Company:	**Dragon Oil plc**
Presenters:	**Hussain Al Ansari, Chief Operating Officer**
	Tarun Ohri, Director of Finance
Conference call:	**2011 Interim Results**
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Tarun Ohri: Good morning, ladies and gentlemen, and welcome to the 2011 Interim Results of Dragon Oil. With me, Tarun Ohri, the Director of Finance, is Mr. Hussain Al Ansari. He's the Chief Operating Officer of the Company. Dr. Abdul Jaleel Al Khalifa is not available today so Mr. Hussain Al Ansari will field all the technical questions in the Q&A session later on, after the presentation.

So if I may look at the highlights of the Interim Results, we have had a production growth of 25% and currently we are producing above 60,000 barrels of oil per day ("bopd"). Our revenue, net profit and cash from operations have doubled and we will talk about this later. Our number of wells drilled has increased to 12 wells as compared to 11, which we had indicated earlier. This is in line with the faster drilling programme and the rigs we have deployed. Currently we have three rigs drilling. Our infrastructure is weighted towards the second half of the year and we continue with our forecast spend in 2011-2013. We talk about our dual strategy for gas monetisation and also the M&A as we go along.

On the production growth, our average production for the first half of the year was 58,000 bopd as compared to around 46,000 bopd last year, and this was on account of two reasons. One was transition to the new infrastructure which is completed, the 30-inch trunkline as well as the expanded Central Processing Facility ("CPF"); and the additional wells we have put in place into production, we drilled about six wells from the Lam 28 using the Iran Khazar rig. The Iran Khazar rig was used on Lam B and on Lam 28 we used the converted land rig, which is the NIS rig. So we had a strong production growth and we continued to deliver on our production targets. We had about 25% growth and we forecast a growth of up to 20% for 2011 on 2010 numbers.

Going forward to the ongoing drilling programme, we've completed seven wells off the 2011 drilling programme. Currently we are drilling three wells, one each by Iran Khazar, Rig 40 and the NIS. After completion of these three wells, we will be drilling two additional wells and hopefully we'll also complete one workover with the Iran Khazar rig of our existing wells. There will be a sidetrack on Lam 13 platform, and we'll use the Rig 40 for that sidetrack.

On the infrastructure upgrades, we are moving ahead with our infrastructure programme and we expect to spend in excess of $200 million, and we have awarded the Zhdanov B platform contract and we expect that platform to be installed by the first quarter of 2012. We also awarded a contract for Block 4 riser platform, which is an in-field gathering station, to enable us to drill and produce and bring the crude oil to onshore processing facility. We also look forward to awarding two additional platforms in the Lam field, which are the Lam D and the Lam E, over the next 18 months, and there would be an ongoing construction of platforms to enable us to exploit the field and the reserves of 639 million barrels of oil that we stated as of December 2010. Our Super M2 jack-up rig is expected to be delivered in the first quarter of next year, along with the land rig in 2012, which would drill from the Zhdanov A platform that is currently being constructed and is expected to be installed in water at the beginning of next year. The Super M2 jack-up would be drilling from the Lam C platform, which is also being constructed.

On the gas monetisation, as you are aware that we've completed the field study and we are awaiting the completion of the compressor station of the government, and we expect it to be completed in about a couple of months' time. We'll be able to push in our unprocessed raw gas into the system and from there into the network of Turkmenistan, and we hope that we'll be able to negotiate a short-term sales agreement realising a certain value for the gas, and once our Gas Treatment Plant ("GTP") is completed in 2013 or early 2014, we'll be able to deliver processed gas into the system, and that's the time where we expect to realise closer to market value for our gas.

Moving onto our diversification strategy, we are looking at assets in the MENA region, which is Middle East/North Africa. We're looking at South East Asia and Central Asia as well. Our acquisition strategy includes looking at corporate acquisitions and also farm-in at asset levels in various regions we look at. There is nothing much at this point in time we could announce, but we're looking at a large number of prospects and primarily we're looking at assets with upfront production and exploration upside, but we have expanded that to look into select assets, which have exploration and we would be farming in to certain assets, and these are primarily in the MENA region. So all this is work in progress and we don't have any announcement to make at this point in time.

Moving over to the financial results summary, our revenue has increased by 91%, leading to a net profit increase from US$137 million to US$309 million, which is a 110%

increase. Our earnings per share have increased from US$0.26 to close to US$0.60 and we have declared a dividend of US$0.09 per share for the interim period. We maintain our unleveraged position; we hold a cash balance of about US$1.4 million.

Next, the income statement, our revenue was up to US$527 million on the back of a strong Brent price for the first half of the year, which was around US$111 as compared to the first half last year when the Brent traded at about US$77 a barrel. Our production this year for the first half was 10.5 million barrels and we increased our production by, like we said, about 25%. The increase in revenues is split almost equally between the volume and the crude oil price, so about 55% was attributable to the crude oil prices and the balance was on account of the increase in the sales volumes.

Our cost of sales moved up to US$109 million. Our operating costs have remained in line with the previous years and we have always given a guidance in the past that our operating costs would range between US$3-4 a barrel. Our operating costs have fallen slightly because of the increased production base. There has been movement in lifting positions and that has caused an increase in the cost of sales. Our administrative expenses have gone down by US$3 million to US$10 million. That's a result of Corporate Social Responsibility ("CSR") activity in 2010 so that one-off expense is not in the first half of the year, but we have committed to build a polyclinic, and that polyclinic in Hazar will be completed over a period of the next 12 months and that, this is a corporate CSR activity, which you will see appearing in the admininstrative expenses going forward.

Our operating profit margin and operating profit has increased to US$407 million as a result of the higher oil price, a result of controlled operating costs and increase in production capacity. And that takes us to the income tax expense. We pay income tax in Turkmenistan at about 25% and our income tax provision is US$107 million for the first half of the year. That leads us to the net profit of US$309 million.

The next slide is on the cash flow. Our closing cash is US$1.4 billion, which includes abandonment and decommissioning funds ("A&D") of US$216 million. As you would have noticed in the press release, we have said that we mobilised an A&D plan in view of using up this fund, which is set aside specifically for abandonment and decommissioning activities over the next 24 months. Majority of our deposits are term deposits and these are held for periods ranging from one month to six months and cash is maintained with international and banks in the UAE and it is spread over nine banks. The cash generated from operations for the first half of this year is US$414 million, which is the cash generated after operations, after tax and if the Brent price continues at a range of about US$90-$110 a barrel—at this point in time there's a lot of pressure on the oil prices but we expect to be able to continue to generate cash from operations from the second half quite similar to the first half of the year.

Moving onto the balance sheet: for the first half of the year, it shows we have a healthy balance sheet. We had capital expenditure of a low quantum of US$151 million and as I've stated earlier, we expect the expenditure and projects activity to pick up in the latter half of the year, and we would be spending about US$200 million on infrastructure and probably an equal amount on drilling expenditure as well.

Our current liabilities are US$457 million, mainly comprised of abandonment and decommissioning liability reserve, which we have created, and income tax liabilities as well. So these are the two main components in the current liabilities.

Moving onto capital expenditure, which comprises drilling and infrastructure, our total capital expenditure was US$151 million, that was attributable to drilling of the six wells, which we completed in the first half of the year and infrastructure spend on Lam C and on Zhdanov A. These are the two platforms currently being constructed and Lam C would be installed by the end of the year, this is a jack-up platform; and Zhdanov A platform will be installed in the first quarter of next year, this is a platform for land rigs.

The last section of the presentation is the outlook on drilling. I've already spoken about the wells to be drilled in 2011 and looking forward for 2011-13, we expect to drill 40 wells, including five appraisal wells. Next year we would be having the new jack-up rig as well as the 3,000 hp rig, and we would expect to be able to drill according to plan with those two new rigs. On infrastructure, other than Zhdanov A platform and the Lam C platform which we talked about, we'll continue to install platforms, which would be required to support the 40 wells in our programme. We maintain our guidance for 2011-13 with respect to our production, which is about 10%-15% on an average per annum over the next three years. We'll be giving further guidance in October with regard to three-year look ahead in September—October.

The next slide on the outlook looks at the gas development and the gas monetisation and as stated we look at the dual monetisation strategy with respect to our short-term gas monetisation for the unprocessed ("raw") gas, which will be supplied and thereafter, once the GTP is on, we'll look at getting market value for our gas. We continue our discussions with the Turkmen authorities. We have not signed a Gas Sales Agreement yet and we hope before we commence deliveries to the Turkmen, we would be able to sign a Gas Sales Agreement.

We continue with the diversification strategy we have discussed, and the dividends, the dividend of US$0.09 was declared by the Board as 2011 interim dividend and we would maintain the level of dividend if our performance and the oil price hold as per plan, and obviously the oil price is something, which is a major contributor to our bottom line and we can't predict oil price at this point in time. Hopefully it should stay in a band of US$90-$110. Though, as you realise, we can operate profitably below those levels as well.

That's all from the presentation from our side. Now I open the floor for questions from everybody on the floor.

Kenan Najafov, Citigroup: Good morning, I was wondering if I can ask a couple of questions, first of all on the operating profit margin. You have touched on it basically but I wonder why the operating profit margin has grown so much in. And it's not just in my, in my calculation, it's not just explained by the oil prices or by revenue if you wish. So the major surprise today to me is not about the revenues but very much about the costs I guess. So anything you could share on that would be great. And the second question is about the interim dividend. Is this sort of designed as being half of the full year dividend? And third question is on your macro view, in terms of the recent concerns, what is your company view for the rest of the year? Thank you.

Tarun Ohri: Okay, thank you for that, for those three questions, and the first question was on the operating profit margin. There are three components to that. First, it's mainly the change in the cost of sales and the administrative expenses. On the administrative expenses, I said there was a one-off cost last year, which is not there this year but that's a small number. The other part is the depletion charge. The depletion charge last year was about US$91 million for the the half year. This year it's US$88 million so proportionately it's much lower, and that arises from the recognition of the gas reserves in late 2010. There is an effect of the lower depletion charge as compared to the previous year. The other aspect is the lifting position. The way the PSA works, at any closing date, we are unable to lift exactly our entitlements, so there's always either an underlift or an overlift in number of barrels. So this has an effect on cost of sales and the operating profit is mainly recognised on the basis of entitlement barrels roughly. So like I said, the operating costs have roughly remained the same but our in-field or Turkmenistan operating costs have come down slightly as a result of higher tariffs. So these are the three main reasons for change in the cost of sales and administrative expenses, which have led to a higher gross profit margin.

On the question of the interim dividend, we have stated in the dividend policy that dividend would be based on our performance and the environment at that point in time having taken into consideration various aspects. The dividend of US$0.09 was declared by the Board, and we expect this $0.09 to be in a range of 40%-60% of the total dividend for the year, and obviously once you've started with the dividend policy, it would continue, and unless of course there is a downturn in the markets and impact on the oil price, we would maintain the dividend in future years. And the only part we can control is to grow our production, and we are quite comfortable that we would be able to match what we forecast and our production profile will grow at 10%-15% over the next three years. And oil prices of course, anybody's guess. I hope that answers your questions.

Clodagh McCarthy, Goodbody: You mentioned that you're currently drilling three wells and two after that. I was just wondering when we can expect the results. And secondly, I was just wondering if you could give us a bit more colour around the compression station and the timeline associated with the gas contracts please? Thank you.

Tarun Ohri: Okay, currently we are drilling three wells, one each with Iran Khazar, Rig 40 and NIS, and we expect these results to come out in this quarter. And obviously there would be two wells after that. On the other question, on the compression station, it's currently being commissioned and will be ready to go in about a couple of months' time. We were expecting that to be completed by the end of August and we are ready to connect to the compression station.

Hussain Al Ansari: Just on the supply, we are ready to supply gas now provided the compression station at the other end in a receiving mode. It's being commissioned as Tarun mentioned, and soon it'll be commissioned, then we'll be supplying the gas as early as September hopefully, you know. That's for the short term.

Tarun Ohri: With regard to the Gas Sales Agreement, being a conscientious operator, we would like to reduce our flare because currently we are flaring about 100 million standard cubic feet of gas and we would, given an opportunity, prefer to push this gas into the Turkmen system and use that as leverage and a discussion point with the Agency, and we are currently pushing for a short-term sales agreement with them at a much lower than market value considering that this is unprocessed raw gas, as we had discussed earlier.

Caren Crowley, Davy: Good morning gentlemen, congratulations on the results. Just a couple of quick questions for you. You talk about looking to lease a new land rig. Can you comment on how powerful that rig is relative to the rigs that are currently in the field? So can it drill to similar depths? Also, is the completion of a well with that rig of roughly the same duration as the completion times for wells currently being drilled at the moment? Secondly, on the production side of things you're going to drill a sidetrack well in the second half of this year. Can you comment what your expectations are for that sidetrack well. Am I right in thinking that the sidetrack is really a horizontal well? On the strategy, you mentioned this morning that you're looking at “select exploration ventures” and I suppose that's new to me and I'm just wondering why, I guess, a change of heart, why are you suddenly considering exploration ventures now whereas you didn't seem to be considering it before? And finally, Tarun, on the unit production costs, you say anywhere in a range from $3-$4 per barrel. There's a lot of talk about hyperinflation in the mining industry and indeed the oil and gas industry, so, you know, what are your expectations for the second half of the year in terms of unit production costs? Thanks.

Tarun Ohri: I’ll take your first question with regards to the new land rig, which is a 3,000 hp rig. Currently the NIS rig is 2,000 hp, so definitely the new land rig is going to be more powerful and we would be able to reduce drilling times, but it all obviously depends on the target. We could have a deeper target or a shallow target. But I believe that in the Zhdanov field, we would be drilling deeper than in the Lam fields. So whilst there’d be some benefit in terms of using a better rig to go to deeper targets, there might not be substantial changes in overall costs for a well.

The second question on the sidetrack, we would be sidetracking two wells on the Lam 13 platform and the sidetrack is not a horizontal well. The two wells we believe we are going to sidetrack, produce very low volumes of crude oil currently and we expect by sidetracking, we would go to a different target from the same well and we would be able to generate about 500-1,000 barrels of additional oil from those wells.

And with regards to the strategy, the M&A strategy, you are right. Previously, I think we had stated that we’re looking at acquisitions with a small amount of production and large exploration or large upside to assets. We have expanded that as a result of looking at various prospects, and there are opportunities in terms of select operational exploration ventures, and these are assets where we would farm-in. These are the prospects we are looking at and obviously we don’t know the outcome yet in terms of what would be the final outcome of that search. So yes, we have expanded the criteria but these are smaller exploration ventures in the MENA region; they are not large deepwater explorations. They are mainly onshore areas.

With regard to the unit production costs, we expect, at least for the second half of 2011, to maintain the same level of operating costs, and there is a lot of pressure in operating costs in Turkmenistan but we don't expect them to grow substantially in 2012 and beyond. The main increase in costs would come in areas of manpower and offshore mobilisation because we are an offshore operator and we need a lot of offshore equipment. So there would be pressure on costs but we don't expect that to materially change our operating cost profile.

Alexander Korneev, Prosperity Capital: It seems to be that the interim dividends that you announced, the UA$0.09, is just slightly more than 10% of the free cash flow that you generated in the first half and the rest clearly goes to the cash position. So my question is what's the rationale of hoarding cash and of not really paying the dividends you can pay? Thank you.

Tarun Ohri: I'm sure in this current environment we have a lot of uses for cash and our new ventures team is looking at various targets. So the prime use of this cash is acquisitions and we are looking at acquisitions in various regions. For example, each acquisition we would look at would range between about US$200-500 million, And this cash also acts as a buffer in case oil price tanks. Our asset in Turkmenistan is self-generating and it's a means to support our pre-investment plans and the cash, the surplus cash generated is primarily to give us better advantage than our competitors, either in a competitive bidding scenario or on a one-to-one acquisition. It adds a lot of strength to our balance sheet and negotiating position. So whilst we are prudent in terms of investing and looking at acquisitions, we are mindful that we need to look at employment of our cash over the longer term.

Tatyana Kalachova, Otkritie: I have a question regarding the gas plant. When do you plan to do the tender and when do you plan to start the construction of the plant? And what would be the cost of this revised, optimized plant, because earlier you said that the plant costs are about $170 million so what would be this plant's cost? And also, would it be fair to assume that the new gas plant would add about 3 kbpd of condensate and 6 million cubic meters of gas per day? The next question would be about the long-term production rates. If we are talking about the production rate after 2013, is it okay to assume that 75 kbpd would be the long-term production; this is the production rate that you are going to achieve if you have 20% growth this year and 10% growth in 2012 and

2013? So, or are you going to grow it further? And the last question is regarding the opex. Would it be fair to assume that when the production grows the opex will grow insignificantly, for example, it will stay at about US$70-$80 million per year? Thank you.

Tarun Ohri: Okay, so that's really packed with lots of questions, so the three main questions of course, one was on the gas plant or gas treatment plant. Initially we had stated that the cost of the gas plant would be about $170 million. We are looking at various ways of optimising this gas plant and we would expect the total cost of the plant to be between a US$100 million to US$170 million. We would obviously know better when we go out to tender and get bids for this plant, but that is the range we are looking at.

The tender of this project would be some time early next year, and this would probably take about 18 months, a year to 18 months to build and construct, and we're expecting a start-up early 2014 for this plant. And this plant would enable us to strip condensate as well, and we'd expect to get about 2,000-3,000 barrels of condensate out of this stripping plant.

With regard to our production growth, we would grow by 10%-15% a year and that would take us to a level of about 75,000 bopd and above in the next two to three years. We have not put out to the market our field production rates because we are looking at field developments and also how the infrastructure, the new infrastructure we put in place in 2010, the 30-inch trunkline and the CPF, how that would react and take all the in-field flow onshore. So once we have greater comfort on the infrastructure, we'd be able to get field production rates as we go along.

And your last question was on the operating costs. We have looked at various scenarios and because of the way we are operating and the offshore nature of our field, there is considerable requirement for things like floating frames and barges as well as vessels for transportation of materials and crew offshore. And it's not easy to get these services or these facilities in the Caspian Sea, and there is pressure on the prices of these services and we expect our operating costs to stay in a range of maybe about US$70-90 million as we progress our field development. It's a large range because of limited services available in the Caspian Sea. At this point in time, we don't know what would be the level on these services and what would be the pricing by the contractors. But hopefully, as we progress our field development, there'll be better options available in the Caspian Sea. Hope that answers your questions.

Vugar Aliyev, Matrix: The first part of my question is about production and reserves. Can you please tell us what your current production is and on your current plans, what do you expect this year's exit rate to be? On reserves, you've had more than six months of production data and you also drilled one delineation well, which is B155. I was wondering if you have a feel on how much of this year's production you would be able to replace at the end of this year, if any. Any guidelines would be very useful. And the last question, Tarun I think earlier on you mentioned about farm-in opportunities, primarily onshore, which would suggest they would be fairly inexpensive from your point of view, but then later when answering one of the questions you mentioned that each acquisition could be between US$200 and US$400 million. So are you considering, or are you pursuing two different strategies to farm-in into selective wells, high potential but lower costs onshore, but also slightly bigger acquisitions? Can you please clarify those two comments? Thank you.

Tarun Ohri: I'll take your last question first in terms of M&A. We are looking at, like I said, various strategies, and the transaction value in all these things would range between US$200-$500 million if you're looking at assets, 2P reserves of about 50 million barrels of oil. But it again then depends on which region you are looking at because each region has its own risks as well as the cost of production varies, whether it is in the MENA region or the Caspian region or other regions. So there is a mix of various cost elements, which play in the acquisition cost. We are also looking at farm-in. What I was referring to earlier was onshore exploration blocks, and these are assets, which we would look to farm-in. We're looking at bidding either in competitive situations or on one-to-one negotiations with current operators. There are various scenarios we're looking at and last year, for example, we looked at over three dozen prospects and there's a lot of work our new business ventures team has done over the past couple of years and the result of these discussions or these bids would depend on bidding strategies of other competitors as well. So there are lots of factors, which come into play for the M&A.

With regard to reserves, you realise that we have 639 million barrels of 2P reserves and we recognise 1.6 TCF of gas, which is equivalent to about 260 million barrels of oil. We still have about 1.4 TCF of gas, which we have classified as contingent resources, and commercialisation or recognition of that would depend on future gas demand as well as the capacity of the GTP, which currently is designed to handle about 200 million standard cubic feet a day.

And reserve replacement obviously depends upon a lot of factors. Our Cheleken Contract Area is mainly a redevelopment of the field, which was earlier developed by the

Soviet specialists. So in terms of exploration upside, there's limited exploration upside or limited opportunity to add reserves in our current field but obviously with certain delineation wells and results of wells in Lam 28 area and other areas, which we will drill, there would be marginal upside and marginal opportunity to add reserves from our existing fields. But because of the fact that it's a redevelopment, lots of wells were drilled by the Russians previously and we've drilled 58 wells, but there's a considerable amount of history in this field and it's mainly a development field with lots of appraisal wells we have planned, about five appraisal wells over the next three years, and that would give us a better understanding and, if possible, to add some reserves to our reserve base.

Yes, our current production rate is above, well above 60,000 barrels of oil per day and we expect that by the year end, we would be able to maintain that level, with the new wells coming on, which would sort of compensate for the decline in the field, and we would be, I could say, well over 65,000. Sixty thousand would be our exit rate for the year.

Kenan Najafov, Citigroup: Hi again, Kenan Najafov, I come back with one question. Can I just clarify the capacity constraints for oil production at the moment across your value chain? What is the current—are there any bottlenecks? What's the capacity at the moment for oil?

Hussain Al Ansari: Also on the production rate?

Tarun Ohri: The two key infrastructure components of our entire processing chain are the 30-inch trunkline, which is 40 km long. It extends from offshore area to the processing plant. We have a processing plant, which would process and separate the oil and water. We have the storage facility as well. But currently, we are able to handle about 100,000 barrels of fluid in the whole system, which includes the trunkline and the CPF. But having said that, there's always excess designed capacity so you could go up to 10% beyond this level.

Tarun Ohri: Yes, thank you, everybody, for participating in the results presentation and all the best. Thank you from Hussain and from me at Dragon Oil.

Hussain Al Ansari: Thank you.