going to be some quick wins that you guys can take on? You certainly have better operational costs and stuff like that. Could there be some upside in performance and cost as you get in there? So what are the quick wins? And if you can give us a sense of when are the fully -- first fully engineered drilled and completed EOG wells, when do those start coming online?

Jeffrey R. Leitzell: Scott, this is Jeff. Yes, we -- as far as the upside, I mean, we see a ton of it. It's obviously on the well cost side. It's on the production performance side. I can give you just a handful of kind of examples here. But just on the logistics and planning, we've got boots on the ground out there with the former Encino employees now with EOG, and we're seeing a lot of opportunities as far as shared infrastructure with pads and gathering systems, facilities. There's a lot of wellsite facilities. We tend to do consolidated facilities, which is going to help a lot. And then I talked a lot about the upside on the midstream. So that's going to be big. On the operations side, I think utilizing EOG technology is going to be huge. We'll get in there, the EOG motors, EOG mud cutters. Our supply chain, obviously, that's going to be a big benefit there. We're looking to do exactly what we've done in all the other basins, too, with a lot of our sourcing. We're going to have close to the well in-basin sand sourcing. We're going to have water recycling. And then obviously, we'll be able to drill longer laterals just with the new acreage footprint that we have that will obviously push a lot lower cost. And then as Ezra talked about earlier, on the production optimization side, we've got a lot of upside there, just utilizing our data, implementing our optimizers, which are going in very, very quickly. And so that's something I think we'll see in the next couple of months. And just applying our expertise and technology from outside the basin, how we share across from each one of our divisions, getting that up to scale, we just see a lot, a lot of upside there in the Utica.

Scott Michael Hanold: Okay. Sounds exciting. My follow-up, and it's probably again for you, Jeff. You talked about 50 wells that you all drilled and completed utilizing, the higher resolution data and sensors and whatnot. Can you give us a sense of what does that translate into, right? So what is the cost to implement that versus maybe D&C; savings and improved EURs? So the bottom line is how meaningful can this be if you expanded it to your entire asset base?

Jeffrey R. Leitzell: Yes. It's very early in the game with the HiFi sensors. But I will say we're extremely excited about it. We're just kind of scratching the surface right now, and we're finding ways every single day that we can probably apply it kind of across the whole portfolio. So just from a cost side, so what we actually did is we acquired this IP at the end of last year, and it just included some software and some patents from a commercial company. And then we've just taken that technology. We've cheapened it up. It doesn't cost very much to run per well. So the costs are pretty low on it. And we've improved the algorithms within the system. And we've integrated all of our EOG data and then basically just started applying it to all of our wells out there. And what it really allows us to do is more than just our precision targeting using gamma ray and kind of staying in zone, we're able to calculate geomechanical properties of the actual rock that we're drilling through. On different downhole drilling parameters on our bottom hole assembly and what we're seeing, identifying faults and fractures, which obviously is going to be huge through the drilling and completion process and then even equipment failures downhole. If we start to get some kind of vibration downhole, we can identify it and we can basically have an ability to be able to trip and minimize any kind of downtime there. So I mean, the upside on this, it's very, very early days, but we see a long, long runway with this. And I think the longer that our team has it in their hands and we're able to see different areas in the field that we're able to apply it and our IS team is to work with it. I think this is going to be a really big needle mover for us from an efficiency standpoint moving forward.

Operator: The next question is from Phillip Jungwirth with BMO.

Phillip J. Jungwirth: In the Delaware, you mentioned adding 9 distinct targets to the development program over the last 5 years. I was just hoping you could give some detail here on the delineation. And in Lea County specifically, what's the maximum wells per DSU you think you can get to now and still meet your premium return hurdle?

Keith P. Trasko: This is Keith. So yes, the zones and targets that we develop in the Delaware Basin, they are going to vary in any given year as we continue to execute our co-development strategy. So one thing we've noticed is we've made significant improvements that support the competitiveness of the shallow targets by lowering the costs and improving the productivity. So that includes the Leonard and the Bone Spring. We're starting to see that they deliver comparable returns greater than 55% at bottom cycle pricing similar to what the Wolfcamp has done. So yes, we noted that we've, in the last 5 years, unlocked 9 additional targets. Those are within all 3 of those main zones, the Leonard, Bone Spring and Wolfcamp in a mixture of those, and there are things that we experiment with all the time on our team to not have kind of a one-size-fits-all development program. So these are things we were able to unlock with lower costs and improved subsurface learnings and the targets themselves are outperforming our expectations. So I think it's important to note that productivity is just kind of one dimension of what we do. We really invest for returns rather than just productivity.

Phillip J. Jungwirth: Okay. Great. And then just following up on that. In the past, you've had this great slide showing the multiyear trend in lower Eagle Ford F&D; just as you've driven those efficiency gains. Wondering if you were to replicate this analysis for the Delaware, how similar do you think it would look also considering the 20% longer laterals this year?

Keith P. Trasko: Okay. Yes. So in the Eagle Ford, we are just a few years ahead of the Delaware as far as we've been developing there for the last 15 years. And yes, you're right, our teams over the last several years have been able to not only drive costs down, but also understand, leverage their learnings from the production and some of the wells they've drilled to where we have some of the best economics in the history of the play in the last several years, and that's after 15 years of development. So if you just take that forward to the Delaware and you think about how many wells we've drilled there, how many years we've been drilling there, we still have several years to go. And kind of use the Eagle Ford as an example there. So we're seeing well costs continuing to go down in the Delaware Basin. Our completions design that we -- our high-intensity completion design is continuing to uplift well production. We've talked in the past that, that has uplifted some subset of our wells that have the right geologic properties up to 20% or so. So you combine those together, and that is going to be continuing to drop our finding cost.

Operator: The next question is from Leo Mariani with ROTH.

Leo Paul Mariani: Obviously, you guys, in your sort of macro overview described perhaps a bit of a squishy oil outlook over the next handful of quarters before some improvements can kind of take place in 2026. Just wanted to kind of get a sense of how you would approach that strategically. It sounded like on the call, you guys were talking about perhaps the opportunity to step up the buyback a bit. Obviously, you've done a little bit of M&A; here recently with Encino and I guess, a small Eagle Ford bolt-on. Do you think there could be other opportunities for bolt-ons as well if we do get a bit of an oil downturn over the next handful of quarters where EOG might be able to take advantage of some of that?

Ezra Y. Yacob: Thanks, Leo. Good question. I think as we absorb this rather large-scale corporate M&A;, I mean, I think we feel outstanding with where we're positioned. We've got 3 real core foundational plays now between the Eagle Ford, the Delaware and the Utica and really a fourth just nipping at their heels there in Dorado. And so even if we see a pullback, I think we'd be well positioned to continue to be opportunistic on things. But I think in general, our foundational plays, at this point, the playbook is typically more to core up and block up acreage kind of via trades and things of that nature. And then to the degree that there might be some small bolt-on packages out there that we could take a look at. But really, the strategy for us hasn't really changed. We are dominated by organic exploration opportunities and being a first mover to get an established position in the sweet spots of these plays for low cost of entry. When we find opportunities to do small bolt-on acquisitions, or a large scale as we have done now with Encino, we'll be active to do that. And it's one of the reasons that we keep such a pristine balance sheet so that we can be countercyclic and strategic, whether it's bolt-ons, acquisitions, leasing and new organic plays, starting to fund some of these international opportunities or leveraging that into stronger marketing agreements. So I think you should look for us if we see a weaker market to continue to be thoughtful and countercyclic on how we invest in the company to improve shareholder value long term.

Leo Paul Mariani: Okay. Appreciate that. And then just I wanted to follow up a little bit on gas macro. If I heard you guys right, obviously, you think there's tremendous growth in demand over the rest of the decade, which certainly seems to be right. But it sounded like you were perhaps maybe a little bit more cautious on the near term. You kind of mentioned not really willing to push the pedal maybe too hard on some of the gas growth in the near term. Obviously, it looks like domestic production has kind of come in higher than I think a lot of folks expected over the last month. So maybe could you kind of talk a little bit more about your near-term thoughts on gas macro heading into the end of the year and into '26?

Ezra Y. Yacob: Yes, Leo, I appreciate that. I may have misspoke just a little bit before then. With respect to our gas business, our dedicated gas business that we're investing in and we have been for the last few years now, we've been strategically aligning that with growth in demand and capturing that demand. And so part of that is with our LNG exposure, which increases from -- over the past few years, has been about 140 million a day that's gone to the LNG agreements. It starts ramping up this year to over 400 million a day. And then eventually, in the next couple of years, it gets all the way up to a Bcf a day that we'll be delivering into the LNG market at various pricing mechanisms. The exciting thing about that and why I mentioned before that, that's really upcoming and transformative for the cash flow generation potential of the company is that in the first 4 years, we've been delivering 140 MMBtu per day into that market. We've realized a cumulative revenue uplift of $1.3 billion. And so over the next few years, as we continue to increase that up all the way to close to 1 Bcf a day, like I said, we see significant upside for that. In addition to that, we've also taken out some other strategic marketing arrangements that allow us to invest in our gas assets like taking out capacity along the Transco Line on the Texas Louisiana Energy Pathway or acronymed as TLEP, which allows us to get some of our gas from Dorado all the way over to the Zone 3 hub in Louisiana, where you can service some of the Southeast power demand and things of that nature. And so we're in a really great position to be able to continue to develop the gas at the right pace. Now I will point out that our focus has always been the volatility, while we do see tremendous gas growth demand or demand and gas growth increasing, the volatility in gas will likely continue to remain. And so that's why we're so committed to investing in these assets at the right pace where we can create value through those cycles and make sure that we're delivering the lowest cost gas to the market.

Operator: We can take 1 more question from Paul Cheng with Scotiabank.

Yim Chuen Cheng: Ezra, over the past, I think that in this earnings season, a lot of your peers have announced some pretty significant cost reduction or business optimization program. EOG did not. But of course, I mean, you guys are doing a lot of things, like Jeff, gave 2 examples this morning. Can you help us maybe to frame it saying that while you are not officially announcing a program, but what is the potential you see from the new technology? How you transform your business? And how much is the potential upside in your free cash flow can generate from those initiatives or what you are doing, say, over the next 2 or 3 years? That's the first question.

Ezra Y. Yacob: Yes, Paul, this is Ezra. Thanks for the question. Yes, I think it's -- you're right, we haven't come out with an official cost reduction plan. It's something that we do 24/7 here at EOG. We're focused on investing at bottom cycle prices. We're invested in utilizing technology to empower our employees to really drive down the costs every way that they can, whether it's well costs on the drilling side, completion side or driving down our operating costs and really expanding the margins for us. So try and frame that up and what it means for future cash flow generation, it might be easiest just to take a look back at what we have done over the last few years. In the last few years, we've got a compound annual growth rate of the regular dividend, which far outpaces our peer group. We've got a pristine balance sheet. And so between -- and then we've got a strong track record of excess cash return. Those are the types of things that are direct output out of working every single day, creating that value in the field at the asset level through collaboration of multidisciplinary teams. Now Jeff has highlighted some specific things like our motor program a couple of years ago. We had our Super Zipper simul-frac operations that have also helped to drive down costs. And then obviously, the exceptionally long laterals that we're drilling now across basically our entire portfolio. And Jeff highlighted, I think, the longest lateral that we've drilled in Texas, which adds tremendous capital efficiency to us. And we are utilizing technology to do that. It's not just our generative AI, which has been very powerful. And the thing about our generative AI is it's really allowing us to capture kind of human intelligence. We've utilized that to help speed up the role -- the integration of Encino as well. But it's the smaller things. It's just the way we organize the data, the data that we create and collect and the way that we allow our engineers, geologists and field employees to be able to engage with that data to really make the impact that they see. Those are the folks that can really impact the business on a day-to-day basis and really drive value for the shareholders.

Yim Chuen Cheng: Great. My second question is that there's a lot of debate about the industry inventory and whether U.S. shale oil is going to reach the peak production or may have already reached peak production as one of your peers believe. And you have said, I mean, as your track record in the Delaware Basin that you have unlocked 9 different new benches to be economically produced over the past 5 years. So just curious that from EOG standpoint, if you're looking at the U.S. shale oil industry, at a $65 to $70 WTI price, do you think we are running out of inventories?

Ezra Y. Yacob: Yes, it's a good question, Paul, and I appreciate that you put a price marker on there. I think it's kind of -- you can't really refute the fact that at current pricing at $65 or $70, the rig count has fallen off pretty hard. And some of that has increased efficiencies, but I think the data is showing that the U.S. doesn't seem to have a lot of incentive to grow at this pricing. Now I think what you're left with is if you filter down from the U.S. into industry or individual companies, I think you're finding companies that are -- and we've talked about it before that are -- you're turning into groups of have and have-nots. You're turning into companies that have invested in infrastructure and scale and data collection to continue to drive down their breakevens. And there are a handful of companies out there that can continue to grow and be very, very profitable at pricing well below $65. And then you've got a series of other companies that, for whatever reason, maybe don't have the scale, don't have the track record or access to the data to continue to make that happen, and they clearly have a higher breakeven. For us, we never discount the ability of our employees or the technology that we empower with them. The U.S. has a vast amount of resources. You heard me briefly talk about the amount of exploration we've got going. And so really, the ability for U.S. unconventional or just U.S. upstream to continue to deliver growth, it's a call on pricing, but it's also on technology. Again, I referenced just what we did to lower the breakeven, not only EOG, but as some of the industry in the last few years, the implementation of simul-fracs, the longer laterals, the ability to drill faster. For EOG, we're specifically applying technology to improve our motor performance, and you've heard us talk about how that's a force multiplier on these longer laterals. And then I do think the next step is going to be some of our generative AI that we're applying. And when I talk about that, it's really been an evolution. We've started with smart technology, utilizing that in really kind of 2018 time frame, especially with the production optimizers that Jeff had talked about before. We've expanded that into machine learning a few years later. And then more recently, we've really got into deep learning and ultimately, the generative AI. And it's really capturing, like I said, the human intelligence. And so things that can't necessarily be bucketized, but you can capture the knowledge, the experiential learning. And what deep learning and our generative AI allows you to do is actually put that into a searchable database that you can really start to unlock trends that were maybe not as apparent without that data. So I'd never count our employees out or our culture to continue to utilize technology, drive down breakevens and unlock additional resources.

Operator: This concludes the question-and-answer session. I would like to turn the conference back over to Mr. Yacob for closing remarks.

Ezra Y. Yacob: We appreciate everyone's time today, and thank you to our shareholders for your support. And special thanks goes out to our employees for delivering another exceptional quarter.

Operator: This concludes the conference. Thank you for attending today's presentation. You may now disconnect.