UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2016

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE TRANSITION PERIOD FROM _________TO _________

Commission file number: 001-35742

ALON USA PARTNERS, LP

(Exact name of Registrant as specified in its charter)

Delaware	46-0810241
(State of organization)	**(I.R.S. Employer Identification No.)**

12700 Park Central Dr., Suite 1600, Dallas, Texas 75251
(Address of principal executive offices) (Zip Code)

(972) 367-3600
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act:

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The number of the Registrant's common limited partner units outstanding as of October 24, 2016, was 62,520,220.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	September 30, 2016	December 31, 2015
	(unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 203,763	$ 132,953
Accounts and other receivables, net	70,884	59,581
Accounts and other receivables, net - related parties	10,191	8,005
Inventories	51,890	35,444
Prepaid expenses and other current assets	5,733	6,745
Total current assets	342,461	242,728
Property, plant and equipment, net	423,187	434,619
Other assets, net	59,402	71,237
Total assets	$ 825,050	$ 748,584
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 292,542	$ 253,325
Accrued liabilities	36,959	40,707
Current portion of long-term debt	2,500	2,500
Total current liabilities	332,001	296,532
Other non-current liabilities	92,095	31,513
Long-term debt	288,986	289,582
Total liabilities	713,082	617,627
Commitments and contingencies (Note 11)		
Partners' equity:		
General Partner	—	—
Common unitholders - 62,520,220 and 62,510,039 units issued and outstanding at September 30, 2016 and December 31, 2015, respectively	111,968	130,957
Total partners' equity	111,968	130,957
Total liabilities and partners' equity	$ 825,050	$ 748,584

The accompanying notes are an integral part of these consolidated financial statements.

ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(unaudited, dollars in thousands except per unit data)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Net sales (1)	$ 462,257	$ 551,813	$ 1,298,723	$ 1,719,319
Operating costs and expenses:				
Cost of sales	404,207	439,678	1,134,275	1,397,395
Direct operating expenses	25,125	24,136	73,424	71,837
Selling, general and administrative expenses	8,153	8,536	24,264	24,654
Depreciation and amortization	14,581	13,697	43,454	41,281
Total operating costs and expenses	452,066	486,047	1,275,417	1,535,167
Operating income	10,191	65,766	23,306	184,152
Interest expense	(8,144)	(11,505)	(28,651)	(34,045)
Other income, net	353	40	550	26
Income (loss) before state income tax expense	2,400	54,301	(4,795)	150,133
State income tax expense	317	525	493	480
Net income (loss)	$ 2,083	$ 53,776	$ (5,288)	$ 149,653
Earnings (loss) per unit	$ 0.03	$ 0.86	$ (0.08)	$ 2.39
Weighted average common units outstanding (in thousands)	62,520	62,510	62,515	62,508
Cash distribution per unit	$ 0.14	$ 1.04	$ 0.22	$ 2.45

(1) Includes sales to related parties of $82,717 and $97,014 for the three months and $222,711 and $281,136 for the nine months ended September 30, 2016 and 2015, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited, dollars in thousands)

	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Cash flows from operating activities:		
Net income (loss)	$ (5,288)	$ 149,653
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation and amortization	43,454	41,281
Unit-based compensation	53	40
Deferred income taxes	—	(736)
Amortization of debt issuance costs	1,335	1,750
Amortization of original issuance discount	480	445
Changes in operating assets and liabilities:		
Accounts and other receivables, net	(7,064)	(3,770)
Accounts and other receivables, net - related parties	(2,186)	(184)
Inventories	(16,446)	3,998
Prepaid expenses and other current assets	1,012	202
Other assets, net	4,573	(5,067)
Accounts payable	22,268	45,194
Accrued liabilities	(2,134)	(16,835)
Other non-current liabilities	18,400	3,261
Net cash provided by operating activities	58,457	219,232
Cash flows from investing activities:		
Capital expenditures	(17,199)	(12,108)
Capital expenditures for turnarounds and catalysts	(9,679)	(3,214)
Net cash used in investing activities	(26,878)	(15,322)
Cash flows from financing activities:		
Distributions paid to unitholders	(2,534)	(28,195)
Distributions paid to unitholders - Alon Energy	(11,220)	(124,950)
RINs financing transactions	54,860	(8,137)
Deferred debt issuance costs	—	(1,800)
Revolving credit facility, net	—	(10,000)
Payments on long-term debt	(1,875)	(1,875)
Net cash provided by (used in) financing activities	39,231	(174,957)
Net increase in cash and cash equivalents	70,810	28,953
Cash and cash equivalents, beginning of period	132,953	106,325
Cash and cash equivalents, end of period	$ 203,763	$ 135,278
Supplemental cash flow information:		
Cash paid for interest, net of capitalized interest	$ 27,219	$ 31,785
Cash paid for income tax	$ 493	$ 1,216
Supplemental disclosure of non-cash activity:		
Capital expenditures included in accounts payable and accrued liabilities	$ —	$ 3,016

The accompanying notes are an integral part of these consolidated financial statements.

ALON USA PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited, dollars in thousands except as noted)

(1) Basis of Presentation

As used in this report, the terms "Alon," the "Partnership," "we," "our" and "us" or like terms refer to Alon USA Partners, LP, and its consolidated subsidiaries or to Alon USA Partners, LP or an individual subsidiary. References in this report to "Alon Energy" refer collectively to Alon USA Energy, Inc. and any of its consolidated subsidiaries, other than Alon USA Partners, LP, its subsidiaries and its general partner.

We are a Delaware limited partnership formed in August 2012 by Alon Energy and its wholly-owned subsidiary Alon USA Partners GP, LLC (the "General Partner"), which owns 100% of our non-economic general partner interest.

These consolidated financial statements and notes are unaudited and have been prepared in accordance with United States generally accepted accounting principles ("GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities Exchange Act of 1934. Accordingly, they do not include all of the information and notes required by GAAP for complete consolidated financial statements.

In the opinion of the General Partner's management, the information included in these consolidated financial statements reflects all adjustments, consisting of normal and recurring adjustments, which are necessary for a fair presentation of our consolidated financial position and results of operations for the interim periods presented. All significant intercompany balances and transactions have been eliminated in consolidation. Certain prior year balances may have been aggregated or disaggregated in order to conform to the current year presentation. Our results of operations for the three and nine months ended September 30, 2016 are not necessarily indicative of the operating results that may be realized for the year ending December 31, 2016.

Our consolidated balance sheet as of December 31, 2015 has been derived from the audited financial statements as of that date. These unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board jointly issued a comprehensive new revenue recognition standard that provides accounting guidance for all revenue arising from contracts to provide goods or services to customers. This standard is intended to improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets. The standard allows for either full retrospective adoption or modified retrospective adoption. In August 2015, the FASB updated the guidance to include a one-year deferral of the effective date for the new revenue standard, making the requirements of the standard effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted for interim and annual periods beginning after December 15, 2016. We are evaluating the guidance to determine the method of adoption and the impact this standard will have on our consolidated financial statements.

In July 2015, the FASB issued an accounting standards update simplifying the measurement of certain inventory. This updated standard simplifies the measurement of inventory by requiring certain inventory to be measured at the lower of cost or net realizable value. The amendments in this accounting standards update are effective for interim and annual periods beginning after December 15, 2016. This accounting standards update does not apply to the subsequent measurement of inventory measured using the last-in, first-out ("LIFO") or retail inventory method, therefore the adoption of this guidance will not have a material effect on our financial position or results of operations.

In February 2016, the FASB issued new guidance on the accounting for leases, which requires lessees to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. The requirements from this guidance are effective for interim and annual periods beginning after December 31, 2018. We are evaluating the guidance to determine the impact this standard will have on our consolidated financial statements.

In June 2016, the FASB issued an accounting standards update requiring the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. Financial institutions and other organizations will now use forward-looking information to better inform their credit loss estimates. The requirements from the updated standard are effective for interim and annual periods beginning after December 15, 2019. We are evaluating the guidance to determine the impact this standard will have on our consolidated financial statements.

(unaudited, dollars in thousands except as noted)

In August 2016, the FASB issued an accounting standards update addressing eight specific cash flow issues with the objective of eliminating the existing diversity in practice. The amendments from this update are effective for interim and annual periods beginning after December 15, 2017. We do not expect application of this standard to have a material effect on our consolidated financial statements.

(2) Fair Value

We determine fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We classify financial assets and financial liabilities into the following fair value hierarchy:

- Level 1 - valued based on quoted prices in active markets for identical assets and liabilities;
- Level 2 - valued based on quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability; and
- Level 3 - valued based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

As required, we utilize valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy. We generally apply the "market approach" to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

The carrying amounts of our cash and cash equivalents, receivables, payables and accrued liabilities approximate fair value due to the short-term maturities of these assets and liabilities. The reported amounts of long-term debt approximate fair value. Derivative instruments are carried at fair value, which are based on quoted market prices. Derivative instruments are our only assets and liabilities measured at fair value on a recurring basis.

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, in the consolidated balance sheets at September 30, 2016 and December 31, 2015:

	Level 1	Level 2	Level 3	Total
As of September 30, 2016				
Assets:				
Fair value hedge of consigned inventory	$ —	$ 5,569	$ —	$ 5,569
Liabilities:				
Commodity contracts (futures and forwards)	1,033	—	—	1,033
As of December 31, 2015				
Assets:				
Fair value hedge of consigned inventory	$ —	$ 11,564	$ —	$ 11,564
Liabilities:				
Commodity contracts (futures and forwards)	40	—	—	40

(3) Derivative Financial Instruments

We selectively utilize crude oil and refined product commodity derivative contracts to reduce the risk associated with potential price changes on committed obligations as well as to reduce earnings volatility. We do not speculate using derivative instruments. Credit risk on our derivative instruments is mitigated by transacting with counterparties meeting established collateral and credit criteria.

Mark to Market

We have certain contracts that serve as economic hedges, which are derivatives used for risk management but not designated as hedges for financial accounting purposes. All economic hedge transactions are recorded at fair value and any changes in fair value between periods are recognized in earnings.

We have contracts that are used to fix prices on forecasted purchases of inventory, which we refer to as futures and forwards. Futures represent trades executed on the New York Mercantile Exchange which have not been closed or settled at the end of the reporting period. Forwards represent physical trades for which pricing and quantities have been set, but the physical product delivery has not occurred by the end of the reporting period.

(unaudited, dollars in thousands except as noted)

Fair Value Hedge

Fair value hedges are used to hedge price volatility of certain refining inventories and firm commitments to purchase inventories. The gain or loss on a derivative instrument designated and qualifying as a fair value hedge, as well as the offsetting gain or loss on the hedged item attributable to the hedged risk, is recognized in earnings in the same period.

We have certain commodity contracts associated with the Supply and Offtake Agreement discussed in Note 5 that have been accounted for as a fair value hedge, which had purchase volumes of 135 thousand barrels of crude oil as of September 30, 2016.

The following tables present the effect of derivative instruments on the consolidated balance sheets:

	As of September 30, 2016			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments:				
Commodity contracts (futures and forwards)	Accounts receivable	$ 427	Accrued liabilities	$ 1,460
Total derivatives not designated as hedging instruments		427		1,460
Derivatives designated as hedging instruments:				
Fair value hedge of consigned inventory	Other assets	$ 5,569		$ —
Total derivatives designated as hedging instruments		5,569		—
Total derivatives		$ 5,996		$ 1,460

	As of December 31, 2015			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments:				
Commodity contracts (futures and forwards)	Accounts receivable	$ 59	Accrued liabilities	$ 99
Total derivatives not designated as hedging instruments		59		99
Derivatives designated as hedging instruments:				
Fair value hedge of consigned inventory	Other assets	$ 11,564		$ —
Total derivatives designated as hedging instruments		11,564		—
Total derivatives		$ 11,623		$ 99

The following tables present the effect of derivative instruments on the consolidated statements of operations:

Derivatives in fair value hedging relationships:

		Gain (Loss) Recognized in Income			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	Location	2016	2015	2016	2015
Fair value hedge of consigned inventory (1)	Interest expense	$ (1,772)	$ 5,990	$ (5,995)	$ 4,495
Total derivatives		$ (1,772)	$ 5,990	$ (5,995)	$ 4,495

(1) Changes in the fair value hedge are substantially offset in earnings by changes in the hedged item.

(unaudited, dollars in thousands except as noted)

Derivatives not designated as hedging instruments:

		Gain (Loss) Recognized in Income			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	Location	2016	2015	2016	2015
Commodity contracts (futures and forwards)	Cost of sales	$ (1,199)	$ 1,251	$ 4,998	$ 622
Total derivatives		$ (1,199)	$ 1,251	$ 4,998	$ 622

Offsetting Assets and Liabilities

Our derivative instruments are subject to master netting arrangements to manage counterparty credit risk associated with derivatives, and we offset the fair value amounts recorded for derivative instruments to the extent possible under these agreements on our consolidated balance sheets.

The following table presents offsetting information regarding our derivatives by type of transaction as of September 30, 2016 and December 31, 2015:

	Gross Amounts of Recognized Assets/Liabilities	Gross Amounts offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not offset in the Statement of Financial Position: Cash Collateral Pledged	Net Amount
As of September 30, 2016						
Derivative Assets:						
Commodity contracts (futures and forwards)	$ 1,174	$ (747)	$ 427	$ (427)	$ —	$ —
Fair value hedge of consigned inventory	5,569	—	5,569	—	—	5,569
Derivative Liabilities:						
Commodity contracts (futures and forwards)	$ 2,207	$ (747)	$ 1,460	$ (427)	$ —	$ 1,033
As of December 31, 2015						
Derivative Assets:						
Commodity contracts (futures and forwards)	$ 192	$ (133)	$ 59	$ (59)	$ —	$ —
Fair value hedge of consigned inventory	11,564	—	11,564	—	—	11,564
Derivative Liabilities:						
Commodity contracts (futures and forwards)	$ 232	$ (133)	$ 99	$ (59)	$ —	$ 40

Compliance Program Market Risk

We are obligated by government regulations to blend a certain percentage of biofuels into the products that we produce and are consumed in the U.S. We purchase biofuels from third parties and blend those biofuels into our products, and each gallon of biofuel purchased includes a renewable identification number, or RIN. To the degree we are unable to blend biofuels at the required percentage, a RINs deficit is generated and we must acquire that number of RINs by the annual reporting deadline in order to remain in compliance with applicable regulations. Alternatively, if we have a RINs surplus, some of those RINs could be sold. Any such sales would be subject to our normal credit evaluation process.

We are exposed to market risk related to the volatility in the price of credits needed to comply with these governmental and regulatory programs. We manage this risk by purchasing RINs when prices are deemed favorable utilizing fixed price purchase contracts. We may also sell the RINs with an agreement to repurchase in the future. Some of these contracts are derivative instruments; however, we elect the normal purchase and sale exception and do not record these contracts at their fair values.

(unaudited, dollars in thousands except as noted)

The cost of meeting our obligations under these compliance programs was $3,712 and $1,868 for the three months ended and $6,620 and $8,369 for the nine months ended September 30, 2016 and 2015, respectively. These amounts are reflected in cost of sales in the consolidated statements of operations.

(4) Inventories

Carrying value of inventories consisted of the following:

	September 30, 2016	December 31, 2015
Crude oil, refined products and blendstocks	$ 39,909	$ 24,548
Crude oil consignment inventory (Note 5) (1)	838	(95)
Materials and supplies	11,143	10,991
Total inventories	$ 51,890	$ 35,444

(1) The fair value of the hedged item designated in our fair value hedge reduced the carrying value of our consigned inventory valued at LIFO below zero at December 31, 2015.

At September 30, 2016 and December 31, 2015, the market value of refined products and blendstock inventories was less than inventories on a LIFO cost basis which resulted in recording a lower of cost or market reserve of $7,350 and $9,396, respectively. At September 30, 2016 and December 31, 2015, the market value of crude oil inventories exceeded LIFO costs, net of the fair value hedged item, by $3,937 and $6,387, respectively.

(5) Inventory Financing Agreement

We have entered into a Supply and Offtake Agreement and other associated agreements (together the “Supply and Offtake Agreement”) with J. Aron & Company (“J. Aron”). Pursuant to the Supply and Offtake Agreement, (i) J. Aron agreed to sell to us, and we agreed to buy from J. Aron, at market prices, crude oil for processing at the Big Spring refinery and (ii) we agreed to sell, and J. Aron agreed to buy, at market prices, certain refined products produced at the Big Spring refinery.

The Supply and Offtake Agreement also provided for the sale, at market prices, of our crude oil and certain refined product inventories to J. Aron, the lease to J. Aron of crude oil and refined product storage facilities, and to identify prospective purchasers of refined products on J. Aron’s behalf.

The Supply and Offtake Agreement has an initial term that expires in May 2021. J. Aron may elect to terminate the Supply and Offtake Agreement prior to the expiration of the initial term beginning in May 2018 and upon each anniversary thereof, on six months prior notice. We may elect to terminate in May 2020 on six months prior notice.

Following expiration or termination of the Supply and Offtake Agreement, we are obligated to purchase the crude oil and refined product inventories then owned by J. Aron and located at the Big Spring refinery at then current market prices.

Associated with the Supply and Offtake Agreement, we have a fair value hedge of our inventory purchase commitment with J. Aron and crude oil inventory consigned to J. Aron (“crude oil consignment inventory”). Additionally, financing charges related to the Supply and Offtake Agreement are recorded as interest expense in the consolidated statements of operations.

At September 30, 2016 and December 31, 2015, we had net current payables of $18,455 and net current receivables of $4,975, respectively, with J. Aron for purchases and sales, and a consignment inventory receivable representing a deposit paid to J. Aron of $6,290 and $6,290, respectively. At September 30, 2016 and December 31, 2015, we had non-current liabilities for the original financing of $7,203 and $9,761, respectively, net of the related fair value hedge.

Additionally, we had net current receivables of $427 and net current payables $99 at September 30, 2016 and December 31, 2015, respectively, for forward commitments related to month-end consignment inventory target levels differing from projected levels and the associated pricing with these inventory level differences.

ALON USA PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(unaudited, dollars in thousands except as noted)

(6) Property, Plant and Equipment, Net

Property, plant and equipment, net consisted of the following:

	September 30, 2016	December 31, 2015
Refining facilities	$ 725,905	$ 709,779
Accumulated depreciation	(302,718)	(275,160)
Property, plant and equipment, net	$ 423,187	$ 434,619

(7) Additional Financial Information

The following tables provide additional financial information related to the consolidated financial statements.

(a) Other Assets, Net

	September 30, 2016	December 31, 2015
Deferred turnaround and catalyst cost	$ 38,199	$ 43,021
Receivable from supply and offtake agreement (Note 5)	6,290	6,290
Fair value hedge of consigned inventory (Note 3)	5,569	11,564
Other	9,344	10,362
Total other assets	$ 59,402	$ 71,237

(b) Accounts Payable

Included in accounts payable was $123,844 and $91,179 related to RINs financing transactions as of September 30, 2016 and December 31, 2015, respectively.

(c) Accrued Liabilities and Other Non-Current Liabilities

	September 30, 2016	December 31, 2015
Accrued Liabilities:		
Taxes other than income taxes, primarily excise taxes	$ 25,186	$ 25,018
Accrued finance charges	293	394
Environmental accrual (Note 11)	1,716	1,716
Commodity contracts	1,460	99
Other	8,304	13,480
Total accrued liabilities	$ 36,959	$ 40,707
Other Non-Current Liabilities:		
Consignment inventory obligation (Note 5)	$ 12,772	$ 21,325
Environmental accrual (Note 11)	4,722	4,725
Asset retirement obligations	3,086	2,927
RINs financing transactions	68,978	—
Other	2,537	2,536
Total other non-current liabilities	$ 92,095	$ 31,513

(unaudited, dollars in thousands except as noted)

(8) Indebtedness

Debt consisted of the following:

	September 30, 2016	December 31, 2015
Term loan credit facility	$ 236,486	$ 237,082
Revolving credit facility	55,000	55,000
Total debt	291,486	292,082
Less: Current portion	2,500	2,500
Total long-term debt	$ 288,986	$ 289,582

Outstanding letters of credit under the revolving credit facility were $91,225 and $48,590 at September 30, 2016 and December 31, 2015, respectively.

The revolving credit facility contains maintenance financial covenants. At September 30, 2016, we were in compliance with these covenants.

(9) Partners' Equity (unit values in dollars)

Cash Distributions

We have adopted a policy pursuant to which we will distribute all of the available cash generated each quarter, as defined in the partnership agreement, subject to the approval of the board of directors of the General Partner. The per unit amount of available cash to be distributed each quarter, if any, will be distributed within 60 days following the end of such quarter.

The following table summarizes the Partnership's cash distribution activity during the period:

	Cash Available for Distribution per Unit (1)	Distribution Amount Per Unit	Total Distribution Amount
First Quarter 2016	$ —	$ 0.08	$ 5,001
Second Quarter 2016	0.14	—	—
Third Quarter 2016	0.15	0.14	8,753

(1) Represents the aggregate cash available for distribution per unit attributable to the period indicated. This represents the difference between cash available for distribution and distributions paid in the table above.

Restricted Units

Non-employee directors of the General Partner are awarded an annual grant of $25 in restricted units, which vest over a period of three years, assuming continued service at vesting. In May 2016, we granted awards of 7,653 restricted common units at a grant date price of $9.80 per unit. In June 2016, we granted awards of 2,528 restricted common units at a grant date price of $9.89 per unit.

(10) Related Party Transactions

Sales and Receivables

Sales to related parties include motor fuels and asphalt sold to other Alon Energy subsidiaries at prices substantially determined by reference to market commodity pricing information. These sales are included in net sales in the consolidated statements of operations. Accounts receivable from related parties includes sales of motor fuels and is shown separately on the consolidated balance sheets.

Costs Allocated from Alon Energy

The Partnership is a subsidiary of Alon Energy and is operated as a component of the integrated operations of Alon Energy. As such, the executive officers of Alon Energy, who are employed by another subsidiary of Alon Energy, also serve as executive officers of the General Partner and Alon Energy's other subsidiaries.

(a) Corporate Overhead Allocations

Alon Energy performs general corporate and administrative services and functions for us and their other subsidiaries, which include accounting, treasury, cash management, tax, information technology, insurance administration and claims processing, legal, environmental, risk management, audit, payroll and employee benefit processing and internal audit services. Alon Energy allocates the expenses actually incurred in performing these services to the Partnership based primarily on the estimated amount of time the individuals performing such services devote to our business and affairs relative to the amount of time they devote to the business and affairs of Alon Energy's other subsidiaries. The management of Alon Energy and the General Partner consider these allocations to be reasonable. We record the amount of such allocations as selling, general and administrative expenses. Our allocation for selling, general and administrative expenses were $3,301 and $2,969 for the three months ended and $10,966 and $8,941 for the nine months ended September 30, 2016 and 2015, respectively.

(b) Labor Costs

As we are operated as a component of Alon Energy's integrated operations, we have no employees. As a result, employee expense costs for Alon Energy employees working in our operations have been allocated to us and recorded as payroll expense in direct operating and selling, general and administrative expenses. The allocated portion of Alon Energy's employee expense costs included in direct operating expenses were $7,391 and $6,848 for the three months ended and $21,723 and $19,872 for the nine months ended September 30, 2016 and 2015, respectively. The allocated portion of Alon Energy's employee expense costs included in selling, general and administrative expenses were $1,178 and $997 for the three months ended and $3,413 and $4,103 for the nine months ended September 30, 2016 and 2015, respectively.

(c) Insurance Costs

Insurance costs related to the Big Spring refinery and wholesale marketing operations are allocated to us by Alon Energy based on estimated insurance premiums on a stand-alone basis relative to Alon Energy's total insurance premium. Our allocation for insurance costs included in direct operating expenses were $1,507 and $1,782 for the three months ended and $3,879 and $5,103 for the nine months ended September 30, 2016 and 2015, respectively.

Leasing Agreements

In June 2014, we entered into six-year lease agreements with a subsidiary of Alon Energy to lease equipment at the Big Spring refinery. The lease agreements were effective July 1, 2014 and require fixed monthly payments amounting to $4,920 annually. Related to these agreements, we recorded selling, general and administrative expense of $1,230 for the three months ended September 30, 2016 and 2015 and $3,690 for the nine months ended September 30, 2016 and 2015.

Transactions with Delek US Holdings, Inc.

In May 2015, Delek US Holdings, Inc. ("Delek") completed the purchase of approximately 48% of Alon Energy's outstanding common stock from Alon Israel Oil Company, Ltd. We have transactions with Delek that occur in the ordinary course of business. Including amounts prior to the transaction, we purchased refined products from Delek of $175 and $5,192 for the three months ended September 30, 2016 and 2015, respectively, and $960 and $7,592 for the nine months ended September 30, 2016 and 2015, respectively.

Distributions

During the nine months ended September 30, 2016, we paid cash distributions of $13,754, or $0.22 per unit, of which $11,220 was paid to Alon Energy. During the nine months ended September 30, 2015, we paid cash distributions of $153,145, or $2.45 per unit, of which $124,950 was paid to Alon Energy.

(11) Commitments and Contingencies

(a) Commitments

In the normal course of business, we have long-term commitments to purchase, at market prices, utilities such as natural gas, electricity and water for use by our refinery, terminals and pipelines. We are also party to various refined product and crude oil supply and exchange agreements, which are typically short-term in nature or provide terms for cancellation.

(b) Contingencies

We are involved in various legal actions arising in the ordinary course of business. We believe the ultimate disposition of these matters will not have a material effect on our financial position, results of operations or liquidity.

(c) Environmental

We are subject to loss contingencies pursuant to federal, state, and local environmental laws and regulations. These laws and regulations govern the discharge of materials into the environment and may require us to incur future obligations to investigate the effects of the release or disposal of certain petroleum, chemical, and mineral substances at various sites; to remediate or restore these sites and to compensate others for damage to property and natural resources. These contingent obligations relate to sites owned by the Partnership and are associated with past or present operations. We are currently participating in environmental investigations, assessments and cleanups pertaining to the refinery, pipelines and terminals. We may be involved in additional future environmental investigations, assessments and cleanups. The magnitude of future costs are unknown and will depend on factors such as the nature and contamination at many sites, the timing, extent and method of the remedial actions which may be required, and the determination of our liability in proportion to other responsible parties.

Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Substantially all amounts accrued are expected to be paid out over the next 15 years. The level of future expenditures for environmental remediation obligations cannot be determined with any degree of reliability.

We have accrued environmental remediation obligations of $6,438 ($1,716 current liability and $4,722 non-current liability) at September 30, 2016, and $6,441 ($1,716 accrued liability and $4,725 non-current liability) at December 31, 2015.

(12) Subsequent Event

Distribution Declared

On October 26, 2016, the board of directors of the General Partner declared a cash distribution to our common unitholders of approximately $9,378, or $0.15 per common unit. The cash distribution will be paid on November 22, 2016 to unitholders of record at the close of business on November 11, 2016.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

References in this report to the "Partnership," "Alon," "we," "our" and "us" or like terms, refer to Alon USA Partners, LP and its consolidated subsidiaries. Unless the context otherwise requires, references in this report to "Alon Energy" refers to Alon USA Energy, Inc. and any of its consolidated subsidiaries other than the Partnership, its subsidiaries and its general partner. The following discussion of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015.

Forward-Looking Statements

Certain statements contained in this report and other materials we file with the SEC, or in other written or oral statements made by us, other than statements of historical fact, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements relate to matters such as our industry, business strategy, goals and expectations concerning our market position, future operations, margins, profitability, capital expenditures, liquidity and capital resources and other financial and operating information. We have used the words "anticipate," "assume," "believe," "budget," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potential," "predict," "project," "will," "future" and similar terms and phrases to identify forward-looking statements.

Forward-looking statements reflect our current expectations of future events, results or outcomes. These expectations may or may not be realized. Some of these expectations may be based upon assumptions or judgments that prove to be incorrect. In addition, our business and operations involve numerous risks and uncertainties, many of which are beyond our control, which could result in our expectations not being realized or otherwise materially affect our financial condition, results of operations and cash flows.

Actual events, results and outcomes may differ materially from our expectations due to a variety of factors. Although it is not possible to identify all of these factors, they include, among others, the following:

- changes in general economic conditions and capital markets;
- changes in the underlying demand for our products;
- the availability, costs and price volatility of crude oil, other refinery feedstocks and refined products;
- changes in the spread between West Texas Intermediate ("WTI") Cushing crude oil and West Texas Sour ("WTS") crude oil or WTI Midland crude oil;
- changes in the spread between Brent crude oil and WTI Cushing crude oil;
- the effects of transactions involving forward contracts and derivative instruments;
- actions of customers and competitors;
- termination of our Supply and Offtake Agreement with J. Aron & Company ("J. Aron"), under which J. Aron is one of our largest suppliers of crude oil and one of our largest customers of refined products. Additionally, upon termination of the Supply and Offtake Agreement, we are obligated to purchase the crude oil and refined product inventories then owned by J. Aron at then current market prices;
- changes in fuel and utility costs incurred by our refinery;
- disruptions due to equipment interruption, pipeline disruptions or failures at our or third-party facilities;
- the execution of planned capital projects;
- adverse changes in the credit ratings assigned to our trade credit and debt instruments;
- the effects and cost of compliance with the renewable fuel standards program, including the availability, cost and price volatility of renewable identification numbers;
- the effects and cost of compliance with current and future state and federal environmental, economic, safety and other laws, policies and regulations;
- the effects of seasonality on demand for our products;
- operating hazards, accidents, fires, severe weather, floods and other natural disasters, casualty losses and other matters beyond our control, which could result in unscheduled downtime;
- the effect of any national or international financial crisis on our business and financial condition; and

- the other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2015 under the caption "Risk Factors."

Any one of these factors or a combination of these factors could materially affect our future results of operations and could influence whether any forward-looking statements ultimately prove to be accurate. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statements. We do not intend to update these statements unless we are required by the securities laws to do so.

Company Overview

We are a limited partnership formed in August 2012 and engaged principally in the business of operating a crude oil refinery in Big Spring, Texas, with a crude oil throughput capacity of 73,000 barrels per day ("bpd"), which we refer to as our Big Spring refinery. We refine crude oil into finished products, which we market primarily in Central and West Texas, Oklahoma, New Mexico and Arizona through our integrated wholesale distribution network to both Alon Energy's retail convenience stores and other third-party distributors. We distribute fuel products through a network of pipelines and terminals that we own or access through leases or long-term throughput agreements.

For additional information on our business, see Items 1. and 2. "Business and Properties" included in our Annual Report on Form 10-K for the year ended December 31, 2015.

Third Quarter Operational and Financial Highlights

Operating income for the third quarter of 2016 was $10.2 million, compared to $65.8 million for the same period last year. Our operational and financial highlights for the third quarter of 2016 include the following:

- Big Spring refinery average throughput for the third quarter of 2016 was 70,063 bpd compared to 75,797 bpd for the third quarter of 2015. The reduced throughput at our Big Spring refinery was the result of a reformer regeneration during the third quarter of 2016.
- Operating margin at the Big Spring refinery was $9.22 per barrel for the third quarter of 2016 compared to $16.71 per barrel for the same period in 2015. This decrease in operating margin was primarily due to a lower Gulf Coast 3/2/1 crack spread and increased RINs costs, partially offset by a widening of both the WTI Cushing to WTI Midland and WTI Cushing to WTS spreads and an increased benefit from the contango market environment which reduced the cost of crude.
- The average Gulf Coast 3/2/1 crack spread was $13.31 per barrel for the third quarter of 2016 compared to $19.77 per barrel for the third quarter of 2015.
- The average WTI Cushing to WTI Midland spread for the third quarter of 2016 was $0.31 per barrel compared to $(0.72) per barrel for the same period in 2015. The average WTI Cushing to WTS spread for the third quarter of 2016 was $0.92 per barrel compared to $(1.46) per barrel for the same period in 2015. The average Brent to WTI Cushing spread for the third quarter of 2016 was $0.74 per barrel compared to $3.78 per barrel for the same period in 2015.
- The average RINs cost effect on the Big Spring refinery operating margin was $0.58 per barrel for the third quarter of 2016, compared to $0.27 per barrel for the same period in 2015.
- The contango environment in the third quarter of 2016 created an average cost of crude benefit of $0.84 per barrel compared to an average cost of crude benefit of $0.57 per barrel for the same period in 2015.
- During the third quarter of 2016, the cash available for distribution was $0.15 per unit, compared to $0.98 per unit during the third quarter of 2015.

Major Influences on Results of Operations

Earnings and cash flows are primarily affected by the difference between refined product prices and the prices for crude oil and other feedstocks. These prices depend on numerous factors beyond our control, including the supply of, and demand for, crude oil, gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and government regulation. While our sales and operating revenues fluctuate significantly with movements in crude oil and refined product prices, it is the spread between crude oil and refined product prices, not necessarily fluctuations in those prices, that affects our earnings.

In order to measure our operating performance, we compare our per barrel refinery operating margin to certain industry benchmarks. We calculate this margin for the Big Spring refinery by dividing the refinery's gross margin by its throughput volumes. Gross margin is the difference between net sales and cost of sales (exclusive of certain inventory adjustments and inclusive of RINs costs).

We compare our Big Spring refinery operating margin to the Gulf Coast 3/2/1 crack spread, which is intended to approximate the refinery's crude slate and product yield. A Gulf Coast 3/2/1 crack spread is calculated assuming that three barrels of WTI Cushing crude oil are converted, or cracked, into two barrels of Gulf Coast conventional gasoline and one barrel of Gulf Coast ultra-low sulfur diesel.

Our Big Spring refinery is capable of processing substantial volumes of sour crude oil, which has historically cost less than intermediate and sweet crude oils. We measure the cost advantage of refining sour crude oil by calculating the difference between the price of WTI Cushing crude oil and the price of WTS, a medium, sour crude oil. We refer to this differential as the WTI Cushing/WTS, or sweet/sour, spread. A widening of the sweet/sour spread can favorably influence the operating margin for our Big Spring refinery. The Big Spring refinery's crude oil input is primarily comprised of WTS and WTI Midland.

In addition, the location of the Big Spring refinery near Midland, the largest origination terminal for West Texas crude oil, provides reliable crude sourcing with a relatively low transportation cost. We are also able to source locally produced crude at Big Spring by truck, which tends to have cost and quality advantages. The WTI Cushing less WTI Midland spread represents the differential between the average per barrel price of WTI Cushing crude oil and the average per barrel price of WTI Midland crude oil. A widening of the WTI Cushing less WTI Midland spread will favorably influence the operating margin for our Big Spring refinery. Alternatively, a narrowing of this differential will have an adverse effect on our operating margin.

Recently, the additional takeaway capacity moving crude from Midland to the Gulf Coast has caused a contraction of the WTI Cushing less WTI Midland spread. In addition, the relative small growth in WTS production compared to WTI production and the relative high demand for WTS has caused a contraction of the WTI Cushing less WTS spread.

Global product prices are influenced by the price of Brent crude which is a global benchmark crude. Global product prices influence product prices in the U.S. As a result, the Big Spring refinery is influenced by the spread between Brent crude and WTI Cushing. The Brent less WTI Cushing spread represents the differential between the average per barrel price of Brent crude oil and the average per barrel price of WTI Cushing crude oil. A widening of the spread between Brent and WTI Cushing will favorably influence the operating margin for our Big Spring refinery.

Our results of operations are also significantly affected by our refinery's operating costs, particularly the cost of natural gas used for fuel and the cost of electricity. Natural gas prices have historically been volatile. Typically, electricity prices fluctuate with natural gas prices.

Demand for gasoline products is generally higher during summer months than during winter months due to seasonal increases in highway traffic. As a result, our operating results for the first and fourth calendar quarters are generally lower than those for the second and third calendar quarters. The effects of seasonal demand for gasoline are partially offset by seasonality in demand for diesel, which in our region is generally higher in winter months as east-west trucking traffic moves south to avoid winter conditions on northern routes.

Safety, reliability and the environmental performance of our refinery is critical to our financial performance. The financial impact of planned downtime, such as a turnaround or major maintenance project, is mitigated through a diligent planning process that considers expectations for product availability, margin environment and the availability of resources to perform the required maintenance.

The nature of our business requires us to maintain crude oil and refined product inventories. Crude oil and refined products are commodities, and we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market value under the last-in, first-out ("LIFO") inventory valuation methodology, price fluctuations generally have little effect on our financial results.

Factors Affecting Comparability

Our financial condition and operating results over the three and nine months ended September 30, 2016 and 2015 have been influenced by the following factor which is fundamental to understanding comparisons of our period-to-period financial performance.

Maintenance and Reduced Crude Oil Throughput

During the nine months ended September 30, 2016, throughput at the Big Spring refinery was reduced as a result of a reformer regeneration during the first quarter of 2016, which was repeated during the third quarter of 2016. Additionally, throughput was reduced as a result of a catalyst replacement for our diesel hydrotreater unit in the first quarter of 2016 and unplanned downtime during the second quarter of 2016 due to a power outage caused by inclement weather, which affected multiple units.

Results of Operations

The period-to-period comparisons of our results of operations have been prepared using the historical periods included in our consolidated financial statements. We refer to our financial statement line items in the explanation of our period-to-period changes in results of operations. Below are general definitions of what those line items include and represent.

Net sales. Net sales consist principally of sales of refined petroleum products, and are mainly affected by refined product prices, changes to the product mix and volume changes caused by operations. Product mix refers to the percentage of production represented by higher value motor fuels, such as gasoline, rather than lower value finished products.

Cost of sales. Cost of sales includes principally crude oil, blending materials and RINs, other raw materials and transportation costs, which include costs associated with our crude oil and product pipelines. Cost of sales excludes depreciation and amortization, which is presented separately in the consolidated statements of operations.

Direct operating expenses. Direct operating expenses include costs associated with the actual operations of the refinery, such as energy and utility costs, routine maintenance, labor, insurance and environmental compliance costs.

Selling, general and administrative expenses. Selling, general and administrative expenses, or SG&A, primarily include corporate overhead costs and marketing expenses. These costs also include actual costs incurred by Alon Energy and allocated to us.

Depreciation and amortization. Depreciation and amortization represents an allocation of the cost of capital assets to expense within the consolidated statements of operations. The cost is expensed based on the straight-line method over the estimated useful life of the related asset. Depreciation and amortization also includes deferred turnaround and catalyst replacement costs. Turnaround and catalyst replacement costs are currently deferred and amortized on a straight-line basis beginning the month after the completion of the turnaround and ending immediately prior to the next scheduled turnaround.

Operating income. Operating income represents our net sales less our total operating costs and expenses.

Interest expense. Interest expense includes interest expense, letters of credit, financing costs associated with crude oil purchases, financing fees, and amortization of both original issuance discount and deferred debt issuance costs but excludes capitalized interest.

ALON USA PARTNERS, LP AND SUBSIDIARIES CONSOLIDATED

Summary Financial Tables. The following tables provide summary financial data and selected key operating statistics for the three and nine months ended September 30, 2016 and 2015. The following data should be read in conjunction with our consolidated financial statements and the notes thereto included elsewhere in this Form 10-Q. All information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" except for Balance Sheet data as of December 31, 2015 is unaudited.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(dollars in thousands, except per unit data, per barrel data and pricing statistics)			
STATEMENTS OF OPERATIONS DATA:				
Net sales (1)	$ 462,257	$ 551,813	$ 1,298,723	$ 1,719,319
Operating costs and expenses:				
Cost of sales	404,207	439,678	1,134,275	1,397,395
Direct operating expenses	25,125	24,136	73,424	71,837
Selling, general and administrative expenses	8,153	8,536	24,264	24,654
Depreciation and amortization	14,581	13,697	43,454	41,281
Total operating costs and expenses	452,066	486,047	1,275,417	1,535,167
Operating income	10,191	65,766	23,306	184,152
Interest expense	(8,144)	(11,505)	(28,651)	(34,045)
Other income, net	353	40	550	26
Income (loss) before state income tax expense	2,400	54,301	(4,795)	150,133
State income tax expense	317	525	493	480
Net income (loss)	$ 2,083	$ 53,776	$ (5,288)	$ 149,653
Earnings (loss) per unit	$ 0.03	$ 0.86	$ (0.08)	$ 2.39
Weighted average common units outstanding (in thousands)	62,520	62,510	62,515	62,508
Cash distribution per unit	$ 0.14	$ 1.04	$ 0.22	$ 2.45
CASH FLOW DATA:				
Net cash provided by (used in):				
Operating activities	$ 11,870	$ 84,834	$ 58,457	$ 219,232
Investing activities	(5,954)	(5,532)	(26,878)	(15,322)
Financing activities	36,027	(93,908)	39,231	(174,957)
OTHER DATA:				
Adjusted EBITDA (2)	$ 25,125	$ 79,503	$ 67,310	$ 225,459
Capital expenditures	4,499	4,322	17,199	12,108
Capital expenditures for turnarounds and catalysts	1,455	1,210	9,679	3,214
KEY OPERATING STATISTICS:				
Per barrel of throughput:				
Refinery operating margin (3)	$ 9.22	$ 16.71	$ 8.52	$ 15.95
Refinery direct operating expense (4)	3.90	3.46	3.85	3.53
PRICING STATISTICS:				
Crack spreads (per barrel):				
Gulf Coast 3/2/1	$ 13.31	$ 19.77	$ 12.57	$ 19.08
WTI Cushing crude oil (per barrel)	$ 44.88	$ 46.41	$ 41.23	$ 50.91
Crude oil differentials (per barrel):				
WTI Cushing less WTI Midland	$ 0.31	$ (0.72)	$ 0.12	$ 0.60
WTI Cushing less WTS	0.92	(1.46)	0.53	0.02
Brent less WTI Cushing	0.74	3.78	0.35	4.28
Product price (dollars per gallon):				
Gulf Coast unleaded gasoline	$ 1.39	$ 1.61	$ 1.30	$ 1.66
Gulf Coast ultra-low sulfur diesel	1.37	1.52	1.25	1.68
Natural gas (per MMBtu)	2.79	2.73	2.34	2.76

BALANCE SHEET DATA (end of period):	September 30, 2016	December 31, 2015
	(dollars in thousands)	
Cash and cash equivalents	$ 203,763	$ 132,953
Working capital	10,460	(53,804)
Total assets	825,050	748,584
Total debt	291,486	292,082
Total debt less cash and cash equivalents	87,723	159,129
Total partners' equity	111,968	130,957

THROUGHPUT AND PRODUCTION DATA:	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2016		2015		2016		2015	
	bpd	%	bpd	%	bpd	%	bpd	%
Refinery throughput:								
WTS crude	34,292	48.9	30,810	40.6	32,189	46.3	35,041	47.0
WTI crude	32,503	46.4	42,503	56.1	34,428	49.4	36,834	49.4
Blendstocks	3,268	4.7	2,484	3.3	2,969	4.3	2,687	3.6
Total refinery throughput (5)	70,063	100.0	75,797	100.0	69,586	100.0	74,562	100.0
Refinery production:								
Gasoline	33,637	48.1	37,503	49.5	33,826	48.7	37,155	49.6
Diesel/jet	26,004	37.2	28,623	37.8	25,108	36.1	27,596	36.9
Asphalt	2,818	4.0	2,452	3.2	2,846	4.1	2,733	3.7
Petrochemicals	3,861	5.5	4,588	6.1	3,611	5.2	4,770	6.4
Other	3,661	5.2	2,595	3.4	4,084	5.9	2,510	3.4
Total refinery production (6)	69,981	100.0	75,761	100.0	69,475	100.0	74,764	100.0
Refinery utilization (7)		99.1%		100.4%		95.5%		98.5%

(1) Includes sales to related parties of $82,717 and $97,014 for the three months ended and $222,711 and $281,136 for the nine months ended September 30, 2016 and 2015, respectively.

(2) Adjusted EBITDA represents earnings before state income tax expense, interest expense and depreciation and amortization. Adjusted EBITDA is not a recognized measurement under GAAP; however, the amounts included in Adjusted EBITDA are derived from amounts included in our consolidated financial statements. Our management believes that the presentation of Adjusted EBITDA is useful to investors because it is frequently used by securities analysts, investors, and other interested parties in the evaluation of companies in our industry. In addition, our management believes that Adjusted EBITDA is useful in evaluating our operating performance compared to that of other companies in our industry because the calculation of Adjusted EBITDA generally eliminates the effects of state income tax expense, interest expense and the accounting effects of capital expenditures and acquisitions, items that may vary for different companies for reasons unrelated to overall operating performance.

Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Some of these limitations are:

- Adjusted EBITDA does not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- Adjusted EBITDA does not reflect the interest expense or the cash requirements necessary to service interest or principal payments on our debt;
- Adjusted EBITDA does not reflect changes in or cash requirements for our working capital needs; and
- Our calculation of Adjusted EBITDA may differ from EBITDA calculations of other companies in our industry, limiting its usefulness as a comparative measure.

Because of these limitations, Adjusted EBITDA should not be considered a measure of discretionary cash available to us to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only supplementally.

The following table reconciles net income (loss) to Adjusted EBITDA for the three and nine months ended September 30, 2016 and 2015:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
	(dollars in thousands)			
Net income (loss)	$ 2,083	$ 53,776	$ (5,288)	$ 149,653
State income tax expense	317	525	493	480
Interest expense	8,144	11,505	28,651	34,045
Depreciation and amortization	14,581	13,697	43,454	41,281
Adjusted EBITDA	$ 25,125	$ 79,503	$ 67,310	$ 225,459

(3) Refinery operating margin is a per barrel measurement calculated by dividing the margin between net sales and cost of sales (exclusive of certain inventory adjustments) by the refinery's throughput volumes. Industry-wide refining results are driven and measured by the margins between refined product prices and the prices for crude oil, which are referred to as crack spreads. We compare our refinery operating margin to these crack spreads to assess our operating performance relative to other participants in our industry.

Refinery operating margin for the three and nine months ended September 30, 2016 excludes gains (losses) related to inventory adjustments of $(1,419) and $2,046, respectively. Refinery operating margin for the three and nine months ended September 30, 2015 excludes losses related to inventory adjustments of $(4,385) and $(2,763), respectively.

(4) Refinery direct operating expense is a per barrel measurement calculated by dividing direct operating expenses by total throughput volumes.

(5) Total refinery throughput represents the total barrels per day of crude and blendstock inputs in the refinery production process.

(6) Total refinery production represents the barrels per day of various refined products produced from processing crude and other refinery blendstocks through the crude units and other conversion units.

(7) Refinery utilization represents average daily crude throughput divided by crude oil capacity, excluding planned periods of downtime for maintenance and turnarounds.

Three Months Ended September 30, 2016 Compared to the Three Months Ended September 30, 2015

Net Sales. Net sales for the three months ended September 30, 2016 were $462.3 million, compared to $551.8 million for the three months ended September 30, 2015, a decrease of $89.5 million, or 16.2%. This decrease was primarily due to lower refined product prices and lower refinery throughput. The average per gallon price of Gulf Coast gasoline for the three months ended September 30, 2016 decreased $0.22, or 13.7%, to $1.39, compared to $1.61 for the three months ended September 30, 2015. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the three months ended September 30, 2016 decreased $0.15, or 9.9%, to $1.37, compared to $1.52 for the three months ended September 30, 2015. Refinery average throughput for the three months ended September 30, 2016 was 70,063 bpd, compared to 75,797 bpd for the three months ended September 30, 2015, a decrease of 7.6%. The reduced throughput at our Big Spring refinery was the result of a reformer regeneration during the third quarter of 2016.

Cost of Sales. Cost of sales for the three months ended September 30, 2016 were $404.2 million, compared to $439.7 million for the three months ended September 30, 2015, a decrease of $35.5 million, or 8.1%. This decrease was primarily due to reduced crude oil prices and lower refinery throughput. The average price of WTI Cushing decreased 3.3% to $44.88 per barrel for the three months ended September 30, 2016 from $46.41 per barrel for the three months ended September 30, 2015.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2016 were $25.1 million, compared to $24.1 million for the three months ended September 30, 2015, an increase of $1.0 million, or 4.1%.

Selling, General and Administrative Expenses. SG&A expenses for the three months ended September 30, 2016 were $8.2 million, compared to $8.5 million for the three months ended September 30, 2015, a decrease of $0.3 million, or 3.5%.

Depreciation and Amortization. Depreciation and amortization for the three months ended September 30, 2016 was $14.6 million, compared to $13.7 million for the three months ended September 30, 2015, an increase of $0.9 million, or 6.6%.

Operating Income. Operating income for the three months ended September 30, 2016 was $10.2 million, compared to $65.8 million for the three months ended September 30, 2015, a decrease of $55.6 million, or 84.5%. This decrease was primarily due to lower refinery throughput and lower refinery operating margin. Refinery operating margin was $9.22 per barrel for the three months ended September 30, 2016, compared to $16.71 per barrel for the three months ended September 30, 2015. This decrease in operating margin was primarily due to a lower Gulf Coast 3/2/1 crack spread and increased RINs costs, partially offset by a widening of both the WTI Cushing to WTI Midland and WTI Cushing to WTS spreads and an increased benefit from the contango market environment which reduced the cost of crude.

The average Gulf Coast 3/2/1 crack spread decreased to $13.31 per barrel for the three months ended September 30, 2016, compared to $19.77 per barrel for the three months ended September 30, 2015. The average WTI Cushing to WTI Midland spread widened to $0.31 per barrel for the three months ended September 30, 2016, compared to $(0.72) per barrel for the three months ended September 30, 2015. The average WTI Cushing to WTS spread widened to $0.92 per barrel for the three months ended September 30, 2016, compared to $(1.46) per barrel for the three months ended September 30, 2015. The average Brent to WTI Cushing spread narrowed to $0.74 per barrel for the three months ended September 30, 2016, compared to $3.78 per barrel for the three months ended September 30, 2015. The contango environment for the three months ended September 30, 2016 created an average cost of crude benefit of $0.84 per barrel, compared to an average cost of crude benefit of $0.57 per barrel for the three months ended September 30, 2015. The average RINs cost effect on refinery operating margin was $0.58 per barrel for the three months ended September 30, 2016, compared to $0.27 per barrel for the three months ended September 30, 2015.

Interest Expense. Interest expense for the three months ended September 30, 2016 was $8.1 million, compared to $11.5 million for the three months ended September 30, 2015, a decrease of $3.4 million, or 29.6%. This decrease was primarily due to the effect of crude oil prices moving further into contango on our supply and offtake agreements.

State Income Tax Expense. State income tax expense was $0.3 million for the three months ended September 30, 2016, compared to $0.5 million for the three months ended September 30, 2015, a decrease of $0.2 million.

Net Income. Net income for the three months ended September 30, 2016 was $2.1 million, compared to $53.8 million for the three months ended September 30, 2015, a decrease of $51.7 million, or 96.1%. This decrease was attributable to the factors discussed above.

Nine Months Ended September 30, 2016 Compared to the Nine Months Ended September 30, 2015

Net Sales. Net sales for the nine months ended September 30, 2016 were $1,298.7 million, compared to $1,719.3 million for the nine months ended September 30, 2015, a decrease of $420.6 million, or 24.5%. This decrease was primarily due to lower refined product prices and lower refinery throughput. The average per gallon price of Gulf Coast gasoline for the nine months ended September 30, 2016 decreased $0.36, or 21.7%, to $1.30, compared to $1.66 for the nine months ended September 30, 2015. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the nine months ended September 30, 2016 decreased $0.43, or 25.6%, to $1.25, compared to $1.68 for the nine months ended September 30, 2015.

Refinery average throughput for the nine months ended September 30, 2016 was 69,586 bpd compared to 74,562 bpd for the nine months ended September 30, 2015, a decrease of 6.7%. The reduced throughput at our Big Spring refinery during the nine months ended September 30, 2016 was the result of a reformer regeneration during the first quarter of 2016, which was repeated during the third quarter of 2016. Additionally, throughput was reduced as a result of a catalyst replacement for our diesel hydrotreater unit in the first quarter of 2016 and unplanned downtime during the second quarter of 2016 due to a power outage caused by inclement weather, which affected multiple units.

Cost of Sales. Cost of sales for the nine months ended September 30, 2016 were $1,134.3 million, compared to $1,397.4 million for the nine months ended September 30, 2015, a decrease of $263.1 million, or 18.8%. This decrease was primarily due to reduced crude oil prices and lower refinery throughput. The average price of WTI Cushing decreased 19.0% to $41.23 per barrel for the nine months ended September 30, 2016 from $50.91 per barrel for the nine months ended September 30, 2015.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2016 were $73.4 million, compared to $71.8 million for the nine months ended September 30, 2015, an increase of $1.6 million, or 2.2%.

Selling, General and Administrative Expenses. SG&A expenses for the nine months ended September 30, 2016 were $24.3 million, compared to $24.7 million for the nine months ended September 30, 2015, a decrease of $0.4 million, or 1.6%.

Depreciation and Amortization. Depreciation and amortization for the nine months ended September 30, 2016 was $43.5 million, compared to $41.3 million for the nine months ended September 30, 2015, an increase of $2.2 million, or 5.3%.

Operating Income. Operating income for the nine months ended September 30, 2016 was $23.3 million, compared to $184.2 million for the nine months ended September 30, 2015, a decrease of $160.9 million, or 87.4%. This decrease was primarily due to lower refinery throughput and lower refinery operating margin. Refinery operating margin for the nine months ended September 30, 2016 was $8.52 per barrel, compared to $15.95 per barrel for the nine months ended September 30, 2015. This decrease in operating margin was primarily due to a lower Gulf Coast 3/2/1 crack spread and a narrowing of the WTI Cushing to WTI Midland spread, partially offset by a widening of the WTI Cushing to WTS spread and an increased cost of crude benefit from the contango market.

The average Gulf Coast 3/2/1 crack spread decreased to $12.57 per barrel for the nine months ended September 30, 2016, compared to $19.08 per barrel for the nine months ended September 30, 2015. The average WTI Cushing to WTI Midland spread narrowed to $0.12 per barrel for the nine months ended September 30, 2016, compared to $0.60 per barrel for the nine months ended September 30, 2015. The average WTI Cushing to WTS spread widened to $0.53 per barrel for the nine months ended September 30, 2016, compared to $0.02 per barrel for the nine months ended September 30, 2015. The average Brent to WTI Cushing spread narrowed to $0.35 per barrel for the nine months ended September 30, 2016 compared to $4.28 per barrel for the nine months ended September 30, 2015. The contango environment for the nine months ended September 30, 2016 created an average cost of crude benefit of $1.39 per barrel, compared to an average cost of crude benefit of $1.04 per barrel for the nine months ended September 30, 2015.

Interest Expense. Interest expense was $28.7 million for the nine months ended September 30, 2016, compared to $34.0 million for the nine months ended September 30, 2015, a decrease of $5.3 million, or 15.6%. This decrease was primarily due to the effect of crude oil prices moving further into contango on our supply and offtake agreements.

State Income Tax Expense. State income tax expense was $0.5 million for the nine months ended September 30, 2016, compared to $0.5 million for the nine months ended September 30, 2015.

Net Income (Loss). Net loss for the nine months ended September 30, 2016 was $5.3 million, compared to net income of $149.7 million for the nine months ended September 30, 2015, a decrease of $155.0 million. This decrease was attributable to the factors discussed above.

Liquidity and Capital Resources

Our primary sources of liquidity are cash on hand, cash generated from our operating activities, borrowings under our revolving credit facility, inventory supply and offtake arrangement and other credit lines. Additionally, we have the ability to utilize a $60.0 million letter of credit facility through Alon Energy for our crude and product purchases.

We have an agreement with J. Aron for the supply of crude oil that supports the operations of the Big Spring refinery. This arrangement substantially reduces our physical inventories and the associated need to issue letters of credit to support crude oil purchases. In addition, the structure allows us to acquire crude oil without the constraints of a maximum facility size during periods of high crude oil prices.

We believe that the aforementioned sources of funds and other sources of capital available to us will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next twelve months. However, future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive, and other factors beyond our control.

Depending upon conditions in the capital markets and other factors, we will from time to time consider the issuance of debt or equity securities, or other possible capital markets transactions, the proceeds of which could be used to refinance current indebtedness, extend or replace our existing revolving credit facility or for other Partnership purposes.

Cash Flows

The following table sets forth our consolidated cash flows for the nine months ended September 30, 2016 and 2015:

	For the Nine Months Ended September 30,	
	2016	2015
	(dollars in thousands)	
Cash provided by (used in):		
Operating activities	$ 58,457	$ 219,232
Investing activities	(26,878)	(15,322)
Financing activities	39,231	(174,957)
Net increase in cash and cash equivalents	$ 70,810	$ 28,953

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $58.5 million during the nine months ended September 30, 2016 compared to $219.2 million during the nine months ended September 30, 2015. The decrease in net cash provided by operating activities of $160.7 million was primarily due to decreased net income (loss) after adjusting for non-cash items of $152.4 million, increased cash used for inventories of $20.4 million, lower cash collected on accounts receivable of $5.3 million and increased cash used for accounts payable and accrued liabilities of $8.2 million, partially offset by increased cash provided by other non-current liabilities of $15.1 million, reduced cash used for other assets of $9.6 million and reduced cash used for prepaid expenses and other current assets of $0.8 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities was $26.9 million during the nine months ended September 30, 2016 compared to $15.3 million during the nine months ended September 30, 2015. The increase in net cash used in investing activities of $11.6 million was primarily due to completing a reformer regeneration and catalyst replacement for our diesel hydrotreater unit during 2016.

Cash Flows Provided by (Used in) Financing Activities

Net cash provided by financing activities was $39.2 million during the nine months ended September 30, 2016 compared to net cash used in financing activities of $175.0 million during the nine months ended September 30, 2015. The change in cash flows from financing activities of $214.2 million was primarily due to reduced distributions to unitholders of $139.4 million, lower repayments of $10.0 million on our revolving credit facility and increased cash received under inventory arrangement transactions of $63.0 million.

Indebtedness

Revolving Credit Facility. We have a $240.0 million revolving credit facility that can be used both for borrowings and the issuance of letters of credit. We had borrowings of $55.0 million and $55.0 million and letters of credit outstanding of $91.2 million and $48.6 million under this facility at September 30, 2016 and December 31, 2015, respectively.

Capital Spending

Each year the board of directors of our General Partner approves capital projects, including sustaining maintenance, regulatory and planned turnaround and catalyst projects that our management is authorized to undertake in our annual capital budget. Additionally, our management assesses opportunities for growth and profit improvement projects on an ongoing basis and any related projects require further approval from the board of directors of our General Partner. Our total capital expenditure plan for 2016 is $31.0 million, which includes expenditures for catalysts and turnarounds and approximately $7.2 million of special regulatory projects. Approximately $26.9 million has been spent during the nine months ended September 30, 2016.

Contractual Obligations and Commercial Commitments

There have been no material changes outside the ordinary course of business from our contractual obligations and commercial commitments detailed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Off-Balance Sheet Arrangements

We have no material off-balance sheet arrangements.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with GAAP. In order to apply these principles, we must make judgments, assumptions and estimates based on the best available information at the time. Actual results may differ based on the accuracy of the information utilized and subsequent events, some of which we may have little or no control over.

Our critical accounting policies are described under the caption “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies” in our Annual Report on Form 10-K for the year ended December 31, 2015. Certain critical accounting policies that materially affect the amounts recorded in our consolidated financial statements are the use of the LIFO method for valuing certain inventories and the deferral and subsequent amortization of costs associated with major turnarounds and catalysts replacements. No significant changes to these accounting policies have occurred subsequent to December 31, 2015.

New Accounting Standards and Disclosures

New accounting standards, if any, are disclosed in Note (1) Basis of Presentation included in the consolidated financial statements included in Item 1 of this report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Changes in commodity prices, purchased fuel prices and interest rates are our primary sources of market risk. Alon Energy's risk management committee oversees all activities associated with the identification, assessment and management of our market risk exposure.

Commodity Price Risk

We are exposed to market risks related to the volatility of crude oil and refined product prices, as well as volatility in the price of natural gas used in our refinery operations. Our financial results can be affected significantly by fluctuations in these prices, which depend on many factors, including demand for crude oil, gasoline and other refined products, changes in the economy, worldwide production levels, worldwide inventory levels and governmental regulatory initiatives. Alon Energy's risk management strategy identifies circumstances in which we may utilize the commodity futures market to manage risk associated with these price fluctuations.

In order to manage the uncertainty relating to inventory price volatility, we have consistently applied a policy of maintaining inventories at or below a targeted operating level. In the past, circumstances have occurred, such as timing of crude oil cargo deliveries, turnaround schedules or shifts in market demand that have resulted in variances between our actual inventory level and our desired target level. Upon the review and approval of Alon Energy's risk management committee, we may utilize the commodity futures market to manage these anticipated inventory variances.

We maintain inventories of crude oil, refined products and blendstocks, the values of which are subject to wide fluctuations in market prices driven by world economic conditions, regional and global inventory levels and seasonal conditions. At September 30, 2016, the market value of refined products and blendstock inventories was less than inventories on a LIFO cost basis which resulted in recording a lower of cost or market reserve of $7.4 million. At September 30, 2016, the market value of crude oil inventories exceeded LIFO costs, net of the fair value hedged item, by $3.9 million.

As of September 30, 2016, we held 0.3 million barrels of refined products and blendstock and 0.5 million barrels of crude oil inventories valued under the LIFO valuation method. If the market value of refined products and blendstock inventories would have been $1.00 per barrel lower, the lower of cost or market recovery recorded for the nine months ended September 30, 2016 would have been $0.3 million lower. If the market value of crude oil would have been $1.00 per barrel lower, the market value of crude oil inventories would have still exceeded LIFO costs, net of the fair value hedged item, by $3.4 million, requiring no inventory adjustment to be made.

All commodity derivative contracts are recorded at fair value and any changes in fair value between periods is recorded in the profit and loss section of our consolidated financial statements. "Forwards" represent physical trades for which pricing and quantities have been set, but the physical product delivery has not occurred by the end of the reporting period. "Futures" represent trades which have been executed on the New York Mercantile Exchange which have not been closed or settled at the end of the reporting period. A "long" represents an obligation to purchase product and a "short" represents an obligation to sell product.

The following table provides information about our commodity derivative contracts as of September 30, 2016:

Description of Activity	Contract Volume (barrels)	Wtd Avg Purchase Price/BBL	Wtd Avg Sales Price/BBL	Contract Value	Market Value	Gain (Loss)
				(in thousands)		
Forwards-short (Crude)	(168,203)	$ —	$ 45.23	$ (7,607)	$ (8,092)	$ (485)
Forwards-long (Gasoline)	268,301	57.19	—	15,344	16,149	805
Forwards-short (Distillate)	(9,784)	—	61.75	(604)	(661)	(57)
Forwards-short (Jet)	(17,313)	—	58.12	(1,006)	(1,080)	(74)
Forwards-long (Slurry)	228	35.40	—	8	8	—
Forwards-long (Catfeed)	23,066	53.56	—	1,235	1,324	89
Forwards-long (Slop)	34,641	35.23	—	1,220	1,345	125
Forwards-short (Propane)	(50,000)	—	19.85	(993)	(1,125)	(132)
Forwards-long (Butane)	75,373	27.70	—	2,088	2,244	156
Futures-long (Crude)	31,000	48.68	—	1,509	1,495	(14)
Futures-short (Gasoline)	(341,000)	—	57.55	(19,623)	(20,954)	(1,331)
Futures-short (Distillate)	(35,000)	—	61.33	(2,146)	(2,261)	(115)

Interest Rate Risk

As of September 30, 2016, our outstanding debt balance of $295.6 million, excluding discounts and debt issuance costs, was subject to floating interest rates, of which $55.0 million was charged interest at the Eurodollar rate plus 3.00% and $240.6 million was charged interest at the Eurodollar rate (with a floor of 1.25%) plus a margin of 8.00%.

An increase of 1% in the Eurodollar rate on our indebtedness would result in an increase in our interest expense of approximately $1.2 million per year.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures

Our management has evaluated, with the participation of our principal executive and principal financial officers, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 as amended (the "Exchange Act")) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms including, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosures.

Changes in internal control over financial reporting

There has been no change in our internal control over financial reporting (as described in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS

Exhibit Number	Description of Exhibit
31.1	Certifications of Chief Executive Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002.
31.2	Certifications of Chief Financial Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002.
101	The following financial information from Alon USA Partners, LP's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows and (iv) Notes to the Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Alon USA Partners, LP By: Alon USA Partners GP, LLC its general partner
Date: October 31, 2016	By: /s/ David Wiessman David Wiessman Executive Chairman of the Board
Date: October 31, 2016	By: /s/ Paul Eisman Paul Eisman President, Chief Executive Officer and Director
Date: October 31, 2016	By: /s/ Shai Even Shai Even Senior Vice President and Chief Financial Officer (Principal Accounting Officer)

Exhibit 31.1

CERTIFICATIONS

I, Paul Eisman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Alon USA Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal controls over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

By: /s/ Paul Eisman

Paul Eisman
President, Chief Executive Officer and Director
of Alon USA Partners GP, LLC
(the general partner of Alon USA Partners, LP)

Exhibit 31.2

CERTIFICATIONS

I, Shai Even, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Alon USA Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal controls over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

By: /s/ Shai Even

Shai Even
Senior Vice President and Chief Financial Officer of
Alon USA Partners GP, LLC
(the general partner of Alon USA Partners, LP)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. §1350,
AS ADOPTED PURSUANT TO §906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the filing of the Quarterly Report on Form 10-Q of Alon USA Partners, LP, a Delaware limited partnership (the "Partnership"), for the period ended September 30, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned officers of the general partner of the Partnership certifies, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership as of the dates and for the periods expressed in the Report.

Date: October 31, 2016

By: /s/ Paul Eisman
Paul Eisman
President, Chief Executive Officer and Director of
Alon USA Partners GP, LLC
(the general partner of Alon USA Partners, LP)

Date: October 31, 2016

By: /s/ Shai Even
Shai Even
Senior Vice President and Chief Financial Officer of
Alon USA Partners GP, LLC
(the general partner of Alon USA Partners, LP)