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The following is a transcript of the SandRidge Energy, Inc. Conference call held on March 1, 2013 to discuss its 2012 fourth quarter and full-year financial and operational results.

Corporate Participants

James D. Bennett Executive Vice President and Chief Financial Officer

Tom L. Ward Chairman and Chief Executive Officer

Matthew K. Grubb President and Chief Operating Officer

Kevin R. White Senior Vice President-Business Development

Other Participants

Neal Dingmann Analyst, SunTrust Robinson Humphrey

Charles A. Meade Analyst, Johnson Rice & Co. LLC

James A. Spicer Analyst, Wells Fargo Securities LLC

Duane M. Grubert Analyst, Susquehanna Financial Group LLP

Jessica S. Lee Analyst, JPMorgan Securities LLC

Brian A. Singer Analyst, Goldman Sachs & Co.

Leon G. Cooperman Founder & Chairman, Omega Advisors, Inc.

Craig K. Shere Analyst, Tuohy Brothers Investment Research, Inc.

Adam Leight Analyst, RBC Capital Markets LLC

Marc T. McCarthy Analyst, Wexford Capital LP

Adam A. Duarte Portfolio Manager, Omega Advisors, Inc.

Richard M. Tullis Analyst, Capital One Southcoast, Inc.

Jeffrey Woolf Robertson Analyst, Barclays Capital, Inc.

Lin Shen Analyst, HITE Hedge Asset Management LLC

Operator: Good day, ladies and gentlemen, and welcome to the Quarter Four 2012 SandRidge Energy Earnings Conference Call. My name is Lisa, and I will be your operator for today. [Operator Instructions] We will conduct a question-and-answer session towards the end of this conference. [Operator Instructions] As a reminder, this call is being recorded for replay purposes.

I would like to turn the call over to Mr. James Bennett, Chief Financial Officer. Please proceed, sir.

James D. Bennett, Executive Vice President and Chief Financial Officer

Thank you, Lisa. Welcome, everyone, and thank you for joining us on our Fourth Quarter and Full Year 2012 Earnings Call. This is James Bennett, Chief Financial Officer, and with me today, are Tom Ward, Chairman and Chief Executive Officer; Matt Grubb, President and Chief Operating Officer; and Kevin White, Senior Vice President of Business Development.

Keep in mind, that today s call will contain forward-looking statements and assumptions, which are subject to risks and uncertainties and actual results may differ materially from those projected in these forward-looking statements. Additionally, we will make reference to adjusted net income, adjusted EBITDA and other non-GAAP financial measures. A reconciliation of any non-GAAP measures we discuss, can be found in our earnings release and on our website.

Please note, that today s call is intended to discuss SandRidge Energy and not our public royalty trusts. Finally, earlier this morning, we filed our Form 10-K, where you could find additional disclosures and information.

Now, let me turn the call over to Tom Ward.

Tom L. Ward, Chairman and Chief Executive Officer

Thank you, James. Welcome to our fourth quarter earnings and operational update. We have now surpassed consensus estimates for our earnings per share in each of our last four quarters and EBITDA in production in three of the last four quarters, including the fourth quarter of 2012.

The Mississippian play continues to have strong production growth coupled with lower cost, which is driving the better-than-anticipated results. We grew our Mississippian production to 35,900 BOE per day in the fourth quarter, which is a 19% quarter-over-quarter increase and up from 15,500 BOE per day a year ago.

We drilled 10 wells in the fourth quarter, with 30-day production average about 800 barrels of oil equivalent per day. These wells were located in Alfalfa, Grant, and Woods counties, Oklahoma. Of these 10, five were above 1,000 BOE barrels of oil equivalent per day and our best well was above 1,500 barrels of oil equivalent per day for the 30-day average.

These 10 wells produced an average of 68% oil. We did not break out the liquid stream until after the start of 2013. We ve also announced the closing of our Permian sale, which has us in the strongest financial position in the company s history, plus the Gulf of Mexico continues to perform above our projections.

As we enter 2013, SandRidge has two key goals, spending at or below our CapEx guidance and meeting our production guidance. These goals are aligned with our core focus to drive rates of return higher in the Mississippian, which we will achieve through improving the average production of new wells, leveraging our infrastructure and continuing to reduce both operating and capital costs.

2013 is a pivotal year for SandRidge. We have a strong cash position and our net debt to EBITDA ratio is approximately two times. This strong liquidity will let us sharply focus on delivering superior rates of return from the Mississippian play.

We have grown our production in the Miss to nearly 36,000 barrels of oil equivalent per day, from a standing start in 2010, with an average of only 15 rigs. Our growth will continue, as we ramp-up to ultimate rig count of 36 rigs by the end of 2013. Our drilling efficiencies have allowed us to reduce the ultimate rig count from 45 rigs that we d previously projected.

In 2012, we spent extensively on our infrastructure system, which provides significant competitive and economic advantages to SandRidge in the Mississippian. Because of the infrastructure development, we are optimizing our system utilization and will drill 80% of our wells this year within our existing system. By doing so, we ll be able to control infrastructure CapEx and grow our production with development wells.

The saltwater disposal system we have built can handle 1.6 million barrels per day of saltwater and we are currently injecting approximately 700,000 barrels of water per day, all of which is produced only from SandRidge operated wells. Effectively disposing produced water in the Mississippian is critical to controlling expenses.

By developing our own disposal infrastructure, we re able to save over $2 per barrel of water, relative to trucking those water volumes. We ve been focused on eliminating our dependence on trucked water and now, we re able to exit the year, trucking less than 1% of our produced water volumes, resulting in considerable LOE savings.

We ve invested over $450 million in the system. As James will discuss, we believe there s a strong market demand for water disposal assets and we are currently evaluating the merits of monetizing our system.

The savings we realized from our efforts to develop and optimize our infrastructure, coupled with the lowest per well drilling and completion cost and lease operating expenses in the industry, is a primary reason that our Mississippian economics are so good and why we ve been able to secure excellent partners to share in those benefits for many years to come.

Access to affordable electricity is also critical in the Mississippian, given the high power demand to run electrical submersible pumps. We have worked to reduce our dependence on diesel generators by tapping into the local power grid. We re able to access power from the grid by constructing our own distribution lines and substations.

We began 2012 with approximately 35% of our wells using power from generators. We successfully reduced that ratio to 13% by year end. Electricity from the grid results in up to $100,000 of savings per well per month, compared to running diesel generators.

We choose to implement electrical submersible comps, because of the increased rates of return they achieve by producing approximately three times the fluid that a gasless system can. In the first 77 wells with over 30 days of production, we ve increased the rate of return up to 86% per well using a $3.1 million well cost.

We anticipate drilling wells for $3 million, or below, in 2013, which would move these rates of return up to 95%. Our company s clear strategy has always been focused on rates of return versus ultimate production numbers. That s the reason we deliberately chose the Mississippian formation and projected our EURs of 300 MBoe to 500 MBoe in 2009.

We knew we were in an active oil system that can be improved by finding more oil and by spending less money to enhance rates of return. These are the two ways to drive rates of return higher. Every day, we focus on both. In November of 2012, we shifted our type curve to an average of 422 MBoe per well, which is down from 456 MBoe that we used earlier in 2012.

The change in November that we made internally, did have an effect on the oil in the front of the curve where rates of return do matter and we adjusted the rate of return down by about 20 points at that time. The discussion today around whether we find 369 MBoe or 422 MBoe has very little effect to the rate of return, because this changes at the end of the life of the well.

It s important to note that 90% of the rate of return of a Miss well is recovered in the first five years. In fact, we now have increased our projected rate of return per well since our November guidance, by lowering well cost and improving our natural gas contract. As you see by our increased Mississippian guidance for 2013, we continue to anticipate finding as much, or more, oil and natural gas as we did in November, but we also acknowledge the different opinion on the end of life for the wells.

We ve said from the outset, that we believe we ll find wells in the Mississippian with a range of 300 MBoe to 500 MBoe per well. Even though we ve taken down the back of the curve, we remain very comfortable with any outcome in this range. We do take comfort in the historical production of the 17,000 vertical wells that have been drilled in this same formations since 1930, that show the very shallow end of life decline that we have been projecting.

As I mentioned, our rate of return has been revised upward, by cutting the cost of our wells down to a fourth quarter estimate of $3.1 million per well from $3.6 million per well in the first quarter of 2012. We project that we ll move our well costs down to below $3 million by the end of 2013.

We have achieved similar cost trends in the LOE in the play, where optimization of our saltwater disposal and electrical infrastructure, has resulted in a 43% decline in operating costs over the course of 2012. The rate of return will also be enhanced by our new contract with Atlas beginning with new wells in 2013.

This percentage of proceeds contract will move our liquids from the natural gas stream into the liquid stream. Our oil production has stayed at between 43% to 50% since the first wells were brought online in 2010, but now our new production stream is divided into 60% to 70% liquids, depending on which part of the field we drill in. The contract will not change our 2013 guidance, but will start to have an effect in 2014 and beyond.

There have been several tests of new formations in Grant and Garfield counties, Oklahoma. These tests look very promising, with wells producing between 350 BOE to 1,000 BOE a day from the middle Mississippian and the Woodford Shale. These are two new zones that we ve not extensively drilled before. We ve watched these wells for over 200 days and can now project that nearly 350,000 additional acres in Oklahoma can be targeted for multiple pay potential, where we control over 400 sections in areas where the upper Mississippian was not as prospective. Dave Lawler will address this new potentially more this new potential more at our Analyst Day.

Our financial expectation for this year, is to be able to clearly define a funding path through 2015, that will allow us to move our Mississippian well count up to 675 wells beginning in 2014, while maintaining a balance between growth and leverage levels. Clearly, with the Miss performing as it is, we will experience strong production and EBITDA growth over the next two years.

We have several avenues which will clearly allow us to continue this growth in the future, such as monetizing our saltwater disposal system, selling additional units in our royalty trusts and finalizing our last JV on our Kansas acreage. A combination of any of these will give us clarity for funding CapEx all the way through 2015.

We also continue to have a good hedge book. We re now hedged approximately 85% on our projected 2013 oil at $98.29. This represents more than 80% of our projected revenue this year. We also have more than 15 million barrels of oil hedged in 2014 and more than 8 million barrels hedged in 2015, while our natural gas volumes remain unhedged.

We are very pleased to close 2012 so strongly and our management team is even more optimistic about 2013. I ll now turn the call over to Matt.

Matthew K. Grubb, President and Chief Operating Officer

Okay. Thanks, Tom. This morning, I will talk about yearend and fourth quarter production performance, yearend reserves, 2013 capital spending and production guidance, Mississippian drilling and operating costs and the year end type curve and wellhead economics.

I do want to remind everybody, that we will be discussing all these items again and in much more detail, at our Analyst Day presentation next Tuesday. Starting with production, we finished 2012 with 33.6 million barrels of oil equivalent. The production split was 18 million barrels of oil, including NGLs, and 93.5 Bcf of natural gas. That is 54% oil, including NGLs and 46% natural gas.

In the fourth quarter, we produced a record 107,000 barrels of oil equivalent per day, for a total of 9.8 million barrels of oil equivalent, which is nearly 4% higher than the third quarter and the split was about 51% oil, including NGLs and 49% natural gas.

With respect to the Mississippian play, we produced 10.1 million barrels of oil equivalent in 2012, or about 163% more than we did in 2011. The production split was about 45% oil and 55% natural gas. We wrapped up 2012 with an especially strong fourth quarter performance in the Mississippian, averaging about 36,000 barrels of oil equivalent per day. This is a 19% quarter-over-quarter production growth, with running only one more rig in the fourth quarter than we did in the third quarter.

Natural gas liquids accounted for only about 2% of the total liquids production in the Mississippian in 2012. However, with an enhanced percent of proceeds gathering and processing agreement that we recently executed Atlas Pipeline, we will now be able to capture incremental NGL volumes on new wells that come online as of January 1, 2013.

The new contract will certainly help us realize more total liquids, but more importantly, it s an overall value enhancement to the play. This contract covers whole, or parts, of 11 counties in Northern Oklahoma and Southern Kansas, and will impact nearly 90% of the wells drilled in 2013.

Our 2013 estimated capital spending is $1.75 billion. This is about 20% lower than our 2012 capital spending of $2.17 billion and the guidance is consistent with what we had previously stated at our third quarter call last November. About 75% of the 2013 capital budget goes to developing the Mississippian play. This includes our plan to drill and complete 581 horizontal producers, 74 disposal wells with all associated water gathering facilities, electrical infrastructure and leasehold maintenance.

Outside of the Miss play, we are looking at a budget of $200 million in the Gulf of Mexico and $140 million in the Permian royalty trust. The plan in the Gulf of Mexico, is to keep production essentially flat, drilling low-risk development projects and recompletions. It should be noted that our land spending has significantly reduced over the past couple of years. In 2011, we spent about $350 million in land, $190 million in 2012 and we expect to spend about $100 million in 2013.

The 2013 production guidance is 34.3 million barrels of oil equivalent. This is about 16 million barrels of oil, including NGLs and 110 Bcf of natural gas, or 47% total liquids and 53% natural gas. The estimated liquids production in 2013, after the effect of the Permian sale, is 89% oil and 11% natural gas liquids, which is about the same as 2012.

Adjusted for major acquisitions and divestitures, the 2013 production guidance represents a year-over-year total production growth of about 18%. The oil growth, including NGLs, is 22% and 16% growth in natural gas production.

We expect another year of strong production performance from our Mississippian play in 2013. We produced 4.6 million barrels of oil and 33 Bcf of natural gas for a total of 10.1 million barrels of oil equivalent from the Miss in 2012. For 2013, we are projecting 8.2 million barrels of oil, with NGLs at 55.5 Bcf of natural gas, for a total of 17.4 million barrels of oil equivalent. This is a year-over-year production growth projection of 78% for oil and NGLs, 68% for natural gas and 72% increase in total barrels equivalent.

Moving to the year-end reserves, please turn to Page 3 of our slide presentation for the conference call. We ended 2012 with proved reserves of 566 million barrels of oil equivalent and associated total proved PV-10 is $7.5 billion. As compared to year end 2011, this is a 20% increase in reserves volume and 9% increase in reserves value. When adjusted for asset sales and production, reserves growth is 37% and value growth is 43%. Year-over-year oil reserves growth was 35% and 62%, when adjusted for sales and production.

The proved developed drilling funding cost was $21.68 per barrel equivalent and the all-in proved developed funding cost, including leasehold and acquisitions, was $24.02 per barrel equivalent. The proved developed drilling funding cost for the Mississippian was $13.91 per barrel equivalent.

The all-in reserves replacement, including revisions, was 454%. And finally, we had negative revisions of 112 million barrels equivalent, of which 88% of the revisions was due to low natural gas pricing.

I will now talk about the Mississippian well costs, the year end type curve and our expectations for wellhead economics. We continue to be very excited about the Mississippian play, along with the long-term growth opportunity and value that it offers to our shareholders. We have said from the beginning, that this is a low-risk play and one that can consistently deliver EURs in the range of 300,000 barrels equivalent to 500,000 barrels equivalent per well.

We have been executing on our strategy of creating value and steadily improving our cost structure in both CapEx and LOE through our upfront commitment to build an operator-owned water gathering and disposal systems, as well electrical infrastructure and our continuous efforts to reduce drilling and completion cost. The Mississippian is the lowest cost horizontal play of scale and we set a goal early on to drill and complete horizontal Mississippian wells with 4,500-foot laterals in the range of $3 million.

Please turn your attention to Page 4 of the slide presentation. In this slide, you will see a very positive drilling completion cost trend in 2012. We were able to reduce well cost by 14%, from $3.6 million in Q1 to $3.1 million in Q4 of 2012. The $500,000 savings per well, were primarily a result of faster drilling times. As you can see, the spud-to-spud time progression went from 27 days per well to 21 days per well during the year. And all service costs have continued to come down, particularly in the area of hydraulic fracturing.

We now believe that we can get drilling and completion cost to $3 million, or below, by the end of 2013. And we will discuss with you several new cost-savings initiatives underway that we are very excited about at our Analyst Day next Tuesday.

With respect to LOE, please turn to Page 5. Now that we have critical mass of water disposal wells in operation and an expansive network of water-gathering pipelines and electrical infrastructure in place, we are able to realize significant operating cost savings over the past year. Our LOE in the Mississippian was $13.38 per BOE in Q4 of 2011 and we ended the year about 43% lower at $7.65 per barrel equivalent in Q4 of 2012.

LOE savings were driven primarily by reduction in trucked water volumes and the number of wells operating on diesel and generators. Our trucked order volumes peaked at around 8% in Q1 2012 and were reduced to less than 1% as we exited 2012. Also, our producing well to disposal well ratio has steadily increased over the last couple of years, showing continuous improvement in our operating efficiency. At the end of 2011, we were at 3.4 producers to one injector. We exited 2012 at 6.4:1 and we anticipate to exit 2013 at about 8:1. Our goal is 10:1 and we are rapidly progressing in that direction.

Also, contributing to LOE reduction, we had 35% of our wells on diesel generators in January of 2012. As a result of our early commitment to electrical infrastructure, we were able to exit 2012 with less than 10% of our wells on diesel generators. Our goal is to have substantially all wells off of diesel generators by the end of this year.

Next, I will discuss the Mississippian type curve and drilling economics. Our year end type curve, including NGLs, is 369,000 barrels equivalent. This is 167,000 barrels total liquids, of which 107,000 barrels is crude oil and 60,000 barrels are NGLs. Natural gas recovery is expected to be about 1.4 Bcf at the wellhead and about 1.2 Bcf at the tailgate of the plant after shrink.

I should also note, that NGL recovery in the year end model assumes 2012 averages in which the plants we re in ethane rejection mode parts of the year. Assuming full ethane recovery, our

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Mississippian curve would increase by another 27,000 barrels of NGLs to 109 to 194,000 barrels total liquids.

The yearend type curve was developed from a production match of 644 PDP wells and the oldest wells now have about three years of production history. These wells span about 300 I m sorry, these wells span about 230 miles across 12 counties in Oklahoma and Kansas and there is a tremendous amount of value due to scale and magnitude of resource potential in this play.

Now, to elaborate a little more about the November type curve and the year end type curve, please go to Page 6 of the presentation. On our Q3 call last November, we projected an EUR of 155,000 barrels of oil and 1.7 Bcf of natural gas. And at that time, we had not executed our contract with Atlas and so NGLs were not included.

So on Page 6, the red curve is the gas and the green is oil. You can see that the November and year end curve match and projections for both gas and oil are very similar and both are a good fit to the actual oil and gas production data.

First, looking at the type curve of natural gas, we could easily argue that the actual gas production is trending higher than both the November and the year end projections, which give us comfort that we could outperform the gas production forecast.

So now, let s look at the oil curve. While the difference in the ultimate oil recovery between the two curves is 45,000 barrels, keep in mind that this is spread out over a period of about 50 years, or about 2.5 barrels of oil per day. The cumulative difference in oil production in the first five years between the two curves is 9,500 barrels, or about five barrels of oil per day.

However, if you would look at the table at the top of Page 6, now that we are capturing NGLs, the year end type curve is actually 4% higher in the total production in the first year than the November type curve and cumulative production after five years is only a difference of about 5%.

So moving to Page 7 to talk about drilling economics. The most important thing to understand in all of this type curve discussion, is the impact on rates of return. Looking at the table at the top of Page 7, you can see the rate of return sensitivity to well costs for the two curves. Assuming $3.1 million for drilling completion costs, the rate of return is 57% for the November type curve and 50% for the year end type curve.

You can also see in the slide that about 90% of the rate of return is generated in the first five years of production and what happens beyond that has little impact on the economic outcome. This is due to low drilling and completion costs, relatively high IPs and particularly, high liquids production on the front end of the hyperbolic curve.

Also, as we continue to have cost improvements, we may achieve even higher rates of return than we had with the previous type curve. For example, referring back to the table in the upper left of Page 7, at $3.2 million, the November type curve delivers 53% rate of return. At $3 million, the year end type curve deliver 55% rate of return. With that said, cost reduction continues to be our primary focus.

Another opportunity to outperform the type curve and enhance value, comes as a result of our water disposal and electrical infrastructure expansions over the past couple of years. We are now able to accelerate installation of electrical submersible pumps, or ESPs, in our Mississippian wells.

Please turn your attention to Page 8. This graph shows the performance of 77 wells on ESPs that had at least 90 days of production at year end 2012. As you can see, while early, these wells have outperformed the year end curve for oil and gas. Even if we assume no improvements in EURs, but only acceleration of production, you can see the tremendous increase in both rate of return and present value across all cost scenarios. And in 2013, we plan to install 300 ESPs to 350 ESPs.

In summary, even though the type curve has changed in the last couple of years across this very large play, the range of the difference in EURs and economic outcome have not changed our view, or our business plan for long-term growth and value creation around the large Mississippian land position and especially now that we have demonstrated our ability to drive down costs, on both CapEx and LOE.

Finally, let s look at Page 9 of the presentation. As you can see, we have had a remarkable quarter-over-quarter production growth in the Mississippian, dating back to the beginning of 2010. We averaged nearly 28,000 barrels of oil equivalent per day in 2012 and with an exit rate of about 36,000 barrels of equivalent per day in the fourth quarter of 2012. And now, we are expecting another great year in 2013, as indicated by our 72% year-over-year projection growth.

With that, I will now turn the call over to James, to discuss our Q4 and year end financials.

James D. Bennett, Executive Vice President and Chief Financial Officer

Thanks, Matt. As Tom discusses and you can see our press release earlier this week, we closed on the sale of our Permian Basin assets for $2.6 billion in cash. When we announced the Permian divestitures in November, we stated that our intent was to use the proceeds to fund the development of our Mississippian assets and for debt reduction. To meet that goal, this week, we announced the redemption of $1.1 billion of long-term debt. This will leave us with the December 31 pro forma debt balance of $3.2 billion and net debt of $1.5 billion.

With the proceeds from this sale and associated debt reduction, our capitalization, liquidity and leverage levels are the best position in the company s history, which puts in a very favorable spot to execute our Mississippian drilling plan.

Now, turning to the fourth quarter results. This was a strong quarter with continued production growth for our Mississippian play and improvements on the cost side, which led to beating consensus estimates in all categories. Production for the quarter averaged 106,800 barrels of oil equivalent per day, a 4% increase in sequential quarterly production and a 60% increase over the comparable 2011 period. The Mississippian continues to be the driver of this production growth, averaging just under 36,000 BOE per day for the quarter, a 19% sequential increase.

In the quarter, we continued to benefit from our commodity hedge program, realizing $39 million of gains on our oil and natural gas hedges. These gains increased our realized oil price by almost $10 per barrel from $81 $61 to $91 per barrel. The combination of Mississippian production growth, a strong hedge position and improvement in lease operating expenses, raised fourth quarter adjusted EBITDA by 7% to $318 million, up from $297 million in the third quarter.

Full year adjusted EBITDA was approximately $1.1 billion and cash flow from operations was $915 million. Recall, that adjusted EBITDA and adjusted net income excludes certain one-time items, such as unrealized gains and losses on commodity hedges, one-time costs and asset impairments. All of these items are outlined in our non-GAAP reconciliation.

Regarding asset impairments, in the fourth quarter, we wrote off $315 million of intangible assets in gas processing facilities. This noncash write-off consisted of $235 million of goodwill related to the Arena acquisition and $80 million related to our legacy CO2 processing plants in the Pinon Field. Now that the Century Plant is complete, use of these legacy plants to process gas will be minimal. Therefore, we wrote off most of the book value of these assets.

Turning to expenses, LOE continues to trend down, as our operation team focuses on cost reduction and we achieve greater economies of scale in the Mississippian play. In the Mississippian, we ve lowered our LOE to under $8 per BOE, down from over $13 in the fourth quarter of 2011. We ve also seen improvements in our Permian Basin and offshore LOE.

In the fourth quarter, we began to accrue costs associated with the CO2 under-deliveries at the Century Plant. This expense totaled $8.5 million and is reflected in Q4 lease operating expense. For the full year 2013, we estimate this same expense will be between $30 million and $36 million, all of which will be accrued in the fourth quarter LOE and is also included in our 2013 guidance.

G&A expense for the quarter does include $28 million of one-time costs related to legal settlements and consent solicitation expenses. Excluding these one-time items, total G&A was $5.61 per BOE for the quarter and $5.92 for the full year, right in line with our guidance range.

Capital expenditures for the quarter totaled $500 million, down from $560 million in the third quarter, due to a reduction in drilling on our Permian Basin assets, continued ramp-down on our leasehold purchases and further improvements in our Mississippian drilling costs. For 2013, we re projecting CapEx of $1.75 billion, consistent with the 2013 guidance we put out in November.

In terms of major changes from 2012 to 2013 CapEx. First, with the sale of the Permian, our 2013 drilling in West Texas is limited to our Permian royalty trust. Second, a decrease in our land purchases from just under $200 million in 2012 to $100 million in 2013. And third, a decrease in infrastructure spending, as we focus on the development of the play where we have existing infrastructure in place.

On the balance sheet and liquidity. At year end, cash was $300 million. Our $775 million revolver was fully undrawn and we had $4.3 billion in total long-term debt. However, with the closing of Permian sale, let me walk through the yearend balance sheet items pro forma for the impact of the divestiture.

Concurrent with the closing, we initiated the make-whole redemption of our 2016 and 2018 bonds. This will reduce our debt by $1.1 billion and we expect the redemption to close by the end of the first quarter, bringing our pro forma year end debt balance down to $3.2 billion and our net debt balance to $1.5 billion.

At year end, our pro forma adjusted EBITDA, which is pro forma for the impact of the Permian and tertiary divestures and offshore acquisitions, was 400 sorry, $748 million, giving us a net debt-to-EBITDA ratio of two times. In terms of liquidity, after applying $1.1 billion towards debt reduction, our pro forma yearend cash balance is approximately $1.7 billion and liquidity is $2.5 billion.

For our 2013 and 2014 CapEx funding plans, with liquidity of $2.5 billion, we have more than funded the shortfall between our 2013 cash flow and the $1.75 billion CapEx budget. In terms of funding through 2014 and 2015, we have several options at our disposal and we ll be working on these in the coming quarters.

This would include a joint venture on our Kansas-Mississippian acreage, where we have 1.3 million net acres; sale or other monetizations, such as creating an MLP of our saltwater disposal midstream business and the potential sale of 650 million of royalty trust units we hold. Finally, if for some reason these, or other funding options, are not available to us, we always have the ability to reduce our CapEx to be closer to spending within our cash flow.

In terms of monetization of our saltwater disposal business, at year end 2012, we had approximately $400 million invested in this system and that number will increase to $650 million at year end 2013. The system currently has 116 disposal wells, 700 miles of gathering lines and 1.6 million barrels a day of disposal capacity, we believe, making it the largest water disposal system in the country.

Our intent is to spend most of this year building out this system and being in a position to monetize this asset late this year or early next. We believe this is a valuable and strategically positioned midstream asset and we ll evaluate the right path forward to unlock the most value, while also maintaining operational flexibility.

That concludes our prepared remarks. Lisa, please open up the line for questions?

Operator: Thank you. [Operator Instructions] Your first question comes from the line of Neal Dingmann from SunTrust. Please proceed.

<Q Neal Dingmann SunTrust Robinson Humphrey>: Morning, gentlemen. Tom, for either you or Matt, just wondering, you outlined in the press release just looking first at the Gulf then, we ll go to the Miss. Just looking at the Gulf, you mentioned about the number of wells drilled and then, the numerous recompletes you had for the year. I m just wondering in the budget, the number of if you re going to do as many recompletes this year? And just your thoughts for you all, as far as, I know you don t normally break out production in each area, but your thoughts about keeping production rather flat this year in the offshore?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah, Neal, in 2013 keep in mind, that the $200 million budget for the Gulf of Mexico is fungible between drilling recompletions and any kind of small bolt-on acquisitions we may have opportunities to look at. One acquisition we did last year, that was around $40 million, was we bought some assets from Hunt, that actually performed really well and we doubled the production since we bought that and closed that back in June.

So going forward in 2013, we re still maintaining a budget of $200 million and the recompletions will probably be about in the low 20s. We have probably 20, 21 recompletions and we re looking at probably seven or eight wells that we could possibly drill next year and that s to maintain kind of flat production year-over-year.

<Q Neal Dingmann SunTrust Robinson Humphrey>: Okay. And then obviously, just turning over the Miss. Obviously, there s a lot of concern that and you addressed on the type curve, just the difference in the earlier and further out. Again, remind us, how often will this be updated? I guess, remind me, number one, how many wells is this based on? And then, number two, would we kind of incorporate that second slide that shows the ESPs? How long do you keep these ESPs on? And again, how will that play, or if it will play in the type curve?

<A Matt Grubb SandRidge Energy, Inc.>: Yes. So we, in our slide presentation on Page 6, it gives you a pretty good visual of the type curve from both gas and oil. And so you can see in this type curve, that is very similar in the two curves. But because these wells are such long life, they do produce a large delta, particularly in oil, where we re talking about 45,000 barrels spread out over 50 years. It s only a few barrels a day and doesn t really impact rate of return.

But as far as the type curve, we typically don t put out a new type curve until the end of the year. So we won t expect to see another type curve here until the end of this year. But I think the good thing is, that this type curve now has developed over a well base of 644 data points and some of these wells are now going on three years old. So I think this, we feel pretty good about the type curve being in the range that we re showing here.

<Q Neal Dingmann SunTrust Robinson Humphrey>: Okay. And then lastly, Tom, just strategically, you do obviously have a solid financial position, don t necessarily need to sell acreage. But just your thoughts, Tom, on strategy for the remainder of this year. Do you see yourself shedding any of the horizontal Miss?

<A Tom Ward SandRidge Energy, Inc.>: Sure. And I d also say, that remember the type curve is those 600 wells are scattered over 200 miles and where our goal is always to have a bell curve of production and we want to move the mean of the production to the right. And so in order to as we drill more wells, you drill better wells around the wells that have been drilled. So even though a type curve is out here, we tend to be able to beat the front end of the type curve, because we re drilling better wells as we drill more.

Then our funding plans, now that we have our self basically funded through 2014, so we re looking for ways to fund out through 2015. And we like to keep ourselves about two years in advance, if we re going to be outspending cash flow. So James has mentioned, that we have several ways of funding. One of those is additional sell of acreage around a JV.

Now keep in mind, that acreage in the Mississippian, there s so much acreage at around 20 million acres just in what we have mapped, that acreage itself is not worth very much. So remember, we spent 200 about $200 per acre to put together our acreage position. So why is it that we can get some multiple of that with a JV partner? Well, it requires you to have infrastructure, so if other parties don t have the infrastructure that we have, obviously, that s worth something.

We ve spent $450 million so far. We ll be over $650 million in infrastructure by the end of the year. Drilling costs also matter and if you re going to do a JV, if you re we average about $1.1 million per well less than the average of our peers. Well, we will save over $300 million this year net to SandRidge, just from the average of our peers in drilling wells. So it whenever you re selling acreage, you re really not selling acreage, you re selling an enterprise. You re selling the ability for a joint venture partner to come and work with us for decades. And that s what is worth it gets priced into price per acre. But that s how come you can have different amounts from different players in this particular play. And remember, it is a niche play, where infrastructure and costs are very, very important.

<Q Neal Dingmann SunTrust Robinson Humphrey>: Thank you, all. Great quarter,

<A Tom Ward SandRidge Energy, Inc.>: Thanks.

Operator: Thank you. The next question comes from the line of Charles Meade from Johnson Rice. Please proceed.

<Q Charles Meade Johnson Rice & Co. LLC>: Morning, gentlemen. Thanks for taking the question. I want to try to drill down a little bit more on the type curve and thanks for giving us the data on what went into it, I believe it was 644 wells, 12 counties, 200 miles. But if I look at your map, it looks to me like that you re oversampled. Versus the way the whole play is going to work out, you re oversampled really in, call it, Woods, Alfalfa and Grant counties. So is there an argument to be made that really the type curve you have is a type curve for those counties, more than a type curve for the play as a whole?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah, look Charles, we when we do a type curve, we put every well we drill in there. And so we re not trying to focus on any kind of sweet spots or local areas. Every well that we drill that we think that came on production is in the type curve. And so you know, yeah, certainly the wells in Alfalfa, Woods and Grant would dominate the type curve, just because we have more wells drilled in those counties and that s where we started the play. Overall, statistically, you can find these type of wells all over the counties we re drilling.

<A Tom Ward SandRidge Energy, Inc.>: I was going to mention one thing on that, Charles, it s Tom. Rodney will be addressing this also on the Analyst Day with the going through the wells we ve drilled. And in each county, we have good wells. So there s a lot of speculation that some one area is not good, other areas are good. But in each of the counties, including Alfalfa County where we have by far the most rigs working today, we drilled some wells that aren t as good as in other counties. Now, we will continue to keep a lot of rigs working there and it s a very good place to drill, but we think we can duplicate that across the play. And Rodney will spend a lot of time going over that at the Analyst Day. Go ahead.

<Q Charles Meade Johnson Rice & Co. LLC>: Got it. And if I could

<A Tom Ward SandRidge Energy, Inc.>: Oh, I m sorry. I interrupted Matt.

<A Matt Grubb SandRidge Energy, Inc.>: No, I think Tom covers it. I was just going to say, you take an area of a township and kind of move this thing around in all these 12 counties that we drill, statistically, you re going to probably see a similar type curve. So all I m saying, is that this curve, I think, is representative of the areas we re drilling.

<Q Charles Meade Johnson Rice & Co. LLC>: Right, right. So it s just yeah, it s exactly representative of what you drilled and I guess it s not representative of where you haven t drilled but and following on, on this theme...

<A Matt Grubb SandRidge Energy, Inc.>: Well, what I m saying is, it s representative in a large area of 12 counties. If you drill enough wells in any of those pick an area in those 12 counties and drill. You would expect this kind of outcome.

<Q Charles Meade Johnson Rice & Co. LLC>: Got it. And then, onto the same theme for the ESP type curves or the ESP wells or the wells you ve put on ESPs. Are those in any one particular geography? Did you guys pick, for example, just Alfalfa to do those, or is that really a fair sampling across all the wells you ve drilled so far?

<A Tom Ward SandRidge Energy, Inc.>: They re across the play where we can put in electrical systems. So it s more defined about how quickly you can put in an electrical system to get an ESP, rather than one particular spot.

<Q Charles Meade Johnson Rice & Co. LLC>: Got it. And the difference on the gas, is that because of ESP, you don t have to use fuel gas for the compressor, the gas lift? Is that why the gas curve goes higher?

<A Matt Grubb SandRidge Energy, Inc.>: Well, the gas curve, the gas production curve is higher is because you re instantaneously lowering the bottom hole flowing pressure of the wells. But typically, these ESPs are running on either generators or electricity that we generate.

<Q Charles Meade Johnson Rice & Co. LLC>: Got it. And then, the last question and this may be something you want to push off to Analyst Day, but what are the what do you think the prospects are for Tom, I think you alluded to this, to truncating the lowest part of your bell curve? Or translating that what are the prospects for not drilling the low wells, the low productivity wells?

<A Tom Ward SandRidge Energy, Inc.>: Sure. Well, what you see over time with us drilling 600 wells, is that the initial production over time has gotten better, even as we step out. Last year, was really the year that we did more of a step out in 2012 and built out our infrastructure system. And now, we re drilling 80% of our wells as development wells within the infrastructure system, where we do have a lot of data.

So you have your developmental wells. You re only using 20% as extension of wells and spending less because logistics are better, where you re closer to your other wells that you re drilling and you have more data. So you should be able to and what we re seeing is, we re drilling better wells because of that and that s why we beat our production in the fourth quarter and I think that s why we ll continue to do that.

<Q Charles Meade Johnson Rice & Co. LLC>: Okay. I ll let someone else go. I ll hop back in the queue. Thanks.

<A Tom Ward SandRidge Energy, Inc.>: Okay. Thanks.

Operator: Thank you. The next question comes from the line of James Spicer from Wells Fargo. Please proceed.

<Q James Spicer Wells Fargo Securities LLC>: Hi, good morning. Just a couple of questions of clarification first. Can you tell us what the premium is that you re paying to take out the 9.875% and 8% bonds?

<A James Bennett SandRidge Energy, Inc.>: Yes. We re doing a make-whole, so it comes to about $104 and $105 roughly for those bonds, respectively. It s a fee plus $50 make-whole.

<Q James Spicer Wells Fargo Securities LLC>: Okay, great. And what s your borrowing base pro forma for the Permian sale?

<A James Bennett SandRidge Energy, Inc.>: Our borrowing base right now is $775 million. We don t anticipate any change in the borrowing base pro forma for this sale. We have our regularly scheduled spring bank meeting late in March and we believe our revolver will stay the same at $775 million.

<Q James Spicer Wells Fargo Securities LLC>: Okay, great. And then finally, you made the comment that you believe you re fully funded through 2014 currently. I guess first of all, can you just clarify that that you re assuming both a combination of cash on hand, as well as revolver availability there? And I assume you re thinking about a similar CapEx in 2014 to 2013 when you say that?

<A James Bennett SandRidge Energy, Inc.>: Yes. James, it does include about a similar level of CapEx. And we re assuming in there, the cash on hand of $1.7 billion and then $775 million revolver, so about $2.5 billion of liquidity right now.

<Q James Spicer Wells Fargo Securities LLC>: Okay, great. That s all I have. Thank you.

<A James Bennett SandRidge Energy, Inc.>: Thank you.

Operator: Thank you for your question. The next question comes from the line of Duane Grubert from Susquehanna Financial. Please proceed.

<Q Duane Grubert Susquehanna Financial Group LLP>: Yeah, guys, I guess the shock to a lot of people today, is when they look at your type curve on Page 6 there and it goes from 152,000 barrels in November to the 107,000 barrels in yearend 2012. I just want to make sure I understand your communication on this. It seems that you re saying, the change in the type curve is the driver here and the majority of those barrels are in the out years. So I wish you guys would just comment a little bit on how do you get confidence in changing your out-year curve to that degree, when no well is older than, say, three years so far?

<A Tom Ward SandRidge Energy, Inc.>: Well, I ll start and then Matt can listen and add to this. Duane, we have personally, I believe that we re being very conservative, because we have 17,000 vertical wells that have produced very flat rates for decades and it s the same rock that we re producing in. So I think that we ve adjusted down at the end of the life of the well accordingly, to being a conservative estimate, but it really doesn t have much of an effect on the front life of the well. In November, that did have an effect on the front life of the well and it changed the rate of return, but it s hard for me to argue what happens out 20-years plus.

All s I can look to, is the producing wells that have produced vertically and I believe that these wells will follow suit. But it really doesn t have much of a difference, as to whether you would choose to drill a well or not based on this outcome.

<Q Duane Grubert Susquehanna Financial Group LLP>: Okay. And then in passing, you guys mentioned the potential for Woodford drilling in some middle Mississippian. Can that went kind of fast for me. Can you say again, how many wells have been drilled? And what kind of results are other people getting? Are they comparable in economics to Mississippian? Or is this like a totally different ballgame?

<A Tom Ward SandRidge Energy, Inc.>: Well, we only have three and those wells are in Garfield and Grant County, Oklahoma. And they have now enough production history. So we didn t come out after day one, we came out after 200 days of production and said it looks like these wells are comparable to our upper Mississippian wells. And that opens up a new area that we have a lot of acreage. And we ll talk more about that. Dave Lawler, will spend a lot of time on this in the Analyst Day.

<Q Duane Grubert Susquehanna Financial Group LLP>: Okay. And then finally, in terms of how much acreage you have developed, how much of it is held by production now of the total inventory? And what might be I know the original intent was to hold it all like in a five-year plan. Where will we be in a year and maybe in three years?

<A Tom Ward SandRidge Energy, Inc.>: I can say, we re about 15% now. Keep in mind, there is still a tremendous acreage available and the Mississippian acreage is not really the driver for being able to make a decision to drill a well. So the what is important, is having the infrastructure system. And if you noticed in the third quarter of last year, we actually added 50,000 acres within our infrastructure system.

So will we drill maybe every acre that we have up through Western Kansas and through Oklahoma? Probably not. But can we drill within our infrastructure system and have 11,000 locations? Yes.

<Q Duane Grubert Susquehanna Financial Group LLP>: Okay. So I think what I heard you say, is there is a subset of the total that would be material enough to support a very large program, so we should get too hung up on if over time, it doesn t all get developed?

<A Tom Ward SandRidge Energy, Inc.>: That s correct.

<Q Duane Grubert Susquehanna Financial Group LLP>: Okay. Thank you very much.

<A Tom Ward SandRidge Energy, Inc.>: Thank you.

Operator: Thank you. The next question comes from Joe Allman from JPMorgan. Please proceed.

<Q Jessica Lee JPMorgan Securities LLC>: Good morning. This is Jessica Lee for Joe Allman. And just we re trying to get an understanding of the Permian sale. I think you booked your year end 2012 PV-10 proved reserves of $3.2 billion and from our understanding that excludes any value for the unbooked reserves. So could you help us think through the decision to sell the Permian at a price below the proved reserves, PV-10?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah. And you know list typically, when you have a reserves value that includes a lot of PUDs, you typically won t get full value for the PUDs. In this particular case, I think we get really good value for the Permian, based both on a dollars per barrel production per day and a multiple on cash flow. And I think it s one of the strongest sales here in recent time.

And so I think it s when you look at the PV-10 for the Permian, is a PV-10 of a PDP and a PV-10 a PUD and clearly, there should be a little bit more risk on the PUDs that the pre-developing wells. And so anyway you want to slice this, I think it s a very good sale for the company.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, great. And for your Mississippian, going back to Mississippian, in terms of your IRRs of 50% or so. Could you walk us through the assumptions you use for that, including the price differentials assumed for oil, gas, NGLs and LOE and production taxes?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah, you know I can probably spend the next 30 minutes on that. Why don t we take that off line and walk you through the model after the call on how we get to those rate of returns and go through the calculations in detail?

<Q Jessica Lee JPMorgan Securities LLC>: Okay, that works. And moving to the Mississippian drilling and completion costs of $3.1 million you guys assumed for the fourth quarter. Can you actually break the cost down into drilling cost only for the production well, completion cost for the production well and the assumed saltwater disposal cost for the well? And just explain the allocation among the three?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah. The $3.1 million does not include any infrastructure cost. It includes all it s the result of the cost of all wells we drill in the fourth quarter, which probably 20%, 25% of those wells had a submersible pumps on them. Wells that didn t have submersible pumps came in less, probably around $3 million per well.

And so when you model that that s how we model and that s how we get to the 50% rate of return as base on wellhead economics of drilling and completion costs.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, so that does not include the saltwater disposal cost?

<A Matt Grubb SandRidge Energy, Inc.>: No, that does not. And what we typically do, is in terms of saltwater disposal, we think about it in terms of about $200,000 additional per well.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, so including saltwater, it d be around $3.3 million?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah, that s right and I think that the point on the slide in the presentation on costs, is that we re working pretty hard to move that number down. We ve already moved it down from $3.6 million to $3.1 million just in 2012. And so I think in 2013, if we can get that down to $3 million or $2.9 million, then your all-in costs are actually going to be kind of where it is now, about $3.1 million.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, great, that s helpful. And just quickly, on your 2013 production guidance, could you breakdown the NGL production and oil production of the guidance?

<A Matt Grubb SandRidge Energy, Inc.>: Yeah, give me just a second here. So in 2013, we have 34.3 million barrels of oil equivalent in our guidance and the gas is 110 Bcf in natural gas, the oil is 14.1 million barrels and the natural gas liquids is 1.8 million barrels.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, great. And just one last quick question for us, do you have an update on the consent solicitation process? We understand the deadline is coming up March 15, so just any comments around that?

<A Tom Ward SandRidge Energy, Inc.>: No, we don t have anything, other than the initial consent that was delivered to the company. So we re not in a position to speculate on that.

<Q Jessica Lee JPMorgan Securities LLC>: Okay, great. Thank you, that was really helpful. That s it for me.

<A Tom Ward SandRidge Energy, Inc.>: Thank you.

Operator: Thank you. Your next question comes from Brian Singer from Goldman Sachs. Please proceed.

<Q Brian Singer Goldman Sachs & Co.>: Thank you and good morning.

<A Tom Ward SandRidge Energy, Inc.>: Morning.

<Q Brian Singer Goldman Sachs & Co.>: As you think about your financing options that you talked about earlier, just a couple questions on that. The first, is what impact, if any, would selling your saltwater disposal business have on operating cost or price realizations? Or I guess to incentivize a separate saltwater disposal business, what would be the incremental agreement that SandRidge would have to reach to that would impact costs? And then second, what level of interest are you seeing in Kansas properties from the broader market?

<A James Bennett SandRidge Energy, Inc.>: Sure, I ll take the infrastructure question, Brian. If we re to sell or monetize that saltwater disposal system, it would result likely in an increase in LOE, as we would have to pay for third party, for water disposal into that system. That being said, if you run the math on it and assume a water disposal cost per barrel of water of anywhere from $1.50 to $2.50 a barrel, depending on where you are, it s very accretive and NPV positive and enterprise value positive, based on where the valuations for these assets trade. So any increase in LOE would be more than offset by an increase in value and valuation, even proceeds.

<A Tom Ward SandRidge Energy, Inc.>: And Brian, with regard to Kansas acreage, we re not doing any process currently. We think that we re highly likely to there seems to be a tremendous amount of interest in wanting to partner for us for all the reasons I said earlier, mainly to do with lower well costs. And there s a tremendous amount of acreage left to be drilled, in even just the Southern counties of Kansas, even if you didn t look at anything to the North and West. So we are not in, currently in negotiations with anyone. We have tremendous liquidity and would look to do something, any two of the three things that we talked about to fund our self through 2015. So this is one option that we d look at more towards the end of the year.

<Q Brian Singer Goldman Sachs & Co.>: Great, thanks. And then, in the past, you ve indicated you got some decent pricing benefits from Mississippi Lime gas. But looking at your guidance post the Permian sale, your gas differential didn t really widened to $0.45 below from $0.40. Is it right to assume that, that is just spreading contracts like the Century Plant contract payments over, or other agreements, over a smaller base of gas production? And if so, can you just refresh us on those contracts and Century, in particular?

<A Kevin White SandRidge Energy, Inc.>: Yes. Brian, the basis on gas this is Kevin. The basis on gas widening is really a result of the new Atlas contract. So the pricing that we ll get for the dry gas there is not going to be premium priced gas like it was in the past. So that s the primary mover for that basis differential.

<Q Brian Singer Goldman Sachs & Co.>: Got it. And can you just give us a refresher on the Century contract? I think in the 10-K, it was saying it was $30 million to $36 million?

<A Kevin White SandRidge Energy, Inc.>: Yeah. That s right.

<Q Brian Singer Goldman Sachs & Co.>: Is that something that just goes on in perpetuity? Or are there any is there any option or move to try to come to any kind of resolution to get that off the books?

<A Kevin White SandRidge Energy, Inc.>: Yeah. We ve got that number baked into our LOE guidance for 2013, as we re not drilling in the Pinon Field any longer. As that production declines, we would expect a gradual increase in that under-delivery payment.

<A Matt Grubb SandRidge Energy, Inc.>: And then, the resolution would be at some point, to find a logical buyer for those properties.

<Q Brian Singer Goldman Sachs & Co.>: Thank you.

<A Matt Grubb SandRidge Energy, Inc.>: Thank you.

Operator: Thank you. Your next question comes from Leon Cooperman from Omega Advisors. Please proceed.

<Q Leon Cooperman Omega Advisors, Inc.>: Thank you. Let me first declare myself. I m not an energy specialist, but I have two that work with me. And I m listening carefully to the call and I find a little confusing. The gentleman a few comments ago said, great quarter. Most everything you say is positive. Stock is down about 8% this morning and we re hovering near historic lows. So and TPG alleges the value of the business is somewhere between $11 and $12 a share, yet we re selling at slightly under half that value.

So I pose three questions. In your view, why? What is The Street missing? Do you have your own view of value of the business? And fourth, what are you going to do to get there? Any help you could be would be very much appreciated. Thank you.

<A Tom Ward SandRidge Energy, Inc.>: Sure. We believe that we do have value. We believe the Mississippian play is an extraordinary asset, as are TPG-Axon does also. And why are we here? Could be that and I can t I m not positive of why we re here, but one theory might be, that we in 2009 had to make a fairly dramatic move with the company. And that did require us to work in orthodox way to get to the point that we have the liquidity we have today and people sometimes like more orthodoxy. And so but I think we can all agree, at least, the people that are visiting about this, can agree that we have a much higher NAV and a better company that we re being valued today.

So we re in agreement with that. And how we re going to get there, is that the last four quarters, we beat consensus. We think the next four quarters, we ll do the same thing. And if we continue to have excellent rates of return out of an incredibly good play, that our value in the company will be recognized and that s the only things I know to say to that.

<Q Leon Cooperman Omega Advisors, Inc.>: Thank you.

Operator: Thank you. The next question comes from Craig Shere. Please proceed.

<Q Craig Shere Tuohy Brothers Investment Research, Inc.>: Morning, guys. Looking forward to the Analyst Day next week. A couple of questions. Were any of the 40 Kansas Miss wells drilled in the extension area beyond just north of the Oklahoma border? And if so, can you discuss some of those results.

<A Tom Ward SandRidge Energy, Inc.>: Sure. We ve had some encouraging results in all areas, including what we used to call the extension, now we just refer to Kansas. But we I would ask you just to wait a couple of days and we ll go through all the counties, including those that you re referring to and what we re finding in each one. There are good results all the way across the play so far.

<Q Craig Shere Tuohy Brothers Investment Research, Inc.>: And how reputable is the reduced well cost, since you re drilling more within existing infrastructure, but your total acreage is vastly exceeds infrastructure? This is picking up off of, I believe, Duane s question about HBP issues. But can you roughly quantify if you re going to have some core drilling, even if it s many, many, many thousands of drill sites, what portion of your acreage that might encompass?

<A Tom Ward SandRidge Energy, Inc.>: Sure. From today, we ve only drilled the Finney County, Kansas. We do have infrastructure across the southern tier of Kansas, up into Ford County and across Oklahoma. That would give us, inside of that infrastructure area, would be enough wells to have us for many, many years of drilling ahead of us. And so I don t know what happens in other parts of Kansas, we re in Oklahoma where we don t have infrastructure, but we do believe that we have the capability to add inexpensive acreage inside of our infrastructure if we didn t drill everything outside the infrastructure. So to answer you, yes, we do high grade in areas that are going doing very well. And I think on Tuesday, you ll notice where our rig count is, is around the better wells that we re drilling.

<Q Craig Shere Tuohy Brothers Investment Research, Inc.>: And on Tuesday, would you be updating any expectations for absolute free cash flow breakeven after all growth CapEx?

<A James Bennett SandRidge Energy, Inc.>: Yes, we ll provide a reconciliation from EBITDA all the way to cash flow and then, the sources to fund between that and the $1.75 billion of CapEx for 2013.

<Q Craig Shere Tuohy Brothers Investment Research, Inc.>: I m sorry, I meant from operating cash flows, in terms of getting your arms around this vast opportunity over the years?

<A James Bennett SandRidge Energy, Inc.>: I don t think we ll be going through, Craig, guidance past 2013. I think we said publicly, that we ll try to keep CapEx around this level and we have $2.5 billion of liquidity right now and we have several options that we re looking at to fund through 2015. So sitting here, February March of 2013, we think we ve got a lot of the next few years mapped out.

<Q Craig Shere Tuohy Brothers Investment Research, Inc.>: Okay and last question, I think this picks up off Neal s question. We had some nice Mississippian mega well performance juice in second quarter 2012 and now fourth quarter 2012, we saw higher midcontinent liquids growth in fourth quarter 2013, then gas volumes a nice change