Helmerich & Payne
Fiscal Third Quarter 2023 Earnings Call Transcript
07/27/2023 11:00 am ET

Operator: Good day, everyone, and welcome to today's Helmerich & Payne's Fiscal Third Quarter Earnings Call. At this time, all participants are in a listen-only mode. Later, you will have an opportunity to ask questions during the question-and-answer period. You may register to ask a question at any time by pressing * 1 on your touchtone phone. Please note this call may be recorded. I will be standing by should you need any assistance.

It is now my pleasure to turn today's call over to vice president of investor relations, Dave Wilson, please go ahead.

David Wilson: Thank you, Ashley, and welcome, everyone, to Helmerich & Payne's conference call and webcast for the third quarter of fiscal year 2023. With us today are John Lindsay, president and CEO; and Mark Smith, senior vice president and CFO. Both John and Mark will be sharing some comments with us, after which, we'll open the call for questions. Before we begin our prepared remarks, I want to remind everyone that this call will include forward-looking statements as defined under the Securities Laws. Such statements are based on current information and management's expectations as of this date are not guarantees of future performance. Forward-looking statements involve certain risks, uncertainties, and assumptions that are difficult to predict. As such, our actual outcomes and results could differ materially. You can learn more about these risks in our Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q, and our other SEC filings. You should not place undue reliance on forward-looking statements, and we undertake no obligation to publicly update these forward-looking statements. We'll also make reference to certain non-GAAP financial measures such as segment operating income, direct margin, and other operating statistics. You'll find the GAAP reconciliation comments and calculations in yesterday's press release. With that said, I'll turn the call over to John Lindsay.

John Lindsay: Thank you, Dave, and good morning, everyone. H&P delivered another outstanding quarter, driven by service quality, technology and reliable execution, enabling us to deliver quality outcomes for our customers.

H&P's financial results for the third fiscal quarter were significant for a few reasons. First, they demonstrate that we are achieving economic returns in the low to mid-teens, which are just above our cost of capital. Second, these financial results were achieved during a slow period when rig activity was declining primarily due to weak natural gas prices. This demonstrates that contract economics rather than market share drove the company's financial performance this quarter. Finally, these results highlight the behavioral change that has transpired within the energy industry, one that reflects fiscal prudence and capital allocation.

Uncertainty continued during the third fiscal quarter and was mostly centered around the macro-outlook for crude oil and natural gas prices. While this created an underlying sense of apprehension in the US drilling market during the quarter, recent ratings are more confident, and we're sensing some optimism on the horizon.

In the near-term, we believe that US rig activity declines will continue into the September-ended quarter, although at a more modest pace than experienced thus far this calendar year. We see these declines as more of a function of customer budget and production discipline rather than a response to short-term commodity price movements, which is a prime example of the behavioral change in the industry. Having already received some promising indications, we expect to see an increase in rig activity during the fourth calendar quarter as our customers establish their capital budgets for 2024.

Commodity prices remain attractive, and we see the customer outlook being more positive regarding medium and long-term energy fundamentals. We believe there will be an increase in the demand for rigs relative to current levels due to fundamental supply and demand dynamics that are inherent in the industry.

The major industry theme is service intensity. Our customers continue to do more with their acreage positions to drive stronger well economics. These desires typically require that our equipment works harder than ever. Laterals are longer, circulating pressures are higher to drill these wells and keep up with customer needs, and this drives costs higher. Our customers benefit from reliability, faster well cycles and better well quality, all of which lowers the total well cost. Our operations and sales teams are working more closely than ever with the customer to deliver more collaborative solutions.

In the face of recent rig count declines, we've been able to remain firm on our contractual economics by working with and collaborating closely with customers on alternative contract models. Our primary commercial model is using performance contracts combined with our technology solutions. Having the operational confidence in our ability to consistently execute enables H&P to enter into alternative contractual arrangements, including our automation solutions, which can result in win-win economics for both customer and H&P.

Today, we have approximately 51% of our active fleet using performance-based contracts, which is a high point since we implemented this new commercial model in 2019. Even with these ongoing efforts, we are anticipating our North America Solutions margins in the fourth fiscal quarter to compress slightly as the rigs idled during the second half of our fiscal year, had been mainly in the spot market and had contractual margins above the overall fleet average. In short, the absence of those rigs, which had leading-edge revenues and margins will likely result in a modest decline in North America Solutions margins during the fourth fiscal quarter.

Expanding our international footprint remains a core strategy for the company, but it is unfolding at a slower pace than expected. Our FlexRig® in Australia is scheduled to commence drilling soon. We look forward to demonstrating our expertise in drilling efficiencies and the power of our technology platform for our customer, Tamboran, as they work to unlock the unconventional resources of the Beetaloo Basin in the Northern Territory.

Additionally, we plan to send a second super-spec rig to the Middle East in anticipation of the pending results of an unconventional tender. This would become our first unconventional rig award in the Middle East. Activities in our other international markets look to remain relatively steady for the foreseeable future.

Capital returns to shareholders remains a priority for the company. Mark will give more specific details, but we repurchased approximately 3.2 million shares for roughly $103 million in the fiscal quarter. Fiscal year-to-date, we have returned approximately $451 million of capital to shareholders through base and supplemental dividends together with share repurchases.

In closing, we remain optimistic that the political and economic uncertainty over the past several quarters, which has impacted the global crude oil and natural gas markets is abating. During the third fiscal quarter, we once again achieved returns in excess of our cost of capital, and, moving forward, our focus will remain on maintaining these levels of returns while delivering superior economic outcomes to our customers. This level of performance is possible because of the service attitude of our people, and their ability to deliver value through drilling efficiencies and technology in collaboration with our customers.

Now, I will turn the call over to Mark.

Mark Smith: Thanks, John. Today, I will review our fiscal third quarter 2023 operating results, provide guidance for the fourth quarter, update remaining full fiscal year 2023 guidance as appropriate and comment on our financial position. Let me start with highlights for the recently completed third fiscal quarter ended June 30, 2023.

The company generated quarterly revenues of $724 million versus $769 million from the previous quarter. As expected, the quarterly decrease in revenue was due primarily to sequentially lower average rig count. Total direct operating costs were $430 million for the third quarter versus $450 million for the previous quarter. The sequential decrease is also attributable to the lower average rig count in North America Solutions.

General and administrative expenses were approximately $49 million for the third quarter. For the full year, we still expect approximately $205 million with the implied sequential increase driven by the timing of professional services and software fees.

During the third quarter, we recognized a loss of approximately $19 million, primarily related to the change in the fair market value of our equity investments, which is reported as a part of loss on investment securities in our consolidated statement of operations.

Our Q3 effective tax rate was approximately 30%, which was slightly above our previously guided range for the quarter due to certain discrete tax adjustments and incremental foreign taxes. We still expect the full-year effective tax rate to range between 23% and 28%.

To summarize this quarter's consolidated results, H&P earned a profit of $0.93 per diluted share versus $1.55 in the previous quarter. As highlighted in our press release, the third quarter earnings per share were negatively impacted by a net $0.16 loss per share of select items consisting primarily of the aforementioned loss on investment securities. Absent these select items, adjusted diluted earnings per share were $1.09 in the third fiscal quarter versus an adjusted $1.26 during the second fiscal quarter.

Capital expenditures for the third quarter of fiscal 2023 were $100 million, which was $15 million more than the previous quarter spend. I will comment later on our revised fiscal 2023 capital expenditure guidance. H&P generated approximately $293 million in operating cash flow during the third quarter of 2023. I will address the company's cash position later in my remarks.

Turning to our other three segments, beginning with the North America Solutions segment, we averaged 166 contracted rigs during the third quarter, down from an average of 183 rigs in fiscal Q2. The exit rig count of 153 was slightly less than our guided range of between 155 and 160 as rigs were released for multiple reasons, including customers exceeding their production targets, customer budget exhaustion, and weak natural gas price levels. This softening in activity caused revenues to decrease sequentially by $34 million. Segment direct margin was $277 million, which was within our April guidance, but sequentially lower than the previous quarter, which came in at $296 million. Performance contracts are made up of approximately 50% of total contracted rigs in the third quarter.

Total segment expenses increased to $18,700 per day in the third quarter from $18,300 per day in the second quarter. Included in the third quarter figure was a select item of approximately $270 per day related to a contingent earn-out liability adjustment for a previous acquisition.

Looking ahead to the fourth quarter of fiscal 2023 for North America Solutions, today, we have 149 rigs contracted, 147 of which are super-spec rigs, and we project some continued softening during the current quarter, which would leave between 141 and 147 contracted rigs at the end of the fourth fiscal quarter.

As we moved through Q3, oil price volatility and forward macro uncertainty were a topic of concern for customers. As we ended Q3 and headed into Q4, we had additional rig releases related to more customer budget exhaustion, customers not wanting to out-drill their production levels, and some recent customer M&A activity. This led to more releases than we had line of sight to just a couple of months ago. This corresponding decrease in number of units working will result in lower North America Solutions revenue levels for Q4 than we previously expected. That said, I would reiterate what John mentioned regarding customer discussions about rig additions in calendar Q4 and how those lead us to believe that we may be reaching a bottom for US rig activity.

Our current revenue backlog from our North America Solutions fleet is roughly $900 million for rigs under term contract. As of today, approximately 62% of the US active fleet is on a term contract.

Average pricing per day should remain relatively flat to slightly down, as high-rate spot rig releases are offset to some extent by legacy term rate rollovers. If we see the aforementioned pickup in activity in calendar Q4, we would expect our average pricing levels to continue.

In the North America segment, we expect direct margins in fiscal Q4 to range between $230 million to $250 million due to the sequential decline in activity levels. We currently expect fourth quarter per-day cost to remain flat at approximately $18,700 per day. This per-day cost is elevated from our expectations a couple of quarters ago due to the idling of rigs in the third and fourth quarters, which results in our overhead absorption being spread over a smaller number of active rigs. As John mentioned, when we look beyond fiscal Q4 to calendar year-end, we believe more rigs will be put back to work, which should reverse some of the near-term impact overhead absorption has on daily costs moving forward in fiscal 2024.

Next, to our International Solutions segment, International Solutions activity ended the third fiscal quarter with 13 rigs drilling on contract. International Solutions results were slightly below previous guidance due to higher-than-expected costs. As we look toward the fourth quarter of fiscal 2023 for international, as John mentioned, we anticipate beginning drilling operations in mid-fourth quarter with the rig that was mobilized to Australia in the third quarter. Expenses associated with advancing our Middle East hub are expected to continue, but at a much lower rate as we wrap up many of our planned preparations. As John mentioned, we are hopeful that those efforts to date will result in an award from a recent tender process. In the fourth quarter, we expect to earn $8 million to $11 million in direct margin aside from any foreign exchange impacts.

Finally, to our Offshore Gulf of Mexico segment, we had four of our seven offshore platform rigs contracted, one of which was on a demobilization rate as the customer has reached the end of its multi-year drilling program. We have active management contracts on three customer-owned rigs, one of which is on active rate. The offshore segment generated a direct margin of $7.3 million during the quarter, which was in-line with our estimate.

As we look toward the fourth quarter of fiscal 2023 for the Offshore Gulf of Mexico segment, one of our platform rigs should complete its demobilization this next week and we expect offshore will generate between $6 million to $8 million of direct margin in Q4.

Let me update full fiscal year 2023 guidance as appropriate. Capital expenditures for the full fiscal 2023 year are now expected to be approximately $400 million, which is a $25 million decrease from our prior guidance range in midpoint. Although we expect the timing of our Capex spend to vary from quarter-to-quarter, supply chain delays have continued to push some planned maintenance Capex from fiscal 2023 to fiscal 2024. In particular, some of our planned component overhauls have been delayed due to lags in obtaining certain parts.

As previously mentioned, our expectations for general and administrative expenses for the full fiscal 2023 year remained $205 million.

We are still estimating our annual effective tax rate to be in the range of 23% to 28% with the variance above US statutory rate of 21% attributed to permanent book-to-tax differences and state and foreign income taxes. Through Q3, we have paid cash tax of approximately $156 million and we're projecting to pay $25 million to $50 million for the remainder of the fiscal year, resulting in an annual cash tax range of $180 million to $205 million.

Now, looking at our financial position, H&P hedged cash and short-term investments of approximately $293 million at June 30, versus an equivalent $245 million in March 31. The sequentially increased cash balance is largely attributable to working capital unlock. Including availability under our revolving credit facility, our liquidity remains relatively flat at just over $1 billion.

Approximately 3.2 million shares were repurchased in fiscal Q3 for about $103 million. Fiscal 2023 repurchases have totaled 6.5 million shares thus far or about $249 million. The repurchases to-date are at an average price of about $38 per share and have reduced shares outstanding from the beginning of fiscal 2023 by approximately 6%. There are 1.3 million shares remaining under the calendar 2023 authorization of 7 million shares.

As John indicated earlier, this fiscal year-to-date, including share repurchases and dividends paid and declared, the company has returned approximately $451 million of capital to shareholders as follows: $104 million in base dividends, $98 million in supplemental dividends, and $249 million in share repurchases. Each of these items, the repurchases of the base and supplemental dividends encompass the capital allocation and shareholder return model that we announced in October at the beginning of fiscal 2023.

Looking ahead to fiscal 2024, we will refresh that model in our annual budgeting process, taking into consideration various factors including expected activity levels, planned capital expenditure levels, and anticipated cash flow margin. We will discuss this plan on our November call.

Finally, a follow-up on John's comments about returns just above cost of capital. On our November 2022 call, we discussed our plan and our need to focus on achieving positive returns as measured in ROIC. In this current fiscal year, we have achieved that necessary step for our shareholders for the first time since 2014. H&P's return focus, combined with our capital allocation execution underscores our strategy to not only enhance the financial returns of the company, but also increase the cash returns provided to shareholders.

That concludes our prepared remarks for the third fiscal quarter. Let me now turn the call over to Ashley for questions.

Operator: Thank you. At this time, if you like to ask a question, please press * 1 on your touchtone phone. You may withdraw yourself at any time by pressing the # key. Once again, that is * and 1.

We will take our first question from Doug Becker with Capital One. Please go ahead.

Doug Becker: Thanks. John, you highlighted the promising indications from customers about increasing activity. I was hoping to get a little more color around the tenor of those conversations.

I'm trying to get a sense of what makes you think it's bonafide incremental interest versus just kicking the tires or a customer looking to play contractors off one another?

John Lindsay: Well, Doug, obviously, it's still early in the year, but we have gotten that feedback, and again, I think it's consistent with the type of feedback that we've received in previous years. Obviously, in July, customers aren't talking specifically about their 2024 budgets, but we do expect that there will be a reset very similar to what we've seen in the last three years as you think about this - their desire to be very disciplined in their budget and in their production profile. As Mark mentioned, some of the releases that we've had, had been really based on just that. It's customers getting to their production levels or getting to their budget levels as they forecast out through the rest of the year.

So, we think it's bonafide. We think the customers intend to pick up activity in calendar Q4, but again, it's still early and we're obviously not in a position to guide toward what that rig count activity would be, but we're definitely seeing the response and we're having the conversations.

Doug Becker: That makes sense. Just when activity does start to pick up, would you expect H&P to add rigs back faster than the industry. Clearly, market share is a byproduct of your economic model, but I want to get a sense that it seems reasonable that you would pick up a little bit of market share when activity does pick up.

John Lindsay: Well, obviously, we're hopeful that we would be in that position. I can say that the rigs that we've idled, we've idled them in a fashion such that they would be ready to go back to work very quickly, very easily, very low cost. So, I think we're positioned well from that perspective. Most of the conversations that we've had are with larger public companies, and obviously, that's - over 70% of the work that we do historically is from large private - or large public E&Ps. So, I think we're positioned well from that perspective and obviously, that would be our hope.

Doug Becker: Then just a quick last one. You gave the preliminary outlook for the 2024 capital budget. If spending is effectively flat year-over-year, is it reasonable to assume the supplemental shareholder return plan would be flat as well?

John Lindsay: Well, again, we're early in the cycle to be talking about - we felt like it was important to bring that up. As I think about this and our conversations internally and with our board, there's a great opportunity for us to do kind of an all of the above like we have been able to do with the base and the supplemental and opportunistic share buybacks. From our perspective, with what we know right now, it seems reasonable, but again, it's early. We were just trying to give some estimate of how we were thinking about the budget without actually guiding to the budget.

Mark Smith: That's right, Doug. I think the press release said, at least from a Capex perspective as we mentioned in prepared remarks, in the back half of this year, we're seeing more delays in the ability to execute on some of our maintenance Capex and we have to continue through with that because we really, as you know, back in the pandemic, had to harvest and cannibalize a lot of parts and we're still catching up with that. So, we've not been able to execute on the full Capex plan for this year, resulting in some of it being deferred to the next year.

So, we just have to see what that is, move a little bit more through the summer, into the fall. As John indicated, it's early, and as we get into the fall, we'll have a little bit more clarity on activity levels for fiscal '24. So, we marry that up with our full-year '24 expectations, the Capex, and then we'll see what the result ability is for the supplemental plan, but the three legs of that plan are certainly part of the DNA that we look to carry forward.

Doug Becker: Got it, thank you.

Operator: We will take our next question from Derek Podhaizer with Barclays. Please go ahead.

Derek Podhaizer: Hey, I wanted to touch on your comments around your daily margins recovering in calendar 4Q, and I would think that would actually be a continued trend downward just given higher spot markets rolling off, repricing below your fleet average there. Can you maybe just talk about what's going on where you see recovery, just the interplay between the day rate and the cost per day? Would this ultimately make calendar 3Q represent the profitability trough for this part of the cycle?

Mark Smith: I'll start this off. Derek, it's Mark. I think our guidance indicates that the margins next quarter will be coming down modestly per day because of those spot roll-offs. So, that's probably at next quarter. If the trough, in fact, is that, that would be the calendar Q3, which is our fiscal Q4, but that's as far as we can see now. Again, we think we have from customer visibility some add-backs in Q4 to start fiscal '24. As it relates to - that's a little bit on the pricing side, because we have quite a few legacy term contracts repricing, which helps offset the spot, the high-end spot contracts coming off.

On the cost side, as I had mentioned, I think we're holding pretty flat with cost across the organization with the exception of absorption from the lesser activity we've experienced last quarter and this coming quarter. If we, in fact, then get into calendar Q4, fiscal Q1 with more activity, that can help alleviate that absorption issue really in the midterm.

John, would you add anything?

John Lindsay: I think you hit it.

Derek Podhaizer: Yes, just because in the press release, so that calendar 4Q, I know that's your fiscal 1Q 2024, you can see daily margins expand from where they're going to go in your fiscal 4Q.

John Lindsay: Derek, I think, again, it's really hard to say at this point and we sure don't want to try to guide for our first fiscal quarter, calendar Q4 in July. Again, we think from an activity perspective, we're going to hit the bottom here in the September quarter or in our fourth fiscal quarter, and we see some activity improvements in calendar Q4. Again, on the pricing front, we don't know for sure where that's going to go. Our expectation is that we're going to be able to maintain pricing. Mark already hit on the cost side of the equation, and the number of rigs we had back, obviously, had an influence on that.

Derek Podhaizer: Got it, okay. No, that's all helpful. Maybe just talk about when we do hit bottom and start seeing the rig cover, can you talk about where you expect the pockets of strength there, gas versus oil, and maybe regionally by basin?

John Lindsay: I think you have to believe that the Permian is going to continue to be strong. It's our largest area of operation by a wide margin and so I think we will see some pickup in activity there. Of course, most of that's oil-related. I do think there will be some pickup in activity in some of the gas basins, but it's really hard to see at this point. But that would be our expectation is activity improvements there and I'm sure there will be some in the Eagle Ford as well.

Derek Podhaizer: Great, appreciate all the color. I'll turn it back.

John Lindsay: Thank you.

Operator: We'll take our next question from David Smith with Pickering Energy. Please go ahead.

David Smith: Hey, good morning, and thank you for letting me on. Mark, in the press release, just circling back to the comments for the preliminary outlook for fiscal 2024 Capex to be at least at fiscal 2023 levels. Recognizing it's really early, but I had to ask, if you can make any comments about that, what that might assume for the lower 48 rig count, but also, if there's any color you can give on the level expected for international growth Capex?

Mark Smith: Thanks for the question, Dave. We're caveating, it's early, but what we see are a few things. We - as I mentioned, are catching up on maintenance Capex. So, there is an amount of maintenance Capex we need to execute on that, in fact, will not necessarily be tied to a specific rig count level in 2024. In other words, we have to catch up on spares, capital spares through our systems, so we can continue to have our 99-plus percent revenue efficiency and uptime on our US fleet, which obviously helps us in the service to our customers and the solutions we provide. So, we will be catching up on that and if - I think it's still going to be in this elevated range that we have for this year, $1.1 million to $1.3 million per active rig per annum on average, but again, that may even skew a little higher with this capital - with the spares componentry work that I'm talking about.

If you take that, if you take a typical international offshore mix to add into that, and if you take some typical corporate spend on top, then you really kind of get to the at-least comments that we had in the press release.

David Smith: All right, appreciate it. A follow-up for John, if I may. Nice, steady progress on increasing the mix of performance contracts. Wondering if you could give us any color on maybe how much of this mix is related to the decline in spot rig activity or if you're seeing customers who were not previously on performance contracts being more willing to adopt them.

John Lindsay: Yes, David, that's a great question. It's a little bit of a mix of both, as you can imagine in the contract mix as rigs are released, but there are some customers that continue to adopt performance-based contracts. They've seen it with some of our other customers and see great performance in a particular area and we get feedback on that and they decided to pursue that.

So, we're very pleased with that and it continues to increase. Again, it's been a hard effort, long effort by our folks, but at the end of the day, what's great about it is it is a win-win contract construct because customer wins, we win when we perform well and our teams do a great job on the performance side. So, I suspect that we'll continue to have more adoption overtime.

Mark Smith: David, this is Mark again. I want to go back to your previous question on Capex. I think I left out one piece for your math there, which is that walking rig converging cadence we also mentioned in the press release. Then you add that in, if we did one per month by the way of example, that gets you to your 400 at least comment. I just wanted to add that back.

David Smith: Got it. Appreciate it. Thank you, all. That's all I got.

John Lindsay: Thank you.

Operator: We'll take our next question from Saurabh Pant with Bank of America. Please go ahead.

Saurabh Pant: Hi. Good morning, John and Mark.

John Lindsay: Good morning.

Saurabh Pant: Hi. I guess maybe a quick follow up on the performance model and tying it up with some of the recent M&A in the industry. One of your large deals acquired a drill bit manufacturer, and obviously, that allows them to integrate along the bottom hole assembly, right? Clearly, it should give them more control and allows them to do more, right?

From an efficiency standpoint, if I think about performance-based models, is that - or maybe something else along the lines of integrating down the wellbore, does that make sense to you? How do you think about it from a big-picture standpoint going forward?

John Lindsay: I wasn't really thinking about it from a bit manufacturing perspective. I know at H&P, we have quite a bit of data, downhole data that we're able to utilize to drive enhanced performance. Obviously, we have software solutions that also assist in driving performance for customers. So, I think the drill bit data that you're talking about is really data that we already have in most cases related to the software that we already have, if that was your question.

Saurabh Pant: Okay. No, John, that was part of the question. I guess, just to clarify, I was thinking from the perspective of controlling more things down the wellbore, if you have control of the drill bit or something else along the wellbore, right? You're more in control of how efficient the well is being drilled, right? I'm just thinking from a performance standpoint, just having more components in the bottom hole assembly, does that help you in the performance model going forward and thinking from a medium to long-term perspective, not just from a data, but from a tool perspective?

John Lindsay: Right. I don't really see that there's a connection back to the rig necessarily, but again, it's a great question. I don't really have [the idea]…

Saurabh Pant: Okay, okay.

John Lindsay: …that there's going to be a competitive advantage there.

Mark Smith: I would just add that, again, it's capital intensive, and we have said for many years, as we look at ancillary businesses where we prefer the software approach related to enhancing our overall drilling solutions and what John was talking about with software through our Drillscan software, we have a lot of data about the bottom hole assembly and drilling and drill bit preference. Remember, customers choose the drill bit completely separately from the rig so we don't see necessarily a synergy there either.

Saurabh Pant: Okay. No, thanks for that answer. Then just one quick clarification, maybe for both John and Mark, but, Mark, maybe more for you. As you think about - I know it's early, right, but as you think about your fiscal '24 supplemental shareholder return plan, I know you said that you still see the [Unintelligible] for sticking to the base dividend, the supplemental dividend and the buyback, but as you look back at fiscal '23 plan - I know it was your inaugural plan. As you look back and see where you think you had the most success and how you can finetune that going forward in fiscal '24, what should we expect from that? What was, in your view, the best part and where do you think you can finetune that plan going forward? I'm particularly thinking about the mix between supplemental dividend and maybe share buybacks.

Mark Smith: Well, Saurabh, that's a hard question to comment on because what we have in our three-pronged plan is, one, with the base dividend, a legacy of 60 years of paying dividends and returns to shareholders, but with the supplemental dividend and the share buyback's flexibility. So, we have repurchased a lot of shares this year. In fact, we believe that this last quarter was a record for the company in terms of shares and dollars repurchased, but that is also because it was a dislocation in the share price from what we believe is a more accurate valuation, and therefore, a good investment for the company.

As we’ve said on previous calls, we have our own modeling that we do with upside, downside base cases. We assess the terminal value and the DCF and we put a multiple on it and we say anything trading below that would be a good investment. So, I guess one could say, if you see a lot of those investments - if the stock is not where you want it to be, if we’re buying back less then we may be returning more in the form of supplemental dividends in cash, but we just have to wait. It’s going to be dependent on the situation at hand at the time and that’s about all we can comment on. It’s a lot easier to comment on things as we’ve actually executed on them and report on them on a quarter looking in the rearview mirror.

Saurabh Pant: No, I guess that’s all fair. You got to maintain a balance between continuity and flexibility. So, I appreciate that answer, Mark. I’ll turn it back, thank you.

John Lindsay: Thank you.

Operator: Thank you. We’ll take our next question from Keith Mackey with RBC Capital Markets. Please go ahead.

Keith Mackey: Hi, good morning. Thanks for taking my questions. I just wanted to return to the discussion around performance-based contracts. Wondering if you can just discuss a little bit more about the average uplift you see from those contracts relative to what you might get on a standard day rate type of contract and is there really any cost associated with it or is it just purely a $1,000 to $2,000 or so margin uplift from an average rig rate?

John Lindsay: I don’t have the numbers in front of me, Mark or…

Mark Smith: $1,000 to $2,000 still.

John Lindsay: Dave might have. So, in average, but that’s across the overall fleet. From a cost perspective, we just touched on it on a previous question to a degree, and that’s related to having the data set, having certain technologies, having a staff of people that know how to the performance contracts into place and working with the customer. So, there are some costs associated with that, but at the end of the day, what we’re trying to do is we’re driving performance improvements for our customers and that’s where the real cost savings are. You’ve probably heard us talk about that before. Reducing our day rate really has very little material impact on the cost of the well, but saving a day or two days or five days and doing it reliably well after well, that’s where the savings are really captured. So, that’s really the focus that we, as an organization, have in working with our customers.

Keith Mackey: Understood. If I could just follow up on the international side. So, got the one rig slated to start drilling in Australia very soon, and then one more going to the Middle East in anticipation of some tender results, but certainly, think there were plans initially to send a handful or so more in the shorter term. Can you just discuss what you’re thinking now around that, the timeline for those incremental rigs? Is this purely a cost decision in the near-term or were there some tender results that maybe didn’t go your way that are leading to the adjusted plans for the Middle East rigs?

Mark Smith: Keith, there are some other tendering opportunities in the region that we are participating in and it will depend upon how those develop over the coming weeks and months and potentially quarters because these things often are slow processes. We don’t plan to incur necessarily mobilization costs until we have clear line of sight to the results of such processes. I hope that’s helpful.

Keith Mackey: Yes, it is. Thanks very much.

Operator: Thank you, and we will take our next question from Arun Jayaram with JPMorgan. Please go ahead.

Arun Jayaram: Hey, gentlemen. At the risk of kind of beating a dead horse, I did want to ask you about the supplemental shareholder return plan. Last year, you announced – gave clarity on the plan in, I think, October of last year. I was wondering if maybe you could give us some thoughts on -- there’s a little bit more uncertainty in the market. Does that change maybe thoughts on when to communicate the plan? How should we think about some of the pushes and pulls relative to last year’s program?

Mark Smith: Thanks for the question, Arun. I’ll start this off. I think last year’s release in October was because the supplemental plan was, in fact, new. It was a different mechanism for us in terms of assessing how we could return more cash to shareholders with the cash flow generation we foresaw, but without necessarily increasing the base dividend as we had historically.

What we did, we did a lot of a lot of soundings with investors and came up with a supplemental plan and I think we believe in it going forward. I think it'd be more normal to see us discuss that plan perhaps in the November earnings call and then dependent on any timing related to declaration of such supplemental dividend, it may be a different timing, but the overall plan would be something that we would discuss, I think, more fulsomely on the annual guidance time frame, which is the November call.

As John mentioned earlier, we have a - it's early in the year and we have a lot of work to get through, but we're a lot more hopeful just about the market as we see the same thing that everyone sees. We don't have a clear crystal ball, but we certainly are hopeful with what we see in the macro environment, for example, with consensus calls for recession starting to come below 50%, and we know that the forward oil strip has had a whole lot higher probability of recession baked into it and I think we're seeing the oil prices go up today because of that. So, there's a lot of macro uncertainty, I think, that's coming out and that will unplay over the next several months, which is, again, ahead of our customers commencing their typically, calendar annual budgeting processes, and as that gets underway, we'll have more intelligence from our sales and operations teams in the field to be able to bake into next year's plan. So, I think that, again, fits more with the November timeframe.

John, would you add any…?

John Lindsay: Well, really, I think I already said it earlier, which is we see the plan providing the flexibility and we think about it from an all-of-the-above standpoint and whether it's the base or supplemental and then depending on share price and having opportunistic share buybacks. We think it's been very effective and it's just too early in the game to be communicating at this point. Mark had a great point about the November timing because that really makes a lot of sense. It won't be something new, something that we're trying to get out there. It's just something that we're building on.

Arun Jayaram: Okay. Just my follow-up. John, you guys historically have worked with the large E&Ps, majors and larger privates, but I was wondering if you could give us maybe some thoughts on - just from the private E&Ps as a whole. What does the conversation level with them, with that group, obviously, a very important customer group, about adding rigs as you get into 2024? Do lower DUC balances - does that feed into thoughts on rig demand next year?

John Lindsay: We haven't spent a lot of time on the DUC counts historically, but clearly, they're low. I think you're right, the private company is very important and we have a lot of really strong relationships and rigs working. I think 30% of our rigs today are working for the smaller private companies. So, a very important customer group.

I think it's still early. I would say most of the rig adds that we've been talking about for calendar Q4 have been with the larger public companies and most of the conversations, not completely, but in most cases. So, no doubt the smaller private companies play an important role and they're an important customer to us. Still really early in the year right now.

As we all know, they tend to be pretty opportunistic as it relates to commodity price and obviously, oil prices have strengthened. They have a tendency to respond pretty quickly to those sort of price inflections, and, of course, natural gas is still - we still don't know a whole lot about that in terms of pricing, but we do expect to see an improvement in pricing there.

Arun Jayaram: Thanks a lot.

John Lindsay: That's about the best I can do right now in terms of - there definitely will be some, but I think at this stage of the game, I'd say most of the responses we've had have been with the larger public companies.

Arun Jayaram: Thanks a lot, John.

John Lindsay: Thank you.

Operator: Thank you. We'll take our next question from Kurt Hallead with Benchmark. Please go ahead.

Kurt Hallead: Hey, good morning, everybody.

John Lindsay: Good morning, Kurt.

Kurt Hallead: John, I'm kind of curious, right, on the international front. I know there are some very good, near-term opportunities for you as you mapped out in a couple of different markets. So, maybe kind of bigger picture and more holistically, it looks like international is on track to maybe represent about 3% of your total gross profit. As you look at it, right, what is the opportunity set internationally and the time and effort it takes to kind of build out an international presence relative to the actual financial impact? Where do you see it maybe in three to five years? I just want to get some context from you on pursuing the international market opportunities and where do you see the upside and the uplift on the financials.

John Lindsay: Well, Kurt, we obviously recognize the need for additional scale and for us, unfortunately - well, not just us, for everyone, unfortunately, international projects move at a much different pace than what we're used to here in the US. I know our teams in the Middle East have done a great job in building relationships and we have a lot of momentum there and so I feel like we're on that verge of - that point of being able to really see some growth there, but again, when you look at the size and the scale of our North America operation, obviously, there's a lot of additional work that we're going to have to do.

So, we recognize the challenge, we're committed to it. We think we have a great team. We do think the international unconventional plays is an area that we can really make a difference. So, as we see unconventional plays grow, we think we're going to have a larger influence there. I hear what you're saying and we recognize the challenge and we're up to it, but I think it is a three-year, five-year time period to do this organically, it just - it's going to take some time.

Kurt Hallead: I appreciate that, and you guys are always very thoughtful and diligent about how you run your business. I was also curious and in the context of that, say, three to five-year window of kind of growing it organically as you go through your strategic planning processes, what percent of your business do you think international can reasonably represent over that time period?

Mark Smith: Kurt, we haven't said. I'll leave it at that, but it's going to be…

Kurt Hallead: I was giving you an opportunity to share. That's okay, all right.

Mark Smith: It's going to be more than 3%, but it's because of the complexity that John mentioned and, as we've discussed, we've been focused on this for a couple of years and it looks like some of that focus is going to at least have some initial positive results and then we'll build on that. That's the plan.

Kurt Hallead: So, my follow-up here is on the performance contract dynamic. You referenced 50% of the rigs were on some sort of performance contract and I know this has been an evolution in development for you guys for quite a number of years now, but it also kind of seems to me, to a certain extent, that there's an ebb and flow to the performance contracts. Has it kind of hit its limitations, do you think, on adoption and does it really resurface every time you got some day rate weakness? I guess I'm just trying to get a sense from you, John, as we've seen it evolve, is it kind of two steps up, one step back or we've hit a point where we could just get a flat line on the adoption of it?

John Lindsay: I think that it has some potential to continue to grow and the reason is when I look at the customer base that we do performance contracts with, there are other customers that are very similar in size and in sophistication in the way that they approach drilling the wells that aren't necessarily using performance-based contracts. So, I think there's a huge upside.

Our sales force spends a lot of time on this and they have a strong belief that there are additional customers out there that will benefit from the performance-based contract, and I think that's what's really key here is, yes, it's a tool in the market that we have been experiencing - this correction that we've been experiencing over the last couple of quarters, but it is also a really good tool for customers in terms of their desire to drive not only greater performance and efficiency, but greater reliability. And we continue to hear from customer after customer that, yes, performance and drilling a "record" well is important, but what's most important is to be able to drill reliably and not have the outliers. To us, that's what performance-based contracts are all about, because there's so much opportunity to standardize on process and technologies and using what works the best.

So, we're excited about it. We think there's additional upside to it. I think we're ever going to have 100% performance contracts, no, but I do think that there's some additional upside ahead.

Kurt Hallead: That's great. Really appreciate the color, thanks.

John Lindsay: Thanks, Kurt.

Operator: At this time, I would like to turn the call back over to John Lindsay for closing remarks.

John Lindsay: Thank you. Appreciate everybody joining us today. As we’ve mentioned during this call, we remain optimistic about the long-term energy fundamentals and the opportunities this provides H&P to create value for shareholders. So, again, thanks for joining us today and we’ll sign off. Thank you.

END