Helmerich & Payne
Fiscal Third Quarter 2021 Earnings Call Transcript
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Operator: Good day, everyone, and welcome to today's Helmerich & Payne Fiscal Third Quarter Earnings Call. At this time, all participants are in a listen-only mode. Later, you'll have an opportunity to ask questions during the question-and-answer session. You may register to ask a question at any time by pressing the * and 1 on your touchtone phone. Please note today's call may be recorded. We will be standing by if you should need any assistance. It is now my pleasure to turn the call over to the VP of Investor Relations, Dave Wilson. Please go ahead.

Dave Wilson: Thank you, Reid, and welcome, everyone, again to Helmerich & Payne's Conference Call and Webcast for the Third Quarter of Fiscal Year 2021. 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, we remind everyone that this call will include forward-looking statements as defined under the securities laws. Such statements are based upon current information and management's expectations as of this date. They're 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 will also be making reference to certain non-GAAP financial measures such as segment operating income and operating statistics. You will find the GAAP reconciliation comments and calculations in yesterday's press release. Like I said, I'll turn the call over to John Lindsay.

John Lindsay: Thank you, Dave, and good morning, everyone. Since the industry rig count hit bottom almost a year ago, H&P's rig count and market share gains have positioned us as the leading drilling outcomes provider in the U.S. land market. In line with our guidance, we exited the third fiscal quarter at 121 rigs, and today, we are at 123 active FlexRigs. We expect to continue to have a moderate and somewhat choppy upward trajectory in our rig count as well as improved pricing over the next quarter.

Although there are approximately 260 idle super-spec rigs available in the U.S. market, we believe fewer than 10 of those rigs have actually worked within the past 12 months and many of those rigs have been idle for well over 18 months. There's a high cost involved in reactivating long idle rigs, which typically presents one of those classic 'pay me now or pay me later' conundrums. Most importantly, striking the right balance to startup [Unintelligible] enhances safety of an operation, but it can also significantly impact the value proposition for customers by driving better metrics and drilling performance, downtime, and crew retention.

Our stellar track record of efficient startups delivers greater customer adoption and is one reason why we consistently outperform as the rig count increases. As demand grows, these reactivation expenses will continue to drive rig pricing higher as the supply of work-ready super-spec rigs become scarce.

All the drivers that lead to enhanced pricing and contract economics are in place. Higher crude price, higher activity levels, higher reactivation cost, pricing discipline within the industry, and perhaps most important of all, our ability to deliver value and better outcomes to our customers.

In light of these factors, we have been in discussions with customers to increase pricing. Further, we remain optimistic that current oil prices will translate into higher 2022 E&P drilling budgets and activity in the U.S. land market. As of today, discussions with customers regarding activity for the rest of 2021 inform our estimate of approximately 50 to 75 incremental industry rigs returning to work by year-end, and we expect that to be back-end loaded in the fourth calendar quarter. That expected rig increase coupled with the long idle fleet also enhances the potential for further rig pricing improvements in the fourth calendar quarter and into 2022. Assuming oil prices remain stable and near current levels, we would not be surprised to see 2022 budgets for public companies drive further incremental increases in rig activity next year.

We expect the Permian will continue to lead the way in incremental rig adds. Our leadership position in this region is multifaceted. We have a superior infrastructure, experienced people, the leading number of active super-spec rigs at 67 rigs, as well as the largest inventory of idle super-spec rigs. This combination of attributes bolsters the company's capacity for further growth in the Permian Basin.

With this context in mind, let's now turn to field performance and the implementation of digital technology solutions combined with new commercial models. There is a growing appreciation for the value proposition H&P provides as we're successfully growing our rig count for the existing customers as well as partnering with new customers to achieve better drilling outcomes.

When utilized on a FlexRig platform, H&P's digital technology and automation solutions like AutoSlide are enhancing drilling outcomes both in terms of efficiency gains and wellbore quality, resulting in improved long-term well economics and returns. We have multiple customers, large and small, public and private, utilizing our FlexRigs and digital and automation technologies. This combination enables them to reliably lower their overall well costs, improve wellbore quality, and reduce downhole risks.

Let me give an example recently where we had a customer with a performance contract that was paying us well over market spot rates. They were nervous about explaining that to their management team. However, they also mentioned to their management team that they were saving over $0.25 million per well by using H&P. So as a result of that realization, management wanted to continue to use H&P on all their wells, and that expanded our rig count with that customer.

This outcome-based approach, which is data-driven, delivers more predictive, consistent, and superior well results over an entire drilling program for our customers. The great news, these aren't one-off examples. We have these partnerships and results with major large E&Ps and private companies.

Over the past few decades, the methods, the equipment, the technology, and the risk profile, and the drilling of unconventional oil and gas wells has evolved significantly. However, the legacy day rate model construct has not. The pricing model for providing better drilling outcomes will continue to evolve, and H&P along with several of our customer partnerships is pioneering new commercial models to better align our performance with our customers' goals and allow us to share in the value-added outcomes we help create. Unless a pricing model can equitably share the benefits derived through better technologies and efficiencies, the ability of the industry to continue to innovate and improve will diminish.

We're pleased to see international activity start to pick up again after a long pandemic-driven hiatus. We are participating in several tenders with both NOCs and IOCs, but these are very thoughtful, slow processes, and uncertain of timing. In addition to working on new growth opportunities, Argentina and Colombia appear to be ready to put rigs back to work during our fourth quarter. We are seeing some traction of our digital technology and automation solutions internationally as well. Our international FlexRig digital platform is capable of hosting our automation solutions, which we believe will be a driver of additional FlexRig adoption.

Before turning the call over to Mark, I wanted to touch on sustainability. We have a long history of offering solutions which help both H&P and our customers' sustainability needs, and we continue to invest in these and other sustainability efforts that benefit all our stakeholders, our employees, our customers, vendors, investors, and society at large.

We're partnering with our customers and taking a thoughtful and methodical approach to offer solutions to fit their desired outcomes, both from an environmental and economic perspective. We have many solutions in our toolkit that we have had for many years, such as using alternative power sources at the rig like natural gas engines, highline power, or dual-fuel engines. More recently, we've invested in energy storage solutions using battery technology and rig engine efficiency software solutions to help reduce greenhouse gas emissions and lower rig fuel consumption.

As I mentioned on the last earnings call, we are committed to publishing our inaugural sustainability report in 2021, which will include important data and information about our sustainability efforts and successes. In parallel to the development of the report, we have also increased sustainability disclosures on our website, which includes data and information about emissions, safety, and diversity, equity, and inclusion.

Last year, one of the renewable investments we made was in geothermal resources. Many years ago, we intermittently drilled conventional geothermal wells, but a new unconventional closed-loop approach to geothermal is creating a viable source for renewable energy going forward. H&P has a team dedicated to investing and participating in geothermal, where our drilling technologies and expertise are readily transferable.

So in closing, we remain optimistic about the industry and our ability to capitalize on our scale and our distinct capabilities as we focus on delivering the best outcomes for customers and value for our shareholders.

Now, I'll turn the call over to Mark.

Mark Smith: Thanks, John. Today, I will review our fiscal third quarter 2021 operating results, provide guidance for the fourth quarter, update remaining full fiscal year 2021 guidance as appropriate, and comment on our financial position.

Let me start with highlights for the recently completed third quarter ended June 30, 2021. The company generated quarterly revenues of $332 million versus $296 million in the previous quarter. The quarterly increase in revenue is due to higher rig count activity in North America Solutions as expected. Total direct operating costs incurred were $257 million for the third quarter versus $232 million for the previous quarter. This sequential increase is attributable to the aforementioned additional rig count in the North America Solutions segment.

General and administrative expenses totaled $42 million for the third quarter, also consistent with our expectations. Our Q3 effective income tax rate was approximately 30%, which was above our previous annual guided range. Taxes were positively impacted by a discrete tax benefit primarily related to a change in the state deferred income tax rate.

To summarize this quarter's results, H&P incurred a loss of $0.52 per diluted share versus a loss of $1.13 in the previous quarter. Third quarter earnings per share were impacted by a net $0.05 gain per share of select items as highlighted in our press release. Absent these select items, adjusted diluted loss per share was $0.57 in the third fiscal quarter versus an adjusted $0.60 loss during the second fiscal quarter.

Capital expenditures for the third quarter of fiscal '21 were $18 million, with year-to-date spending levels below our previous implied guidance. Planned spending continues to shift to the right, but we are expecting a more significant spend in our fourth fiscal quarter, which we will discuss later.

Turning to our three segments, beginning with the North America Solutions segment. We averaged 119 contracted rigs during the third quarter, up from an average of 105 rigs in fiscal Q2. As John mentioned, we exited the third fiscal quarter with 121 contracted rigs. We also had approximately 15 rigs roll off term contracts and into shorter-term contracts during the quarter as customers maintained their budgeted drilling programs. Revenues were sequentially higher by $31 million due to the aforementioned activity increase. North America Solutions operating expenses increased $20 million sequentially in the third quarter, primarily due to the addition of 12 rigs. The one-time reactivation expenses associated with those rigs was approximately $6 million in fiscal Q3.

Looking ahead to the fourth quarter of fiscal '21 for North America Solutions. As expected, rig count growth was more moderate during the third quarter. As of today's call, we have 123 contracted rigs, and our expectation is to end the fourth quarter of fiscal '21 with between 127 and 132 contracted rigs. Publicly traded customers continue to operate within their calendar year budget plans, so most of our recent active rig additions were driven by privately held customers. We still see opportunities for publicly traded customers to add rigs late in this calendar year as capital budgets are refreshed heading into 2022.

In the North America Solutions segment, we expect gross margins to range between $72 million to $82 million with no early termination revenue expected. As we continue to add rigs, one-time reactivation expenses continue to pressure margins. We expect those expenses to be approximately $8 million in the fourth quarter. As I mentioned in the last quarter, the length of time a rig has been idle, and the costs required to reactivate it have a direct correlation. Most of the rigs we are reactivating in the fourth quarter have been idle for 12-plus months. Reactivation costs are mostly incurred in the quarter of startup, so the absence of such costs in future quarters is margin accretive. That said, some expected reactivation costs in the quarter ended September 30 will be for rigs readied for October commitments.

As John mentioned, we are expecting to achieve higher pricing in light of higher demand and tight ready-to-work super-spec supply. However, due to varying effective dates of new rates, most of the benefits on margins will be realized in fiscal 2022. Our current revenue backlog from our North America Solutions fleet is roughly $493 million for rigs under term contract.

Regarding our International Solutions segment, International Solutions business activity averaged approximately five active rigs quarter-on-quarter, and we did add a sixth rig late in the third fiscal quarter. Margin contribution was in line with expectations for the quarter, albeit towards the low end of the range. As we look toward the fourth quarter of fiscal 2021 for International, currently, our activity in Bahrain is holding steady with three rigs working, and we have three rigs under contract in Argentina.

During the quarter, we expect a little churn in our international rigs as a rig in Bahrain is expected to stack, but an additional rig in Argentina is expected to commence work. Further, the contracted rig in Colombia is expected to commence operations very late in the quarter. In the fourth quarter, we expect operating gross margins to be between breakeven and a loss of $2 million apart from any foreign exchange impacts.

Turning to our Offshore Gulf of Mexico segment. We continue to have four of our seven offshore platform rigs contracted. Offshore generated a gross margin of $9 million during the quarter, which is at the high end of our guided range. As we look toward the fourth quarter of fiscal 2021 for the offshore segment, we expect that offshore will generate between $7 million and $9 million of operating gross margin.

To conclude third quarter results commentary, I will highlight our Non-operating and Other Segment activity. As a reminder, at the start of fiscal 2020, we elected to set up a wholly-owned insurance captive to ensure the deductibles for our workers' compensation, general liability, and automobile liability insurance programs from October 1, 2019, forward. Our operating segments pay monthly premiums to the captive for the estimated losses based on an annual external actuarial analysis.

The result is a transfer of risk from our operating subsidiaries to the captive for the deductibles, which are our self-insurance retention. The actuarial estimated underwriting expense can vary from quarter-to-quarter as claims developed, get settled, or dismissed. For the three months ended June 30, 2021, the estimated reserves in the captive were adjusted upward for self-insurance claim developments.

Now, let me look forward to the fourth fiscal quarter and update fiscal full year 2021 guidance as appropriate. Capital expenditures for the full fiscal year 2021 are now expected to be at the low end of the previously guided range of $85 million to $105 million with, as mentioned earlier, more spend expected during the fourth fiscal quarter than the preceding three-quarter average. This back-end weighted fiscal year spend is primarily due to some skidding to walking pad capability conversions as a result of select customer demand.

Our expectations for general and administrative expenses for the full fiscal year '21 have not changed and remain at approximately $160 million. We also remain comfortable with the 19% to 24% range for estimated annual effective tax rate and do not anticipate incurring any significant cash tax in fiscal year ‘21. The difference in effective rate versus statutory rate is related to permanent book-to-tax differences as well as state and foreign income taxes.

Now, looking at our financial position. We had cash and short-term investments of approximately $558 million in June 30, 2021 versus $562 million in March 31, including availability under our revolving credit facility, liquidity was approximately $1.3 billion. Our debt-to-capital at quarter end was about 14% and our net cash position again exceeds our outstanding bond. As a reminder, we have no debt maturing until 2025, and our credit rating remains investment grade.

Given our current outlook for activity, we expect to see minimal changes in our cash balances at fiscal year-end compared to June 30 balances. At today’s activity levels, we believe our 0.4 early operating earnings will fund our maintenance capital expenditures, debt service costs, and dividends. Our expectations beyond next quarter for rising activity drives our run rate cash generation higher, while on the other hand, at least in the short term, a good portion of that higher cash generation will be consumed by reactivation expenses and working capital investments required to enable that future higher activity.

As John mentioned, cost control remains a high priority. Since we last spoke on the March earnings call, we are advancing along several workstreams that are being carried out in parallel to adjust our cost structure. Some items expected to be completed in the fourth fiscal quarter will culminate in approximately $7 million in annualized savings primarily in operating expenses. We are working on other initiatives that will be completed in the coming quarters to further optimize future run rate expenses. As these plans progress, we will provide updates on future calls about the expected magnitude and timing of these various cost structure initiatives.

That concludes our prepared comments for the third quarter. Now, let me turn the call over to Reid for questions.

Operator: At this time, if you’d like to ask a question, please press the * and 1 on your touchtone phone. You may remove yourself from the queue by pressing the # key. As a reminder, if you're using speakerphone, please pick up your handset to provide optimal sound quality. Again, that is * and 1.

We will take our first question from Tommy Moll with Stephens. Please go ahead.

Tommy Moll: Good morning and thanks for taking my questions.

John Lindsay: Good morning, Tommy.

Tommy Moll: John, I wanted to start on the issue of cost inflation. Any anecdotes or numbers you could offer in terms of what you're seeing, whether it be on the labor side, transport, materials, anything that's hitting that average daily cost line you'd want to call out?

John Lindsay: Tommy, our labor costs have not increased. We didn't reduce our wages in the field operation during the downturn, and so there hasn't been any impact there. There's not really anything specific that we can point to right now other than just the cost associated with reactivating rigs. I think overall, you've heard a discussion just in the industry in general in terms of tubulars, both casing as well as drill pipe, and I think that's, you know. Drill pipe is probably something that will be, you know, something we're going to have to be acquiring more of in the near future. And I would imagine with steel prices, that the cost of tubulars are going to be higher there. So those are the things that come to mind right now on the inflation side.

Tommy Moll: That's helpful. Thank you, John. I wanted to follow up on the geothermal comments that you made. In the earnings release, you talked about some investment opportunities into other companies. So I just wondered if you could share any thoughts around what those might look like, or should we think about these as likely modest-size investments or something larger? And more broadly, just anything else you want to offer in terms of the opportunity you're going after there with geothermal generally would be great.

John Lindsay: Sure. Well, like we said in our remarks, we think it's a great opportunity that there are several different technologies that are out there that are much different than conventional geothermal that we've seen forever. I mean, I remember hearing about wells we drilled probably back in the '60s and the '70s but much different type of operation. I think these are opportunities for us, yes, to make investments in the companies, which we have, but they've been modest investments. But it gets us a seat at the table and there are some partnership opportunities. There's some transferable expertise that we have as a driller and as a technology provider that we can use. So we've made some really strong, what I would consider early partnerships with three different companies, and I think we're going to actually have one operation that will be starting up here soon, a drilling operation, if I'm not mistaken. So that's encouraging. Mark, do you have anything?

Mark Smith: No, John. Just that as it relates to that drilling operation, we have some of these investments into these early partnerships that are in cash and some are in the form of in-kind investments through the drilling services. In addition to the three John mentioned, we have a couple of other things in the pipeline, including an LOI on the line. So, excited about a variety of different technologies in the geo spectrum, including the closed-loop system John mentioned in the prepared remarks as well as some other burgeoning technologies as well.

Tommy Moll: Thank you both. I'll turn it back.

John Lindsay: All right, Tommy. Thanks.

Operator: Again, that is * and 1 to ask a question. We'll go next to John Daniel with Daniel Energy Partners. Please go ahead.

John Daniel: Hey, good morning, guys. Thank you, guys, for…

John Lindsay: Hi, John.

John Daniel: …letting me in the call. Hey, I'm driving here, so I might have missed something. But if I heard you correctly, opportunity for, call it, 50 to 75 rigs across the U.S. by year-end?

John Lindsay: Yes.

John Daniel: And mental math says here about 25% of the U.S. market ballpark, give or take, and you have an excellent reputation. So my question is, what if you just said "no" to your customers if they don't want to sign your pricing model? What happens?

John Lindsay: Well, I would imagine there would be – well, first of all, that, you know. You know us, that wouldn't be our approach. We -

John Daniel: No, I know that's not your style, just it's a hypothetical.

John Lindsay: Right. We see this as a, really as a partnership.

John Daniel: Right.

John Lindsay: But clearly, the market is tight and customers are looking for the best solutions. They're looking to have better outcomes, more reliable outcomes. We have a great track record for starting rigs up out of stack. As I said in the remarks, there's less than 10 rigs that have worked in the last year; everything else is 15 to 18 months. I mean, they've been idle for a long time. So, you want to make certain that you're working with somebody that's going to be able to deliver coming right out of the chute. So, I, you know. It's a great question, but a difficult one to answer. I think in general; we'd be able to – and really, the encouraging news is that we do have customers that are interested in shifting the model because they see better results out of it. So while there's going to be some customers that are going to want to continue to use the day rate model, that's fine. We'll obviously be pushing pricing on the day rate model as well.

John Daniel: Do you find that those willing to sort of embrace that model in the view, are they, you know? I don't want to say private companies aren't sophisticated; that would be offensive to some of my friends, but is it the larger public people that are more likely to embrace the model or no?

John Lindsay: John, in past cycles, I would, you know. Of course, we didn't have near as many rigs working for private companies back in those days. But I've been very encouraged that whether a super major, large independent, mid-cap, PE-backed, small private company, across the board we have customers that are interested in technology. They're interested in trying to figure out how to be more effective, more efficient, more reliable. I mean, we're all trying to do this, right? We're trying to make our business as efficient and effective as possible, and we're working together with other suppliers on location to do that.

So, I see it as really across the board, and I think we'll continue to see that trend. A great example is, look at the number of private companies today that are using AC drive super-spec rigs, whereas three years ago, in many cases, they were using smaller players with SCR rigs and even some mechanical rigs.

So, there's a big shift. Those private companies that are the most sophisticated, that are the best in doing what they do, they're the ones that are getting the investment dollars, and we're just pleased to be able to partner with them.

John Daniel: Okay. Well, very good color and good anecdotes in the messaging or on the prepared remarks. The final one for me, more, I guess, housekeeping, I guess, but can you remind me where you peaked in Argentina? And then, just some thoughts on that specific market as you head into next year.

John Lindsay: I want to say 10 or 11. I guess, was it 10 to 11, Dave? Do you remember the account we had at the map?

Cara Hair: Eleven.

Dave Wilson: Yes.

John Lindsay: Eleven? Yes. So, we have three working now and the fourth one is, as we said, about to go back to work with discussions with operators for even more interest.

John Daniel: Okay. Thank you, guys, very, very much.

John Lindsay: Thanks, John. Be careful.

Operator: We'll go next to Vebs Vaishnav with Coker & Palmer. Please go ahead.

Vebs Vaishnav: Hey, guys, thank you for taking my question.

John Lindsay: That's all right.

Vebs Vaishnav: So, it seems like the near-term dated improvements can come from as the rigs that have been idle for a long time, they have to be unstacked. Maybe if you can just frame it for us, like what is the rig reactivation cost today, where can it go, and how are you getting paid for that? And maybe just on top of that, if you can think of – if you can help us just think about what drives day rate improvements from thereon, given we still have about 200 super-spec rigs available. That will be helpful.

John Lindsay: Vebs, we'll start – I'll start with just the reactivation process and then turn it over to Mark. But I think cost-wise, we're probably, at least in our fleet today, $400,000 to $500,000 to reactivate a rig. And early on, as you think about how many rigs we've reactivated, we've reactivated, I think, 76 or 77 rigs. So those early rigs were $100,000, $150,000. So, as we've gotten deeper into the rigs that have been idle a longer period of time, obviously, it costs more money.

Our goal is to get that reactivation cost paid back, and there are several different ways to do it. Obviously, term is, you know, a portion of the term or performance-based pricing. But we're just not going to go out and reactivate a rig and spend $400,000 or $500,000 and just drill one well. We're going to have to have quite a bit of work lined up, and then again, we're going to want to be able to share in the improved outcomes that we're delivering. And fortunately, like I said before in our prepared remarks and the earlier question, we do have customers that are willing to do that. What else to add on to his question?

Mark Smith: I'll just footnote that with some little bit of numbers detail, John. And if you think about, Vebs, the margins from our perspective, really the regular apples-to-apples, quarter-to-quarter operating margins bottomed out in Q4 of fiscal 2020. And what we've seen this year, margins are affected by these recommissioning costs primarily. And if you think about what we just guided for Q4 that we're in now, $8 million. If you do the math on that, that can basically equate to about $700 a day detriment to our Q4 earnings. So, in the absence of that, Q1 fiscal '22, $700 improvement in margins just for those reactivated rigs. Is that helpful?

Vebs Vaishnav: Yeah, fair. And actually, that's a good segue into my next question. So you guys, obviously, have done a good job on bringing down the costs. You are still working on that, I can understand. Let's say, in a couple of years, maybe if we are talking about 200 rigs, H&P rigs working, how should we think about normalized cost where we don't have this rig reactivation cost and we have kind of normalized the base cost levels? Can it be back to, say, $13,000 and $14,000 –

Mark Smith: That would be –

Vebs Vaishnav: Sorry.

Mark Smith: Sorry, go ahead.

Vebs Vaishnav: Oh, I was just trying to say, if it would come back to $13,000, $14,000 level, or is that a different level now?

Mark Smith: It's TBD. There are pressures in multiple directions, but just to remind you a little bit, last year, we had significant across-the-board cost reductions. I think we took in the last fiscal year, about $50 million out of OPEX, $25 million out of SG&A, and that was to reduce what had been a growth scale for the company. So we did not cut to the bone, and we have the largest super-spec capacity, so we have available to put back to work, and we have the highest public company exposure, which positions us well, as John mentioned, for potential calendar year 2022 budgets and resulting rig additions.

So, what we're working on now, Vebs, is really further cost-out initiatives that are very targeted. We're trying to improve efficiencies internally in processes, service delivery models, automation, and technology. So that $7 million we just mentioned is the first installment as we continue to work through numerous workstreams internally.

It's too early to tell. But suffice it to say, we are working to get that historical daily average cost back down and then just see how the market moves in the interim, not related to any inflation questions. As John said, we certainly aren't experiencing that in labor today, but we just have to see as we unfold through the coming quarters what happens if the pressure's the other direction.

Vebs Vaishnav: Maybe if I can ask, squeeze in last one? So, obviously, you guys lowered the cap ex budget towards the lower end for this fiscal year. Given the steel prices increasing and activity increasing, how should we think about cap ex for next year?

Mark Smith: Well, we've been at this lower cap ex level, as you said, and in the short short-term, we hope to continue a bit of momentum in that range. But I think it's early days. We're actually in our budgeting process as we speak, so not ready to be definitive yet. But through fiscal '22, I could see – we're south of $500,000 per active rig maintenance cap ex per annum today. I could see us going from a $500 million to $750 million range in fiscal '22, although as I said, early days in our budgeting process. And then as we move through time, maybe to fiscal '23, prognosticating back to the historical range of $750,000 to $1 million.

So, we're still benefiting from being able to harvest a lot of the componentry that we had back when we were scaled up to be a larger growth company. As we move through time and reactivate rigs, we'll obviously have to eventually catch back up with harvesting those components that have really benefited us here in fiscal '21.

Vebs Vaishnav: That's helpful color. Thank you and thank you for taking my questions.

John Lindsay: Thank you.

Operator: We will go next to Waqar Syed with ATB Markets. Please go ahead.

Waqar Syed: Thank you for taking my questions. John, as your rigs return back to work in the international markets, do you expect the day rates to be higher than what they were getting before they were stacked, or do you think there are going to be discounts versus prior day rates?

John Lindsay: Well, we have some rigs that have gone back. I'm not certain on what our level of pricing is today versus when they idled. I don't know, Dave, if you do or -

Dave Wilson: No, it's going to vary.

John Lindsay: Yes. I think it's, some cases, they'll probably be similar. And again, I wish I knew more of the details, Waqar, but I don't at this stage. I would imagine early on, there'll be probably some discount compared to when there were more rigs running just from a supply/demand perspective.

Waqar Syed: Okay. So, the market right now for International generally, you would say is still… despite reactivations, cost of reactivations, rates are likely to be softer for now until maybe a year or so from now when the market tightens a little bit. Is that a fair statement?

John Lindsay: It's really hard to say, Waqar, to say a year. I mean you heard us say before, it's really hard to see out more than a quarter or two, but it doesn't take much activity to tighten that rig count – rig supply up pretty quickly in countries like Argentina as an example. And in that sort of a case, I think we could see some improved pricing pretty quickly. But the international market has just responded very slowly, and again, our expectation is it's going to pick up here soon, but it's hard to say that much on the pricing side.

Mark Smith: John, I'll just add to that. I think in certain markets, it could be analogous to what we've been talking about today with the U.S. For example, some of these customers in Argentina are interested, Waqar, in super-spec. So again, you get to that very tight supply meeting that customer demand, and that is, as we are experiencing in the U.S. now, it's very helpful to pricing.

Waqar Syed: Yes. Now, in Bahrain, you mentioned that your rig is stacked. In general, our view would have been that more rigs are going to go back to work, so this is kind of a surprising data point that a rig is being stacked that was working. Is there anything specific to that particular rig or that particular client, or how should we be reading that datapoint?

Mark Smith: It's just where the customer is at this point in the program.

John Lindsay: Yes. I think it's budget driven. It's one of those things that we're so good, we drilled ourselves a little bit out of work.

John Lindsay: And so, I think we had three rigs running and they just have enough budget to run two for the next whatever period of time, my assumption would be the third rig would eventually go back to work. But generally speaking, there's not been a huge change in the program.

Waqar Syed: Okay. Just last question. We hear about labor shortages and especially on the trucking side and with truck drivers. Are you seeing any inefficiencies develop in the whole drilling process because the sites are not getting ready on time, pads are not getting ready on time, or a customer or any other service companies are not getting equipment on time at the well site, and thus, time to drill wells is increasing, or you're not seeing that at the moment?

John Lindsay: Waqar, at least in our operations, I can't really speak to others, we've got very high levels of performance, efficiency levels are high. Our customers are managing their pad construction well. I mean, you're right; there is really an overall national shortage on truck drivers. To my knowledge, we've not had a huge impact in moving our rigs.

The good news is, is we don't move rigs as often as we used to because of pad drilling. But in general, I see us performing at very, very high levels. Really, we've not had any challenges to speak of related to people. We've got a great group of people in the field, great leadership, and a pretty strong bench. So, we're pleased with that. But I can't think of anything where we're having to wait and we're seeing inefficiencies.

Waqar Syed: Great. Thank you very much. Appreciate the answers.

John Lindsay: Thank you, Waqar.

Operator: We will go next to Neil Mehta with Goldman Sachs.

Ati Modak: This is Ati on for Neil. So looking at the rest of the year and into 2022, most of the incremental activity here on seems like it could be driven by the majors, potentially some private as well. Could you remind us of the exposure you have with them relative to your peers and what the upside could look like for you in terms of the number of rigs that could be added from here on?

John Lindsay: Sure. That's a great question. I will say that it's interesting and we've all heard these numbers. But one snapshot is the last 100 days, 42 rigs have gone to work and 39 of those rigs were from privates. So, privates have really been making a difference in '21. In about 75% of the work, we got 11 of those 42 rigs.

But I think going forward, it's going to be a combination of the majors, large independents. I think just the publicly traded companies in general, when budgets are reset for 2022, let's assume the current budgets are $45 million to $50 million. If you think about a $60 million, $65 million-type number, it's going to have, I think, a pretty significant pickup in activity. So, I think it could be that we're seeing some of that even hitting at the back half of the year.

I think our current exposure, I think we've got 35% of our current fleet working for privates. Historically, it's been 20%. So we're very pleased with that ability, but we still have 65% of our current fleet with the publics.

And if you look at those customers who were our largest customers, those top 10 customers, prior to the pandemic, those were the companies that reduce their rig counts the most. So again, our hope is that those companies are responding in a strong fashion for a much stronger '22, and we'll see an outsized growth on our rig count. That's our hope.

Ati Modak: Great. And then it looks like around 80% of current active rigs are super-spec based on the supply numbers you provided. What do you view as the upper limit to the super-spec rig share of the active U.S. rig count?

John Lindsay: Well, as you said, it continues to grow share. I think today, Dave, it's 70 -- there are 70 still SCR rigs, legacy rigs that are out there working. We're seeing really just every type of E&P out there, small and large that are continuing to shift to super-spec capacity. I mean, it really makes all the sense in the world because you're going to, you know. Laterals are getting longer, well complexity is getting greater, and those rigs just have a much greater capacity to drill those wells and do it in a really efficient fashion. I mentioned in my prepared remarks about data. It's really difficult to utilize a dataset coming off of an old technology, SCR, mechanical-type rig. So, the data set that we're creating coming off of our FlexRig platform really enables us to utilize technology and software solution that you just can't do with an older-generation rig. So, I think at some point in time, you're just going to continue to see those rig numbers continue to drop and get displaced because the value proposition is so huge.

Ati Modak: Great. That's very helpful. Thank you. I'll turn it back.

John Lindsay: Okay, thank you.

Operator: We'll go next to Derek Podhaizer with Barclays.

Derek Podhaizer: Hey, good morning. So, it looks like your margin…

John Lindsay: Good morning.

Derek Podhaizer: …implies margins are [struggling] a bit for all the reasons you mentioned before, and, Mark, I think you touched on it a little bit, but thoughts on if fiscal 4Q represents the bottom in the North America Solution margin, and if you see margin growth heading into fiscal 1Q '22?

Mark Smith: Yes. Well, I said Q4 '20. So certainly, we're going to continue to have, as I've mentioned, drag on current earnings with the recommissioning expenses. But as those free up eventually and you have a more normalized higher rig count, certainly more cash flow and margin from the absence of those costs. But maybe more importantly, all the stuff John has been talking about this morning related to pricing that can help drive up those margins. So, I think those two things added together bode quite well potentially for fiscal '22.

Derek Podhaizer: Got it. So just to clarify, do you believe margins will come up from this 6,600 implied range even with the burden of the reactivation costs, just thinking about the trajectory as we start in fiscal '22?

Mark Smith: Well, that's going to depend. We just have to see how many reactivations we have in those quarters that we have not yet guided to.

Derek Podhaizer: Okay. Understood. I want to expand on the geothermal market. I want to get your thoughts on what you see as a total addressable market for you guys? And maybe any insight on what that can mean in your top-line growth over the next three to five years as this starts to unfold?

John Lindsay: I mean, obviously, we've done some modeling, but I think it's still too early for us to put a number out there because these technologies are really still in the development stages. I mean, the technology looks great, but we've got to go out and actually do the work and see what kind of energy can be generated over time. But I think it could be a bit of a needle mover, and again, I think the internal capacities that we have and expertise we have is really aligned well with that. But I just think trying to give a number today is pretty hard to do.

Mark Smith: And just a footnote, some details why that's so hard. In our own research and modeling, certainly what we're trying to do is have an alternative use for the installed rig base of assets, and we do see opportunity for that. But as John's saying, what that is, it's hard to pinpoint if you even go to U.S. Department of Energy potential well that could be drilled, it just varies wildly. And why is that? That's because all of these technologies are in such early-stage development, it's hard to know which of them will be successful, and if successful, to what scale they'll be applied. So more to come, but early days.

John Lindsay: Yes. Yes and again, I think one of the things that's exciting for us is the transferability of these technologies that we're using to drill these horizontal wells. We drilled a U-shape horizontal well a couple of weeks ago that was just amazing when you look at it, and you just think about that type of technology and how we're just continuing to advance in our capabilities. But as Mark said, it's just impossible to nail a number at this stage.

Derek Podhaizer: Right. No, fair enough. All that color was very helpful. And then if I could just squeeze in one more, you talked about some of the newer equipment on the rig side, emissions-friendly, also helps economically. Can you just maybe give us some details around the emission savings when thinking about highline or dual-fuel or some of the power management with battery backup? I'm just curious your thoughts on how much emissions this is saving and how much of a needle mover this is for your customers as far as being used more friendly with ESG.

John Lindsay: Yes. Highline power has been around for a very long time that we've worked. In fact, the very first FlexRigs that we built, the very first one we built was actually on highline power. The problem is, of course, with the local grid. So, again, and then it also depends on where is the power that's generating? Are you burning natural gas or coal? As an example. So, clearly, the natural gas is just a super clean fuel. What we've seen as a company, over to Dave, whatever the last two, three years we've had, what's our percentage in emission reduction?

Dave Wilson: Around 10%.

John Lindsay: 10%, 11% and a lot of that, I would say, we've been successful by more manual methods. So I think as we become more effective with power management at the rig site, even burning diesel, we're going to continue to improve our emissions. I don't have it on dual-fuel, or I don't -

Mark Smith: No, it's really going to depend on the location and application.

John Lindsay: Yes. Yes, there are some challenges at times associated with dual-fuel applications with methane slip. But what we do know is that we are continuing to drive improvements. You'll see that in our sustainability report that we'll publish later this year. Obviously, the battery power has some advantages at this stage of the game, not super economic because the cost of the batteries. There are some other solutions that we're working on internally to help our customers together, working with our customers to reduce emissions. But I don't have any real hard and fast numbers at this point.

Derek Podhaizer: Got it. Okay.

John Lindsay: More to come on that. You'll see that in October/November timeframe.

Derek Podhaizer: Great and I look forward to it. That's all my questions. Thank you.

John Lindsay: Okay. Thank you.

Mark Smith: Time for one last question, Dave, because we started a little late.

Dave Wilson: Yes.

Operator: We'll take our last question from Arun Jayaram. Please go ahead.

Arun Jayaram: Hey, good morning. Arun Jayaram with JPMorgan. John, you mentioned -

John Lindsay: Good morning.

Arun Jayaram: Good morning. You mentioned for the calendar year you expect maybe 50 to 75 incremental rigs industry-wide with some potential for maybe a mixed shift over time towards the publics. I was wondering if you can maybe comment on at a basin level where are you seeing some of the incremental rig demand, and are you starting to see some improvement in demand conditions in natural gas basins with natural gas now, at least the stock prices, near-term prices at $4.00 per MCF?

John Lindsay: We are. We were actually talking about that this morning. It's been about 30 days or so since that real uptick in nat gas prices, and we're starting to see that flow through and hopefully going to begin to see customers investing more in the drill bit for the natural gas side. I think that's encouraging. So any of the natural gas areas, some of the gassier areas, even in the Eagle Ford, we're seeing some interest. So really, it's kind of across the board as you look at the – whether it's in the Northeast or the other gassy basins.

Arun Jayaram: Got it. And then you mentioned in terms of the majors, you would expect to call it their activity has been actually down since the bottom of the rig count, so you would expect the new budgets and next year that could rekindle some of that demand for the majors, is that correct?

John Lindsay: Right. That's what we're expecting and what we're seeing in discussions with customers. And it really, it only makes sense. Everybody has done, all of the E&P's have done such a great job in terms of being disciplined and sticking to their budgets. Clearly, in a higher commodity price environment, whatever that oil price may be, $60, $65, $70, we're going to see much larger budgets than what we have today. So I do expect to see the rig counts grow with the majors as well as really all of the publicly traded companies that we've had conversations with, at least, have talked about having rig needs late Q4 or into the first calendar quarter of '22.

Arun Jayaram: Great. And then just my follow-up. John, the whole industry has been driven by daywork kind of philosophy, right, from the history, and you've articulated kind of the evolution of your contracting philosophy. It's just more wanted to ask you about what kind of barriers do you see from traditional E&P, major procurement departments who are focused on daywork? So, I'm trying to think about how – is it difficult to break down some of these historical barriers as you kind of move forward?

John Lindsay: I would, you know. I think I would characterize it as change. Well, change is never easy, and this industry isn't easy to change. I mean, we all struggle with it. But at the same time, we're also challenged in each of our companies to figure out ways to do things better, more efficiently, and you can't – you save your way to prosperity. You've got to invest in -

John Lindsay: You've got to invest in technologies. And so, yes, I mean, supply chain plays a role. But in the customers, again, like I said earlier, large and small that we partner with today, there's a value component that supply chain recognizes.

So using that example of, if we're able to work together, deploy our technologies, and be able to share in those savings and we're saving the customer $0.25 million a well, well, that's really what they want, right?

And so, it's really leveraging the technology, building commercial models that make sense for both parties. We just want to share in that because we're investing real money in our technology solutions. We've invested millions and millions of dollars in these solutions, and they, at the end of the day, add great value for customers.

So, it's like anything. It's slow in some respects. The early days of the FlexRig were not easy. But we have early adopters, and that's the great news. This business is pretty small, so people share ideas and begin to want to try it out. So we're encouraged by that.

Arun Jayaram: Great. Thanks a lot, John.

John Lindsay: All right. Thank you. Have a good day.

Operator: There are no further questions. I'll turn it back to the speakers for closing remarks.

John Lindsay: Okay. Thanks again, everybody. Sorry for a little bit of a late start there. But again, we remain optimistic about the industry and how things are looking for the rest of '21 and going into '22. So look forward to talking with you in November. Take care.

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