Houston, TX | November 2, 2021

3Q 2021 Earnings Package

PLAINS ALL AMERICAN

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Third-Quarter 2021 Earnings Conference Call

Tuesday, November 2, 2021

Roy Lamoreaux:

Thank you, Chino. Good afternoon, and welcome to Plains All American's third-quarter 2021 earnings call. Today's slide presentation is posted on the Investor Relations website under the "News & Events" section at plainsallamerican.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. 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 the Q&A session, including: Harry Pefanis, President; Chris Chandler, Executive Vice President and COO; Jeremy Goebel, Executive Vice President and CCO; and Chris Herbold, Senior Vice President, Finance and CAO.

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

Willie Chiang:

Thank you, Roy and thanks everyone for joining our call. What a difference a quarter makes. Since our last earnings call, oil and gas prices are materially higher as global demand returns to pre-pandemic levels, and the markets are increasingly concerned about a supply demand imbalance. Once again, the Permian appears to be the obvious choice for increasing domestic oil production, reinforcing our confidence in the long-term outlook for our business.

In terms of the third quarter, we delivered better than expected Adjusted EBITDA of $519 million despite some operational challenges at our Fork Saskatchewan fractionation facility, and we continued to execute on a number of our initiatives.

We have maintained our 2021 Adjusted EBITDA guidance of plus or minus $2.175 billion, despite an approximately $40 million negative impact of non-recurring and timing-related items, which includes a fire that we experienced at our Fort Sask facility in late September. Al will discuss the 2021 EBITDA impact related to these items in his prepared comments.

With respect to Fort Sask, while it's unfortunate this incident occurred, I want to acknowledge our Canadian team's execution of our emergency response plan, and that fortunately, no injuries occurred. Our team has been assessing the damaged area and making the appropriate repairs to return capacity to service in the near future.

Now, let me shift to our 2021 outlook and positioning for 2022, which is summarized on slides 3 and 4. Notably, we further reduced 2021 investment capital by $50 million and have increased forecasted 2021 Free Cash Flow after Distributions by the corresponding amount to plus or minus $1.4 billion. This reflects our continued execution of the goals and initiatives we outlined at the beginning of the year, which have centered on maximizing free cash flow. Consistent with our plan, we have allocated this free cash flow to reduce debt and execute our repurchase program, and we have improved visibility to increase cash returned to our equity holders, including prudent distribution growth, as leverage approaches our target metrics.

Additionally, in October we closed the Plains Oryx Permian Basin joint-venture and are confident in our ability to achieve the JV synergies that we previously identified; in fact, we expect some of the synergies will be recognized earlier in 2022 than anticipated. An overview of the JV is included in the appendix.

With respect to our remaining key projects, the fully-contracted Wink-to-Webster JV pipeline running from the Permian to Houston area markets is scheduled to enter full-service around year end, with committed volumes scheduled to begin ramping in 1Q22 and continuing into 2023. Additionally, the MVC-backed Capline JV reversal for southbound service from Patoka to St. James is on track. Line fill from Patoka has commenced, which is expected to be completed in December and is on schedule for January 2022 in-service date. Capline's initial throughput is expected to be approximately 100,000 barrels per day, and the system has adequate capacity to serve growth in Canadian production.

Regarding Sustainability, we have continued to advance on multiple fronts. Since publishing our Sustainability Report in July, we have received positive feedback from investors and have seen notable improvements in our ESG scores from a key third-party ESG rating agency. In August, we announced further improvements to our governance, resulting in 100% of Plains' Directors now being subject to public election. And just last week, we announced the appointment of Dan Noack to the role of Vice President, Emerging Energy and Process Optimization and the formation of a cross-functional Emerging Energy team. Dan has been with Plains for 13 years, most recently as Vice President, Operations for our natural gas storage business. We are taking a thoughtful and disciplined approach to evaluating a number of opportunities in and around our existing asset base and operations. We look forward to sharing more information, as appropriate, in the future.

Let me make some comments on global supply and demand and industry fundamentals that are shown on slide 5, and further detailed in the appendix. Hydrocarbons are absolutely critical to the global economy. Global demand is recovering to pre-Covid levels, resulting in sustained inventory draws against a multi-year backdrop of reduced upstream investment and a continuation of OPEC discipline. Global energy markets are tight, with shortages in traditional energy sources – including natural gas, coal, and crude oil – as evidenced by the increase in most all commodity prices as seasonal heating demand approaches. Global supply chain disruptions are exacerbating product shortages in certain regions and incentivizing increasing coal-fired power generation in others.

We believe North American energy supply will play a very key role in satisfying global demand, and the Permian is positioned to drive the vast majority of U.S. short-cycle production growth. Permian completion activity has increased since our prior earnings call, reinforcing our confidence in the magnitude of production growth, which could be approximately 2 million barrels per day in 4-5 years, assuming no material change in present-day producer discipline and capital recycle rates, as well as no significant supply chain impacts. We look forward to providing additional updates in February with the benefit of timely data following the completion of producer budgeting season that is currently underway. We believe that Plains is very well positioned to serve the global call on North American energy supply, which also positions us well to generate significant free cash flow going forward, which is summarized on slide 6.

With that, I will turn the call over to Al to cover our third-quarter financials, full-year guidance and capital allocation.

Al Swanson:

Thanks, Willie. An overview of our third-quarter results is illustrated on slide 7 within the context of our full-year guidance and directional estimates for the quarter. Third-quarter Adjusted EBITDA of $519 million exceeded our guidance expectations, driven by stronger throughput across our Permian pipeline systems and hub terminals, as well as incremental NGL sales in Canada, partially offset by operating expenses associated with the Fort Sask incident and a continuation of S&L margin compression. Additional detail on our third-quarter Transportation and Facilities segment results is summarized on slide 8.

Our capitalization and liquidity metrics are provided on slide 9. Total debt decreased approximately $650 million during the quarter and approximately $1 billion since year-end 2020, as proceeds from the gas storage divestiture were temporarily used to reduce bank debt and commercial paper borrowings. We intend to ultimately use the proceeds to retire the $750 million senior notes due in June 2022 at the March 2022 par call date. Our long-term debt to Adjusted EBITDA ratio was 3.8 times at quarter end, which remains above the high-end of our target range and reinforces our commitment to further reduce debt.

Slide 10, provides a recap of our capital allocation plans for the year, including a summary of the equity repurchase activity we have completed since we implemented the plan last November. In total, we have repurchased 18.1 million PAA common units for $167 million, with $64 million repurchased in the third quarter. As Willie mentioned, and as detailed on slide 11, we have further reduced 2021 investment capital and continue to expect an annual run rate to range between $200 to $300 million.

As detailed on slide 12, we maintained our 2021 Adjusted EBITDA guidance of plus or minus $2.175 billion, reflecting third-quarter Transportation segment over performance, offset by an estimated $25 million impact from the Fort Sask incident, in addition to approximately $15 million in timing-related items comprised of Wink to Webster entering full-service roughly 2-months later than we had previously forecasted and an MVC deficiency timing shift into the first quarter 2022. I would also note that 2021 Guidance does not incorporate the Plains Oryx Permian Basin JV, as we do not expect the JV to have a material incremental net EBITDA impact on our full-year 2021 results, which is consistent with our discussion on our JV announcement conference call. Slide 13 puts our November guidance into context relative to our initial 2021 guidance furnished in February and illustrates the most notable drivers to date and expected through year end.

Acknowledging the significant degree to which the margin-based earnings reported within our S&L segment have continued to evolve over the past several years, we are currently reviewing our reporting segments to ensure alignment with our current and future operating decisions as well as the competitive environment in which we operate. If through this review we determine a segment change is warranted, we intend to incorporate this change within our fourth-quarter earnings release, our 2022 financial and operating guidance, and our 2021 10-K.

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

Willie Chiang:

Thanks, Al. Our third-quarter results reflect continued solid execution of our plan. We've made progress reinforcing our balance sheet and divesting non-core assets at attractive multiples while exercising strong capital discipline and preserving our most notable strengths:

- We have an integrated "well-head to market" asset base and business model;
- We have strong alignment with customers and partners throughout the industry value chain;

- We have strategic positioning in key U.S. and Canadian producing regions, demand centers and export outlets;
- We have leading Permian franchise with significant operating leverage; and
- We have Investment Grade credit ratings

As we look forward, this positions us to generate significant positive free-cash flow for years to come, benefiting from improving global fundamentals and a growing Permian Basin. Owners of PAA and PAGP are positioned to benefit from this growth through our commitment to increasing cash returned to equity holders over time.

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

Roy Lamoreaux:

Thanks, Willie. Prior to opening the call to Q&A, I would mention that a summary of our 2021 goals and key takeaways from today's call are provided on slides 14 and 15. 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.

As we look forward, this positions us to generate significant positive free cash flow for years to come, benefiting from improved global fundamentals and a growing Permian Basin. Owners of PAA and PAGP are positioned to benefit from this growth through our commitment to increasing cash return to equity holders over time.

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

Roy I. Lamoreaux - *Plains GP Holdings, L.P. - VP, IR & Communications*

Thanks, Willie. Prior to opening the call to Q&A, I would mention the summary of our 2021 goals, and key takeaways from today's call are provided on Slides 14 and 15. 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. Jino, we're now ready to open the call for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) We do have a question from Michael Blum from Wells Fargo.

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

I had a question on M&A, really on the asset divestiture side. Obviously, you guys have been pretty aggressive over the last few years, I'd say, on that front. Do you think you're effectively done after this year, or do you see continued asset divestitures in '22 and beyond?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Michael, this is Willie. Thanks for the question, and I appreciate the acknowledgment that we have been aggressive in optimizing our portfolio through sales. We've completed $4.5 billion worth of asset sales in the last number of years, and we think we're probably at the end of the significant asset sales. However, we continue to look at all kinds of opportunities. And we believe in the efforts of continuous improvement. We always look to see if assets are worth more to others, and there's a win-win there. So at this point in time, we do not anticipate announcing a formal debt disposition program for 2022. Hopefully, that helps.

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

Yes. That helps. Thank you. Maybe on a related note, any updates you can provide in terms of efforts to either repurpose or rationalize pipeline capacity out of the Permian? I know you're seeing strong Permian volume growth, but there is still a decent amount of excess capacity? Thanks.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Yes. I'm going to let Jeremy address this, but I do want to make a comment. I think we've proven ourselves that as far as repurposing and optimization, and I'll just point out that, both Wink-to-Webster, the project is a result of consolidation and rationalization of a number of shippers. And if you think about our repurposing of Capline and reversing it from an idle line to a line that's going to go on service, it's completely in our playbook, but I'll let Jeremy talk about the Permian and our thoughts.

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. The industry as a whole, so not just Plains, all the large owners of the pipeline are looking at it. Some projects make more sense than others. At this time, nothing has been announced, but I would tell you that everyone wants that to happen, but the counter to that is you're also going to look at supply and demand and -- based on production growth. So I think it's something we continue to look at. We'll look at with other partners, we'll look for rationalization and cost reductions across the system, we'll look for repurposing assets. A lot of that's new. Some of the potential alternatives that Dan is looking at in our -- in the group -- in Chris's group, Dan Noack that Willie announced, he's going to look at potential projects. So I think we're early in the process at some of those, but the industry is looking at gas conversions, refined products conversions, all kinds -- not just in the Permian but across the system. So I think stay tuned, but this is something that is going to take time. It's going to take industry partners to make that work. And we're aware of it. We're going to keep looking at it, but no update at this time.

Operator

Next one on the queue is Shneur Gershuni from UBS.

Shneur Z. Gershuni - *UBS Investment Bank, Research Division - Executive Director in the Energy Group and Analyst*

Maybe to start off, there have been a lot of comments throughout this earnings season about positive developments in the Permian from a production perspective. Some of the majors were talking about more volumes. You have a slide on that as well also. With the JV in place now with Oryx, do you feel that Plains is better able to capitalize on this growth? Are you able to give us a little bit more color than you were able to give at the time of the announcement?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Again, I'll ask Jeremy to comment on this. But the whole purpose we did the Oryx JV is if you think about -- back to rationalization and trying to be capital efficient, we think that was clearly a win-win-win, right. Win for Oryx, win for us, and win for customers and putting that together. But everything we've done around the Permian is really focused around how do we build that integrated value chain from wellhead all the way to markets. And with the ability for us to first purchase, we think that really gives us a differentiated view of the Permian. So short answer is, I think it's absolutely key to additionally building out our system in the Permian. And I don't know Jeremy if you have any other comments you want to make about it.

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

Shneur, we just closed in about a month ago. And so what I would say is transitions run very smooth. Objective #1 is turn the pipeline over safely, continue operations, and service existing customers. And so, that process is all going very well. I'd say you've already seen capital rationalization, our ability to defer or eliminate whether it's expansions of our system or there are -- putting new connections in place. So I think we're seeing some of those on the cost side. We're rationalizing there. Commercially, we are approaching -- now we're finally allowed to jointly approach our large customers and our smaller customers. And we canvas all the customers, and they're generally very excited about Plains taking over operatorship. We're looking for long-term solutions, extensions of contracts, a very stable long-term cash flow from this asset, and initial results are positive, and we're going to continue to drive for that. So just on the intra-basin movements alone, we're looking to take the system, which has got expanded reliability, quality control, and connectivity, and create long-term partnerships with our customers. And that's where that focus has been, and it's going very well.

Shneur Z. Gershuni - *UBS Investment Bank, Research Division - Executive Director in the Energy Group and Analyst*

Great. Really appreciate that. And maybe as a follow-up question here, it seems you purchased about $64 million units during the quarter, $160 million since the authorization was in place. So you've reduced your units outstanding by -- on my math, about 2.5%. Your free cash flow after dividend is actually increasing based on your guide, and I know the formula is up to 25%, you've reiterated that in the past. But even if I take into account asset sale adjustment-related debt reduction, it sort of suggests that you've got about $150 million worth of capacity into year-end. Do you expect that to still be a part of the plan? And is that the expectation that the Board likely has for next year that you'll have a similar up to 25% view in terms of returning capital to unitholders?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Well, Shneur, I think we've demonstrated that we are definitely executing against the plan. We've got a slide somewhere in the presentation that kind of talks about all of the conditions that we look at including outlook, value of the units, the yield of the units. And so, we intend to continue to buy. I don't think we're going to be specific about how much, when, or where, but that clearly continues to be part of the capital allocation plan along with the primary piece going to debt reduction. Al, you want to add anything to that?

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

Yes. No, I would echo that. Clearly, we have tried to articulate that the math formula is to come up with a limit. Primary focus is to try to manage our leverage in the very near term as Willie mentioned, and clearly, we're still running above it. But we thought we could do it in a balanced way to implement some repurchases in the meantime. We would plan to probably provide commentary on those percentages or the free cash flow allocation for 2022 on the February call.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Shneur, I wanted to add one thing to the -- to Jeremy's comments on the Oryx JV. We can't give you a lot of details right now because we're just kind of in the midst of transition, a successful transition moving forward. But I will highlight that as we announced at the -- when we announced the deal, there's a lot of acreage dedication that anchors volumes there. And I also want to complement Jeremy's team and Brett Wiggs' team. As we've gotten together, there's a lot of excitement anytime you get two good teams working together. So I do think we're going to continue to make progress, and we'll be able to share more on the next call.

Operator

Next one on the queue is Jeremy Tonet from J.P. Morgan.

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

Just a couple of high-level macro questions, if I could. Just wondering about Cushing operating, we've seen inventories really reaching these very low levels. Do you see an impact on the market here as this continues to drain? Do you see reversal of this at any point? Just wondering if you could talk about, I guess, what impacts this could have in -- on the crude oil market as a whole and exports as well?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Jeremy, our Jeremy, you want to talk about that?

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

So Cushing inventory, so it's been declining since COVID, right. This has been a long decline, and it accelerated recently. And so, what that does is it just creates a situation with steep backwardation and it tightens Brent and WTI, right. So the thing about that is the scarcity of availability for crude, right. So that creates the demand in Cushing for neat barrels as opposed to blended settled barrels of the NYMEX. So think about that, it could pull additional barrels from different regions in the Permian for operating. And so, it ebbs and flows, right. So that's going to be a pull away from exports. So this is not something -- when everyone said that basin is going to completely dry up, that doesn't always happen. This is something that's cyclical. And so parts of it, the pull towards the water will move barrels that way. Right now, you've got to pull towards Cushing just because you've got limited inventory. So that's a -- moving barrels in that direction. So arbs get solved, right? If there's a pull towards Cushing, barrels flow to Cushing, pull the water. So crude markets are just not static, and that will impact margins as a refiner. So this is a -- it's not a simple yes or no answer. I would just say that as the inventories decline, there's less barrels to physically settle contracts. It's going to pull more neat barrels from different basins. So as and when production grows in the Rockies or the Mid-Continent, that's going to pull barrels from the Permian Basin. That's one way to think about that.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

And Jeremy, Cushing remains a very key hub, right. And we think it continues to remain a very key hub going forward.

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

Operationally, those barrels are needed in those terminals that are most connected to supply sources and distribution sources. We'll continue to operate and be profitable in spite of a steeply backwardated market that's against storage.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

I will tell you that we are seeing some pressure on margin or recontracting on the Cushing storage. So that may be a factor of the lower tank use today.

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

Got it. That's helpful. Thanks. And thinking about the Permian and the levels of growth that you outlined there, potentially getting pretty strong in the coming years here. Just wondering how you think bottlenecks in the basin could emerge and not on the crude oil side, but on the natural gas side. Just curious if you think that, that could be something of a speed bump a couple of years down the road as far as nat gas takeaway needs and new pipeline needed for that and whether that could slow down crude oil production.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Well, I think back to what our Jeremy was talking about on rationalization and optimization within the basin, I think there's a lot yet to be played out. If you do look at the constraints, natural gas is probably one of the first constraints you hit with the growth in the production. And if you compound that with the desire for the industry to not flare as much, it puts a little additional pressure on that. So I think there's a lot yet to come on opportunities to optimize, hopefully within existing pipes, and that's more to come as we go forward.

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

Jeremy, this is Jeremy. The way I'd look at it is there's going to be a few constraints, right. Labor, pressure pumping, other types of supply constraints on the service side. Gas is one that's depending on your production forecast '23 and '24. On the negative side, from flowing barrels is that's a positive side, I would say, for the industry as a whole. There's a resistance to flaring now, which is I think positive from an ESG perspective, but it could constrain production. We've seen it at times, processing plants go down or other things in the field. But I think the industry is getting better at thinking more forward and solving those issues and taking capacity out of the basin to do it. So I think the gas issue does get solved and everyone is aware of it. There's three projects out there chasing it. So I think whether that happens or a conversion happens, I think that one gets solved. More -- right in front of us is the labor thing -- labor issue that's affecting all markets. And then potentially, the lack of maintenance on service equipment. I think those are the negatives. I think on the positive side, what we're seeing from a growth standpoint is less activity and more accomplishment on the gathering side. The desire to reduce methane emissions is going to have fewer connections, bigger connections, very efficient operations on the gas, crude, and water side. So I think you're going to see the industry move to more efficient, less potential emissions points, which is good for our capital going into the ground. It's less capital to get more barrels to the system. So I think you're going to see some negatives and positives come out of this. But I think all in all, we're going to work -- the industry will solve these issues.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

It does reinforce the need for all parts of the value chain to work together. If you think about efficient value chains, I think global situation is going to force that on us. We were in the peer growth mode where everybody was growing. And now as we have a little bit of a check step, this efficiency mode or optimization is going to play out with more and more players.

Operator

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

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

What share of EBITDA roughly is linked to PPI or some other inflation index? And do you anticipate that if costs go up less than that, this could provide a material benefit over the next 12 months, or should I not get too excited about that?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Yes. Generally speaking, I would tell you, we have -- we would expect to be able to offset cost increases with our escalators. There may be some timing issues there. I don't know if anyone wants to offer any more detail.

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. So we have -- the way you look at it as some of the longer-term contracts have -- including the acreage dedication in the Permian are exposed. And so some of them have caps, a lot of the producers' recognizing this. Caps could be in the range of 3% to 3.5%. Some of them have banking, some of them don't. So yes, we are absolutely exposed. That will be incorporated in our guidance when we have a better view in February. But I would say we're monitoring it. We're paying attention that should more than offset the cost, but it's something that will give you a better sense for what that impact is because some movements like spot movements won't be impacted by that. So it's not take all of it, we will be exposed to that. But I would just say, let us give you some guidance in February once we have a better sense for what that looks like and what volumes on different pipes will look like.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Jeremy, do you want to just confirm what you mean by exposed?

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

Well, we have escalators. Exposed just means we have escalators attested. There's an opportunity for exposure to escalation. You're also exposed to cost, but lower capital budget, higher revenue exposure should be directionally positive, but we'll give more guidance in the spread early in February.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Jean Ann, did that answer your question?

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

Yes, yes, it did. Yes. So it's moderately positive. So appreciate that. And then as my follow-up, congrats on getting the Capline reversal done. On that $100,000 that's flowing out, are you able to say roughly how much is coming from Canadian crude versus U.S.? And kind of talk about what would -- what you would need to see for that number to go up? Is it just kind of more production in the Bakken and in Canada? Or are there kind of specific third-party projects or expansions that could lead to Capline getting more crude over the next year or two?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Well, there's never an easy answer to this, but I'll let Jeremy give it his best shot here.

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

Jean Ann, I'd say to your first question, we would expect it to be 100% Canadian crude. And to your second question, I think there's a number of projects potentially restructuring how crude gets across the Canadian border and what markets it goes to. And so, once there's clarity with Enbridge and its shippers and TransCanada and its shippers, I think we'll see how much -- how many barrels flow to Patoka and the potential to expand it. So we definitely think there's opportunities to increase from where it is today, but there needs to be certainty of which barrels end up in Patoka and U.S. shipper industry to get there.

Operator

Next one on the queue is Colton Bean from Tudor, Pickering, Holt & Company.

Colton Westbrooke Bean - *Tudor, Pickering, Holt & Co. Securities, LLC, Research Division - Director of Infrastructure Research*

So first, just wanted to follow-up on Willie's comment around lower storage rates at Cushing. Any rough sense as the volume's rolling over the next year or 2? And just general exposure there?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Jeremy?

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

I'd say we actively manage it, so it's staggered over time. And obviously, the further out you get. I think the near-term uncertainty is less. We're just putting it out there that, hey, there is some exposure. It's not (inaudible). It's nowhere near 100% of the contracts. And it's -- generally, for our facilities, they're highly contracted assets. And for the next 12 months, they'll be highly contracted assets. But we're just making people aware that lower inventories does put pressure on whether it's spot movements or there's no contango opportunities around there. So some of that is more of the opportunistic storage that our customers experience won't be there. So it's going to be limited to throughput and storage rates, but incremental successive storage rates will be at lower rates than historical ones. So there's no near-term cliff. It's not like Cushing is going to be fully exposed next year. It's a much smaller portion of that. It's just something we're pointing out that backward dated markets make it tougher on facilities. And operationally, you're running with no cushion, right? You're running as bottoms in the system.

Colton Westbrooke Bean - *Tudor, Pickering, Holt & Co. Securities, LLC, Research Division - Director of Infrastructure Research*

Got it. And then maybe switching back to Capline. You mentioned needing to know how many volumes show up in Patoka. Is that kind of the preferred option now as seeing what producers and refiners are looking at? Or is there any opportunity to structure a bundled rate all the way from Alberta?

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

I think there's always opportunities. But I think the key thing now is they're trying -- Enbridge is trying to understand what the rules are, right, to how they agree on what it is. So in the future, certainly to have a joint rate. But I think near term, getting it there and having a rate across, I think we take this uncertainty where the barrels will end. We've had discussions with all the longer-term carriers. But I think the uncertainty of what the structure looks like and what they can offer is precient relative to adding additional joint tariffs with third-party.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Colt, the comment I would make, this is Willie again, is if you think about the longer picture, there's always going to be abnormalities over periods of time whether or not you're going to be up in a backwardated market, contango markets. If you think about the production profile and what we believe to be the energy demand that's going to be needed in the world, long term, barrels are going to flow to the water. And it may be quarter, 2 quarters, 3 quarters away, but as constraints get fixed, efficient paths to markets ultimately get filled. And that's what we believe in and that's what we're planning for.

Operator

Next on our queue is Chase Mulvehill from Bank of America.

Chase Mulvehill - *BofA Securities, Research Division - Research Analyst*

So I just wanted to come back to the line of questioning around the Permian. I think last quarter on the conference call you guys talked about kind of stabilization of Permian oil volumes kind of in the near-term and you really didn't expect much growth until you got to around the mid part of next year. So if I missed it I apologize, but could you kind of update us on kind of your view of Permian oil volumes over the near term? And do you expect those to grow now just given the higher oil price?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Yes. So Chase, we probably would rather give a much better update after we hear what all the producers are going to be doing. But you're correct in that -- on our last earnings call, we had a lower rate than we thought the year would end at. And I think because of the increased completions I mean, it's stepped up. Clearly, it's higher. I think the trajectory is probably similar where it's going to be flatter and then rise in 2022. Jeremy, you want to add to that?

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

Chase, we had the last call in May, and I'd say July and August were strong months from -- the end of June, July, and August were strong months for completion. And so our 4.5 to 4.6 has moved to 4.8 to 4.9, which is more in line with consensus. But after that call -- I'm sorry, in August, we were just starting to see that wave, and now we're seeing that continue. I think you're always going to see towards the end of the year as people make sure they hit their capital budgets a bit of a slowdown, but usually, it ramps up in the first part of next year when capital budgets are reloaded. So I think from a shape perspective, it will continue to grind higher. I'd say drilled and uncompleted wells, that inventory continues to get exhausted. You're going to need to see rigs to show up to sustain growth. And so we'd expect to see some of that in the first quarter of next year. Without giving specific guidance, the way to think about it is the private operators continue to add completion crews and rigs as you've seen and the industry has seen. I think your large and mid-sized independents are largely holding the line even at $80 oil. I don't know, third-party pressure whether it be from the government or investors are starting looking for growth at those levels because the returns are high, but they're holding the line. We're also seeing the integrated start to look to step out and potentially add activity. So it's not a perfect picture right now, but we have a good sense for what's happening. And we'll have a better one in February. But if I were to give you a qualitative answer to what's going to drive growth, right now it looks like the integrators will start to step up activity and the privates will drive growth. You'll see allocations of capital. That will be important to people allocating capital to other basins at the higher prices since they do work at these prices or do they stay within the Permian and let those decline. I think these are all things that will bear out between now and February.

Chase Mulvehill - *BofA Securities, Research Division - Research Analyst*

All right. That's helpful. We're pretty bullish on the whole full-service kind over here, we're pretty bullish on activity levels in 2022. So a quick follow-up question. There's a lot of questioning around kind of Cushing and I guess, maybe I have a question on inventories. Obviously, inventories are below 5 year averages or even 5-year lows for this time of the year. Obviously, global oil supply-demand dynamics are pretty tight with OPEC still holding crude off the market when we probably need more at this point. But as we kind of move into 2022, balance is probably -- at least kind of balanced out a little bit. And maybe there may be a little bit oversupply depending on kind of what happens with Iran and some other things. But when you think about that and things kind of moving from being significantly undersupplied to more balanced, you might start filling Cushing again on the inventory side. So when that happens, where do you think those barrels actually come from? And if they're coming from the Permian, just kind of help us understand the operating leverage you would have as those barrels come back into Cushing if they come from the Permian?

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

Sure. I think where they come from is, once again, depending on the capital allocation to the Rockies, Mid-Continent, and absent growth in those markets. In Canada, you're going to have some from the Line 3 expansion. But absent that, you're going to see -- if you see continued increased refining runs, you're going to need to pull on the Permian to supply those because inventory isn't supply and that in-basin in Sunrise would be our primary exposure there, the uncontracted portions of it. And you've seen throughout different quarters this year when there is a pull when Canadian upgraders are down or when the balances pull like they are today, you'll see exposure from the basin corridor, and that's a pull-through from the gathering system to the -- on the Sunrise in basin. I'd say that's the primary leverage. And then any time there's throughput in a terminal, there's additional fees and terms associated with that in the Cushing markets as well. So that's where you would see that -- we do agree with you that if demand continues to grow at this pace and there's no additional upsets from COVID, supply will be outstripped -- or demand will outstrip supply, and that should drive additional rigs and allocation of capital to the Permian because you'd have to think at this point there's probably higher discount rates and the steep backwardation associated with longer-dated projects. It probably pulls capital into short-cycle projects. You probably see even more waiting with the guys who have other options. And so we do agree with you that, that could happen. But forecasting that is pretty difficult from where we sit right now, but we will have a better sense in February.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Chase, one thing to add to that, if you -- I'll just -- I want to just give you a perspective of our system that we have in the Permian. If you think about our gathering intra-basin and long-haul lines, we have access to multiple markets. So as Jeremy described what was happening and the flexibility on basin, if the arb supports moving barrels to the coast, they go to the coast. If the arb supports going to Cushing, we have the flexibility to get volumes on basin going up to Cushing. What it does do is a lot of the volumes that we have going to the coast are supported by minimum volume commitments. So a person can opt to send that up to Cushing, which we would get the benefit of the tariff, and we would then have a little bit more noise on the transportation side on -- if a barrel didn't flow, we still get paid. There'll be some deficiency payments. But I just wanted to reinforce, it's a benefit of the system that we have and that we have multiple outlets that we could get some benefit from.

Operator

For the next question, we do have Becca Followill from U.S. Capital Advisors.

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

You guys talked a little bit about -- that you're evaluating S&L and your reporting mechanisms. If you choose to pull that into other segments, is there any other visibility that you're maybe considering in terms of maybe providing additional information on Canada or for other segment reporting?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

I'm going to let Al Swanson address that Becca.

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

Yes. We're going to take a look at what we think the right reporting would be structured, Becca, and we do decide to make a change, which we haven't yet. We'll come out with that in February. So I think it's premature to try to speculate on potential changes, especially when we haven't decided for sure that we're going to make any.

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

Can we put in requests in the meantime?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Our IR team is available for phone calls after the conference call always.

Roy I. Lamoreaux - *Plains GP Holdings, L.P. - VP, IR & Communications*

Bring it on, Becca. Bring it on.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

As you know, I mean, the reported -- the segment reporting structure needs to mirror kind of how we are managing the business. So there's some very particular rules around that, that we have to keep in mind as well.

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

Got you. Thank you. And I don't know if you talked about it earlier in the prepared remarks, I apologize if you did, the $200 million asset impairment, what was that for?

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Al, you want to cover that?

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

Yes. It was our remaining terminal out on the East Coast at Yorktown.

Operator

There are no further questions on the queue. I will now turn the call over back to the presenters.

Wilfred C.W. Chiang - *Plains All American Pipeline, L.P. - CEO & Chairman of Plains All American GP LLC*

Well, once again, we thank you for your continued interest and support of Plains. We look forward to giving you more updates as we go forward. Please stay safe, and I will say, Go Astros. Thank you very much.

Operator

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

Houston, Texas | November 2, 2021

3Q21 EARNINGS CALL

PLAINS ALL AMERICAN

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, 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.plainsallamerican.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.

3Q21 Earnings Call Highlights & Outlook

Since 2Q21 Call

- Reported Adj. EBITDA of $519MM
- Reduced Total Debt ~$650MM (~$1 B since YE-2020)
- Repurchased $64MM common units ($167MM since Nov-2020 authorization)
- Closed Plains Oryx Permian JV October 5th

2021 Outlook

- Maintained Adj. EBITDA (G) of +/- $2.175 B despite ~$40MM negative impact of non-recurring and timing-related items (Ft. Sask, W2W, MVC deficiency)
- Further reduced 2021 investment capital $50MM (reduced $150MM since Feb(G))
- Increased forecasted FCFaD +$50MM to +/- $1.40 B

2021(G) : Furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit). Feb(G): Furnished February 9, 2021.
Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

2021 Execution Reinforces Positioning for 2022+

Maximizing FCF	✓ Closed >$870MM in asset sales, $50MM pending (~$920MM total vs. $750MM target) ✓ Reduced total 2021(G) capital (Investment & MCX) ~$165MM vs. Feb(G) ($455MM vs. $620MM)
Capital Allocation	✓ Reduced debt by ~$1 B since YE-2020 ✓ Repurchased $114MM of common equity ($167MM since Nov-2020 authorization) ✓ Improved visibility for additional repurchases / prudent distribution growth as leverage decreases
Optimizing Portfolio	✓ Closed Plains Oryx Permian JV – integration, synergy capture, and operating leverage on track ✓ Executing W2W & Capline, MVC's contributing 1Q22 and beyond
Sustainability (ESG)	✓ Published 2020 Sustainability Report with enhanced disclosure ✓ Improved Governance: 100% of directors now subject to public election ✓ Formed Plains' Emerging Energy team, advancing multiple opportunities

2021(G) : Furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit). Feb(G): Furnished February 9, 2021.

Hydrocarbons Remain Critical to Supply Global Energy Demand

North America key to global supply response

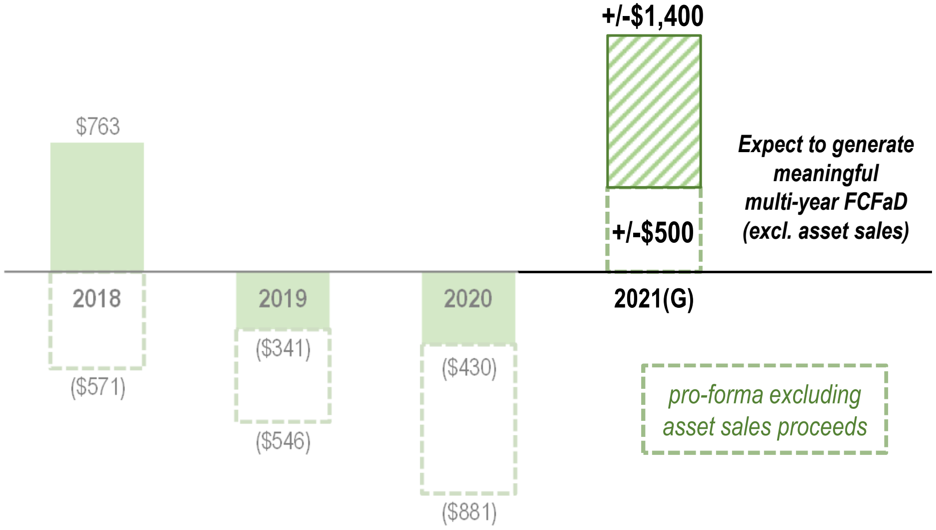
- **Tight global energy markets highlighting need for security of global supply**
  - Global demand approaching pre-COVID levels, resulting in sustained inventory draws against a backdrop of prolonged reduction in upstream investment & continued OPEC discipline
  - Commodity prices responding
- **North American energy supply key to global demand; Permian positioned to drive growth**
  - North America offers most responsibly produced hydrocarbon supply available
  - U.S. short-cycle shale among most economic and well positioned supply options available
  - Permian positioned to drive vast majority of U.S. short-cycle production growth in 2022 and beyond
- **Plains positioned to generate significant +FCF, reduce debt, increase cash returned to equity holders**
  - Significant operating leverage, positioned to capture Permian growth

Positioned to Generate Meaningful Free Cash Flow Going Forward

Balanced approach prioritizing debt reduction and equity returns

FCF after Distributions *(+$50MM vs. Aug(G))*

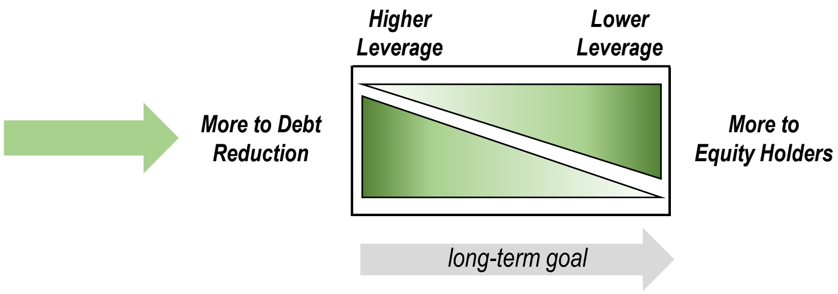
($ in millions)



Note: FCFaD estimate does not factor in material changes in ST working capital

Directional Allocation of FCFaD

(balanced approach)

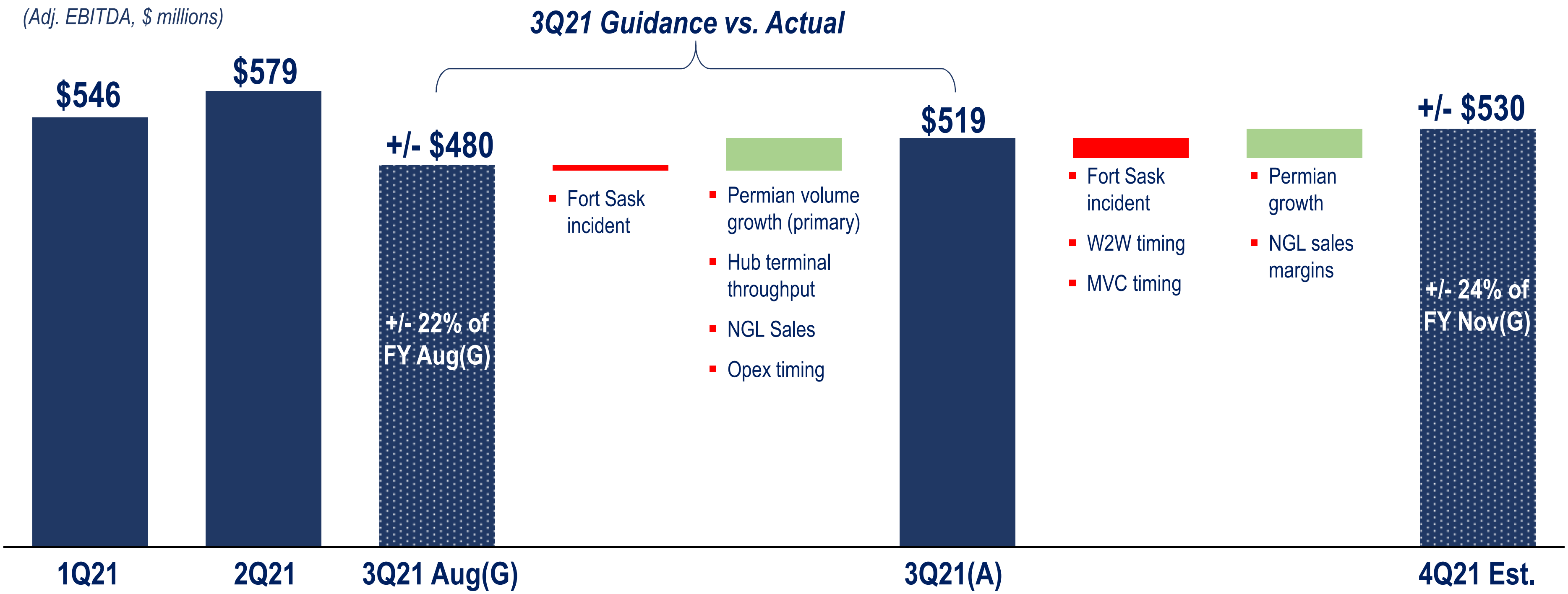


- **FCFaD driven by business performance and estimated run-rate investment capital of +/-$200-$300MM / year**
- **Shift to increasing cash returned to equity holders (repurchases / distribution increases) as leverage decreases**

2021(G): Furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit). Aug(G): Furnished August 3, 2021. Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

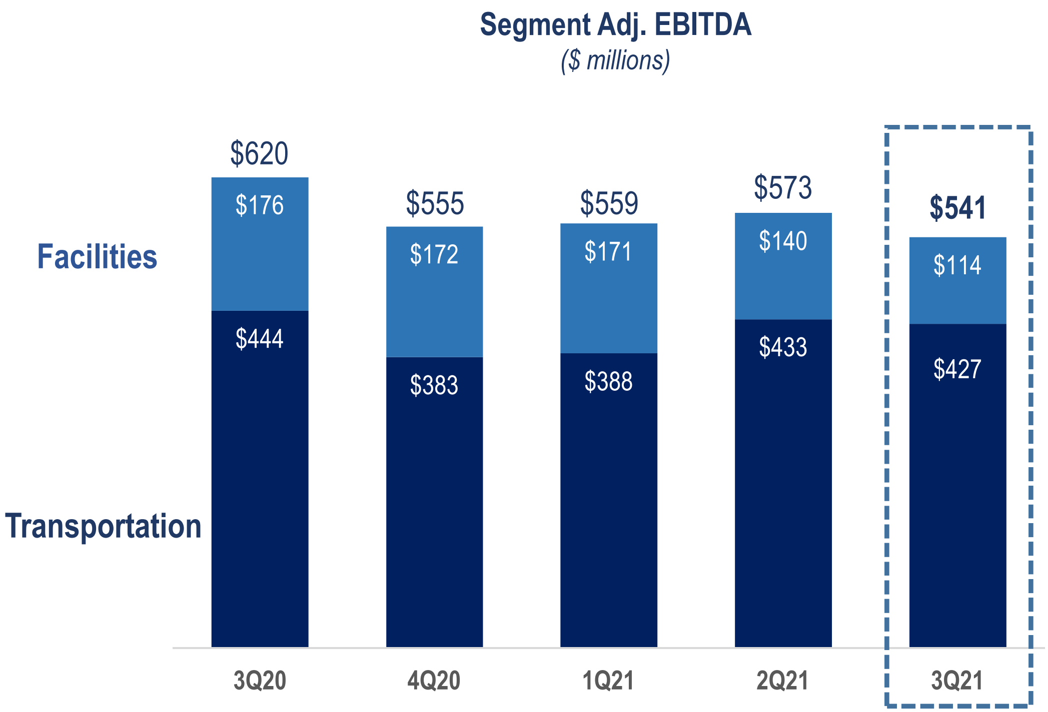
Key Drivers: 3Q21 Results & 4Q21 Estimate

Maintaining full-year 2021(G) of +/- $2.175 B despite impact of non-recurring and timing-related items



Note: over-performance illustrated above (green) includes the adverse impact of crude oil margin compression.
4Q21 Est. / 2021(G): Furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit). Aug(G): Furnished August 3, 2021.
Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

3Q21 Transportation & Facilities Segment Results



3Q Facilities Segment Results

- Q/Q: impact of asset sales, Ft. Sask incident and opex timing
- Y/Y: impact of intersegment-fee adjustment, asset sales and Ft. Sask incident

3Q Transportation Segment Results

- Q/Q: benefit of increased Permian throughput offset by MVC timing
- Y/Y: benefit of increased throughput offset by lower tariffs on certain long-haul volumes

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

Capitalization, Credit Metrics & Liquidity

Reduced total debt $1B since YE-2020

($ billions)

Capitalization	12/31/20	6/30/21	9/30/21	
ST Debt	$0.8	$1.5	$0.8	
LT Debt	9.4	8.4	8.4	
Total Debt	$10.2	$9.8	$9.2	
Partners' Capital	9.7	9.6	9.3	
Total Book Cap (including ST Debt)	$20.0	$19.5	$18.5	
Credit Stats & Liquidity				**Internal Target**
LT Debt / Book Cap	49%	47%	47%	**≤ 50%**
Total Debt / Book Cap (1)	51%	51%	50%	**≤ 60%**
LTM Adj. EBITDA / LTM Int.	5.9x	5.4x	5.1x	**> 3.3x**
LT Debt / LTM Adj. EBITDA	3.7x	3.5x	3.8x	**3.0 - 3.5x (2)**
Total Debt / LTM Adj. EBITDA	4.0x	4.2x	4.2x	
Committed Liquidity	$2.2	$2.6	$2.8	

- Reduced bank debt & commercial paper via asset sales proceeds
- Expect to retire $750MM senior notes (due June 2022) at March 2022 par call date (currently classified as ST debt)
- Renewed and extended credit facilities on Aug. 26th

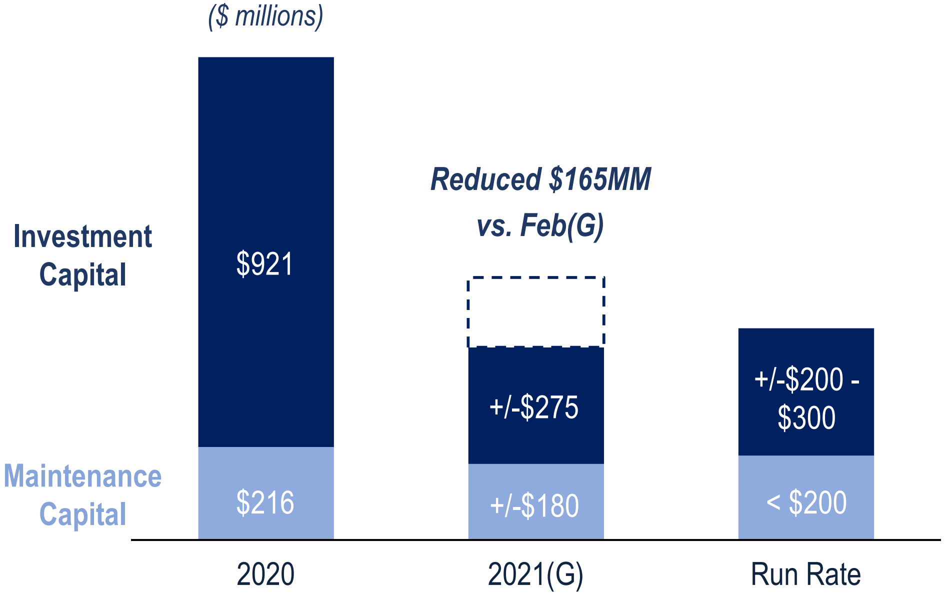
(1) "Total Debt" and "Total Book Cap" include short-term debt for purposes of the ratio calculation.
(2) Targeted leverage assumes normalized S&L contribution.

Capital Allocation Overview

- 2021: Allocate 75%+ of FCFaD to debt reduction & the balance to equity repurchases
  - Includes debt reduction required to neutralize impact of lost EBITDA from 2021 asset sales
  - Allocation to buy-backs of “up to” 25% of FCFaD represents a limit, as opposed to a “target” for 2021
- $167MM in PAA common unit repurchases since Nov-2020 Board authorization ($64MM in 3Q21)
- Timing / pace of equity repurchase activity driven by multiple considerations:
  - Business outlook & positioning
  - Financial performance
  - Relative equity valuation / current yield
  - Trajectory for achieving / maintaining targeted leverage
  - Asset sales impacts (neutralize leverage impact from divested EBITDA)

Disciplined Capital Investment

Focused on High-Return, "Must Do, No Regrets"



- **2021 Investment Capital**
  - Reductions driven by further cost optimization and discontinued projects
- **2022+ Investment Capital ~$200-$300MM[1]**
  - ~50%: Wellhead & CDP Connections (paced w/ producer activity levels)
- **Run Rate Maintenance Capital: < $200MM[2]**

2021(G) and Run Rate: Furnished November 2, 2021 (2022+ assumes +/- $60 / Bbl WTI price environment); Feb(G): Furnished February 9, 2021.
(1) Does not incorporate POPJV consolidation impacts.
(2) Average annual estimate: annual amount may be impacted by timing and/or turnaround projects.

2021 Guidance Update

Increased forecasted FCFaD to +/- $1.4 B

($ millions, except per-unit results)

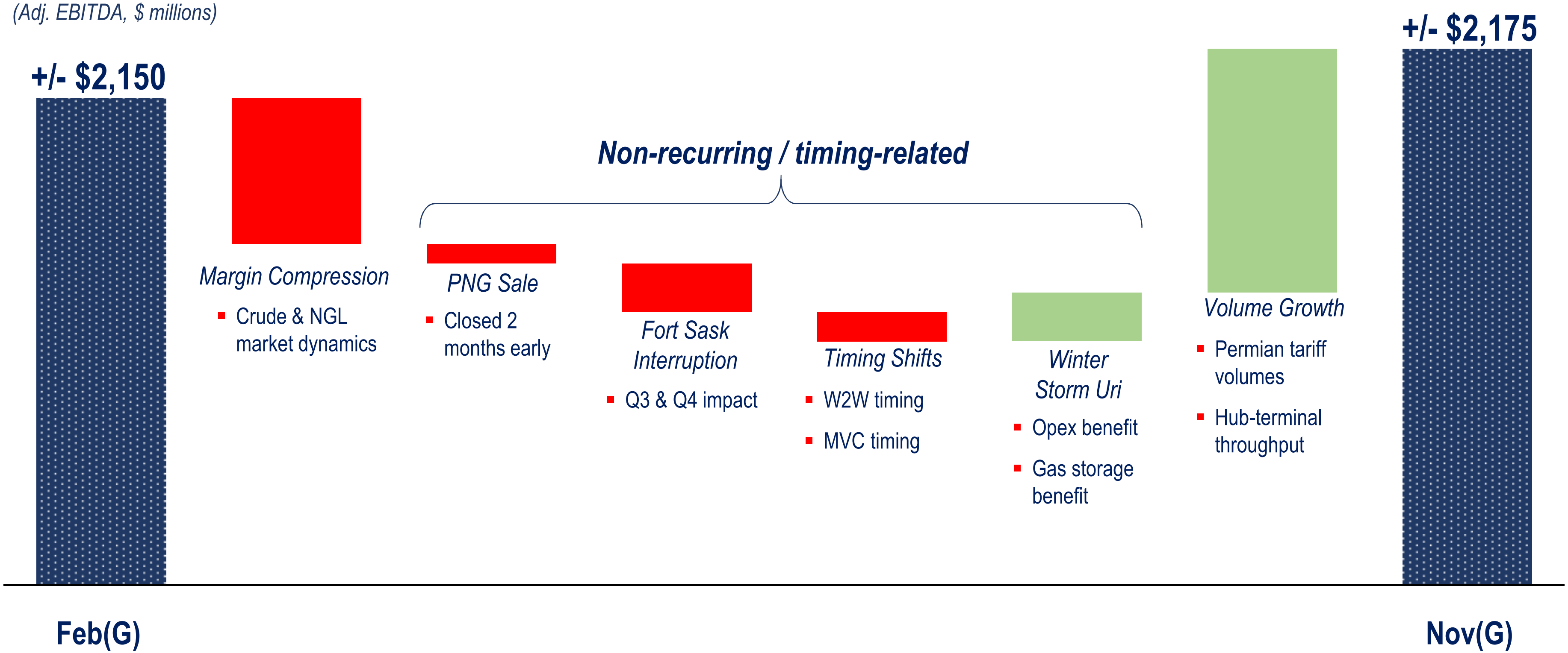
Adj. EBITDA	Aug(G)	Nov(G)
Transportation	+/-$1,635	+/-$1,670
Facilities	+/-$540	+/-$530
Fee-Based	**+/-$2,175**	**+/-$2,200**
S&L, other	+/-$0	+/-$(25)
Total	**+/-$2,175**	**+/-$2,175**
Other		
Implied DCF / CUE[1]	$1.90	$1.92
Adj. NI / Diluted Unit	$0.96	$0.92
Investment Capital	$325	$275
Maintenance Capital	$180	$180
FCFaD (exc. Asset Sales)[2]	**+/-$450**	**+/-$500**
2021 Asset Sales	**~$920**	**~$920**

- **Nov(G) Adj. EBITDA vs. Aug(G):**
  - **Transportation:** Q3 over-performance driven by higher than anticipated throughput across multiple systems
  - **Facilities:** Maintenance & repairs associated with Fort Sask
  - **S&L:** Commercial impact of Fort Sask combined with less-favorable crude oil differentials
- **Nov(G)** excludes Plains Oryx Permian Basin JV
  - Consistent with expectations at announcement, do not expect JV to have a material incremental net EBITDA impact on FY-2021 results

Nov(G): Full-year 2021 guidance furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit); Aug(G): full-year 2021 guidance Furnished August 3, 2021.
(1) Implied DCF per Common Unit & Common Unit Equivalent.
(2) FCFaD estimate does not factor in material changes in ST working capital.

Key Drivers: 2021 Feb(G) vs. Nov(G)

Maintaining full-year 2021(G) of +/- $2.175 B despite impact of non-recurring and timing-related items



Nov(G): Full-year 2021 guidance furnished November 2, 2021; Feb(G): Full-year 2021 guidance furnished February 9, 2021.

Overview of 2021 Goals

Run a safe, reliable and responsible operation

- 2021: Targeting 20% Y/Y reduction in TRIR and Federally Reportable Releases

Generate meaningful Free Cash Flow after Distributions

- Forecasted 2021 FCFaD +/- $1.4 B (vs. Feb-2021 high-end forecast of +/-$1.05 B)

Strengthen balance sheet / financial flexibility

- Expected total 2021 asset sale proceeds of ~$920MM (vs. $750MM target)

Advance sustainability program and disclosures

- Published 2020 Plains Sustainability Report; Announced formation of Emerging Energy Team

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2021(G): Furnished November 2, 2021 (2021 FCFaD assumes current annualized distribution rate of $0.72 per common unit); Feb(G): Furnished February 9, 2021.

3Q21 Earnings Call Key Takeaways

- **Solid 3Q21 results and execution of capital allocation priorities**
- **Continued execution of 2021 initiatives reinforces positioning in 2022+**
- **Increased forecasted 2021 FCFaD by $50MM to +/- $1.4 B[(1)]**
- **Completed Plains Oryx Permian JV – integration and synergies on track**
- **Fundamentals increasingly constructive, Permian is growth driver**
- **Plains well positioned to generate significant positive FCF going forward**
  - Reinforces further reducing leverage and increasing cash returned to equity holders

2021(G): Furnished November 2, 2021.
(1) Includes $920MM in asset sales proceeds ($50MM pending) or +/- $500MM excluding asset sales proceeds; Assumes current annualized distribution rate of $0.72 / common unit.

Plains Sustainability Report Highlights

For full sustainability report and disclosures, please visit https://www.plainsallamerican.com/sustainability.

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Long-Term Outlook for Energy Industry Supports Conviction in Plains' Cash Flow Sustainability

- **Expect absolute demand for nearly all forms of energy to increase long-term**
- **Evolution to lower carbon intensity to occur over extended time period; will require all sources of energy (including hydrocarbons) to meet demand & bridge to the future**
- **Hydrocarbons will remain essential to global population growth & improving quality of life**
  - Mobility, power generation, heating and cooling, steel, cement, plastics & fertilizers
- **Midstream will remain an essential link between energy supply & demand**

Emerging Energy Team

Announced Oct-2021

- **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
- **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 participating in collaborative sustainability initiatives: Greater Houston Partnership Energy Transition, Energy Infrastructure Council (EIC), API among others**

Plains 2020 Sustainability Report Highlights

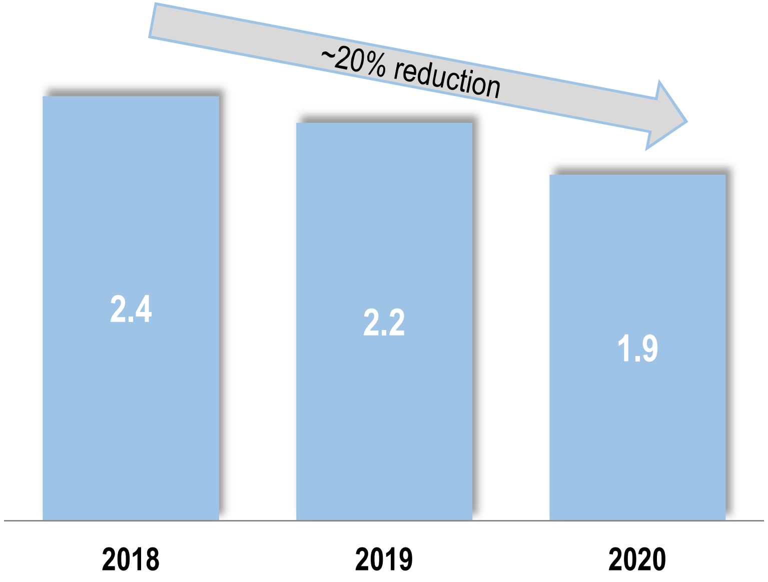
Published July-2021

- **Comprehensively describes Sustainability program, strategy and performance, along with 130+ quantitative metrics (expanded from 64 in 2019), highlights include:**
  - Inaugural publication of GHG emissions, reflecting ~20% reduction from 2018 – 2020 with total emissions comparing favorably to peers
  - Formation of a Health, Safety, Environmental and Sustainability Board Committee to provide oversight of sustainability function and reporting
  - Continued expansion and refinement of philanthropy and volunteerism efforts in communities where we operate
- **Enhanced alignment with Energy Infrastructure Council (EIC), Sustainability Accounting Standards Board (SASB) and Global Reporting Initiative (GRI) frameworks**
- **Welcome your feedback on 2020 report and overall Sustainability program**

2020 Scope 1 & 2 Emissions

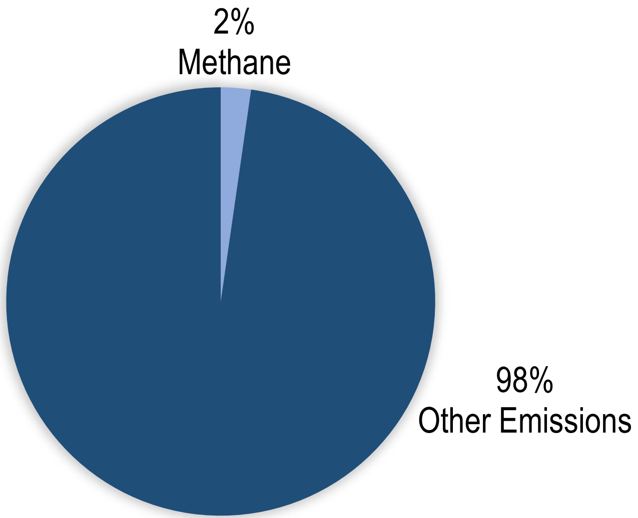
~20% improvement over last 3 years

Total Scope 1 + Scope 2 GHG Emissions (mmt CO2e)



-- Evaluating an emissions reduction target --

2020 Scope 1 Emissions Percentage Methane

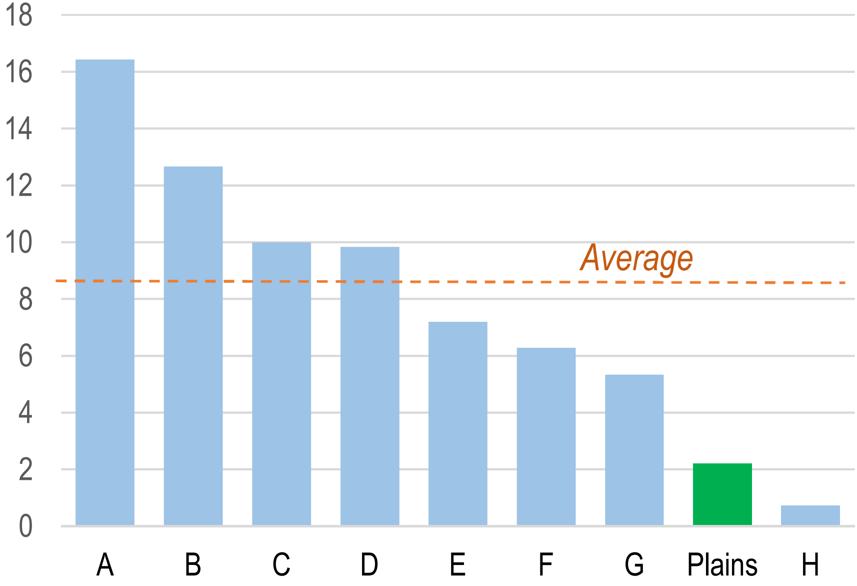


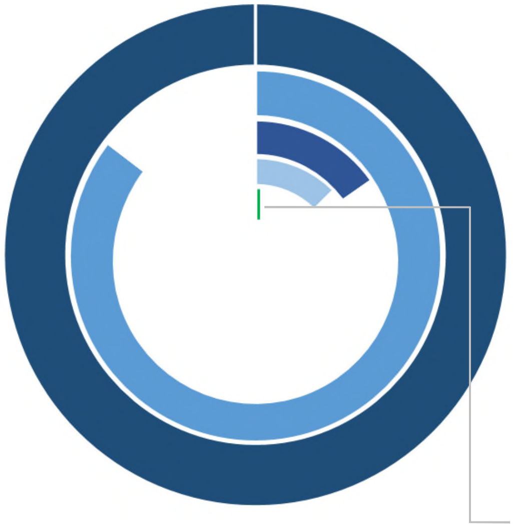
Context for Emissions Estimations & Comparisons

- Emissions estimation methodologies vary across the industry
  - Plains endeavored to report comprehensive emissions for the full enterprise
    - Includes GHGs for material activities (i.e. pipeline, trucking, storage, fractionation and processing)
  - Guidance on estimation of additional emissions metrics (e.g. emissions throughput intensity, Scope 3 emissions) continues to evolve, and diversity of Plains' activities present unique considerations for these calculations, as a result, Plains is not currently reporting these metrics
  - We continue to actively engage in / monitor the development / evolution of estimation guidance standards and will consider updates to our disclosure as guidance evolves

2019 Emissions in Perspective

Total Scope 1 + Scope 2 GHG Emissions Among Peers[1] (mmt CO2e)





Worldwide Emissions (mmt CO2e)[2]

43,100
Energy & Non-energy Sources

36,800
Energy Sources

U.S. Emissions (mmt CO2e)[3]

6,600
Energy & Non-energy Sources

5,400
Energy-related

Plains Emissions (mmt CO2e)[4]

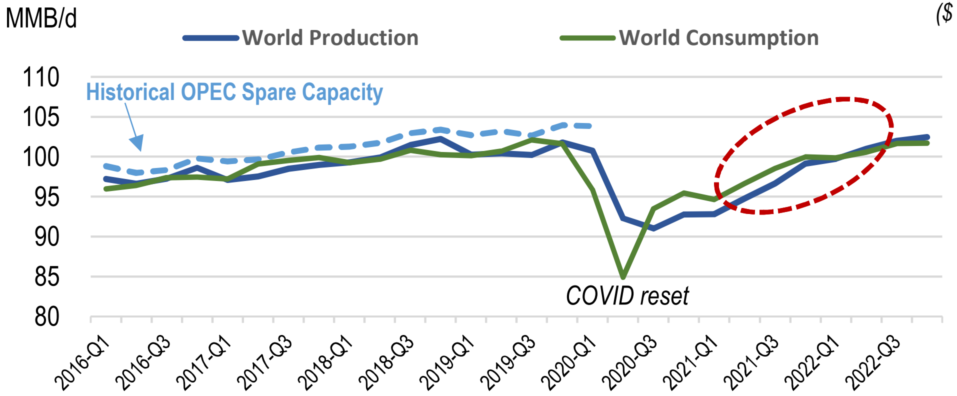
2

(1) Peers based on Plains' 2020 Total Shareholder Return Proxy Group where data is available; Peer data in certain cases contains emissions from parent company activities which may not be directly comparable to our business.
(2) Global Carbon Project, 2019 (3) U.S. EPA, 2019 (4) Includes Scope 1 and 2 emissions.

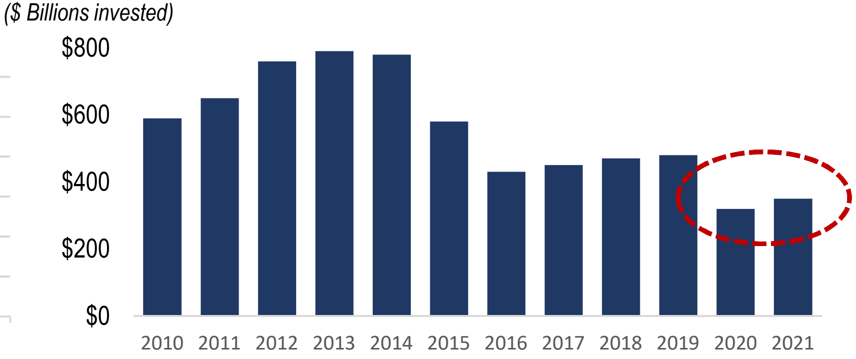
APPENDIX

Fundamentals Highlighting Hydrocarbons are Critical

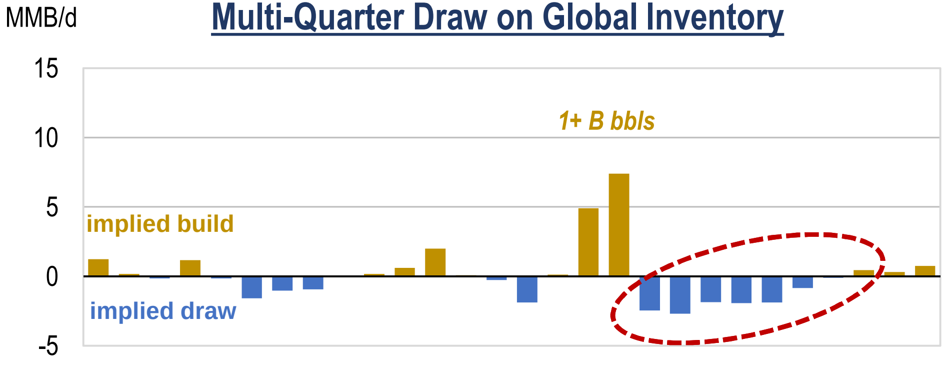
Global Supply & Demand Rebalancing[1]



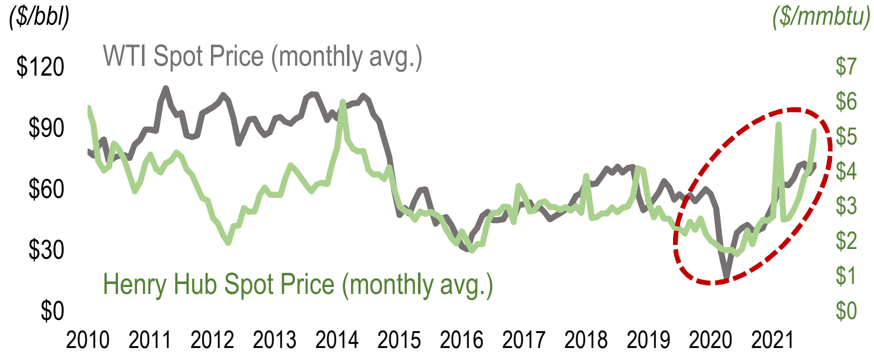
Prolonged Reduction in Upstream Investment[2]



Multi-Quarter Draw on Global Inventory



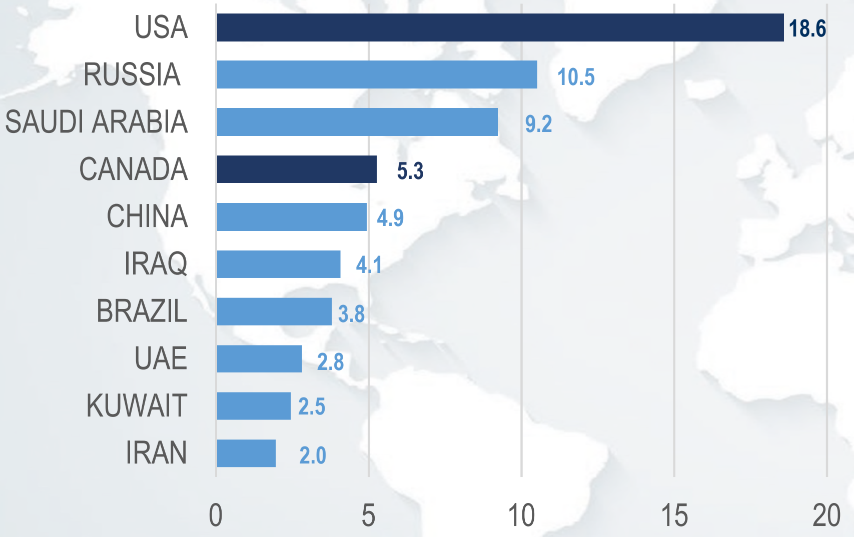
Commodity Prices Responding



(1) EIA October 2021 STEO (includes crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.)
(2) IEA & PAA Internal Estimates

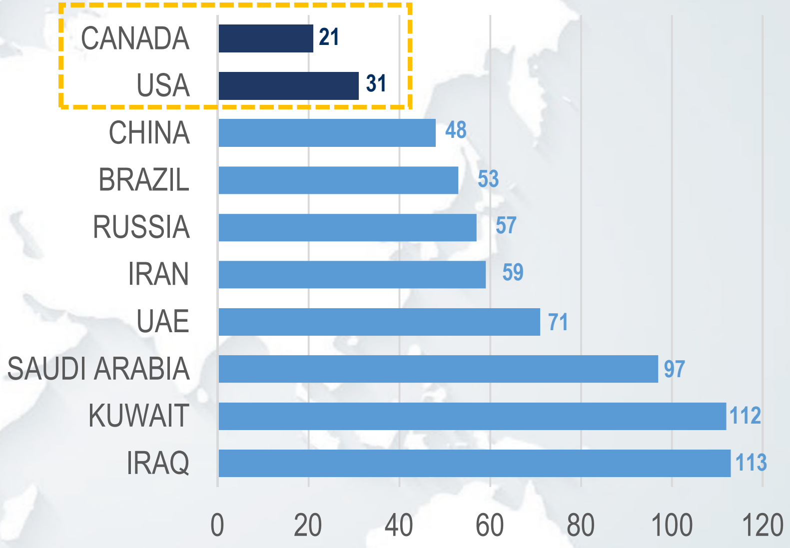
North American Energy: The Responsibly Produced Option

TOP 10 LIQUIDS PRODUCING NATIONS MMB/D AT YE2020



Source: EIA October 2021 STEO. Liquids includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

UN SDG RANK (LOWER IS FAVORABLE)



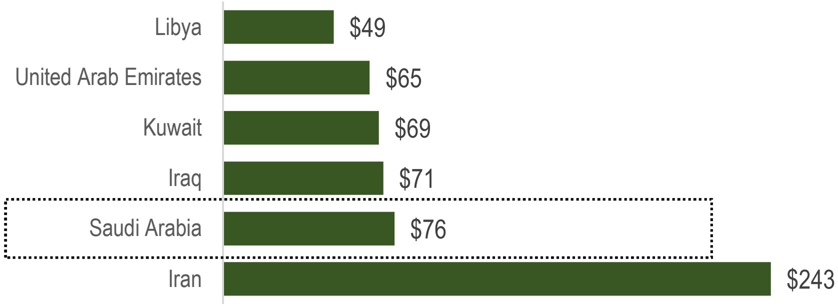
2020 Country ranking relative to UN Sustainable Development Goals (SDG)

North America Key to Meeting Global Energy Demand

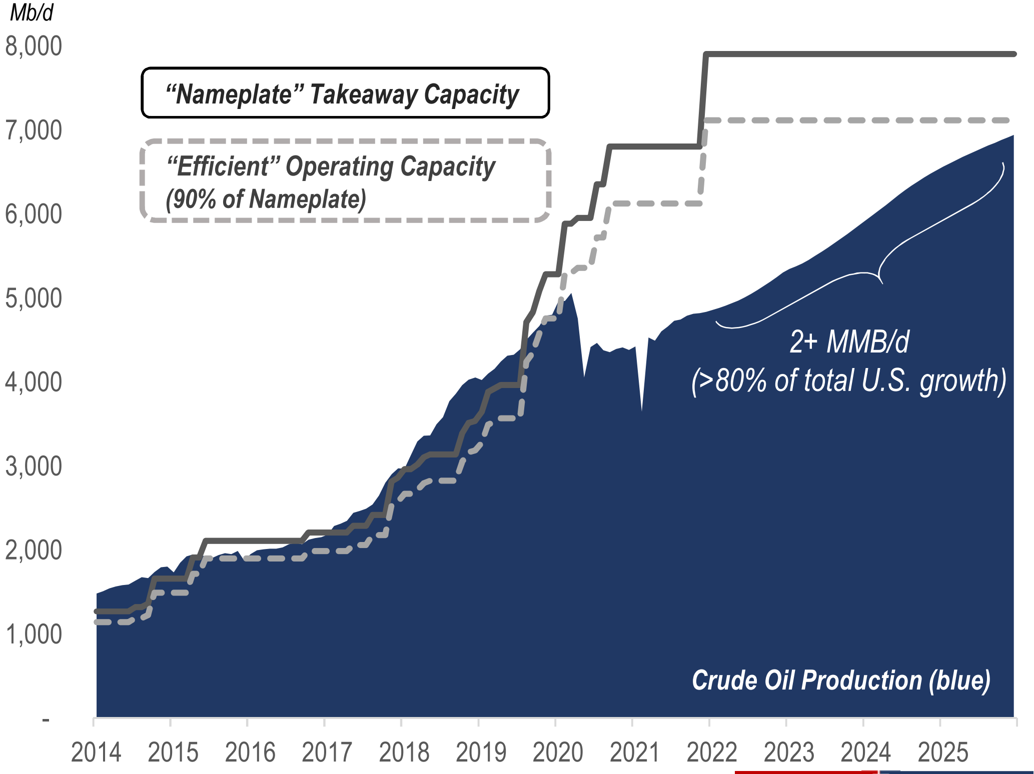
Expect Permian to Drive Vast Majority of U.S. Short-Cycle Production Growth

New Supply Development Breakevens[1]

Fiscal Breakevens[2]

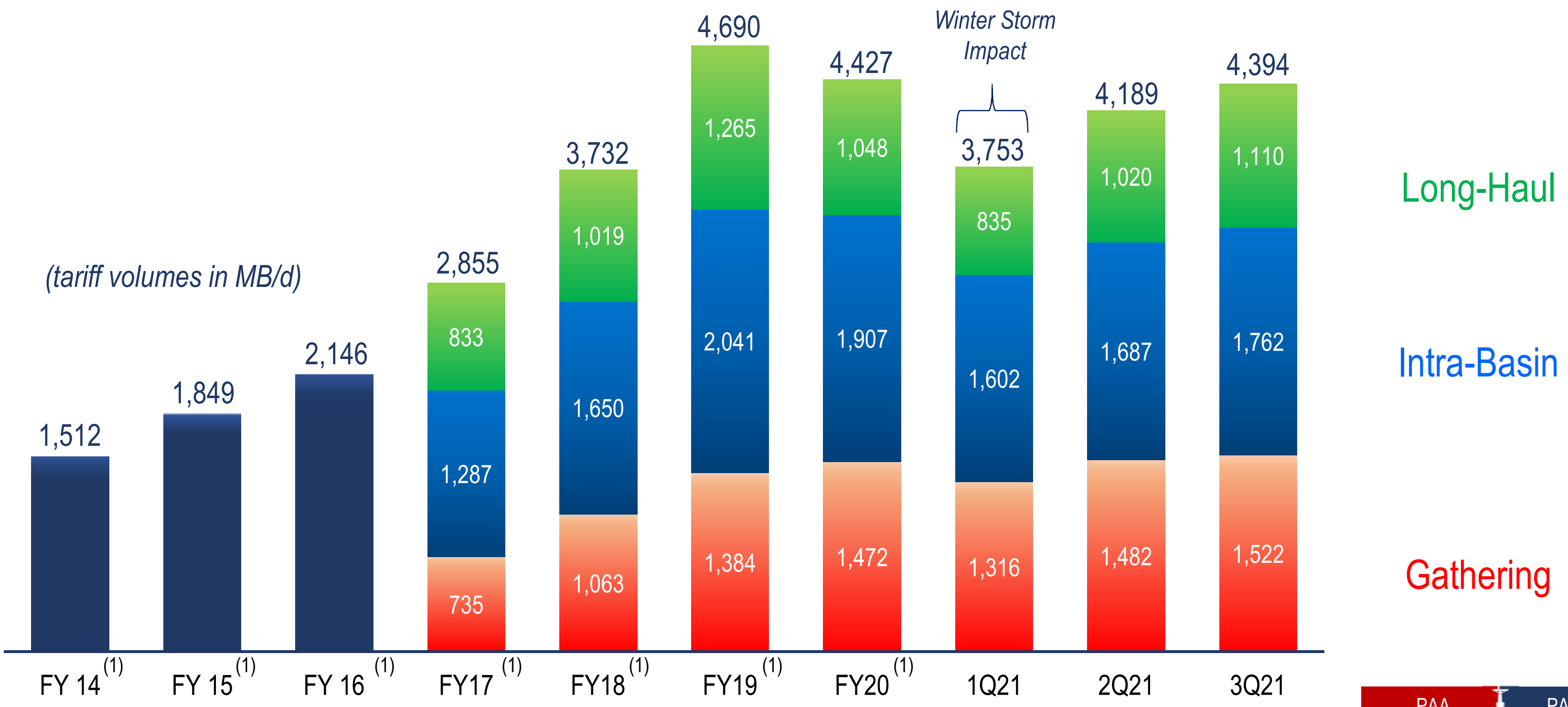


Permian Positioned for Multi-Year Growth[3]



(1) S&P Global Platts ($/Bbl, Brent) (2) International Monetary Fund ($/Bbl, Brent) (3) PAA Estimates, Enverus

Plains' Permian Tariff Volumes



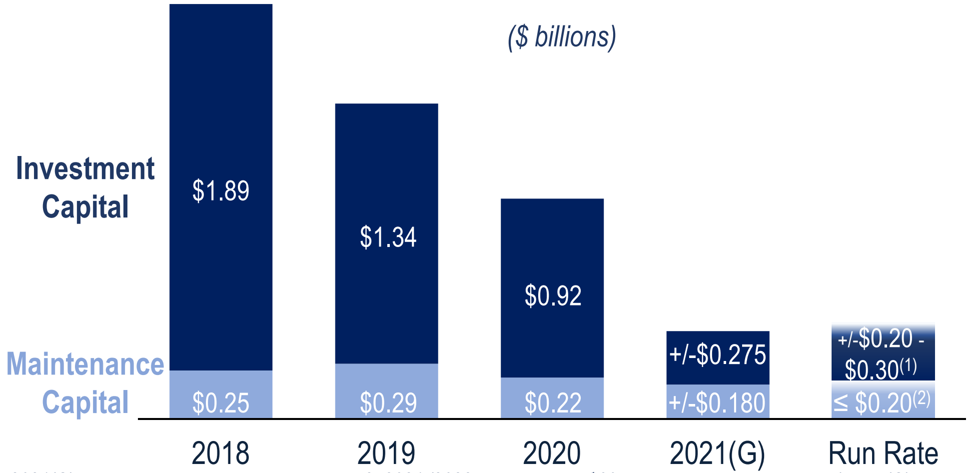
(1) Represents full-year averages.

Reinforcing Transition to Positive Free Cash Flow

Lower Capital Investment & Proceeds from Asset Sales Benefitting Free Cash Flow

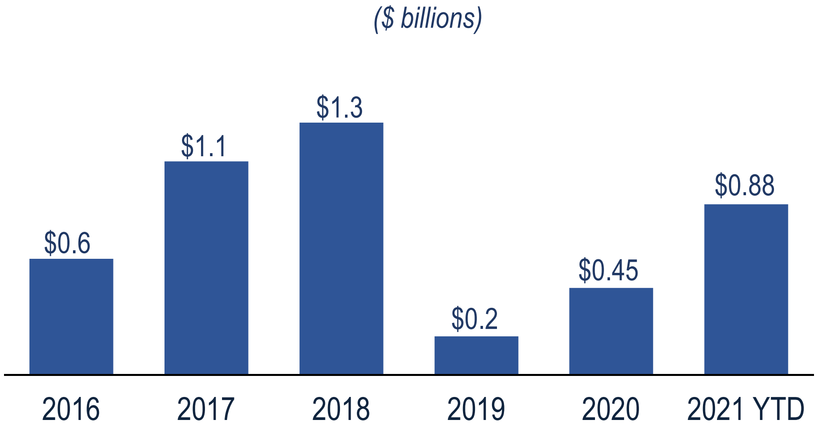
Capital Investment

- Reduced 2021 Investment capital $50MM vs. Aug(G)
- Completing multi-year capital program
- Substantially lower capital going forward



Asset Sales

- 2016 – 2021: ~$4.5 B in cumulative divestitures (combination of non-core sales and strategic JVs)
- FY 2021: Expect ~$920MM (vs. $750MM targeted)



2021(G) and Run Rate: Furnished November 2, 2021 (2022+ assumes +/- $60 / Bbl WTI price environment); Aug(G): Furnished August 3, 2021.

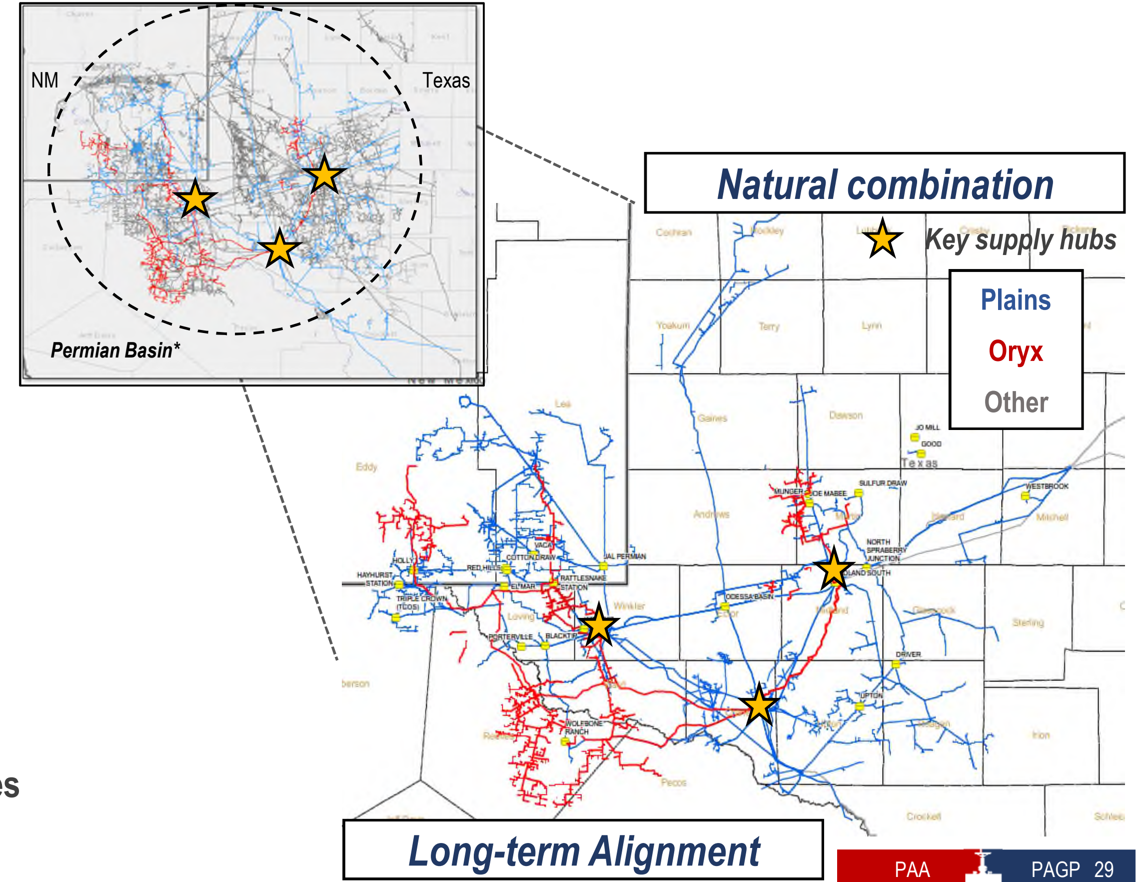
(1) Does not incorporate POPJV consolidation impacts.

(2) Average annual estimate: annual amount may be impacted by timing and/or turnaround projects.

Plains Oryx Permian Basin JV

Strategic Alignment, Multiple Benefits

- **Significant value for customers – increases connectivity, flexibility and access to markets**
- **Complementary assets – enhances system shipper diversification, economies of scale, quality of long-term free cash flow**
  - Well established long-term relationships with large public and private producers
- **High quality, long-term committed acreage – multi-decade inventory life, vast majority w/ projected IRR of 25% – 50%+ (~$50 / Bbl WTI) in both Delaware and Midland Basins**
- **Near-term FCF accretive to Plains & Oryx, plus upside leverage with Permian growth & synergies**



Map Source: DrillingInfo; includes operational gathering and transmission lines; "Other" reflected in grey comprised of >30 third-party operators.

Plains Oryx Permian Basin JV Offers Customers Enhanced Flexibility, Optionality and Connectivity

	Pro-Forma
Pipeline Miles *(PAA ~3,900 / Oryx ~1,600)*	~ 5,500
Pipeline Capacity (mmb/d) *(PAA ~5.8 / Oryx ~1.0)*	~ 6.8
Direct Downstream Connections *(PAA 10 / Oryx 8)*	10+
Dedicated System Acres[(1)] (millions) *(PAA ~2.8 / Oryx ~1.3)*	~ 4.1
Inventory Life (wtd. avg. years remaining)	> 30
Core & Tier I Producer Drilling Inventory[(2)]	~ 75%
% Committed Acreage on Fed Lands *(PAA ~15% / Oryx <10%)*	~ 12%
Contract Tenor (wtd. avg. years remaining) *(PAA ~6.0 / Oryx ~9.5)*	~ 7.0
Total Customers	50 – 85+
% Public / % Private (acreage wtd.)	~ 80% / ~ 20%
Forecasted 2021 FCF ($ in millions) *(PAA ~$425 / Oryx ~$200)*	+/- $625

65% / 35% Ownership Primarily Driven by:

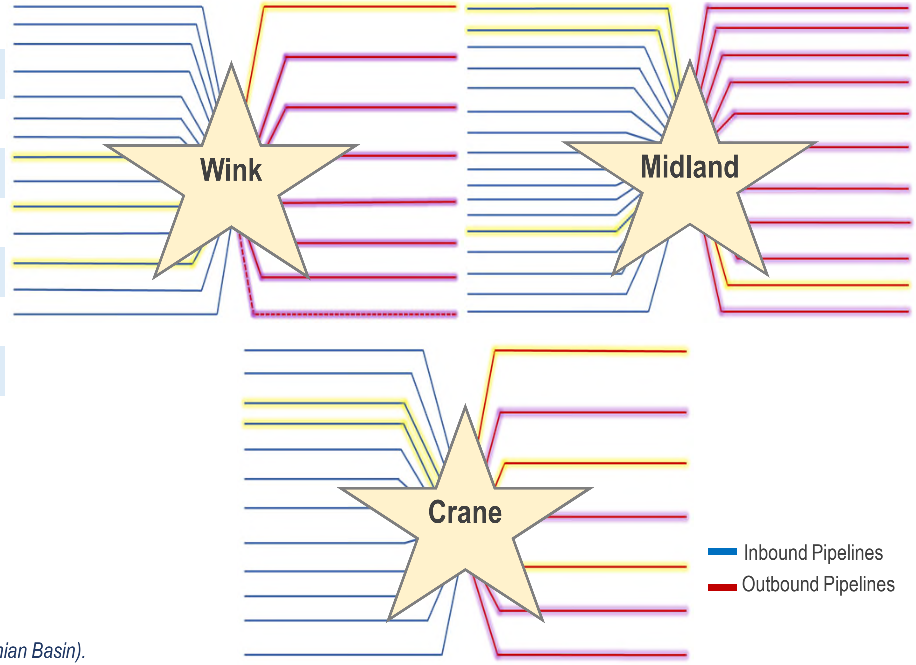
Core & Tier 1 Inventory[(2)] Contributions: PAA ~65% / Oryx ~35%

5 Year FCF Avg: PAA ~65% / Oryx ~35%

Connectivity to all major Permian intra-basin hubs

yellow highlights = pro-forma new connections for existing PAA shippers

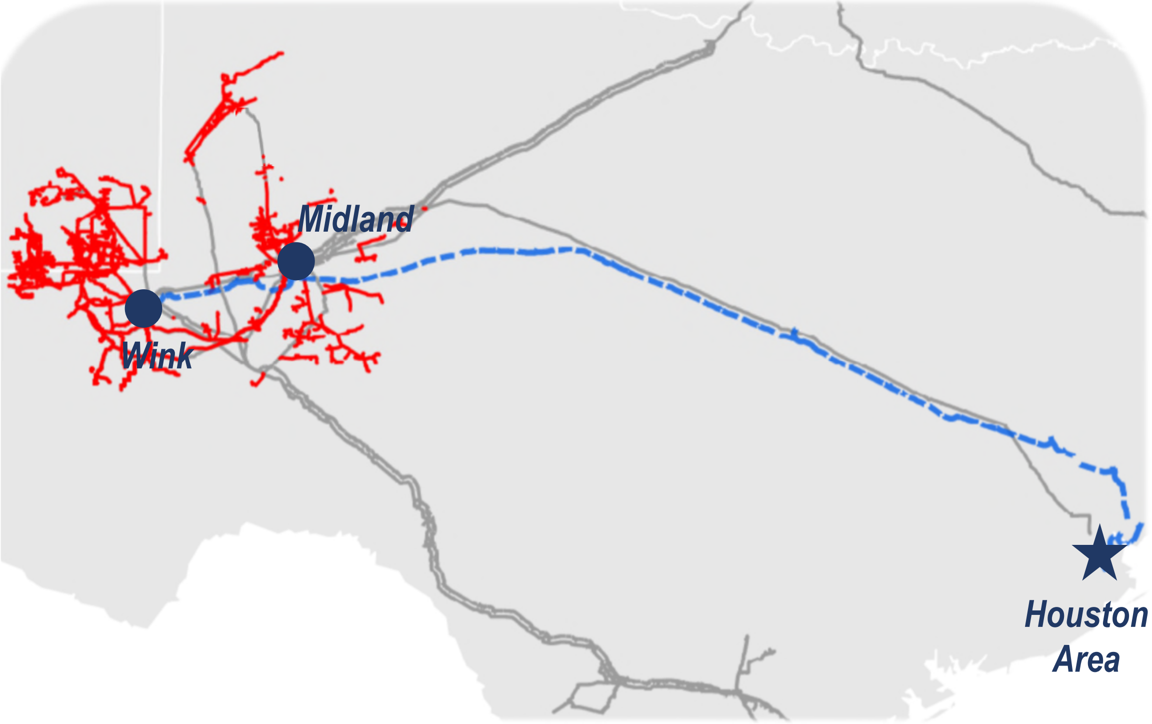
purple highlights = pro-forma gained capacity / optionality for Oryx shippers



Note: Connectivity diagrams reflect selected PAA & Oryx connectivity (does not represent all pipeline connectivity in the Permian Basin).

(1) Includes supply and facilities dedications. (2) Core & Tier I drilling locations projected IRR of 25% - 50%+ based on WTI of ~$50 / Bbl; ~75% represents percentage of Core & Tier 1 locations relative to total estimated locations contractually dedicated to the assets.

Permian to USGC: Wink to Webster



Wink to Webster
Plains' Gathering (includes Plains Oryx Permian Basin JV)
(other Plains assets in grey)

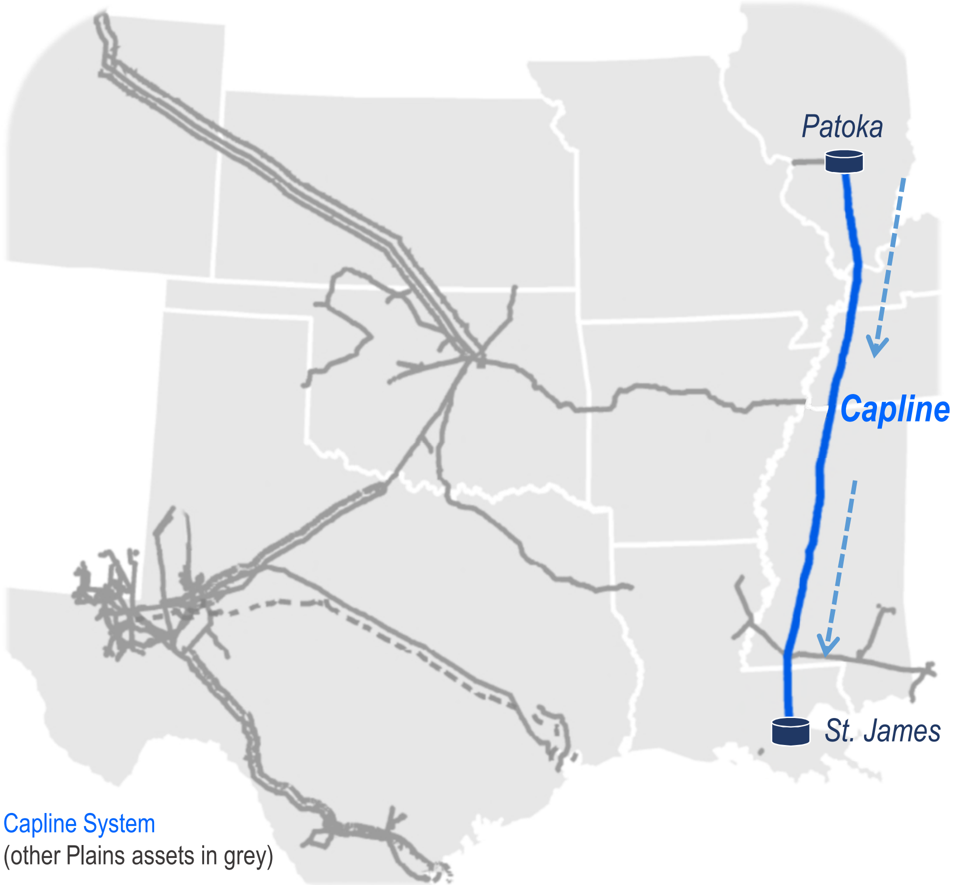
Current Status

- Midland-to-Webster entered service Jan-2021
- MVCs ramping from 1Q22 through 2023
- Deferred portion of investment to align w/ MVC ramp

Project Overview

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

Patoka to St. James: Capline Reversal



Capline System
(other Plains assets in grey)

Current Status

- Linefill in process, to be completed Dec-21
- On track for Jan-22 in-service
- Initial throughput ~100mb/d, with additional capacity to meet growth in Canadian production

Project Overview

- Reversal of 40" pipe to southbound service
- Origin: Patoka, Illinois
- Destination: St. James, Louisiana
- PAA JV ownership: ~54% (non-operated equity interest asset)
- Other JV partners: MPLX & BP
- Independent of Diamond Expansion

Free Cash Flow: Historical Detail

GAAP CFFO to Non-GAAP FCF

	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20	2020	1Q21	2Q21	3Q21	YTD	LTM
Net Cash Provided by Op. Activities (GAAP)	$ 733	$ 2,499	$ 2,608	$ 2,504	$ 890	$ 84	$ 282	$ 258	$ 1,514	$ 791	$ 235	$ 336	$ 1,361	$ 1,620
Net Cash Used in Investing Activities	(1,273)	(1,570)	(813)	(1,765)	(610)	(248)	(208)	(27)	(1,093)	(108)	(175)	761	478	451
Cash Contributions from Noncontrolling Interests	-	-	-	-	8	2	1	1	12	1	-	-	1	2
Cash Distributions Paid to Noncontrolling Interests[1]	(4)	(2)	-	(6)	-	(4)	(2)	(4)	(10)	(6)	-	(4)	(10)	(14)
Sale of Noncontrolling Interest in a Sub	-	-	-	128	-	-	-	-	-	-	-	-	-	-
Free Cash Flow (non-GAAP)	**$ (544)**	**$ 927**	**$ 1,795**	**$ 861**	**$ 288**	**$ (166)**	**$ 73**	**$ 228**	**$ 423**	**$ 678**	**$ 60**	**$ 1,093**	**$ 1,830**	**$ 2,059**
Total Distributions[2]	(1,627)	(1,391)	(1,032)	(1,202)	(299)	(193)	(168)	(193)	(853)	(167)	(192)	(166)	(526)	(718)
FCF after Distributions (non-GAAP)	**$ (2,171)**	**$ (464)**	**$ 763**	**$ (341)**	**$ (11)**	**$ (359)**	**$ (95)**	**$ 35**	**$ (430)**	**$ 511**	**$ (132)**	**$ 927**	**$ 1,304**	**$ 1,341**

- Absent short-term changes in the working capital, we expect our cash generation combined with lower investment & maintenance capital to benefit free cash flow in 2021 and beyond.

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

Management uses the non-GAAP financial measures Free Cash Flow ("FCF") and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, 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.

2021(G) as of November 2, 2021

($ in millions, except per-unit data)	Twelve Months Ended December 31, 2019	2020	2021 (G) + / -
Segment Adjusted EBITDA			
Transportation	$ 1,722	$ 1,616	$ 1,670
Facilities	705	731	530
Fee-Based	**$ 2,427**	**$ 2,347**	**$ 2,200**
Supply and Logistics	803	210	(25)
Adjusted other income/(expense), net	7	3	—
Adjusted EBITDA	**$ 3,237**	**$ 2,560**	**$ 2,175**
Interest expense, net of certain non-cash items	(407)	(415)	(405)
Maintenance capital	(287)	(216)	(180)
Current income tax expense	(112)	(51)	(15)
Other	(55)	3	(10)
Implied DCF	**$ 2,376**	**$ 1,881**	**$ 1,565**
Preferred unit distributions paid	(198)	(198)	(200)
Implied DCF Available to Common Unitholders	**$ 2,178**	**$ 1,683**	**$ 1,365**
Implied DCF per Common Unit and Common Unit Equivalent	$ 2.91	$ 2.29	$ 1.92
Distributions per Common Unit (1)	$ 1.38	$ 0.90	$ 0.72
Common Unit Distribution Coverage Ratio (1)	2.17x	2.57x	2.64x
Diluted Adjusted Net Income per Common Unit	$ 2.51	$ 1.55	$ 0.92

2021(G): Furnished November 2, 2021. (1) 2021(G) reflects the current annualized distribution rate of $0.72 per common unit.
Note: Please visit IR page of www.plainsallamerican.com for reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

2021(G) as of November 2, 2021

($ in millions, except per-unit and per-barrel data)	Twelve Months Ended December 31,					
	2019		2020		2021 (G)	
						+ / -
Operating Data						
Transportation						
Average daily volumes (MBbls/d)		6,893		6,340		6,250
Segment Adjusted EBITDA per barrel	$	0.68	$	0.70	$	0.73
Facilities						
Average capacity (MMBbls/Mo)		125		124		110
Segment Adjusted EBITDA per barrel	$	0.47	$	0.49	$	0.40
Supply and Logistics						
Average daily volumes (MBbls/d)		1,369		1,318		1,475
Segment Adjusted EBITDA per barrel	$	1.61	$	0.43	$	(0.05)
Investment Capital	**$**	**1,340**	**$**	**921**	**$**	**275**

2021(G): Furnished November 2, 2021.
Note: Please visit IR page of www.plainsallamerican.com for reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Condensed Consolidating Balance Sheet of Plains GP Holdings (PAGP)

($ in millions)	September 30, 2021 PAA	September 30, 2021 Consolidating Adjustments [1]	September 30, 2021 PAGP	December 31, 2020 PAA	December 31, 2020 Consolidating Adjustments [1]	December 31, 2020 PAGP
ASSETS						
Current assets	$ 4,874	$ 3	$ 4,877	$ 3,665	$ 3	$ 3,668
Property and equipment, net	13,084	6	13,090	14,611	9	14,620
Investments in unconsolidated entities	3,710	—	3,710	3,764	—	3,764
Deferred tax asset	—	1,423	1,423	—	1,444	1,444
Linefill and base gas	901	—	901	982	—	982
Long-term operating lease right-of-use assets, net	374	—	374	378	—	378
Long-term inventory	221	—	221	130	—	130
Other long-term assets, net	1,033	(2)	1,031	967	(2)	965
Total assets	$ 24,197	$ 1,430	$ 25,627	$ 24,497	$ 1,454	$ 25,951
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 5,397	$ 2	$ 5,399	$ 4,253	$ 2	$ 4,255
Senior notes, net	8,327	—	8,327	9,071	—	9,071
Other long-term debt, net	61	—	61	311	—	311
Long-term operating lease liabilities	326	—	326	317	—	317
Other long-term liabilities and deferred credits	789	—	789	807	—	807
Total liabilities	14,900	2	14,902	14,759	2	14,761
Partners' capital excluding noncontrolling interests	9,152	(7,800)	1,352	9,593	(8,129)	1,464
Noncontrolling interests	145	9,228	9,373	145	9,581	9,726
Total partners' capital	9,297	1,428	10,725	9,738	1,452	11,190
Total liabilities and partners' capital	$ 24,197	$ 1,430	$ 25,627	$ 24,497	$ 1,454	$ 25,951

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

Houston, Texas | November 2, 2021

3Q21
EARNINGS CALL

PLAINS
ALL AMERICAN

Plains All American Reports Third-Quarter 2021 Results

Houston, TX – November 2, 2021– Plains All American Pipeline, L.P. (Nasdaq: PAA) and Plains GP Holdings (Nasdaq: PAGP) today reported third-quarter 2021 results and provided the following updates:

- Successfully completed formation of Plains Oryx Permian Basin strategic joint venture (closed October 5th); cashless transaction, debt-free entity, near-term free cash flow accretive to Plains and Oryx, with targeted JV synergies of $50–$100 million or more
- Reported a net loss for the period of $59 million, including the non-cash impact of an approximately $220 million asset impairment charge
- Reported third-quarter Adjusted EBITDA of $519 million and maintained full-year 2021 Adjusted EBITDA guidance of +/- $2.175 billion (includes approximately $40 million impact of Fort Saskatchewan incident and other timing-related items)
- Increased forecasted 2021 Free Cash Flow after Distributions by $50 million to +/- $1.4 billion, or +/- $500 million excluding proceeds from asset sales
- Reduced 2021 capital (investment and maintenance) guidance by an additional $50 million to +/- $455 million, approximately 30% below February guidance
- Reduced total debt by approximately $650 million in the period and by approximately $1 billion since year-end 2020
- Continued utilizing the November 2020 repurchase authorization during the period, bringing total cumulative repurchases to $167 million, or 18.1 million PAA common units

"We delivered third-quarter results that exceeded our expectations, increased our full-year Free Cash Flow outlook and maintained full-year Adjusted EBITDA guidance despite the impact of non-recurring and timing-related items," stated Willie Chiang, Chairman and CEO of Plains. "Importantly, we continue to execute across multiple key initiatives, all of which are aimed at maximizing free cash flow to reinforce our balance sheet and generate attractive returns for our equity holders. Integration of the Plains Oryx Permian Basin joint venture is well underway, and we are increasingly confident in the synergies the JV is positioned to capture, the value of the operating leverage embedded within our system, and the magnitude of production growth the basin is positioned to deliver over the next several years."

- more -

Plains All American Pipeline

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

GAAP Results	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	% Change	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	% Change
Net income/(loss) attributable to PAA [1]	$ (59)	$ 143	**	$ 143	$ (2,562)	**
Diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	**	$ (0.01)	$ (3.72)	**
Diluted weighted average common units outstanding	715	728	(2)%	719	728	(1)%
Net cash provided by operating activities	$ 336	$ 282	19 %	$ 1,361	$ 1,256	8 %
Distribution per common unit declared for the period	$ 0.18	$ 0.18	— %	$ 0.54	$ 0.54	— %

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

(1) Reported results for the nine months ended September 30, 2021 include aggregate non-cash asset impairments of approximately $695 million related to the sale of our gas storage assets and the write-down of certain crude oil terminal assets. Reported results for the nine months ended September 30, 2020 include aggregate non-cash goodwill and asset impairments and the write-down of certain of our investments in unconsolidated entities totaling $3.3 billion, representing a nine-month net loss of $4.55 after tax per common unit.

Non-GAAP Results [1]	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	% Change	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	% Change
Adjusted net income attributable to PAA	$ 208	$ 382	(46)%	$ 653	$ 1,070	(39)%
Diluted adjusted net income per common unit	$ 0.22	$ 0.46	(52)%	$ 0.70	$ 1.26	(44)%
Adjusted EBITDA	$ 519	$ 682	(24)%	$ 1,643	$ 2,001	(18)%
Implied DCF per common unit and common unit equivalent	$ 0.48	$ 0.63	(24)%	$ 1.51	$ 1.84	(18)%
Free Cash Flow	$ 1,093	$ 73	**	$ 1,830	$ 195	**
Free Cash Flow after Distributions	$ 927	$ (95)	**	$ 1,304	$ (466)	**

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

(1) See the section of this release entitled “Non-GAAP Financial Measures and Selected Items Impacting Comparability” and the tables attached hereto for information regarding our Non-GAAP financial measures, including their reconciliation to the most directly comparable measures as reported in accordance with GAAP, and certain selected items that PAA believes impact comparability of financial results between reporting periods.

- more -

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

	Segment Adjusted EBITDA		
	Transportation	Facilities	Supply and Logistics
Three Months Ended September 30, 2021	$ 427	$ 114	$ (23)
Three Months Ended September 30, 2020	$ 444	$ 176	$ 61
Percentage change in Segment Adjusted EBITDA versus 2020 period	*(4)%*	*(35)%*	**
Percentage change in Segment Adjusted EBITDA versus 2020 period further adjusted for impact of divested assets (1)	*(4)%*	*(26)%*	*N/A*

	Segment Adjusted EBITDA		
	Transportation	Facilities	Supply and Logistics
Nine Months Ended September 30, 2021	$ 1,248	$ 425	$ (31)
Nine Months Ended September 30, 2020	$ 1,233	$ 560	$ 205
Percentage change in Segment Adjusted EBITDA versus 2020 period	*1 %*	*(24)%*	**
Percentage change in Segment Adjusted EBITDA versus 2020 period further adjusted for impact of divested assets (1)	*1 %*	*(20)%*	*N/A*

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

(1) Estimated impact of divestitures completed during 2020 and 2021, assuming an effective date of January 1, 2020. Divested assets primarily included certain NGL storage terminals, Los Angeles Basin crude oil storage terminals and natural gas storage facilities that were previously included in our Facilities segment and the sale of a portion of our interest in a joint venture pipeline that was previously reported in our Transportation segment.

Third-quarter 2021 Transportation Segment Adjusted EBITDA decreased 4% versus comparable 2020 results primarily due to lower tariffs on certain long-haul volumes partially offset by an overall increase in tariff volumes.

Third-quarter 2021 Facilities Segment Adjusted EBITDA decreased 35% versus comparable 2020 results primarily due to the impact of asset sales and reduced NGL intersegment fees.

Third-quarter 2021 Supply and Logistics Segment Adjusted EBITDA decreased versus comparable 2020 results primarily due to contango margins realized in the third quarter of 2020, partially offset by reduced NGL intersegment fees.

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

Financial and Operating Guidance (unaudited)
(in millions, except volumes, per unit and per barrel data)

	Twelve Months Ended December 31,		
	2019	2020	2021 (G)
			+ / -
Segment Adjusted EBITDA			
Transportation	$ 1,722	$ 1,616	$ 1,670
Facilities	705	731	530
Fee-Based	**$ 2,427**	**$ 2,347**	**$ 2,200**
Supply and Logistics	803	210	(25)
Adjusted other income/(expense), net [1]	7	3	—
Adjusted EBITDA [2]	**$ 3,237**	**$ 2,560**	**$ 2,175**
Interest expense, net of certain non-cash items [3]	(407)	(415)	(405)
Maintenance capital	(287)	(216)	(180)
Current income tax expense	(112)	(51)	(15)
Other	(55)	3	(10)
Implied DCF [2]	**$ 2,376**	**$ 1,881**	**$ 1,565**
Preferred unit distributions paid [4]	(198)	(198)	(200)
Implied DCF Available to Common Unitholders	**$ 2,178**	**$ 1,683**	**$ 1,365**
Implied DCF per Common Unit and Common Unit Equivalent [2]	$ 2.91	$ 2.29	$ 1.92
Distributions per Common Unit [5]	$ 1.38	$ 0.90	$ 0.72
Common Unit Distribution Coverage Ratio	2.17x	2.57x	2.64x
Diluted Adjusted Net Income per Common Unit [2]	$ 2.51	$ 1.55	$ 0.92
Operating Data			
Transportation			
Average daily volumes (MBbls/d)	6,893	6,340	6,250
Segment Adjusted EBITDA per barrel	$ 0.68	$ 0.70	$ 0.73
Facilities			
Average capacity (MMBbls/Mo)	125	124	110
Segment Adjusted EBITDA per barrel	$ 0.47	$ 0.49	$ 0.40
Supply and Logistics			
Average daily volumes (MBbls/d)	1,369	1,318	1,475
Segment Adjusted EBITDA per barrel	$ 1.61	$ 0.43	$ (0.05)
Investment Capital	**$ 1,340**	**$ 921**	**$ 275**

(G) 2021 Guidance forecasts are intended to be + / - amounts.

(1) Represents "Other income, net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of $(17) million and $(36) million for the twelve months ended December 31, 2019 and 2020, respectively. See the "Selected Items Impacting Comparability" table for additional information.

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(2) See the section of this release entitled "Non-GAAP Financial Measures and Selected Items Impacting Comparability" for information regarding non-GAAP financial measures and, for the historical 2019 and 2020 periods, see the Non-GAAP Reconciliation tables attached hereto for a reconciliation of such non-GAAP financial measures to the most directly comparable measures as reported in accordance with GAAP. We do not provide a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures on a forward-looking basis as it is impractical to forecast certain items that we have defined as "Selected Items Impacting Comparability" without unreasonable effort, due to the uncertainty and inherent difficulty of predicting the occurrence and financial impact of such items 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.

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

(4) Cash distributions paid to our preferred unitholders during 2019 and 2020. 2021(G) reflects the current annualized distribution requirement of $2.10 per Series A preferred unit and the current annualized distribution requirement of $61.25 per Series B preferred unit.

(5) Cash distributions per common unit paid during 2019 and 2020. 2021(G) reflects the current annualized distribution rate of $0.72 per common unit.

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 Tuesday, November 2, 2021 to discuss the following items:

1. PAA's third-quarter 2021 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/mharyy4f.

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

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

Performance Measures

Management believes that the presentation of Adjusted EBITDA and Implied DCF provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations and (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions. We also present these and additional non-GAAP financial measures, including adjusted net income attributable to PAA and basic and diluted adjusted net income per common unit, as they are measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and/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.

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 September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
REVENUES	$ 10,776	$ 5,833	$ 29,089	$ 17,327
COSTS AND EXPENSES				
Purchases and related costs	10,074	5,107	26,743	15,000
Field operating costs	274	254	746	811
General and administrative expenses	67	61	205	201
Depreciation and amortization	178	160	551	493
(Gains)/losses on asset sales and asset impairments, net	221	(2)	592	617
Goodwill impairment losses	—	—	—	2,515
Total costs and expenses	10,814	5,580	28,837	19,637
OPERATING INCOME/(LOSS)	(38)	253	252	(2,310)
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	69	89	190	280
Gain on/(impairment of) investments in unconsolidated entities, net	—	(91)	—	(182)
Interest expense, net	(106)	(113)	(319)	(329)
Other income/(expense), net	(10)	5	13	(7)
INCOME/(LOSS) BEFORE TAX	(85)	143	136	(2,548)
Current income tax expense	(8)	(17)	(11)	(39)
Deferred income tax benefit	38	20	27	32
NET INCOME/(LOSS)	(55)	146	152	(2,555)
Net income attributable to noncontrolling interests	(4)	(3)	(9)	(7)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAA	$ (59)	$ 143	$ 143	$ (2,562)
NET INCOME/(LOSS) PER COMMON UNIT:				
Net income/(loss) allocated to common unitholders — Basic and Diluted	$ (109)	$ 93	$ (7)	$ (2,712)
Basic and diluted weighted average common units outstanding	715	728	719	728
Basic and diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	September 30, 2021	December 31, 2020
ASSETS		
Current assets (including Cash and cash equivalents of $191 and $22, respectively)	$ 4,874	$ 3,665
Property and equipment, net	13,084	14,611
Investments in unconsolidated entities	3,710	3,764
Linefill and base gas	901	982
Long-term operating lease right-of-use assets, net	374	378
Long-term inventory	221	130
Other long-term assets, net	1,033	967
Total assets	$ 24,197	$ 24,497
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 5,397	$ 4,253
Senior notes, net	8,327	9,071
Other long-term debt, net	61	311
Long-term operating lease liabilities	326	317
Other long-term liabilities and deferred credits	789	807
Total liabilities	14,900	14,759
Partners' capital excluding noncontrolling interests	9,152	9,593
Noncontrolling interests	145	145
Total partners' capital	9,297	9,738
Total liabilities and partners' capital	$ 24,197	$ 24,497

DEBT CAPITALIZATION RATIOS
(in millions)

	September 30, 2021	December 31, 2020
Short-term debt	$ 808	$ 831
Long-term debt	8,388	9,382
Total debt	$ 9,196	$ 10,213
Long-term debt	$ 8,388	$ 9,382
Partners' capital	9,297	9,738
Total book capitalization	$ 17,685	$ 19,120
Total book capitalization, including short-term debt	$ 18,493	$ 19,951
Long-term debt-to-total book capitalization	47%	49%
Total debt-to-total book capitalization, including short-term debt	50%	51%

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

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER COMMON UNIT [1]
(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Basic and Diluted Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ 143	$ (2,562)
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(1)	(1)	(1)
Net income/(loss) allocated to common unitholders	$ (109)	$ 93	$ (7)	$ (2,712)
Basic and diluted weighted average common units outstanding [2] [3]	715	728	719	728
Basic and diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)

(1) We calculate net income/(loss) 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/(loss) per common unit for the three and nine months ended September 30, 2021 and 2020 as the effect was antidilutive.

(3) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For the three and nine months ended September 30, 2021 and 2020, 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/(loss) per common unit.

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

NON-GAAP RECONCILIATIONS

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

(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Basic Adjusted Net Income per Common Unit				
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ 143	$ (2,562)
Selected items impacting comparability - Adjusted net income attributable to PAA [(2)]	267	239	510	3,632
Adjusted net income attributable to PAA	$ 208	$ 382	$ 653	$ 1,070
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(2)	(1)	(3)
Adjusted net income allocated to common unitholders	$ 158	$ 331	$ 503	$ 918
Basic weighted average common units outstanding	715	728	719	728
Basic adjusted net income per common unit	$ 0.22	$ 0.46	$ 0.70	$ 1.26
Diluted Adjusted Net Income per Common Unit				
Net income/(loss) attributable to PAA	$ (59)	$ 143	$ 143	$ (2,562)
Selected items impacting comparability - Adjusted net income attributable to PAA [(2)]	267	239	510	3,632
Adjusted net income attributable to PAA	$ 208	$ 382	$ 653	$ 1,070
Distributions to Series A preferred unitholders	(37)	(37)	(112)	(112)
Distributions to Series B preferred unitholders	(12)	(12)	(37)	(37)
Other	(1)	(1)	(1)	(1)
Adjusted net income allocated to common unitholders	$ 158	$ 332	$ 503	$ 920
Basic weighted average common units outstanding	715	728	719	728
Effect of dilutive securities:				
Series A preferred units [(3)]	—	—	—	—
Equity-indexed compensation plan awards [(4)]	—	—	—	—
Diluted weighted average common units outstanding	715	728	719	728
Diluted adjusted net income per common unit	$ 0.22	$ 0.46	$ 0.70	$ 1.26

(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 and nine months ended September 30, 2021 and 2020 as the effect was antidilutive.

(4) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For the three and nine months ended September 30, 2021 and 2020, the effect of equity-indexed compensation plan awards was antidilutive.

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

NON-GAAP RECONCILIATIONS (continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Basic net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)
Selected items impacting comparability per common unit [1]	0.37	0.33	0.71	4.98
Basic adjusted net income per common unit	$ 0.22	$ 0.46	$ 0.70	$ 1.26
Diluted net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)
Selected items impacting comparability per common unit [1]	0.37	0.33	0.71	4.98
Diluted adjusted net income per common unit	$ 0.22	$ 0.46	$ 0.70	$ 1.26

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

	Twelve Months Ended December 31,	
	2020	2019
Basic net income/(loss) per common unit	$ (3.83)	$ 2.70
Selected items impacting comparability per common unit [1]	5.38	(0.14)
Basic adjusted net income per common unit	$ 1.55	$ 2.56
Diluted net income/(loss) per common unit	$ (3.83)	$ 2.65
Selected items impacting comparability per common unit [1]	5.38	(0.14)
Diluted adjusted net income per common unit	$ 1.55	$ 2.51

(1) See the "Selected Items Impacting Comparability" table 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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net Income/(Loss) to Adjusted EBITDA and Implied DCF Reconciliation				
Net Income/(Loss)	$ (55)	$ 146	$ 152	$ (2,555)
Interest expense, net	106	113	319	329
Income tax expense/(benefit)	(30)	(3)	(16)	7
Depreciation and amortization	178	160	551	493
(Gains)/losses on asset sales and asset impairments, net	221	(2)	592	617
Goodwill impairment losses	—	—	—	2,515
(Gain on)/impairment of investments in unconsolidated entities, net	—	91	—	182
Depreciation and amortization of unconsolidated entities (1)	21	18	109	51
Selected items impacting comparability - Adjusted EBITDA (2)	78	159	(64)	362
Adjusted EBITDA	$ 519	$ 682	$ 1,643	$ 2,001
Interest expense, net of certain non-cash items (3)	(99)	(107)	(301)	(313)
Maintenance capital	(43)	(53)	(116)	(157)
Current income tax expense	(8)	(17)	(11)	(39)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings (4)	9	(1)	11	7
Distributions to noncontrolling interests (5)	(4)	(2)	(10)	(6)
Implied DCF	$ 374	$ 502	$ 1,216	$ 1,493
Preferred unit distributions paid (6)	(37)	(37)	(137)	(137)
Implied DCF Available to Common Unitholders	$ 337	$ 465	$ 1,079	$ 1,356
Weighted Average Common Units Outstanding	715	728	719	728
Weighted Average Common Units and Common Unit Equivalents	786	799	790	799
Implied DCF per Common Unit (7)	$ 0.47	$ 0.64	$ 1.50	$ 1.86
Implied DCF per Common Unit and Common Unit Equivalent (8)	$ 0.48	$ 0.63	$ 1.51	$ 1.84
Cash Distribution Paid per Common Unit	$ 0.18	$ 0.18	$ 0.54	$ 0.72
Common Unit Cash Distributions (5)	$ 129	$ 131	$ 389	$ 524
Common Unit Distribution Coverage Ratio	2.61x	3.54x	2.77x	2.59x
Implied DCF Excess	$ 208	$ 334	$ 690	$ 832

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

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

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

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

(5) Cash distributions paid during the period presented.

(6) Cash distributions paid to our preferred unitholders 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)
(in millions, except per unit and ratio data)

	Twelve Months Ended December 31,	
	2020	2019
Net Income/(Loss) to Adjusted EBITDA and Implied DCF Reconciliation		
Net Income/(Loss)	$ (2,580)	$ 2,180
Interest expense, net	436	425
Income tax expense/(benefit)	(19)	66
Depreciation and amortization	653	601
(Gains)/losses on asset sales and asset impairments, net	719	28
Goodwill impairment losses	2,515	—
(Gain on)/impairment of investments in unconsolidated entities, net	182	(271)
Depreciation and amortization of unconsolidated entities [1]	73	62
Selected items impacting comparability - Adjusted EBITDA [2]	581	146
Adjusted EBITDA	$ 2,560	$ 3,237
Interest expense, net of certain non-cash items [3]	(415)	(407)
Maintenance capital	(216)	(287)
Current income tax expense	(51)	(112)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [4]	13	(49)
Distributions to noncontrolling interests [5]	(10)	(6)
Implied DCF	$ 1,881	$ 2,376
Preferred unit distributions paid [6]	(198)	(198)
Implied DCF Available to Common Unitholders	$ 1,683	$ 2,178
Weighted Average Common Units Outstanding	728	727
Weighted Average Common Units and Common Unit Equivalents	799	798
Implied DCF per Common Unit [7]	$ 2.31	$ 2.99
Implied DCF per Common Unit and Common Unit Equivalent [8]	$ 2.29	$ 2.91
Cash Distribution Paid per Common Unit	$ 0.90	$ 1.38
Common Unit Cash Distributions [5]	$ 655	$ 1,004
Common Unit Distribution Coverage Ratio	2.57x	2.17x
Implied DCF Excess	$ 1,028	$ 1,174

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

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

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

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

(5) Cash distributions paid during the period presented.

(6) Cash distributions paid to our preferred unitholders during the period presented.

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

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

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

NON-GAAP RECONCILIATIONS (continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Basic net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)
Reconciling items per common unit [1] [2]	0.62	0.51	1.51	5.58
Implied DCF per common unit	$ 0.47	$ 0.64	$ 1.50	$ 1.86
Basic net income/(loss) per common unit	$ (0.15)	$ 0.13	$ (0.01)	$ (3.72)
Reconciling items per common unit and common unit equivalent [1] [3]	0.63	0.50	1.52	5.56
Implied DCF per common unit and common unit equivalent	$ 0.48	$ 0.63	$ 1.51	$ 1.84

	Twelve Months Ended December 31,	
	2020	2019
Basic net income/(loss) per common unit	$ (3.83)	$ 2.70
Reconciling items per common unit [1] [4]	6.14	0.29
Implied DCF per common unit	$ 2.31	$ 2.99
Basic net income/(loss) per common unit	$ (3.83)	$ 2.70
Reconciling items per common unit and common unit equivalent [1] [3]	6.12	0.21
Implied DCF per common unit and common unit equivalent	$ 2.29	$ 2.91

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

(2) Based on weighted average common units outstanding for the period of 715 million, 728 million, 719 million and 728 million, respectively.

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

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

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

NON-GAAP RECONCILIATIONS (continued)
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Free Cash Flow and Free Cash Flow after Distributions Reconciliation [1]:				
Net cash provided by operating activities	$ 336	$ 282	$ 1,361	$ 1,256
Adjustments to reconcile net cash provided by operating activities to free cash flow:				
Net cash provided by/(used in) investing activities	761	(208)	478	(1,066)
Cash contributions from noncontrolling interests	—	1	1	11
Cash distributions paid to noncontrolling interests [2]	(4)	(2)	(10)	(6)
Free Cash Flow	$ 1,093	$ 73	$ 1,830	$ 195
Cash distributions [3]	(166)	(168)	(526)	(661)
Free Cash Flow after Distributions	$ 927	$ (95)	$ 1,304	$ (466)

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

(2) Cash distributions paid during the period presented.

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

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

SELECTED ITEMS IMPACTING COMPARABILITY
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Selected Items Impacting Comparability: [1]				
Gains/(losses) from derivative activities and inventory valuation adjustments [2]	$ (9)	$ (98)	$ 36	$ (203)
Long-term inventory costing adjustments [3]	13	(2)	81	(66)
Deficiencies under minimum volume commitments, net [4]	(56)	(64)	(31)	(69)
Equity-indexed compensation expense [5]	(6)	(5)	(14)	(13)
Net gain/(loss) on foreign currency revaluation [6]	(18)	10	(3)	(11)
Significant transaction-related expenses [7]	(2)	—	(5)	(3)
Net gain on early repayment of senior notes [8]	—	—	—	3
Selected items impacting comparability - Adjusted EBITDA	$ (78)	$ (159)	$ 64	$ (362)
Gain on/(impairment of) investments in unconsolidated entities, net	—	(91)	—	(182)
Gains/(losses) on asset sales and asset impairments, net	(221)	2	(592)	(617)
Goodwill impairment losses	—	—	—	(2,515)
Tax effect on selected items impacting comparability	32	9	18	44
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (267)	$ (239)	$ (510)	$ (3,632)

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

(2) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify 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 investing activities, such as the purchase of linefill.

(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 expenses associated with the Plains Oryx Permian Basin joint venture transaction, which closed on October 5, 2021, and the acquisition of Felix Midstream LLC in February 2020.

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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SELECTED ITEMS IMPACTING COMPARABILITY (continued)
(in millions)

	Twelve Months Ended December 31, 2020	Twelve Months Ended December 31, 2019
Selected Items Impacting Comparability: [(1)]		
Losses from derivative activities and inventory valuation adjustments [(2)]	$ (460)	$ (158)
Long-term inventory costing adjustments [(3)]	(44)	20
Deficiencies under minimum volume commitments, net [(4)]	(74)	18
Equity-indexed compensation expense [(5)]	(19)	(17)
Net gain on foreign currency revaluation [(6)]	16	1
Line 901 incident [(7)]	—	(10)
Significant transaction-related expenses [(8)]	(3)	—
Net gain on early repayment of senior notes [(9)]	3	—
Selected items impacting comparability - Adjusted EBITDA	$ (581)	$ (146)
Losses from derivative activities [(2)]	—	(1)
Gain on/(impairment of) investments in unconsolidated entities, net	(182)	271
Gains/(losses) on asset sales and asset impairments, net	(719)	(28)
Goodwill impairment losses	(2,515)	—
Tax effect on selected items impacting comparability	76	12
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (3,921)	$ 108

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

(2) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify 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 investing activities, such as the purchase of linefill.

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

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

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

(6) During the periods presented, there were fluctuations in the value of the Canadian dollar to the U.S. dollar, resulting in the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. These gains and losses are not integral to our core operating performance and were thus classified as a selected item impacting comparability.

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

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

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

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

SELECTED FINANCIAL DATA BY SEGMENT
(in millions)

	Three Months Ended September 30, 2021			Three Months Ended September 30, 2020		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 529	$ 226	$ 10,515	$ 494	$ 271	$ 5,537
Purchases and related costs [1]	(75)	(1)	(10,488)	(60)	(2)	(5,510)
Field operating costs [1] [2]	(149)	(86)	(43)	(139)	(73)	(46)
Segment general and administrative expenses [2] [3]	(25)	(20)	(22)	(22)	(18)	(21)
Equity earnings in unconsolidated entities	67	2	—	87	2	—
Adjustments: [4]						
Depreciation and amortization of unconsolidated entities	20	1	—	17	1	—
(Gains)/losses from derivative activities and inventory valuation adjustments	—	(9)	22	—	(6)	94
Long-term inventory costing adjustments	—	—	(13)	—	—	2
Deficiencies under minimum volume commitments, net	56	—	—	64	—	—
Equity-indexed compensation expense	3	1	2	3	1	1
Net loss on foreign currency revaluation	—	—	3	—	—	4
Significant transaction-related expenses	1	—	1	—	—	—
Segment Adjusted EBITDA	$ 427	$ 114	$ (23)	$ 444	$ 176	$ 61
Maintenance capital	$ 22	$ 18	$ 3	$ 34	$ 10	$ 9

(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.

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

SELECTED FINANCIAL DATA BY SEGMENT

(in millions)

	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 1,568	$ 741	$ 28,222	$ 1,530	$ 860	$ 16,371
Purchases and related costs [1]	(181)	(7)	(27,985)	(184)	(12)	(16,227)
Field operating costs [1] [2]	(394)	(238)	(126)	(440)	(233)	(149)
Segment general and administrative expenses [2] [3]	(79)	(60)	(66)	(73)	(63)	(65)
Equity earnings in unconsolidated entities	185	5	—	276	4	—
Adjustments: [4]						
Depreciation and amortization of unconsolidated entities	107	2	—	49	2	—
(Gains)/losses from derivative activities and inventory valuation adjustments	(1)	(19)	(3)	—	(5)	215
Long-term inventory costing adjustments	—	—	(81)	—	—	66
Deficiencies under minimum volume commitments, net	33	(2)	—	64	5	—
Equity-indexed compensation expense	8	3	3	8	2	3
Net (gain)/loss on foreign currency revaluation	—	—	2	—	—	(9)
Significant transaction-related expenses	2	—	3	3	—	—
Segment Adjusted EBITDA	$ 1,248	$ 425	$ (31)	$ 1,233	$ 560	$ 205
Maintenance capital	$ 68	$ 39	$ 9	$ 98	$ 40	$ 19

(1) Includes intersegment amounts.

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

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

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

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

OPERATING DATA BY SEGMENT [1]

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Transportation segment (average daily volumes in thousands of barrels per day):				
Tariff activities volumes				
Crude oil pipelines (by region):				
Permian Basin [2]	4,394	4,200	4,114	4,507
South Texas / Eagle Ford [2]	311	370	315	383
Central [2]	483	388	441	383
Gulf Coast	176	137	161	133
Rocky Mountain [2]	344	238	320	251
Western	224	232	239	217
Canada	230	303	279	291
Crude oil pipelines	6,162	5,868	5,869	6,165
NGL pipelines	165	180	176	187
Tariff activities total volumes	6,327	6,048	6,045	6,352
Trucking volumes	58	67	62	75
Transportation segment total volumes	6,385	6,115	6,107	6,427
Facilities segment (average monthly volumes):				
Liquids storage (average monthly capacity in millions of barrels) [3]	100	111	100	110
Natural gas storage (average monthly working capacity in billions of cubic feet)	23	67	54	66
NGL fractionation (average volumes in thousands of barrels per day)	119	110	130	129
Facilities segment total volumes (average monthly volumes in millions of barrels) [4]	108	125	113	125
Supply and Logistics segment (average daily volumes in thousands of barrels per day):				
Crude oil lease gathering purchases	1,372	1,147	1,300	1,181
NGL sales	87	83	139	132
Supply and Logistics segment total volumes	1,459	1,230	1,439	1,313

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

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

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

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

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

NON-GAAP SEGMENT RECONCILIATIONS
(in millions)

Fee-based Segment Adjusted EBITDA to Adjusted EBITDA Reconciliation:

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Transportation Segment Adjusted EBITDA	$ 427	$ 444	$ 1,248	$ 1,233
Facilities Segment Adjusted EBITDA	114	176	425	560
Fee-based Segment Adjusted EBITDA	$ 541	$ 620	$ 1,673	$ 1,793
Supply and Logistics Segment Adjusted EBITDA	(23)	61	(31)	205
Adjusted other income/(expense), net [1]	1	1	1	3
Adjusted EBITDA [2]	$ 519	$ 682	$ 1,643	$ 2,001

(1) Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of $11 million, $(4) million, $(12) million and $10 million for the three and nine months ended September 30, 2021 and 2020, respectively. See the "Selected Items Impacting Comparability" table for additional information.

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

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

	Three Months Ended September 30, 2021			Three Months Ended September 30, 2020		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Segment Adjusted EBITDA	$ 427	$ 114	$ (23)	$ 444	$ 176	$ 61
Impact of divested assets [1]	—	(6)	—	—	(31)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 427	$ 108	$ (23)	$ 444	$ 145	$ 61

	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Segment Adjusted EBITDA	$ 1,248	$ 425	$ (31)	$ 1,233	$ 560	$ 205
Impact of divested assets [1]	—	(58)	—	(1)	(101)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 1,248	$ 367	$ (31)	$ 1,232	$ 459	$ 205

(1) Estimated impact of divestitures completed during 2020 and 2021, assuming an effective date of January 1, 2020. Divested assets primarily included certain NGL storage terminals, Los Angeles Basin crude oil storage terminals and natural gas storage facilities that were previously included in our Facilities segment and the sale of a portion of our interest in a joint venture pipeline that was previously reported in our Transportation segment.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

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

	Three Months Ended September 30, 2021			Three Months Ended September 30, 2020		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 10,776	$ —	$ 10,776	$ 5,833	$ —	$ 5,833
COSTS AND EXPENSES						
Purchases and related costs	10,074	—	10,074	5,107	—	5,107
Field operating costs	274	—	274	254	—	254
General and administrative expenses	67	1	68	61	1	62
Depreciation and amortization	178	1	179	160	1	161
(Gains)/losses on asset sales and asset impairments, net	221	—	221	(2)	—	(2)
Total costs and expenses	10,814	2	10,816	5,580	2	5,582
OPERATING INCOME/(LOSS)	(38)	(2)	(40)	253	(2)	251
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	69	—	69	89	—	89
Gain on/(impairment of) investments in unconsolidated entities, net	—	—	—	(91)	—	(91)
Interest expense, net	(106)	—	(106)	(113)	—	(113)
Other income/(expense), net	(10)	—	(10)	5	—	5
INCOME/(LOSS) BEFORE TAX	(85)	(2)	(87)	143	(2)	141
Current income tax expense	(8)	—	(8)	(17)	—	(17)
Deferred income tax benefit	38	7	45	20	(5)	15
NET INCOME/(LOSS)	(55)	5	(50)	146	(7)	139
Net (income)/loss attributable to noncontrolling interests	(4)	30	26	(3)	(119)	(122)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	$ (59)	$ 35	$ (24)	$ 143	$ (126)	$ 17
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			186
BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			$ (0.12)			$ 0.09

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

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 29,089	$ —	$ 29,089	$ 17,327	$ —	$ 17,327
COSTS AND EXPENSES						
Purchases and related costs	26,743	—	26,743	15,000	—	15,000
Field operating costs	746	—	746	811	—	811
General and administrative expenses	205	4	209	201	5	206
Depreciation and amortization	551	2	553	493	2	495
(Gains)/losses on asset sales and asset impairments, net	592	—	592	617	—	617
Goodwill impairment losses	—	—	—	2,515	—	2,515
Total costs and expenses	28,837	6	28,843	19,637	7	19,644
OPERATING INCOME/(LOSS)	252	(6)	246	(2,310)	(7)	(2,317)
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	190	—	190	280	—	280
Gain on/(impairment of) investments in unconsolidated entities, net	—	—	—	(182)	—	(182)
Interest expense, net	(319)	—	(319)	(329)	—	(329)
Other income/(expense), net	13	—	13	(7)	—	(7)
INCOME/(LOSS) BEFORE TAX	136	(6)	130	(2,548)	(7)	(2,555)
Current income tax expense	(11)	—	(11)	(39)	—	(39)
Deferred income tax (expense)/ benefit	27	(16)	11	32	145	177
NET INCOME/(LOSS)	152	(22)	130	(2,555)	138	(2,417)
Net (income)/loss attributable to noncontrolling interests	(9)	(145)	(154)	(7)	1,876	1,869
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	$ 143	$ (167)	$ (24)	$ (2,562)	$ 2,014	$ (548)
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			184
BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			$ (0.12)			$ (2.97)

[1] Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET DATA
(in millions)

	September 30, 2021			December 31, 2020		
	PAA	Consolidating Adjustments [(1)]	PAGP	PAA	Consolidating Adjustments [(1)]	PAGP
ASSETS						
Current assets	$ 4,874	$ 3	$ 4,877	$ 3,665	$ 3	$ 3,668
Property and equipment, net	13,084	6	13,090	14,611	9	14,620
Investments in unconsolidated entities	3,710	—	3,710	3,764	—	3,764
Deferred tax asset	—	1,423	1,423	—	1,444	1,444
Linefill and base gas	901	—	901	982	—	982
Long-term operating lease right-of-use assets, net	374	—	374	378	—	378
Long-term inventory	221	—	221	130	—	130
Other long-term assets, net	1,033	(2)	1,031	967	(2)	965
Total assets	$ 24,197	$ 1,430	$ 25,627	$ 24,497	$ 1,454	$ 25,951
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 5,397	$ 2	$ 5,399	$ 4,253	$ 2	$ 4,255
Senior notes, net	8,327	—	8,327	9,071	—	9,071
Other long-term debt, net	61	—	61	311	—	311
Long-term operating lease liabilities	326	—	326	317	—	317
Other long-term liabilities and deferred credits	789	—	789	807	—	807
Total liabilities	14,900	2	14,902	14,759	2	14,761
Partners' capital excluding noncontrolling interests	9,152	(7,800)	1,352	9,593	(8,129)	1,464
Noncontrolling interests	145	9,228	9,373	145	9,581	9,726
Total partners' capital	9,297	1,428	10,725	9,738	1,452	11,190
Total liabilities and partners' capital	$ 24,197	$ 1,430	$ 25,627	$ 24,497	$ 1,454	$ 25,951

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

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Basic and Diluted Net Income/(Loss) per Class A Share				
Net income/(loss) attributable to PAGP	$ (24)	$ 17	$ (24)	$ (548)
Basic and diluted weighted average Class A shares outstanding	194	186	194	184
Basic and diluted net income/(loss) per Class A share	$ (0.12)	$ 0.09	$ (0.12)	$ (2.97)

(1) For the three and nine months ended September 30, 2021 and 2020, the possible exchange of AAP units and AAP Management units would not have had a dilutive effect on basic net income/(loss) per Class A share.

Forward-Looking Statements

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

- 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, natural gas liquids ("NGL") and natural gas production (whether due to reduced producer cash flow to fund drilling activities or the inability of producers to access capital, or both, the unavailability of pipeline and/or storage capacity, the shutting-in of production by producers, government-mandated pro-ration orders, or other factors), which in turn could result in significant declines in the actual or expected volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets and/or the reduction of commercial opportunities that might otherwise be available to us;
- 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);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, NGL and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;

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- 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;
- 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;
- 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;
- the impact of current and future laws, rulings, governmental regulations, trade policies, accounting standards and statements, and related interpretations, including legislation or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing or that prohibit the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- general economic, market or business conditions in the United States and elsewhere (including the potential for a recession or significant slowdown in economic activity levels 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 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;

- more -

- 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;
- 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 NGL. PAA owns an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles more than 6 million barrels per day of crude oil and NGL in its Transportation segment. PAA is headquartered in Houston, Texas. More information is available at www.plainsallamerican.com.

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

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Third-Quarter 2021

PAA & PAGP

Non-GAAP & Supplemental Reconciliations

Non-GAAP Reconciliations and Supplemental Calculations: Table of Contents

Introduction

Non-GAAP Financial Measures and Selected Items Impacting Comparability

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

The primary additional measures used by management are 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 and gains and losses on significant asset sales by such entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability ("Adjusted EBITDA"), Implied Distributable Cash Flow ("DCF"), Free Cash Flow and Free Cash Flow after Distributions.

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

Performance Measures

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

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

Liquidity Measures

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

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Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2018 - 2021 (in millions) (1) (2)

Selected Items Impacting Comparability (3)

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities and inventory valuation adjustments	$ 131	$ (86)	$ (9)	$ 36	$ (4)	$ (99)	$ (98)	$ (258)	$ (460)	$ 97	$ (51)	$ 30	$ (234)	$ (158)	$ 19	$ (232)	$ 108	$ 610	$ 505
Long-term inventory costing adjustments	41	27	13	81	(115)	51	(2)	21	(44)	21	(25)	1	22	20	13	(5)	10	(38)	(21)
Deficiencies under minimum volume commitments, net	32	(6)	(56)	(31)	2	(7)	(64)	(5)	(74)	7	(1)	4	8	18	(10)	(3)	4	2	(7)
Equity-indexed compensation expense	(5)	(4)	(6)	(14)	(4)	(5)	(5)	(5)	(19)	(3)	(4)	(5)	(4)	(17)	(11)	(12)	(14)	(19)	(55)
Net gain/(loss) on foreign currency revaluation	8	7	(18)	(3)	(46)	23	10	28	16	(4)	(8)	5	7	1	(8)	4	2	3	1
Significant transaction-related expenses	—	(3)	(2)	(5)	(3)	—	—	—	(3)	—	—	—	—	—	—	—	—	—	—
Line 901 incident	—	—	—	—	—	—	—	—	—	—	(10)	—	—	(10)	—	—	—	—	—
Net gain on early repayment of senior notes	—	—	—	—	—	3	—	—	3	—	—	—	—	—	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	$ 207	$ (65)	$ (78)	$ 64	$ (170)	$ (34)	$ (159)	$ (219)	$ (581)	$ 118	$ (99)	$ 35	$ (201)	$ (146)	$ 3	$ (248)	$ 110	$ 558	$ 423
Gains/(losses) from derivative activities	—	—	—	—	—	—	—	—	—	—	(1)	—	—	(1)	3	—	—	—	4
Gain (loss) on/(impairment of) investments in unconsolidated entities, net	—	—	—	—	(22)	(69)	(91)	—	(182)	267	—	4	—	271	—	—	210	(10)	200
Gains/(losses) on asset sales and asset impairments, net (4)	(2)	(369)	(221)	(592)	(619)	1	2	(101)	(719)	(4)	4	7	(34)	(28)	—	81	(2)	36	114
Goodwill impairment losses	—	—	—	—	(2,515)	—	—	—	(2,515)	—	—	—	—	—	—	—	—	—	—
Tax effect on selected items impacting comparability	(15)	1	32	18	23	11	9	31	76	24	(9)	(27)	24	12	(28)	24	29	(120)	(95)
Selected items impacting comparability - Adjusted net income attributable to PAA	$ 190	$ (433)	$ (267)	$ (510)	$(3,303)	$ (91)	$ (239)	$ (289)	$ (3,921)	$ 405	$ (105)	$ 19	$ (211)	$ 108	$ (22)	$ (143)	$ 347	$ 464	$ 646

Net Income/(Loss) to Adjusted EBITDA Reconciliation

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 423	$ (216)	$ (55)	$ 152	$(2,845)	$ 144	$ 146	$ (25)	$ (2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180	$ 288	$ 100	$ 710	$ 1,117	$ 2,216
Interest expense, net	107	107	106	319	108	108	113	108	436	101	103	108	114	425	106	111	110	104	431
Income tax expense/(benefit)	24	(10)	(30)	(16)	21	(12)	(3)	(26)	(19)	24	(23)	41	25	66	61	(16)	(10)	163	198
Depreciation and amortization	177	196	178	551	168	166	160	160	653	136	147	156	163	601	127	130	129	136	520
(Gains)/losses on asset sales and asset impairments, net	2	369	221	592	619	(1)	(2)	101	719	4	(4)	(7)	34	28	—	(81)	2	(36)	(114)
Goodwill impairment losses	—	—	—	—	2,515	—	—	—	2,515	—	—	—	—	—	—	—	—	—	—
(Gain on)/impairment of investments in unconsolidated entities, net	—	—	—	—	22	69	91	—	182	(267)	—	(4)	—	(271)	—	—	(210)	10	(200)
Depreciation and amortization of unconsolidated entities (5)	20	68	21	109	17	16	18	22	73	12	14	18	16	62	14	14	15	13	56
Selected items impacting comparability - Adjusted EBITDA	(207)	65	78	(64)	170	34	159	219	581	(118)	99	(35)	201	146	(3)	248	(110)	(558)	(423)
Adjusted EBITDA	$ 546	$ 579	$ 519	$ 1,643	$ 795	$ 524	$ 682	$ 559	$ 2,560	$ 862	$ 784	$ 731	$ 860	$ 3,237	$ 593	$ 506	$ 636	$ 949	$ 2,684

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

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 423	$ (216)	$ (55)	$ 152	$(2,845)	$ 144	$ 146	$ (25)	$ (2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180	$ 288	$ 100	$ 710	$ 1,117	$ 2,216
Less: Net income attributable to noncontrolling interests	(1)	(4)	(4)	(9)	(2)	(2)	(3)	(3)	(10)	—	(2)	(5)	(1)	(9)	—	—	—	—	—
Net income/(loss) attributable to PAA	422	(220)	(59)	143	(2,847)	142	143	(28)	(2,590)	970	446	449	306	2,171	288	100	710	1,117	2,216
Selected items impacting comparability - Adjusted net income attributable to PAA	(190)	433	267	510	3,303	91	239	289	3,921	(405)	105	(19)	211	(108)	22	143	(347)	(464)	(646)
Adjusted net income attributable to PAA	$ 232	$ 213	$ 208	$ 653	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 565	$ 551	$ 430	$ 517	$ 2,063	$ 310	$ 243	$ 363	$ 653	$ 1,570

(1) Amounts may not recalculate due to rounding.
(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(3) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.
(4) During the fourth quarter of 2018, we began classifying net gains and losses on asset sales and asset impairments as a "Selected Item Impacting Comparability" of net income. Prior period amounts have been recast to reflect this change.
(5) Adjustment to add back our proportionate share of depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities.

PLAINS ALL AMERICAN PIPELINE, L.P.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2014 - 2017 (in millions) [(1) (2)]

Selected Items Impacting Comparability [(3)]

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

Net Income to Adjusted EBITDA Reconciliation

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

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

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

(1) Amounts may not recalculate due to rounding.
(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(3) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.
(4) During the fourth quarter of 2018, we began classifying net gains and losses on asset sales and asset impairments as a "Selected Item Impacting Comparability" of net income. Prior period amounts for 2016-2017 have been recast to reflect this change. Amounts prior to 2016 were immaterial.
(5) Adjustment to add back our proportionate share of depreciation and amortization expense of, and gains or losses on significant asset sales by, unconsolidated entities.

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Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2010 - 2013 (in millions) [1] [2]

Selected Items Impacting Comparability [3]

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

Net Income to Adjusted EBITDA Reconciliation

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

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

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

[1] Amounts may not recalculate due to rounding.
[2] Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
[3] For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.
[4] Adjustment to add back our proportionate share of depreciation and amortization expense of, and gains or losses on significant asset sales by, unconsolidated entities.

PLAINS ALL AMERICAN PIPELINE, L.P.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA: 2006 - 2009 (in millions) (1) (2)

Selected Items Impacting Comparability (3)

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

Net Income to Adjusted EBITDA Reconciliation

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

Net Income to Adjusted Net Income Attributable to PAA Reconciliation

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

(1) Amounts may not recalculate due to rounding.
(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(3) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

PLAINS ALL AMERICAN PIPELINE, L.P.

Reconciliation to Adjusted EBITDA and Adjusted Net Income: 2002 - 2005 (in millions) [(1) (2)]

Selected Items Impacting Comparability [(3)]

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

Net Income to Adjusted EBITDA Reconciliation

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

Net Income to Adjusted Net Income Reconciliation

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

[(1)] Amounts may not recalculate due to rounding.
[(2)] Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
[(3)] For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Basic Adjusted Net Income Per Common Unit

	2021 Q1	2021 Q2	2021 Q3	2021 YTD	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 YTD	2019 YTD	2018 YTD	2017 YTD
Net income/(loss) attributable to PAA	$ 422	$ (220)	$ (59)	$ 143	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171	$ 2,216	$ 856
Selected items impacting comparability - Adjusted net income attributable to PAA (3)	(190)	433	267	510	3,303	91	239	(289)	3,921	(108)	(646)	102
Adjusted net income attributable to PAA	$ 232	$ 213	$ 208	$ 653	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063	$ 1,570	$ 958
Distributions to Series A preferred unitholders (4)	(37)	(37)	(37)	(112)	(37)	(37)	(37)	(37)	(149)	(149)	(149)	(142)
Distributions to Series B preferred unitholders (4)	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(49)	(49)	(11)
Other	(1)	(1)	(1)	(1)	(2)	(1)	(2)	(1)	(4)	(6)	(6)	(17)
Adjusted net income allocated to common unitholders	$ 182	$ 163	$ 158	$ 503	$ 405	$ 183	$ 331	$ 211	$ 1,129	$ 1,859	$ 1,366	$ 788
Basic weighted average common units outstanding	722	720	715	719	728	728	728	726	728	727	726	717
Basic adjusted net income per common unit	$ 0.25	$ 0.23	$ 0.22	$ 0.70	$ 0.56	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.56	$ 1.88	$ 1.10

Diluted Adjusted Net Income Per Common Unit

	2021 Q1	2021 Q2	2021 Q3	2021 YTD	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 YTD	2019 YTD	2018 YTD	2017 YTD
Net income/(loss) attributable to PAA	$ 422	$ (220)	$ (59)	$ 143	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171	$ 2,216	$ 856
Selected items impacting comparability - Adjusted net income attributable to PAA (3)	(190)	433	267	510	3,303	91	239	289	3,921	(108)	(646)	102
Adjusted net income attributable to PAA	$ 232	$ 213	$ 208	$ 653	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063	$ 1,570	$ 958
Distributions to Series A preferred unitholders (4)	(37)	(37)	(37)	(112)	—	(37)	(37)	(37)	(149)	—	(149)	(142)
Distributions to Series B preferred unitholders (4)	(12)	(12)	(12)	(37)	(12)	(12)	(12)	(12)	(49)	(49)	(49)	(11)
Other	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(3)	(4)	(17)
Adjusted net income allocated to common unitholders	$ 182	$ 163	$ 158	$ 503	$ 443	$ 183	$ 332	$ 211	$ 1,131	$ 2,011	$ 1,368	$ 788
Basic weighted average common units outstanding	722	720	715	719	728	728	728	726	728	727	726	717
Effect of dilutive securities:												
Series A preferred units (5)	—	—	—	—	71	—	—	—	—	71	—	—
Equity-indexed compensation plan awards (6)	—	—	—	—	1	—	—	—	—	2	2	1
Diluted weighted average common units outstanding	722	720	715	719	800	728	728	726	728	800	728	718
Diluted adjusted net income per common unit	$ 0.25	$ 0.23	$ 0.22	$ 0.70	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51	$ 1.88	$ 1.10

(1) Amounts may not recalculate due to rounding.
(2) We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.
(3) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(4) Distributions pertaining to the period presented.
(5) For certain periods presented, the possible conversion of our Series A preferred units was excluded from the calculation of diluted adjusted net income per common unit as the effect was antidilutive.
(6) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For certain periods presented, such equity-indexed compensation plan awards did not change the presentation of diluted weighted average common units outstanding or diluted adjusted net income per common unit.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Basic Adjusted Net Income Per Common Unit

	2021 Q1	2021 Q2	2021 Q3	2021 YTD	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 YTD	2019 YTD	2018 YTD	2017 YTD
Basic net income/(loss) per common unit	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.70	$ 2.77	$ 0.96
Selected items impacting comparability per common unit (2)	(0.26)	0.60	0.37	0.71	4.54	0.12	0.32	0.40	5.38	(0.14)	(0.89)	0.14
Basic adjusted net income per common unit	$ 0.25	$ 0.23	$ 0.22	$ 0.70	$ 0.56	$ 0.25	$ 0.45	$ 0.29	$ 1.55	$ 2.56	$ 1.88	$ 1.10

Diluted Adjusted Net Income Per Common Unit

	2021 Q1	2021 Q2	2021 Q3	2021 YTD	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 YTD	2019 YTD	2018 YTD	2017 YTD
Diluted net income/(loss) per common unit	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.65	$ 2.71	$ 0.95
Selected items impacting comparability per common unit (2)	(0.26)	0.60	0.37	0.71	4.53	0.12	0.33	0.40	5.38	(0.14)	(0.83)	0.15
Diluted adjusted net income per common unit	$ 0.25	$ 0.23	$ 0.22	$ 0.70	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51	$ 1.88	$ 1.10

(1) Amounts may not recalculate due to rounding.
(2) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

PLAINS ALL AMERICAN PIPELINE, L.P.

PAA Credit Metrics (in millions, except ratio amounts): 2013 - 2021 [1]

Debt Capitalization Ratios

	As of			As of December 31,							
	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	2020	2019	2018	2017	2016	2015	2014	2013
Short-term debt	$ 254	$ 1,456	$ 808	$ 831	$ 504	$ 66	$ 737	$ 1,715	$ 999	$ 1,287	$ 1,113
Senior notes, net	9,073	8,326	8,327	9,071	8,939	8,941	8,933	9,874	9,698	8,699	6,670
Other long-term debt, net	265	63	61	311	248	202	250	250	677	5	5
Long-term debt	9,338	8,389	8,388	9,382	9,187	9,143	9,183	10,124	10,375	8,704	6,675
Total debt	$ 9,592	$ 9,845	$ 9,196	$ 10,213	$ 9,691	$ 9,209	$ 9,920	$ 11,839	$ 11,374	$ 9,991	$ 7,788
Long-term debt	$ 9,338	$ 8,389	$ 8,388	$ 9,382	$ 9,187	$ 9,143	$ 9,183	$ 10,124	$ 10,375	$ 8,704	$ 6,675
Partners' capital	10,084	9,640	9,297	9,738	13,195	12,002	10,958	8,816	7,939	8,191	7,703
Total book capitalization	$ 19,422	$ 18,029	$ 17,685	$ 19,120	$ 22,382	$ 21,145	$ 20,141	$ 18,940	$ 18,314	$ 16,895	$ 14,378
Total book capitalization, including short-term debt	$ 19,676	$ 19,485	$ 18,493	$ 19,951	$ 22,886	$ 21,211	$ 20,878	$ 20,655	$ 19,313	$ 18,182	$ 15,491
Long-term debt-to-total book capitalization	48 %	47 %	47 %	49 %	41 %	43 %	46 %	53 %	57 %	52 %	46 %
Total debt-to-total book capitalization, including short-term debt	49 %	51 %	50 %	51 %	42 %	43 %	48 %	57 %	59 %	55 %	50 %

(1) Amounts may not recalculate due to rounding.

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

Debt Capitalization Ratios

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

(1) Amounts may not recalculate due to rounding.
(2) The adjustments represent the portion of our $500 million, 4.25% senior notes that had been used to fund hedged inventory and would have been classified as short-term debt if funded on our credit facilities. These notes were issued in July 2009 and the proceeds were used to supplement capital available from our hedged inventory facility. These notes matured in September 2012.

PLAINS ALL AMERICAN PIPELINE, L.P.

Implied Distributable Cash Flow (in millions, except per unit and ratio data): 2017 - 2021 (1)

Implied Distributable Cash Flow Reconciliation

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended December 31,			
	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	2020	2019	2018	2017
Adjusted EBITDA	$ 546	$ 579	$ 519	$ 1,643	$ 795	$ 524	$ 682	$ 2,001	$ 2,560	$ 3,237	$ 2,684	$ 2,082
Interest expense, net of certain non-cash items (2)	(101)	(101)	(99)	(301)	(103)	(103)	(107)	(313)	(415)	(407)	(419)	(483)
Maintenance capital	(35)	(37)	(43)	(116)	(51)	(54)	(53)	(157)	(216)	(287)	(252)	(247)
Current income tax expense	(1)	(1)	(8)	(11)	(6)	(15)	(17)	(39)	(51)	(112)	(66)	(28)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings (3)	5	(5)	9	11	(2)	11	(1)	7	13	(49)	1	(10)
Distributions to noncontrolling interests (4)	(6)	—	(4)	(10)	—	(4)	(2)	(6)	(10)	(6)	—	(2)
Implied DCF	$ 408	$ 435	$ 374	$ 1,216	$ 633	$ 359	$ 502	$ 1,493	$ 1,881	$ 2,376	$ 1,948	$ 1,312
Preferred unit distributions paid (4) (5)	(37)	(62)	(37)	(137)	(37)	(62)	(37)	(137)	(198)	(198)	(161)	(5)
Implied DCF available to common unitholders	$ 371	$ 373	$ 337	$ 1,079	$ 596	$ 297	$ 465	$ 1,356	$ 1,683	$ 2,178	$ 1,787	$ 1,307
Weighted average common units outstanding	722	720	715	719	728	728	728	728	728	727	726	717
Weighted average common units and common unit equivalents	793	791	786	790	799	799	799	799	799	798	797	784
Implied DCF per common unit (6)	$ 0.51	$ 0.52	$ 0.47	$ 1.50	$ 0.82	$ 0.41	$ 0.64	$ 1.86	$ 2.31	$ 2.99	$ 2.46	$ 1.82
Implied DCF per common unit and common unit equivalent (7)	$ 0.51	$ 0.52	$ 0.48	$ 1.51	$ 0.79	$ 0.42	$ 0.63	$ 1.84	$ 2.29	$ 2.91	$ 2.38	$ 1.67
Cash distribution paid per common unit	$ 0.18	$ 0.18	$ 0.18	$ 0.54	$ 0.36	$ 0.18	$ 0.18	$ 0.72	$ 0.90	$ 1.38	$ 1.20	$ 1.95
Common unit cash distributions (4)	$ 130	$ 130	$ 129	$ 389	$ 262	$ 131	$ 131	$ 524	$ 655	$ 1,004	$ 871	$ 1,386
Common unit distribution coverage ratio	2.85x	2.87x	2.61x	2.77x	2.27x	2.27x	3.54x	2.59x	2.57x	2.17x	2.05x	0.94x
Implied DCF excess/(shortage)	$ 241	$ 243	$ 208	$ 690	$ 334	$ 166	$ 334	$ 832	$ 1,028	$ 1,174	$ 916	$ (79)

(1) Amounts may not recalculate due to rounding.
(2) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.
(3) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, of unconsolidated entities, gains and losses on significant asset sales by such entities and selected items impacting comparability).
(4) Cash distributions paid during the period presented.
(5) A pro-rated initial distribution on the Series B preferred units was paid on November 15, 2017. The current $0.5250 quarterly ($2.10 annualized) per unit distribution requirement of our Series A preferred units was paid-in-kind for each quarterly distribution since their issuance through February 2018. Distributions on our Series A preferred units have been paid in cash since the May 2018 quarterly distribution. The current $61.25 per unit annual distribution requirement of our Series B preferred units, which were issued in October 2017, is payable in cash semi-annually in arrears on May 15 and November 15.
(6) Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period.
(7) Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid (if any), divided by the weighted average common units and common 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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Implied Distributable Cash Flow (in millions, except per unit and ratio data): 2006 - 2016 (1) (2)

Implied Distributable Cash Flow Reconciliation

	Twelve Months Ended December 31,										
	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
Adjusted EBITDA	$ 2,169	$ 2,213	$ 2,229	$ 2,314	$ 2,124	$ 1,598	$ 1,106	$ 1,022	$ 887	$ 779	$ 511
Interest expense, net (3)	(451)	(417)	(334)	(296)	(285)	(253)	(248)	(224)	(196)	(162)	(86)
Maintenance capital	(186)	(220)	(224)	(176)	(170)	(120)	(93)	(81)	(81)	(50)	(28)
Current income tax (expense)/benefit	(85)	(84)	(71)	(100)	(53)	(38)	1	(15)	(9)	(3)	—
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings (4)	(29)	(14)	(32)	(32)	(15)	10	6	(8)	(4)	(14)	(8)
Distributions to noncontrolling interests (5)	(4)	(4)	(3)	(49)	(48)	(40)	(10)	(2)	—	—	—
Interest income	—	—	—	—	—	—	—	—	—	—	1
Non-cash amortization of terminated interest rate and foreign currency hedging instruments	—	—	—	—	—	—	—	—	—	1	2
Other	—	—	—	—	—	(1)	—	—	—	—	—
Implied DCF	$ 1,414	$ 1,474	$ 1,565	$ 1,661	$ 1,553	$ 1,156	$ 762	$ 692	$ 597	$ 551	$ 392
Cash distributions paid per common unit	$ 2.65	$ 2.76	$ 2.55	$ 2.33	$ 2.11	$ 1.95	$ 1.88	$ 1.81	$ 1.75	$ 1.64	$ 1.44
Common unit cash distributions (5) (6)	$ 1,627	$ 1,671	$ 1,407	$ 1,160	$ 968	$ 791	$ 682	$ 605	$ 532	$ 451	$ 263
Common unit distribution coverage ratio	0.87x	0.88x	1.11x	1.43x	1.60x	1.46x	1.12x	1.14x	1.12x	1.22x	1.49x
Implied DCF excess/(shortage)	$ (213)	$ (197)	$ 158	$ 501	$ 585	$ 365	$ 80	$ 87	$ 65	$ 100	$ 129

(1) Amounts may not recalculate due to rounding.
(2) For information regarding our calculation of implied DCF and common unit distribution coverage ratio, please refer to our latest issued PAA & PAGP Earnings Release.
(3) The 2011-2016 periods presented exclude certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.
(4) Represents the difference between non-cash equity earnings in unconsolidated entities (2012-2016 periods have been adjusted for our proportionate share of depreciation and amortization and gains or losses on significant asset sales) and cash distributions received from such entities.
(5) Cash distributions paid during the period presented.
(6) Common unit cash distributions include distributions paid to the general partner during the period presented.

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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			YTD	Three Months Ended			YTD	Twelve Months Ended	
	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ (3.98)	$ 0.13	$ 0.13	$ (3.72)	$ (3.83)	$ 2.70
Reconciling items per common unit	—	0.89	0.62	1.51	4.80	0.28	0.51	5.58	6.14	0.29
Implied DCF per common unit	$ 0.51	$ 0.52	$ 0.47	$ 1.50	$ 0.82	$ 0.41	$ 0.64	$ 1.86	$ 2.31	$ 2.99

Implied DCF Per Common Unit and Common Unit Equivalent

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended	
	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.51	$ (0.37)	$ (0.15)	$ (0.01)	$ (3.98)	$ 0.13	$ 0.13	$ (3.72)	$ (3.83)	$ 2.70
Reconciling items per common unit and common unit equivalent	—	0.89	0.63	1.52	4.77	0.29	0.50	5.56	6.12	0.21
Implied DCF per common unit and common unit equivalent	$ 0.51	$ 0.52	$ 0.48	$ 1.51	$ 0.79	$ 0.42	$ 0.63	$ 1.84	$ 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): 2016 - 2021 (1)

Free Cash Flow and Free Cash Flow after Distributions Reconciliation

	2021				2020					2019	2018	2017	2016
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD	YTD	YTD
Net cash provided by operating activities	$ 791	$ 235	$ 336	$ 1,361	$ 890	$ 84	$ 282	$ 258	$ 1,514	$ 2,504	$ 2,608	$ 2,499	$ 733
Adjustments to reconcile net cash provided by operating activities to free cash flow:													
Net cash provided by/(used in) investing activities	(108)	(175)	761	478	(610)	(248)	(208)	(27)	(1,093)	(1,765)	(813)	(1,570)	(1,273)
Cash contributions from noncontrolling interests	1	—	—	1	8	2	1	1	12	—	—	—	—
Cash distributions paid to noncontrolling interests (2)	(6)	—	(4)	(10)	—	(4)	(2)	(4)	(10)	(6)	—	(2)	(4)
Sale of noncontrolling interest in a subsidiary	—	—	—	—	—	—	—	—	—	128	—	—	—
Free Cash Flow	$ 678	$ 60	$ 1,093	$ 1,830	$ 288	$ (166)	$ 73	$ 228	$ 423	$ 861	$ 1,795	$ 927	$ (544)
Cash distributions (3)	(167)	(192)	(166)	(526)	(299)	(193)	(168)	(193)	(853)	(1,202)	(1,032)	(1,391)	(1,627)
Free Cash Flow after Distributions	$ 511	$ (132)	$ 927	$ 1,304	$ (11)	$ (359)	$ (95)	$ 35	$ (430)	$ (341)	$ 763	$ (464)	$ (2,171)
Less: Asset sales proceeds				(878)					(451)	(205)	(1,334)		
Free Cash Flow after Distributions excluding asset sales proceeds				$ 426					$ (881)	$ (546)	$ (571)		

(1) Amounts may not recalculate due to rounding.
(2) Cash distributions paid during the period presented.
(3) Cash distributions paid to our preferred and common unitholders during the period presented. The 2016 period also includes distributions paid to our general partner.

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

Reconciliation to Adjusted EBITDA

	Three Months Ended			YTD	Three Months Ended			YTD	Twelve Months Ended December 31,			
	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021	Sep 30, 2021	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Sep 30, 2020	2020	2019	2018	2017
Transportation Segment Adjusted EBITDA	$ 388	$ 433	$ 427	$ 1,248	$ 442	$ 346	$ 444	$ 1,233	$ 1,616	$ 1,722	$ 1,508	$ 1,287
Facilities Segment Adjusted EBITDA	171	140	114	425	210	174	176	560	731	705	711	734
Fee-based Segment Adjusted EBITDA	$ 559	$ 573	$ 541	$ 1,673	$ 652	$ 520	$ 620	$ 1,793	$ 2,347	$ 2,427	$ 2,219	$ 2,021
Supply and Logistics Segment Adjusted EBITDA	(13)	5	(23)	(31)	141	3	61	205	210	803	462	60
Adjusted other income/(expense), net [2]	—	1	1	1	2	1	1	3	3	7	3	1
Adjusted EBITDA [3]	$ 546	$ 579	$ 519	$ 1,643	$ 795	$ 524	$ 682	$ 2,001	$ 2,560	$ 3,237	$ 2,684	$ 2,082

(1) Amounts may not recalculate due to rounding.
(2) Represents "Other income/(expense), net" adjusted for selected items impacting comparability. For more information please refer to our recently issued PAA & PAGP Earnings Releases.
(3) See the "Net Income/(Loss) to Adjusted EBITDA Reconciliation" tables for reconciliation to Net Income/(Loss).

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Segment Supplemental Calculations: 2018 - 2021 (in millions, except volumes and per unit data) [1]

Segment Adjusted EBITDA

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA	$ 388	$ 433	$ 427	$ 1,248	$ 442	$ 346	$ 444	$ 383	$ 1,616	$ 399	$ 410	$ 462	$ 451	$ 1,722	$ 335	$ 360	$ 388	$ 425	$ 1,508
Facilities Segment Adjusted EBITDA	171	140	114	425	210	174	176	172	731	184	172	173	176	705	185	171	173	181	711
Fee-based Segment Adjusted EBITDA	$ 559	$ 573	$ 541	$ 1,673	$ 652	$ 520	$ 620	$ 555	$ 2,347	$ 583	$ 582	$ 635	$ 627	$ 2,427	$ 520	$ 531	$ 561	$ 606	$ 2,219
Supply and Logistics Segment Adjusted EBITDA	$ (13)	$ 5	$ (23)	$ (31)	$ 141	$ 3	$ 61	$ 4	$ 210	$ 278	$ 200	$ 92	$ 232	$ 803	$ 72	$ (26)	$ 75	$ 342	$ 462

Total Average Volumes [2]

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation total average volumes (thousands of barrels per day)	5,681	6,248	6,385	6,107	7,255	5,914	6,115	6,082	6,340	6,504	6,787	7,081	7,191	6,893	5,328	5,797	6,015	6,404	5,889
Facilities total average volumes (millions of barrels per month) [3]	115	115	108	113	127	124	125	121	124	124	124	125	126	125	124	124	123	124	124
Supply and Logistics total average volumes (thousands of barrels per day)	1,394	1,464	1,459	1,439	1,538	1,171	1,230	1,333	1,318	1,456	1,260	1,270	1,492	1,369	1,392	1,202	1,237	1,403	1,309

Segment Adjusted EBITDA Per Barrel

	2021				2020					2019					2018				
	Q1	Q2	Q3	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Transportation Segment Adjusted EBITDA per barrel	$ 0.76	$ 0.76	$ 0.73	$ 0.75	$ 0.67	$ 0.64	$ 0.79	$ 0.69	$ 0.70	$ 0.68	$ 0.66	$ 0.71	$ 0.68	$ 0.68	$ 0.70	$ 0.68	$ 0.70	$ 0.72	$ 0.70
Facilities Segment Adjusted EBITDA per barrel	$ 0.49	$ 0.40	$ 0.35	$ 0.42	$ 0.55	$ 0.47	$ 0.47	$ 0.47	$ 0.49	$ 0.49	$ 0.46	$ 0.46	$ 0.47	$ 0.47	$ 0.50	$ 0.46	$ 0.47	$ 0.49	$ 0.48
Supply and Logistics Segment Adjusted EBITDA per barrel	$ (0.11)	$ 0.04	$ (0.17)	$ (0.08)	$ 1.00	$ 0.03	$ 0.54	$ 0.03	$ 0.43	$ 2.12	$ 1.74	$ 0.79	$ 1.69	$ 1.61	$ 0.57	$ (0.24)	$ 0.66	$ 2.65	$ 0.97

(1) Amounts may not recalculate due to rounding.
(2) Average volumes are calculated as the total volumes (attributable to our interest) for the period divided by the number of days or months in the period.
(3) Facilities segment total volumes are calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

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

Segment Adjusted EBITDA

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

Total Average Volumes (2)

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

Segment Adjusted EBITDA Per Barrel

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

(1) Amounts may not recalculate due to rounding.
(2) Average volumes are calculated as total volumes for the period (attributable to our interest) divided by the number of days or months in the period.
(3) Facilities segment total volumes are calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.
(4) Beginning in fourth-quarter 2017, PAA determined rail load and unload volumes (Facilities segment) and waterborne cargos (Supply and Logistics segment) were not primary drivers of the operations of the segment. Therefore, Facilities and Supply and Logistics segment total volumes have been recast to exclude such volumes.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Segment Adjusted EBITDA

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

Total Average Volumes [2]

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

Segment Adjusted EBITDA Per Barrel

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

(1) Amounts may not recalculate due to rounding.
(2) Average volumes are calculated as total volumes for the period (attributable to our interest) divided by the number of days or months in the period.
(3) Facilities segment total volumes are calculated as the sum of: (i) liquids storage capacity; (ii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.
(4) Beginning in fourth-quarter 2017, PAA determined rail load and unload volumes (Facilities segment) and waterborne cargos (Supply and Logistics segment) were not primary drivers of the operations of the segment. Therefore, 2013 Facilities and Supply and Logistics segment total volumes have been recast to exclude such volumes. Prior to 2013, PAA did not report rail volumes and waterborne cargos were not a material percentage of Supply and Logistics segment volumes.

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

Segment Adjusted EBITDA

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

Total Average Volumes (2)

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

Segment Adjusted EBITDA per Barrel

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

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