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1Q 2022 Earnings Package

PLAINS ALL AMERICAN

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First-Quarter 2022 Earnings Conference Call

Wednesday, May 4, 2022

Roy Lamoreaux:

Thank you, Chino. Good afternoon, and welcome to Plains All American's first-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: 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. Good afternoon everyone, and thank you for joining us. Our business is off to a strong start to the year, reporting solid first-quarter Adjusted EBITDA attributable to PAA of $614 million, which is above our previous expectations. Given the quarter performance and our outlook for the balance of the year, we are increasing our full-year 2022 Guidance for Adjusted EBTIDA by $75 million to plus or minus $2.275 billion, with a bias to the upside. This is primarily driven by constructive fundamentals and the associated benefits of a higher commodity price environment within both our Crude and NGL segments. Al will provide more detail on our quarterly results and our full-year outlook in his portion of the call.

Current global events have highlighted and reaffirmed the importance of hydrocarbons in everyday life, spurring a renewed focus on energy security and the need for safe, reliable, and responsibly produced energy. The North American energy industry plays a critical role with an abundance of resources, access to capital, a skilled labor force, and innovative technology. We believe the call on North American shale, more specifically the Permian, will remain strong for decades, and our integrated midstream asset base and business model will play a critical role connecting energy supply with global demand.

As shown on slide 4, we are executing on our levers for maximizing unitholder returns. In the Permian, we continue to expect at least 600,000 barrels per day of production growth in 2022, of which we anticipate capturing approximately an incremental 280,000 tariff barrels per day on our Permian gathering systems, year-end 2021 to year-end 2022. As a result of our system flexibility and operating leverage, we have added an incremental 45,000 barrels per day of contracted short-term volumes to our Permian long-haul pipelines versus our full-year expectations in February. As Permian production continues growing beyond 2022, we expect meaningful growth on both our gathering and long-haul systems. In our NGL segment, we expect continued growth in Western Canadian gas production and improving NGL supply and demand fundamentals, combined with a higher price environment, this drives our focus on optimizing and debottlenecking our existing facilities and operations to allow additional volume capture over the next several years. Additionally, we continue pursuing capital-efficient emerging energy opportunities such as the recently announced MOU with Atura Power, a subsidiary of the Ontario government, to conduct a feasibility study which could result in adding hydrogen storage capability at our Windsor, Ontario salt cavern storage facility. This would directly support Atura Power's Brighton Beach Generation Station and aligns with a larger hydrogen strategy outlined recently by the Province of Ontario.

Regarding our financial strategy, we expect to continue generating significant multi-year Free Cash Flow, and we will allocate this cash in a balanced manner to maximize unitholder returns. Our near-term focus will continue to prioritize debt reduction, while also increasing cash returned to equity holders and making disciplined capital investments. In that regard, we announced a $0.15 per unit annualized distribution increase last month and have cumulatively repurchased approximately $250 million of common equity under our repurchase program since inception.

As shown on slides 5 and 6, demand recovery contrasted against the multi-year backdrop of reduced upstream investment, is causing a tight supply and demand balance resulting in global inventories drawing down and hovering at multi-year lows, all of which underpins a higher commodity price environment. The conflict between Russia and Ukraine has further exacerbated market tightness and increased commodity price volatility. We expect U.S. shale production, led by the Permian will continue to be crucial to supplying and meeting global energy demand, with Plains' integrated system and business model well positioned to benefit and generate significant, multi-year Free Cash Flow. This is supported by our Permian gathering system and four million dedicated acres with approximately half of total horizontal Permian rigs currently located on that acreage, our highly contracted long-haul pipelines and meaningful Permian operating leverage as well as our existing critical infrastructure in other key producing North American basins. Furthermore, high levels of cash flow and strong distribution coverage position us to reach our leverage target in mid-2023, with meaningful capacity to further increase cash returns to equity holders and drive strong unitholder returns both near and longer term.

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

Al Swanson:

Thanks, Willie. We reported first-quarter Adjusted EBITDA of $614 million which includes the benefit of NGL seasonality, higher volumes and commodity prices, and the start-up of the Capline and Wink to Webster pipelines. Slides 7 and 8 contain quarter-over-quarter and year-over-year Segment Adjusted EBITDA walks which provide more detail on our first-quarter performance.

A summary of our 2022 guidance is located on slides 9 through 11. We've increased our full-year 2022 Adjusted EBITDA guidance by $75 million to plus or minus $2.275 billion. The increase is driven by several factors including the benefit of improved frac spreads and volumes in our NGL business and improvements in our crude oil segment, including increased volumes benefitting our Permian system as well as higher pricing on pipeline loss allowance barrels, partially offset by reduced merchant opportunities.

As detailed in our earnings release, we reached agreements in principle to settle two class action lawsuits regarding Line 901 and recorded an $85 million increase in our net expense associated with the Line 901 incident, which has been treated as a selected item impacting comparability and excluded from Adjusted EBITDA. The first is a class action lawsuit pending in federal court in California which is proposed to be settled for $230 million. We believe this will be substantially reimbursed by insurance. The second is a derivative suit pending in Delaware Chancery court, and the proposed settlement includes the payment of approximately $2 million in attorney's fees and other non-financial terms. More information regarding the settlement of these matters and the changes to our Line 901 accruals is set forth in the Line 901 update included in the earnings press release.

An overview of our current financial profile is provided on slide 12. We remain focused on generating significant Free Cash Flow and allocating it through a balanced approach that reflects a continued focus on debt reduction in the near-term. For 2022, excluding the anticipated impacts of the Line 901 settlement and our estimate of timing of the insurance reimbursement, our Free Cash Flow guidance is relatively unchanged. Giving effect to this timing, we have reduced our guidance by $150 million. Importantly, the impact is expected to reverse over the next 12 months and our year-end 2022 leverage guidance remains at plus or minus 4.25 times. Accordingly, we are maintaining the amount of cash available to be allocated to discretionary unit repurchases for 2022 from what we indicated in our February guidance which was approximately $100 million.

Our capital program outlook is unchanged from last quarter and is summarized on Slide 13. We remain committed to capital discipline and expect consolidated 2022 investment capital of plus or minus $330 million and maintenance capital of plus or minus $220 million.

A summary of our capital allocation framework is on slide 14. In the first quarter, we repaid $750 million of Senior Notes and repurchased 2.4 million common units for $25 million leaving up to $75 million available for potential discretionary repurchases over the balance of the year.

Additionally, in response to feedback, we have included several slides in today's appendix which are designed to provide additional detail and improved visibility into our new crude and NGL segments, both from a historical and forward-looking perspective.

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

Willie Chiang:

Thanks, Al. Our business is off to a very positive start in 2022, supported by constructive fundamentals, a favorable commodity price environment and increasing volumes on our Permian JV and long-haul systems. As such, we remain well positioned to continue executing against our 2022 goals as outlined on slide 15.

Before opening the call to Q&A, I'd like to share some comments on our longer-term outlook and on how we have positioned ourselves for 2023 and beyond. As I stated earlier, we believe the Permian will be critical to meeting increasing global oil demand. Slide 16 shows our Permian production outlook against current takeaway capacity out of the Basin. Our February outlook for production reflected growth of approximately 600,000 barrels per day per year over the next several years, increasing to over 7 million barrels per day by 2025. We currently have a slight positive bias to our production forecast and will update if appropriate later this year. Any meaningful incremental production above the approximately 600,000 barrels per day growth should benefit our systems.

Looking at Permian takeaway, current nameplate capacity is approximately 8 million barrels per day, of which we believe that slightly greater than 7 million barrels per day, or roughly 90%, is efficient operating capacity. As production and long-haul utilization continue to increase, spare capacity will begin tightening and tariffs to the water should return to more normalized levels. In fact, we have begun to see the early innings of this in forward markets as indicated by the Midland to U.S. Gulf Coast spreads to the water doubling in 2023 to approximately $0.80 per barrel, and tripling in 2024 to approximately $1.25 per barrel from today's prompt month of approximately $0.40 per barrel.

My point is, Plains has a critical asset base in a key producing basin, and we have pipe in ground with meaningful available capacity across our system and minimal capital requirements. Our integrated business model and asset base allows us to move energy to multiple markets safely, reliably, and responsibly, and will benefit from any production accelerating beyond our current expectations, whether it be capturing additional growth, or improved long-haul margins from current market levels today.

As illustrated on slide 17, in recent years, we've taken numerous steps to position our business to be successful in any environment. We've strived for operating excellence, improving our safety and environmental metrics greater than 50% since 2017. We've continued to optimize our asset base, completing over $4.5 billion of non-core asset sales and forming greater than 15 strategic joint ventures, most recently forming the Permian gathering JV, a system backed by 4 million long-term, dedicated acres. Furthermore, we have continued investing in our key legacy assets while exercising capital discipline, creating operating leverage throughout the assets with minimal future capital requirements. In our NGL business, we continue to further optimize our facilities and operations through commercial alignment and are evaluating some high-return debottlenecking opportunities.

Financially, we expect to continue generating significant, multi-year Free Cash Flow and achieve our targeted leverage by mid-2023. We have positioned ourselves to continue taking a balanced capital allocation approach, including our commitment to maintaining our Investment Grade rating and increasing overall returns to our equity holders. While we are focused on and expect capital-efficient growth in our business, even at current EBITDA levels, we have a strong distribution coverage of approximately 250%, giving us meaningful capacity for growth in equity returns. In summary, we believe we are well positioned now and into the future.

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

<u>Roy Lamoreaux:</u>

Thanks, Willie. A summary of key takeaways from today's call are provided on slide 18. 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.

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

Looking at Permian takeaway, the current nameplate capacity is approximately 8 million barrels a day, of which, we believe that slightly greater than 7 million barrels a day or roughly 90% is the efficient operating capacity.

As production and long haul utilization continue to increase, spare capacity will begin tightening and tariffs to the water should return to a more normalized level. In fact, we've begun to see the early innings of this in forward markets, as indicated by the Midland to U.S. Gulf Coast spreads to the water doubling in 2023 to approximately $0.80 a barrel and tripling in 2024 to approximately $1.25 per barrel from today's prompt month of approximately $0.40 a barrel. So my point is, Plains has a critical asset base in a key producing basin, and we have pipe in the ground with meaningful available capacity across our system with minimal CapEx requirements.

Our integrated business model and asset base allows us to move energy to multiple markets safely, reliably and responsibly and will benefit from any production accelerating beyond our current expectations, whether it's capturing additional growth or improved long-haul margins from current market levels today. As illustrated on Slide 17, in recent years, we've taken numerous steps to position our business to be successful in any environment. We've strived for operating excellence, improving our safety and environmental metrics greater than 50% since 2017. We've continued to optimize our asset base, focused our business by completing over $4.5 billion of noncore asset sales and created additional alignment through 15 JV, strategic joint ventures, and most recently, forming the Permian gathering JV, which is a system backed by 4 million long-term dedicated acres.

Furthermore, we have continued investing in our key legacy assets while exercising capital discipline, creating operating leverage throughout the assets with minimal future capital requirements. In our NGL business, we continue to further optimize our facilities and operations through commercial alignment and are evaluating some high-return debottlenecking opportunities.

Financially, we expect to continue generating significant multiyear free cash flow and achieve our targeted leverage by 2023 -- mid-2023. We have positioned ourselves to continue taking a balanced capital allocation approach, including our commitment to maintaining our investment-grade rating and increasing overall returns to our equity holders. While we are focused on and expect capital-efficient growth in our business, even at current EBITDA levels, we have a strong distribution coverage of approximately 250%, giving us meaningful capacity for growth and equity returns. In summary, we believe we are well-positioned now and into the future.

So with that, I'll turn the call over to Roy.

Roy I. Lamoreaux - *Plains All American Pipeline, L.P. - VP of IR, Communications & Government Relations - Plains All American GP LLC*

Thanks, Willie. A summary of the key takeaways from today's call are provided on Slide 18. (Operator Instructions). This will allow us to address the top questions from as many participants as tracked in our available time this afternoon. Additionally, our Investor Relations team plans to be available throughout the week to address additional questions. Chino, we're now ready to open the call for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). First question comes from the line of Jeremy Tonet from JPMorgan.

Jeremy Bryan Tonet - *JPMorgan Chase & Co, Research Division - Senior Analyst*

Just wanted to start off, I guess, with Oryx a bit more. and kind of how the integration is going there? And do you see, I guess, the integration leading to new commercial opportunities? Or just a bit more color, I guess, on progress there would be helpful.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Jeremy? Why don't you cover that?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Thanks, Jeremy, for the question. This is Jeremy Goebel. Look, so based on when we formed the JV, it's outperforming expectations just from an activity standpoint as well as from a synergy capture standpoint, where -- if we had to approximate today, it's roughly 10% ahead of schedule. We are getting closer to finalizing the integration process, but we do see more opportunities, but we're making sure we're operating safely and efficiently and providing customer service.

We're actively in engagement with extending contracts with customers. I'd say it's going certainly as well, but I would dare to say better than planned and we'd expect to continue to grow that position. Customers are excited about it. It offers more service, as we talked about, more connectivity and optionality. So I think it's borne out to be good for the shareholders of the JV as well as the customers, and we'll look to continue to prove ourselves to the customers and growth business.

Jeremy Bryan Tonet - *JPMorgan Chase & Co, Research Division - Senior Analyst*

Got it. that's very helpful there. And then kind of pivoting towards, I guess, energy evolution opportunities. You talked about the hydrogen storage opportunity there. And just wondering, I guess, how deep do you see the opportunity set at this point? What's the path forward, I guess, with that to figuring out whether that's something real? And I guess, could there be other hydrogen or other energy evolution opportunities with converting existing assets?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Jeremy, this is Willie. Let me make a couple of comments, and then I know Chris will talk specifically about the hydrogen opportunity. As we've articulated before, we've got a pretty broad asset base and the focus on emerging technologies is how do we integrate that in with our existing assets, particularly around our areas of competency as well as our asset base. So when we think about things, it's how do you connect it in with the existing systems we have. Chris, can you cover the hydrogen piece?

Christopher R. Chandler - *Plains All American Pipeline, L.P. - Executive VP & COO of Plains All American GP LLC*

Yes, sure. This is Chris Chandler. What's exciting about hydrogen for this particular opportunity is it can be used as a means to store renewable energy. And the concept there is when there's excess renewable energy, you can use that to create hydrogen. And obviously, you can store hydrogen, in our case, in underground salt caverns. It's a well-proven technology. It's been done across the industry for decades.

In our case, our Windsor facility sits right next door adjacent to the Ontario Power Station that Atura has today. And we could repurpose existing caverns or develop new caverns very cost efficiently to be able to store hydrogen. And then in the middle of the night when the sun isn't shining or the wind isn't blowing, that hydrogen can be used to generate power with existing power generation assets like gas turbines or boilers. So we're evaluating that particular opportunity in Ontario, but that technology can be applied everywhere. And the Canadian government certainly interested in it in areas beyond just that particular location. And with our storage position across Canada, we see multiple opportunities for similar technology adoption.

Operator

Next one on the queue is Michael Blum from Wells Fargo.

Michael Jacob Blum - *Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst*

So I wanted to ask first about volumes or production growth. Obviously, the public E&Ps, it seems they're staying on message in terms of capital discipline. But you and many of your midstream peers are talking about seeing higher volumes across your systems now and also into the rest of the year and beyond. So just wanted to try to reconcile that. And are you seeing any change in producer activity or messaging?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Jeremy?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Michael, this is Jeremy Goebel. What I would say is it's consistent with what we stated in the first quarter. You saw volumes surge in the fourth quarter of last year than December, January were somewhat soft, somewhat due to weather, somewhat due to slower completions. We've seen that cadence increase as you exit the first quarter and into the second. And it's largely driven by private operators, integrated, but the independents are talking about total production profile. So they are declining in other areas and growing in the Permian.

So Permian as a whole is consistent, other basins are consistent with where we had them. But by and large, based on what we see across the basin, we're seeing it trend in line to slightly above, as Willie said. And the producer mix is that's consistent with what we thought. And we see roughly half the activity within the basin on dedicated acres that Willie was talking about. So that gives us pretty good insight. So far, it's tracking.

I'd say the things we're watching are labor and manpower. Natural gas takeaway seems to be getting solved. So there are some governors on growth, but so far so good. And we look -- like Willie said, we have a positive bias that some activity probably gets brought from the beginning of next year to the fourth quarter, given the higher prices at this level versus where they were expected when they came into the year.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

And Michael, the only thing I would add is, as Jeremy talked about, you might pull some barrels in, that the lag of additional activity is going to be back-end loaded, but the most important piece is momentum into 2023.

Michael Jacob Blum - *Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst*

Got it. Other question I just wanted to ask was about the guidance, specifically the NGL segment. Just if you could just talk through the drivers there a little bit? Just wanted to make sure I understood how much of that is volume driven versus spreads. So...

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

So Michael, we've actually put some additional disclosure in the back as a result of some feedback -- number of feedback we got. And I think what I'd like to do is ask Jeremy Goebel to walk through 2 slides there, which I think are 1 or 2 slides to kind of give you the perspective of how we look at the business, and that may answer your question. Jeremy?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Sure, Michael. If everybody can flip to Slide 27, it's just an overview of the assets. I think the first thing that we see in general as we move NGLs west to east, we gather in the Fort Sask, which is near Edmonton on the far West. So we aggregate third-party supply, we fractionate, store and transport for them to market. That's part of the third-party business. We actually buy some additional Y-grade as well as gather some Y-grade from Cochrane and we move that east for further fractionation at Sarnia.

At Empress, which is the next dot over, we extract -- that's our largest straddle plant. We pull NGLs out in annual keep whole contracts and basically take the Y-grade NGLs in exchange for keeping whole on AECO gas, will fractionate some there and sell into local markets on that PPTC pipeline or will move further east to Sarnia for further fractionation in sale. So that's how it flows.

So when we talk about third-party business, a lot of that's around the Fort Sask in Windsor and St. Clair, those would be 2 of the bigger locations for third party. And then when we talk about Empress, and part of that Cochrane straddle, that's where we get the Y-grade that -- on the keep whole contract.

So if you could then flip to Slide 30. If you look at Slide 30, this gives you a sense for the breakdown. So that fee-for-service business around the storage assets in the East and around the fractionation, storage and transport assets in the West, that's at 35%. The remaining 65% is associated with roughly 50,000 barrels a day of straddle. And think of that as roughly 2/3 at Empress and 1/3 coming off the Cochrane plant. So that's the main driver. So that 65% associated with the straddle, it's the keep whole construct and then the rest is the fee-for-service business.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Michael, does that help?

Michael Jacob Blum - *Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst*

Yes, very helpful.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

And there's some additional information there on Slide 31 that will give you kind of the hedge profile that we've had. And so I think it will allow folks to better understand our business.

Operator

Next one on the queue is Jean Ann Salisbury from Bernstein.

Jean Ann Salisbury - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Analyst*

I really appreciate the extra slides that you've added. I wanted to ask about Slide 16 with your Permian growth and takeaway chart. Can you kind of talk about what you mean by efficient operating capacity within 90%? Is that kind of your number with no drag-reducing agents or something else?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Essentially, it is. As you start getting into the higher flow rates on the pipelines, you start to get less efficient. So certainly, if you go back in time and you look at the 2014, in the earlier periods, there were times when the arbitrage opportunity was very, very significant and people utilized that capacity. A more normal efficiency point would be roughly 90%.

Jean Ann Salisbury - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Analyst*

Okay. So would you say that it's fair that if -- people's concern, I guess, is just maintaining the rates that you have now, the 7 million barrels a day of kind of the right target versus production?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Well, what's shown on that is we haven't updated our guidance on production. It's still roughly 600,000 barrels a day per year with -- as we pointed out, some -- our expectation for an upward bias. There are others out there that have higher production profiles than we do, and that's what's shown in the upside sensitivity. And the way, Jean Ann, I would think about this slide is there was a view that it's hard for us to participate in any of the growth. And what this is intended to show is that as growth increases, we clearly will get the benefit of that in our gathering systems as well as other systems.

So that definitely allows us to participate in the volume growth. And then the other component of that is, as the utilization increases, we would expect that the arbitrage, as the forward market of -- my comments earlier, it starts to widen back out and get back to, what I would call, more -- a more normalized environment. So -- and then we would obviously benefit from that as we go forward with spot rates.

Jean Ann Salisbury - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Analyst*

Yes. That makes sense. And I guess just as a follow-up on that, are you seeing any interest here and from customers on blending and extending contracts? And I guess, similarly, are you interested here in blending and extending?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Jeremy, why don't you talk about?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Jean Ann, this is Jeremy. I'd say it's a combination of things. We are in active discussions and filling spot space at market rates on shorter-term deals. So through next year, most of our spot capacity is taken to the Gulf Coast at current rates or higher. And the expectation is to keep it in shorter rates and then enter those dialogues when we get closer to what we view those normalized rates. So we -- right now is not the time to enter into long-term deals.

We're doing some, but it's -- they're a step to match what the current market looks. So we're not locking in the $0.40 tariffs for anything other than month-to-month. It's those $0.80-plus that you do maybe a year, and then you look to some that may be step up to that $1.25 level. But when we -- when you talk about blend and extend on some of our larger contracts, I think patience on both us and the operator, they're very comfortable with us on the gathering side. So we continue to extend those agreements to align for the longer term.

So we're very comfortable that we'll have the volume on the system and the customers on the system. It's just a matter of timing. And like we said, they're very happy with the arrangements we have today, and we look to extend those when we're both aligned on that, but it's probably a next year thing than before it is today. That way, they can make sure they get the space, and we can make sure we have a constructive dialogue around aligning on longer-term rates.

Operator

Next one on the queue is Neil (inaudible) from Bank of America.

Unidentified Analyst

Just a follow-up on Slide 16 as well. Very useful. It looks like in 2025 is -- with the upside case, you're at that 90% utilization and you hit that normalized rate. Any color on what that normalized rate is? I know you talked about the 2024 rate being about $1.25 with the forward curve. But when you head up against that 90% or more, what do you expect that the rate should be?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Yes, Neil, this is Willie. So one of the purposes of us showing this is I don't think it's a binary equation where you hit a certain point and you achieve a different tariff rate. What we've typically seen is as you start ramping up and capacity gets tighter, you'll start to see an increase. You don't have to get to the 90% before you start seeing the increase. And then ultimately, when you think about what a tariff rate might be, it really is going to be set by what the incremental -- if you were to build a new pipeline, what that would cost. And we expect that to be higher than perhaps it has been in the past. The last round of pipes were built in 2019. And as you go forward, and you have to build new pipes, one could argue that with maybe some supply chain issues and steel costs and permitting issues, it gets more and more challenging. So there might even be some upward price adjustment on what might the tariff be.

Jeremy, do you have anything to add on that?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Yes. No. I think Willie is correct in this assumption. And that's going to be based on term, origin, what other services are offered. So we'd prefer not to speculate on that, but the forward market is indicating a -- something that's getting more healthy and a more constructive dialogue between the carrier and the operator. And the industry is comfortable with this. So we'll provide further guidance on longer-term rates as we get closer. That's our view.

Unidentified Analyst

That's perfect. And just as a follow-up, kind of close to the 900,000 barrels a day that you control of crude, could you walk through maybe some of the ways you're able to capture the commodity upside right now, whether it's blending or being able to control the barrel through long-haul pipes, et cetera? Just maybe what the short-term drivers are for right now?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

There -- we've got a pretty -- we've got a very flexible system. And what I would tell you is the immediate benefits of a higher priced environment is process loss allowance. We have an increased -- it's a higher price capture on that. So that would be something that's very easy to quantify. The other pieces between blending, arbitrage, contango storage really depends on a lot of market issues. So it's hard to point out specific things that we might be capturing other than point out that over a long period of time when the opportunities are there, we are -- we have a whole organization that focuses on being able to capture those opportunities. Jeremy, anything to add?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Yes. I'd say the other piece that's out of that is just from an activity standpoint with long-term dedications, more activity, yields more tariffs. So it's additional tariffs, higher PLA capture. On the NGL business, obviously, the frac spread exposure is there. We have those long-term dedications, also have the tariff escalators. So it's -- there's a number of functions that capture that. Now that's offset to some extent by cost on the operations side, if you have a large capital budget, there's additional cost there. But having a smaller capital budget where some of it is insulated. So I agree completely with Willie, those are just a couple of supplemental ways that we do benefit from inflation or higher prices.

Operator

Next on the line is Brian Reynolds from UBS.

Brian Patrick Reynolds - *UBS Investment Bank, Research Division - Analyst*

Maybe just a follow-up on a quick guidance question. The $75 million guidance raise. Just kind of curious, is it really just relates to -- Permian crude gathering volumes in the NGL segment with roughly no change in the long haul in terms of just EBITDA contribution?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

I'm going to let Al talk about that, but there is a component in that. We were able to get some additional long-haul, shorter-term contracts done that added to our guidance number. So the point I would make there is to reinforce what I just said earlier, it's -- sometimes you can't -- it's not a formula that you can look at if the opportunities are there, and it makes sense for the different partners. We've been able to add some short-term long-haul components in there. But you're right, it's volumes in NGL, volumes in crude as well as pricing impacts both on PLA and frac spreads. Al, anything to add?

Al P. Swanson - *Plains All American Pipeline, L.P. - Executive VP & CFO of Plains All American GP LLC*

Yes. No, you covered it. I think you summarized it, so the NGL's more commodity-based crude had positive PLA pricing, positive volumes, partially offset by just lower merchant opportunities primarily up in Canada.

Brian Patrick Reynolds - *UBS Investment Bank, Research Division - Analyst*

Great. I appreciate the color. And then maybe just to dive a little bit deeper into the long-haul segment. It appears that you're receiving roughly 45,000 barrels per day of deficiency payments in your guidance for 2022. But it looks like we saw a 45,000 barrel per day upward revision in the long-haul volumes with the updated guidance. On the last call, you talked about kind of anywhere from 1.5 years to 2 years for the Permian to kind of soke up those excess spot barrels and with the Wink-to-Webster ramp, et cetera. I was curious, just based off of the guidance update with matching that 45,000 to 45,000 for the 2022 guidance whether that was potentially pulled forward so maybe a 1Q '23 benefits where we could get above those MBC levels as it relates to Plains?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Brian, if I understand your question, trying to match up the barrels for barrels. I think the key point on the long haul barrels is those are additional volumes we were able to capture. It isn't tied with a shifting of volumes anywhere, if that helps to answer your question.

Brian Patrick Reynolds - *UBS Investment Bank, Research Division - Analyst*

So as it relates to potential earnings inflection is kind of cadence the same as the last call kind of still middle of next year to end of next year based off of just the Permian production outlook in terms of getting above MBCs?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Well, if I understand your question, it's -- what we're trying to show with 16 is that regardless of the MBCs, there's opportunities to capture additional volumes. So clearly, on our Permian gathering -- on the Permian gathering sector, we've got an additional capture on the slides of another 30,000 barrels a day versus what we had in February, which totals 280,000 barrels a day in the gathering system, right? So that's a piece of growth that we are capturing. And then the other opportunities are opportunities that we'll catch when the opportunities present themselves.

So the key point, I don't want people to walk away with this that until MBCs fill up, there's no opportunities for Plains to capture additional volumes, right? That's part of our guidance and -- guidance upgrade is additional volumes we have been able to catch. The comment that was made in the fourth quarter call was if you think about it just mathematically, you've got additional MBCs coming on. And if you were to mathematically match an additional production volume, that would be the theoretical number, but there's always opportunities out there to capture additional barrels.

Operator

Next one on the queue is Rebecca Followill from U.S. Capital Advisors.

Rebecca Gill Followill - *U.S. Capital Advisors LLC, Research Division - Senior MD & Head of Research*

Just a lot going on this afternoon. So if you could just clarify again on the $150 million decrease in free cash flow. How much of that was working capital? And how much of that was Line 901?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Al?

Al P. Swanson - *Plains All American Pipeline, L.P. - Executive VP & CFO of Plains All American GP LLC*

Primarily, we assumed and modeled it as Line 901. We believe there will be timing between the time we pay and the time we're ultimately reimbursed by insurance. We are assuming some increased working capital roughly offset by the stronger performance that we're modeling in the company.

Rebecca Gill Followill - *U.S. Capital Advisors LLC, Research Division - Senior MD & Head of Research*

Perfect. The return of the insurance payments that's this year or does that bleed into 2023?

Al P. Swanson - *Plains All American Pipeline, L.P. - Executive VP & CFO of Plains All American GP LLC*

No, that is -- we're assuming some of the collections will straddle into 2023. So in theory, there will be a higher -- our free cash flow will benefit in 2023 due to the timing.

Operator

Next question comes from the line of Sunil Sibal from Seaport Global Securities.

Sunil K. Sibal - *Seaport Global Securities LLC - MD & Senior Energy Infrastructure Analyst*

I just wanted to go back to the Slide 30 again for a couple of seconds. So between the February guidance and your current guidance, between the 3 components of the pie chart, have you been able to hedge at better rates than you were hedging in February? Or is it just the view because the unhedged prices have moved up, you're getting a significant upside?

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Jeremy?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Sunil, this is Jeremy Goebel. I would say it's a combination of the two. We actively monitor it. When we see prices spike, we might layer in some additional hedges. But coming into this year, the hedges -- the most recent hedges are at higher rates, and we've had additional volume, as Willie said. So part of the outperformance is order flows from Western Canada to the Eastern markets have been higher. So we extract additional NGLs, and that's all at the spot rates. So those sales will be this year or next year, some combinations. So it's volume -- it's a combination of incremental volume at unhedged levels, securing some additional hedges at higher prices and then capturing the higher prices on the unhedged component, which is roughly 20% for the remainder of the year.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

And Sunil, just to make sure, we -- the predominant amount of 2022 frac spreads is hedged.

Sunil K. Sibal - *Seaport Global Securities LLC - MD & Senior Energy Infrastructure Analyst*

Okay. And then kind of a follow-up to that. Is the market deep enough for you to hedge '23 also? Or is that mostly unhedged?

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Sunil, this is Jeremy again. We actively monitor. Think of it as a rolling program. So we have an active 2023. And once again, we're opportunistic around when they do that. We'll provide further guidance as we get into '23, but it's -- we manage it as an operation and manage earnings associated, and we're trying to capture higher levels as well. So we'll continue to update you on that, but we -- there is a deep enough market. And it's very thin in '24, but '23 is pretty active.

Sunil K. Sibal - *Seaport Global Securities LLC - MD & Senior Energy Infrastructure Analyst*

Got it. And then lastly, could you remind us on the process loss allowance? How much is typically the bps you get on the volumes that you move as PLA? Or is there any other good way to think about that margin sensitivity?

Unidentified Company Representative

It's 3 million barrels.

Jeremy L. Goebel - *Plains All American Pipeline, L.P. - Executive VP & Chief Commercial Officer of Plains All American GP LLC*

Yes. It's substantial. It's 2 million to 3 million barrels a year associated with PLA depending upon operating performance, and we continue to optimize around that. So it's a big footprint. That's predominantly in the U.S. where we do collect that, but it's substantial.

Operator

And there are no further questions in queue. I will now turn the call over back to the presenters.

Wilfred C.W. Chiang - *Plains GP Holdings, L.P. - Chairman & CEO of PAA GP Holdings LLC*

Yes. So this is Willie. I'll just close with thank you for your participation on the call. I know there's a lot going on. We've appreciated the feedback. We've had many discussions with folks, and as always, we're trying to further improve our disclosure and transparency and how we run the business. And I do know that as we've changed our segments, there's an opportunity to continue to make improvements. So I appreciate the support and feedback, and we'll look forward to updating you as we go forward. Thank you very much.

Operator

This concludes today's conference call. Thank you for participating. You may now disconnect.

1Q22 Earnings Call

May 4, 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.

1Q22 Earnings Call Highlights & Outlook

Constructive fundamentals, capturing Permian growth & increasing 2022(G)

Since 4Q21 Call

- Adj. EBITDA[(1)]: $614MM
- Equity Repurchases: $25MM (~$250MM since Nov-20 authorization)
- Increased annualized distribution $0.15/unit

2022 Outlook

- Global events, tight supply & demand driving higher commodity price environment
- Adj. EBITDA(G)[(1)] +/- $2.275B: +$75MM vs. Feb(G)
- Expect +/- 280 mb/d of Permian gathering growth (YE-21 to YE-22)
- YE-22 leverage[(2)] +/- 4.25x

2022(G) : Furnished May 4, 2022. Feb(G): Furnished February 9, 2022
(1) Attributable to PAA. (2) See Definitions.
Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Levers for Maximizing Unitholder Returns

Crude

- **Capture Permian volume growth with minimal CAPEX (operating leverage)**
  - ✓ Anticipate +/- 600 mb/d/yr. of production growth for next few yrs. & +/- 280 mb/d of gathering system growth (YE-21 to YE-22)
  - ✓ Expect gathering system growth will position for long-haul system growth over time
- **Optimize existing assets (brownfield asset expansion, strategic JVs, etc.)**

NGL

- **Optimize NGL facilities & operations through commercial alignment**
- **Execute high-return, capital-efficient optimization and debottlenecking projects**

Emerging Energy

- **Evaluate capital-efficient opportunities utilizing existing assets**
  - ✓ Announced hydrogen storage MOU with Atura Power, subsidiary of Ontario government
- **Evaluate renewable power / battery utilization opportunities to lower emissions / costs**

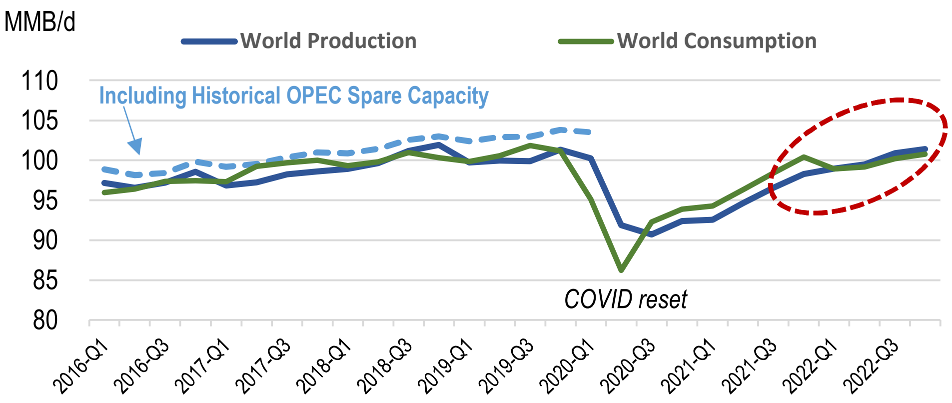
Financial

- **Deliver significant multi-year Free Cash Flow**
- **Achieve midpoint of targeted leverage range by mid-2023 (3.75x – 4.25x)**
- **Increase cash returned to equity holders (significant coverage / FCFaD)**
  - ✓ Increased annualized distribution by $0.15/unit, ~$250MM of repurchases since Nov-2020

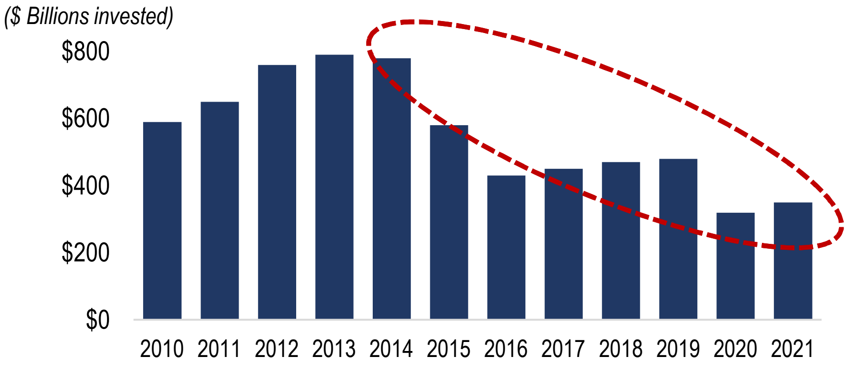
Fundamentals: Increasing Demand, Tighter Oil Balance

North American hydrocarbons are key to meeting global demand

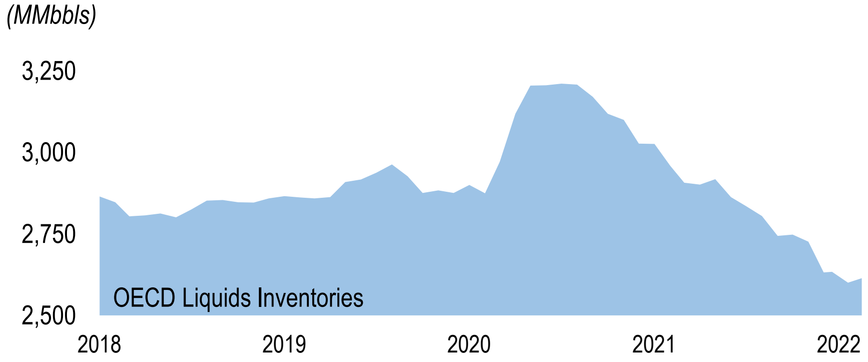
Global Supply & Demand Rebalancing[1]



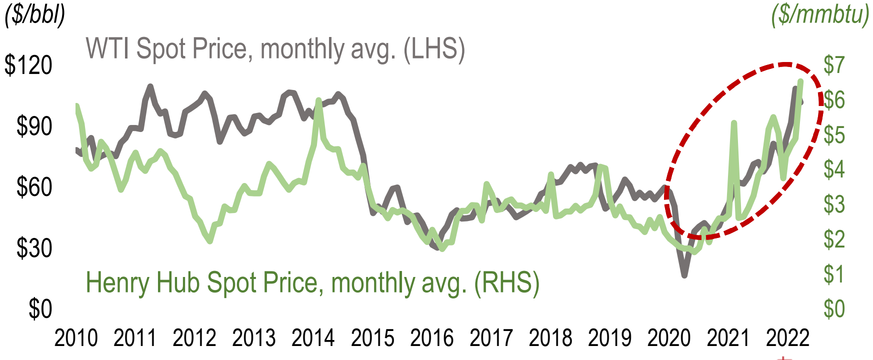
Prolonged Reduction in Upstream Investment[2]



Global Inventories at Multi-Year Lows[1]



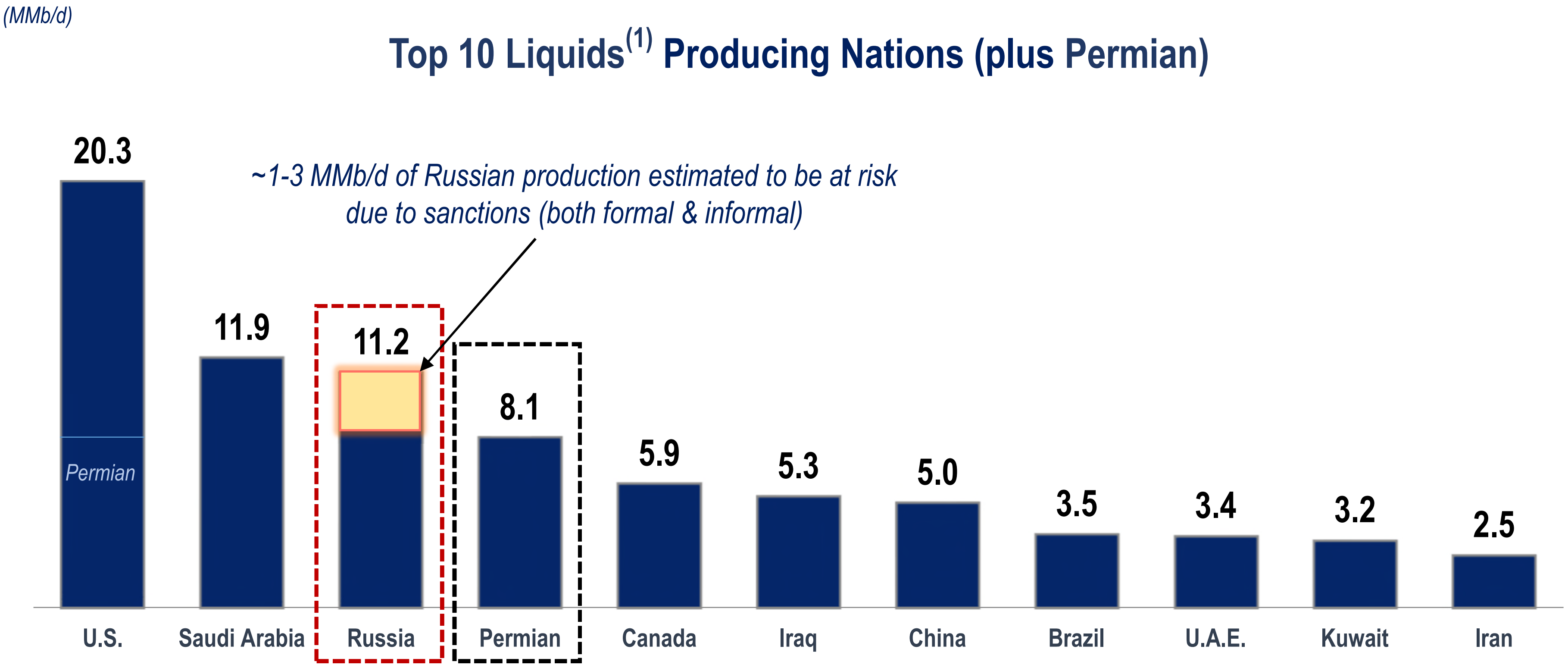
Commodity Prices Responding



(1) EIA April 2022 STEO – includes crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains. (2) IEA & PAA Internal Estimates.

World Needs North American Energy Supply

Permian Basin increasingly critical in supplying global energy markets

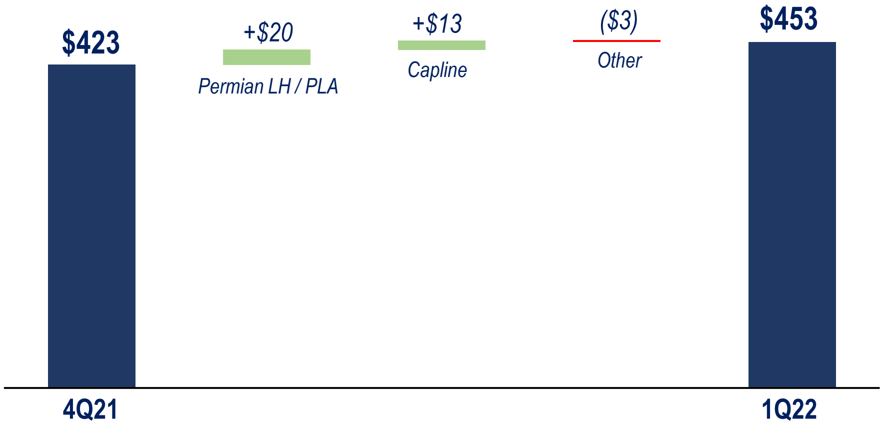


Source: raw data provided by EIA & PAA Estimates.
(1) Liquids includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

Key Drivers: 4Q21 to 1Q22

($ millions)

Crude Oil Segment Adjusted EBITDA



NGL Segment Adjusted EBITDA

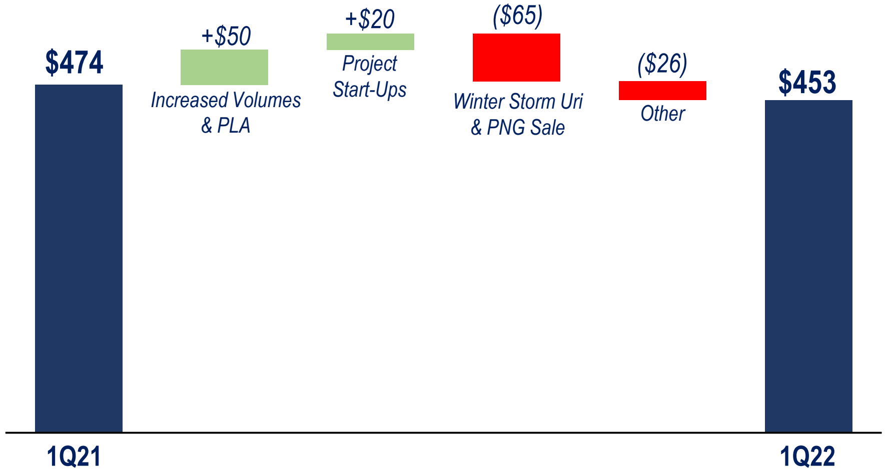
- **Crude Oil Segment**
  - **Permian LH:** deficiency payment and start-up of W2W, partially offset by lower Basin LH volumes
  - **Capline:** start-up of Capline reversal
  - **Other:** less favorable merchant activities partially offset by favorable opex

- **NGL Segment**
  - **Ft. Sask:** incident cost & associated impact to 4Q21
  - **Sales Margin & Volume:** improved frac spread & increased sales volumes

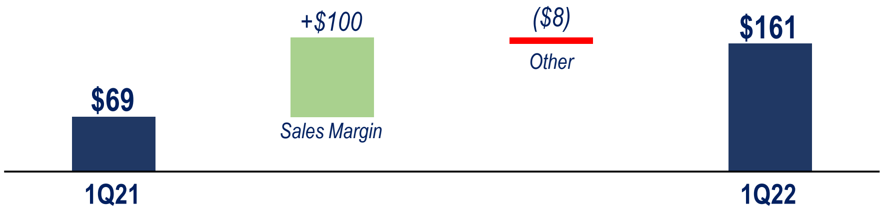
Key Drivers: 1Q21 to 1Q22

($ millions)

Crude Oil Segment Adjusted EBITDA



NGL Segment Adjusted EBITDA



- **Crude Oil Segment**
  - **Increased Volumes & PLA:** higher tariff volumes as a result of increased production, deficiency payments & higher commodity prices
  - **Project Start-Ups:** primarily start-up of Capline & W2W
  - **Winter Storm Uri & PNG Sale:** 1Q21 benefit of power savings & PNG operations
  - **Other:** primarily less favorable merchant activities including 2020 contango opportunities realized in 2021

- **NGL Segment**
  - **Sales Margin:** improved frac spread & sales prices partially offset by lower sales volumes

2022(G): Financial Metrics

Stronger long-term outlook, generating meaningful FCF & coverage, continuing leverage reduction

($ millions, except per-unit metrics)

Adjusted EBITDA / DCF

Segment Adjusted EBITDA	Feb(G) (+/-)	May(G) (+/-)
Crude Oil	$1,820	$1,845
NGL	380	430
Other Income	-	-
Adj. EBITDA attributable to PAA	**$2,200**	**$2,275**
Implied DCF to Common	$1,400[2]	$1,450
Implied DCF / CUE[1]	$2.00[2]	$2.08
Distribution Coverage (Common)	240%[2][3]	250%[3]
Year-End Leverage Ratio[1]	4.25x	4.25x

Cash Flow

	Feb(G) (+/-)	May (G) (+/-)
Cash Flow from Ops (CFFO)[1]	$2,100	$1,950[4]
Asset Sales	$100	$100
FCF[1]	$1,400	$1,250[4]

Capital *(Consistent with Feb(G))*

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

2022(G) / May(G): Furnished May 4, 2022. Feb(G): Furnished February 9, 2022

(1) See Definitions. (2) Reflects change in calculation methodology to deduct Investment Capital of Noncontrolling Interests. (3) Distribution Coverage 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. (4) Reduction in Cash Flow due to timing of insurance settlement & working capital needs; expected to reverse out over next ~12 months.

2022(G): Operational Metrics

Additional volumes added since February Guidance

2022 Operational Guidance

(table data reflects full-year averages)	Feb (G) (+/-)	May (G) (+/-)	Δ
Crude Oil Segment			
Crude Pipeline Volumes (Mb/d)	**7,150[1]**	**7,330[1]**	***+180***
Permian	**5,250[1]**	**5,365[1]**	***+115***
Gathering	2,345[1]	2,375[1]	*+30*
Intra-Basin	1,915[1]	1,955[1]	*+40*
Long-Haul	990	1,035	*+45*
Other	**1,900**	**1,965**	***+65***
Commercial Storage Capacity (mmbbls/mo)	72	72	-
NGL Segment			
NGL Sales (Mb/d)	140	140	-
Fractionation Volumes (Mb/d)	120	125	*+5*

2022(G) / May(G): Furnished May 4, 2022. Feb(G): Furnished February 9, 2022

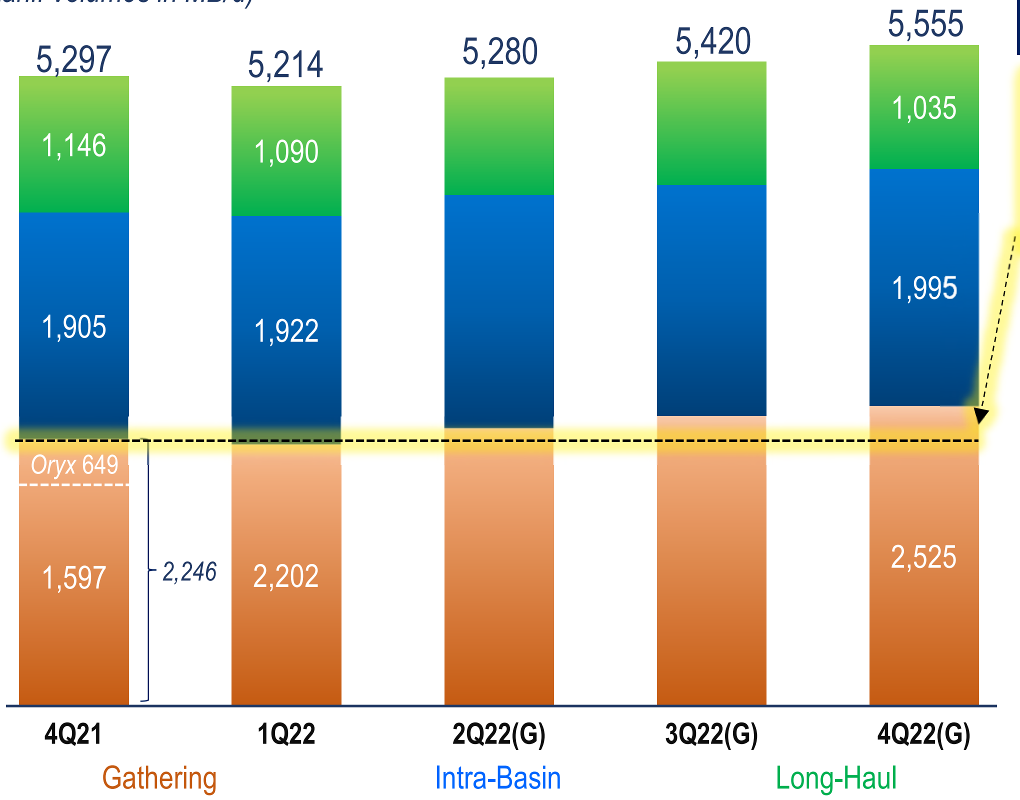
(1) Permian JV volumes on a consolidated (8/8ths) basis. See Definitions.

- **Permian: leveraged to production growth**
  - **2022 FY Avg. May(G) vs. Feb(G)**
    - Increased gathering & intra-basin volumes
    - Incremental short-term long-haul MVCs
- **Other Crude: increases across multiple regions**
- **NGL: increased straddle production driving higher fractionation volumes**

Permian Gathering & Intra-Basin Driving Volume Growth

Underpinned by ~4MM long-term, dedicated acres

(tariff volumes in MB/d)



4Q22(G) vs. 4Q21: ↑260 Mb/d

- **Gathering: ↑ 280 Mb/d**
  - Production growth benefitting Permian JV
- **Intra-Basin: ↑90 Mb/d**
  - Production growth benefitting Permian JV
- **Long-Haul: ↓110 Mb/d**
  - Reflects 4Q21 spot long-haul volumes shifting to long-term contracted W2W volumes (16% ownership)
  - Partially offset by incremental 45 Mb/d of short-term MVCs (vs. Feb(G))

2022(G): Furnished May 4, 2022. Feb(G): Furnished February 9, 2022.
Note: Permian JV volumes on a consolidated (8/8ths) basis. See Definitions.

Current Financial Profile

S&P / Fitch: BBB-, Stable **Moody's: Baa3, Stable**

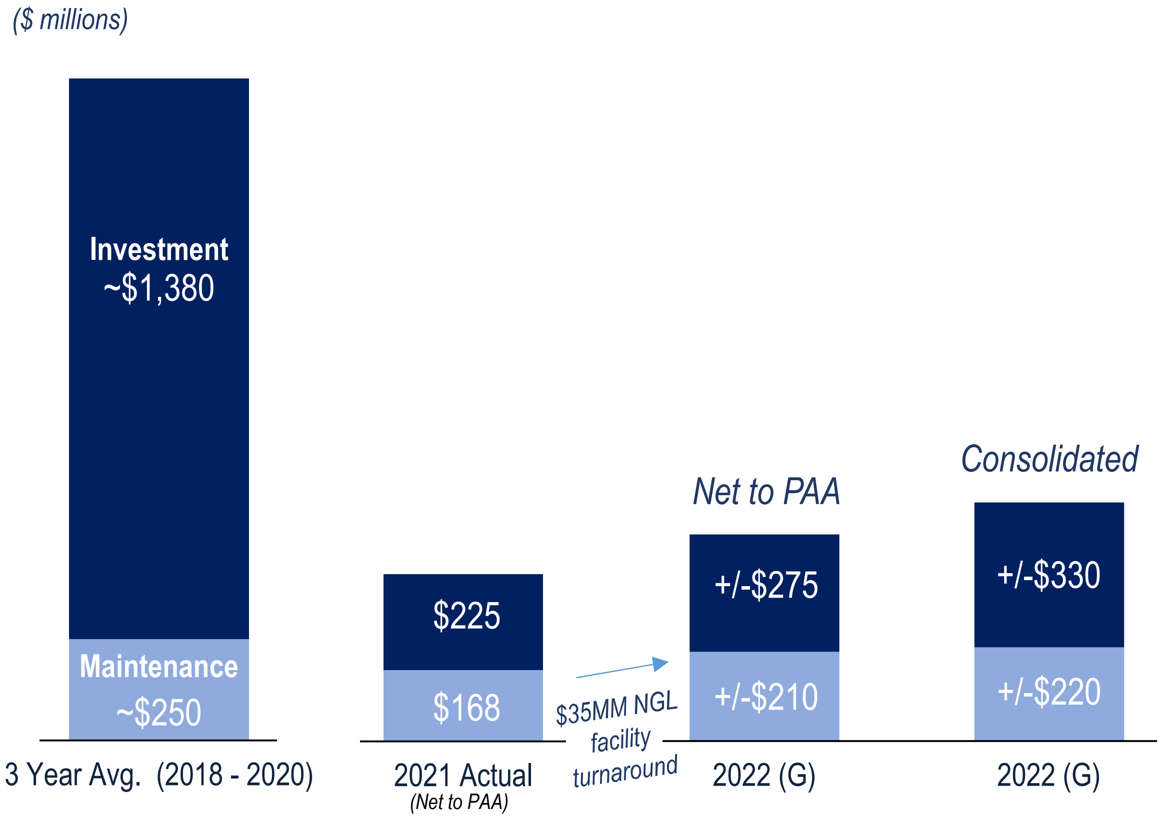
	12/31/21	3/31/22	Target
Cash & Equivalents	$449	$114	
Short-Term Debt	$822	$900	
Long-Term Debt	$8,398	$7,986	
Total Debt	$9,220	$8,886	
Adj. EBITDA (LTM)(1)	$2,196	$2,267	
Credit Stats & Liquidity			**Target**
Leverage Ratio(2)	4.5x	4.4x	3.75x – 4.25x
Committed Liquidity ($ bln)	$3.0	$2.4	

- Retired $750MM Sr. Notes 3/1/22
- Expected YE-22 Leverage Ratio(2): ***+/- 4.25x***

2022(G): Furnished May 4, 2022.
(1) Attributable to PAA. (2) See Definitions.
Note: Please visit https://ir.paalp.com for reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Disciplined Capital Investment

Multi-Year Buildout Complete, Significant Operating Leverage, Focused on High-Return Projects



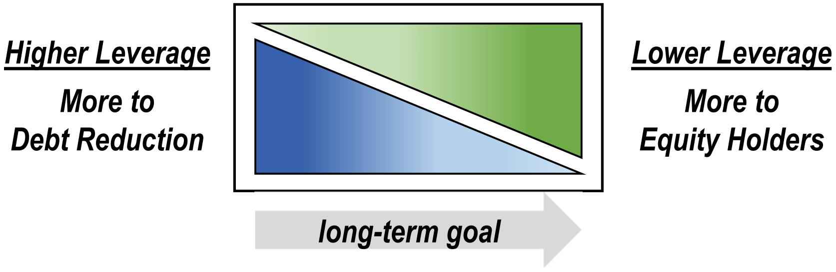
- **2022(G) Investment Capital: $330MM**
  - ~50% Wellhead & CDP Connections (paced w/ producer activity levels)
  - Expect to capture capital synergies through Permian Gathering JV
- **Consolidated Run Rate Maintenance[(1)]: <$200MM**

2022(G) and Run Rate: Furnished May 4, 2022. (1) Average annual estimate: annual amount may be impacted by timing and/or turnaround projects.

Capital Allocation: Continued Debt Reduction While Increasing Returns to Equity Holders Over Time

- Executing 2022 capital allocation priorities
  - Repaid $750MM of Senior Notes
  - Repurchased $25MM of common units (~$250MM since Nov-2020 authorization)
  - Increased annualized common distribution $0.15/unit
- Expect increased equity holder returns as leverage lowers; equity return considerations:
  - ~250% Distribution Coverage illustrates excess cash flow available for capital allocation
  - Business outlook, Leverage (expect to achieve target mid-2023), Valuation / current yield

Capital Allocation Priorities



Equity Returns
Increase Cash Returned to Equity Holders

Disciplined Investments
High Returns

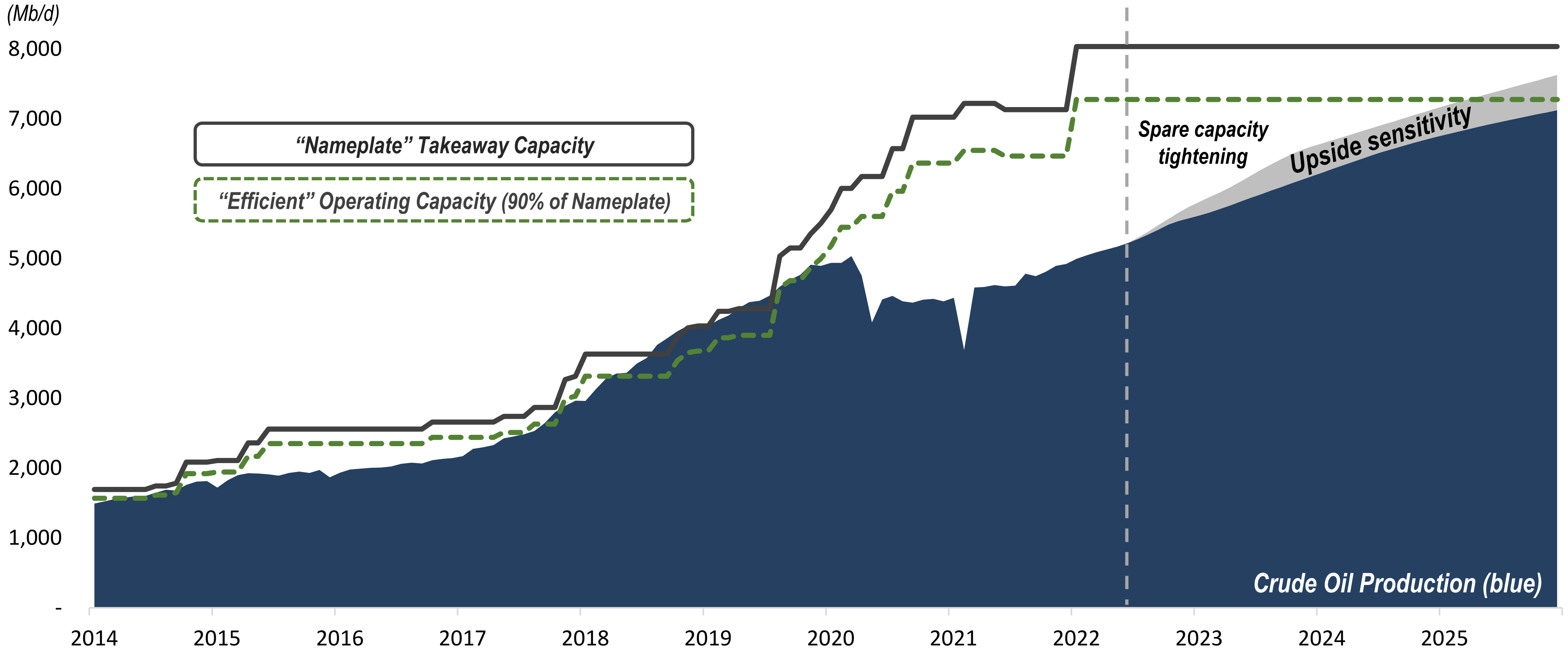
Debt Reduction
Achieve Targeted Leverage

Overview of 2022 Goals

- Run a safe, reliable and responsible operation
- Generate meaningful Free Cash Flow
- Strengthen balance sheet / financial flexibility
- Increase returns to equity holders

Permian Production Growth Driving Increased Utilization

Expect to capture additional volumes & improved long-haul margins



Source: PAA Estimates, Enverus.

Well Positioned for 2023+

Streamlined asset base, stronger balance sheet, meaningful Free Cash Flow generation

Asset Base

- ✓ *Focus on operating excellence*
- ✓ *Fully integrated business model & asset base, from lease to market*
- ✓ *Significant operating leverage, ability to grow with minimal capex*
- ✓ *Permian gathering system anchored by ~4MM acres of long-term dedications*
- ✓ *Opportunities for further optimization & low cost / high-return debottlenecking, as well as further alignment with strategic JV partners*

Balance Sheet

- ✓ *Expect to achieve leverage target mid-2023*
- ✓ *Investment grade balance sheet, substantial coverage & liquidity*
- ✓ *Continued focus on debt reduction & steady EBITDA growth to benefit longer-term leverage*
- ✓ *~$4.5B in cumulative asset sales since 2016*

Capital Allocation

- ✓ *Expect to generate significant Free Cash Flow over next number of years*
- ✓ *Ability to self-fund routine capital program*
- ✓ *Significant capacity to increase returns to equity holders as leverage decreases*

1Q22 Earnings Call Key Takeaways

Constructive fundamentals, capturing Permian growth

- **Solid 1Q22 results and increased 2022 Adj. EBITDA(G)(1) to +/- $2.275B**
- **Global events reinforcing that hydrocarbons / Permian key to global energy security**
- **Capturing meaningful Permian growth with minimal additional capex**
- **Fundamentals constructive, building momentum into 2023+**
- **Positioned to generate significant FCF with meaningful capacity to increase returns to equity holders**

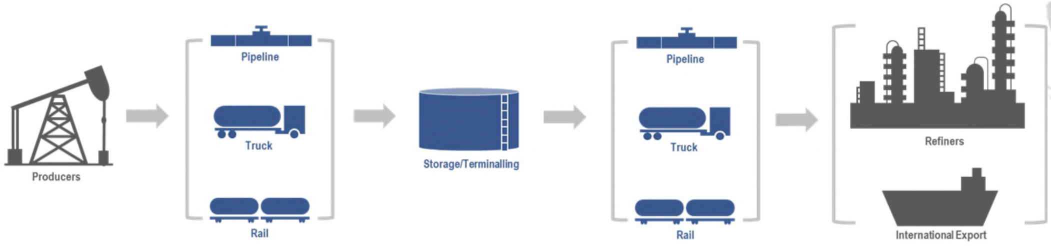
2022(G) : Furnished May 4, 2022.
(1) Attributable to PAA.

Appendix

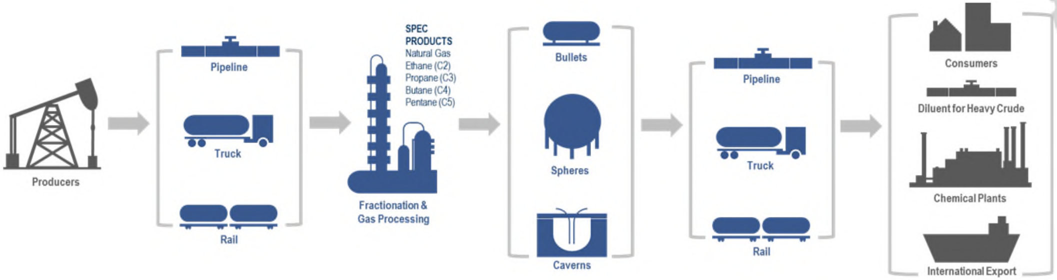
Plains: Critical Infrastructure, Integrated Model

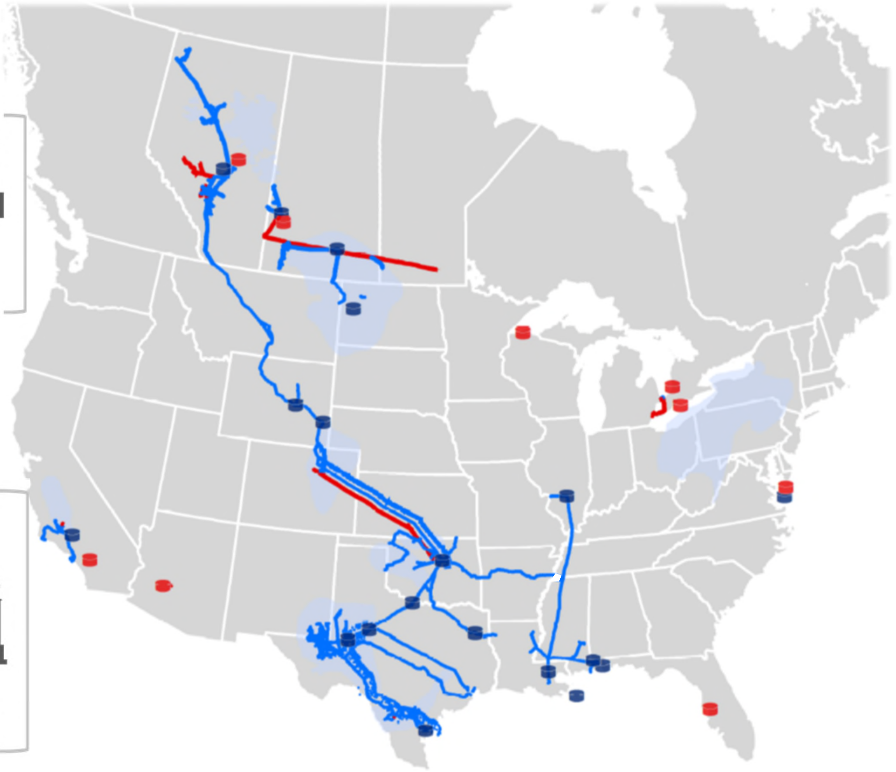
Full-service: supply aggregation, quality segregation, flow assurance, access to multiple markets

Crude Oil Activities



NGL Activities





Crude Oil (blue)
NGL (red)

Overview of Plains' Business

Integrated model across crude & NGL business platforms

Crude Oil Segment *(~80% of 2022(G))*

- ***Assets:*** Pipelines, storage, terminalling & trucks
- ***Commercial Profile:*** long-term minimum volume commitments, acreage dedications, leased capacity & spot utilization
- ***Drivers:*** Demand / production growth, volume throughput

>1 MMb/d
Crude Purchase Volume

~18k
Crude Pipeline Miles

>6 MMb/d
Crude Pipeline Tariff Volume

>110 MMbbls
Crude Storage Capacity

4
Crude Oil Marine Facilities

NGL Segment *(~20% of 2022(G))*

- ***Assets:*** Fractionation, straddle, pipelines, storage, terminalling & rail capacity
- ***Commercial Profile:*** Gathering / fractionation / storage / terminalling services agreements, gas processing / straddle production & merchant activities
- ***Drivers:*** Frac spread, supply volume & regional pricing differentials

>130 Mb/d
NGL Sales

~200 Mb/d
NGL Fractionation Capacity

~6 Bcf/d
Straddle Capacity

~30 MMbbls
NGL Storage Capacity

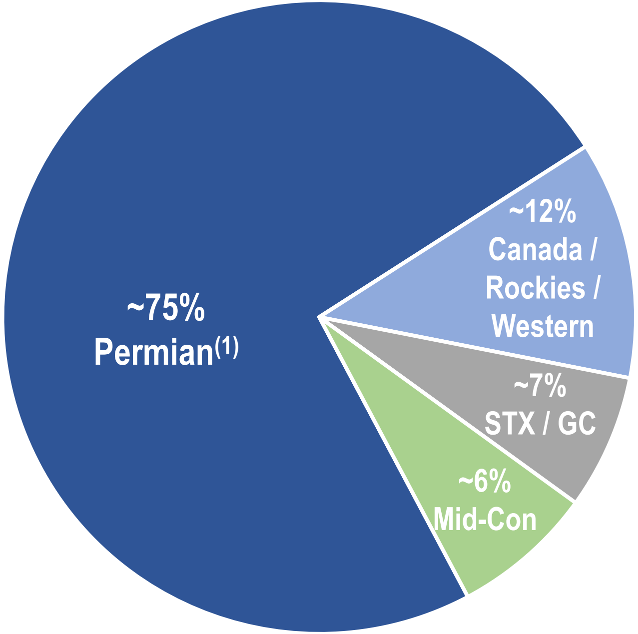
3,900
NGL Rail Cars

2022(G): Segment Adjusted EBITDA furnished May 4, 2022.
Note: Operating & asset-level data as of 12/31/21.

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

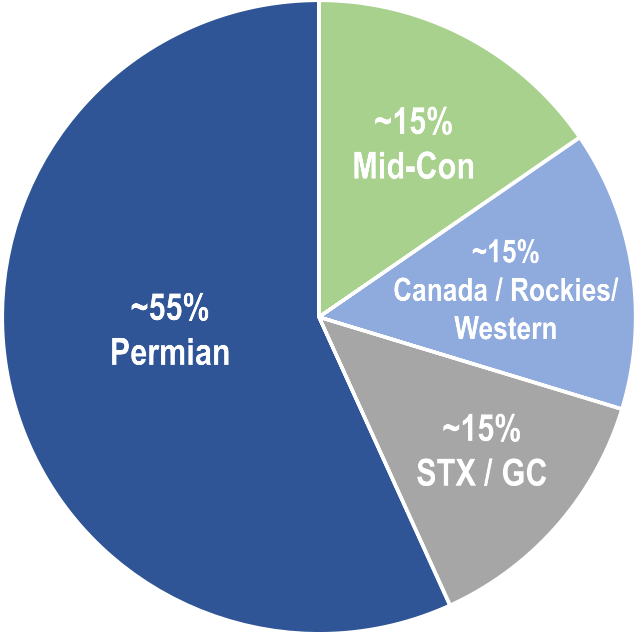
Regional Detail

2022(G): 7,330 Mb/d Pipeline Volumes



2022(G): $1,845MM Adj. EBITDA(2)

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

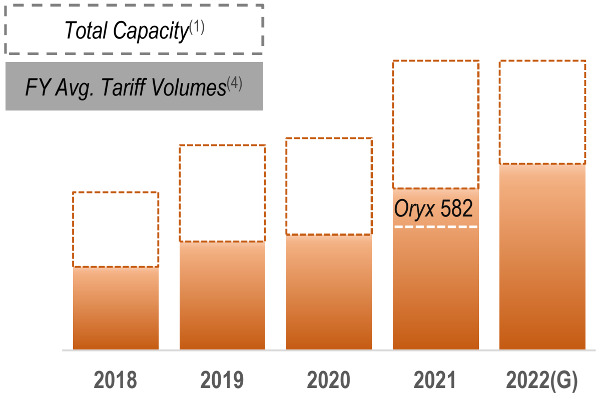


2022(G): Furnished May 4, 2022. (1) Includes consolidated Permian JV volumes. (2) Adj. EBITDA attributable to PAA.
(3) Terminals include Cushing, Patoka, St. James, and Others. Majority of EBITDA associated to terminals in Mid-Con and South Texas / Gulf Coast regions.

Plains' Permian System: Highly Integrated, Substantial Leverage to Permian Growth

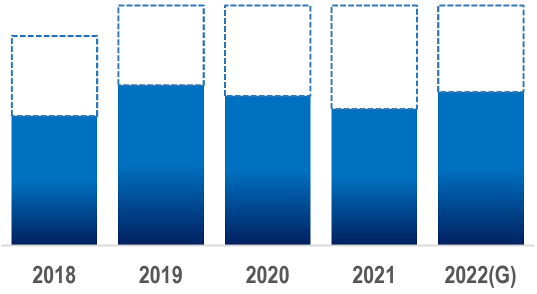
Gathering

- Capacity[1]: ~3.7 MMB/d
- Representative Net Revenue[2]:+/- $0.60 - $1.60/bbl
- 2022(G) FY Tariff Volumes[4]: ~2.4 MMB/d
- ~4MM dedicated acres (>6 yr wtd, avg. term)
- 1st purchase ~1.1 MMB/d, >80% term contracted
- Multi-decade inventory life
- +/- $150MM of run-rate investment capital



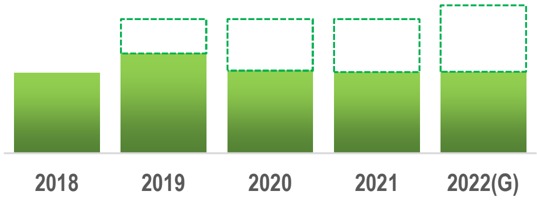
Intra-Basin

- Capacity[1]: ~3.1 MMB/d
- Representative Net Revenue[2]: +/- $0.20 - $0.40/bbl
- 2022(G) FY Tariff Volumes[4]: ~2.0 MMB/d
- Connectivity to key in-basin hubs & long-haul pipelines
- Provides flexibility, optionality & market liquidity
- Minimal future capital requirement



Long-Haul

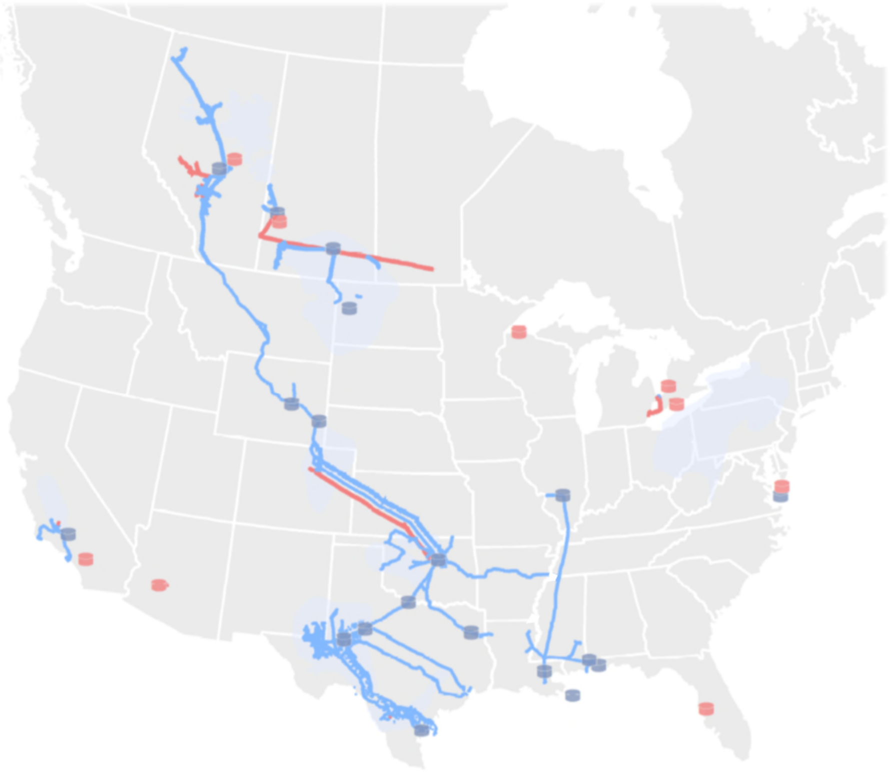
- Capacity[1]: ~1.7 MMB/d
- Representative Net Revenue[2]: +/- $0.45[3] - $2+/bbl
- 2022(G) FY Tariff Volumes[4]: ~1.0 MMB/d
- Supply-push & demand-pull pipelines
- >70% 3rd party contracted[5] (>90% excluding Basin Pipeline)
- ~4.5 yr. avg. remaining contract tenor
- Minimal future capital requirement



(1) Based on YE 2021 nameplate. Long-Haul capacities are net to Plains' interest. Gathering / Intra-Basin capacity utilization dependent upon location of future activity. (2) Representative net revenue / bbl provided as a range; multiple factors can cause to be inside or outside of range. (3) $0.45/bbl represents incentive tariff rate expiring 12/31/22. (4) 2021 & 2022 Gathering and Intra-basin volumes are presented on a consolidated basis (FY21 includes historical Oryx volumes). Long-Haul volumes are net to Plains' interest. (5) Based on 90% of nameplate capacity.

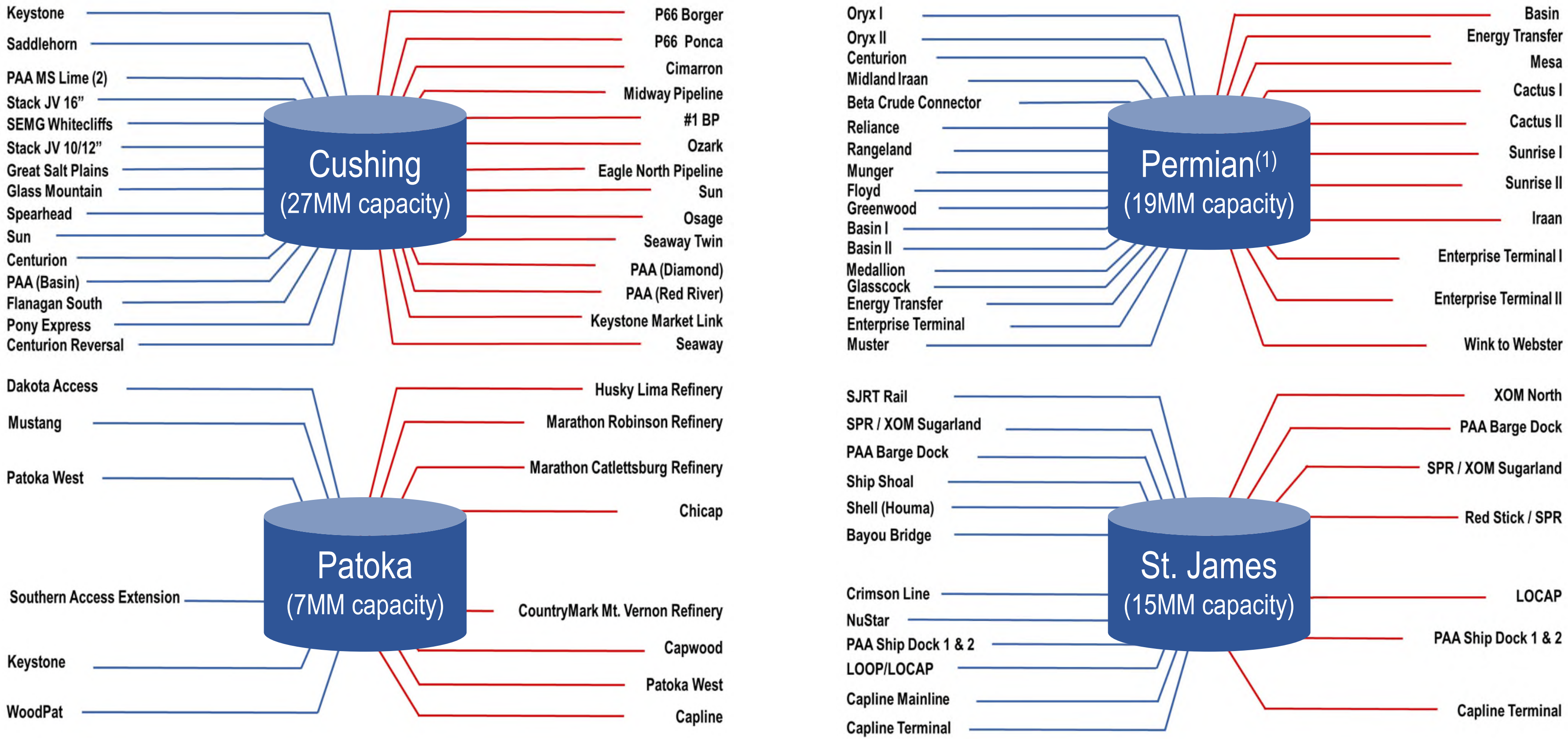
Long-Haul Pipelines Substantially Backed by Long-Term 3rd Party Contractual Commitments

- **Combination of supply-push and demand-pull pipelines**
- **Integrated with Plains' hub terminals at Cushing, Midland, Patoka and St. James**
- **Key long-haul pipes >70% 3rd party contracted(1) with average <u>remaining</u> term of 5-years:**
  - Permian Long-Haul: >70% (>90% excl. Basin); ~4.5 years
  - Rockies to Cushing(2): >60%; >4 years
  - Downstream of Cushing: >70%; ~5 years
- **Further complemented by:**
  - Long-term committed acreage dedicated to Permian gathering systems
  - Term-contracted 1st purchased lease supply



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

Crude Oil Hub Terminals: Leading Demand-Hub Positioning Enables Pipeline & Commercial Opportunities, Strong Connectivity Supports Demand

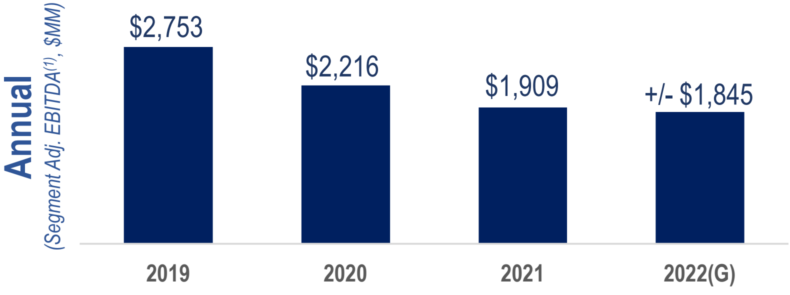


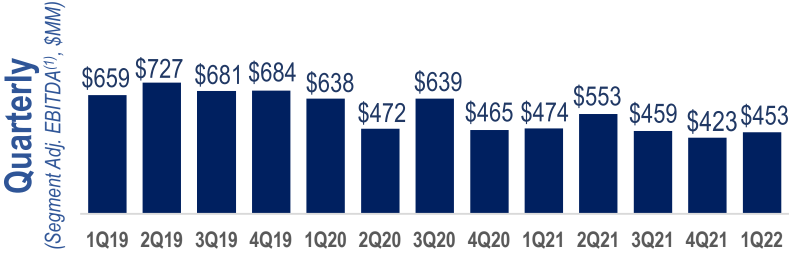
Inbound Pipelines
Outbound Pipelines
(includes direct & indirect connections)

(1) Capacity includes all Permian Area storage; connections only include Midland connectivity.

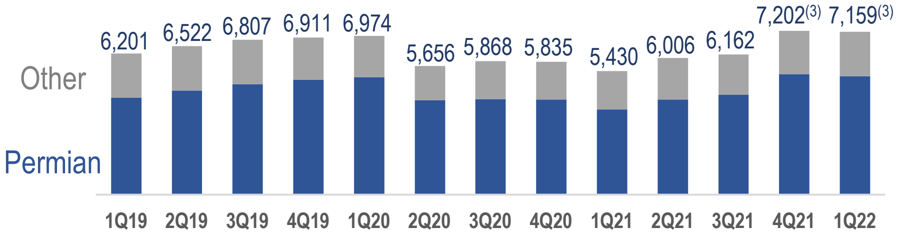
Crude Segment Detailed Data (2019 – 2022)

- **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

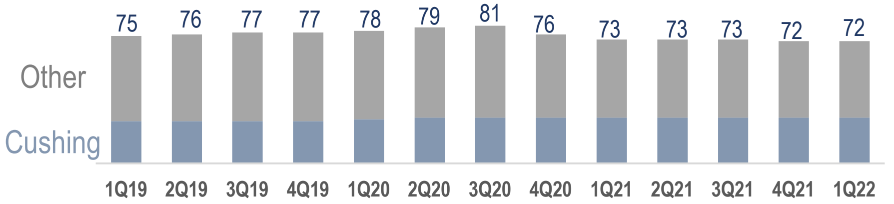




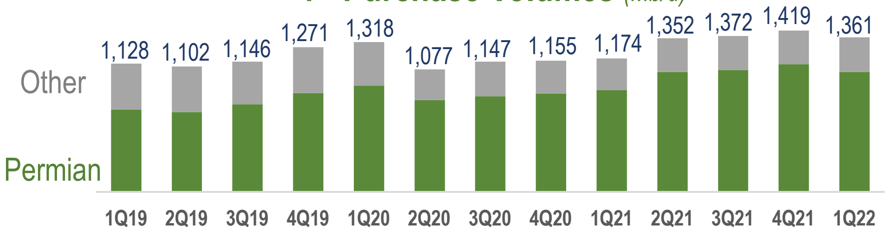
Pipeline Tariff Volumes[2] *(Mb/d)*



Storage Capacity *(MMbbls/mo)*



1st Purchase Volumes *(Mb/d)*



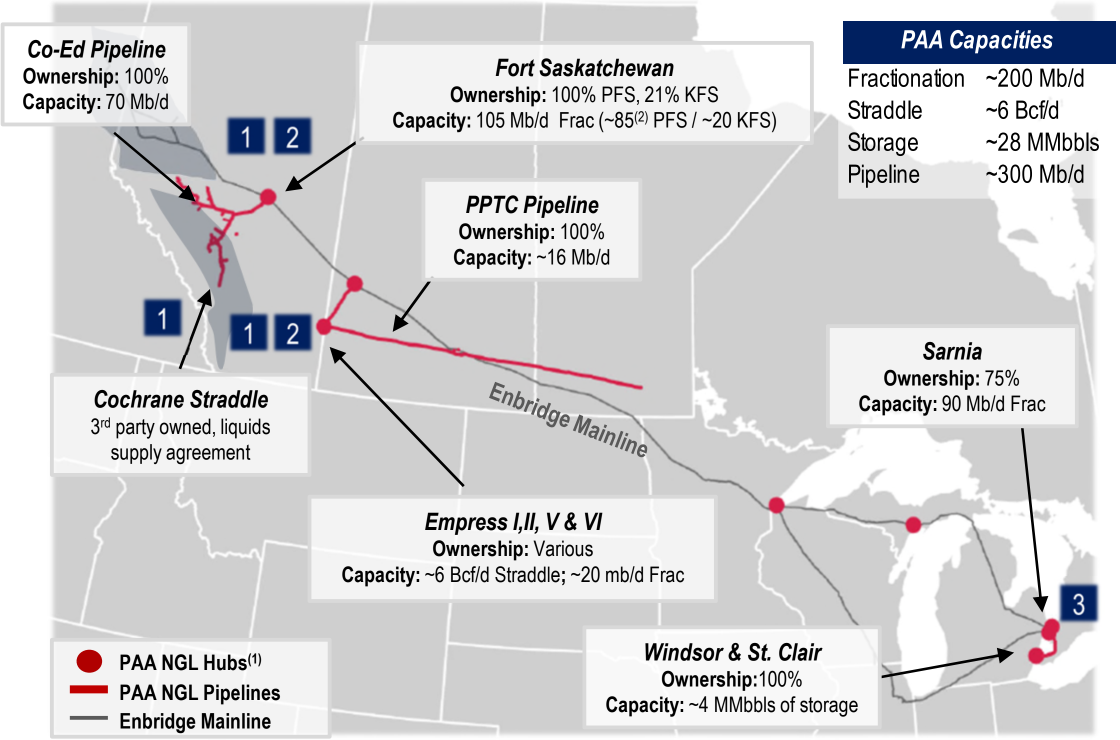
2022(G): Furnished May 4, 2022.
(1) See Definitions. (2) Excludes trucking (3) Includes legacy Oryx volume.

NGL Segment: Highly Integrated & Strategically Positioned Assets

Aggregate, Process, Transport & Sell

Directional Illustration

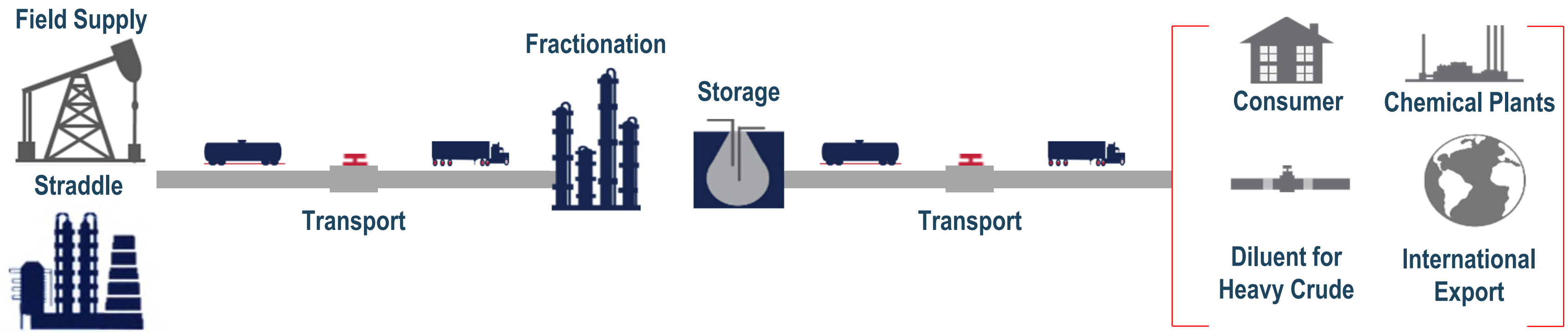
1. Aggregate western Canada field supply & extract / purchase NGL mix at straddles (Empress & Cochrane)
2. Fractionate western supply into component products, sell locally and / or transport raw NGL / mix to downstream markets
3. Fractionate at Sarnia, seasonally store & sell products in peak demand (Winter) months in Ontario / U.S. markets



PAA Capacities	
Fractionation	~200 Mb/d
Straddle	~6 Bcf/d
Storage	~28 MMbbls
Pipeline	~300 Mb/d

Note: Asset-level data as of 12/31/21.
(1) Not all PAA NGL assets included within map. (2) Includes ~45 mb/d of C5+ / Debutanizer capacity.

NGL Business & Value Chain Overview



Straddle

~6 Bcf/d Capacity

Utilization benefitting from increasing WCSB production

Transport

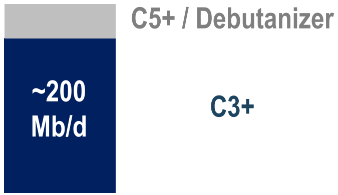
Co-Ed Pipeline: connects Cochrane Straddle & field supply to Ft. Sask

PPTC Pipeline: transports spec products to demand markets

Rail & trucking provides additional optionality / flexibility

Fractionation

~245 Mb/d



Potential for debottlenecking opportunities

Storage

~28 MMbbls

Supported by fee-for-service and marketing volumes

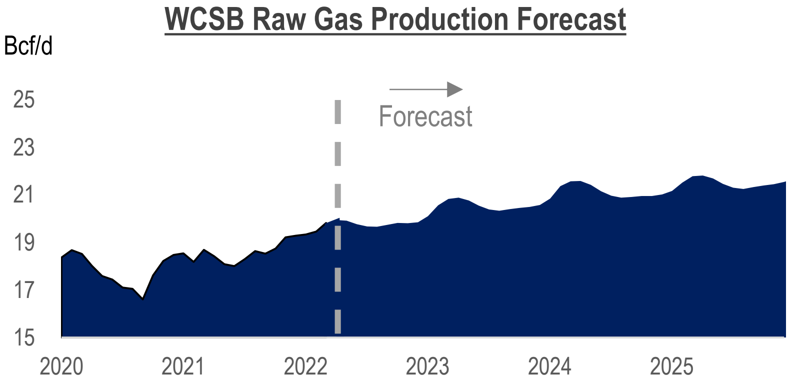
Deliver

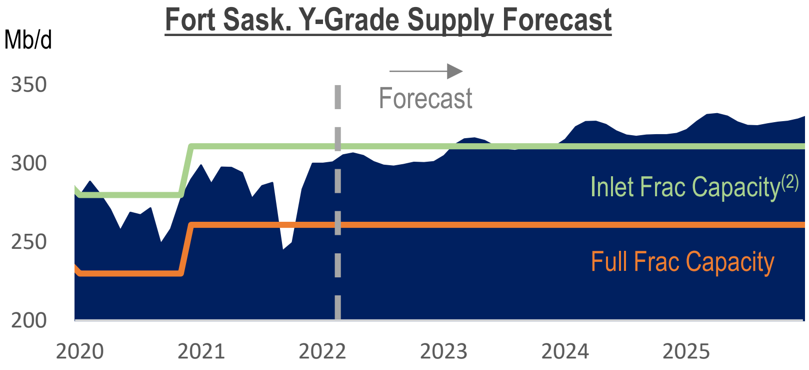
Access to multiple markets (Canada / U.S.)

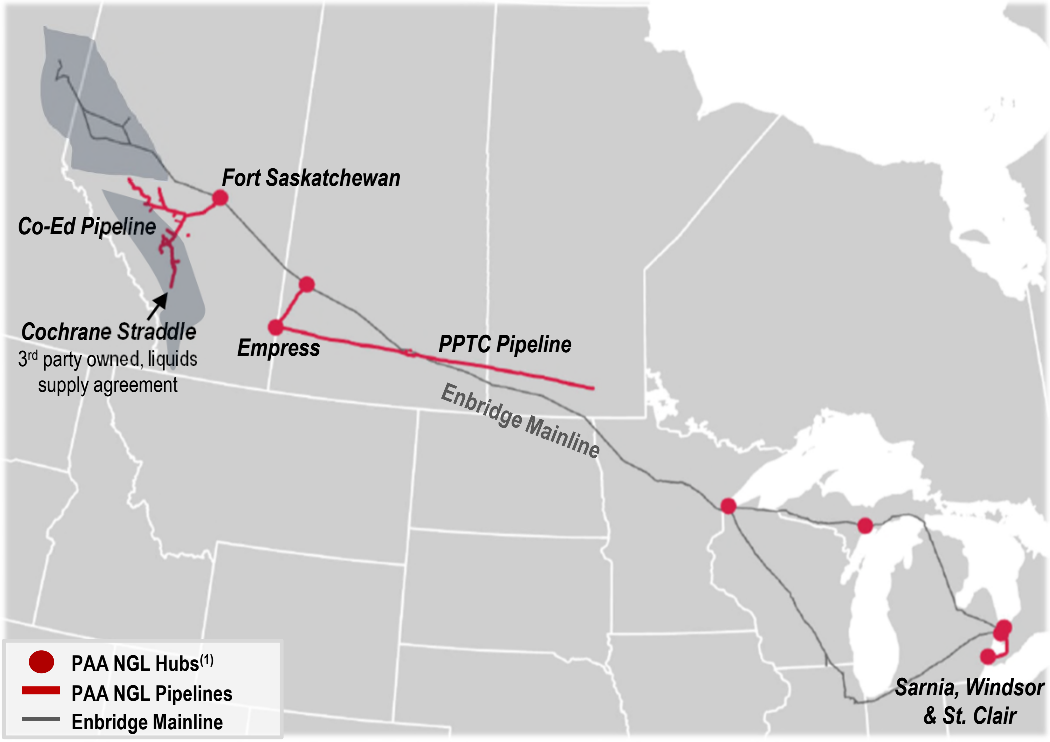
Expect multi-year Western Canadian Propane demand growth

Note: Asset-level data as of 12/31/21.

Integrated & Strategically Positioned NGL Assets Aligned with Constructive Fundamentals





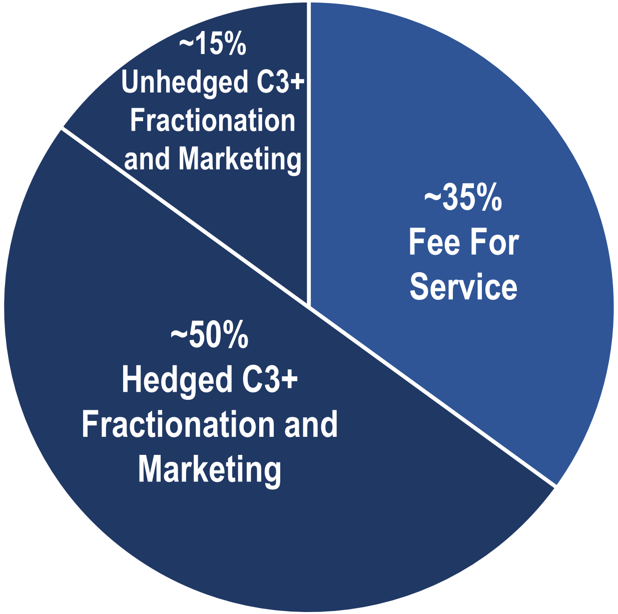


Source: PAA Estimates
(1) Not all PAA NGL assets included within map. (2) Inlet capacity includes C5+ / Debutanizer capacity.

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)
  - ~50 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 (~50 Mb/d)
  - Ethane: cost recovery model (~40 Mb/d)

2022(G): $430MM Adj. EBITDA(3)

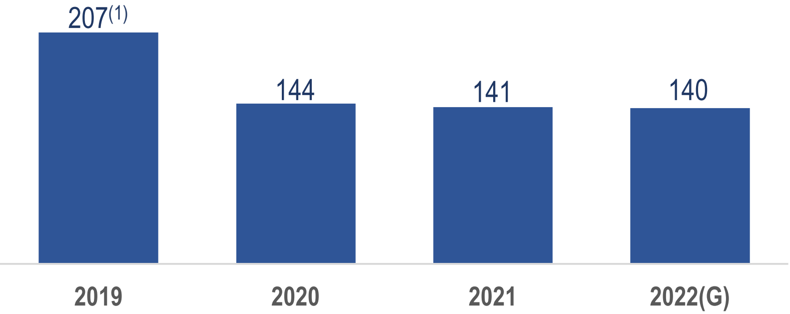


2022(G): Furnished May 4, 2022.

(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

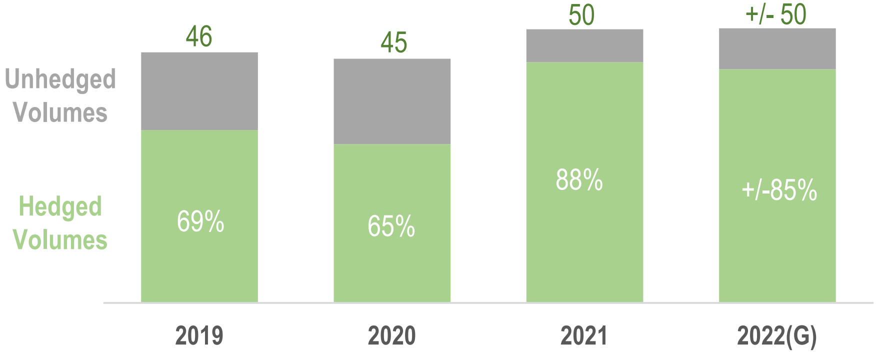
NGL Total Sales *(Mb/d)*



Hedging Profile (2019 – 2022(G))

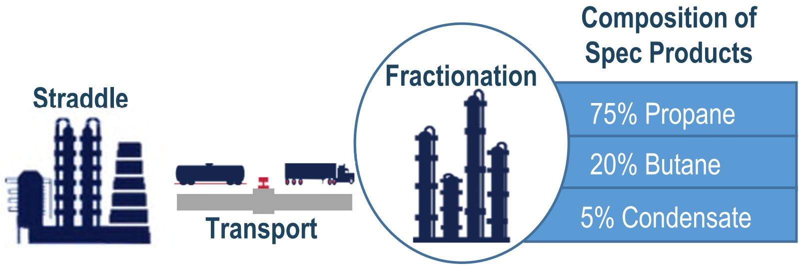
(table data reflects full-year averages)	2019	2020	2021	2022(G)
NGL Segment				
C3+ Spec Product Sales[2] (Mb/d)	46	45	50	+/- 50
% of C3+ Sales Hedged[3]	69%	65%	88%	+/- 85%

C3+ Spec Product Sales[2] *(Mb/d)*



+/- 50 Mb/d Benefit from Frac Spread

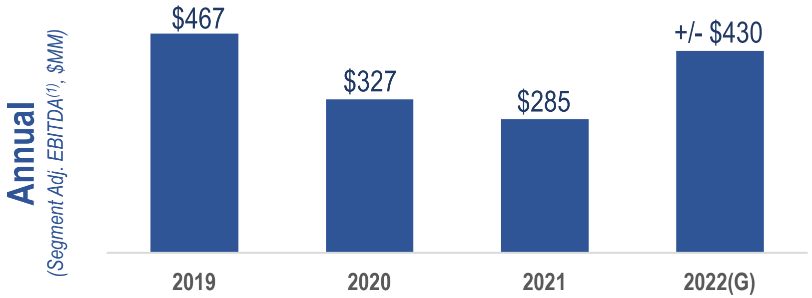
(+/- 85% of 2022 volumes hedged)

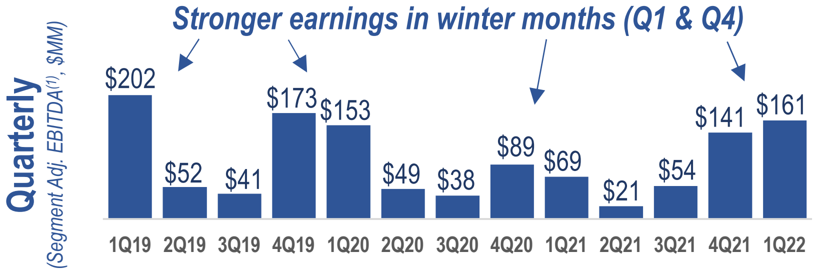


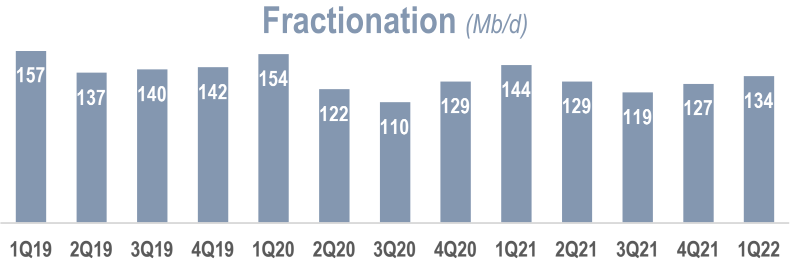
2022(G): Furnished May 4, 2022. (1) Decrease in sales from 2019 to 2020 a result of elimination of low margin spot business and asset dispositions. (2) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread. (3) Annual Frac spread volume hedged as a percentage of total C3+ volume produced / forecasted that is exposed to frac spread.

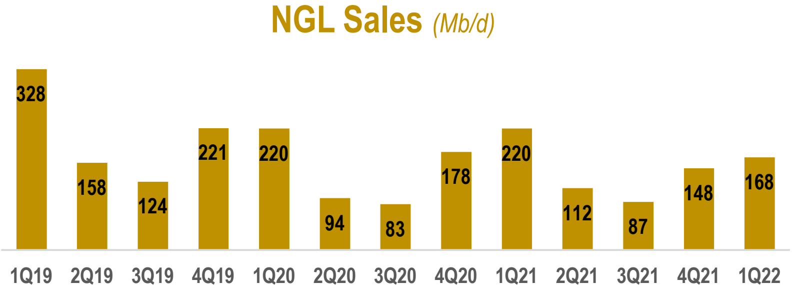
NGL Segment Detailed Data (2019 – 2022)

- **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







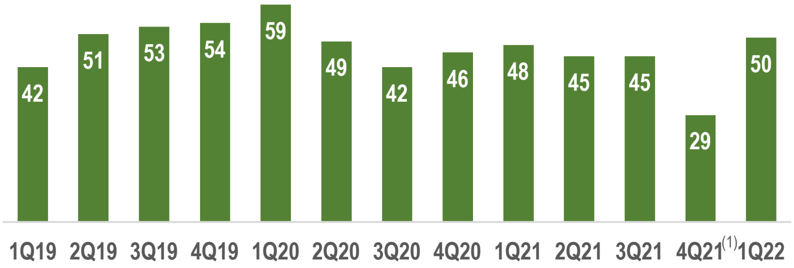


2022(G): Furnished May 4, 2022.
(1) See Definitions.

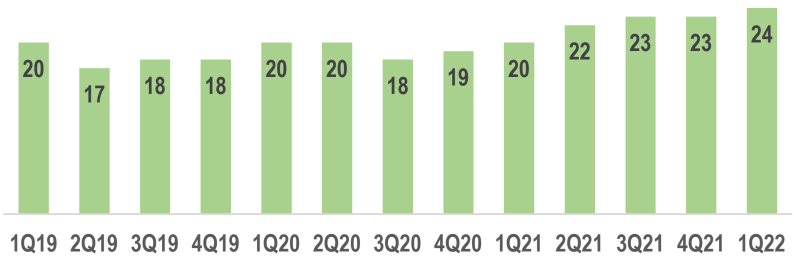
Additional NGL Detail: Fractionation Volumes by Asset

(Mb/d)

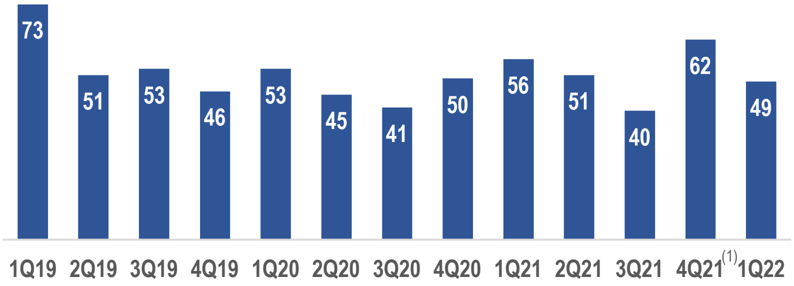
Fort Sask



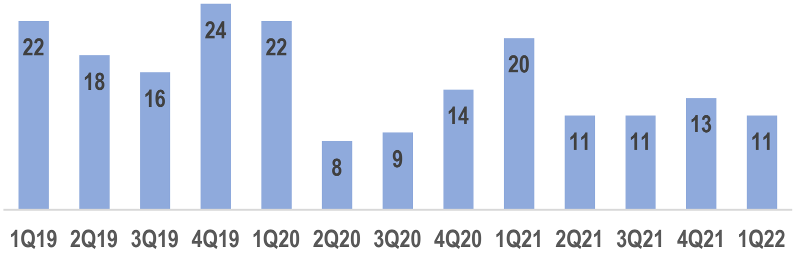
Empress



Sarnia



Other



(1) Throughput volume impacted by Fort Sask Incident.

Emerging Energy Team

- **Cross-functional team led by Vice President of Emerging Energy & Process Optimization**
- **Evaluating wide range of energy evolution opportunities through thoughtful and disciplined approach in and around our assets and core competencies**
  - Includes: hydrogen and carbon-related infrastructure, solar and low-carbon fuels
  - Seeking to align leading Canadian cavern storage position with renewable opportunities
- **Key objectives of Plains' Emerging Energy team:**
  - Optimizing / repurposing assets
  - Reducing GHG emissions
  - Evaluating emerging energy alternatives
- **Committed to maintaining capital discipline and increasing returns to equity holders**

Plains & Atura Hydrogen Storage Feasibility Study Overview

- **Announced Memorandum of Understanding (MOU) with Atura Power in April 2022**
- **Feasibility study of low-carbon hydrogen and subsurface storage**
  - Analyze design & construction of 20-megawatt electrolyzer (to be owned by Atura) adjacent to Atura power gen facility
  - Potential to convert and/or expand Plains’ Windsor salt-caverns facilities to hydrogen storage
- **Plains owns ~28 million barrels of NGL storage capacity, including more than 50 storage caverns with significant connectivity**

Free Cash Flow: Historical Detail

GAAP CFFO to Non-GAAP FCF

	2016	2017	2018	2019	2020	1Q21	2Q21	3Q21	4Q21	2021	1Q22
Net Cash Provided by Op. Activities (GAAP)	$ 733	$ 2,499	$ 2,608	$ 2,504	$ 1,514	$ 791	$ 235	$ 336	$ 635	$ 1,996	$ 340
Net Cash (Used in) / Provided by Investing Activities	(1,273)	(1,570)	(813)	(1,765)	(1,093)	(108)	(175)	761	(92)	386	(81)
Cash Contributions from Noncontrolling Interests	-	-	-	-	12	1	-	-	-	1	-
Cash Distributions Paid to Noncontrolling Interests(1)	(4)	(2)	-	(6)	(10)	(6)	-	(4)	(4)	(14)	(59)
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**
Total Distributions(2)	(1,627)	(1,391)	(1,032)	(1,202)	(853)	(167)	(192)	(166)	(190)	(715)	(164)
FCF after Distributions (non-GAAP)	**$ (2,171)**	**$ (464)**	**$ 763**	**$ (341)**	**$ (430)**	**$ 511**	**$ (132)**	**$ 927**	**$ 349**	**$ 1,654**	**$ 36**

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)

	March 31, 2022			December 31, 2021		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
ASSETS						
Current assets	$ 8,097	$ 3	$ 8,100	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,864	5	14,869	14,903	6	14,909
Investments in unconsolidated entities	3,807	—	3,807	3,805	—	3,805
Intangible assets, net	1,901	—	1,901	1,960	—	1,960
Deferred tax asset	—	1,341	1,341	—	1,362	1,362
Linefill	919	—	919	907	—	907
Long-term operating lease right-of-use assets, net	387	—	387	393	—	393
Long-term inventory	374	—	374	253	—	253
Other long-term assets, net	293	—	293	251	(2)	249
Total assets	$ 30,642	$ 1,349	$ 31,991	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 8,570	$ 2	$ 8,572	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,931	—	7,931	8,329	—	8,329
Other long-term debt, net	55	—	55	69	—	69
Long-term operating lease liabilities	331	—	331	339	—	339
Other long-term liabilities and deferred credits	901	—	901	830	—	830
Total liabilities	17,788	2	17,790	15,799	2	15,801
Partners' capital excluding noncontrolling interests	10,043	(8,503)	1,540	9,972	(8,439)	1,533
Noncontrolling interests	2,811	9,850	12,661	2,838	9,806	12,644
Total partners' capital	12,854	1,347	14,201	12,810	1,367	14,177
Total liabilities and partners' capital	$ 30,642	$ 1,349	$ 31,991	$ 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 & Red River JV are presented on a consolidated (8/8ths) basis; all other volumes are presented net to our interest

1Q22 Earnings Call

May 4, 2022

PLAINS

Plains All American Reports First-Quarter 2022 Results

Houston, TX – May 4, 2022– Plains All American Pipeline, L.P. (Nasdaq: PAA) and Plains GP Holdings (Nasdaq: PAGP) today reported first-quarter 2022 results and provided the following updates:

- Reported first-quarter Net income attributable to PAA of $187 million and Net cash provided by operating activities of $340 million

- Reported strong first-quarter Adjusted EBITDA attributable to PAA of $614 million and increased full-year 2022 Adjusted EBITDA attributable to PAA guidance by $75 million to +/- $2.275 billion

- Forecast Permian gathering volume growth of +/- 280 thousand barrels per day in 2022 (YE-21 to YE-22)

- Increased annualized common distribution by $0.15 to $0.87 per unit and repurchased $25 million of common units in the first quarter

"Our business is off to a positive start in 2022, supported by constructive, long-term fundamentals and a strong commodity price environment," stated Willie Chiang, Chairman and CEO of Plains. "We delivered strong first-quarter results above our previous expectations and increased our 2022 Adjusted EBITDA guidance by $75 million to $2.275 billion, with a bias to the upside. Current global events have reaffirmed the importance of energy in everyday life and the need for reliable, secure and responsibly produced energy. Our integrated business model and asset base is critical to meeting global energy demand, and we are very well positioned to generate significant multi-year Free Cash Flow and maximize unitholder returns for years to come."

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

Plains All American Pipeline

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

GAAP Results	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021	% Change
Net income attributable to PAA	$ 187	$ 422	(56)%
Diluted net income per common unit	$ 0.19	$ 0.51	(63)%
Diluted weighted average common units outstanding	705	722	(2)%
Net cash provided by operating activities	$ 340	$ 791	(57)%
Distribution per common unit declared for the period	$ 0.2175	$ 0.18	21 %

Non-GAAP Results (1)	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021	% Change
Adjusted net income attributable to PAA	$ 266	$ 232	15 %
Diluted adjusted net income per common unit	$ 0.31	$ 0.25	24 %
Adjusted EBITDA	$ 690	$ 546	26 %
Adjusted EBITDA attributable to PAA (2)	$ 614	$ 543	13 %
Implied DCF per common unit and common unit equivalent	$ 0.56	$ 0.51	10 %
Free Cash Flow	$ 200	$ 678	(71)%
Free Cash Flow after Distributions	$ 36	$ 511	(93)%

(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.

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

	Segment Adjusted EBITDA [1] [2]	
	Crude Oil	**NGL**
Three Months Ended March 31, 2022	$ 453	$ 161
Three Months Ended March 31, 2021	$ 474	$ 69
Percentage change in Segment Adjusted EBITDA versus 2021 period	***(4)%***	***133 %***
Percentage change in Segment Adjusted EBITDA versus 2021 period further adjusted for impact of divested assets [3]	***3 %***	***133 %***

(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 certain natural gas storage facilities previously included in our Crude Oil segment.

First-quarter 2022 Crude Oil Segment Adjusted EBITDA decreased 4% versus comparable 2021 results primarily due to (i) the sale of our natural gas storage facilities in August of 2021 and (ii) gains related to hedged power costs resulting from Winter Storm Uri recognized in the first quarter of 2021. These items were partially offset by increased earnings in the first quarter of 2022 from higher tariff volumes on our pipelines.

First-quarter 2022 NGL Segment Adjusted EBITDA increased 133% versus comparable 2021 results primarily due to the favorable impact of higher realized fractionation spreads and higher NGL sales prices, partially offset by lower NGL sales volumes.

Line 901 Update

Included in our results for the first quarter of 2022 is a net increase of $85 million in our estimate of aggregate total costs we have incurred or will incur with respect to the May 2015 Line 901 incident. Such net increase is included in the table attached to this release entitled "Selected Items Impacting Comparability" and is net of amounts we believe are probable of recovery from insurance. The increase in estimated costs includes, among other items, the combined impact of agreements in principle regarding the proposed settlement of two lawsuits that arose out of the Line 901 incident, a class action lawsuit pending in the United States District Court for the Central District of California (the "Class Action Lawsuit") and a derivative lawsuit pending in the Delaware Chancery Court (the "Derivative Lawsuit").

With respect to the Class Action Lawsuit, which involves claims by (i) a class of commercial fishermen and processors and (ii) a class of beachfront and shoreline property owners, Plains has agreed to pay $230 million to fully and finally settle all of the plaintiff's claims. We believe these claims are covered by insurance and, subject to our policy limits, we expect a significant portion of this settlement will be recoverable from our insurance carriers. The settlement is subject to negotiation of final documentation and approval of the trial court.

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With respect to the Derivative Lawsuit, wherein the plaintiff alleges that PAGP's Board of Directors failed to exercise proper oversight over PAA's pipeline integrity efforts, Plains has agreed to settle the lawsuit in exchange for (i) the payment by us of approximately $2 million of attorney's fees to plaintiff's counsel (which amount our director and officer insurance provider has agreed to pay) and (ii) non-monetary compensation in the form of the agreement of Plains to comply with various covenants regarding the implementation and/or continuation of certain Board oversight practices with respect to pipeline integrity. The settlement is subject to court approval and notice to all PAA unitholders, which will be effected following Chancery Court approval via the filing by PAA with the Securities and Exchange Commission of a Current Report on Form 8-K.

We have made adjustments to our total estimated Line 901 costs that incorporate the anticipated settlements described above and general refinements of previous cost estimates, and we have adjusted the receivable we recognized for costs related to the Line 901 incident that we believe are probable of recovery from insurance carriers, net of deductibles. Effective as of March 31, 2022, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will increase by $230 million to $725 million, of which the remaining undiscounted net liability is approximately $95 million, consisting of approximately $335 million of gross remaining liability offset by approximately $240 million of remaining costs that we expect to recover from insurance. Full collection of the amounts we believe are recoverable from our insurance carriers will reach the limit of our $500 million 2015 insurance program applicable to the Line 901 incident.

Taking into account the costs that we have included in our total estimate of costs for the Line 901 incident and considering what we regard as very strong defenses to the claims made in our remaining Line 901 lawsuits, we do not believe the ultimate resolution of such remaining lawsuits will have material adverse effect on our consolidated financial condition, results of operations or cash flows.

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.

Conference Call

PAA and PAGP will hold a joint conference call at 4:00 p.m. CT on Wednesday, May 4, 2022 to discuss the following items:

1. PAA's first-quarter 2022 performance;
2. Capitalization and liquidity; and
3. Financial and operating guidance.

Conference Call Webcast Instructions

To access the internet webcast, please go to https://edge.media-server.com/mmc/p/hq8d7unf.

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.

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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 be further 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. 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, 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.

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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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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 March 31,	
	2022	2021
REVENUES	$ 13,694	$ 8,383
COSTS AND EXPENSES		
Purchases and related costs	12,785	7,392
Field operating costs	346	219
General and administrative expenses	82	67
Depreciation and amortization	230	177
(Gains)/losses on asset sales and asset impairments, net	(42)	2
Total costs and expenses	13,401	7,857
OPERATING INCOME	293	526
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	97	88
Interest expense, net	(107)	(107)
Other expense, net	(37)	(60)
INCOME BEFORE TAX	246	447
Current income tax expense	(19)	(1)
Deferred income tax expense	(2)	(23)
NET INCOME	225	423
Net income attributable to noncontrolling interests	(38)	(1)
NET INCOME ATTRIBUTABLE TO PAA	$ 187	$ 422
NET INCOME PER COMMON UNIT:		
Net income allocated to common unitholders — Basic and Diluted	$ 137	$ 371
Basic and diluted weighted average common units outstanding	705	722
Basic and diluted net income per common unit	$ 0.19	$ 0.51

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(in millions)

	March 31, 2022	December 31, 2021
ASSETS		
Current assets (including Cash and cash equivalents of $114 and $449, respectively)	$ 8,097	$ 6,137
Property and equipment, net	14,864	14,903
Investments in unconsolidated entities	3,807	3,805
Intangible assets, net	1,901	1,960
Linefill	919	907
Long-term operating lease right-of-use assets, net	387	393
Long-term inventory	374	253
Other long-term assets, net	293	251
Total assets	$ 30,642	$ 28,609
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 8,570	$ 6,232
Senior notes, net	7,931	8,329
Other long-term debt, net	55	69
Long-term operating lease liabilities	331	339
Other long-term liabilities and deferred credits	901	830
Total liabilities	17,788	15,799
Partners' capital excluding noncontrolling interests	10,043	9,972
Noncontrolling interests	2,811	2,838
Total partners' capital	12,854	12,810
Total liabilities and partners' capital	$ 30,642	$ 28,609

DEBT CAPITALIZATION RATIOS

(in millions)

	March 31, 2022	December 31, 2021
Short-term debt	$ 900	$ 822
Long-term debt	7,986	8,398
Total debt	$ 8,886	$ 9,220
Long-term debt	$ 7,986	$ 8,398
Partners' capital excluding noncontrolling interests	10,043	9,972
Total book capitalization excluding noncontrolling interests ("Total book capitalization")	$ 18,029	$ 18,370
Total book capitalization, including short-term debt	$ 18,929	$ 19,192
Long-term debt-to-total book capitalization	44%	46%
Total debt-to-total book capitalization, including short-term debt	47%	48%

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

COMPUTATION OF BASIC AND DILUTED NET INCOME PER COMMON UNIT [1]

(in millions, except per unit data)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Basic and Diluted Net Income per Common Unit		
Net income attributable to PAA	$ 187	$ 422
Distributions to Series A preferred unitholders	(37)	(37)
Distributions to Series B preferred unitholders	(12)	(12)
Other	(1)	(2)
Net income allocated to common unitholders	$ 137	$ 371
Basic and diluted weighted average common units outstanding [2] [3]	705	722
Basic and diluted net income per common unit	$ 0.19	$ 0.51

(1) We calculate 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 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 per common unit for the three months ended March 31, 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 months ended March 31, 2022 and 2021, the effect of equity-indexed compensation plan awards was antidilutive, or did not change the presentation of diluted weighted average common units outstanding or diluted net income per common unit.

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 March 31,	
	2022	2021
Basic and Diluted Adjusted Net Income per Common Unit		
Net income attributable to PAA	$ 187	$ 422
Selected items impacting comparability - Adjusted net income attributable to PAA [2]	79	(190)
Adjusted net income attributable to PAA	$ 266	$ 232
Distributions to Series A preferred unitholders	(37)	(37)
Distributions to Series B preferred unitholders	(12)	(12)
Other	(1)	(1)
Adjusted net income allocated to common unitholders	$ 216	$ 182
Basic and diluted weighted average common units outstanding [3] [4]	705	722
Basic and diluted adjusted net income per common unit	$ 0.31	$ 0.25

(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 net income per common unit for the three months ended March 31, 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 months ended March 31, 2022 and 2021, the effect of equity-indexed compensation plan awards was antidilutive, or did not change the presentation of diluted weighted average common units outstanding or diluted adjusted net income per common unit.

Net Income Per Common Unit to Adjusted Net Income Per Common Unit Reconciliation:

	Three Months Ended March 31,	
	2022	2021
Basic and diluted net income per common unit	$ 0.19	$ 0.51
Selected items impacting comparability per common unit [1]	0.12	(0.26)
Basic and diluted adjusted net income per common unit	$ 0.31	$ 0.25

(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 to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation:

	Three Months Ended March 31,	
	2022	**2021**
Net Income	$ 225	$ 423
Interest expense, net	107	107
Income tax expense	21	24
Depreciation and amortization	230	177
(Gains)/losses on asset sales and asset impairments, net	(42)	2
Depreciation and amortization of unconsolidated entities [(1)]	20	20
Selected items impacting comparability - Adjusted EBITDA [(2)]	129	(207)
Adjusted EBITDA	$ 690	$ 546
Adjusted EBITDA attributable to noncontrolling interests	(76)	(3)
Adjusted EBITDA attributable to PAA	$ 614	$ 543
Adjusted EBITDA	$ 690	$ 546
Interest expense, net of certain non-cash items [(3)]	(101)	(101)
Maintenance capital	(27)	(35)
Investment capital of noncontrolling interests [(4)]	(15)	—
Current income tax expense	(19)	(1)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [(5)]	(31)	5
Distributions to noncontrolling interests [(6)]	(59)	(6)
Implied DCF	$ 438	$ 408
Preferred unit distributions paid [(6)]	(37)	(37)
Implied DCF Available to Common Unitholders	$ 401	$ 371
Weighted Average Common Units Outstanding	705	722
Weighted Average Common Units and Common Unit Equivalents	776	793
Implied DCF per Common Unit [(7)]	$ 0.57	$ 0.51
Implied DCF per Common Unit and Common Unit Equivalent [(8)]	$ 0.56	$ 0.51
Cash Distribution Paid per Common Unit	$ 0.18	$ 0.18
Common Unit Cash Distributions [(6)]	$ 127	$ 130
Common Unit Distribution Coverage Ratio	3.16x	2.85x
Implied DCF Excess	$ 274	$ 241

(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 Per Common Unit to Implied DCF Per Common Unit and Common Unit Equivalent Reconciliation:

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Basic net income per common unit	$ 0.19	$ 0.51
Reconciling items per common unit [1] [2]	0.38	—
Implied DCF per common unit	$ 0.57	$ 0.51
Basic net income per common unit	$ 0.19	$ 0.51
Reconciling items per common unit and common unit equivalent [1] [3]	0.37	—
Implied DCF per common unit and common unit equivalent	$ 0.56	$ 0.51

(1) Represents adjustments to Net Income to calculate Implied DCF Available to Common Unitholders. See the “Net Income 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 705 million and 722 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 March 31, 2022	Three Months Ended March 31, 2021
Net cash provided by operating activities	$ 340	$ 791
Adjustments to reconcile net cash provided by operating activities to free cash flow:		
Net cash used in investing activities	(81)	(108)
Cash contributions from noncontrolling interests	—	1
Cash distributions paid to noncontrolling interests [2]	(59)	(6)
Free Cash Flow	$ 200	$ 678
Cash distributions [3]	(164)	(167)
Free Cash Flow after Distributions	$ 36	$ 511

(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 March 31,	
	2022	2021
Selected Items Impacting Comparability: [1]		
Gains/(losses) from derivative activities and inventory valuation adjustments [2]	$ (132)	$ 131
Long-term inventory costing adjustments [3]	92	41
Deficiencies under minimum volume commitments, net [4]	(6)	32
Equity-indexed compensation expense [5]	(7)	(5)
Net gain on foreign currency revaluation [6]	9	8
Line 901 incident [7]	(85)	—
Selected items impacting comparability - Adjusted EBITDA	$ (129)	$ 207
Gains/(losses) on asset sales and asset impairments, net	42	(2)
Tax effect on selected items impacting comparability	8	(15)
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (79)	$ 190

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

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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 March 31, 2022		Three Months Ended March 31, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Revenues [1]	$ 13,079	$ 735	$ 7,853	$ 639
Purchases and related costs [1]	(12,393)	(512)	(7,047)	(454)
Field operating costs [2]	(282)	(64)	(165)	(54)
Segment general and administrative expenses [2] [3]	(63)	(19)	(50)	(17)
Equity earnings in unconsolidated entities	97	—	88	—
Adjustments: [4]				
Depreciation and amortization of unconsolidated entities	20	—	20	—
(Gains)/losses from derivative activities and inventory valuation adjustments	59	29	(159)	(39)
Long-term inventory costing adjustments	(85)	(7)	(35)	(6)
Deficiencies under minimum volume commitments, net	6	—	(32)	—
Equity-indexed compensation expense	7	—	5	—
Net gain on foreign currency revaluation	(1)	(1)	(1)	—
Line 901 incident	85	—	—	—
Adjusted EBITDA attributable to noncontrolling interests [5]	(76)	—	(3)	—
Segment Adjusted EBITDA [6]	$ 453	$ 161	$ 474	$ 69
Maintenance capital	$ 19	$ 8	$ 28	$ 7

(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 March 31,	
	2022	**2021**
Crude Oil Segment Volumes		
Crude oil pipeline tariff volumes (by region) [1]:		
Permian Basin [2]	5,214	3,753
South Texas / Eagle Ford [2]	365	320
Mid-Continent [2]	472	373
Gulf Coast	196	145
Rocky Mountain [2]	346	287
Western	235	237
Canada	331	315
Crude oil pipeline tariff volumes (average volumes in thousands of barrels per day) [1] [2]	7,159	5,430
Commercial crude oil storage capacity (average monthly volumes in millions of barrels) [2] [3]	72	73
Crude oil lease gathering purchases (average volumes in thousands of barrels per day) [1]	1,361	1,174
NGL Segment Volumes		
NGL fractionation (average volumes in thousands of barrels per day) [1]	134	144
NGL pipeline tariff volumes (average volumes in thousands of barrels per day) [1]	176	183
NGL sales (average volumes in thousands of barrels per day) [1]	168	220

(1) 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.

(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 March 31,	
	2022	2021
Crude Oil Segment Adjusted EBITDA	$ 453	$ 474
NGL Segment Adjusted EBITDA	161	69
Segment Adjusted EBITDA	$ 614	$ 543
Adjusted other income/(expense), net [1]	—	—
Adjusted EBITDA attributable to PAA [2]	$ 614	$ 543

(1) Represents "Other expense, net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of $37 million and $60 million for the three months ended March 31, 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 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 March 31, 2022		Three Months Ended March 31, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Segment Adjusted EBITDA	$ 453	$ 161	$ 474	$ 69
Impact of divested assets [1]	—	—	(35)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 453	$ 161	$ 439	$ 69

(1) Estimated impact of divestitures completed during 2021, assuming an effective date of January 1, 2021. Divested assets primarily included certain 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 March 31, 2022			Three Months Ended March 31, 2021		
	PAA	Consolidating Adjustments (1)	PAGP	PAA	Consolidating Adjustments (1)	PAGP
REVENUES	$ 13,694	$ —	$ 13,694	$ 8,383	$ —	$ 8,383
COSTS AND EXPENSES						
Purchases and related costs	12,785	—	12,785	7,392	—	7,392
Field operating costs	346	—	346	219	—	219
General and administrative expenses	82	1	83	67	1	68
Depreciation and amortization	230	1	231	177	1	178
(Gains)/losses on asset sales and asset impairments, net	(42)	—	(42)	2	—	2
Total costs and expenses	13,401	2	13,403	7,857	2	7,859
OPERATING INCOME	293	(2)	291	526	(2)	524
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	97	—	97	88	—	88
Interest expense, net	(107)	—	(107)	(107)	—	(107)
Other expense, net	(37)	—	(37)	(60)	—	(60)
INCOME BEFORE TAX	246	(2)	244	447	(2)	445
Current income tax expense	(19)	—	(19)	(1)	—	(1)
Deferred income tax expense	(2)	(14)	(16)	(23)	(29)	(52)
NET INCOME	225	(16)	209	423	(31)	392
Net income attributable to noncontrolling interests	(38)	(149)	(187)	(1)	(321)	(322)
NET INCOME ATTRIBUTABLE TO PAGP	$ 187	$ (165)	$ 22	$ 422	$ (352)	$ 70
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			194
BASIC AND DILUTED NET INCOME PER CLASS A SHARE			$ 0.11			$ 0.36

(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)

	March 31, 2022			December 31, 2021		
	PAA	Consolidating Adjustments (1)	PAGP	PAA	Consolidating Adjustments (1)	PAGP
ASSETS						
Current assets	$ 8,097	$ 3	$ 8,100	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,864	5	14,869	14,903	6	14,909
Investments in unconsolidated entities	3,807	—	3,807	3,805	—	3,805
Intangible assets, net	1,901	—	1,901	1,960	—	1,960
Deferred tax asset	—	1,341	1,341	—	1,362	1,362
Linefill	919	—	919	907	—	907
Long-term operating lease right-of-use assets, net	387	—	387	393	—	393
Long-term inventory	374	—	374	253	—	253
Other long-term assets, net	293	—	293	251	(2)	249
Total assets	$ 30,642	$ 1,349	$ 31,991	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 8,570	$ 2	$ 8,572	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,931	—	7,931	8,329	—	8,329
Other long-term debt, net	55	—	55	69	—	69
Long-term operating lease liabilities	331	—	331	339	—	339
Other long-term liabilities and deferred credits	901	—	901	830	—	830
Total liabilities	17,788	2	17,790	15,799	2	15,801
Partners' capital excluding noncontrolling interests	10,043	(8,503)	1,540	9,972	(8,439)	1,533
Noncontrolling interests	2,811	9,850	12,661	2,838	9,806	12,644
Total partners' capital	12,854	1,347	14,201	12,810	1,367	14,177
Total liabilities and partners' capital	$ 30,642	$ 1,349	$ 31,991	$ 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 PER CLASS A SHARE [1]
(in millions, except per share data)

	Three Months Ended March 31, 2022	Three Months Ended March 31, 2021
Basic and Diluted Net Income per Class A Share		
Net income attributable to PAGP	$ 22	$ 70
Basic and diluted weighted average Class A shares outstanding	194	194
Basic and diluted net income per Class A share	$ 0.11	$ 0.36

[1] For the three months ended March 31, 2022 and 2021, the possible exchange of AAP units and AAP Management units would not have had a dilutive effect on basic net income 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:

- 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 natural gas liquids ("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;
- the effects of competition and capacity overbuild in areas where we operate, including 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;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- 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 growth, and the timing, pace and extent of economic recovery) that impact demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and commercial opportunities available to us;
- 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 arise out of pandemic related concerns, 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;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

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- loss of key personnel and inability to attract and retain new talent;
- 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;
- 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;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event that materially impacts our operations, including cyber or other attacks on our electronic and computer systems;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- 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, 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;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- failure to implement or capitalize, or delays in implementing or capitalizing, on investment capital projects, whether due to permitting delays, permitting withdrawals or other factors;
- shortages or cost increases of supplies, materials or labor;
- 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 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;
- the effectiveness of our risk management activities;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

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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 6 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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First-Quarter 2022

PAA & PAGP

Non-GAAP & Supplemental Reconciliations

Non-GAAP Reconciliations and Supplemental Calculations: Table of Contents

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PLAINS ALL AMERICAN PIPELINE, L.P.

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.

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	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)	$ 131	$ (86)	$ (9)	$ 249	$ 285	$ (4)	$ (99)	$ (98)	$ (258)	$ (460)	$ 97	$ (51)	$ 30	$ (234)	$ (158)
Long-term inventory costing adjustments	92	41	27	13	13	94	(115)	51	(2)	21	(44)	21	(25)	1	22	20
Deficiencies under minimum volume commitments, net	(6)	32	(6)	(56)	38	7	2	(7)	(64)	(5)	(74)	7	(1)	4	8	18
Equity-indexed compensation expense	(7)	(5)	(4)	(6)	(5)	(19)	(4)	(5)	(5)	(5)	(19)	(3)	(4)	(5)	(4)	(17)
Net gain/(loss) on foreign currency revaluation	9	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)	—	—	—	(15)	(15)	—	—	—	—	—	—	(10)	—	—	(10)
Net gain on early repayment of senior notes	—	—	—	—	—	—	—	3	—	—	3	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	$ (129)	$ 207	$ (65)	$ (78)	$ 280	$ 343	$ (170)	$ (34)	$ (159)	$ (219)	$ (581)	$ 118	$ (99)	$ 35	$ (201)	$ (146)
Gains/(losses) from derivative activities	—	—	—	—	—	—	—	—	—	—	—	—	(1)	—	—	(1)
Gain (loss) on/(impairment of) investments in unconsolidated entities, net	—	—	—	—	2	2	(22)	(69)	(91)	—	(182)	267	—	4	—	271
Gains/(losses) on asset sales and asset impairments, net	42	(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	(15)	1	32	(63)	(44)	23	11	9	31	76	24	(9)	(27)	24	12
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (79)	$ 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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 423	$ (216)	$ (55)	$ 497	$ 648	$ (2,845)	$ 144	$ 146	$ (25)	$ (2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180
Interest expense, net	107	107	107	106	106	425	108	108	113	108	436	101	103	108	114	425
Income tax expense/(benefit)	21	24	(10)	(30)	88	73	21	(12)	(3)	(26)	(19)	24	(23)	41	25	66
Depreciation and amortization	230	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)	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	—	—	—	—	(2)	(2)	22	69	91	—	182	(267)	—	(4)	—	(271)
Depreciation and amortization of unconsolidated entities [(4)]	20	20	68	21	14	123	17	16	18	22	73	12	14	18	16	62
Selected items impacting comparability - Adjusted EBITDA	129	(207)	65	78	(280)	(343)	170	34	159	219	581	(118)	99	(35)	201	146
Adjusted EBITDA	$ 690	$ 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)	(3)	(4)	(5)	(82)	(94)	(2)	(2)	(4)	(5)	(14)	—	(3)	(5)	(2)	(10)
Adjusted EBITDA attributable to PAA	$ 614	$ 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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 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)	(1)	(4)	(4)	(47)	(55)	(2)	(2)	(3)	(3)	(10)	—	(2)	(5)	(1)	(9)
Net income/(loss) attributable to PAA	187	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	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(405)	105	(19)	211	(108)
Adjusted net income attributable to PAA	$ 266	$ 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.

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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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 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	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders [(4)]	(37)	(37)	(37)	(37)	(37)	(149)	(37)	(37)	(37)	(37)	(149)	(149)
Distributions to Series B preferred unitholders [(4)]	(12)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(1)	(1)	(2)	(3)	(2)	(1)	(2)	(1)	(4)	(6)
Adjusted net income allocated to common unitholders	$ 216	$ 182	$ 163	$ 158	$ 180	$ 683	$ 405	$ 183	$ 331	$ 211	$ 1,129	$ 1,859
Basic weighted average common units outstanding	705	722	720	715	709	716	728	728	728	726	728	727
Basic adjusted net income per common unit	$ 0.31	$ 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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 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	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders [(4)]	(37)	(37)	(37)	(37)	(37)	(149)	—	(37)	(37)	(37)	(149)	—
Distributions to Series B preferred unitholders [(4)]	(12)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(1)	(1)	(2)	(3)	(1)	(1)	(1)	(1)	(2)	(3)
Adjusted net income allocated to common unitholders	$ 216	$ 182	$ 163	$ 158	$ 180	$ 683	$ 443	$ 183	$ 332	$ 211	$ 1,131	$ 2,011
Basic weighted average common units outstanding	705	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	722	720	715	709	716	800	728	728	726	728	800
Diluted adjusted net income per common unit	$ 0.31	$ 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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Basic net income/(loss) per common unit	$ 0.19	$ 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	(0.26)	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	$ 0.25	$ 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	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Diluted net income/(loss) per common unit	$ 0.19	$ 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	(0.26)	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	$ 0.25	$ 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.

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

Debt Capitalization Ratios

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

(1) Amounts may not recalculate due to rounding.

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

Implied Distributable Cash Flow Reconciliation

	Three Months Ended		Twelve Months Ended December 31,		
	Mar 31, 2022	Mar 31, 2021	2021	2020	2019
Adjusted EBITDA	$ 690	$ 546	$ 2,290	$ 2,560	$ 3,237
Interest expense, net of certain non-cash items [2]	(101)	(101)	(401)	(415)	(407)
Maintenance capital	(27)	(35)	(168)	(216)	(287)
Investment capital of noncontrolling interests [3]	(15)	—	(9)	—	—
Current income tax expense	(19)	(1)	(50)	(51)	(112)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [4]	(31)	5	16	13	(49)
Distributions to noncontrolling interests [5]	(59)	(6)	(14)	(10)	(6)
Implied DCF	$ 438	$ 408	$ 1,664	$ 1,881	$ 2,376
Preferred unit distributions paid [5]	(37)	(37)	(198)	(198)	(198)
Implied DCF available to common unitholders	$ 401	$ 371	$ 1,466	$ 1,683	$ 2,178
Weighted average common units outstanding	705	722	716	728	727
Weighted average common units and common unit equivalents	776	793	787	799	798
Implied DCF per common unit [6]	$ 0.57	$ 0.51	$ 2.06	$ 2.31	$ 2.99
Implied DCF per common unit and common unit equivalent [7]	$ 0.56	$ 0.51	$ 2.06	$ 2.29	$ 2.91
Cash distribution paid per common unit	$ 0.18	$ 0.18	$ 0.72	$ 0.90	$ 1.38
Common unit cash distributions [5]	$ 127	$ 130	$ 517	$ 655	$ 1,004
Common unit distribution coverage ratio	3.16x	2.85x	2.85x	2.57x	2.17x
Implied DCF excess	$ 274	241	$ 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.

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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		Twelve Months Ended		
	Mar 31, 2022	Mar 31, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.51	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit	0.38	—	1.51	6.14	0.29
Implied DCF per common unit	$ 0.57	$ 0.51	$ 2.06	$ 2.31	$ 2.99

Implied DCF Per Common Unit and Common Unit Equivalent

	Three Months Ended		Twelve Months Ended		
	Mar 31, 2022	Mar 31, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.51	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit and common unit equivalent	0.37	—	1.51	6.12	0.21
Implied DCF per common unit and common unit equivalent	$ 0.56	$ 0.51	$ 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.

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Free Cash Flow (in millions): [1]

Free Cash Flow and Free Cash Flow after Distributions Reconciliation

	2022 Q1	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 YTD	2020 YTD	2019 YTD
Net cash provided by operating activities	$ 340	$ 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)	(108)	(175)	761	(92)	386	(1,093)	(1,765)
Cash contributions from noncontrolling interests	—	1	—	—	—	1	12	—
Cash distributions paid to noncontrolling interests [2]	(59)	(6)	—	(4)	(4)	(14)	(10)	(6)
Sale of noncontrolling interest in a subsidiary	—	—	—	—	—	—	—	128
Free Cash Flow	$ 200	$ 678	$ 60	$ 1,093	$ 539	$ 2,369	$ 423	$ 861
Cash distributions [3]	(164)	(167)	(192)	(166)	(190)	(715)	(853)	(1,202)
Free Cash Flow after Distributions	$ 36	$ 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.

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

Segment Adjusted EBITDA (3)

	2022	2021					2020					2019				
	Q1	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Crude Oil Segment Adjusted EBITDA	$ 453	$ 474	$ 553	$ 459	$ 423	$ 1,909	$ 638	$ 472	$ 639	$ 465	$ 2,216	$ 659	$ 727	$ 681	$ 684	$ 2,753
NGL Segment Adjusted EBITDA	161	69	21	54	141	285	153	49	38	89	327	202	52	41	173	467
Segment Adjusted EBITDA	$ 614	$ 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	2	1	1	—	3	1	2	4	1	7
Adjusted EBITDA attributable to PAA (5)	$ 614	$ 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	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	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	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	1,174	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	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	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	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.