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National Fuel Gas Company

Third Quarter 2017 Earnings Conference Call

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Graham Price, *Raymond James*

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PRESENTATION

Operator:

Good morning. My name is Leandra (phon) I will be your Conference Operator today. At this time, I would like to welcome everyone to the Q3 2017 National Fuel Gas Company Earnings Conference Call. All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question and answer session. If you would like to ask a question during this time, simply press star, then the number one on your telephone keypad. If you would like to withdraw your question, press the pound key.

Thank you. Mr. Brian Welsch, Director of Investor Relations, you may begin your conference.

Brian Welsch:

Thank you, Leandra, and good morning. We appreciate you joining us on today's conference call for a discussion of last evening's earnings release.

With us on the call from National Fuel Gas Company are Ron Tanski, President and Chief Executive Officer; Dave Bauer, Treasurer and Principal Financial Officer; and John McGinnis, President of Seneca Resources Corporation. At the end of the prepared remarks, we will open the discussion to questions.

The third quarter fiscal 2017 earnings release and August Investor Presentation have been posted on our Investor Relations website. We may refer to these materials during today's call.

We would like to remind you that today's teleconference will contain forward-looking statements. While National Fuel's expectations, beliefs and projections are made in good faith and are believed to have a reasonable basis, actual results may differ materially. These statements speak only as of the date on which they are made, and you may refer to last evening's earnings release for a listing of certain specific risk factors.

National Fuel will be participating in the Barclays Energy Conference next month in New York City. If you plan on attending, please contact me or the conference planners to schedule a meeting with the Management Team.

With that, I'll turn it over to Ron Tanski.

Ronald Tanski:

Thank you, Brian, and good morning, everyone. We're very pleased with our operating performance for the quarter, and as you can see from our earnings guidance, we expect that our fourth quarter results will also be in line with Street expectations. Over the summer so far, field conditions have been excellent for our construction crews undertaking our various upgrade and modernization programs in our pipelines in the Utility segment and Pipeline and Storage segments. It would have been a great construction season for our Northern Access Project also. Unfortunately, it's been the lawyers that have been very busy on that project since April.

Our appeal of the New York Department of Environmental Conservation’s denial is on file in Federal Court in the Second Circuit and we have litigation filed at the New York State Court regarding the denial of the various state permits. If the timing of our litigation is similar to that of Constitution Pipeline’s Second Circuit case, it could be next spring before we get an answer from the court. So as I mentioned last call, this project is on hold and if we have to go the full litigation route, that hold would likely last until 2020. However, with the quorum re-established at the Federal Energy Regulatory Commission as of yesterday, it's possible that FERC could adopt our arguments and our rehearing request and determine that the DEC waive its opportunity to act on our water quality certification by exceeding the timeframes set out in FERC's scheduling order. If that were to happen we could receive a notice to proceed from FERC much earlier.

In the Utility segment, we filed an appeal of the rate order from the New York Public Service Commission. There were a number of issues that we raised. The two primary ones being the low authorized rate of return and the low equity component. So while the lawyers are busy, field operations in both the Pipeline and Storage and Utility segments are moving along quite well and we once again expect that our systems will be in tip top shape when we enter into this year's heating season.

Looking a little farther out, we're seeing continued economic development and expansion in Pennsylvania, and that's driving a couple of our projects that are also moving along on schedule. Our $27.5 million Line D Expansion project designed to move more gas to the Erie, Pennsylvania market area, should be coming online this November, which will add $2 million in annual revenues. We're also planning for a mid 2019 in-service date for our lateral to the Shell Cracker Plant in western Pennsylvania. That $18 million project would add another $3.25 million in annual revenues.

We're also pleased to report that we have precedent agreements in place for our Empire North Expansion Project. Given the commitments that we have, this project will be designed as a 205,000 dekatherm per day expansion of our Empire Pipeline that could be operational around November 2019 or the beginning of our 2020 fiscal year. Our initial capital cost estimates are in the $135 million range, and this project would add approximately $25 million in annual revenues. We're in the process of assembling our FERC application and we'll be making that filing over the next few months. Since this project is all compression with no major pipeline construction, we would expect that the permitting for the project should not run into major roadblocks.

At our Exploration and Production operation, Seneca is transitioning from its Marcellus Development Program to a Utica Development Program. Our initial Utica results in the Western Development Area indicate that per well reserves may be significantly higher than our Marcellus wells and drive better economics. John will get into more detail regarding this transition in a little bit, but overall we expect that our two rig Utica Program can deliver a 10% to 15% compound annual growth rate and production for at least the next three years. This production growth will drive the growth and earnings at both Seneca and our Gathering business over most of the same time period. The only exception to that earnings trajectory is our next fiscal year where we expect earnings to be down slightly. The earnings decrease is the result of a number of higher priced hedge contracts rolling off of Seneca's hedge book. Now this is not a surprise as we have regularly delineated information on all of Seneca's hedges in our earnings releases. Dave will get into more details of next year's earnings drivers later in the call.

I'll wrap up by saying that our core business plan remains intact. We've got great assets and we're continually working to make them better. Seneca continues to develop economic reserves even at today's commodity prices and has been successful at layering in firm sales to match our expected increased production levels. Our pipeline engineers are always looking at ways to expand throughput on our system and expect we'll be able to continue adding small incremental projects, like the Line D expansion I mentioned earlier, and a host of expansions that we've completed through the years along our Line N corridor.

While each individual project is not major, let me remind you that we have invested approximately $500 million in expansion pipeline projects since 2010 that have associated annual incremental revenues of $106 million. Over the same timeframe, we've also invested $510 million in gathering pipelines that have added $110 million in incremental revenues, and that's on top of the $350 million in normal modernization investment in our system over the same period.

Our consolidated outlook for this year and next year is to live within cash flows, increase production and keep our utility customers' annual bill affordable. This past June, we increased our dividend yet again, and we plan to operate the Company to be in a position to consider another increase next year.

Now, John McGinnis will give an update on Seneca's activities.

John McGinnis:

Thanks, Ron, and good morning, everyone. Seneca produced 42.7 net Bcfe during the third quarter, a decrease of 1.3 Bcfe or 3% versus the prior year's third quarter. In Pennsylvania, we produced 38 Bcf for the quarter, a decrease of 1 Bcf or 2% versus the prior year. This decrease in gas production was due mainly to a lower operating interest on new Marcellus wells related to the IOG Joint Development Agreement in the WDA, a one-rig program since March of 2016, a natural decline over the last 12 months in the EDA where the last development pad was brought online over two years ago.

Our operated gas production during this quarter, however, actually increased 5% from the prior year. In May, we added a second rig in Pennsylvania. This rig is currently drilling wells in Lycoming County in preparation for the onset of Atlantic Sunrise. We are currently planning on drilling 17 wells on three pads in this area before moving the rig north to Tioga and begin drilling Utica wells on our DCNR 007 tract. The first Lycoming pad, which consists of seven wells, is scheduled to be online by our second quarter fiscal '18 and first production from our 007 Utica wells should occur early in fiscal '19.

In California, we produced 668,000 barrels of oil during the third quarter, a decrease of 54,000 barrels from our third quarter last year. This increase or decrease was primarily due to changes in our steam operations and a significant reduction in well workover activity beginning last year as a result of low oil prices. Quarter-over-quarter, our oil production was essentially flat and we have recently ramped up our workover activity. As a result, our total LOE increased $1.8 million this quarter or $0.07 per Mcfe on a per unit basis, driven mainly by this increase in workover activity and partially due to increased steam fuel cost. We will see higher LOE through the remainder of the year as we continue to bring on idle wells in

California. In fiscal '18, we expect to see California per unit LOE moderate with production flat to slightly growing.

In terms of guidance for the remainder of this fiscal year, net production will range between 170 to 180 Bcfe, an increase of 2.5 Bcfe at the midpoint. Even though we have had some curtailments recently as a result of reduced spot prices, this midpoint assumes minimal curtailment and is about 8.5% higher than our total net production last year. Our forecasted increase year-over-year was driven primarily by greater spot sales through most of the year, offset by a lower working interest as a result of the IOG Joint Development Agreement. Cap ex should range between $230 million to $250 million LOE between $0.95 and $1. G&A around $0.35. DD&A around $0.65. All on a per unit basis.

Moving to the Utica Point Pleasant appraisal program, we are now producing from five wells in the WDA Clermont/Rich Valley area. Our latest Utica well in this area has now been online for just over two months and is our best well to date from this program. In fact, this well is projected to be the largest shale well we have drilled in the WDA. The projected EUR per thousand foot for this well is over 2 Bcf, and as a result, we are now increasing our Utica type curve in this area to range between 1.6 to 2 Bcf per thousand foot. Three additional WDA Utica wells are scheduled to be online late this calendar year. But unless we are completely surprised, we are now planning to move to full WDA Utica development by the end of our next fiscal year.

Our Utica Development Program will begin on currently producing Marcellus pads in order to leverage our existing upstream and midstream infrastructure to drive capital, operational and marketing efficiencies. The ability to return to producing pads to drill Utica development wells while utilizing existing midstream infrastructure is a tremendous economic advantage for our Company. We now expect to flow anywhere from 2 to 3 times as much gas through our gathering system versus our original estimates, amplifying the returns of our integrated upstream and midstream businesses.

In terms of our fiscal '18 guidance, we are now forecasting higher capital expenditures ranging between $275 million to $325 million. In Pennsylvania, we'll spend between $240 million to $208 million, around $60 million more than we will spend this fiscal year at the midpoint. The key drivers for this increase include utilizing a two-rig program for a full year and drilling and completing a greater number of 100% working interest wells. One rig will focus in the WDA drilling both Marcellus and Utica wells, and other rig will be active in the EDA drilling Marcellus wells on Lycoming and Utica wells in Tioga. We have 12 more Marcellus wells to complete in our IOG Joint Development Agreement and those are currently scheduled to occur during the first half of 2018.

Net production is expected to range between 185 to 200 Bcfe, a forecasted increase of around 10% year-over-year. Our fiscal '18 production forecast, however, assumes no curtailment throughout the year. We currently estimate between 30 to 40 Bcf available for sale into the spot market, so obviously depending on pricing, these volumes are at risk for curtailment. However, with projects like Columbia's Leach XPress and ETP's Rover forecasted to go on service later this fall or early next year, adding almost 5 Bcf per day of new capacity, we expect in-basin pricing will be more attractive and curtailments will be more modest over the last couple of years.

We approach fiscal '18 with 90 Bcf of production locked in physically and financially at a realized price of 2.61 per Mcf. In addition, we have another 46.5 Bcf of production with basis protection through our firm sales portfolio. While realized prices are down somewhat from fiscal 2017, we are very pleased with our position and that these prices generate very economic returns for both our Utica and Marcellus Development Programs.

Looking out three to five-plus years, you will note in our IR presentation published last night that we had been busy securing additional firm sales to support our 10%-plus per annum production growth target. I think we're in great shape to fulfill this commitment with our two-rig program and our marketing portfolio. Finally, in California, we are forecasting production to be around 20 Bcfe. Much of our development activity next year will continue to focus in Midway Sunset, both in our legacy properties and on our new farm-in opportunities at Pioneer and South Midway and 17N in North Midway. California continues to be a great business for us, with stable production, modest growth opportunities and the steady cash flow.

With that, I'll turn it over to Dave.

David Bauer:

Thank you, John. Good morning, everyone. National Fuel's third quarter consolidated earnings were $0.69 per share, an increase of a penny from last year's operating results and right in line with Street consensus. Last night's release does a good job describing the major year-over-year variances, but there are a few items worth noting.

Starting with Seneca, per unit LOE has trended higher in recent quarters. This is solely related to our California operations, where as John said earlier, we increased workover activity and started new steam floods at some of our recent farm-in properties. LOE per unit in Appalachia is flat year-over-year. We expect steaming costs to remain at an elevated level for the next few quarters. Once the formation heats up, steaming expense should moderate which, combined with increased production in the east, should cause our consolidated per unit LOE to return to a more normalized level. DD&A was $0.64 per Mcfe for the quarter, down $0.07 from the prior year, largely as a result of the ceiling test impairments that were recorded throughout fiscal '16 Over time, depending on service cost inflation and the timing of reserve bookings, we expect our long-term DD&A rate will settle in the $0.70 per Mcfe area.

Turning to the regulated businesses, revenue on our Pipeline and Storage segment was down year-over-year for two reasons. First, lower tariff rates were in effect this year as a result of rate case settlements at both Supply Corp. and Empire. As a reminder, Supply's rate case settlement in 2015 had a 2% step-down in tariff rates in November of '15 and again in November of '16. Empire settled a Section 5 rate proceeding last summer that similarly lowered some of its tariff rates, with the first step-down occurring this past October and another again this coming October.

The second driver of lower revenue was a decrease in short-term revenues on our system, which for the most part we had expected. For example, over the past few years, as certain producers have grown into their firm transportation capacity commitments on our system, we've been able to generate a modest amount of additional revenues from secondary transportation services. Today, as we had expected, those producers are now generally using 100% of their capacity which has largely eliminated that incremental revenue opportunity.

In the Utility, in April, the New York Commission issued an order approving a $5.9 million rate increase. Given that we're in the summer months, the rate order did not have a material impact on third quarter earnings.

Looking to the remainder of the year, we're tightening our fiscal '17 earnings guidance to a range of $3.25 to $3.35 per share. The details supporting this range were included in last night's press release and are not materially different from our prior guidance. One thing of note, given the general sustained improvement in spot prices, we're no longer forecasting production curtailments. Our updated fiscal '17 production guidance of 170 to 180 Bcfe assumes about 5 Bcf of spot sales for the fourth quarter.

Turning to fiscal '18, we're initiating preliminary earnings guidance in the range of $2.70 to $3.05 per share. Substantially all of the projected drop in earnings is attributable to the expiration of natural gas and crude oil hedge contracts that had been put in place in a higher commodity price environment. Heading in a positive direction, as John mentioned earlier, Seneca's production for 2018, is expected to be in the range of 185 to 200 Bcfe at the midpoint, a 10% increase over our fiscal '17 expected production. From a NYMEX perspective, we're forecasting $3 per MMBtu for gas and $50 a barrel for oil, and both of these are generally consistent with the forward strip.

We're fairly well hedged heading into the start of the fiscal year with 52% of our gas production hedged and 45% of our oil production hedged. Unfortunately, because of the contracts that rolled off, we're hedged at a lower price. Compared to last year, we expect after hedging natural gas and crude oil prices, will be lower by about 40 Mcf and $4 a barrel, respectively, which will impact earnings by about $0.55 per share. Again, this drop in hedge price is by far the largest driver of next year's earnings change.

As with our fourth quarter guidance, we're no longer forecasting curtailments. At the midpoint, our guidance assumes 30 to 40 Bcf of natural gas spot sales at a price of $2.40 per MMBtu. Spot pricing in Appalachia has moved around a fair amount over the past year and is difficult to forecast, but the $2.40 per MMBtu that we're using is generally in line with our average spot sales during fiscal '17. At the end of the day, variability in spot prices will be a significant driver of earnings volatility. As a frame of reference, a $0.25 difference in spot pricing would impact earnings by about $0.06 per share.

We expect Seneca's unit cost in fiscal '18 will be similar to fiscal '17. As I mentioned before, there is some modest upward pressure on LOE due to increased workover and steaming activity in California. However, due to increased production in the east, we're forecasting LOE per unit to be more or less flat year-over-year. The increased production will likely drive G&A per Mcf a little lower, and depending on service cost inflation and the timing of reserve adds, it's possible DD&A could be a couple of pennies higher, but all-in we don't see much of a year-over-year variance in Seneca's per unit operating cost.

Seneca's increased production guidance of 185 to 200 Bcfe will drive a corresponding 10%-plus growth rate in the Gathering segment revenues. As a result, we expect Gathering revenues for 2018 will be in the range of $115 million to $125 million.

In our Pipeline and Storage segment, we're expecting revenues to be flat year-over-year at about $295 million. The Line D project will add revenues but that'll be offset by the rate settlements that I mentioned earlier and other normal contract activity. Obviously, we planned on Northern Access driving near-term growth in this business, and with its delay our expectations have been tempered. Nevertheless, as we look to 2019 and beyond, our Empire North Project, the further expansion of the Line N system and the continued modernization of our system, should provide long-term growth for the Pipeline business as we continue to work the regulatory challenges for Northern Access.

At the Utility, our guidance reflects a return to normal weather which should add $7 million to $8 million to our margin in Pennsylvania. Recall that unlike New York, Pennsylvania does not have a weather normalization mechanism. Our guidance also reflects the full impact of the $5.9 million rate award mentioned earlier.

Operating expenses including O&M, depreciation and property taxes are expected to increase by about 2% to 3% across our regulated subsidiaries. Several factors are driving this increase. O&M is expected to increase mostly due to higher personnel related cost, including labor, healthcare and retirement benefits. Higher spending on safety and on our Pipeline Integrity Program is also a factor. Property taxes and depreciation expense will increase largely as a result of plant additions over the last couple of years.

Switching gears to capital, complete details are in the earnings release so I'll only hit the high points. Our fiscal '17 forecast is largely unchanged. The small decrease in the midpoint is caused by the timing of spending between fiscal years. For fiscal '18, our initial projection is for spending between $535 million and $645 million, at the midpoint of slightly more than $100 million increase over fiscal '17. John already touched on the increase in Seneca's planned spending, so I'll focus on the other businesses.

Pipeline and Storage spending is expected to be up by about 20%, largely due to an increase in infrastructure or modernization spending. We typically target about $40 million per year in these projects, but the past two years have been well below that level. We're tackling a few larger projects this year which will cause modernization spending to nearly double.

In our Gathering business, we expect capital to be in the range of $60 million to $80 million. This increase is largely driven by Seneca's second rig and various infrastructure additions needed in advance of Seneca's Atlantic Sunrise capacity becoming available.

At the Utility, spending should be consistent with fiscal '17 within a range of $90 million to $100 million.

From a financing perspective, our cash from operations should exceed our capital spending for both fiscal '17 and '18. When you take into consideration our dividend, we expect a modest cash need which will be met from the cash we have on the balance sheet. We have a $300 million debt maturity in April of 2018 and another $250 million in 2019. Both of these issuances carry higher coupon rates, so in the coming months we'll be evaluating our strategy to manage these maturities.

In conclusion, National Fuel's in great shape. At a two-rig program, Seneca should be able to grow production by 10%-plus per year for the next several years, which will drive earnings in both our E&P and Gathering businesses. At the regulated businesses, the delay in Northern Access is certainly disappointing, but the opportunities on the Empire and Line N systems will be sources of future growth. While 2018 earnings will not benefit as much as in prior years from our hedge book, we're very well-positioned to deliver long-term growth and strong returns in the years to come.

With that, I'll close and ask the Operator to open the line for questions.

Operator:

At this time, I would like to remind everyone, in order to ask a question, you can press star, then the number one on your telephone keypad. We'll pause for just a moment to compile the Q&A roster.

Your first question comes from the line of Graham Price with Raymond James. Your line is open.

Graham Price:

Hi. Good morning and thanks for taking my questions. Just wanted to get a sense of timing kind of around the 12 remaining joint development wells. I know that you're targeting first half '18 for those, to complete those, but was just kind of wondering if you think those will be kind of spaced evenly or maybe weighted towards one quarter or another?

John McGinnis:

Yes, absolutely. The timing will probably be more towards the back half of that—by our third fiscal quarter.

Graham Price:

Okay. Thank you, that's helpful. Then just real quick for my follow-up. It looks like you've done a really nice job in filling in those firm sales since the Northern Access delay. But looking at Slide 22, did see that there's a little bit of a dip there right before Atlantic Sunrise comes on. I'm just kind of wondering if you see opportunities to fill in that gap.

John McGinnis:

Yes. Sort of a bit on purpose is where prices have dipped a little bit, so we're—as we get closer to winter months we look for opportunities to layer in additional sales, but we are also waiting to get a bit more visibility related to the turn on date to Atlantic Sunrise and as we begin to see, get more information about when that's actually to come on it'll give us a better perspective in terms of how we want to fill in those gaps.

Graham Price:

Okay. Okay, thank you. That makes a lot of sense. That's it for me. Thanks.

John McGinnis:

Yes.

Operator:

Your next question comes from the line of Chris Sighinolfi with Jefferies. Your line is open.

Chris Sighinolfi:

Hey, good morning guys.

Ronald Tanski:

Good morning Chris.

Chris Sighinolfi:

Thanks for taking my questions. Have a couple of different topic areas I want to hit on, but if I could start with the Gathering cap ex. I know last night you had mentioned and I know we've been talking about for a couple of quarters the prospect of potentially a Utica transition and the opportunity to leverage some of the spending that's already been put in the ground in terms of gathering infrastructure, etc. So looking at—I know you have some tie-ins to, I think, TGP 300, the Gathering cap ex number for '18 up slightly year-on-year, obviously your production is up as well. Just wondering how we should see I guess over time as you transition on John's schedule to Utica to think about what that ratable number might be on Gathering if you're assuming 10% production growth? And then also as sort of a related question, where we might see those efficiencies show up whether they be all in the Gathering division or does Seneca benefit at all from that? If you could talk about the relationship between the two groups as it pertains to utilization of shared infrastructure over time.

Ronald Tanski:

Sure Chris. Dave has—we've got kind of a Gantt chart, if you will, with respect to all that spending so I'll let him address that timing.

David Bauer:

Yes, Chris, I think you'll see 2018 is going to be a little bit higher largely because we're going to be building a compressor station on the Trout Run system in advance of Northern Access coming online. That'll be a decent slug (phon) of capital. When you think longer term on Gathering cap ex of the two-rig program, is more likely in the, call it, $35 million to $40 million area on an annual basis. But this year will be a little higher because of that compressor station.

Chris Sighinolfi:

Okay.

David Bauer:

And then in terms of...

Chris Sighinolfi:

Sorry, and Dave, that was ahead of Atlantic Sunrise?

David Bauer:

Yes.

Chris Sighinolfi:

Okay.

David Bauer:

And then in terms of where we'll see the efficiencies, I think it'll largely be on Seneca where we'll...

Chris Sighinolfi:

Is the thought that their rate sort of runs lower as they share...

David Bauer:

I'm sorry, Chris. I said that completely backwards. We'll see it on Midstream where we'll likely keep the rate the same on Midstream so you'll see a outsized cash flows and earnings on the Gathering side of the business.

Chris Sighinolfi:

Okay. Relative to the amount their spending if the returns...

David Bauer:

Right.

Chris Sighinolfi:

All right. Got it.

David Bauer:

Right. Their return on capital should go up meaningfully.

John McGinnis:

Yes, and Chris, this is John. In terms of Seneca's perspective, there will be some savings. Returning to these pads, we estimate roughly $300,000 per well since we're returning to pads that have already been built and all the production equipment is there. So there will be some improved efficiencies there as well.

Chris Sighinolfi:

Okay. Wonderful. I guess if I could hit it then to the pipeline. Dave, you had mentioned—obviously we see a tick up in the maintenance integrity and modernization spending. You had mentioned some under spending perhaps relative to sort of a normal cadence. In the last couple of years you obviously had some projects. Just wondering—a couple of questions on that. One, sort of how do we think about the decisions around that allocation? Is there a formal process you go through with FERC on that? Is that

Company discretion in terms of which projects happen in which order? And then I had a separate question on Northern Access—or sorry, on Empire North.

David Bauer:

Yes. So from how we assess which projects that we're going to build, our engineers are regularly looking at our system and prioritizing the areas that we think are in need of modernization. In terms of interaction with FERC, to the extent that the projects are big enough, we have 7C application processes that have to be followed, but there isn't a specific direction from FERC on which parts of our system to attack before others.

Chris Sighinolfi:

Okay, and...

John McGinnis:

Did that help?

Chris Sighinolfi:

No, that is helping. And I guess with regard to that workload, do you wind up with any system enhancements as part of that effort, or is that simply making sure that the system—that the aged, either the most aged or in the most critical areas, that you have assets in place that are capable of operating safely, all of it?

David Bauer:

Yes. I mean it typically to the extent that there's a market, we'd look to use that modernization in conjunction with the expansion efforts. So if you go back over time, a lot of the work that we did on Line N in the Tuscarora area involved both expansions and modernization.

Chris Sighinolfi:

Okay. And then I guess with regards to Empire North, which I think was Slide 39, congrats on getting the precedent agreements signed. I know you were talking about that ever since the open season. Saw the cap ex come down, $185 million to $135 million. I'm assuming that's just the scope change. It looks like there was less of an interest going to Hopewell but I just want to make sure I was interpreting that correctly.

John McGinnis:

Yes. We had had—there was a wide variety of sizes of the project and we honed in on the 205 million a day and are sharpening our pencils on capital estimates and we're coming into the $135 million area.

Ronald Tanski:

Yes, so the big change in that cap ex will be going from the original conception of 300,000 dekatherm per day project would have required three compressor stations, going down to 205, we get it down to two compressor stations.

Chris Sighinolfi:

Okay, that's very helpful. I guess a final question for me and I'll hop back in the queue is more of a market-based question, a philosophical question. We've seen some M&A in the Northeast clearly on E&P

combinations. I guess right now most notably Rice and EQT seen some acreage swaps on the E&P side but also seen some Northeast E&P companies from a share price perspective under tremendous pressure. I'm just wondering if assets were to—midstream assets or additional reserve opportunities were to fall out from any of that, I guess, two questions. One, how do you see that landscape? Second, what's your appetite to participate? And then we've also seen more recently some joint ventures on pipes, I guess, again, most recently would have been Blackstone and Rover. I know with the delay on Northern Access you've talked about opportunities to maybe get on to some other systems that are being advanced through the FERC process. I'm just wondering if there's any appetite or ability to participate on a joint venture basis in that. So kind of two parts but same type of question with regard to appetite or even how you see the landscape.

Ronald Tanski:

Well with respect to your first point, yes, you always see some moving around of some assets. As we look at it, Chris, first of all we've—first and foremost, we want to look at making sure we've got enough inventory to fill up the capacity that we have committed over the next five to ten years. So yes, we're always looking at various acreage, tracks that fill in some of the spots that adjoin our existing production and drilling activities and trying to plan that out far enough in advance so that we make sure we have that inventory available. So John's team is constantly looking at that aspect.

With respect to major M&A, I wouldn't necessarily see that on our schedule just because we have a bunch of our own acreage available that we need to—most of its fee so we don't have to worry about it expiring—but we already have that on our books.

With respect to JVs on pipelines, yes, that always is another aspect that we like to think of projects and things where it solves problems for both entities in terms of joining up with somebody who either has capacity or market and isn't just building a pipeline but it can also bring production along with it or a market on the other end. So yes, we continue to look at those.

Chris Sighinolfi:

Okay, great. Thanks again for all the time and additional color this morning. I really appreciate it.

Operator:

Your next question comes from the line of Holly Stewart with Scotia Howard Weil. Your line is open.

Holly Stewart:

Good morning gentlemen.

Ronald Tanski:

Hi Holly.

Holly Stewart:

Maybe first, John, you mentioned some recent curtailments in Northeast PA. I'm assuming that means FY 4Q, but could you give us maybe just a little bit of color on that? And then you mentioned also that there was nothing in the guide for curtailments for '18. So is there a pricing point or some way for us to sort of think about that on a go-forward basis?

John McGinnis:

Sure. The recent curtailment has only been two or three days across the last couple of weeks on certain receipt points. So it wasn't even across the entire system, it is more focused on certain receipt points. So a bit more sporadic and to date has not really been a large shift in volumes. In terms of next year, I don't like to talk about at what price we curtail because I know there's a lot of other producers that are out in the same area. We do have price targets that we do shut (phon) in but that's just something I'd prefer not to talk about.

Holly Stewart:

Yes, fair enough. Maybe also kind of shifting to the Utica. I thought we had talked about last quarter there were about three wells that were completed, either late last quarter or end of this quarter. I know you mentioned one and you increased the EUR per thousand based on that. Is there any color on the other two, if I had that right?

John McGinnis:

Yes. Actually, there is. In terms of EUR—there's five wells now producing and in terms of EUR three out of our first five should range anywhere from 1.8 to just over 2 Bcf per thousand foot. In fact, two of them we think now will be over two. The other two wells we just brought on about three months ago and they're estimated at a range between 1 and 1.4 and the difference here is we believe this decrease occurred because we brought both of these wells online much more aggressively and we're now thinking that we may have actually damaged the reservoir a little bit most likely by crushing sand. The reservoir pressures in the Utica are well over twice that observed in the Marcellus and again since we're using that standard white sand rather than high strength proppant, so there is increased risk for that type of damage.

So these wells are still larger than what we saw but a little bit less than the other three. Obviously now we recognize that the drawdown management is critically important for the success of these wells and as we move forward we're just going to be more cautious and our latest wells are a perfect example of that.

Holly Stewart:

Okay. Okay, that's perfect. And then maybe one final one for Ron. You highlighted that if the FERC picks up your argument on Northern Access that the timing could be expedited maybe pretty significantly. Is the way to think about that we should just be looking at the Millennium appeal that's going on right now?

Ronald Tanski:

Yes, I guess that's one probably pretty good indication. The other thing though is the—obviously without a quorum for the last six months, there's a pretty big backlog, so I would expect their first order of business would be getting through the certificate proceedings before they start reacting to the rehearing order. So there's a couple of things going on there. But yes, I think the Millennium, their handling of Millennium's request would be a pretty good indication, and then you have to ask yourself if that's going to happen before the end of August when DEC might be expected to actually rule on that water quality certification.

Holly Stewart:

Okay. Okay, that's helpful. Thanks guys.

Operator:

Your next question comes from the line of Becca Followill with U.S. Capital Advisors. Your line is open.

Becca Followill:

Good morning. On Slide 21 there's a range of Utica locations of 125 to 500 plus. Can you talk about what encompasses that pretty wide range?

John McGinnis:

Yes, absolutely. The 125 are actually locations that we will be able to return to currently producing Marcellus pads. So that is where the minimum comes from. And then the 500 plus is—our most recent well was in an area called Rich Valley and as I said before that's performed very well and we think that there'll be some running room as we move to the southwest along that area, and if there is it adds inventory very quickly.

Becca Followill:

And that gets you to the 500 by just including the Rich Valley area?

John McGinnis:

Not—Rich Valley and then additional acreage as we move to the southwest.

Becca Followill:

Okay.

John McGinnis:

And we'll be drilling one more appraisal well even further to the southwest during fiscal '18 and that will pretty much—at least at that stage it'll give us a sense of what to expect between Rich Valley and that well.

Becca Followill:

Okay, thank you. And then in the past some of the companies that have moved to a Utica program have talked about maybe having to build a different gathering system but I understand that you don't have to make any changes to your system that's just using existing infrastructure, no additional cap ex.

John McGinnis:

I wouldn't say no additional cap ex. It'll be minimal. We'll be increasing the size of some of these pads, there'll be a little bit of cap ex on the midstream side, but a fraction of what the initial costs were. But no, we will not have to change—use a separate pipeline system.

David Bauer:

Because each of our pads have both high and low pressures.

Becca Followill:

Okay, that's what I needed. And then finally, given the pad drilling, should we expect any lumpiness to '18 production across the course of the fiscal year?

John McGinnis:

Yes. Whether we're drilling Utica or Marcellus wells, we typically drill anywhere from 6 to 12 wells per pad and in some cases now we're drilling some—10 to 12 Marcellus wells and 3 to 4 Utica wells. So yes, there will be lumpy production growth across the entire year.

Becca Followill:

Is it more back-end loaded or?

John McGinnis:

No. It's—no, it looks like we reached in our—in terms of our forecast, it looks like peak production is around the January/February area and then again around the May/June/July area.

Becca Followill:

Great. So maybe fiscal first quarter is a little softer?

John McGinnis:

Yes.

Becca Followill:

Okay, perfect. Thank you, that's what I needed. Appreciate it.

John McGinnis:

Yes.

Operator:

Due to technical difficulties at the beginning of the webcast, a full replay of today's call will be available at approximately 2 o'clock p.m. Eastern Standard Time by accessing the archive on the National Fuel Investor Relations website. I will now turn the call back over to the presenters for final remarks.

Brian Welsch:

Thank you Leandra. We'd like to thank everyone for taking the time to be with us today. A replay of this call will be made available at approximately 3 p.m. Eastern time on both our website and by telephone and will run through the close of business on Friday, August 11. To access the replay online, please visit our Investor Relations website at investor.nationalfuelgas.com, and to access by telephone, call 1-855-859-2056, and enter the conference ID number 51109130. This concludes our conference call for today. Thank you, and good-bye.

Operator:

This concludes today's conference call. You may now disconnect.