TRANSATLANTIC ENERGY SECURITY DIALOGUE

London-Washington

10 December 2013

Agenda

PART 1 DATA OF CONCERN

DC time
9.00 - 9.10 Introduction and context of debate: **Jeremy Leggett**, author, The Energy of Nations: Risk Blindness and the Road to Renaissance.

9.10 - 9.25 Global oil and gas overview: **Mark Lewis**, former head of energy research, Deutsche Bank.

9.25 - 9.45: Shale overview: **Dave Hughes**, Canadian geoscientist, expert in shale.

9.45 - 10:30 Discussion

PART 2: IMPLICATIONS OF CONCERN

10.30 – 10.45: Implications for UK industry: **John Miles**, Arup.

10.45 - 10.55: Implications for US economy: **Klaus Hubacek**, University of Maryland and **Christian Kerschner** (from Berlin), Humboldt University

10.55 - 11:05: Implications for militaries: **Paul Sullivan**, National Defense University

11.05 - 11.15 Implications for climate: **Rear Admiral Neil Morisetti**

11.15 – 12.00 Discussion

Participants

LONDON:

Godfrey Boyle, Emeritus Professor of Renewable Energy, Department of Engineering & Innovation, The Open University
Jeff Chandler, Head of Gas Strategy, SSE.
Mark Davis, Junior Partner, Oil & Gas Practice, McKinsey & Company
Maj Gen (Rtd) John Drewienkiewicz, former Chief Engineer, British Army
Tim Eggar, Former Energy Minister
John Hemming, Liberal Democrat MP
Kimberley Henderson, Senior Programme Officer, New Climate Economy
Isabel Hilton, Director, China Dialogue
Jeremy Leggett, Chairman, Carbon Tracker; Co-convenor, Transatlantic Energy Security Dialogue.
Mark Lewis, former head of energy research, Deutsche Bank
Larry MacFaul, Senior Researcher, Verification Technology Information Centre
Michael Meacher, Labour MP; former Minister of Environment
John Miles, Director, Arup.
Rear Admiral Neil Morisetti, former Commander UK Maritime Forces, former United Kingdom's Climate and Energy Security Envoy.
Walt Patterson, Associate Fellow, Chatham House.
Adam Poole, Analyst, Buro Happold.
Chris Skrebowski, ex Editor, Petroleum Review
David Rice, Cambridge Programme for Sustainability Leadership; ex director of policy, BP.
Simon Roberts, Associate, Arup.
Nick Robins, Director, Centre for Climate Excellence, HSBC
Bill Royce, SVP Cleantech Energy & Sustainability EMEA, Weber Shandwick

Unable to attend, but wanted to be kept informed:

David Addison, Investment Team, Virgin; Member, UK Industry Taskforce on Peak Oil and Energy Security
Maria Allen, Special Advisor to Minister Climate Change Greg Barker MP
Simon Ashwell, Director, European Energy Policy, GE
Mike Barry, Director, Plan A, M&S
Nick Fox, Director of Communications, Virgin Group; Member, UK Industry Taskforce on Peak Oil and Energy Security
Zac Goldsmith, Conservative MP; Member, Energy & Environment Select Committee.
John Gummer, Former energy and climate change minister, Conservative.
Charles Hendry, Conservative MP, Former Energy Minister.
Anthony Hobley, Partner, Norton Rose Fulbright; CEO-designate, Carbon Tracker Initiative

Tim Jackson, former Economics Commissioner, Commission for Sustainable development.
Bernice Lee, Fellow, Royal Institution for International Affairs
Ian Marchant, former CEO, SSE; Member, UK Industry Taskforce on Peak Oil and Energy Security
John Nagle, Head of Energy, Cabinet Office.
Vincent Neate, Climate Change Partner, KPMG.
Cleo Paskal, Royal Institution for International Affairs
Andreas Persbo, Executive Director, Verification Technology Information Centre
Laura Sandys, Conservative MP, PPS to the Minister for Climate Change, Greg Barker MP
Paul Spedding, Oil & Gas Analyst, HSBC
Steve Stewart, Director of Communications, Stagecoach.

WASHINGTON DC
(either present at the briefing site, dialed in via conference lines, or were unable to attend (yet desired to be updated on future developments)

Steve Andrews, retired oil industry consultant and analyst.
James Blatchford, Director of Policy, Securing America's Future Energy.
Craig Connelly, Senator Tom Udall's office.
David Daniels, Ph.D., Chief Energy Modeler, Office of Energy Analysis, Energy Information Administration.
Daniel L. Davis, Lt. Col, US Army, energy and foreign policy researcher and author; ; Co-convenor, Transatlantic Energy Security Dialogue.
Shukria Dellawar, Analyst, Center for International Policy.
Ryan Fitzpatrick, Senior Policy Advisor for Clean Energy, Third Way.
Benjamin Freeman, Policy Advisor, National Security Program, Third Way.
Melissa Holtmeyer, Senator Bernie Sander's office.
Guenter Hormandinger, First Counselor – Environment, Delegation of the European Union to the United States of America.
Ryan Hilley, Secretary Denis McGinn's office (Assistant Sec Navy), US Navy.
Klaus Hubacek, Ph.D, Professor, Department of Geographical Sciences, University of Maryland, College Park.
David Hughes, Geoscientist, 32-year vet of Geological Survey of Canada; Fellow of Post Carbon Institute; President of Global Sustainability Research Inc.
John Kachtik, Senator John Thune's Office.
Richard Kidd, Deputy Assistant Secretary of the Army (Energy and Sustainability), US Army.
Jörg Kinnen, Counselor, Energy and Environment, Embassy of the Federal Republic of Germany.
Yancy Lindsey, Secretary Denis McGinn's office (Assistant Sec Navy), US Navy.
Ken Locklin, Managing Director, Impax Asset Management (US) LLC.
Douglas Macgregor, Defense and foreign policy consultant, Glenside Analysis, Inc.
Robert T. Macguire, former Deputy General Counsel, US Air Force.

Jan Lars Mueller, Executive Director, Association for the Study of Peak Oil & Gas USA.
Chris Nelder, energy analyst, author, and consultant; Policy Officer with the Global Footprint Network.
Franklin Nutter, President, Reinsurance Association of America.
Carly Robinson, Senator Mark Udall's office.
Cheryl Rosenblum, Director of Strategic Development, Center for Naval Analysis.
Michael Shank, Foreign Policy Director, Friends Committee on National Legislation.
Paul Sullivan, National Defense University, Georgetown.
Ben Wainwright, Secretary Denis McGinn's office (Assistant Sec Navy), US Navy.

EDITED TRANSCRIPT[1]

Part One presentations: Data Of Concern

Jeremy Leggett: The tableau here is one of systemic risk in energy markets; that's what I'm hoping we can have a good discussion on: particularly pertaining to oil and gas where a number of us - but by no means all of us in this room and I'm guessing your room as well - have some concerns about security of supply.

We know from the financial crisis that big industries are capable of catastrophic miscalculations on systemic risk analysis. If it's true of the financial sector, to what extent might we fear it in our sector in energy? My personal view (and we'll be hearing personal views this afternoon, I don't think anyone's going to be speaking for their institutions) is yes. I personally worry about four in particular.

The first is climate. That is something we'll hear about from Rear Admiral Neil Morisetti later on. This is obviously a risk which is very high consequence, probably with a majority view that we do have a clear and present danger, or an emerging danger.

We also have an overlapping risk which is the capitalisation of the carbon bubble in the capital markets: the extent that we're creating exposure by not recognising the risk of stranded assets. That is terribly pertinent to the development of oil and gas reserves and resources. Can the capex that the industry wants, expects and needs to meet demand be mobilised on the scale they're going to require? Mark Lewis, who was Head of Energy Research at Deutsche Bank will talk about that.

Next of course is shale and although we have a dominant narrative in the energy industry, there are those of us who have big concerns. David Gughes will present on that.

The final concern is oil depletion: do we have any concerns about oil supply going forward in our oil dependent economies? I think probably a majority of us in a self-selecting group like this do have worries about that, but there are a lot of

[1] Edits are from conversational English to written English only. Minor deletions of wording in the presentations. More substantive omissions have been from the discussion where the content repeated or the audio was poor.

uncertainties to wrestle with and hopefully that's going to be a major piece in our dialogue here today and going forward.

I think the final thought I'd offer, and I make this point in the book that I've written recently, *The Energy of Nations*, is that there is another body of knowledge that we probably collectively haven't paid as much attention to as we might, and that is the discoveries that the neuroscientists and the psychologists have made of late. There has been an explosion of understanding in that science and it's relevance to our individual and collective dilemmas. Neuroscientists are discovering many things about what they call the predictable irrationality of our individual and collective thinking. The way we're prone to what they call the incumbency effect. We have an optimism bias. All these things that make us much more comfortable with comforting narratives than we are as individuals and in our groups with uncomfortable narratives. That I think is a factor that needs to be perhaps considered a little bit more in all these things than we normally tend to do.

Daniel Davis: Thank you. ....I do want to point out that this is being recorded so if anybody has any issues with that just let me know. Our intent is for this to be on the record so if anybody wants to make a comment but they don't want it to be on the record, naturally we'll respect that entirely. We have a handful of media folks here who have either dialled in or are here in the room and they will definitely respect anything here, they're very helpful, they're people we wouldn't have brought in otherwise. So we definitely would like to have an open discussion and open debate, so by all means if you disagree with something, let us know what you think and share your views on it and then we'll go from there. So with that I think we should jump right into Mark's presentation.

Mark Lewis: **The three witches: decline rates, soaring capex, and falling exports** (see powerpoint presentation)

I've got 15 minutes to run through some big picture points really on the oil market and I thought an interesting way of doing this would be to pick out the three things that I think ring the most alarm bells for me personally when I look at the oil market.

Slide 1: I've got a picture up there, a famous picture of Macbeth with the three witches, and of course the point about Macbeth is that he's warned at the beginning - or the prophecy is - that he will get the kingdom ...but that the story will end badly for him, and he won't be able to bequeath anything. The narrative running through Macbeth is about the lack of legacy for future generations, which is pertinent to my conclusions.

Slide 2: The three witches in my presentation are the very high decline rates that we're seeing globally. ....Secondly the soaring capex requirements to find new oil, which is a subject of an op-ed piece that Danny and I wrote in the FT a couple of weeks ago. And thirdly the problem of falling exports of crude oil globally which has been a phenomenon since 2005.

Slide 3: I want to run through the headline points on those three issues as I see them.

On decline rates, consider the IEA's World Energy Outlook published last month. They calculated if you look all of the fields currently producing conventional crude oil today, they produce about 69 million barrels of oil and that with ongoing investment in those fields over time that is natural, you would get to 28 million barrels by 2035.

Now interestingly that works out to a decline rate of not far short of 3%. And yet in the comprehensive study that the IEA did in the World Energy Outlook of the observed decline rate of the 1,600 fields that provide 70% of the world's oil today and that are post-peak, you have an observed decline rate of 6.2%. So I think there is a potential discrepancy, an optimistic discrepancy between what the IEA is saying about the rate at which fields that are currently producing today will decline in the future relative to what they have said the observed rate of decline is in the fields that are post-peak.

....This is why one of the key leitine motifs in the World Energy Outlook is that the main threat to future oil supply is insufficient investment, because this decline rate is going on all the time. There's an old adage in the oil industry that rust never sleeps and in the same way decline rates never stop. They decline all the time unless you're putting in more investments. So that's the first key point that I think doesn't get enough coverage in mainstream analysis of oil markets.

Slide 4: The second key point, very much related to that, has to do with investment requirements. I was absolutely stunned when reading this year's World Energy Outlook. If you look at the raw numbers, global upstream capex for the oil and gas industry - and about 75% of the total is just for oil - has trebled in real terms since 2000. The IEA estimates that upstream capex this year will be about $700 billion compared with $250 billion in 2000 in real terms. Those numbers are in constant dollars. So that is a real term increase of nearly three times.

Over the same period the increase in the oil supply has only been about 12%. So you've had a 200% increase in capex effectively for a 12% increase in global oil supply. That is a very striking number and one I think that should be ringing alarm bells. It indicates to me that something has fundamentally changed in the economics of the oil industry and that you're having to invest more and more for diminishing incremental production.

One other thing I would draw your attention to on this slide, given how much focus there is at the moment on the rising production of oil in the United States in particular, is the two bars on the left, production and investment in 2013. If you look at that you'll see that OECD in North America is producing about 20% of the world's oil at the moment but OECD in North America accounts for 50% of the world's capex for oil. So that again is a huge discrepancy. Yes, there is an undeniablye fantastic increase in oil production going on in the United States, and to a lesser extent in Canada, at the moment but that chart shows you that it's coming at a very real cost in terms of the very high levels of capex.

My final point on this issue would be that despite the fact that upstream capex has nearly trebled in real terms since 2000, the IEA then says that for its forecast of total oil increasing by about 12 million barrels a day out to 2035, upstream capex will remain broadly flat at current levels in real terms. I think they must be assuming a very significant increase in the productivity of that capex and in the efficiency of improvement in the productivity of the technology.

Now, we've just raised the question, is that consistent with the trend that we've seen over the last 12 years and is it therefore a plausible assumption or are we going to see a continuation of rising real term capex spend for increasingly less impressive incremental returns?

Slide 5: My third key point has to do with declining exports of crude oil. I think this is, again, very much an under-studied feature of global oil markets. If you look at the increase in global oil consumption since the year 2000, the world as a whole has seen an increase of 13.4%, 10.3 million barrels a day. That's from 2000 to 2010. OPEC's consumption has risen by 56%. or four times faster than total world consumption. That, by any standard, is a staggering difference: four times faster than overall world consumption has risen.

Slides 6 & 7: A large part of that increase is explained by the population dynamics in the OPEC countries. OPEC's population has increased at twice the rate of the world as a whole: 26% since 2000 compared with 13%. So very clearly if they're increasing their consumption four times faster and their population is increasing twice as fast, then roughly speaking one would say half of the increase in consumption relative to the world as a whole is being driven by the faster population increase. It's fair to say, by the way, that this trend is expected to continue. The UN's central population forecast has OPEC's population continuing to increase much more quickly than that of the world as whole between 2010 and 2020, 23% versus 13% of the world as a whole out to 2020.

Slide 8: But the second feature explaining soaring OPEC oil demand is the very high degree of subsidy on domestic consumption. The IEA's World Energy Outlook shows fossil fuel subsidies as a whole increased to $544 billion in 2012. Of that about half, $270 billion, was subsidies for oil, with Iran and Saudi Arabia dominating.

So that is fuelling an astronomical increase in the consumption of oil in the leading OPEC producers, and clearly unless there is a concomitant increase in the production of oil from these countriesmpanies, that has to be eating into their exports of crude oil.

Slide 9: That is exactly what we find. ....The United States EIA database shows that global crude exports increased actually year on year from 2001 through to 2005, peaked in 2005 and have been trending down since 2009. That's just for crude oil. But if you looked at the BP database, you would find a similar pattern. So there is no doubt that the very rapid population increase and the high level of subsidies in these countries is leading to pressure on global exports of crude oil.

This, in my view, is one of the main reasons why oil prices have risen so spectacularly since 2005. I don't think that's a coincidence.

Slide 10: If you then look at projected crude oil exports and imports out to 2035 the IEA in its base case is projectings an increase in global exports of crude oil from 35 million barrels a day in 2012 to 38 million barrels a day by 2035. All of that increase is coming from the Middle East, mostly from Iraq. In fact I think even Saudi Arabia is flat in the IEA's projection, so nearly all of that increase in global crude exports essentially is coming from Iraq and some of it from Kazakhstan.

I would just raise the question, is that a plausible scenario given the trend that we've seen since 2005 and given two further points. Firstly, that we know that the OPEC countries will continue to grow their populations much more quickly than the world as a whole over the next 20 years. Secondly, the fact that removing the subsidies in these countries would undoubtedly have a big impact on their domestic political stability.

All I can do is raise the question: is it plausible in the current socio-political environment in the Middle East and in other OPEC countries that these countries would be able to remove the subsidies on domestic consumption of oil without the risk of greater domestic stress ides and social disorder in those countries?

I think those are two very big question marks over the plausibility of that scenario about moving from 35 million barrels a day to 38 million barrels a day of exports by 2035.

Slide 11: So to recap. I think you've got these three major issues that are simply not being covered by the mainstream media. The first is decline rates that eat away at your daily production and mean that you've got to replace between three and 3.5 million barrels a day per year of production just to stand still, before you even think about adding new production. Put that against the numbers that we're seeing out of the United States in terms of the tight oil production and the increases there. Spectacular as they are, you're looking at increments on year on year additions of one million to 1.5 million barrels a day. We're losing three times that amount every year or certainly 2.5 to three times that amount every year just from natural decline rates.

The second is the very much greater expense, in terms of upstream capex, that the industry is having to spend now to get at that incremental oil production. That is a function of geology and the fact that we're moving further and further up the industry cost curve and we're having to look for oil in places that are much more difficult to access such as the Brazilian pre-salt deposits, the Canadian tar sands and even the US light tight oil which doesn't come cheap, with a marginal cost of production there of probably around $80 a barrel.

The third is the point about exports and the extent to which, if that trend of declining exports were to continue - which I think it probably will unless you can find a way of removing subsidies in these countries without precipitating serious political upset - then you have three major question marks in my view over where the oil market is going

Those are all, in my view, bullish for prices.

David Hughes: **The "shale revolution": myths and realities**
(see powerpoint presentation)
Slide 1: I'd like to talk about shale, first a general overview and then I'd like to look at one shale gas play and one tight oil play in the US just to show you what's happening.

Slide 2: The conventional wisdom is that the US is on the verge of energy independence thanks to the shale revolution. Shale gas production will continue to grow and prices will be cheap, less than 4.50 out for ten years and $6 out for the next 20 years. This is the EIA's reference case 2013. The way is clear for LNG exports from the US to monetize the shale bounty. The same thing from Canada: Canada is looking at exporting a lot of LNG. Tight oil will allow US production to exceed that of Saudi Arabia and US imports will shrink to zero.

Slide 3: In their reference case forecast, the EIA is suggesting that shale gas will more than double by 2040. The only growth in gas production in the US is shale and shale will be 50% of 2040 production. Canadian imports of LNG iwill shrink to zero by about 2020.

Slide 4: The EIA reference case for oil suggests a secondary peak in 2019. US oil's primary peak was back in 1970. Shale oil will grow to a maximum around 2020 and then plateau after that. Other sources of oil will, in general, decline.

Slide 5: The IEA's projection of where incremental additions will come from: in general the Middle East, deep water Brazil, light tight oil and unconventional oil. Light tight oil is forecast to grow to a maximum about 2025 and then shrink to about what it is today. So, light tight oil is forecast to more than double going forward.

Slide 6: The EIA's June data on shale gas production from different plays in the US shows that that the Marcellus is the only play that's really growing rapidly now. Collectively all plays outside of the Marcellus peaked in mid-2012. They're now down about 5% below peak. If we look at all the plays outside of the tight oil plays like the Eagle Ford and the Bakken, peak was in late 2011. Production is now down about 12% from peak. Shale gas is about 42% of total US gas production currently.

Slide 7: This shows the six main tight oil plays, from the EIA's new DPR spreadsheet that they put out last month. These plays also produced a lot of conventional oil and natural gas liquids.

Slide 8: If we take the natural gas liquids and conventional out of this projection this is what actual net tight oil production looks like in the US. The two most important plays are the Eagle Ford and the Bakken, producing about 74% of all US tight oil.

Slide 9: The EIA's 2011 map of distribution of shale plays in North America shows they are very widely distributed, one would say almost ubiquitous.

Slide 10: But when you look at where the production is coming from, 68% of shale gas production comes from three plays, the Marcellus, Haynesfield and Barnett, and 92% of it comes from six plays. So there are some very good plays and then there are all the rest of the plays.

Slide 11: The same thing is observed with the tight oil. The Bakken and Eagle Ford produced 74% of the total. The top four plays produced 85% of the total. So, all the rest of the plays in the US – there's about 20 of them – only produced 15% of the tight oil.

Slide 12: My work has come up with what I call the shale play lifecycle. Discovery is followed by a leasing frenzy. Leases come, are held by production required, so you really have to drill in order to hold the leases. A drilling boom follows the leasing frenzy. Sweet spots are identified. Because of that drilling boom, they're targeted and drilled off. All parts of shale plays are not uniformly productive. Production rises very rapidly. These wells are maintained for cashflow even though they might not be economic on a full cycle basis. Sweet spots become saturated. Oil quality and field production decline. That's happening in plays like the Haynesfield: they've become what I call middle-aged after just five years.

Slide 13: I'd like to look at the Haynesfield as an example of shale gas. As I said, it didn't exist in 2008. This is the distribution of well quality; the red dots are the highest, initial productivity, the black dots, are the lowest. So you can see that of the total extent of the play, the sweet spots are relatively small proportions of it.

Slide 14: If we look at production in the Haynesfield versus the number of wells drilled, there's about 3,500 wells drilled. Production peaked in early 2012. It's now down about 27% below peak.

Slide 15: This is the reason for that: the individual well declining from a typical Haynesfield well. The three year decline is about 89% in production. So the message is: you have to keep drilling.

Slide 16: This is a measure of overall field decline. If you didn't drill a well after January 1st 2012, so if you stopped drilling, field production would decline about 47% in one year. Mark Lewis was showing much lower decline rates for the overall conventional fields in the world.

Slide 17: If we look at the top five shale plays, they constitute 81% of US gas production. We can see that the average three year decline is about 84% ranging from high in Haynesfield to a low of about 77% of the Woodford.

Slide 18: This is the field decline for those same five fields, 81% of US shale gas production. The average one year field decline is 37%. That really requires a drilling treadmill to offset.

Slide 19: If we look at what's happening in those same five plays, we can see first of all Haynesfield is really in the most serious decline but four of those five plays are either at plateau or in decline. The only play that's really growing at this point is the Marcellus in Pennsylvania and Western Virginia.

Slide 20: This is just a stacked plot of those same plays. If we look at all the plays outside of the Pennsylvania Marcellus, they collectively peaked in mid-2012. They're now down about 12% below peak. So the Marcellus in Pennsylvania is allowing shale gas production to remain flat. It's compensating for the declines in those other plays.

Slide 21: Part of the reason for the declines is rig count. Because of the price of gas the rig count in plays like the Haynesfield has fallen off and in the Barnett and to a certain extent in the Marcellus. Of the gas rigs that are in play in the US, roughly 40% are being applied to those three plays.

Slide 22: The concept of sweet spots is very important. This is where shale gas all got started in the Barnett play of East Texas. You can see the red sweet spot which is currently being saturated with wells, the much larger area with a few wells; mostly black dots are the lowest productivity wells.

Slide 23: This is really what I call the lifecycle of a shale play. Typically after discovery, sweet spots have been identified so average well quality goes up. And if you look at the dark blue line, which is Marcellus, you can see that average well quality is still going up, so the sweet spots are still being identified. Technology is making a difference. If we look at plays like the Woodford, the average well is declining in quality and so I would classify the Woodford as in early old age. The

Haynesfield is in late middle age, average well quality has declined. So geology is winning out over technology.

Slide 24: If we turn to tight oil plays, the Eagle Ford and the Bakken being the top two as I mentioned, they're attracting about 27% of all of the oil rigs. The rig count for oil has gone up a lot since just 2011: it's nearly double.

Slide 25: If we look at the Bakken, which is really where tight oil got started - in North Dakota and Montana - we can see that there are about 6,500 producing wells. Production has grown very rapidly from almost nothing in the early 2000s.

Slide 26: If we look at well declines, we can see that it's the same exact pattern as in shale gas. The three year decline in the Bakken is about 84%.

Slide 27: If we look at the field decline in the Bakken - what the field production would look like if you didn't drill a well after January 1st 2012 - we can see that the one year field decline is about 44%. So you have to keep drilling.

Slide 28: This is the reason: the distribution of wells coloured by initial productivity, so well quality. You can see the sweet spot in Mountrail County, which is being saturated with wells, and then much broader areas of lower quality wells. So the same exact pattern applies to tight oil as shale gas.

Slide 29: If we look at production in the Bakken by county, we can see that the top two counties, Mountrail and McKenzie, produced 52% of the oil, the top four counties produced 85%, the bottom ten counties produced only 15%. So as you move out of the sweet spot and into the lower quality areas, the drilling intensity and the amount of capex has to go up a lot to compensate field decline.

Slide 30: Tight oil declines by county for the Bakken: you can see the top four counties are a lot more productive than all the rest, about twice as productive so that's where the capex is being spent at this point in time. But there are only a limited number of sweet spot locations to drill.

Slide 31: If we look at the total distribution of wells in the US side of the Bakken, it's pretty well defined. The edges are low productivity wells. It's unlikely that we're going to find much more. It's possible to calculate the aerial distribution of productive ground in the Bakken. My calculations are about 13,000 square miles. The EIA is suggesting two to four wells per square mile, two wells in North Dakota and four wells in Montana.

Slide 32: It is pretty easy to put this into a spreadsheet and do a calculation of when the Bakken is going to peak. There's a 44% field decline rate. The higher production goes, the more wells you need just to offset decline. There are about 2,000 wells per year going into the Bakken right now at about $ nine million each so 18 billion worth of capex into the Bakken.

My calculations are that it will continue to grow to about 2015. It'll peak at just over a million barrels per day and then it will decline. The last well drilled for that location will occur at about 2025 or 2026 and this assumes a drilling rate of 2,000 wells today declining to about 1,000 going forward. I have risked and un-risked calculations. Un-risked assumes that 100% of those locations are available. Risked assumes that only 80% are available. So we'll still recover a lot more oil out of the Bakken. The risked scenario is 4.5 billion barrels ultimate. We have recovered just under a billion barrels so there's still four to five times as much oil to be recovered but it will peak fairly soon.

Slide 33: I did the same thing for Eagle Ford. The Eagle Ford will peak at higher levels than the Bakken: about 1.4 million barrels per day. Collectively in a risk scenario these two plays will produce about 11 billion barrels by 2035. The last well will be drilled somewhere around 2025 in both cases.

As Mark was pointing out, we need to drill 48,000 more wells in these two plays to make this scenario happen and that is about $450 billion of capex that will have to go into these two plays to make this scenario happen. The other thing to point out is the first 25% is the most economic part of those fields. The last 75% will require much higher prices in order to make it work.

Slide 34: My conclusions. Shale gas production in several top plays is declining. Tight oil production from the top two plays is likely to peak in a 2016-2017 timeframe. High well and field decline rates mandate sustained high levels of drilling to maintain production. Sweet spots become exhausted early on in field development; hence drilling rates must continue to escalate to maintain production levels. Liquids production with associated gas has allowed gas production to remain stable for now. US gas production has been on a plateau for about the last 12 months but long term sustainability is questionable in my view. High quality shale plays are not ubiquitous. 68% of shale gas production comes from three plays. 74% of tight oil production comes from two plays. Environmental concerns of fracking are widespread and are likely to escalate with the escalating drilling treadmill needed to maintain, let alone grow, shale gas and oil production. There was a global frack down that was held in mid-October, I think, in 26 countries so that's also an issue going forward.

Part One Discussion

David Hughes: I think there are certainly other fields but there have been quite a lot of drilling and so far they haven't been nearly as productive. I just finished a major study of the Monterey shale in California and that play was supposed to have 64% of all US tight oil resources. If you look at the quality of the wells compared to the Bakken or the Eagle Ford, they just don't stack up. I think that that number is totally overblown. So we're still finding things out, so there could be come surprises, but I wouldn't really count on it. And the IEA isn't counting on it either if you look at their scenario of peaking of tight oil around 2025 and then collapsing to today's levels by 2035.

Jeremy Leggett: I'm wondering if you'd care to comment on the company by company patterns. One of the things I find that is always surprising to people who accept the narrative of an age of plenty and a new age of fossil fuels is to hear that the US gas industry as a whole is losing money.

David Hughes: I'm not really probably the best person to ask that question but certainly if you look at companies like Shell, Shell is basically looking to sell up a couple of billion dollars worth of their Eagle Ford properties, so that's both gas and tight oil. Rex Tillerson from Exxon made the comment, when the price of gas bottomed out in 2012, I bet they're losing their shirts; it's all in the red. If you look at what's happened in the Haynesfield, they need to drill about 600 wells per year just to offset field decline. They're only drilling 400. The reason for that is gas prices close to $4 are not high enough to justify the capex to even stem declines. So the plays that are really making money I would say are the combination plays where both associated gas and tight oil is being produced. The Eagle Ford is really the poster child of that.

Jeremy Leggett: Anything you wanted to add on the companies perhaps, Mark?

Mark Lewis: Well, I'm not as close to the US situation as Dave is but I think it is clear that one of the phenomena that we've noticed is companies being forced to liquidate assets to pay for further investment in new reserves because the cashflow at current prices is simply not high enough for them to be able to afford new investments. And if you don't book new reserves then you've got no future growth and you get punished on your share prices. So they're in this terrible situation where they either have to sell assets to continue growing or not grow at all. And your share price is going to suffer either way it seems to me. I think, as Dave pointed out very clearly, if prices are not high enough to justify new investment then why would you invest other than for a very short term way of maybe trying to keep your share price up artificially? Sooner or later, as has been done with the case of Chesapeake, that simply cannot work.

Jan-Lars Mueller: Mark, you talk about the significant increase in investment to get a progressively smaller outcome and then given the treadmill that you were talking about, does there come a break at some point where they just say it's just not worth it either as a company or as an industry and so they start putting their money elsewhere in short term stuff?

Mark Lewis: I think the real issue there is, and maybe it's still too early to tell but I think one of the points that we made in our article was that what you've seen in the last three years is that this fabulous increase in capex for the industry as a whole has really only been made possible by the correspondingly fabulous increase in oil prices since the beginning of the century. So from 2000 the oil price has increased in percentage terms by almost exactly the same amount as the increase in capex. They've both trebled more or less in real terms. However, what is very interesting to note is that since the beginning of 2011 the oil price has basically been flat - or in fact this year has averaged a little bit below the price that it averaged in 2012 and 2011 in real terms - whereas industry capex has gone up a further 20%.

....I think that is the trend we've started to see in the last two or three years in the industry, for some of these enormously capital intensive projects (oil sands projects in Canada, deep water offshore projects in West Africa or in Brazil) is that because these projects have never been done before nobody really does know for sure what the cost is. If you're going to drill a well in Texas or you're going to drill a well in a part of the world that is very familiar in the Middle East, there's so much experience of drilling in those areas that we know what the cost is. But as we're being forced year after year to be more ambitious in terms of the locations we're drilling in, nobody really knows for sure what the cost is there. And one of the things we found specifically in the oil sands in Canada is that in the last two or three years costs have increased by a further 10%, and as I said, prices just haven't been keeping pace.

So I think, Danny, the real question that I think it's still early to judge, but that should be getting much broader discussion in the industry, is what's going to happen if we see this continuing divergence between cost increases and oil prices flatlining or perhaps declining ever so slightly, particularly in the US where North American oil prices obviously are lower than brent prices internationally? And if you're seeing this cost escalation in Canada in particular but the Canadian oil producers are not able to get the higher prices they need to justify that, then at some point you would have to think that the investment will have to stop. But I think nobody really knows yet where we are on that.

David Hughes: Exactly as you've said, Mark, the marginal cost of a surface mine with an upgrader is now in the $105 a barrel range if you're going to build a greenfield project and that's up, I think, about 10% from 2011. ....I've also looked at forecasts for oil sands production going back to 2005 just to see how accurate they were compared to actual production. They've always overestimated if you look at the projection versus what actually happened. So yes, I think prices are going to go higher still.

Mark Lewis: And I think that's exactly the same pattern as is being observed with Brazilian pre-salt where the capex requirements are turning out to be larger than expected. The day for that production coming on-stream is being delayed. You're seeing it in Kazakhstan with the Kashagan Field and offshore West Africa. So I think that is the point, Danny, that something will have to give if this trend of the flatlining prices but rising costs and therefore higher capex, investors and shareholders are going to start saying we can't support further investment at these levels, you need to cut back on the capex. And you're starting to see that. I think most of the international oil companies, the non-nationally owned oil companies are cutting back on capex in their plans for the next two or three years.

Jeremy Leggett: Just a quick observation on capex from our experience at Carbon Tracker. We launched our second report in April this year at Bloomberg's headquarters in London. For those of you who haven't seen the report, one of the main thrusts of it was to look at capex deployment and the extent at which that might be a risk. In the top 200 oil, gas and coal companies in the world total capex was $670 billion plus in 2012. Dividends going back to the shareholders were $120 billion plus. So a big mismatch there. When we finished the presentation of the report, one of the people who commented on it was Paul Spedding, the senior oil and gas analyst at HSBC. He made the point that the arguments that he'd heard about stranded carbon-fuel asset risk, combined with some of the profitability factors that Mark mentioned, meant that he would be recommending to his bank's clients that they didn't support deploying the capex and that it should be returned in essence to the shareholders. If more people come around to that point of view in 2014, then this is going to be a factor as well I think.

Walt Patterson: I'm not a hydrocarbon person but the information that we've been hearing from both the speakers today strikes me as something that ought to be getting through to the political classes. In the United Kingdom we have a group of politicians who are still euphoric about the potential of shale in the UK and of course the same is true in a number of European countries. I wonder just how well the political classes in the US understand the significance of what we've been hearing today. Can you give us an idea as to whether the euphoria we know in the UK is also true in the US or are they beginning to get a little uneasy about this?

Daniel Davis: I'll tell you my personal observation from some comments or conversations that I've had with folks round the Hill. There is starting to be some understanding that the data doesn't seem to be lining up, generally. I originally spoke with one very senior official just two weeks ago who told me that he had had some conversations with some folks up in Wall Street recently, where they were discussing some of these things. They said, they thought privately - just under the radar, certainly under the public radar - there is a recognition that there are some issues that are played, and they're starting to look at them more closely.

Chris Nelder: When I was a lot younger I was a freelance writer in this area for quite a few years, and have struggled repeatedly to pitch stories that actually explain this data and show the disconnect between the reality of production data, the reality of prospects in drilling, as compared with this broader narrative. And I frequently engage with writers in the major publications ....and try to engage with them about what the data actually says, and what I've found is that there's a very strong bias toward telling an optimistic story: that it's really about the narrative and it's really about the story telling. Nobody wants to know the data. Nobody wants to see the data. The editors don't want stories that are organised around data, they want narratives, they want quotes, they want credibility, they want high profile people that they can cite. It's all about authority, it's not about the facts. So I've had a very difficult time selling these stories. I've succeeded in getting my articles - which are very data heavy - published, on a frequent basis, but not in the high profile publications.

What I have noticed, however, is that, especially since I've been engaging with the writers and editors in these major publications, for the last few years, oftentimes I will put out a story that really focuses attention on the new data, and then about six weeks later some variant of that story will start showing up in the New York Times, the Wall Street Journal and the Financial Times, and a fragment of the story starts to get out. Some doubt about the official narrative starts to creep in to their reporting. They start backing off from the big, bullish narrative, and start saying, well, there are concerns about whether or not this whole thing can be maintained, whether or not this growth trend can continue.

So I think there's a lag effect. I think it's very difficult to overcome the bias for a positive story, for an optimistic story, but eventually they have to capitulate to what the data actually says. It's just, there's a big lag. So the data that Dave is presenting, for example, right now, we can all see there's an opportunity for a real peak in the US shale oil production by 2016. I would not expect that to show up in the mainstream press until after it's already happened. So they won't talk about that until probably 2017.

Steve Andrews: I would agree with Chris that it is unlikely to change dramatically until the facts of a slowdown in the rate of increase start to become apparent. Let me just give you a simple anecdote. Back in 1970 the US oil production peaked originally at about 9.6 million barrels a day of crude. Everyone knows that. The Oil and Gas Journal had a graph, which they had published weekly for a decade, showing the rate of increase, at a weekly basis, annual basis and decade long basis. It took two years of downturn before they then eliminated showing that graph any more.

So they actually didn't want to show the new news, and this was the industry subtracting a message from their readership, so the optimism bias is alive and well, and for good reason, frankly. We have seen the fastest rate of increase in oil production in US history. That is an amazing accomplishment by the industry, and it should not be overlooked. It should be acknowledged, and to a certain degree, celebrated. But the things that are around the edges, the three witches that Mark referred to, are not appreciated. And the larger context at the world level: ....the significance of the US boom is, I think, way overhyped in the international dialogue by OPEC, by IEA, even by the EIA. I think the euphoria is far from ended, but there are some cracks, perhaps at the edge, and I really appreciate Dave bringing facts, highlighting the facts such as he has this morning.

Chris Skrebowski: A question for both Dave and Mark. Interest rates are going to rise at some point. A, when do they think it's going to happen, and, B, when interest rates get back to, quote unquote, normal levels, what is this going to do to the industry?

Mark Lewis: Having recently left a major investment bank, I think that's a great point. This huge increase in capex that Dave and I were talking about has occurred, at a time of record low interest rates, in much of the world, so it is a very open question about what will happen to those levels of investment once interest rates go up again.

To the extent that the level of investment, as the IEA said - that quote I cited in my presentation that future investment is really the single most important factor regarding future oil supply - if interest rates were to rise, and certainly if they rise too aggressively, that is going to make borrowing more expensive, and it's going to make the very highly capital intensive plays that we've been talking about a lot less attractive. The tar sands, the pre-salt in Brazil, these are hugely capital intensive projects.

As to your question about when that will happen that is debated daily in all the major financials, and I haven't met an expert yet who really knows the answer to that question, so I wouldn’t really like to comment. But I think, certainly if the US economy continues to show the kind of positive surprises that it showed in the most recent job data, last week, I think an increase in interest rates is probably going to happen sooner, rather than later.

Chris Nelder: I'd just like to point out I think there's an interesting implication in the new love fest with Paul Krugman and Larry Summers, suggesting that we've entered an era of endless stagnation with a negative real natural interest rate that QE cannot overcome. If that were to remain the case, we might see continued capex expenditures in upstream oil and gas that would seem unbelievable to us today. There might be a risk of that. I just want to point that out.

Mark Lewis: I wouldn’t dispute that, Chris, but my point would be that we've already had this record level of capex, and we've had four years in a row now of consecutive increase to all-time real record levels of spending, and the oil supply still hasn’t grown by that much. So it seems to me, if I've understood your point correctly, the best case is that interest rates remain at very, very low levels and the industry is able to still spend these enormous numbers for very small incremental increases in oil supply. The worst case is interest rates do start going up at some point, it becomes more expensive to borrow money, and it becomes therefore less attractive to invest unless oil prices start rising correspondingly.

David Hughes: I'd just like to add that those peaking scenarios that I showed (for key shale plays) had no capex constraints but assumed that 48,000 additional wells would be drilled, so really they're a best case scenario. If there’s a rise in interest rates ..... the economics are not going to be as good. It's a best case scenario all around.

Günter Hörmandinger: Just a few years back, nobody expected shale to happen. Now it does, and we're discussing that that we've already seen the end. This just hasn’t found its way into public narrative yet. Is there another surprise lurking out there? I'm thinking methane hydrates, or other unconventionals, and to what extent will that maybe replicate the gold rush we see in this particular sector?

David Hughes: I'd say that’s always possible. I went through the whole list of unconventional fuels, and published that in February of this year. Hydrates are fabulous: 45,000 trillion cubic feet potential, but if you look around the world, people spend a lot of money - in particular the Americans and the Japanese - ....and certainly small amounts of hydrates in association with conventional gas have been produced, but at extremely low rates and at extremely high costs.

Mark Lewis: ....Obviously as prices rise there are all kinds of incentives for new technologies to emerge, so one should never rule that out. By the same token it's extremely difficult to foresee political developments. But it's also very difficult to think of any positive above ground surprises that we've experienced over the last seven or eight years; plenty of negative ones, if you think about Iraq, for example, which, for the IEA is the single largest source of increased oil supply between now and 2035. Iraq accounts for fully half of all the incremental oil supply between now and 2035 in the IEA scenario. Iraq is obviously causing a huge amount of concern now, and certainly the numbers that they themselves were talking about in terms of increased production, by 2017, are looking like complete fantasies. I think you have to remember that as well. There's plenty of scope for things to go wrong in a way that is not factored into business-as-usual scenarios, on the political side.

On the Arab spring, and so on, if we were to see any kind of internal turmoil in Saudi Arabia, for example, then that could upset everybody's equation much more dramatically than anything else we've even mentioned here today. It would require a greater expert on Saudi society to offer a view on that than I'm qualified to give. But that is obviously a big potential black swan out there, in the same way that nobody really saw the events in Egypt coming before they happened.

Jeremy Leggett: (Returning to methan hydrates) there is an issue with the carbon arithmetic here: at what point does a potential carbon source like methane hydrates get declared out of bounds? I'm sure everyone here remembers that in the era of Lord Browne at BP the tar sands were declared out of bounds by BP, for climate change reasons. Now, of course that's all changed under the subsequent leadership. But consider some of the round numbers of carbon. The IEA was saying we can only afford to burn 1,000 gigatonnes. Last week we had Jim Hanson and a group of eminent climate scientists say last week that we need to be using half that figure, 500 billion tonnes. And I recall a figure from an IPCC report about the methane hydrates that there could be as much as 10,000 gigatonnes of carbon in that particular form of fossil fuel. At that point we're just so far beyond two degrees Celsius that we can forget it.

Also, an operational point about that particular deposit: in a former life, as a geologist, I drilled through a methane hydrate deposit, with an American team of scientists offshore Mexico. There were some very nervous people on the ship for quite a while. You know how it works; there's free gas underneath the ice deposit, or the hydrate deposit, and a school of thought that this is how you get the Bermuda Triangle, so this is not easy stuff to extract.

Chris Nelder: An article in the Atlantic earlier this year, Will We Never Run Out of Oil? by Charles Mann, was all about the potential for methane hydrates. I was asked to respond to that. I noted that Japan's the only real serious experimenter in methane hydrates so far. It's taken them ten years and $700 million to produce about 4 million cubic feet of gas, which is about $16,000 worth of gas, in the US, at today's prices. So they've got a very expensive, experimental pilot project going there, and nothing more. We have no idea what the actual cost of production will be. We have no idea what their ability to achieve flow rates will be. My back of the envelope calculation suggests that it will not likely be economic unless imported LNG gas prices go significantly higher in Japan.

Paul Sullivan: In response to Mark Lewis' question about can the subsidies be taken off in the Arab world and not have political instability, also in Iran, the answer of course is no. I've spent quite a lot of time in that part of the world. If you took the subsidies off in Egypt today there would be trouble today. If you took the subsidies off in Saudi Arabia today there would be trouble today. The king wrote a cheque for $130 billion as the Arab spring was going forward, in order to keep the peace. It's very unlikely he's going to get rid of the subsidy, and even not just to households.

It's also to produce aluminium, petrochemicals, a huge construction boom, put forth in Saudi Arabia. This will slow down as well, and cut into their employment rate.

John Miles: I'd like to ask Dave just for a bit of illumination on some of the key information he was presenting. The discussion has focused around the fact that we've just found this unexpected windfall, and before we know it, it's all over. So a key part of this afternoon's discussion is the fact of this decline rate on the back side of the peak, and of course all of that discussion is going to be sensitive to that rate of decline.

I had thought, when you went through your presentation, Dave, that one of the things that was causing the decline was the lack of drilling at a later date, for one reason or another, but you said a few minutes ago that you had made no limitation on new drilling at all. In fact, you allowed maximum new drilling to occur. So could you just go back to that point, revisit it for me, and explain what's the one-liner? What is it that makes it decline like that? What's the assumption in your analysis?

David Hughes: There's no assumption. That's physical data, based on a database called Drilling Info, which is used by most companies, as well as the EIA. So the data that I showed was real data.

Why are the declines are so high? A conventional reservoir has at least some permeability - probably several times, on average, what a shale play has - so we're artificially inducing the permeability very rapidly, but the amount of gas we can propagate to one of those artificial fractures is quite small, because of the impermeability of the rock, so that's why it comes out in a big flush, and we have to go back and refrack it, create some more artificial permeability, or drill somewhere else, drill another well. That's what's happening.

John Miles: I understand that, Dave, but why don't we just go back and refrack that original well?

David Hughes: Refracking: I guess the jury is out on that. A University of Texas in Austin study just published has suggested that refracking may add 2-3% to the ultimate recoverable gas. The fracking part of drilling is generally 50% or more of the total well cost, so you really have to look at the economics of doing that.

John Miles: Sure, but my point is refracking seems like the obvious thing to do. The simple explanations of fracking suggest that you create these fractures and then they sort of close up, despite the fact that you put proppants down there, and the logical solution to that would be just to do it again, and yes, it pushes the price up, but this is not the most expensive form of oil, so even if you push the price up it's not as difficult as getting a pre-salt oil off Brazil. I'm struggling to understand why we are so confident that these curves are going to go down so swiftly.

David Hughes: Well, I don't think the fractures close up. I think the reason the declines go down so fast is because you're producing the oil from very close to those fractures, and it's gone.

Refracking is maybe further breaking up rock that's already been broken up, and so the question is how much additional oil can you get? The jury is still out on that, but I think it would be a lot less than the initial frack job.