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 JUNE 30, 2014

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 August 1, 2014, was 62,506,550.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2014	December 31, 2013
	(unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 81,099	$ 153,583
Accounts and other receivables, net	86,173	123,781
Accounts and other receivables, net - related parties	15,642	14,621
Inventories	70,446	49,146
Prepaid expenses and other current assets	15,675	4,642
Total current assets	269,035	345,773
Property, plant and equipment, net	460,097	472,885
Other assets, net	83,191	31,266
Total assets	$ 812,323	$ 849,924
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 236,857	$ 280,774
Accrued liabilities	47,024	44,492
Current portion of long-term debt	2,500	2,500
Total current liabilities	286,381	327,766
Other non-current liabilities	43,953	34,894
Long-term debt	340,844	341,822
Total liabilities	671,178	704,482
Commitments and contingencies (Note 11)		
Partners' equity:		
General Partner	—	—
Common unitholders - 62,506,550 and 62,502,467 units issued and outstanding at June 30, 2014 and December 31, 2013, respectively	141,145	145,442
Total partners' equity	141,145	145,442
Total liabilities and partners' equity	$ 812,323	$ 849,924

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 June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Net sales (1)	$ 725,852	$ 865,694	$ 1,582,312	$ 1,669,861
Operating costs and expenses:				
Cost of sales	665,398	767,322	1,424,444	1,417,525
Direct operating expenses	25,152	27,314	54,093	57,736
Selling, general and administrative expenses	6,784	5,065	11,152	12,730
Depreciation and amortization	9,508	11,243	19,575	23,307
Total operating costs and expenses	706,842	810,944	1,509,264	1,511,298
Operating income	19,010	54,750	73,048	158,563
Interest expense	(11,569)	(8,970)	(22,893)	(18,362)
Other income, net	601	14	613	18
Income before state income tax expense	8,042	45,794	50,768	140,219
State income tax expense	240	473	725	1,373
Net income	$ 7,802	$ 45,321	$ 50,043	$ 138,846
Earnings per unit	$ 0.12	$ 0.73	$ 0.80	$ 2.22
Weighted average common units outstanding (in thousands)	62,504	62,502	62,504	62,502
Cash distribution per unit	$ 0.69	$ 1.48	$ 0.87	$ 2.05

(1) Includes sales to related parties of $152,170 and $156,043 for the three months and $291,183 and $297,942 for the six months ended June 30, 2014 and 2013, 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 Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Cash flows from operating activities:		
Net income	$ 50,043	$ 138,846
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	19,575	23,307
Amortization of debt issuance costs	1,018	990
Amortization of original issuance discount	272	251
Changes in operating assets and liabilities:		
Accounts and other receivables, net	37,608	(25,211)
Accounts and other receivables, net - related parties	(1,021)	1,586
Inventories	(21,300)	3,028
Prepaid expenses and other current assets	(11,033)	4,219
Other assets, net	(1,053)	553
Accounts payable	(26,977)	2,335
Accrued liabilities	(10,959)	1,401
Other non-current liabilities	9,059	1,938
Net cash provided by operating activities	45,232	153,243
Cash flows from investing activities:		
Capital expenditures	(11,439)	(9,157)
Capital expenditures for turnarounds and catalysts	(25,447)	(4,819)
Net cash used in investing activities	(36,886)	(13,976)
Cash flows from financing activities:		
Distributions paid to unitholders	(10,010)	(23,579)
Distributions paid to unitholders - Alon Energy	(44,370)	(104,550)
Inventory agreement transactions	(25,200)	—
Deferred debt issuance costs	—	(205)
Revolving credit facility, net	—	(49,000)
Payments on long-term debt	(1,250)	(1,250)
Net cash used in financing activities	(80,830)	(178,584)
Net decrease in cash and cash equivalents	(72,484)	(39,317)
Cash and cash equivalents, beginning of period	153,583	66,001
Cash and cash equivalents, end of period	$ 81,099	$ 26,684
Supplemental cash flow information:		
Cash paid for interest, net of capitalized interest	$ 23,203	$ 17,601
Cash paid for income tax	$ 725	$ 1,373
Supplemental disclosure of non-cash activity:		
Capital expenditures included in accounts payable and accrued liabilities	$ 28,741	$ —

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," "us" or "our" refer to Alon USA Partners, LP, one or more of its consolidated subsidiaries or all of them taken as a whole. References in this report to "Alon Energy" refer collectively to Alon USA Energy, Inc. and its consolidated subsidiaries, other than Alon USA Partners, LP, its subsidiaries and its general partner.

Alon is a Delaware limited partnership formed in August 2012 by Alon Energy and its wholly-owned subsidiary Alon USA Partners GP, LLC (the "General Partner"). On November 26, 2012, we completed our initial public offering of 11,500,000 common units representing limited partner interests.

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 six months ended June 30, 2014 are not necessarily indicative of the operating results that may be realized for the year ending December 31, 2014.

Our consolidated balance sheet as of December 31, 2013 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, 2013.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board 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 requirements from the new standard are effective for interim and annual periods beginning after December 15, 2016, and early adoption is not permitted. The standard allows for either full retrospective adoption or modified retrospective adoption. We are evaluating the guidance to determine the method of adoption and the impact of this standard 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.

(unaudited, dollars in thousands except as noted)

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 and the Renewable Identification Numbers ("RINs") obligation are our only assets and liabilities measured at fair value on a recurring basis.

The RINs obligation represents the period-end deficit, if any, after considering any RINs acquired or under contract, necessary to meet our requirements to blend biofuels into the products we have produced. The RINs obligation is categorized as level 2 of the fair value hierarchy and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

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 June 30, 2014 and December 31, 2013:

	Level 1	Level 2	Level 3	Total
As of June 30, 2014				
Liabilities:				
Commodity contracts (futures and forwards)	$ 329	$ —	$ —	$ 329
Fair value hedge	—	4,696	—	4,696
As of December 31, 2013				
Assets:				
Commodity contracts (futures and forwards)	$ 22	$ —	$ —	$ 22
Liabilities:				
Fair value hedge	—	2,304	—	2,304
RINs obligation	—	334	—	334

(3) Derivative Financial Instruments

Mark to Market

Commodity Derivatives. We selectively utilize crude oil and refined product commodity derivative contracts to reduce the risk associated with potential price changes on committed obligations. 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.

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.

As of June 30, 2014, we have accounted for certain commodity contracts as fair value hedges with contract purchase volumes of 304 thousand barrels of crude oil with remaining contract terms through May 2019.

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

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

	As of June 30, 2014			
	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	$ 520	Accrued liabilities	$ 849
Total derivatives not designated as hedging instruments		$ 520		$ 849
Derivatives designated as hedging instruments:				
Fair value hedge		$ —	Other non-current liabilities	$ 4,696
Total derivatives designated as hedging instruments		—		4,696
Total derivatives		$ 520		$ 5,545

	As of December 31, 2013			
	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	$ 303	Accrued liabilities	$ 281
Total derivatives not designated as hedging instruments		$ 303		$ 281
Derivatives designated as hedging instruments:				
Fair value hedge		$ —	Other non-current liabilities	$ 2,304
Total derivatives designated as hedging instruments		—		2,304
Total derivatives		$ 303		$ 2,585

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 June 30,		For the Six Months Ended June 30,	
	Location	2014	2013	2014	2013
Fair value hedge	Cost of sales	$ (1,569)	$ (4)	$ (2,392)	$ (1,598)
Total derivatives		$ (1,569)	$ (4)	$ (2,392)	$ (1,598)

Derivatives not designated as hedging instruments:

		Gain (Loss) Recognized in Income			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	Location	2014	2013	2014	2013
Commodity contracts (futures & forwards)	Cost of sales	$ (2,898)	$ (1,001)	$ (2,275)	$ 6,650
Total derivatives		$ (2,898)	$ (1,001)	$ (2,275)	$ 6,650

(unaudited, dollars in thousands except as noted)

Offsetting Assets and Liabilities

Our derivative financial 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 June 30, 2014 and December 31, 2013:

	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 June 30, 2014						
Derivative Assets:						
Commodity contracts (futures & forwards)	$ 566	$ (46)	$ 520	$ (520)	$ —	$ —
Derivative Liabilities:						
Commodity contracts (futures & forwards)	$ 895	$ (46)	$ 849	$ (520)	$ —	$ 329
Fair value hedge	4,696	—	4,696	—	—	4,696
As of December 31, 2013						
Derivative Assets:						
Commodity contracts (futures & forwards)	$ 514	$ (211)	$ 303	$ (281)	$ —	$ 22
Derivative Liabilities:						
Commodity contracts (futures & forwards)	$ 492	$ (211)	$ 281	$ (281)	$ —	$ —
Fair value hedge	2,304	—	2,304	—	—	2,304

Compliance Program Market Risk

We are obligated by government regulations to blend a certain percentage of biofuels into the products we produce that 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 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.

We are exposed to market risk related to the volatility in the price of credits needed to comply with these government regulations. We manage this risk by purchasing RINs when prices are deemed favorable utilizing fixed price purchase contracts. 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.

During the three months ended June 30, 2014, we generated RINs credits of $759, as a result of reduced production during the planned turnaround at our refinery, compared to RINs costs of $8,016 for three months ended June 30, 2013. RINs costs were $2,167 and $8,016 for the six months ended June 30, 2014 and 2013, respectively. These amounts are reflected in cost of sales. We utilized carryover RINs from 2012 to completely offset our first quarter 2013 RINs deficit.

(4) Inventories

Our inventories (including inventory consigned to others) are stated at the lower of cost or market. Cost is determined under the last-in, first-out (LIFO) method for crude oil, refined products and blendstock inventories. Materials and supplies are stated at average cost.

(unaudited, dollars in thousands except as noted)

Carrying value of inventories consisted of the following:

	June 30, 2014	December 31, 2013
Crude oil, refined products and blendstocks	$ 39,665	$ 25,246
Crude oil inventory consigned to others	21,388	14,214
Materials and supplies	9,393	9,686
Total inventories	$ 70,446	$ 49,146

Market values of crude oil, refined products and blendstock inventories exceeded LIFO costs by $24,735 and $21,216 at June 30, 2014 and December 31, 2013, respectively.

(5) Inventory Financing Agreement

The Partnership has 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 to J. Aron, and J. Aron agreed to buy from us, 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 2019. J. Aron may elect to terminate the Supply and Offtake Agreement prior to the expiration of the initial term beginning in May 2016 and upon each anniversary thereof, on six months prior notice. We may elect to terminate in May 2018 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.

At June 30, 2014 and December 31, 2013, we had net current receivables of $19,914 and $11,640, respectively, from J. Aron for sales and purchases, non-current liabilities related to the original financing of $33,499 and $24,482, respectively, and a consignment inventory receivable representing a deposit paid to J. Aron of $6,290 and $6,290, respectively.

Additionally, we had current receivables of $520 and current payables of $263 at June 30, 2014 and December 31, 2013, 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.

(6) Property, Plant and Equipment, Net

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

	June 30, 2014	December 31, 2013
Refining facilities	$ 681,594	$ 677,085
Accumulated depreciation	(221,497)	(204,200)
Property, plant and equipment, net	$ 460,097	$ 472,885

(7) Additional Financial Information

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

(a) Other Assets, Net

	June 30, 2014	December 31, 2013
Deferred debt issuance costs	$ 6,764	$ 7,782
Receivable from supply agreement	6,290	6,290
Deferred turnaround and catalyst cost	60,783	7,774
Other	9,354	9,420
Total other assets	$ 83,191	$ 31,266

(unaudited, dollars in thousands except as noted)

(b) Accrued Liabilities and Other Non-Current Liabilities

	June 30, 2014	December 31, 2013
Accrued Liabilities:		
Taxes other than income taxes, primarily excise taxes	$ 16,341	$ 30,354
Accrued finance charges	647	1,365
Environmental accrual (Note 11)	1,307	1,307
Commodity contracts	849	281
Other	27,880	11,185
Total accrued liabilities	$ 47,024	$ 44,492
Other Non-Current Liabilities:		
Consignment inventory obligation	$ 33,499	$ 24,482
Environmental accrual (Note 11)	5,640	5,640
Asset retirement obligations	2,015	1,973
Other	2,799	2,799
Total other non-current liabilities	$ 43,953	$ 34,894

(8) Indebtedness

Debt consisted of the following:

	June 30, 2014	December 31, 2013
Term loan credit facility	$ 243,344	$ 244,322
Revolving credit facility	100,000	100,000
Total debt	343,344	344,322
Less: Current portion	2,500	2,500
Total long-term debt	$ 340,844	$ 341,822

Outstanding letters of credit under the revolving credit facility were $58,963 and $109,772 at June 30, 2014 and December 31, 2013, respectively.

Our revolving credit facility contains maintenance financial covenants. At June 30, 2014, 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 and 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.

During the six months ended June 30, 2014, we paid the following cash distributions:

Date Paid	Distribution Amount Per Unit	Total Distribution Amount
May 21, 2014	$ 0.69	$ 43,130
March 3, 2014	0.18	11,250

Restricted Units

In May 2014, we granted awards to non-employee directors of the General Partner of 4,083 restricted common units at an average grant date price of $18.38 per unit, which vest over a period of three years, assuming continued service at vesting.

(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 include sales of motor fuels and are 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 to our consolidated financial statements as selling, general and administrative expenses. Our allocation for selling, general and administrative expenses were $3,225 and $3,529, for the three months ended June 30, 2014 and 2013, respectively, and $5,968 and $6,444 for the six months ended June 30, 2014 and 2013, 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 and recorded as payroll expense and included in direct operating expenses within the consolidated statements of operations. The allocated portion of Alon Energy's employee expense costs included in direct operating expenses were $7,091 and $5,650 for the three months ended June 30, 2014 and 2013, respectively, and $13,706 and $11,958 for the six months ended June 30, 2014 and 2013, 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 $1,818 and $2,658 for the three months ended June 30, 2014 and 2013, respectively, and $3,636 and $5,262 for the six months ended June 30, 2014 and 2013, respectively.

Leasing Agreements

In June 2014, we entered into six year lease agreements with a subsidiary of Alon Energy to lease equipment used at the Big Spring refinery. The lease agreements are effective July 1, 2014 and require fixed monthly payments amounting to $4,920 annually.

The transaction was reviewed and approved by the Conflicts Committee of our General Partner, in consultation with independent consultants.

Distributions

During the six months ended June 30, 2014, we paid cash distributions of $54,380, or $0.87 per unit. Total cash distributions paid to Alon Energy were $44,370. During the six months ended June 30, 2013, we paid cash distributions of $128,129, or $2.05 per unit. Total cash distributions paid to Alon Energy were $104,550.

(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 is impossible to determine with any degree of reliability.

We have accrued environmental remediation obligations of $6,947 ($1,307 accrued liability and $5,640 non-current liability) at June 30, 2014 and December 31, 2013.

(12) Subsequent Event

Distribution Declared

In August 2014, the board of directors of the General Partner declared a cash distribution to our common unitholders of approximately $8,130, or $0.13 per common unit. The cash distribution will be paid on August 25, 2014 to unitholders of record at the close of business on August 18, 2014.

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

References in this report to "we," "our," "us" or like terms, refer to Alon USA Partners, LP and its subsidiaries, also referred to as the "Partnership" or "Alon." Unless the context otherwise requires, references in this report to "Alon Energy" refers to Alon USA Energy, Inc. and any of its 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, 2013.

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 our largest supplier of crude oil and our largest customer 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 failure 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 of and cost of compliance with the Renewable Fuel Standards 2 ("RFS2") requirements, including the availability, cost and price volatility of Renewable Identification Numbers ("RINs");
- the effects and cost of compliance with current and future state and federal environmental, economic, safety and other laws, policies and regulations;
- operating hazards, natural disasters, casualty losses and other matters beyond our control;
- 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, 2013 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 Delaware limited partnership formed in August 2012 by Alon USA Energy, Inc. (NYSE: ALJ) ("Alon Energy") to own, operate and grow our strategically located refining and petroleum products marketing business. Our integrated downstream business operates primarily in the South Central and Southwestern regions of the United States. We own and operate a crude oil refinery in Big Spring, Texas with total crude oil throughput capacity of approximately 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 West and Central Texas, Oklahoma, New Mexico and Arizona through our wholesale distribution network to both Alon Energy's retail convenience stores and other third-party distributors.

We sell refined products in both the wholesale rack and bulk markets. We focus our marketing of transportation fuels on West and Central Texas, Oklahoma, New Mexico and Arizona through our physically-integrated refining and distribution system. We distribute fuel products through a product pipeline and terminal network of seven pipelines and five terminals that we own or access through leases or long-term throughput agreements.

Second Quarter Operational and Financial Highlights

Operating income for the second quarter of 2014 was $19.0 million, compared to $54.8 million for the same period last year. Our operational and financial highlights for the second quarter of 2014 include the following:

- During the second quarter of 2014, we completed the planned turnaround and the vacuum tower project at the Big Spring refinery, which has allowed us to increase the refinery's crude oil throughput by 3,000 bpd to 73,000 bpd.
- Big Spring refinery average throughput for the second quarter of 2014 was 38,994 bpd compared to 72,124 bpd for the second quarter of 2013. The lower throughput was primarily due to the planned turnaround during the second quarter of 2014.
- Operating margin at the Big Spring refinery was $17.04 per barrel for the second quarter of 2014 compared to $14.99 per barrel for the same period in 2013. This increase in operating margin was primarily due to a widening of both the WTI Cushing to WTS spread and the WTI Cushing to WTI Midland spread, partially offset by a lower Gulf Coast 3/2/1 crack spread. During the second quarter of 2014, we generated RINs credits of $0.8 million, as a result of reduced production during the planned turnaround, compared to RINs costs of $8.0 million for the second quarter of 2013.
- The average WTI Cushing to WTS spread for the second quarter of 2014 was $7.88 per barrel compared to $0.36 per barrel for the same period in 2013. The average WTI Cushing to WTI Midland spread for the second quarter of 2014 was $8.37 per barrel compared to $0.14 per barrel for the same period in 2013.
- The average Gulf Coast 3/2/1 crack spread was $16.42 per barrel for the second quarter of 2014 compared to $21.17 per barrel for the second quarter of 2013, which was primarily influenced by a reduction in the Brent to WTI Cushing spread. The average Brent to WTI Cushing spread for the second quarter of 2014 was $7.56 per barrel compared to $12.51 per barrel for the same period in 2013.
- During the second quarter of 2014, we paid cash distributions of $43.1 million, or $0.69 per unit, compared to $92.5 million, or $1.48 per unit during the second quarter of 2013.

Major Influences on Results of Operations

Earnings and cash flow 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, and not necessarily fluctuations in those prices, that affect 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.

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 priced crude oil.

In addition, we have been able to capitalize on the oversupply of West Texas crudes in Midland, the largest origination terminal for West Texas crude oil, resulting from increased production in the Permian Basin coupled with infrastructure constraints. Although West Texas crudes are typically transported to Cushing and to the Gulf Coast for sale, current logistical and infrastructure constraints are limiting the ability of Permian Basin producers to transport their production to Cushing and to the Gulf Coast. The resulting oversupply of West Texas crudes at Midland has depressed Midland crude prices and enabled us to obtain an increased portion of our crude supply at discounted prices to Cushing. Moreover, by sourcing West Texas crude oils at Midland, we are able to eliminate the cost of transporting crude to and from Cushing. 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 can favorably influence the operating margin for our Big Spring refinery.

Global product prices are influenced by the price of Brent crude which is a global benchmark crude. Global product prices set 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 can favorably influence the operating margins 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 substantial quantities of 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 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 six months ended June 30, 2014 and 2013 have been influenced by the following factors which are fundamental to understanding comparisons of our period-to-period financial performance.

Maintenance and Turnaround Impact on Crude Oil Throughput

During the three months ended June 30, 2014, we completed both the planned turnaround and the vacuum tower project at the refinery, which will increase our distillate yield, improve energy efficiency and allow us to better optimize our crude slate. Due to these events, refinery throughput was reduced during the three and six months ended June 30, 2014.

Renewable Fuel Standard

During the three months ended June 30, 2014, we generated RINs credits of $0.8 million, as a result of reduced production during the planned turnaround, compared to RINs costs of $8.0 million for the three months ended June 30, 2013. RINs costs were $2.2 million and $8.0 million for the six months ended June 30, 2014 and 2013, respectively. We utilized carryover RINs from 2012 to completely offset our first quarter 2013 RINs deficit.

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, other raw materials and transportation costs. 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. All operating costs associated with our crude oil and product pipelines are considered to be transportation costs and are reflected in cost of sales in the consolidated statements of operations.

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 to expense within the consolidated statements of operations of the carrying value of capital assets. The value is allocated 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 six months ended June 30, 2014 and 2013. 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, 2013 is unaudited.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(dollars in thousands, except per unit data, per barrel data and pricing statistics)			
STATEMENTS OF OPERATIONS DATA:				
Net sales (1)	$ 725,852	$ 865,694	$ 1,582,312	$ 1,669,861
Operating costs and expenses:				
Cost of sales	665,398	767,322	1,424,444	1,417,525
Direct operating expenses	25,152	27,314	54,093	57,736
Selling, general and administrative expenses	6,784	5,065	11,152	12,730
Depreciation and amortization	9,508	11,243	19,575	23,307
Total operating costs and expenses	706,842	810,944	1,509,264	1,511,298
Operating income	19,010	54,750	73,048	158,563
Interest expense	(11,569)	(8,970)	(22,893)	(18,362)
Other income, net	601	14	613	18
Income before state income tax expense	8,042	45,794	50,768	140,219
State income tax expense	240	473	725	1,373
Net income	$ 7,802	$ 45,321	$ 50,043	$ 138,846
Earnings per unit	$ 0.12	$ 0.73	$ 0.80	$ 2.22
Weighted average common units outstanding (in thousands)	62,504	62,502	62,504	62,502
Cash distribution per unit	$ 0.69	$ 1.48	$ 0.87	$ 2.05
CASH FLOW DATA:				
Net cash provided by (used in):				
Operating activities	$ (35)	$ (13,403)	$ 45,232	$ 153,243
Investing activities	(18,259)	(7,257)	(36,886)	(13,976)
Financing activities	(68,955)	(143,128)	(80,830)	(178,584)
OTHER DATA:				
Adjusted EBITDA (2)	$ 29,119	$ 66,007	$ 93,236	$ 181,888
Capital expenditures	7,277	6,216	11,439	9,157
Capital expenditures for turnarounds and catalysts	10,982	1,041	25,447	4,819
KEY OPERATING STATISTICS:				
Per barrel of throughput:				
Refinery operating margin (3)	$ 17.04	$ 14.99	$ 15.56	$ 21.18
Refinery direct operating expense (4)	7.09	4.16	5.33	4.85
PRICING STATISTICS:				
Crack spreads (per barrel):				
Gulf Coast 3/2/1	$ 16.42	$ 21.17	$ 16.61	$ 24.76
WTI Cushing crude oil (per barrel)	$ 103.04	$ 94.20	$ 100.86	$ 94.23
Crude oil differentials (per barrel):				
WTI Cushing less WTI Midland	$ 8.37	$ 0.14	$ 5.96	$ 3.91
WTI Cushing less WTS	7.88	0.36	5.79	5.86
Brent less WTI Cushing	7.56	12.51	10.25	16.98
Product price (dollars per gallon):				
Gulf Coast unleaded gasoline	$ 2.81	$ 2.69	$ 2.73	$ 2.77
Gulf Coast ultra-low sulfur diesel	2.92	2.86	2.93	2.97
Natural gas (per MMBtu)	4.58	4.02	4.65	3.76

BALANCE SHEET DATA (end of period):	June 30, 2014	December 31, 2013
	(dollars in thousands)	
Cash and cash equivalents	$ 81,099	$ 153,583
Working capital	(17,346)	18,007
Total assets	812,323	849,924
Total debt	343,344	344,322
Total debt less cash and cash equivalents	262,245	190,739
Total partners' equity	141,145	145,442

THROUGHPUT AND PRODUCTION DATA:	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2014		2013		2014		2013	
	bpd	%	bpd	%	bpd	%	bpd	%
Refinery throughput:								
WTS crude	12,634	32.4	53,627	74.4	23,927	42.7	49,446	75.1
WTI crude	23,391	60.0	17,180	23.8	29,652	52.9	14,380	21.8
Blendstocks	2,969	7.6	1,317	1.8	2,471	4.4	2,009	3.1
Total refinery throughput (5)	38,994	100.0	72,124	100.0	56,050	100.0	65,835	100.0
Refinery production:								
Gasoline	17,484	45.1	35,057	48.7	26,835	48.0	32,436	49.4
Diesel/jet	12,315	31.8	24,748	34.4	18,461	33.0	22,038	33.6
Asphalt	1,660	4.3	4,453	6.2	2,529	4.5	3,909	6.0
Petrochemicals	1,825	4.7	4,628	6.4	3,111	5.5	4,179	6.4
Other	5,483	14.1	3,088	4.3	5,022	9.0	3,029	4.6
Total refinery production (6)	38,767	100.0	71,974	100.0	55,958	100.0	65,591	100.0
Refinery utilization (7)		85.4%		101.2%		95.7%		97.1%

(1) Includes sales to related parties of $152,170 and $156,043 for the three months and $291,183 and $297,942 for the six months ended June 30, 2014 and 2013, 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 to Adjusted EBITDA for the three and six months ended June 30, 2014 and 2013:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(dollars in thousands)			
Net income	$ 7,802	$ 45,321	$ 50,043	$ 138,846
State income tax expense	240	473	725	1,373
Interest expense	11,569	8,970	22,893	18,362
Depreciation and amortization	9,508	11,243	19,575	23,307
Adjusted EBITDA	$ 29,119	$ 66,007	$ 93,236	$ 181,888

(3) Refinery operating margin is a per barrel measurement calculated by dividing the margin between net sales and cost of sales 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.

(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 oil 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 feedstocks through the crude units and other conversion units.

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

Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2013

Net Sales. Net sales for the three months ended June 30, 2014 were $725.9 million, compared to $865.7 million for the three months ended June 30, 2013, a decrease of $139.8 million. This decrease was due to lower refinery throughput, partially offset by increased sales of purchased products and higher refined product prices during the three months ended June 30, 2014 compared to the same period last year. Refinery average throughput for the three months ended June 30, 2014 was 38,994 bpd compared to 72,124 bpd for the three months ended June 30, 2013, a decrease of 45.9%. During the three months ended June 30, 2014, we completed both the planned turnaround and the vacuum tower project at the refinery, which will increase our distillate yield, improve energy efficiency and allow us to better optimize our crude slate. Due to these events, refinery throughput was reduced during the three months ended June 30, 2014. The average per gallon price of Gulf Coast gasoline for the three months ended June 30, 2014 increased $0.12, or 4.5%, to $2.81, compared to $2.69 for the three months ended June 30, 2013. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the three months ended June 30, 2014 increased $0.06, or 2.1%, to $2.92, compared to $2.86 for the three months ended June 30, 2013.

Cost of Sales. Cost of sales for the three months ended June 30, 2014 were $665.4 million, compared to $767.3 million for the three months ended June 30, 2013, a decrease of $101.9 million. This decrease was primarily due to lower refinery throughput, partially offset by increased products purchased to meet contractual obligations during the planned turnaround.

Direct Operating Expenses. Direct operating expenses for the three months ended June 30, 2014 were $25.2 million, compared to $27.3 million for the three months ended June 30, 2013, a decrease of $2.1 million, or 7.7%. This decrease was primarily due to lower overall direct operating expenses as a result of the shut down for the turnaround as well as lower insurance costs.

Selling, General and Administrative Expenses. SG&A expenses for the three months ended June 30, 2014 were $6.8 million, compared to $5.1 million for the three months ended June 30, 2013, an increase of $1.7 million, or 33.3%, primarily due to higher employee related costs.

Depreciation and Amortization. Depreciation and amortization for the three months ended June 30, 2014 was $9.5 million, compared to $11.2 million for the three months ended June 30, 2013, a decrease of $1.7 million, or 15.2%. This decrease was primarily due to reduced amortization of turnaround and catalyst replacement costs during the three months ended June 30, 2014.

Operating Income. Operating income for the three months ended June 30, 2014 was $19.0 million, compared to $54.8 million for the three months ended June 30, 2013, a decrease of $35.8 million. This decrease was primarily due to the planned turnaround, partially offset by higher refinery operating margin. Refinery operating margin was $17.04 per barrel for the three months ended June 30, 2014, compared to $14.99 per barrel for the three months ended June 30, 2013. This increase in operating margin was primarily due to a widening of both the WTI Cushing to WTS spread and the WTI Cushing to WTI Midland spread, partially offset by a lower Gulf Coast 3/2/1 crack spread. The average Gulf Coast 3/2/1 crack spread decreased to $16.42 per barrel for the three months ended June 30, 2014, compared to $21.17 per barrel for the three months ended June 30, 2013, which was primarily influenced by a reduction in the Brent to WTI Cushing spread. The average Brent to WTI Cushing spread for the three months ended June 30, 2014 was $7.56 per barrel compared to $12.51 per barrel for the three months ended June 30, 2013. The WTI Cushing to WTS spread widened for the three months ended June 30, 2014 to $7.88 per barrel compared to $0.36 per barrel for the three months ended June 30, 2013. The WTI Cushing to WTI Midland spread widened to $8.37 per barrel for the three months ended June 30, 2014, compared to $0.14 per barrel for the three months ended June 30, 2013. Also impacting operating income and refinery operating margin during the three months ended June 30, 2014, were RINs credits of $0.8 million, generated as a result of reduced production during the planned turnaround, compared to RINs costs of $8.0 million for the three months ended June 30, 2013.

Interest Expense. Interest expense for the three months ended June 30, 2014 was $11.6 million, compared to $9.0 million for the three months ended June 30, 2013, an increase of $2.6 million. This increase was primarily due to higher financing costs associated with crude oil purchases as a result of a backwardated crude oil market.

Net Income. Net income for the three months ended June 30, 2014 was $7.8 million, compared to $45.3 million for the three months ended June 30, 2013, a decrease of $37.5 million. This decrease was attributable to the factors discussed above.

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

Net Sales. Net sales for the six months ended June 30, 2014 were $1,582.3 million, compared to $1,669.9 million for the six months ended June 30, 2013, a decrease of $87.6 million. This decrease was primarily due to lower refinery throughput and lower refined product prices, partially offset by increased sales of purchased products. Refinery average throughput for the six months ended June 30, 2014 was 56,050 bpd compared to 65,835 bpd for the six months ended June 30, 2013, a decrease of 14.9%. During the six months ended June 30, 2014, we completed both the planned turnaround and the vacuum tower project at our refinery, which will increase our distillate yield, improve energy efficiency and allow us to better optimize our crude slate. Due to these events, refinery throughput was reduced during the six months ended June 30, 2014. The average per gallon price of Gulf Coast gasoline for the six months ended June 30, 2014 decreased $0.04, or 1.4%, to $2.73, compared to $2.77 for the six months ended June 30, 2013. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the six months ended June 30, 2014 decreased $0.04, or 1.3%, to $2.93, compared to $2.97 for the six months ended June 30, 2013.

Cost of Sales. Cost of sales for the six months ended June 30, 2014 were $1,424.4 million, compared to $1,417.5 million for the six months ended June 30, 2013, an increase of $6.9 million. This increase was primarily due to an increase in crude oil prices and increased products purchased to meet contractual obligations during the planned turnaround, partially offset by reduced refinery throughput. The average price of WTI Cushing increased 7.0% to $100.86 per barrel for the six months ended June 30, 2014 from $94.23 per barrel for the six months ended June 30, 2013. The WTI Cushing to WTI Midland spread widened 52.4%, to $5.96 per barrel for the six months ended June 30, 2014, compared to $3.91 per barrel for the six months ended June 30, 2013. Additionally, cost of sales for the six months ended June 30, 2014 and 2013 includes RINs costs of $2.2 million and $8.0 million, respectively, for the purchase of RINs needed to satisfy our obligation to blend biofuels into the products we produce.

Direct Operating Expenses. Direct operating expenses for the six months ended June 30, 2014 were $54.1 million, compared to $57.7 million for the six months ended June 30, 2013, a decrease of $3.6 million, or 6.2%. This decrease was primarily due to lower major maintenance and insurance costs, partially offset by higher utility costs for the six months ended June 30, 2014.

Selling, General and Administrative Expenses. SG&A expenses for the six months ended June 30, 2014 were $11.2 million, compared to $12.7 million for the six months ended June 30, 2013, a decrease of $1.5 million, or 11.8%. This decrease was primarily due to lower marketing expenses for the six months ended June 30, 2014.

Depreciation and Amortization. Depreciation and amortization for the six months ended June 30, 2014 was $19.6 million, compared to $23.3 million for the six months ended June 30, 2013, a decrease of $3.7 million due to reduced amortization of turnaround and catalyst replacement costs.

Operating Income. Operating income for the six months ended June 30, 2014 was $73.0 million, compared to $158.6 million for the six months ended June 30, 2013, a decrease of $85.6 million. This decrease was primarily due to lower refinery operating margins and lower refinery throughput. Refinery operating margin was $15.56 per barrel for the six months ended June 30, 2014, compared to $21.18 per barrel for the six months ended June 30, 2013. This decrease in operating margin was primarily due to a lower Gulf Coast 3/2/1 crack spread, partially offset by a widening WTI Cushing to WTI Midland spread. The average Gulf Coast 3/2/1 crack spread decreased 32.9% to $16.61 per barrel for the six months ended June 30, 2014, compared to $24.76 per barrel for the six months ended June 30, 2013, which was primarily influenced by a reduction in the Brent to WTI Cushing spread. The average Brent to WTI Cushing spread for the six months ended June 30, 2014 was $10.25 per barrel compared to $16.98 per barrel for the six months ended June 30, 2013. Also impacting operating income and refinery operating margin for the six months ended June 30, 2014 and 2013 were RINs costs of $2.2 million and $8.0 million, respectively.

Interest Expense. Interest expense was $22.9 million for the six months ended June 30, 2014, compared to interest expense of $18.4 million for the six months ended June 30, 2013, an increase of $4.5 million. This increase was primarily due to higher financing costs associated with crude oil purchases as a result of a backwardated crude oil market.

Net Income. Net income for the six months ended June 30, 2014 was $50.0 million, compared to $138.8 million for the six months ended June 30, 2013, a decrease of $88.8 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.

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.

Cash Flows

The following table sets forth our consolidated cash flows for the six months ended June 30, 2014 and 2013:

	For the Six Months Ended June 30,	
	2014	2013
	(dollars in thousands)	
Cash provided by (used in):		
Operating activities	$ 45,232	$ 153,243
Investing activities	(36,886)	(13,976)
Financing activities	(80,830)	(178,584)
Net decrease in cash and cash equivalents	$ (72,484)	$ (39,317)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $45.2 million during the six months ended June 30, 2014 compared to $153.2 million during the six months ended June 30, 2013. The reduction in net cash provided by operating activities of $108.0 million was primarily attributable to lower net income after adjusting for non-cash items of $92.5 million, decreased cash provided by accounts payable and accrued liabilities of $41.7 million and higher cash used on increases of inventories of $24.3 million, partially offset by increased cash collected on accounts receivable of $60.2 million.

Cash Flows Used In Investing Activities

Net cash used in investing activities was $36.9 million during the six months ended June 30, 2014 compared to $14.0 million during the six months ended June 30, 2013. The increase in net cash used in investing activities of $22.9 million was primarily due to an increase in capital expenditures and capital expenditures for turnarounds and catalysts associated with the planned turnaround completed during the second quarter of 2014.

Cash Flows Used In Financing Activities

Net cash used in financing activities was $80.8 million during the six months ended June 30, 2014 compared to $178.6 million during the six months ended June 30, 2013. The reduction in net cash used in financing activities of $97.8 million was primarily attributable to lower distributions to unitholders of $73.7 million and reduced payments on financing arrangements of $23.8 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. Borrowings of $100.0 million and $100.0 million and letters of credit of $59.0 million and $109.8 million were outstanding under this facility at June 30, 2014 and December 31, 2013, respectively.

Capital Spending

Each year the Board of Directors of our General Partner approves capital projects, including sustaining maintenance, regulatory and planned turnaround projects that our management is authorized to undertake in our annual capital budget. Additionally, at times when conditions warrant or as new opportunities arise, growth and profit improvement projects may be approved. Our total capital expenditure plan, including expenditures for catalysts and turnarounds, for 2014 is $67.0 million. Approximately $36.9 million has been spent during the six months ended June 30, 2014.

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, 2013.

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, 2013. 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, 2013.

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.

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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. As of June 30, 2014, we held 0.7 million barrels of crude oil and refined product inventories valued under the LIFO valuation method. Market value exceeded carrying value of LIFO costs by $24.7 million. We refer to this excess as our LIFO reserve. If the market value of these inventories had been $1.00 per barrel lower, our LIFO reserve would have been reduced by $0.7 million.

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 June 30, 2014:

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-long (Crude)	2,410	$ 96.24	$ —	$ 232	$ 236	$ 4
Forwards-long (Gasoline)	338,986	126.60	—	42,917	43,382	465
Forwards-long (Distillate)	142,600	125.57	—	17,906	17,893	(13)
Forwards-short (Jet)	(26,766)	—	123.56	(3,307)	(3,287)	20
Forwards-long (Slurry)	1,179	92.10		109	109	—
Forwards-long (Catfeed)	65,326	121.29	—	7,924	7,985	61
Forwards-long (Slop)	10,438	95.15	—	993	995	2
Forwards-short (Propane)	(29,981)	—	41.73	(1,251)	(1,270)	(19)
Futures-short (Crude)	(145,000)	—	105.47	(15,293)	(15,279)	14
Futures-short (Gasoline)	(460,000)	—	126.50	(58,189)	(58,796)	(607)
Futures-short (Distillate)	(150,000)	—	123.25	(18,488)	(18,744)	(256)

Interest Rate Risk

As of June 30, 2014, our outstanding debt balance of $346.3 million, excluding discounts, was subject to floating interest rates, of which $246.3 million was charged interest at the Eurodollar rate (with a floor of 1.25%) plus a margin of 8.00% and $100.0 million was charged interest at the Eurodollar rate plus 3.5%, subject to a minimum interest rate of 4.0%.

An increase of 1% in the Eurodollar rate on indebtedness would result in an increase in our interest expense of approximately $0.7 million per year.

ITEM 4. CONTROLS AND PROCEDURES

(1) 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.

(2) 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. We are transitioning our assessment of our internal control effectiveness over financial reporting from the criteria outlined by the 1992 framework of the Committee of Sponsoring Organizations of the Treadway Commission to its 2013 framework. We expect to complete this transition during 2014.

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS

Exhibit Number	Description of Exhibit
10.1	Amendment to Supply and Offtake Agreement dated as of February 1, 2013 between J. Aron & Company and Alon USA, LP (incorporated by reference to Exhibit 10.5 to Alon USA Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2014, SEC File No. 001-32567).
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 June 30, 2014, 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: August 8, 2014

By: /s/ David Wiessman
David Wiessman
Executive Chairman of the Board

Date: August 8, 2014

By: /s/ Paul Eisman
Paul Eisman
President, Chief Executive Officer and Director

Date: August 8, 2014

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) 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
    c) 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: August 8, 2014

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) 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
   c) 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: August 8, 2014

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 June 30, 2014, 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: August 8, 2014

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: August 8, 2014

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)