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CONSOL Energy Analyst Conference 2014

MR. DAN ZAJDEL: All right, it's 8 o'clock, let's get started. Good morning everybody and welcome to CONSOL Energy's 2014 analyst day. I'd like to thank all of you for attending. My name is Dan ZAJDEL, and I'm CONSOL Energy's vice president of investor relations. I'd like to offer a special welcome to those in our audience who traveled to New York today to be with us in person. I would also like to thank everyone who is listening to the webcast this morning. We're very excited about today's program, and you can see the agenda on the screen here. We look forward to laying out in detail our plans to develop the tremendous opportunities set in front of us. We will be sharing a significant amount of information with you today, and we believe that this will increase your understanding of our company. Another goal today is to showcase our management team, which Nick DeIuliis, our president and CEO, will discuss more fully. First, though, we need to make some safety and housekeeping announcements. If we need to exit the suite, please proceed to the rear of the room at my right. Go out the doors, past the hallway, and up the 12 steps to 58th street to exit. I would also ask you to please silence all of your phones.

I also need to remind everyone that during today's presentation, we will be making forward-looking statements, including statements regarding our goals, expectations, beliefs, projections, forecasts, etc. As we adjust the microphone, thank you. Please refer to our SEC form 10k for a listing of underlying risks. Please also recognize that under applicable law, we undertake no duty to update any forward-looking statements, and you should not place undue reliance on such statements.

At your seats, and posted on the investor relations portion of our website at www.consolenergy.com, is today's agenda and slides. I won't read it to you, but you can see we have a very full four or five hours. One item that you should note is that we are asking that you save all of your questions until the end of today's prepared remarks. With that, it's my pleasure to introduce Steve Johnson, our general counsel and chief legal officer. Steve?

MR. STEVE JOHNSON: Thank you Dan. Good morning, thank you all for being with us this morning. I'm pleased to tell you that about 15 minutes ago, we announced an important strategic step for CONSOL Energy and our shareholders. As I hope you've seen by now, we issued a press release announcing that CONSOL and our JV partner, Noble Energy, intend to form a master limited partnership to provide midstream gathering services for production from jointly-owned acreage in the Marcellus Shale. In furtherance of the formation of the MLP, CONSOL and Noble have caused a registration statement on form S1 to be confidentially submitted to the Securities and Exchange Commission for an initial public offering of common units of the MLP. Federal Securities laws prevent us from providing any additional information regarding the MLP at this time. So while we would like to discuss the MLP in more detail, we are very limited in what we can say, and we will not be able to take any questions regarding the MLP this morning. Thank you for your understanding on this point. With that, I'm going to turn it over to our president and CEO, Nick DeIuliis.

MR. NICK DEIULIIS: Good morning everyone. On April 19 of this year, CONSOL Energy celebrated its 150th anniversary. And those 150 years--they've been epic, they've been fascinating, and they certainly create a sense of urgency that the management team takes very seriously. But it's also history. It's in the past, and the people in this room, and the people this management team work for, the shareholders, they of course base their investment decisions not on past successes, but where we think and where we believe the best interests of the company lie in the future. So today, we convene to talk about that future and all the ways this company is going to create value and grow in AV for the shareholders moving forward. And in doing so, we're going to introduce a higher degree of transparency for a clearer understanding of the company, as well as the necessary components to better understand what the inherent value of CONSOL Energy is.

But before we get into the details, let's first step back for just a moment and outline how we arrived at this point in time. And over the course of the last 10 years, we've been assembling the assets to allow us to build an E&P company that is going to rival all of our peers when you look at both size and scope. The assets are in place, the team is in place, and last fall, as you know, we made a very decisive move and pronounced shift in the direction of our E&P

business and growth strategy. And, as our first quarter 2014 results show, the strategy's moving on all cylinders, which, of course, is a very good thing.

With that backdrop, I want to begin by addressing a central question of who we are as a company today, on the heels of one of the most transformative and important periods in CONSOL's long history, and I want to be as clear as we can on this point. So, who are we? We are a growing E&P company that's focused on developing the Appalachian shales. And we've got the benefit of a capitalized, premier, best-in-class set of coal assets that serves as an underpinning to help fund that E&P growth. So again, I'll just say that one more time. Who are we? We are a growing E&P company. We're focused on those Appalachian shales, and we've got the benefit of best-in-class and premier coal assets that are going to be an underpinning and funding source for that E&P growth. So CONSOL, it might be 150 years old, and we've got a great track record of creating shareholder value over the last 15 years, but I really believe--and I think you'll agree based on what you see today--our best days lie in front of us.

Now, we've got our senior management team here today. They're going to provide a deep dive into our major segments, into our assets, our plans, and our ability to execute. But before I turn the day over to them, I wanted to highlight a couple of key points, and I want to start with our values. Safety, compliance, continuous improvement -- those are our core values. And we always talk about this and emphasize this within the company; they are values, not priorities. Priorities change with changing times and circumstances. An example of that, in hot markets, production growth might end up trumping unit costs. The flip side of that, in weak markets of course, unit cost can take a precedent, or higher priority, than production growth or production ramp. But values, they're a constant. They don't change, no matter what the internal and external conditions might be, or what the timing might be. And I know you've probably, or a lot of you have probably, heard us talk about our values of safety and compliance in the past, but this just isn't qualitative talk that has no impact, or doesn't correlate to financial performance. There's no doubt in our minds that, at least for the industries we operate within, of course natural gas and coal being the two predominant ones, the safest and the most compliant operators out there -- guess what? They're going to be the most efficient, and also the most profitable.

And those core values correlate to best-in-class financial performance. Those core values, in fact, are prerequisites to strong financial performance. That's the message that we try to convey through our quarterly responsibility report, which strives to continually track and measure those core values using KPIs that directly correlate to financial results. And, oh by the way, as we were talking about this earlier this morning to some of you in this room, the importance of safety and compliance are only going to grow moving forward. Natural gas and coal are two industries, for better or for worse, that are facing growing regulatory oversight, they're facing higher standards and expectations on safety and compliance, and they're facing increased transparency on safety and compliance performance.

So if you can't hang in the new normal of safety and compliance expectations, you're not going to be able to hang in these industries, and that's a fact. For those that can, their shareholders are going to be rewarded and they're going to be rewarded with consistent reliable execution and growth. Another way of saying this, at the end of the day, if we're the safest and most compliant, we should have a lower discount rate applied to us when calculating NAV compared to peers.

Now we know that everything we need to do has to be consistent with our core values. Next, I want to talk about what we, as management, consider to be our top duty to be on behalf of the shareholders who take an interest in CONSOL Energy. And the top duty of this team is simple. We're paid to allocate the cash flow of the shareholders in a manner that increases the company's NAV per share. Now I said NAV; some of you might look at parameters or metrics like enterprise values or NPV; you can pick your poison but the key is that it's one of those metrics per share and not one of those metrics in and of themselves. And we view ourselves of stewards of the shareholders assets and cash flow. Yeah, we get paid to maximize that cash flow by optimizing efficiencies and we're going to talk a lot about the numerous ways that we're going there today, but we also get paid to put that cash flow to work in the right places and at the right times.

That means, in addition to reducing costs and maximizing unit revenues, and optimizing production, we need to obsess as well about capital expenditures and investments, about dividends, about share count reduction, and MNA. Allocation of cash flow is critical, it can make a huge difference for a company that's as asset rich as CONSOL Energy is and who operates in such volatile industries as natural gas and coal. It's a huge opportunity to see cash flow allocation increasing NAV per share, especially if we efficiently execute our strategy and plans.

We've got these core values -- safety and compliance are the great constants, and we view our main duty as management to grow our NAV per share by continually improving our performance and by allocating cash flows to the right places at the right times. Now let's talk about what strategy and tactics flow from the values and main duty of management in the company. People often look at CONSOL and see a complex animal that requires a complex strategy. Actually, when you boil it down, our strategy is quite simple.

When we looked out at the macro landscape for our primary customer base, which is, of course, the US power generating industry, we saw some very interesting trends. The first trend that we saw was the declining share of the US grid going to nuclear; the best proxy for this is the recommissioning rates for existing nuke plants that are far from 100 percent. We also looked out there and saw declining market share for coal-fired generation on the grid because of the ongoing onerous domestic regulatory environment. And the last thing that we saw was that renewables are very limited in what they can actually deliver when it comes to reliability and share of the grid. Especially for the Eastern United States which is, of course, our primary area of focus and interest.

The way we view renewables, it's a single-digit share of the grid and it comes at a very high cost and low reliability. Those three trends that we saw across nukes, across the coal fleet, and across the renewables, led us to two conclusions. First one is a pretty obvious one, which is that natural gas is the de facto choice for new megawatt-hour demand as well as for backfilling the market share that's going to be ceded by nukes and coal. That is a bullish indicator for natural gas.

The second conclusion we saw wasn't as obvious as the first one, and that's that even though our coal share of the grid is declining, the coal plants that survive are going to be the lowest heat rate, most efficient, most technologically-advanced coal plants out there. Those plants are now going to compete increasingly, not with low cost nukes or sister coal plants like they used to or they did yesterday on that grid, but instead, increasingly looking into tomorrow, with natural gas and renewables. That means those surviving coal plants are going to run at the highest capacity factors that they ever have and they're going to be able to garner healthy dark spreads over more costly competitors.

Strategically, we take those two conclusions for our primary market and we apply them to our asset base. And when we apply them to our asset base, we want to grow natural gas production, since we see bullish indicators for natural gas pricing due to that rising demand from the grid that we just spoke about. Incidentally, when you look beyond the grid for natural gas, we see vast emerging markets for our products as well. And that's everything from chemicals, to plastics, metals, glass, food processing, pharmaceuticals, and, of course, transportation. The end-user opportunities for natural gas are rapidly evolving and they provide tremendous upside in the coming years.

We also want to operate the lowest cost, most productive, and most quality-advantaged coal complexes out there. And we want to link those mines to those must-run flagship coal plants I just spoke about because, just like those flagship coal plants, those flagship coal mines are going to experience bullish price indicators despite the overall reduced coal utilization levels that we're going to see nationally. The most productive coal complexes become more profitable because they're going to serve a market that constrains low cost competition. There's more margin to share between us and the power plant.

And strategically on the metallurgical side, we look out into the future -- what do we see? We see a truly global met market, North America being the price taker of that global met market, and the global met market is of course an extremely volatile one. What do we want to do there? We want to operate only the lowest-cost operations that we can find and we need to be prepared to ride the volatility of that global market. That means exerting both strong cost controls and supply discipline. Those two things are going to be essential if we want to be successful on the metallurgical side.

You look at our major tactical actions recently and they've been very consistent with the strategy that we just discussed and covered. Our E&P division, of course, is targeting 30 percent production growth over the next three years. On the coal side, we rationalized our coal portfolio down to the three premier coal complexes, two for thermal and one for the low vol met side in North America. At Buchanan today, we're exerting supply discipline where we ride out the trough in the market but we're also, and this is important, poised to react quickly to the inevitable market tightening when it occurs.

By the way, we created a new balance sheet in the middle of all this, with the deleveraging of billions of dollars of balance sheet liabilities and with strengthening leverage ratios that continue to unfold by the quarter. In addition to these tactical moves, our shift to a growing E&P division is clearly illustrated through a number of financial metrics, including EBITDA, and you can see that on the bottom half of this slide, which breaks down segment contributions over time.

If you look at the first quarter of 2014 as an example or snapshot, the E&P division contributed roughly half of the EBITDA, or the equivalent amount of EBITDA that the coal division did. And when you look forward into the future, that trajectory of higher E&P contributions to EBITDA is going to continue. We expect our E&P division to make up two-thirds of our projected EBITDA in 2016, which compares to about a third in 2013. These two segments have flipped in a very short period of time, from a one-third/two-thirds mix to two-thirds/one third. That's hard evidence of the course of the strategic shift in action that we just talked about.

The foundation of our strategic shift was accelerated in 2010 and 2011, when we acquired Dominion Resources' Appalachian E&P business. Back then, and subsequent to that, we entered into our JVs with Noble and Hess in the Marcellus and Utica, respectively, that helped speed up the development of those shale assets. And many of you are familiar with the specifics of our JVs, but slide 7,up there now, serves as sort of a cheat sheet throughout the day to go back to when you look at how ownership of our assets changes by pay zone and geography.

Use this again as a reference point when you're developing views of NAV as we go through these different Marcellus, Utica and Upper Devonian segments, and it is a function of geography and pay zone. For example, with the Utica, and we're talking Utica Ohio opportunity, which of course is a 50-percent interest through the JV, but when we're talking Pennsylvania and West Virginia, Utica opportunities, that's 100 percent that we own. When we're talking Pennsylvania and West Virginia Marcellus, that's 50 percent because of our JV. When we talk Marcellus in Ohio, that's 100 percent CONSOL Energy.

As you can see, we're evolving at a rapid clip but of course we are far from done; in fact, we are just getting started. As I said earlier, today is about creating transparency on metrics that drive our NAV per share, what our plans and views are on those metrics over time, and how we plan to execute our plans to provide confidence to the shareholder base that's out there today. What we want to provide is the ability for you to walk away with a clear understanding of who we are and what we plan to do, what our major NAV contributors are, and what the likelihood of success is moving forward. We will provide our view on some of these metrics to drive NAV per share in black-and-white terms.

We'll give you the number. While we will discuss our plans and views on others without providing specific guidance, and leave the assumption of the specific number itself up to you. But through the course of the day, our goal is to leave you with the following key takeaways, and we broke them into the three major buckets that are shown here.

The first one is that we've got tier one assets across our entire Appalachian-centric portfolio, and that's true for both E&P and coal. So you're going to see our positions and sweet spots in both the wet and dry portions in both the Marcellus and the Utica.

You're going to see and hear about the multiple stack pay opportunities that we see in our Appalachian basin. You're going to see on the thermal coal side one of the highest-Btu coals in Bailey and what that means for us. And what you're going to see on the metallurgic low vol coal side, is the lowest-cost met mine in North America with Buchanan. The second major takeaway, we've got a new generation of a management team that not only retains all the power and the upside importance of CONSOL's core values, but we're also laser-focused on driving NAV per share.

So you're going to hear from Tim Dugan in a minute, our COO on the E&P side. He brings a wealth of shale experience to the company. And from Larry Cavallo, who heads up our exploration and development effort under Tim. They're going to show you our current status and how we're improving. You're going to hear about areas where we believe we're leading the industry. An example of that is lean manufacturing and what that means moving forward. You're going to hear from Jimmy Brock, our COO on the coal side; he's got the strongest management team he's ever had at CONSOL and that's saying something given how long he's been with this company and the depth of our team historically.

He'll show you how our recent coal capital investments have made us more efficient and more reliable and how they're going to make us more profitable. You're going to hear from Jim Grech, our chief commercial officer, who's going to unveil a concept that we've talked about and really spent time on day in and day out throughout all of our efforts -- stacked customers. We're going to talk about stacked pay zones on the E&P side, we're going to talk about stacked customers on the commercial side, and we're leveraging that concept with historic customer relationships to sell them the new product now, natural gas, and take us to a new level.

You'll also hear from Jim McCaffrey, who works with Jim Grech on the coal market side, about how we're working to maximize the revenue of each and every Btu of energy that we sell. Third major takeaway, we've got a very strong balance sheet and we've got major and significant internal funding sources for our 30 percent gas production growth targets. You're going to see that coal has moved into maintenance of production mode. In the first quarter this year, coal generated over 200 million dollars in cash with regard to our overall financial performance.

You're going to see that our JV partners owe us a collective two billion dollars in the form of carry. This year we expect to collect about 300 million dollars of that. You're going to see that we've got a suite of non-core assets sales when Steve Johnson, our chief legal officer, presents what we've done historically, and more importantly, what that means moving forward for non-core asset monetization and how that's going to drive NAV per share. Then we're going to wrap up with our CFO Dave Khani who most of you know. He's going to show you how we're growing E&P at a significant rate but we're doing that at the same time we're improving our leveraging ratios and liquidity, while we're reducing our cost and while we're driving down our cost to capital.

Lower discount rates of course, are critically important because that can increase NAV per share. So it's one thing to grow production at the rate we are but to do it at the same time while we're improving and strengthening our financial performance, that's a very powerful combination. Bottom line, we believe you'll leave today with a much better understanding of the value of the new CONSOL team, which is managing a tremendous asset base. It's a team that has the experience, it has the skill set, and it has the makeup to execute the strategy and the tactics and the plans that we have and that we're going to discuss today. And this team didn't come together by accident; it was built person-by-person with the bigger picture in mind. We've got the assets, we developed a strategy and we built a thorough process to methodically execute and grow.

One of the cornerstones of our legacy has been the ability to adapt and to innovate and to reinvent over many, many decades; and as I said earlier, I believe our best days are lying in front of us. And with that now I'm going to turn it over to our COO on the E&P side, Tim Dugan, and he's going to dive into the specifics of what's going on with E&P. Thanks.

MR. TIM DUGAN: Good morning. We've got a lot to talk about today. I apologize up front, I've got a little bit of a cough today so I apologize for having a cough drop in my mouth. But we've got a lot of good things to talk about, we're going to talk about the Marcellus, we're going to talk about the Utica, we're going to talk about stack pays and the upside that we have in several of these areas. You know, we're very fortunate in the asset base that we have here. We look at the Marcellus, it's really going to drive our growth this year and be a major part of our growth next year; but it is not our only growth engine.

The Utica will be a growth engine, is a growth engine and it's still evolving and it has the potential to be a larger resource potential than what the Marcellus is. We're excited about it but to start, I just wanted to, being that I'm the newest member of the management team, take a minute and just give you a little bit of my background. Tell you a little bit about me.

As Nick said, I bring over 30 years of experience in the E&P industry, I've worked in several of the major conventional shale plays in the country, the Varnette, the Haynesville, the Marcellus, the Utica and the Upper Devonian. Most recently, prior to coming to CONSOL, I was at Chesapeake Energy, were I served as the Vice President of the Appalachian South business unit. I was responsible for planning, development, and operations in Utica and the southern half of the Marcellus. Early on in my time with Chesapeake, I worked on the Dallas-Fort Worth Airport project, which was the first major airport in the country to undergo major oil and gas development. There's some specific experience there that I bring that fits in well with CONSOL, with our airport project coming up at the Pittsburgh International Airport. I've also held roles at EQT and Cabot in my past operational roles with all three companies. As I came to CONSOL, there was really a lot of work already going on, good work, so we got a solid team and Nick talked about continuous improvement. In the next couple slides I'm going to show you, we'll go through some of that work that has already been done, and the great improvements that the team has already made. And I think really what I was able to bring to CONSOL is more consistency in our operations; consistency in how we do things -- we had several areas somewhat operating differently, and we've been able to somewhat bring them together.

Create more consistent operations, consistent, efficient planning and we're seeing the benefits of that. Our goals going forward are pretty simple, we want to improve our well results and our bottom line is we want to improve our value creation, improve our rate of return. What we're trying to do really isn't any different than what you'll see from our peers, they want to drive their cost down, they want to drill better wells but there are several things that help us stand apart from our peers.

We’ll do that better than our peers but we’ve got several things in our favor. Our land position, 87 percent of our acreage is HPP and we’ll talk about that, but the benefits that come from having the majority of your land held by production are far-reaching and there are many, many benefits to that. Infrastructure, we’ve got water infrastructure in place that provides us a tremendous advantage when it comes to completions. You’ll see as we talk about this, we don’t have a lot of wells in inventory; once we drill wells we get them completed, once we get them completed, we get them in line. You’ll see some companies that have significant wells waiting on pipeline, significant wells waiting on completion.

As we sit here today, we have two wells today, within the company, that are waiting on completion. We’re closing those cycle times, we’re compressing them so we’re getting wells inline sooner and we’re being more efficient. We’ll tell you about how we’re doing that and why we are better than our peers. Then the other piece is cataloging the value that we have in other zones. We’re going to talk about stack pays, the benefit of upper Devonian, the benefit of the Utica that underlies the Marcellus. But also some of the other areas in the company where we’ve got significant acreage positions.

Out in the Illinois basin, down in Tennessee, areas that we’re not focused on right now but hold value in the future. They also hold stack pay potential. So we’ve got a lot to talk about and we’ll be able to answer questions when we’re done here at the end of the day. This slide here, just looking back at some of the work that’s already been done, the improvements that we’ve already made.

If you look at the two graphs on the left, the top graph is average completed lateral length over the last six years. As you can see, we’re continuously increasing our completed lateral length. I do want to note that this is completed lateral length; you’ll see some other numbers throughout the presentation where we’re going to talk about drilled lateral length per year. These are wells that were completed and turned inline in the years noted. You see a continually increasing lateral length so we’re drilling longer laterals but we’re not just drilling longer laterals, we’re drilling better wells.

We’re looking at where we’re landing our laterals, the rock that we’re in and how we’re completing them so we’re drilling longer laterals but we're also drilling better wells and the end result is that we're getting better wells. Lower left is our stages per well. Our completion procedures, our completion techniques, continue to evolve; you look at 2008-2010, we were completing eight stages per well. Laterals were shorter but in the last two years we've had a significant ramp-up in the number of stages that we complete per well. As we start moving to reduced cluster spacing, shorter stage lengths, we're contacting more rock and the end result is better wells.

Getting more reserves. Those are operational improvements but when you look to the right, and you look at our average max IPs per well and our average 30-day rates per well, they were down in 2008-2010. We're at 3.6 IP and average 30-day rates just over 3 million a day. Then you move out to 2014 and what we're projecting there, and the numbers are more than three times, we're looking at IPs of 11 and a half million per day average rate. A 30-day sustained rate of 9.8 million per day. Significant improvements, some of those due to longer laterals, but a good bit due to better wells.

Improved completion techniques, improved drilling techniques and the focus of our teams making sure that we are drilling the best wells first. When you look at EURs, continually seeing an increase in our EURs per well and again, the benefit of longer laterals but also benefitting from improved techniques all across the board. CONSOL has consistently been able to add reserves at low cost. When you look at an industry average, reserve replacement, the industry itself averages 316 percent reserve replacement. Over the last three years, we've averaged 515 percent.

In 2013 our reserve replacement rate was 914 percent, and we added 1.63 TCF of reserves through the drill bit at a finding cost of 42 cents an MCF. So we continue to improve. On the fining cost, all in finding cost, industries average 3.85 and we're at 88 cents per MCF over the last three years. We continue to be an industry leader from a cost standpoint and we continue to improve and get better. Looking at our 2013 reserves, we've added over 1.7 TCF to our reserve base; 1.63 of that came through the drill bit and again, we did it at a low cost, 42 cents an MCF. We had a 44 percent increase in our overall reserves. But the Marcellus itself grew by 87 percent in 2013, and we're projecting the same growth in 2014 in the Marcellus.

That will be the major source of our growth in 2014 and on. But as you'll see as we talked about that, the Utica is going to become a larger and larger portion of that growth. We've already mentioned the reserve replacement 948 percent and then on the right side there is our reserve growth, averaging over 30 percent growth per year. 2010 and 2011 were anomalies; Nick mentioned that in 2010 our acquisition of Dominion Resources added about a TCF to our reserve base and then in 2011 we had our JV with Noble and a divestiture that cut some reserves back. But when your normalize that, we're consistently showing reserve growth each year.

Just looking at the resource potential that we have here. Looking at really the top three lines, the Marcellus, the Utica and the upper Devonian, we've got over 40 years of organic drilling potential in our current asset base. In the Marcellus alone, we've got only 30 years, and that's assuming about 300 wells per year, we've got the potential for over 30 years of drilling in the Marcellus alone. In the Utica, these are three key reserves so we're showing about 3000 locations there but when you look at the acreage and our asset position in the Utica, as it extends eastward into Southwest PA and North West Virginia,that number will climb. The potential in the Utica will rival what we have in the Marcellus.

We have years and years of potential ahead of us; we're just beginning to scratch the surface. Just summarizing really what we're going to talk about today, we're going to talk about the Marcellus Shale, it is really our growth engine over our next several years, and it's going to grow on an average of in excess of 60 percent a year for the next several years. So it's going to be a significant part of what we do and I talked about some of the things that allow us to stand out from our peers, and one of them is the laterals that we can drill. Because of our acreage position, we've got a majority of our acreage held by production; our heritage and legacy acreage that comes, in some cases, through our coal side, allows us to drill longer lateral.

We've got long contiguous blocks of acreage so we can drill consistently 8000-foot laterals. There's tremendous benefit in doing that because we're able to capture the same resource with significant less wells. When we talk about acreage and potential, a lot of times we do that based on an average 5000-foot lateral because that seems to be the industry standard that everybody uses to compare. But if we drill 8000-foot laterals, we're going to access the same resource potential with 35 to 40 percent less wells. We're going to take advantage of existing infrastructure, less pads, less wells, less roadwork, so we'll be able to capture those resources at significantly less cost.

Looking at our continuous improvement, we will exceed industry standards. We continue to improve the quality of wells we're drilling so you'll see our EURs per thousand foot go up, they're continuing to improve. We're reducing our cost, and when I say that we're reducing our cost, it's not that we're out beating our vendors down trying to get another dollar out of them, we're improving how we do things, we're being more efficient, we're doing more with less. Taking our cycle times and compressing them, so we're drilling our wells in less days, we're completing our wells in shorter times, we're reducing our rig move time, and that saves a tremendous amount of money.

Between the improved wells and lower cost, we're going to see improved rates of return, and then the upside potential that comes from enhanced completion techniques, enhanced production techniques; there's a lot of upside that's not built into our current reserve base. The Utica shale, the excitement about the Utica shale, increases every day. These last couple of years the industry has been focused on the wet gas portion of the Utica, there's been a lot of development there, a lot of great results, but now the excitement is starting to build about the dry gas.

We're seeing significant results, we're currently drilling our first Utica dry gas well, and we're drilling the top hole over in Monroe County, Ohio. In 2015, we will have more Utica wells in our plan as the dry gas continues to expand; we're watching what our peers are doing, but hopefully at the end of the day you'll see that we've got a well-thought-out strategy for our Utica development as well as our Marcellus development. There's infrastructure, our development will match the infrastructure build-out and our marketing plans, and it will all come together.

We've got a solid acreage position in the wet area with our JV with Hess Corporation in Noble, Harrison, Belmont and Guernsey counties. We just today are bringing on a new pad, our Noble 19 pad, the infrastructure is building out there, and we’re eliminating pipeline constraints so we’re going to see some growth there. Then in the dry gas, we’ll talk about that more, but we’ve got a significant acreage position there in Eastern Ohio, Southwest PA and Northern West Virginia, and as Nick noted on one of his final slides, one of the important things there is that’s an area where we have 100 percent of the acreage. It’s outside of our JVs, its 100 percent CONSOL -- our Utica dry gas acreage.

Then, looking at future development, stack pay potential, just about every Marcellus acre we have has stack pay potential -- whether it’s the underlying Utica that we can develop on the same pad with the Marcellus or the upper Devonian that lies above the Marcellus -- the ability to develop several of the Upper Devonian shales. When we talk about the Upper Devonian, there’s going to be a lot of talk about the Burkett but there’s also the Rhinestreet, the Geniseo -- there are several shales that make up the Upper Devonian. The stack pay potential is significant and we’ll talk about some of these areas that we’re currently focused on, Pittsburgh International Airport, Southwest PA, Monroe County, Ohio, where we’re currently drilling top holes on Marcellus and Utica wells on the same pad.

Then the acreage position that we have in those areas, in Southwest PA and Northern West Virginia, 472 thousand acres of Utica dry gas potential. We’re excited about that and it’s going to be part of our growth in years to come. This is just looking at our activity for 2014, our drilling schedule, turning line and completion, you can see the majority of the activity where we’re going to drill 182 wells in the Marcellus, 181 of those are within our JV with Noble. The one that is not is the Monroe County well that we talked about that we’re drilling top holes on right now. We’ve got 33 Utica wells planned, and the majority of those are within the wet gas.

You will see the dry gas of that expand in 2015 and 2016 as we increase our activity there. Then in the Upper Devonian, we’ve already drilled one Upper Devonian well that we’ll talk about later. We’ve had significant results, we’re really excited about what we’ve seen there. The potential is tremendous, we’ll drill eight more of those this year. This is the activity that will drive our 30 percent growth in 2014. Again, we’re looking at 30 percent growth over the next three years, and I’ll say it again, the Marcellus is going to be the big driver for that in 2014 and 2015. As you can see, we grew 87 percent in just the Marcellus last year, and we'll do it again this year.

Significant growth again in 2015 and 2016 to meet that overall 40 percent growth rate, the Marcellus will continue 44 and 60 percent in 2015 and 2016. Our budget really is aligned with our growth; as coal operations moved into a maintenance-of-production mode, 74 percent of our 1.5 billion dollar budget will be focused on growing the Marcellus and Utica shales. An important piece of that is the carry that we'll capture this year from our JV partner in the Marcellus, Noble. Without changing activity, we'll reduce our budget through carry by 200 million dollars this year by take or net E&P budget down to 900 million dollars.

We'll continue to spend a portion of our budget on land acquisition, looking for bolt-on acreage for our core areas, increasing our position in key areas in the Marcellus and Utica. In 2013, we spent almost 20 percent of our budget in land acquisitions, really preparing ourselves and aligning our land strategy with the expected ramp-up in activity and production that we're seeing in 2014. We'll continue to add acreage where it fits and makes sense but we are well set to take advantage of our growth strategy for the next three years and beyond.

Just looking at where we're going to spend our capital this year. In the Marcellus we'll spend 825 million dollars on drilling and completion, pretty evenly split between the wet and dry, the dry is with our JV with Noble, we operate the dry gas area, Noble operates the wet gas area so our capital is split pretty evenly between the two. Then over in the Utica, we've got 115 million dollars we'll spend, with the bulk of that in the wet gas area, Noble, Guernsey, Belmont and Harrison Counties. Then we'll spend about 10 million dollars in the dry gas over in Monroe County.

Let's talk a little bit about our JVs; they're a significant part of our growth, they're very important to us, and we think we found the right partners when we put these JVs together. We were able to bring in two companies that have global expertise that matched up very well with our Appalachian expertise. In the Marcellus, we partnered with Noble Energy, as most of you know. It's a 50-50 JV, and the JV includes 345 thousand net acres and it covers the

Marcellus, it's very specific zones it covers from the Burkett to the - -, again that's where the Utica in those areas is 100 percent CONSOL and is outside of the JV.

The JV comes with about 1.9 billion dollars in carry, of which we have captured just a small portion of it so far; we've still got 1.86 billion to recover. And the carry is triggered by the Henry Hubs spot price, if it averages over three dollars or four dollars an MCF for three months, the carry kicks in; we're currently in the carry so we're capturing carry now and we expect that to continue to quite a while. Then when the Henry Hub price drops below four dollars for three consecutive months, the carry will go off. But Noble will pay, when the carry is on, Noble pays one-third of our 50 percent of eligible costs.

Eligible costs include drilling and completion capital, facilities, pad construction. Does not include LOE, leases, delay rentals or seismic activity. Then over on the Utica, another 50-50 JV, a little bit smaller. Just over 6,000 acres that have to pay 60 percent of our cost until we recoup the carry from them, so essentially our costs right now in the Utica are about 25 percent of the total costs. We're got a total carry there of 335 million dollars, of which 208 million remain to be recovered. Very similar on the carry eligible items, with the exception of the seismic; seismic is covered by carry in the Utica so we've got drilling and completion, facilities, pad construction and seismic that is covered by the carry.

We continue; you know we talk a lot about getting our cost down, our capital cost, our drilling cost, completion cost, pad construction, but we're also focused on lowering our unit costs. We expect to see a five to ten percent reduction in our unit costs over the next three years. A lot of that is going to be driven by the increase in volumes, as our production mix shifts more towards the low cost Marcellus production, you'll see going from 2014 to 2016 the Marcellus becomes a much larger portion of our overall production.

That in and of itself will be a major drive in reducing our unit costs over the next several years. That being said, we will lower our LOE costs; the costs that we can control, will be focused on and will lower. One of the things we did when we, as I came in this was already in the works, were centralizing a lot of our staff, last year we had a lot of our staff -- our geologists, our engineers, our regulatory personnel, mid-stream personnel, permitting, all different groups -- routing our regional offices, so we had them out in Central PA, Southwest PA and Northern West Virginia. One of the things that we did early this year is that we centralized our main resource, our people.

We brought them into Canonsburg, our main headquarters, and had everybody centralize there. In doing so, we put together asset teams, we put together three asset teams and then an exploration and production and technology team. The asset teams broken down, we've got a Northern Marcellus team, a Southern Marcellus team and a Utica team. Their goal, they're made up of, what you see there is probably less than half of the team members, the engineering, geology, marketing, land, midstream, water operations permitting, we've got folks from supply chain management, from accounting, from our R&D group. We're got probably 20 to 25 members on each team and their task really is to make sure that we're drilling our best wells. That they're ready to be drilled when they need to be, that we're drilling our best wells first and that we're prioritizing our assets.

A big part of it is having things ready to drill but they're also focused on the existing asset base and how can they improve our operations, how can they assist in adding efficiencies, not just to our operations but to our planning. At the end of the day, these teams are going to compete for capital so when we look at our budget in 2015, 2016 and beyond, what these teams do is going to play a big part in how we distribute our capital, where our development plans go. We want to drill our best wells but when we talk about drilling our best wells, it's not just the best rock, it's got to be where we have the best rock, where we have takeaway capacity, where we've got processing capacity, where we've got the marketing agreements to move the product.

There are a lot of components that go into that and when we talk about it, probably a good example of that is when we look at the Utica dry gas development, there's a lot of excitement about that but there's also some challenges there. Infrastructure, and some areas it makes sense to take that dry Utica gas and blend it with wet Marcellus gas, it's an ethane solution, you can blend the Btu down so you can move more product but in some areas, where you're blending dry

Utica gas with wet Marcellus, you're going to be paying for processing dry Utica gas where you don't need to.

You're able to fill the capacity with the Marcellus, so does it really make sense to emphasize the development of dry Utica gas at this time when you don't have a takeaway for that dry gas. That all goes into the planning, the asset teams look at that and that's a big piece of what they do. It's all part of their planning, their optimization and competing for capital. Then we've put together an exploration and production and technology team; it's very important, the exploration piece, they're looking at our assets outside of the Marcellus and Utica, understanding what we have there and the value that we can create.

Then on the production technology side they're looking at new technologies for drilling, for completions, pad construction, how we build our pads to make sure that they're going to hold up for the life of the well. How we handle our water, how we handle our liquids, looking at how we can do things safer. SO they're looking at new technologies, new products, evaluating them and then helping roll those into our daily operations.

Just looking at a couple of things, when talking about the asset teams, they're really focused on our development programs, getting everything ready so our operations guys can go out and execute but they're also looking at our existing asset base. This is one of the projects they worked on, looking at how we can optimize our production. We have found that in most cases, when we drill our frac plugs out, it's more economical to run our tubing right then, so that we don't have to come back with a rig and a snubbing unit and incur the several hundred thousand dollar cost, a half a million dollar cost, to return to a pad to run the tubing. We're running the tubing up front but on our good high-rate wells, that tubing creates a downhole choke, so our teams have worked, they've done a lot of work to understand, if we flow our wells up the tubing and up the - - we can increase our capacity but making sure that we do that safely.

They've gone through and they've done erosional velocity calculations to understand how high they can get that rate without creating damage and without creating failures. On this particular well, the Kuhns 3B, which happens to be the longest lateral that we have drilled to date, it's about a

10,500 foot lateral, it was the longest well we drilled up until about a week ago. We started flowing this well up the annulus and we saw over a 30 percent increase in flow; initially we thought we would see an initial bump, it would drop down to the original decline but what we've seen here, we've seen a sustained increase in flow, so we're flowing this up the backside and the tubing, we're eliminating a downhole choke but in doing so we've added over 30 percent production to this well. And that's going to result in almost a 30 percent increase in our EUR.

Something we're going to do going forward on all of our high-rate wells, there may be some cases still where, in areas where we see really good results that we may hold the tubing back and not run it upfront. But the majority of our wells we'll be able to run the tubing in it, it's more economical but we'll do it in a way that we can take advantage of those high rates. Here's another one, a lot of potential here, we've got about 260 Marcellus wells that are already producing. We talk a lot about RCS/SSL and the benefits we see from that but we've got 200+ wells out there that were completed with 300- to 500-foot stage lengths.

We are the first in the industry that we know of to go out and recomplete a Marcellus well. This is our GH15 that we recompleted last year. Original EUR was 3.9 BCF, we went in and recompleted it using RCS, did additional stages and we added 2.1 BCF to that and this is a relatively short lateral, Less than 3,000 feet I believe. Actually, I think it might be less than 2,000 feet. It's less than 2,000 feet. So we added over 2 BCF to a 2,000 foot lateral. You can see the red, out on the right, is the production when we brought that online; after the recompletion, we really took it back up to its original IP and then over on the left, the green, we took that and we just put the increased production, or the recompleted production at time zero and if you look at that closely, you can see that the decline on it is actually a little shallower than the original decline.

A lot of benefits for recompletion and we've got over 200 candidates that we can do this to. We currently just did three other wells in this area, we're in the process of doing a second pad with three additional wells on it. Looking at the economics of this, for about 1.8 to 2.1 to 2.2 million dollars we can recomplete a well, generate a rate of return anywhere from 20 percent on a poorer well or one where we get a little less out of it; not a poorer well, that was a poor choice of words, but anywhere from 20 percent upwards of 100 percent rate of return on these recompletions.

Significant upside that we can go back and capture from our existing well base. Then field optimization, pressure optimization, looking at, this is an example of where we have a high pressure system; the blue line is our Nineva pipeline system. Operating at about 1200 pounds, and the red line below is our Nineva 41 pad, we're able to take the Nineva 41 pad from the high pressure system where it was flowing into a 1200-pound line, put it into a low pressure system at about 250 pounds and, really without spending any money, we were able to increase production on that pad by 10 million a day by getting it into a lower pressure system.

At the same time, as we pulled those volumes out of the high pressure system, we also brought on an additional 4500 horsepower at our McQuay station. And that, in conjunction with the removal of the Nineva 41 volumes, we were able to increase the volumes on that line by 10 million a day. We added 4500 horsepower compression, we moved one pay from a high pressure system to a low-pressure system, and we added 20 million a day without adding any additional wells to the system.

The teams are looking at ways to optimize our field operations, our pressures, and one thing to point out here is the important of maintaining control of our midstream operations allowing us to react to situations like this and manage our field pressures and our field systems, in a much more efficient way. It's important to us that we maintain control of those facilities.

Now looking at the Marcellus shale, specifically, we've got 436 thousand net acres and again, one of the important things here is 87 percent of that is HPP, so our drilling programs are not driven by acreage retention, so we're not only drilling a well here, a well there just to hold acreage. It allows us to go out and drill the best wells, we're able to go out and drill longer laterals, and take advantage of the acreage that we have and plan much better. In the Marcellus alone, we're got almost 22 TCF of 3P reserves and over 8900 gross potential locations. And again, 87 percent growth last year, we're going to see 87 percent growth this year in the Marcellus. It will be our primary growth engine this year.

Our liquids production is growing. Last year it was about two percent of our overall production, this year, as we expand the we gas area, you'll see that grow to about five to eight percent of our overall production. We currently have 10 rigs operating in the Marcellus between ourselves and our JV partner Noble, and we talked about RCS/SSL, last year we were really testing that, we did it on about two dozen, a little less than two dozen pads. This year, it will become our standard completion procedure and we will do it on 100 percent of our operated wells.

What you see here, and Larry is going to talk about this in more detail when he gets up, but each of the five areas there are our type curve areas, Larry is going to go through the individual type curves in detail, but as I talked about the asset teams earlier, our North Marcellus team makes up what is listed there as CPA, South West PA and the North wet gas. Then our South Marcellus team is focused on the West Virginia and the southwest gas areas.

This is really just a fairway map to show, it's a EUA per foot but really the point here is just to show you that our acreage lies within the richest part of the Marcellus fairway. Just an acreage summary, we talked a lot, net acreage, gross wells, we want to make sure that we're not confusing the issue anywhere. In total in the Marcellus, we got 790 thousand acres, 690 thousand of that lies within our JV with noble. Net is 345 thousand acres, but then outside of the JV, we got 100 thousand acres that is 100 percent CONSOL. Total, we're got 445 thousand net acres, in the Marcellus.

When we look at development potential, and again, assuming the industry standard 5,000 foot, that's 86 acre spacing, allows us, on those numbers, over 8900 potential wells to drill. But if you take that this year we will average 8,000 feet in lateral length, so if you take an 8,000 foot lateral length suddenly we can drill 35 percent less wells and capture the same resource potential. And we're really only scratched the surface, we've only developed about 3 percent of our acreage so far. So we've got a lot of potential ahead of us.

This is just showing, looking at the wells we drilled, normalized to a 5,000 foot lateral length, the wells we drilled, the lower curve is 2008-2011 and it's showing you the improvement that we've seen in 2012, 2013. Continuous improvement, we've improved our drilling and completion techniques, there's a lot of potential in 2014, in a year or two, when we look back at 2014, you will see a curve that will sit above the 2012-2013 curve. There's very little RCS/SSL in these numbers here. I believe in 2012 there were 16 of the 61 wells that make up that curve had RCS/SSL in them; in 2014, it will be 100 percent of those wells.

A lot of upside of RCS/SSL, but also the enhanced production techniques and some of the other things that we're doing to improve our operations will see the benefit of in 2014 and 15. Looking at our drilling cost, on the left are our historical drilling cost, it's non-RCS so an average 5,000 foot lateral with historical cost about 6.1, 6.2 million dollars per well, drilling and completion cost. One of the things to note here, you look at the narrow band as lateral lengths increase, you see a very narrow band along that trend, we don't see a lot of outliers, which speaks to the quality of our drilling and completion staff.

We don't have a lot of train wrecks; we have very consistent planning in how we do things, so they're very good at cost control and understanding how to work around issues and problems. So we don't have a lot of outlets where, you see one or two there, where costs are above the curve. Then as you move to the right, those are our 15 or so wells that were completed with RCS/SSL, it does come at an additional cost, we're doing more stages; the stages are cheaper but we're doing more so it adds about a half a million dollars to each well.

So a 5,000-foot lateral with RCS/SSL is about 6.6 million dollars per well and this is the base point that we're using. We're going to reduce our costs by at least 15 percent by 2015. So we're looking at these costs and how we can get them down by 15 percent. I think it's worth noting that we're not, when we talk about cost reduction, it's not just getting our costs down. Our completion is an area where we're spending more money to improve our results. We're going to make sure that we do it as efficiently as possible so we minimize the additional cost, but where it makes sense, we're going to spend money to improve our results.

Again, we talk a lot about the benefits of longer laterals, this just showing the impact on rate of return and lateral length, at 5,000 foot our historical costs show a 50 percent rate of return but you take that out to 8,000 feet and we're at 73 percent. Then the middle curve is our cost with RCS/SSL and efficiencies built in, so better well results, so we're seeing a higher rate of return. The dashed line at the top is our improved cost, our enhanced cost, with the carry built in that we will capture from our JV partner.

Lateral length makes a big difference. It cuts down on a lot of what we have to do. Less top holes, less production equipment, less pads need to be built, water systems, everything; we're able to take advantage of the existing infrastructure but really drill less wells, less impact to the environment, just overall benefits are tremendous. Looking at drilling, a scenario where we've seen continuous improvement over the years and really there's a lot of numbers there, but if you focus on the average lateral length, the fourth line down, in 2011 we averaged 3,852-foot laterals; it's increased steadily each year. Last year we were just shy of 8,000 feet at 7,970, but then when you drop down to the last line, our average cost per lateral foot, in 2011 we were at 552 dollars per foot, 2013 we were at 278 dollars per foot. Significant improvement and those numbers continue to come down.

In the first quarter of 2014, we average 398 feet but if you notice, we drilled slightly shorter laterals, we will finish the year averaging almost 8,000-foot laterals. Just last week we drilled our longest lateral to date, we were, I think it was about, 10,970 feet, so we're 30 feet shy of 11,000 feet. We drilled that well at an average cost per lateral foot of 258 dollars. We've seen other wells that have been in the low 300s, so we continue, through longer laterals, improved drilling efficiencies. We are getting our cost down.

And just looking at some of the things that are going to help us drive our cost down, improved operations, one of them is air directional and we'll talk a little bit more about that in a minute. But air directional, the more that we can do with air directional, the top hole rig, the less we have to do at the horizontal rig and the lower our costs. We're looking at advancements in technology; one of the big ones is the rotary - - that we use. It's become an industry standard; it comes at a higher cost, but if we can take that rotary steerable and drill that curve in the lateral in one run so we're run tripping out of the hole several times to swap out bottom hole assemblies, the benefit is not just drilling a better well bore, staying in zone, but it's also drilling it quicker and actually lowering our cost.

Rig movements -- we will reduce the cost of our rig moves, a year ago we were moving rigs in 14 days. In the last months we've moved three rigs in seven days, so we've seen tremendous improvement there and we've got a target of five days; we will get there very soon. Then we've got to start doing it repeatedly and consistently.

Contract improvements, we're looking at all our contracts with our vendors. We're moving more toward incentive-based contracts so that there's reason for the vendors, the contractors, to want to do better, to drill better wells, to drill faster, and do it safer.

One of the other things that have made a big difference, top holes, we're looking at, when we bring our top hole rig in, those rigs are small enough that we can actually put two rigs on a location so when we go in and drill six top holes, we can bring in two rigs at the same time, each of them drilling three wells and cut the time on that pad in half. Rather than a rig being there three months, we can have two rigs there for a month and a half. When we start adding up all these pieces to cycle time, cutting our rig move from 14 days to 7 days, cutting down the cycle time for the top hole rig, reducing our drilling days, reducing our completion time, suddenly, we're turning our wells in line much sooner. Rather than turning a well in line in October, we're going to be turning it in line in early September, late August and we can an additional production impact from that.

Again, it's adding value. These are some of steps that will get us to that 15 percent reduction, we're well on our way there, we're already seeing a lot of improvements and our costs are coming down. Then the air directional, I want to talk about that because this is pretty exciting, nobody else in the industry is doing this, we're trying to get more out of our top hole rigs. Every dollar we spend on a top hole rig saves us three dollars on the horizontal rig. It used to be that we'd take the top hole rig and drill the vertical section down to the kickoff point, we would move that rig off and bring in the horizontal rig and the horizontal rig would drill the curve and the lateral. We started to push our top hole rigs a little bit, we're looking at actually bringing in larger top hole rigs so we can drill deeper and further.

This example here, there's a lot of numbers there but if you look at the second one down, the kickoff point on the NV58, we were able to drill down to 6,800 feet, which we drilled down at a 24-degree inclination. On the NV34, we just drilled down to the kickoff point, so we drilled down 5,600 feet so we drilled an additional 1,100 feet on the NV 58, got into the curve and what that ended up doing for us, the section highlighted in red there, is the amount of curves that the horizontal rig had to come in and drill. Because the top hole rig was able to drill to 24 degrees on the NV58 the horizontal rig only had to drill 782 feet of the curve before it got into the lateral. On the NV34 it had to drill the entire curve, so it had to drill 2,074 feet of the curve.

That does a lot of things for us. When you go back to, if you recall, what I just said about the rotary steerable, one of the things that we're doing there is we want to be able to run the rotary steerable but be able to do it in one run. The more we can do with the top hole rig the more likely we are to be able to bring in that horizontal rig using the rotary steerable and drill the remaining curve in lateral with one run. It'll save us a couple days tripping time if we can do that with one run. The more we can do at these top hole rigs -- it provides a lot of advantages. It also reduces our cost.

Completions very similar to what we're looking at on drilling. If you look at stages per well, back in 2011 we were averaging 12 stages per well. Last year we started to test RCS/SSL and our stages increased. We got up to an average of 26 stages per well. This year we will average 58 stages per well. A significant increase in stages. Stage cost goes down. You can see we went from 205,000 a stage in 2011 to 114,000 a stage. We're pumping smaller stages. We're pumping more of them. The end result is about a half a million dollar decrease in our well costs.

But the best part of it is we're seeing better wells. We see a 30 to 40% increase in our IPs with RCS/SSL and a 15 to 20% increase in our reserve. We're spending a little more money to get better results.

When we look at efficiencies right now we averaged about four stages a day in 2013. From the time we start a completion job until we end, we average four stages a day. We're targeting eight stages a day. That in itself will provide significant savings. It'll save almost a half a million dollars a well, but more importantly it will cut seven days off of our completion cycle time, getting wells in line sooner.

This is just a 15% reduction we're going to see on the completion side. A lot of it will come – we're renegotiating contracts with our major vendors on the completion side. We've already seen a benefit there. Our prices are coming down. Efficiency increases I just talked about -- we're going to go from four stages a day to eight stages a day. We've already seen pads where we've been able to average six stages per day from start to end. We're halfway there. We will get to eight stages a day. We've had 24 hour periods where we've done as many as 11 stages. We're figuring out how to do it more consistently and make it repeatable.

Then our design. RCS/SSL is a big part of our improvement. We're seeing tremendous benefits from it, but we're not at the optimized completion procedure yet. We still have a lot to look at, to work on. We're looking at pump rates. We're looking at our sand schedule, the amount of pump rates we run, the additives we use, the impact to the water we use on the additives. There's a lot of work to be done in our completion. We think that'll continue to evolve and improve as we move forward.

That's just looking at the efficiencies I mentioned. If we can go where we are now looking at our current stage cost of 114,000 per stage, if we can take that from four stages a day to eight stages a day we will take our completion cost down. Our stage cost will drop through efficiencies, and rental costs that we have on additional equipment out there. We're able to lower those costs. But the net result is a $430,000 savings per well and a seven-day decrease in cycle time. That is significant when you look at the impact that has on our production. All this really is de-risking our growth strategy of 30% a year. We're well on our way to achieving that 30% growth.

Just a schematic looking at the RCS/SSL. What we did several years back, we're looking at 300-foot stages, 60 feet between clusters. Now we've got it down to 150-foot stages and 30 feet between clusters. The end result really is that we're contacting twice as much rock as we were previously. More pathways for the hydrocarbons to flow and it's resulting in 40% increase in IPs and a 15 to 20% increase in EURs.

Then this just shows the areas where we have done RCS/SSL to date. It's been spread through our three operating areas of Central PA, Southwest PA, and West Virginia. We've seen most results as far as production results in Southwest PA. Just recently brought on our first RCS/SSL pad in Central PA. I think the second pad is coming on now. We have seen results, the results that match what we thought we'd see. We're seeing improved flows. And then in West Virginia, we've had a couple wells come on down there that were treated with RCS/SSL and seeing improved results there as well.

I'm going to turn it over to Larry. He's going to talk about type curves, go through the Marcellus and the Utica. But again, a lot of upside to what we're doing. I'm going to come back and we're going to talk about some of the additional upside we have. But Larry is going to go through the Marcellus and Utica type curves and really go through in more detail the areas that are going to drive our growth in the next several years.

MR. LARRY CAVALLO: Thank you, Tim. My name is Larry Cavallo. I'm Vice President of Exploration Development for CONSOL. I have 28 years Appalachian-only gas experience, and I came to CONSOL in 2010 with the Dominion E&P acquisition.

I'm going to walk you through our Marcellus and Utica operations by providing similar information in a similar format for six operating areas within the Marcellus and three operating areas within the Utica. You will see the first public unveiling of our type curves and I hope to provide you with enough information that you can construct your own NAV model.

As I go through each area you will see that we have a large inventory of high quality, contiguous HPP legacy assets and several new, exciting prospects that will provide development opportunities to feed the growth of our E&P business for many years to come.

This slide is provided as a quick reference guide of all of our Marcellus operations. I will cover each area individually, in detail. But I will remind you now that five of these six areas are in our 50/50 joint venture with Noble, the exception being the Ohio acreage in Monroe County, Ohio, 11,000 acres there.

Across all of the Marcellus though we currently have 10 horizontal rigs drilling on the 436,000 net acres that contain nearly 9,000 drill sites. We expect the reserves from those sites to range between 1.3 and 2.1 Bcf per thousand feet of lateral. With a portfolio of this size, it is clear that the Marcellus will be a main growth driver of CONSOL's E&P efforts going forward.

The first of the Marcellus operating areas is Southwest PA where CONSOL drilled its first Marcellus well, where the bulk of our activity has been to this point, and where our best Marcellus reservoir resides. Shown on the map are results from a few of our recent pads that are a mixture of RCS and non-RCS wells. But to be clear, and as Tim said, we are 100% in with RCS in 2014 in Southwest PA. We have approximately 45,000 net acres and over 700 gross drilling locations in Southwest PA. We currently have 128 wells online producing and will turn 19 wells online during the course of 2014.

We expect to drill seven wells per pad with average lateral lengths of 8,800 feet. We expect those wells to cost $9.4 million after completion with RCS. Our blended type curve for the area suggests 2.1 Bcf per thousand feet of lateral. But I want to note here, we've given you blended type curves to represent the weighted average well across the entirety of graphic footprint of each area. There'll be some places where our wells will be better. There'll be some places in each area the wells will not be quite as good. But we feel this blended, weighted average well provides you with the type of granularity you need to build your model.

On the top of this slide is a graphic representation of Southwest PA's 5,000 foot RCS-type curve. We expect that 5,000-foot well to have a 30-day IP of eight million cubic feet per day or 240 million cubic feet of production the first month. We expect that well to provide 10.5 Bcf of reserves at a cost of $6.6 million. With the efficiency gains Tim spoke of we expect to drop that cost over the next year and a half to $5.6 million. The effective cost to CONSOL after those gains and with the Noble carry included should be $4.7 million.

In the lower right we provided ATAX rates and returns of the 5,000-foot type curve at various gas prices. It's shown for our historic well cost in gray after the efficiency gains in purple. And with the effect of those gains and a Noble carry in the dashed line at the top. I need to point out though that these type curves economics cost on the 5,000-foot lateral provided just for you to compare to other industry standards. We really expect to drill a lot longer wells; specifically we will drill our 2014 Southwest PA wells to an average length of 8,800 feet. Those wells in turn will provide 18.5 Bcf of reserves at a historic well cost of 9.4. That cost will drop to $8 million after efficiency gains and an effective cost to CONSOL after the Noble carry of $6.6 million.

In other words, drilling our Southwest PA laterals to 8,800 feet provides us with 76% more lateral footage than a 5,000-foot well. But we get that at only a 44% greater cost. You can see the leveraging that that provides for us. Comparing those 8,800-foot returns to the 5,000-foot type curve immediately above it you can see we expect the longer laterals to provide ATAX rates and returns of 78% at historic cost, 104% with the gains, efficiency gains, and 144% with the Noble carry included. That's compared to the 5,000-foot well and 57%, 76%, and 105% with the Noble carry. Those numbers really show we are fortunate to have contiguous HBP leasehold that allows us to drill these long laterals.

Tim mentioned we started adopting RCS completions last year. What we have here is the area that we've been doing this in Southwest PA. It's our - -. It illustrates why we've made the change. It shows actual and forecasted production, normalized back to 5,000-feet laterals from one area of Southwest PA. The non-RCS/SSL wells are shown in the darker brown and the historic type curve for those wells equates to 1.4 Bcfe per thousand feet.

In red we show the normalized production for the newer wells that were recently completed with RCS. Comparing those two sets of wells it is very apparent we are getting much more production per foot from the RCS/SSL completions. We're so confident that we've shifted our type curves from the North Nineveh area upward by 18% from 1.4 to 1.7 Bcfe per thousand feet.

Here's another area of Southwest PA. It's a little further south. It's an area where we've traditionally gotten better wells compared to north Nineveh. It's in Greene County. It includes our Greene Hill, our Morris, and our Nineveh fields. Our type curves for Greene Hill, Morris, and Nineveh have historically been 1.9 Bcf per thousand feet of lateral. Layering in that same 18 to 20% increase in reserves from RCS/SSL brings that type curve up to 2.3 Bcf per thousand feet. This compares to 2.1 Bcf per thousand feet published by EQT for the area and 2.3 Bcf per thousand feet of lateral published by Range for the area. We expect to drill approximately 88 wells in these three fields over the next three years and we're anxious to see how RCS impacts the production from those wells.

I'll shift now to the second operating area; Northern West Virginia dry. This is an area that's going to become increasingly more important for CONSOL as we begin operations beneath Dominion Transmission Storage, the eastern half of which is shown on the map to the right.

Also shown on the map are the Philippi 4 pad that has three non-RCS wells, the Philippi 13 pad that has six RCS wells, and the single well delineation pads of Audra [phonetic] 3 and Century 3 further to the south. We have approximately 105,000 net acres and over 2,300 gross locations available to be drilled in Northern West Virginia dry. We currently have 22 wells in line out of Philippi, Audra, Century, and further to the south and out. We will turn 21 wells in line during the course of 2014.

We expect to drill six wells per pad with average lateral length of 6,800 feet. We expect those wells to cost 7.9 million per well after completion with RCS, and our blended type curve for the area projects 1.8 Bcfe per thousand feet of lateral.

We expect the Northern West Virginia dry 5,000-foot RCS-type well to have a 30-day IP of 6.6 million cubic feet per day or 200 million cubic feet of production its first month. We expect that well to provide 8.8 Bcf of reserves at a cost of $6.6 million. That cost will drop to $5.6 with efficiency gains and the effective cost to CONSOL after the gains and the Noble carry will be $4.7 million. Historic ATAX rates and returns on that 5,000-foot type well at $4 gas is 30%, 40% after efficiency gains, and 54% after the Noble carry.

The wells we expect to drill in 2014, however, and as I said earlier, are much longer and should provide 12 Bcf in reserves at historic cost of $7.9 million, $6.7 million after efficiency gains, and effective cost to CONSOL after the Noble carry of $5.6 million. Again, you can compare the rates and returns shown on the yellow box in the lower right corner to those in the graph above it at $4 gas to see the value of longer laterals.

We've completed the Philippi 13 pad with RCS/SSL shown here in red. It's compared to the existing non-RCS Philippi 4 pad shown in brown. We've had some pipeline constraints in the area masking some of our earlier results, but I think you can see that we've seen some uplift from RCS. We will continue to use RCS/SSL in West Virginia throughout 2014 and we are forecasting the same magnitude of production and reserve increase we've seen in Southwest PA and our competition has seen and spoken about in Northern West Virginia.

As such, we've increased our Northern West Virginia dry type curve from 1.5 per thousand feet of lateral to 1.8 Bcf per thousand feet of lateral, roughly equal to the published type curve by Antero for the region.

Before I leave Northern West Virginia I want to talk to you about our 90,000-acre farm-in underneath Dominion Transmission Storage field, which straddles the boundary between the Northern West Virginia dry operating area and the south wet gas operating area. The DTI farm-in shown here in blue provides the kind of HBP and contiguous acres that we love. It's the kind of acreage that we can drill long laterals and get better economic returns from. We expect the farm-in to provide over 600 gross Marcellus wells of 8,000 feet lateral length with additional potential from the Upper Devonian.

We also have very high expectations for the qualities of these wells. In essence the property has been de-risked by Antero, with 1.7 Bcf per thousand feet well results right up to the Northern Boundary of the field shown here in red, circled in red. Also the previously mentioned Audra 3 and Century 3 single well delineation pads that we drilled last year. As you can see on the eastern side of the map, the Audra 3 was an 8,700-foot lateral that has produced nearly 1.0 Bcf its first year.

Likewise, a little further south in Northern Upshur County, the Century 3 well was a 7,500-foot-long well and it produced nearly 600 Bcf its first five months. Both wells showed very good results. Both we're very excited about. Both wells projecting towards 1.7 Bcf of reserve per thousand feet of lateral. Here's the important point -- those wells were both completed without the benefit of RCS and SSL. Clearly we expect that RCS and SSL will make those results better. We've de-risked around the eastern side of the field and Antero has proven the Marcellus quality right up to the edge of the field.

I'll stay in dry gas but shift northward to our third operating area that we refer to as Central PA. Before I go any further though, I want to address the name CPA. It's really more for internal use at CONSOL. It's not meant to imply that our leasehold is in the central part of the state of Pennsylvania. As the map shows, our properties are almost entirely in Westmoreland and Indiana Counties, which our competition includes in their Southwest PA regions.

Also shown on the map are a couple of recent pads we've drilled in our Maymont field in Westmoreland County. There are a total of nine non-RCS/SSL wells on those two pads between 7,000 and 8,000 feet long. Average first month production from those two pads has been very strong, between three quarters to 1.0 Bcf production per well.

Further south are some short competitor laterals that have equally strong results. We have approximately 110,000 acres in the region and over 2,000 gross drilling locations in Central PA. We currently have 40 wells online from the Maymont Field and we'll turn 14 wells online during the course of 2014. We expect to drill six wells per pad with average lateral length of 6,900 feet. We expect those wells to cost $8 million per well after RCS completion and our blended type curve suggests 1.6 Bcfe per thousand feet of lateral.

We do plan to drill a few one- and two-well delineation pads in 2014 and 2015 in Southern and Central Indiana County to help us delineate and better understand the quality of our acreage there. Also worth noting, as Tim mentioned, we very recently completed our very first three pads in Central PA using RCS. Results have started coming in in the last 48 hours. Really excited about those and hopefully we'll have more to talk about in our next quarterly ops release.

We expect a Central PA 5,000-foot RCS-type well to have a 30-day IP of 5.9 million cubic feet per day or 177 million cubic feet of production its first month. We expect that well to provide 8.0 Bcf of reserves at a cost of $6.6 million; $5.6 million after efficiency gains and an effective cost of $4.7 million to CONSOL after the gains and with the Noble carry.

Historic rates of return for the 5,000-foot well at $4 gas is 28%, 36% after efficiency gains, and 50% with the Noble carry. The wells we expect to drill in 2014 will be much longer. They should average 6,900 feet in lateral length and provide 11 Bcf of reserves per well. They come with a historic cost of $8 million, $6.8 million after the gains and an effective cost to CONSOL after the Noble carry of $5.7 million. We expect them to yield rates of returns of 33%, 44%, and 60% after the efficiency gains and with the Noble carry.

As I mentioned before and Tim mentioned before me, we have just recently completed some RCS wells in CPA and we're confident that we will be able to increase our reserve per foot. We have increased our type curve for the area from 1.4 Bcf per thousand feet of lateral to 1.6 Bcf per thousand feet of lateral. For comparison purpose, a little further north, EQT has published a type curve of 1.4 Bcf per thousand feet of lateral.

As a lead in to our next operating area, north wet gas, I want to highlight the 9,000 contiguous acres we've leased underneath the Pittsburgh International Airport. We have rights there for the Upper Devonian, the Marcellus, and the Utica Shales and we expect we may ultimately drill 45 wells in each formation. Tim will talk more about the stacked nature of the shales at the airport, but I separated this lease from the rest of North Wet Gas because it's being operated by CONSOL as opposed to the rest of North Wet Gas that will be operated by Noble.

This map shows the rest of the North Wet Gas operating area. In Northern Washington County, just south of our Pittsburgh Airport lease, are a couple of competitor pads with short laterals and average six month production totaled between 300 and 400 million cubic feet of gas and 3,500 to 6,500 feet, 6,600 barrels of oil per well.

Further south, along the PA/West Virginia border, is our Majorsville Field where Noble has drilled, completed, and turned in line 66 wells. A couple of the very recent and very strong multi-well pads are shown on the map. We have approximately 60,000 net acres and over 1,600 gross drilling locations across North Wet Gas.

We will turn in 63 wells online during the course of 2014, with average lateral lengths – we expect to drill six wells per pad with average lateral lengths of 7,900 feet. Noble has also been experimenting with RCS and SSL completions. Our blended type curve for the North Wet Gas area after RCS completions suggests 1.7 Bcf per thousand feet of lateral, and we expect life of reserve condensate yields of five barrels per million cubic feet of gas and NGL yields of 25 barrels per million cubic feet of gas.

We expect the North Wet Gas 5,000-foot RCS-type well to have a 30-day IP of 6.6 million cubic feet equivalent per day or 200 million cubic feet equivalent its first month. We expect that well to provide 8.7 Bcf equivalent of reserves at a cost of $6.6 million. Costs should be driven down to $5.6 million after efficiency gains and the effective cost to CONSOL after carry and the efficiency gains should be $4.7 million. Historic rates and returns for the 5,000-foot-type curve at $4 gas is 32%, 43% after efficiency gains, and 59% with the Noble carry.

The wells we expect to drill in 2014 should average 7,900 feet in lateral length and provide 13.4 Bcf equivalent in reserves at a historic cost of $8.7 million. We should be able to drive that cost to $7.5 million after efficiency gains and the effective cost to CONSOL after efficiency gains and with the Noble carry should be $6.2 million. After-tax rate of returns for the longer laterals will be 49%, 65%, and 90% after the efficiency gains and with the Noble carry.

Tim spoke of the continuous improvement of CONSOL's early Marcellus well results. Slide 59 is the corresponding slide for Noble Energy results in the North Wet Gas operating area. Their early wells drilled in 2012 normalized back to 5,000 feet are shown by the red line. The blue line represents 2,013 well results normalized back to 5,000 feet. And then the first 12 wells of 2014 are shown by the red dots in the upper portion of the graph.

It's important to note that only two of those 12 wells were completed with RCS and SSL. As the graph illustrates, Noble has shown year-over-year well improvements of 15 to 20% over the last couple years and we expect that improvement to continue with more adoption of RCS/SSL completion techniques.

Slide 60 shows why we like the liquid component that comes from the North Wet Gas area. With our high activity levels and northern wet gas we expect the liquid component of our net production to grow accordingly. As previously announced, approximately 2% of our 2013 net production came from hydrocarbon liquids. We expect the liquid component to increase by 135% compounded growth rate to represent 5 to 8% this year and 10 to 15% of our production in 2016.

The graph on the right illustrates why we want that liquid component to grow. Using the March 2014 NYMEX price of $4.90 per mcf the shorter bar on the left shows the price uplift from 1 mcf of 1070 Btu gas that nets a price of $5.23 after adjusting for heating value.

However, the bar on the right is much taller. It's made taller by the $3.34 price uplift that comes from three net components impacting 1 mcf of 1230 Btu gas. $0.46 is coming from the five barrels per million cubic feet of condensate production. $2.95 coming from the 43 barrels per million cubic feet of NGLs after processing. $5.16 comes from the post-process shrunk, residue gas stream and its remaining 1057 Btu heating value. Clearly this graph illustrates the great value derived from process wet gas.

The final Marcellus operating area is also a wet area. We call it South Wet Gas and it is also primarily non-operated by CONSOL. I say primarily because we will be operating the western half of the Dominion Storage Field farm-in. Most of our current knowledge of this area comes from third-party results, as shown by the three multi-well pads highlighted on the right side of the map.

There are several lateral lengths – there are average lateral lengths of about 3,700 feet, have six-month production averages of approximately 500 million cubic feet of gas and 500 to 2,500 barrels of condensate. However, we will be able to tap our own results very soon as Noble has three wells currently undergoing completion. The Shirley 1 pad with six wells of approximately 8,700 feet in length, the Pensborough 1 pad that has nine wells approximately 6,800 feet long, and the Oxford 1 pad that has six wells of 6,400 feet length.

They also have one pad drilling there, the Pensborough 1 pad that has 12 wells.

We have approximately 105,000 net acres and over 2,200 gross drilling locations for this area. We currently have three wells online and we'll turn 24 wells online during the course of 2014. We expect to drill six wells per pad, an average lateral length of 8,100 feet. We expect drilling completion costs to be $8.9 million and our blended type curve for the area with RCS and SSL included suggest 1.4 Bcfe per thousand feet of lateral. We expect life-of-reserve condensate yields to be five barrels per million cubic feet of gas and NGL yields to be 33 barrels per million cubic feet of gas.

We expect the South Wet Gas 5,000-foot RCS-type well to have a 30-day IP of 5.4 million cubic feet equivalents per day or 160 million cubic feet equivalents of production its first month. We expect that well to provide 7 Bcf equivalents of reserves at a cost of $6.4 million. Historic after-tax rate of returns of that 5,000-foot-type curve at $4 gas prices is 18%, 24% after efficiency gains, and 33% with the Noble carry included.

The wells we expect to drill in 2014 should be longer, should average 8,100 feet in lateral length and provide 11.3 Bcf in equivalent reserves at a historic cost of $8.9 million, $7.6 million after the efficiency gains, and an effective cost to CONSOL after the Noble carry of $6.3 million. The longer laterals are ATAX rates and returns to 30%, 40%, and 54% after efficiency gains and the Noble carry included.

That concludes Marcellus. Quite frankly, as much as we have going on in the Marcellus and despite the great impact it will have on our growth, I'm even more excited about the Utica. I'm excited because of the size of our footprint there. I'm excited about the very geologic and engineering challenge it's going to pose. And I'm excited about the opportunity to transfer the technology and the skills we've developed in the Marcellus to the Utica.

We have approximately 581,000 net acres and over 3,000 growth potential drill sites in the Utica. We currently have 18 wells online and we'll turn 43 wells online during the course of 2014. We expect to drill four to five wells per pad with average lateral lengths of 7,000 feet. We have three blended type curve areas -- The first being an Ohio Wet Gas at 1.9 Bcfe per thousand feet of lateral that represents Noble, Eastern Guernsey, Western Belmont, and Central Harrison Counties.

Our second type curve, Ohio Dry Gas, predicts 2.4 Bcf per thousand feet of lateral and covers the area of Jefferson, Eastern Harrison, Central Belmont, and our new project area in Monroe County, which I'll cover more soon.

The third curve, Pennsylvania West Virginia Dry, as the name suggests, represents our 100% working interest Utica properties in Pennsylvania and West Virginia. Our type curve for this large area currently predicts 1.8 Bcf per thousand feet of lateral. We currently have three horizontal rigs operating across the Utica and plan to drill 33 gross wells in 2014.

Our runway for growth in the Utica is quite large. As Slide 65 depicts, the Utica represents a very large potential resource for CONSOL. We have over 650,000 gross acres. That includes net acres within the JV and over 500,000 acres outside of any JV. Those 650,000 acres could allow for the drilling of over 3,000 wells, even after applying significant risk to the locations due to the exploratory nature of the play. I want to repeat that. We still think there are 3,000 Utica locations after applying appropriate risk due to the exploratory nature of the play.

We have very few wells producing and we have only 34 wells in our year-end 2013 proven reserve database, meaning 1% of our net Utica acreage has been developed and there's lots more to come. As you'll see in the later slides, there is a very real and developing sense of optimism within CONSOL and across the industry for the dry Utica moving eastward out of Ohio and into Pennsylvania and West Virginia.

In the Utica we are currently producing about 35 gross million cubic feet equivalents per day, but we expect that to grow an astounding 270% CAGR the next three years. That's before factoring in any success from Pennsylvania West Virginia Dry Utica.

The third-party midstream is finally catching up. We expect to begin turning online three 10,000-foot laterals on the Noble 19 pad in northern Noble County as early as this weekend. I can update you now that those wells started flowing back at 6:30 this morning. These wells are direct offsets to our Noble 16A well that was 5,000 foot long and tested 12 million cubic feet per day and 760 barrels of oil per day after four days of continuous flow.

With 43 wells coming online by the end of the year, we expect our current joint venture gross production of 35 million cubic feet equivalents per day to grow to well over 175 million cubic feet equivalents per day by the end of 2014.

On the drilling side of the Utica cost equation, we have TD'ed three wells thus far in 2014. As the case was for the Marcellus, those early laterals have been considerably shorter than our 2013 wells. Approximately 4,900 feet in length compared to 7,000 feet in 2013. While we've been able to drive the average cost per foot of measured depth down from $366 to $332 per foot year-over-year, the short laterals mean our costs per lateral foot have gone up.

As was the case also for the Marcellus we expect the laterals for the remainder of 2014 to be longer, our cost per lateral foot to go down as the year progresses. In fact, we expect that to be improved over the $366 we did in 2013.

Tim talked about the efficiencies we expect to gain in our Marcellus drilling and here is a similar slide for the Utica. I'm not going to go into great detail. I will point out though that there is approximately $900,000 in savings projected from shorter 9-5/8″ casing set points. To date we have opted to set 9-5/8″ casing to the top of the curve to help minimize mud losses.

By tracking the competitor activity across the whole of the Utica it's apparent that that's not always necessary. We will experiment with shorter setting points going forward. Most likely there will be some areas we can get by with shorter setting points and some areas that we can't. However, if successful, the shorter casing set points coupled with the other efficiencies Tim described in the Marcellus could help us drive our Utica drilling costs of a 5,000-foot well from $4.5 million to $3.2 million.

On the completion side of the Utica we are understandably a little further down the learning curve than we are in the Marcellus, but we are making up ground fast by optimizing completion design and reducing costs. We have eliminated gel and resin coated sand completely from all frac designs. Those two factors alone allowed us to drive all-in stage costs from $310,000 in 2012 to $224,000 in 2013. We expect better pricing with incentive-based contracts going forward and we've already started gaining on the number of stages we get pumped per day.

Late last year we also started implementing RCS and SSL frac designs on our Utica completions. That methodology seems to be working at 150 feet per stage length. However, the Utica is a different animal than Marcellus, and as we continue to experiment we may find 200 feet or 225 feet or 175 feet perhaps works even better. As such, with better pricing, stage efficiency gains, and approved RCS/SSL designs we are forecasting a 15% reduction of all end-stage costs from our current costs of $155,000 today to $132,000 by the end of 2015.

I'll get back now to the three Utica operating areas I introduced earlier and walk you through our view of each area and the status of our type curves there. Slide 74 represents the same operating area summary that I provided you for the Marcellus. You may want to tag this slide for easy reference later. Before you leave this page, please note that all this acreage and all these wells represent 26 Tcfe of potential resource base to CONSOL. Yes, I said that right. 26 Tcfe of potential resource that may prove to be even larger than the Marcellus for us.

As you will see in a few minutes, the vast majority of that potential was underneath our mostly 100% working interest Utica leases in Pennsylvania and West Virginia. And none of that Pennsylvania and West Virginia acreage is in the Hess JV and very, very little of it is in the Noble JV.

We refer to our first operating area in the Utica as Ohio Wet Gas. You might say it represents the traditional area of Utica development, if you can say anything that's three years old is traditional. This map was constructed internally using published IP rates converted to barrels of oil equivalent per day per foot of lateral. It represents our concept of the liquid hydrocarbon sweet spot. It's delineated by a bunch of hot profile wells, only a few of which I've included here.

These wells include the Chesapeake Buell Well, which really put the Utica play on the map for everyone, the Gulfport Wagner and Shugert, CONSOL's own Noble 16A Well, which brought the play southward into Noble County, and the Antero Miley and other surrounding wells that validated the Noble 16A Well results and pushed the liquid sweet spot a little eastward into Western Monroe County.

Most of CONSOL and Hess JV activity today and the majority of our JV wells over the next few years will be in this sweet spot where we control 17% of what we consider to be productive for the Wet Utica.

We have approximately 84,000 net acres in the Ohio Wet Gas area, with 36,000 of those being in the core of the play. We have over 500 potential locations in the court area alone. 16 wells are online today and 41 wells will come online during the course of 2014.

We expect to drill four to five wells per pad with average lateral lengths of 7,000 feet that cost $9.6 million to drill and complete with RCS. Our blended type curve for the area suggests 1.9 Bcf per thousand feet of lateral and we expect life-of-reserve condensate yields of five barrels per million cubic feet of gas and NGL yields of 48 barrels per million cubic feet of gas.

The 5,000-foot RCS-type curve on the right side of the slide shows our expectation of 9.6 Bcf equivalents. It compares to two published Antero-type curves. They are 1,200 to 1,225 Btu, high rich gas-type curve at 2.8 Bcf per thousand feet and they're 1,225 to 1,250 Btu high rich gas condensate type curve at 1.9 Bcf per thousand feet.

Projected onto the type curve in brown is actual production from some of our core area JV wells and a few competitor wells, normalized back to 5,000 feet lateral length. The actual data being much higher than the type curve combined with the Antero-type wells I just spoke of leads me to believe that there is significant upside to our blended type curve for this area.

While the wet gas of the Utica may be considered traditional exploration, elsewhere in the Utica is moving very, very quickly. A great deal of drilling is shifted eastward into the dry gas portion of the Ohio Utica. Two years ago CONSOL targeted an area of northeastern Monroe County where we were able to assemble 11,000 contiguous acres that we feel has both dry Utica potential and wet Marcellus potential. That acreage outside of the JV owned 100% by CONSOL and shown on this map has become the centerpiece of our second Utica operating area known as Ohio Dry Gas.

A picture is sometimes worth a thousand words and as this map shows, our acreage has been triangulated by very large flow dry gas wells. To the south there is the Magnum Hunter Stalder Well that tested 32.5 million cubic feet per day. Directly to the north lies the Gulfport Irons Wells, two-well pad, one of which tested 30 million cubic feet a day. And to the northeast over into the West Virginia panhandle the Chevron Conner Well that reportedly tested 25 million cubic feet per day.

As we speak and as Tim mentioned, we are top hole drilling one Marcellus and one Utica well on the Monroeville project. We've collected cords. We've logged a pilot hole. And we expect it to TD both horizontal wells this year. We plan completion to start in early 2015 and midstream to be in place for sales by the fall of 2015. Needless to say, we are very anxious to get the results of these wells. We have room for 100 Utica wells, 100 Marcellus wells, and we believe the leasehold to contain 2.6 TCF of resource. We expect to drill this prospect up completely over the next three years.

However, the Ohio Dry Gas area is not confined just to Monroe County. We still have 14,000 net acres of dry Utica gas in our Hess JV. Across our Ohio Dry Gas area we have over 300 Utica well locations. The 5,000-foot RCS-type curve on the right side of the slide built using actual normalized production from two competitors' wells shows our expectation of 12 Bcf or 2.4 Bcf per thousand feet of lateral from the Ohio Dry Gas area. That type curve compares directly to Antero's published type curve of less than 1,100 Btu dry gas at 2.4 Bcf per thousand feet of lateral.

That's really just emphasizing this last type curve area for the Utica. We call our final Utica operating area Pennsylvania West Virginia Dry Gas. As this map suggests, Utica Exploration hasn't stopped at the Ohio border. Instead it's progressing rapidly into Northern West Virginia and Southwest PA where we hold 100% of 472,000 acres.

That acreage includes our Pittsburgh Airport lease in Allegheny County, our legacy foothold in Southwest PA, our Moundsville, West Virginia project just across the river from the Monroe County, Ohio project, and a portion of our Northern West Virginia leasehold. This map highlights more successful wells and ongoing drilling activity than I can cover. But I do want to point out a few significant and recent wells.

On the left side of the map there is the Bigfoot Well in Central Belmont County that tested 42 million cubic feet per day. North of the airport project, along the top side of the map, there are several successful dry gas wells drilled by Rice, Chesapeake, and Range Resources.

Coming down the right side of the map is a recently-announced Range Resource test being drilled in Washington County, PA. In the panhandle of West Virginia there is the Gas Star Simms pad, expected to TD this summer. In Wetzel County, West Virginia, there is a Stone Energy Pribble pad expected to TD this fall and the Chesapeake Messenger Well that should be near TD as we speak.

Finally in Powered [phonetic] County, Antero is planning to spot a well this quarter and Magnum Hunter expects to release some results this fall from their Stewart Wynn Lynn [phonetic] pad.

No doubt that is a lot of exciting drilling activity. But the real unknown remains how far east will the Utica produce? Where will become too deep and too mature for hydrocarbon production? That answer remains to be seen, but be certain CONSOL will be watching all this activity very closely as we play for a dry Utica test in Pennsylvania or West Virginia in 2015. At our current estimate of the eastern production limit, we feel we have 472,000 acres for development -- 300,000 in Pennsylvania and 172,000 in West Virginia -- and over 2,200 gross undrilled well locations. Our blended 5,000 RCS-type curve shown on the right side of this graph suggests 1.8 Bcf per thousand feet of lateral. Same competitor production that I used earlier is projected over the type curve here in brown and indicates again there is significant upside potential to our type curve, at least in some portions of Pennsylvania and West Virginia.

So there you have our views, our economics, a look at our type curves and what we feel about our potential in six Marcellus and three Utica operating areas. I feel we have a great understanding of where the Marcellus is going and where we still need to do a little bit of delineation before moving into full-scale development. Our 21.9 Tcf of Marcellus resource based coupled with contiguous HBP leasehold is poised to lead our 30% year-over-year production growth going forward. While neither CONSOL nor any other operator can provide quite as much detail across the totality of Utica, I feel we have a great handle on our significant piece in the Ohio wet Utica. We are positioned very well in what could prove to be the best part of the Ohio dry Utica, and we have 100% ownership in what could ultimately prove to be a huge Utica dry gas resource in Pennsylvania and West Virginia. It is truly mind-boggling to me that over time the Utica may prove to be an even larger resource base to CONSOL than the Marcellus.

As I hand this back to Tim to cover the Upper Devonian, the potential stack pays and to wrap up the E&P portion of the presentation, I'll remind you of a couple of key slides at your disposal when building your NAV model. Slide 7, covered by Nick, is a nice ownership scorecard by formation. Slide 16, covered by Tim, is a summary of our 2014 drilling program. Slide 44 is a summary of our Marcellus operating areas right down to the type curve level. And slide 74 does the same for the Utica. Thanks for your time. I look forward to your questions later and I'll hand it back to Tim.

MR. TIM DUGAN: All right. We've talked a lot about the Marcellus and Utica, the two areas that are really going to drive our growth for years to come. And the Marcellus in the near term, Utica becoming a bigger and bigger piece of that as we move forward but two tremendous growth engines that we have available to us that are just going to present us opportunity for years. We talked about some of the upside in the Marcellus with our recompletions to our existing asset base, wells that are already producing, some optimization opportunities with enhanced production techniques, field optimization, working with our midstream group to optimize field pressure and enhance flows.

But what we're going to talk about now is what I think is really the true, the largest piece of the upside that we have available to us, and that is the stack pay potential. It is tremendous when you look at the numbers. We're going to start looking at the upper Devonian and this is just a map of the Burkett, the Upper Devonian asset. As I said earlier, the Upper Devonian consists of several different shales. You know there's a lot of focus on the Burkett right now. We are going to drill some Rhinestreet wells this year but there are other shales in there, the Geneseo and there are a couple of others that fit into the Upper Devonian. So there is a lot of potential there.

But this map here highlights what we know of today as the Burkett sweet spot. We have considerable acreage in the Burkett sweet spot. But keep in mind as you see our acreage there some of it outside of that sweet spot. This is just the Burkett. We feel that all of our Marcellus acreage has Upper Devonian potential.

Last year we drilled our first Burkett well. It was our first really stacked-pay development. We drilled one Burkett well on a pad with five Marcellus wells in Southwest PA. It was just about a 4,900-foot lateral. We fraced it with 17 stages. We were the first to zipper-frac a Burkett well with a Marcellus well, and we think that provided us with tremendous benefits and improved our results. The Burkett well had an initial IP of three million a day. And here over 340 days later it is still producing at 2.7 million a day. So a very shallow decline. It looks like it's going to produce 1.0 Bcf in its first year, so significant results.

But going back to the zipper frac, we think we enhanced both the Marcellus and the Burkett with the way we completed these wells and we'll do more of it in the future. But as we alternated back and forth between the Burkett and the Marcellus, as we did the Burkett, we created a pressure pocket. And because of the separation between the two zones being only a couple hundred feet, as we pressured up the Burkett, it helped us contain our Marcellus frac and get even better frac extension in the Marcellus. So we think the two fed off each other and really enhanced the results in both. The best two Marcellus wells on that pad of the five we drilled are the two Marcellus wells that underlie the Burkett.

So they had open flows of nine and ten million a day, so really good wells. But that Burkett well, if we were to take a look at the decline curve here, when you look at the curve it looks essentially flat for the first 340 days. It inclined for a while and it's been a relatively flat and very shallow decline. But if we were to take the six Bcf-type curve and properly fit it to the production, that makes this a nine-Bcf well. The way that's declining, we essentially are adding reserves to this well every day. So if we can repeat this several thousand times, we'll be golden for years to come.

We're excited about what the Burkett offers. But again, this was a stacked pay. So we were able to drill this Burkett well on a Marcellus pad. We already had the roadwork done, pipelines are in place, water infrastructure is in place. So a lot of benefits from an economic standpoint to doing this, but the results are just tremendous.

Now we look at stacked pays. Just about all of our Marcellus acreage. When we look at the acreage that we have, our 436,000 net acres in the Marcellus, just about every one of those acres either has Utica potential underlying it or Upper Devonian potential above it. In many cases, most cases, we've got the potential for both, to develop the Utica under the Marcellus, come up above and develop Upper Devonian. In some cases in the Upper Devonian we've got the potential to develop the Burkett and the Rhinestreet. So our traditional pad has six wells on it, six Marcellus wells on it. You put in the stacked pay potential, we could have up to 24 wells on a pad, six Utica, six Marcellus, six Burkett, six Rhinestreet, and that has just tremendous advantages.

It's not just the infrastructure, but if you think about it, it's 75% less pads, roadwork, water infrastructure, you know, so it's taking advantage of existing but it requires less development of other pads. So much less of an environmental footprint if you think about developing these sections individually and every pad having six wells, we're eliminating tremendous activity but providing amazing results.

So just looking at some of the areas that we're focused on right now that have stacked pay potential and we'll look at a couple of them more closely. The Pittsburgh International Airport, probably our most visible project we've done to date, Operations are underway there. We're building pads, clearing rights-of-way. We’ll start our first well in August of this year. See first production in early 2015. As Larry said, we've got 45 Marcellus wells planned there. We've got the potential to drive 45 Upper Devonian wells and 45 Utica wells. So the resource potential on those 9,000 contiguous acres, we’ll look at that in a minute, is significant when you look at what we can add to the Marcellus potential that we're targeting right now.

Then down in Monroe County. We've talked about that a little bit. We're already underway there drilling top holes on Utica and the Marcellus well. There's also Upper Devonian potential there. Right now we're looking primarily at Utica and Marcellus, but there is additional potential there as well. Southwest PA, south of the airport, east of the Monroe County activity, we've got all four zones there. And then the Dominion Transmission acreage, the 90,000 contiguous acres that we picked up from Dominion Transmission in late 2013, we've got the potential there for four pay zones off one pad.

This is just a schematic of what it might look like. It's exciting to think about the opportunities, but it will take some innovation, some enhancements in technology, some changes in the way we do things when you think about putting 24 wells on a pad. That's a lot of tanks, that's a lot of production equipment, separators, so we're looking at how we can redesign our pads, redesign possibly our production equipment, maybe looking at stacked production units. How we can take advantage of tanks. It provides so many advantages when we look at this and looking at the other pieces, looking at the timing of the development.

In some areas it may make sense to go in and drill out a pad completely and drill the Marcellus, the Utica, the Burkett and do them all at once because you've got the takeaway capacity there. In Monroe County there are benefits to blending the dry gas with the wet gas and enhancing our capacity. In some areas it will make sense to come in and do the Marcellus, maybe come in two years later as the Marcellus starts to decline, and come in and drill the Utica and help us keep our pipes full. You know, maintain our pipeline capacity for longer periods of time. As the Utica starts to decline, we come in and do the Upper Devonian. It will just help us keep the pipes full for a longer period of time.

So there are a lot of development scenarios we're looking at. We're looking at enhancements in our technology, in the way we do things, but the upside to the stacked pay makes all that well worth the effort and the investment.

Just look at Southwest PA. Right now we're drilling and developing the Marcellus. There's about 3.4 Tcf of resource potential in Southwest PA with the Marcellus alone. When you look at the stacked pay potential and you add those in, we go from 3.4 to over 9 Tcf of potential. Just tremendous value without having to build additional pads, upgrade additional roads, build additional water infrastructure, pipelines. The advantages are tremendous.

In general when you look at these plays developing them on their own and being able to do the stacked pay from the same pad, in very general numbers we're seeing at least a 10% increase in rate of return. When you look at, say, developing the Burkett on a stand-alone basis, building the pad, building the pipeline, the water infrastructure, and 10% is probably a conservative number. But there's the benefit that the rate of return is significant.

And then the airport. Larry showed this slide, but to break it down, the Marcellus at the airport we're looking at 600 Bcf in reserves at the airport. You add in the Upper Devonian, another 420 Bcf and then you look at the Utica, which potentially could be the biggest piece of the airport potential. Those 9,000 acres contribute over a Tcf-and-a-half to our reserve base and this is just two areas. Between those two areas we've got over 10-1/2 Tcf of potential from a relatively small amount of acreage. So when you get down and you look at that 90,000 acres that we have with the Dominion acreage and you move over into Monroe County and those are just four areas we're focused on right now. Start looking across our entire asset base and the potential from the stacked pays is just, it's amazing. It's really very significant.

I just want to take a minute -- we talk a lot about the Marcellus, the Utica, we talked about our EPT team -- the exploration, production, technology team -- and they are looking at some of the other assets we have and we just want to take a minute to mention them. Our Virginia coalbed methane, this is really, where our gas business started. The operations down there are done in conjunction with our

Buchanan mine. The CBM wells drilled stay out ahead of the mining, degas the coal and make it safer for Jimmy's group to go in and mine the coal. But there's a lot of potential down there. It is a significant part of our current production base. We produce about 231 million cubic feet a day from our Virginia CBM wells.

We've got about 3,000 producing wells. There are about 2,700 potential locations down there that could be drilled, half a Bcf per well in potential, at a cost of about $400,000 per well. Right now our annual decline rate there is about 5% to 7%. We are still drilling down there. I think we'll drill about 60 or 70 CBM wells this year to stay out ahead of the mining activity. But it's an area that has -- it's a significant part of our base production. I do think there's some opportunities for optimization here. We talk a lot about the Marcellus and Utica but we do have people that are focused on this production. Optimizing this production, arresting the decline a little bit, you know if we can take that from 5% to 7% down to 3% to 4%, tremendous increase in production and economic benefit.

Our conventional wells, our shallow oil and gas wells, 2.3 million acres. All of this is held by production. So it provides us a lot of flexibility for future development. Most of this acreage was acquired by our Dominion E&P acquisition in 2010. We've got 70,000 potential gross locations. We've got 10,000 wells producing right now that produce a total of 61.5 million a day. These are all vertical wells that come at a cost of $400,000 each and could potentially add a quarter Bcf per well. Very shallow decline, steady production, 3% to 5%, but again, here's an area where we have opportunities for optimization of our production to arrest that decline a little bit and improve the economics and operating costs.

Then some other areas, our Chattanooga shale, Monteagle and Conasauga shale down in Tennessee, we've got a significant acreage positioned down there, 243,000 net acres, 2,170 gross locations. Horizontal wells down there in the Chattanooga come at a cost of about $1.5 million each with a Bcf per well of potential. Currently we produce about 7.5 million a day there, annual decline rate of 17%. But this is an area below the Chattanooga -- we've got the Monteagle that has potential, that's an oil zone. And then below that the Conasauga shale. So it's an area that has stacked pay potential. It's worth noting that in the State of Tennessee we've got the second-best producing well in the State of Tennessee when we look at oil. We also have the top five producing gas wells in the state of Tennessee. It's an area that we think has a lot of potential and as we take the learnings from the Marcellus and Utica and what we can learn from developing stacked pays, we think this is an area of future growth and potential value that we'll be able to take advantage of.

Then the Illinois Basin, we've got a large acreage position out there, 277,000 net acres, 14,000 gross locations. We really have essentially no production out there, about 200 million a day. But the potential there for stacked pays between the Mississippian and Devonian sandstones and carbonates, the New Albany Shale and the Maquoketa, which is an equivalent to the Utica Point Pleasant. We think that's an area that again, as we learn more about stacked pays and how to develop them economically, that we'll be able to take those learnings and apply that to this significant acreage position that we have in the Illinois basin.

So just to wrap up the E&P piece, we're excited about the team we have in place and we think we've got the right people and the right assets in place to be able to drive value for CONSOL. 30% growth, a lot of what we're already done in 2014 we feel like we've de-risked our growth projections for 2014, '15 and '16. The implementation of the asset teams has been a tremendous benefit in planning and execution. We continue to drive our costs down with efficiencies and lean manufacturing, decreasing our cycle times. Some of the things we've already seen, we're well on our way to that 15% production in costs.

I think we'll exceed that. We'll all be very pleased with what we're looking at next year at this time when we look at our costs. Not just the costs, but the quality of wells that we're drilling. The asset teams are going to make sure that we are drilling our best wells on our best acreage and that we're drilling wells that we can move the product. One of the important things we talk about, we've mentioned several times, 87% of acreage is held by production. That is key to a solid development program, managing our inventory of wells. As I said earlier, having all that acreage HBP we can plan around, make sure we're drilling wells, that we can drill them, complete them and get them turned in line in a very reasonable timeframe. We won't have a lot of wells waiting on pipeline and we won't have a lot of wells sitting and waiting on completions. So we're going to spend the money, get the wells ready and we'll get production quicker than our peers. A lot of that has to do with our acreage position, being able to drill longer laterals and manage our inventory.

Then the stacked pay potential, the upside there is just none of that is built into our current reserve base, but the potential for stacked pays is significant. It's going to be a tremendous upside to our growth. Then some of the base production I went through. We've got a solid base production with our CBM and conventional assets and the joint ventures are a significant part of our growth. We continue to work with Noble and Hess. We're excited about what they're doing and what we're doing together and improving our processes. So the future looks bright. We're excited about what's ahead of us and at this point I'm going to hand it over to Jim Grech to talk about marketing.

MALE VOICE #1: I'm going to take a ten-minute break. We'll reconvene at 10:30. We'll just break things up before we get into the gas market. We'll back and up and running at 10:30.

Okay, I don’t know if our webcast audience heard that but--

[AUDIO STOP]

[AUDIO START]

--and we look forward to you rejoining us with Jim Grech's presentation in a few minutes. Thank you.

[MUSIC]

MALE VOICE #1: Okay we're going to resume the presentations with Jim Grech. Jim is our chief commercial officer and let me turn it over to Jim.

MR. JIM GRECH: I'll give everybody a minute more to get seated here. Okay I'm going to get started. I have a tendency to walk around a lot. So I'm going to have to try to stay in front of this mic and make sure my voice doesn't wander.

At CONSOL Energy when we look at energy marketing, we look at the Appalachian Basin as a whole. So that's where I'm going to start out today. I'm going to tell you how we look at the

Appalachian Basin as an energy market and then we'll get down into the specifics of our gas marketing portfolio.

So starting with that macro work, I'm going to hit on some of the themes that Tim hit on earlier, but how does that translate to our marketing strategy? We're looking at the Appalachian Basin, looking at this stratigraphic column here. We'll start from the bottom 10,000 feet and work our way up to the surface, starting with the Utica, Utica shale down at 10,000 feet. You can see the area. It's covering an area in Pennsylvania, West Virginia and Ohio.

Working our way up to the 7,000-foot level, we hit the Marcellus shale. Right above the Marcellus shale you're going to have the Upper Devonian, that's some Burkett and Rhinestreet plays that Tim was talking about. Conventional shale oil and gas, bigger fairway they are going all the way down into West Virginia and down into Virginia.

Then you start hitting the coal seams, the Pocahontas coal seam down in Virginia, the Pittsburgh 8 coal seam up in Pennsylvania and West Virginia, and the associated CBM plays, and then of course you've got the Central App coal seams above that.

So this is an energy-rich base that has a lot of potential for growth; and just one quick statistic. If you were to look at gas production in 2012 the basin was about 5.9 Bcf a day. Two years later we're over 14 Bcf a day in gas production. So in two years that's a 240% increase in gas production out of the basin.

Now when we market our products, we market it like the customers look at when they're buying. That is, our customers, when they purchase energy, they purchase it on a cents per million Btu basis, cents per million Btu delivered basis. They don't necessarily look at things as buying a ton of coal or a dekatherm of gas. They're buying delivered Btus. They convert that to a busbar cost of electricity or transform it into another form of energy and move it down the line.

So when we market, we market delivered Btu, delivered cents per million Btu. That's how customers evaluate when they buy coal and gas. It's not really a ton or a dekatherm market, as much as it's an energy market and the cost of a Btu delivered and transformed into a product. Again, sticking with the basin and building on that theme.

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MR. JIM GRECH: - - with the base and building on that theme, let's look where CONSOL's assets are. There's a series of circles that are going to come up on the screen and for gas it'll be the size of the gas reserves and dekatherms, and coal and tons of coal, so you're looking where our Marcellus Shale assets are a little bit different way of looking at it than the way Tim had it shown on the slides. Then Utica Shale, coming over there you see in Ohio, getting in there with the Marcellus Shale in West Virginia and Southwest PA, so starting to see those stacked plays that Tim was talking about. Upper Devonian, Burkett and Rhinestreet, up there in the Pennsylvania area. We start coming again to the conventional where we have reserves down in, all the way down into West Virginia, up into Pennsylvania again from our Dominion E&P acquisition where we have our conventional oil and gas reserves. Coalbed methane reserves, substantial reserves down in Virginia. And then getting to our coal reserves, the Buchanan and Miller Creek Mines down in Virginia and West Virginia and up in Pennsylvania were we have our Bailey Complex.

Now when we look at our reserves, some of the numbers we have on the reserves shown on this chart here on slide 99 that just came up in the lower hand, uh, right-hand corner -- the 5.7 Tcf of gas, people can put their arms around that. And you look at the last one, the three billion tons of coal reserves -- if you're in the coal industry you understand what that means. But to put it on equal footing so you can draw a parallel to the energy, the Btu content, this year out of the three billion tons of coal, we're going to market and sell about 32 million -- 32 million out of three billion. On a Btu equivalency and margin equivalency to gas, that's about .4 Tcf. A tremendous amount of energy. 32 million tons of coal out of that three billion equates to about .4 Tcf of gas. So when we look at the energy reserves that CONSOL has, we look at the energy content -- again back to that's what the customers are buying. And we have tremendous energy reserves in the Appalachian Basin.

We have synergies, we have operational synergies with these reserves. The coordination of drilling gas wells in the active mining area —- a very complicated process —- we do it all the time. We have water synergies, we have right-of-way synergies, we have surface synergies, supply chain management synergies, and permitting synergies. So there's a lot of operational synergies but from a marketing perspective, we look at it as, what do these stacked resources give us that makes us unique in our marketing.

That brings us to a concept we call stacked customers. And when you look at this chart, look at this map, we have on here the red circles are the natural gas plants here on slide 100, and the yellow circles are the coal plants. The green lines are the pipelines connecting, going through the region. So we've been here 150 years. We've been serving these customers for many decades, built some very strong relationships from our Chairman and CEO on down, and we use those relationships to get into some unique business deals. And when we have stacked customers —- we've talked about stacked resources —- stacked customers, what's our definition of a stacked customer? That's where from one acre in the Appalachian Basin we generate multiple products to sell to one customer. So one acre, multiple products —- sell it to one customer.

And the best way to continue this is to give you an example. Let's talk about our products first. Here we have thermal coal, met coal, and of course we export both of those products and Jimmy McCaffrey will talk in more detail about our coal franchise, and Jimmy Brock. On the gas side, NGL sales, domestic ethane sales, dry gas sales —- we also export ethane, export LNG, and we'll have a little bit to say about that as we get further into the presentation. So these are all the products that we sell to our customers. Sort of one-sided at the moment, but being that we're so large in the Basin and the presence that we have there, we also do a fair amount of procurement and purchasing from the same people we're selling to. On land, or oil, gas, coal reserves, we're a substantial acquirer of that in the Basin. We contract for gathering services, processing services, firm transportation on pipelines, all things, all services we acquire from the same people we're selling things to. Stacked customers.

And last, we're a significant power purchaser, especially our coal mines use a significant amount of energy, and we are a large power purchaser from some of the people that we're actually selling the coal and gas to, to create the electricity. One more example on that to give you a better understanding of the value we see when we talked about stacked customers and stacked resources. Let's take Dominion. We've been selling to Dominion for many decades -- coal and gas. Back in 2010, a large part due to that relationship and the relationship of our chairman with their chairman, we bought their E&P company. That got us jump-started into the gas business above our CBM. We bought the 90,000 acres to DTI storage field. How did that come about? In large part because of the relationship that our chairman had with their chairman. We purchased gathering from them, we purchased processing from them, we purchased FT from them. We purchased power from them. We're in discussions today along all of those touchpoints of value with them. That's what we mean when we say we have stacked customers, stacked resources in the Basin.

And so I hear a lot why —- one of the questions I'm sure I'll be asked later on -- when are you going to split your coal and gas company? When I look at it from a marketing perspective, I prefer to take the other side of that question -- Why aren't other people doing exactly what we're doing? Why aren't other people extracting the value from all these pieces of the Basin like we are? And I know the answer to that question —- because other companies can't duplicate what we have. Certainly nobody can duplicate our coal resources, and there are arguably out there companies with as good of gas resources as we have, but nobody has that combination. It's unique in the marketplace. It's a definite advantage we bring to the marketing side of our business and something, as I said, that can't be easily duplicated in the marketplace.

So that was a higher level. We're going to start getting down into the details of our portfolio on the natural gas sales. David Khani will go into a lot of detail on the hedging. Right now we have 74% of our gas volumes hedged for 2014, and again when we do our hedging, we look at it on an energy basis. We look at all the Btus we're selling, coal and gas, and how many of those Btus do we have hedged. Not just a coal hedge or a gas hedge, but how many Btus. And we look at it as a portfolio. And again, David will go into a lot of detail on that. Been in the Basin a long time, we have 80 customers and growing in five different markets.

Firm transportation, I'm going to show you the details on our firm transportation. We have a very robust, low-cost base that we're going to grow off of. It's in place, we've de-risked from a production standpoint the ability to flow the gas, and now we're working on, and we have been maximizing, the margin side on the sales of the gas. Substantial low-cost base to grow off of, same story with the NGL processing as we get into that. Have a substantial low-cost base in place already, de-risked our portfolio from the aspect of can we handle the volumes, can we process it, is it going to be a bottleneck. You'll see that that's not the case. We have optionality on the sales of the NGLs. We can either use marketers which we've been doing right now, and we have the RR option to take the gas, take the NGLs back from the marketers and market them directly. Same with ethane —- a lot of optionality there, we'll talk about that. We have optionality with our own assets to do ethane rejection and/or take it to market and sell it. We have the contracts in place. So I'm going to go into more detail in each of these areas.

On the FTs, as I just said, we have this robust, low-cost base in place, and if you're looking at here on slide 103, look down on the chart in the lower right-hand corner, the 2013 going to 2016. The numbers there in the blue, the 25 cents, the 24 cents going up to 26 cents —- that's a number that you hear most commonly out there in the industry and what we're talking about FT. So that's the one you can compare to. We show it and above that you also have some variable costs that you always have to put on top of that for fuel - - when people are talking about their FT. And that's where you get to 34 to 37 cents. And again, this is just showing a short picture of our FT. We have contracts that go on for decades. These costs that we have are locked in for quite a few years out to the future.

Now, it's a great base to build off of, but as our production volumes grow we do have to add onto this FT. And we're going to do that a couple of different ways. One is we're going to do what we call sculpting, or layering in smaller portions of FT with sales to customers already associated with the FT, or the customers have the FT is probably a better way to say it —- or release capacity from producers that are long FT. And that's what we call sculpting or layering in smaller portions of FT, shorter commitments. The other side of that is, we will still commit to long term FT, but it's going to have to give us the market diversity we're looking for and get us to markets where we think there is a good potential for a positive basis over the long term. And we'll get some examples on all of these points.

Okay, this is our current position, again with some more detail, drilling down into our FT. You can see that the one Bcf a day we have in 2014 and the pipes were on going to 1.3 Bcf a day in 2016. Now I want to stress a point -– you know, we say 150 years, you know, we've been in the Basin —- we've also been in the gas business for a few decades as CONSOL energy with our CBM business and Dominion E&P business. Been in the Basin a lot longer than that in the gas business. And because of that, we've got an FT position that was built in previous years, signed up for 20-, 30-year terms at very low cost. So our history in the Basin —- we're not new to this. We've been here. We've been in the gas business. Haven't been that loud about it, but because we've been in the business that long, we've been able to build this position, this substantial position at 1.3 Bcf at some very attractive rates. So from a risk perspective, again, we've de-risked our portfolio. The production that Tim's going to produce, we have our firm transportation in place to move that gas.

Now I talked about sculpting or layering in—here's some examples of what we're talking about. Coming up first with our production area. Now with this producing area, we've just recently in the last few months entered into 175,000 Mcf a day of out-of-Basin export sales contracts, and we also entered into 125,000 Mcf a day of some short haul capacity in the Basin to get us some sales points that can get us out of the Basin. So here's the first two that we're going to talk about. TETCO team South and our TETCO Open Project —- 30,000 a day and 50,000 a day, new deals that we have starting in 2014 and 2015. Again, smaller volumes, shorter terms, and we can announce today that with that capacity we've entered into a deal with Cheniere for an export LNG contract. It's pending their board approval, which we expect to get today. I didn't have it in time when I came up here to make that announcement, but we fully expect to get their board approval. So now we've diversified our portfolio and have entered into the export LNG market, and it's a market we're going to hopefully participate in some more.

The red line there is our short haul capacity. Coming out of our DTI storage field is future production area for us. Takes us up to a point in Ohio where you can access multi, several interstate pipelines and get it to different markets. That's a deal we put in place at some very attractive rates here not that long ago. Have entered into a couple of other contracts. TETCO Gas City project, 47,000 a day, getting us over to Gas City from Uniontown, and then we'll also have taken 47,000 a day of E&R capacity, getting us up into the Michigan MichCon markets. So when we talked about layering, sculpting smaller deals to fill out our portfolio, here's a few examples of what we're talking about and what we're actively adding into our portfolio on a very frequent basis.

Let's talk about our gas marketing a little bit. Have 80 customers currently in five different markets. And you can see from the chart on the lower right-hand corner there on slide 106 what the percentages are in the markets. Our goal though, in the chart on the upper left-hand corner, is to get to a 50/50 split. Right now we're at about a third of the gas we export out of the Basin and we fully expect by 2016 to be getting about half of that gas out of the Basin. A variety of different contracts we're entering into, whether they're multi-year contracts, monthly contracts, daily contracts, all different types. And we've built in some optionality. And a good example of that is what happened in the first quarter of this year. We have the ability to move gas over to the East Tennessee and the TETCO on five, and the TETCO on three. Those bases had some great run-ups in the daily markets in the first quarter. We were able to move gas to those sales points, and we had a very, very good realization in our gas portfolio in the first quarter. Just some more of that example is the diversification of markets, and so we're going to talk about basis. There's a lot of talk about basis, and I thought we'd give you CONSOL's view on basis, and why we think diversification is key to a gas marketing portfolio.

Now when people talk about in-basin gas, the sales points that we talk about and I think other people talk about are three, and they're shown on this map here. You have Dominion South, the TCO-pool basis, and the TETCO M2. So you look at those three sales points and we show a calendar year '14 average basis, and then calendar year '16 —- these are from May, towards the end of May, some of these numbers here, so they were real-time numbers back then. And you can see the projections are, they're going out into the future, that the basis stays relatively constant but negative. TCO-pool gets a little worse. TCO-pool is where we have about a third of our gas being sold this year for our in-basin gas sales. So that's in-basin, reflects all of production coming online, and I think reflects some of the uncertainty of the demand and the takeaway, the timing of that and what it's going to mean to the basis.

Let's go down to the Gulf. The East LA could have put the West LA markets down there. You have a slightly negative basis and it looks fairly steady. We think that's a market that's going to have a lot of volatility in the basis. There's a lot of projected industrial demand growth in that area, and also you have a lot of LNG export capacity coming online. We think that's a market that's going to have a lot of volatility and a market that we want to start accessing more.

Going up to the north, you get to Chicago and the Dawn Hub basis. Chicago takes a big drop to 2016. We think that's in part due to the reversal, a lot of the gas looking to be flowing back to the Chicago market. Could be other aspects too, but that's one of the reasons we think that you see that drop there. Dawn Hub -— Dawn gets you in MichCon, Dawn's in Canada, a relatively strong basis, again, and I think it reflects some supply going up into that market that isn't there currently.

Going over to the east coast, Transco Zone 5, very strong basis, a market that we're targeting. We think that that strength there is reflective of the power generation —- more gas consumption and the increased new builds of gas generation that are on the books that have been announced to be down in that market. TETCO M3, let's focus on TETCO M3 —- look at it right there, shows a 46 cent 2014 average price, 23 cent in 2016. Again, this is one of the markets in the first quarter where we were able to take advantage of the daily volatility in that market along with Zone 5. So you look at these numbers and it gives an air of certainty —- here's these forecasts, here's the numbers, let's put all our gas to Transco Zone 5, or let's put it all to TETCO M3. Well, physically you can't do that and I don't think strategically you want to do that either. And let's take a look at TETCO M3. This chart has a Henry Hub, the basis, and the net prices, and I'm just going to highlight the TETCO M3 here on page 108 for you. Have the red checkered box going around the TETCO M3, and let's look at the basis. Now remember —- go back to the previous chart if I can —- maybe I shouldn't -— okay, 46 cents up there in the upper right-hand corner for 2014. Okay, TETCO M3, 92 cents January, $7.83— this is just the basis now —- February, a dollar for March, April minus 18 cents, May minus 78 cents —- seven dollars less than February. Just a few months' difference.

Now we were able to take great advantage of that in the first quarter. Gave us some great price realizations. It's not there for us in the second quarter. Shoulder months, less volatility, less demand, maybe it'll come back in the summer, maybe it won't. But this is a great example of what we —- our view is on basis. It's very volatile. You can maybe look directionally at markets where you think demand's going to come on or there's too much supply, or supply is going to leave the Basin, but you have to have diversity in your portfolio. You have to build your FT position and your sales portfolio to give you that versatility to be in all these different markets because it's going to be volatile. And we don't pretend that we have the ability any better than anybody else to predict what the basis is going to be exactly in 2016, but directionally, again, we're looking at these markets and the markets we want to be in.

So we said, when we talked about our FT, we will selectively add in FT, term FT, to give us this market diversity. It isn't all going to be this layering, inter-sculpting of our portfolio. We're going to have to take some bigger chunks of FT as our production grows, getting out later, you know, to later years of the decade. So let's look at some different markets here and what we're doing. Okay again, you've got the in-Basin basis, the TETCO M2, TCO-pool, Dominion South. We're in active discussions right now and we hope to have an announcement here in the near term about our commitment to capacity and pipeline projects going up to the Dawn Hub and the MichCon markets. Very active discussions —- there's a few projects out there and we're very excited about one of the ones that we, like I said, hope to be announcing here soon our participation in. Looks like a good market up there, very consistent, great winter loads. I announced that we have that deal with Cheniere for some export LNG. We're in discussions to add more of that business into our portfolio right now getting us down to the Gulf, getting us that market diversification. Again, new market that we think's going to be very, very volatile due to the potential for the demand growth there with the industrial growth in the LNG.

Southeast Pipeline projects —- this is heating up a lot. The announcements for potential pipeline projects there —- again we're in active discussions for capacity on these pipes. Maybe not as imminent an announcement as going up to the north or down to the Gulf, but we're very optimistic that we'll be participating in that, and when we look at going up to the north or down to the southeast, I'm going to draw back to that stacked customers example I gave earlier. There's DTE, there's Duke, there's Dominion —- a lot of companies that we do business with in these markets that we can maybe get some other value exchanges for in exchange for our participation in these pipeline projects.

Okay, let's go to our natural gas processing portfolio. Again, the same theme as our FT. We've significantly de-risked our portfolio in terms of having adequate capacity not only to move the gas but process the gas. We show on this chart here we have 224 Mcf a day capacity in 2014, growing to 415 Mcf a day in 2016. We have contracts with four major processing companies at seven different locations. Our marketing side of this right now —- we've been utilizing near-term market power of our midstream partners, they've been very good aggregators of our NGLs and other people's, getting us the best back-margin. But as those volumes grow we have the optionality in our contracts to start, to take the NGLs directly and do the end-customer marketing ourselves, and as our volumes grow that's probably what we're going to end up doing. And on the ethane, again, we have a lot of flexibility with our ethane marketing and we'll talk about our facilities and our contracts there as well.

Okay, Majorsville —- most of our NGL processing in the past year has been at Majorsville. You look at that tremendous growth we've had there over the last two years, but as I just said, we've added in other contracts, it won't all be at Majorsville in the future. We have seven different locations where we'll be processing gas. We've got a contract with Blue Racer for Noble County in Ohio, for our Utica —- I think Larry mentioned that before. So we have this explosive growth coming. Larry had a slide, it was on slide 60, where he showed some of that growth. From 2014 to 2015 our NGL volumes are going to double. So I mentioned before that we've had midstream aggregators help us market the volumes because it hasn't been that significant, you can see it right there on that chart. But the volumes are going to double from '14 to '15. They're going to take another significant jump from '15 to '16. They're going to have a greater impact on our realizations, the uplift we're going to get from the NGLs, we have the processing in place, we have one marketing option in place right now, we're looking at some other marketing options that are our call if we want to take the marketing and do it ourselves. Whatever gets us the best margin, the best netback, that's what we're going to do.

I want to stress though, with the growth, the 415 Mcf a day of capacity we'll have by '16 —- we are in position to handle all this liquid. We have the processing capability to handle it. It won't be a bottleneck for us, just like the FT. Same with our processing. We've de-risked the production side of our portfolio, we have the contracts in place to handle the volume growth, and the other piece of the job we have here in marketing is to maximize the margins that we get for the NGLs and the gas.

Ethane —- continuing with that theme of diversification and optionality here on page 112 —- we have a unique asset, it's maybe a little bit hard to see on that map there, but we have our own ethane line going from Majorsville down the McQuay. It's a 17-mile line, so we can take pure ethane from Majorsville up to 5,000 barrels a day on our 17-mile line down the McQuay where we have large volumes of dry gas from our dry gas production and our CBM. Get that in and get the heat content value for that ethane, ethane rejection down at McQuay. That's one of the ways we do ethane rejection, a facility we have in place. We also though, have built in optionality to sell the ethane. We have a contract with Shell for the Shell cracker, and we're optimistic that by the end of this year we'll have a positive announcement for the go-ahead with the Shell cracker. We have the contract we have with INEOS for export, taking the ethane over to Marcus Hook in Philadelphia and then on to Europe. Those contracts are in place. We're in active discussions for getting capacity on the ATEX line to Mont Belvieu, and there's been a lot of contracting for the capacity of this ATEX line. But the reality is only about 30 to 35% of the volume is actually being used even though there's been a lot of contracting, so there's a lot of release capacity available out there in the market at very attractive prices from producers that have overcommitted to the capacity on this ATEX line. So we're out actively going after that release capacity.

Same strategy we have with our FT. There's producers out there that have won very long on FT, don't have the production yet to back-fill it, and there's release capacity available out there in the market. Part of that sculpting that I talked about, picking up selective pieces to add to our portfolio.

So again, with the ethane we have a lot of optionality, we want to use ethane rejection, do we want to sell it, do we want to sell it internationally, sell it domestically? We've built all that flexibility into our portfolio.

So in summary, we've hit on some strategic themes here. On our transportation we've put in place, have had in place actually, because of our history in the Basin. A very strong, low-cost base to build off of, significantly derisked our production with having no bottlenecks because of inability to move the gas, writing sales in there, I mean writing more FT in, either through term FT —- gets us to specific markets, or through the sculpting and shorter-term deals. And the NGL processing, continuing with the same theme —- strong, low-cost base to build off of, won't be a bottleneck for us, de-risked as part of our portfolio, won't stop production. We have flexibility in how we market it —- use midstream marketers, midstream aggregators or take the marketing in hand and do it ourselves. And again on the ethane there, on that point, if we have the facilities to do the ethane rejection or to sell it into the marketplace. Again, whatever gives us the best margin back.

On the sales side of our portfolio, we're going to continue with our hedge program to help mitigate that risk and we're going to keep adding in customers to get us the market diversifications and building on that stacked customer theme, taking advantage of what we have in the Basin. So the themes that we've been hitting on —- de-risked our portfolio, strong low-cost base to grow off of, an energy marketing approach that's Btu-based, energy-based, building off of our stacked reserves, using our relationships to enter into negotiations what we will call our stacked customers, or stacked negotiations. Hitting on all those value exchanges we have with the customers, and again, we feel that's a position that makes us unique in the Basin. It's more of, we think, the model of how energy marketing should be done in the Basin and one that we feel can't be duplicated because we don't think anybody can put the assets together in the Basin that we have. So I thank you for the time today. Hopefully I was informative enough for you, and I'm going to turn it over -- we're going to go to the coal side of the business and we're going to start with Jimmy Brock, our Chief Operating Officer of Coal.

MR. JIMMY BROCK: Thanks Jim. It's a pleasure for me to be here to talk to you about our premier best-in-class coal operations today, and I'll start out with a little bit of background about myself. You heard Nick talk this morning that I'm a career CONSOL operator. I've actually been in the industry for 34 years, all of it with CONSOL Energy, and pretty much held almost every management position we have coming up through, so it's exciting for me to talk about coal today. And we've invested in our coal operations throughout the past decade to emerge as a stronger, more efficient company to compete in any economic and regulatory environment. From these investments, many advancements have been implemented to make the mining process safer and more productive for our employees and our shareholders. These projects will increase efficiency, improve unit cost and productivity across our coal operational footprint, positioning us very well to meet the needs of the market.

So let's talk about these individual operations. First slide I'm going to put up -— you heard Nick talk about our core values this morning. Well, ours are no different —- on the coal side we operate within our core values. Every decision we make is made off those core values; and so how are we doing in that area? If you look at our safety, the bar on the left is the industry average, the red bar is CONSOL Energy, the first bar there represents our incident rate which is the number of recordable accidents you have, or exceptions, times 200,000 divided by the exposure hours that you have. This one is a four-year weighted average —- you can see that the industry average is 5.29, and at CONSOL we're 1.97, or about 2-1/2 times better than the industry average. The next bar is an important one. On the left is 3.42, on the right is 1.22 -— these are what we call significant and substantial violations. They are the orders or the violations that cost the most, have the opportunity to have the coal miner section of the mine shut down. And these are based on 100 inspection hours for the last 12 months. And the bar on the very right is our environmental, which we take very seriously. If you look, these are just simply numbers of NOVs and we had 112 NOVs in 2011, 79 in 2012, 42 in 2013, and in 2014 we're also trending downward. So our core values we take very seriously, and we monitor ourselves. Even though we're pleased with the reductions we have in the industry, we'll never be satisfied until we drive that number down to zero.

Talking about our actual complex, our regions a little bit. First what I want to talk about is our Pennsylvania region, Pennsylvania operations which consist of our Enlow Fork Mine, our Bailey Mine, and our newest-starting BMX Mine. Move over to Virginia, down in southwestern Virginia is our Buchanan Mine. If you move on over to West Virginia, down in southern West Virginia in Mingo County, that is our Miller Creek Mine, our complex down there, which consists of a surface mine, two underground coal mines that are down in Mingo County. And we'll talk about each one of them individually.

Bailey Complex -— if you look at the Bailey Complex, it's located in West Finley, PA. We have mine life of like 25 years there, 625 million tons of reserves, it's a thermal with some crossover high-vol metallurgical coal, has a production capacity of about 28 million tons. We run five longwalls and 18 miner units there. We'll talk about some of the upgrades, I'll highlight a few of them for you. The ones that are important —- they're all important, but the one that'll be the most meaningful for us -- is the upgrade we did at the Preparation Plant. We took that plant from 6,300 tons per hour to an 8,200-tons-per-hour plant by adding more circuits to the plant. We also built a new train loadout; I'll have a slide that'll cover that one shortly.

And then the other one I want to talk about is our overland belt. We put in a new slope at Enlow Fork. We put in a new overland belt system, 5.4 miles of overland belt that will basically make that a new coal mine, and I'll show that in a future slide here. But the important thing about sealing -— we'll seal off 28 square miles of Enlow Fork Mine. Now that does a few things for us. Number one, it's less to maintain. But the most important thing is it reduces risk to any of our employees and also reduces the maintenance cost of maintaining that area of the mine. So we're excited to get that behind us. We started in December of this year —- or December of last year and actually started producing on the overland belts in January of this year.

Our BMX Mine I mentioned at the start, that's our new longwall mine. We started that up in March of this year. Five million tons of capacity there —- all I'll tell you, it's a normal start-up. We had some issues at first with our belts and the normal things that we typically have.

This slide here is one I want to use for comparison. You heard me talk a little bit about the size, but I want to give you the magnitude when I talk about sealing. The picture on the left there, it depicts Manhattan Island. As you can see, it's 33.8 square miles. The one on the right is our Enlow Fork Mine alone, and it's 33.5 square miles, so it's basically the size of Manhattan, the Enlow Fork Coal Mine, and we'll be sealing all of the shaded areas you see there. The area in blue is already sealed, the areas in green will be the ones that we will seal by end of this year, which will only leave us those reserves going up to the north. Basically 85% of the Enlow Fork Mine will be sealed, leaving us to mine those new reserves. And then you see our corridor coming out to the east, there will be our access to our eastern reserves at Enlow Fork. So the mine is positioned very well for the future. New mine, low cost.

This is the new batch weigh system that we put in for Bailey. It services Bailey, Enlow, and BMX as the coal comes over to our new train loadout. We have around-the-clock reliability there. We have strong relationships and services with both railroads, the NS as well as CSX, and the ability to load up to ten trains a day —- we put in a new sidetrack this year. And our coal peers, you know, most of the first quarter blamed rail issues for the weak quarter one, but for us it was actually a strength. If you look at our deliveries on right there, we had a record-breaking first quarter despite the most severe weather we've had in many years. We loaded 1,100 railcars in a 24-hour period, we loaded 115,000 clean tons in one day, and we loaded 660,000 clean tons and 51 trains in one week. We have an online quality monitoring system that can monitor the quality of the coal as soon as the railcar is loading. It's cutting edge, it's the best capacity in the east as far as loading trains. We can load trains .8 to .9 miles an hour, and our marketing team, our transportation logistics team, has done an outstanding job of making sure that we keep that coal moving. Because as I told you, with all the new developments and technologies we have in these coal mines, if logistics doesn't do their part, doesn't get it away, then we recognize very early where a bottleneck would be, and they've done a tremendous job in this area here, with the new loadout.

Next is our Buchanan Mine, it's located down in Buchanan County, Virginia -— has a mine life of about 20 years, reserves of 98 million tons. It's a low-vol met coal. We have one longwall and five miner units running in the mine. Annual production capacity of 5.2 million tons a year. Lower cost than most of Central App, union-free operation, quality is sought out worldwide for steel making purposes. Easy access to the ports. A couple upgrades we did there I'll highlight down at Buchanan —- we moved our service shaft, an old shaft, turned it into a supply shaft and a ventilation shaft with a warehouse, and that alone eliminated seven miles each way to haul supplies into the mine. We were taking them in the very first portal over at Paige —- now we have this to bring them in which eliminates seven miles one way and gives us a lot of flexibility on how we supply the mine and how we lower our costs for those supplies travelling in and out of the mines. It also gets our employees 30 minutes closer to the face which eliminates overtime, but number one keeps them in the coal and keeps them producing more.

Next we'll talk about Miller Creek. I talked a little earlier about that one. It's the surface mine and two underground mines down there —- we have nine years on the current permit that we have and 15 additional years on our western expansion area, which we're in the process of permitting now. It's high quality reserves -— about 13 million tons on the current permit, 20 million tons of future, and it's owned-in-fee, high-Btu, low-sulfur compliance coal. We have loaders that load the coal there at the surface. We have annual production of about four million tons a year and 29 annual cubic feet of bank yards move there.

So in summary, I want to say that with the improvements that we've made on our existing operations, we're basically now running new coal mines with higher-than-ever efficiency ratings and low maintenance cost. Our leaner and more efficient fleet is now operating six state-of-the-art longwalls, 23 CM sections, and is set to produce between 31 and 33 million tons of coal annually. So again, I can't stress enough about the management team we have there. I think it's the best in the industry. We assembled those and we added some folks to it when we sold the five West Virginia longwall mines. They're the best you can assemble. Very proud of all them. The assets are the best you can have -- they're low cost, we've invested in these mines, heavily capitalized. They haven't been capital-short for any reason, I mean, we've done it for the last decade. They're ready to go now, they'll be low-cost and we're set to produce in any market situation we have. Thank you for your time. And now I'd like to turn it over to Jim McCaffrey who is our Senior Vice President of Energy Marketing.

MR. JIM MCCAFFREY: Well thank you, Jimmy. And I am Jim McCaffrey, Senior Vice President of Energy Marketing with primary responsibility for coal sales. Now I've got a little bit more time than Jim -- this is my 38th year with CONSOL. I started with CONSOL as a coal miner, and a little over 30 years ago I had the great good fortune to be in charge of the crew that mined the first shuttlecar to come out of the Bailey Mine. So what a great pleasure it is for me to be still selling and talking about what I think is the best mining complex on the planet. So let's get started.

You know, when we go out on a sales call, we sell coal, but we sell more than just coal. We sell Jimmy's excellent team -- and believe me, he does have an excellent team -- we sell Bailey, Buchanan, and Miller Creek's reliability, dependability, and quality. We sell CONSOL's strong credit position, which many of our competitors can't duplicate. And we sell our core values of safety, compliance, and continuous improvement. And our customers know that we'll never embarrass them. They'll never be embarrassed by dealing with us, and they know we always stand by our deals. Now our coal fleet will generate strong cash flows. Jimmy already told you that we divested our high-cost operations and our current mines are running very well. We will make money. The question is not if we'll make money, but how much money we'll make. And Bailey is well-positioned and will thrive. We are advantaged at Bailey in a post-MATS and carbon-constrained world, and we'll talk about that today. Couple that with our excellent cost and the future is very bright. And I want you to think about Buchanan as a giant free option for cash, and we'll talk about that some too. Any market improvement in the met market is going to immediately improve cash flow from Buchanan.

Now here's a look at our five-year price history for the three mines. This is nothing for me to brag about, but our first-quarter pricing was at or near its five-year low. Bailey priced in right around its five-year average of $64, Buchanan priced in around $77 —- well below its five-year average of $135 —- and Miller Creek priced in around $63, well below its five-year average of $70. Having said all this, the company still earned 50 cents a share and booked $116 million of net income in the first quarter, and the coal group generated cash flow of $213 million. Now let's discuss what that means. Look at these Q1 cash costs —- $39.37 for the company, $34.57 for Bailey, $57.79 for Buchanan, and $55.63 for Miller Creek. Now take a look at the Q1 margins and the potential margin generated with this cash cost when compared to our five-year pricing range. The company generated Q1 cash margins of $26.84. Bailey generated approximately $30 per ton, and when compared to the five-year historical range could generate cash flows ranging from $25 to $34 a ton, and that's not a reach for the Bailey Mine. Buchanan generated approximately $19 a ton, and when compared to its five-year historical range could generate cash margins ranging from that $19 to $135 per ton. And like I said before, any improvement in the met market will benefit Buchanan cash flow very rapidly. And even Miller Creek generated $7 per ton, and when compared to its five-year historical range could generate cash margins ranging from $7 to $19 per ton.

Now you know what that means, of course —- it means that we're a cash generating machine for the company. If you look at these potential cash generation ranges, Bailey's potential cash generation ranges from 700 million to 960 million dollars a year. And for Miller Creek it's 22 million to 74 million dollars annually. Thus total potential for thermal coal cash margins could exceed one billion dollars a year. One billion dollars. When you add Buchanan in there, Buchanan has the ability to generate cash ranging from 80 million to 700 million dollars. So all told, the coal division can potentially generate 800 million to 1.7 billion dollars —- that's 1.7 billion dollars —- of annual cash flow.

And these mines have 20-plus years of reserves. Now I should also mention that most of these reserves are held in fee or by low-cost legacy leases. This is unlike our competition in the west, which needs to lease coal from the U.S. government on a regular basis.

So let's discuss our markets. Jimmy hit on this, but I'd like to discuss logistics for a moment. Remember, a coal contract is not a sale. The sale takes place when the coal is delivered into the customer's railcar or vessel. Now as Jimmy already told you, this past winter, when our competition complained about rail service, we had record deliveries from Bailey. Our logistics team is strong and knowledgeable and has 50-plus years of experience. We maintain excellent customer relationships and communication, and we have constant dialog and great relationships with the railroads. The railroads, both the CSX and the NS, have made capital investments and significant improvements, with the help and guidance of our logistics team, to help rail logistics for Bailey and to enable the kind of delivery process that Jimmy discussed when he showed you that one slide about the Bailey loadout. Now Bailey is a dual-served mine. We can reach anywhere in the eastern United States through the NS or CSX system. The NS system is in red on this map, the CSX system is in blue. The vast majority of our customers are reached with single-line hauls. This is an advantage also over many of our competitors. And we can reach the world through our dually-served Baltimore terminal in Baltimore which has 15 million tons of annual throughput capacity and has allowed us to ship to 22 different countries. It also give us the flexibility to put Bailey into the domestic met market or into the export met market, and that allows us to get the best return possible for a Bailey ton.

Buchanan and Miller Creek are also both NS-served, allowing them to reach both domestic and export customers. And of course they reach their export customers through both Baltimore and NS' Lambert's Point.

Now we've worked hard in recent years to attain a specific customer base. This did not happen by accident. We have methodically developed our baseload customers for years. In our portfolio we have large plants with low heat rates. They're environmentally controlled and they're logistically favorable to us, and they match up well with our high-Btu coals. Now these are the plants that will run harder and at higher capacity factors in a post-MATS carbon-constrained world. That's why Bailey will be in demand. Additionally, in the last five years our portfolio has moved from 25% regulated and 75% merchant to 50% regulated and 44% merchant. That further de-risked our Bailey operations. Now east of the Mississippi, there are 807 million tons of potential coal burn. We have divided this into regions to show you where, and what, our future potential is. Our core markets are really located in the mid-Atlantic and the southeast, shown in green and red on this map. In the mid-Atlantic region there's a total of 39 million tons burned and there's 13 CNX customers that were involved with burning 21 million tons. In 2014 we have six million tons of that business. In the southeast, colored in red on this map, there's a total tons burned of 71 million tons, and we have 11 CNX customer plants burning 22 million tons and in '14 we have five million tons of this business —- pardon me -- 14 million tons of this business. And in the other region, the kind of our extended marketplace colored in brown here -— there's a total of 657 million tons burned, and there's 11 CNX customer plants burning 22 million tons, and we have five million tons of that business. And interestingly enough, interests from these large-base power plants in this extended region has been growing. Many of these plants have renewed desire for high-energy Bailey coal to improve their output. They're also interested in diversifying their supply chain away from the western railroad system. And finally, export in the yellow box there —- I just put it as approximately 100 million tons a year, it's fluctuated, as you know, over the last several years. But we have seven million tons going to export. The point is that we have more-than-adequate market opportunity, even in a post-MATS, carbon-constrained world, for our tons and particularly our Bailey tons. And remember, our flexibility to take Bailey to export and met markets allows us to manage the margins for our customers for our products.

Finally, we have a stable of long-term customers, over two dozen that have been with us for 35 years or longer. One domestic customer has been with us for 125 years. Every time we meet, they ask for the old customer discount. Believe me, they do -— it's a real bone of contention. And we have one international customer with whom we've been dealing with for over 100 years. So we have a leading, experienced sales team. They're incentivized for success. Maybe you're wondering about competition for the Illinois Basin. As Jim Grech explained earlier, we sell delivered Btus, and our coal Btus travel very well.

Now take a look at this map. I'd like you to locate the locations of our coal mines. You know, here in Virginia is our Buchanan Mine. In southern West Virginia is our Miller Creek Mine, and in southwest Pennsylvania is our Bailey Mine. And Bailey is in a real logistical sweet spot for both domestic and export deliveries. Now here's where the Illinois Basin is located out here. So you can see that logistically we have an advantage over the Illinois Basin. In fact, in our core markets, Illinois Basin on a delivered-Btu basis is transportation-disadvantaged \$13-\$15 in the mid-Atlantic region. And in the southeast region, it's transportation-disadvantaged between nine and ten dollars. When looking at export, the majority of the Illinois Basin coal delivers down the Mississippi to the Gulf. And in the export market, we have a \$16-\$17 transportation advantage. Now combine this transportation advantage with the cost I showed you earlier, and Bailey can compete effectively in any market. So compared to the Illinois Basin, Bailey's in the sweet spot, burns with more energy creating more megawatt output at a power station, and it burns with less CO2 -– we'll get to that in a minute.

Now MATS is coming. And MATS will definitely create winners and losers, there's no doubt about that. And Bailey's going to be a big winner. Some coal-fired plants will go away. In fact, 17 gigawatts of retirements have already taken place. We anticipate another 40 gigawatts of retirements between now and 2020. This equates to 95 million tons of U.S. production. But only 10 gigawatts and 16 million tons of that are in the east, and only two gigawatts or four million tons of that are currently CNX customers. And currently we're only shipping one million tons to plants that have announced retirements. Furthermore as nukes and coal units shut down, and as renewables underperform, we expect our customers to increase their capacity. The customers we have targeted will run more, increasing their share, and in turn our share, of the market.

Now this is a good time to discuss CO2. Now who knows if, when, and to what degree the final rule look like. But here's what we do know. Significant coal burn will survive, and these plants will run harder and at higher capacity factors. These stations will demand Bailey's Btus. Coal burn lost will largely be replaced by natural gas, which benefits us at CONSOL. Our logistics access to export opportunities —- primarily from the Bailey Mine and from Buchanan —- will be unaffected. And Buchanan as a met product will be unaffected by CO2. On top of that, it's a fact that high-rank, high-Btu coals like Bailey burn more efficiently in low-rate heat plants, and release less carbon. It's also a fact that low-ash coals release less carbon than high-ash coals. Bailey is typically an 8% ash —- Illinois Basin coals are marketed at 10% and higher ash. And it's also a fact that high Btu coal and a net calorific value basis releases significantly less CO2 than subbituminous PRB coals, up to 7% less. So in a carbon-constrained world, or in a cap and trade environment, Bailey has a major advantage over Illinois Basin and the PRB.

Now let's look at some recent events. In Q1, coal inventories hit their lowest level since March 2006. And in the same quarter, gas storage levels were also at their lowest in 11 years. Now this generated a lot of volatility in the gas markets and coal demand spiked, and utilities got busy trying to rebuild their inventories. To further exacerbate this problem, railroads could not respond to the demand. As mentioned earlier, this actually opened up opportunities for Bailey as utilities began to place more value on a diversified supply chain. Now the question is, who will bail whom out and how?

In recent weeks gas storage has improved. But trading activity indicates that there's still concern over inventory being restocked by winter. This will lead to higher pricing. But you can't look at this in a vacuum; you have to look at the coal side too. Doyle forecasts a range for year-end coal inventory between 84 million and 154 million, with the likely number to be 120 million. We think it's a little less than that, we think it'll be between 110 and 120 million. But 110-120 million would be 50-60 million tons less than the post-financial crisis five-year average inventory. This will definitely lead to higher coal pricing.

Now I want to discuss with you our view of the power markets. This is not intended to represent any definitive market but is a model just to give you our view. So I'm going to show you a typical power dispatch curve, and we're going to start here —- on the Y axis is price, and on the X axis is demand. Sorry —- and every day power producers bid in to the power market and it creates this power dispatch curve. On the left, on the low end are your low-priced renewables and nukes. All along the curve are power producers that are generating power either through coal-fired or gas-fired stations. And then as you get up to the top of the curve you'll find some oil-fired guys. So this is what the curve looks like, and every day demand is set, and wherever demand intersects that curve, price is set for everybody below that curve. And this just represents the hourly swing that might occur during a typical day. So market could be set up here as well. So what we think is going to happen as this MATS takes place, and coal-fired units do go away, some coal-fired units do go away, and also as some nukes are not re-commissioned, we think that that curve is going to move to the left, creating a steeper slope sooner and creating some marginal opportunity for the power generators. Now when that happens, volatility is going to increase and there's going to be more demand for natural gas to burn in natural gas stations. And when that happens, we think coupled with the chemical industry and industrial and export, then natural gas prices will go up. And as natural gas prices go up, we think the curve will be shifted upwards, creating again additional margin for the utilities.

Now that's our view of the markets going forward. And we also think what'll happen —- and when this happens is that our low-rate heat plants that we've been targeting as customers will run harder and that'll create more opportunity for our high-Btu coal. Now we can already see the beginning of this in the recent PJM capacity auction. Demand response and imported power were de-emphasized, and more credit was given through higher pricing to steel in the ground. Now CONSOL has tackled this margin gap. First of all our sales guys are trained to go after this. This is a margin that we want a share of. And we've tackled it through methods like creative pricing indexed to the price of power. And we also have our portfolio differentiated in a number of different ways for pricing and timing to create extra value and derisk the portfolio.

Finally, before I conclude I want to talk briefly about Buchanan. Now in the beginning of May we elected to reduce production at Buchanan, and subsequently we had a layoff.

Now we can sell the Buchanan coal —- I want to make that clear —- we can sell the Buchanan coal. But with the well-documented oversupply in the metallurgical market, the prices from China were just not acceptable. Now I'm not going to predict the BMA today, I'm not going to predict the timing of the market recovery, but I will say there's no good reason for this market not to be stronger. And a stronger market will get Buchanan back into the game relatively quickly. For now, we're going to de-emphasize China in our portfolio. It was a big emphasis the last several years and we're de-emphasizing it, and we're focused on our other domestic customers and some other worldwide opportunities in Europe and Korea, etc. Now we're going to continue to work to get Buchanan back to full production as rapidly as we can, but let me leave you with some thoughts on Buchanan. Buchanan will be relatively unaffected by CO2 regulation. We have the financial wherewithal and the discipline to idle a mine or to reduce production when the price drops below the cost. Many of our competitors haven't exhibited that discipline, and we think ultimately they'll pay the price for that. And finally, as I said earlier, we think Buchanan is a big free option for cash, which takes me back to the fact that our coal division can generate margins of cash from 800 million to 1.7 billion dollars annually. And we will deliver the cash flow to fund the company's future growth.

So in conclusion, we have the assets and the logistics to run and run well. We will make money in coal. Bailey is well positioned for a post-MATS, carbon-constrained world, and Bailey will be in demand as remaining plants seek to increase their output. And Bailey has the cost to compete in any market. We're also seeing continued strong interest for Bailey in the markets, based on these regions. And we're proceeding on our planned pricing commitments for 2015 and 2016 and it's proceeding as planned. And finally, Buchanan is a sleeping giant with the potential to be a fountain of cash flow and it's a free option in our stock price today. So thank you for your kind attention and now I'm going to introduce Chief Legal Officer Steve Johnson.

MR. STEVE JOHNSON: [Pause] Thank you, Jim. I'm going to talk to you now about our program to monetize our non-core assets. But let me begin by telling you what I hope you take away from this presentation. Here's the takeaway, over the next five years, we expect to sell $1 billion of non-core assets. Now, let me tell you why we and you can have confidence that we can achieve this goal. Over the last two years, we have undertaken a focused effort to monetize our non-core assets. And we've been successful in that effort. We have sold assets for almost $400,000,000 in cash. Now I'm not going to go over the whole list, but let me mention a couple of them. The largest cash transaction was the sale of our 50% interest in our Young's Creek joint venture with Chevron Mining Company. We sold our interest to Cloud Peak for $170,000,000 in cash.

And we retained an 8% royalty on 200,000,000 tons. The largest transaction, by value, was our contribution of 60,000,000 tons of net coal reserves to our western Alleghany energy joint venture with Rosebud Mining; that joint venture is located in Indiana and Armstrong Counties, Pennsylvania. Thus far we have received $15,000,000 in earnings on our interest in joint ventures, as well as production royalties. And this joint venture is self-funding. As you can see from these two examples, we retained a royalty interest or equity interest in several of these transactions, and we put the MPV of the future payment streams, that we expect to receive from these transactions, at over $500,000,000. So you can see we derive both current and future value from these transactions.

But the bigger point is that we have demonstrated our ability to sell assets, which adds credibility to our plan to see $1 billion of non-core assets over the next five years. The transactions I just mentioned did not include the sale of our West Virginia mines to Murray Energy. We closed that transaction in December 2013, so obviously a transformative transaction for us, in that we sold assets with lower growth prospects and turned our focus on our higher growth E&P business. And in the process, as Nick mentioned, we significantly delivered our balance sheet, the Murray Energy transaction had a total value of 4.4 billion dollars including $850,000,000 in cash. And Murray Energy acquired 2.4 billion dollars of balance sheet liabilities and another $941,000,000 of UMWA Pension Plan obligations.

Now let me tell you exactly what we're talking about when we say that we're going to monetize our non-core assets. This slide shows you some of the assets we can sell. Lee me run down the list quickly, I'll talk more about the Illinois Basin reserves in a minute. The Fola/Birch/Canfield Reserve in Central App is a thermal met-coal reserve and we believe it’s the largest remaining reserve block in Central App. The Itmann Reserve is a met coal reserve in southern West Virginia, the Amonate Mining Complex is a permitted and idled mining complex in southwest Virginia, also producing met coal, and we think that the Itmann and Amonate assets should have a lot of value especially when the met coal market returns. Nordegg is in Alberta; Emery is a permitted and idled mine in Utah. I’ll talk more about our Baltimore Terminal and Cardinal States Gathering System in a minute.

Burning Star No. 5 is a reclaimed surface property in Illinois that we’ve seen a lot of interest in. Just as a data point, we sold our Burning Star No. 4 surface property, which was listed on a previous slide, in 2012 for $2,700 per acre. More broadly we have 375,000 surface acres in 15 states. In a minute I’ll talk more about what we’re doing with our surface properties. Then we have some Utica Shale and Marcellus Shale that are —- those acres are not in our long-term drilling program and we’ll seek to monetize those acres, as well. And finally the other category there represents several smaller business units and investments that we are looking to sell as we continue to focus on our core assets. As you can see the number there represents the value of those business units. With all this, we think it’s very reasonable to believe that we can realize at least $1,000,000,000 of value from the sale of these assets over the next five years.

Now let me drill down in a little more detail on some of the opportunities that we’re looking at, so you can better understand the type of assets that we’re talking about. Let’s look at the Illinois Basin first; in the 1980s the Illinois Basin accounted for more than 25% of CONSOL Energy’s coal production and we still control significant reserves there. We have over 1 billion tons of reserves and resources in the Illinois Basin, 45% of which are owned in fee. On this map, focus on the yellow blocks, which are the reserves and resources we control. You can see that they’re surrounded by active mines and reserves. We’re going to run a competitive process for these reserves and we think a number of coal operators are going to be interested, including Peabody, Alliance, Foresight, Murray Energy, and others.

Cardinal States Gathering System consists of 112 miles of pipes serving our CBM field in southwest Virginia. The system has a capacity of 250,000,000 cubic feet per day. Look at the Cardinal States number 2 line which is the green line, running north to south on the east side of the map, this is a 30-mile, 20-inch, high-pressure pipeline that connects to Columbia Gas Transmissions' KA20 line there in the north, and in the south it connects to Spectra's Jewell Ridge Lateral Pipeline, the Jewell Ridge lateral then connects East Tennessee's Natural Gas' mainline and provides access to Tennessee, Virginia and North Carolina markets. And, by the way, we have an option to acquire that Jewell Ridge Lateral Pipeline. As producers look for more outlets for their Marcellus Shale production, we think that the strategic value of the Cardinal States Gathering System is going to increase because it does connect these two interstate pipelines.

This asset is on the shelf right now; we can pull it down at any time to sell to a third party, we can sell it to the MLP we announced this morning, we can joint-venture it. Or we can sell it, even as part of a package that would include our CBM assets in southwest Virginia. Our Baltimore terminal, as Jim mentioned, is a very valuable strategic asset for us right now. This export terminal gives us access to global markets and those markets, as Jim said, are growing. It's served by two railroads and has a throughput capacity of 15,000,000 tons a year. This asset is on the shelf, but we are prepared to pull it down very quickly, if and when the time is right to do so. And here, I should mention, with respect to all of our assets, non-core assets, we're not running a fire sale, we can be patient, we expect to get full value for any of the assets that we sell. Finally let me talk to you about our surface properties; as I mentioned earlier, we have over 375,000 surface acres. Over 100,000 acres of that surface is in southwest Pennsylvania and northern West Virginia.

That surface control gives our gas operations a real strategic advantage when it comes to things like well pads, compressor stations and pipeline rights-of-way. Just to give you a sense of how valuable that surface control is, over the last 28 months, we have received $23,000,000 for rights-of-way we have granted to third parties on that surface acreage. About $900,000 a month on a pretty steady basis. But what we've done more broadly, with respect to our surface acres, is identify the dozen or so best commercial opportunities for those acres. Our Mon-View project, which you see here on the map, is just one example of the value that we think we can realize from our surface control. The other opportunities are similar. Interstate 79, seen right there in the middle of the map running north to south, is the highway that connects Pittsburgh and Morgantown, West Virginia.

You can see the WVU Coliseum there on the east side of that aerial photograph. If you look at the east side of Interstate 79, that's a commercial retail development. We contributed over 400 acres to that development project, we are a 50/50 partner in that project, we contributed no cash, took no capital risk, and we received in the past several years $20,000,000 from that development project. Now we are looking to expand that project to the east side of the highway there, where we have over 350 acres. We may contribute those acres to a real estate development partnership, similar to what we did on the east side of the highway, although we will contribute no cash and take no capital risk, or we may simply sell those acres outright, we're looking at both options, we'll do whatever has the greatest MPV, to consult.

So this is intended to just give you some idea of the commercial opportunities that we have for our surface acreage. As I said there are a number of other similar projects that we are looking at for those acres. So before I turn it over to Dave, let me just say that, you can see that over the last 150 years, we have acquired a lot of assets that are no longer core to our business. These are tier-one, high-quality assets. We're going to continue to focus on monetizing those assets and we think our plan to sell $1,000,000,000 of assets, over the next five years, is a very achievable goal. That concludes my portion of the presentation, I'm going to turn it over now to Dave Khani our CFO. Thanks.

MR. DAVE KHANI: Good morning, or I should say, good afternoon. As Steve said, I'm Dave Khani; I'm the Chief Financial Officer of CONSOL Energy. So far today, we've provided a lot of key data and strategy of how we're going to grow our future cash flow stream. Today, I'm going to focus on three key areas; one is how we fund our EMP growth, two is how we capture the equity upside for our equity stakeholders, while protecting the downside for our debt holders, and three is how that all translates into a lower cost of capital. So the common thread throughout our company is our investment philosophy, how we manage risk, and our ability to take care of all of our stakeholders. I think there are three, excuse me, four key drivers to this, one is having a rich organic opportunity set located within a very tight geographic footprint.

CONSOL has operated elsewhere -- Australia, Canada -- it's realized that our best core area, and best energy footprint sits within that core area, where we can maximize our intrinsic value. Second is we do take the long-term approach to developing our assets. We spend a little bit more time and it may —- to develop the strategy and to execute, but it is built to last. Third, the core values that everybody's talked about today of safety and compliance, it ties a little bit to taking time to developing assets, but it also de-risks that growth profile. And then fourth, we always want to maintain a strong balance sheet and liquidity. This gives us optionality to how we finance our growth. Now let's take a look at our forecasted cash flows and our forecasted capital expenditures. So we provide a range here, so this is the first time we've provided it, and we provide a range around here based upon production levels, modest movements in commodity prices, carry, non-core asset sales, and some capital efficiency trends that Tim has talked about.

What's not built in here is the stack play potential upside and the full benefits of our CF. So before you pull out your rulers and try to figure out what the gap is here, it's a few hundred million dollars over time. We expect to close the gap materially. So the key takeaway here is we want to be a very different E&P company. We want to try for meaningful and consistent production growth at or above 30% and while maintaining our debt levels. This gives us optionality, to either dial up our growth rate or buy back stock. So now let me talk about the capital investment side of the table; as Jimmy Brock has highlighted, our mines are very well-capitalized and most can run for 25-plus years, past the next three administrations. Our investment track record has been solid, as we mainly focused on our organic growth in our backyard.

Over the past eight years, we invested about 2.1 billion dollars in efficiency projects as we opened up new mines at a fraction of some of the 2011 M&A deals. As investors, you know the entry point is very important in determining the rate of return. Now all this ties to our E&P, investment philosophy to toggle over and accelerate our E&P growth. As we shifted from a long-term CBM player to a shale producer, we acquired the Dominion assets and people in 2010 to build our shale portfolio. We delineated for about a year, and then we brought in solid partners to accelerate this value. So over the past four years, we've invested significantly in the assets and the process, and we're now beginning to realize improving recycle ratios. Now Tim talked about some of our history and we have a good strong base of activity. So over the past five years, we've increased our E&P production, improved reserves by 85% and 300% respectively.

Now, this includes the acquisition from Dominion, but it also includes the divestures to Noble and Antero in 2011. Based on our forecasted drilling pace, we are only booked out to about three years of activity below the five-year-threshold. And as you can see our drill bit F&D over the last five years has averaged about .43, very low and—compared to industry averages. Now let's look at how we're starting to realize improving cash flows relative to our investment needs or traditionally known as recycle ratio. We expect to see this recycle ratio improve from about 1.5 times over the last four years to over four times, based on several key items. One is the pace of inventory and land will slow and now the production will ramp. Second is our liquids production mix will go from 0% to about 10 to 15% by 2016. Third, we're improving our completion techniques and we're driving down our capital costs, that Tim and his team has highlighted. And then fourth, we're going to start to recognize the carry and the midstream impacts that we highlighted through our MLP announcement today.

Now let's put all together some of the pieces that even Steve Johnson and others have talked about. As we're driving up our operating cash flow for our E&P division, let's look at the funding levers we have to maintain strong liquidity and current debt balances. These seven levers here, highlighted on this page, can be measured in several billions of dollars. And let's go through a couple of them on the next several slides. First we will be implementing the MLP, let's talk about why; one, it gives us access to low cost of capital and the drive to lower the capital intensity of our business. Second, it maintains operation control, as you know the whole space is growing very quickly and the ability to control where, when and what in building your gathering system, being able to distribute your gas, and products is very important.

And then third, as we're trying to unlock the sum of the parts value, we're giving you another currency here to value the midstream business. Now let's take a look at the map here of our Marcellus acreage, which ties to their cone gathering system, which ties to our MLP. As you can see, we've invested about $400,000,000-plus through the first quarter of this year to develop our gathering system. Now Tim has highlighted the JVs and the value they bring, but let me hit if from another angle. These two JVs bring 2.1 billion dollars of value through the JV carries, one for Marcellus and obviously one for the Utica. Now they provide technical and operational teamwork to help accelerate the learning curve. Second, it provides a strong funding bridge between the gap -— ramp-up period and cash flow. It significantly improves the rates of return, highlighted by Larry in his slides.

And fourth, it provides opportunities to JV on additional zones and additional acreage. So the following slides will demonstrate how our strategy, and actions and transparency have lowered the underlying execution risk to this volatile commodity price period. Now this slide goes back about —- from the five years, from the sale of five mines, and captures the purchase of the Dominion assets, the non-core asset sales, and the strategic shift toward being an E&P company with a coal stub. The graph highlights our beta or measured relative stock volatility to the New York Stock Exchange and Index. Beta is a key component in calculating the cost of equity. This graph highlights that while our stock has gone up over the past year, our beta continues to decline lower than our E&P and coal peers. The next set of slides will provide the drivers to this decline of volatility.

So first our production guidance has been traditionally met or exceeded for the last three-plus years in aggregate. This is more impressive when you factor in that 100% of our coal production is mined 100% underground. And we faced one of the most volatile coal periods in the last three decades. Now this is how luck, our investment, our engineering focus, our coal reserves, and our marketing prowess all help drive this performance. Now as you can see, we've instilled this into our E&P operations and expect Tim and his team to take it up a notch. Second, now Tim has hit this, that our unit costs are expected to climb, and provide more predictability in our business. And I want to apprise you how we get there, so in the next two years, we do expect our unit costs to decline 5% to 10% from an approving mix towards our Marcellus production and a modest benefit from spreading over our fixed costs over a larger production base.

Now this graph highlights all the five key unit operating-cost items and we expect three of the five to decline, LOE, DD&A and Direct Admin, over the next couple of years. While firm transportation and processing as well as production taxes and taxes will be flat to rising. Now this reflects higher processing costs from rising liquids production, modestly rising firm transportation costs, and higher taxes located in West Virginia. Now let's move over to coal, the coal operations are in a different state, as they're well-developed, and well-capitalized. So over the next couple years, we expect coal unit costs to be relatively flat. Now what's a few factors that drive this? One is the market, if we can sell 100% of what we produce, unit costs will go down. Second, as we are layering in our BMX mine it is a lower cost, lower than at mine, relative to higher cost Central App. So we expect that, in the second half of this year, unit costs will come down.

However I will caution, as the met market does come back, we expect unit costs will go up; however we do expect margin to go up, as well. And then third, our internal goal is to keep underlying inflation such as labor and safety relatively flat and offset by more standardization at our mines and some of our vendor and supply chain management efforts. Now not depicted in any of these slides is a reduction that we've had at our corporate headquarters. Over the last two years, we've reduced our corporate headcount and administrative expenses by over 30%. And more recently by about $100,000,000 from the sale of the five mines. So now that we've painted a picture of consistency of production, flat to declining unit costs, it's now time to talk about how we manage our commodity price risk. So nearly 20 years as a coal and natural gas analyst, I deeply forecasted the trends of these commodities and the macro trends.

Now since all commodity producers are essentially price takers, it seemed very important to me that understanding these major price trends should drive decisions around capital spending and project rates of return. So one of the tasks we undertook, nearly three years ago, was strengthening our internal commodity forecasting team. To capture these big price trends and create clear pricing signals throughout our whole organization. We use this to contract our coal, hedge our gas, value our assets, and drive cost reductions inefficiencies. This adds a sense of urgency and timing to all we do. Now specifically we have built out domestic and international supply and demand models for all our major commodities. We supplement these forecasts with the purchase of raw data and always benchmark against strident consultants. In the end our independent views enable us to make smarter decisions and all the announcers we employ have commercial use.

So, while we don't publish our forecast, I will give you one of them. We did set a $4.25 natural gas non-expense benchmark price for 2014 and we did this in early 2000—November 2013. And we —- and then later had our board approve it for our PO and budgeting process. At the time we set it, the strip was set at $3.66 per MMBtu and as we expected normal winter would drive that number up. And lo and behold winter weather was stronger than normal and jumped up higher, and I'll talk about how we captured that, as well. So this pictorial shows how we —- how coal and gas -- interact and how the end markets -— and the end markets which they serve. This framework helps us focus on the key drivers and how we position our strategy to capitalize on it. As Nick highlighted earlier, our strategy ties perfectly to growing our E&P business, while selling off our lower margin coal mines.

So while we experienced the supply shock for the shales and the massive productivity improvements, natural gas demand will play catch-up. We see natural gas demand conservatively rising about 17-1/2 Bcf per day, through 2020. Overall weather impacts still dominate demand in the near-term, there are a couple of demand trends that we are focused on. First, will be the rising industrial demand for natural gas and natural gas liquids, which will also has important read-across and implications for improving power and steel consumption. For example there are 115 U.S. chemical plants on the drawing board to capitalize on cheap U.S. feedstock versus expensive international plants that focus on oil. The second key trend is the mix shift and power generation towards natural gas. The negative demand for -- trend for coal has been in place for a while, but the pricing impact has been muted as the coal industry avoided spending meaningful organic capital, instead relied on M&A.

We expect MATS and the current regulations to drive domestic coal market share down to about 32% from about 40% expected in 2014. EPA's recent carbon announcement will reduce market share further; however, we believe we are well-positioned with high Btu aiding the efficiency trend. We do not see coal going away, just being deemphasized. So we measure the underlying commodity risk using a tool, called, "Value at Risk" or "VAR", so in contrast to coal, natural gas and natural gas liquid supply and growth has a head start over the demand side. As a result we have to manage these risks and our growth profile. So one of the benefits for CONSOL is having coal as a separate fuel source. The correlation to natural gas is significantly less than one, due to the major quality differences between the thermal coals, the contract periods, the global connectivity, and the completely different end market for met coal.

As I said, we use VAR as the measure to measure this volatility. We define VAR as the monthly volatility at a 95% confidence infill. By measuring the risk, using our fundamental analysis and getting consistent market touches through our sales and marketing teams, we can better understand our commodity exposure. So this next slide provides a recent VAR measure for each of our major commodities, thermal, met and natural gas. As you can see, natural gas carries the largest monthly volatility or VAR at 18%. With met coal 11% and thermal at 9%. The portfolio effect of combining all these commodities together creates a combin -- a VAR of about 12%. And through our coal contracting and our hedging, we'll reduce it down to about two and a half percent. Again another synergy of having coal and gas together. So the benefit of creating more predictable production and cost streams enables us to feel more comfortable to lock in our revenues and thus our margins.

Now earlier, Jim McCaffrey provided a view on how we expect our contract or open coal position in the face of environmental impacts. Let me delve into the gas hedging program. We currently employ two hedging processes for natural gas, a program hedge and an active hedge. Our hedge proc —- a program hedge is multi-year and is layered on systematically above a certain internal price threshold. Our active hedge supplements our hedge —- our program hedge and will lock improved undeveloped production at an even higher price threshold. We'll implement bases hedges when feasible, and we'll incorporate direct sales as a means to limit basis impact. Now the bottom table here highlights our hedged revenue position for both coal and gas for 2014 through 2016. As you can see, we're very locked up for 2014. During the next several months, and presently today, we are layering coal contracts and hedging our gas —- open gas position, to capitalize on the low coal and gas inventories that were highlighted by Jim earlier.

Now let's go look at our active hedge process. Our active hedge process involves regular meetings and constant monitoring of various different markets and price points. The top right table highlights that we believe we locked about 89% of our overall coal and gas volumes for 2014. This compares about 86% of our revenues hedged and highlighted in the prior page. So the bottom table highlights how we've added 2014 period gas hedges over time, versus our major Marcellus peers. As you can see, we've layered in our program hedge up to about 35% through October 2013 and then we've added about 40% in the winter months through our active hedge process. So over the past two years, we've developed a discipline process to protect cash flows, as well as capture market volatility. Through this process, fundamental analysis, and existing and flexible firm transportation capacity we believe it can realize one of the highest gas prices realizations within our Marcellus peers. So now we present it —- we've provided an outlook for repeatability, strong production growth and an ability to hold or improve margins, which all drive lower beta and improving equity value. We went to highlight how we've improved and shrinked our debt cost to capital.

So with the sale of five mines, we've de-risked our balance sheet by removing legacy liabilities, including the unknown risk of how the 1974 multi-employer pension fund will be funded. As you can see, we cut our legacy liabilities by 56% and our cash service expenses by about 53%. In addition we expect long-term rates will eventually rise, causing the present value of these balance sheet liabilities to shrink even faster than the underlying five and a half percent, long-term decline and expected cash services expenses. So by reducing these liabilities we were able to go out and refinance our debt at more attractive rates and terms. As we highlighted in our earnings coal in late April, we essentially completed three financing initiatives including refinancing our one and a half percent 2017 maturity, general obligation into an E&P-specific obligation.

We're converting our coal and gas revolver today into an E&P-specific revolver for $2,000,000,000. So while we're rebranding our equity, we've already converted more than half of our debt and liquidity into E&P-based instruments. In addition, we've significantly pushed out the debt maturity out next several years. Now these actions have reduced our interest expense and interest rates by about 1% for about slightly more than 50% of our outstanding debt. We will have the option to refinance our 20/20's and 20/21 maturities over time. Now let's focus on our methodology to add or reduce leverage. The top left chart highlights where our combined debt to even ratios are, and where we expect them to be based on our base case, high case and low case for commodity prices. As you can see, we expect our base case to decline to very close to three times a year in 2014 and gets very close to two times at year end, 2015.

Our target zone is between two and three times and compares very favorably to strong E&P companies and meaningfully lower than our coal peers. Our target leverage will move up and down based upon the security of our underlying cash flows. Now the bottom chart breaks out our coal and E&P division debt to multiples, the coal-only multiple comes down very fast as a result of BMX coming online, combined with our lower capex going forward. While our E&P division comes down nicely through this solid growth of - -. Just a second, okay so while —- so now let's —- now that we focused on our debt and equity highlights in the prior slides, our strategy overall has been to reduce our weighted average costs of capital. The three graphs here highlight our coal, weighted average costs of capital, our E&P weighted off —- weighted costs of capital in maroon, and our blended weighted costs of capital in gray.

Over the past year and a half we have lowered our blended weighted of average cost of capital down to about 1% down to about 9.25% and expect it to go below 9% by year end 2015, assuming the debt markets cooperate. So as you're putting together all your non-asset value models, we want to make sure we hit one major key point; not all discount rates should be equal for all companies. Now we run our own internal net asset value, which obviously we do not provide but I can tell you this, for every 1% decline in discount rate, it increases our internal net asset value by about 15%. So think about this, while we're giving you the picture of rising cash flows in driving our non-asset value higher through activity level, we're trying to also attack it through the bottom discount rate and hit it from both angles. So let me summarize my presentation today before I pass it over to Nick, we have a powerful asset base that can take care of both debt and equity stakeholders.

We're focused on driving our rates of return higher and our capital intensity lower. Now management is incented this way or long-term incentives are tied to rising ROCE, as well as driving our share price higher. And we helped it -— we hope to do so even in a flat commodity price environment through a focused and thoughtful approach to executing our game plan. With that I'll pass it over to Nick.

MR. NICK DELULIIS: Thanks Dave, this concludes the presentation section of what we had planned for today, and before we get into lunch and the Q&A, want to go back and talk about the primary drivers or objectives we had for today. One was to of course introduce our wider management team, the people who make the plans and opportunities to actually come home to roost day in and day out. I think today's venue gave you a great chance to see that team in action and where we're heading. Another objective was to provide another layer or level of transparency on what we're doing across our different segments, whether it's E&P or whether it's the coal segment or water and how that changes and might unfold over time, with the things that drive and the metrics that drive NAV per share. And that brings up, really the one and only point I wanted to make in conclusion, which is that metric or variable of time. A lot of what you've seen today, from what our drilling plans are, production growth, expectations, EURs per thousand foot, what's happening on the coal side, with the ongoing unit costs of our Bailey Complex and pricing prospects. Coming off of carbon and MATS types of regulations, those change and they change significantly in relatively short periods of time, based on the trajectories and the plans we put out there.

So, thinking through NAV per share and thinking through what our opportunities are, that’s going to change significantly as time unfolds, so keep that in mind and where you need or have questions on that, let us know and we’ll assist and engage in that discussion where we can. And going back to our ultimate duty or view of things, NAV per share is driving our decisions, as that time unfolds. Opportunities because of the financial metrics, when you roll them all up, that Dave just covered, there’s going to be additional options and tools in our arsenal to help drive that NAV per share. And that’s something, that again, is going to happen in a relatively short period of time, based on what you’ve seen today, and that’s a good thing. So I want to thank you for attending, I think we’ve got some logistics here that Dan’s going to cover between now and lunch and Q&A, and I’ll turn it over to him.

MR. ZAJDEL: Okay, thanks Nick. What we’re going to do is take a short 10-minute break and we’re going to have some lunch, which is in the back of the room. I would ask that you get your lunch as quickly as possible, and maybe we’ll start with the back row and then work towards the front of the room, So we don’t cluster around the serving area. Please get your lunch, return to your seat as quickly as possible, and then we will begin the Q&A portion as you eat your lunch and we will have microphones; again, because of the webcasts, we ask that you ask the questions into a microphone, so that the folks on the webcast can hear it. So we’ll go ahead and take a short 10 minute break, thanks.

[END RECORDING]

[START RECORDING]

MR. ZAJDEL: Okay, I think we're going to begin the question and answer session. Since this is being webcast, if you'd please raise your hand. We have two folks in the back who will be passing a microphone to you so you can ask the question, and the folks on the webcast can hear it. So, let's go ahead and get started. I see a question up front here. We'll start up here with Neil Mehta.

MR. NEIL MEHTA: Thank you very much. Can you hear me?

MR. NICK DEIULIIS: Yes, I can hear you fine, thanks.

MR. NEIL MEHTA: I just wanted to turn to slide 175, I'm sorry to get into the nitty-gritty here, but you've got some forecasts for '14, '15, and '16 [inaudible] net income. So, just a couple clarifying questions.

The first question is, is that based on the forward curve or your point of view on the market, and I know you're not in a position where you're can tell us exactly the spot point for what you're embedding for gas, and maybe NAP here. Can you talk about, directionally, are you above or below the forward curve? Then, the second piece is embedded in here any assumption of non-core asset sales.

MR. DEIULIIS: Yeah, hi. That is our internal forecast, it is not usually different from the forward curve. Although I will tell you there's no real forward curve for thermal and met. So, it's a very independent view on thermal and met. And, we do have asset sales built into our cash flow projections, but not into our net income.

MR. MEHTA: Okay, and because the '15 number is actually $100 million above consensus, and the '14 number is a little bit light. Is the '14 number--you said you used 425 natural gas -- or, have you updated that point of view based on recent movements?

MR. DEIULIIS: We've updated based on our current hedge position that we've highlighted, so that number's come up.

MR. MEHTA: Okay. And then, just two M&A restructuring questions. The first, can you talk about the potential for bolt-on acquisitions around the Marcellus and Utica acreage. And then, the second question that's become topical with the Foresight IPO and the success of ARLP is the idea of a coal MLP. Given that you're such a free cash flow machine at your coal business, do you think that makes sense? And, if not, why not?

MR. JIMMY BROCK: I'll answer the first part, and Dave Khani can comment on the second part, the MLP on the coal side. The first part of the question, M&A with E&P segment, and the coal segment, for that matter, really going to look and concentrate on opportunities or asset acquisitions that supplement, extend as laterals, as Tim and Larry talked about. Extend contiguous fields that we've put together and consolidated in the Marcellus and Utica, and not be looking at either area within the Marcellus and Utica, outside of our current core, so I don't think you'll see us jumping into something like northeast Pennsylvania, or certainly not areas outside of our northern Appalachian area of emphasis.

So, M&A's going to be pretty straightforward on the E&P side; it's basically adding on and supplementing what we already have in place. And then, on the coal side, same situation. Unless there's some reserve opportunity that is contiguous to the Bailey or Miller Creek or Buchanan Complex. If you look at what Jimmy Brock had presented, we have 25-year mine lives across Bailey and Buchanan, wouldn't be something that interests us. On the M&A front, expect some boring, quiet activity outside of asset bolt-ons. On the coal MLP, I'll let, as I said, Dave comment on that.

MR. DAVID KHANI: We do have the assets to do a coal MLP, but it would make us more comfortable to move down that path is having more long-term contracts underlying our coal production.

MALE VOICE 1: I have a similar question on the gas side. We've seen a couple of IPOs recently of mineral rights on the gas side, fetch maybe 5% yield or so, seems like yield instruments are in vogue these days; would you guys consider doing something like that in the gas business?

MR. KHANI: Well, I think right now the best cash flow stream that we'd want to MLP, or put some sort of yield instrument, really ties to our CONE asset; it's got a lot of growth, and it's low-cost. Marcellus is tied to it, so I think right now the best cash flow stream to monetize is that CONE gathering tied to our Marcellus. Beyond that, we have other assets, and we'd probably think about whether we'd rather sell them than MLP.

MODERATOR: Okay, question from Neil Dingmann.

MR. NEIL DINGMANN: Just had a question about well costs. I think I was talking to Tim and Larry a little bit. You have, I think, on your Utica well costs run $9.6 million. I know, Tim, you and I talked a little bit about -- you mentioned about the air rigs coming in, about eliminating the intermediate case, and there's a number of things, obviously, that you all have discussed today on that, so is that just going to be trial and error, or can you give us an idea of your thoughts, on how quick, and how much you can bring these Utica well costs down.

MR. TIM DUGAN: Well, I think we'll have the Utica well costs down below $10 million by 2015, that's our goal. The deeper casing, we'll look at that regionally, by area. I know from my past experience there's areas where we don't have to set deep casing; instead of setting 6 or 7,000 feet, we can set it at 2,500 or 3,000 feet. So, we'll do that area by area.

There's some areas where it will be necessary, there's some areas where we're going to have to work with state agencies. At this point the initial wells in West Virginia, they very likely will require the deep casing; they might change their mind based on some of the recent wells that were drilled. And we'll look at all of that as we move forward, but $10 million is very achievable, and we'll get there.

MR. DINGMAN: And then, the follow-up to that; just in that eastern area, I guess for either you, Tim, or Jim, on the marketing side, is it how you develop that? Is that going to be dictated a bit on what the takeaway is? I think you said maybe Fall of next year you expect quite a bit of sales to ramp up -- is that mostly dictated by the takeaway there that's now -- maybe Jim could talk a little bit about what's available, either through yourselves or some of the larger lines. I’m just kind of curious about takeaway.

MR. DUGAN: I'll let Jim answer that, but I will say that our development plans all along are one of the reasons our asset teams are to make sure our development plans match up with our marketing plans. I'll let Jim talk about the specific plans for that area.

MR. JIM GRECH: And, Neil, just so I understand, you're talking about just in Utica?

MR. DINGMAN: Primarily in Utica, on that eastern side, and down in the southeast, all the way down to West Virginia.

MR. GRECH: We don't see any issues with the takeaway capacity, some of those projects there, there's a lot of take-away potential being built above Clarington and Kensington, points in Ohio, and so right now we don't see anything as far as takeaway capacity, limiting the production side of it. And, if there was, I probably wouldn't be up here talking, because I'm not allowed -- my job is to make sure that doesn't happen. Again, we see enough capacity, either existing or coming online or we have under contract right now, to not inhibit production in any way.

MR. DINGMAN: Thank you.

MODERATOR: Question from Lucas?

LUCAS: Hey, David. On page 145 you show your capex, and essentially running a little bit ahead of your free cash flow, my question is, making up this difference with asset sales must do, but would you also consider other sources of funding for this gap over the next few years?

MR. KHANI: The gap is between 100 million and a couple 100 million a year. That could come through either a little bit more asset sales, it could come through pulling on the revolver, it could come through better hedging, it could come through a lot of efficiencies, and things that I talked about, are not flowing 100% through, which is RCS; we have some capital reductions in there.

So, there's things that we will do over time to be more efficient and close that gap. We wanted to paint the picture here, that we're actually very close, and we still have a little work to do, but we'll close that gap. You will not find us doing an equity offering to close that gap.

MODERATOR: Okay, question from Timna Tanners [phonetic].

MS. TIMNA TANNERS: Thank you. Along the same lines, on the monetization discussion on page 138, could you give us a little bit more color on the timing for stress-testing purposes, what you're looking for on maybe the met or thermal markets, or at what price you might want to sell those -- what's the environment for sales, and where you are in terms of some of the different projects versus others that up for divestiture.

MR. DUGAN: Yeah, sure. We obviously have our own internal views of the value of these assets, but what we tried to do for you today was give you some confidence that we can sell a billion dollars over the five years without attaching specific value to any particular asset. Hopefully you can get some sense, and draw your own conclusions, based on some of the metrics we have there.

I will tell you that the Illinois basin reserves--that marketing effort is just underway, and we would hope to execute a transaction sometime this year. But we are also working to monetize a number of other assets at the same time. So, again, it's not a fire sale; we want full value for the assets, but our most active effort right now is probably the Illinois Basin reserves you see there, as well as the surface acreage opportunities that I mentioned.

MODERATOR: Sven?

SVEN: Thinking about your stacked formations: if you were to develop them simultaneously -- I mean, is it possible to develop them simultaneously, or does Utica gas -- are the pressures too high to be accommodated by the existing infrastructure you've got, and given the infrastructure you've got right now in the midstream, if you were to develop the Utica more aggressively, would you have to make extra investments to accommodate those higher pressures coming from the Utica?

MR. DUGAN: We can develop them simultaneously, whether that makes the most economic sense, you know, we're looking at several development scenarios. The pressures, I don't think, will be a significant issue, although parts of the Utica are higher pressured as you go south, the pressure gradient increases.

But, I think once you get the wells in line, I don't think that would be a significant issue. It's going to be more--the stacked play development, it's going to be more planning around the infrastructure, what's available, take-away capacity, and the progression that we want to develop those in. But, there will be some areas, like the Monroe County, it probably makes sense there to go in and develop the Utica and the Marcellus jointly.

SVEN: And lastly, on that page, 138 again, with all those assets were prospectively for sale, I didn't see anything about the CBM assets, but I think you did mention the possibility of adding that to the list, just verbally, after the slide. So, I was wondering why it was not included on the slide, or if I misunderstood the presentation.

MR. DUGAN: No, you're right, it's not on the slide as a particular asset that we're currently looking at monetizing, but certainly if it makes sense to do that, we would do that.

I mentioned in the context of the Cardinal States Gathering System, if it makes sense to package that asset with the sale of CBM that's in southwest Virginia, we would absolutely consider doing that.

SVEN: Does its usefulness as a tool to degasify your coal mining, does that complicate its separation in any way or form?

MR. DUGAN: Well, you know, we actually did that separation when we spun out CNX Gas in 2005, there was that separation of two different companies with two different sets of shareholders, and we had an agreement. It requires a lot of coordination between the gas side and the mining side, but it is something you can do by contractual agreement, and requiring a certain level of coordination between the mining operations and the gas operations.

SVEN: Thank you.

MODERATOR: Okay, any other questions?

MALE VOICE 2: Hi. I had a question on slide -- what number is it here -- it's the E&P division, it's showing your tight curves, your enhanced tight curves for the Kuhns 3B well. I don't see a page number here, but it's early in the deck. So, this is not in your resource potential estimates, am I correct there?

UNIDENTIFIED SPEAKER: Yes, that's correct.

MALE VOICE 2: And, secondarily, could you talk about maybe [inaudible] that you're using for your plays, since you haven't disclosed that, if you can disclose it, and second of all, what gives you confidence that you're accessing new reserves here versus acceleration here?

MR. STEVE JOHNSON: Okay, that's that one. Typically our terminal decline on our Marcellus wells is in the neighborhood of 5-6%. On this, to mention this, on this Coons well, that was our record-long lateral. We have -- we've discovered that you have to produce these wells a little bit different. That tubing acts as a choke, down hole; you can't get all the gas flow out at one time from these wells, so what we did here was simply flow up the tubing, and around the tubing, to get more gas at one given time out. The fact that it has sustained -- and this graph's a month or so older -- the fact that it's sustained over a period of time tells us exactly a reserve pick-up, by flowing up the annals and the tubing at the same time. Did that answer your question?

MALE VOICE 2: Yes. I mean, is it a desorption kind of a mechanism? There's not pressure support, per se, if you're just kind of [crosstalk].

MR. JOHNSON: No, it's not like coalbed methane. It's much simpler than that. If we had not done that, then the decline curve would've been projected off of the production prior to that bump, and it would have been like the red line on that graph. So, over time, that well would've looked like it had less reserves than it actually does. Now we can set our decline curve on the higher blue line after the annular flow, and you gain that volume between the red curve and the higher blue line on the end of the graph. That's the reserves you're gaining by doing that.

MALE VOICE 2: If I could ask one more. You book reserves on kind of a three-year forward basis on your PUDs; what improvements and capital visibility, or manpower visibility going out, will you need to book on five years and be more like your peer group?

MR.JOHNSON: When you look at our reserve number, and you try to get a feel for what's going to happen looking out over time, the approach we take with booking crude reserves is going to be, on a relative basis, more conservative than you might see with others, just because we view that as one of those sacrosanct numbers within our SEC reporting. You've got the PUD issue, going to PDPs, but the other item to take into account when you're looking out into the future on reserves, is what those PUDs will come into PDPs as.

So, we talked about RCS and SSL, and our current 5.7 trillion cubic feet, the only benefit of RCS and SSL we have in there are the wells that have already employed those. It's only in the PDP numbers. So, those PUDs -- not only are they going to become PDPs as they get drilled within the next three years, there's also going to be this impact of the completion techniques that are applied to them, and what differentiation or differential that creates on the PDP that goes into the reserve number, as well.

So, when we start to look at that waterfall diagram for reserves from year-end '14 to year-end '15 -- or, I'm sorry -

- year-end '14 relative to year-end '13, one of the things you're probably going to see is a breakout of one of the current components of that waterfall into those two types of examples. PUDs going to PDPs, which we always did, but also what has happened to that PUD in terms of its EUR per thousand, versus what it was in at as a PUD at the end of the prior year.

MALE VOICE 2: Thank you.

MALE VOICE 3: Hi, good afternoon. When you think about the strategic direction to drive net asset value appreciation to the share price and the IRs [phonetic] are pretty compelling, even at a conservative gas price view; it seems like you'd want to grow production as quick as you can, so, how should we think about production and growth potential in 2016, through, say, 2020, and would you be willing to increase leverage on the balance sheet at the high end of the band you laid out to continue to do that, if the economics were still compelling.

MR. KHANI: The way we think through that -- and this really applies even to the front three years, not just into the outer years that you referenced -- there's a couple of things that are occurring at the same time, which create some decision points, or options, moving forward. One thing that's happening is, on the coal side, we've got this free-cash-flow-generating segment of what we do. Again, once we get into the new positioning and the new pricing environment for the Bailey Complex, coupled with what happens on the met international, global side.

That number -- our expectation is -- that number continues to grow. You look at the balance sheet Dave Khani presented, the balance sheet snapshot and how much that has changed on the right side of the balance sheet over the past 12 months, coupled with those leveraging metrics that he presented, and how that's going to unfold, not in '15, '16, but quarter by quarter for 2014. And then, the third one is where we started the day, Tim and Larry talking about that lean manufacturing and continuous improvement; whether it's the collision techniques, or the mobilization/demobilization, or the stack pays, and all the shared infrastructure; those three things, in total, are going to create opportunity in one of two forms. It's going to be either the opportunity to produce the same gas production target, but at a much less, and lower, capital intensity.

So, basically, we get the production ramp, but we do it more efficiently, spend less capital, more offered in cash flow, to deploy into other things that we discussed, whether it's the share account reduction, the balance sheet and leveraging of metrics there, or dividends, M&A, all those other things that are out there. Or, it creates the opportunity to grow gas production further because we've got the wherewithal to do that; because of the de-bottlenecking, coupled with the financial wherewithal.

Which one of those two we choose at that point and time really comes down to where we're trading at, versus our view of what the NAV per share opportunity is. And, our job right now, and our attention and our focus right now, is to create and accelerate those times when we have those options to choose from, as soon as we can. Which again goes back to everything we're doing on the E&P side, to what we're doing with the pricing and margining on the coal side, to what's happening on the balance sheet and leveraging ratios, et cetera.

FEMALE VOICE 1: Two questions: First, on lateral lengths, I think Tim, you mentioned, both in the Marcellus and the Utica, that your laterals have been shorter thus far year to date than your projection at year-end, so why the shorter laterals so far? And second question on inter-lateral spacing: any down-spacing testing that's either planned for this year, maybe into next year?

MR. DUGAN: On the lateral lengths, it just worked out that the wells we've drilled so far this year have been a little bit shorter; there was one bed that drilled out in the Utica, that the laterals, the units had already been put together, so they were a little shorter, but in the Marcellus, our lateral lengths are getting longer, we're actually doing a lot of work to try and understand what is the optimum lateral length. You know, we've drilled as long as 11,000 feet; we're looking at where there's a break-over point there, but we're very comfortable with 8,000 feet. In our acreage position, the fact that the majority of it is HPP allows us to drill those longer laterals.

MR. JOHNSON: On the inter-lateral spacing, we've proven over time that the old style of frac -- 300-foot stages -- that 750 feet was the best one-size-fits-all for all of our assets from CPA through southwest PA, into northern West Virginia. Now, that changes with RCS. Now, with RCS, what I believe is occurring, we are distributing that frac along the lateral ladder, and we're not reaching as far out, so we think that inter-lateral spacing can shrink down.

We do have two inter-lateral tests planned in southwest PA this year. We're going to do a variety of spacing on the same pads, and then our partner, Noble, has proposed a test in the north wet gas window as well, where it may be more critical in the liquid windows to have the proper spacing. So, we'll be learning a lot from those three tests this year, and adjusting accordingly.

FEMALE VOICE 1: What's the wet inter-lateral spacing test?

MR. JOHNSON: It's in Moundsville, where we're going to do a variety of micro-size, make fiber optics in a well, actually putting some downhole gauges and watching pressures as we produce these wells, so it'll be--

FEMALE VOICE 1: [Interposing] Is it 500 feet? Or 750?

MR. JOHNSON: 750 feet is what our default is, in the wet, right now.

FEMALE VOICE 1: Thank you.

MR. JORGE BERISTAIN: Hi. Jorge Beristain with Deutschebank. My question is, I know it’s early days on the Utica, the dry gas, but could you try to dimension the size of that opportunity in terms of rough value, because you've said you have maybe 600,000 perspective acres, so larger than what you have in the Marcellus, and any kind of potential costs, roughly, to develop these wells. Would they cost the same or more expensive than what you do right now at the Marcellus, and then, what the op ex would be given that they're deeper. If you just kind of have a relative order of magnitude.

MR. DUGAN: I think it's early days to probably put a value on it. We're in the middle of cataloging it. We have opportunities either to potentially JV with some of our existing partners, or do it 100% ourselves, so, I'd just refrain from giving a value today. We probably need to do some testing, and watch some of the activity and see how it plays out before we put--ascribe some value.

MODERATOR: I think we're going to have time for one last question, if we could. Go ahead, Paul.

MR. PAUL FORWARD: It's Paul Forward, with Stifel. I just want to get back to the question on -- are you targeting 5-10% unit cost productions in gas over the next three years; just wondering if you can talk about -- I mean, considering the volume uplift, you might be able to do better than 10%, if things go right. I was just wondering if you can talk about what might get you beyond a 10% improvement in unit cost in gas, as you go through this volume surge?

MR. BROCK: There will be opportunities to improve upon that. We're going to watch and see how the wells flow, and how it takes our cost [unintelligible] down. Tim is working on some of the things on our conventional [unintelligible] gas that can take it down as well, as well as our CVM.

So, a lot of focus in the near term has been growing that Marcellus and just having the mix shift itself will take down the unit cost. And then, the secondary things that Tim will be working on in these others areas also, because some of these areas are higher cost, and just tweaking the production just a little bit will take those unit costs down further.

MODERATOR: Okay, I do see one more hand, there. We'll make that one the final question. Go ahead, Josh.

JOSH DONFELD: Great presentation, guys. I have kind of a philosophical question for you guys. This is a very, very asset-rich company. How do investors get comfortable with management's desire and aggressiveness in making sure that the value beyond the producing coal assets, and the asset sales that you laid out, and the gas assets will be realized in an expeditious fashion? People threw out some ideas, like coal MLP, coal royalties, other kinds of royalties from your timber assets; can you talk about how aggressive you plan to be with these other ideas?

MR. KHANI: I think there's two thoughts when you were asking your question that came to mind. One, is getting comfortable that we're going to pursue these with the zest that you want to see, based on what our prior, and our recent prior actions have been. So, when we see opportunities, whether they're structural or sale-related, or monetization-related, or some hybrid of that, we've got a track record now, over the past 2-3 years, where we've taken those and pursued those.

A lot of those were what I'll call planned or, process-driven, whether it was something that we drove, process-wise, or a third party did, and others were very opportunistic, where we saw the opportunity, and we wanted to go through that window to take advantage of the opportunity itself. So, we got a track record, not just on the non-core monetization, but on much larger structural deals that, basically, some give you some comfort that we're going to continue on that track. The other side of it is looking at the opportunity and optionality that exists within the asset base beyond what I'll call core Marcellus, core Utica, and those two coal complexes.

A day like today, with the transparency that's created in laying that out, along with the track record and a willingness to consider these different options that will drive the NAV per share. There's going to be feedback from others, third parties, our banking advisors and friends, where they see maybe a window of opportunity that we won't necessarily see today. And, I think that feedback loop, and the feedback that comes out of this day, today, is going to provide some opportunities as well.

Whether that changes the list that Steve Johnson presented, whether that changes the number in terms of the number that we monetize, or the way that we do that, time will tell. Philosophically, we're there; we see the opportunity that lays in front of us with that area of our business, and I think in terms of the frequency of the number of things to consider, today can only help bring a higher number of opportunities to our feet to consider, versus what we would've had if we didn't do something like today. So, if you've got any good ideas, let myself or Josh know, and we'll jump on it.

MODERATOR: Okay, with that, the final two housekeeping items are, replay: there will be a replay of this broadcast today. It'll take us a day or so to get it up on the website, but there will be a replay available for the next 30 days. And then, secondly, if you missed part of the discussion, or you want to replay it in a different way, we will have a transcript available of the entire meeting by approximately mid-week, next week. So, you can then pursue that at your leisure. We thank everybody for attending. The IR folks will be in the office next week, so any follow-up questions, we'll be happy to take them. Thanks very much for attending.

[Applause]

[END RECORDING]