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QEP - Q2 2012 QEP Resources, Inc. Earnings Conference Call

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OVERVIEW:

QEP reported 2Q12 net loss of $1m.

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OVERVIEW

QEP reported 2Q12 net loss of $1m.

FINANCIAL DATA

A. **2Q12 net loss = $1m.**

B. **2Q12 EBITDA = $338.5m.**

C. **1H12 CapEx (accrual basis) = $731m.**

D. **2Q12-end total assets = $7.6b.**

E. **2Q12-end total debt = $1.87b.**

F. **2Q12-end cash = $146m.**

PRESENTATION SUMMARY

I. 2Q12 FINANCIALS (R.D.)

A. **Management Update:**
   1. Greg Bensen, joined Co. three months ago as part of IR team.
   2. Scott Gutberlet has been promoted to VP of Commercial and Technical Services.

B. Highlights:
1. Production 79.6 Bcfe.
   a. 20% was composed of crude oil and natural gas liquids.
2. Updated operating activities in core areas.
3. Updated 2012 guidance:
   a. Lowered top end of EBITDA slightly to be $1.35-1.4b, reflecting weaker crude oil and NGL prices.
   b. Production 305-310 Bcfe.
   c. Raised bottom end of CapEx to be $1.45-1.5b.

C. Financial Results:
1. In 1Q12, elected to discontinue hedge accounting.
   a. Entire change in mark-to-market value of driven portfolio runs through income statement instead of through other comprehensive income.
2. Settled derivative impact:
   a. No longer included in revenue section of income statement.
   b. Reported below operating income line.
3. NGL revenues from midstream business together with NGL revenues from E&P business.
4. In 4Q11, changed presentation of transportation expenses.
   a. Historically, netted transportation expenses against revenues.
   b. Now reporting these expenses in separate line item in OpEx section of income statement.
   c. Recast historical revenue and product price data to reflect change in presentation.

D. Results Vs. 1Q12:
1. Slightly stronger financial performance in QEP Energy, Co.'s E&P business.
2. Somewhat weaker financial performance in QEP Field Services, Co.'s gathering and processing business.
3. QEP Energy reported 7% higher equipment production, which included sequentially higher crude oil and NGL production.
   a. Production increase offset by 6% decrease in QtoQ net realized equivalent prices.
4. Field Services results were lower primarily due to lower:
   a. NGL volumes.
   b. Prices.

E. EBITDA:
1. $338.5m.
   a. Down $7m or 2% than 1Q12.
   b. Up $2m from 2Q11.
2. Aggregate contribution:
   a. QEP Energy $266m or 79%.
   b. QEP Field Services $72m or about 21%.
3. Vs. 1Q12:
   a. QEP Energy up about $5m.
   b. Field Services down $13m.
4. Drivers:
   a. QEP Energy production of 79.6 Bcfe.
      i. 7% higher than 74.2 Bcfe in 1Q12.
      ii. 23% higher than 64.7 Bcfe in 2Q11.
   b. Oil volumes 1.3m barrels, up 7% from 1Q12.
   c. NGL volumes 1.3m barrels, up 6% from 1Q12.
   d. Combined oil and NGL volumes 2.6m barrels.
      i. Doubled 1.3m barrels of combined volumes in 2Q11.

F. QEP Energy:

1. Net realized equivalent price (includes settlement of all commodity derivatives) averaged $5.13 per Mcfe.
   a. 6% lower than $5.47 per Mcfe in 1Q12.
   b. $0.58 per Mcfe lower than $5.71 in 2Q11.
   c. Lower equivalent price reflects field level gas prices that were $2.17 per Mcf or 20% lower than 1Q12.
2. Commodity derivatives portfolio contributed $117m of EBITDA.
   a. 1Q12, $83m.
   b. 2Q11, $37m.
3. Derivatives portfolio added $1.47 per Mcfe to net realized price.
   a. 1Q12, $1.13 per Mcfe.
   b. 2Q11, $0.57 per Mcfe.
4. Combined lease operating, transportation and production tax expenses $117m; up from:
   a. $114m in 1Q12.
   b. $103m in 2Q11.
5. On per unit basis, combined LOE, transportation and production tax expenses were $1.47 per Mcfe.
   a. 1Q12, $1.54 per Mcfe.
   b. 2Q11, $1.58 per Mcfe.

G. **QEP Field Services:**
1. EBITDA $72m, down:
   a. About $13m than 1Q12.
   b. $15m than 2Q11.
2. Processing margin down $12m or 26% in 1Q12 on 8% lower NGL sales volumes and 11% lower realized NGL prices, offset somewhat by shrinkage expense that was sequentially $2m lower.
3. Fee-based processing volumes up 8% from 1Q12.
   a. Flat processing fees.
4. Gathering margin up $3m or 7% on:
   a. 8% higher gas gathering volumes of 1.47m MMBtu per day.
   b. Avg. gathering fee about $0.34 per MMBtu.

H. **Other Metrics:**
1. Net loss $1m, driven by:
   a. $49m impairment of crude properties.
   b. $38m loss on mark-to-market value of derivatives portfolio.
2. Impaired properties were primarily matures higher operating cost for gas properties in western Midcontinent region that were impacted by lower crude oil , NGL and natural gas prices.
3. In beginning of year, Co. discontinued these hedge accounting.
   a. Change of mark-to-market value of derivatives portfolio runs to income statement as opposed to other comprehensive income.
   b. In spite of $38m unrealized loss, total 1H12 unrealized gain for derivatives portfolio was $90m.
   c. Unrealized gains and losses are non-cash items; adjusted for it in EBITDA calculation.
4. Sequential DD&A expenses $214m.
   a. Up $15m.
5. Interest expense up $3.5m vs. 1Q12 due to new senior notes issued on March 1.

I. **1H12 CapEx:**
1. Accrual basis, $731m.
2. E&P activities $642m.
3. Midstream business $86m.
4. Continues to focus on directing as much capital as possible to higher return crude oil and liquids-rich natural gas plays.

J. **Balance Sheet (2Q12-end):**

1. Total assets $7.6b.
2. Shareholder equity $3.4b.
3. Total debt $1.87b.
4. Cash $146m.
5. Net debt $1.72b.
   a. 1.2 times multiple of trailing 12 months EBITDA.
6. In April, entered into $300m five-year term loan agreement with a group of financial institutions which has substantially same price fee and covenants of $1.5b revolving credit agreement.
   a. Drove entire amount under term loan.
   b. Paid off balance outstanding under revolving credit.
   c. Put cash on balance sheet.
7. Entered $300m of interest rate swaps, which effectively fixes interest rate under term loan at 2.82% for LIBOR term loan as long as applicable margin until term loan stays at 1.75%.

II. 2Q12 OPERATIONAL REVIEW (C.S.)

A. QEP Energy:

1. Record productions 79.6 Bcfe.
   a. Up 23% YoverY.
   b. Up 7% over 1Q12.
2. Continued to make good progress on organically crude oil and NGL production growth.
3. Crude Oil & NGL:
   a. Comprised 20% of total volumes.
   b. Field level sales represented 52% of production revenues.
   c. Production 2.6m barrels vs. little less than 1.3m barrels a year-ago.
      i. Roughly 106% increase.
      ii. Up 7% vs. 1Q12.
   d. Crude oil comprised exactly 50% of total liquids production.
4. Northern Region:
   a. Production up 30% vs. 2Q11, driven by:
      i. 33% increase in Pinedale gas and liquids production.
      ii. 30% increase in Legacy Division production; driven by increased in oil production in Williston Basin and 18% increase in Uinta Basin volumes.
   b. Crude oil and NGL production 1.8m barrels, up152% over 2Q11 and 7% over 1Q12.
      i. YoverY increases were driven by, 93% increase in crude oil production in Legacy Division, primarily from Williston Basin, growing volume of NGL production at Pinedale due to start up of Blacks Fork II cryogenic gas processing plant that came online on middle of last year, and 244% increase in NGL production associated with new fee-based processing arrangement between QEP Energy and QEP Field Services or cryogenic gas processing of portion QEP Energy is growing Uinta Basin volumes; that contract was effective on 05/01/12.
   c. Crude oil comprised 52% of total liquids production.
5. Southern Region:
   a. Production up:
      i. 18% from 2Q11.
      ii. 7% sequentially from 1Q12.
   b. Midcontinent Division production driven by increased liquids-rich production in Cana Shale and Wash plays and increased crude oil production in Marmaton and Tonkawa plays up 14% from year-ago.
   c. Production from Haynesville/Cotton Valley Division was up:
      i. 20% from a year-ago.

- **ii.** 10% sequentially from 1Q12 as Co. turned a few new wells to sales late in 1Q12 on one of its 80 acre space pilot development units.
- **d.** Crude oil and NGL production 777,000 barrels; up:
  - **i.** 43% from 2Q11.
  - **ii.** 5% sequentially from 1Q12.
- **e.** Crude oil comprised 47% of total liquids production.

B. Midstream Field Services Business:

1. Good qtr.
   - **a.** Financial results were hurt by sharp decline in NGL prices coupled with slight increase in natural gas prices, which together negatively impacted keep-whole processing margins.
2. Avg. realized NGL price $0.96 a gallon.
   - **a.** 2Q11, $1.27 per gallon.
   - **b.** 1Q12, $1.07 per gallon.
   - **c.** Biggest component of decline has been drop in avg. price of ethane in Mt. Belvieu; down 51% from avg. price in 2Q11 and 31% from 1Q12.
     - **i.** Ethane price drop is magnified by increase in percentage of ethane and avg. NGL barrel due to start up of Blacks Fork II plant last summer.
3. Ethane comprises roughly 55% of unfractionated raw NGL or Y-grade mix in vs. about 48% in 2Q11.
4. NGL volumes, 41.4m gallons.
   - **a.** Up 14% over 2Q11.
   - **b.** Down about 8% sequentially from 1Q12 due to new fee-based processing arrangement, QEP Field Services entered into QEP Energy in Uinta Basin, which effectively transfer about 3m gallons of NGLs from Field Services to Energy in 2Q.
5. While decline in NGL prices certainly impacted, it is important to note that unfractionated Y-grade NGL product from Rockies plants, all ends up down in Mt. Belvieu which is premium market for NGLs.
   - **a.** Even with recent pull back in prices, processing margins remain positive though they are not nearly positive they were six months ago.
   - **b.** Co. continues to run cryo plants in Rockies in ethane recovery mode.
6. Gathering volumes up 11% YoverY, driven primarily by increased volumes on Blacks Fork, Cotton Valley, Hosston and Haynesville systems down in Northwest Louisiana.

C. Remainder of 2012 Outlook:

1. Continues to make changes in capital allocation in QEP Energy in response to commodity prices and cost pressures.
   - **a.** Allocates 90% of forecasted 2012 capital in QEP Energy to crude oil and liquid-rich natural gas plays.
2. Pinedale:
   - **a.** At Pinedale, continues to refine well design by optimizing subsurface well placement to avoid fracturing affairs.
   - **b.** Able to increase number of fracture stimulation stages, individual fracture stimulation size in total interval that Co. is treating to maximize recovery of reserves.
   - **c.** Results from handful of wells completed with this latest optimization show better initial production rates, similar decline rates to wells that Co. has drilled previously and hence higher ultimate recoveries that have attractive finding and development costs.
   - **d.** Decided to defer completion of few wells in Pinedale into next year to take advantage of Contango in forward in natural gas curve.
   - **e.** In Uinta Basin, Co. is making good progress on Red Wash Lower Mesaverde wet gas play.
     - **i.** Should get another 20 or so wells completed in this play during 2H12 including some additional 10 and 20 acre space pilot wells that help Co. figure out optimum well density and fuel development.
     - **ii.** Based on knowledge and experience from Pinedale, placed aforementioned pilot wells adjacent to some of older wells that are been online for several years in order to accelerate understanding of prudential drainage and frac stimulation interference issues.
   - **f.** Now building first of what will be many Pinedale-style multi-well pads in Uinta Basin.

g. With all focus on shale plays, it is important to note that tight sand plays like those at Red Wash in Pinedale offer excellent economics in many way superior shale plays because culminations are far more concentrated.
h. World class gas field in no small part because of over 1 mile thick stack of discontinuous sands that comprise gross pay interval.
    i. This translates into massive amount of gas per square mile.
i. Lower Mesaverde has all markings of world class asset.
    i. Has staged discontinuous sands and while gross pay interval is not as thick as it is at Pinedale.
    ii. Intervals are shallower so the wells are cheaper to drilling complete.
    iii. Because of richness of Mesaverde gas, well economics are every bit it good and in fact even better than those at Pinedale.
j. Concentration of gas and plays in both of aforementioned assets means there is less wasted motion during drilling completion operations due to more wells from each surface pad locations which means less investment in gathering systems.
    i. All of above translates into lower costs and higher margins.
k. In addition to Mesaverde directed activity, Co. has a drilling rig in Uinta Basin that's focused on drilling horizontal and vertical oil wells that targeting various reservoirs in Green River Formation.

3. Williston Basin, Bakken/Three Forks Play:
    a. Continued to fight high costs and permitting delays are hampering out of progress.
    b. Co. is suffering from high secondary service cost that are things downstream of completed well primarily associated with water handling.
        i. Already solved half of problem by drilling own water source wells to drive down cost of obtaining and trucking water used in fracture stimulations.
    c. On flow back produced water side, wells on west side of Lake Sakakawea are connected to third-party gathering system that gathers water.
        i. This system is not working properly.
        ii. Co. is working diligently with owner to get it fixed.
        iii. Parts of it are undersized to handle ever increasing volume of water that's coming from QEP and other operators' wells in the area.
        iv. Right now, Co. is paying to truck most of flow back water and is costing over $1m per well extra to do so.
        v. Will get this problem fixed.
        vi. There is dangers on relying on third-parties to provide gathering services.
    d. Permitting all reservations has remained a challenge.
        i. Dropped a drilling rig from program mostly because of cost associated with water handling issues, but also because Co. is struggling to get enough drilling permits on reservation to keep ahead of rigs.
        ii. Despite statements from Department of Interior, improved process and reduced permitting backlog Co. has not seen it.
    e. Even with aforementioned challenges, still anticipate completing about 14 new Bakken/Three Forks wells in 2H12.
4. Powder River Basin:
    a. In Eastern Wyoming, pleased with results for first QEP-operated horizontal Sussex oil well which came online with 24 hour peak rate of little over 1,600 barrels equivalent a day.
    b. Has couple more wells in progress in play targeting Sussex.
        i. Has permitting activities underway to permit additional wells to test other deeper targets including Shannon sand, which is look-alike to Sussex and Niobrara and Frontier formation.
    c. Has significant number of additional well locations in various stages of permitting in play.
        i. Majority of them require BLM approval.
        ii. On 08/01/12, yet to see first permit on federal land.
5. Midcontinent Division:
    a. Has number of wells in progress on liquid-rich portion of Cana Shale play, where Co. is focused on drilling up leasehold on 80 acre density.
        i. Most of these wells will not come online until late this year.

6. Granite Wash/Marmaton/Atoka Wash Plays:
   a. Reported number of operated and non-operated well reserves.
      i. All of these horizontal wells are targeting relatively shallow oil and liquids-rich gas horizons.
7. Haynesville Play:
   a. Dropped last rig.
   b. To take advantage of Contango in forward gas curve, selected to defer remaining five drilled in (indiscernible) wells until next year.

D. Other Update:

1. On 07/31/12, provided update on estimated probable and possible reserves and petroleum resource potential on Co.'s extensive leasehold positions.
2. Last time Co. reported estimated probable and possible reserves and resource potential that it put out in connection with spin-off in summer 2010.
   a. Strived to update these estimates earlier the year and tried to do it outside of normal year-end reserve reporting cycle because of amount of workload involved both for Co.'s folks and for Ryder Scott, QEP's reserve evaluator.
3. At 2011-end:
   a. Improved reserves of 3.6 Tcfe.
   b. Estimated probable reserves of 7.7 Tcfe.
   c. Estimated possible reserves 9.5 Tcfe.
   d. Petroleum resource potential, almost 20 Tcfe.
4. There is a lot of high quality future drilling opportunities in portfolio that are economics comprises under $4 of gas and $9 for oil.
5. Field Services:
   a. Plans call for investment of roughly $170m in several major projects and has a number of smaller ones.
   b. Construction is proceeding smoothly on Iron Horse II plant, which is next cryogenic gas processing plant in Uinta Basin in Eastern Utah.
      i. Plant will have inlet capacity of roughly 150m cubic foot a day and expected to be operational by early 2013.
      ii. About half of capacity of this plant is contracted to third-party producer under fee-based processing arrangement.
      iii. Other half will be available to process QEP Energy's growing liquids-rich gas volumes from Red Wash Lower Mesaverde play.
   c. Commenced construction of 10,000 barrel per day expansion on existing 5,000 barrel per day NGL fractionation capacity at Blacks Fork complex in Western Wyoming.
      i. Expanded facility is designed to provide additional options for marketing purity propane, iso and normal butane and gasoline range products to premium value local, regional, national markets.
      ii. Co. can deliver aforementioned product by truck in close by market; doubling rail loading capacity adjacent to plant, so that it can deliver into more distant markets.
      iii. Expects aforementioned new fractionators to be in service toward 2Q13-end.
   d. Has ongoing gathering system construction in well connections activities and continuing work on preliminary design, engineering and procurement activities related to additional new gas processing facilities in Rockies.

E. Summary:

1. Continued to make great progress on organic growth of crude oil and NGL production at QEP Energy by allocating capital, the highest return projects in portfolio.
   a. 90% of capital has being allocated to oil and natural gas, liquids-rich plays.
2. On 07/31/12, reaffirmed production guidance.
   a. Still on track to deliver production stream.
   b. This year will be comprised of at least 20% oil and NGLs.
3. Teams of talented asset managers continues to look for ways to drive down cost and enhance financial performance in upstream and midstream businesses.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions)

Our first question comes from William Butler from Stephens. Your line is open.

William Butler - *Stephens - Analyst*

Good morning.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Hi, William.

William Butler - *Stephens - Analyst*

I was wondering if you guys could provide some color, now that we've gone to zero rigs in the Haynesville, on what the production profile could look like in the second half of the year?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, obviously, William, it will go down. We would expect to start to see declines on the order of maybe sequentially 10% a quarter, starting in the third quarter. Remember, we did put some wells online earlier in the first quarter of this year, so, those wells will continue to hold plateau, but obviously, we can't keep production flat forever with no drilling activity.

William Butler - *Stephens - Analyst*

Right, and the deferrals of the completions, too. So, now that you all ceased all activity there, and just thinking maybe more broadly about the Haynesville, has it gotten to the point like the Barnett where it's almost getting mature, and is that an asset that you all would actually consider selling at this point?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Everything is for sale for the right price. Although intuitively, it doesn't feel like the right time to sell a dry natural gas [asset that's] at the bottom of the cycle, and it's far from mature. In fact, it has a huge amount of both proved reserve and future development potential, William. And we think it's a very high-quality asset. And at gas prices a little north of $4, it becomes an attractive investment opportunity for us in our portfolio. So, at this point, we don't have any plans to sell it.

Richard Doleshek - *QEP Resources Inc - EVP and CFO*

And William, it's got very low operating cost on an LOE and production tax basis; it's about $0.40 per Mcfe. So, on just a pure operating basis, it generates great cash flow, and we don't have really a lot of carrying costs in terms of lease, maintenance, things like that, so we can just keep it in inventory.

William Butler - *Stephens - Analyst*

Okay, yes, I guess I used the word mature; it's all on a relative basis. And then on the Lower Mesa Verde, any idea in terms of 10-acre pilots, what the timing might be on that?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

We'll get the wells drilled in the second half of this year, William, and from what we've seen -- you get some, what I would call instantaneous data as you drill these wells adjacent to wells that have been online. You will see, or you have a good chance of seeing partially depleted sands as you drill, or after we drill, we sometimes run RFTs to get pressure data. So, that will give you some realtime data. But the real proof in the pudding, if you will, is from production performance on the well after it's been online, and you see -- whether or not you see impact from the adjacent closely spaced well. That takes a year or so, frankly, to see fully.

And if you'll note, I can't remember which slide it is, now slide 7 in our presentation, we show red and blue ovals there, and you can see the 10-acre ovals are being held out, and we're basically laying the field development plan out on 10-acre spacing, but we'll start out by drilling the 20-acre spaced wells, and we can come back in and infill with 10 acres as we get enough data to gain confidence on the effective drainage area of these wells. It's just going to take a while, and it's basically the exact same process we went through at Pinedale, where, if you'll recall, we started out basically with a grid of 40-acre wells, and then just kept tightening the grid until now we're at 5 acres -- probably we averaged about 8 acres at Pinedale.

So, the other thing that we look for, and that we will refine as we drill more closely spaced wells, is the exact azimuth of the frac wings off of these wells because at Pinedale now, we're able to predict within a very narrow aperture exactly where these fractures go. And so, we avoid actually physically hitting the offset fracture -- the offset frac wing in the offset well by very carefully placing these wells in the subsurface, and that's data you can't model. You have to get it from realtime experience, and we'll be getting that data as well.

William Butler - *Stephens - Analyst*

Okay. Thank you. And one last question on the Sussex, certainly looks like an encouraging well, two questions there. Assume by your comments, that was on private property? And then, is there any visibility on the timing of BLM permits that you all can talk about?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, it's been frustrating for us. The BLM field office that handles permitting for that area is woefully understaffed. They have a large backlog. They don't even have some of the key people that they need in order to process permits to do on-site inspections and things like that. So, staffing issue; they're aware of it. We are not the only operator who is very actively campaigning to have them address this issue. We hope we'll be able to address it through maybe sharing some personnel from other field offices that aren't as busy, and they're focused on that, William. I can't give you an exact timeline.

The good news is, we still have some additional targets that we can access from private property, including deeper horizons underneath the Sussex that I mentioned in my prepared remarks, the Shannon and the Niobrara and Frontier. So, we have some additional work we can do on private land while we wait for the permit backlog to clear.

William Butler - *Stephens - Analyst*

Okay, what percentage of the acreage there is private versus BLM?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

The vast majority of it is BLM. And I guess what I should point out is that, if there is 1 acre of land in a 640-acre section, you need a BLM APD in order to drill anywhere in that section, even if the actual physical location of the well, the surface location of the well or the subsurface trajectory of the well doesn't touch Federal minerals. You're going to have to have an APD if there's 1 acre in a 640-acre unit.

William Butler - *Stephens - Analyst*

Okay, I appreciate the color. Keep up the good work.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks, William.

Operator

Thank you. Our next question comes from Andrew Coleman from Raymond James. Your line is open.

Andrew Coleman - *Raymond James - Analyst*

Thank you very much for taking my questions, and good morning.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Good morning, Andrew.

Andrew Coleman - *Raymond James - Analyst*

Had a question I guess to delve more into the Haynesville data -- how many wells, or what percentage of your well-count there is still on restricted rate?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Boy, that's a good question. I can't answer it. Let me answer it a different way. We see a plateau -- all of the wells are choked, okay? They're all on a -- they all start out on either roughly a 1,264 choke, and they all exhibit a plateau period. And that plateau period probably averages six months; some a little shorter, some have been plateaued for a year or so. And part of that just depends on exactly where the well was located in our acreage. And when they come off, we just let them decline "normally," so we're not changing the choke size. And so, what you'll see is that the decline post-plateau is 55% or so averaged in the first year.

So, if you go back and sort of go quarter-by-quarter, and I can't do this in my head, but if you go back quarter-by-quarter and just look at the well completions that we've made quarter-to-quarter. And then assume that once those wells come on, if they all came on exactly in the middle of the quarter, that they would stay on a plateau for on average six months. You'll get at the question that I think that you're trying to get me to answer, which I just can't in my head, about how the families of wells end their plateau and start their decline.

Andrew Coleman - *Raymond James - Analyst*

Okay, yes, just trying to get a sense of that, you said 10% per-quarter, and that might be a little -- it could be lower.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

It's going to be hyperbolic, right, so you're going to see a higher decline initially, and then it's going to flatten quarter-to-quarter. I'm just thinking about the next couple of quarters.

Andrew Coleman - *Raymond James - Analyst*

And then I guess next question is -- how much compression do you have in the field, and are you thinking about adding more compression, or would you wait until next year to do that?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

This is the interesting thing, and we talk about this quite a bit when we're on the road comparing and contrasting different shale plays, and I think this is an interesting point that is missed by a lot of people. There is zero horsepower of compression in the Haynesville field, and you compare that, or rather, contrast that with the Marcellus where most of the wells there need compression after the first 60 to 120 days, maybe even sooner, depending on where you are in the play. Our wells -- probably average flowing pressure on our wells is probably 5,000 or 6,000 pounds. Very few of the wells are even close to line pressure yet. So, there's a heck of a lot of reservoir energy to help. And as Richard commented earlier, that's what makes the cash costs so low in this play. And I think people miss that, but it's a very important point.

Andrew Coleman - *Raymond James - Analyst*

Okay, so, even then when they're declining, they are still declining with 5,000 pounds on?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Yes, there's a great slide, if you refer back to our analyst day presentation from November 14 last year, and I don't know if this page number is right, but in our slide number 123, if the book that I happen to have here is the correctly numbered one, but there's a slide that shows the Haynesville well ultimate recoveries and net present values are improved with restricted initial flow rates. And what it shows is, it's two graphs on the same slide, and the bottom one shows flowing pressure versus cumulative gas production. What it does is, it shows you that, in a family of four wells that we put in here -- four QEP wells with almost 3.8 Bcf of cumulative production, those wells were flowing at about 5,000 pounds of pressure. So, at what is effectively the half-life of the well, you still have flowing pressures of five times our gathering system MAOP roughly.

Andrew Coleman - *Raymond James - Analyst*

Okay, so, there's no risk then of wells getting backed out because of pressure.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

No, the only wells that get backed out are non-Haynesville wells. Now, when you move out of the sweet spot, when you move out of the core area, the wells exhibit a completely different behavior. They don't -- the rates decline and flowing pressures decline very rapidly and they hit line pressure very early in their lives. But this is the hallmark of the core of the Haynesville play, and it's a relatively limited footprint when you think about it.

Andrew Coleman - *Raymond James - Analyst*

Okay, I'll throw in two other ones -- would you see the Pinedale declining as well, given deferred completion activity there? And then I guess lastly, if you could opine on perhaps what an exit mix might look like if you say you're going to be at least 20% liquids through the end of the year, how much above that could you get if the gas declines?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Okay, Pinedale doesn't decline, other than we see that seasonal blip down in the wintertime when we intentionally shut down completion activities. And it's all weather-dependent, Andrew, but it starts sometime usually in late November, early December when we basically stop completing wells during the coldest months of the winter, and then we start back up in March or April. This year, we were able to start really early because we didn't have a winter, so Pinedale production volumes will continue to grow.

And as for mix, I think our exit mix will be higher than 20%. It will probably be 23%, 24%, but I don't have an exact number for year-end.

Andrew Coleman - *Raymond James - Analyst*

Okay. Alright, thank you very much. I'll get back in the queue.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks, Andrew.

Operator

Thank you. Our next question comes from Brian Corales from Howard Weil. Your line is open.

Brian Corales - *Howard Weil - Analyst*

Good morning, guys.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Good morning, Brian.

THOMSON REUTERS

Brian Corales - *Howard Weil - Analyst*

Just getting back to the Bakken, Chuck, I think you said in the past, running three to four rigs isn't necessarily optimal in terms of efficiency standpoint. And now that you're dropping a rig, where do you sit with the play? Is it one that -- is it time to get out? Do you need to get bigger, or where does that sit over the next year or two?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

It's a good question. You're right, three rigs is suboptimal. Five or six rigs is probably the right size, so that you get some -- the economies of scale that we like to see. And that would be -- if you think about our Haynesville program when we were running that at full scale, it was about six rigs; same at Pinedale. We continue to look for opportunities to get bigger there, and we've continued to identify some areas where we think we may be able to do that.

If we're unable to do that, it's a valid question, and we obviously look at our assets and constantly evaluate whether they're worth more to us and our shareholders, or to somebody else. And the same answer basically applies that applied to the question on the Haynesville, and that is -- the asset's for sale for the right price. And it's simply a matter of looking at the value of the asset on a PV basis versus an offer that we would receive, and which makes the most sense for us and for our shareholders.

Brian Corales - *Howard Weil - Analyst*

And maybe to expand on that, if you look at your true oil assets, the Powder, which you've talked about permitting may be tough and in western Oklahoma, could we continue to see more capital go to those areas, or are they at levels that you can't expand today?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, there are certainly limitations right now on the Powder. I think those issues get fixed. There's a lot of operators who are all very exercised about the delays and inability to get permits in the Powder. So, that ultimately gets fixed. And there is the ability to accelerate there with additional permits because there are, not only just -- it's not like the Bakken Three Forks where basically you have two reservoirs -- there's a stacked sequence that we can target.

In the Midcontinent, it's going to be a struggle to drive a lot of additional activity there by allocating additional capital. Part of it is just the variability in results, and not wanting to go faster than we can evaluate each well that we drill. So that we don't end up like we ended up earlier in the Granite Wash play, where we had a series of wells being completed back-to-back, and each well just confirmed the bad results from the previous one. So, we need to be careful not to go too fast -- to outrun the data.

The other area that we haven't talked about, where I think there is, longer term, in the next year or two, potential to accelerate oil production, is in the Uinta Basin, as we gather more data on the Green River formation oil reservoirs and distribution of oil in that play. There's a ton of oil in place there that has not been touched by the existing wells that have been drilled in the field, and we know that oil is there. We just don't know where it is exactly. We know it's inside the limits of the field, and so we just need additional subsurface control in order to develop a drilling program to get after it.

Brian Corales - *Howard Weil - Analyst*

Okay, thank you.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks, Brian.

Operator

Thank you. Our next question comes from Hsulin Peng from Robert W. Baird. Your line is open.

Hsulin Peng - *Robert W. Baird - Analyst*

Good morning, everyone. So, my question, want to talk about Bakken. I know you guys mentioned that you're drilling your own water wells. Can you talk about the timing of when you think the water issues could be resolved, such that it can bring down the well cost?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Hsulin, there's a short-term solution. The water supply wells are there, so, that part of the equation has been solved. The challenge is moving the produced water, primarily the flow-back water, which is the high volume part of the life of the well, and we're trucking it right now. There are some intermediate or interim steps that we can do, and we're working with the owner of the water gathering system to do those. And that involves mainly adding additional pumps so that we can shove more water through the system, and that's going to take a quarter or so to get it done.

And then the second step is, we will need -- they will need, and we are helping them with this because they didn't even have a hydraulic model on their water gathering system, so they don't even know how the flow works on it. We're building a hydraulic model on their system, so that we can help them understand how a gathering system works. But we're going to have to -- they are going to have to loop or add additional pipe in parts of their system in order to handle the volumes of water that we are forecasting and the other operators are forecasting in the area. And that will take longer, but the intermediate step is three or four months away.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay, got it. No that sounds good. And then second question is -- can you just give us your outlook on NGL pricing for the next 12 to 18 months?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

I'll give it to you; I'm not sure what it's worth. But on the two parts that matter, ethane and propane -- I'll start with propane. As you know, propane inventories skyrocketed last winter as a result of no heating demand, and so we ended the winter season with a lot of propane in storage. That inventory level has come down in the second quarter, and continues to come down. In addition, there are debottlenecking projects under way to move -- to increase the export capacity of propane from the Mont Belvieu area. So, there's some incremental steps that are being done there. And then there are several new export projects under construction that come on next year.

So, the propane bottleneck and excess supply gets worked off. And you can see that propane prices have turned back up from a low in late May, early June, and are now up significantly from that bottom. And in part, that's a result of -- and this is at Mont Belvieu, and that's as a result of the inventory being worked off.

Ethane -- we've seen ethane bottom and come back up as well. There were obviously some -- there were problems because of the propane storage inventory levels that drove ethane prices down, as well as problems with -- as a result of crackers being offline. Those crackers are back online now, and you're seeing ethane prices back up to around $0.40 or so a gallon at Mont Belvieu from a low that was a good $0.10 or so below that at the bottom back in May, early June.

So, for the rest of the year, I see some strengthening in propane. I think ethane prices will continue to recover some, but it's all about location. And as I mentioned in my prepared remarks, our NGL product all shows up in the Gulf Coast region at Mont Belvieu, and there I think the situation is fundamentally much better than it is at Conway where ethane prices are still negative. The frac spread's still negative. Ethane prices are roughly $0.07 or $0.08 at Conway today, and that's about $1.20 or so in MMBtu's, so the frac spread's quite -- is negative. And, as a result, most of the plants in the Midcontinent region are still running in ethane rejection mode.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay, that's helpful. And my last question, then I'll let someone else ask, is -- can give us your current thoughts on M&A? Any desire to streamline your current portfolio, whether it's addition or subtraction?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Streamline by addition. (laughter) That's a sort of a double entendre. Look, we like our diversified portfolio because we've been able to demonstrate time and again that when we face problems, either permitting problems or well-cost problems or commodity price challenges, that we've been able to allocate capital away from the area which is causing us challenges. And move it to other parts of our portfolio, and continue to deliver profitable growth. And I think that is one of the virtues of a diversified portfolio. And as a result, we continue to look at our core assets, and look for opportunities to get bigger in those areas where we currently have activity, because of the attractiveness of having multiple opportunities and multiple projects in which to invest capital.

We tend to probably be more acquisitive than to be divesting of assets, especially -- you've already heard my comments. I think the timing around divestitures of dry gas assets is absolutely worst time to be selling is in this market. So, it's unlikely you'll see us make any major divestitures. With that being said, we're always looking at our portfolio, and trimming things that we think are more valuable to other people than they are to us, and that effort continues.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay, how about additions potentially. Any area that you would be interested in?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, we continue to look for opportunities to get oilier. We've continued to look at property acquisitions focused on the core oil areas where we are active, both in the Midcontinent and in the Rockies. And we've exposed a lot of bids, and we've made unsolicited offers on a number of properties; we've been unsuccessful to-date. We think we're pricing these offers reasonably, and we'll continue to do so. Ultimately, I think we'll be successful.

Hsulin Peng - *Robert W. Baird - Analyst*

Okay, great. That's it for me, thank you.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks, Hsulin.

Operator

Thank you. Our next question comes from Subash Chandra from Jefferies. Your line is open.

Subash Chandra - *Jefferies - Analyst*

Yes, good morning. Couple of working interest questions. First, in the Pinedale, the dry gas Pinedale operators, probably one of the basins where they're showing very large sequential declines here in Q2. Is your working interest going up materially from non-consents or anything else? And then in the Sussex as well, what do you think your working interest will be on wells in your development program if and when that occurs?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

So, at Pinedale, yes, our working interest has gone up because we've seen other operators who don't benefit -- our partners who don't benefit from the uplift associated with gas processing who clearly have different well economics as a result -- non-consent our wells. So, we've gone from a little over 60% average working interest to a little over 70% average working interest in the wells that we've drilled so far this year, Jay? (multiple speakers) We anticipate to be completed this year.

And I think that's a good thing for our shareholders because in essence, we're acquiring reserves in a very low-cost gas field from them -- from it as a result of those non-consents. And again, it shows the advantage of having a midstream business, and being able to capitalize on the processing margin, which is still positive and still enhances the value of the production streams sufficiently that it makes the wells quite economic.

Your second question on the Powder River Basin, we probably average -- the Sussex play, we probably average 40% to 50% working interest across our acreage. I think we've got about, little under [120,000] net acres in the Sussex, and it's a fragmented -- it's a chunk of acreage, but our interest is not 100% across it. So, we typically in a unit will have anywhere from 40% to 50% interest.

Subash Chandra - *Jefferies - Analyst*

So, it looks like from your non-op activity, and then even your op activity, that there's a lot of interest from other players to participate in these wells and/or explore on their own?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Right.

Subash Chandra - *Jefferies - Analyst*

Could you describe who they are, privates or publics, and do you think that they have the pocketbooks to make it for a while?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Yes, looking -- so, are you specifically focused, Subash, on the Powder?

Subash Chandra - *Jefferies - Analyst*

Yes, specifically on the Sussex wells.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

The primary player, one of the primary players is a private. And then the other players in the immediate vicinity are large publics, so there's a mixture. But some of the recent wells we've drilled -- the largest non-op partner has been a private who appears to be very well funded and very aggressive in the play. In fact, they've -- we borrowed a drilling rig from them to drill these three wells because they're facing the same challenges that we are with permits, so we've been sharing a hot rig, rather than moving one in the play just to drill a handful of wells ourselves.

Subash Chandra - *Jefferies - Analyst*

In Red Wash, you've given us a lot of detail, and maybe I missed this, but what are your current thoughts on continuity? I guess you're still working on the frac orientation question, and what do you think about variance of individual well EURs?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

So, we gave you a pro bit plot or a probability distribution plot back in the analyst meeting last year, and I'll tell you at the outset, this is a statistical play. We see wide variability in EURs from 0.5 a Bcf to over 4 Bcfe per well. It is the result of the geology. There are a series of sands that are stacked, and each well bore samples that sequence, and in some well bores you get a lot of sands and other well bores you get a lower number of sands. The result though is a very robust and economic program that shows an average of about 2.3 Bcfe.

Our CFO likes to just simplify it and say 2, 2 and 2 -- 2 Bcfe, $2 million a well, and 2-million-cubic-feet equivalent of initial production. And that's probably a simplistic but reasonable way to look at it, Subash. And the challenge for us, and the opportunity is to set up on pads, and start doing what I think is our core competence, which is [whole] manufacturing. I don't accept the $2 million well cost. I think we can drill these wells -- drill and complete them for a lot less than that cost, as we move into Pinedale-like development. And that's what excites me because we're at the cusp of doing that. We're building our first pads to start doing that today.

Subash Chandra - *Jefferies - Analyst*

And that variability, you would, in contrast to the Pinedale, would be far greater in that the Pinedale just had a bigger vertical column?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

It's sort of the power of numbers. So, in Pinedale, you have basically 1,100 to 1,200 gross feet of -- I'm sorry, net feet of pay in a 5,500-foot thick gross column. And so, the geologic variability gets smooth because you just have so many more sands that you sample. But we see the same variability in other areas, and in the Mesa Verde and the Uinta Basin where other operators are developing it. And this looks very similar to us, and so, again, I think you have to look at it as a statistical play. You have to think about it in terms of just multiple samples.

And one of the reasons -- people asked us early on -- why don't you have a bunch of rigs out there drilling? We needed to gather the statistical data to be confident that we had the right mean, that we had the right distribution of results, and that it makes sense from a development perspective. The more data we get, the more confident we are that we have a very strong and very robust project economics.

Subash Chandra - *Jefferies - Analyst*

At what price for gas and NGL do you think you're outside the comfort zone on wellhead IRRs?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

In the Mesa Verde play?

Subash Chandra - *Jefferies - Analyst*

Yes.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

I think we have a slide in the back of our IR package that shows that, but it's around a $2 gas price, and we would be -- probably sub-$2 gas price and with a $85 WTI and the current ratios of oil and NGL prices to WTI. So, it withstands a very low gas price.

Subash Chandra - *Jefferies - Analyst*

Okay. I was just curious because I guess you got Devon out there talking about sub-30% ratio NGL to TI, and if you had a view on the NGL component?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Devon is not an operator in the Uinta Basin, so I'm a little confused.

Subash Chandra - *Jefferies - Analyst*

Okay. And then in the Bakken, do you think you get a 10,000-barrel exit rate this year, or is that, given what you discussed, too much to hope for?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

I can't predict it at this point. It really depends on the timing of when we get this water handling system problem solved, and how fast we can get wells completed.

Subash Chandra - *Jefferies - Analyst*

Okay. That's all I have, thank you.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks.

Operator

Thank you. Our next question comes from Brian Velie from Capital One. Your line is open.

Brian Velie - *Capital One - Analyst*

Good morning, everyone.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Hi, Brian.

Brian Velie - *Capital One - Analyst*

Just a quick question in the Pinedale. With the improved completion procedures that you're using, and the uptick that you're seeing in IPs, what would that take the average Bcfe EUR from and to? I'm modeling it at about 4.5 Bcfe right now. Does that bump it to close to 5 Bcfe, and if so, what does that turn your rate of returns into there for the play?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

It's going to be variable, Brian. What we are seeing is that, on the low end, we're getting a couple of -- 0.2 or so of a Bcfe of improvement. And on the high end, it may be 0.7 Bcfe to 1 Bcf of improvement in EURs. And we just don't have enough data yet to confidently put it across the whole field and say it's going to raise the average by X percent. It's just too early to do that.

But there is a definite increase in initial rate; the shape of the type curve, the initial decline and terminal decline seem to be completely consistent with our earlier well results, so there's just basically a bulk shift up in the type curve, which could result in a 10% or 12% increase in the EURs across the field. We just don't know yet.

Brian Velie - *Capital One - Analyst*

Okay. And then, where are your rates of return right now in the Pinedale, maybe pre that improvement or being conservative in figuring that in right now?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Again, they vary from the flanks, sort of low to mid teens, up to well north of 20%, 25% across the crest, and it depends on well EUR. And as you'll remember, there's a distribution of well results across Pinedale with the down dip most or deepest wells on the flanks of the structure having the lowest EURs, and the wells on the crests having the highest EURs. And some of the crestal wells are probably north of 40% returns even at current prices because they are very strong wells.

Brian Velie - *Capital One - Analyst*

Okay, that's helpful. Thank you very much.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thank you.

Operator

Thank you. Our next question comes from Andre Benjamin from Goldman Sachs. Your line is open.

Andre Benjamin - *Goldman Sachs - Analyst*

Good afternoon.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Hi, Andre.

Andre Benjamin - *Goldman Sachs - Analyst*

First question is to follow-up on one of the previous questions asked a little bit more directly -- how are you thinking about the prospectivity of your acreage, and the amount of running room you have in the Texas Panhandle and the various zones, given the increased focus on the Marmaton and Tonkawa, versus less discussion at Granite Wash? How many locations do you think you have in those different zones? And check your prior comments, do those indicate you're kind of effectively writing off the Granite Wash, or is it just being de-prioritized?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Specifically with respect to the Granite Wash, our focus here for the past year, or maybe a little over a year now, has been on the shallowest zones. So, on the Cherokee and shallower sands and the, for lack of a better term, Hogshooter of Missourian, or whatever you want to call this shallowest, most very oily interval, the recent well results suggest that there are a couple or three shallow very oily reservoirs there that appear to be quite economic. They're relatively limited an area like [Stent], so, the total inventory of those oil zone targets in oil zone locations is maybe several dozen. And there's still an open question about exactly how many of those zones will be commercial, because there are various sands within the so-called Hogshooter of Missourian intervals, some of which are relatively thin, and may or may not be commercial. And we're watching a lot of wells being drilled around us, and we'll have a better idea as we see some performance from those wells.

The Marmaton and Tonkawa, we gave, in our IRR materials back at our -- in November at our analyst day, sort of an overview of our inventory in those plays, and it's an evolving view of those reservoirs because we continue to get new wells drilled in the play, and it changes our interpretation of the distribution of targets. So, the key there is going to be just continuing to watch not only our own well results, but that of offset operators as the drilling continues in the play. But the key point on all of these Midcontinent oil reservoirs is that they are not a typical resource play because they are not shales. They are sandstones and carbonates, and they're deposited in a totally different environment, so there's a lot of lateral and vertical variability in the plays.

We have not written off the Granite Wash. We have steered clear of the deeper intervals in the Granite Wash because they're dry gas, so, in the current price environment, as we go through our capital allocation exercise, they don't get any capital. Those targets do not get drilling capital, but they are still there, and they are still viable from a geologic and technical perspective. And they are economic at higher gas prices, but today, they are not getting drilled because they don't meet our -- well, they don't fall inside the window of where we're allocating capital.

Andre Benjamin - *Goldman Sachs - Analyst*

All that's very helpful color. I guess on the Bakken, just want to understand the potential to get back the fourth rig. Was it the same rig that you just added, I believe it was in June or so; do you still have it on the contract, and would it be hard to get it back if, say, oil prices were to rise?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Let me answer them in no particular order. It is a rig that we've had under contract for a very long time, and it was the poorest of the rigs that we had running in the Bakken; we would not want it back. We can pick up rigs in the Williston Basin, interestingly today. There are rigs available in the play, and so, we could pick up a rig tomorrow if we were comfortable that we could deal with the water issues. And I think the water issues right now are driving the cost, and are really a rate-limiting step.

Permitting is a concern. The issues with the permits are, it limits our flexibility, and ability to move rigs to pads where we think we would have less issues with water handling. So, in other words, we have permits, but they're not in the right places to move the rigs today in order to avoid the water handling issues. As we get additional permits, and it gives us additional flexibility, we can add a rig or maybe even two rigs back to this program. But it's going to take us about a quarter to work through these issues and make sure that, if we do add a rig, that we can keep it running.

Andre Benjamin - *Goldman Sachs - Analyst*

One last big-picture question. As you think about the liquids growth potential with your portfolio and balance sheet, what liquids growth rate do you think you'll target over the next couple years? Maybe a little color on the growth contribution from the key plays you're focused on. And then whether you would try to do that spending within cash flow, or whether you'd be more willing to outspend for the sake of higher return growth?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

So, looking at our existing portfolio, the sort of natural growth rate is probably -- we'll be 20% liquids this year, maybe 25% next year. It will cap out somewhere between 30% and 35% of our total volume, just because of the inventory and ability to really drive that growth.

Would we outspend cash flow to drive liquids growth if the plays are economic? Yes. I mean, we're probably not going to outspend two-fold or three-fold to do it, but would we do it within some reason without incurring a ton of additional leverage? Yes, we probably would, if the plays make economic sense, and we're comfortable that they'll continue to make sense.

Andre Benjamin - *Goldman Sachs - Analyst*

Thank you.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks, Andre.

Operator

Thank you. Our next question comes from Dan McSpirit from BMO Capital Markets. Your line is open.

Dan McSpirit - *BMO Capital Markets - Analyst*

Thank you, gentlemen. Good morning.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Hi, Dan.

Dan McSpirit - *BMO Capital Markets - Analyst*

Turning to the balance sheet and the ratio of debt to EBITDA, is that expected to change much here going forward from the sub-1.5 times we calculate today? And then secondly, in the context of an acquisition where debt could be used to help permanently finance a transaction, how far would you stretch that ratio?

Richard Doleshek - *QEP Resources Inc - EVP and CFO*

Dan, it's Richard. I don't think the ratio of debt to EBITD is going to change because we incurred more indebtedness. I think we're going to be at about that same level of debt that we ended the quarter with today, at the end of the year, excluding an acquisition transaction. So, the issue is going to be -- what does the denominator do? So, that we won't increase [debt], we'll still be at about that $1.87 billion through the end of the year, and just how the trailing-12 months quarters roll on versus roll off.

With regard to using what amount of debt as the level of permanent capital for acquisitions, we've worked very hard the first half of this year to get liquid. We're sitting on [$1.65] billion of cash and availability under the revolver, and I think it's probably safe to assume that if we did do an acquisition, you'd see a short-term bump in that ratio. And if it goes north of 1.5 to 2 times, you ought to expect that we would be very active in terms of delevering that -- the balance sheet after a transaction.

Dan McSpirit - *BMO Capital Markets - Analyst*

Got it. And recognizing that you do possess abundant liquidity today, just returning to a statement you made earlier about everything is for sale, I guess in the context of portfolio management here, if you were to monetize assets today, that is, divest those assets today, how would you rank them as most likely to less likely to be divested?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, one of the places, or most obvious sources of liquidity, Dan, would be something around our midstream business because of the inherent multiple advantage of that business. So, a partial monetization through a strategic partnership or formation of an MLP, we've talked about and thought about, and I'm sure if you've listened in on previous calls, we've been asked about those. But one of the things that has basically made us pause and not do it is the obvious question about use of proceeds. If we found an acquisition, and it was of sufficient size that we got outside of our leverage comfort zone that Richard mentioned, which is basically 1.5 times, 1.5, 1.6 times, one obvious source of liquidity would be to proceed with a partial monetization of that business.

But we clearly also like the business, and we want to continue to control it because a good example is this water gathering system where owning and operating your own assets between the wellhead and the point-of-sales, and all of those sort of auxiliary assets that make production possible, is absolutely critical to be in a successful E&P Company. And we think that the model that we have is unique, and it provides shareholders value that other companies just don't have.

Dan McSpirit - *BMO Capital Markets - Analyst*

Got it. Looking at the probable and possible reserve table that you released in a separate press release yesterday after market close, the Haynesville and the Cotton Valley make up a significant percentage of both the probable and possible reserve totals. What percentage of the 2.4 Tcfe of resource potential under that category is economic today at strip pricing, again, recognizing the low, low operating costs in the Haynesville?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

So, the Haynesville -- the probable and possible stuff all falls inside that $4 and $90 window. And then the resource potential is basically everything outside of that. So, in the Haynesville-Cotton Valley division, a lot of the resource potential category is the upside and horizontal Cotton Valley wells, additional what I would call fringe Haynesville. So, the stuff that's up in the extreme northeastern corner of our acreage, where we don't have any reserves booked today. But the biggest piece of it is in the Cotton Valley where we have -- we've drilled a number of horizontal Cotton Valley wells back two years ago, and they're decent wells. They just aren't economic at sub-$4 gas.

Dan McSpirit - *BMO Capital Markets - Analyst*

Okay, got it. And then just to clarify on the statements made earlier about delays and permitting laws on the reservation in the Williston Basin. Can you provide some color, some context on why that is and, again, just to confirm here that this is an issue not unique to QEP?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

It is absolutely an issue not unique to QEP. It is a function of Federal employees, and the foot speed at which they process permit applications compared to the State of North Dakota. So, everything inside the reservation boundaries requires both BIA and BLM involvement to get a permit, and we've seen a growing backlog of permit applications for wells being drilled inside the reservation boundary. I think that, in part, it has been a result of a gross underestimation of the level of activity inside the reservation boundaries. So, the office that issues the permits is understaffed, chronically so.

There was an effort to bring in a group of people from outside of that office, a so-called strike team to help get caught up. And that did help some, but they were only there for a finite period of time, and when they left, the backlog just came right back. And that has not been addressed by the Department of Interior yet, and is something that, again, we're not the only ones who are pounding on the table to try to get attention on it.

And one of the challenges is that the same people that we hire, engineers and specialists that are necessary to issue these permits -- we're competing for the same talent. And the Federal Government really struggles to, A, hire, and then once they hire, retain the specialists that are needed because the industry ends up being our worst enemy and cannibalizing those staff. And it's extremely difficult, as you can imagine, to get people to live in North Dakota. The housing issues just are quite an impediment to hiring people and getting them up there.

One of the approaches has been to, in the past and in other areas, has been for the industry to pay for hosted workers or for consultants to come in to help the field offices process the permits. And that has met with deaf ears; that proposal has met with deaf ears so far. And that's an applicable concept, not only for the Fort Berthold reservation in North Dakota, but also for other areas where we're facing challenges like the Powder River Basin.

Dan McSpirit - *BMO Capital Markets - Analyst*

Got it. Thanks for the comments.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thanks.

Operator

Thank you. Our next question comes from Hubert van der Heijden from Tudor, Pickering Holt. Your line is open.

Hubert van der Heijden - *Tudor, Pickering, Holt - Analyst*

Good morning. Just real quick on the Bakken, could you talk a little bit about how the wells are performing in terms of the learning curve there, and what are you seeing on the drilling and completing cost side, other than the increased costs for the water flow back handling?

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Well, we've provided type curves and sort of a range of well results from our previous communications and in our IR materials. The range, the short laterals are [300,000], 350,000 barrels, and then, if you look at the best wells in the play and in our area, they approach 1 million barrels, and we've seen very strong Three Forks as well as middle Bakken wells. The learning curve, as far as drilling and completion on the drilling side, our drill times have come down. The drilling portion of the well construction costs have actually reduced over time as we've gotten better at drilling our wells and running liner, et cetera. I'll remind you, we are drilling some extra long laterals. Some of our wells have measured depths that approach 23,000 feet, so, we do have a relatively higher well cost as a result of that.

On the completion side, we haven't seen any moderation in pumping services cost, and that has been an area that has continued to drive up the total completed well cost. We have made some progress on completion design optimization around that, but it has not resulted in a reduction in the completion cost.

The biggest single driver in the well cost inflation that we've seen has been this, sort of what I call secondary service costs of handling water. We participate in a lot of wells that are operated by others, and with one glaring exception, one company that has been very good at holding the line on costs, our experience seems to mirror that of other operators that are operating both on the reservation and off the reservation, and that is that well costs have continued to escalate or spiral upward, despite a flattening of rig count and, therefore, completion activity, so our experience hasn't been unique. We've seen other operators, in fact, who have had higher well costs than ours as a result of inefficiencies and continued service cost escalation.

Hubert van der Heijden - *Tudor, Pickering, Holt - Analyst*

Okay, thank you. That's all I had. That was very helpful.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thank you.

Operator

Thank you. I'd now like to turn the conference back to Mr. Stanley for closing remarks.

Chuck Stanley - *QEP Resources Inc - Chairman, President and CEO*

Thank you, Mary. Thanks to everyone for calling in today, and thank you for your interest in QEP. We'll be on the road at various conferences over the next few weeks. We look forward to seeing you soon and, of course, we would welcome you here to our hometown for an upcoming conference in a few weeks. With that, everyone, have a good day.

Operator

Ladies and gentlemen, this concludes today's conference. Thank you for your participation, and have a wonderful day. You may all disconnect.