

# [***Q1 2020 Energy Transfer LP Earnings Call - Final***](https://advance.lexis.com/api/document?collection=news&id=urn:contentItem:5YWV-0N21-DXH2-60B5-00000-00&context=1516831)

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May 11, 2020 Monday

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**Length:** 8589 words

**Body**

Corporate Participants

\* Kelcy L. Warren

Energy Transfer LP - Chairman & CEO of LE GP, LLC

\* Marshall S. McCrea

Energy Transfer Operating, L.P. - Chief Commercial Officer & Director of Energy Transfer Partners, L.L.C.

\* Thomas E. Long

Energy Transfer LP - Group CFO & Director of LE GP, LLC

Conference Call Participants

\* Christine Cho

Barclays Bank PLC, Research Division - Director & Equity Research Analyst

\* Colton Westbrooke Bean

Tudor, Pickering, Holt & Co. Securities, Inc., Research Division - Director of Midstream Research

\* Jean Ann Salisbury

Sanford C. Bernstein & Co., LLC., Research Division - Senior Analyst

\* Jeremy Bryan Tonet

JP Morgan Chase & Co, Research Division - Senior Analyst

\* Keith T. Stanley

Wolfe Research, LLC - Research Analyst

\* Michael Jacob Blum

Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst

\* Michael Jay Lapides

Goldman Sachs Group Inc., Research Division - VP

\* Pearce Wheless Hammond

Simmons & Company International, Research Division - MD & Senior Research Analyst

\* Shneur Z. Gershuni

UBS Investment Bank, Research Division - Executive Director in the Energy Group and Analyst

\* Spiro Michael Dounis

Crédit Suisse AG, Research Division - Director

\* Ujjwal Pradhan

BofA Merrill Lynch, Research Division - Associate

Presentation

OPERATOR: Greetings, and welcome to the Energy Transfer First Quarter Earnings Call. (Operator Instructions) As a reminder, this conference is being recorded.

I would now like to turn the conference over to your host Mr. Tom Long, Chief Financial Officer. Please go ahead, sir.

THOMAS E. LONG, GROUP CFO & DIRECTOR OF LE GP, LLC, ENERGY TRANSFER LP: Thank you, operator, and good afternoon, everyone, and welcome to the Energy Transfer First Quarter 2020 Earnings Call. And we really want to thank all of you for joining us today. I'm also joined today by Kelcy Warren, Mackie McCrea and other members of the senior management team, who are here to help answer your questions after our prepared remarks. Hopefully, all of you have seen our press release we issued earlier this afternoon as well as the slides posted to our website.

As a reminder, we will be making forward-looking statements within the meaning of Section 21E of the Security Exchange Act of 1934. These statements are based upon our current beliefs as well as certain assumptions and information currently available to us and are discussed in more detail in our quarterly report on Form 10-Q for the first quarter of 2020. I'll also refer to adjusted EBITDA, distributable cash flow or DCF and distribution coverage ratio, all of which are non-GAAP financial measures. You'll find a reconciliation of our non-GAAP measures on our website. And we expect our 10-Q to be filed later today.

The current COVID-19 pandemic has impacted our nation in more ways than one. As we navigate through this uncertainty, we want to start today by thanking our team of more than 12,000 men and women across the country for their remarkable contributions and incredible commitment during this challenging time. We understand and appreciate the tremendous amount of hard work and coordination it requires to keep our assets running safely and efficiently while keeping energy products moving, both for the benefit of our partnership and our country.

Now before addressing the current market conditions brought on by COVID-19 and the OPEC oversupply, I'm going to start with a few of our first quarter 2020 highlights. For the first quarter, we generated adjusted EBITDA of $2.64 billion and DCF attributable to the partners of ET, as adjusted, of $1.42 billion; and our coverage ratio for the quarter was 1.72x, which resulted in excess cash flow after distributions of $594 million. Adjusted EBITDA was adversely affected by inventory valuation adjustments of $213 million in the first quarter of 2020, which I will discuss further in the segment reviews. Without these adjustments, first quarter adjusted EBITDA would have been approximately $2.85 billion, and both adjusted EBITDA and DCF results would have been above our expectations.

During the first quarter, we also brought our seventh fractionator at Mont Belvieu online, which brings our total fractionation capacity at Mont Belvieu to over 900,000 barrels per day. Additionally, our 200 million cubic foot per day Panther II processing plant in the Permian Basin was placed into full commercial service in January of 2020.

Finally, in January, we completed dual offerings of debt and perpetual preferred in the aggregate amount of $6.1 billion. A portion of the proceeds from these offerings were used to redeem all of our 2020 maturities, with the remainder used to pay down short-term borrowings on our credit facility. We had a strong liquidity position of approximately $4 billion at the end of the first quarter. Additionally, we have a very manageable $1.4 billion of maturities in 2021.

Now looking at our 2020 outlook. Although the current year has become increasingly challenging in the energy industry and has resulted in lower financial projections across the midstream space, we believe that our fully integrated, diversified asset base offers unique benefits and a foundation that has been built to help mitigate cyclical markets. In light of the significant weakness in crude oil prices due to the COVID-19 demand disruption and additional OPEC supply, we are revising our 2020 adjusted EBITDA guidance range to $10.6 billion to $10.8 billion. In addition, as producers curtail drilling, and in some situations, shut-in existing wells, we do expect some short-term volume reductions in crude associated with gas and NGLs. Helping to offset the impacts from lower volumes and lower commodity prices, we expect increases related to the addition of the SemGroup assets as well as contributions from the ramp-up of Mariner East, Frac VII, new processing in the Permian as well as full year contributions from projects that went into service in 2019.

We are also taking additional steps to keep our assets running efficiently and our cash flows steady as we navigate the tough market conditions and challenges ahead. These include cost reduction measures and reduced 2020 growth CapEx expenditures. Commercially, our team is focused on locking in existing volumes for longer terms and this continues to take precedence over development of new assets. Operationally, we are leveraging our extensive infrastructure to help drive operational efficiencies and optimize our assets. As a result, through the combination of our diverse asset base and a lot of hard work from our talented employees, we have found some new opportunities during this disruption. The wide and profitable contango spreads on virtually all of our hydrocarbon products is allowing us to capture significant margins utilizing our extensive network of storage assets. Through the end of 2020, we have contracted 6.2 million barrels of crude oil storage capacity in the Department of Energy's strategic petroleum reserve. We have a connection to the reserve through our Nederland terminal, so this is an efficient extension for our franchise.

In addition, due to this pressure on our business, we have identified and are executing on significant cost-cutting initiatives both in our corporate offices as well as our field operations. As a result, we expect to save $200 million to $250 million relative to our 2020 budget. We have also further reviewed our growth capital expenditures for 2020, including project spend today, completion dates, economic impact on delaying particular projects and near-term cash flows.

Approximately 70% of the growth capital spent in 2020 will be spent on projects that are 60% or more complete and are expected to be in service in 2020 or early 2021. This includes Mariner East, the Lone Star Express expansion and the Orbit and other LPG export projects at Nederland. However, we have decided to delay some projects, including Frac VIII and select Canadian projects as well as change the scope of the Ted Collins pipeline. Based on our outlook for the current market, we are reducing our 2020 growth capital expenditures by at least $400 million to $3.6 billion, and we are evaluating another $300 million to $400 million for potential reduction this year. Although we anticipate growing the business over the next several years, and we are continually evaluating new opportunities given our asset footprint, we view it as unlikely we will add any major organic growth projects to our backlog for 2021. As we think about future capital spend over the next 3 to 4 years, we anticipate an annual run rate of less than $2 billion. We remain committed to generating free cash flow and still expect to be free cash flow positive in 2021 after growth capital and equity distributions.

Looking more closely at our growth projects. I'll now walk through our recent developments. We are transitioning the Ted Collins crude oil pipeline into the Ted Collins link, which will reduce capital spend and increase the utilization of existing assets, while providing the same market connectivity between our Nederland and Houston terminals. The Ted Collins link will be a much less expensive and quicker alternative that will allow us to transport up to 275,000 barrels per day from West Texas and Nederland to our Houston terminal and is expected to be in service in the fourth quarter of 2021.

The Moore Road pipeline is now in service. This pipeline expands and improves our existing access to and from our Houston terminal and export facilities as well as access to Houston Ship Channel refineries. Regarding the Bakken pipeline capacity optimization, as we have previously mentioned, the Bakken pipeline received sufficient market interest to move forward with plans to further optimize system capacity. The initial phase of the optimization above the pipe's current capacity of 570,000 barrels per day will accommodate the volume commitments made by shippers during the recent open season. Subject to completion of the permitting process, we now expect this additional capacity to be in service in the second quarter of 2021.

Now moving on to Mariner East system. Total NGL volumes through the Marcus Hook Industrial Complex averaged 226,000 barrels per day during the first quarter with 17,000 barrels per day coming in by other modes, including rail and third-party pipelines. At the beginning of this year, we reached an agreement with the Pennsylvania Department of Environmental Protection, that will allow us to complete the construction of projects we have underway in Pennsylvania. And in April, we started to ramp up some additional volumes on the Mariner East system. Customers at our Marcus Hook Complex are taking advantage of the flexibility that our Mariner East system has to offer by placing barrels for the upcoming winter season into local markets.

We are pleased to be connected to the new CPV Fairview power plant in Cambria County for the local ethane supply from Mariner East for Pennsylvania power generation. This connection enables further market flexibility for shippers on the Mariner East system, while advancing local energy initiatives with efficient transportation options. At the same time, international demands for propane and butane has remained strong, even while motor fuel demand has waned because of COVID-19. This is helping our Appalachian producers find a market for their products.

Looking ahead, we are anxiously awaiting the next phase of the project, which we now expect to be in service in the first quarter of 2021, while the final phase completed in the second quarter of 2021. In addition, we continue our expansion at the Marcus Hook terminal as it provides customers with the most efficient way to reach the best markets for their product. This expansion will provide approximately 50,000 barrels per day of incremental NGL throughput capacity at the terminal in the first quarter of 2021, accommodating volume growth from Mariner East.

Moving on to our Lone Star assets, Frac VII is now in service and has ramped up as expected.

As mentioned, we are delaying the construction of Frac VIII based on our current supply and volume expectations, along with our customers' volume expectations. We now expect to be in service in the first quarter of 2022. And we are in the final stages of construction on our 24-inch 352-mile Lone Star Express expansion, which will add over 400,000 barrels per day of NGL pipeline capacity from the Permian Basin to the Lone Star Express 30-inch pipeline south of Fort Worth, Texas. We continue to expect the expansion to be in service in the fourth quarter of 2020.

In light of the current conditions, we have converted some of our storage facilities at Mont Belvieu to allow us to store a significant amount of natural gasoline and diesel barrels into 2021, which provides us with significant contango revenue. This demonstrates another valuable benefit of our dynamic franchise. Looking at our LPG expansion project at Nederland, we have recently found a very cost-effective way to modify this expansion, which will increase the capacity from 235,000 barrels per day to 300,000 barrels per day. LPG demand has remained strong as has demand for this project, which will further integrate our Mont Belvieu assets with our Nederland assets to expand our LPG export capabilities. Construction is progressing well, and it remains on schedule to be in service in the fourth quarter of 2020. The conversion of the White Cliffs Pipeline from crude oil to NGL service is complete and volumes on this pipe, which runs from Platteville, Colorado to Cushing, Oklahoma, began flowing in December of 2019. Construction on our Orbit ethane export joint venture with Satellite Petrochemical is nearing completion, and we expect the project to be ready for commercial service in the fourth quarter of this year.

Turning to gas processing in West Texas.

Our 200 million cubic foot per day Panther II processing plant in the Permian Basin was placed into full commercial service in January of 2020. With the completion of this plant, which is fully subscribed, we are now capable of processing more than 2.7 Bcf per day in the Permian Basin.

Let's take a little closer look at the first quarter results. Consolidated adjusted EBITDA was $2.64 billion compared to $2.74 billion for the first quarter of 2019. The change from the prior period was primarily due to crude oil and NGL and refined products inventory valuation adjustments of $213 million that adversely affected adjusted EBITDA in the first quarter of 2020. Crude oil and NGL and refined products had a positive impact of $27 million in the first quarter of 2019 for a total impact of $240 million from the first quarter of 2019 to the first quarter of 2020.

DCF attributable to the partners as adjusted was $1.42 billion for the first quarter, down $177 million compared to the same period last year. This is primarily due to the decrease in adjusted EBITDA. Distribution coverage ratio for the first quarter was 1.72x. In March, Energy Transfer announced a distribution of $0.305 per common unit for the first quarter or $1.22 per common unit on an annualized basis. This distribution is consistent with the fourth quarter of 2019 and will be paid to unitholders of record as of the close of business on May 7.

Let's look at the results by segment. Starting with NGL and refined products, adjusted EBITDA was $663 million compared to $612 million for the same period last year. This increase was due to record frac and NGL transportation volumes, which were partially offset by a $59 million impact from changes in inventory valuation adjustments in the first quarter of 2020 versus a $9 million valuation adjustment in the first quarter of 2019.

NGL transportation volumes on our wholly-owned and joint venture pipelines increased to 1.4 million barrels per day compared to 1.2 million barrels per day for the same period last year. The majority of the increase in volumes was on our pipelines that of the Permian Basin and North Texas regions as well as on our Mariner East pipeline system. First quarter average fractionated volumes increased to 804,000 barrels per day compared to 678,000 barrels per day for the first quarter of 2019. For the crude oil segment, adjusted EBITDA was $591 million compared to $744 million for the same period last year. This was primarily driven by a change in inventory valuation adjustments of $190 million.

In the first quarter of 2019, we had a positive $36 million adjustment. And in the first quarter of 2020, we had a negative $154 million adjustment.

In the first quarter, a portion of the barrels previously recognized as operational inventory have been reclassified as a long-term asset, which is expected to help reduce the volatility of earnings in the crude segment. Going forward, based on our current business operations, we expect our inventory that is subject to these adjustments to be between 3 million to 4 million barrels. Crude transportation volumes increased to 4.5 million barrels per day compared to approximately 4 million barrels per day for the same period last year, primarily due to increased barrels out of our existing Texas pipelines, volume growth in the Bakken and the initiation of service of Phase 2 of the Bayou Bridge pipeline in the second quarter of 2019 as well as the acquisition of SemGroup assets in the fourth quarter of 2019.

For midstream, adjusted EBITDA was $383 million compared to $382 million for the first quarter of 2019. Higher midstream throughput volumes were partially offset by lower NGL and gas prices, which impacted results by $22 million. Gathered gas volumes were 13.3 million MMBtus per day compared to 12.7 million MMBtus per day for the same period last year. This increase was due to volume growth across the majority of our operating regions and demonstrates the strength of both our customer base and our asset footprint.

In our interstate segment, adjusted EBITDA was $404 million compared to $456 million for the first quarter of 2019. This was primarily a result of the contractual rate change at the Lake Charles facility as well as lower demand for services on several of our pipes. And in our intrastate segment, adjusted EBITDA was $240 million compared to $252 million in the first quarter of last year. This was primarily due to higher transport fees from the ramp-up of the Red Bluff Express, increased storage margin from a higher storage optimization and new contracts. These were offset by lower revenues from pipeline optimization activities.

Let's now look at the CapEx for the quarter ended March 31, 2020, Energy Transfer spent approximately $1 billion on organic growth projects primarily in the NGL and refined products and midstream segments, excluding SUN and USAC CapEx. And as a reminder, nearly 70% of the capital spend in 2020 is on projects which are more than 60% complete and are expected to be in service in 2020 and early 2021. And as I mentioned earlier, for the full year 2020, we now expect to spend approximately $3.6 billion primarily in our NGL and refined products and midstream segments, and we are evaluating another $300 million to $400 million for potential reduction this year.

Looking briefly at our liquidity position. Late in 2019 and early this year, we successfully completed financing transactions, which provided an efficient funding source and bolstered our liquidity position. This included debt and perpetual preferred dual offerings completed in January 2020 in the aggregate amount of $6.1 billion, for which we used a portion of the proceeds to redeem all of our 2020 maturities. The remainder of the proceeds were used to pay down short-term borrowings under our credit facility. As of March 31, 2020, total available liquidity under our revolving credit facility was approximately $4 billion and our leverage ratio was 4.12x for the credit facility. And as a reminder, looking forward, we have a very manageable $1.4 billion of maturities in 2021.

We continue to target a rating agency leverage ratio of 4 to 4.5x.

In conclusion, I just want to reiterate that we are very pleased to have delivered another solid quarter. Throughout the remainder of 2020, we continue to expect our fully integrated multiproduct assets as well as our predominantly fee-based cash flows to offset headwinds this year. And the ramp-up of growth projects, which are expected to drive near and long-term value will continue to generate excess cash flow and fund our growth projects. In addition, our extensive storage capabilities, combined with our recently leased space at the SPR are providing valuable opportunities to capture upside related to the contango spreads. We remain committed to our investment-grade rating and our strong liquidity position provides us with the financial flexibility as we navigate through this uncertain time. However, we know that it is imperative to remain mindful of our spending, and we'll continue our disciplined approach to capital expenditures while also pursuing additional cost savings. Safety and project execution remain among our top priorities, and we want to once again thank our employees for their hard work and continued support during this challenging time. Operator, let's open the call up to Q&A.

Questions and Answers

OPERATOR: (Operator Instructions) Your first question comes from the line of Jeremy Tonet with JPMorgan.

JEREMY BRYAN TONET, SENIOR ANALYST, JP MORGAN CHASE & CO, RESEARCH DIVISION: Just want to start off with discussing, I guess, your assumptions on recovery post-COVID as far as both on the demand side and the supply side, just trying to think through how you guys view the world, how that factored into your guidance? And if you kind of bounce this off the agencies and if they were kind of comfortable with your outlook at this point?

MARSHALL S. MCCREA, CHIEF COMMERCIAL OFFICER & DIRECTOR OF ENERGY TRANSFER PARTNERS, L.L.C., ENERGY TRANSFER OPERATING, L.P.: This is Mackie. Yes, let me start, and then Tom can follow-up. As everybody knows, we're in kind of unprecedented times that nobody could ever predicted the entire world, country to be shut down. So things really got difficult kind of last part of April and then in May. However, how it's impacting our assets in a couple of ways, is we -- for example, in our G&P assets, we have had some volumes shut in. However, just to give you an example, in the Midland Basin, we've had about 8% of the volume shut in. That was beginning of May. And as of today, we've seen about 25% of that turn back on. So as we look -- that as an example, and as we look through all of our assets and all of our segments, we see that things have bottomed out, in our opinion, and that things are improving, and they're going to grow. A lot of it, of course, depends on WTI, where is WTI going to go. We are pleased by how it's kind of strengthened and hanging in the mid-$25 range and the curves kind of show it growing throughout the rest of the year, and we're pretty optimistic that's going to be the path that we're on. So from an Energy Transfer perspective, we think things have bottomed out. How quickly they'll grow remains to be seen. But we do expect, if not faster growth, at least gradual growth for the next quarter. And we've injected that in our projections and in our discussions with the rating agencies.

THOMAS E. LONG: And I'll chime in. Jeremy, I'll chime in here real quick on the rating agency part of it. We do continue to work with them very close as they continue to evaluate projections and et cetera. As always, we feel like we're -- we have great credibility with them. We're going to continue to work with them. We're also highlighting all the other levers -- various levers that we have to pull. The CapEx, like we've talked about, that aspect of it, the cost, several things that we've looked at. So all in all, our dialogue with the agencies continued, and we will, like always, just give them the best information, the best forecast we have.

JEREMY BRYAN TONET: Yes, that's helpful. And just wanted to touch on the CapEx side. What would get you to the other side as far as pulling that point down the incremental $300 million to $400 million CapEx that's under evaluation? How do you see CapEx trending in '21 at this point?

MARSHALL S. MCCREA: This is Mackie again. We look at our projects, we look at the realization and timing of fielding those projects and some of the hurdles that we have. In addition to that, we consistently look at those projects that, as we've talked about, are down the road always, but where it might make sense to push some of those dollars further out into '21 or even further in some cases. So it's not day-to-day, certainly a weekly analysis that we make, and those are real dollars that we believe are quite possible that we could push out of 2020, getting us closer to that $3 billion range. But there's a lot of unknowns right now. Certain things could happen in the Middle East. We heard Saudi Arabia cut another 1 million barrels today. I mean, there's things that could really turn this around in a big way that would cause us to continue on the path we're on and bring those projects on timely. But we're certainly looking at it closely, and we'll do everything we can from the standpoint of delaying costs where it's prudent and where it makes sense.

THOMAS E. LONG: And we're not trying to give guidance for 2021 right now. But I will say $2 billion or less, we do feel good about right now for 2021 and beyond.

OPERATOR: Your next question comes from the line of Shneur Gershuni with UBS.

SHNEUR Z. GERSHUNI, EXECUTIVE DIRECTOR IN THE ENERGY GROUP AND ANALYST, UBS INVESTMENT BANK, RESEARCH DIVISION: And maybe to start off, Mackie and Kelcy. Just wanted to touch on the CapEx side. I realize it's difficult to make adjustments to the 2020 CapEx numbers when you've got so many big projects that are in-flight right now. Tom just mentioned CapEx under $2 billion for the next 3 to 4 years. Is there a scenario where '21 could be materially lower than $2 billion if we kind of have an ***environment*** that we're in right now or a little bit better than where we're in right now? I'm just trying to understand how low can CapEx go if we're in an oversupply situation for crude heading into next year.

MARSHALL S. MCCREA: Yes, Shneur, this is Mackie. Here's how I'd answer that is that the projects, even some of the projects that we've deferred, we have commitments, and in many cases, demand charges that are kicking in. So it really doesn't make sense at some point to delay those projects past a certain point, a certain kind of deadline for those, so that when the commitments and the demand charges kick in.

So to answer that question, do we think it could materially and say, knock it down to $1 billion or less? That's unlikely. I think Tom said it well, we expect to be between $1.5 billion and $2 billion over the next 3 or 4 years. But certainly, depending on circumstances, we'll continue to evaluate that up or down, but that's a pretty good range right now.

SHNEUR Z. GERSHUNI: Okay. No. I appreciate the color. And maybe as a follow-up for Tom. I appreciate the slides that you guys shared with us today, and you have this sensitivities updated now for 5% to 10% for commodities and spreads and so forth. Just trying to understand the sensitivity around that. So when I look at that today, do I look at your current guidance today and say there's 5% to 10% of exposure there. But is that based on where NGL prices are today and gas prices are today and where spreads are today? And so things would have to be materially worse to see the downside with respect to that -- those types of sensitivities?

THOMAS E. LONG: Yes, it is. That's the short answer. It is based upon our current prices, both prices and spreads.

OPERATOR: Your next question comes from the line of Jean Ann Salisbury with Bernstein.

JEAN ANN SALISBURY, SENIOR ANALYST, SANFORD C. BERNSTEIN & CO., LLC., RESEARCH DIVISION: It seems like your expectation around spread earnings have fallen by a few hundred million dollars since the beginning of the year guidance, which is somewhat surprising given the contangos and crude and refined products. Can you just say what the moving pieces are in that bucket, maybe the inventory valuations in there?

MARSHALL S. MCCREA: As far as the inventory valuations, we do not have that baked in to the guidance other than what we've reported here in the first quarter.

THOMAS E. LONG: And I'll follow-up to that. On the -- certainly, the spreads across Texas on our crude business have tightened. However, offsetting that is we're seeing in our storage business, significant contango spreads that we haven't seen in a long, long time that kind of counteracts the negative impacts to the narrowing spreads on the crude business.

JEAN ANN SALISBURY: Okay. It looks like overall, it went down there, I guess, versus the last time. So is the -- I guess, the crude pipeline spreads loss is bigger than the contango spread. I just want to make sure I kind of get it.

THOMAS E. LONG: I need to make sure I'm following your question on this one. You're saying went down. As far as the guidance goes? Is that your...

JEAN ANN SALISBURY: Yes. That's it.

THOMAS E. LONG: Yes. You are correct.

JEAN ANN SALISBURY: And then is there -- it's kind of related to Jeremy's question earlier, but is there a decline in overall U.S. or Permian production that you're using this year to kind of get to this forecast and kind of anchor that if it's better or worse than that, then you'll be better or worse than that?

MARSHALL S. MCCREA: This is Mackie. I'll start. As I mentioned earlier, we have seen some shut-ins and certainly significant slowing down. However, based on where kind of WTI is now and our optimism that we think that we'll see it kind of hanging there and start to strengthen, we don't -- we think volumes will recover maybe faster than some others over the next 30 to 60 days. So we don't anticipate notwithstanding some significant circumstances, we don't anticipate volume staying down where they are for any significant period of time.

OPERATOR: Your next question comes from the line of Michael Blum with Wells Fargo.

MICHAEL JACOB BLUM, MD AND SENIOR ANALYST, WELLS FARGO SECURITIES, LLC, RESEARCH DIVISION: Maybe just to make sure I just clarify one of the questions that was just asked. So in the slide deck, the 2.5% to 5% of the pie that is labeled as spread, does that capture for your 2020 guidance? Does that capture your contango upside this year?

I just want to clarify that.

THOMAS E. LONG: Yes, it does.

MICHAEL JACOB BLUM: Okay. Great. My other question was just on Frac VII that just went into service, and then Frac VIII. Is Frac VII fully contracted? And where does Frac VIII kind of stand at that point? Or do you still have capacity left to turn out there?

MARSHALL S. MCCREA: Yes, Michael, this is Mackie. Frac VII is completely full. It's running at 97%. If you look at all of our fracs, we're running significantly above the nameplate of those. And so those volumes were, of course, designated to go to Frac VIII. We're able to extend Frac VIII out to '22 because of the additional capacity that we have above nameplate. But right now, we have a lot of NGLs in storage, we brought it on. And so some of it's coming out of storage, but we've been running our frac full and will for a number of days and months at its current status.

OPERATOR: Your next question comes from the line of Michael Lapides with Goldman Sachs.

MICHAEL JAY LAPIDES, VP, GOLDMAN SACHS GROUP INC., RESEARCH DIVISION: Just looking at Slides 4 and 5. The pie chart on Slide 4, where you show the adjusted EBITDA breakout in 90% to 95% fee-based. Can you break that large piece of the pie into what percent of that is take-or-pay? And what percent of that is you've got the fee or the tariffs set, but you've got volumetric exposure.

THOMAS E. LONG: Well, Michael, I'll start with that one. Probably if you turn to Slide 5 in the deck, that's the way we've captured it for 2019. I don't know that that's necessarily moving a lot. We obviously can follow-up with you afterwards. But I think you can kind of see how much of that from at least from a midstream standpoint, is fee-based versus keep whole, POP, et cetera. And then if you look at the other pie chart beside it, you'll see the MVCs. Is that the question you're kind of...

MICHAEL JAY LAPIDES: Yes. Except I'm not just referring to the midstream segment, I'm referring to the entire business.

So if I look on Slide 5, the table on the right-hand side, like very easy question. How much of the EBITDA of crude oil is take-or-pay versus volumetric and albeit fixed fee but volumetric. And same thing on interstate transport, like how much of that is take-or-pay?

THOMAS E. LONG: And Michael, we don't have that broke out here right now. We'll have to follow back up with you later.

MICHAEL JAY LAPIDES: Got it. Happy to follow up with Bill and team offline. Just one other question. Can you help clarify a little bit about the in-service dates on Mariner East 2X? And just kind of what you're seeing and when you expect the in-service? I know you mentioned it on the call in the prepared remarks. But can you just clarify the time line for that?

MARSHALL S. MCCREA: You bet. This is Mackie. Well, first of all, we are bringing on additional capacity, about 25,000 barrels June 1. So that's very positive, and that is already committed with demand charges. And then we now have moved slightly from fourth quarter this year to first quarter of next year, our next significant expansion completion of Mariner. And in the final 2X, we expect to be completed in the second quarter of '21.

OPERATOR: Your next question comes from the line of Spiro Dounis with Crédit Suisse.

SPIRO MICHAEL DOUNIS, DIRECTOR, CRéDIT SUISSE AG, RESEARCH DIVISION: Just want to go back to the cost cuts you all mentioned in the slides, it looks like $200 million to $250 million for this year versus budget. How much of that showed up in the first quarter? And I guess, how should we think about you realizing that the rest of the year? And then more broadly, how much would you characterize as sustainable so we could see it happen again in '21 versus maybe just deferring out some costs?

THOMAS E. LONG: Yes. Listen, this is Tom. Do you mind just starting over with the question when it -- when you started off, it came through a little fuzzy.

SPIRO MICHAEL DOUNIS: Yes. No worries. Hopefully, this time works better. Just on the cost cuts, the $200 million to $250 million, just curious how much of that showed up in the first quarter? And then how should we think about you realizing that those savings for the rest of the year? In other words, how much of that is really sustainable versus just deferred?

THOMAS E. LONG: No, I would put all of it really as sustainable. And as far as how it's spread through the year, it's going to be spread very even through the year. If you really take the first quarter and evaluate that and then go kind of go through -- remember, this is G&A and OpEx. So if you will kind of spread those throughout the year, you'll see those. And we may actually, as we continue to evaluate, we may be able to identify additional amounts there.

SPIRO MICHAEL DOUNIS: Okay. Perfect. Second one, just on M&A. Would still of the eager mindset as far as that goes now, it would seem like this is an opportune time to consolidate the industry here. You guys have obviously not been shy about doing that in the past where you could. So I would appreciate your view right now in the M&A landscape, both on individual assets, but also just on corporate M&A too.

KELCY L. WARREN, CHAIRMAN & CEO OF LE GP, LLC, ENERGY TRANSFER LP: Yes, this is Kelcy, and you're correct. It's just part of our business plan and always will be. We are -- it's all hands on deck right now to make sure our business is healthy and performing. But it is something that is -- that we look at every day. We talk about it every day. I will tell you that the one thing, if there's any guidance I give you on this is that we would not do anything that was not deleveraging. So you can then begin to look at possibilities that may or may not be there and that would certainly need to apply to whatever possibilities there were.

OPERATOR: Your next question comes from the line of Christine Cho with Barclays.

CHRISTINE CHO, DIRECTOR & EQUITY RESEARCH ANALYST, BARCLAYS BANK PLC, RESEARCH DIVISION: So if I could start with the CapEx. You guys say that 70% of this year's CapEx is for projects that are more than half complete or supposed to be in service this year or next year. For the $300 million to $400 million that you're evaluating to further reduce, would you say that is looking to reduce spend on the projects that are supposed to come online this year or next year? And you're maybe thinking about deferring it, or are those reductions mostly tied to projects that are contemplated to be in service post 2021?

MARSHALL S. MCCREA: This is Mackie. I'll start, if Tom wants to follow up. But it's a little bit of both. We -- some of the projects, we're optimistic and hopeful that we do come in under what our expectations and what our budget is. And then some of these are we -- whether we get them completed by the end of this year or push them into next year, and then kind of the third basket is, are there some that as we evaluate it, as I said earlier, over the coming weeks and months, does it make sense to defer those and push some of those projects in next year and out of 2020.

CHRISTINE CHO: Okay. That makes sense. And then if I could go -- move over to the DAPL expansion, can you tell us how much you're expanding it? And what sort of flexibility do the customers have to potentially push back this in-service date if we are in a prolonged downturn? I'm just trying to reconcile the need for additional capacity versus the current outlook for production in the basin. And would be curious if this is one of those projects in that $300 million to $400 million being evaluated.

THOMAS E. LONG: Certainly, it's in that one of those baskets. But right now, DAPL has been such an incredible project, and it's been such a shot in the arm for North Dakota and really, for our country, so it's gone exceptionally well. Our open season went exceptionally well. We do expect to have expanded in 2021, and we're hopeful to get the final regulatory approval soon. However, that doesn't mean that depending on circumstances and depending on shippers and shippers' interest in different approaches that there might not be some options or some things we can do. But the bottom line is we have commitments. These are demand charge based commitments for long periods of time. And if other arrangements are not made and we're in service the second quarter of 2021, those commitments will kick in.

CHRISTINE CHO: And are you able to tell us how much you're going to be expanding by?

THOMAS E. LONG: The open season is completed, as you know. And right now, we anticipate expanding somewhere in the 740,000, 750,000 barrel range. That certainly can change as discussions go on, but that's kind of a ballpark.

OPERATOR: Your next question comes from the line of Pearce Hammond with Simmons Energy.

PEARCE WHELESS HAMMOND, MD & SENIOR RESEARCH ANALYST, SIMMONS & COMPANY INTERNATIONAL, RESEARCH DIVISION: Two questions here. First, other midstream companies have highlighted some strength in the LPG export business. And it sounded like in your prepared remarks that you're seeing the same. So I wanted to get some color from you on that. And then the second question, which dovetails with the first, which -- what is your outlook for ethane, propane and butane demand this year?

MARSHALL S. MCCREA: This is Mackie again. What an exciting part of our business. We needed to build fracs after all the transportation we signed up, then we need to find a home as we kind of saturated the industry, kind of saturated the domestic market. We kicked off Mariner South a number of years ago, and that's gone exceptionally well for us, and we're close to adding another, as you heard, 300,000 barrels of LPG capability, and it's much needed with all the downturn and all the turmoil and everything that's been going on in the last 30, 45 days. That's been a shining light. We have tremendous amount of demand. We're in constant conversations. We're in the process of selling out whatever capacity that we're adding for some periods of time, and we see that to be a significant growth vehicle for our partnership for many years to come.

PEARCE WHELESS HAMMOND: And then my quick follow-up pertains to storage upside as well as on the SPR. But tell us a little bit more about the upside that you've got from your storage capabilities. And what does it mean being the successful bidder on that lease crude oil storage capacity in the SPR?

MARSHALL S. MCCREA: Well, as you can imagine, right now, having storage of a number of products, of course, including crude is very valuable. Our existing Nederland and other stores that we have around the state and the country has been benefited in a big way and will for the remainder of this year and the contango spreads. And likewise, the SPR, winning that bid was important from the standpoint of revenue for us in locking and contango, but it also is as important for our producers. When it looked like there weren't going to be any markets and that all these barrels that we buy on a consistent basis and transport on a consistent basis to try to kind of make sure there was a market for all that, we thought it was necessary for our customers to find more space, more capacity for their barrels. And so things certainly have slowed down on the market side, but we needed that to have that, call it, market for all the barrels that we buy for our customers to make sure our customers' barrels move.

OPERATOR: Your next question comes from the line of Ujjwal Pradhan with Bank of America.

UJJWAL PRADHAN, ASSOCIATE, BOFA MERRILL LYNCH, RESEARCH DIVISION: First one on the Haynesville Basin and some of your assets that you have operating there. We have heard from a few of your peers on growing interest in the assets and activity in the basin. Can you speak to what you're seeing or what your expectations are across your gathering assets as well as the Tiger pipeline?

MARSHALL S. MCCREA: Yes. The Haynesville has been an interesting area, in that it had tremendous potential in growth for a number of years and then slowed down for a number of years, and now it's got its second leg.

And we've, on any given day, we're moving 2 Bcf and the interesting thing, and the very beneficial thing about Haynesville and our Tiger system is it's a bidirectional system. So not only can we move east, which is predominantly where gas is always wanting to go, but where now -- the interest is find its way back into Texas into our intrastate network, ultimately find its way down to the Ship Channel into LNG markets. So that's been a very positive growth area for our assets. We expect those to stay -- to keep Tiger full for many years to come. Likewise, the gathering assets we have kind of in North Louisiana, especially the gas that needs treating, even in these times, when there's been kind of some areas where gas is -- I mean, products are being shut in, we're seeing growth in the leaner gas plays, which is, of course, the Haynesville play. So that's a really -- as I mentioned earlier, at a tough time when a lot of gas and oil is being shut in, we see that as a growth area, even as we speak.

UJJWAL PRADHAN: Got it. And maybe on your expectation for positive free cash flow starting in 2021. Could you please speak to the commodity price and spread opportunity assumptions baked in it? And how big of a priority this is for ET today?

MARSHALL S. MCCREA: Well, we've not put out guidance for 2021, as you know. But I think it is worth talking about when you look at 2019, we had over $3 billion of what we call retained cash flow. That's above the distributions. When you really look at this year and you see where our guidance -- where we currently have guidance, you'll see that we have free cash flow, we're right at that cusp. When you get to the $2 billion and less than $2 billion for 2021, you can really look and see what type of now free cash flow we have. And that's what we're going to continue to use as our EBITDA grows as these projects we've talked about today. That's what we're going to be using to start lowering the debt levels from that standpoint. But we'll probably talk more about later in the year on 2021. Right now it's about looking at where you think the curves are, where the price deck when you look out at some of the longer-term price decks.

OPERATOR: Your next question comes from the line of Keith Stanley with Wolfe Research.

KEITH T. STANLEY, RESEARCH ANALYST, WOLFE RESEARCH, LLC: I wanted to start just with 2 clarifications. So on the Bakken pipeline, do you have firm commitments for most of that capacity step-up from 570,000 to 750,000 barrels a day? Or is the expansion size larger than the commitments? And then second one was just I want to confirm that the $200 million inventory write-down headwind in EBITDA for the first quarter. You're assuming that headwind is in the $10.6 billion to $10.8 billion guidance for the year. So absent that, the guidance would have been even $200 million higher.

MARSHALL S. MCCREA: I'll start -- this is Mackie. I'll start with the first, and let Tom on the second. Yes, in our open seasons, we've got commitment for significant volumes. And so the vast majority of the capacity that we're expanding is demand charge capacity.

Of course, we've got a whole room for walk-up and that type of capacity. But yes, the majority of it is demand.

THOMAS E. LONG: And as far as the second part of your question, I would say that the $213 million you saw in the first quarter, yes, it is baked into the $10.6 billion to $10.8 billion guidance we have.

KEITH T. STANLEY: Okay, great. And then, Tom, on the balance sheet, can you just remind us the leverage target for the company and you talked about using free cash flow starting next year to potentially be a vehicle to pay down debt. Has the strategy changed at all on how you're approaching the balance sheet and leverage, just given what's happened in the oil market?

THOMAS E. LONG: Obviously, a very, very good question, Keith. And no, it is not. We're going to continue to target that 4 to 4.5. We -- when you really look out at 2021, I know we keep using the free cash flow term, but we're excited to get into that phase of being able to now start paying down the debt. As you see projects come on, as we continue to pull the other levers of lowering some of the CapEx. So a lot of our growth is going to come from nothing more than a lot of the projects you've heard us talk about here today. But nothing changed as far as strategy goes.

OPERATOR: Your next question comes from the line of Colton Bean with Tudor, Pickering, Holt & Company.

COLTON WESTBROOKE BEAN, DIRECTOR OF MIDSTREAM RESEARCH, TUDOR, PICKERING, HOLT & CO. SECURITIES, INC., RESEARCH DIVISION: Just a quick clarification around the contango discussion thus far. I think, Tom, you may have noted that the 2.5% to 5% capture the marketing contribution there. But the footnote looks like there should be some degree of earnings and fee-based as well. So is the bulk of the benefit showing up in spread? Or is the market base rate that you're charging yourself is that actually accounting for the majority showing up in fee?

THOMAS E. LONG: I would not -- let me think through that for a moment. We do have some showing up in the fee, the portion -- any of the portion that's held by the marketing arm, but I would not say the majority of it, no.

COLTON WESTBROOKE BEAN: Okay. And so fair to say that the market base rate has not moved up materially, just given what we've seen in the last 1.5 months or so?

THOMAS E. LONG: That's correct.

COLTON WESTBROOKE BEAN: Got it. And then just on the midstream, as you evaluate your Northeast gathering footprint, can you frame for us the relative drivers versus rich exposure and particularly in the condensate handling?

MARSHALL S. MCCREA: This is Mackie again. Yes, clearly condensate handling has become an issue, really not just in the Northeast, but elsewhere. We are working closely with producers that really don't have a lot of options to utilize some of our assets to help them move their condensate. How long this will last? Who knows. Like we said earlier, we don't think this is going to last a long time and things are going to recover. Demand is going to increase, and we'll find a home for that. But around the condensate, we really don't see that as a long-term problem, and we're doing everything we can to help producers in the short term. And then I don't know if I answer your entire question or not.

COLTON WESTBROOKE BEAN: Yes. That's helpful. And I guess, one, I guess, have you seen any curtailments to date on condensate? And then two, just kind of your broader rich gas exposure relative to dry.

MARSHALL S. MCCREA: Yes. I'm not aware of any condensate that has impacted ours. I'm mainly talking about condensate that's with other midstream companies where they're looking for help for their -- a home for their condensate.

OPERATOR: Ladies and gentlemen, we have reached the end of the question-and-answer session, and I would like to turn the call back to Mr. Tom Long for closing remarks.

THOMAS E. LONG: Thank all of you once again for joining us today. We really do appreciate your support. We really enjoy talking with you, and we look forward to follow-up calls after this one. Thank you.

OPERATOR: This concludes today's conference. You may disconnect your lines at this time. Thank you for your participation.

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**Load-Date:** June 18, 2020

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