National Fuel Gas Company

Fourth Quarter Fiscal 2017 Earnings Conference Call

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CORPORATE PARTICIPANTS

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Holly Stewart, *Scotia Howard Weil*

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Tate Sullivan, *Sidoti & Company*

Chris Sighinolfi, *Jefferies*

PRESENTATION

Operator:

Good morning, my name is Kelly and I will be your conference Operator today. At this time, I would like to welcome everyone to the Fourth Quarter 2017 National Fuel Gas Company Earnings Conference Call. All participants are in a listen-only mode. After the presentation, 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. 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, Kelly, 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 fourth quarter fiscal 2017 earnings release and November 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 Jefferies Energy Conference later this month in Houston. 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. Thanks for joining us today. Our 2017 fiscal year was another strong year for National Fuel, both earnings-wise and operationally. Each of our main operating segments posted strong earnings that were in line with our projections, and Dave Bauer and John McGinnis will give more details about segment earnings drivers later in the call.

As we noted in the guidance section of the release, earnings for our 2018 fiscal year are forecast to be down slightly. In large part, the decrease results from lower realized commodity prices in our Exploration and Production segment, where the higher priced financial hedges that we had in place have rolled off. Forward strip prices remain relatively flat, and a $3.00 per MMBtu strip price and a $2.40 per MMBtu spot price for our natural gas production have been built into our forecast for next year. While this flat pricing appears to be the new normal and resets the base of our pricing assumptions moving forward, we illustrate in our Investor Relations slide deck that our drilling program remains economic in this environment.

Unfortunately, we'll be missing the boost to earnings that we had expected from our Northern Access Project, which has been delayed, and our Second Circuit litigation against the New York DEC, oral argument for our case has been scheduled for November 16. If we were to use the Constitution lawsuit as an indicator of the timeline, we may not get a decision from the court until August. Remember that the facts in our case are different from the facts in Constitution's and we're not discouraged by the outcome in that case.

As you know, we're also awaiting FERC action on our request for rehearing with respect to our waiver argument regarding New York's action—or, more appropriately, inaction—on our Water Quality Permit application. It's hard to project a timeline for an answer on that rehearing, since FERC seems to busy clearing up their certificate application backlog that built up when they had no quorum. Add to that the additional litigation that the New York DEC is piling on in the Millennium Valley Lateral proceeding, and it's anyone's guess when we might get an answer. We are encouraged, however, that FERC will have a full complement of Commissioners with yesterday's Senate confirmation of the last two Commissioners. I believe that FERC's staff never really slowed down on their standard workload during the administration turnover, but it will be good to have a complete slate of Commissioners, so that major policy issues can be addressed.

In the meantime, Seneca continues, as planned, to delineate our Utica Shale acreage in the Western Development Area. We've also resumed drilling in our Eastern Development Area, in order to have plenty of production available to flow into Transco's Atlantic Sunrise project. As we noted in our guidance section in the release, we project that Seneca's production next year will be in the range of 185 billion to 200 billion cubic feet equivalent, approximately a 10% increase in production over fiscal 2017, and we'll accomplish this while generally living within our projected cash flow.

We continue to have discussions with others regarding joint projects that could provide an outlet for Marcellus gas of Seneca, and others, where the project would take a path that avoids the permitting pitfalls presented by New York. Nothing is far enough along on this front for me to be in a position to provide any substantive comments today. We are, however, in the process of preparing our FERC application for our Empire North Project. While this project does provide for additional volumes of natural gas to flow into New York, we've designed the project to primarily be a compression project. We believe that the construction activities involved for Empire North won't require a Water Quality Certificate from the state, since the project is designed to increase throughput on our existing Empire Pipeline System. As a reminder, this project will add 205,000 dekatherm per day of throughput, have a capital cost of $135 million, and is expected to come online in November of 2019.

We expect fiscal 2018 to be another year where we'll be living within cash flow. Our $535 million to $645 million capital expenditure program, that we have summarized in the release, will continue to focus on growth across the Company. Our ongoing system modernization program in the regulated segments will continue to increase rate base in those segments and will continue to increase Seneca's production through the ongoing development of Seneca's reserves, both in the Utica Shale and in the Marcellus Shale. The Utica development will have the add-on effect of providing additional growth in our Gathering segment. The Marcellus development, in the Eastern Development Area, will utilize existing gathering facilities and will be used to fill our Atlantic Sunrise Capacity when that comes online in mid-2018.

In summary, we're busy in each of our operating segments and each one is moving in the right direction for fiscal 2018.

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

John McGinnis:

Thanks, Ron, and good morning, everyone. Seneca produced 40.4 Bcfe during the fourth quarter, compared to 39.8 Bcfe in last year's fourth quarter. Total annual net production was 173.5 Bcfe this year. That is a new annual high for Seneca and was an 8% increase year-over-year and a total of 10% over the past two years, even while dropping to one rig for much of that time and entering into a Joint Development Agreement where Seneca's working interest was reduced to 20%. Additionally, Seneca has generated significant positive cash flow each of the last two years, all in spite of weathering a tough commodity price environment. We achieved this through a combination of best-in-class Marcellus well costs, a Joint Development Agreement with IOG, and continuing to follow a disciplined risk management approach, by locking in prices, physically and financially, when opportunities arise. Moving forward, we should continue to be cash flow neutral to positive over the next few years, even with our forecasted 10% plus average annual production growth, as we execute on our long-term development plans.

Our production growth for the year was largely driven by stronger than expected Marcellus well performance, including better than projected flush production rates, as we've brought on previously curtailed wells, and minimal curtailments due to the improved strength in the spot market. For the year, we curtailed a total of 6.2 Bcf net, compared to 34.6 Bcf last year. Much of these curtailed volumes actually occurred very early and very late in the fiscal year.

Our capital expenditures totaled $246 million, an increase of $147 million, compared to last year. The key drivers for this increase included lower year-over-year upfront and working interest proceeds associated with the IOG Joint Development Agreement, bringing on a second rig in May, and drilling and completing a greater number of 100% working interest wells. In Pennsylvania, we have now drilled all 75 Marcellus wells in our IOG Joint Development and we're currently completing the final 12-well pad. This final pad should be online sometime during our second quarter.

For the year, our proved reserves increased by 305 Bcfe, or 17%, to a total of around 2.15 Tcfe. This increase was primarily due to two key factors: reserves added from our Pennsylvania development program and positive reserve revisions as a result of the improved pricing. Only 28% of our proved reserves are currently categorized as proved undeveloped. Utica reserves now count for nearly 10% of our total and, as we move forward with full development in both the Western Development Area and on our Tioga 007 track, this percentage will grow quickly.

Finally, we continue to reduce our three-year average F&D costs. Our three-year average is now at $0.98 per Mcfe, and this reduction was driven by a combination of improved drill bit F&D and positive price revisions given higher prices both in Pennsylvania and California. Going forward, this number should continue to decrease as Pennsylvania becomes a greater overall percentage of our capital program.

We now have eight Utica wells on production in the WDA and we'll be shifting to 100% WDA Utica development program by the end of this fiscal year. Our three new wells have been online for less than 30 days and they have not yet reached peak production, as a result of our conservative drawdown management program bringing these wells online slowly. Early indications suggest, however, that they will be similar on, a per-foot basis, to our previous appraisal wells, and, therefore, we have now generated an initial WDA Utica type curve based on the first five wells. This type curve was included in our IR deck last night, along with our CRV and Marcellus type curve. Our Utica type curve assumes an EUR of 1.7 Bcf per thousand foot, compared to 1.1 Bcf per thousand foot related to our CRV Marcellus well. To date, all of our WDA Utica wells exhibit very shallow declines, as compared to our Marcellus wells, and so far we've been very pleased with the results.

In California, we have produced 674,000 barrels of oil during the fourth quarter, up very slightly from the third quarter. Annual net production in California was down about 5% year-over-year to 3.2 MBOE. As I stated last quarter, this decrease is primarily due to changes in our steam operations and the significant reduction in well workover activity as a result of low oil prices. During the fourth quarter, however, our oil production has increased by around 300 boe per day, as we ramp up our workover activity. In tandem, total LOE also increased 4.6 million this quarter, or $0.10 per Mcfe on a per unit basis, driven mainly by this increase in workover activity and due to increased steam fuel costs. We will see higher LOEs through the remainder of the first half of the year, as we continue to bring on idle wells in California, and these costs, however, should return to more typical numbers by the end of our second quarter.

For fiscal 2018, we are forecasting capital expenditures to range between $275 million to $325 million. California ranges between $30 million to $40 million and Pennsylvania between $245 million to $285 million. We will remain at a two-rig pace in Pennsylvania, with one rig active drilling both Marcellus and Utica wells in the WDA, and the other rig drilling Marcellus wells in Lycoming and Utica wells in Tioga. For much of the year, we will remain at a single completion crew, but at times we will need to bring in a second crew.

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 minimal curtailment through the remainder of the year. We enter fiscal '18 with the pricing for 96 Bcf for 55% of our production locked in, physically and financially, at a realized price of $2.59 per Mcf. We currently estimate that we'll sell around 32 Bcf into the spot market, but, obviously, depending on pricing, these volumes are at risk for curtailment and would reduce the forecasted projection range just discussed.

Finally, in California, we're forecasting production to be around 3.3 MMBOE. Sixty percent of our oil production is hedged at an average price of $54.30 per barrel, and much of our development activity this year will continue to focus in Midway Sunset, both on our legacy properties and on our new farm-in opportunities at Pioneer and South Midway, and 17-N in North Midway. A key risk related to the start-up of these programs is obtaining Aquifer Exemption approval to allow us to begin injecting steam into these reservoirs. The approval process has been slow, but once we obtain the necessary permits, we'll move forward quickly.

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

David Bauer:

Thanks, John. Good morning, everyone. Last night, National Fuel reported fourth quarter earnings per share of $0.53. While this was lower than the $0.66 per share in last year's fourth quarter, earnings were right in line with our projections. For the full fiscal year, operating results were $3.30 per share, an increase of 7%.

Earnings for the quarter at the regulated subsidiaries were pretty straightforward. The only item of note was O&M expense in the Pipeline and Storage segment, which was up $3.4 million over last year. During the quarter, we incurred about $1.5 million in costs to overhaul two major compressor units. While overhauls, themselves, aren't unusual, we typically don't have two in one quarter. We also saw an increase in project development costs, mostly related to the Empire North Project. As you recall, we take a conservative approach with respect to these costs and expense them in the early stages of development.

At Seneca, production for the year was a little below the midpoint of our guidance. In the latter part of the quarter, spot pricing in Appalachia dropped significantly from levels we saw earlier in the year. Not only did this reduce price realizations relative to forecast, but it also led us to curtail 2.5 Bcf of production during the quarter, which, in addition to impacting Seneca's production, had a follow-on effect on our Gathering business. Spot prices have remained depressed throughout October, but as cold weather returns and as new infrastructure is added in the basin, we expect prices will recover.

There were a couple of unusual expense items during the quarter at Seneca that we don't expect to repeat.

First, LOE came in at $1.07 per Mcfe, which was meaningfully higher than in prior quarters, but it was generally in line with our projections. As John mentioned earlier, this increase was largely due to the timing of workover activity in California, which was back-weighted to the third and fourth quarters. Looking to next year, we expect LOE to return to the $0.90 to $1.00 per Mcfe range.

Second, Seneca's other operating expense for the quarter reflects a $2.4 million payment to reimburse a Canadian pipeline operator for costs related to a project to develop new capacity downstream of Northern Access. That payment, essentially, puts the development of the Canadian capacity on hold, pending the approval of Northern Access. Once that happens, development of that capacity will recommence and Seneca will recoup the $2.4 million payment.

Lastly, our consolidated effective tax rate was significantly lower than prior quarters. This was driven by two main factors.

First, is an adjustment to Seneca's Pennsylvania deferred income tax liability that is related to its capacity on Atlantic Sunrise. As a result of that project, more of Seneca's production is expected to be transported out of Appalachia and, therefore, less of its income will be taxed in Pennsylvania. This allows us to reduce Seneca's PA deferred tax liability, which benefited Seneca's effective rate for the quarter. We had a similar adjustment a few years back related to our Northern Access 2015 capacity.

Second, with oil prices at current levels, we're able to take advantage of tax credits related to enhanced oil recovery activities at our California operations. These credits are available on a year-to-year basis, depending on historical oil prices. This credit will apply again in 2018, but if oil prices rise in the future, it will phase out.

Our fiscal 2018 guidance assumes an effective tax rate in the range of 38% to 38.5%.

On the tax reform front, yesterday, the Chairman of the House Ways and Means Committee released the 429-page Tax Cuts and Jobs Act. This bill includes a substantial tax rate reduction, from 35% to 20%, as well as many other changes to the Tax Code. Our initial take on the proposal is positive, but it obviously has a long way to go before becoming law.

There are two other items of note that occurred during the quarter.

First, we refinanced $300 million of 6.5% interest rate notes that had been scheduled to mature in April 2018. To do this, we issued $300 million of new 10-year notes that carry a rate of 3.95%, and executed the make-whole option on our 2018 maturity. This transaction was well received in the market and will translate into meaningful interest savings. However, because the two components of the refinancing straddle fiscal years, at September 30th, both cash and long-term debt on the balance sheet are temporarily inflated by $300 million. The call of the 2018 bonds settled in the middle of October, so as of today our long-term debt is back to $2.1 billion.

In the Pipeline and Storage segment, FERC recently approved a surcharge related to new pipeline safety and greenhouse gas emissions regulations. As part of Supply Corporation's 2015 settlement with our shippers, parties agreed to a recovery mechanism that became available if costs related to new regulation exceeded a certain threshold. We reached that threshold and, therefore, filed, and received approval, for a surcharge that will add about $4 million in additional revenue next year. We have taken this item into account when we established initial guidance. As a result, there isn't any change to our Pipeline and Storage revenue forecast, which remains at $295 million.

Turning to guidance, aside from the items I touched on earlier, not much has changed since our initial fiscal 2018 projections we provided last quarter. We're modestly tightening our earnings guidance to a range of $2.75 to $3.05 per share. This increase is largely the result of lower expected interest expense as a result of the bond refinancing. Detailed assumptions are included on Page 7 of last night's earnings release, as well as in the appendix of the Investor Relations deck.

Our NYMEX assumptions of $3.00 for natural gas and $50 for oil are unchanged. We're starting the new fiscal year 60% hedged for oil and 55% for gas. This is right in line with our policy and we'll continue to look for opportunities to layer in additional hedges as the year progresses. A fair amount of our unhedged production, or volumes that will flow into our Sunrise capacity. Construction of that project has begun and, as we get more clarity on the exact in-service date, we'll look to layer in additional trades.

The midpoint of our 185 to 200 Bcfe production guidance range assumes we sell about 32 Bcf of spot volumes in Appalachia at an average price of $2.40 per MMBtu. This is higher than the prices we have seen over the past few shoulder months. As I mentioned earlier, we expect that colder weather and additional pipeline capacity will benefit prices in the Basin. So, for now, we're keeping that spot price assumption the same. To give you a sense of the potential impact on earnings, if actual spot pricing differs from our assumptions, we would expect earnings to be lower by about $0.055 per share for every $0.25 per MMBtu change in average spot prices.

Looking at capital spending, our guidance of $535 million to $645 million is unchanged. For the year, we expect cash from operations to exceed capital spending by about $50 million at the midpoint of our guidance. This is consistent with our goal of living within cash flows for the next three to five years.

In conclusion, National Fuel is in a very good position. At a two-rig program, we expect to grow our Upstream and Gathering businesses by 10% a year for at least the next three years, all while living within cash flows. On the regulated side of the business, pipeline development opportunities, combined with the ongoing need to modernize our system, will contribute to long-term growth in rate base. Our balance sheet is strong and should continue to strengthen, providing flexibility to pursue additional opportunities as they arise.

With that, I'll turn it over to the Operator to open the line for questions.

Operator:

At this time, I would like to remind everyone, if you would like to ask a question, please press star, followed by the number one on your telephone keypad.

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

Holly Stewart:

Good morning, gentlemen.

Ronald Tanski:

Good morning, Holly.

Holly Stewart:

Maybe first for John, if you could just give us a sense of—I think you said in 2019, the WDA would be just, you know, specific to Utica development, but give us a sense, this year, in 2018, in both the WDA and EDA, kind of the split there between Marcellus and Utica; and if you've got well count numbers, that would be great.

John McGinnis:

Sure. As I mentioned in the discussion just now, we still have three wells that are currently coming on and we will be drilling three more wells, I think, for the—at least bring in three more wells online during 2018 in the WDA area. So, we'll be doing some drilling. I don't have that drill count now, but I know we'll be bringing on three additional wells. Out East, once we're done in Gamble, we'll be moving to Tioga, on our first pad there, and I believe it's seven wells that we'll be drilling on that pad, and that will all take place during this fiscal year. We won't see production from that until 2019. I believe we head there in the second quarter.

Holly Stewart:

Thank you. Then, another one, just on Atlantic Sunrise, if you could maybe help us just to understand how you envision that project filling up. Is it 100% full on day one? Is that existing production versus incremental production? I'm just trying to think about how you utilize that project from the get-go.

John McGinnis:

Yes, it'll be full on day one. We have existing production there now, could fill it today. We're projecting that it comes on in July, and if we see that it's going to slip a little bit, we may be out in the market trying to fill that gap, but as of today, we could fill it from day one.

Holly Stewart:

Okay, great, and then just one final one for me, and Dave referenced it in his comments, but just wanted to follow up. Assuming at this point, and given where we are in the spot market, we are still curtailing volumes for 1Q?

John McGinnis:

Yes.

Holly Stewart:

Okay. Thanks, guys.

Operator:

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

Graham Price:

Hey, good morning, guys. Just real quick, on the Utica test wells, I just wanted to get a sense of maybe how much testing is left with regards to determining optimal profit loads and staged spacing, things like that, and any potential uplift to EUR that we could see from that?

John McGinnis:

Yes, quite a bit of testing is left to do. For example, in the three most recent wells, we actually tested three different targets, and they're all within 30/40 feet of each other, but we've actually seen differences even with that small of a change. As we move forward, we will—it will be an ongoing, I guess, testing program. We will be changing—at least into for the next year, we'll be testing different stage spaces, spacing. We'll be testing different well spacing, as well. So, there's still quite a bit of work to do. And in terms of improving these well results significantly, I don't think that will happen. It's more towards fine-tuning and cost saving.

Graham Price:

Okay, got it. Thanks, that's great. Then, real quick, for my follow-up, just wondering about completed well costs for those eight Utica wells that have been drilled. I know that these costs will be coming down, but just kind of wanted to get a sense of maybe where you're at today.

John McGinnis:

Well, overall, they're about 20% higher, and most of that is on the completion side. I don't know what they are today, but I know we're expecting, on the completion side, they'll be a little north of $3 million, once we move into full development.

Graham Price:

Okay, and you expect to move to full development late in 2018?

John McGinnis:

Yes, yes, towards the end of 2018, moving into 2019, we will have fine-tuned our completion practices and be moving forward on that.

Graham Price:

Okay, perfect. Thanks, guys. That's it for me.

Operator:

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

Becca Followill:

Good morning, guys. Just following up on that question, I think you said its $3 million for completed well costs, for just the completions portion?

John McGinnis:

It will be a little over, between $3 million and $3.5 million.

Becca Followill:

Then, the drilling portion?

John McGinnis:

We're estimating a little over $2 million, between $2 million and $2.5 million. So, all in, between $5.5 million to $6.5 million. I think we're looking at $6 million, $6.2 million.

Becca Followill:

That's where you expect to be?

John McGinnis:

That's where we expect to be.

Becca Followill:

Okay, perfect.

John McGinnis:

It's a little more expensive now, because we do a lot of science on these pads—on these wells. Our stage spacing is tighter than what I think it'll end up. So, there's still a lot of work to do, but it'll reduce as we go forward.

Becca Followill:

How long do you think to get to that level?

John McGinnis:

Within a year, nine months to a year.

Becca Followill:

Okay, and targeted well spacing at this point?

John McGinnis:

Good question. Probably minimum, a thousand foot, but I think we'll probably start a little wider than that, around 1,200, but that's something we are still working out.

Becca Followill:

Great, and then the last question is, can you tell us how much gas was curtailed during October?

John McGinnis:

About 1.5 Bcf.

Becca Followill:

Great. Thank you, guys.

Operator:

Your next question comes from the line of Tate Sullivan of Sidoti. Your line is open.

Tate Sullivan:

Great. Thank you for taking my question, and good morning, and thanks for the detail earlier on the lower tax rate and the higher debt at the end of the quarter, too. Can you go into more detail on your utility, just in terms of the customer growth rates year-over-year—I think it declined slightly in Pennsylvania—and give some context for those rates of growth?

David Baur:

Sure. As you know, we've got a pretty high concentration of the customer base in both New York and PA. It's better than 95%. There is some population growth, but we don't count on large growth in customer count, probably in the half-a-percent area per year.

Tate Sullivan:

About half-a-percent per year?

David Baur:

Yes.

Tate Sullivan:

Great. Then, the year-over-year decline in the quarter in the utility, was some of that weather-related in Pennsylvania or was it mostly the lower rate case coming through in New York in April?

David Baur:

So, you're saying the earnings of—

Tate Sullivan:

For just the utility.

David Baur:

Quarter-over-quarter?

Tate Sullivan:

Year-over-year.

David Baur:

Oh, year-over-year. Yes, the biggest chunk of that is going to be weather in Pennsylvania, which was—I think the winter was somewhere in the 10% warmer than normal area. On top of that, we had some costs creep on the O&M side, but weather was by far the biggest factor.

Tate Sullivan:

Okay. Okay, thank you very much for that. Thanks.

David Baur:

You bet.

Operator:

Again, to ask a question, it is star, one from your telephone keypad. Your next question comes from the line of Chris Sighinolfi of Jefferies. Your line is open.

Chris Sighinolfi:

Hey, good morning, guys.

Ronald Tanski:

Good morning, Chris.

Chris Sighinolfi:

Dave, I just had a question with regard to the timing of that deferred tax liability reassessment. Was that due to something within the regulatory approval process for Atlantic Sunrise or the fact that you were heading into a fiscal year, or something else? I guess, what made you take a reassessment at this point?

David Baur:

This is with respect to the Atlantic Sunrise adjustment?

Chris Sighinolfi:

Yes, exactly, your PA tax going down.

David Baur:

Yes, you've got to pick a time, when we make the adjustment. We've, typically, been pretty conservative and waited until we've seen shovels in the ground to make the adjustment. So, with construction pretty much underway on Atlantic Sunrise, the probability of that project being completed was high, in our estimate, and that led us to record the adjustment.

Chris Sighinolfi:

Okay, that's helpful, and I guess, what would be, you know, next steps for Empire North? I did see some incremental Precedent Agreement volumes added, I think, since the last call, and you had obviously mentioned in your prepared remarks some additional expensing items associated with that project this past quarter, so I'm just wondering what milestones to look forward to as to gauge progress on that and potential timeline for it.

Ronald Tanski:

Yes, the next steps would be the actual filing of the FERC application for the 7(c) for that project, Chris, and—yes, that's basically it. The spending to date has been preliminary engineering for the compressor sites and logistics for that. So, we're looking to get that done pretty close to the end of the year. As a matter of fact, we're starting outreach hearings, or outreach meetings next week to cover any questions that locals might have with respect to the siting of those compressor sites.

Chris Sighinolfi:

Ron, when you say the end of the year, you mean this calendar year?

Ronald Tanski:

Yes, the calendar year, I'm sorry.

Chris Sighinolfi:

Okay. I guess, with regard to the Precedent Agreements in place on that project, are those both third-parties, or is Seneca represented at all in them?

Ronald Tanski:

No, Seneca is not represented. A portion of it, however, is our Utility, and I forget the exact portion of that. Dave, can you—

David Baur:

Yes, it's relatively small.

Ronald Tanski:

Yes, it's relatively small, but it's third-party production that would be utilizing that space.

Chris Sighinolfi:

Okay. Two more questions, if I could. One was—Dave, if I heard you correctly with regard to the payment made, I guess that was to TransCanada just to keep on ice for some time the ability to carry the Northern Access points all the way into Dawn; is that right? Is that sort of how to understand it? Then, if Northern Access does eventually go forward, they complete their portion of the build and you get reimbursed?

Ronald Tanski:

That's exactly right, Chris. It basically suspends the project until we get approval on Northern Access.

Chris Sighinolfi:

Okay, okay. Then, I guess the final question for me is just there's—there was a shareholder proposal or idea floated about tracking stock, potentially, for your utility company. I have my own thoughts about it, but I was just curious if you guys had obviously considered that and thought about it either on the Management Team or conversations at the Board level, and what, if any, response or thoughts you've given that.

Ronald Tanski:

Yes, it's a little tough to comment on that right at this point in time, Chris. We're in the process. You know, the lawyers are concerned about anything we say being considered proxy solicitation. So, I'd just prefer not to comment on it at this point.

Chris Sighinolfi:

Okay, fair enough. Well, thanks again for the color and I look forward to seeing you guys in Houston later this month.

Ronald Tanski:

Sounds good. Thanks.

Operator:

Again, if you would like to ask a question, please press star, then the number one from your telephone keypad.

There seem to be no further questions at this time. I turn the call back to the presenters for closing remarks.

Brian Welsch:

Thank you, Kelly. We'd like to thank everyone for taking the time to be with us today. A replay of this call will be available at approximately 3:00 p.m. Eastern Time on both our website and by telephone, and will run through the close of business on Friday, November 10. To access the replay on line, please visit our Investor Relations website at investor.nationalfuelgas.com. To access by telephone, call 1-800-585-8367 and enter conference ID number 96083185. This concludes our conference call for today. Thank you and good-bye.

Operator:

This does conclude today's call. You may now disconnect.