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3Q 2022 Earnings Package

PLAINS ALL AMERICAN

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Third-Quarter 2022 Earnings Conference Call

Wednesday, November 2, 2022

Roy Lamoreaux:

Thank you, Therese. Good afternoon, and welcome to Plains All American's third-quarter 2022 earnings call. Today's slide presentation is posted on the Investor Relations website under the "News & Events" section at plains.com, where an audio replay will also be available following today's call. Important disclosures regarding forward-looking statements and non-GAAP financial measures are provided on slide 2. An overview of today's call is provided on slide 3. 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 CEO, and Al Swanson, Executive Vice President and CFO. Other members of our team will be available for Q&A, including: Harry Pefanis, President; Chris Chandler, Executive Vice President and COO; Jeremy Goebel, Executive Vice President and CCO; and Chris Herbold, Senior Vice President, Finance and CAO.

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

Willie Chiang:

Thanks Roy and thank you everyone for joining us this afternoon. Today we announced strong third-quarter results above our expectations, reflecting continued execution of our long-term goals and initiatives, and strong performance in both our Crude Oil and NGL segments. In summary:

- Third-quarter Adjusted EBITDA attributable to PAA was $623 million
- We increased our full-year 2022 Adjusted EBITDA guidance by $75 million to $2.450 billion, which is $250 million above our initial February guidance. The year-to-date

increase is driven by outperformance in both our Crude Oil and NGL segments due to the capture of additional volumes, higher commodity prices and favorable margin-based opportunities.

- Additionally, today we announced and closed an $85 million acquisition of an additional 5% interest in the Cactus II Pipeline, bringing our total ownership to 70%.
- Importantly, we ended the quarter with leverage of 3.7x and expect to end the year at 3.8x, both below the midpoint of our targeted leverage range, supporting increasing returns of capital to our equity holders.
- As such, within today's earnings release, we laid out a multi-year capital allocation and financial framework which I will discuss shortly.

Before that, I wanted to reiterate our views on why we remain constructive on long-term industry fundamentals. Notwithstanding global economic uncertainty and continued volatility in the commodity markets, we continue to expect global energy supply and demand to remain tight. As shown on slide 4, for the past number of years and for a number of reasons, there has been a lower level of investment in the upstream sector, reducing resource development. At the same time, energy demand continues to grow while historical supply buffers in the form of OPEC+ spare capacity and global inventories are greatly reduced and have been further impacted by recent geopolitical events. Year-to-date, we have seen US Strategic Petroleum Reserve draws of approximately 190 million barrels and commercial inventories remain at or below historic levels over the same timeframe. Global markets remain tight, and the world needs short-cycle North American production growth.

As summarized on slide 5, we have made meaningful progress on our long-term goals and initiatives, and as such, 2022 is a positive inflection point for Plains. For the last several years, we have focused on deleveraging by maximizing Free Cash Flow and reducing absolute debt. The success of this effort, when combined with solid operating, commercial, and financial performance, enabled us to achieve our leverage objectives well ahead of our initial expectations and to accelerate returns to equity holders while providing greater clarity on our multi-year capital allocation framework. As described in our press release this afternoon, we provided updates to our capital allocation and financial framework as follows:

- We currently intend to recommend to the Board a $0.20 per unit annualized increase in our quarterly distribution payable in February of 2023.
- Beyond 2023, as part of our annual budget review process with the Board, we anticipate targeting annualized distribution increases of approximately $0.15 per unit each year until reaching a targeted Common Unit Distribution Coverage Ratio of approximately 160%.
- We anticipate leverage migrating below the low-end of our targeted range of 3.75 – 4.25 times in 2023, consistent with our objective of achieving and maintaining mid-BBB and equivalent credit ratings.
- Additionally, opportunistic unit repurchases will remain a component of our capital allocation framework, which will be a dynamic assessment of business outlook, market environment and capital allocation options.

As we look forward, we remain focused on driving shareholder value and improving the resilience of our earnings by leveraging our existing Crude Oil and NGL infrastructure. This includes capital-efficient brownfield expansions and debottlenecking opportunities underpinned by contractual commitments, potential bolt-on acquisitions such as the Advantage JV and the acquisition of additional interest in Cactus II, and optimizing and aligning existing assets with emerging energy opportunities. In Canada, we recently completed a win-win, non-cash transaction to gain full ownership of our existing Empress facilities in exchange for a long-term processing capacity lease at the facility, allowing us to further optimize and operate the assets more efficiently over time. Additionally, we continue to evaluate capital-efficient debottlenecking and expansion projects around our Fort Saskatchewan facilities and hope to be able to share additional detail over the coming quarters.

With that, I will turn the call over to Al.

Al Swanson:

Thanks, Willie. We reported third-quarter Adjusted EBITDA of $623 million which includes the benefit of increased volumes across our systems, primarily within the Permian, higher commodity prices as well as Canadian margin-based opportunities. Slides 17 and 18 in today's appendix contain quarter-over-quarter and year-over-year Segment Adjusted EBITDA walks which provide more detail on our third-quarter performance.

A summary of our progress on our goals, key financial and operating metrics, and 2022 guidance is located on slides 6 through 9. We've increased our full-year 2022 Adjusted EBITDA guidance by $75 million to plus or minus $2.450 billion, primarily driven by strong third-quarter performance. Slide 6 shows our key 2022 financial metrics and reflects strong common distribution coverage of 265% and Free Cash Flow after Distributions of $670 million, which provides ample capacity supporting our multi-year capital allocation framework. I would note that we have left our asset sales target at $200 million, but as a result of the current volatility in capital markets, the remaining $140 million that hasn't closed could shift into the first half 2023. Additionally, going forward, Cactus II will be consolidated into PAA's future period financials. Similar to the Permian JV, volumes will be reported on a consolidated basis and earnings on a proportional basis.

Before providing more detail on today's capital allocation announcement, I wanted to share a few directional comments on 2023, with formal guidance to come early next year. We continue to expect growth in our Crude Oil business, primarily driven by our Permian operating leverage and improving margins on short-term contracted long-haul opportunities. For our NGL segment, we currently anticipate lower C3+ spec product sales volumes due to a 3rd party facility turnaround and the absence of 2022 weather benefits. Furthermore, current forward markets indicate lower year-over-year frac spreads. The combination of these items could lower 2023 NGL Segment Adjusted EBITDA by roughly $100 million versus 2022 guidance.

In regard to capital allocation, our proposed long-term capital allocation framework and financial strategy are summarized on slides 10 through 13. We are focused on generating meaningful multi-year Free Cash Flow and improving shareholder returns by 1) increasing returns of capital to equity holders, 2) making disciplined accretive investments, and 3) ensuring balance sheet flexibility.

With respect to increasing returns of capital to our equity holders in a long-term sustainable manner, as shown on slide 11 and detailed in our earnings press release, we intend to recommend to our Board an annualized increase of $0.20 per common unit for our quarterly distribution to be paid in February, which is one quarter earlier than when we would normally implement a change to our quarterly distribution. Beyond 2023, we will continue to evaluate our capital allocation program, financial positioning, investment opportunities and business outlook with our Board of Directors as part of our annual budgeting process. Subject to that process, we currently anticipate targeting annualized distribution increases of approximately $0.15 per unit per year until reaching a targeted Common Unit Distribution Coverage Ratio of approximately 160%. Upon reaching our target coverage, subsequent distribution increases will be driven by future DCF growth and evaluated as part of our annual budgeting process. Opportunistic equity repurchases will remain a component of our long-term capital program. Since the inception of the program, we have repurchased $300 million of our $500 million authorization or approximately 4% of our common units outstanding.

With respect to capital investments going forward, as summarized on slide 12, we will continue our disciplined approach focusing on high-return expansion and debottlenecking opportunities that leverage our existing Crude Oil and NGL infrastructure. Longer-term, we continue to expect self-funding annual routine investment capital through our excess cash flow and coverage.

Regarding our balance sheet, as described on slide 13, we have achieved our leverage goals and anticipate migrating leverage below the low-end of our target range of 3.75-4.25 times in 2023. We will take a prudent long-term approach focusing on increasing cash returned to equity holders while maintaining and improving financial flexibility, consistent with our objective of achieving a mid-BBB equivalent credit rating.

Before I turn the call back to Willie, I wanted to provide a brief update on potential changes to the pricing of our Series A and B preferred equity securities. The Series A security issued in 2016 currently has a yield of 8.0% and contains a one-time option for the holders to reprice the security based on the 10-year US treasury rate plus 5.85%. The holders will have the opportunity to reprice the security during a 30-day period beginning in late January 2023; if the right is exercised, we would anticipate the yield rising to approximately 10% based on current treasury rates. After repricing, we will obtain a call right at 110% of par. The Series B security issued in 2017 has a fixed yield of 6.125% for the first five years, shifting to floating on November 15, 2022 at a new rate of Three-Month LIBOR plus 4.11%. Upon the shift to floating, the security becomes callable at 100% of par. If both were to reprice at current market conditions, total annual preferred dividends would increase by approximately $55 million to approximately $255 million per year. Even with the potential increase, we still have ample financial flexibility to continue lowering leverage and increasing returns of capital to common equity holders in a manner consistent with what we have described on today's call.

With that I will turn the call back to Willie.

Willie Chiang:

Thanks, Al. Today's results reflect another solid quarter of performance and execution. Although we are monitoring current macro and geopolitical events, we believe long-term fundamentals remain constructive, and that our business will continue to perform well in the current and longer-term environment. We have made steady progress reducing leverage and creating additional financial flexibility, which has positioned us to provide additional clarity on our multi-year capital allocation framework. We will continue to take a long-term, disciplined approach to our business and the execution of our capital allocation priorities.

We appreciate your continued interest and support, and we look forward to providing further updates along with formal 2023 guidance on our earnings conference call in February. A summary of key takeaways from today's call is provided on slide 14. With that, I will turn the call 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 throughout the week to address additional questions.

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

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progress reducing leverage and creating additional financial flexibility, which has positioned us to provide additional clarity on our multi-year capital allocation framework.

We will continue to take a long-term disciplined approach to our business and the execution of our capital allocation priorities. We appreciate your continued interest and support and we look forward to providing further updates along with our formal 2023 guidance on our earnings call in February. Summary of the key takeaways from today's call is provided on slide 14.

With that, I'll turn the call over to Roy to lead us through 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 for as many of our participants is practical on our available time this afternoon. Additionally, our Investor Relations team plans to be available throughout the week to address additional questions. Therese, we're now ready to open the call for questions.

QUESTION AND ANSWER SECTION

Operator: Thank you. [Operator Instructions] Our first question is from Michael Blum from Wells Fargo. Michael?

Michael Blum Q

Analyst, Wells Fargo Securities LLC

Thanks. Good afternoon, everyone. Yeah, maybe to start with the distribution growth announcements here, seems like you really tilted the scales towards distribution over buybacks so I'm wondering if you could just kind of talk through the thought process there.

Willie C. W. Chiang A

Chairman & Chief Executive Officer, Plains All American Pipeline LP

Sure, Michael. Thanks for the question. We have, and the reason for that is as we think about our capital allocation process, it's a pretty dynamic matrix that we look at with a number of things. And the goal is to really help improve the value of the company and ability to be able to have additional cash flow which we can distribute back to unitholders.

And as we think about that, we think the distribution is the most efficient way to do that as far as returns – get returns back to – get back to unitholders versus buybacks. And it's really for that reason and the progress that we've made so far that we've articulated this multi-year strategy.

Michael Blum Q

Analyst, Wells Fargo Securities LLC

Got it. Thanks for that. Also, just wanted to ask about Permian growth. Would love to get your latest thoughts on where things are trending both for this year and into 2023. I'm sure you saw some of the comments from some of the majors on perhaps a slight slowdown, so want to [ph] kind of hear lay of land (16:59). Thanks.

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

A

Well, Michael, let me – I'll give you some comments. We are going to wait till 2023 February to give detailed guidance. But where it stands right now is it's really in lockstep with what we've expected. Year-end to year-end growth in 2022 can be roughly 650,000 barrels a day. We premised roughly 10% increase in rigs, running about 150 to 160 rigs next year, and that's what we'll have to kind of validate as we go through the next number of months in talking to the producers. But I will highlight that with that growth, if you take a look at the market capture of our volumes, we've been very successful in being able to capture volumes into our gathering joint venture, which ultimately feeds the rest of the business.

Michael Blum
Analyst, Wells Fargo Securities LLC

Q

Great. Thanks. Thanks, Willie.

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

A

Thanks, Michael.

Operator: Thank you, Michael. Our next question will be coming from Keith Stanley with Wolfe Research. Mr. Stanley?

Keith Stanley
Analyst, Wolfe Research LLC

Q

Hi. Thank you. I guess sticking with the distribution, can you explain a little more how you came to the 160% minimum coverage threshold using DCF for future dividend growth? And I also wanted to ask, you talked about the [ph] preps (18:24) going at variable rates, which is pretty expensive source of capital. So, how did you balance what's a very robust dividend growth plan against alternative uses like trying to pay down that preferred equity?

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

A

Yeah, Keith, Mr. Stanley, let me take that and I'll let Al talk about the press. Hey, on the 160% coverage, what we're driving for there is as you know, we're funding CapEx from cash flow. And as we put this multi-year trajectory out on the increase, the 160% target is really kind of a governor to make sure that we've got adequate coverage in cash flow to build to cover our routine CapEx expectations, our annual program, as well as a little bit of extra dry powder to be able to further take our leverage down and be prepared for anything that might present itself. So the 160% is really to make sure that we're conservative and fund our CapEx in the future going forward.

Al, you want to take the [ph] preps? (19:31)

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

A

Yeah. I'll take a shot at the [ph] preps (19:34). Between the two, the one that was repriced today will be about 10%. We view that right now on a 50/50 basis and have the equity component of that. It's less than our cost of capital today. We trade at, what, a DCF yield of probably 18% 10-year money. Today, it's probably 7%. 50/50 would be 13.5%. So, while it's more expensive, it's still not more expensive when you look at the components of it relative to our cost of capital.

We're too new in to just having hit and got to our leverage objective to use a deleveraging or a leveraging, excuse me, i.e. go use that to take that out in the near-term. Clearly, our objective that you heard in our comments is to continue to move leverage down so at some point, we may have a capacity to deal with that. But today, we don't believe that would be prudent, to use leveraging transaction to try to reduce that cost. It's actually pretty manageable relative to what the current capital markets are providing and we surely don't want to use equity – common equity to try to take it out at this point. But all of that could be on the table a year or two down the road, and the important thing is we do see call options coming our way with this. So, we do control our destiny a little bit when we get into a position to be able to deal with it.

Keith Stanley
Analyst, Wolfe Research LLC

Q

Got it. Thanks. If I could just clarify, second question, on your expectation to be below the low end of leverage range in 2023 and you gave some puts and takes on next year. But is that assuming that you repay – that you continue to repay debt with some of your free cash flow through 2023?

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

A

Yeah. Our intent, again, if you think of what we are mentioning with the distribution and being capital-disciplined on investments, we will still have very strong cash flow after distributions and our intent will be to continue to reduce debt. We do, when we look into the future, believe we'll have cash flow growth as well. But bottom line is we do expect to continue to pay down debt and reduce debt and increase the flexibility. We don't want to get to the point of setting a new range now. We intend to migrate below and then operate there for a while and we can reevaluate that in the future.

Keith Stanley
Analyst, Wolfe Research LLC

Q

Thank you.

Operator: Thank you. Our next question comes from Brian Reynolds of UBS. Brian, your line is open.

Brian Reynolds
Analyst, UBS Securities LLC

Q

Hi. Good afternoon. Maybe just a quick follow-up on some of the capital allocation questions. You got $2.2 billion in [ph] preps (22:39) that can convert next year but you also have the $1.1 billion in long-term debt that can be refinanced in 2023. So, kind of just curious as you enter the year, like what your priorities just given the equity credit for the [ph] preps (22:52). Is it your priority to refinance that debt? And I guess kind of a follow-up question, can you just remind us of your liquidity particularly the cash plus the revolver and your ability to use that to manage potentially a reduction in rates, call it, a year from now? Thanks.

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

A

Brian, this is Al. We have – as of the end of September, we had $3.3 billion of liquidity, which included $600 million of cash on the balance sheet. The cash is earning more than the first note that matures early next year or we would have taken it out before end of the year. It became where we could take it out at par here just yesterday, but we'll take it out next year. Our intent would be to take and retire the $1.1 billion next year and not access the market. And that will be part of our deleveraging.

We would fully expect the [ph] preps (23:50) to remain out. Again, while the rates are going up and obviously we don't know where the Fed will stop, so the one that floats may become an issue. But we would not intend to be looking at retiring those next year.

Brian Reynolds
Analyst, UBS Securities LLC

Q

Great. Thanks for the clarification and maybe just a simple operational question. It seems like [ph] pad 2 (24:14) movements were a little noisy, particularly with some refinery movements. Just kind of curious if you can talk about those inter-basin volumes during the quarter and if that's something that could – that's a trend that could continue into 2023 if you think that's more of a singular event for the quarter. Thanks.

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

A

Hey, Jeremy, why don't you take that one?

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

A

Hey, Brian. This is Jeremy. The [ph] pad 2 (24:36) movements, low inventories at Cushing and you haven't seen a ton of growth in the Rockies. And you've even seen some facilities offline in Canada which yield higher movements [ph] up base (24:49) and with the frac spreads you're seeing, specifically on the diesel side.So, we're going to expect that to continue as long as refining runs and refining demand remains strong. So that we'd expect to continue.

The inter-basin movements were a function of production growth in the Permian Basin and you can almost look at the gathering volume has grown, the inter-basin volumes grow accordingly. We would expect that to continue as well.

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

A

And Brian, this is Willie.

Brian Reynolds
Analyst, UBS Securities LLC

Q

I appreciate the [ph] comment. (25:15) Yeah, go ahead [indiscernible] (25:17).

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

A

Just reinforcing a point that we always like to talk about, when you think about our system, there's a lot of flexibility and access to multiple markets. So I'll just remind you that barrels could be going to the coast but if the markets are such they want to go to Cushing and we have the capability to do that. So that's kind of a benefit of flexibility.

Brian Reynolds
Analyst, UBS Securities LLC

Q

Thanks. Fair enough. I'll jump back in the queue. I appreciate the color.

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

A

Thanks, Brian.

Operator: Thank you. Our next question is from Jeremy Tonet of JPMorgan Securities.

Jeremy Tonet
Analyst, JPMorgan Securities LLC

Q

Hi.

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

A

Hey, Jeremy.

Jeremy Tonet
Analyst, JPMorgan Securities LLC

Q

This is Jeremy. Yeah, good afternoon. I just want to dive in real quick here. A little bit more on the guidance. I think for crude oil it's [ph] $18.90 (26:07) in August and it was [ph] $19.55 (26:10) now. And just wondering if you could provide a bit more color on what changed between August and now to drive that uptick.

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

A

Yeah. The majority of it is third quarter performance and some of the margin opportunities we've seen, primarily up in Canada were likely the bulk of it. We also seen some just kind of temporary spot movements on our assets, but the margin opportunities were the majority of it.

Jeremy Tonet
Analyst, JPMorgan Securities LLC

Q

Got it. Thanks. And then pivoting over to Cactus, just wondering if you could provide some color with regard to acquisition multiple or accretion expected, just trying to see how that fits in there versus other opportunities.

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

A

Jeremy, let me take this one. That was a win-win deal. It was a good deal for everybody. The way we look at this is West was interested in selling. It was a negotiated deal. It allows now both Enbridge and us, it allows us to strengthen our relationship. And I think the way it's set up is if you to think about our assets, we're stronger on the gathering side. And if you think about Enbridge, they're stronger on the downstream side. So it really fits as far as integration and our expectation is that the joint venture will be able to extract some more synergies and additional volumes as we go forward. I'll probably leave it at that and not get into multiple discussion.

Jeremy Tonet
Analyst, JPMorgan Securities LLC

Q

Got it. I'll leave it there. Thank you.

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

A

Thank you.

Operator: Thank you. Our next question is from Jean Salisbury from Bernstein. Jean?

Jean Ann Salisbury
Analyst, Sanford C. Bernstein & Co. LLC

Q

Hi. Yeah, I just want to make sure I understand what's driving the crude pipeline EBITDA this year. On slide 17, you have a helpful bridge of the Crude segment versus last quarter and kind of call out both increased volumes and then also MVC payments. So I just want to – does that mean that people are effectively paying new MVC's pipelines that don't go to [ph] the US (28:18) Gulf Coast in the Permian? But then you're over your MVC level in getting spot rates on the pipelines that are going to the Gulf Coast? And is that like a sustainable setup?

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

A

Jean Ann, this is Jeremy. Yes, we are receiving some MVC but we're also – [ph] replacing (28:36) with some incentive tariff. We expect that to go away, the shippers start to ship to the MVC levels which we fully expect that to happen shortly.

So, I'd say that that has been temporal as the spreads have been in, but as spreads widen, you would expect that to be different. And so Cushing, that's not on MVC. There are some components that is and from a recontracting standpoint, we continue to add more on a term basis across both the Cushing corridor as well as the corridor at Corpus. So, there's plenty of demand for capacity to the coast at increasing levels.

Jean Ann Salisbury
Analyst, Sanford C. Bernstein & Co. LLC

Q

Got it. That makes sense. And then I was just wondering if there's any update on the Fort Sask expansion? Should we be assuming any CapEx for that in 2023?

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

A

Yeah. We're still developing the project, Jean Ann. We don't [indiscernible] (29:27) specific to talk about. I would leave that to our – hopefully in February, on our February call where I'll have a little more info on that. We'll share it at that point.

Jean Ann Salisbury
Analyst, Sanford C. Bernstein & Co. LLC

Q

Okay. Sounds good. Thank you.

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

A

Thank you.

Operator: Thank you, Jean. Our next question is from Neel Mitra from Bank of America. Neel?

Neel Mitra
Analyst, BofA Securities, Inc.

Q

Hi. Good afternoon, guys. Just wanted to look at the distribution in light of your commodity and volumetric exposure. Obviously, you benefit this year from the frac spread in Canada and your gathering rate has some volumetric exposure as well. Are you looking to term up some of the long-haul pipelines to be able to maintain that fixed increase every year? How are you looking at that exposure?

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

A

Well, we're absolutely looking at how do you firm up additional volumes. I made a comment earlier about taking some of the volatility out and getting kind of fixed volumes. So, we're working on that every single day but I don't know if I get a specific question in areas there.

Neel Mitra
Analyst, BofA Securities, Inc.

Q

Yeah. I think I was just asking kind of how are you looking at all kind of the commodity exposure when you evaluated the fixed distribution increase. Are you comfortable with a certain run rate with the Canadian assets or just volumetric growth in the Permian?

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

A

I got your question. Maybe if you take a look at [ph] nine, (31:33) if I understand your question, when we think about the higher prices, it definitely benefits us, primarily in PLA and frac spreads. And if you look at where we started the year at, we had a more modest expectations of crude oil environment roughly selling $5 and for the year, we're probably going to average close to [ph] $95 (31:53). So there's a piece of that that is related to oil price but we think as we go forward, we're going to be able to capture some of that and that's all been factored in as we think about our distribution coverage going forward.

Neel Mitra
Analyst, BofA Securities, Inc.

Q

Got it. And then my second question is in regards to Cactus I and II and your Corpus Christi exposure. You had record exports out of the Gulf Coast for two quarters in a row. Corpus Christi disproportionally benefited so I was wondering how sustainable you think that growth is going to Corpus Christi in light of the exports.

And then the second part of that would be how should we think about the MVC impact of the second round of minimum volume commitments from Wink to Webster?

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

A

Jeremy, you want to take that one?

Jeremy L. Goebel A
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

Sure. On the Corpus Christi [indiscernible] (33:00) expand the [indiscernible] (33:05) which will benefit all the docks. So there's plenty of capacity to export. The pipelines are filling up but the rates are going up for the marginal capacity, which benefits the pipeline owners, the dock owners. So, there is substantial capacity to expand. Right now, we've got the best logistics in the highest price which is yielding why there is twice as many exports out there as any other port. There is use for exports across the Gulf Coast, but Corpus Christi would expect to continue to receive a significant portion of those. I think that answers your first question.

The second one on – was it minimum volume commitments?

Neel Mitra Q
Analyst, BofA Securities, Inc.

On Wink to Webster.

Jeremy L. Goebel A
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

Oh, on Wink to Webster.

Neel Mitra Q
Analyst, BofA Securities, Inc.

[indiscernible] (33:47).

Jeremy L. Goebel A
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

Impact is consistent with what we said in February. They ramp in February of next year and production growth this year has absorbed those MVCs from this year and next year, we would expect the same thing. And so growth is on pace with where we thought. There might be some bumps through the natural gas takeaway or others but longer term, we fully expect that to take place. And the larger impact in there is felt in Houston as you have Wink to Webster shippers moving their lease book back to Midland. So it doesn't necessarily import the barrels that are for export because that's all priced in to the forward differential and it will all be priced into our guidance. So we fully expect to be full to the coast in our pipelines next year, but for the margins to heal over time, you'll need some MVCs to be absorbed by production growth.

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

You there, Neel?

Neel Mitra Q
Analyst, BofA Securities, Inc.

Yes, I am. Thanks.

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

Did that answer your question?

Neel Mitra
Analyst, BofA Securities, Inc.

Q

It did, it did. I appreciate it.

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

A

Fundamentally, our view is global. Demand is going to continue for crude oil and if you think about the export and the sources that we think it's coming from North America. So, we think it's a pretty constructive environment for exports in the US.

Neel Mitra
Analyst, BofA Securities, Inc.

Q

Got it. Got it.

Operator: Thank you, Neel. Our next question is coming from Michael Cusimano from Pickering Energy Partners. Please go ahead.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Hey. Good afternoon, everyone. Hey, good afternoon, everyone.

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

A

Hi, Michael.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Just wanted to go back to a comment you made earlier on year-over-year crude growth.

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

A

Yeah.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Just first, can you elaborate if you were specifically talking about volumes or EBITDA or both?

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

A

I'm sorry. The numbers I was giving you were volumes from year-end to year-end 2022 to 2023 of roughly 650,000 barrels a day. And just to make sure I communicated effectively, we talked about checking 2023, the rig count – the horizontal rig count in the Permian, our assumption was roughly 350 to 360 rigs. We're running about 330 right now.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Okay. And I think I might have missed it but maybe I thought you made a comment about growing the Crude segment in 2023. And I was curious if that was explicitly about volumes or earnings.

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

A

No. We didn't give – I didn't give you any guidance on overall crude volumes. Jeremy, did you have something you wanted to add to that?

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

A

Yeah. I think his comment in the script, I think, was from Al actually was that we would expect year-over-year growth. And so remember, our gathering system benefits from production growth in the field. So I think it was just a comment to say the same type of growth we saw this year, we would expect to see that on the gathering side with some incremental growth due to increased volumes and increased margins on the long-haul business as well as a step-up in MVC is on the Wink to Webster project. I think that was the comment.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Okay. And then I guess do you think – as my follow-on, do you think that would – the growth that you'd expect would outweigh maybe the conservatism on the price deck that you would assume from any pipeline loss allowance uplift or things like that?

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP

A

Hey, Michael. This is Jeremy. We were just trying to get some directional indication of the impact of frac spreads and it's been so significant. The intent was not to provide guidance for next year. We'll update everybody on guidance for the Crude Oil and the NGL business in February.

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

A

The other piece on – that we wanted to give you a heads up on is there are some plant outages that you probably wouldn't have insight into. So, we wanted to give a heads up that there will be an impact on that as well so – on the NGL business.

Michael Cusimano
Vice President, Pickering Energy Partners LP

Q

Got it. And then on the NGL business, is the downtime related to the smaller expansion as you had mentioned last quarter? And if so, what's the timing look like for when that's completed or resolved?

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

A

Yeah. I'm not going to give you specifics on it only because it's a third-party supplier. It's a third-party straddle plant that impacts the Fort Sask business. So I'll hold off on that.

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP
A

And it is independent...

Michael Cusimano
Vice President, Pickering Energy Partners LP
Q

All right.

Jeremy L. Goebel
Chief Commercial Officer & Executive Vice President, Plains All American Pipeline LP
A

...of the project that you referenced.

Michael Cusimano
Vice President, Pickering Energy Partners LP
Q

Okay. Understood. Got it. That's all for me. Appreciate the help.

Operator: Thank you very much and our final question comes from Sunil Sibal from Seaport Global.

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

Hi, Sunil.

Sunil Sibal
Analyst, Seaport Global Securities LLC
Q

Yes, hi. Hi. Good afternoon, everybody. So staying on the NGL segment, could you give us a sense of how much of that NGL exposure for 2023 is hedged at this point of time?

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

Sunil, we're not going to share that at this point. We'll share more in February.

Sunil Sibal
Analyst, Seaport Global Securities LLC
Q

All right. Then if I look at the metrics that you laid out on slide 6 with regard to the 2022 guidance update, so seems like adjusted EBITDA is moving up by $75 million. However, the implied DCF [ph] to common (39:20) is flat versus your August guidance. So, I was just curious. What's the difference that keeps the DCF flat?

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

Yeah. This is Al. I'll take a shot at it. One, Canadian taxes; two, some of the timing around distributions and earnings on – being different on unconsolidated entities as well as on our non-controlling interest, distributions to non-controlling interest. And then the last one is just we probably should have rounded down last quarter. We've been trying to keep those numbers kind of [audio gap] (40:03-40:14) round. So, no one thing, a number of different things, but good question.

Sunil Sibal
Analyst, Seaport Global Securities LLC
Q

But your free cash flow is still going up. So, you kind of recoup some of all these factors when you look at the free cash flow?

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

Correct.

Sunil Sibal
Analyst, Seaport Global Securities LLC
Q

Oh, okay. Thanks for that.

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

Thanks, Sunil.

Operator: Thank you, Sunil. And at this time, I'd like to turn it back over to the company for their closing remarks.

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

Great. Thanks, Therese. Thanks, everyone, for joining us and for your questions and your interest in our company. We look forward to giving you updates. Have a nice evening.

Operator: [audio gap] (40:59). You may now disconnect. Have a good evening.

3Q22 Earnings Call

November 2, 2022

PLAINS

Forward-Looking Statements & Non-GAAP Financial Measures Disclosure

- This presentation contains forward-looking statements, including, in particular, statements about the performance, plans, strategies and objectives for future operations of Plains All American Pipeline, L.P. ("PAA") and Plains GP Holdings, L.P. ("PAGP"). These forward-looking statements are based on PAA's current views with respect to future events, based on what we believe to be reasonable assumptions. PAA and PAGP can give no assurance that future results or outcomes will be achieved. Important factors, some of which may be beyond PAA's and PAGP's control, that could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements are disclosed in PAA's and PAGP's respective filings with the Securities and Exchange Commission.

- This presentation also contains non-GAAP financial measures relating to PAA, such as Adjusted EBITDA attributable to PAA, Implied DCF and Free Cash Flow. A reconciliation of these historical measures to the most directly comparable GAAP measures is available in the Investor Relations section of PAA's and PAGP's website at www.plains.com, select "PAA" or "PAGP," navigate to the "Financial Information" tab, then click on "Non-GAAP Reconciliations." PAA does 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 it has defined as "Selected Items Impacting Comparability" without unreasonable effort. Definitions for certain non-GAAP financial measures and other terms used throughout this presentation are included in the appendix.

3Q22 Earnings Call Highlights & Outlook

Executing on our plan, increasing returns of capital to equity holders

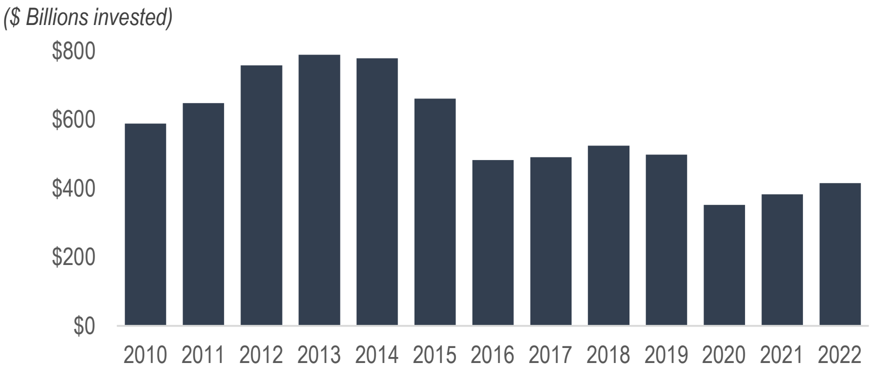
- **Strong Q3 Adj. EBITDA[(1)] $623MM:**
  - Benefit of increased Permian tariff volumes, higher commodity prices & Canadian margin-based opportunities
- **Raised 2022 Adj. EBITDA(G)[(1)] to +/- $2.450B**
  - +$75MM vs. Aug(G): +$65MM Crude Segment, +$10MM NGL Segment
  - +$250MM vs. Feb(G): +$135MM Crude Segment, +$115MM NGL Segment
- **Achieved leverage of 3.7x (below mid-point of target range), expect +/- 3.8x at YE-22**
- **Long-term fundamentals remain constructive; hydrocarbons & Permian key to global energy security; monitoring near-term market volatility**
- **Provided multi-year capital allocation and financial framework – generating significant FCF, improving financial flexibility & returns of capital to equity holders**
  - Targeting multi-year, sustainable distribution growth & opportunistic repurchases

2022(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022. Feb(G): Furnished February 9, 2022.
(1) Attributable to PAA.
Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

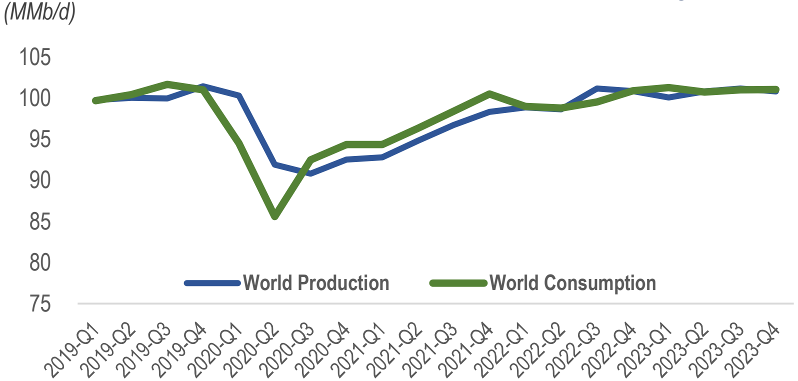
Long-Term Fundamentals Remain Constructive

North American hydrocarbons are key to meeting global demand

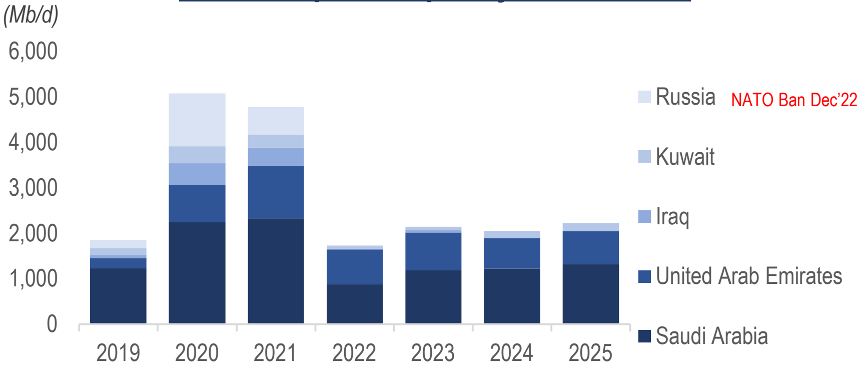
Prolonged Underinvestment in Global Upstream[1]



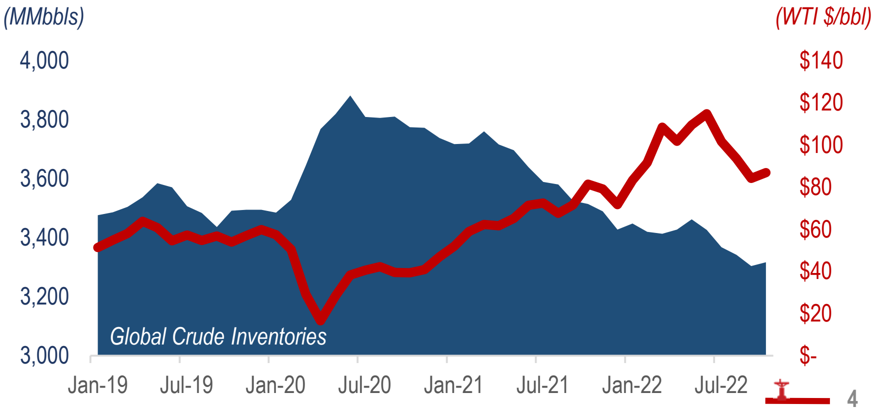
Global Demand Has Outpaced Supply[2]



OPEC+ Spare Capacity is Limited[3]



Global Inventories at Multi-Year Lows[4]



Sources: (1) IEA (2) EIA STEO (3) S&P Global Platts Estimates (4) Kpler (includes SPR's).

Meaningful Progress on Long-Term Goals & Initiatives

Plains has reached a positive inflection point & is well positioned

Asset Base

- ✓ Completed large-scale multi-year capital program, meaningful Crude & NGL operating leverage
- ✓ Formed 15+ strategic JVs, including Plains Oryx Permian JV
- ✓ Improved Safety & Environmental performance >50% & ~40%, respectively, since 2017
- ✓ Reduced Scope 1 & 2 GHG emissions in each of the last 4 years

Balance Sheet

- ✓ Achieved leverage below mid-point of target range
- ✓ Improved financial flexibility
- ✓ Investment grade rating at all 3 agencies
- ✓ Reduced debt >$1.7B since YE-20
- ✓ $3.3B in committed liquidity
- ✓ ~$4.5B in asset sales since 2016

Capital Allocation

- ✓ Increased distribution $0.15/unit in May 2022
- ✓ Repurchased ~$300MM of common units since Nov-2020
- ✓ Announced multi-year capital allocation & financial framework
- ✓ Self-funding annual routine capital program

2022(G): Financial Metrics

Increasing EBITDA, generating meaningful FCF, significant distribution coverage & achieved leverage targets

($ millions, except per-unit metrics)

Adjusted EBITDA / DCF

Segment Adjusted EBITDA	Aug(G) (+/-)	Nov(G) (+/-)
Crude Oil	$1,890	$1,955
NGL	485	495
Other Income	-	-
Adj. EBITDA attributable to PAA	**$2,375**	**$2,450**
Implied DCF to Common	$1,550	$1,550
Implied DCF / CUE	$2.20	$2.20
Distribution Coverage (Common)[1]	265%	**265%**
Year-End Leverage Ratio	4.0x	**3.8x**

Cash Flow

	Aug(G) (+/-)	Nov(G) (+/-)
Cash Flow from Ops (CFFO)	$2,050	$2,175
Asset Sales	$200	$200
FCF	$1,400	**$1,450**[2]
FCFaD	$620	**$670**[1][2]

Capital *(Consistent with Aug(G))*

	Nov (G) (+/-) Net to PAA	Nov (G) (+/-) Consolidated
Investment	**$275**	**$330**
Permian JV	$110	$165
Other	$165	$165
Maintenance	**$210**	**$220**
Total	**$485**	**$550**

Note: Green highlight denotes key financial metrics discussed on Third-Quarter Earnings Conference Call.
2022(G) / Nov(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
(1) Distribution Coverage & FCFaD reflect cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year.
(2) Includes impact of cash paid for Cactus II acquisition on November 2, 2022.

2022(G): Operational Metrics

Capturing incremental Long-Haul barrels, Gathering growth consistent with Aug(G)

(table data reflects full-year averages)	**Aug (G) (+/-)**	**Nov (G) (+/-)**	Δ
Crude Oil Segment			
Crude Pipeline Volumes (Mb/d)	**7,410**	**7,550**	***+140***
Permian	**5,490**	**5,630**	***+140***
Gathering	2,375	2,375	-
Intra-Basin	2,000	2,065	+65
Long-Haul	1,115	1,190	+75
Other	**1,920**	**1,920**	-
Commercial Storage Capacity (mmbbls/mo)	72	72	-
NGL Segment			
NGL Sales (Mb/d)	140	140	-
C3+ Spec Product Sales[(1)]	55	55	-
Fractionation Volumes (Mb/d)	135	135	-

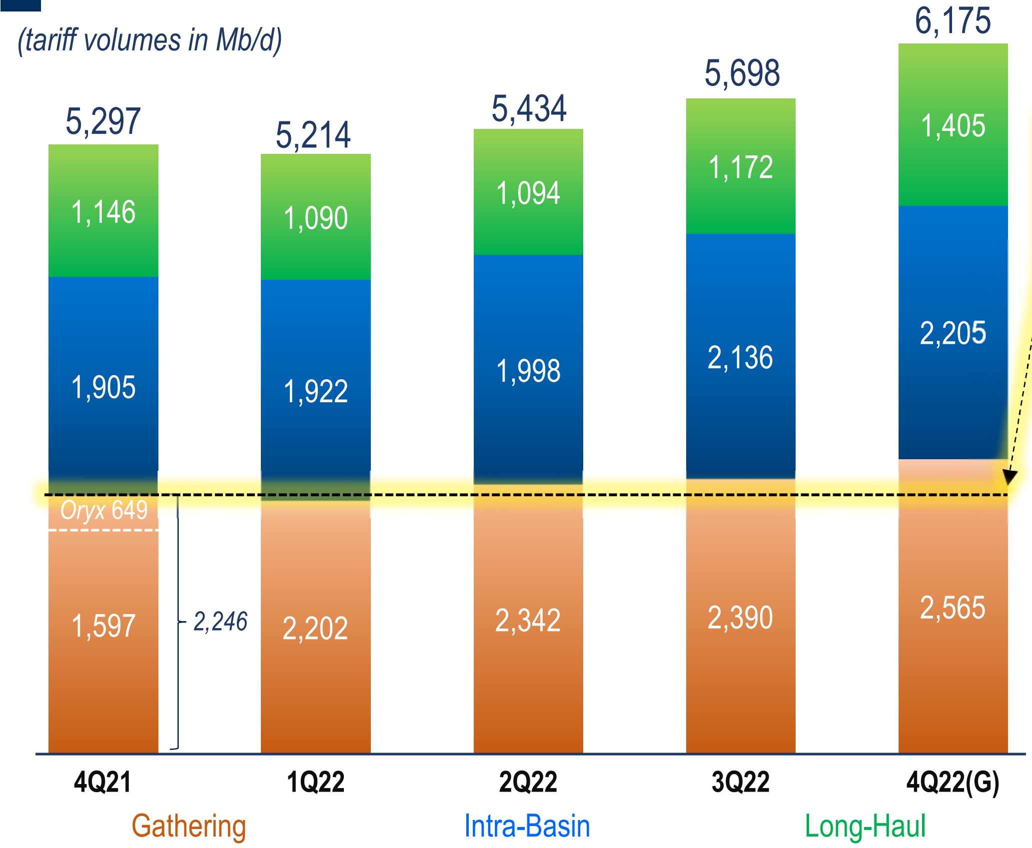
Intra-Basin: *increased volumes supporting downstream movements*

Long-Haul: *Increased long-haul flows to USGC & Cactus II consolidation (+30 Mb/d)*

2022(G) / Nov(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
Note: Permian JV & 2 months of Cactus II (Nov(G) only) volumes on a consolidated (8/8ths) basis.
(1) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread.

Capturing Permian Volume Growth

Permian building momentum, additional volumes added since Aug(G)



4Q22(G) vs. 4Q21: ↑880 Mb/d

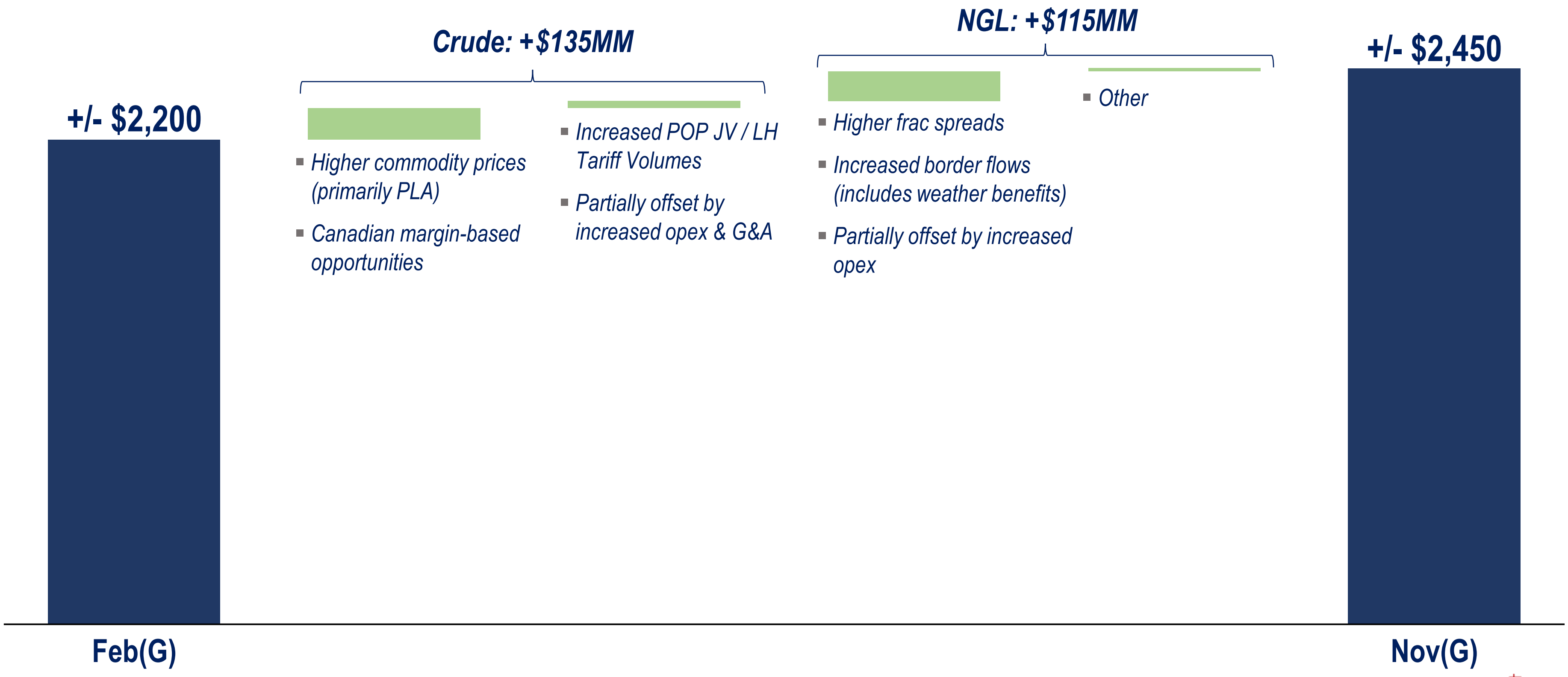
- **Gathering: ↑ 320 Mb/d**
  - Tracking in-line-with expectations
- **Intra-Basin: ↑300 Mb/d**
  - Increased volumes supporting downstream movements
  - Benefitting from Advantage JV bolt-on in 2H22
- **Long-Haul: ↑260 Mb/d**
  - Increasing demand from USGC export markets & Cushing refiners
  - Includes benefit of Cactus II consolidation (+125 Mb/d)

2022(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
Note: Permian JV & 2 months of Cactus II (2022(G) only) volumes on a consolidated (8/8ths) basis.

2022 Key Drivers: Feb(G) vs. Nov(G)

Solid execution, additional volume capture & favorable commodity price environment driving full-year outlook higher

(Adj. EBITDA attributable to PAA, $ millions)



Nov(G): Furnished November 2, 2022. Feb(G): Furnished February 9, 2022.

Long-Term Financial Strategy & Capital Allocation Framework

Generating significant FCF, improving financial flexibility & increasing returns of capital to equity holders

Focus Areas

I ***Increasing Long-Term Returns of Capital to Equity Holders***

– Multi-year, sustainable distribution growth

II ***Disciplined Capital Investments***

– Maintain financial discipline & self-fund annual routine capital with cash flow

III ***Long-Term Balance Sheet Stability & Financial Flexibility***

– Maintain flexibility through cycles & create additional dry powder

Capital Allocation Summary

2022	▪ Achieved leverage target (3Q22: 3.7x, YE-22: +/- 3.8x) ▪ Increased distribution $0.15/unit in May 2022 ▪ Completed opportunistic repurchases of $75MM YTD, $300MM since Nov-20 authorization ▪ Continued capital discipline / asset optimization
2023	▪ Intend to recommend $0.20/unit annualized distribution increase for 4Q22 (payable Feb-23), opportunistic repurchases ▪ Continued capital discipline / asset optimization ▪ Migrate leverage below target range (3.75x – 4.25x)
Beyond 2023	▪ Anticipate targeting annualized distribution increase of ~$0.15/unit annually(1), subject to target coverage ratio of ~160%, opportunistic repurchases ▪ Continued capital discipline / asset optimization ▪ Continue migrating leverage lower

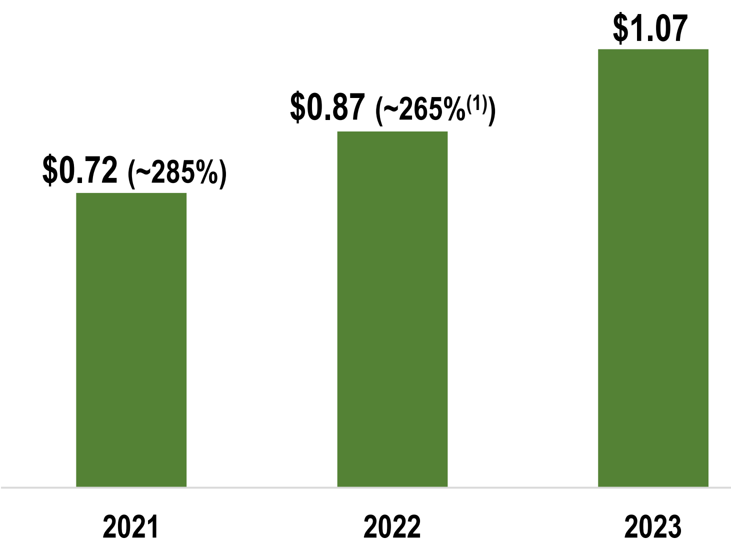
(1) Expected to align with standard beginning-of-the-year annual budgeting process with any future adjustments occurring in the first quarter of each calendar year and payable in May.

Increasing Long-Term Returns of Capital to Equity Holders

Targeting multi-year, sustainable distribution growth & opportunistic repurchases

($/Unit; Common Distribution Coverage)

2023: +$0.20/unit annualized (+23%) vs. 2022 (Payable Feb-23)[2]



2023+: ~$0.15/unit annually[3] (targeting ~160% Coverage)

Beyond 2023+ Considerations

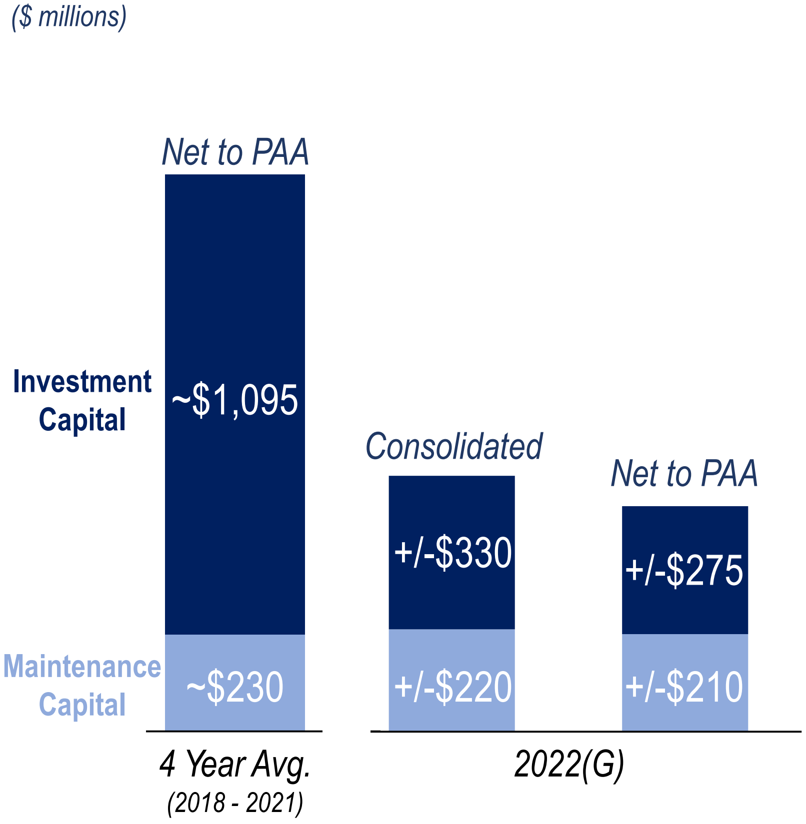
- Subject to financial positioning, business outlook & investment opportunities
- Upon reaching target coverage, further distribution increases driven by future DCF growth & competing allocation priorities
- Opportunistic repurchases

(1) Reflects cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year. (2) Management intends to recommend increase to our Board. (3) Future potential increases expected to align with standard beginning-of-the-year annual budgeting process with any future adjustments occurring in the first quarter of each calendar year and payable in May.

II

Disciplined Capital Investments

Pursuing & developing capital-efficient expansion & debottlenecking opportunities



- **Maintain financial discipline on future investments**
- **Create long-term shareholder value by leveraging existing crude & NGL infrastructure**
  - Capital-efficient brownfield expansions & debottlenecking opportunities, underpinned by contractual commitments
  - Building resilience in fee-based earnings
  - Wellhead & CDP Connections (~50% of routine investment capital; paced w/ producer activity)
  - Optimizing & aligning assets with emerging energy opportunities
- **Self-fund annual routine capital with cash flow**
  - 160% coverage target provides ample capacity

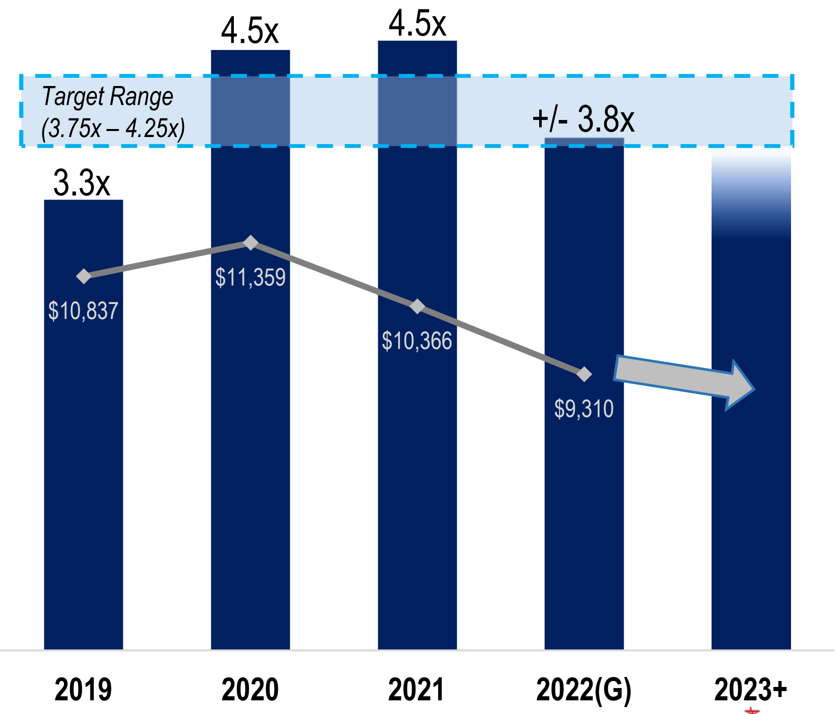
2022(G): Furnished November 2, 2022.

III Long-Term Balance Sheet Stability & Financial Flexibility

Lowers risk & creates additional flexibility for returns to equity holders & investment opportunities

- Ensure balance sheet flexibility through cycles
  - Achieve & maintain mid-BBB / Baa credit ratings
- Anticipate leverage below target range in 2023 & to continue migrating lower over time
  - Continue reducing debt with excess FCF
  - Creates additional dry powder for strategic investments, opportunistic repurchases & buffer for business uncertainty

Leverage Ratio & Total Debt[1]



2022(G): Furnished November 2, 2022.

(1) Leverage Ratio & Total Debt include 50% of PAA Preferred Securities. 2019 – 2021 include benefit of outsized margin-based earnings.

3Q22 Earnings Call Key Takeaways

Long-term constructive fundamentals, returning capital to equity holders, capturing Permian growth

- **Solid 3Q22 execution & results - capturing Permian growth via operating leverage**
  - Increased 2022 Adj. EBITDA(G)[1] by $75MM to +/- $2.450B
- **Achieved leverage objectives earlier than anticipated (3Q22: 3.7x, YE-22: +/- 3.8x)**
- **Long-term fundamentals constructive; hydrocarbons & Permian key to global energy security**
- **Provided multi-year capital allocation and financial framework – generating significant FCF, improving financial flexibility & returns of capital to equity holders**
  - Targeting multi-year, sustainable distribution growth & opportunistic repurchases

2022(G): Furnished November 2, 2022.
(1) Attributable to PAA.

Appendix

Incremental Updates:

- Segment Adj. EBITDA Walks
- Financial & Operational Updates

PLAINS

Overview of 2022 Goals

Run a safe, reliable and responsible operation

Generate meaningful Free Cash Flow

Strengthen balance sheet / financial flexibility

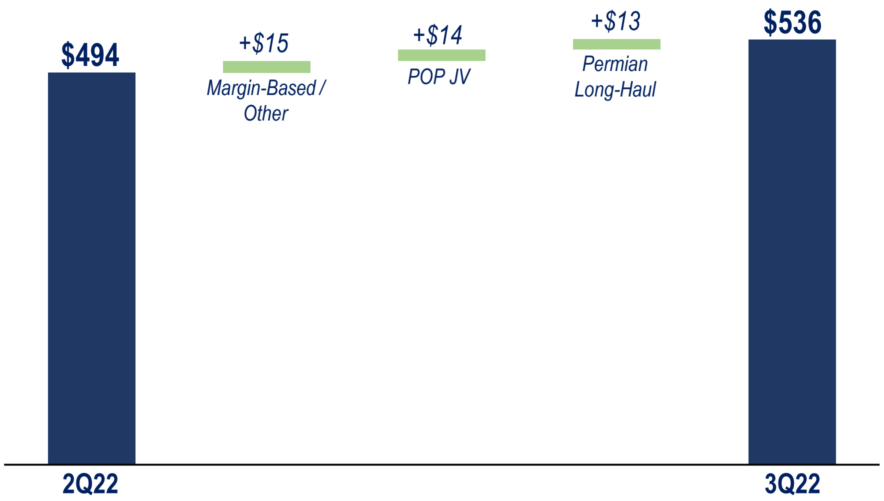
Increase returns of capital to equity holders

PLAINS ALL AMERICAN

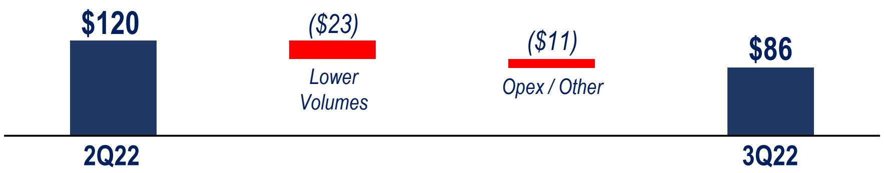
Key Drivers: 2Q22 to 3Q22

($ millions)

Crude Oil Segment Adjusted EBITDA



NGL Segment Adjusted EBITDA

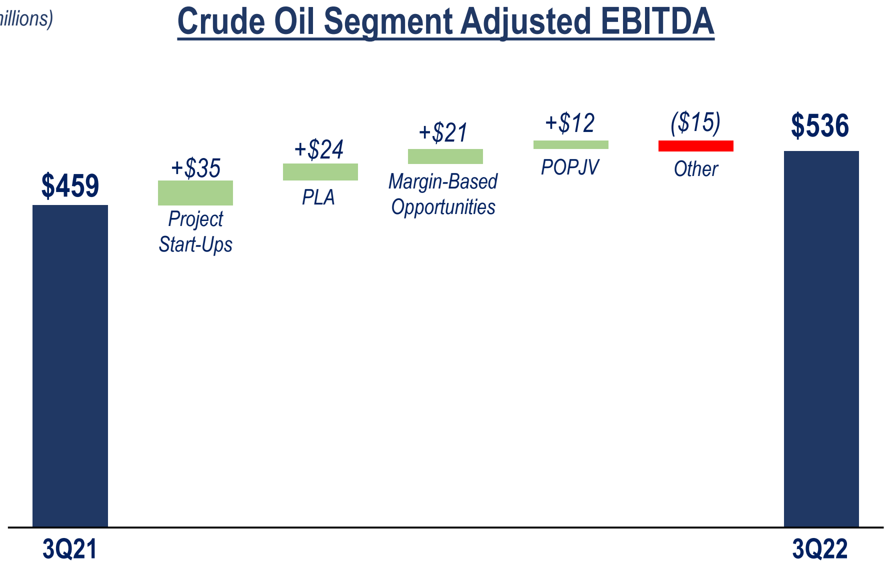


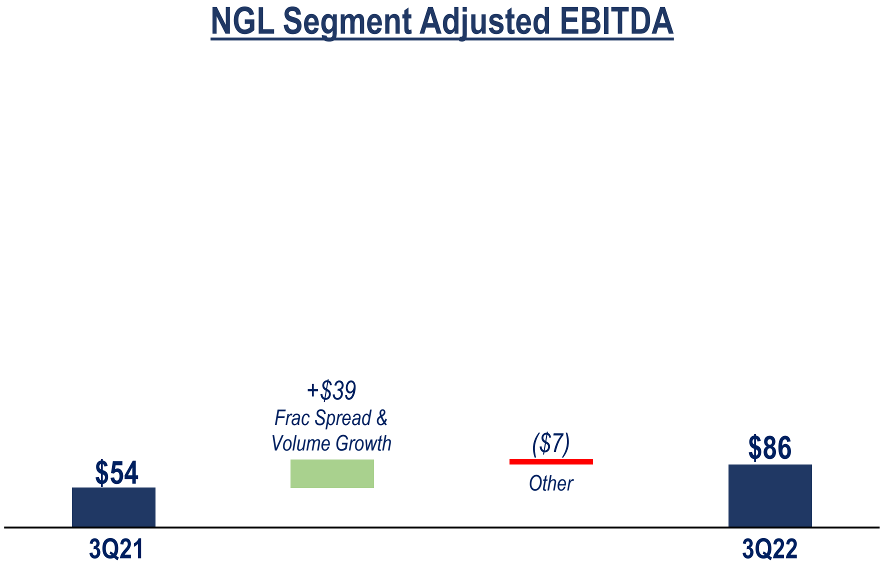
- **Crude Oil Segment**
  - **Margin-Based / Other:** benefit of margin-based opportunities in Canada
  - **POP JV**: increased volumes on JV gathering & intra-basin systems
  - **Permian Long-Haul:** increased volumes to US Gulf Coast further benefitted by MVC deficiency payments received in 3Q22

- **NGL Segment**
  - **Lower Volumes:** planned 3Q22 frac turnaround at Empress; lower border flows into Empress due to the absence of 2Q22 weather benefit
  - **Opex / Other:** primarily increased utility costs

Key Drivers: 3Q21 to 3Q22

($ millions)





- **Crude Oil Segment**
  - **Project Start-Ups:** primarily start-up of Capline & W2W
  - **PLA:** benefit of higher commodity prices
  - **Margin-Based Opportunities:** benefit of margin-based opportunities in Canada
  - **POP JV:** increased volumes on JV gathering systems
  - **Other:** 3Q21 benefit of PNG operations & 3Q22 impact of asset downtime due to maintenance and repairs

- **NGL Segment**
  - **Frac Spread & Volume Growth:** benefit of higher commodity prices & increased straddle plant production

Current Financial Profile

Achieved leverage below mid-point of target range

	12/31/21	9/30/22	Target
Balance Sheet			
Cash & Equivalents	$449	$623	
Short-Term Debt	822	459	
Long-Term Debt	8,398	7,986	
Total Debt	**$9,220**	**$8,445**	
Adj. EBITDA (LTM)[1]	**$2,196**	**$2,415**	
Credit Stats & Liquidity			
Leverage Ratio	**4.5x**	**3.7x**	**3.75x - 4.25x**
Committed Liquidity ($ bln)	$3.0	$3.3	
Investment Grade Balance Sheet	BBB- / BBB- / Baa3		

2022(G): Furnished November 2, 2022.

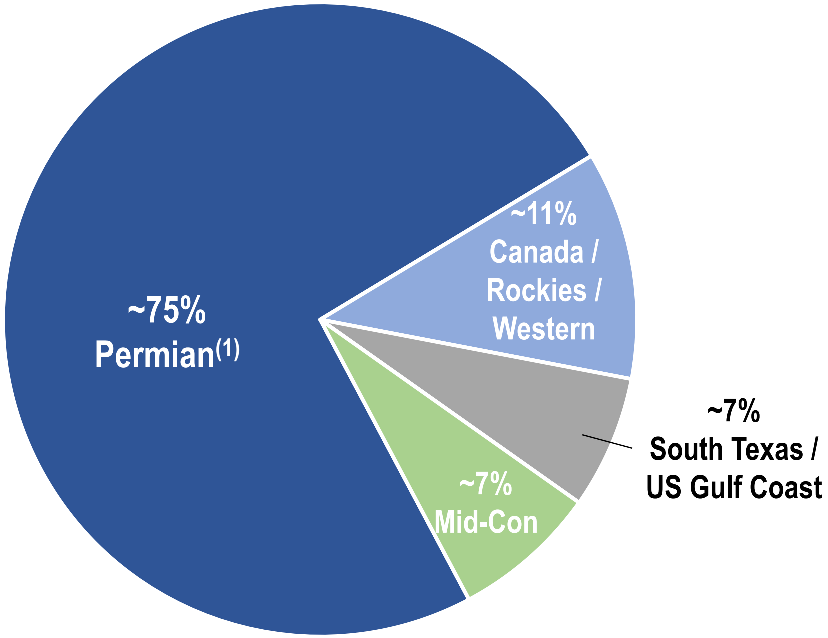
(1) Attributable to PAA.

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

Crude Oil Segment 2022(G): +/- 80% of Adj. EBITDA

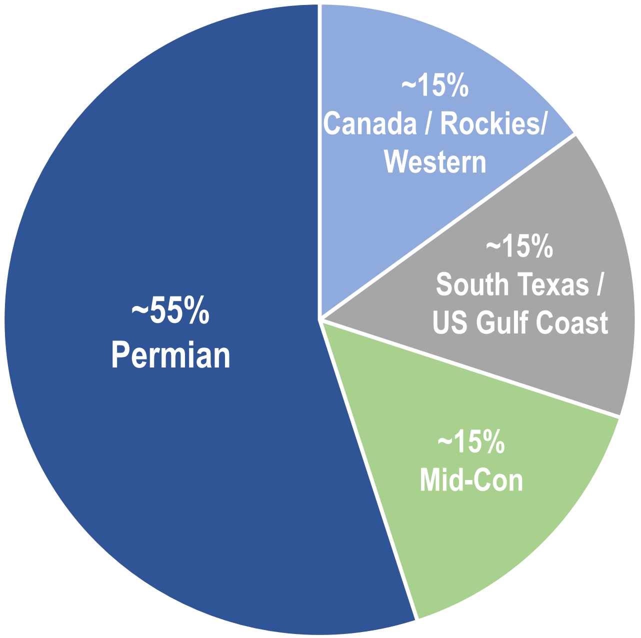
Regional Detail

2022(G): 7,550 Mb/d Pipeline Volumes



2022(G): $1,955MM Adj. EBITDA(2)

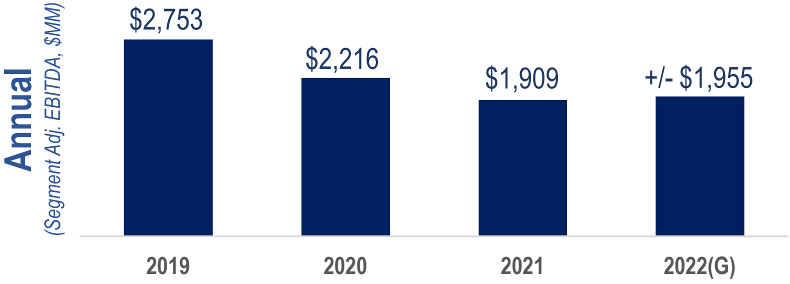
Includes +/-$200MM from Storage Terminals(3)

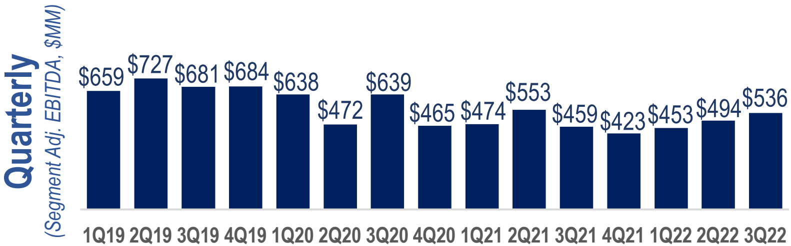


2022(G): Furnished November 2, 2022. (1) Includes consolidated Permian JV & 2 months of Cactus II volumes. (2) Attributable to PAA.
(3) Terminals include Cushing, Patoka, St. James, and Others. Majority of EBITDA associated to terminals in Mid-Con and South Texas / Gulf Coast regions.

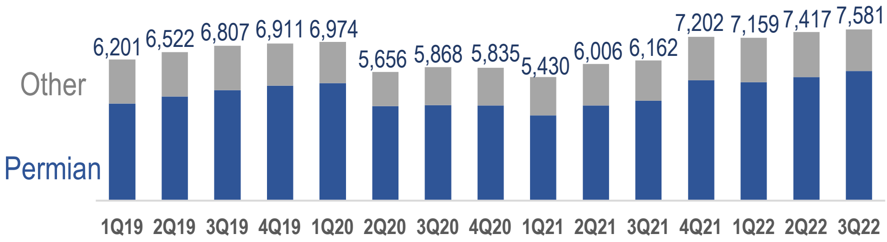
Crude Oil Segment Detailed Data (2019 – 2022)

- **Crude Oil Segment Considerations / Context:**
  - COVID-19 production reset - L48 onshore ↓ >2MMB/D from Mar-20 peak, competitive market dynamics
  - Outsized margin capture 2019 – 2021; not expected to continue in 2022
  - ~$1.4B in non-core / strategic JV asset sales since 2019

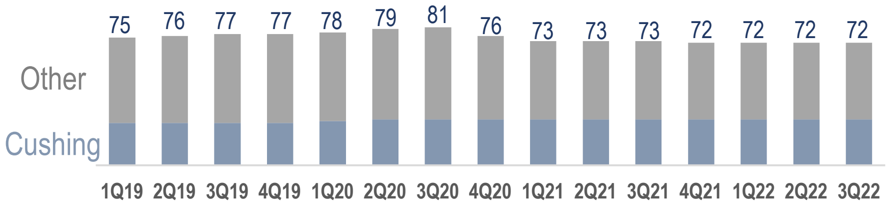




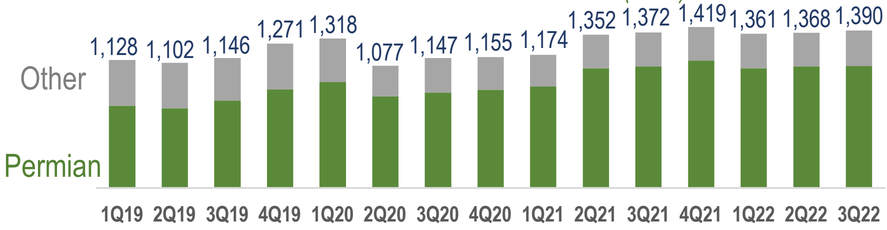
Pipeline Tariff Volumes[1] *(Mb/d)*



Commercial Storage Capacity *(MMbbls/mo)*



1st Purchase Volumes *(Mb/d)*

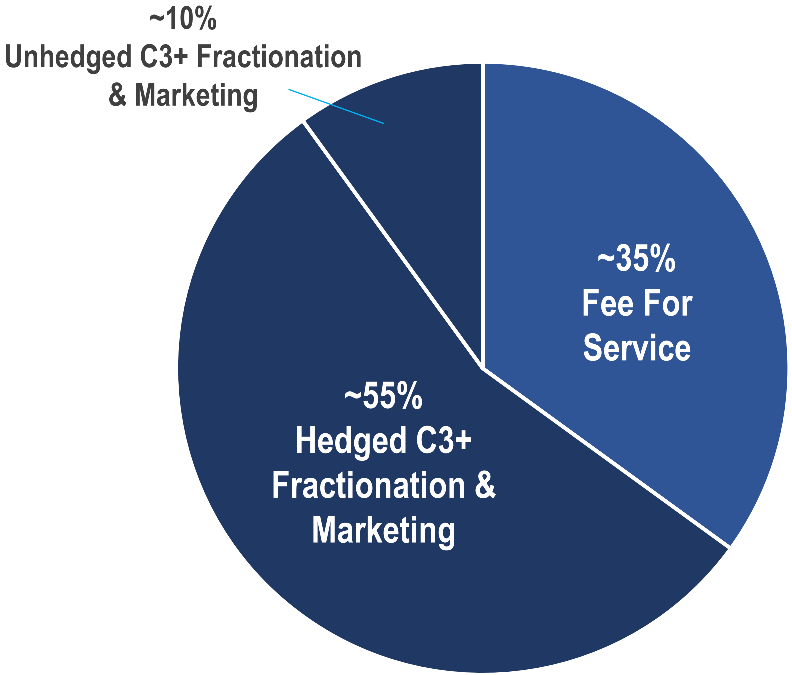


2022(G): Furnished November 2, 2022.
(1) Excludes trucking.

NGL Segment 2022(G) Detail: +/- 20% Total Adj. EBITDA

- **Majority of EBITDA generated by C3+ frac spread benefit**
  - Hedge frac spread (12+ months rolling)
  - Purchase AECO nat gas & sell spec products (C3+) on Mont Belvieu pricing(1)
  - ~55 Mb/d of total NGL sales benefit from Frac Spread
- **Fee-for-Service**
  - Third-party throughput(2): fractionate, store, and transport (~45 Mb/d not included in reported NGL sales)
  - Net purchased volume (purity and Y-grade): transport, fractionate, store & sell (~45 Mb/d)
  - Ethane: cost recovery model (~40 Mb/d)

2022(G): $495MM Adj. EBITDA(3)



2022(G): Furnished November 2, 2022.

(1) Exposed to basis pricing differentials (2) Buy / Sell agreements with 3rd parties. (3) Attributable to PAA; Earnings profile can be impacted by timing of product lifting / sales.

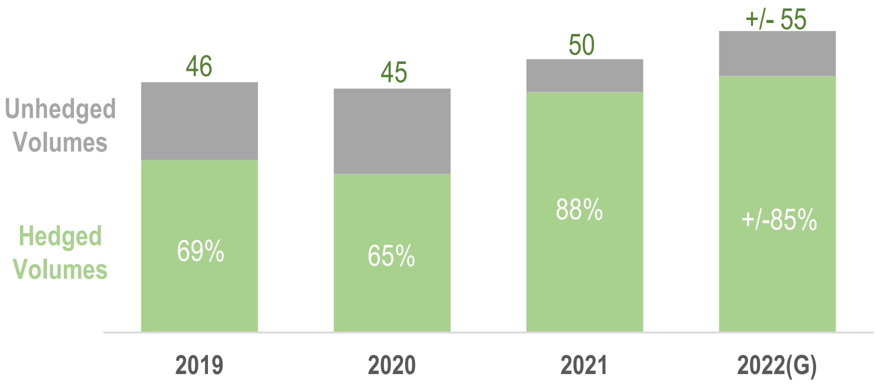
NGL Segment Frac Spread & Hedging Profile

- **At current forward markets, 2023 NGL Adj. EBITDA could be ~$100MM below 2022**
  - Lower C3+ Spec Product Sales as a result of a 3rd party turnaround & absence of 2Q22 weather benefits
  - Lower year-over-year frac spreads

Hedging Profile (2019 – 2022(G))

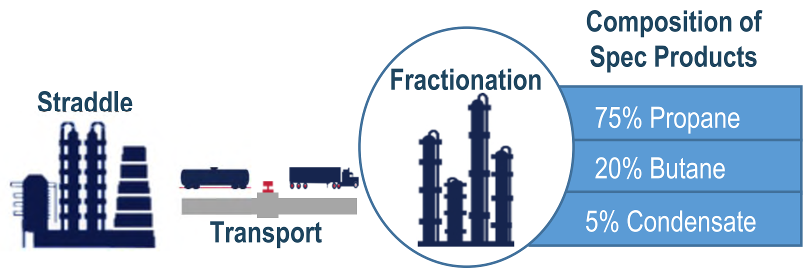
(table data reflects full-year averages)	2019	2020	2021	2022(G)
NGL Segment				
C3+ Spec Product Sales[1] (Mb/d)	46	45	50	+/- 55
% of C3+ Sales Hedged[2]	69%	65%	88%	+/- 85%

C3+ Spec Product Sales[1] *(Mb/d)*



+/- 55Mb/d Benefit from Frac Spread

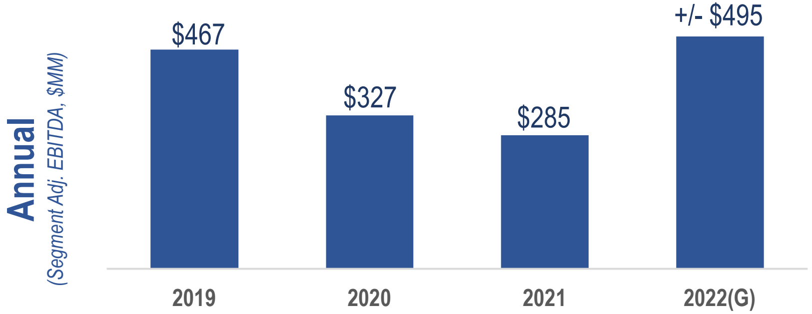
(+/- 85% of 2022 volumes hedged)

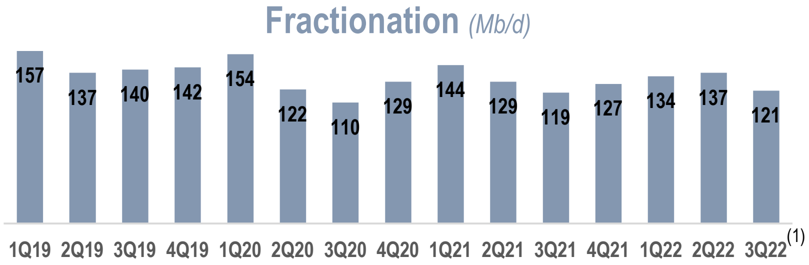


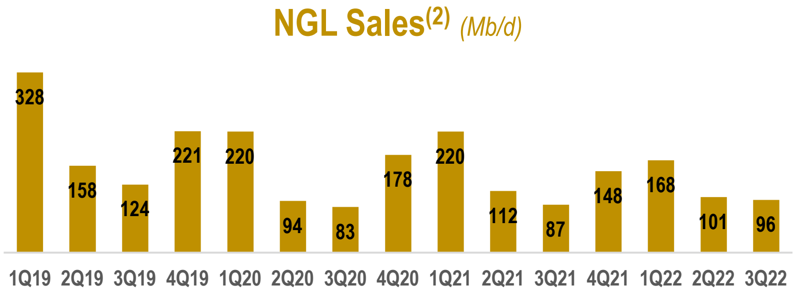
2022(G): Furnished November 2, 2022. (1) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread. (2) Annual Frac spread volume hedged as a percentage of total C3+ volume produced / forecasted that is exposed to frac spread.

NGL Segment Detailed Data (2019 – 2022)

- **NGL Segment Considerations / Context:**
  - ~$175MM in non-core asset sales since 2019
  - Seasonally stronger demand / sales in winter months
  - Frac spread hedging & 3rd party contracts helps improve predictability







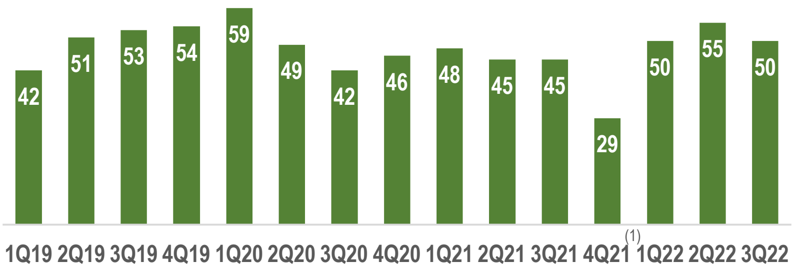
2022(G): Furnished November 2, 2022.

(1) Throughput volume impacted by turnaround at Empress. (2) Decrease in sales from 2019 to 2020 a result of elimination of low margin spot business and asset dispositions.

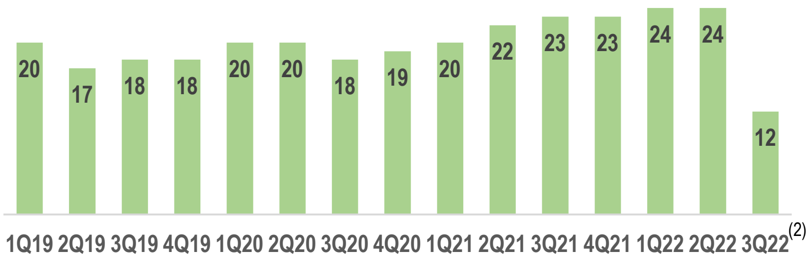
Additional NGL Detail: Fractionation Volumes by Asset

(Mb/d)

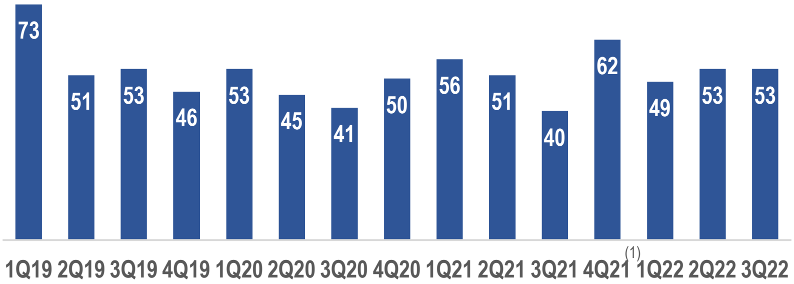
Fort Sask



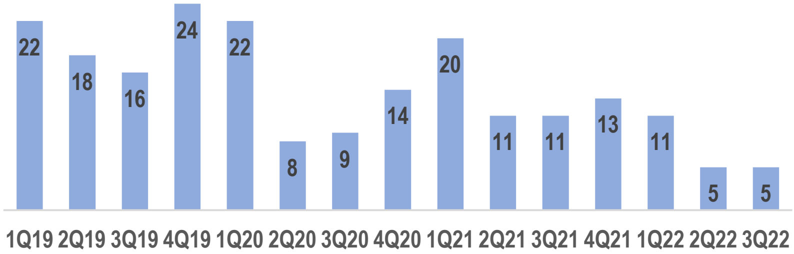
Empress



Sarnia



Other



(1) Throughput volume impacted by Fort Sask Incident. (2) Throughput volume impacted by turnaround at Empress.

Free Cash Flow: Historical Detail

GAAP CFFO to Non-GAAP FCF

	2016	2017	2018	2019	2020	1Q21	2Q21	3Q21	4Q21	2021	1Q22	2Q22	3Q22	YTD
Net Cash Provided by Op. Activities (GAAP)	$ 733	$ 2,499	$ 2,608	$ 2,504	$ 1,514	$ 791	$ 235	$ 336	$ 635	$ 1,996	$ 340	$ 792	$ 941	$ 2,074
Net Cash (Used in) / Provided by Investing Activities	(1,273)	(1,570)	(813)	(1,765)	(1,093)	(108)	(175)	761	(92)	386	(81)	(42)	(168)	(291)
Cash Contributions from Noncontrolling Interests	-	-	-	-	12	1	-	-	-	1	-	-	26	26
Cash Distributions Paid to Noncontrolling Interests(1)	(4)	(2)	-	(6)	(10)	(6)	-	(4)	(4)	(14)	(59)	(62)	(73)	(194)
Sale of Noncontrolling Interest in a Sub	-	-	-	128	-	-	-	-	-	-	-	-	-	-
Free Cash Flow (non-GAAP)	**$ (544)**	**$ 927**	**$ 1,795**	**$ 861**	**$ 423**	**$ 678**	**$ 60**	**$ 1,093**	**$ 539**	**$ 2,369**	**$ 200**	**$ 688**	**$ 726**	**$ 1,615**
Total Distributions(2)	(1,627)	(1,391)	(1,032)	(1,202)	(853)	(167)	(192)	(166)	(190)	(715)	(164)	(215)	(189)	(569)
FCF after Distributions (non-GAAP)	**$ (2,171)**	**$ (464)**	**$ 763**	**$ (341)**	**$ (430)**	**$ 511**	**$ (132)**	**$ 927**	**$ 349**	**$ 1,654**	**$ 36**	**$ 473**	**$ 537**	**$ 1,046**

Expect to generate meaningful multi-year Free Cash Flow based on financial performance and continued capital discipline

(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 ("FCFaD") to assess the amount of cash that is available for distributions, debt repayments, equity repurchases 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 Consolidated Financial Statements and accompanying notes.

Condensed Consolidating Balance Sheet of Plains GP Holdings (PAGP)

	September 30, 2022			December 31, 2021		
	PAA	Consolidating Adjustments (1)	PAGP	PAA	Consolidating Adjustments (1)	PAGP
ASSETS						
Current assets	$ 5,574	$ 2	$ 5,576	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,565	4	14,569	14,903	6	14,909
Investments in unconsolidated entities	3,684	—	3,684	3,805	—	3,805
Intangible assets, net	1,785	—	1,785	1,960	—	1,960
Deferred tax asset	—	1,325	1,325	—	1,362	1,362
Linefill	954	—	954	907	—	907
Long-term operating lease right-of-use assets, net	338	—	338	393	—	393
Long-term inventory	301	—	301	253	—	253
Other long-term assets, net	256	—	256	251	(2)	249
Total assets	$ 27,457	$ 1,331	$ 28,788	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 5,333	$ 2	$ 5,335	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,934	—	7,934	8,329	—	8,329
Other long-term debt, net	52	—	52	69	—	69
Long-term operating lease liabilities	300	—	300	339	—	339
Other long-term liabilities and deferred credits	1,095	—	1,095	830	—	830
Total liabilities	14,714	2	14,716	15,799	2	15,801
Partners' capital excluding noncontrolling interests	9,944	(8,435)	1,509	9,972	(8,439)	1,533
Noncontrolling interests	2,799	9,764	12,563	2,838	9,806	12,644
Total partners' capital	12,743	1,329	14,072	12,810	1,367	14,177
Total liabilities and partners' capital	$ 27,457	$ 1,331	$ 28,788	$ 28,609	$ 1,369	$ 29,978

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

Definitions

- **Adjusted EBITDA:** adjusted earnings before interest, taxes, depreciation and amortization (Consolidated)
  - Attributable to PAA where noted; Segment Adjusted EBITDA by definition is attributable to PAA
- **Implied Distributable Cash Flow (DCF) Per Common Unit & Common Unit Equivalent (CUE):** Adjusted EBITDA (Consolidated) less interest expense net of certain non-cash items, maintenance capital, current income tax expense, investment capital of noncontrolling interests, distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings, distributions to noncontrolling interests and preferred unit distributions paid adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common unit equivalents outstanding for the period
- **Cash Flow from Operations (CFFO):** Net Cash Provided by Operating Activities (GAAP)
- **Free Cash Flow (FCF):** net cash provided by operating activities (CFFO), less net cash used in investing activities, further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests
- **Free Cash Flow after Distributions (FCFaD):** FCF further reduced by cash distributions paid to preferred and common unitholders
  - 2022(G) FCFaD assumes cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year.
- **CFFO, FCF & FCFaD** estimates do not factor in material, unforeseen changes in ST working capital (i.e. hedged inventory storage activities / volume / price / margin)
- **Leverage Ratio:** Total Debt plus 50% of PAA Preferred Securities less cash divided by LTM Adj. EBITDA attributable to PAA
- **Pipeline Volumes:** pipeline volumes associated with the Permian JV, Cactus II JV & Red River JV are presented on a consolidated (8/8ths) basis; all other volumes are presented net to our interest

3Q22 Earnings Call

November 2, 2022

PLAINS

Plains All American Reports Third-Quarter 2022 Results, Increases 2022 Guidance and Announces Multi-Year Capital Allocation Framework

Houston, TX – November 2, 2022 – Plains All American Pipeline, L.P. (Nasdaq: PAA) and Plains GP Holdings (Nasdaq: PAGP) today reported third-quarter 2022 results and provided the following highlights and increase to 2022 guidance:

- Third-quarter Net income attributable to PAA of $384 million and Net cash provided by operating activities of $941 million
- Delivered strong third-quarter Adjusted EBITDA attributable to PAA of $623 million
- Increased guidance for full-year 2022 Adjusted EBITDA attributable to PAA by $75 million to +/- $2.450 billion, representing a $250 million increase compared to initial February 2022 guidance as a result of increased Permian tariff volumes, higher commodity prices and margin-based opportunities
- Achieved leverage ratio below the mid-point (4.0x) of targeted range, expect year-end 2022 leverage of +/- 3.8x

Capital Allocation Framework Update

Plains has made significant progress on strengthening its financial position and continues to execute on its long-term goals of generating meaningful Free Cash Flow, maintaining capital discipline, improving financial flexibility, and increasing returns of capital to equity holders via both distribution growth and opportunistic equity repurchases. Plains has achieved leverage below the mid-point of its targeted leverage range well ahead of expectations entering 2022 and now anticipates exiting the year with a leverage ratio of approximately 3.8x.

Given the progress made on deleveraging, solid financial and operating performance, and confidence in the long-term outlook of the business, we are providing the following multi-year capital allocation and financial framework:

- Management currently intends to recommend to the Board of Directors of PAA GP Holdings LLC (“the Plains Board”) an annualized increase of $0.20 to PAA’s and PAGP’s fourth-quarter 2022 distribution payable in February 2023 (one quarter earlier than our standard beginning-of-the-year annual budgeting process), which would increase the annualized rate from $0.87 to $1.07 per common unit and Class A share
- Beyond 2023, as part of its standard annual review process, management anticipates targeting annualized common distribution increases of approximately $0.15 per unit each year until reaching a targeted Common Unit Distribution Coverage Ratio of approximately 160%
- Maintaining capital discipline, enhancing financial flexibility and achieving mid-BBB/Baa credit ratings remain top priorities; management anticipates leverage migrating below the low-end of the targeted 3.75x - 4.25x range in 2023
- Opportunistic unit repurchases will remain a component of our long-term capital allocation framework

“We continue to execute, and we maintain a constructive view of long-term global energy fundamentals. We also believe our business has reached a positive inflection point, and we are pleased to be achieving our leverage objectives earlier than anticipated, allowing us to increase returns of capital to equity holders in a prudent, long-term manner,” stated Willie Chiang, Chairman and CEO of Plains. “Given the positive outlook for our business, operating leverage across our crude oil and NGL footprints and continued focus on capital discipline, we are positioned to continue generating Free Cash Flow and increasing returns to our equity holders over multiple years while further enhancing our financial flexibility.”

- more -

Consistent with past practice, the Plains Board will consider management's recommendation prior to its approval and declaration of the distribution for the fourth quarter of 2022, payable in February of 2023. Moving forward, Plains management intends to review specific capital allocation recommendations with the Plains Board during its standard beginning-of-the-year annual budgeting process with any future adjustments occurring in the first quarter of each calendar year and payable in May. Future recommendations will be subject to financial positioning, investment opportunities and the general outlook for business, industry and macro economy.

Plains All American Pipeline

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

	Three Months Ended September 30,		%	Nine Months Ended September 30,		%
GAAP Results	**2022**	**2021**	**Change**	**2022**	**2021**	**Change**
Net income/(loss) attributable to PAA	$ 384	$ (59)	**	$ 774	$ 143	**
Diluted net income/(loss) per common unit	$ 0.48	$ (0.15)	**	$ 0.89	$ (0.01)	**
Diluted weighted average common units outstanding	698	715	(2)%	702	719	(2)%
Net cash provided by operating activities	$ 941	$ 336	180 %	$ 2,074	$ 1,361	52 %
Distribution per common unit declared for the period	$ 0.2175	$ 0.18	21 %	$ 0.6525	$ 0.54	21 %

	Three Months Ended September 30,		%	Nine Months Ended September 30,		%
Non-GAAP Results (1)	**2022**	**2021**	**Change**	**2022**	**2021**	**Change**
Adjusted net income attributable to PAA	$ 280	$ 208	35 %	$ 805	$ 653	23 %
Diluted adjusted net income per common unit	$ 0.33	$ 0.22	50 %	$ 0.93	$ 0.70	33 %
Adjusted EBITDA	$ 721	$ 519	39 %	$ 2,115	$ 1,643	29 %
Adjusted EBITDA attributable to PAA (2)	$ 623	$ 514	21 %	$ 1,851	$ 1,631	13 %
Implied DCF per common unit and common unit equivalent	$ 0.55	$ 0.48	15 %	$ 1.68	$ 1.51	11 %
Free Cash Flow	$ 726	$ 1,093	(34)%	$ 1,615	$ 1,830	(12)%
Free Cash Flow after Distributions	$ 537	$ 927	(42)%	$ 1,046	$ 1,304	(20)%

** 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 our Non-GAAP financial measures, including their reconciliation to the most directly comparable measures as reported in accordance with GAAP, and certain selected items that PAA believes impact comparability of financial results between reporting periods.

(2) Excludes amounts attributable to noncontrolling interests in the Plains Oryx Permian Basin LLC joint venture (the "Permian JV') and Red River Pipeline LLC.

333 Clay Street, Suite 1600 Houston, Texas 77002 713-646-4100 / 866-809-1291

Summary of Selected Financial Data by Segment (unaudited)
(in millions)

	Segment Adjusted EBITDA [1] [2]	
	Crude Oil	**NGL**
Three Months Ended September 30, 2022	$ 536	$ 86
Three Months Ended September 30, 2021	$ 459	$ 54
Percentage change in Segment Adjusted EBITDA versus 2021 period	***17 %***	***59 %***
Percentage change in Segment Adjusted EBITDA versus 2021 period further adjusted for impact of divested assets [3]	***18 %***	***59 %***

	Segment Adjusted EBITDA [1] [2]	
	Crude Oil	**NGL**
Nine Months Ended September 30, 2022	$ 1,482	$ 367
Nine Months Ended September 30, 2021	$ 1,486	$ 144
Percentage change in Segment Adjusted EBITDA versus 2021 period	***— %***	***155 %***
Percentage change in Segment Adjusted EBITDA versus 2021 period further adjusted for impact of divested assets [3]	***4 %***	***155 %***

(1) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our Chief Operating Decision Maker ("CODM") determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts for prior periods have been recast to reflect this modification.

(2) During the fourth quarter of 2021, we effected changes in the primary financial information provided to our CODM (our Chief Executive Officer) for assessing performance and allocating resources to present two operating segments, Crude Oil and NGL. Prior to the fourth quarter of 2021, this information was organized into three operating segments: Transportation, Facilities and Supply and Logistics. The change in our segments is reflective of a change in how our CODM views our business and stems primarily from (i) a multi-year transition in the midstream energy industry driven by increased competition that has reduced the stand alone earnings opportunities of our supply and logistics activities such that those activities now primarily support our effort to increase the utilization of our Crude Oil and NGL assets and (ii) internal changes regarding the oversight and reporting of our assets and related results of operations. All segment data and related disclosures for earlier periods presented herein have been recast to reflect the new segment reporting structure.

(3) Estimated impact of divestitures completed during 2021, assuming an effective date of January 1, 2021. Divested assets primarily included natural gas storage facilities previously included in our Crude Oil segment.

Third-quarter 2022 Crude Oil Segment Adjusted EBITDA increased 17% versus comparable 2021 results primarily due to (i) higher tariff volumes on our pipelines and higher loss allowance revenue attributable to higher commodity prices and (ii) Canadian margin-based opportunities. These items were partially offset by the impact of asset sales and asset downtime associated with maintenance and repairs.

Third-quarter 2022 NGL Segment Adjusted EBITDA increased 59% versus comparable 2021 results primarily due to the favorable impact of higher realized fractionation spreads between the price of natural gas and the extracted NGL ("frac spreads").

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 attached hereto.

- more -

Conference Call

PAA and PAGP will hold a joint conference call at 4:30 p.m. CT on Wednesday, November 2, 2022 to discuss the following items:

1. PAA's third-quarter 2022 performance;
2. Capitalization and liquidity;
3. Financial and operating guidance; and
4. Updated multi-year capital allocation framework.

Conference Call Webcast Instructions

To access the internet webcast, please go to https://edge.media-server.com/mmc/p/u9gkztmh.

Alternatively, the webcast can be accessed on our website (www.plains.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. Slides will be posted prior to the call and a complete transcript will be posted after the call at the above referenced website.

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, common equity repurchases and other general partnership purposes. The primary additional measures used by management are Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow ("DCF"), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, 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. Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income, 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 accompanying notes. In addition, we encourage you to visit our website at www.plains.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. We do not reconcile non-GAAP financial measures on a forward-looking basis as it is impractical to do so without unreasonable effort.

Performance Measures

Management believes that the presentation of Adjusted EBITDA, Adjusted EBITDA attributable to PAA 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 either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results 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 Condensed Consolidated Financial Statements. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. 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.

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, common equity repurchases and other general partnership purposes. Free Cash Flow is defined as Net Cash Provided by Operating Activities, less Net Cash Provided by/(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, net of proceeds from the sales of assets and further impacted by distributions to and contributions from noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Free Cash Flow after Distributions.

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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,	
	2022	2021	2022	2021
REVENUES	$ 14,336	$ 10,776	$ 44,390	$ 29,089
COSTS AND EXPENSES				
Purchases and related costs	13,071	10,074	41,181	26,743
Field operating costs	318	274	971	746
General and administrative expenses	83	67	243	205
Depreciation and amortization	238	178	711	551
(Gains)/losses on asset sales and asset impairments, net	—	221	(46)	592
Total costs and expenses	13,710	10,814	43,060	28,837
OPERATING INCOME/(LOSS)	626	(38)	1,330	252
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	105	69	306	190
Gain on investment in unconsolidated entities	1	—	1	—
Interest expense, net	(99)	(106)	(305)	(319)
Other income/(expense), net	(82)	(10)	(237)	13
INCOME/(LOSS) BEFORE TAX	551	(85)	1,095	136
Current income tax expense	(12)	(8)	(60)	(11)
Deferred income tax (expense)/benefit	(97)	38	(117)	27
NET INCOME/(LOSS)	442	(55)	918	152
Net income attributable to noncontrolling interests	(58)	(4)	(144)	(9)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAA	$ 384	$ (59)	$ 774	$ 143
NET INCOME/(LOSS) PER COMMON UNIT:				
Net income/(loss) allocated to common unitholders — Basic and Diluted	$ 333	$ (109)	$ 621	$ (7)
Basic and diluted weighted average common units outstanding	698	715	702	719
Basic and diluted net income/(loss) per common unit	$ 0.48	$ (0.15)	$ 0.89	$ (0.01)

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	September 30, 2022	December 31, 2021
ASSETS		
Current assets (including Cash and cash equivalents of $623 and $449, respectively)	$ 5,574	$ 6,137
Property and equipment, net	14,565	14,903
Investments in unconsolidated entities	3,684	3,805
Intangible assets, net	1,785	1,960
Linefill	954	907
Long-term operating lease right-of-use assets, net	338	393
Long-term inventory	301	253
Other long-term assets, net	256	251
Total assets	$ 27,457	$ 28,609
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 5,333	$ 6,232
Senior notes, net	7,934	8,329
Other long-term debt, net	52	69
Long-term operating lease liabilities	300	339
Other long-term liabilities and deferred credits	1,095	830
Total liabilities	14,714	15,799
Partners' capital excluding noncontrolling interests	9,944	9,972
Noncontrolling interests	2,799	2,838
Total partners' capital	12,743	12,810
Total liabilities and partners' capital	$ 27,457	$ 28,609

DEBT CAPITALIZATION RATIOS
(in millions)

	September 30, 2022	December 31, 2021
Short-term debt	$ 459	$ 822
Long-term debt	7,986	8,398
Total debt	$ 8,445	$ 9,220
Long-term debt	$ 7,986	$ 8,398
Partners' capital excluding noncontrolling interests	9,944	9,972
Total book capitalization excluding noncontrolling interests ("Total book capitalization")	$ 17,930	$ 18,370
Total book capitalization, including short-term debt	$ 18,389	$ 19,192
Long-term debt-to-total book capitalization	45%	46%
Total debt-to-total book capitalization, including short-term debt	46%	48%

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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,	
	2022	2021	2022	2021
Basic and Diluted Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	$ 384	$ (59)	$ 774	$ 143
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Amounts allocated to participating securities	(2)	(1)	(4)	(1)
Net income/(loss) allocated to common unitholders	$ 333	$ (109)	$ 621	$ (7)
Basic and diluted weighted average common units outstanding [(2)] [(3)]	698	715	702	719
Basic and diluted net income/(loss) per common unit	$ 0.48	$ (0.15)	$ 0.89	$ (0.01)

(1) We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income/(loss). 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 was excluded from the calculation of diluted net income/(loss) per common unit for the three and nine months ended September 30, 2022 and 2021 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 and nine months ended September 30, 2022 and 2021, the effect of equity-indexed compensation plan awards was either antidilutive or did not change net income/(loss) per common unit.

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

NON-GAAP RECONCILIATIONS

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,	
	2022	2021	2022	2021
Basic and Diluted Adjusted Net Income per Common Unit				
Net income/(loss) attributable to PAA	$ 384	$ (59)	$ 774	$ 143
Selected items impacting comparability - Adjusted net income attributable to PAA [2]	(104)	267	31	510
Adjusted net income attributable to PAA	$ 280	$ 208	$ 805	$ 653
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Amounts allocated to participating securities	(2)	(1)	(4)	(1)
Adjusted net income allocated to common unitholders	$ 229	$ 158	$ 652	$ 503
Basic and diluted weighted average common units outstanding [3] [4]	698	715	702	719
Basic and diluted adjusted net income per common unit	$ 0.33	$ 0.22	$ 0.93	$ 0.70

(1) We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income. 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. See the "Selected Items Impacting Comparability" table for additional information.

(3) The possible conversion of our Series A preferred units was excluded from the calculation of diluted adjusted net income per common unit for the three and nine months ended September 30, 2022 and 2021 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 treasury stock method in guidance issued by the FASB. For the three and nine months ended September 30, 2022 and 2021, the effect of equity-indexed compensation plan awards did not change adjusted net income per common unit.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Basic and diluted net income/(loss) per common unit	$ 0.48	$ (0.15)	$ 0.89	$ (0.01)
Selected items impacting comparability per common unit [1]	(0.15)	0.37	0.04	0.71
Basic and diluted adjusted net income per common unit	$ 0.33	$ 0.22	$ 0.93	$ 0.70

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

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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)
Net Income/(Loss) to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net Income/(Loss)	$ 442	$ (55)	$ 918	$ 152
Interest expense, net	99	106	305	319
Income tax expense/(benefit)	109	(30)	177	(16)
Depreciation and amortization	238	178	711	551
(Gains)/losses on asset sales and asset impairments, net	—	221	(46)	592
Gain on investment in unconsolidated entities	(1)	—	(1)	—
Depreciation and amortization of unconsolidated entities (1)	21	21	58	109
Selected items impacting comparability - Adjusted EBITDA (2)	(187)	78	(7)	(64)
Adjusted EBITDA	$ 721	$ 519	$ 2,115	$ 1,643
Adjusted EBITDA attributable to noncontrolling interests	(98)	(5)	(264)	(12)
Adjusted EBITDA attributable to PAA	$ 623	$ 514	$ 1,851	$ 1,631
Adjusted EBITDA	$ 721	$ 519	$ 2,115	$ 1,643
Interest expense, net of certain non-cash items (3)	(96)	(99)	(295)	(301)
Maintenance capital	(76)	(43)	(146)	(116)
Investment capital of noncontrolling interests (4)	(20)	—	(50)	—
Current income tax expense	(12)	(8)	(60)	(11)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings (5)	(22)	9	(48)	11
Distributions to noncontrolling interests (6)	(73)	(4)	(194)	(10)
Implied DCF	$ 422	$ 374	$ 1,322	$ 1,216
Preferred unit distributions paid (6)	(37)	(37)	(137)	(137)
Implied DCF Available to Common Unitholders	$ 385	$ 337	$ 1,185	$ 1,079
Weighted Average Common Units Outstanding	698	715	702	719
Weighted Average Common Units and Common Unit Equivalents	769	786	773	790
Implied DCF per Common Unit (7)	$ 0.55	$ 0.47	$ 1.69	$ 1.50
Implied DCF per Common Unit and Common Unit Equivalent (8)	$ 0.55	$ 0.48	$ 1.68	$ 1.51
Cash Distribution Paid per Common Unit	$ 0.2175	$ 0.18	$ 0.6150	$ 0.54
Common Unit Cash Distributions (6)	$ 152	$ 129	$ 432	$ 389
Common Unit Distribution Coverage Ratio	2.53x	2.61x	2.74x	2.77x
Implied DCF Excess	$ 233	$ 208	$ 753	$ 690

(1) Adjustment to exclude our proportionate share of depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities.

(2) See the "Selected Items Impacting Comparability" table for additional information.

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

(4) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.

(5) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, and selected items impacting comparability of unconsolidated entities).

(6) Cash distributions paid during the period presented.

(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 unit equivalents 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 Unit Equivalent Reconciliation:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Basic net income/(loss) per common unit	$ 0.48	$ (0.15)	$ 0.89	$ (0.01)
Reconciling items per common unit (1) (2)	0.07	0.62	0.80	1.51
Implied DCF per common unit	$ 0.55	$ 0.47	$ 1.69	$ 1.50
Basic net income/(loss) per common unit	$ 0.48	$ (0.15)	$ 0.89	$ (0.01)
Reconciling items per common unit and common unit equivalent (1) (3)	0.07	0.63	0.79	1.52
Implied DCF per common unit and common unit equivalent	$ 0.55	$ 0.48	$ 1.68	$ 1.51

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

(2) Based on weighted average common units outstanding for the period of 698 million, 715 million, 702 million and 719 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.

Free Cash Flow and Free Cash Flow after Distributions Reconciliation (1):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net cash provided by operating activities	$ 941	$ 336	$ 2,074	$ 1,361
Adjustments to reconcile net cash provided by operating activities to free cash flow:				
Net cash (used in)/provided by investing activities	(168)	761	(291)	478
Cash contributions from noncontrolling interests	26	—	26	1
Cash distributions paid to noncontrolling interests (2)	(73)	(4)	(194)	(10)
Free Cash Flow	$ 726	$ 1,093	$ 1,615	$ 1,830
Cash distributions (3)	(189)	(166)	(569)	(526)
Free Cash Flow after Distributions	$ 537	$ 927	$ 1,046	$ 1,304

(1) Management uses the Non-GAAP financial liquidity measures Free Cash Flow and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases 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.

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

SELECTED ITEMS IMPACTING COMPARABILITY
(in millions)

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Selected Items Impacting Comparability: (1)				
Gains/(losses) from derivative activities and inventory valuation adjustments (2)	$ 327	$ (9)	$ 167	$ 36
Long-term inventory costing adjustments (3)	(83)	13	22	81
Deficiencies under minimum volume commitments, net (4)	(16)	(56)	(31)	(31)
Equity-indexed compensation expense (5)	(9)	(6)	(24)	(14)
Net loss on foreign currency revaluation (6)	(32)	(18)	(42)	(3)
Line 901 incident (7)	—	—	(85)	—
Significant transaction-related expenses (8)	—	(2)	—	(5)
Selected items impacting comparability - Adjusted EBITDA	$ 187	$ (78)	$ 7	$ 64
Gains from derivative activities	2	—	6	—
Gain on investment in unconsolidated entities	1	—	1	—
Gains/(losses) on asset sales and asset impairments, net	—	(221)	46	(592)
Tax effect on selected items impacting comparability	(85)	32	(90)	18
Other (9)	(1)	—	(1)	—
Selected items impacting comparability - Adjusted net income attributable to PAA	$ 104	$ (267)	$ (31)	$ (510)

(1) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability. See the "Net Income/(Loss) to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation" and "Computation of Basic and Diluted Adjusted Net Income Per Common Unit" table for additional details on how these selected items impacting comparability affect such measures.

(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 differences in the timing of earnings from the derivative instruments and the underlying transactions and exclude the related gains and losses in determining adjusted results such that the earnings from the derivative instruments and the underlying transactions impact adjusted results in the same period. In addition, we exclude gains and losses on derivatives that are related to (i) investing activities, such as the purchase of linefill, and (ii) purchases of long-term inventory. We also exclude the impact of corresponding inventory valuation adjustments, as applicable.

(3) We carry crude oil and NGL inventory that is 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, and certain of our equity method investments, 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 capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We, or our equity method investees, 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, or our equity method investees, 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 or equity earnings, 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 be settled in units and awards that will be settled in cash. The awards that will 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, as applicable. The portion of compensation expense associated with awards that will 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 the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. These gains and losses are not integral to our core operating performance 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 expenses associated with the Permian Basin joint venture transaction announced in July 2021.

(9) Includes other immaterial selected items impacting comparability, as well as the noncontrolling interests' portion of selected items.

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

SELECTED FINANCIAL DATA BY SEGMENT
(in millions)

	Three Months Ended September 30, 2022		Three Months Ended September 30, 2021	
	Crude Oil	**NGL**	**Crude Oil**	**NGL**
Revenues [1]	$ 13,675	$ 770	$ 10,701	$ 166
Purchases and related costs [1]	(12,938)	(242)	(9,971)	(194)
Field operating costs [2]	(235)	(83)	(213)	(61)
Segment general and administrative expenses [2] [3]	(64)	(19)	(49)	(18)
Equity earnings in unconsolidated entities	105	—	69	—
Adjustments: [4]				
Depreciation and amortization of unconsolidated entities	21	—	21	—
(Gains)/losses from derivative activities and inventory valuation adjustments	(33)	(343)	(158)	171
Long-term inventory costing adjustments	80	3	(3)	(10)
Deficiencies under minimum volume commitments, net	16	—	56	—
Equity-indexed compensation expense	9	—	6	—
Net (gain)/loss on foreign currency revaluation	(2)	—	3	—
Significant transaction-related expenses	—	—	2	—
Adjusted EBITDA attributable to noncontrolling interests [5]	(98)	—	(5)	—
Segment Adjusted EBITDA [6]	$ 536	$ 86	$ 459	$ 54
Maintenance capital	$ 35	$ 41	$ 24	$ 19

(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.

(5) Reflects amounts attributable to noncontrolling interests in the Permian JV (beginning October 2021) and Red River Pipeline LLC.

(6) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our CODM determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts attributable to noncontrolling interests for periods prior have been recast to reflect this modification.

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

SELECTED FINANCIAL DATA BY SEGMENT
(in millions)

	Nine Months Ended September 30, 2022		Nine Months Ended September 30, 2021	
	Crude Oil	**NGL**	**Crude Oil**	**NGL**
Revenues [1]	$ 42,694	$ 2,075	$ 28,333	$ 1,034
Purchases and related costs [1]	(40,495)	(1,065)	(26,146)	(875)
Field operating costs [2]	(749)	(222)	(582)	(164)
Segment general and administrative expenses [2] [3]	(186)	(57)	(151)	(54)
Equity earnings in unconsolidated entities	306	—	190	—
Adjustments: [4]				
Depreciation and amortization of unconsolidated entities	58	—	109	—
(Gains)/losses from derivative activities and inventory valuation adjustments	(3)	(360)	(242)	219
Long-term inventory costing adjustments	(18)	(4)	(65)	(16)
Deficiencies under minimum volume commitments, net	31	—	31	—
Equity-indexed compensation expense	24	—	14	—
Net (gain)/loss on foreign currency revaluation	(1)	—	2	—
Line 901 incident	85	—	—	—
Significant transaction-related expenses	—	—	5	—
Adjusted EBITDA attributable to noncontrolling interests [5]	(264)	—	(12)	—
Segment Adjusted EBITDA [6]	$ 1,482	$ 367	$ 1,486	$ 144
Maintenance capital	$ 80	$ 66	$ 75	$ 41

(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.

(5) Reflects amounts attributable to noncontrolling interests in the Permian JV (beginning October 2021) and Red River Pipeline LLC.

(6) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our CODM determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts attributable to noncontrolling interests for periods prior have been recast to reflect this modification.

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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,	
	2022	2021	2022	2021
Crude Oil Segment Volumes				
Crude oil pipeline tariff volumes (by region) [1]:				
Permian Basin [2]	5,698	4,394	5,450	4,114
South Texas / Eagle Ford [2]	344	311	349	315
Mid-Continent [2]	553	483	503	441
Gulf Coast	252	176	216	161
Rocky Mountain [2]	304	344	334	320
Western	108	224	209	239
Canada	322	230	326	279
Crude oil pipeline tariff volumes (average volumes in thousands of barrels per day) [1] [2]	7,581	6,162	7,387	5,869
Commercial crude oil storage capacity (average monthly volumes in millions of barrels) [2] [3]	72	73	72	73
Crude oil lease gathering purchases (average volumes in thousands of barrels per day) [1]	1,390	1,372	1,373	1,300
NGL Segment Volumes				
NGL fractionation (average volumes in thousands of barrels per day) [1]	121	119	131	130
NGL pipeline tariff volumes (average volumes in thousands of barrels per day) [1]	182	165	182	176
NGL sales (average volumes in thousands of barrels per day) [1]	96	87	121	139

(1) Average daily volumes calculated as the total volumes (attributable to our interest for assets owned by unconsolidated entities or undivided joint interests) for the period divided by the number of days in the period. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

(2) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.

(3) Average monthly capacity calculated as total volumes for the period 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)

Segment Adjusted EBITDA to Adjusted EBITDA attributable to PAA Reconciliation:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Crude Oil Segment Adjusted EBITDA	$ 536	$ 459	$ 1,482	$ 1,486
NGL Segment Adjusted EBITDA	86	54	367	144
Segment Adjusted EBITDA	$ 622	$ 513	$ 1,849	$ 1,630
Adjusted other income/(expense), net (1)	1	1	2	1
Adjusted EBITDA attributable to PAA (2)	$ 623	$ 514	$ 1,851	$ 1,631

(1) Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of $83 million and $11 million for the three months ended September 30, 2022 and 2021, respectively and $239 million and $(12) million for the nine months ended September 30, 2022 and 2021, respectively. See the "Selected Items Impacting Comparability" table for additional information. Adjusted other income/(expense), net attributable to noncontrolling interests is less than $1 million for each of the periods presented.

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

Reconciliation of Segment Adjusted EBITDA to Segment Adjusted EBITDA further adjusted for impact of divested assets:

	Three Months Ended September 30, 2022		Three Months Ended September 30, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Segment Adjusted EBITDA	$ 536	$ 86	$ 459	$ 54
Impact of divested assets (1)	—	—	(6)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 536	$ 86	$ 453	$ 54

	Nine Months Ended September 30, 2022		Nine Months Ended September 30, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Segment Adjusted EBITDA	$ 1,482	$ 367	$ 1,486	$ 144
Impact of divested assets (1)	—	—	(58)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 1,482	$ 367	$ 1,428	$ 144

(1) Estimated impact of divestitures completed during 2021, assuming an effective date of January 1, 2021. Divested assets primarily included natural gas storage facilities previously included in our Crude Oil segment. Note: The natural gas storage business captured one-time benefits from Winter Storm Uri in the first quarter 2021.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Three Months Ended September 30, 2022			Three Months Ended September 30, 2021		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 14,336	$ —	$ 14,336	$ 10,776	$ —	$ 10,776
COSTS AND EXPENSES						
Purchases and related costs	13,071	—	13,071	10,074	—	10,074
Field operating costs	318	—	318	274	—	274
General and administrative expenses	83	1	84	67	1	68
Depreciation and amortization	238	1	239	178	1	179
(Gains)/losses on asset sales and asset impairments, net	—	—	—	221	—	221
Total costs and expenses	13,710	2	13,712	10,814	2	10,816
OPERATING INCOME/(LOSS)	626	(2)	624	(38)	(2)	(40)
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	105	—	105	69	—	69
Gain on investment in unconsolidated entities	1	—	1	—	—	—
Interest expense, net	(99)	—	(99)	(106)	—	(106)
Other expense, net	(82)	—	(82)	(10)	—	(10)
INCOME/(LOSS) BEFORE TAX	551	(2)	549	(85)	(2)	(87)
Current income tax expense	(12)	—	(12)	(8)	—	(8)
Deferred income tax (expense)/benefit	(97)	(20)	(117)	38	7	45
NET INCOME/(LOSS)	442	(22)	420	(55)	5	(50)
Net (income)/loss attributable to noncontrolling interests	(58)	(291)	(349)	(4)	30	26
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	$ 384	$ (313)	$ 71	$ (59)	$ 35	$ (24)
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			194
BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			$ 0.36			$ (0.12)

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

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in millions, except per share data)

	Nine Months Ended September 30, 2022			Nine Months Ended September 30, 2021		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 44,390	$ —	$ 44,390	$ 29,089	$ —	$ 29,089
COSTS AND EXPENSES						
Purchases and related costs	41,181	—	41,181	26,743	—	26,743
Field operating costs	971	—	971	746	—	746
General and administrative expenses	243	4	247	205	4	209
Depreciation and amortization	711	2	713	551	2	553
(Gains)/losses on asset sales and asset impairments, net	(46)	—	(46)	592	—	592
Total costs and expenses	43,060	6	43,066	28,837	6	28,843
OPERATING INCOME	1,330	(6)	1,324	252	(6)	246
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	306	—	306	190	—	190
Gain on investment in unconsolidated entities	1	—	1	—	—	—
Interest expense, net	(305)	—	(305)	(319)	—	(319)
Other income/(expense), net	(237)	—	(237)	13	—	13
INCOME BEFORE TAX	1,095	(6)	1,089	136	(6)	130
Current income tax expense	(60)	—	(60)	(11)	—	(11)
Deferred income tax (expense)/benefit	(117)	(44)	(161)	27	(16)	11
NET INCOME	918	(50)	868	152	(22)	130
Net income attributable to noncontrolling interests	(144)	(600)	(744)	(9)	(145)	(154)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	$ 774	$ (650)	$ 124	$ 143	$ (167)	$ (24)
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			194
BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			$ 0.64			$ (0.12)

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

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET DATA
(in millions)

	September 30, 2022			December 31, 2021		
	PAA	Consolidating Adjustments (1)	PAGP	PAA	Consolidating Adjustments (1)	PAGP
ASSETS						
Current assets	$ 5,574	$ 2	$ 5,576	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,565	4	14,569	14,903	6	14,909
Investments in unconsolidated entities	3,684	—	3,684	3,805	—	3,805
Intangible assets, net	1,785	—	1,785	1,960	—	1,960
Deferred tax asset	—	1,325	1,325	—	1,362	1,362
Linefill	954	—	954	907	—	907
Long-term operating lease right-of-use assets, net	338	—	338	393	—	393
Long-term inventory	301	—	301	253	—	253
Other long-term assets, net	256	—	256	251	(2)	249
Total assets	$ 27,457	$ 1,331	$ 28,788	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 5,333	$ 2	$ 5,335	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,934	—	7,934	8,329	—	8,329
Other long-term debt, net	52	—	52	69	—	69
Long-term operating lease liabilities	300	—	300	339	—	339
Other long-term liabilities and deferred credits	1,095	—	1,095	830	—	830
Total liabilities	14,714	2	14,716	15,799	2	15,801
Partners' capital excluding noncontrolling interests	9,944	(8,435)	1,509	9,972	(8,439)	1,533
Noncontrolling interests	2,799	9,764	12,563	2,838	9,806	12,644
Total partners' capital	12,743	1,329	14,072	12,810	1,367	14,177
Total liabilities and partners' capital	$ 27,457	$ 1,331	$ 28,788	$ 28,609	$ 1,369	$ 29,978

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

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE [(1)]
(in millions, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Basic and Diluted Net Income/(Loss) per Class A Share				
Net income/(loss) attributable to PAGP	$ 71	$ (24)	$ 124	$ (24)
Basic and diluted weighted average Class A shares outstanding	194	194	194	194
Basic and diluted net income/(loss) per Class A share	$ 0.36	$ (0.12)	$ 0.64	$ (0.12)

(1) For each of the three and nine months ended September 30, 2022 and 2021, the possible exchange of AAP units and AAP Management units would not have had a dilutive effect on basic net income/(loss) per Class A share.

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:

- general economic, market or business conditions in the United States and elsewhere (including the potential for a recession or significant slowdown in economic activity levels, the risk of persistently high inflation and continued supply chain issues, the impact of coronavirus variants on demand and growth, and the timing, pace and extent of economic recovery) that impact (i) demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and (ii) commercial opportunities available to us;
- declines in global crude oil demand and crude oil prices (whether due to the COVID-19 pandemic, future pandemics or other factors) that correspondingly lead to a significant reduction of North American crude oil and NGL 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;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil and NGL and resulting changes in pricing conditions or transportation throughput requirements;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- the effects of competition and capacity overbuild in areas where we operate, including downward pressure on rates and margins, contract renewal risk and the risk of loss of business to other midstream operators who are willing or under pressure to aggressively reduce transportation rates in order to capture or preserve customers;
- 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 that adversely impact our business;
- environmental liabilities, litigation or other events that are not covered by an indemnity, insurance or existing reserves;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event that materially impacts our operations, including cyber or other attacks on our electronic and computer systems;

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- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the impact of current and future laws, rulings, governmental regulations, executive orders, trade policies, accounting standards and statements, and related interpretations, including legislation, executive orders or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing or that prohibit the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines;
- loss of key personnel and inability to attract and retain new talent;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- 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;
- 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, and the successful integration and future performance of acquired assets or businesses;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;
- 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 (such as 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, supply chain issues, legal constraints (including governmental orders or guidance), or other factors or events;
- the incurrence of costs and expenses related to unexpected or unplanned capital expenditures, third-party claims or other factors;
- 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;
- the amplification of other risks caused by volatile financial markets, capital constraints, liquidity concerns and inflation;
- the use or availability of third-party assets upon which our operations depend and over which we have little or no control;
- the currency exchange rate of the Canadian dollar to the United States dollar;
- 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;
- significant under-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

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- risks related to the development and operation of our assets; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the processing, transportation, fractionation, storage and marketing of NGL as discussed in the Partnerships' filings with the Securities and Exchange Commission.

About Plains:

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil and natural gas liquids (NGL). PAA owns an extensive network of pipeline gathering and transportation systems, in addition to terminalling, storage, processing, fractionation and other infrastructure assets serving key producing basins, transportation corridors and major market hubs and export outlets in the United States and Canada. On average, PAA handles more than 7 million barrels per day of crude oil and NGL.

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.

PAA and PAGP are headquartered in Houston, Texas. For more information, please visit www.plains.com.

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FY 2022 Financial & Operating Guidance

November 2, 2022

Forward-Looking Statements & Non-GAAP Financial Measures Disclosure

- This presentation contains forward-looking statements, including, in particular, statements about the performance, plans, strategies and objectives for future operations of Plains All American Pipeline, L.P. ("PAA") and Plains GP Holdings, L.P. ("PAGP"). These forward-looking statements are based on PAA's current views with respect to future events, based on what we believe to be reasonable assumptions. PAA and PAGP can give no assurance that future results or outcomes will be achieved. Important factors, some of which may be beyond PAA's and PAGP's control, that could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements are disclosed in PAA's and PAGP's respective filings with the Securities and Exchange Commission.

- This presentation also contains non-GAAP financial measures relating to PAA, such as Adjusted EBITDA attributable to PAA, Implied DCF and Free Cash Flow. A reconciliation of these historical measures to the most directly comparable GAAP measures is available in the Investor Relations section of PAA's and PAGP's website at www.plains.com, select "PAA" or "PAGP," navigate to the "Financial Information" tab, then click on "Non-GAAP Reconciliations." PAA does 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 it has defined as "Selected Items Impacting Comparability" without unreasonable effort. Definitions for certain non-GAAP financial measures and other terms used throughout this presentation are included in the appendix.

2022(G): Financial Metrics

Increasing EBITDA, generating meaningful FCF, significant distribution coverage & achieved leverage targets

($ millions, except per-unit metrics)

Adjusted EBITDA / DCF

Segment Adjusted EBITDA	Aug(G) (+/-)	Nov(G) (+/-)
Crude Oil	$1,890	$1,955
NGL	485	495
Other Income	-	-
Adj. EBITDA attributable to PAA	**$2,375**	**$2,450**
Implied DCF to Common	$1,550	$1,550
Implied DCF / CUE	$2.20	$2.20
Distribution Coverage (Common)[1]	265%	**265%**
Year-End Leverage Ratio	4.0x	**3.8x**

Cash Flow

	Aug(G) (+/-)	Nov(G) (+/-)
Cash Flow from Ops (CFFO)	$2,050	$2,175
Asset Sales	$200	$200
FCF	$1,400	**$1,450**[2]
FCFaD	$620	**$670**[1] [2]

Capital (Consistent with Aug(G))

	Nov (G) (+/-) Net to PAA	Nov (G) (+/-) Consolidated
Investment	**$275**	**$330**
Permian JV	$110	$165
Other	$165	$165
Maintenance	**$210**	**$220**
Total	**$485**	**$550**

Note: Green highlight denotes key financial metrics discussed on Third-Quarter Earnings Conference Call.
2022(G) / Nov(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
(1) Distribution Coverage & FCFaD reflect cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year.
(2) Includes impact of cash paid for Cactus II acquisition on November 2, 2022.

2022(G): Operational Metrics

Capturing incremental Long-Haul barrels, Gathering growth consistent with Aug(G)

(table data reflects full-year averages)	Aug (G) (+/-)	Nov (G) (+/-)	Δ
Crude Oil Segment			
Crude Pipeline Volumes (Mb/d)	**7,410**	**7,550**	***+140***
Permian	**5,490**	**5,630**	***+140***
Gathering	2,375	2,375	-
Intra-Basin	2,000	2,065	+65
Long-Haul	1,115	1,190	+75
Other	**1,920**	**1,920**	-
Commercial Storage Capacity (mmbbls/mo)	72	72	-
NGL Segment			
NGL Sales (Mb/d)	140	140	-
C3+ Spec Product Sales[1]	55	55	-
Fractionation Volumes (Mb/d)	135	135	-

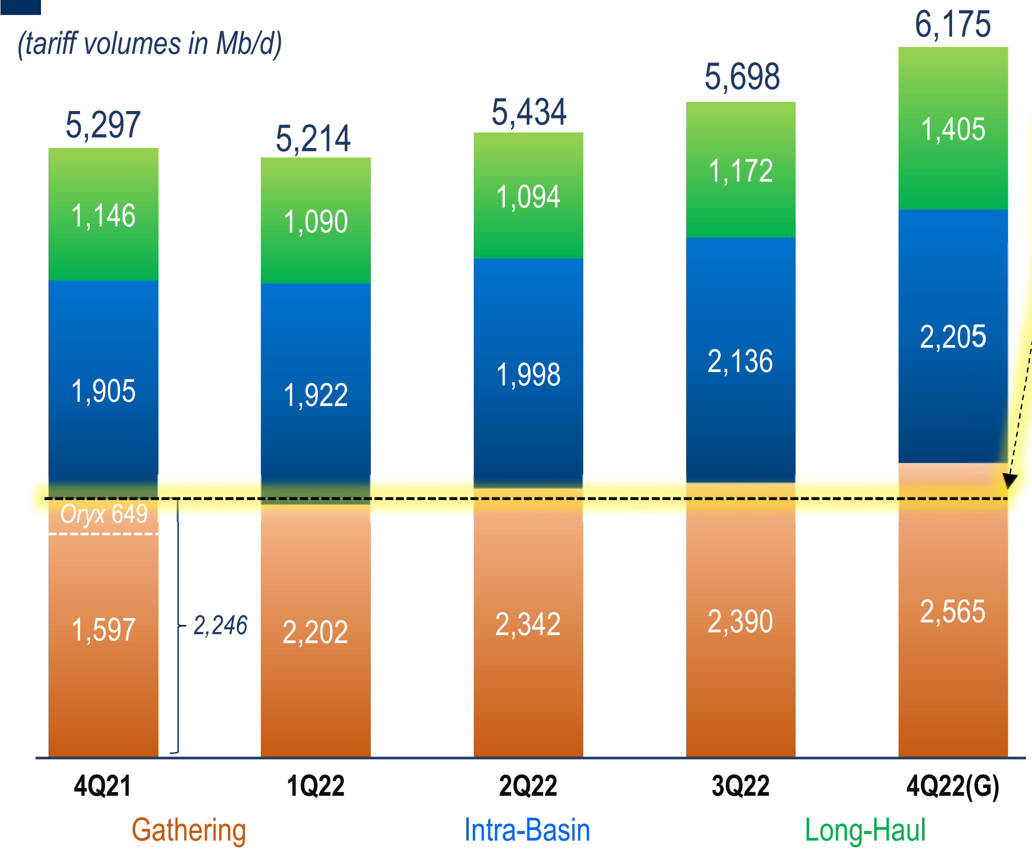
Intra-Basin: *increased volumes supporting downstream movements*

Long-Haul: *Increased long-haul flows to USGC & Cactus II consolidation (+30 Mb/d)*

2022(G) / Nov(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
Note: Permian JV & 2 months of Cactus II (Nov(G) only) volumes on a consolidated (8/8ths) basis.
(1) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread.

Capturing Permian Volume Growth

Permian building momentum, additional volumes added since Aug(G)



4Q22(G) vs. 4Q21: ↑880 Mb/d

- ***Gathering: ↑ 320 Mb/d***
  - Tracking in-line-with expectations
- ***Intra-Basin: ↑300 Mb/d***
  - Increased volumes supporting downstream movements
  - Benefitting from Advantage JV bolt-on in 2H22
- ***Long-Haul: ↑260 Mb/d***
  - Increasing demand from USGC export markets & Cushing refiners
  - Includes benefit of Cactus II consolidation (+125 Mb/d)

2022(G): Furnished November 2, 2022. Aug(G): Furnished August 3, 2022.
Note: Permian JV & 2 months of Cactus II (2022(G) only) volumes on a consolidated (8/8ths) basis.

Third-Quarter 2022

PAA & PAGP

Non-GAAP & Supplemental Reconciliations

PLAINS ALL AMERICAN PIPELINE, L.P.

Non-GAAP Reconciliations and Supplemental Calculations: Table of Contents

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, common equity repurchases and other general partnership purposes. The primary additional measures used by management are Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow ("DCF"), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects 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. Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income/(Loss), 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 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 either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results 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. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. All 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, common equity repurchases 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 cash received from or paid to noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Free Cash Flow after Distributions.

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Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA (in millions) (1) (2)

Selected Items Impacting Comparability (3)

	2022				2021					2020					2019				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities and inventory valuation adjustments	$ (132)	$ (28)	$ 327	$ 167	$ 131	$ (86)	$ (9)	$ 249	$ 285	$ (4)	$ (99)	$ (98)	$ (258)	$ (460)	$ 97	$ (51)	$ 30	$ (234)	$ (158)
Long-term inventory costing adjustments	92	13	(83)	22	41	27	13	13	94	(115)	51	(2)	21	(44)	21	(25)	1	22	20
Deficiencies under minimum volume commitments, net	(6)	(10)	(16)	(31)	32	(6)	(56)	38	7	2	(7)	(64)	(5)	(74)	7	(1)	4	8	18
Equity-indexed compensation expense	(7)	(7)	(9)	(24)	(5)	(4)	(6)	(5)	(19)	(4)	(5)	(5)	(5)	(19)	(3)	(4)	(5)	(4)	(17)
Net gain/(loss) on foreign currency revaluation	9	(19)	(32)	(42)	8	7	(18)	11	7	(46)	23	10	28	16	(4)	(8)	5	7	1
Significant transaction-related expenses	—	—	—	—	—	(3)	(2)	(11)	(16)	(3)	—	—	—	(3)	—	—	—	—	—
Line 901 incident	(85)	—	—	(85)	—	—	—	(15)	(15)	—	—	—	—	—	—	(10)	—	—	(10)
Net gain on early repayment of senior notes	—	—	—	—	—	—	—	—	—	—	3	—	—	3	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	$ (129)	$ (51)	$ 187	$ 7	$ 207	$ (65)	$ (78)	$ 280	$ 343	$ (170)	$ (34)	$ (159)	$ (219)	$ (581)	$ 118	$ (99)	$ 35	$ (201)	$ (146)
Gains/(losses) from derivative activities	—	4	2	6	—	—	—	—	—	—	—	—	—	—	—	(1)	—	—	(1)
Gain (loss) on/(impairment of) investments in unconsolidated entities, net	—	—	1	1	—	—	—	2	2	(22)	(69)	(91)	—	(182)	267	—	4	—	271
Gains/(losses) on asset sales and asset impairments, net	42	3	—	46	(2)	(369)	(221)	—	(592)	(619)	1	2	(101)	(719)	(4)	4	7	(34)	(28)
Goodwill impairment losses	—	—	—	—	—	—	—	—	—	(2,515)	—	—	—	(2,515)	—	—	—	—	—
Tax effect on selected items impacting comparability	8	(13)	(85)	(90)	(15)	1	32	(63)	(44)	23	11	9	31	76	24	(9)	(27)	24	12
Other	$ —	$ —	$ (1)	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (79)	$ (57)	$ 104	$ (31)	$ 190	$ (433)	$ (267)	$ 219	$ (291)	$(3,303)	$ (91)	$ (239)	$ (289)	$(3,921)	$ 405	$ (105)	$ 19	$ (211)	$ 108

Net Income/(Loss) to Adjusted EBITDA attributable to PAA Reconciliation

	2022				2021					2020					2019				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 251	$ 442	$ 918	$ 423	$ (216)	$ (55)	$ 497	$ 648	$(2,845)	$ 144	$ 146	$ (25)	$(2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180
Interest expense, net	107	99	99	305	107	107	106	106	425	108	108	113	108	436	101	103	108	114	425
Income tax expense/(benefit)	21	47	109	177	24	(10)	(30)	88	73	21	(12)	(3)	(26)	(19)	24	(23)	41	25	66
Depreciation and amortization	230	242	238	711	177	196	178	223	774	168	166	160	160	653	136	147	156	163	601
(Gains)/losses on asset sales and asset impairments, net	(42)	(3)	—	(46)	2	369	221	—	592	619	(1)	(2)	101	719	4	(4)	(7)	34	28
Goodwill impairment losses	—	—	—	—	—	—	—	—	—	2,515	—	—	—	2,515	—	—	—	—	—
(Gain on)/impairment of investments in unconsolidated entities, net	—	—	(1)	(1)	—	—	—	(2)	(2)	22	69	91	—	182	(267)	—	(4)	—	(271)
Depreciation and amortization of unconsolidated entities (4)	20	17	21	58	20	68	21	14	123	17	16	18	22	73	12	14	18	16	62
Selected items impacting comparability - Adjusted EBITDA	129	51	(187)	(7)	(207)	65	78	(280)	(343)	170	34	159	219	581	(118)	99	(35)	201	146
Adjusted EBITDA	$ 690	$ 704	$ 721	$ 2,115	$ 546	$ 579	$ 519	$ 646	$ 2,290	$ 795	$ 524	$ 682	$ 559	$ 2,560	$ 862	$ 784	$ 731	$ 860	$ 3,237
Less: Adjusted EBITDA attributable to noncontrolling interests	(76)	(89)	(98)	(264)	(3)	(4)	(5)	(82)	(94)	(2)	(2)	(4)	(5)	(14)	—	(3)	(5)	(2)	(10)
Adjusted EBITDA attributable to PAA	$ 614	$ 615	$ 623	$ 1,851	$ 543	$ 575	$ 514	$ 564	$ 2,196	$ 793	$ 522	$ 678	$ 554	$ 2,546	$ 862	$ 781	$ 726	$ 858	$ 3,227

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

	2022				2021					2020					2019				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 251	$ 442	$ 918	$ 423	$ (216)	$ (55)	$ 497	$ 648	$(2,845)	$ 144	$ 146	$ (25)	$(2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180
Less: Net income attributable to noncontrolling interests	(38)	(48)	(58)	(144)	(1)	(4)	(4)	(47)	(55)	(2)	(2)	(3)	(3)	(10)	—	(2)	(5)	(1)	(9)
Net income/(loss) attributable to PAA	187	203	384	774	422	(220)	(59)	450	593	(2,847)	142	143	(28)	(2,590)	970	446	449	306	2,171
Selected items impacting comparability - Adjusted net income attributable to PAA	79	57	(104)	31	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(405)	105	(19)	211	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 280	$ 805	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 565	$ 551	$ 430	$ 517	$ 2,063

(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 (including write-downs related to cancelled projects) of unconsolidated entities.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Basic Adjusted Net Income Per Common Unit

	2022				2021					2020					2019
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 203	$ 384	$ 774	$ 422	$ (220)	$ (59)	$ 450	$ 593	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171
Selected items impacting comparability - Adjusted net income attributable to PAA (3)	79	57	(104)	31	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 280	$ 805	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders (4)	(37)	(37)	(37)	(112)	(37)	(37)	(37)	(37)	(149)	(37)	(37)	(37)	(37)	(149)	(149)
Distributions to Series B preferred unitholders (4)	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(2)	(4)	(1)	(1)	(1)	(2)	(3)	(2)	(1)	(2)	(1)	(4)	(6)
Adjusted net income allocated to common unitholders	$ 216	$ 210	$ 229	$ 652	$ 182	$ 163	$ 158	$ 180	$ 683	$ 405	$ 183	$ 331	$ 211	$ 1,129	$ 1,859
Basic weighted average common units outstanding	705	702	698	702	722	720	715	709	716	728	728	728	726	728	727
Basic adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.33	$ 0.93	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.56	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.56

Diluted Adjusted Net Income Per Common Unit

	2022				2021					2020					2019
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 203	$ 384	$ 774	$ 422	$ (220)	$ (59)	$ 450	$ 593	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171
Selected items impacting comparability - Adjusted net income attributable to PAA (3)	79	57	(104)	31	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 280	$ 805	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders (4)	(37)	(37)	(37)	(112)	(37)	(37)	(37)	(37)	(149)	—	(37)	(37)	(37)	(149)	—
Distributions to Series B preferred unitholders (4)	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(2)	(4)	(1)	(1)	(1)	(2)	(3)	(1)	(1)	(1)	(1)	(2)	(3)
Adjusted net income allocated to common unitholders	$ 216	$ 210	$ 229	$ 652	$ 182	$ 163	$ 158	$ 180	$ 683	$ 443	$ 183	$ 332	$ 211	$ 1,131	$ 2,011
Basic weighted average common units outstanding	705	702	698	702	722	720	715	709	716	728	728	728	726	728	727
Effect of dilutive securities:															
Series A preferred units (5)	—	—	—	—	—	—	—	—	—	71	—	—	—	—	71
Equity-indexed compensation plan awards (6)	—	—	—	—	—	—	—	—	—	1	—	—	—	—	2
Diluted weighted average common units outstanding	705	702	698	702	722	720	715	709	716	800	728	728	726	728	800
Diluted adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.33	$ 0.93	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51

(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 or did not change the presentation of diluted adjusted net income per common unit.
(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 adjusted net income per common unit.

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

Basic Adjusted Net Income Per Common Unit

	2022				2021					2020					2019
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.48	$ 0.89	$ 0.51	$ (0.37)	$ (0.15)	$ 0.56	$ 0.55	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.70
Selected items impacting comparability per common unit [2]	0.12	0.08	(0.15)	0.04	(0.26)	0.60	0.37	(0.31)	0.40	4.54	0.12	0.33	0.40	5.38	(0.14)
Basic adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.33	$ 0.93	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.56	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.56

Diluted Adjusted Net Income Per Common Unit

	2022				2021					2020					2019
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Diluted net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.48	$ 0.89	$ 0.51	$ (0.37)	$ (0.15)	$ 0.56	$ 0.55	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.65
Selected items impacting comparability per common unit [2]	0.12	0.08	(0.15)	0.04	(0.26)	0.60	0.37	(0.31)	0.40	4.53	0.12	0.33	0.40	5.38	(0.14)
Diluted adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.33	$ 0.93	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51

(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.

PLAINS ALL AMERICAN PIPELINE, L.P.

PAA Credit Metrics (in millions, except ratio amounts)[1]

Debt Capitalization Ratios

	2022			2021				2020	2019
	As of March 31,	As of June 30,	As of September 30,	As of March 31,	As of June 30,	As of September 30,	As of December 31,	As of December 31,	As of December 31,
Short-term debt	$ 900	$ 630	$ 459	$ 254	$ 1,456	$ 808	$ 822	$ 831	$ 504
Senior notes, net	7,931	7,933	7,934	9,073	8,326	8,327	8,329	9,071	8,939
Other long-term debt, net	55	53	52	265	63	61	69	311	248
Long-term debt	7,986	7,986	7,986	9,338	8,389	8,388	8,398	9,382	9,187
Total debt	$ 8,886	$ 8,616	$ 8,445	$ 9,592	$ 9,845	$ 9,196	$ 9,220	$ 10,213	$ 9,691
Long-term debt	$ 7,986	$ 7,986	$ 7,986	$ 9,338	$ 8,389	$ 8,388	$ 8,398	$ 9,382	$ 9,187
Partners' capital excluding noncontrolling interests	10,043	9,931	9,944	9,943	9,495	9,152	9,972	9,593	13,062
Total book capitalization excluding noncontrolling interests ("Total book capitalization")	$ 18,029	$ 17,917	$ 17,930	$ 19,281	$ 17,884	$ 17,540	$ 18,370	$ 18,975	$ 22,249
Total book capitalization, including short-term debt	$ 18,929	$ 18,547	$ 18,389	$ 19,535	$ 19,340	$ 18,348	$ 19,192	$ 19,806	$ 22,753
Long-term debt-to-total book capitalization	44 %	45 %	45 %	48 %	47 %	48 %	46 %	49 %	41 %
Total debt-to-total book capitalization, including short-term debt	47 %	46 %	46 %	49 %	51 %	50 %	48 %	52 %	43 %

(1) Amounts may not recalculate due to rounding.

Implied Distributable Cash Flow (in millions, except per unit and ratio data)[1]

Implied Distributable Cash Flow Reconciliation

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended December 31,		
	Mar 31, 2022	Jun 30, 2022	Sep 30, 2022	Sep 30, 2022	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	2021	2020	2019
Adjusted EBITDA	$ 690	$ 704	$ 721	$ 2,115	$ 546	$ 579	$ 519	$ 1,643	$ 2,290	$ 2,560	$ 3,237
Interest expense, net of certain non-cash items [2]	(101)	(97)	(96)	(295)	(101)	(101)	(99)	(301)	(401)	(415)	(407)
Maintenance capital	(27)	(43)	(76)	(146)	(35)	(37)	(43)	(116)	(168)	(216)	(287)
Investment capital of noncontrolling interests [3]	(15)	(15)	(20)	(50)	—	—	—	—	(9)	—	—
Current income tax expense	(19)	(30)	(12)	(60)	(1)	(1)	(8)	(11)	(50)	(51)	(112)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [4]	(31)	5	(22)	(48)	5	(5)	9	11	16	13	(49)
Distributions to noncontrolling interests [5]	(59)	(62)	(73)	(194)	(6)	—	(4)	(10)	(14)	(10)	(6)
Implied DCF	$ 438	$ 462	$ 422	$ 1,322	$ 408	$ 435	$ 374	$ 1,216	$ 1,664	$ 1,881	$ 2,376
Preferred unit distributions paid [5]	(37)	(62)	(37)	(137)	(37)	(62)	(37)	(137)	(198)	(198)	(198)
Implied DCF available to common unitholders	$ 401	$ 400	$ 385	$ 1,185	$ 371	$ 373	$ 337	$ 1,079	$ 1,466	$ 1,683	$ 2,178
Weighted average common units outstanding	705	702	698	702	722	720	715	719	716	728	727
Weighted average common units and common unit equivalents	776	773	769	773	793	791	786	790	787	799	798
Implied DCF per common unit [6]	$ 0.57	$ 0.57	$ 0.55	$ 1.69	$ 0.51	$ 0.52	$ 0.47	$ 1.50	$ 2.06	$ 2.31	$ 2.99
Implied DCF per common unit and common unit equivalent [7]	$ 0.56	$ 0.57	$ 0.55	$ 1.68	$ 0.51	$ 0.52	$ 0.48	$ 1.51	$ 2.06	$ 2.29	$ 2.91
Cash distribution paid per common unit	$ 0.18	$ 0.2175	$ 0.2175	$ 0.6150	$ 0.18	$ 0.18	$ 0.18	$ 0.54	$ 0.72	$ 0.90	$ 1.38
Common unit cash distributions [5]	$ 127	$ 153	$ 152	$ 432	$ 130	$ 130	$ 129	$ 389	$ 517	$ 655	$ 1,004
Common unit distribution coverage ratio	3.16x	2.61x	2.53x	2.74x	2.85x	2.87x	2.61x	2.77x	2.85x	2.57x	2.17x
Implied DCF excess	$ 274	$ 247	$ 233	$ 753	$ 241	$ 243	$ 208	$ 690	$ 949	$ 1,028	$ 1,174

(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) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.
(4) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, gains and losses on significant asset sales by such entities and selected items impacting comparability of unconsolidated entities).
(5) Cash distributions paid during the period presented.
(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, divided by the weighted average common units and common unit equivalents 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.

PLAINS ALL AMERICAN PIPELINE, L.P.

Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Unit Equivalent Reconciliation [(1) (2)]

Implied DCF Per Common Unit

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended		
	Mar 31, 2022	Jun 30, 2022	Sep 30, 2022	Sep 30, 2022	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.48	$ 0.89	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit	0.38	0.35	0.07	0.80	—	0.89	0.62	1.51	1.51	6.14	0.29
Implied DCF per common unit	$ 0.57	$ 0.57	$ 0.55	$ 1.69	$ 0.51	$ 0.52	$ 0.47	$ 1.50	$ 2.06	$ 2.31	$ 2.99

Implied DCF Per Common Unit and Common Unit Equivalent

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended		
	Mar 31, 2022	Jun 30, 2022	Sep 30, 2022	Sep 30, 2022	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.48	$ 0.89	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit and common unit equivalent	0.37	0.35	0.07	0.79	—	0.89	0.63	1.52	1.51	6.12	0.21
Implied DCF per common unit and common unit equivalent	$ 0.56	$ 0.57	$ 0.55	$ 1.68	$ 0.51	$ 0.52	$ 0.48	$ 1.51	$ 2.06	$ 2.29	$ 2.91

(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 unit equivalent, please refer to our latest issued PAA & PAGP Earnings Release.

PLAINS ALL AMERICAN PIPELINE, L.P.

Free Cash Flow (in millions): [1]

Free Cash Flow and Free Cash Flow after Distributions Reconciliation

	2022 Q1	2022 Q2	2022 Q3	2022 YTD	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 YTD	2020 YTD	2019 YTD
Net cash provided by operating activities	$ 340	$ 792	$ 941	$ 2,074	$ 791	$ 235	$ 336	$ 635	$ 1,996	$ 1,514	$ 2,504
Adjustments to reconcile net cash provided by operating activities to free cash flow:											
Net cash provided by/(used in) investing activities	(81)	(42)	(168)	(291)	(108)	(175)	761	(92)	386	(1,093)	(1,765)
Cash contributions from noncontrolling interests	—	—	26	26	1	—	—	—	1	12	—
Cash distributions paid to noncontrolling interests [2]	(59)	(62)	(73)	(194)	(6)	—	(4)	(4)	(14)	(10)	(6)
Sale of noncontrolling interest in a subsidiary	—	—	—	—	—	—	—	—	—	—	128
Free Cash Flow	$ 200	$ 688	$ 726	$ 1,615	$ 678	$ 60	$ 1,093	$ 539	$ 2,369	$ 423	$ 861
Cash distributions [3]	(164)	(215)	(189)	(569)	(167)	(192)	(166)	(190)	(715)	(853)	(1,202)
Free Cash Flow after Distributions	$ 36	$ 473	$ 537	$ 1,046	$ 511	$ (132)	$ 927	$ 349	$ 1,654	$ (430)	$ (341)

(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.

Segment Information (dollars in millions) [1] [2]

Segment Adjusted EBITDA [3]

	2022				2021					2020					2019				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Crude Oil Segment Adjusted EBITDA	$ 453	$ 494	$ 536	$ 1,482	$ 474	$ 553	$ 459	$ 423	$ 1,909	$ 638	$ 472	$ 639	$ 465	$ 2,216	$ 659	$ 727	$ 681	$ 684	$ 2,753
NGL Segment Adjusted EBITDA	161	120	86	367	69	21	54	141	285	153	49	38	89	327	202	52	41	173	467
Segment Adjusted EBITDA	$ 614	$ 614	$ 622	$ 1,849	$ 543	$ 574	$ 513	$ 564	$ 2,194	$ 791	$ 521	$ 677	$ 554	$ 2,543	$ 861	$ 779	$ 722	$ 857	$ 3,220
Adjusted other income/(expense), net [4]	—	1	1	2	—	1	1	—	2	2	1	1	—	3	1	2	4	1	7
Adjusted EBITDA attributable to PAA [5]	$ 614	$ 615	$ 623	$ 1,851	$ 543	$ 575	$ 514	$ 564	$ 2,196	$ 793	$ 522	$ 678	$ 554	$ 2,546	$ 862	$ 781	$ 726	$ 858	$ 3,227

Segment Operational Information

	2022				2021					2020					2019				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Crude Oil Segment Volumes:																			
Crude oil pipeline tariff volumes (average volumes in thousands of barrels per day) [6][7]	7,159	7,417	7,581	7,387	5,430	6,006	6,162	7,202	6,205	6,974	5,656	5,868	5,835	6,082	6,201	6,522	6,807	6,911	6,613
Commercial crude oil storage capacity (average monthly volumes in millions of barrels) [7][8]	72	72	72	72	73	73	73	72	73	78	79	81	76	79	75	76	77	77	76
Crude oil lease gathering purchases (average volumes in thousands of barrels per day) [6]	1,361	1,368	1,390	1,373	1,174	1,352	1,372	1,419	1,330	1,318	1,077	1,147	1,155	1,174	1,128	1,102	1,146	1,271	1,162
NGL Segment Volumes:																			
NGL fractionation (average volumes in thousands of barrels per day) [6]	134	137	121	131	144	129	119	127	129	154	122	110	129	129	157	137	140	142	144
NGL pipeline tariff volumes (average volumes in thousands of barrels per day) [6]	176	187	182	182	183	181	165	189	179	187	194	180	177	184	210	182	193	184	192
NGL sales (average volumes in thousands of barrels per day) [6]	168	101	96	121	220	112	87	148	141	220	94	83	178	144	328	158	124	221	207

(1) Amounts may not recalculate due to rounding.
(2) During the fourth quarter of 2021, we reorganized our historical operating segments: Transportation, Facilities and Supply and Logistics into two operating segments: Crude Oil and Natural Gas Liquids (“NGL”). The change in our segments stems from several factors including, (i) a multi-year transition in the midstream energy industry driven by increased competition that has reduced the stand alone earnings opportunities of our supply and logistics activities such that those activities now function as a business development effort to help maximize the utilization of our Crude Oil and NGL assets and (ii) internal changes regarding the oversight and reporting of our assets and related results of operations. All segment data and related disclosures for earlier periods presented herein have been recast to reflect the new segment reporting structure.
(3) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Plains Oryx Permian Basin joint venture formation in October 2021, our Chief Operating Decision Maker (“CODM”) determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts for prior periods have been recast to reflect this modification.
(4) Represents “Other income/(expense), net” as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability. See the “Selected Items Impacting Comparability” table for additional information. Adjusted other income/(expense), net attributable to noncontrolling interests is less than $1 million for each of the periods presented.
(5) See the “Net Income/(Loss) to Adjusted EBITDA attributable to PAA Reconciliation” table for reconciliation to Net Income/(Loss).
(6) Average daily volumes calculated as the total volumes (attributable to our interest for pipelines owned by unconsolidated entities or undivided joint interests) for the period divided by the number of days in the period. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.
(7) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.
(8) Average monthly capacity calculated as total volumes for the period divided by the number of months in the period.