Company Name: Valero Energy
Company Ticker: VLO US
Date: 2018-04-26
Event Description: Q1 2018 Earnings Call

Market Cap: 48,065.07
Current PX: 111.54
YTD Change($): +19.63
YTD Change(%): +21.358

Bloomberg Estimates - EPS
Current Quarter: 2.413
Current Year: 7.309
Bloomberg Estimates - Sales
Current Quarter: 24712.857
Current Year: 97900.444

Q1 2018 Earnings Call

Company Participants

- John Locke
- Joseph W. Gorder
- Michael S. Ciskowski
- Gary Simmons
- R. Lane Riggs
- Jason Fraser
- Richard F. Lashway

Other Participants

- Doug Terreson
- Brad Heffern
- Neil Mehta
- Paul Cheng
- Roger D. Read
- Manav Gupta
- Benny Wong
- Prashant Rao
- Justin S. Jenkins
- Blake Fernandez
- Phil M. Gresh
- Ryan Todd
- Matthew Blair
- Craig K. Shere

MANAGEMENT DISCUSSION SECTION

Operator

Good day, ladies and gentlemen, and welcome to the Q1 2018 Valero Energy Corp. Earnings Conference Call. At this time, all participants are in a listen-only mode. Later, we will conduct a question-and-answer session and instructions will follow at that time. [Operator Instructions]

And I would like to introduce your host for today's conference, Mr. John Locke. Sir, you may begin.

John Locke

Good morning. Welcome to Valero Energy Corporation's first quarter 2018 earnings conference call. With me today are Joe Gorder, our Chairman, President and Chief Executive Officer; Mike Ciskowski, our Executive Vice President and CFO; Lane Riggs, our Executive Vice President and COO; Jay Browning, our Executive Vice President and General Counsel, and several other members of Valero's senior management team.

If you have not received the earnings release and would like a copy, you can find one on our website at valero.com. Also attached to the earnings release are tables that provide additional financial information on our business segments. If you have any questions after reviewing these tables, please feel free to contact our Investor Relations team after the call.

I would like to direct your attention to the forward-looking statement disclaimer contained in the press release. In summary, it says that statements in the press release and on this conference call that state the company's or management's expectations or predictions of the future are forward-looking statements intended to be covered by the Safe Harbor provisions under federal securities laws. There are many factors that could cause actual results to differ from our expectations, including those we've described in our filings with the SEC.

Now, I will turn the call over to Joe for opening remarks.

Joseph W. Gorder

Well, thanks, John, and good morning, everyone. We started the year with bullish fundamentals, healthy product demand and days of supply for [ph] total light (02:26) products below the five-year range. However, as the quarter progressed, winter storms, fog along the Gulf Coast and strong refinery utilization delayed seasonal product draws, creating some margin headwinds.

But despite these challenges, Valero performed well and delivered solid financial results. As you know, we've been investing growth capital in logistics projects. An excellent example of this is the Diamond Pipeline, which is running well and enabling us to capture additional margin into our refining system.

We increased pipeline throughput during the quarter, which provided our Memphis refinery with greater access to Cushing and Midland crudes that are cost advantage versus LLS. We made additional investments in logistics to further reduce secondary costs and increase margin capture.

We acquired the SemLogistics Milford Haven fuel storage facility in Wales. We also entered into a joint ownership agreement with Sunrise Pipeline LLC, a new pipeline connecting Midland and Wichita Falls, Texas. Construction also continues on the Central Texas pipelines and terminals and the Pasadena products terminal. We expect these investments to improve flexibility in product and feedstock supply in our refineries when completed in 2019 and 2020.

Turning to our refining investments. Work remains on track for the Diamond Green Diesel capacity expansion and the Houston and St. Charles alkylation units. These projects should start up between the third quarter of this year and 2020. In addition, our board of directors approved the construction of a 45-megawatt cogeneration plant at the Pembroke refinery. We expect to see lower operating costs and improved electricity and steam supply reliability when the project is completed in 2020.

Turning to cash returns to stockholders. We paid out 57% of our first quarter adjusted net cash provided by operating activities. And we continue to target an annual payout ratio of between 40% to 50%.

In closing, we remain optimistic about the margin environment for the year. Global economies are growing. Product demand is strong, particularly in Latin America. And days of supply refine light product inventories are below five-year averages. With our highly reliable and flexible refining system, we are well positioned to capture margin tailwinds arising from these positive trends.

And with that, John, I'll hand the call back to you.

John Locke

Thank you, Joe. For the first quarter, net income attributable to Valero stockholders was $469 million or $1.09 per share compared to $305 million or $0.68 per share in the first quarter of 2017. First quarter 2018 adjusted net income attributable to Valero stockholders was $431 million or $1 per share. For reconciliations of actual to adjusted amounts, please refer to the financial tables that accompany this release.

Operating income for the refining segment in the first quarter of 2018 was $922 million compared to $640 million for the first quarter of 2017. Excluding $170-million benefit from the retroactive Blender's Tax Credit and $10 million of expenses, primarily related to ongoing repairs at certain of our refineries to address damage resulting from Hurricane Harvey in 2017 and other increment weather conditions the first quarter of 2018, operating income for the first quarter of 2018 was $762 million.

The increase from 2017 is attributed primarily to higher distillate margins, which were partially offset by narrower discounts for medium and heavy sour crudes versus Brent.

Refinery throughput volumes averaged 2.9 million barrels per day, which was 93,000 barrels per day higher than the first quarter of 2017. Throughput capacity utilization was 94% in the first quarter of 2018. Refining cash operating expenses of $3.78 per barrel were $0.09 per barrel lower than the first quarter of 2017, mainly due to higher throughput in the first quarter of 2018.

The ethanol segment generated $45 million of operating income in the first quarter of 2018 compared to $22 million in the first quarter of 2017. The increase from 2017 was primarily due to stronger distillers grain prices.

Operating income for the VLP segment in the first quarter of 2018 was $84 million compared to $70 million in the first quarter of 2017. The increase from 2017 was attributed mainly to contributions from the Port Arthur terminal assets and Parkway Pipeline, which were acquired in November of 2017.

For the first quarter of 2018, general and administrative expenses were $238 million and net interest expense was $121 million. Depreciation and amortization expense was $498 million and the effective tax rate, excluding the retroactive Blender's Tax Credit, was 22% in the first quarter of 2018.

With respect to our balance sheet at quarter-end, total debt was $9 billion, and cash and temporary cash investments were $4.7 billion, of which $71 million was held by VLP. Valero's debt-to-capitalization ratio, net of $2 billion in cash, was 24%. At the end of March, we had $5.4 billion of available liquidity, excluding cash, of which $750 million was available for only VLP.

We generated $138 million of net cash from operating activities in the first quarter. Included in this amount is a $1.1-billion use of cash to fund working capital. Excluding working capital, net cash provided by operating activities was approximately 1.2 billion.

Moving to investing activities. We made $631 million of growth and sustaining capital investments, of which $448 million was for expenditures to sustain the business, including $220 million for turnaround and catalyst costs. The balance of capital invested in the quarter was for growth.

With regard to financing activities. We returned $665 million to our stockholders in the first quarter. $345 million was paid as dividends with the balance used to purchase 3.5 million shares of Valero common stock. As of March 31, we have approximately 3.5 billion of share repurchase authorization remaining.

Capital investments for 2018 are expected to total $2.7 billion with about $1.7 billion allocated to sustaining the business and $1 billion to growth. Included in the total are turnarounds, catalysts and joint venture investments.

For modeling our second quarter operations, we expect throughput volumes to fall within the following ranges: U.S. Gulf Coast at 1. 61 million to 1.66 million barrels per day; U.S. Mid-Continent at 460,000 to 480,000 barrels per day; U.S. West Coast at 280,000 to 300,000 barrels per day; and North Atlantic at 355,000 to 375,000 barrels per day.

We expect refining cash operating expenses in the second quarter to be approximately $3.85 per barrel. Our ethanol segment is expected to produce a total of four million gallons per day in the second quarter. Operating expenses should average $0.37 per gallon, which includes $0.05 per gallon for noncash costs such as depreciation and amortization.

For 2018, we continue to expect the annual effective tax rate to be about 22%. For the second quarter, we expect G&A expenses, excluding corporate depreciation, to be approximately $180 million. Net interest expense is estimated at $120 million. And total depreciation and amortization expense should be approximately $520 million.

Lastly, we expect RINs expense for the year to be between $500 million and $600 million, which is approximately $200 million lower than previous guidance, primarily due to lower RINs prices.

That concludes our opening remarks. Before we open the call to questions, we will again respectfully request that callers adhere to our protocol of limiting each turn in the Q&A to two questions. If you have more than two questions, please rejoin the queue as time permits. This will help us to ensure that other callers have time to ask their questions.

Q&A

Operator

[Operator Instructions] Our first question comes from the line of Doug Terreson with Evercore ISI. Your line is now open.

<Q - Doug Terreson>: Good morning, everybody.

<A - Joseph W. Gorder>: Good morning, Doug.

<Q - Doug Terreson>: Hi. So, first I want to say congratulations to Mike and have enjoyed working with you over the years and good luck in the future, first of all.

<A - Michael S. Ciskowski>: Thanks, Doug.

<Q - Doug Terreson>: You're welcome. And my question is on IMO 2020 and specifically how you guys are thinking about the type of products that are likely to be provided to the market b it seems that many [ph] fuels (12:21) are still in the design phase and there's a lot of uncertainty in that area. And on marine fuel blends, how challenging the issues of compatibility, stability and availability of supply along these marine fuel networks are likely to be as the market goes through the transition in coming years? So two questions on IMO 2020.

<A - Gary Simmons>: Yeah, Doug. This is Gary. I think I'll start with the latter part of it but I think you really hit the nail on the head in terms of the challenges on IMO and the fuel quality. A lot of these blends, it's about stability of the fuel. And so we are certainly doing a lot of work in that area to understand some of these blends and things that can be done to be able to produce the [ph] 0.5-way percent back (13:05).

But because a lot of those challenges, certainly the industry today is pointing more towards a lot more ULSD in the marine bunker business and that's the reason it's the stability of the fuel.

<Q - Doug Terreson>: Okay, thank you.

<A - John Locke>: Thanks Doug.

Operator

Thank you. And our next question comes from the line of Brad Heffern with RBC Capital Market. Your line is now open.

<Q - Brad Heffern>: Hey, good morning everyone.

<A - Joseph W. Gorder>: Brad.

<Q - Brad Heffern>: Joe, on the repurchase front. Obviously, the stock's up almost 70% over the past year. At some point, is there a change in the calculation there where some of the cash looks more attracted to M&A or maybe the dividend or some other use rather than the repurchase, or is it really just a flywheel for access capital?

<A - Joseph W. Gorder>: It's the latter. And capital allocation framework we've used now for several years just remains in place. We'll continue to invest for growth. We will continue to maintain our commitment to the dividend. And we'll use surplus cash for share repurchases.

That being said, if we saw a transaction out there that we thought was excellent and that provided synergies for the company, we wouldn't hesitate to approach it. But that's been part of the model, the framework now for several years. So I don't expect anything really to change going forward.

<Q - Brad Heffern>: Okay. Thanks for that. And then maybe, for Gary I'll ask another IMO question. Obviously, we're all consumed with all the positive potential benefits from that. Are there any offsets that you guys are thinking about, I'm particularly thinking about if industry [ph] runs (14:56) move up a lot in order to meet the distillate side of the equation, are we going to see weakness in gasoline? But any other thoughts along those lines will be helpful.

<A - Gary Simmons>: No, I think that we're – we actually feel that IMO will be supportive of gasoline cracks as well, and the reason for that is a lot of the low-sulfur feedstocks that are going to cat crackers today to produce gasoline, you want to pull those in to make the low-sulfur marine bunker [ph] rolls back (15:23). So I think overall, IMO is very supportive to both gasoline and distillate.

<Q - Brad Heffern>: Okay. Thanks all.

Operator

And our next question comes from the line of Neil Mehta with Goldman Sachs. Your line is now open.

<Q - Neil Mehta>: Good morning team. I just wanted to start with a big thank you to [ph] Ciskowski (15:44) you came into the role 15 years ago. We looked this morning, the stock is up 1,300%, over 4x the market before even looking at the dividends. We know the ride hasn't been linear, but it has been a great one and we appreciate your steady hand at the helm of a financial shift.

<A - Joseph W. Gorder>: So, Neal, Donna has got a high bar to jump over...

<Q - Neil Mehta>: Well, the questions I had here were all in the crude differential because you guys have unique perspective on this. And first one I'll start on the light side. So we've seen WTI Midland really widen out here in 2018, you guys have a good perspective on this, especially now with your involvement with Sunrise and with very new – a few new pipelines coming into, let's call it, the back half of 2019. There's investor concern, certainly, on the producer side that these differentials really could widen out towards trucking economics.

So I want to get your perspective on what's going on in the Midland? Is there sufficient trucks to ultimately move the crude from West Texas down from to the refining centers at Corpus Christi? Are there constraints, and how does this all kind of play out? And then I have a follow-up on the heavy side.

<A - Gary Simmons>: Hey, Neil, this is Gary. I think when you look at kind of what's happened to the Midland market over the last six months, November we had the enterprise, the Midland-to-Sealy pipeline come on with 450,000 barrels a day of takeaway capacity. As that started up, the Midland Cushing spread came in fairly narrow and then we continue to see production ramp-up, which as the production ramped up pretty much all the pipeline capacity at either Cushing or to the Gulf Coast was again being consumed.

And then in the first quarter, I think, to compound all that, you had some refinery maintenance in the Mid-Continent. And so some of the demand for some of those Midland barrels that's typically there went away and so the Midland Cushing spread really widen out. I think we see – what we see is that as refining capacity comes back on in the Mid-Continent, that Midland Cushing spread will come back in some. But as you get out later this year and early into 2019, it does look like once again production will ramp up to the point where logistics will be a limit and [ph] we'll be (17:56) in for a period where that Midland Cushing spread will be relatively wide until the next pipeline project come online.

<Q - Neil Mehta>: And do you have a view, Gary, in terms of how much it will cost to truck crude from West Texas down to the Gulf Cost assuming that is the [ph] marginal barrel (18:14)?

<A - Gary Simmons>: We did a little bit of that when the differential blew out several years ago, and I don't remember what the numbers are, Neil. But it's expensive to move by truck.

<Q - Neil Mehta>: All right. Great. And a follow-up question on the heavy side. We've seen this Canadian differentials tighten up here. It's going to be a big turnaround season in May and June. But production looks like it going to keep on ramping towards the end of year. So just thoughts on Western Canada? And then also LLS Maya, which has increased despite some of these Venezuela issues would be helpful.

<A - Gary Simmons>: Okay. I'll start in Canada. Yeah, I think we saw Canadian differentials really blow out and then have since come in some. We had the Fort Hills production come online. And so increase in production you were definitely limited on the logistics to be able to clear the barrel. Some of it was the increase in production, but we also had – Keystone had a pressure restriction, which de-rated that line.

And then, a lot of issues around the rail, both weather-related issues around rail and also the lack of locomotives. So then as we moved further in the quarter, we saw some seasonal maintenance being – occurring up in Western Canada, which lowered production.

At the same time, Keystone was able to restore their capacity. We've seen some improvement in the rail. So those differentials have come back in some. But ultimately, I think, we view that production in Western Canada will outpace the ability to clear that barrel until one of the cross-border pipelines comes one, which is more a 2020 discussion. I think you'll see relatively wide discounts in Western Canada on those barrels.

At the Maya LLS, I think when you look at Maya and the Maya formula, a lot of the components of the Maya formula contributed to Maya moving weaker. WTS moved weaker. Fuel oil moved weaker. And the Brent [ph] TI are (20:10) widening out all contributed to Maya moving weaker.

And certainly, they can correct that with adjustments to the K, but what we saw in the first quarter was a lot of their demand was down due to U.S. Gulf Coast refinery maintenance. And so they were actually low in production. And within being at a position of having length I think they were reluctant to change the K. And so we saw Maya very competitively priced during the quarter.

<Q - Neil Mehta>: Appreciate the insights, guys.

<A - Joseph W. Gorder>: Thanks, Neil.

Operator

Thank you. And our next question comes from the line of Paul Cheng with Barclays. Your line is now open.

<Q - Paul Cheng>: Hey, guys. Good morning.

<A - Joseph W. Gorder>: Good morning, Paul.

<Q - Paul Cheng>: First I want to [ph] say (20:53) congratulations to Mike, and wish you a wonderful time on the retirement. But are you sure that you're so young that you want to retire? What are you going to do with all the time?

<A - Michael S. Ciskowski>: Yeah, thanks, Paul. I think it's probably a little late for that. But yeah, I appreciate it. Thank you very much.

<Q - Paul Cheng>: Has been a fun ride for all this year that I was not following the sector as long as you have been in the sector, but has been a fun ride. So, thank you for all the help throughout the decades.

<A - Michael S. Ciskowski>: You're welcome.

<Q - Paul Cheng>: I guess, I have two question. First for Gary. It seems that people are talking about the IMO 2020. I'm just curious that have you guys heard anything related to the [ph] low surface engine (21:39), would that have any unexpected consequences in terms of the machine how they are going to run, [indiscernible] (21:47)?

And also that have you heard any – because I heard someone talking about a cheaper new technology may be able to directly convert the high [ph] sulfur we see into the low sulfur (21:56) bunker fuel without going through the hydrocracker or the cooking technology. Wondering if you heard anything about that. So that's the first question.

Second question then how much is the Midland crude you currently will be able to run in McKee and the rest of your system? And that – how much more that you think you may be able to get [ph] for the pipeline if said (22:22) you have any additional arrangement?

<A - Gary Simmons>: Okay. I'll start. So, I think your first question was the impact that running a lower sulfur fuel may have on the ships' engines.

<Q - Paul Cheng>: That's correct.

<A - Gary Simmons>: I think that we see a lot of the ships today when they get into these areas next to the shoreline are burning diesel anyway, and so they have some history on burning low sulfur fuels and I'm not aware of any negative impact that had on engine wear. The second part of that question in terms of technology to convert resid to low sulfur [ph] diesel, I'll let (22:56) Lane answer.

<A - R. Lane Riggs>: Yeah. I mean, I guess our view is [indiscernible] (23:00) was pretty expensive to do. I mean somebody had to go out and try to build something like this and just some where you have to have all the infrastructure.

So one of these looks a whole lot like maybe it's not a resid cracker but it's a resid hydro trigger, we have some experience with those. Their best use would be put into an existing refinery. I don't know if anybody is seriously looking at this at this time. I hear a lot talk about it, but I guess I'll leave it at that.

<Q - Paul Cheng>: Okay. So, you are a bit skeptical about the [ph] claim (23:31) that this brand – I mean, I heard someone talking about this brand-new technology may be much cheaper, a quarter of the corresponding hydrocracking solution. So just curious that you guys have any thought on that.

<A - R. Lane Riggs>: Yeah. I think, what I would say is skepticism is maybe overstating it a bit. I'm just saying, no matter what, it would be pretty expensive and it would have to be a refiner that would probably have to be able to do this. And I think everybody wants to – I think people want to see the market evolve before they commit that much money, particularly to a new technology that people aren't familiar with.

<Q - Paul Cheng>: Okay. Very good.

<A - Gary Simmons>: Then on your Midland question, I guess all – really our capacity to run Midland is we could run as much Midland – 1.6 million barrels a day of light sweet capacity we have could be all Midland. I'm sure, what you are getting at is how much of that could we get is actually priced at Midland type values.

Today, a lot of the crude we run at Ardmore and McKee is priced off of Midland. We don't divulge the number and some of the reasons for that is that pricing contracts are negotiable and up all the time, so that number flows a little bit. But we run a lot of Midland priced crude at both McKee and Ardmore.

And then, we recently announced the Sunrise project, which will give us another 100,000 barrels a day of Midland priced crude that we can take into Ardmore and McKee. And in addition to that, we're certainly looking at all these pipeline projects from the Permian to the Gulf and evaluating opportunities to get more Midland priced crude, both to our Gulf Coast system and to the export refineries.

<Q - Paul Cheng>: Gary, when is Sunrise is up and running will be?

<A - Gary Simmons>: First quarter of 2019? [indiscernible] (25:21) first quarter of 2019.

<Q - Paul Cheng>: Thank you. Thank you very much.

<A - Joseph W. Gorder>: Thank you, Paul.

Operator

Thank you. And our next question comes from the line of Roger Read with Wells Fargo. Your line is now open.

<Q - Roger D. Read>: Yeah. Good morning. And Mike enjoy it. You won't have to listen to us Wall Streeters too much anymore.

<A - Michael S. Ciskowski>: Okay. Sounds great.

<Q - Roger D. Read>: I might have detected a little too much enthusiasm in that response. Hey, shifting gears a little bit here, guys, crude has been running up, wholesale price has been moving up, cracks look good. First time in several years, we're looking at retail gasoline closing in on $3. What is your thought on where we might see a demand response and kind of how do you – what experience gives you maybe that confidence?

<A - Gary Simmons>: You know Roger, I don't know that we have an exact number. We certainly haven't seen a negative reaction to the Street price yet in terms of the demand response. And our view has always been certainly where crude got to be over $100 a barrel there was certainly demand destruction that took place there. But somewhere I think between an $80 and $100 range is when you start to see some demand destruction start to take place if crude gets that high.

<A - Joseph W. Gorder>: It's always [ph] muted (26:50) though. I mean, if you look at what's really happened and you look at type of vehicles that are being purchased today, I think Ford has announced that they are not going to make cars – so many cars anymore. And it's because of the demand for light trucks and SUVs.

So Roger, from a practical standpoint, either with the higher price, it's going to be difficult for people to moderate their consumption that much based on the vehicles that they are buying today.

<Q - Roger D. Read>: Yeah. Absolutely. Just always good to get somebody who has got their hands a little closer to it than the rest of us. The other question I had, Latin America has been a nice area for margin growth, market share growth for you. I was just curious, Venezuela from a refining standpoint has, I guess, now finally shut down.

What beyond them backing out of the market have you seen in growth, in other words what do you think is probably a true growth rate out of Latin America that we should think about maybe more from this point forward, given that I guess you got a normalized activity level from refining in Latin America from this point forward?

<A - Gary Simmons>: Yeah, Roger, I don't know if I can give you an absolute number. We [ph] can give with you with (28:06) John to give you what that figure is. But the way we look at it is we kind of looked at a reasonable ramp-up and refinery utilization rates, and we're confident that demand growth in the region outpaces any kind of a reasonable ramp up in refinery utilization. It's kind of the way we've looked at that market. But in terms of absolute growth, I'm not sure I can give you a number of what we planned on.

<Q - Roger D. Read>: Okay. I appreciate it. Thank you.

Operator

Thank you. And our next question comes from the line of Manav Gupta with Credit Suisse. Your line is now open.

<Q - Manav Gupta>: Thank you so much guys for taking my question. My first question is last year Mexico did approach you for possible help in fixing their assets and offered a percentage ownership. You did decline the offer. Can you talk a little bit about what you saw on those refineries because of which you decided not to go ahead with it?

And second one is I may be wrong on this, but you have a coker project at Port Arthur. Can you just add some more color about it. I'm not looking for an EBITDA guidance, but generally some specifics around the project?

<A - Joseph W. Gorder>: Yeah. So, Manav, let's go ahead, and I'll let Lane talk a little bit about – and it's not specific just to Mexico, but it's specific to what it would take to turn around a challenged refinery, because we have tons of experience with that. So Lane, you want to share your thoughts?

<A - R. Lane Riggs>: Yeah. So [indiscernible] (29:36) I mean really all of Latin America has some more or less exposure to the sort of having a lack of, I would say, maintenance capital. So overtime their operations and their reliability have eroded. Largely probably because of the flat price in crude they can't really fund – they can't fund their operations.

And so depending on how long and how deep that sort of that story goes, it takes a long time to recover. I mean, like some conversations that we've had – some of these counterparties in the past was it's at least two turnaround cycles. And you really have to – you have to [indiscernible] (30:15) your management a long time. And there is a lot of work involved in this, a lot of time if you think about two turnaround cycles, well that's 6 years or 10 years. That typically out – that sort of is a longer duration than a lot of the sort of the political types or certainly the – [ph] even (30:33) some of the management involvement trying to get this done.

So it's a very, very, very difficult thing to turnaround a refining complex when it's gotten in states of many of these Latin American refiners are in.

<A - Joseph W. Gorder>: On coker.

<A - R. Lane Riggs>: I'm sorry. [indiscernible] (30:49) Port Arthur, we're still working with all the [ph] further stakeholders and (30:52) Port Arthur community along with the [indiscernible] (30:55) to get that permit move forward. We fully expect to get a permit sometime this year on it.

<Q - Manav Gupta>: Thank you so much guys. Thank you.

<A - Joseph W. Gorder>: Thank you.

Operator

Thank you. And our next question comes from the line of Benny Wong with Morgan Stanley. Your line is now open.

<Q - Benny Wong>: Hi, thanks guys. I just want to get your view. One of the things being proposed is making higher octane level in gasoline the standard in the U.S. and – as a potential replacement for the RFS. Just wondering if you could share your views on the merits of that proposal and any color on how it's been received by the other side, and what you think is maybe the sticking points of making it happen.

<A - Joseph W. Gorder>: Yeah. So why don't we let Jason talk about maybe the process here a little bit. And then if Gary or Lane want to talk about what it takes, that would be great.

<A - Jason Fraser>: Yeah, Benny, this is Jason. You're right. That is something that's being talked about in the context of the legislative long-term reform of the RFS moving to high efficiency high octane fuel standard. And [indiscernible] (31:59) working on this with the autos for around a year now. And the conversations have expanded recently to include the retailers [ph] in the (32:06) ethanol.

And we do think this will be a win all around for everybody. It helped the autos by – enable them to make more efficient vehicles. So it can hit the CAFE standards easier. It'd be a win for ethanol because ethanol is an excellent low cost source of octane. So an increased demand for ethanol. And we would all benefit making internal combustion engine more competitive longer term against [indiscernible] (32:29). So we do think it's something that at least to be looked at.

[indiscernible] (32:35)

<A - R. Lane Riggs>: Well – so, this is Lane. From a gasoline blending perspective, clean high octane component like [indiscernible] (32:44) in this process. They help dilute out some of the other sort of aromatic-based octane that are in the gasoline pool.

And like Jason alluded to, it will require a certain amount of ethanol. I mean, the industry has gotten used to ethanol in the blends and it is a source of octane. And so that definitely is going to be a part of the blend.

I think on balance, what you have to deal with is the light naphtha. Some light naphtha – [indiscernible] (33:10) going to have to find its way somewhere else, whether it goes into the olefins – the olefins crackers or somewhere else, but that's a [ph] string (33:17) that we'll – that the industry will be trying to fall between higher [indiscernible] (33:22) components to blend it off and just getting it out of the pool.

<Q - Benny Wong>: And do you guys have any color if ethanol or the corn side is open to this or they have any opposition?

<A - Jason Fraser>: This is Jason, again. I think they are still trying to get their arms around it. But the initial indications from some of the larger ethanol producers are they acknowledge kind of this [ph] 95 (33:45) type of level, or I think they call it 91 AKI, which is roughly equivalent to something that makes sense for the market.

<Q - Benny Wong>: Thanks. Appreciate that. And just if – I have a follow-up, if I may. And apologies if you guys have touched on it in your prepared remarks. Just – is there an update on the status of the Texas City Refinery?

<A - R. Lane Riggs>: So, hi Benny, this is Lane. No, we haven't said anything yet. So I think I've talked to you last, [ph] I don't know at (34:17) Friday at the Valero Texas Open, but [indiscernible] (34:19) we're going to bring forward to the SEC [ph] alky (34:24) turnaround. We [ph] had scheduled at (34:25) Texas City this past fall, we're just bringing it forward, we want to execute it now.

<Q - Benny Wong>: Great. Appreciate it.

Operator

Thank you. And our next question comes from the line of Prashant Rao with Citigroup. Your line is now open.

<Q - Prashant Rao>: Good morning. Thanks for taking the question. I wanted to turn the focus to the West Coast. So, this quarter [ph] you're in the black (34:49) better 1Q performance than last year. And we did have some concerns in the market about West Coast operating conditions in general for the industry earlier in 1Q.

So kind of wanted to get your thoughts on outlook for the remainder of the year. Maybe, addressing where we are now versus where I think the market might have been concerned about, maybe, a month or two ago. [ph] Because this seem (35:12) like a turning point from last year and a stronger starting point so I just want to sort of get a read dynamically how we should be thinking about those for rest of the year.

<A - Gary Simmons>: Yes, so I think what we saw on the West Coast is certainly the inventory draw we saw this week and getting below that 30 million-barrel threshold, I think, provided a lot of support for the market. Overall, we still believe that the West Coast has long refining capacity. And so as long as all the refineries are running at high utilization rates, the market really can't absorb all the production. But when the refinery goes down, you see spikes in the market and the market becomes short.

I think longer term, the things I look to that can help that market is really the opening up and deregulation in Mexico. I think you will see exports from the West Coast that will go to the west side of Mexico. And then, you'll also see is some of the cross-border sales ramp up, in markets like El Paso you will start to see some more West Coast barrels serving the Arizona market which will help bring that market back into balance.

<Q - Prashant Rao>: Okay. Thanks. That's helpful. And then, just a quick question on – I think we've talked about this earlier, about the medium sour availability being a little bit more difficult in the current environment. Just wanted to get your sense or longer term thoughts in addressing that where there might be sourcing there or is that something that we should just be sort of expecting intermediate terms to still be a little bit [indiscernible] (36:39)? And then maybe coming back next year [indiscernible] (36:43) get your read dynamics on the market?

<A - Gary Simmons>: Yeah. So I think there's not a problem really with availability of medium sour crude product system. It's just not priced to where we show an economic incentive to maximize those barrels. However they are, certainly, inter-related. And I think we see that medium sours will continue to price at a level where we wouldn't expect to run a high-volume medium sour crude until the OPEC production comes back online, whenever that is, if it is later this year or early next year. But I think if the OPEC production comes back online and you get that additional supply in the market, you will see those medium discounts widen and we'll bring them back into our system.

<Q - Prashant Rao>: All right. Thanks very much for the time.

<A - Joseph W. Gorder>: Thanks, Prashant.

Operator

Thank you. And our next question comes from the line of Justin Jenkins with Raymond James. Your line is now open.

<Q - Justin S. Jenkins>: Hey. Good morning everybody. I guess, I will start maybe with a corollary to Roger's gasoline question but more on the diesel front. You've got inventories as low as they've been since 2014 here in the U.S. and obviously [indiscernible] (37:46). So if prices on diesel continue to move higher as maybe we'd all expect, does that start to impact the demand equation there and maybe even the broader economy, or how should we think about that one?

<A - Gary Simmons>: Yeah. I think we see diesel demand that's very strong. And as you mentioned, 28 million barrels below where we were last year, we had good [indiscernible] (38:06) demand with little colder weather in the Northeast. And then, we're seeing very strong [ph] rack (38:11) demand. I think some it is economic growth and then a lot of it is just the increase in the upstream activity. But the big thing to us is as we started to get out of typical heating well season you could see in the stats we actually had record exports. And we're seeing just overall what appears to be an overall global short of distillate barrels available.

So I think we feel like that the distillate market is going to be – remain very strong throughout this year, and then you certainly – as you alluded to, we'll start to see an IMO impact that affects us on the distillate side as well. When that starts to kick in, I'm not sure. But we certainly feel that we're in for a very good year in terms of the diesel fundamentals.

<Q - Justin S. Jenkins>: Perfect. Appreciate that. Maybe on the midstream side. Gary, you alluded to the potential for pipeline participation towards your Gulf Coast assets. But I'm curious, Joe or even Gary, how you think about getting closer to the wellhead in the Permian to gather crude and may be control that barrel further?

<A - Gary Simmons>: Yeah. So, I think, any of these projects that come couple of reasons. One is to lower our deliver cost of crude and then also it allows us better control online, Rich Lashway and my group certainly evaluate all of them. And it's for a couple of reasons. One, is to lower our delivery cost accrued, and then also it allows us better control over the quality of the barrel that we're running in our refining system.

So for those reasons, we're involved in all these processes on the new lines coming on. And certainly look to participate if it makes sense for us to do so.

<Q - Justin S. Jenkins>: Okay. I'll leave it there. Thanks guys.

Operator

Thank you. And our next question comes from the line of Blake Fernandez with Scotia Howard Weil. Your line is now open.

<Q - Blake Fernandez>: Hey, guys. Good morning. Mike, I will certainly miss the opportunity to catch up with you over in West Texas. It's been a good run and congrats to you man.

<A - Michael S. Ciskowski>: Thanks, Blake.

<Q - Blake Fernandez>: I wanted to go back. I know you've kind of addressed, Gary, some of the, I guess, the mediums and likes, but a lot of the inbound questions we've been getting from clients recently has been on where we stand with regard to maxing out light sweet processing.

I think you had mentioned to me last week that you're backing out mediums and going to max light sweet and heavy, but can you say – I mean, have you fully exhausted your capability of running light sweet at this point?

<A - Gary Simmons>: Pretty much, Blake. If you look at where we were in the first quarter, we said that we ended at 1.6 million barrels a day of light sweet crude processing capacity. Although it wasn't fully utilized, a lot of the capacity that wasn't used, it was because we had maintenance going on at a couple of our refineries that backed out some of that light sweet crude processing capacity. But we pretty much – our economic signals are pointing us to maximize light sweet pretty much everywhere we can.

<Q - Blake Fernandez>: Okay. The second question, your utilization rates along with the industry have been pretty well above what historical norms would suggest and above expectations. And I'm just curious if you have any thoughts around, maybe, what's driving that and the sustainability of that. Is that just kind of capacity creep maybe to where the nameplate numbers are a little bit stale, or is just reliability improving, or any thoughts you have there?

<A - Gary Simmons>: I think when I go back and look at the trend in refinery utilization, some of it is tied to the trend in running lighter crude. So as the API – average API gravity of the crude slate has gone up throughout the industry, utilization has gone up with it. So we certainly see at some of our refineries, as we run a lighter diet, it enables us to run higher rates. So with that, you would expect that as the crude quality discounts widen and the slate gets heavier, maybe there's a chance utilization falls back off if that occurs.

<Q - Blake Fernandez>: Got it.

<A - R. Lane Riggs>: Hey – hey, Blake, [ph] I'll just add other thing (41:55). I think one of the things you've seen over the last few years is different than maybe historically. So there's been a call on crude capacity signals, that's pretty much been the most economic unit in the refinery. So all refiners will do everything to make sure that capacity is always well utilized, feedstocks were in front of it. You might even [ph] encouraged (42:14) to merge to make sure that in fact you don't lose capacity.

So, I mean, that's clearly been part of what's going on with respect to the utilization, because that number is [ph] creating the capacity (42:24), it's not buying intermediates and other things.

<Q - Blake Fernandez>: Got it. Okay. Thank you, guys.

<A - Joseph W. Gorder>: Thanks, Blake.

Operator

Thank you. And our next question comes from the line of Phil Gresh with JPMorgan. Your line is now open.

<Q - Phil M. Gresh>: Hi. Yes. Hi, good morning. Thanks for taking the question. First one is just on LLS discounts to Brent. We started to see those widen out a bit here this year, starting to creep higher towards the Houston side. And I presume some of that [indiscernible] (42:53). But just curious how you think about LLS discounts moving towards say relative to Houston?

<A - Gary Simmons>: Yeah, Phil. I think to some degree, we're starting to view LLS as somewhat of a stranded crude marker. I think especially since we exited that market. When we started at the Diamond Pipeline, there's just not a lot of liquidity around LLS anymore. And so to us, the more relevant marker to look for the U.S. Gulf Coast light sweet is that [ph] AMH (43:24) marker. And that's the one we tend to look at more heavily than LLS.

<Q - Phil M. Gresh>: Okay. Got it. That makes sense. The second question is just around the California refining market. I want to get your latest thoughts on Wilmington and the hydrofluoric acid phase-out discussions. I know there's a committee meeting coming up this weekend. There are some slides published in advance of that meeting, talking about potentially phasing out HFA altogether, which I know would be a fairly costly endeavor. So I just want to get your viewpoint on this HFA phase out, particularly given the costs relative to the size of the refinery?

<A - R. Lane Riggs>: Yes. This is Lane. Hey. We just really continue to work with the community and the SCAQMD out there and then other stakeholders really to arrive at what we think will ultimately be a reasonable solution. [ph] We're just (44:16) that's sort of what we've been stating in all the calls and all the conferences and that still what we believe.

<Q - Phil M. Gresh>: So just to clarify, I mean, you wouldn't at this point say a phase out of HFA would be a nonstarter for you guys?

<A - R. Lane Riggs>: Say that again?

<Q - Phil M. Gresh>: The idea that HFA would be phased out for sulfuric or some other solution, is that a non-starter from a cost perspective?

<A - R. Lane Riggs>: It's well – it would absolutely – we're building an alkylation unit in our Houston refinery and [ph] over (44:50) at St. Charles. And so you're talking about something on the order of $0.5 billion. If in fact we build the sulfuric acid and that it would be in California, so it would be probably even more. So it'll be a very, very, very expensive endeavor, if there is a [ph] short fuse on the (45:05) phase-out in the West Coast.

<Q - Phil M. Gresh>: Okay. Thank you.

Operator

Thank you. And our next question comes from the line of Doug Leggate with Bank of America Merrill Lynch. Your line is now open.

<Q>: This is [ph] Clay (45:20) on for Doug. Thanks for taking my question. A lot of things have been touched here. So I just want to get your thoughts on Latin America. Obviously, the underperformance in that refining system has played a big role in creating the opportunity to ramp U.S. product exports. Just want to know what the prognosis is today, and if there are any upside risk to crude runs that you guys are watching out for.

<A - Gary Simmons>: I don't think we see anything that causes us a pause for what we're doing in Latin America. We still see very good product demand [ph] pools (45:50) for gasoline and distillate. I don't think we see anything on the horizon that's going to change that.

<Q>: All right. Thanks guys.

<A - Joseph W. Gorder>: Thank you.

Operator

Thank you. And our next question comes from the line of Ryan Todd with Deutsche Bank. Your line is now open.

<Q - Ryan Todd>: Thanks. Maybe a follow-up question. You addressed your view on overall kind of Canadian heavy and heavy differences earlier. But can you talk about within your system and how much Canadian heavy are you able to run right now? What are the – I realize it's going to be difficult until the cross-border pipelines potentially in 2020, but are there any – is there any possibility of you being able to increase your heavy crude runs over the next couple of years? And maybe are you seeing any impacts from falling Venezuelan volumes or have you still had a strong heavy availability in the Gulf?

<A - Gary Simmons>: Yeah. So in the quarter, we ran about 180,000 barrels a day of heavy Canadian, Ryan, and it's not really a limit in our system. It's more of an economic optimization. So we could run a lot more heavy Canadian if the economic signals pointed us in that direction. But it would be at the expense of some of the other Latin American grades, be it Venezuelan or Maya. Some of those grades we would pushout if the Canadian was more economic.

Follow-up, I guess, in Venezuela, we've certainly seen some issues with production and issues around logistics. But for the most part, the volumes we got in Venezuela on the first quarter were consistent with what our historical volumes have been. And we continue to see good value for those barrels versus our other heavy sour alternatives.

<Q - Ryan Todd>: Great. Thanks. That's helpful. And maybe – maybe one follow-up on [ph] it feels that you've talked (47:42) about Latin America a lot today. But there is – Petrobras is obviously looking for partners into [ph] about (47:51) some opening up of the markets there and partnerships in some of the refineries down there. Do you view that as a similar situation of what you're describing earlier with PEMEX, or how do you view the potential opportunities of the Brazilian market?

<A - Joseph W. Gorder>: Well, this is Joe. I mean, we'll take a look. I think it's too early for us to answer your question specifically as you asked it though. I mean, we just don't know yet. So I mean, just like many others I'm sure we'll just take a look to see what the opportunity looks like to see [ph] what we can do (48:20) with it. And then, we'll let you know more about it later.

<Q - Ryan Todd>: Great. Thanks Joe.

<A - Joseph W. Gorder>: Thanks Ryan.

Operator

Thank you. And our next question comes from the line of Matthew Blair with Tudor, Pickering, Holt. Your line is now open.

<Q - Matthew Blair>: Hey, good morning everyone. Maybe to circle back. I think it was Lane's comment, talking about how the crude tower is pretty much been the most economical part of the refinery today. So just looking at your Gulf Coast system, you've run about [ph] 1.44 (48:53) of crude, but you produce [ph] 1.84 (48:57) products even after the recent crude topper projects at Corpus and Houston. Is there any thought to adding more crude distillation capacity on the Gulf Coast? And what kind of economics are you seeing on those recent topper projects?

<A - R. Lane Riggs>: Well. This is Lane, again. The issue you have – there's a limit to how much you can run crude because at some point – or even build it out, when we put our two crude toppers on, we sized them such that they would match our downstream capability, particularly in diesel hydrotreating, so we wouldn't have to go out and try to market something that didn't meet the [indiscernible] (49:41).

And so I think when many people look at a crude unit project, they're going to have to – there's other units involved. We were – and the reason [ph] that we were (49:52) able to do that because we were buying a number of intermediate feedstocks in lieu of crude. So that's the size. For us to go up a lot more in that space, we would have to invest in diesel hydrotreating and gasoline hydrotreating. What was the second part of your question?

<Q - Matthew Blair>: What kind of returns are you seeing on the Corpus and Houston toppers?

<A - R. Lane Riggs>: [indiscernible] (50:13) give you the specifics, they have been great projects. They've exceeded our funding decisions with respect to IRR. So They've been great projects for us.

<Q - Matthew Blair>: Yeah, yeah. Seems like it. Second question is on product exports. So you reported 271,000 barrels per day of product exports. I think that was down quite a bit year-over-year. Was that due to higher ethanol blends in Brazil this year? And can you also provide a split between how much was gasoline and how much was diesel?

<A - Gary Simmons>: Yes. So we start with that. We did 73,000 barrels a day of gasoline exports and our diesel exports were 163,000 barrels a day. The year-over-year numbers are down fairly significantly, and there's a number of reasons for that. Joe alluded to weather issues in the Gulf, especially a lot of fog that prohibited us from exporting during the quarter. Also we had some refinery maintenance that limited production.

But the biggest thing was really probably more the strength of the U.S. market. So we have the ability to put barrels on the water and for us during [indiscernible] (51:25) we actually saw a lot better value to take those barrels we're putting on the water to the Florida market, for instance, rather than the export market. So a lot of our dock capacity was consumed taking barrels [ph] like to the Florida market, waterborne (51:36) markets in the U.S. rather than the export market.

I don't think it's any indication of lack of demand it was just – we always view that as an economic optimization and we had better netbacks [ph] to send (51:50) to other markets.

<Q - Matthew Blair>: Got it. Thank you very much.

Operator

Thank you. And our next question comes from the line of Craig Shere with Tuohy Brothers. Your line is now open.

<Q - Craig K. Shere>: Good morning.

<A - Joseph W. Gorder>: Good morning, Craig.

<Q - Craig K. Shere>: I understand there is not really a [ph] governor (52:08) or upper limit on share price as far as buyback considerations. But is there an upper limit of the cash holdings that could impact targeted payouts if attractive M&A really doesn't materialize over the next two to three years?

And as a follow-up to that, can you opine on what you might see long-term in terms of industry consolidation in midstream versus refining?

<A - Joseph W. Gorder>: Okay, Mike, do you want to do the first one?

<A - Michael S. Ciskowski>: Yeah, I mean, we continue to evaluate the cash flow uses and the allocation of the surplus cash flow. That has not changed. We continue to allocate it per capital allocation framework. Right now, our payout ratio is 40% to 50%. If cash were built significantly over the next several quarters, surely, we would have to look at that to see whether we need to adjust that payout ratio in absence of any type of M&A opportunity.

<A - Joseph W. Gorder>: Okay, and Craig, on the second part of your question, it was the consolidation, whether it would be in refining or MLPs?

<Q - Craig K. Shere>: And which might come earlier, right.

<A - Joseph W. Gorder>: Yeah, okay, this is purely an opinion, right. And I open it up to any members of the team if they want to comment also. But I just don't think there's going to be a significant amount of opportunity for consolidation on the refining side of the business from Valero's perspective, because we really like our portfolio today. We have an excellent portfolio. I mean, there's things that we [ph] could bolt onto in that (53:46) would be nice to have. But as far as creating – needing to do a transaction to create a lot more critical mass, that's just not something that we need to do today.

So opportunistically, we look at everything, but practically speaking, we don't feel we need to do anything. Now, could there be more consolidation? Sure. I think people are always looking for different ways to grow their businesses. And certainly, if you can create synergy by combining, it makes a lot of sense to do that. In the MLP space, I don't know. Rich, do you have a view?

<A - Richard F. Lashway>: I [ph] wouldn't (54:26) say that it would be a challenge to think of consolidation right now in the – the MLP market is everybody's kind of reassessing the access to the equity capital market. So it doesn't seem like that there would be a momentum for that to happen right now [ph] to let (54:45) equity capital markets kind of gets figured out.

<Q - Craig K. Shere>: Okay. I mean, that all makes sense. It just sounds like eventually the payout ratio is going to have to rise overtime?

<A - Joseph W. Gorder>: [indiscernible] (55:00) The ratio might rise, but probably [ph] that's harder because it's going to stay (55:04) somewhat consistent. You know the volatility that we historically had in this business, which we have done our best as a team to try to strip. And so you always want to be careful with the dividend and be sure that once you put it in place, that is our commitment to our owners and we're going to be sure we do everything we can to sustain that dividend.

And so Mike – we don't have a particular targeted number because Mike and Donna always look at the forecasted cash, what the balances look like going forward. And we've told the market for several years now we're not going to hoard cash and we [ph] haven't (55:46). And so I think, Craig, you should just assume that if we find ourselves sitting on a pot full of cash that we're going to return it.

<Q - Craig K. Shere>: Great. Thanks for the thoughts.

<A - John Locke>: Thanks, Craig.

Operator

Thank you. And this does conclude today's Q&A session. And I'd like to return the call to Mr. John Locke for any closing remarks.

John Locke

Okay. Well, thanks, everyone. We appreciate you joining us today. Feel free to give the IR team a call if you have any additional questions. Thank you.

Operator

Ladies and gentlemen, thank you for participating in today's conference. This does conclude the program, and you may all disconnect. Everyone, have a great day.