**Miscellaneous Haynesville Shale Information**
**1st Qtr 2010 Analyst Calls**

## Chesapeake

**David Heikkinen - Tudor, Pickering, Holt**
"And then kind of thinking about the split now of 50 rigs targeting oil, and you've given us acreage. Now, I'll try to think about activity level on each one of those and then your gas activity levels for each of the gas shales. Can you talk about, going forward, after the joint ventures and kind of carries are done, what your activity level will be in each play?"

**Marcus Rowland**
"Well, it's completely dependent among gas prices and to a lesser extent oil prices. I mean right now, as I've stated on numerous occasions, I believe at least half and probably 2/3 or 3/4 of our gas drilling is what I would call involuntary. It's being incentivized by something other than the gas price. It might be the realization of a carry in the Marcellus or in the Barnett. It might be the need to hold acreage in the Haynesville, for example or it could be a combination of those two things. And I think that's, in large part, true across the industry that there's an enormous amount of drilling today that is economic. It's just economic for reasons other than what current gas prices are. But how we look at is a couple of years from now, our gas plays would be largely HBP. We will have ramped up our oil drilling quite aggressively. We will then be moving into a phase of needing to HBP our oil leasehold as well. But the difference between our gas plays and oil plays is of course first, the oil plays are valued at 3x:1 on a unit of production basis on the price alone. Plus there is no amount of success that I think we and our colleagues can have in the industry to really drive down oil prices with our success in finding, I think, new reserves of oil onshore in the U.S. And my guess is offshore oil drilling just got a little more difficult and probably more expensive. And so I think the stage is set for there to be a real rejuvenation in onshore American oil production. It'll be led by the same people that led the rejuvenation of the gas business, of which of course we're one. So if you get into a world where gas prices remain at $4 two years from now, I could see a scenario where the majority of our drilling is simply on oil projects and we'll let our gas projects HBP. If you get back to a scenario where gas prices are $6 to $7, which we expect, then you'll probably see a more balanced approach, so highly price dependent."

## Comstock

**Jay Allison**
"We are excited about our prospects for reserve growth this year, despite the weak natural gas prices, we are well-positioned to have substantial reserve growth at a very low finding cost. Our 2010 drilling program is estimated to cost around $385 million. We'll focus almost exclusively on developing our Haynesville Shale acreage but do we have the flexibility to reduce this budget with three of our seven rigs coming off their contract this year, we'll take a hard look at our budget in June when the first of the three rig contract expires."

**Roland Burns**

"Well John, I think the acreage did increase to a little over a thousand acres… So I think our average lease cost for actual purchased acreage in the quarter was probably close to $7000 an acre."

**Leo Mariani - RBC**
"You guys discussed potentially moving your CapEx budget around this June depending on what gas prices, any color around what type of gas price you are looking forward to keep yourself at six rigs here?"

**Roland Burns**
"Actually we are running seven rigs now. In the beginning of March we added the seventh rig to the Haynesville program. So we are running seven rigs in that program and of the seven we mentioned that three come off contract this year and the first of those three is in June. So I think as we looked forward, we set our overall plan into the seven rigs based on around a $5 NYMEX gas price because we achieved that in the first quarter and we are obviously off of that for the month of April and May. It's not looking like we will hit that, so I think that we will have to, we do not really have a set number on the pas price that we are looking to not utilize that rig. We will have to kind of evaluate how we think the gas market looks for the next twelve months plus and just aside on if we want to continue to drill or if we want to start to pull the budget in a little bit."

**Jay Allison**
"It's 130,000 net acres. So this is the second full year that we've had with the drilling program and unlike a lot of companies I think we only have to drill maybe three or of the Haynesville well this year that we're drilling the whole acreage. The rest of the wells that we are drilling really continue to prove up by Toledo Bend South. We probably need to drill a lower Haynesville well and Toledo Bend South, maybe several. We need to drill some addition Bossier wells or upper Haynesville wells in Toledo Bend South. Same way with Logansport, really think through end of the second maybe third quarter once the G&G side of Comstock is confident that they totally understand our footprint in the Haynesville, then I think we do take a look and pull it back and as Roland mentioned, we have three rigs rolling out this year. One in June, one in August and one in November, so we can let those three rigs go without paying any penalty at all and we'll take a hard look at that when it makes sense and as Roland said, the first quarter, we averaged more than $5 for our gas price so that was in our model. We thought that we had averaged a little over $5 for year. It looks like that's not going to happen in the second quarter, so if we need to tweak the drilling program back, we will and we'll take the first look in June. I hope that helps?"

**Leo Mariani - RBC**
"It sounds like you guys are still testing everything for the next several months and after that it will be more of a economic decision based on gas prices."

**Jay Allison**
"Our balance sheet got stronger from yearend to the end of the first quarter. We've not diluted the stockholders, our risk reward profile is not altered. I mean we're keeping our eye on creating value and we're not drilling these wells to hold leases. It's a much more important reason, we are drilling these

wells to figure out where the better part of this Haynesville is, whether it's Tier 1, Tier 3 and you notice that at the beginning of '09 when we drilled wells in Harrison County, then we stopped, we moved over to DeSoto, we moved to Sabine. I mean we moved the program around because we can… We drill with our own people, we drill on our own acreage and we drill with our own money and if we need to stop it, then we'll do that."

**Leo Mariani - RBC**
"Okay. Jumping over to the Bossier wells. I think that was your second well that you guys talked about here. Just any update on your first well in terms of how it's holding up and how long the well has been in production?"

**Mack Good**
"The well is currently flowing approximately $12 million a day on [18/64"] Choke, pressure is stable, it's performing extremely well. And as you mentioned an upper Haynesville or middle Bossier completion. So it really sets up the whole converse acreage block quite nicely for continued development in that part of the Haynesville."

**Leo Mariani - RBC**
"Okay, and roughly how long is that well been producing?"

**Mack Good**
"About a month and half, six weeks."

**Leo Mariani - RBC**
"Okay. Jumping over to Waskom, it looks like you had a pretty good well this quarter just any observations about the kind of quality your acreage there. It seems as though it's one of the better East Texas wells, so any thoughts on kind of permeability and porosity in that area?"

**Mack Good**
"The porosity is anywhere from 10 to 12%. Perm as it is and the rest of play in the nanodarcy range. I think what we believe is that not just on the Texas side, but also on the Louisiana side by the increasing the number of stages in the [proppant] loading per stage, you get a more effective completion of reservoir and the amount of proppant, the type of proppant placed in sequence will change depending upon what locale you are in within the play. There is no doubt in our minds that we will see improved performance on the Texas side and Louisiana side by increasing the number of stages and proppant pump on the overall completion. "

**Brian Corales - Howard Weil**
"It sounds like you all started restricting some of the flow rates for these Haynesville wells, can you all maybe talk about what kind of flow rates you are seeing after say 30 to 60 days with those. Are they better than the previous wells."

**Mack Good**
"We've just started that whole process and so we don't have 30 days worth of comparison history that we can point to, but we've seen data to suggest that and a number of examples that we've seen that demonstrates that the [cumulative] curves for a well that's choked back in different places in the play require different choke settings within the context of the definition of what choke back is. but that you can get the same [cumulative] production that you would versus a well that was produced in a standard manner, say a [26/64"] choke being the standard choke setting for a new completion versus a [16/64"] or an [18/64"] choke setting on the choke back comparison wells that are similar in every other way and you will the [cumulative] curves will cross in about 10 months to a year and four months and the net production rate will be the same about six months later. So you've got those elements, but the real payoff is that you get a softer decline on the choked back well because the idea being is that you are keeping those hydraulic fractures that you created via however many stages you pumped, frac stages you pumped open and more conductive over a longer period of time. So your EURs, then again we have seen evidence of this specific data that confirms a 20% to 30% EUR improvement is the result of that. But Comstock has just started looking at that on a very surgical basis and so I can't give you 30-day comparisons."

**Brian Corales - Howard Weil**
"With the longer laterals and more frac stages, more proppant, what are you all seeing on the near term or the recent AFEs?"

**Mack Good**
"Well, there is a number of things that work there and I'll try not to get too much detail into the answer, but all of the frac vendors, all of the high pressure pumping service providers, the wireline services, the perforating services, et cetera. Costs have increased because of the demand for those services within the Haynesville play and other shale plays in the region. And so, you have that regardless to how many stages you pump. And then the increased number of stages that we pump obviously takes more time to accomplish if the vendor, the pumping service vendor has gone to daylight service only and there was a time when the vendors were predominantly providing 24 hour operations. Well the problem there is that it has been extremely difficult to find time, the vendor is finding time to maintain their equipment and long story made short, a number of them have gone to daylight operations only for half to two thirds of their crews. So, that has drawn out the amount of time that it takes to complete the well and as a result the daily costs for the completion is gone up. So, you add more proppant, more stages, you add the elements that I mentioned, you are approaching a $9 million D&C for an 18 stage well at this time given the current cost structure."

**Mack Good**
"Sure Jeff, the costs are being impacted by the increased demand for high pressure service in the Haynesville as well as other shale plays in the region. And so the drilling complete cost have certainly come up from third quarter last year to where we were we had drilling complete cost of around $8 million to our current $9 million estimate. That is partly as a consequence of the increased demand, but it is also a consequence of the vendors, the high pressured service providers, taking a step back from

their 24 hour operations and going to daylight operations only, so they can provide some time for equipment maintenance.

On your question about the geological differences between Toledo Bend North and South and Logansport, we find the porosity and porosity thickness and the clay content of the shale are the primary drivers. The lower Haynesville thins as you go south, the upper Haynesville thickens in certain places along with improved [proxy] development as you go south.  We find that the upper is also prevalent across Logansport and Toledo Bend North and Toledo Bend South, it's very good, the southern location. Clay content is another key, it is a highly variable attribute in the play. You can see that especially on the Texas side, stretching into Louisiana side. And what the operators are doing to address that are finding different ways to complete the wells with specialty products that provide and enhance performance in those zones that have a higher clay content, but certainly in order to get maximum fractures developed when you treat the well you would like the shale to be more brittle just to keep it simple here and some places in the play the shale is more elastic and as a consequence you are not able to get a good fracture network developed from your pumping of the frac stages."

## Devon

**David Hager**
"Yes, we have several wells that we're planning to drill down there, because San Augustine County is where we have exclusively term acres down in San Augustine County. We also have term acreage up in Shelby. And so some of the wells we've been drilling in Shelby, and I alluded to, were actually to evaluate the term acreage in Shelby. We have both term and acreage held by production in Shelby. But we are currently -- we have one well that has finished drilling down there, and we're waiting a frac on that. That would be the sublet well, where that frac should start around the end of May or so. We also have a couple of wells that are currently drilling down -- that well, by the way, is a Bossier Shale well that's awaiting frac-ing. We also have two more wells that we're drilling currently down in San Augustine County, one a Bossier Shale well, one a Haynesville Shale well. And we're going to focus the bulk of our activities for the remainder of the year on San Augustine, Sabine and the Southern parts of Shelby County to really get a good handle on what the potential is of our term acreage."

## El Paso

**Brent Smolik**
"The only negative news in the Haynesville is the stimulation cost were up about 10% since the beginning of the year and we continue to experience upward cost pressure in the field. We have gotten our – we had gotten our average completed well cost down to about $7.5 million and today that cost is more like $8 million to $9 million for well.  And I believe this is part of why you have heard a number of operators discuss reductions in their Haynesville activity levels. We have not made a decision yet to reduce activity, but there is a logical limit to high service cost and low natural gas prices and we are getting close."

**Craig Scherer – Tuohy Brothers Investment Research**
"Brent, one for you, and then one for Jim. Again here – first, are you experimenting at all with choking back on Haynesville IP rates? And if so, what are you seeing from that effort? Are you looking at some of the announcements that others are doing in that regard?"

**Brent Smolik**
"Yes, Craig, our practice has always been to limit the drawdown on our completions. And so that's – we are not starting to choke them back, we have always held them back. But the way you should think about that is somewhere else we are just capable of delivering more at relatively low drawdowns and that's where we think we have got an advantage area.  These wells are just capable of higher rates, even though at the bottom, situation wouldn't be drawn it down more than a 1500 to 2000 pounds. So we have always used that practice. We do watch the other competitors quite closely and we have got interest in a couple of those well, so we have got the dataset and we will continue to monitor them but we're not pulling the wells hard."

**Craig Scherer – Tuohy Brothers Investment Research**
"Well, to the degree you've had that practice in the past how flat is the initial production, is it three months or two months of good flat IP rate or how does that work?"

**Brent Smolik**
"Yes it's just we get some early flattish production but it's a month of two and then those wells go on decline. So we're not curtailing them all the way back down to like 10 million a day when they're capable of 20 but that's what you're getting at in those kinds of cases. But while we're curtailing – what we're managing closely is the drawdown at the completion across the fracs. And so the wells will decline fairly quickly but they'll start at 20 – 17, 18, 20 million a day rates."

## EnCana

**Randy Eresman**
"We're really seriously thinking about moving ahead with that and the money largely targets moving to gas factories in places like the Haynesville and so they're demonstration of what the future might be so I think its pretty important that we get one done this year, or at least get one started."

## EOG

**Mark Papa**
"Yes, it's -- our current rig activity there in the Haynesville is about 11 rigs and we've projected our total North American gas close this year is going to be in the range of 1% to 2%. So we're very cognizant of the fact that the gas market has got a whole lot of gas in storage right now and the last thing we need is everybody to be drilling a zillion gas wells in North America. And so what we've done is, we've

tempered, significantly, our gas drilling in all those discretionary areas such as in our Rocky Mountain gas drilling area, and we've considerably slowed down in the Barnett Shale where we've got most of our acreage vested. And so that kind of leaves us with three places where we have to drill a certain amount to hold acreage. The biggest of those is the Haynesville and then we've got the Marcellus and, to some degree, the Horn River. At this stage, we're going to stick with our plan of running roughly 11 rigs and generating that 1% to 2% North American gas production growth. I guess if gas were to fall south of $4 and we were to believe that it was just going to stay there permanently, we'd reassess that."

"It's tough call, here. It's a logical question. Is it the [indiscernible]? We do vis a vis the Haynesville, but our read is that: One, it's hard for anybody to predict long-term gas prices, we can take a stab at it, but we're wrong as often as we are right. So, at this point, we are not anxious to forfeit any of that Haynesville acreage and just give it up."

EXCO

**Doug Miller**
"…We got out of most of our conventional. We still think today that conventional gas takes at least $6.50 NYMEX to make a reasonable return."

"You will see that we are going to move some of our rigs. We're about 100% HBP on our acreage now, so we have the flexibility to move around"

"We will continue to drill in DeSoto Parish, which we consider our core, and one of the major core areas. Every well we've drilled in there has exceeded our expectations – our early expectations. We now kind of expect 20 million a day. But we will continue – from a science standpoint we will be checking different proppants. We will try to figure different ways to source and clean up frac water. And most importantly, I think this year we will figure out spacing. We will get into that a little later on. We are going to be completing four wells on a 320 [ph] to test 80 acre spacing, actually later this month I think"

"Boone asked me here a couple of weeks ago, could we get to 25 to 30 Tcf a year. The answer is we probably could, but we couldn't at $4 gas. Conventional gas needs to shut down – will shut down eventually at these prices"

"We are already seeing rigs moving from the Haynesville down to the Eagle Ford. There is a huge lease play going on down there, and there's going to have to be a lot of drilling going on"

"We are going to be a gas company. We think two, three years from now we are going to see 25 to 30 Tcf a year of demand. We are going to need all the shale. We are going to need conventional. We are going to need LNG. We are going to need Canadian imports to get to that"

**Hal Hickey**

“And we're very aware of the weak natural gas pricing and the increases from drilling and completion service costs, and in turn we're monitoring our program. We do have flexibility. About half of our rigs are on long-term contracts, but other half or so are on well-to-well contracts. So if we aren't realizing the economic returns that we demand, we do have some flexibility that we may exercise. And in fact, we have elected to defer of the drilling in parts of the Haynesville play. We are focusing on DeSoto. Some of those other parts don't give us the economic returns we want, and in turn we are moving out of those areas.”

“We are starting up a 500 million a day treating facility at the very northwest corner of Red River Parish, Louisiana. It ties into Regency, where we have a large firm transportation commitment with them. We have about 475 million a day at that interconnect.”

**David Heikkinen – Tudor, Pickering, Holt**
“Okay. And then just specifically on 3-D in the Haynesville, what is that going to accomplish for you?”

**Doug Miller**
“Well, what it accomplishes is our faults. And we're trying to identify exactly where the faults are, because we have proven to ourselves that drilling into a fault is a problem. And so there are clearly bigger faults in the area, which we – we know where they are. But I would say that identifying the smaller faults and knowing exactly where you are is going to make it a lot easier.”

“I think right now if with the current curve at $4 here or $4.50, it was going to be our suggestion to shut down in Harrison County and allocate some of those rigs that we have that were budgeted over there and move those down. I think – we evaluated Common with six rigs running at year-end. I think both us and BG still contemplate that. I think the land is in good shape. I think the opportunity is there. Now the question is, is it four incremental or is it four that we move from Caddo and Harrison? And right now I think me and Steve and Hal are kind of pushing towards let's shut her down in Harrison County, because HBP over there. And at 12 million a day, you saw our chart, the rate of return is less than 10%, and we shouldn't be drilling over there. So I think right now we might – I think we only have two or three rigs up there, so we could incrementally be up one or two with the Common deal, but we would be moving rigs from northern Caddo and Harrison.”

**Hal Hickey**
“The couple of restricted choke tests Doug is referring to, we've seen a lot of the information that's out there publicly. We feel really good about the choke program we have in place. As Doug mentioned, all the way back – if you go back to our first completion back in December of 2008, we actually introduced a choke management program at that point. So every well we've ever tested we've restricted the draw down and restricted the choke. But some of the other operators are holding further back. They are pulling – they're holding the wells back on, for example, like a 14 or a 16 – 64 inch choke. We've got a couple of wells we've tested. And I would say basically we are probably almost two months into those tests right now. And if you look at the results, it's hard to get real excited about it when you compare

those results to our regional wells. But we're watching it. We're going to continue to monitor it and be aware of what others are doing as well."

## Forest

**John Ridens**
"In our Haynesville/Bossier program, we added almost 17,000 net acres of land in the core during the first quarter. This increases our core acreage to almost 28,000 net acres. We currently have two wells pending completion in Red River Parish. In addition to our operated activity, we participated in two outside operated wells completed in the first quarter for average initial rates of 22 million cubic feet per day. We have four rigs drilling, two in Woodardville Field in Red River Parish and two drilling in the Sabine Parish portion of the Bossier. As we have stated previously, the majority of our drilling this year is to hold leases, and we will have almost all of our land held in this play by the end of 2010."

## Noble Energy

**Dave Stover**
"In our two active onshore gas programs, the Haynesville and the Piceance, we'll reduce operated activity during the second half of the year. We plan to drop one of our two rigs in the East Texas Haynesville program by June and move our only Piceance rig to Iron Horse around August."

"I mean, when we look at our current position, we're in good shape as far as being able to hold everything (Haynesville) with one rig. In fact, I don't think we would even have to use the one rig the full year to hold acreage. We're looking at it from a level of activity there that we're comfortable with the environment."

## Petrohawk

**Leo Mariani - RBC Capital Markets Corporation**
"It sounds like you guys are going to more restricted rate, choke back wells in Haynesville. You guys feel pretty confident that you've sort of hit that, that crossover point on the production rate, and can you just give us some detail on kind of how much production history you've got and kind of roughly when do you get to that, that crossover point where it makes sense to choke the wells back?"

**Floyd Wilson**
"Leo, I think we've probably some curves on that prior to today. I think as a generalization in every case, we project that we catch up on [cumulative] within a year, sometimes less than that. And that's what our target is. And we've seen enough positive results from this that we're basically putting all new wells and most of our existing wells on a restricted rate program at varying choke size is depending on where they are within the field."

**Mark Mize**

"The only thing I would add there to what Floyd said is that the way we have it mapped, we see some operated sections on the south end of our position that probably don't have Haynesville potential, but they have Bossier potential. So I think towards the end of the year, as we get a little further down the evaluation of the Bossier, we'll probably drill some of those sections that probably only require a well into the Bossier. We'll certainly drill a tail into the Haynesville and confirm our bias that the Haynesville is pinched out that far south. But I think there's a handful of wells that late this year, early next year, we could drill as Bossier stand-alone wells."

**Michael Hall**

"Any chance on giving some initial thoughts on what rig counts will look like in 2011 in your respective plays, the Eagle Ford and the Haynesville in particular?"

**Floyd Wilson**

"Michael, in a general sense, we're planning on a relatively flat budget, keeping in mind that we've got quite a bit of optionality built into that. And whenever the lease capture issue in the Haynesville is behind us, we are in the midst of growing the very important business there, KinderHawk, so we intend to keep those pipes full. I think, at this stage, if you just look about a relatively flat budget and flat rig count in the various areas, you'd be fairly accurate."

**Dan McSpirit - BMO Capital Markets Canada**

"Then turning to the restricted rate program in the Haynesville, how should the first year decline rate compare to those wells drilled, say, with a 26/64" choke or put online with that choke size? And then by how much time, maybe I guess, measured in years do you postpone compression?"

**Floyd Wilson**

"The decline rate is about half, it's 40% to 50% in the general sense, at the worst. The postponement of compression is, we haven't quite run the full study on that. But I think on a intuitive basis, we've said it is four, five years probably. We have found out that in some of the earliest wells we drilled within the Haynesville, that we were considering compression on those. And we started restricting the producing rates on those and they're not going to need any compression anytime soon. So it's quite an economic jewel there to postpone compression. So four or five years is our best guess right now."

**Gil Yang - BofA Merrill Lynch**

"While in that context, I think you've commented that all your Haynesville acreage will be held by, I think, the middle of 2011, is that correct?"

**Floyd Wilson**

"Most of them. Substantially, all the material acreage by somewheres around the middle of the year. We have some 2012 expirations. They're not a huge number, but we're not under the gun on every single lease there. And as I pointed out, I think to you, in our last meeting, there are certainly some acreage around the fringe that we didn't intend to hold. It's not a huge component. But we don't feel the need to hold every single acre that we own there."

**Ronald Mills - Johnson Rice & Company, L.L.C.**
"First question really probably for Mark, on the gathering fees, I know you all talked about in your 8-K, that gathering fee is about $0.30 or so for your production under that deal. Did you all already did an accounting for that in those realized price and so therefore you're kind of robbing Paul to pay Peter?"

**Mark Mize**
"Up until this point, all of Hawkville services was a wholly-owned sub of HK. So to the extent, there were revenues or expenses being generated internally, those were obviously eliminated in consolidation. And then going forward with KinderHawk, being a completely independent third-party, I mean, there will be a gathering fee paid and per the agreement, it's $0.34 and there's an additional amount that goes on top of that based on CO2. And we would expect under the equity method approach on the way it's going to roll up in HK, you're probably looking at a number probably around -- we're still working through this, but maybe call it $0.20 for the full year 2010 and probably a little more than that in third quarter and fourth quarter."

**Chris Pikul - Morgan Keegan & Company, Inc.**
"We've heard from other operators that service companies have had to cut back or restrict some of their activity from kind of 24 hours to daylight only to better maintain their equipment. I guess specific to you guys, are you seeing anything incrementally out there that could, in any way, hamper your Haynesville program for the year?"

**Richard Stoneburner**
"No, we made that move probably nine months ago. I think the first probably three, four, five months we were going 24/7 and realized that not just the equipment but the people, it was too demanding. You really weren't being as efficient as you were with just running daylight. So we've been doing that for a long time. And as I said previously, with our current level of activity, I think we're a preferred customer, if you will, and we're getting pretty darn good service out there, both places."

**Subash Chandra - Jefferies & Company, Inc.**
"I guess I saw somewhere like almost 1 million acres of Haynesville acreage turning over coming due, I guess, in the next year and a half or so. I mean, does it make any sense to double down and to perhaps instead of looking for new areas, actually recommit to the Haynesville?"

**Floyd Wilson**
"Well, I don't know about doubling down. We've doubled down a few times in the past two years and it's worked out well so far. And I would hate to think that we wouldn't have gone out and found the Eagle Ford just because we were so enamored with the Haynesville. So I would have to say that there is a lot of acreage that may or may not turn over. We're very happy with our key position in the area. And we're always looking if we can find a low-entry place, but everyone else is looking, too. So it's not like a

big free-for-all where it's growing on trees. So we're cognizant of all the plays in the country and we're pretty comfortable right where we are."

**Richard Stoneburner**

"Subash, I'd just add that we're very particular about the Haynesville acreage that we would try and commit to. And based on our drilling plans and all the unitization filings that have been made within what we call the core, I'd be very surprised if very much quality acreage turned over in the Haynesville."

<u>Questar</u>

**Brian Singer - Goldman Sachs**

"Can you talk in more detail on the Haynesville just specifically with regards to the chokes or the modified flow backs? What do you seeing some of those wells whether it's the ones you announced to any prior wells that you choked back and what are your current views on EUR implications?"

**Chuck Stanley**

"We would view the results from this list of wells that we turned to sales in the past quarter its being comparable to the earlier wells that we completed and reported the higher rates and 20 million to 30 million cubic per day initial rates. These wells are being substantially choke back we are attending to minimize draw down at the formation in order to avoid any damage sort of reservoirs. We have a small group of wells that we are practicing this modified flow back procedure on today and what we see is at any given point on the cumulative production curves a higher falling bottom hole pressure compared to wells that we flow back basically unconstrained. So after recovering a Bcf of gas, we're seeing a 15% to 20% higher in flowing bottom hole pressure compared to a well that flowed back hard initially. We don't know exactly why, this behavior is occurring, but we suspect it's a combination of more evenly de-watering the fractures along the entire length of the lateral potentially avoiding closure of the near well bore fracture and allowing for a complete dewatering and flow back of the entire length of the fracture and a few other sort of thesis on why it works, but the empirical evidence seems to suggest that these wells over the long haul going to recover more of gas than the well has floated back hard initially, because of lack of damage of total incomplete dewatering of the individual fractures."

**Carl Kirst - BMO Capital**

"A follow-up from Brian's question, the Haynesville check. How long do you need before you get comfortable that we actually will ultimately see higher recoveries? Is it another few quarters? Is it another few years? I mean, what's that point that gives you extra comfort that the modified flow back will indeed give you better results? "

**Chuck Stanley**

"I guess that totally, intellectually honest answer is, after the well has been depleted, one can surmise from a basically cumulative production versus pressure plot that if a well after recovering say 50% of its projected reserves as a higher flowing pressure than one that has been unconstrained, that the ultimate recovery. Of course, we can't predict what will happen 10, 15 years from now, but if you look at it just from an MPD or present value perspective, you quickly overcome the apparent higher economic value of having well that will produce at 30 million or 40 million cubic feet a day for a couple of months and then decline very rapidly versus one that you constrain at 10 million or 15 million cubic feet a day and let it basically plateau for that period of time.  If you recover another Bcf of incremental reserves from the well, there is this concept from my youth about maximum efficient rate in oil and gas facilities and you can spend a lot of extra capital on well site facilities, separators, dehigh equipment, et cetera to accommodate a flush production rate of two or three times the stabilized rate on these wells and the economics for putting out additional facilities, additional top site facilities to handle a couple of months 25 million cubic feet or 30 million cubic feet a day rate, are quickly consumed when that well comes off at a fairly high decline rates. So we're trying to not only manage production to avoid reservoir advantage, but we're also trying to optimize returns here by focusing on the rate at which we generate the highest returns at any given gas price for the shareholder."

**Chuck Stanley**
"As a reminder our average producing well on our acreage in the core of the Haynesville, it's booked at about 6.8 Bcfe, our gross basis, all of our proved undeveloped locations booked at 6 Bcfe. We've only assigned two development locations at 648 per unit. So, we've got a lot of room to increase reserves in our Haynesville property as we gain more confidence in well performance which will ultimately dictate the reserve assignments in the proved developed producing wells and also more confidence in the ultimate spacing of the wells and add additional PUD locations in each individual unit."

**Gil Yang - Bank of America**
"And just to finish up on that, how should we think of the decline curve for the wells on restricted flow rates? Is it flat for six months and then starts to decline? Or is it just a sort of exponential decline through it's whole life or is it still hyperbolic early on?"

**Chuck Stanley**
"They exhibit basically a plateau period, they are basically are flat and so, flat reductions, declining pressure and then after six months or slowly break over and then they follow the normal hyperbolic decline curve that we described previously for an un-constraining well and ultimately they will applied now into (*exponential*) decline after after several years.

**Gil Yang - Banc of America Merrill Lynch**
"Okay, and do you then at that six months breakpoint, the plus or minus obviously but at that six months breakpoint do you then let it follow unconstrained like you would normal or you still restricted it?"

**Chuck Stanley**
"Well, in absence if you hold a constant choke with flowing pressure decline ultimately the well will behave hyperbolic decline curve with a constant choke, so it in essence makes its unconstrained production performance after six months plus play plateau or so."

“We don’t anything to open the choke on the well; we just let it basically start to decline naturally, when it does.”