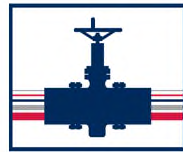


Houston, TX | November 2, 2020

3Q 2020 Earnings Package



PLAINS
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Index

- Conference Call Transcript
- Conference Call Slides
- PAA / PAGP Earnings Release and Guidance
- PAA Non-GAAP Reconciliations



Third-Quarter 2020 Earnings Conference Call

Monday, November 2, 2020

Roy Lamoreaux:

Thank you, Christi. Good afternoon, and welcome to Plains All American's third-quarter earnings conference call. Today's slide presentation is posted on the Investor Relations, News & Events section of our website at plainsallamerican.com, where audio replay will also be available following our call today. Later this evening we plan to post our "Earnings Package" to the Investor Kit section of our IR website, which will include today's transcript and other reference materials. Important disclosures regarding forward looking statements and non-GAAP financial measures are provided on slide 2 of today's presentation. A condensed consolidating balance sheet for PAGP and other reference materials are located in the appendix.

Today's call will be hosted by Willie Chiang, Chairman and Chief Executive Officer and Al Swanson, Executive Vice President and Chief Financial Officer. Additionally, Harry Pefanis, President and Chief Commercial Officer; Chris Chandler, Executive Vice President and Chief Operating Officer; Jeremy Goebel, Executive Vice President – Commercial; and Chris Herbold, Senior Vice President and Chief Accounting Officer, along with other members of our senior management team are available for the Q&A portion of today's call.

With that, I will now turn the call over to Willie.

Willie Chiang:

Thanks, Roy. Hello everyone, and thank you for joining us. This afternoon we reported solid third-quarter results in all three of our operating segments, which Al will discuss in more detail during his portion of the call. A summary of highlights from today's call are provided on slide 3, which reflects our progress in a number of areas,

including: raising our 2020 Guidance, executing non-core asset sales, providing 2021 preliminary guidance, targeting an additional \$600 million or more of asset sales, and progressing our shift to positive free cash flow, which leads to today's buy-back announcement. A few of these are replicated in our key messages for today's call (summarized on slide 4), which highlight positive momentum as we enter 2021.

- First, we are well on our way in our transition to positive Free Cash Flow after distributions.
- Second, our year-to-date performance continues to highlight the value of our integrated business model.
- Third, we continue to successfully execute across each of our key initiatives.
- And as a result of our progress and our outlook, we have announced a \$500 million equity buy-back program that we plan to execute in a balanced manner, allowing us to continue to reduce leverage while maximizing value to shareholders. Let me elaborate on each of these points a bit further.

Starting with Free Cash Flow, we have reached an inflection point where going forward we expect to generate meaningful Free Cash Flow after distributions and net investment capital on an annual basis. As illustrated on slide 5, we expect 2021 Free Cash Flow after distributions to total roughly \$300 million, or over \$900 million when including our \$600-plus million of additional asset sales we are targeting in 2021. Our preliminary guidance for 2021 Adjusted EBITDA is plus or minus \$2.2 billion. This includes the estimated impact of our targeted asset sales and assumes a \$50 million contribution from our Supply & Logistics segment. We intend to provide formal guidance for 2021 on our February earnings call.

Regarding our 2020 year-to-date results, as shown on slide 6, our business has performed well despite a very challenging year. This afternoon we increased our full-year 2020 Adjusted EBITDA guidance to \$2.585 billion, which is now in-line with the

initial full-year 2020 guidance we furnished in February, pre-Covid 19 and is \$85 million above our most recent August 2020 guidance.

These results highlight the value of our integrated business model and while challenging to forecast, we have demonstrated our ability to capture margin-based opportunities during periods of volatility through our extensive asset base. Our integrated model, meaningful term supply, and committed acreage position also enhances our ability to move additional volumes on our system over a long time horizon. As a case in point, and as illustrated on slide 7, you can see the significant increase in our term-supply and Permian acreage position, which we believe is highly strategic in the current environment and brings additional value to the table as we work with customers, partners and peers to optimize and rationalize infrastructure capacity. Additionally, as summarized on slide 8, we have a strong portfolio of long-haul pipelines representing a combination of supply-push and demand-pull pipelines. These systems are underpinned by long-term third party MVCs, and are further complemented by long-term dedications of lease supply to our lease gathering business and strong integration with our hub terminals. Included on the slide is a summary of third-party contractual support underpinning our key long-haul systems and the average remaining term of these contracts. In addition to our MVCs, our termed-up lease supply provides us an additional level of insurance that our pipelines will continue to be utilized in a variety of market conditions.

Throughout the year we've continued to execute across a number of key initiatives, which are recapped on slide 9. We continue to operate safely and reliably, embracing COVID protocols in both the field and offices, social distancing, and working remotely as conditions warrant. I want to acknowledge and thank all of our PAA team members for their hard work and dedication to driving continuous improvement, which is evident through our year-to-date safety and environmental performance metrics.

As discussed previously, and as Al will discuss further, we are squarely focused on maximizing Free Cash Flow, reducing leverage, minimizing investment capital, and increasing shareholder returns. Regarding portfolio optimization, on October 15th we closed on the sale of our LA terminals, generating proceeds of approximately \$200 million, which brings year-to-date proceeds from asset sales to approximately \$450 million. Additionally, we announced a strategic asset swap with IPL – Interpipeline that reinforces our NGL asset position at our Empress complex in Canada. We continue to advance additional asset sales opportunities and have established an additional \$600 million as our 2021 asset sales target, with the potential for upside to this target.

We have also made solid progress in our efforts to streamline and drive efficiencies across all aspects of our business, and we've realized meaningful cost savings. We currently expect to realize \$125 million a year or more of fixed-cost savings that should endure in future years. This exceeds the high-end of our previously estimated cost savings range of \$50 to \$100 million. At the same time, we've continued to advance our Sustainability initiatives. Highlights of our progress are summarized on slides 18 through 23 of today's slide presentation.

Before I turn the call over to Al I'd like to touch on a couple of other matters that are currently topical. First, regardless of the outcome of tomorrow's election, our long-term outlook is constructive. We recognize that a potential change in the Administration, could create headwinds for the industry and for Plains; however, it could also bring benefits, particularly for those with pipe in the ground. Slide 34 of the Appendix outlines some of our thoughts regarding a potential change in the Administration.

Additionally, with respect to an energy transition, we believe alternative sources of energy will continue to grow and will be an important addition to meeting global energy needs, but we also firmly believe that hydrocarbons will be needed for decades and will remain an integral part of global energy supply.

As illustrated on slide 10, we believe global demand recovery is a question of “when” and not “if” which, over time, should drive a return of constructive oil price levels, sustainable North American production, and higher production levels in key onshore shale basins. The location, scope and flexibility of our integrated system matched with the capabilities of our team positions Plains favorably in such an environment. In short, we believe we are well positioned to manage through the current environment, and benefit as demand recovers over time.

In regards to energy markets, current negative investor sentiment has impacted the entire sector, including our equity securities, which continue to trade at levels that ascribe minimal value to the long-term durability of our business. We believe this provides a significant value-investment opportunity. For that reason, and considering our progress across multiple key initiatives and our constructive longer-term outlook, today we announced a \$500 million common equity repurchase program. As AI will discuss further, we plan to take a balanced approach and allocate up to 25% of our Free Cash Flow after distributions to buybacks and 75% or more to continue to reduce leverage over time. As AI will discuss further, this will include a \$75 million allocation to buybacks in 2020 and up to a 25% allocation of Free Cash Flow after distributions in 2021.

With that I will turn the call over to AI.

AI Swanson:

Thanks, Willie. During my portion of the call, I’ll recap our third-quarter results, review our current capitalization, liquidity, and leverage metrics and provide additional color with respect to our outlook for 2020 and 2021.

As shown on slide 11, third-quarter fee-based Adjusted EBITDA of \$620 million exceeded expectations in both the Transportation and Facilities segments. On a comparative basis, Transportation Segment results increased over second-quarter 2020, driven by a \$25 million timing benefit related to MVC deficiencies that occurred during

the second quarter, in addition to a modest increase in tariff volumes and continuation of cost optimization initiatives. Relative to third-quarter 2019, the slightly lower segment results reflect the COVID-related impacts on producer activity levels. Additionally, one accounting related item I will note is that in the third quarter we recorded a \$91 million non-cash impairment within our investments in unconsolidated entities attributable to a joint venture in the midcontinent area. With respect to the Facilities segment, our third-quarter results exceeded expectations primarily due to operational cost savings and higher than expected revenues at our Cushing facility. On a comparative basis, the segment was in-line with second-quarter 2020 and third-quarter 2019, effectively absorbing the impact of asset sales. Third-quarter 2020 S&L results of \$61 million benefited from contango-margins as a result of transactions entered into earlier in the year.

Moving to our capitalization and liquidity, a summary of key metrics is provided on slide 12. Our long-term debt to Adjusted EBITDA ratio of 3.3 times benefitted from trailing twelve months S&L results of \$437 million. The leverage ratio would be 3.8 times if normalized using our initial 2020 S&L Adjusted EBITDA guidance of \$75 million, reflecting leverage slightly above the high end of our target level, thus underpinning our focus on reducing leverage. This week we will repay our \$600 million February 2021 senior notes via the par call option. We have no other near-term maturities, and our total committed liquidity at quarter-end was \$2.8 billion, or approximately \$2.2 billion pro-forma for retiring the notes. We do not expect to access the capital markets for the foreseeable future.

Now I will shift to our outlook for 2020 and 2021, which is summarized on slide 13. As Willie mentioned, we have increased our 2020 Adjusted EBITDA guidance by \$85 million to plus or minus \$2.585 billion, which is primarily attributable to the Transportation Segment and is driven by our third-quarter results and our expectations through the balance of the year, including the visibility for timely shipment of MVC-backed volumes on our long-haul pipes.

With respect to our preliminary guidance for 2021, which is net of the assumed impact of targeted asset sales, underpinning our outlook is an assumption for the crude oil price environment and producer activity levels to remain relatively unchanged throughout the majority of the year. Therefore, an acceleration of demand recovery and corresponding improvement in commodity prices relative to current levels would be a net positive to our outlook and potentially favorable to our 2021 preliminary guidance. As we have communicated previously, we expect challenging market conditions for our S&L segment in 2021.

Moving to slide 14, our expectations for 2020 and 2021 investment capital remain unchanged on a combined basis, but reflects a \$50 million shift from 2020 into 2021 due to project timing. I'll note that roughly 50% of the 2021 amount is comprised of the Wink-to-Webster and Diamond / Capline projects, and roughly 20-25% is related to high-return wellhead and CDP connections that we expect to be paced with producer activity levels. The balance is associated with smaller high-return projects. A status update and high-level overview for the Wink-to-Webster and Diamond / Capline projects is provided on slides 31 and 32 of the Appendix of today's slide presentation.

Beyond 2021, assuming an approximately \$50 per barrel oil price environment, we estimate our run-rate investment capital to be within a range of \$200 to \$300 million annually. Based on this range, high-return wellhead and CDP connections would represent approximately 50%. However, if we remain at current price levels, we would anticipate total investment capital to be at an even lower level. I would also note that we do not have any material capital commitments beyond 2021. Additionally, we estimate annual maintenance capital to be \$200 million or less on a run-rate basis.

We are very focused on disciplined management of our balance sheet, minimizing capital investment and maximizing Free Cash Flow. I'll note that a detailed breakdown of our Free Cash Flow is provided on slide 25 within the Appendix. As shown, our Free Cash Flow for the last twelve months is a positive \$521 million, while Free Cash Flow after distributions was a negative \$464 million.

With regard to the unit repurchase program, as Willie noted, and as summarized on slide 15 and illustrated on slide 16, we will be disciplined in how we allocate capital. We plan to allocate capital to buybacks in a balanced manner consistent with our priority of reducing leverage over time. As we generate additional Free Cash Flow and lower our leverage, we expect to be able to increase the allocation to buy-backs over time. For the balance of 2020, we currently intend to allocate up to \$75 million for repurchases, which effectively equates to the increased 2020 guidance. For 2021, we currently intend to allocate up to 25% of Free Cash Flow after distributions for equity repurchases. The allocation within this range may scale up or down depending on asset sales, financial performance and other factors. For example, in the absence of asset sales, we may allocate up to 25% of Free Cash Flow after distributions towards equity repurchases. In the event of meaningful assets sales, we may allocate a higher relative percentage towards debt reduction in recognition of the loss of EBITDA associated with the assets sold. To be clear, and this is important, we will not utilize debt to fund equity repurchases.

With that, I will turn the call back over to Willie.

Willie Chiang:

Thanks, Al. Before opening to Q&A, let me reinforce three critical points, which are summarized on slide 17.

- First, we believe we are well positioned to manage through the current environment, and emerge stronger. We have strong conviction in the durability of our business, and we have a long-term positive outlook for the future. Our asset base is well positioned to move North American production to market, and we have a prominent integrated franchise in the Permian with significant termed-up supply, committed acreage, integrated systems, long-haul MVCs, and access to multiple markets. We believe the Permian will lead the recovery and North America will

continue to be the short-cycle solution to meeting the world's supply needs. We certainly understand the longer-term transition to lower carbon energy, and we believe that ultimate global population growth and improvement of quality of life standards will drive the need for all energy sources, including conservation and efficiency. Any energy transition will be underpinned by significant allocation to hydrocarbons (including oil) for multiple decades

- Second, we are making meaningful progress on enhancing our Financial Flexibility and lowering leverage, and we remain very focused on further progress as we manage through the near-term challenges.
- And third, we will continue to drive for strong alignment with our investors and external stakeholders. We have had conversations with many of you over the past several months, and we thank you for your feedback, which has been extremely valuable to help us shape enhancements we have made and those that we are continuing to advance. We are very focused on managing our business to generate sustainable Free Cash Flow after distributions and improving shareholder returns, which has been a significant focus of today's call. I would also highlight that we have made considerable enhancements to our governance and sustainability frameworks in addition to the safety and environmental commitment that I previously mentioned. In addition to the Sustainability presentation and additional disclosures available on our website, we have included a summary overview and some additional detail within the Appendix of today's presentation that I would encourage you to review.

So, thank you again for your feedback; we look forward to continuing these discussions, and we appreciate your continued support.

With that, I will turn the call back over to Roy to lead us into Q&A.

Roy Lamoreaux:

Thanks, Willie. As we enter the Q&A session, please limit yourself to one question and one follow up question and then return to the queue if you have additional follow-ups. This will allow us to address the top questions from as many participants as practical in our available time this afternoon. Additionally, our IR team plans to be available this evening and into the balance of the week to address additional questions.

Christi, we are now ready to open the call for questions.

I would also highlight that we've made considerable enhancements to our governance and sustainability frameworks in addition to the safety and environmental commitment that I previously mentioned.

In addition to the sustainability presentation and additional disclosures available on our website, we've included a summary overview and some additional detail within the appendix of today's presentation that I would encourage you to review. So thank you again for your feedback. We look forward to continuing these discussions, and we appreciate your continued support.

With that, I'll turn the call back over to Roy to lead us into Q&A.

Roy I. Lamoreaux

Vice President-Investor Relations, Communications & Government Relations, Plains All American Pipeline LP

Thanks, Willie. As we enter the Q&A session, please limit yourself to one question and one follow-up question and return to the queue if you have additional follow-ups. This will allow us to address the top questions from as many participants as practical in our available time this evening. Additionally, our Investor Relations team plans to be available this evening and into the balance of the week to address additional questions.

Kristi, we're now ready to open the call for questions.

QUESTION AND ANSWER SECTION

Operator: Thank you. [Operator Instructions] We'll take our first caller, Shneur Gershuni from UBS. Your line is open.

Shneur Z. Gershuni

Analyst, UBS Securities LLC

Hi. Good afternoon, everyone. Maybe to start off today if we can start with the preliminary guidance for 2021, Willie, you coined a phrase something about going from support mode to efficiency mode with respect to costs. I was just wondering if you can talk us through, of the cost optimizations you've achieved, how much is baked into your 2021 guide? Is there any incremental opportunity that's not there? And maybe as part of the guidance question, if you can share with us the EBITDA associated with the planned \$600 million of sales that you outlined in your presentation?

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

Thanks, Shneur, for the question. One of the things we've really focused on is not setting a target for cost reductions. I think, as I've shared before, I've been burned too many times where you set a target. And that's exactly the number you get, whether it's a good answer or a bad answer. So we've really pushed the organization to be as efficient as we can.

So the answer to your question of how much of it is baked into 2021 guidance is yet to be determined, because we continue to make progress as we go forward. And that's why we'll give you a formal guidance on that in 2021 in February. But I do want Chris Chandler to chat a little bit about the cost savings that we've got and what the

configuration of some of those savings are. And then maybe, AI, you want to take the EBITDA question? I think, is it \$40 million that's associated with 2021 guidance? I just stole your thunder. I'm sorry about that.

Chris R. Chandler*Chief Operating Officer & Executive Vice President, Plains All American Pipeline LP*

A

This is Chris Candler. So I'll provide some additional color on the cost savings without trying to tie it to our actual 2021 plan, as Willie mentioned. But we're working very hard to ensure these savings are sustainable. We believe we've reduced our fixed costs by \$125 million to \$150 million compared to 2019, and that would exclude any benefit from asset sales or reductions in variable costs. We would expect to achieve these savings if we're in an environment similar to the one that we're currently in.

They're really from a number of categories. So it can be things like personnel costs; it's efficiency-related improvements; it's organizational streamlining; it's consolidation and closure of field offices; it's supply chain improvements; it's a reduction in the number of generators that we use to operate our assets; it's moving volumes from trucks onto pipelines; it's consolidating information systems and so on.

So we expect to sustain cost reductions in all of those categories going forward. And we'll provide additional color on that when we release our formal 2021 guidance.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

AI, do you want to add anything more to the...

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

A

Yeah. Shneur, we assumed, clearly, not all of the asset sales happening early in the year. So therefore, it's not as big of an impact that Willie mentioned, the \$40 million. That's an approximate based off of more of a midyear type of a convention.

Shneur Z. Gershuni*Analyst, UBS Securities LLC*

Q

Great. And then maybe as a follow-up, just a clarification. With respect to the buybacks, thank you for taking a formulaic approach to the buybacks. I think the transparency will be much appreciated. I was just wondering if you can clarify, if you do asset sales, does that count as part of the free cash flow and, therefore, some of that would be available for buybacks as well too as part of your 25% formula. Or is that excluded from that?

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

A

This is AI. No, it would be included. Clearly, we will use judgment as to the quantity of EBITDA that we're selling. And in my prepared comments I talked about maybe changing the allocation a little bit based on that consideration. But no, our definition of free cash flow, when we lay out the calculation on the slide, includes all investing activities, asset sales, as well as maintenance capital and the investment capital.

Shneur Z. Gershuni*Analyst, UBS Securities LLC*

Q

Perfect. Thank you very much, guys. Really appreciate the color today, and stay safe.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Hey, Shneur. I'll just make another comment. This is Willie. When we think about consensus of roughly \$2.3 billion, I don't know if you were getting after this, but as far as kind of normalizing that, we have \$50 million assumed in our S&L segment. I don't know what others have, but I've seen a \$100 million in some of the consensus numbers. As well as when you take that \$50 million plus the EBITDA, it kind of gets you to that same ZIP code if you normalize the two.

Shneur Z. Gershuni*Analyst, UBS Securities LLC*

Q

Yes, that's something we were after. Thank you for that.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Yeah.

Operator: And next, we'll go to Jeremy Tonet from JPMorgan. Your line is open.

Jeremy Tonet*Analyst, JPMorgan Securities LLC*

Q

Hi, good afternoon.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Hi, Jeremy. Good afternoon.

Jeremy Tonet*Analyst, JPMorgan Securities LLC*

Q

Hi. Just want to follow-on with the asset sales there and want to see the \$600 million, I think you've talked about it a few different ways before. How much of that is kind of incremental to what you guys have said before with asset sales? Seems like some has slid from 2020 to 2021. So just want to see what was incremental there? How far advanced are you in these? How much certainty do you have to these closing? And when you talk about debt reduction here, I don't know if I heard explicitly perhaps how they fit into that versus the other buybacks and outright debt reduction. So just wondering if you could help us on those points?

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Hey, Jeremy, let me start with this. I'm going to ask Jeremy Goebel to kind of fill in the blanks here. So we've said \$600 million. As far as potential upside, it could be several hundred for 2021. On the \$440 million that we announced – or \$450 million for 2020 against the \$600 million, all we're doing is we're kind of resetting the slate now. And going forward, our target is \$600 million-plus. So, Jeremy, you might want to chat a little bit more.

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

Hey, Jeremy. This is Jeremy Goebel. We have a continuous process of streamlining our asset base. And as we look at cost reductions, we look at the whole organization. This is Chris's [Chandler] team, it's the rest of the group around identifying which assets could potentially be sold, what is worth more to someone else than us, and does it involve looking at external markets, what do people want.

We've got substantial inbounds on certain assets, and those will be the ones that we look to sell. They're good assets, but they're better off in someone else's hands based on our use of available capital for potential de-leveraging and buybacks. So the \$450 million, as Willie said, that closed against the \$600 million this year. The way you're looking at it, potentially \$150 million again to next year. And that \$600 million target, we'd look to exceed if we can be successful in all the opportunities we're looking for.

AI mentioned the midyear convention, which gives you a sense. You guys understand the timing of investment banking processes and how they roll. So I think you'd see early as second quarter, and then stuff could go into the second half of next year, if that helps, from a timing perspective.

Alan P. Swanson

Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP

A

And, Jeremy, I think you threw in a question on the repurchase. You probably get your follow-up embedded in there. But we would look at only common equity repurchases and not either of the two preferred securities at this time.

Jeremy Tonet

Analyst, JPMorgan Securities LLC

Q

Got it. Thanks. If I'm allowed one more, I just want to go to Jeremy as far as the – you gave a great picture as far as what the demand recovery could look like. But just wondering how you think that could translate into supply side, different basins, next year. Just wondering if you could give us a flavor for – any thoughts you have for volume increases or decreases by basin across your footprint?

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

A

Hey, Jeremy. Good question. I think as we looked at it, based on – just how we talk to producers and our customers, I'd say 20% to 30% of cash flows is going to go back to shareholders, roughly 70% to 75% or 80% recycle ratio probably on the lower end for next year, at less than \$50, we assume that that's going to be the market. Our forecast, as mentioned in here, is based on \$40 to \$45 oil for next year.

What that looks like in the Permian Basin is largely flat to fourth quarter throughout the year, exit of 4.1%. Maybe there's some growth. And that's lumpy across the system based on timing of completions, but largely managing cash flow in that.

The recent wave of M&A could yield some disproportionate allocation to the Permian away from other basins. We're seeing that with some of customers, which could yield the incremental cash flow. But right now, we're sticking with roughly flat to the fourth quarter. And for other basins, you could see continued declines. But largely what you're seeing most producers do is, the declines have started in the second quarter. They are stabilizing now. You can drill an uncompleted well, and we'll try to do that throughout next year, and reevaluate as demand returns, and you get back to a more favorable pricing environment for them to get the drill bit back to work.

Jeremy Tonet*Analyst, JPMorgan Securities LLC*

Got it, thank you.

Q

Operator: And next, we'll go to Keith Stanley from Wolfe Research. Your line is open.

Keith Stanley*Analyst, Wolfe Research LLC*

Hi. Thanks. Just following up on the asset sales, can you give a sense of confidence or visibility and being able to execute at prices you think are adequate. I guess, we haven't really seen a lot of new asset sales since the pandemic. So any sort of early read you have or visibility on getting good prices?

Q

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

I'll make a comment, Keith. We have been successful in transacting on number of asset sales, as you know. I think this will take us above \$3.5 billion worth of asset sales, and we've been able to do them at good values. I don't think we're prepared to give you any more detail at this point. And as we go forward into 2021 on our guidance, if we have some additional information, we can give you some. But we wouldn't have announced our intent if we didn't have some confidence that we can move forward with these.

A

Keith Stanley*Analyst, Wolfe Research LLC*

Okay, great. And second question is just on the updated guidance for transportation for the year. It's up \$80 million. The volume outlook's pretty similar. So can you just talk a little more to some of the big changes that are causing Q3 and Q4 EBITDA to be higher in transportation than your expectations last call?

Q

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

AI, why don't you take that?

A

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

Sure. I'll take a shot at it. Yeah, no, EBITDA \$80 million volume's kind of flattish. If you recall, back in May, shortly following the pandemic, we lowered our Transportation segment quite meaningfully, about \$300 million. And the only reason I'm mentioning that is that as the business performed a little bit better in the second quarter, we had a little bit of cushion in our model. But following the big change in the uncertainties, we chose to retain some cushion in our guidance when we put it out in August.

A

And then, lower cost's being a big part of it. Some of which aren't volume related, it's just cost management. And then, a little bit of it is with some of our Canadian pipes with a average higher margin, just kind of the business mix, are really the three key things. But we did have a little bit of cushion in our model when we updated guidance last time.

Keith Stanley*Analyst, Wolfe Research LLC*

Q

Great, thank you.

Operator: And next, we'll go to Michael Lapides from Goldman Sachs. Your line is open.

Michael Lapides

Analyst, Goldman Sachs & Co. LLC

Q

Hey, guys. Congrats on a good quarter and I appreciate the announcement and the detail on capital allocation. Really, just when you think about the asset portfolio mix outside of the Permian and may be inbound into the Cushing and into the Gulf Coast, how do you think about what in the Plains portfolio over time may prove to be non-core? Like, obviously, you've got the \$600 million. You haven't disclosed what that specifically is. But when you think about kind of the other parts of the business that may not be core to kind of your long-term five-year plus strategy, how do you think about what might fit into that bucket?

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

A

Michael, I know what you're after. You're after the list which we're not going to share right now. But I'll tell you the way we think about this is everything that we do is really part of the integrated approach. So what you've seen us on the asset sales that we've transacted, probably the best example I can give you is some of the transactions we did out in California.

If you think about the ability of integrated pull-through on some of those systems, the less integrated pull-through that it has probably gives us more opportunity for some – gives it have more opportunity at value with somebody else than ourselves. So I would tell you the integrated model is very, very key. And you've seen us sell some other assets that as we think about where future outlook of capacity may go, again, if it fits better in someone else's portfolio, we've been willing to do that.

So unfortunately, I'm not going to be able to give you much specifics other than as you think about assets, things that aren't tied to integration. But the other point I would tell you is we've done quite a bit on strategic joint ventures in working with other companies in efforts of rationalization and creating more capital efficiency for multiple parties. So hopefully that helps.

Michael Lapides

Analyst, Goldman Sachs & Co. LLC

Q

No, that helps, and then just kind of a nuts and bolts question on cost management. If I look at the nine-month or the year-to-date income statement, G&A is down \$24 million year-to-date, field OpEx is down \$172 million, so call it almost \$200 million year to date. Is what you're implying that some of that will actually come back next year? Because if you're running at almost \$200 million year to date down and you're talking about kind of \$125 million – \$150 million, it almost implies some of that comes back.

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

A

I'm going to let Chris Chandler address this. But what I'll tell you is, we're very deliberate about how we think about this. Sometimes you can think about costs, and it's variable and fixed. And what we've shared with you is what we think are enduring fixed expense costs reduction, so it's truly what you'll see at a minimum versus volume related. But, Chris, why don't you share a bit more?

Chris R. Chandler*Chief Operating Officer & Executive Vice President, Plains All American Pipeline LP*

A

Sure, this is Chris. You've got the right numbers. Our combined operating and G&A costs are down almost \$200 million versus the same period in 2019. And while we can't directly compare that to the \$125 million to \$150 million reduction in fixed costs that I mentioned earlier, it is reasonable to think as some of that difference being related to variable costs and our expectations for what we expect to spend in 2021 and in future years.

The other thing to think about there is part of our cost reductions in 2020 are deferrals into 2021. These can be things like not wanting to undertake large maintenance or overhaul activities and bring outsiders into our assets in a COVID environment. If we have the flexibility within our inspection programs and the regulatory requirements, we've deferred some of those activities into 2021 primarily due to COVID. So those are just a few examples of why the numbers are different.

Michael Lapidès*Analyst, Goldman Sachs & Co. LLC*

Q

Got it. Thank you, guys, much appreciated.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Michael, this is Willie. You've talked about operating costs and G&A, and Chris touched on it. But it's more than that, right? So if you look at our maintenance capital expenses, not only do we talk about the investment capital having high returns, but the maintenance capital we've been successful in being able to bring those numbers down a little bit. That will endure over a period of time. So it's really cost across every bit of the organization and how we spend money.

Michael Lapidès*Analyst, Goldman Sachs & Co. LLC*

Q

Got it, I appreciate it, Willie. I'll follow up with a few offline. Thank you, guys.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Thanks.

Operator: And we'll go next to Tristan Richardson from Truist Securities. Your line is open.

Tristan Richardson*Analyst, Truist Securities*

Q

Hi, good evening. Thanks for all the commentary on 2021 and again, the detailed commentary on repurchase. It's more insight than we're used to. Just one quick question on the leverage target and the trigger. So that sliding scale of the repurchase allocation, is the desire to get to a certain point within the 3.0 to 3.5 times before ramping that relative percentage, or if we're in that band, it really just opens it up for you?

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

AI, do you want to take that?

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

A

No, we won't have a specific trigger, nor will we necessarily assume you've got to hit the exact low end. There's a number of variables. I think we summarized it on one of the slides that we would consider as we think about it. Clearly, the up to 25% of free cash flow after dividends is where we feel like is the right allocation until we see progress on leverage being one, but then the other variables as well with regard to just industry conditions, market conditions, et cetera. So no, we're not going to provide an exact formula for how we do it.

Tristan Richardson*Analyst, Truist Securities*

Q

Thanks, Al. And then just to follow up, curious on the fee-based 2021 versus 2020. Can you talk a little about how much we should think of as the delta there being asset sales versus new project contributions like Wink to Webster and just the strong Q1 2020 making for a difficult comp?

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

This is Jeremy. The way to think about Q1 2020 is you still didn't have all the long-haul pipes in the Permian in service. So EPIC and Gray Oak were ramping. So on the legacy pipes, there was more there. That makes it a tougher comp.

I'd say with regard to project contribution, as some of our partners I think have said earlier today, Wink to Webster ramps up this year. That's reflected in our guidance next year. Essentially, think of it as the Midland to ECHO portion will be available. We still have some origination work and some destination work that we've kind of slowed down some of the capital spend to ensure we had the maximum efficiency of capital with our partners. And so it will be later in the year, second half to early fourth quarter when that starts up full. So there's a slight ramp from probably the beginning of the second quarter through to the fourth quarter. And at that point, the TSA's trigger. So the real contribution from Wink to Webster doesn't start until the fourth quarter.

And then Diamond/Capline is really a first quarter of – very beginning of 2022 startup is the way to think about it. So this year is more of a transition year for those two projects. So you think of the comp year over year to the first quarter is largely driven by the new pipes weren't on Wink to Webster and Gray Oak. And then the fourth quarter of this year, that will be somewhat steady state until the fourth quarter of next year, and then you'll have the start of the ramps of the new projects.

Tristan Richardson*Analyst, Truist Securities*

Q

Great. Thank you, guys, very much.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Thank you, Tristan.

Operator: And next, we'll go to Ujjwal Pradhan from Bank of America. Your line is open.

Ujjwal Pradhan*Analyst, Bank of America Merrill Lynch*

Q

Thanks for taking my question and thanks for all the detailed color on the capital allocation plan so far. Firstly, just one more clarification on the asset sales. Willie, you said it earlier, the expected contribution is around \$40 million next year, assuming a midyear sale. I think that would imply around 7.5 times EBITDA multiple. My question is, is that right and could the total asset sale proceed be larger next year if the EBITDA multiple could be better than that?

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

Hey, Ujjwal, this is Jeremy Goebel. We certainly think it could be substantially better than that. We're specifically not providing detail because we're in the process of discussing with buyers. So I find it difficult to do projections on that front for that reason. But there are substantial assets which will have significant interest, and we're going to absolutely do our best to get the highest number and we look to significantly exceed that number that you referenced. I'd just say that we'll give you more color as we have it, but at this point we don't.

I'd echo Willie's comment. The way to think about non-core for us is something that doesn't meet the integration of our pipeline facilities and marketing type businesses, where we can't get the full integrated high-efficiency network that we have. And so, we're going to continue to look for those opportunities. And don't look at this as a 12-month cycle. There's a continuous pruning and simplification for us to just become very efficient.

And so, this is a continuous process and we'll update you guys as we have the opportunity to. But right now, we're kind of in the middle of the sausage making, and it wouldn't be prudent for us to advise you on specifics such as valuation.

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

A

And this is AI. My comment earlier about midyear convention was trying to illustrate that we didn't assume January 1. That was an approximate. So don't take an exactly linear calculation to that.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

I'll tell you – this is Willie. Ujjwal, another key point to make as we think about cost reductions and simplifying the business as far as streamlining. With asset sales – with assets that aren't core to you, as we've sold over the last number of years, it has really, I think, enhanced our ability to be able to streamline more because you can focus more on the key assets that you have versus trying to spread yourself across lots of different assets.

Ujjwal Pradhan*Analyst, Bank of America Merrill Lynch*

Q

Got it. Very helpful. And my second follow-up here on the federal land exposure. Sorry to go back on this, but this certainly has been a key focus as far as election is concerned. So last year, you had noted you had close to or less than, I believe, 20% of your dedicated Permian acres in federal lands. And as you're looking at your current daily volume gathered on those acres, are you able to share any level's they're at and how much of that will downstream through your long-haul pipes? And subsequently, if the respected producers have shifted production, do you expect to see the replacement volumes appearing in your system? Thank you.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

So, Ujjwal, this is Willie. I want to start on that. We talked about 20%, but what I would almost rather do is focus on the 80% that's not on federal lands. So when you think about the 80 percentage of the acreage we've got, there's a deep inventory that the producers have as far as well sites there.

And when you go to the federal lands, I think the one thing I want to highlight is that there are volumes that are flowing today as we think about potential restrictions on federal lands. The way we view it is most of that is going to be in the future. Being able to take back leases on federal lands, we don't think is in the purview right now.

And you also have the producers that have built up a pretty healthy inventory of drilling permits. So I don't want people to take away from this that any risk to federal lands takes existing volumes up our system.

I don't know, Jeremy, if you want to add anything to that?

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

A

No, Willie. I'd say it's appropriate. We talk to our customers all the time and they feel comfortable they have a contract with the federal government to develop those assets. They have multi-year inventory with options to extend. They have substantial inventory because they have much higher rig counts now than the activity. So I'd say those are in hand. I think the base case is a view that there'll be a delayed permitting process. But with multi-year inventories of drilling ahead of them, they can plan for that in advance.

So I'd say the view of everything stops immediately on day one, that doesn't make a lot of sense. Could there be delays in permitting going back to Obama era? Yes. Could it be if the Trump administration wins, I think there's a lot of permutations and it's not an on/off switch? And the State of New Mexico will have something to say about that. There's substantial revenues associated with oil and gas business.

So we feel comfortable with our customers that they're going to continue to execute. And to the extent they don't, it makes a lot of the other assets we have worked quite a bit. And you think of a tougher regulatory environment, if that impacts other operators, that can positively impact ours that are operating.

Depending upon how far the pendulum swings, we could benefit in different ways. So this is not linear and located just in New Mexico. This could impact the Williston Basin and push barrels to our systems and other places. So you have to look at this more across the entire regulatory environment and it's not a binary switch.

Ujjwal Pradhan

Analyst, Bank of America Merrill Lynch

Q

Appreciate the color. Very helpful. And if I may just squeeze a quick one. With the buyback language, you indicated you could repurchase either PAA or PAGP units. What could drive the decision between buying back those two units?

Alan P. Swanson

Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP

A

This is Al. I think the primary one will be the value and the prices of securities. Our intent will be to focus on PAA initially.

Ujjwal Pradhan

Analyst, Bank of America Merrill Lynch

Q

Got it, thank you.

Operator: We'll go next to Jean Ann Salisbury from Bernstein. Your line is open.

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

Hi, Jean Ann.

Jean Ann Salisbury

Analyst, Sanford C. Bernstein & Co. LLC

... on long-haul. Hi, can you hear me?

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

We can now.

Jean Ann Salisbury

Analyst, Sanford C. Bernstein & Co. LLC

Okay, great. I just had a market share question. If I divide your long-haul Permian volumes by total Permian, it looks like you are losing some market share from 28% in first quarter to about 22% now. Is that mainly a function of the pipelines ramping that Jeremy referenced in an earlier question? And is the current 22% stable number until Wink to Webster start?

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

Jean Ann, hi, this is Jeremy Goebel. We don't get in specifics on pipes. But what you would say is there are probably some loss in spot volumes, which would be expected. This would be a stable number. I think I'd reference you to page 8 in the presentation. We've listened to our investors and provided some more disclosure there. And we're very comfortable with our Permian long-haul position.

And one of the unique things that we haven't really ramped up is our lease supply pushing barrels to market, and that's something that we have the opportunity to do and bring barrels at the profitability, and margin is there. In some cases, we can make the same amount by selling it in basin versus shipping on a pipeline. So we have some tools that others don't. And longer-term, we'll fill our pipelines while others are looking for supply.

So the view of it's a cliff and everything goes away. Plains will be the one that has volumes on their systems all the time. As we show on, I think it's on page 4 in the presentation or page 7, we control enough volume to basically fill our pipelines if we wanted to if the arbs and the opportunities are there.

No one else can say that. So I think the view that the contracts will dictate where the volumes flow is a little bit different. We can make markets. We can do some other tools. I'd say some of the volumes that came off into the Mid-Continent, those were looking to figure out ways. And as domestic demand pulls more barrels to Cushing, you could see some move more in that direction.

So there's a lot of things at play. It's not as simple as saying it's going to be static and linear. It's market-driven. And we'll have a hand to say in that because we control enough supply to kind of push barrels to where the differentials support.

Jean Ann Salisbury

Analyst, Sanford C. Bernstein & Co. LLC

Q

Got it. Makes sense. And, yeah, I appreciate the disclosure on slide 8. Just had a quick clarifying question on that. Does that include acreage dedications and is the 90% contracted ex-basin? Is that, like, 90% of 90% nameplate, per the footnote?

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

A

Yes, the way to think about it is the 90% of 90%. And then, of our total commitments, I believe, there's 100,000 that are acreage dedication, the rest are MVC. And those that are acreage dedications are well inside of their production levels needed to fill them.

Jean Ann Salisbury

Analyst, Sanford C. Bernstein & Co. LLC

Q

Great. Yeah, I really appreciated your additional disclosure. That's all for me. Thank you.

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

A

Yeah.

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

A

You know, I think Jean Ann, this is Willie again. One of the things you're really seeing is back to my comment of growth versus efficiency mode, we are firmly in efficiency mode. And when you think about our footprint and the flexibility that it has, we're continuing to push on optimization, and we find different ways to be able to generate value versus just running more volumes on new lines.

Jean Ann Salisbury

Analyst, Sanford C. Bernstein & Co. LLC

Q

Great. Thank you.

Operator: And we'll go next to Colton Bean from Tudor, Pickering, Holt. Your line is open.

Colton Bean

Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.

Q

Thank you. So just to follow up on all the questions around the 2021 guide, if you look at the fee based portion of \$2.15 billion and add back the \$40 million that's associated with asset sales, compared to the Q4 fee based run rate, it actually looks like the numbers are up marginally. I guess, one, is that a fair characterization that from an exit to exit perspective your earnings are actually flat to actually a little bit better for fee based. And then second, is that primarily a function of Permian drilling and offsetting declines in other basins?

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Jeremy?

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

Thanks for the question. What specific numbers are you looking for? I just want to make sure I match up to the trend that you're looking at.

Colton Bean*Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.*

Q

[indiscernible] (00:51:21)

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

I'd view this largely as flat to fourth quarter as we've said from the beginning. I think that's the way to look at it, it's going to be noise but the general trend would be consistent with fourth quarter because you think you're at largely at MVC levels on the long-haul pipes and your gathering systems are basically flat production, aren't gathering, exposure outside the Permian is very minimal at this point contributing to this. So the Permian gathering trend plus the long-haul trends in the facilities are relatively stable as you see across the assets. That's the way I would look at it.

Colton Bean*Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.*

Q

Okay, so it sounds like...

Alan P. Swanson*Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP*

A

And we would intend to [indiscernible] (00:52:01) provide more detailed guidance.

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

And another thing to think about is, remember the basis for this and I think it's somewhere in the presentation but it says \$30 to \$45, we're basically assuming close to 80% refining utilization in that neighborhood for the downstream pipes. So, anything better than that, that's going to drive potential outperformance.

Colton Bean*Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.*

Q

Understood. And just briefly on the \$200 million to \$300 million of long-term investment, you mentioned the 50% that might be allocated to well connects, could you just frame at a high level what the expectation be for that other 50%, just the types of projects?

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Sure. You think about it just facilities types expansions, we have a lot of exposure in Canada, potentially expansions of just along the pipeline system. Domestically, it could be, like I said, facilities in and around some of our terminals and docks and assets. But the vast majority we would look at, and it's all going to be paced, time independent, and somewhere between, as the numbers would articulate, \$75 million to \$150 million depending on pricing environments around some of our gathering systems.

And those we have a very high threshold, and Chris's team has worked really well with the commercial team and driving down cost 30% to 40% on a per unit type gathering cost. So we're going to look at even driving further efficiencies by recycling pumps and equipment as production flows from one area to the other. So we're going to keep driving that sustaining capital number down, and in a very cost effective – in a very operationally and safe way. But we're looking at that number and we hope to continue to beat that number and drive it down. What would be a really big win for us is if producers continue the trend of coming behind existing pads and wells, then we're going to get free production and that's when the sustaining capital really drops.

So in the Delaware Basin, where we have a lot of gathering exposure, if you're not building laterals, all you're doing is coming behind existing batteries. That's when that number can get really low. And that's what we're looking forward to as producers get more and more efficient.

Colton Bean

Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.

Q

Understood, I appreciate the detail.

Operator: And next we'll go to Gabe Moreen from Mizuho. Your line is open.

Gabriel Moreen

Analyst, Mizuho Securities USA LLC

Q

Hi. Good afternoon, guys. Two quick ones for me. One is on the balance sheet and the leverage metrics, just wondering how the new capital return framework fits within, I guess, the goal of maybe being investment-grade again at all the agencies and also whether the agencies, I guess, that have unit IG are comfortable with the plan here?

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

A

AI?

Alan P. Swanson

Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP

A

We believe it is compatible with IG, and we are taking a very disciplined approach to that allocation. Probably what's embedded under it is what you're hearing us talk about is being free cash flow positive, one, after distributions and 75% of that being allocated to reduce debt, the absolute reduction of debt, not counting on EBITDA growth, et cetera, to necessarily delever. So it's a very disciplined approach. We think it is consistent with IG metrics. And ultimately, if we don't generate free cash flow after dividends, we won't be buying in any equity in 2021 or beyond. So that's a little bit of where we're intensely focused. I think you kind of heard that in Willie's comments on running a very disciplined approach to how we run the company.

Gabriel Moreen*Analyst, Mizuho Securities USA LLC*

Q

Thanks, Al. And then maybe as a follow-up for me on election eve, I don't want a promise of have read my lips, no new acquisitions. But I'm just curious with all the talk about consolidation within I guess the energy sector at large, how the capital return frame work and I guess the focus on dispositions would fit into I guess a general viewpoint of midstream consolidation, and whether assets that are attractive and ancillary to your footprint come to market, whether you pull the trigger based on your current I guess, guidance and outlook there.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

Gabe, this is Willie. When we think about – I've talked about rationalization. A lot of the things that you've seen in our playbook around strategic joint ventures in doing things that are leverage-friendly and accretive. I think you're going to see more of those. Pure asset sales in some of the assets we've got, I think valuation differentials will probably create a little bit of hesitation to move on some of those. So hopefully that's helpful.

Jeremy L. Goebel*Executive Vice President-Commercial, Plains All American Pipeline LP*

A

Gabe, this is Jeremy, just a couple other thoughts. One, our securities, we're buying them now, we're not issuing any rights. I think us using our currency to buy something is largely off the table. What we're looking more is cashless transactions. As Willie said, it's a relative value exercise. The seller is less concerned about the absolute value at that point. You can still enter into strategic JVs with others and get to a point where you extract the synergies on a relative basis. And so those are tougher deals to pull off, to be honest with you, but the industry is motivated to get towards getting the right answers and taking out idle capacity and getting to a point where you can have reasonable returns.

So I think we'll continue to look for opportunities to do that. But our focus will be doing it in a very disciplined way and getting valuation right and doing it in a cashless manner where you can still extract the synergies.

Willie C. W. Chiang*Chairman & Chief Executive Officer, Plains All American Pipeline LP*

A

I think the other way to think about this, Gabe, is you've heard us talk a lot about driving free cash flow plus and all the levers that go into that. So for us to do something that would increase debt maybe near term for a long-term return, that's just not in the playbook right now.

Gabriel Moreen*Analyst, Mizuho Securities USA LLC*

Q

Thanks, guys.

Operator: And next we'll go to Sunil Sibal from Seaport Global Securities. Your line is open.

Sunil Sibal*Analyst, Seaport Global Securities LLC*

Q

Hi, good afternoon, guys, and thanks for all the clarity. Also, thanks for taking my question. So a couple of questions. So first, when we look at the transportation segment, it seems like this quarter you benefited about \$65 million or so from the MVC payment. How should we think about that going forward? Obviously, you're guiding to

a kind of similar level of activity where you are going forward. And then how should we also think about that in the context of your customer credit quality? Thanks.

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

A

AI, do you want to take that?

Alan P. Swanson

Chief Financial Officer & Executive Vice President, Plains All American Pipeline LP

A

As far as the fourth quarter, we expect to see shipments roughly in line with the contractual requirements. Clearly, if that doesn't happen frequently, there's a delay and you might see the collections actually come in first quarter of next year, et cetera, if that was the nature of the question. Clearly, with regard to the third quarter, we had some of that MVC amount related to second quarter, and some of it was self-contained inside of the third quarter itself.

Sunil Sibal

Analyst, Seaport Global Securities LLC

Q

Okay. Then my follow-up was on the industry environment. So, we've seen a fair bit of upstream M&A, just curious, what are your thoughts on how does it impact the midstream and how do you see the environment for midstream M&A? Obviously, you guys have been active in some asset transactions, but do you see the upstream M&A kind of facilitating any corporate M&A in the midstream also?

Jeremy L. Goebel

Executive Vice President-Commercial, Plains All American Pipeline LP

A

Hi Sunil, this is Jeremy Goebel. First question was, how does it impact us? And I'd say from a midstream standpoint, we generally have larger customers. And this leads to better credits, larger customers, which should be generally a benefit to us. Each individual transaction is different. And the acquirer generally will have existing relationships. So we may need to make some new friends. But generally, we have a lot to offer and a big supply position to help with marketers. And on the upstream side, we have systems that are interconnected to anyone and everyone. So we, we generally play nice in the sandbox with the bigger customers. And I think that's the trend which you would expect.

The second part of your question was associated with do you upstream yielding a midstream? I think the answer is its inevitable and it will happen. But just like investment cycles, upstream first, midstream next, downstream following, you'll see that it's going to take some time, I think there's the self-help that everybody's doing. Chris articulated a lot that we're doing on our end. I think all of our customers are in a similar boat. The distribution model and the MLPs have makes it a little bit more difficult than I think leverage is an impediment to transaction. So, there's some capital, everybody's going to have to heal up their balance sheets and get to a place to where deals can happen. So I think there's probably some time, but it is inevitable that it will happen. It's just – it may take some time to get there.

Sunil Sibal

Analyst, Seaport Global Securities LLC

Q

Got it. Thanks for all the color.

Willie C. W. Chiang

Chairman & Chief Executive Officer, Plains All American Pipeline LP

I want to thank everybody for joining our call today. Appreciate you are following us and your continued support and look forward to touching base throughout the remainder of this week and in the future. Thank you.

Roy I. Lamoreaux

Vice President-Investor Relations, Communications & Government Relations, Plains All American Pipeline LP

Thanks, everyone.

Operator: And that does conclude our call for today. Thank you for your participation. You may now disconnect.

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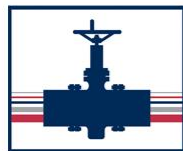
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Houston, Texas | November 2, 2020

3Q20 EARNINGS CALL



PLAINS
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3Q20 Earnings Call: Highlights

- 3Q20 Adj. EBITDA: \$682mm (exceeded expectations in all 3 segments)
- Increased 2020(G): Adj. EBITDA +/- \$2.585 B (\$85mm increase, or 3%)
- Completed sale of LA Basin Terminals⁽¹⁾ (2020 YTD asset sales proceeds: ~\$450mm)
- Furnished 2021(PG): Adj. EBITDA +/- \$2.2 B (\$2.15 B Fee-based, \$50mm S&L)
 - Net of LA Basin Terminals sale and \$600+mm of additional asset sales targeted in 2021
- 2021 FCF: roughly \$300mm (or ~\$900+ mm, including benefit of asset sales targeted in 2021)
- Announced \$500mm common equity repurchase program
- Driving for continuous improvement in alignment with investors and external stakeholders

(1) Closed on October 15, 2020, generated proceeds of approximately \$200 million.

2020(G) & 2021(PG): Adj. EBITDA guidance and preliminary guidance as of November 2, 2020.

Note: See slide 25 for definition and reconciliation of Free Cash Flow ("FCF"), and please visit <https://ir.paalp.com> for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.



3Q20 Earnings Call: Key Messages

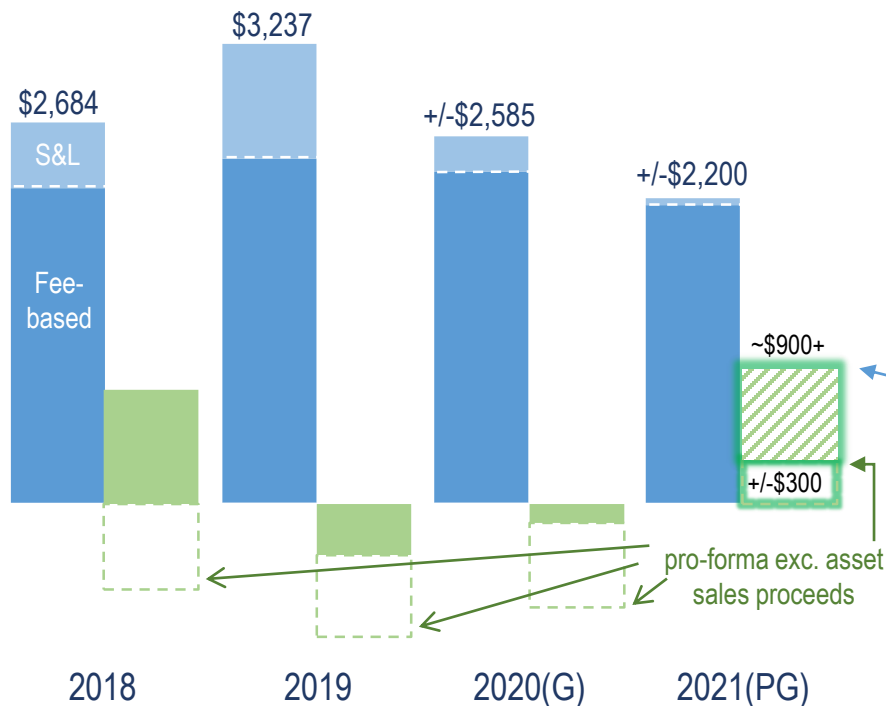
- **Shifting to positive Free Cash Flow (FCF) after distributions**
 - Visibility for additional FCF via asset sales and reduced capital investment going forward
 - Focused on continued portfolio optimization, de-leveraging & returning cash to shareholders
- **Integrated business model benefiting 2020 results; reinforces long-term positioning**
 - Significant and long-term lease-supply commitments
 - Provides producers w/ competitive price and flow assurance
 - Provides Plains flexibility to capture arb opportunities and helps enable capacity optimization / rationalization
 - Key long-haul pipelines substantially backed by long-term 3rd party contractual commitments
- **Successfully executing key initiatives**
 - Operating Excellence | FCF / Financial Flexibility | Portfolio Optimization | Streamlining / Cost Reductions
- **Announced \$500mm common equity repurchase program**
 - Balanced approach of returning capital to equity holders while continuing to reduce leverage over time
 - Buy-back allocation: up to \$75mm in 2020 and up to 25% of FCF after distributions in 2021

Transitioning to Positive Free Cash Flow After Distributions

Line of sight to sustainably generating meaningful FCF on an annual basis

\$ millions

Adj. EBITDA vs. FCF (after distributions)



- 2021 FCF after distributions: +/- \$300mm
 - excludes proceeds from asset sales (targeting \$600+mm in 2021)
 - excludes material changes in short-term working capital (i.e. hedged inventory storage activities / volume / price / margin)

- 2021 FCF after distributions equates to ~\$900+ mm when including proceeds from targeted asset sales

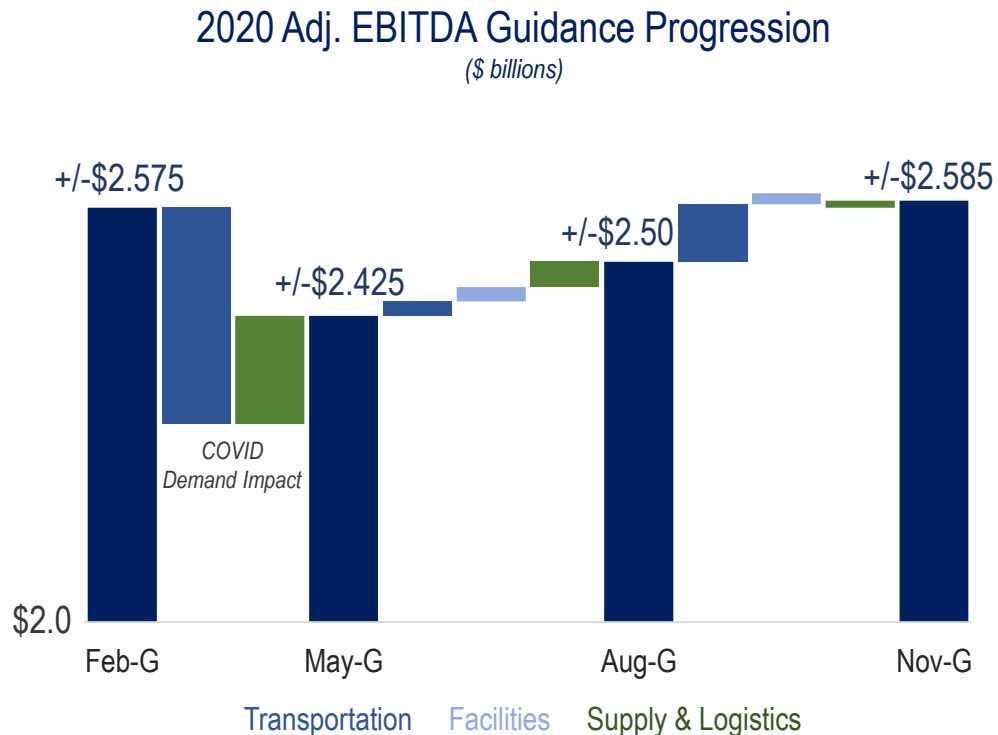
2020(G) & 2021(PG): Adj. EBITDA guidance and preliminary guidance as of November 2, 2020.

Note: See slide 25 for definition and reconciliation of Free Cash Flow ("FCF"), and please visit <https://ir.paalp.com> for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

2020 YTD Results Highlight Value of Integrated Business Model

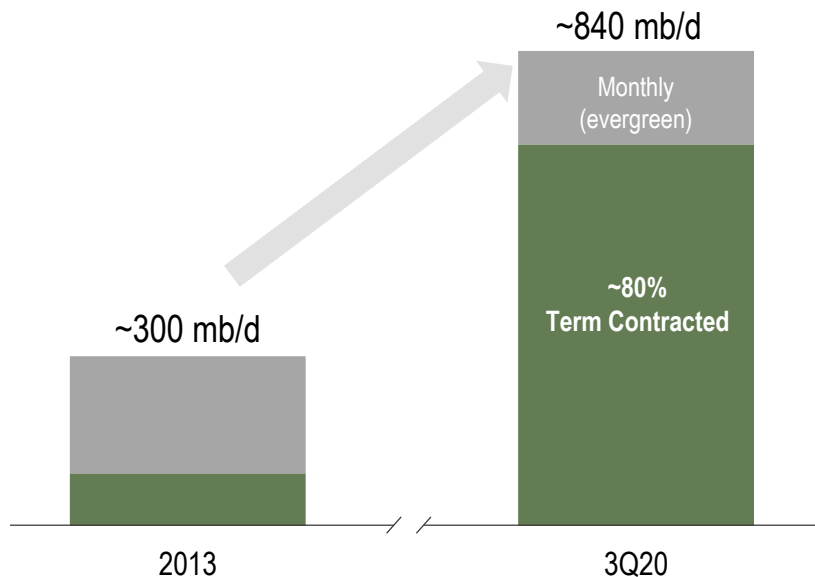
Current guidance in-line w/ initial Feb 2020(G) furnished pre-COVID

- Business has performed well despite challenging year
- Nov 2020(G) in-line w/ Feb(G)
(\$85mm above Aug(G))
- Integrated model has enabled capture of margin-based opportunities; longer-term, positioned to capture volumes on our system

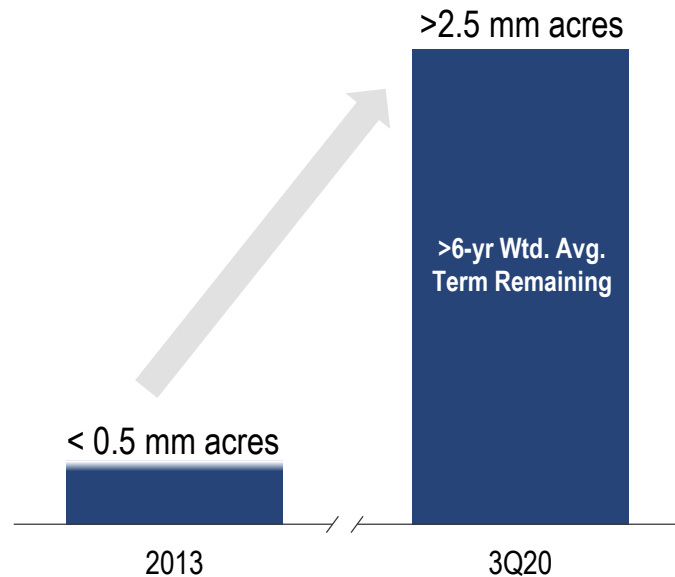


Term Supply & Committed Acreage Position: Enhances Long-Term Volume Security on Plains' Systems; Highly Strategic for Optimization & Rationalization Opportunities

Permian 1st Purchased Lease Supply
(3Q20 vs. 2013)



Permian Acreage Dedications
(3Q20 vs. 2013)



Note: Quantity and location of dedicated acres undisclosed due to confidentiality agreements.

Strong Portfolio of Long-Haul Pipelines, Substantially Backed by Long-Term 3rd Party Contractual Commitments

- Key long-haul pipes underpinned by 3rd party shipper commitments:
 - >70% 3rd Party Contracted ⁽¹⁾ 5+ yrs avg. remaining term
 - Permian Long-Haul: >70% (>90% excl. Basin); 5+ yrs.
 - Rockies to Cushing⁽²⁾: >70%; 5+ yrs.
 - Downstream of Cushing: >70%; 5+ yrs.
- Combination of supply-push and demand-pull pipelines
- Integrated w/ Plains' hub terminals at Cushing, Midland and St. James
- Further complemented by our long-term dedications of lease supply to our lease gathering business



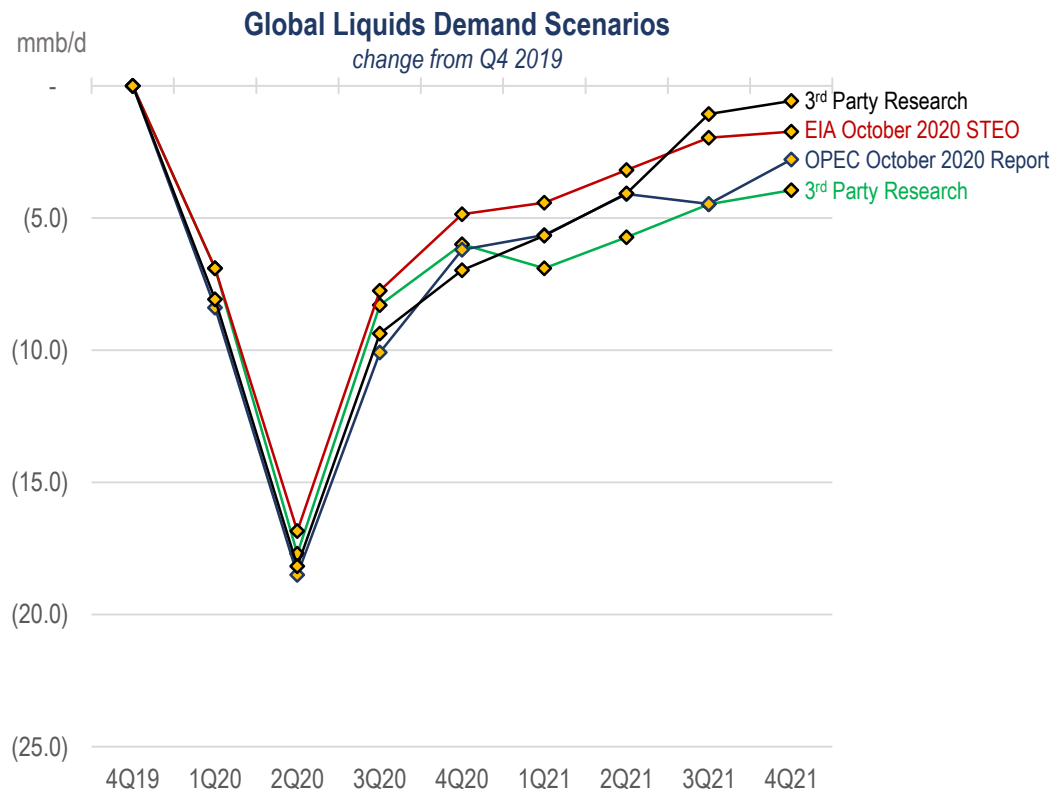
(1) Based on 90% of nameplate capacity
(2) Includes Saddlehorn and White Cliffs Pipeline systems

Executing Key Initiatives

- **Advancing safe, reliable and responsible operations**
 - 2020 YTD: ~50% improvement in Safety & Environmental performance metrics vs. 2017
- **Positive FCF inflection: maximizing FCF, reducing leverage, minimizing investment capital, and increasing shareholder returns**
- **Advancing portfolio optimization / rationalization**
 - Closed sale of LA Basin Terminals Oct. 15th for proceeds of ~\$200mm (2020 YTD proceeds: ~\$450mm)
 - Executed strategic asset swap with IPL, reinforcing Plains' strategic NGL positioning at Empress (additional transaction detail available in Appendix slide 33)
 - Advancing additional asset sales opportunities (targeting \$600+mm in 2021)
- **Streamlining & driving efficiencies across all areas of our business**
 - Captured >\$100mm of fixed-cost savings (exceeds the high-end of previously estimated range)
 - Expected to endure in future years

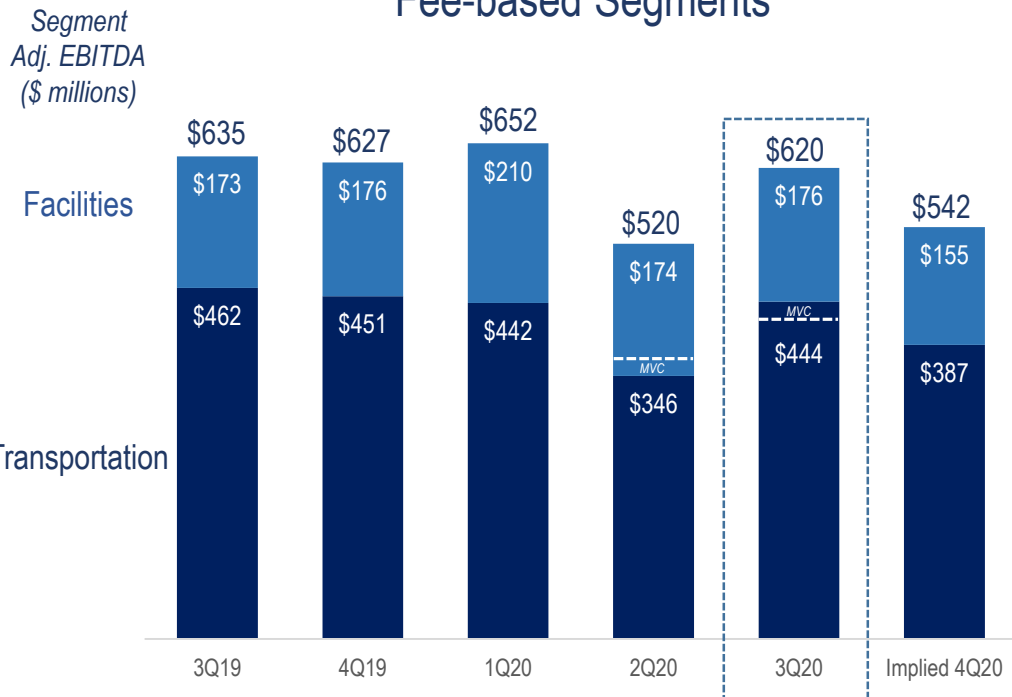
Visibility for Global Demand Recovery & Return of Sustainable North American Production

- Plains' view: demand recovery / return to constructive commodity price levels are a question of “when” not “if”
- Variables of Supply Response
 - ✓ Global demand recovery
 - ✓ OPEC compliance
 - ✓ Inventory levels / Commodity Prices
 - ✓ Upstream reinvestment levels
 - ✓ Political / Regulatory / Legislative matters



3Q20 Fee-Based Results Overview

Fee-based Segments



3Q Transportation Segment Results

- Ahead of expectations
 - Q/Q: \$25mm benefit of 2Q MVC deficiency, increased throughput, and cost reductions
 - Y/Y: lower production due to COVID demand impacts

3Q Facilities Segment Results

- Ahead of expectations
 - Q/Q & Y/Y: in-line as cost reductions and hub terminal revenues effectively absorbing the impact of asset sales

4Q vs. 3Q Comparison

- Impacted by MVC timing & asset sales, timing of expenses

Capitalization, Liquidity & Other Updates

(\$ billions)

Capitalization	12/31/2019	9/30/2020	
ST Debt	\$0.5	\$0.8	
LT Debt	9.2	9.4	
Partners' Capital	13.2	9.9	
Total Book Cap	\$22.4	\$19.2	
Credit Stats & Liquidity			Target
LT Debt / Book Cap	41%	49%	≤ 50%
Total Debt / Book Cap ⁽¹⁾	42%	51%	≤ 60%
LTM Adj. EBITDA / LTM Int.	7.6x	6.5x	> 3.3x
LT Debt / LTM Adj. EBITDA	2.8x	3.3x ⁽³⁾	3.0 - 3.5x ⁽²⁾
Total Debt / LTM Adj. EBITDA	3.0x	3.6x	
Committed Liquidity	\$2.5	\$2.8	

- Repaying \$600mm Feb-2021 Sr. Notes in Nov-2020 via par call option
 - Pro-Forma Committed Liquidity: \$2.2 B
 - No other near-term maturities
- Do not expect to access capital markets for foreseeable future
- 2021: 75+% of FCF after distributions to be allocated to debt reduction

(1) "Total Debt" and "Total Book Cap" include short-term debt for purposes of the ratio calculation.

(2) Targeted leverage assumes normalized S&L contribution.

(3) Reflects 3Q20 actual (not adjusted for normalized S&L or ~\$25mm of cash on B/S). For illustrative purposes, would be 3.8x using S&L Adj. EBITDA of \$75mm per 2020(G) furnished February 4, 2020.

2020 Guidance Update & Outlook for 2021

- 2020(Nov-G) increase driven by 3Q20 results & reflects expectations through balance of 2020
- 2021(PG) Adj. EBITDA: +/- \$2.2 B (\$2.15 B fee-based, \$50mm S&L)
 - Net of LA Basin Terminals sale (closed in Oct-20) and assumed impact of 2021 targeted asset sales (\$600+mm)
 - Assumes crude oil price environment & producer activity levels remain relatively unchanged throughout 2021 (1H:\$40, 2H:\$45)
 - Acceleration of demand recovery & corresponding improvement in commodity prices relative to current levels would be a net positive

(\$000s, except per-unit results)

Adj. EBITDA	2020 (Aug-G)	2020 (Nov-G)	Δ
Transportation	\$1,540	\$1,620	+\$80
Facilities	700	715	+\$15
Fee-Based	\$2,240	\$2,335	+\$95
S&L, other	260	250	(\$10)
Total	\$2,500	\$2,585	+\$85
Per-Unit			
Implied DCF / CUE ⁽¹⁾	\$2.23	\$2.35	+\$0.12
Adj. NI / Diluted Unit ⁽²⁾	\$1.49	\$1.59	+\$0.10

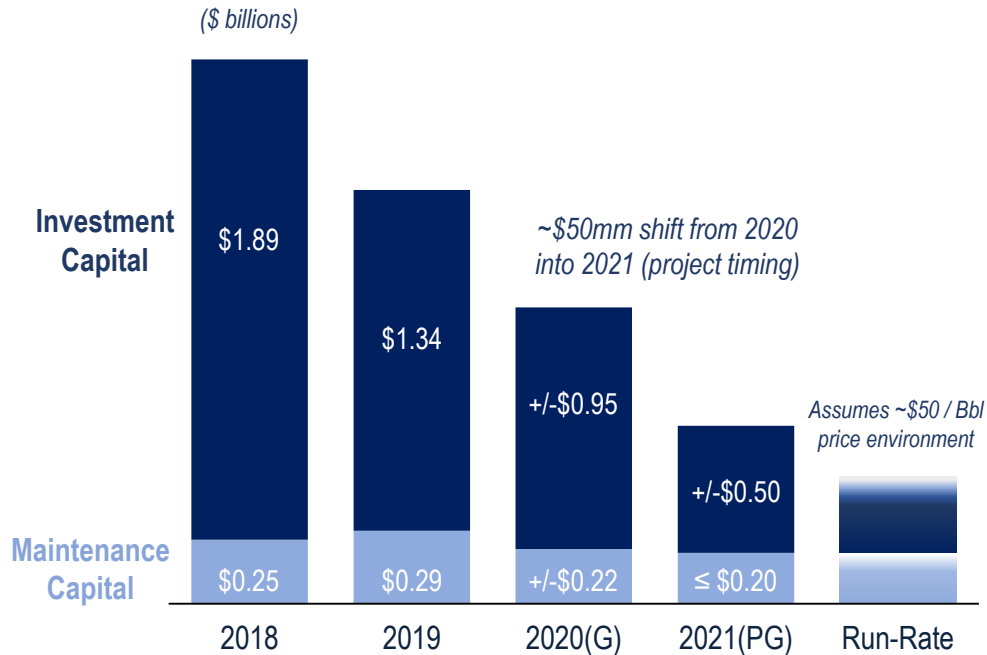
Aug-G: Furnished August 4, 2020.

Nov-G & 2021(PG): Furnished November 2, 2020.

(1) Implied DCF per Common Unit & Common Unit Equivalent

(2) Excludes ~\$3.2 billion of non-cash charges incurred in 1Q20.

Meaningful Capital Investment Reductions



- Continue to challenge all investment capital (high-return “must do / no regrets”)
- 2021 Investment Capital:
 - ~50%: W2W & Diamond / Capline
 - ~20%-25%: Wellhead & CDP Connections (paced w/ producer activity levels in 2021+)
- Est. Run-rate Capital (assuming ~\$50/Bbl)
 - Investment: ~\$200-\$300mm
 - ~50%: Wellhead & CDP Connections (paced w/ producer activity levels)
 - No material capital commitments beyond 2021
 - Maintenance: less than \$200mm

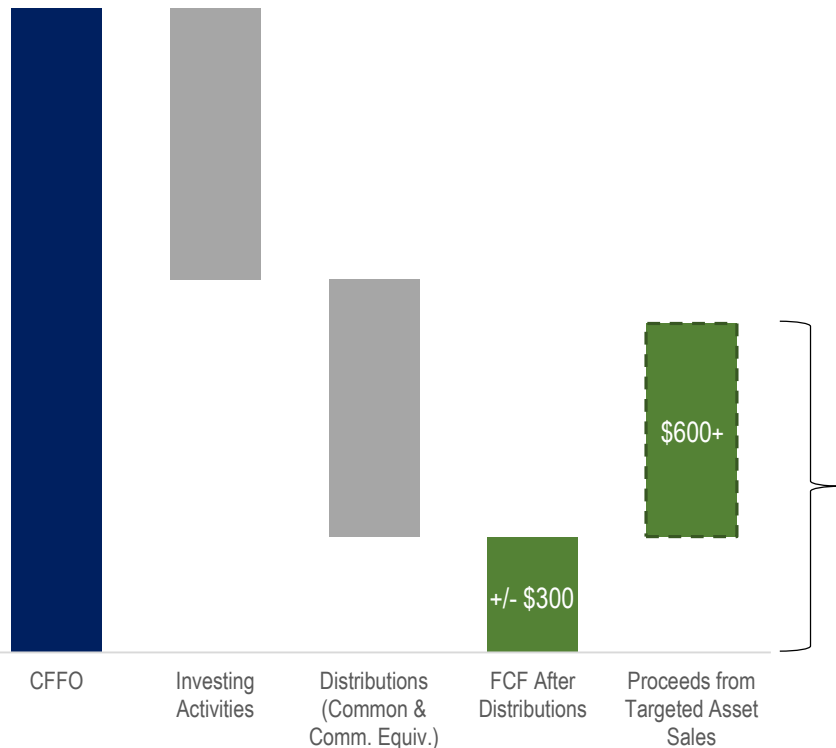
Announced \$500mm Common Equity Repurchase Program

- Additional method of returning capital to investors through a balanced approach
- Allocate up to \$75 MM in 2020; allocate up to 25% 2021 FCF after distributions (allocation within this range may scale up or down depending on asset sales, financial performance and other factors)
 - Will review targets annually, or as needed
- Balance of FCF (75% or more) to be allocated to debt reduction
- Timing / pace of potential repurchase activity to be determined by weighing multiple factors:
 - Business outlook & positioning
 - Trajectory to achieve and maintain targeted LTD / Adj. EBITDA ratio of 3.0–3.5x
 - Financial performance
 - Catalysts for increasing FCF (i.e. asset sales)
 - PAA & PAGP absolute & relative equity valuation / yield vs. other capital allocation alternatives

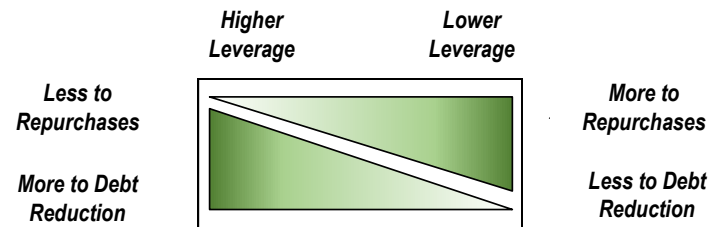
Allocation of FCF After Distributions (Directional Illustration)

2021: plan to allocate up to 25% of FCF after distributions

Illustrative 2021 Free Cash Flow (\$ millions)



Directional Allocation (Blended Approach)



- Timing / pace / magnitude of repurchase activity to be utilized in a balanced approach consistent w/ priority of reducing leverage
- Allocation may scale up / down depending on asset sales, financial performance and other factors
- For example: may allocate higher relative percentage of FCF after distributions toward debt reduction in the event of meaningful asset sales

Key Takeaways: 3Q20 Earnings Call

- **Plains is well positioned to manage through current environment**
 - Strong conviction in the long-term durability of our business
 - Critical asset base, prominent and highly integrated Permian franchise
 - The Permian (and hydrocarbons in general) will be an integral part of the world's supply needs for multiple decades
- **Continue to make meaningful progress on enhancing our financial flexibility**
 - Visibility to sustainably generating meaningful free cash flow after distributions
 - Enhances our ability to reduce debt and increase cash returned to shareholders
- **Driving for continuous improvement in alignment with investors and external stakeholders**
 - Governance: closely aligned w/ C-Corps; compensation framework further aligned w/ investors (see slides 19 & 20)
 - Sustainability Disclosures: significant additional information published in Aug-2020 and more to come (see slides 21 & 22)
 - Safety & Environmental: consistently “raising the bar” and advancing culture of continuous improvement (see slide 23)

Sustainability Update

Please visit <https://www.plainsallamerican.com/sustainability>
for full sustainability presentation and disclosures.



Plains' Governance Closely Aligned with C-Corps

Driving for continuous improvement in all aspects of Sustainability

- Public Election of Independent Directors on a staggered 3-yr rolling basis (commenced in 2018 per 2016 Simplification Transaction)
- Mandatory Majority-Independence – currently 64% (have had majority since 2018 but formalized requirement in 2019)
- Lead Independent Director, alongside Chairman, responsible for leading one Unified Board of Directors (PAA & PAGP)
- Significant Board and Executive Equity Ownership (~13% as of May-2020 proxy filing)
- No Incentive Distribution Rights (“IDRs”) or “Golden Share”⁽¹⁾
- Significant Variable / At-risk Executive Compensation Structure (88% for CEO, 83% avg. for other Named Executive Officers)

1 for 1 Economic & Voting Rights

PAA GP HOLDINGS LLC (PAGP GP)
(Unified Board of Directors)



**PLAINS GP
HOLDINGS**

(NYSE: PAGP) 1099 SECURITY
(Public Investors)



PLAINS AAP, L.P. (AAP)⁽²⁾
(Private Owners & Management)



**PLAINS
ALL AMERICAN
PIPELINE, L.P.**

(NYSE: PAA) K-1 SECURITY
Public Investors • Series A & B Preferred
• 100% of Plains' assets & operations

⁽¹⁾ Incentive Distribution Rights (“IDRs”) give a general partner an increasing share of incremental distributable cash flow based upon certain conditions. “Golden Share” Refers to a control right granted in certain partnership agreements whereby the holder has the right to direct certain activities of the partnership, including the unilateral right to appoint and replace board members, irrespective of the holder's economic interest.

⁽²⁾ Right to exchange AAP Unit for PAGP Class A Share, or alternatively, right to redeem AAP Unit for PAA Common Unit



Multiple Enhancements to Executive Compensation

Have further aligned with investors and evaluating additional enhancements

- Have engaged independent compensation consultant and have proactively sought investor feedback
- Examples of recent enhancements:
 - 2018: Converted annual-bonus program to a more formula-based model (includes target metrics for per-unit financial results and Safety & Environmental metric)
 - 2019: Implemented annual compensation benchmark studies via 3rd party compensation consultant
 - 2020: Named new Chairman of Compensation Committee (committee of 100% independent directors)
 - 2020: Added TSR Metric to LTI program (considered various returns-based incentive metrics)
 - 2020: Added S&P 500 within TSR benchmarking group used in LTI program
 - 2020: Increased multi-year accountability (3-yr cumulative) to DCF / CUE⁽¹⁾ metric in LTI program
 - 2020: Added Leverage Modifier to DCF/CUE metric in LTI program – aligns w/ company deleveraging
- Potential additional enhancements: Clawback Policy and Ownership Guidelines

(1) DCF / CUE = Distributable Cash Flow per Common Unit & Common-Unit Equivalent

Sustainability Presentation (Published Aug-2020)

Excerpt Below: "The Building Blocks of our Sustainability Program"

VALUES



Safety & Environmental Stewardship



Accountability



Ethics & Integrity



Respect & Fairness

FOCUS AREAS



Environment

- Operational Safety
- Environmental Strategy



Social

- Employee Considerations
- Stakeholder Engagement



Governance

- Governance Practices

OVERSIGHT

Board of Directors



Chairman & CEO



Sustainability Executive Committee



VP Sustainability Committee

ADMINISTRATION



Implementation

- Ensure we are living and advancing our Values
- Continuously improve our safety and environmental performance
- Limit environmental impacts and resource utilization
- Incorporate ESG best practices / risk mitigation into our operations



Community Investment

- Support charitable initiatives that align with our values and improve communities where we operate
- Participate in volunteerism that complements our charitable giving, engages employees and increases visibility in our communities

Link to full presentation here:

<https://www.plainsallamerican.com/getattachment/Sustainability/Sustainability-Information/Sustainability-at-Plains.pdf?lang=en-US>



Detailed Data Disclosure (Published Aug-2020)

Excerpts Below: Link to full presentation here: <https://www.plainsallamerican.com/careers/career-opportunities/fy2019-plains-sustainability-report.pdf>

PIPELINE AND ASSET INTEGRITY	2019	2018	2017	GRI/SASB
Integrity and Maintenance Expenditures (mm)	\$512	\$468 ^a	\$520	— EM-MD-540a.4
Pipeline Miles Assessed via In-line Inspection ^b	8,717	6,870	7,647	— EM-MD-540a.2
Pipeline Control Center Simulator Trainings ^c	681	682	275	404-2 —

SAFETY	2019	2018	2017	GRI/SASB
Employee Total Recordable Injury Rate (TRIR) ^d (per 200,000 work hours)	0.52	0.74	0.81	403-9 EM-EP-320a.1
Contractor Total Recordable Injury Rate (per 200,000 work hours)	0.26	0.38	0.57	403-9 EM-EP-320a.1
Employee Lost Time Injury Rate (per 200,000 work hours)	0.17	0.53	0.35	403-9 —
Employee Fatalities	0	0	0	403-9 EM-EP-320a.1
Contractor Fatalities ^e	1	0	0	403-9 EM-EP-320a.1
Employee Motor Vehicle Incident Rate (per one million miles)	0.94	1.40 ^f	1.63	—
Emergency Preparedness Tabletop Exercises	153	118	94	404-2 EM-EP-320a.1
Large-scale Emergency Preparedness Exercises	12	6	1	404-2 EM-EP-320a.1
Emergency Preparedness Specialty Exercises ^g	17	7	8	404-2 EM-EP-320a.1

Corporate and Regulatory Asset Security Plans ^h	57	79	55	—
Qualified Individual Notification Drills ⁱ	214	203	206	404-2 —
Employees Trained on Emergency Response	3,934	3,074	2,407	404-2 —
Employees Trained on the Incident Command System	2,428	1,111	1,042	404-2 —
Agencies/Response Organizations Trained on Emergency Preparedness	576	297	382	—
First Responders Trained on Emergency Preparedness ^j	2,123	909	1,380	— EM-EP-320a.1

ENVIRONMENTAL ¹¹	2019	2018	2017	GRI/SASB
Number of Federally Reportable Releases ¹²	23	31	36	306-3 EM-MD-540a.1
Barrels of Petroleum Liquids Transported (B)	2.6	2.3	2.0	—
Percentage of Barrels Safely Delivered	>99.999%	>99.999%	>99.999%	—

PUBLIC AWARENESS AND DAMAGE PREVENTION	2019	2018	2017	GRI/SASB
Pipeline Safety Guides Distributed to the Public ¹³	365,272	154,800	413,272	—
Call Before you Dig One-call Tickets Processed	254,827	242,855	243,715	— EM-MD-540a.4
Public Awareness Safety Trainings	172	120	226	—
Third-party Line Strikes Resulting in a Release	0	1	3	— EM-MD-540a.4

EMPLOYEE ¹⁴	2019	2018	2017	GRI/SASB
Employees Located in the United States	3,683 (32 states)	3,660 (34 states)	3,577 (32 states)	102-7 —
Employees Located in Canada	1,315 (4 provinces)	1,237 (4 provinces)	1,206 (4 provinces)	102-7 —
Percentage of Field Employees	68%	69%	71%	102-8 —
Percentage of Non-exempt Employees	54%	55%	57%	—
Number of Employees Hired	930	620	588	401-1 —
Voluntary Employee Turnover Rate	10%	10%	11%	401-1 —
Percentage of Female Employees	21%	21%	20%	102-8, 405-1 —
Percentage of Management Roles Filled by Females <i>Employees at Manager, Director and above levels</i>	19%	22%	20%	405-1 —
Percentage of Executive Roles Filled by Females <i>Employees at the Vice President, Senior Vice President and Executive levels</i>	12%	14%	7%	—
Percentage Minority Employees in the United States ¹⁵	30%	28%	27%	405-1 —
Houston Chronicle Top Workplaces Rank Among Large Companies	6	7	12	—

BOARD COMPOSITION	2020	2019	2018	GRI/SASB
Number of Board Members	11	13	12	—
Number / Percentage of Independent Directors ¹⁶	7 / 64%	7 / 54%	6 / 50%	102-22 —
Percentage of Directors Subject to Public Election <i>3-year staggered term</i>	64%	54%	50%	—
Number / Percentage of Female Directors	1 / 9%	1 / 8%	0	102-22, 405-1 —
Number / Percentage of Minority Directors ¹⁷	1 / 9%	2 / 15%	2 / 17%	102-22, 405-1 —
Average Age of Independent Directors	62	67	68	102-22, 405-1 —
Average Tenure of Independent Directors	9	12	14	102-22 —
Total Number of Board Meetings Held During the Fiscal Year	5 (as of 5/31)	7	4	—
Average Board Meeting Attendance	100%	98%	98%	—

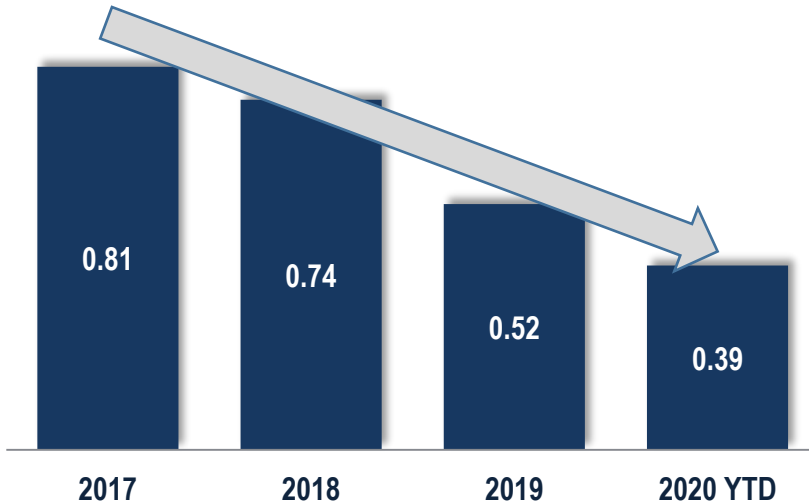
EXECUTIVE COMPENSATION	2020	2019	2018	GRI/SASB
Percentage of Director and Executive Officer Equity Ownership <i>As of date of annual meeting proxy statement</i>	13%	16%	17%	—
Percentage of CEO Target Compensation "At Risk" ¹⁸ For Fiscal Year	88%	88%	88% / 0% ¹⁹	—
Average Percentage of All Named Executive Officer (other than CEO) Target Compensation "At Risk" For Fiscal Year	84%	84%	84%	—

Health, Safety & Environmental

2020 YTD: ~50 % improvement in TRIR & Federally Reportable Releases vs. 2017.

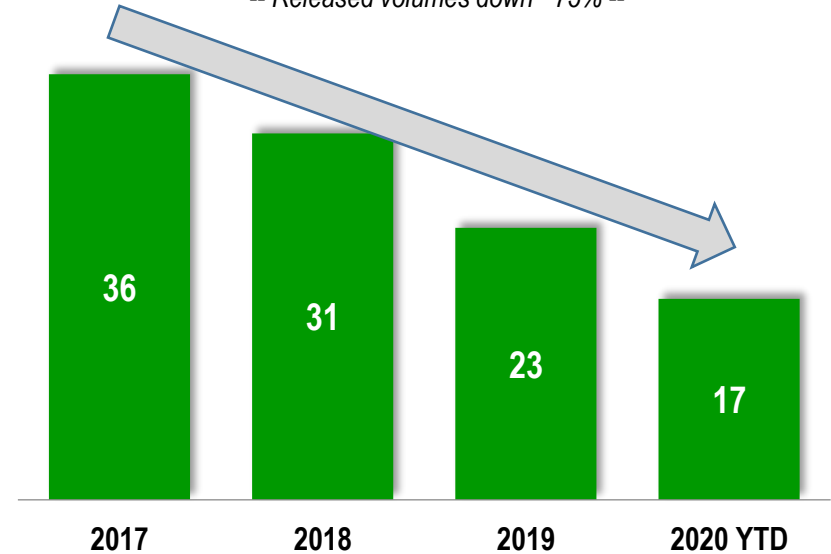
Total Recordable Injury Rate (TRIR)

-- Lost Workday Cases down ~75% --



Federally Reportable Releases

-- Released volumes down ~75% --



*-- 2020 Performance Target: 20% Y/Y reduction in TRIR & Federally Reportable Releases --
(company-wide performance metric)*

APPENDIX



Free Cash Flow

GAAP CFFO to Non-GAAP FCF

	2016	2017	2018	1Q19	2Q19	3Q19	4Q19	2019	1Q20	2Q20	3Q20	2020 YTD	LTM
Net Cash Provided by Op. Activities (GAAP)	\$ 733	\$ 2,499	\$ 2,608	\$ 1,033	\$ 431	\$ 314	\$ 726	\$ 2,504	\$ 890	\$ 84	\$ 282	\$ 1,256	\$ 1,982
Net Cash Used in Investing Activities	(1,273)	(1,570)	(813)	(429)	(549)	(389)	(398)	(1,765)	(610)	(248)	(208)	(1,066)	(1,464)
Cash Contributions from Noncontrolling Interests	-	-	-	-	-	-	-	-	8	2	1	11	11
Cash Distributions Paid to Noncontrolling Interests ⁽¹⁾	(4)	(2)	-	-	-	(4)	(2)	(6)	-	(4)	(2)	(6)	(8)
Sale of Noncontrolling Interest in a Sub	-	-	-	-	128	-	-	128	-	-	-	-	-
Free Cash Flow (non-GAAP)	\$ (544)	\$ 927	\$ 1,795	\$ 604	\$ 10	\$ (79)	\$ 326	\$ 861	\$ 288	\$ (166)	\$ 73	\$ 195	\$ 521
Total Distributions ⁽²⁾	(1,627)	(1,391)	(1,032)	(255)	(324)	(299)	(324)	(1,202)	(299)	(193)	(168)	(661)	(985)
FCF after Distributions (non-GAAP)	\$ (2,171)	\$ (464)	\$ 763	\$ 349	\$ (314)	\$ (378)	\$ 2	\$ (341)	\$ (11)	\$ (359)	\$ (95)	\$ (466)	\$ (464)

- Absent short-term changes in the working capital associated with hedged inventory storage, we expect our cash generation combined with lower capital investment to benefit free cash flow for the balance of the year and into 2021 and beyond.

(1) Cash distributions paid during the period presented.

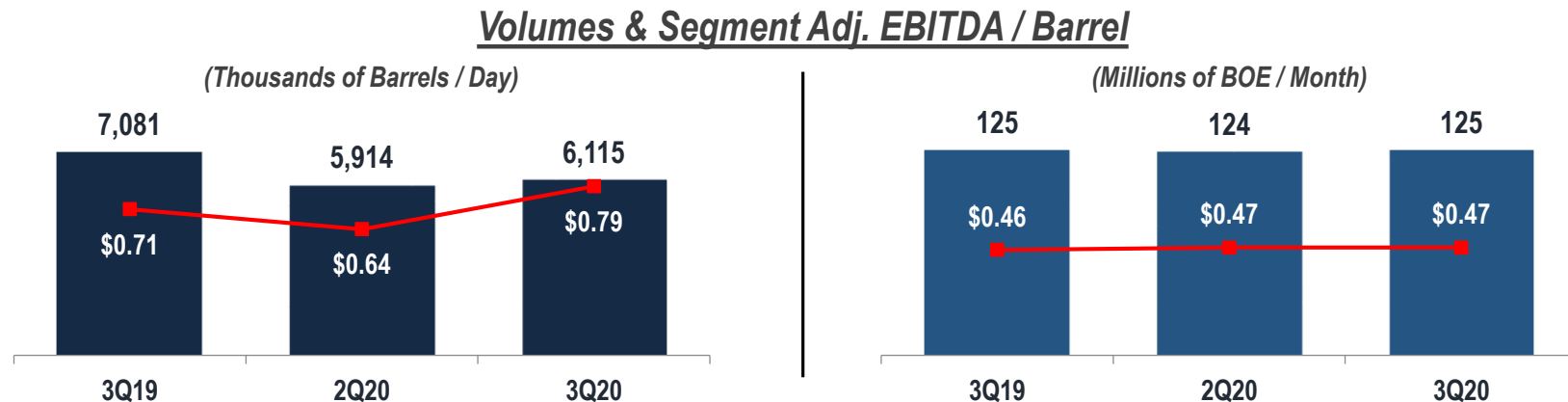
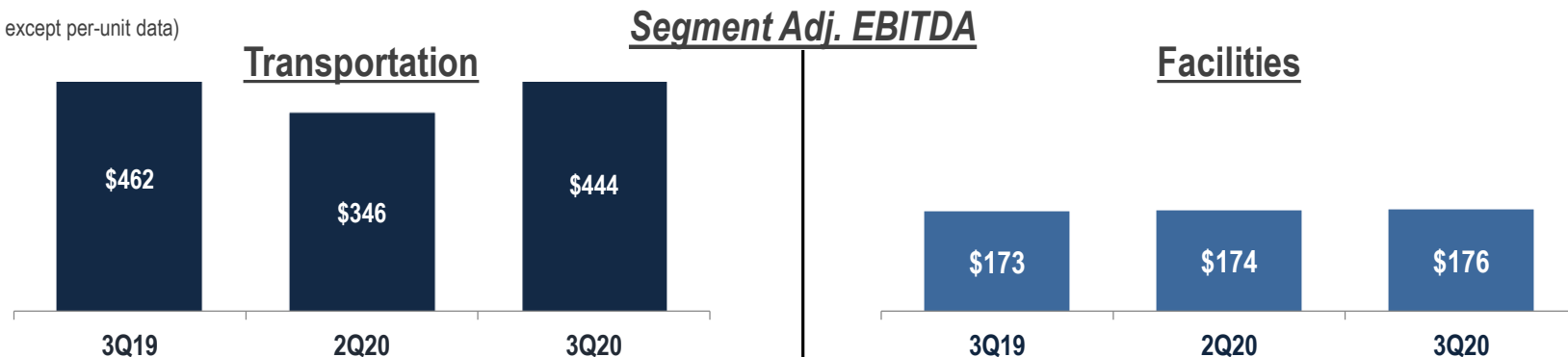
(2) Cash distributions paid to our preferred and common unitholders during the period presented. The 2016 period also includes distributions paid to our general partner.

Management uses the non-GAAP financial measures Free Cash Flow ("FCF") and Free Cash Flow After Distributions to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes. FCF is defined as net cash provided by operating activities, less net cash used in investing activities, which primarily includes acquisition, expansion and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests. FCF is further reduced by cash distributions paid to preferred and common unitholders to arrive at FCF after Distributions.

Our definition and calculation of FCF may not be comparable to similarly-titled measures of other companies. FCF and FCF After Distributions are reconciled to net cash flows from operating activities, the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and accompanying notes.

PAA 3Q20 Fee-Based Segment Overview

(\$ in millions, except per-unit data)

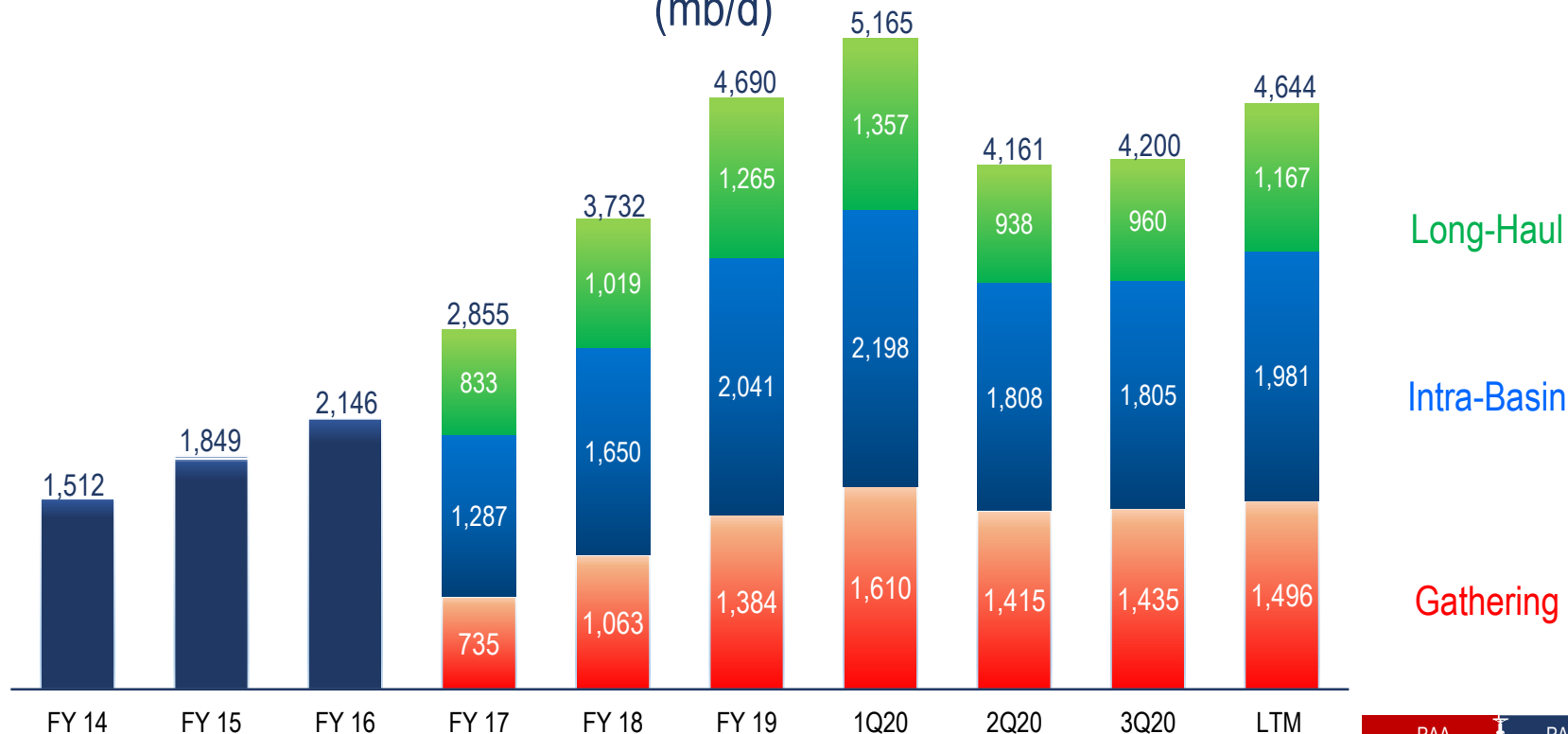


Note: please visit <https://ir.paalp.com> for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Permian Tariff Volumes – Historical Summary

PAA Permian Tariff Volumes

(mb/d)



Note: Bars represent full-year averages with the exception of quarterly breakdown.

2020(G) as of November 2, 2020

	Twelve Months Ended December 31,		
	2018	2019	2020 (G)
(\$ in millions, except per-unit data)			+ / -
Segment Adjusted EBITDA			
Transportation	\$ 1,508	\$ 1,722	\$ 1,620
Facilities	711	705	715
Fee-Based	\$ 2,219	\$ 2,427	\$ 2,335
Supply and Logistics	462	803	250
Adjusted other income/(expense), net	3	7	—
Adjusted EBITDA	\$ 2,684	\$ 3,237	\$ 2,585
Interest expense, net of certain non-cash items	(419)	(407)	(415)
Maintenance capital	(252)	(287)	(215)
Current income tax expense	(66)	(112)	(50)
Other	1	(55)	20
Implied DCF	\$ 1,948	\$ 2,376	\$ 1,925
Preferred unit distributions paid	(161)	(198)	(200)
Implied DCF Available to Common Unitholders	\$ 1,787	\$ 2,178	\$ 1,725
Implied DCF per Common Unit and Common Equivalent Unit	\$ 2.38	\$ 2.91	\$ 2.35
Distributions per Common Unit ⁽¹⁾	\$ 1.20	\$ 1.38	\$ 0.90
Common Unit Distribution Coverage Ratio ⁽¹⁾	2.05x	2.17x	2.63x
Diluted Adjusted Net Income per Common Unit	\$ 1.88	\$ 2.51	\$ 1.59

2020(G): Furnished Nov. 2, 2020. (1) 2020(G) reflects the annualized distribution rate of \$1.44 per common unit paid in February, and the decreased annualized distribution rate of \$0.72 per common unit for the remainder of the year. Note: Please visit IR page of www.plainsallamerican.com for reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

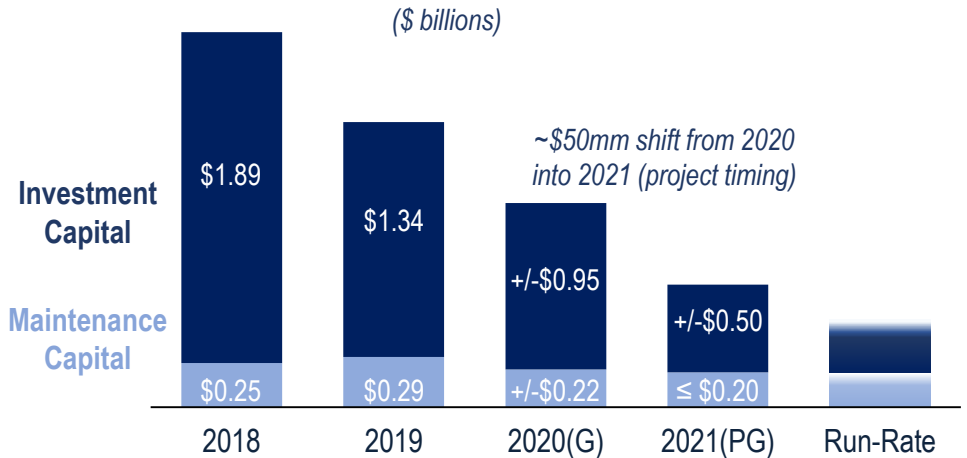
2020(G) as of November 2, 2020

	Twelve Months Ended December 31,		
	2018	2019	2020 (G)
(\$ in millions, except per-unit data)			+ / -
Operating Data			
Transportation			
Average daily volumes (MBbls/d)	5,889	6,893	6,380
Segment Adjusted EBITDA per barrel	\$ 0.70	\$ 0.68	\$ 0.69
Facilities			
Average capacity (MMBbls/Mo)	124	125	124
Segment Adjusted EBITDA per barrel	\$ 0.48	\$ 0.47	\$ 0.48
Supply and Logistics			
Average daily volumes (MBbls/d)	1,309	1,369	1,290
Segment Adjusted EBITDA per barrel	\$ 0.97	\$ 1.61	\$ 0.53
Investment Capital	\$ 1,888	\$ 1,340	\$ 950
Fourth-Quarter Adjusted EBITDA as Percentage of Full Year	35%	27%	23%

Reinforcing Transition to Positive Free Cash Flow

Capital Investment Decreasing

- Completing multi-year capital program
- Substantially lower investment going forward
- Lower maintenance capex

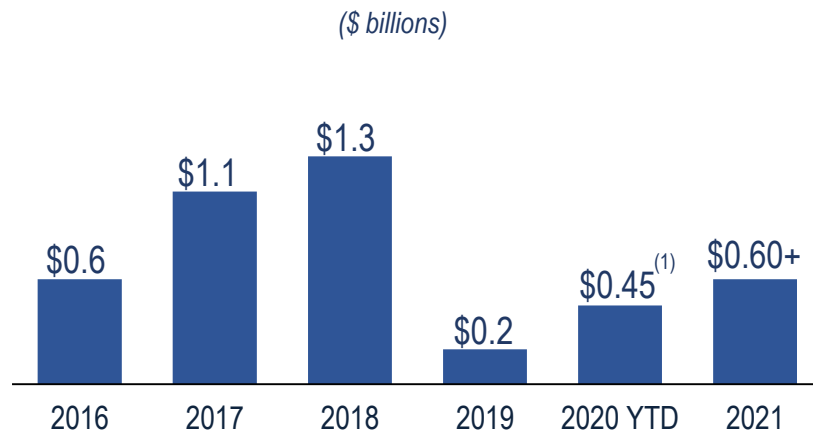


Assumes ~\$50 / Bbl price environment

2020(G), 2021(PG) and Run Rate: Furnished November 2, 2020
 (1) Includes the sale of LA terminals completed in mid-October.

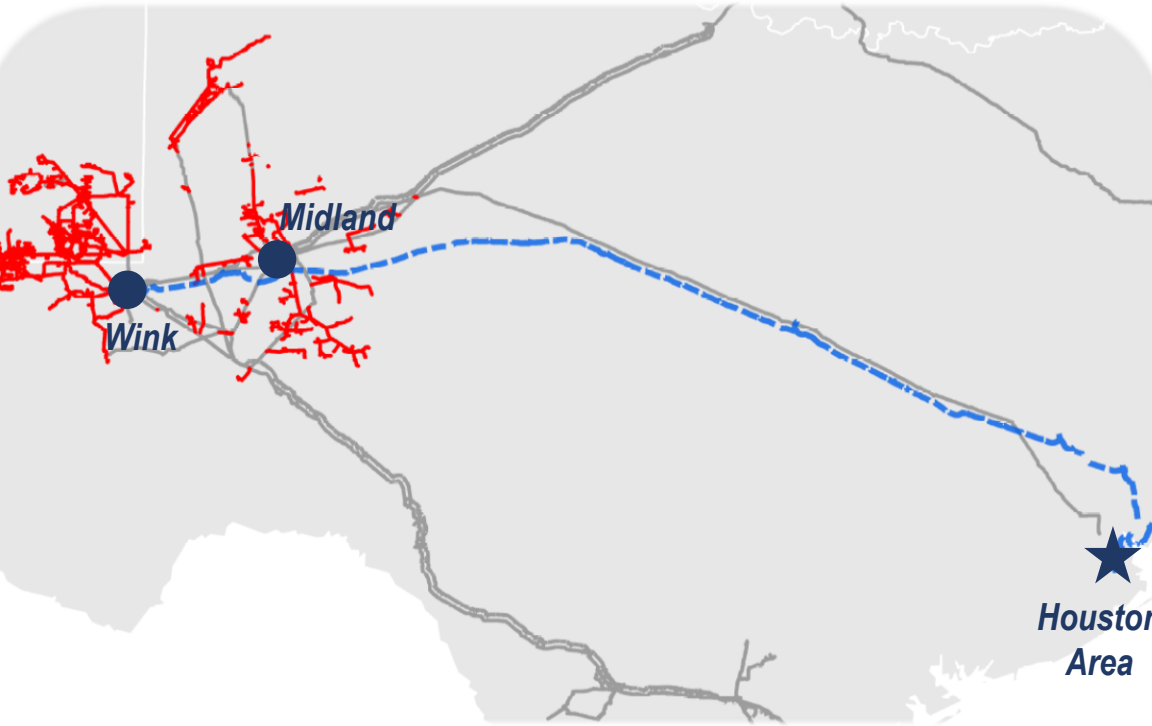
Asset Sales Increasing

- >\$3.6 B in cumulative divestitures (2016 – 2020 YTD)
- Combination of non-core sales and strategic JVs
- Targeting additional \$600+mm in 2021



Permian to USGC: Wink to Webster

Project sanctioned and progress advancing



Status Update

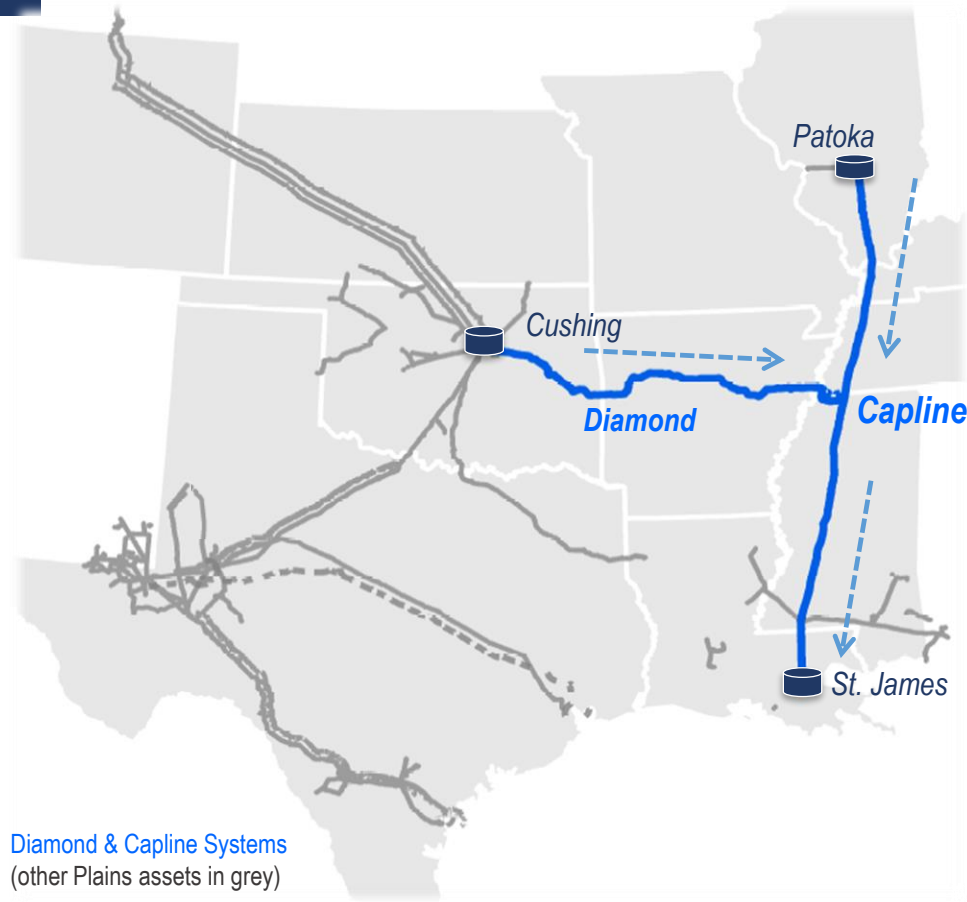
- Midland-to-Webster partial in-service early 2021
- MVCs ramping from 4Q21 through 2023
- Deferring portion of investment to align w/ MVC ramp

Project Overview

- ~1.5 mmb/d capacity (36" diameter)
- Highly contracted, long-term MVCs
- Origins: Wink & Midland
- Destinations: ECHO, Webster, Baytown, TX City
- W2W JV ownership: 71% of capacity
- PAA: 16% of W2W JV ownership
- Other JV partners: XOM, Lotus, MPLX, DK, RTLR
- UJI w/ EPD: 29%, Midland-to-Webster segment

Diamond Expansion / Extension & Capline Reversal

Diamond in-service targeted 4Q 2021 and Capline in-service targeted 1Q22



Diamond Expansion / Extension

- ~200 mb/d expansion & modest extension (contractually supported)
- Plains' ownership: 50%

Capline Reversal

- Reversal of 40" pipe to southbound service (contractually supported)
- Plains' ownership: 54% (non-operated equity interest asset)

Asset Exchange Advances Portfolio Optimization Strategy

Executed Definitive Agreement w/ Inter Pipeline (TSX: IPL) for Asset Exchange

- A win-win exchange that advances Plains' portfolio optimization strategy
 - Further streamlines Plains' assets and operations – coring up NGL business at Empress; increasing scale and operational efficiency in market hub asset in region w/ attractive long-term fundamentals at an attractive value
 - Monetizes crude oil system at an attractive value from a third-party well positioned to generate meaningful synergies on the asset, while preserving Plains' downstream synergies of volumes flowing through Western Corridor system
- Plains to convey 10-mile 90mb/d Milk River crude pipeline system & contribute USD \$26mm in true-up consideration
 - Not directly connected with other Plains assets; alignment with IPL's systems, which deliver vast majority of volume
- Plains to secure 2.7 Bcf/d of natural gas processing capacity at Empress II & V facilities (Plains currently operates)
 - Brings Plains' ownership of Empress II and Empress V to 100% (previously 0% and 50%, respectively)
 - Aligns with strategy of focusing on bulk transactions at large hub assets vs. smaller volumes at distal distribution facilities
 - Fundamentals support additional gas flows / Potential for upstream pipeline capacity to be expanded by third parties
 - Simplifies plant operations (able to optimize gas flows between plants), JV structure and accounting
- Asset exchange is expected to close in early 2021, subject to customary closing conditions, including regulatory approvals

Investor FAQ: What Are the Potential Implications / Risks Associated With a Potential Change in Administration following the 2020 Election

- Potential Ban of Fracking on Federal Leases
 - Most of the producers on our Permian Basin assets believe they have the permits to develop their Federal lands
 - No direct exposure in the Bakken or Powder River
 - If producer access to further development is limited/restricted, expect producers to shift activity / continue to develop private lands
 - While a ban could impact the growth on our ACC gathering system, our backbone infrastructure in the Delaware Basin should position us to participate in growth in other portions of the Permian as producers re-direct capital to non-Federal lands in the Delaware Basin
- Expect to see more regulations and a slower process to approve permits
 - Could impact the pace at which producers develop their resources
 - However, this should also make pipe in the ground more valuable
- Outstanding NW 12 Permits
 - Do not expect to have any outstanding permit requests in front of the next Administration



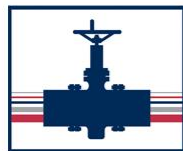
Condensed Consolidating Balance Sheet of Plains GP Holdings (PAGP)

(\$ in millions)	September 30, 2020			December 31, 2019		
	PAA	Consolidating Adjustments ⁽¹⁾	PAGP	PAA	Consolidating Adjustments ⁽¹⁾	PAGP
ASSETS						
Current assets	\$ 3,405	\$ 2	\$ 3,407	\$ 4,612	\$ 2	\$ 4,614
Property and equipment, net	14,618	9	14,627	15,355	12	15,367
Investments in unconsolidated entities	3,743	—	3,743	3,683	—	3,683
Goodwill	—	—	—	2,540	—	2,540
Deferred tax asset	—	1,438	1,438	—	1,280	1,280
Linefill and base gas	966	—	966	981	—	981
Long-term operating lease right-of-use assets, net	395	—	395	466	—	466
Long-term inventory	120	—	120	182	—	182
Other long-term assets, net	999	(2)	997	858	(2)	856
Total assets	\$ 24,246	\$ 1,447	\$ 25,693	\$ 28,677	\$ 1,292	\$ 29,969
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	\$ 3,804	\$ 1	\$ 3,805	\$ 5,017	\$ 2	\$ 5,019
Senior notes, net	9,069	—	9,069	8,939	—	8,939
Other long-term debt, net	312	—	312	248	—	248
Long-term operating lease liabilities	337	—	337	387	—	387
Other long-term liabilities and deferred credits	873	—	873	891	—	891
Total liabilities	\$ 14,395	\$ 1	\$ 14,396	\$ 15,482	\$ 2	\$ 15,484
Partners' capital excluding noncontrolling interests	9,706	(8,234)	1,472	13,062	(10,907)	2,155
Noncontrolling interests	145	9,680	9,825	133	12,197	12,330
Total partners' capital	9,851	1,446	11,297	13,195	1,290	14,485
Total liabilities and partners' capital	\$ 24,246	\$ 1,447	\$ 25,693	\$ 28,677	\$ 1,292	\$ 29,969

⁽¹⁾ Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

Houston, Texas | November 2, 2020

3Q20 EARNINGS CALL



PLAINS
ALL AMERICAN



FOR IMMEDIATE RELEASE

Plains All American Pipeline and Plains GP Holdings Report Third-Quarter 2020 Results

(Houston — November 2, 2020) Plains All American Pipeline, L.P. (NYSE: PAA) and Plains GP Holdings (NYSE: PAGP) today reported third-quarter 2020 results and furnished updated 2020 guidance in addition to several other significant updates, which are highlighted below.

Summary Highlights

- Reported net income for the quarter of \$143 million
- Delivered third-quarter 2020 Adjusted EBITDA of \$682 million
- Completed the sale of LA Basin Terminals (closed October 15, 2020) for approximately \$200 million (brings year-to-date asset sales proceeds to approximately \$450 million)
- Increased full-year 2020 Adjusted EBITDA guidance to +/- \$2.585 billion (increase of \$85 million, or 3%)
- Provided preliminary estimate for 2021 Adjusted EBITDA of +/- \$2.2 billion (assumes a \$50 million contribution from the Supply & Logistics segment, and is net of the LA Basin Terminals sale and \$600 million or more of additional asset sales targeted in 2021)
- Provided preliminary estimate for 2021 Free Cash Flow after distributions of roughly \$300 million, or \$900 million or more when including the benefit of proceeds from additional asset sales targeted in 2021
- Announced \$500 million Common Equity Repurchase Program intended to be utilized as an additional method of returning capital to investors

“We delivered third-quarter results favorable to our expectations and raised our full-year 2020 guidance, which is now in-line with our beginning of the year pre-COVID expectations,” stated Willie Chiang, Chairman and CEO of Plains. “We have continued to execute across each of our key initiatives: operating safely and reliably, maximizing Free Cash Flow after distributions, reducing leverage, minimizing capital investment, optimizing our assets, streamlining our organization and reducing costs throughout the business.”

Mr. Chiang continued, “Our current equity valuation does not reflect the strength of our asset base or the long-term durability of our business, and we have reached an inflection point where we expect to generate meaningful levels of Free Cash Flow after distributions. Given the combination of these factors, today we announced a \$500 million common equity repurchase program to be used as an additional method of returning capital to investors. In addition to reducing debt, we believe it is appropriate to allocate a portion of our Free Cash Flow after distributions to invest in our equity.”

- more -

Plains All American Pipeline

Summary Financial Information (unaudited)
(in millions, except per unit data)

<i>GAAP Results</i>	Three Months Ended September 30,		%	Nine Months Ended September 30,		%
	2020	2019		2020	2019	
			Change			Change
Net income/(loss) attributable to PAA ⁽¹⁾	\$ 143	\$ 449	(68)%	\$ (2,562)	\$ 1,865	(237)%
Diluted net income/(loss) per common unit	\$ 0.13	\$ 0.55	(76)%	\$ (3.72)	\$ 2.28	(263)%
Diluted weighted average common units outstanding ⁽²⁾	728	800	(9)%	728	800	(9)%
Net cash provided by operating activities	\$ 282	\$ 314	(10)%	\$ 1,256	\$ 1,778	(29)%
Distribution per common unit declared for the period	\$ 0.18	\$ 0.36	(50)%			

- (1) Reported results for the nine months ended September 30, 2020 include aggregate non-cash goodwill and asset impairments and the write-down of certain of our investments in unconsolidated entities totaling \$3.3 billion representing a nine-month net loss of \$4.55 after tax per common unit.
- (2) For the three and nine months ended September 30, 2019, includes all potentially dilutive securities (our Series A preferred units and equity-indexed compensation awards) outstanding during the period. See the “Computation of Basic and Diluted Net Income/(Loss) Per Common Unit” table attached hereto for additional information.

<i>Non-GAAP Results ⁽¹⁾</i>	Three Months Ended September 30,		%	Nine Months Ended September 30,		%
	2020	2019		2020	2019	
			Change			Change
Adjusted net income attributable to PAA	\$ 382	\$ 430	(11)%	\$ 1,070	\$ 1,546	(31)%
Diluted adjusted net income per common unit	\$ 0.46	\$ 0.52	(12)%	\$ 1.26	\$ 1.88	(33)%
Adjusted EBITDA	\$ 682	\$ 731	(7)%	\$ 2,001	\$ 2,377	(16)%
Implied DCF per common unit and common equivalent	\$ 0.63	\$ 0.63	— %	\$ 1.84	\$ 2.21	(17)%
Free cash flow	\$ 73	\$ (79)	**	\$ 195	\$ 535	**
Free cash flow after distributions	\$ (95)	\$ (378)	**	\$ (466)	\$ (343)	**

** Indicates that variance as a percentage is not meaningful.

- (1) See the section of this release entitled “Non-GAAP Financial Measures and Selected Items Impacting Comparability” and the tables attached hereto for information regarding certain selected items that PAA believes impact comparability of financial results between reporting periods, as well as for information regarding non-GAAP financial measures (such as Adjusted EBITDA, Implied DCF, Free Cash Flow and Free Cash Flow After Distributions) and their reconciliation to the most directly comparable measures as reported in accordance with GAAP.

- more -

Segment Adjusted EBITDA for the third quarter and first nine months of 2020 and 2019 is presented below:

Summary of Selected Financial Data by Segment (unaudited)

(in millions)

	Segment Adjusted EBITDA		
	Transportation	Facilities	Supply and Logistics
Three Months Ended September 30, 2020	\$ 444	\$ 176	\$ 61
Three Months Ended September 30, 2019	\$ 462	\$ 173	\$ 92
Percentage change in Segment Adjusted EBITDA versus 2019 period	(4)%	2 %	(34)%

	Segment Adjusted EBITDA		
	Transportation	Facilities	Supply and Logistics
Nine Months Ended September 30, 2020	\$ 1,233	\$ 560	\$ 205
Nine Months Ended September 30, 2019	\$ 1,271	\$ 529	\$ 571
Percentage change in Segment Adjusted EBITDA versus 2019 period	(3)%	6 %	(64)%

Third-quarter 2020 Transportation Segment Adjusted EBITDA decreased 4% versus comparable 2019 results due to reductions in tariff volumes in multiple regions resulting from lower crude oil prices, reduced drilling and completion activity and compressed regional basis differentials, partially offset by the benefit of minimum volume commitment deficiency payments associated with second quarter deficiencies.

Third-quarter 2020 Facilities Segment Adjusted EBITDA increased 2% versus comparable 2019 results primarily due to operational cost savings, increased spot activity at certain of our West Coast crude oil storage terminals and increased capacity at certain of our Mid-Continent and Gulf Coast crude oil storage terminals, partially offset by decreased activity at certain of our rail terminals resulting from less favorable market conditions and the impact of asset sales.

Third-quarter 2020 Supply and Logistics Segment Adjusted EBITDA decreased 34% versus comparable 2019 results due to less favorable crude oil differentials in both the Permian Basin and Canada, partially offset by the benefit of contango-based margin opportunities.

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2020 Full-Year Guidance

The table below presents our full-year 2020 financial and operating guidance:

Financial and Operating Guidance (unaudited)

(in millions, except volumes, per unit and per barrel data)

	Twelve Months Ended December 31,		
	2018	2019	2020 (G)
			+ / -
Segment Adjusted EBITDA			
Transportation	\$ 1,508	\$ 1,722	\$ 1,620
Facilities	711	705	715
Fee-Based	\$ 2,219	\$ 2,427	\$ 2,335
Supply and Logistics	462	803	250
Adjusted other income/(expense), net	3	7	—
Adjusted EBITDA ⁽¹⁾	\$ 2,684	\$ 3,237	\$ 2,585
Interest expense, net of certain non-cash items ⁽²⁾	(419)	(407)	(415)
Maintenance capital	(252)	(287)	(215)
Current income tax expense	(66)	(112)	(50)
Other	1	(55)	20
Implied DCF ⁽¹⁾	\$ 1,948	\$ 2,376	\$ 1,925
Preferred unit distributions paid ⁽³⁾	(161)	(198)	(200)
Implied DCF Available to Common Unitholders	\$ 1,787	\$ 2,178	\$ 1,725
Implied DCF per Common Unit and Common Equivalent Unit ⁽¹⁾	\$ 2.38	\$ 2.91	\$ 2.35
Distributions per Common Unit ⁽⁴⁾	\$ 1.20	\$ 1.38	\$ 0.90
Common Unit Distribution Coverage Ratio	2.05x	2.17x	2.63x
Diluted Adjusted Net Income per Common Unit ⁽¹⁾	\$ 1.88	\$ 2.51	\$ 1.59
Operating Data			
Transportation			
Average daily volumes (MBbls/d)	5,889	6,893	6,380
Segment Adjusted EBITDA per barrel	\$ 0.70	\$ 0.68	\$ 0.69
Facilities			
Average capacity (MMBbls/Mo)	124	125	124
Segment Adjusted EBITDA per barrel	\$ 0.48	\$ 0.47	\$ 0.48
Supply and Logistics			
Average daily volumes (MBbls/d)	1,309	1,369	1,290
Segment Adjusted EBITDA per barrel	\$ 0.97	\$ 1.61	\$ 0.53
Investment Capital	\$ 1,888	\$ 1,340	\$ 950
Fourth-Quarter Adjusted EBITDA as Percentage of Full Year	35%	27%	23%

- more -

(G) 2020 Guidance forecasts are intended to be + / - amounts.

- (1) See the section of this release entitled “Non-GAAP Financial Measures and Selected Items Impacting Comparability” and the Non-GAAP Reconciliation tables attached hereto for information regarding non-GAAP financial measures and, for the historical 2018 and 2019 periods, their reconciliation to the most directly comparable measures as reported in accordance with GAAP. We do not provide a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures on a forward-looking basis as it is impractical to forecast certain items that we have defined as “Selected Items Impacting Comparability” without unreasonable effort, due to the uncertainty and inherent difficulty of predicting the occurrence and financial impact of and the periods in which such items may be recognized. Thus, a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures could result in disclosure that could be imprecise or potentially misleading.
- (2) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.
- (3) Cash distributions paid to our preferred unitholders during the year presented. Distributions on our Series A preferred units were paid-in-kind for the February 2018 quarterly distribution. Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. Distributions on our Series B preferred units are payable in cash semi-annually in arrears on May 15 and November 15.
- (4) Cash distributions per common unit paid during 2018 and 2019. 2020 (G) reflects the annualized distribution rate of \$1.44 per common unit paid in February and the decreased annualized distribution rate of \$0.72 per common unit for the remainder of the year.

Plains GP Holdings

PAGP owns an indirect non-economic controlling interest in PAA’s general partner and an indirect limited partner interest in PAA. As the control entity of PAA, PAGP consolidates PAA’s results into its financial statements, which is reflected in the condensed consolidating balance sheet and income statement tables included at the end of this release. Information regarding PAGP’s distributions is reflected below:

	Q3 2020	Q2 2020	Q3 2019
Distribution per Class A share declared for the period	\$ 0.18	\$ 0.18	\$ 0.36
Q3 2020 distribution percentage change from prior periods		— %	(50)%

Conference Call

PAA and PAGP will hold a joint conference call at 4:30 p.m. CT on Monday, November 2, 2020 to discuss the following items:

1. PAA’s third-quarter 2020 performance;
2. Capitalization and liquidity; and
3. Financial and operating guidance.

Conference Call Webcast Instructions

To access the internet webcast, please go to https://event.webcasts.com/starthere.jsp?ei=1378562&tp_key=8945f97d3b.

Alternatively, the webcast can be accessed on our website (www.plainsallamerican.com) under Investor Relations (Navigate to: Investor Relations / either “PAA” or “PAGP” / News & Events / Quarterly Earnings). Following the live webcast, an audio replay in MP3 format will be available on our website within two hours after the end of the call and will be accessible for a period of 365 days. A transcript will also be available after the call at the above referenced website.

- more -

Non-GAAP Financial Measures and Selected Items Impacting Comparability

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes.

The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization of unconsolidated entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability (“Adjusted EBITDA”), Implied distributable cash flow (“DCF”), Free Cash Flow and Free Cash Flow After Distributions.

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income/(Loss), and Free Cash Flow and Free Cash Flow After Distributions are reconciled to Net Cash Provided by Operating Activities, (the most directly comparable measures as reported in accordance with GAAP) for the historical periods presented in the tables attached to this release, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and notes thereto. In addition, we encourage you to visit our website at www.plainsallamerican.com (in particular the section under “Financial Information” entitled “Non-GAAP Reconciliations” within the Investor Relations tab), which presents a reconciliation of our commonly used non-GAAP and supplemental financial measures.

Performance Measures

Management believes that the presentation of Adjusted EBITDA and Implied DCF provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations and (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions. We also present these and additional non-GAAP financial measures, including adjusted net income attributable to PAA and basic and diluted adjusted net income per common unit, as they are measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” on our Condensed Consolidated Financial Statements. Such amounts are presented net of applicable amounts subsequently recognized into revenue. Furthermore, the calculation of these measures contemplates tax effects as a separate reconciling item, where applicable. We have defined all such items as “selected items impacting comparability.” Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures, referred to as adjusted results, but not impact other non-GAAP financial measures. We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, divestitures, investment capital projects and numerous other factors. These types of variations may not be separately identified in this release, but will be discussed, as applicable, in management’s discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

- more -

Liquidity Measures

Management also uses the non-GAAP financial measures Free Cash Flow and Free Cash Flow After Distributions to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes. Free Cash Flow is defined as Net Cash Provided by Operating Activities, less Net Cash Used in Investing Activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to preferred and common unitholders to arrive at Free Cash Flow After Distributions.

Forward-Looking Statements

Except for the historical information contained herein, the matters discussed in this release consist of forward-looking statements that involve certain risks and uncertainties that could cause actual results or outcomes to differ materially from results or outcomes anticipated in the forward-looking statements. These risks and uncertainties include, among other things, the following:

Factors Related Primarily to the COVID-19 Pandemic and Excess Supply Situation:

- further declines in global crude oil demand and crude oil prices that correspondingly lead to a significant reduction of domestic crude oil, natural gas liquids (“NGL”) and natural gas production (whether due to reduced producer cash flow to fund drilling activities or the inability of producers to access capital, or both, the unavailability of pipeline and/or storage capacity, the shutting-in of production by producers, government-mandated pro-ration orders, or other factors), which in turn could result in significant declines in the actual or expected volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets and/or the reduction of commercial opportunities that might otherwise be available to us;
- uncertainty regarding the length of time it will take for the United States, Canada, and the rest of the world to contain the spread of the COVID-19 virus to the point where restrictions on various commercial and economic activities are lifted and the extent to which consumer demand and demand for crude oil rebound once such restrictions are lifted;
- uncertainty regarding the future actions of foreign oil producers such as Saudi Arabia and Russia and the risk that they take actions that will prolong or exacerbate the current over-supply of crude oil;
- uncertainty regarding the timing, pace and extent of an economic recovery in the United States and elsewhere, which in turn will likely affect demand for crude oil and therefore the demand for the midstream services we provide and the commercial opportunities available to us;
- the effect of an overhang of significant amounts of crude oil inventory stored in the United States and elsewhere and the impact that such inventory overhang ultimately has on the timing of a return to market conditions that are more conducive to an increase in drilling and production activities in the United States and a resulting increase in demand for the midstream services we provide;
- the refusal or inability of our customers or counterparties to perform their obligations under their contracts with us (including commercial contracts, asset sale agreements and other agreements), whether justified or not and whether due to financial constraints (reduced creditworthiness, liquidity issues or insolvency), market constraints, legal constraints (including governmental orders or guidance), the exercise of contractual or common law rights that allegedly excuse their performance (such as force majeure or similar claims) or other factors;
- our inability to perform our obligations under our contracts, whether due to non-performance by third parties, including our customers or counterparties, market constraints, third-party constraints, legal constraints (including governmental orders or guidance), or other factors;
- operational difficulties due to physical distancing restrictions and the additional demands such restrictions may place on our employees;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial and hedging strategies;

- more -

- our inability to reduce capital expenditures to the extent forecasted, whether due to the incurrence of unexpected or unplanned expenditures, third-party claims or other factors;
- the inability to complete forecasted asset sale transactions due to governmental action, litigation, counterparty non-performance or other factors;

General Factors:

- the effects of competition, including the effects of capacity overbuild in areas where we operate;
- negative societal sentiment regarding the hydrocarbon energy industry and the continued development and consumption of hydrocarbons, which could influence consumer preferences and governmental or regulatory actions in ways that adversely impact our business;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, NGL and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event, including cyber or other attacks on our electronic and computer systems;
- the successful integration and future performance of acquired assets or businesses and the successful operation of joint ventures and joint operating arrangements we enter into from time to time, whether relating to assets operated by us or by third parties;
- failure to implement or capitalize, or delays in implementing or capitalizing, on investment capital projects, whether due to permitting delays, permitting withdrawals or other factors;
- shortages or cost increases of supplies, materials or labor;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations, including legislation or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- general economic, market or business conditions (both within the United States and globally and including the potential for a recession or significant slowdown in economic activity levels) and the amplification of other risks caused by volatile financial markets, capital constraints and liquidity concerns;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;
- the currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- non-utilization of our assets and facilities;

- more -

- increased costs, or lack of availability, of insurance;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the effectiveness of our risk management activities;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of NGL as discussed in the Partnerships' filings with the Securities and Exchange Commission.

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil, NGL and natural gas. PAA owns an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles more than 6 million barrels per day of crude oil and NGL in its Transportation segment. PAA is headquartered in Houston, Texas. More information is available at www.plainsallamerican.com.

PAGP is a publicly traded entity that owns an indirect, non-economic controlling general partner interest in PAA and an indirect limited partner interest in PAA, one of the largest energy infrastructure and logistics companies in North America. PAGP is headquartered in Houston, Texas. More information is available at www.plainsallamerican.com.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
REVENUES	\$ 5,833	\$ 7,886	\$ 17,327	\$ 24,515
COSTS AND EXPENSES				
Purchases and related costs	5,107	6,855	15,000	21,218
Field operating costs	254	316	811	983
General and administrative expenses	61	74	201	225
Depreciation and amortization	160	156	493	439
(Gains)/losses on asset sales and asset impairments, net	(2)	(7)	617	(7)
Goodwill impairment losses	—	—	2,515	—
Total costs and expenses	5,580	7,394	19,637	22,858
OPERATING INCOME/(LOSS)	253	492	(2,310)	1,657
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	89	102	280	274
Gain on/(impairment of) investments in unconsolidated entities, net	(91)	4	(182)	271
Interest expense, net	(113)	(108)	(329)	(311)
Other income/(expense), net	5	5	(7)	23
INCOME/(LOSS) BEFORE TAX	143	495	(2,548)	1,914
Current income tax expense	(17)	(19)	(39)	(72)
Deferred income tax (expense)/benefit	20	(22)	32	30
NET INCOME/(LOSS)	146	454	(2,555)	1,872
Net income attributable to noncontrolling interests	(3)	(5)	(7)	(7)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAA	<u>\$ 143</u>	<u>\$ 449</u>	<u>\$ (2,562)</u>	<u>\$ 1,865</u>
NET INCOME/(LOSS) PER COMMON UNIT:				
Net income/(loss) allocated to common unitholders — Basic	\$ 93	\$ 399	\$ (2,712)	\$ 1,710
Basic weighted average common units outstanding	728	728	728	727
Basic net income/(loss) per common unit	<u>\$ 0.13</u>	<u>\$ 0.55</u>	<u>\$ (3.72)</u>	<u>\$ 2.35</u>
Net income/(loss) allocated to common unitholders — Diluted	\$ 93	\$ 436	\$ (2,712)	\$ 1,826
Diluted weighted average common units outstanding	728	800	728	800
Diluted net income/(loss) per common unit	<u>\$ 0.13</u>	<u>\$ 0.55</u>	<u>\$ (3.72)</u>	<u>\$ 2.28</u>

NON-GAAP ADJUSTED RESULTS

(in millions, except per unit data)

- more -

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Adjusted net income attributable to PAA	\$ 382	\$ 430	\$ 1,070	\$ 1,546
Diluted adjusted net income per common unit	\$ 0.46	\$ 0.52	\$ 1.26	\$ 1.88
Adjusted EBITDA	\$ 682	\$ 731	\$ 2,001	\$ 2,377

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(in millions)

	September 30, 2020	December 31, 2019
ASSETS		
Current assets	\$ 3,405	\$ 4,612
Property and equipment, net	14,618	15,355
Investments in unconsolidated entities	3,743	3,683
Goodwill	—	2,540
Linefill and base gas	966	981
Long-term operating lease right-of-use assets, net	395	466
Long-term inventory	120	182
Other long-term assets, net	999	858
Total assets	\$ 24,246	\$ 28,677
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	\$ 3,804	\$ 5,017
Senior notes, net	9,069	8,939
Other long-term debt, net	312	248
Long-term operating lease liabilities	337	387
Other long-term liabilities and deferred credits	873	891
Total liabilities	14,395	15,482
Partners' capital excluding noncontrolling interests	9,706	13,062
Noncontrolling interests	145	133
Total partners' capital	9,851	13,195
Total liabilities and partners' capital	\$ 24,246	\$ 28,677

DEBT CAPITALIZATION RATIOS

(in millions)

- more -

	September 30, 2020	December 31, 2019
Short-term debt	\$ 790	\$ 504
Long-term debt	9,381	9,187
Total debt	<u>\$ 10,171</u>	<u>\$ 9,691</u>
Long-term debt	\$ 9,381	\$ 9,187
Partners' capital	9,851	13,195
Total book capitalization	<u>\$ 19,232</u>	<u>\$ 22,382</u>
Total book capitalization, including short-term debt	<u>\$ 20,022</u>	<u>\$ 22,886</u>
Long-term debt-to-total book capitalization	49 %	41 %
Total debt-to-total book capitalization, including short-term debt	51 %	42 %

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER COMMON UNIT ⁽¹⁾

(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Basic Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	\$ 143	\$ 449	\$ (2,562)	\$ 1,865
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(1)	(1)	(6)
Net income/(loss) allocated to common unitholders	<u>\$ 93</u>	<u>\$ 399</u>	<u>\$ (2,712)</u>	<u>\$ 1,710</u>
Basic weighted average common units outstanding	728	728	728	727
Basic net income/(loss) per common unit	<u>\$ 0.13</u>	<u>\$ 0.55</u>	<u>\$ (3.72)</u>	<u>\$ 2.35</u>
Diluted Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	\$ 143	\$ 449	\$ (2,562)	\$ 1,865
Distributions to Series A preferred unitholders	(37)	—	(112)	—
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(1)	(1)	(2)
Net income/(loss) allocated to common unitholders	<u>\$ 93</u>	<u>\$ 436</u>	<u>\$ (2,712)</u>	<u>\$ 1,826</u>
Basic weighted average common units outstanding	728	728	728	727
Effect of dilutive securities:				
Series A preferred units ⁽²⁾	—	71	—	71
Equity-indexed compensation plan awards ⁽³⁾	—	1	—	2
Diluted weighted average common units outstanding	<u>728</u>	<u>800</u>	<u>728</u>	<u>800</u>
Diluted net income/(loss) per common unit	<u>\$ 0.13</u>	<u>\$ 0.55</u>	<u>\$ (3.72)</u>	<u>\$ 2.28</u>

⁽¹⁾ We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

⁽²⁾ The possible conversion of our Series A preferred units and the impact of equity-indexed compensation plan awards was excluded from the calculation of diluted net income/(loss) per common unit for the three and nine months ended September 30, 2020 as the effect was antidilutive.

⁽³⁾ Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For the three months ended September 30, 2020, there were no potentially dilutive equity-

- more -

indexed compensation plan awards and for the nine months ended September 30, 2020, the effect of equity-indexed compensation plan awards was antidilutive.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED ITEMS IMPACTING COMPARABILITY

(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Selected Items Impacting Comparability: ⁽¹⁾				
Gains/(losses) from derivative activities, net of inventory valuation adjustments ⁽²⁾	\$ (98)	\$ 30	\$ (203)	\$ 76
Long-term inventory costing adjustments ⁽³⁾	(2)	1	(66)	(3)
Deficiencies under minimum volume commitments, net ⁽⁴⁾	(64)	4	(69)	10
Equity-indexed compensation expense ⁽⁵⁾	(5)	(5)	(13)	(13)
Net gain/(loss) on foreign currency revaluation ⁽⁶⁾	10	5	(11)	(6)
Line 901 incident ⁽⁷⁾	—	—	—	(10)
Significant acquisition-related expenses ⁽⁸⁾	—	—	(3)	—
Net gain on early repayment of senior notes ⁽⁹⁾	—	—	3	—
Selected items impacting comparability - Adjusted EBITDA	\$ (159)	\$ 35	\$ (362)	\$ 54
Losses from derivative activities ⁽²⁾	—	—	—	(1)
Gain on/(impairment of) investments in unconsolidated entities, net	(91)	4	(182)	271
Gains/(losses) on asset sales and asset impairments, net	2	7	(617)	7
Goodwill impairment losses	—	—	(2,515)	—
Tax effect on selected items impacting comparability	9	(27)	44	(12)
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ (239)	\$ 19	\$ (3,632)	\$ 319

⁽¹⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽²⁾ We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining adjusted results. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable, as well as the mark-to-market adjustment related to our Preferred Distribution Rate Reset Option.

⁽³⁾ We carry crude oil and NGL inventory comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and write-downs of such inventory that result from price declines as a selected item impacting comparability.

⁽⁴⁾ We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on our capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results.

⁽⁵⁾ Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability.

⁽⁶⁾ During the periods presented, there were fluctuations in the value of the Canadian dollar to the U.S. dollar, resulting in gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability.

⁽⁷⁾ Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance.

⁽⁸⁾ Includes acquisition-related expenses associated with the Felix Midstream LLC acquisition in February 2020.

⁽⁹⁾ Includes net gains recognized in connection with the repurchase of our outstanding senior notes on the open market.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED ITEMS IMPACTING COMPARABILITY (continued)

(in millions)

	Twelve Months Ended December 31,	
	2019	2018
Selected Items Impacting Comparability: ⁽¹⁾		
Gains/(losses) from derivative activities, net of inventory valuation adjustments ⁽²⁾	\$ (158)	\$ 505
Long-term inventory costing adjustments ⁽³⁾	20	(21)
Deficiencies under minimum volume commitments, net ⁽⁴⁾	18	(7)
Equity-indexed compensation expense ⁽⁵⁾	(17)	(55)
Net gain on foreign currency revaluation ⁽⁶⁾	1	1
Line 901 incident ⁽⁷⁾	(10)	—
Selected items impacting comparability - Adjusted EBITDA	\$ (146)	\$ 423
Gains/(losses) from derivative activities ⁽²⁾	(1)	4
Gain on investment in unconsolidated entities	271	200
Gains/(losses) on asset sales and asset impairments, net	(28)	114
Tax effect on selected items impacting comparability	12	(95)
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ 108	\$ 646

⁽¹⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽²⁾ We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining adjusted results. In addition, we exclude gains and losses on derivatives that are related to investing activities, such as the purchase of linefill. We also exclude the impact of corresponding inventory valuation adjustments, as applicable, as well as the mark-to-market adjustment related to our Preferred Distribution Rate Reset Option.

⁽³⁾ We carry crude oil and NGL inventory comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and write-downs of such inventory that result from price declines as a selected item impacting comparability.

⁽⁴⁾ We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on our capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results.

⁽⁵⁾ Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability.

⁽⁶⁾ During the periods presented, there were fluctuations in the value of the Canadian dollar to the U.S. dollar, resulting in gains and losses that were not related to our core operating results for the period and were thus classified as a selected item impacting comparability.

⁽⁷⁾ Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED ADJUSTED NET INCOME PER COMMON UNIT⁽¹⁾

(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Basic Adjusted Net Income per Common Unit				
Net income/(loss) attributable to PAA	\$ 143	\$ 449	\$ (2,562)	\$ 1,865
Selected items impacting comparability - Adjusted net income attributable to PAA ⁽²⁾	239	(19)	3,632	(319)
Adjusted net income attributable to PAA	\$ 382	\$ 430	\$ 1,070	\$ 1,546
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(2)	(1)	(3)	(4)
Adjusted net income allocated to common unitholders	\$ 331	\$ 380	\$ 918	\$ 1,393
Basic weighted average common units outstanding	728	728	728	727
Basic adjusted net income per common unit	\$ 0.45	\$ 0.52	\$ 1.26	\$ 1.92
Diluted Adjusted Net Income per Common Unit				
Net income/(loss) attributable to PAA	\$ 143	\$ 449	\$ (2,562)	\$ 1,865
Selected items impacting comparability - Adjusted net income attributable to PAA ⁽²⁾	239	(19)	3,632	(319)
Adjusted net income attributable to PAA	\$ 382	\$ 430	\$ 1,070	\$ 1,546
Distributions to Series A preferred unitholders	(37)	(37)	(112)	—
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(1)	(1)	(2)
Adjusted net income allocated to common unitholders	\$ 332	\$ 380	\$ 920	\$ 1,507
Basic weighted average common units outstanding	728	728	728	727
Effect of dilutive securities:				
Series A preferred units ⁽³⁾	—	—	—	71
Equity-indexed compensation plan awards ⁽⁴⁾	—	1	—	2
Diluted weighted average common units outstanding	728	729	728	800
Diluted adjusted net income per common unit	\$ 0.46	\$ 0.52	\$ 1.26	\$ 1.88

⁽¹⁾ We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ The possible conversion of our Series A preferred units were excluded from the calculation of diluted net income per common unit for the three and nine months ended September 30, 2020 and the three months ended September 30, 2019 as the effect was antidilutive.

⁽⁴⁾ Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the

- more -

treasury stock method in guidance issued by the FASB. For the three months ended September 30, 2020, there were no potentially dilutive equity-indexed compensation plan awards and for the nine months ended September 30, 2020, the effect of equity-indexed compensation plan awards was antidilutive.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS

Net Income/(Loss) Per Common Unit to Adjusted Net Income Per Common Unit Reconciliations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Basic net income/(loss) per common unit	\$ 0.13	\$ 0.55	\$ (3.72)	\$ 2.35
Selected items impacting comparability per common unit ⁽¹⁾	0.32	(0.03)	4.98	(0.43)
Basic adjusted net income per common unit	<u>\$ 0.45</u>	<u>\$ 0.52</u>	<u>\$ 1.26</u>	<u>\$ 1.92</u>
Diluted net income/(loss) per common unit	\$ 0.13	\$ 0.55	\$ (3.72)	\$ 2.28
Selected items impacting comparability per common unit ⁽¹⁾	0.33	(0.03)	4.98	(0.40)
Diluted adjusted net income per common unit	<u>\$ 0.46</u>	<u>\$ 0.52</u>	<u>\$ 1.26</u>	<u>\$ 1.88</u>

⁽¹⁾ See the “Selected Items Impacting Comparability” and the “Computation of Basic and Diluted Adjusted Net Income/(Loss) Per Common Unit” tables for additional information.

	Twelve Months Ended December 31,	
	2019	2018
Diluted net income per common unit	\$ 2.65	\$ 2.71
Selected items impacting comparability per common unit ⁽¹⁾	(0.14)	(0.83)
Diluted adjusted net income per common unit	<u>\$ 2.51</u>	<u>\$ 1.88</u>

⁽¹⁾ See the “Selected Items Impacting Comparability” table for additional information.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)

(in millions, except per unit and ratio data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net Income/(Loss) to Adjusted EBITDA and Implied DCF Reconciliation				
Net Income/(Loss)	\$ 146	\$ 454	\$ (2,555)	\$ 1,872
Interest expense, net	113	108	329	311
Income tax expense/(benefit)	(3)	41	7	42
Depreciation and amortization	160	156	493	439
(Gains)/losses on asset sales and asset impairments, net	(2)	(7)	617	(7)
Goodwill impairment losses	—	—	2,515	—
(Gain on)/impairment of investments in unconsolidated entities, net	91	(4)	182	(271)
Depreciation and amortization of unconsolidated entities ⁽¹⁾	18	18	51	45
Selected items impacting comparability - Adjusted EBITDA ⁽²⁾	159	(35)	362	(54)
Adjusted EBITDA	\$ 682	\$ 731	\$ 2,001	\$ 2,377
Interest expense, net of certain non-cash items ⁽³⁾	(107)	(104)	(313)	(298)
Maintenance capital	(53)	(85)	(157)	(204)
Current income tax expense	(17)	(19)	(39)	(72)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings ⁽⁴⁾	(1)	(13)	7	(12)
Distributions to noncontrolling interests ⁽⁵⁾	(2)	(4)	(6)	(4)
Implied DCF	\$ 502	\$ 506	\$ 1,493	\$ 1,787
Preferred unit distributions paid ⁽⁶⁾	(37)	(37)	(137)	(137)
Implied DCF Available to Common Unitholders	\$ 465	\$ 469	\$ 1,356	\$ 1,650
Weighted Average Common Units Outstanding	728	728	728	727
Weighted Average Common Units and Common Equivalent Units	799	799	799	798
Implied DCF per Common Unit ⁽⁷⁾	\$ 0.64	\$ 0.64	\$ 1.86	\$ 2.27
Implied DCF per Common Unit and Common Equivalent Unit ⁽⁸⁾	\$ 0.63	\$ 0.63	\$ 1.84	\$ 2.21
Cash Distribution Paid per Common Unit	\$ 0.18	\$ 0.36	\$ 0.72	\$ 1.02
Common Unit Cash Distributions ⁽⁵⁾	\$ 131	\$ 262	\$ 524	\$ 741
Common Unit Distribution Coverage Ratio	3.54x	1.79x	2.59x	2.23x
Implied DCF Excess	\$ 334	\$ 207	\$ 832	\$ 909

⁽¹⁾ Adjustment to add back our proportionate share of depreciation and amortization expense of unconsolidated entities.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

⁽⁴⁾ Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization).

⁽⁵⁾ Cash distributions paid during the period presented.

⁽⁶⁾ Cash distributions paid to our preferred unitholders during the period presented. The current \$0.5250 quarterly (\$2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution from their issuance through February 2018. Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. The current \$61.25 per unit annual distribution requirement of our Series B preferred units, is payable in cash semi-annually in arrears on May 15 and November 15.

⁽⁷⁾ Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period.

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⁽⁸⁾ Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common equivalent units outstanding for the period. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, in whole or in part, subject to certain minimum conversion amounts.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)

(in millions, except per unit and ratio data)

	Twelve Months Ended December 31,	
	2019	2018
Net Income to Adjusted EBITDA and Implied DCF Reconciliation		
Net Income	\$ 2,180	\$ 2,216
Interest expense, net	425	431
Income tax expense	66	198
Depreciation and amortization	601	520
(Gains)/losses on asset sales and asset impairments, net	28	(114)
Gain on investment in unconsolidated entities	(271)	(200)
Depreciation and amortization of unconsolidated entities ⁽¹⁾	62	56
Selected items impacting comparability - Adjusted EBITDA ⁽²⁾	146	(423)
Adjusted EBITDA	<u>\$ 3,237</u>	<u>\$ 2,684</u>
Interest expense, net of certain non-cash items ⁽³⁾	(407)	(419)
Maintenance capital	(287)	(252)
Current income tax expense	(112)	(66)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings ⁽⁴⁾	(49)	1
Distributions to noncontrolling interests ⁽⁵⁾	(6)	—
Implied DCF	<u>\$ 2,376</u>	<u>\$ 1,948</u>
Preferred unit distributions paid ⁽⁶⁾	(198)	(161)
Implied DCF Available to Common Unitholders	<u>\$ 2,178</u>	<u>\$ 1,787</u>
Weighted Average Common Units Outstanding	727	726
Weighted Average Common Units and Common Equivalent Units	798	797
Implied DCF per Common Unit ⁽⁷⁾	\$ 2.99	\$ 2.46
Implied DCF per Common Unit and Common Equivalent Unit ⁽⁸⁾	\$ 2.91	\$ 2.38
Cash Distribution Paid per Common Unit	\$ 1.38	\$ 1.20
Common Unit Cash Distributions ⁽⁵⁾	\$ 1,004	\$ 871
Common Unit Distribution Coverage Ratio	2.17x	2.05x
Implied DCF Excess	\$ 1,174	\$ 916

⁽¹⁾ Adjustment to add back our proportionate share of depreciation and amortization expense of unconsolidated entities.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

⁽⁴⁾ Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization).

⁽⁵⁾ Cash distributions paid during the period presented.

⁽⁶⁾ Cash distributions paid to our preferred unitholders during the period presented. The \$0.5250 quarterly (\$2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution from their issuance through February 2018. Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. The \$61.25 per unit annual distribution requirement of our Series B preferred units, is payable in cash semi-annually in arrears on May 15 and November 15.

⁽⁷⁾ Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period.

⁽⁸⁾ Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common equivalent units outstanding for the period. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, in whole or in part, subject to certain minimum conversion amounts.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)

Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Equivalent Unit Reconciliations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Basic net income/(loss) per common unit	\$ 0.13	\$ 0.55	\$ (3.72)	\$ 2.35
Reconciling items per common unit ^{(1) (2)}	0.51	0.09	5.58	(0.08)
Implied DCF per common unit	<u>\$ 0.64</u>	<u>\$ 0.64</u>	<u>\$ 1.86</u>	<u>\$ 2.27</u>
Basic net income/(loss) per common unit	\$ 0.13	\$ 0.55	\$ (3.72)	\$ 2.35
Reconciling items per common unit and common equivalent unit ^{(1) (3)}	0.50	0.08	5.56	(0.14)
Implied DCF per common unit and common equivalent unit	<u>\$ 0.63</u>	<u>\$ 0.63</u>	<u>\$ 1.84</u>	<u>\$ 2.21</u>

	Twelve Months Ended December 31,	
	2019	2018
Basic net income per common unit	\$ 2.70	\$ 2.77
Reconciling items per common unit ^{(1) (4)}	0.29	(0.31)
Implied DCF per common unit	<u>\$ 2.99</u>	<u>\$ 2.46</u>
Basic net income per common unit	\$ 2.70	\$ 2.77
Reconciling items per common unit and common equivalent unit ^{(1) (3)}	0.21	(0.39)
Implied DCF per common unit and common equivalent unit	<u>\$ 2.91</u>	<u>\$ 2.38</u>

⁽¹⁾ Represents adjustments to Net Income to calculate Implied DCF Available to Common Unitholders. See the “Net Income/(Loss) to Adjusted EBITDA and Implied DCF Reconciliation” table for additional information.

⁽²⁾ Based on weighted average common units outstanding for the period of 728 million, 728 million, 728 million and 727 million, respectively.

⁽³⁾ Based on weighted average common units outstanding for the period, as well as weighted average Series A preferred units outstanding of 71 million for each of the periods presented.

⁽⁴⁾ Based on weighted average common units outstanding for the period of 727 million and 726 million, respectively.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)

(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Free Cash Flow and Free Cash Flow After Distributions Reconciliation ⁽¹⁾:				
Net cash provided by operating activities	\$ 282	\$ 314	\$ 1,256	\$ 1,778
Adjustments to reconcile net cash provided by operating activities to free cash flow:				
Net cash used in investing activities	(208)	(389)	(1,066)	\$ (1,367)
Cash contributions from noncontrolling interests	1	—	11	—
Cash distributions paid to noncontrolling interests ⁽²⁾	(2)	(4)	(6)	(4)
Sale of noncontrolling interest in a subsidiary	—	—	—	128
Free cash flow	\$ 73	\$ (79)	\$ 195	\$ 535
Cash distributions ⁽³⁾	(168)	(299)	(661)	(878)
Free cash flow after distributions	\$ (95)	\$ (378)	\$ (466)	\$ (343)

⁽¹⁾ Management uses the Non-GAAP financial measures Free Cash Flow and Free Cash Flow After Distributions to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes.

⁽²⁾ Cash distributions paid during the period presented.

⁽³⁾ Cash distributions paid to preferred and common unitholders during the period.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED FINANCIAL DATA BY SEGMENT

(in millions)

	Three Months Ended September 30, 2020			Three Months Ended September 30, 2019		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues ⁽¹⁾	\$ 494	\$ 271	\$ 5,537	\$ 597	\$ 291	\$ 7,542
Purchases and related costs ⁽¹⁾	(60)	(2)	(5,510)	(55)	(3)	(7,337)
Field operating costs ^{(1) (2)}	(139)	(73)	(46)	(172)	(92)	(56)
Segment general and administrative expenses ^{(2) (3)}	(22)	(18)	(21)	(26)	(21)	(27)
Equity earnings in unconsolidated entities	87	2	—	102	—	—
Adjustments: ⁽⁴⁾						
Depreciation and amortization of unconsolidated entities	17	1	—	18	—	—
(Gains)/losses from derivative activities, net of inventory valuation adjustments	—	(6)	94	(1)	(3)	(25)
Long-term inventory costing adjustments	—	—	2	—	—	(1)
Deficiencies under minimum volume commitments, net	64	—	—	(4)	—	—
Equity-indexed compensation expense	3	1	1	3	1	1
Net (gain)/loss on foreign currency revaluation	—	—	4	—	—	(5)
Segment Adjusted EBITDA	\$ 444	\$ 176	\$ 61	\$ 462	\$ 173	\$ 92
Maintenance capital	\$ 34	\$ 10	\$ 9	\$ 42	\$ 28	\$ 15

⁽¹⁾ Includes intersegment amounts.

⁽²⁾ Field operating costs and Segment general and administrative expenses include equity-indexed compensation expense.

⁽³⁾ Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

⁽⁴⁾ Represents adjustments utilized by our CODM in the evaluation of segment results. Many of these adjustments are also considered selected items impacting comparability when calculating consolidated non-GAAP financial measures such as Adjusted EBITDA. See the “Selected Items Impacting Comparability” table for additional discussion.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED FINANCIAL DATA BY SEGMENT

(in millions)

	Nine Months Ended September 30, 2020			Nine Months Ended September 30, 2019		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues ⁽¹⁾	\$ 1,530	\$ 860	\$ 16,371	\$ 1,712	\$ 880	\$ 23,480
Purchases and related costs ⁽¹⁾	(184)	(12)	(16,227)	(155)	(10)	(22,599)
Field operating costs ^{(1) (2)}	(440)	(233)	(149)	(532)	(267)	(195)
Segment general and administrative expenses ^{(2) (3)}	(73)	(63)	(65)	(80)	(62)	(83)
Equity earnings in unconsolidated entities	276	4	—	274	—	—
Adjustments: ⁽⁴⁾						
Depreciation and amortization of unconsolidated entities	49	2	—	45	—	—
(Gains)/losses from derivative activities, net of inventory valuation adjustments	—	(5)	215	1	(15)	(46)
Long-term inventory costing adjustments	—	—	66	—	—	3
Deficiencies under minimum volume commitments, net	64	5	—	(10)	—	—
Equity-indexed compensation expense	8	2	3	6	3	4
Net (gain)/loss on foreign currency revaluation	—	—	(9)	—	—	7
Line 901 incident	—	—	—	10	—	—
Significant acquisition-related expenses	3	—	—	—	—	—
Segment Adjusted EBITDA	\$ 1,233	\$ 560	\$ 205	\$ 1,271	\$ 529	\$ 571
Maintenance capital	\$ 98	\$ 40	\$ 19	\$ 110	\$ 74	\$ 20

⁽¹⁾ Includes intersegment amounts.

⁽²⁾ Field operating costs and Segment general and administrative expenses include equity-indexed compensation expense.

⁽³⁾ Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

⁽⁴⁾ Represents adjustments utilized by our CODM in the evaluation of segment results. Many of these adjustments are also considered selected items impacting comparability when calculating consolidated non-GAAP financial measures such as Adjusted EBITDA. See the “Selected Items Impacting Comparability” table for additional discussion.

- more -

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)
OPERATING DATA BY SEGMENT ⁽¹⁾

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Transportation segment (average daily volumes in thousands of barrels per day):				
Tariff activities volumes				
Crude oil pipelines (by region):				
Permian Basin ⁽²⁾	4,200	4,852	4,507	4,568
South Texas / Eagle Ford ⁽²⁾	370	429	383	445
Central ⁽²⁾	388	538	383	524
Gulf Coast	137	176	133	160
Rocky Mountain ⁽²⁾	238	284	251	300
Western	232	212	217	196
Canada	303	316	291	319
Crude oil pipelines	5,868	6,807	6,165	6,512
NGL pipelines	180	193	187	195
Tariff activities total volumes	6,048	7,000	6,352	6,707
Trucking volumes	67	81	75	86
Transportation segment total volumes	6,115	7,081	6,427	6,793
Facilities segment (average monthly volumes):				
Liquids storage (average monthly capacity in millions of barrels) ⁽³⁾	111	110	110	109
Natural gas storage (average monthly working capacity in billions of cubic feet)	67	63	66	63
NGL fractionation (average volumes in thousands of barrels per day)	110	140	129	145
Facilities segment total volumes (average monthly volumes in millions of barrels) ⁽⁴⁾	125	125	125	124
Supply and Logistics segment (average daily volumes in thousands of barrels per day):				
Crude oil lease gathering purchases	1,147	1,146	1,181	1,126
NGL sales	83	124	132	202
Supply and Logistics segment total volumes	1,230	1,270	1,313	1,328

⁽¹⁾ Average volumes are calculated as the total volumes (attributable to our interest) for the period divided by the number of days or months in the period.

⁽²⁾ Region includes volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

⁽³⁾ Includes volumes (attributable to our interest) from facilities owned by unconsolidated entities.

⁽⁴⁾ Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP SEGMENT RECONCILIATIONS

(in millions)

Fee-based Segment Adjusted EBITDA to Adjusted EBITDA Reconciliations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Transportation Segment Adjusted EBITDA	\$ 444	\$ 462	\$ 1,233	\$ 1,271
Facilities Segment Adjusted EBITDA	176	173	560	529
Fee-based Segment Adjusted EBITDA	\$ 620	\$ 635	\$ 1,793	\$ 1,800
Supply and Logistics Segment Adjusted EBITDA	61	92	205	571
Adjusted other income/(expense), net ⁽¹⁾	1	4	3	6
Adjusted EBITDA ⁽²⁾	\$ 682	\$ 731	\$ 2,001	\$ 2,377

	Twelve Months Ended December 31,	
	2019	2018
Transportation Segment Adjusted EBITDA	\$ 1,722	\$ 1,508
Facilities Segment Adjusted EBITDA	705	711
Fee-based Segment Adjusted EBITDA	\$ 2,427	\$ 2,219
Supply and Logistics Segment Adjusted EBITDA	803	462
Adjusted other income/(expense), net ⁽³⁾	7	3
Adjusted EBITDA ⁽²⁾	\$ 3,237	\$ 2,684

⁽¹⁾ Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of \$(4) million, \$(1) million, \$10 million and \$(17) million for the three and nine months ended September 30, 2020 and 2019, respectively. See the "Selected Items Impacting Comparability" table for additional information.

⁽²⁾ See the "Net Income/(Loss) to Adjusted EBITDA and Implied DCF Reconciliation" table for reconciliation to Net Income/(Loss).

⁽³⁾ Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of \$(17) million and \$10 million for the twelve months ended December 31, 2019 and 2018, respectively.

- more -

PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Three Months Ended September 30, 2020			Three Months Ended September 30, 2019		
	PAA	Consolidating Adjustments ⁽¹⁾	PAGP	PAA	Consolidating Adjustments ⁽¹⁾	PAGP
REVENUES	\$ 5,833	\$ —	\$ 5,833	\$ 7,886	\$ —	\$ 7,886
COSTS AND EXPENSES						
Purchases and related costs	5,107	—	5,107	6,855	—	6,855
Field operating costs	254	—	254	316	—	316
General and administrative expenses	61	1	62	74	1	75
Depreciation and amortization	160	1	161	156	1	157
(Gains)/losses on asset sales and asset impairments, net	(2)	—	(2)	(7)	—	(7)
Goodwill impairment losses	—	—	—	—	—	—
Total costs and expenses	5,580	2	5,582	7,394	2	7,396
OPERATING INCOME	253	(2)	251	492	(2)	490
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	89	—	89	102	—	102
Gain on/(impairment of) investments in unconsolidated entities, net	(91)	—	(91)	4	—	4
Interest expense, net	(113)	—	(113)	(108)	—	(108)
Other income, net	5	—	5	5	—	5
INCOME BEFORE TAX	143	(2)	141	495	(2)	493
Current income tax expense	(17)	—	(17)	(19)	—	(19)
Deferred income tax (expense)/benefit	20	(5)	15	(22)	(21)	(43)
NET INCOME	146	(7)	139	454	(23)	431
Net income attributable to noncontrolling interests	(3)	(119)	(122)	(5)	(356)	(361)
NET INCOME ATTRIBUTABLE TO PAGP	<u>\$ 143</u>	<u>\$ (126)</u>	<u>\$ 17</u>	<u>\$ 449</u>	<u>\$ (379)</u>	<u>\$ 70</u>
BASIC NET INCOME PER CLASS A SHARE			<u>\$ 0.09</u>			<u>\$ 0.41</u>
DILUTED NET INCOME PER CLASS A SHARE			<u>\$ 0.09</u>			<u>\$ 0.41</u>
BASIC WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			<u>186</u>			<u>168</u>
DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			<u>186</u>			<u>168</u>

- more -

- ⁽¹⁾ Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Nine Months Ended September 30, 2020			Nine Months Ended September 30, 2019		
	PAA	Consolidating Adjustments ⁽¹⁾	PAGP	PAA	Consolidating Adjustments ⁽¹⁾	PAGP
REVENUES	\$ 17,327	\$ —	\$ 17,327	\$ 24,515	\$ —	\$ 24,515
COSTS AND EXPENSES						
Purchases and related costs	15,000	—	15,000	21,218	—	21,218
Field operating costs	811	—	811	983	—	983
General and administrative expenses	201	5	206	225	4	229
Depreciation and amortization	493	2	495	439	2	441
(Gains)/losses on asset sales and asset impairments, net	617	—	617	(7)	—	(7)
Goodwill impairment losses	2,515	—	2,515	—	—	—
Total costs and expenses	19,637	7	19,644	22,858	6	22,864
OPERATING INCOME/(LOSS)	(2,310)	(7)	(2,317)	1,657	(6)	1,651
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	280	—	280	274	—	274
Gain on/(impairment of) investments in unconsolidated entities, net	(182)	—	(182)	271	—	271
Interest expense, net	(329)	—	(329)	(311)	—	(311)
Other income/(expense), net	(7)	—	(7)	23	—	23
INCOME/(LOSS) BEFORE TAX	(2,548)	(7)	(2,555)	1,914	(6)	1,908
Current income tax expense	(39)	—	(39)	(72)	—	(72)
Deferred income tax (expense)/benefit	32	145	177	30	(95)	(65)
NET INCOME/(LOSS)	(2,555)	138	(2,417)	1,872	(101)	1,771
Net (income)/loss attributable to noncontrolling interests	(7)	1,876	1,869	(7)	(1,481)	(1,488)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	<u>\$ (2,562)</u>	<u>\$ 2,014</u>	<u>\$ (548)</u>	<u>\$ 1,865</u>	<u>\$ (1,582)</u>	<u>\$ 283</u>
BASIC NET INCOME/(LOSS) PER CLASS A SHARE			<u>\$ (2.97)</u>			<u>\$ 1.73</u>
DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			<u>\$ (2.97)</u>			<u>\$ 1.72</u>
BASIC WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			<u>184</u>			<u>163</u>
DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			<u>184</u>			<u>165</u>

- more -

⁽¹⁾ Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

- more -

PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET DATA

(in millions)

	September 30, 2020			December 31, 2019		
	PAA	Consolidating Adjustments ⁽¹⁾	PAGP	PAA	Consolidating Adjustments ⁽¹⁾	PAGP
ASSETS						
Current assets	\$ 3,405	\$ 2	\$ 3,407	\$ 4,612	\$ 2	\$ 4,614
Property and equipment, net	14,618	9	14,627	15,355	12	15,367
Investments in unconsolidated entities	3,743	—	3,743	3,683	—	3,683
Goodwill	—	—	—	2,540	—	2,540
Deferred tax asset	—	1,438	1,438	—	1,280	1,280
Linefill and base gas	966	—	966	981	—	981
Long-term operating lease right-of-use assets, net	395	—	395	466	—	466
Long-term inventory	120	—	120	182	—	182
Other long-term assets, net	999	(2)	997	858	(2)	856
Total assets	<u>\$ 24,246</u>	<u>\$ 1,447</u>	<u>\$ 25,693</u>	<u>\$ 28,677</u>	<u>\$ 1,292</u>	<u>\$ 29,969</u>
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	\$ 3,804	\$ 1	\$ 3,805	\$ 5,017	\$ 2	\$ 5,019
Senior notes, net	9,069	—	9,069	8,939	—	8,939
Other long-term debt, net	312	—	312	248	—	248
Long-term operating lease liabilities	337	—	337	387	—	387
Other long-term liabilities and deferred credits	873	—	873	891	—	891
Total liabilities	<u>\$ 14,395</u>	<u>\$ 1</u>	<u>\$ 14,396</u>	<u>\$ 15,482</u>	<u>\$ 2</u>	<u>\$ 15,484</u>
Partners' capital excluding noncontrolling interests	9,706	(8,234)	1,472	13,062	(10,907)	2,155
Noncontrolling interests	145	9,680	9,825	133	12,197	12,330
Total partners' capital	<u>9,851</u>	<u>1,446</u>	<u>11,297</u>	<u>13,195</u>	<u>1,290</u>	<u>14,485</u>
Total liabilities and partners' capital	<u>\$ 24,246</u>	<u>\$ 1,447</u>	<u>\$ 25,693</u>	<u>\$ 28,677</u>	<u>\$ 1,292</u>	<u>\$ 29,969</u>

⁽¹⁾ Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

- more -

PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE

(in millions, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Basic Net Income/(Loss) per Class A Share				
Net income/(loss) attributable to PAGP	\$ 17	\$ 70	\$ (548)	\$ 283
Basic weighted average Class A shares outstanding	186	168	184	163
Basic net income/(loss) per Class A share	<u>\$ 0.09</u>	<u>\$ 0.41</u>	<u>\$ (2.97)</u>	<u>\$ 1.73</u>
Diluted Net Income/(Loss) per Class A Share				
Net income/(loss) attributable to PAGP	\$ 17	\$ 70	\$ (548)	\$ 283
Incremental net income attributable to PAGP resulting from assumed exchange of AAP Management Units	—	—	—	1
Net income/(loss) attributable to PAGP including incremental net income from assumed exchange of AAP Management Units	<u>\$ 17</u>	<u>\$ 70</u>	<u>\$ (548)</u>	<u>\$ 284</u>
Basic weighted average Class A shares outstanding	186	168	184	163
Dilutive shares resulting from assumed exchange of AAP Management Units	—	—	—	2
Diluted weighted average Class A shares outstanding	<u>186</u>	<u>168</u>	<u>184</u>	<u>165</u>
Diluted net income/(loss) per Class A share ⁽¹⁾	<u>\$ 0.09</u>	<u>\$ 0.41</u>	<u>\$ (2.97)</u>	<u>\$ 1.72</u>

⁽¹⁾ For the three and nine months ended September 30, 2020 and 2019, the possible exchange of any AAP units would not have had a dilutive effect on basic net income/(loss) per Class A share. For the three months ended September 30, 2020 and 2019 and the nine months ended September 30, 2020, the possible exchange of AAP Management units would not have had a dilutive effect on basic net income/(loss) per Class A share.

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PLAINS
ALL AMERICAN
PIPELINE, L.P.

Third-Quarter 2020

PAA & PAGP

Non-GAAP & Supplemental Reconciliations

Non-GAAP Reconciliations and Supplemental Calculations: Table of Contents

Page 1	Introduction
Page 2	Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2018 - 2020
Page 3	Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2014 - 2017
Page 4	Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2010 - 2013
Page 5	Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2006 - 2009
Page 6	Reconciliation to Adjusted EBITDA and Adjusted Net Income: 2002 - 2005
Page 7	Adjusted Net Income Per Common Unit
Page 8	Net Income/(Loss) Per Common Unit to Adjusted Net Income Per Common Unit Reconciliation
Page 9	PAA Credit Metrics: 2013 - 2020
Page 10	PAA Credit Metrics: 2004 - 2012
Page 11	Cash Distribution Coverage: 2016 - 2020
Page 12	Cash Distribution Coverage: 2006 - 2015
Page 13	Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Equivalent Unit Reconciliation
Page 14	Free Cash Flow 2016-2020
Page 15	Reconciliation of Fee-based Segment Adjusted EBITDA to Adjusted EBITDA
Page 16	Segment Supplemental Calculations: 2018 - 2020
Page 17	Segment Supplemental Calculations: 2014 - 2017
Page 18	Segment Supplemental Calculations: 2010 - 2013
Page 19	Segment Supplemental Calculations: 2006 - 2009

Introduction

Non-GAAP Financial Measures and Selected Items Impacting Comparability

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes.

The primary additional measures used by management are earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization of, and gains and losses on significant asset sales by, unconsolidated entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability (“Adjusted EBITDA”), Implied distributable cash flow (“DCF”), Free Cash Flow and Free Cash Flow After Distributions.

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income/(Loss), and Free Cash Flow and Free Cash Flow After Distributions are reconciled to Net Cash Provided by Operating Activities, (the most directly comparable measures as reported in accordance with GAAP) for the historical periods presented in the following pages, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements in our Annual Reports on Form 10-K, our Condensed Consolidated Financial Statements in our Quarterly Reports on Form 10-Q and notes thereto. We do not provide a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures on a forward-looking basis as it is impractical to forecast certain items that we have defined as “Selected Items Impacting Comparability” without unreasonable effort, due to the uncertainty and inherent difficulty of predicting the occurrence and financial impact of and the periods in which such items may be recognized. Thus, a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures could result in disclosure that could be imprecise or potentially misleading.

Performance Measures

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations and (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions. We also present these and additional non-GAAP financial measures, including adjusted net income attributable to PAA and basic and diluted adjusted net income per common unit, as they are measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains or losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” in our Consolidated Financial Statements in our Annual Reports on Form 10-K and our Condensed Consolidated Financial Statements in our Quarterly Reports on Form 10-Q. Such amounts are presented net of applicable amounts subsequently recognized into revenue. Furthermore, the calculation of these measures contemplates tax effects as a separate reconciling item, where applicable. We have defined all such items as “selected items impacting comparability.” Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures, referred to as adjusted results, but not impact other non-GAAP financial measures. We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, investment capital projects and numerous other factors and will be discussed, as applicable, in management’s discussion and analysis of operating results in our Quarterly Report on Form 10-Q and in our Annual Report on form 10-K for the period(s) applicable.

Liquidity Measures

Management also uses the non-GAAP financial measures Free Cash Flow and Free Cash Flow After Distributions to assess the amount of cash that is available for distributions, debt repayments and other general partnership purposes. Free Cash Flow is defined as Net Cash Provided by Operating Activities, less Net Cash Used in Investing Activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to preferred and common unitholders to arrive at Free Cash Flow After Distributions.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2018 - 2020 (in millions)^{(1) (2)}

Selected Items Impacting Comparability⁽³⁾

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities, net of inventory valuation adjustments	\$ (4)	\$ (99)	\$ (98)	\$ (203)	\$	97	\$ (51)	\$ 30	\$ (234)	\$ (158)	\$ 19	\$ (232)	\$ 108	\$ 610	\$ 505
Long-term inventory costing adjustments	(115)	51	(2)	(66)		21	(25)	1	22	20	13	(5)	10	(38)	(21)
Deficiencies under minimum volume commitments, net	2	(7)	(64)	(69)		7	(1)	4	8	18	(10)	(3)	4	2	(7)
Equity-indexed compensation expense	(4)	(5)	(5)	(13)		(3)	(4)	(5)	(4)	(17)	(11)	(12)	(14)	(19)	(55)
Net gain/(loss) on foreign currency revaluation	(46)	23	10	(11)		(4)	(8)	5	7	1	(8)	4	2	3	1
Significant acquisition-related expenses	(3)	—	—	(3)		—	—	—	—	—	—	—	—	—	—
Line 901 incident	—	—	—	—		—	(10)	—	—	(10)	—	—	—	—	—
Net gain on early repayment of senior notes	—	3	—	3		—	—	—	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	\$ (170)	\$ (34)	\$ (159)	\$ (362)	\$	118	\$ (99)	\$ 35	\$ (201)	\$ (146)	\$ 3	\$ (248)	\$ 110	\$ 558	\$ 423
Gains/(losses) from derivative activities	—	—	—	—		—	(1)	—	—	(1)	3	—	—	—	4
Gain on/(loss on or impairment of) investments in unconsolidated entities, net	(22)	(69)	(91)	(182)		267	—	4	—	271	—	—	210	(10)	200
Gains/(losses) on asset sales and asset impairments, net ⁽⁴⁾	(619)	1	2	(617)		(4)	4	7	(34)	(28)	—	81	(2)	36	114
Goodwill impairment losses	(2,515)	—	—	(2,515)		—	—	—	—	—	—	—	—	—	—
Tax effect on selected items impacting comparability	23	11	9	44		24	(9)	(27)	24	12	(28)	24	29	(120)	(95)
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ (3,303)	\$ (91)	\$ (239)	\$ (3,632)	\$	405	\$ (105)	\$ 19	\$ (211)	\$ 108	\$ (22)	\$ (143)	\$ 347	\$ 464	\$ 646

Net Income/(Loss) to Adjusted EBITDA Reconciliation

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	\$ (2,845)	\$ 144	\$ 146	\$ (2,555)	\$	970	\$ 448	\$ 454	\$ 307	\$ 2,180	\$ 288	\$ 100	\$ 710	\$ 1,117	\$ 2,216
Interest expense, net	108	108	113	329		101	103	108	114	425	106	111	110	104	431
Income tax expense/(benefit)	21	(12)	(3)	7		24	(23)	41	25	66	61	(16)	(10)	163	198
Depreciation and amortization	168	166	160	493		136	147	156	163	601	127	130	129	136	520
(Gains)/losses on asset sales and asset impairments, net	619	(1)	(2)	617		4	(4)	(7)	34	28	—	(81)	2	(36)	(114)
Goodwill impairment losses	2,515	—	—	2,515		—	—	—	—	—	—	—	—	—	—
(Gain on)/loss on or impairment of investments in unconsolidated entities, net	22	69	91	182		(267)	—	(4)	—	(271)	—	—	(210)	10	(200)
Depreciation and amortization of unconsolidated entities ⁽⁵⁾	17	16	18	51		12	14	18	16	62	14	14	15	13	56
Selected items impacting comparability - Adjusted EBITDA	170	34	159	362		(118)	99	(35)	201	146	(3)	248	(110)	(558)	(423)
Adjusted EBITDA	\$ 795	\$ 524	\$ 682	\$ 2,001	\$	862	\$ 784	\$ 731	\$ 860	\$ 3,237	\$ 593	\$ 506	\$ 636	\$ 949	\$ 2,684

Net Income/(Loss) to Adjusted Net Income Attributable to PAA Reconciliation

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	\$ (2,845)	\$ 144	\$ 146	\$ (2,555)	\$	970	\$ 448	\$ 454	\$ 307	\$ 2,180	\$ 288	\$ 100	\$ 710	\$ 1,117	\$ 2,216
Less: Net income attributable to noncontrolling interests	(2)	(2)	(3)	(7)		—	(2)	(5)	(1)	(9)	—	—	—	—	—
Net income/(loss) attributable to PAA	(2,847)	142	143	(2,562)		970	446	449	306	2,171	288	100	710	1,117	2,216
Selected items impacting comparability - Adjusted net income attributable to PAA	3,303	91	239	3,632		(405)	105	(19)	211	(108)	22	143	(347)	(464)	(646)
Adjusted net income attributable to PAA	\$ 456	\$ 233	\$ 382	\$ 1,070	\$	565	\$ 551	\$ 430	\$ 517	\$ 2,063	\$ 310	\$ 243	\$ 363	\$ 653	\$ 1,570

(1) Amounts may not recalculate due to rounding.

(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

(3) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

(4) During the fourth quarter of 2018, we began classifying net gains and losses on asset sales and asset impairments as a "Selected Item Impacting Comparability" of net income. Prior period amounts have been recast to reflect this change.

(5) Adjustment to add back our proportionate share of depreciation and amortization expense of, and gains or losses on significant asset sales by, unconsolidated entities.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2014 - 2017 (in millions) ^{(1) (2)}

Selected Items Impacting Comparability ⁽³⁾

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities, net of inventory valuation adjustments	\$ 285	\$ 15	\$ (214)	\$ (28)	\$ 59	\$ (122)	\$ (93)	\$ 69	\$ (227)	\$ (374)	\$ (91)	\$ (60)	\$ 39	\$ 2	\$ (110)	\$ 65	\$ (14)	\$ 27	\$ 166	\$ 243
Long-term inventory costing adjustments	(7)	(7)	16	22	24	(23)	67	(38)	51	58	(38)	23	(47)	(37)	(99)	—	—	—	(85)	(85)
Deficiencies under minimum volume commitments, net	(11)	14	(8)	3	(2)	(27)	(8)	(25)	14	(46)	—	—	—	—	—	—	—	—	—	—
Equity-indexed compensation expense	(3)	(9)	(7)	(5)	(23)	(4)	(11)	(8)	(10)	(33)	(11)	(11)	—	(5)	(27)	(19)	(17)	(12)	(8)	(56)
Significant acquisition-related expenses	(5)	(1)	—	—	(6)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Net gain/(loss) on foreign currency revaluation	3	8	11	—	21	3	(1)	(3)	(7)	(8)	27	(1)	(6)	1	21	(5)	11	(16)	(3)	(13)
Line 901 incident	—	(12)	—	(20)	(32)	—	—	—	—	—	—	(65)	—	(18)	(83)	—	—	—	—	—
Net loss on early repayment of senior notes	—	—	—	(40)	(40)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	\$ 262	\$ 8	\$ (202)	\$ (68)	\$ 1	\$ (173)	\$ (46)	\$ (5)	\$ (179)	\$ (403)	\$ (113)	\$ (114)	\$ (14)	\$ (57)	\$ (298)	\$ 40	\$ (20)	\$ (1)	\$ 70	\$ 89
Gains/(losses) from derivative activities	—	(2)	(8)	—	(10)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Gains/(losses) on asset sales and asset impairments, net ⁽⁴⁾	5	(5)	(15)	(94)	(109)	6	(70)	84	—	20	—	—	—	—	—	—	—	—	—	—
Tax effect on selected items impacting comparability	(42)	(7)	48	18	16	20	11	9	27	67	27	5	1	—	32	(9)	—	(1)	(43)	(52)
Deferred income tax expense	—	—	—	—	—	—	—	—	—	—	—	(22)	—	—	(22)	—	—	—	—	—
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ 225	\$ (6)	\$ (177)	\$ (144)	\$ (102)	\$ (147)	\$ (105)	\$ 88	\$ (152)	\$ (316)	\$ (86)	\$ (131)	\$ (13)	\$ (57)	\$ (288)	\$ 32	\$ (20)	\$ (2)	\$ 27	\$ 37

Net Income to Adjusted EBITDA Reconciliation

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 444	\$ 189	\$ 34	\$ 191	\$ 858	\$ 203	\$ 102	\$ 298	\$ 127	\$ 730	\$ 284	\$ 124	\$ 250	\$ 248	\$ 906	\$ 385	\$ 288	\$ 324	\$ 390	\$1,386
Interest expense, net	129	127	134	120	510	112	114	113	127	467	105	107	109	111	432	80	84	87	95	348
Income tax expense/(benefit)	66	10	(45)	14	44	19	(5)	1	11	25	16	33	17	34	100	48	22	20	81	171
Depreciation and amortization	126	124	136	131	517	120	134	117	143	514	104	108	107	113	432	94	98	95	98	384
(Gains)/losses on asset sales and asset impairments, net	(5)	5	15	94	109	(6)	70	(84)	—	(20)	—	—	—	—	—	—	—	—	—	—
Depreciation and amortization of unconsolidated entities ⁽⁵⁾	14	4	13	13	45	12	13	13	13	50	10	11	12	12	45	6	7	7	10	29
Selected items impacting comparability - Adjusted EBITDA	(262)	(8)	202	68	(1)	173	46	5	179	403	113	114	14	57	298	(40)	20	1	(70)	(89)
Adjusted EBITDA	\$ 512	\$ 451	\$ 489	\$ 631	\$2,082	\$ 633	\$ 474	\$ 463	\$ 600	\$2,169	\$ 632	\$ 497	\$ 509	\$ 575	\$2,213	\$ 573	\$ 519	\$ 534	\$ 604	\$2,229

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 444	\$ 189	\$ 34	\$ 191	\$ 858	\$ 203	\$ 102	\$ 298	\$ 127	\$ 730	\$ 284	\$ 124	\$ 250	\$ 248	\$ 906	\$ 385	\$ 288	\$ 324	\$ 390	\$1,386
Less: Net income attributable to noncontrolling interests	—	(1)	(1)	—	(2)	(1)	(1)	(1)	(1)	(4)	(1)	—	(1)	(1)	(3)	(1)	(1)	(1)	(1)	(2)
Net income attributable to PAA	444	188	33	191	856	202	101	297	126	726	283	124	249	247	903	384	287	323	389	1,384
Selected items impacting comparability - Adjusted net income attributable to PAA	(225)	6	177	144	102	147	105	(88)	152	316	86	131	13	57	288	(32)	20	2	(27)	(37)
Adjusted net income attributable to PAA	\$ 219	\$ 194	\$ 210	\$ 335	\$ 958	\$ 349	\$ 206	\$ 209	\$ 278	\$1,042	\$ 369	\$ 255	\$ 262	\$ 304	\$1,191	\$ 352	\$ 307	\$ 325	\$ 362	\$1,347

⁽¹⁾ Amounts may not recalculate due to rounding.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

⁽⁴⁾ During the fourth quarter of 2018, we began classifying net gains and losses on asset sales and asset impairments as a "Selected Item Impacting Comparability" of net income. Prior period amounts for 2016-2017 have been recast to reflect this change. Amounts prior to 2016 were immaterial.

⁽⁵⁾ Adjustment to add back our proportionate share of depreciation and amortization expense of, and gains or losses on significant asset sales by, unconsolidated entities.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2010 - 2013 (in millions) ^{(1) (2)}

Selected Items Impacting Comparability ⁽³⁾

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities, net of inventory valuation adjustments	\$ 24	\$ 26	\$ (59)	\$ (51)	\$ (59)	\$ (59)	\$ 72	\$ (31)	\$ (56)	\$ (74)	\$ 20	\$ 21	\$ 31	\$ (11)	\$ 62	\$ 19	\$ 21	\$ (42)	\$ (12)	\$ (14)
Equity-indexed compensation expense	(24)	(16)	(12)	(12)	(63)	(26)	(12)	(12)	(10)	(59)	(14)	(20)	(6)	(37)	(77)	(14)	(9)	(10)	(33)	(67)
Net loss on early repayment of senior notes	—	—	—	—	—	—	—	—	—	—	(23)	—	—	—	(23)	—	—	(6)	—	(6)
Significant acquisition-related expenses	—	—	—	—	—	(4)	(9)	—	(1)	(14)	(4)	—	—	(6)	(10)	—	—	—	—	—
PNGS contingent consideration fair value adjustment	—	—	—	—	—	(1)	—	—	—	(1)	—	—	—	(1)	(1)	(1)	(1)	(1)	—	(2)
Insurance deductible related to property damage incident	—	—	—	—	—	—	—	—	—	—	(1)	—	—	—	(1)	—	—	—	—	—
Net gain/(loss) on foreign currency revaluation	8	(4)	2	(7)	(1)	—	(16)	11	(1)	(7)	—	—	(17)	10	(7)	—	—	—	—	—
Other	1	—	—	—	(1)	—	—	—	—	(1)	—	—	(1)	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	\$ 9	\$ 6	\$ (69)	\$ (69)	\$ (124)	\$ (90)	\$ 35	\$ (32)	\$ (68)	\$ (156)	\$ (22)	\$ 1	\$ 7	\$ (45)	\$ (57)	\$ 4	\$ 11	\$ (59)	\$ (45)	\$ (89)
Tax effect on selected items impacting comparability	(5)	(1)	15	8	16	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Asset impairments	—	—	—	—	—	—	—	(125)	(41)	(166)	—	—	—	—	—	—	—	—	—	—
Other	—	—	1	—	2	1	—	—	—	2	2	—	—	—	2	—	—	—	—	—
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ 4	\$ 5	\$ (53)	\$ (61)	\$ (105)	\$ (90)	\$ 35	\$ (157)	\$ (109)	\$ (320)	\$ (20)	\$ 1	\$ 7	\$ (44)	\$ (55)	\$ 4	\$ 11	\$ (59)	\$ (45)	\$ (89)

Net Income to Adjusted EBITDA Reconciliation

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 536	\$ 300	\$ 237	\$ 318	\$1,391	\$ 237	\$ 386	\$ 173	\$ 330	\$1,127	\$ 185	\$ 233	\$ 288	\$ 288	\$ 994	\$ 151	\$ 133	\$ 84	\$ 146	\$ 514
Interest expense, net	79	77	74	83	313	67	77	76	76	297	67	64	64	65	261	58	62	64	64	248
Income tax expense/(benefit)	53	18	9	19	99	20	10	13	11	54	13	9	6	17	45	—	—	(4)	3	(1)
Depreciation and amortization	80	89	91	106	365	58	84	208	124	473	61	61	63	56	241	67	64	61	64	256
Depreciation and amortization of unconsolidated entities ⁽⁴⁾	4	5	6	6	22	4	4	4	6	17	—	—	—	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	(9)	(6)	69	69	124	90	(35)	32	68	156	22	(1)	(7)	45	57	(4)	(11)	59	45	89
Adjusted EBITDA	\$ 743	\$ 483	\$ 486	\$ 601	\$2,314	\$ 476	\$ 526	\$ 506	\$ 615	\$2,124	\$ 348	\$ 366	\$ 414	\$ 471	\$1,598	\$ 272	\$ 248	\$ 264	\$ 322	\$1,106

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 536	\$ 300	\$ 237	\$ 318	\$1,391	\$ 237	\$ 386	\$ 173	\$ 330	\$1,127	\$ 185	\$ 233	\$ 288	\$ 288	\$ 994	\$ 151	\$ 133	\$ 84	\$ 146	\$ 514
Less: Net income attributable to noncontrolling interests	(8)	(8)	(6)	(9)	(30)	(7)	(8)	(8)	(10)	(33)	(3)	(8)	(7)	(10)	(28)	—	(2)	(3)	(4)	(9)
Net income attributable to PAA	528	292	231	309	1,361	230	378	165	320	1,094	182	225	281	278	966	151	131	81	142	505
Selected items impacting comparability - Adjusted net income attributable to PAA	(4)	(5)	53	61	105	90	(35)	157	109	320	20	(1)	(7)	44	55	(4)	(11)	59	45	89
Adjusted net income attributable to PAA	\$ 524	\$ 287	\$ 284	\$ 371	\$1,466	\$ 320	\$ 343	\$ 322	\$ 429	\$1,414	\$ 202	\$ 224	\$ 274	\$ 322	\$1,021	\$ 147	\$ 120	\$ 140	\$ 187	\$ 594

⁽¹⁾ Amounts may not recalculate due to rounding.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

⁽⁴⁾ Adjustment to add back our proportionate share of depreciation and amortization expense of, and gains or losses on significant asset sales by, unconsolidated entities.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2006 - 2009 (in millions) ^{(1) (2)}
Selected Items Impacting Comparability ⁽³⁾

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities, net of inventory valuation adjustments	\$ 48	\$ 19	\$ 11	\$ (20)	\$ 58	\$ (5)	\$ (87)	\$ 98	\$ (12)	\$ (4)	\$ (17)	\$ 15	\$ (13)	\$ (9)	\$ (24)	\$ (1)	\$ (2)	\$ 18	\$ (19)	\$ (4)
Equity-indexed compensation expense	(9)	(15)	(12)	(14)	(50)	(6)	(15)	(3)	2	(21)	(18)	(19)	—	(6)	(44)	(11)	(6)	(10)	(16)	(43)
Net gain on purchase of remaining 50% interest in PNGS	—	—	9	—	9	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Gains on Rainbow acquisition-related foreign currency and linefill hedges	—	—	—	—	—	—	11	—	—	11	—	—	—	—	—	—	—	—	—	—
Net loss on early repayment of senior notes	—	—	—	(4)	(4)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Gains on sale of linefill	—	—	—	—	—	—	—	—	—	—	—	—	—	12	12	—	—	—	—	—
PNGS contingent consideration fair value adjustment	—	—	—	(1)	(1)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cumulative effect of change in acct. principle	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	6	—	—	—	6
Net gain/(loss) on foreign currency revaluation	10	2	—	—	12	—	—	(8)	(13)	(21)	—	—	—	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	\$ 49	\$ 6	\$ 8	\$ (39)	\$ 24	\$ (11)	\$ (91)	\$ 87	\$ (23)	\$ (35)	\$ (35)	\$ (4)	\$ (13)	\$ (3)	\$ (56)	\$ (5)	\$ (9)	\$ 8	\$ (35)	\$ (41)
Deferred income tax expense	—	—	—	—	—	—	—	—	—	—	—	(11)	—	—	(10)	—	—	—	—	—
Selected items impacting comparability - Adjusted net income attributable to PAA	\$ 49	\$ 6	\$ 8	\$ (39)	\$ 24	\$ (11)	\$ (91)	\$ 87	\$ (23)	\$ (35)	\$ (35)	\$ (15)	\$ (13)	\$ (3)	\$ (66)	\$ (5)	\$ (9)	\$ 8	\$ (35)	\$ (41)

Net Income to Adjusted EBITDA Reconciliation

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 211	\$ 136	\$ 122	\$ 110	\$ 580	\$ 92	\$ 41	\$ 206	\$ 98	\$ 437	\$ 85	\$ 105	\$ 98	\$ 77	\$ 365	\$ 63	\$ 80	\$ 95	\$ 46	\$ 285
Interest expense, net	51	56	59	58	224	42	49	52	53	196	41	41	39	41	162	15	18	19	32	85
Income tax expense/(benefit)	1	(2)	2	5	6	(2)	5	3	1	8	—	12	3	1	16	—	—	—	—	—
Depreciation and amortization	58	56	59	63	236	48	52	49	61	211	40	52	43	45	180	22	21	24	33	100
Selected items impacting comparability - Adjusted EBITDA	(49)	(6)	(8)	39	(24)	11	91	(87)	23	35	35	4	13	3	56	5	9	(8)	35	41
Adjusted EBITDA	\$ 272	\$ 240	\$ 234	\$ 275	\$ 1,022	\$ 191	\$ 238	\$ 223	\$ 236	\$ 887	\$ 201	\$ 214	\$ 196	\$ 167	\$ 779	\$ 105	\$ 128	\$ 131	\$ 146	\$ 511

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 211	\$ 136	\$ 122	\$ 110	\$ 580	\$ 92	\$ 41	\$ 206	\$ 98	\$ 437	\$ 85	\$ 105	\$ 98	\$ 77	\$ 365	\$ 63	\$ 80	\$ 95	\$ 46	\$ 285
Less: Net income attributable to noncontrolling interest	—	—	—	—	(1)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Net income attributable to PAA	211	136	122	110	579	92	41	206	98	437	85	105	98	77	365	63	80	95	46	285
Selected items impacting comparability - Adjusted net income attributable to PAA	(49)	(6)	(8)	39	(24)	11	91	(87)	23	35	35	15	13	3	66	5	9	(8)	35	41
Adjusted net income attributable to PAA	\$ 162	\$ 130	\$ 114	\$ 149	\$ 555	\$ 103	\$ 132	\$ 119	\$ 121	\$ 472	\$ 120	\$ 120	\$ 111	\$ 80	\$ 431	\$ 68	\$ 89	\$ 88	\$ 81	\$ 326

⁽¹⁾ Amounts may not recalculate due to rounding.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

Reconciliation to Adjusted EBITDA and Adjusted Net Income: 2002 - 2005 (in millions) ^{(1) (2)}
Selected Items Impacting Comparability ⁽³⁾

	2005					2004					2003					2002				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities, net of inventory valuation adjustments	\$ (13)	\$ (13)	\$ 6	\$ 1	\$ (19)	\$ 8	\$ (7)	\$ 1	\$ (1)	\$ 1	\$ 1	\$ —	\$ (3)	\$ 2	\$ —	\$ (3)	\$ 1	\$ —	\$ 2	\$ —
Equity-indexed compensation expense	(2)	(8)	(7)	(9)	(26)	(4)	—	—	(4)	(8)	—	—	(7)	(21)	(29)	—	—	—	—	—
Cumulative effect of change in accounting principle	—	—	—	—	—	(3)	—	—	—	(3)	—	—	—	—	—	—	—	—	—	—
Net gain/(loss) on foreign currency revaluation	(1)	1	(2)	(1)	(2)	—	1	3	2	5	—	—	—	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—	—	(2)	(2)	—	—	—	—	—	—	—	—	(2)	(2)
Selected items impacting comparability - Adjusted EBITDA	\$ (16)	\$ (20)	\$ (2)	\$ (9)	\$ (47)	\$ —	\$ (6)	\$ 4	\$ (5)	\$ (7)	\$ 1	\$ —	\$ (10)	\$ (19)	\$ (29)	\$ (3)	\$ 1	\$ —	\$ —	\$ (2)
Selected items impacting comparability - Adjusted net income	\$ (16)	\$ (20)	\$ (2)	\$ (9)	\$ (47)	\$ —	\$ (6)	\$ 4	\$ (5)	\$ (7)	\$ 1	\$ —	\$ (10)	\$ (19)	\$ (29)	\$ (3)	\$ 1	\$ —	\$ —	\$ (2)

Net Income to Adjusted EBITDA Reconciliation

	2005					2004					2003					2002				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 33	\$ 62	\$ 69	\$ 54	\$ 218	\$ 28	\$ 36	\$ 42	\$ 25	\$ 130	\$ 24	\$ 23	\$ 12	\$ —	\$ 59	\$ 14	\$ 17	\$ 16	\$ 18	\$ 65
Interest expense, net	15	14	16	15	59	10	10	13	15	47	9	9	9	9	35	7	6	7	9	29
Depreciation and amortization	19	19	20	25	84	13	16	16	23	69	11	11	12	12	46	7	7	9	11	34
Selected items impacting comparability - Adjusted EBITDA	16	20	2	9	47	—	6	(4)	5	7	(1)	—	10	19	29	3	(1)	—	—	2
Adjusted EBITDA	\$ 83	\$ 115	\$ 107	\$ 103	\$ 408	\$ 51	\$ 68	\$ 67	\$ 67	\$ 252	\$ 43	\$ 43	\$ 43	\$ 40	\$ 169	\$ 31	\$ 29	\$ 33	\$ 38	\$ 130

Net Income to Adjusted Net Income Reconciliation

	2005					2004					2003					2002				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income	\$ 33	\$ 62	\$ 69	\$ 54	\$ 218	\$ 28	\$ 36	\$ 42	\$ 25	\$ 130	\$ 24	\$ 23	\$ 12	\$ —	\$ 59	\$ 14	\$ 17	\$ 16	\$ 18	\$ 65
Selected items impacting comparability - Adjusted net income	16	20	2	9	47	—	6	(4)	5	7	(1)	—	10	19	29	3	(1)	—	—	2
Adjusted net income	\$ 49	\$ 82	\$ 71	\$ 63	\$ 265	\$ 28	\$ 42	\$ 38	\$ 29	\$ 137	\$ 23	\$ 23	\$ 21	\$ 19	\$ 88	\$ 17	\$ 16	\$ 16	\$ 18	\$ 67

⁽¹⁾ Amounts may not recalculate due to rounding.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

⁽³⁾ For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

Adjusted Net Income Per Common Unit (in millions, except per unit data) ^{(1) (2)}

Basic Adjusted Net Income Per Common Unit

	2020				2019					2018	2017
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD
Net income/(loss) attributable to PAA	\$ (2,847)	\$ 142	\$ 143	\$ (2,562)	\$ 970	\$ 446	\$ 449	\$ 306	\$ 2,171	\$ 2,216	\$ 856
Selected items impacting comparability - Adjusted net income attributable to PAA ⁽³⁾	3,303	91	239	3,632	(405)	105	(19)	211	(108)	(646)	102
Adjusted net income attributable to PAA	\$ 456	\$ 233	\$ 382	\$ 1,070	\$ 565	\$ 551	\$ 430	\$ 517	\$ 2,063	\$ 1,570	\$ 958
Distributions to Series A preferred unitholders ⁽⁴⁾	(37)	(37)	(37)	(112)	(37)	(37)	(37)	(37)	(149)	(149)	(142)
Distributions to Series B preferred unitholders ⁽⁴⁾	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(49)	(11)
Other	(2)	(1)	(2)	(3)	(2)	(2)	(1)	(2)	(6)	(6)	(17)
Adjusted net income allocated to common unitholders	\$ 405	\$ 183	\$ 331	\$ 918	\$ 514	\$ 500	\$ 380	\$ 466	\$ 1,859	\$ 1,366	\$ 788
Basic weighted average common units outstanding	728	728	728	728	727	727	728	728	727	726	717
Basic adjusted net income per common unit	\$ 0.56	\$ 0.25	\$ 0.45	\$ 1.26	\$ 0.71	\$ 0.69	\$ 0.52	\$ 0.64	\$ 2.56	\$ 1.88	\$ 1.10

Diluted Adjusted Net Income Per Common Unit

	2020				2019					2018	2017
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD
Net income/(loss) attributable to PAA	\$ (2,847)	\$ 142	\$ 143	\$ (2,562)	\$ 970	\$ 446	\$ 449	\$ 306	\$ 2,171	\$ 2,216	\$ 856
Selected items impacting comparability - Adjusted net income attributable to PAA ⁽³⁾	3,303	91	239	3,632	(405)	105	(19)	211	(108)	(646)	102
Adjusted net income attributable to PAA	\$ 456	\$ 233	\$ 382	\$ 1,070	\$ 565	\$ 551	\$ 430	\$ 517	\$ 2,063	\$ 1,570	\$ 958
Distributions to Series A preferred unitholders ⁽⁴⁾	—	(37)	(37)	(112)	—	—	(37)	—	—	(149)	(142)
Distributions to Series B preferred unitholders ⁽⁴⁾	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(49)	(11)
Other	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)	(4)	(17)
Adjusted net income allocated to common unitholders	\$ 443	\$ 183	\$ 332	\$ 920	\$ 552	\$ 538	\$ 380	\$ 504	\$ 2,011	\$ 1,368	\$ 788
Basic weighted average common units outstanding	728	728	728	728	727	727	728	728	727	726	717
Effect of dilutive securities:											
Series A preferred units ⁽⁵⁾	71	—	—	—	71	71	—	71	71	—	—
Equity-indexed compensation plan awards ⁽⁶⁾	1	—	—	—	2	2	1	1	2	2	1
Diluted weighted average common units outstanding	800	728	728	728	800	800	729	800	800	728	718
Diluted adjusted net income per common unit	\$ 0.55	\$ 0.25	\$ 0.46	\$ 1.26	\$ 0.69	\$ 0.67	\$ 0.52	\$ 0.63	\$ 2.51	\$ 1.88	\$ 1.10

(1) Amounts may not recalculate due to rounding.

(2) We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

(3) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

(4) Distributions pertaining to the period presented.

(5) For certain periods presented, the possible conversion of our Series A preferred units was excluded from the calculation of diluted adjusted net income per common unit as the effect was antidilutive.

(6) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For certain periods presented, such equity-indexed compensation plan awards did not change the presentation of diluted weighted average common units outstanding or diluted net income per common unit.

Net Income/(Loss) Per Common Unit to Adjusted Net Income Per Common Unit Reconciliation ⁽¹⁾

Basic Adjusted Net Income Per Common Unit

	2020				2019					2018	2017
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD
Basic net income/(loss) per common unit	\$ (3.98)	\$ 0.13	\$ 0.13	\$ (3.72)	\$ 1.26	\$ 0.54	\$ 0.55	\$ 0.35	\$ 2.70	\$ 2.77	\$ 0.96
Selected items impacting comparability per common unit ⁽²⁾	4.54	0.12	0.32	4.98	(0.55)	0.15	(0.03)	0.29	(0.14)	(0.89)	0.14
Basic adjusted net income per common unit	<u>\$ 0.56</u>	<u>\$ 0.25</u>	<u>\$ 0.45</u>	<u>\$ 1.26</u>	<u>\$ 0.71</u>	<u>\$ 0.69</u>	<u>\$ 0.52</u>	<u>\$ 0.64</u>	<u>\$ 2.56</u>	<u>\$ 1.88</u>	<u>\$ 1.10</u>

Diluted Adjusted Net Income Per Common Unit

	2020				2019					2018	2017
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD
Diluted net income/(loss) per common unit	\$ (3.98)	\$ 0.13	\$ 0.13	\$ (3.72)	\$ 1.20	\$ 0.54	\$ 0.55	\$ 0.35	\$ 2.65	\$ 2.71	\$ 0.95
Selected items impacting comparability per common unit ⁽²⁾	4.53	0.12	0.33	4.98	(0.51)	0.13	(0.03)	0.28	(0.14)	(0.83)	0.15
Diluted adjusted net income per common unit	<u>\$ 0.55</u>	<u>\$ 0.25</u>	<u>\$ 0.46</u>	<u>\$ 1.26</u>	<u>\$ 0.69</u>	<u>\$ 0.67</u>	<u>\$ 0.52</u>	<u>\$ 0.63</u>	<u>\$ 2.51</u>	<u>\$ 1.88</u>	<u>\$ 1.10</u>

(1) Amounts may not recalculate due to rounding.

(2) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

PAA Credit Metrics (in millions, except ratio amounts): 2013 - 2020 ⁽¹⁾

Debt Capitalization Ratios

	As of March 31,	As of June 30,	As of September 30,	As of December 31,						
	2020			2019	2018	2017	2016	2015	2014	2013
Short-term debt	\$ 363	\$ 729	\$ 790	\$ 504	\$ 66	\$ 737	\$ 1,715	\$ 999	\$ 1,287	\$ 1,113
Senior notes, net	8,941	9,067	9,069	8,939	8,941	8,933	9,874	9,698	8,699	6,670
Other long-term debt, net	477	326	312	248	202	250	250	677	5	5
Long-term debt	9,418	9,393	9,381	9,187	9,143	9,183	10,124	10,375	8,704	6,675
Total debt	<u>\$ 9,781</u>	<u>\$ 10,122</u>	<u>\$ 10,171</u>	<u>\$ 9,691</u>	<u>\$ 9,209</u>	<u>\$ 9,920</u>	<u>\$ 11,839</u>	<u>\$ 11,374</u>	<u>\$ 9,991</u>	<u>\$ 7,788</u>
Long-term debt	\$ 9,418	\$ 9,393	\$ 9,381	\$ 9,187	\$ 9,143	\$ 9,183	\$ 10,124	\$ 10,375	\$ 8,704	\$ 6,675
Partners' capital	9,722	9,802	9,851	13,195	12,002	10,958	8,816	7,939	8,191	7,703
Total book capitalization	<u>\$ 19,140</u>	<u>\$ 19,195</u>	<u>\$ 19,232</u>	<u>\$ 22,382</u>	<u>\$ 21,145</u>	<u>\$ 20,141</u>	<u>\$ 18,940</u>	<u>\$ 18,314</u>	<u>\$ 16,895</u>	<u>\$ 14,378</u>
Total book capitalization, including short-term debt	<u>\$ 19,503</u>	<u>\$ 19,924</u>	<u>\$ 20,022</u>	<u>\$ 22,886</u>	<u>\$ 21,211</u>	<u>\$ 20,878</u>	<u>\$ 20,655</u>	<u>\$ 19,313</u>	<u>\$ 18,182</u>	<u>\$ 15,491</u>
Long-term debt-to-total book capitalization	49 %	49 %	49 %	41 %	43 %	46 %	53 %	57 %	52 %	46 %
Total debt-to-total book capitalization, including short-term debt	50 %	51 %	51 %	42 %	43 %	48 %	57 %	59 %	55 %	50 %

(1) Amounts may not recalculate due to rounding.

PAA Credit Metrics (in millions, except ratio amounts): 2004 - 2012 ⁽¹⁾

Debt Capitalization Ratios

	As of December 31,								
	2012	2011	2010	2009	2008	2007	2006	2005	2004
Short-term debt	\$ 1,086	\$ 679	\$ 1,326	\$ 1,074	\$ 1,027	\$ 960	\$ 1,001	\$ 378	\$ 176
Senior notes, net	5,971	4,236	4,363	4,136	3,219	2,623	2,623	947	797
Other long-term debt, net	310	258	268	6	40	1	3	5	152
Long-term debt	6,281	4,494	4,631	4,142	3,259	2,624	2,626	952	949
Less: Adjustments ⁽²⁾	—	—	(466)	(222)	—	—	—	—	—
Adjusted long-term debt	6,281	4,494	4,165	3,920	3,259	2,624	2,626	952	949
Adjusted total debt	<u>\$ 7,367</u>	<u>\$ 5,173</u>	<u>\$ 5,491</u>	<u>\$ 4,994</u>	<u>\$ 4,286</u>	<u>\$ 3,584</u>	<u>\$ 3,627</u>	<u>\$ 1,330</u>	<u>\$ 1,125</u>
Adjusted long-term debt	\$ 6,281	\$ 4,494	\$ 4,165	\$ 3,920	\$ 3,259	\$ 2,624	\$ 2,626	\$ 952	\$ 949
Partners' capital	7,146	5,974	4,573	4,159	3,552	3,424	2,977	1,331	1,070
Total book capitalization	<u>\$ 13,427</u>	<u>\$ 10,468</u>	<u>\$ 8,738</u>	<u>\$ 8,079</u>	<u>\$ 6,811</u>	<u>\$ 6,048</u>	<u>\$ 5,603</u>	<u>\$ 2,282</u>	<u>\$ 2,019</u>
Total book capitalization, including short-term debt	<u>\$ 14,513</u>	<u>\$ 11,147</u>	<u>\$ 10,064</u>	<u>\$ 9,153</u>	<u>\$ 7,838</u>	<u>\$ 7,008</u>	<u>\$ 6,604</u>	<u>\$ 2,660</u>	<u>\$ 2,195</u>
Adjusted long-term debt-to-total book capitalization	47 %	43 %	48 %	49 %	48 %	43 %	47 %	42 %	47 %
Adjusted total debt-to-total book capitalization, including short-term debt	51 %	46 %	55 %	55 %	55 %	51 %	55 %	50 %	51 %

(1) Amounts may not recalculate due to rounding.

(2) The adjustments represent the portion of our \$500 million, 4.25% senior notes that had been used to fund hedged inventory and would have been classified as short-term debt if funded on our credit facilities. These notes were issued in July 2009 and the proceeds were used to supplement capital available from our hedged inventory facility. These notes matured in September 2012.

Cash Distribution Coverage (in millions, except per unit and ratio data): 2016 - 2020 ⁽¹⁾

Cash Distribution Coverage (based on distributions paid within the period presented)

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended December			
	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Mar 31, 2019	Jun 30, 2019	Sep 30, 2019	Sep 30, 2019	2019	2018	2017	2016
Adjusted EBITDA	\$ 795	\$ 524	\$ 682	\$ 2,001	\$ 862	\$ 784	\$ 731	\$ 2,377	\$ 3,237	\$ 2,684	\$ 2,082	\$ 2,169
Interest expense, net of certain non-cash items ⁽²⁾	(103)	(103)	(107)	(313)	(97)	(98)	(104)	(298)	(407)	(419)	(483)	(451)
Maintenance capital	(51)	(54)	(53)	(157)	(46)	(72)	(85)	(204)	(287)	(252)	(247)	(186)
Current income tax expense	(6)	(15)	(17)	(39)	(30)	(24)	(19)	(72)	(112)	(66)	(28)	(85)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings ⁽³⁾	(2)	11	(1)	7	2	—	(13)	(12)	(49)	1	(10)	(29)
Distributions to noncontrolling interests ⁽⁴⁾	—	(4)	(2)	(6)	—	—	(4)	(4)	(6)	—	(2)	(4)
Implied DCF	\$ 633	\$ 359	\$ 502	\$ 1,493	\$ 691	\$ 590	\$ 506	\$ 1,787	\$ 2,376	\$ 1,948	\$ 1,312	\$ 1,414
Preferred unit distributions paid ^{(4) (5)}	(37)	(62)	(37)	(137)	(37)	(62)	(37)	(137)	(198)	(161)	(5)	—
General partner cash distributions ⁽⁴⁾	—	—	—	—	—	—	—	—	—	—	—	(565)
Implied DCF available to common unitholders	<u>\$ 596</u>	<u>\$ 297</u>	<u>\$ 465</u>	<u>\$ 1,356</u>	<u>\$ 654</u>	<u>\$ 528</u>	<u>\$ 469</u>	<u>\$ 1,650</u>	<u>\$ 2,178</u>	<u>\$ 1,787</u>	<u>\$ 1,307</u>	<u>\$ 849</u>
Weighted average common units outstanding	728	728	728	728	727	727	728	727	727	726	717	464
Weighted average common units and common equivalent units	799	799	799	799	798	798	799	798	798	797	784	522
Implied DCF per common unit ⁽⁶⁾	\$ 0.82	\$ 0.41	\$ 0.64	\$ 1.86	\$ 0.90	\$ 0.73	\$ 0.64	\$ 2.27	\$ 2.99	\$ 2.46	\$ 1.82	\$ 1.83
Implied DCF per common unit and common equivalent unit ⁽⁷⁾	\$ 0.79	\$ 0.42	\$ 0.63	\$ 1.84	\$ 0.87	\$ 0.71	\$ 0.63	\$ 2.21	\$ 2.91	\$ 2.38	\$ 1.67	\$ 1.63
Cash distribution paid per common unit	\$ 0.36	\$ 0.18	\$ 0.18	\$ 0.72	\$ 0.30	\$ 0.36	\$ 0.36	\$ 1.02	\$ 1.38	\$ 1.20	\$ 1.95	\$ 2.65
Common unit cash distributions ^{(4) (8)}	\$ 262	\$ 131	\$ 131	\$ 524	\$ 218	\$ 262	\$ 262	\$ 741	\$ 1,004	\$ 871	\$ 1,386	\$ 1,627
Common unit distribution coverage ratio	2.27x	2.27x	3.54x	2.59x	3.00x	2.02x	1.79x	2.23x	2.17x	2.05x	0.94x	0.87x
Implied DCF excess/(shortage)	\$ 334	\$ 166	\$ 334	\$ 832	\$ 436	\$ 266	\$ 207	\$ 909	\$ 1,174	\$ 916	\$ (79)	\$ (213)

(1) Amounts may not recalculate due to rounding.

(2) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(3) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization and gains and losses on significant asset sales).

(4) Cash distributions paid during the period presented.

(5) A pro-rated initial distribution on the Series B preferred units was paid on November 15, 2017. The current \$0.5250 quarterly (\$2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution since their issuance through February 2018.

Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. The current \$61.25 per unit annual distribution requirement of our Series B preferred units, which were issued in October 2017, is payable in cash semi-annually in arrears on May 15 and November 15.

(6) Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period.

(7) Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid (if any), divided by the weighted average common units and common equivalent units outstanding for the periods. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, in whole or in part, subject to certain minimum conversion amounts.

(8) Common unit cash distributions include distributions paid to the general partner for the 2016 period.

Cash Distribution Coverage (in millions, except ratio data): 2006 - 2015^{(1) (2)}
Cash Distribution Coverage (based on distributions paid within the period presented)

	Twelve Months Ended December 31,									
	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
Adjusted EBITDA	\$ 2,213	\$ 2,229	\$ 2,314	\$ 2,124	\$ 1,598	\$ 1,106	\$ 1,022	\$ 887	\$ 779	\$ 511
Interest expense, net ⁽³⁾	(417)	(334)	(296)	(285)	(253)	(248)	(224)	(196)	(162)	(86)
Maintenance capital	(220)	(224)	(176)	(170)	(120)	(93)	(81)	(81)	(50)	(28)
Current income tax (expense)/benefit	(84)	(71)	(100)	(53)	(38)	1	(15)	(9)	(3)	—
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings ⁽⁴⁾	(14)	(32)	(32)	(15)	10	6	(8)	(4)	(14)	(8)
Distributions to noncontrolling interests ⁽⁵⁾	(4)	(3)	(49)	(48)	(40)	(10)	(2)	—	—	—
Interest income	—	—	—	—	—	—	—	—	—	1
Non-cash amortization of terminated interest rate and foreign currency hedging instruments	—	—	—	—	—	—	—	—	1	2
Other	—	—	—	—	(1)	—	—	—	—	—
Implied DCF	<u>\$ 1,474</u>	<u>\$ 1,565</u>	<u>\$ 1,661</u>	<u>\$ 1,553</u>	<u>\$ 1,156</u>	<u>\$ 762</u>	<u>\$ 692</u>	<u>\$ 597</u>	<u>\$ 551</u>	<u>\$ 392</u>
Cash distributions paid per common unit	\$ 2.76	\$ 2.55	\$ 2.33	\$ 2.11	\$ 1.95	\$ 1.88	\$ 1.81	\$ 1.75	\$ 1.64	\$ 1.44
Common unit cash distributions ^{(5) (6)}	\$ 1,671	\$ 1,407	\$ 1,160	\$ 968	\$ 791	\$ 682	\$ 605	\$ 532	\$ 451	\$ 263
Common unit distribution coverage ratio	0.88x	1.11x	1.43x	1.60x	1.46x	1.12x	1.14x	1.12x	1.22x	1.49x
Implied DCF excess/(shortage)	\$ (197)	\$ 158	\$ 501	\$ 585	\$ 365	\$ 80	\$ 87	\$ 65	\$ 100	\$ 129

(1) Amounts may not recalculate due to rounding.

(2) For information regarding our calculation of implied DCF and common unit distribution coverage ratio, please refer to our latest issued PAA & PAGP Earnings Release.

(3) The 2011-2015 periods presented exclude certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(4) Represents the difference between non-cash equity earnings in unconsolidated entities (2012-2015 periods have been adjusted for our proportionate share of depreciation and amortization and gains or losses on significant asset sales) and cash distributions received from such entities.

(5) Cash distributions paid during the period presented.

(6) Common unit cash distributions include distributions paid to the general partner during the period presented.

Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Equivalent Unit Reconciliation ^{(1) (2)}
Implied DCF Per Common Unit

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended	
	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Mar 31, 2019	Jun 30, 2019	Sep 30, 2019	Sep 30, 2019	Dec 31, 2019	Dec 31, 2018
Basic net income/(loss) per common unit	\$ (3.98)	\$ 0.13	\$ 0.13	\$ (3.72)	\$ 1.26	\$ 0.54	\$ 0.55	\$ 2.35	\$ 2.70	\$ 2.77
Reconciling items per common unit	4.80	0.28	0.51	5.58	(0.36)	0.19	0.09	(0.08)	0.29	(0.31)
Implied DCF per common unit	<u>\$ 0.82</u>	<u>\$ 0.41</u>	<u>\$ 0.64</u>	<u>\$ 1.86</u>	<u>\$ 0.90</u>	<u>\$ 0.73</u>	<u>\$ 0.64</u>	<u>\$ 2.27</u>	<u>\$ 2.99</u>	<u>\$ 2.46</u>

Implied DCF Per Common Unit and Common Equivalent Unit

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended	
	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Mar 31, 2019	Jun 30, 2019	Sep 30, 2019	Sep 30, 2019	Dec 31, 2019	Dec 31, 2018
Basic net income/(loss) per common unit	\$ (3.98)	\$ 0.13	\$ 0.13	\$ (3.72)	\$ 1.26	\$ 0.54	\$ 0.55	\$ 2.35	\$ 2.70	\$ 2.77
Reconciling items per common unit and common equivalent unit	4.77	0.29	0.50	5.56	(0.39)	0.17	0.08	(0.14)	0.21	(0.39)
Implied DCF per common unit and common equivalent unit	<u>\$ 0.79</u>	<u>\$ 0.42</u>	<u>\$ 0.63</u>	<u>\$ 1.84</u>	<u>\$ 0.87</u>	<u>\$ 0.71</u>	<u>\$ 0.63</u>	<u>\$ 2.21</u>	<u>\$ 2.91</u>	<u>\$ 2.38</u>

(1) Amounts may not recalculate due to rounding.

(2) For information regarding our reconciliation of net income per common unit to implied DCF per common unit and common equivalent unit, please refer to our latest issued PAA & PAGP Earnings Release.

Free Cash Flow (in millions): 2016 - 2020⁽¹⁾

Free Cash Flow and Free Cash Flow After Distributions Reconciliation

	2020				2019					2018	2017	2016
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD	YTD
Net cash provided by operating activities	\$ 890	\$ 84	\$ 282	\$ 1,256	\$ 1,033	\$ 431	\$ 314	\$ 726	\$ 2,504	\$ 2,608	\$ 2,499	\$ 733
Adjustments to reconcile net cash provided by operating activities to free cash flow:												
Net cash used in investing activities	(610)	(248)	(208)	(1,066)	(429)	(549)	(389)	(398)	(1,765)	(813)	(1,570)	(1,273)
Cash contributions from noncontrolling interests	8	2	1	11	—	—	—	—	—	—	—	—
Cash distributions paid to noncontrolling interests ⁽²⁾	—	(4)	(2)	(6)	—	—	(4)	(2)	(6)	—	(2)	(4)
Sale of noncontrolling interest in a subsidiary	—	—	—	—	—	128	—	—	128	—	—	—
Free cash flow	\$ 288	\$ (166)	\$ 73	\$ 195	\$ 604	\$ 10	\$ (79)	\$ 326	\$ 861	\$ 1,795	\$ 927	\$ (544)
Cash distributions ⁽³⁾	(299)	(193)	(168)	(661)	(255)	(324)	(299)	(324)	(1,202)	(1,032)	(1,391)	(1,627)
Free cash flow after distributions	\$ (11)	\$ (359)	\$ (95)	\$ (466)	\$ 349	\$ (314)	\$ (378)	\$ 2	\$ (341)	\$ 763	\$ (464)	\$ (2,171)

(1) Amounts may not recalculate due to rounding.

(2) Cash distributions paid during the period presented.

(3) Cash distributions paid to our preferred and common unitholders during the period presented. The 2016 period also includes distributions paid to our general partner.

Reconciliation of Fee-based Segment Adjusted EBITDA to Adjusted EBITDA (in millions) ⁽¹⁾

Reconciliation to Adjusted EBITDA

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended December 31,			
	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Mar 31, 2019	Jun 30, 2019	Sep 30, 2019	Sep 30, 2019	2019	2018	2017	2016
Transportation Segment Adjusted EBITDA	\$ 442	\$ 346	\$ 444	\$ 1,233	\$ 399	\$ 410	\$ 462	\$ 1,271	\$ 1,722	\$ 1,508	\$ 1,287	\$ 1,141
Facilities Segment Adjusted EBITDA	210	174	176	560	184	172	173	529	705	711	734	667
Fee-based Segment Adjusted EBITDA	\$ 652	\$ 520	\$ 620	\$ 1,793	\$ 583	\$ 582	\$ 635	\$ 1,800	\$ 2,427	\$ 2,219	\$ 2,021	\$ 1,808
Supply and Logistics Segment Adjusted EBITDA	141	3	61	205	278	200	92	571	803	462	60	359
Adjusted other income/(expense), net ⁽²⁾	2	1	1	3	1	2	4	6	7	3	1	2
Adjusted EBITDA ⁽³⁾	<u>\$ 795</u>	<u>\$ 524</u>	<u>\$ 682</u>	<u>\$ 2,001</u>	<u>\$ 862</u>	<u>\$ 784</u>	<u>\$ 731</u>	<u>\$ 2,377</u>	<u>\$ 3,237</u>	<u>\$ 2,684</u>	<u>\$ 2,082</u>	<u>\$ 2,169</u>

(1) Amounts may not recalculate due to rounding.

(2) Represents "Other income/(expense), net" adjusted for selected items impacting comparability. For more information please refer to our recently issued PAA & PAGP Earnings Releases.

(3) See the "Net Income/(Loss) to Adjusted EBITDA Reconciliation" tables for reconciliation to Net Income/(Loss).

Segment Supplemental Calculations: 2018 - 2020 (in millions, except volumes and per unit data) ⁽¹⁾
Segment Adjusted EBITDA

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA	\$ 442	\$ 346	\$ 444	\$ 1,233	\$	399	\$ 410	\$ 462	\$ 451	\$ 1,722	\$ 335	\$ 360	\$ 388	\$ 425	\$ 1,508
Facilities Segment Adjusted EBITDA	210	174	176	560		184	172	173	176	705	185	171	173	181	711
Fee-based Segment Adjusted EBITDA	\$ 652	\$ 520	\$ 620	\$ 1,793	\$	583	\$ 582	\$ 635	\$ 627	\$ 2,427	\$ 520	\$ 531	\$ 561	\$ 606	\$ 2,219
Supply and Logistics Segment Adjusted EBITDA	\$ 141	\$ 3	\$ 61	\$ 205	\$	278	\$ 200	\$ 92	\$ 232	\$ 803	\$ 72	\$ (26)	\$ 75	\$ 342	\$ 462

Total Average Volumes ⁽²⁾

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation total average volumes (thousands of barrels per day)	7,255	5,914	6,115	6,427		6,504	6,787	7,081	7,191	6,893	5,328	5,797	6,015	6,404	5,889
Facilities total average volumes (millions of barrels per month) ⁽³⁾	127	124	125	125		124	124	125	126	125	124	124	123	124	124
Supply and Logistics total average volumes (thousands of barrels per day)	1,538	1,171	1,230	1,313		1,456	1,260	1,270	1,492	1,369	1,392	1,202	1,237	1,403	1,309

Segment Adjusted EBITDA Per Barrel

	2020					2019					2018				
	Q1	Q2	Q3	YTD		Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA per barrel	\$ 0.67	\$ 0.64	\$ 0.79	\$ 0.70	\$	0.68	\$ 0.66	\$ 0.71	\$ 0.68	\$ 0.68	\$ 0.70	\$ 0.68	\$ 0.70	\$ 0.72	\$ 0.70
Facilities Segment Adjusted EBITDA per barrel	\$ 0.55	\$ 0.47	\$ 0.47	\$ 0.50	\$	0.49	\$ 0.46	\$ 0.46	\$ 0.47	\$ 0.47	\$ 0.50	\$ 0.46	\$ 0.47	\$ 0.49	\$ 0.48
Supply and Logistics Segment Adjusted EBITDA per barrel	\$ 1.00	\$ 0.03	\$ 0.54	\$ 0.57	\$	2.12	\$ 1.74	\$ 0.79	\$ 1.69	\$ 1.61	\$ 0.57	\$ (0.24)	\$ 0.66	\$ 2.65	\$ 0.97

(1) Amounts may not recalculate due to rounding.

(2) Average volumes are calculated as the total volumes (attributable to our interest) for the period divided by the number of days or months in the period.

(3) Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

Segment Supplemental Calculations: 2014 - 2017 (in millions, except volumes and per unit data) ⁽¹⁾

Segment Adjusted EBITDA

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA	\$ 273	\$ 298	\$ 363	\$ 354	\$ 1,287	\$ 281	\$ 274	\$ 308	\$ 278	\$ 1,141	\$ 256	\$ 267	\$ 265	\$ 268	\$ 1,056	\$ 219	\$ 236	\$ 244	\$ 280	\$ 979
Facilities Segment Adjusted EBITDA	188	180	182	184	734	167	161	171	171	667	144	146	148	150	588	159	138	149	151	597
Fee-based Segment Adjusted EBITDA	\$ 461	\$ 478	\$ 545	\$ 538	\$ 2,021	\$ 448	\$ 435	\$ 479	\$ 449	\$ 1,808	\$ 400	\$ 413	\$ 413	\$ 418	\$ 1,644	\$ 378	\$ 374	\$ 393	\$ 431	\$ 1,576
Supply and Logistics Segment Adjusted EBITDA	\$ 51	\$ (28)	\$ (56)	\$ 92	\$ 60	\$ 184	\$ 39	\$ (17)	\$ 151	\$ 359	\$ 231	\$ 84	\$ 95	\$ 157	\$ 568	\$ 194	\$ 144	\$ 141	\$ 173	\$ 651

Total Average Volumes ⁽²⁾

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation total average volumes (thousands of barrels per day)	4,754	5,163	5,341	5,477	5,186	4,608	4,781	4,602	4,558	4,637	4,244	4,529	4,545	4,491	4,453	3,840	3,931	4,226	4,314	4,079
Facilities total average volumes (millions of barrels per month) ^{(3) (4)}	131	132	127	129	130	125	124	129	129	127	118	119	119	122	120	114	113	114	115	114
Supply and Logistics total average volumes (thousands of barrels per day) ⁽⁴⁾	1,267	1,150	1,131	1,329	1,219	1,221	1,061	1,090	1,241	1,153	1,267	1,125	1,110	1,165	1,166	1,166	1,070	1,124	1,267	1,157

Segment Adjusted EBITDA Per Barrel

	2017					2016					2015					2014				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA per barrel	\$ 0.64	\$ 0.63	\$ 0.74	\$ 0.70	\$ 0.68	\$ 0.67	\$ 0.63	\$ 0.73	\$ 0.66	\$ 0.67	\$ 0.67	\$ 0.65	\$ 0.64	\$ 0.65	\$ 0.65	\$ 0.63	\$ 0.66	\$ 0.63	\$ 0.71	\$ 0.66
Facilities Segment Adjusted EBITDA per barrel	\$ 0.48	\$ 0.45	\$ 0.48	\$ 0.48	\$ 0.47	\$ 0.45	\$ 0.43	\$ 0.44	\$ 0.44	\$ 0.44	\$ 0.41	\$ 0.41	\$ 0.41	\$ 0.41	\$ 0.41	\$ 0.46	\$ 0.41	\$ 0.44	\$ 0.44	\$ 0.44
Supply and Logistics Segment Adjusted EBITDA per barrel	\$ 0.45	\$ (0.27)	\$ (0.54)	\$ 0.75	\$ 0.13	\$ 1.66	\$ 0.41	\$ (0.16)	\$ 1.32	\$ 0.85	\$ 2.03	\$ 0.82	\$ 0.93	\$ 1.47	\$ 1.33	\$ 1.85	\$ 1.48	\$ 1.36	\$ 1.48	\$ 1.54

(1) Amounts may not recalculate due to rounding.

(2) Average volumes are calculated as total volumes for the period (attributable to our interest) divided by the number of days or months in the period.

(3) Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

(4) Beginning in fourth-quarter 2017, PAA determined rail load and unload volumes (Facilities segment) and waterborne cargos (Supply and Logistics segment) were not primary drivers of the operations of the segment. Therefore, Facilities and Supply and Logistics segment total volumes have been recast to exclude such volumes.

Segment Supplemental Calculations: 2010 - 2013 (in millions, except volumes and per unit data) ⁽¹⁾

Segment Adjusted EBITDA

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA	\$ 179	\$ 172	\$ 211	\$ 220	\$ 782	\$ 177	\$ 184	\$ 194	\$ 204	\$ 759	\$ 143	\$ 137	\$ 155	\$ 160	\$ 595	\$ 134	\$ 135	\$ 142	\$ 138	\$ 549
Facilities Segment Adjusted EBITDA	156	153	150	169	629	100	119	143	141	502	87	91	96	107	381	61	72	75	75	284
Fee-based Segment Adjusted EBITDA	\$ 335	\$ 325	\$ 361	\$ 389	\$ 1,411	\$ 277	\$ 303	\$ 337	\$ 345	\$ 1,261	\$ 230	\$ 228	\$ 251	\$ 267	\$ 976	\$ 195	\$ 207	\$ 217	\$ 213	\$ 833
Supply and Logistics Segment Adjusted EBITDA	\$ 407	\$ 154	\$ 124	\$ 209	\$ 893	\$ 197	\$ 221	\$ 169	\$ 267	\$ 855	\$ 117	\$ 136	\$ 161	\$ 200	\$ 613	\$ 79	\$ 40	\$ 48	\$ 109	\$ 277

Total Average Volumes ⁽²⁾

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation total average volumes (thousands of barrels per day)	3,641	3,603	3,741	3,859	3,712	3,166	3,563	3,530	3,656	3,479	3,003	3,049	3,025	3,111	3,047	2,793	3,082	3,072	2,995	2,986
Facilities total average volumes (millions of barrels per month) ⁽³⁾⁽⁴⁾	112	114	113	113	113	91	109	111	113	106	77	82	84	86	82	66	70	71	72	70
Supply and Logistics total average volumes (thousands of barrels per day) ⁽⁴⁾	1,141	1,013	1,001	1,142	1,074	932	971	995	1,113	1,003	900	818	852	894	866	809	747	786	796	784

Segment Adjusted EBITDA Per Barrel

	2013					2012					2011					2010				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA per barrel	\$ 0.55	\$ 0.52	\$ 0.61	\$ 0.62	\$ 0.58	\$ 0.60	\$ 0.57	\$ 0.58	\$ 0.61	\$ 0.60	\$ 0.53	\$ 0.49	\$ 0.55	\$ 0.56	\$ 0.53	\$ 0.53	\$ 0.48	\$ 0.50	\$ 0.50	\$ 0.50
Facilities Segment Adjusted EBITDA per barrel	\$ 0.46	\$ 0.45	\$ 0.44	\$ 0.50	\$ 0.46	\$ 0.37	\$ 0.36	\$ 0.43	\$ 0.42	\$ 0.39	\$ 0.37	\$ 0.37	\$ 0.38	\$ 0.41	\$ 0.39	\$ 0.31	\$ 0.35	\$ 0.35	\$ 0.35	\$ 0.34
Supply and Logistics Segment Adjusted EBITDA per barrel	\$ 3.96	\$ 1.67	\$ 1.35	\$ 1.99	\$ 2.28	\$ 2.33	\$ 2.50	\$ 1.85	\$ 2.61	\$ 2.34	\$ 1.46	\$ 1.82	\$ 2.05	\$ 2.43	\$ 1.94	\$ 1.09	\$ 0.60	\$ 0.66	\$ 1.49	\$ 0.97

(1) Amounts may not recalculate due to rounding.

(2) Average volumes are calculated as total volumes for the period (attributable to our interest) divided by the number of days or months in the period.

(3) Facilities segment total volumes is calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

(4) Beginning in fourth-quarter 2017, PAA determined rail load and unload volumes (Facilities segment) and waterborne cargos (Supply and Logistics segment) were not primary drivers of the operations of the segment. Therefore, 2013 Facilities and Supply and Logistics segment total volumes have been recast to exclude such volumes. Prior to 2013, PAA did not report rail volumes and waterborne cargos were not a material percentage of Supply and Logistics segment volumes.

Segment Supplemental Calculations: 2006 - 2009 (in millions, except volumes and per unit data) ⁽¹⁾

Segment Adjusted EBITDA

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA	\$ 117	\$ 122	\$ 135	\$ 130	\$ 502	\$ 92	\$ 114	\$ 120	\$ 129	\$ 456	\$ 82	\$ 89	\$ 92	\$ 92	\$ 356	\$ 43	\$ 57	\$ 58	\$ 63	\$ 221
Facilities Segment Adjusted EBITDA	47	54	59	56	217	32	38	40	46	156	24	32	29	32	116	4	9	10	17	40
Fee-based Segment Adjusted EBITDA	\$ 164	\$ 176	\$ 194	\$ 186	\$ 719	\$ 124	\$ 152	\$ 160	\$ 175	\$ 612	\$ 106	\$ 121	\$ 121	\$ 124	\$ 472	\$ 47	\$ 66	\$ 68	\$ 80	\$ 261
Supply and Logistics Segment Adjusted EBITDA	\$ 107	\$ 59	\$ 37	\$ 84	\$ 287	\$ 66	\$ 85	\$ 49	\$ 58	\$ 256	\$ 90	\$ 93	\$ 75	\$ 43	\$ 300	\$ 59	\$ 63	\$ 62	\$ 66	\$ 249

Total Average Volumes ⁽²⁾

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation total average volumes (thousands of barrels per day)	2,900	3,074	2,919	2,794	2,921	2,758	3,038	2,982	3,030	2,948	2,719	2,879	2,809	2,859	2,817	2,471	2,104	2,235	2,580	2,207
Facilities total average volumes (millions of barrels per month) ⁽³⁾	58	60	61	64	61	56	58	58	58	56	45	46	50	53	48	24	25	25	34	27
Supply and Logistics total average volumes (thousands of barrels per day)	833	739	709	807	772	890	825	782	868	841	880	830	819	854	846	859	720	769	859	783

Segment Adjusted EBITDA per Barrel

	2009					2008					2007					2006				
	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA per barrel	\$ 0.45	\$ 0.44	\$ 0.50	\$ 0.50	\$ 0.47	\$ 0.37	\$ 0.41	\$ 0.44	\$ 0.46	\$ 0.42	\$ 0.33	\$ 0.34	\$ 0.36	\$ 0.35	\$ 0.35	\$ 0.19	\$ 0.30	\$ 0.28	\$ 0.26	\$ 0.27
Facilities Segment Adjusted EBITDA per barrel	\$ 0.27	\$ 0.30	\$ 0.32	\$ 0.30	\$ 0.30	\$ 0.19	\$ 0.23	\$ 0.23	\$ 0.26	\$ 0.23	\$ 0.18	\$ 0.23	\$ 0.19	\$ 0.20	\$ 0.20	\$ 0.05	\$ 0.12	\$ 0.14	\$ 0.17	\$ 0.12
Supply and Logistics Segment Adjusted EBITDA per barrel	\$ 1.42	\$ 0.88	\$ 0.56	\$ 1.14	\$ 1.02	\$ 0.81	\$ 1.13	\$ 0.67	\$ 0.74	\$ 0.84	\$ 1.13	\$ 1.23	\$ 0.99	\$ 0.53	\$ 0.97	\$ 0.76	\$ 0.95	\$ 0.88	\$ 0.83	\$ 0.87

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