Rocktoff William
Form 4
March 09, 2010

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL	
OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
Rocktoff William

(Last) (First) (Middle)

400 N ASHLEY DRIVE, SUITE 2800

(Street)

TAMPA, FL 33602

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
SYKES ENTERPRISES INC [SYKE]

3. Date of Earliest Transaction (Month/Day/Year)
03/05/2010

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
VP & Corporate Controller

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative	2. Conversion	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if	4. Transaction	5. Number of	6. Date Exercisable and Expiration Date	7. Title and Amount of Underlying Securities	8. Price Derivat

Security (Instr. 3)	or Exercise Price of Derivative Security		any (Month/Day/Year)	Code (Instr. 8)		Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		(Month/Day/Year)		(Instr. 3 and 4)		Securit (Instr. 5
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Restricted Stock	$ 24.23	03/05/2010		A		871		(1)	(1)	Common Stock	871	$ 0

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Rocktoff William 400 N ASHLEY DRIVE SUITE 2800 TAMPA, FL 33602			VP & Corporate Controller	

Signatures

/s/ Martin A. Traber, Attorney-In-Fact for William Rocktoff	03/09/2010
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The restricted stock was granted to the Reporting Person pursuant to the Issuer's 2001 Equity Incentive Plan and vesting is subject to previously established specific performance criteria through March 5, 2013.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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72

9

Retained fuel revenues
14

16

(2
)

34

46

(12
)
Storage margin, including fees
10

4

6

29

24

5

Total gross margin
$
172

$
164

$
8

$
525

$
520

$
5

Segment Adjusted EBITDA. For the three months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- a decrease of $1 million in transportation fees due to lower throughput volumes;
- an increase of $6 million in natural gas sales (excluding changes in unrealized losses of $1 million) and other primarily due to higher realized gains from the buying and selling of gas along our system;
- a decrease of $2 million from the sale of retained fuel primarily due to lower throughput volumes;
- an increase of $2 million in storage margin (excluding net changes in unrealized amounts of $4 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below; and
- a decrease of $1 million in general and administrative expenses due to lower insurance costs, as well as lower allocated overhead costs due to shared services cost savings.

Segment Adjusted EBITDA. For the nine months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our intrastate transportation and storage segment increased due to the net impacts of the following:

- an increase of $3 million in transportation fees despite lower throughput volumes, due to fees from renegotiated and newly initiated fixed fee contracts primarily on our Houston Pipeline system;
- an increase of $14 million in natural gas sales (excluding changes in unrealized loss of $5 million) primarily due to higher realized gains from the buying and selling gas along our system;
- a decrease of $9 million from the sale of retained fuel (excluding changes in unrealized losses of $3 million) primarily due to significantly lower market prices. The average spot price at the Houston Ship Channel location decreased 18% for the nine months ended September 30, 2016 compared to the same period last year;
- an increase of $24 million in storage margin (excluding net changes in unrealized amounts of $19 million related to fair value inventory adjustments and unrealized gains and losses on derivatives), as discussed below;
- a decrease of $4 million in operating expenses due to decreases in project related and office expenses; and
- a decrease of $4 million in general and administrative expenses due to lower legal fees and insurance costs.

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Storage margin was comprised of the following:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Withdrawals from storage natural gas inventory (MMBtu)	11,547,500	—	11,547,500	33,205,000	15,782,500	17,422,500
Realized margin on natural gas inventory transactions	$ (3)	$ (4)	$ 1	$ 33	$ 8	$ 25
Fair value inventory adjustments	(4)	(16)	12	52	7	45
Unrealized gains (losses) on derivatives	12	19	(7)	(74)	(10)	(64)
Margin recognized on natural gas inventory, including related derivatives	5	(1)	6	11	5	6
Revenues from fee-based storage	5	5	—	18	19	(1)
Total storage margin	$ 10	$ 4	$ 6	$ 29	$ 24	$ 5

The changes in storage margin were primarily driven by the timing of withdrawals and sales of natural gas from our Bammel storage cavern.

Interstate Transportation and Storage

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Natural gas transported (MMBtu/d)	5,385,679	5,903,285	(517,606)	5,527,607	6,187,218	(659,611)
Natural gas sold (MMBtu/d)	19,478	19,171	307	19,398	16,894	2,504
Revenues	$ 236	$ 248	$ (12)	$ 729	$ 767	$ (38)
Operating expenses, excluding non-cash compensation, amortization and accretion expenses	(76)	(78)	2	(223)	(221)	(2)
Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses	(13)	(14)	1	(36)	(43)	7
Adjusted EBITDA related to unconsolidated affiliates	131	130	1	376	369	7
Other	—	—	—	2	—	2
Segment Adjusted EBITDA	$ 278	$ 286	$ (8)	$ 848	$ 872	$ (24)

Volumes. For the three months ended September 30, 2016 compared to the same period last year, transported volumes decreased 346,817 MMBtu/d on the Trunkline pipeline primarily due to lower utilization resulting from lower customer demand, a decrease of 115,926 MMBtu/d on the Sea Robin pipeline due to reduced supply as a result of producer system maintenance and overall lower production, and a decrease of 107,178 MMBtu/d on the Transwestern pipeline due to lower customer demand in the West and San Juan areas, partially offset by opportunities in the Texas Intrastate markets.

Transported volumes for the nine months ended September 30, 2016 compared to the same period last year decreased 491,518 MMBtu/d on the Trunkline pipeline due to the transfer of one of the pipelines at Trunkline which was repurposed from natural gas service to crude oil service and lower utilization resulting from lower customer demand, and a decrease of 78,843 MMBtu/d on the Sea Robin pipeline due to reduced supply as a result of producer system maintenance and overall lower production.

Segment Adjusted EBITDA. For the three months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effect of the following:

- a decrease of $9 million in revenues due to contract restructuring on the Tiger pipeline, a decrease of $6 million due to lower rates on the Panhandle, Trunkline and Transwestern pipelines due to weak spreads, and a decrease of $3 million on the Sea

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Explanation of Responses:

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Robin pipeline due to declines in production and third party maintenance. These decreases were partially offset by higher reservation revenues on the Transwestern pipeline of $4 million from a growth project and higher parking revenues of $2 million, primarily on the Panhandle pipeline; partially offset by

- a decrease of $2 million in operating expenses primarily due to lower maintenance projects and lower allocated costs; and
- a decrease of $1 million in selling, general and administrative expenses primarily due to insurance proceeds received in 2016 and lower allocated costs.

Segment Adjusted EBITDA. For the nine months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our interstate transportation and storage segment decreased due to the net effects of the following:

- a decrease of $17 million in revenues due to contract restructuring on the Tiger pipeline, a decrease of $14 million due to the transfer of one of the Trunkline pipelines which was repurposed from natural gas service to crude oil service, a decrease of $11 million due to the expiration of a transportation rate schedule on the Transwestern pipeline, a decrease of $10 million due to lower reservation revenues on the Panhandle and Trunkline pipelines from capacity sold at lower rates and lower sales of capacity in the Phoenix area on the Transwestern pipeline, and a decrease of $8 million on the Sea Robin pipeline due to declines in production and third party maintenance. These decreases were partially offset by higher reservation revenues on the Transwestern pipeline of $16 million from sales of capacity in the East and West, primarily associated with a growth project, and higher parking revenues of $8 million, primarily on the Panhandle and Trunkline pipelines; partially offset by
- an increase of $2 million in overall operating expenses primarily due to the prior period credit and settlement of ad valorem taxes in 2015 of $5 million, partially offset by lower maintenance project costs of $2 million due to scope and level of activity; and
- a decrease of $7 million in overall selling, general and administrative expenses primarily due to $4 million in lower allocated costs and $3 million associated with insurance proceeds and a refund of franchise taxes.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Gathered volumes (MMBtu/d)	9,675,003	10,384,106	(709,103)	9,853,502	9,957,494	(103,992)
NGLs produced (Bbls/d)	420,877	413,426	7,451	440,124	393,480	46,644
Equity NGLs (Bbls/d)	34,341	26,296	8,045	31,847	28,175	3,672
Revenues	$1,343	$ 1,379	$ (36)	$3,765	$ 3,770	$ (5)
Cost of products sold	867	915	(48)	2,415	2,423	(8)
Gross margin	476	464	12	1,350	1,347	3
Unrealized losses on commodity risk management activities	—	—	—	—	82	(82)
Operating expenses, excluding non-cash compensation expense	(153)	(148)	(5)	(453)	(433)	(20)
Selling, general and administrative expenses, excluding non-cash compensation expense	(17)	(9)	(8)	(42)	(36)	(6)
Adjusted EBITDA related to unconsolidated affiliates	7	6	1	19	14	5
Other	1	2	(1)	1	3	(2)
Segment Adjusted EBITDA	$314	$ 315	$ (1)	$875	$ 977	$ (102)

Volumes. Gathered volumes decreased during the three and nine months ended September 30, 2016 compared to the same periods last year primarily due to declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions. NGL production increased for the three and nine months ended September 30, 2016 compared to the same periods last year due to increased gathering and processing capacities in the Permian and Cotton Valley regions, partially offset by declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions.

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Gross Margin. The components of our midstream segment gross margin were as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Gathering and processing fee-based revenues	$393	$418	$ (25)	$1,177	$1,182	$ (5)
Non fee-based contracts and processing	83	46	37	173	165	8
Total gross margin	$476	$464	$ 12	$1,350	$1,347	$ 3

Segment Adjusted EBITDA. For the three months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net effects of the following:

- an increase of $27 million in non-fee based margin due to volume increases in the Permian region, partially offset by volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions; and
- an increase of $10 million in non-fee based margins due to higher crude oil and NGL prices; offset by
- a decrease of $25 million in fee-based margin due to volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increased gathering and processing volumes in the Permian and Cotton Valley regions; and
- an increase in general and administrative expenses of $8 million primarily due to an increase of $3 million in insurance allocation from corporate, a decrease of $3 million in capitalized overhead, and an increase of $2 million in legal expenses.

Segment Adjusted EBITDA. For the nine months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our midstream segment decreased due to the net effects of the following:

- a decrease of $14 million in non-fee based margins due to lower natural gas prices and a $18 million decrease in non-fee based margins due to lower crude oil and NGL prices;
- a decrease of $5 million in fee-based margin due to volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions, partially offset by increased gathering and processing volumes in the Permian and Cotton Valley regions;
- a decrease in gross margin of $85 million due to lower benefit from settled derivatives used to hedge commodity margins; and
- an increase in operating expenses of $20 million primarily due to the King Ranch acquisition in the second quarter of 2015 and assets recently placed in service in the Permian and Eagle Ford regions; partially offset by
- an increase of $39 million in non-fee based margin due to volume increases in the Permian region, partially offset by volume declines in the South Texas, North Texas, and Mid-Continent/Panhandle regions.

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Liquids Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Liquids transportation volumes (Bbls/d)	647,018	509,894	137,124	612,815	486,041	126,774
NGL fractionation volumes (Bbls/d)	338,237	228,695	109,542	349,986	231,161	118,825
Revenues	$1,207	$ 858	$ 349	$3,236	$2,521	$ 715
Cost of products sold	927	615	312	2,438	1,882	556
Gross margin	280	243	37	798	639	159
Unrealized (gains) losses on commodity risk management activities	5	(4)	9	20	—	20
Operating expenses, excluding non-cash compensation expense	(43)	(40)	(3)	(121)	(114)	(7)
Selling, general and administrative expenses, excluding non-cash compensation expense	(2)	(4)	2	(12)	(12)	—
Adjusted EBITDA related to unconsolidated affiliates	—	—	—	2	5	(3)
Segment Adjusted EBITDA	$240	$ 195	$ 45	$687	$518	$ 169

Volumes. For the three and nine months ended September 30, 2016 compared to the same periods last year, NGL transportation volumes increased in all major producing regions, including the Permian, North Texas, Southeast Texas, Eagle Ford, and Louisiana. Our crude pipeline, originating in Nederland and delivering into Lake Charles, also began transporting volumes in April 2016, and transported approximately 69,000 Bbls/d and 42,000 Bbls/d during the three and nine months ended September 30, 2016, respectively.

Average daily fractionated volumes increased for the three and nine months ended September 30, 2016 compared to the same periods last year due to the ramp-up of our third 100,000 Bbls/d fractionator at Mont Belvieu, Texas, which was commissioned in late December 2015, as well as increased producer volumes, as mentioned above.

Gross Margin. The components of our liquids transportation and services segment gross margin were as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Transportation margin	$124	$109	$ 15	$355	$289	$ 66
Processing and fractionation margin	103	76	27	296	217	79
Storage margin	50	41	9	148	124	24
Other margin	3	17	(14)	(1)	9	(10)
Total gross margin	$280	$243	$ 37	$798	$639	$ 159

Segment Adjusted EBITDA. For the three and nine months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to our liquids transportation and services segment increased due to the net impacts of the following:

- increases in transportation fees of $15 million and $66 million, respectively, primarily due to higher volumes transported out of the Permian and North Texas regions;
- increases of $27 million and$79 million, respectively, in processing and fractionation margin (excluding changes in unrealized gains of $1 million for the three month period and unrealized losses of $2 million for the nine month period) primarily due to the ramp-up of our third 100,000 Bbls/d fractionator at Mont Belvieu, Texas, along with higher producer volumes, primarily from West Texas. Additionally, the three and nine months ended September 30, 2016 also reflect additional increases of $1 million and $19 million, respectively, from the commissioning of the Mariner South LPG export project during February 2015. Margin associated with our off-gas fractionator in Geismar, Louisiana decreased by $5 million for the nine months ended September 30, 2016 as NGL and olefin market prices

decreased significantly for the comparable periods;

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- increases in storage margin of $9 million and $24 million, respectively, partially due to an increase in demand for leased storage capacity as a result of favorable market conditions, which increased fee-based storage revenues by $2 million and $7 million, respectively. The remainder of the storage margin increases were primarily due to increases in throughput fees, as shuttle volumes increased for the three and nine months ended September 30, 2016 by 9% and 24%, respectively;
- a decrease of $6 million and an increase of $8 million, respectively, in other margin (excluding increases in unrealized losses of $9 million and $18 million, respectively) primarily due to fluctuating optimization opportunities at our Mont Belvieu facility; and
- increases in operating expenses of $3 million and $7 million, respectively, primarily due to increased costs associated with our third fractionator at Mont Belvieu.

Investment in Sunoco Logistics

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$2,189	$2,406	$(217)	$6,234	$8,181	$(1,947)
Cost of products sold	1,818	2,144	(326)	5,116	7,240	(2,124)
Gross margin	371	262	109	1,118	941	177
Unrealized (gains) losses on commodity risk management activities	16	(31)	47	33	(9)	42
Operating expenses, excluding non-cash compensation expense	(38)	(40)	2	(90)	(116)	26
Selling, general and administrative expenses, excluding non-cash compensation expense	(25)	(23)	(2)	(72)	(68)	(4)
Inventory valuation adjustments	(37)	103	(140)	(143)	44	(187)
Adjusted EBITDA related to unconsolidated affiliates	25	18	7	60	44	16
Segment Adjusted EBITDA	$312	$289	$23	$906	$836	$70

Segment Adjusted EBITDA. For the three months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the following:

- an increase of $11 million from Sunoco Logistics' NGLs operations, primarily attributable to increased volumes and fees from Sunoco Logistics' Mariner NGLs projects of $23 million, which includes Sunoco Logistics' NGLs pipelines and Marcus Hook and Nederland facilities; and
- an increase of $26 million from Sunoco Logistics' refined products operations, primarily due to improved operating results from Sunoco Logistics' refined products pipelines of $11 million, which benefited from higher volumes on Sunoco Logistics' Allegheny Access pipeline, and higher results from Sunoco Logistics' refined products acquisition and marketing activities of $10 million. Improved contributions from joint venture interests of $3 million and Sunoco Logistics' refined products terminals of $2 million also contributed to the increase; offset by
- a decrease of $14 million from Sunoco Logistics' crude oil operations, primarily due to lower operating results from Sunoco Logistics' crude oil acquisition and marketing activities of $38 million, which includes transportation and storage fees related to Sunoco Logistics' crude oil pipelines and terminal facilities, resulting from lower crude oil differentials compared to the prior year period. This decrease was partially offset by improved results from Sunoco Logistics' crude oil pipelines of $21 million which benefited from the Delaware Basin Extension and Permian Longview and Louisiana Extension pipelines that commenced operations in the third quarter 2016. Higher contributions from joint venture interests of $4 million also contributed to the offset.

For the nine months ended September 30, 2016 compared to the same period last year, Segment Adjusted EBITDA related to Sunoco Logistics increased due to the net impacts of the following:

- an increase of $63 million from Sunoco Logistics' refined products operations, primarily due to improved operating results from Sunoco Logistics' refined products pipelines of $29 million, which benefited from higher volumes on Sunoco Logistics' Allegheny Access pipeline, and higher results from Sunoco Logistics' refined products acquisition and marketing activities

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of $20 million. Higher earnings attributable to Sunoco Logistics' refined products terminals of $7 million and improved contributions from joint venture interests of $7 million also contributed to the increase;

- an increase of $6 million from Sunoco Logistics' NGLs operations, primarily due to increased volumes and fees from Sunoco Logistics' Mariner NGLs projects of $73 million, which includes Sunoco Logistics' NGLs pipelines and Marcus Hook and Nederland facilities. These factors were largely offset by lower operating results from Sunoco Logistics' NGLs acquisition and marketing activities of $66 million; and
- an increase of $1 million from Sunoco Logistics' crude oil operations, primarily due to improved results from Sunoco Logistics' crude oil pipelines of $116 million which benefited from the Permian Express 2 pipeline that commenced operations in third quarter 2015 and the Delaware Basin Extension and Permian Longview and Louisiana Extension pipelines that commenced operations in the third quarter 2016. Higher results from Sunoco Logistics' crude oil terminals of $20 million, largely related to Sunoco Logistics' Nederland facility, and improved contributions from joint venture interests of $9 million also contributed to the increase. These positive factors were largely offset by a decrease in operating results from Sunoco Logistics' crude oil acquisition and marketing activities of $140 million, which includes transportation and storage fees related to Sunoco Logistics' crude oil pipelines and terminal facilities, due to lower crude oil differentials and decreased volumes.

Retail Marketing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$—	$1,363	$(1,363)	$—	$11,705	$(11,705)
Cost of products sold	—	1,149	(1,149)	—	10,519	(10,519)
Gross margin	—	214	(214)	—	1,186	(1,186)
Unrealized (gains) losses on commodity risk management activities	—	(1)	1	—	2	(2)
Operating expenses, excluding non-cash compensation expense	—	(149)	149	—	(701)	701
Selling, general and administrative expenses, excluding non-cash compensation expense	—	(8)	8	—	(99)	99
Inventory valuation adjustments	—	4	(4)	—	(60)	60
Adjusted EBITDA related to unconsolidated affiliates	83	135	(52)	208	136	72
Segment Adjusted EBITDA	$83	$195	$(112)	$208	$464	$(256)

Due to the transfer of the general partnership interest of Sunoco LP from ETP to ETE in 2015 and completion of the dropdown of remaining Retail Marketing interests from ETP to Sunoco LP in March 2016, the Partnership's retail marketing segment has been deconsolidated, and the segment results now reflect an equity method investment in limited partnership units of Sunoco LP. As of September 30, 2016, the Partnership owns 43.5 million Sunoco LP common units, representing 45.6% of Sunoco LP's total outstanding common units.

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All Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Revenues	$956	$976	$ (20)	$2,521	$2,439	$ 82
Cost of products sold	877	855	22	2,263	2,107	156
Gross margin	79	121	(42)	258	332	(74)
Unrealized (gains) losses on commodity risk management activities	1	(7)	8	19	—	19
Operating expenses, excluding non-cash compensation expense	(20)	(33)	13	(57)	(79)	22
Selling, general and administrative expenses, excluding non-cash compensation expense	(14)	(33)	19	(60)	(112)	52
Adjusted EBITDA related to unconsolidated affiliates	(20)	47	(67)	1	103	(102)
Other	23	23	—	71	71	—
Eliminations	(19)	(25)	6	(45)	(49)	4
Segment Adjusted EBITDA	$30	$93	$ (63)	$187	$266	$ (79)

Amounts reflected in our all other segment primarily include:

- our natural gas marketing and compression operations;
- a non-controlling interest in PES, comprising 33% of PES' outstanding common units; and
- our investment in Coal Handling, an entity that owns and operates end-user coal handling facilities.

For the three and nine months ended September 30, 2016 compared to the same periods last year, Segment Adjusted EBITDA related to our all other segment decreased primarily due to decreases of $65 million and $102 million, respectively, in Adjusted EBITDA related to our investment in PES. The three and nine months ended September 30, 2016 also reflected lower gross margin of $42 million and $74 million, respectively, and lower operating expenses of $13 million and $22 million, respectively, primarily resulting from a decrease in revenue-generating horsepower and lower project revenue from our compression operations and unfavorable results from our natural resources operations, as reflected above, as well as lower selling, general and administrative expenses resulting from a decrease in transaction-related expenses.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our ability to satisfy our obligations and pay distributions to our Unitholders will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management's control.

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We currently expect the following capital expenditures in 2016 to be within the following ranges:

	Growth		Maintenance	
	Low	High	Low	High
Direct[1]:				
Intrastate transportation and storage[2]	$40	$50	$20	$25
Interstate transportation and storage[2][3]	210	250	95	105
Midstream	1,225	1,275	100	110
Liquids transportation and services				
NGL	875	900	20	25
Crude[2][3]	300	325	—	—
All other (including eliminations)	90	100	40	45
Total direct capital expenditures	$2,740	$2,900	$275	$310

(1) Direct capital expenditures exclude those funded by our publicly traded subsidiary.

(2) Net of amounts forecasted to be financed at the asset level with non-recourse debt of approximately $1.17 billion.

(3) Includes capital expenditures related to our proportionate ownership of the Bakken, Rover and Bayou Bridge pipeline projects.

We expect total direct growth capital expenditures of approximately $1.9 billion in 2017, net of amounts expected to be financed at the asset level.

The assets used in our natural gas and liquids operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, delays from steel mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

We generally fund maintenance capital expenditures and distributions with cash flows from operating activities. We generally fund growth capital expenditures with proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units, dropdown proceeds or the monetization of non-core assets or a combination thereof.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions, and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in “Results of Operations” above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation, depletion and amortization expense and non-cash compensation expense. The increase in depreciation, depletion and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense resulted from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such as the changes in the value of derivative assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Nine months ended September 30, 2016 compared to nine months ended September 30, 2015. Cash provided by operating activities during 2016 was $2.47 billion compared to $1.99 billion for 2015 and net income was

$986 million and $1.50 billion for 2016 and 2015, respectively. The difference between net income and cash provided by operating activities for the nine months

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ended September 30, 2016 primarily consisted of net changes in operating assets and liabilities of $172 million and non-cash items totaling $1.03 billion.

The non-cash activity in 2016 and 2015 consisted primarily of depreciation, depletion and amortization of $1.47 billion and $1.45 billion, respectively, non-cash compensation expense of $60 million and $59 million, respectively, and equity in earnings of unconsolidated affiliates of $260 million and $388 million, respectively. Non-cash activity in 2016 also included deferred income taxes of $154 million, impairment of investment in an unconsolidated affiliate of $308 million and inventory valuation adjustments of $143 million.

Cash paid for interest, net of interest capitalized, was $1.10 billion and $1.08 billion for the nine months ended September 30, 2016 and 2015, respectively.

Capitalized interest was $148 million and $108 million for the nine months ended September 30, 2016 and 2015, respectively.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash distributions from our joint ventures, and cash proceeds from sales or contributions of assets or businesses. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Nine months ended September 30, 2016 compared to nine months ended September 30, 2015. Cash provided by investing activities during 2016 was $3.64 billion compared to cash used in investing activities of $5.15 billion for 2015. Total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2016 were $5.74 billion. This compares to total capital expenditures (excluding the allowance for equity funds used during construction and net of contributions in aid of construction costs) for 2015 of $6.50 billion. Additional detail related to our capital expenditures is provided in the table below. During 2016, we received $2.20 billion in cash related to the contribution of our Sunoco, Inc. retail business to Sunoco LP. During 2015, we received $980 million in cash related to the Bakken Pipeline Transaction and paid $604 million in cash for all other acquisitions.

The following is a summary of capital expenditures (net of contributions in aid of construction costs) for the nine months ended September 30, 2016:

	Capital Expenditures Recorded During Period		
	Growth	Maintenance	Total
Direct[1]:			
Intrastate transportation and storage	$34	$ 11	$45
Interstate transportation and storage[2]	138	55	193
Midstream	868	82	950
Liquids transportation and services[2]	1,460	14	1,474
All other (including eliminations)	66	32	98
Total direct capital expenditures	2,566	194	2,760
Indirect[1]:			
Investment in Sunoco Logistics	1,237	40	1,277
Total capital expenditures	$3,803	$ 234	$4,037

(1) Indirect capital expenditures comprise those funded by our publicly traded subsidiary; all other capital expenditures are reflected as direct capital expenditures.

(2) Includes capital expenditures related to the Bakken, Rover and Bayou Bridge pipeline projects, which includes $268 million related to Sunoco Logistics' proportionate ownership in the Bakken and Bayou Bridge pipeline projects.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

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Nine months ended September 30, 2016 compared to nine months ended September 30, 2015. Cash used in financing activities during 2016 was $1.03 billion compared to cashed provided by financing activities of $3.35 billion for 2015. In 2016 and 2015, we received net proceeds from Common Unit offerings of $794 million and $1.03 billion, respectively. In 2016 and 2015, our subsidiaries received $1.31 billion and $1.27 billion, respectively, in net proceeds from the issuance of common units. During 2016, we had a net increase in our debt level of $1.76 billion compared to a net increase of $3.19 billion for 2015. We have paid distributions of $2.67 billion to our partners in 2016 compared to $2.25 billion in 2015. We have also paid distributions of $334 million to noncontrolling interests in 2016 compared to $247 million in 2015. In addition, we have received capital contributions of $187 million in cash from noncontrolling interests in 2016 compared to $583 million in 2015.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2016	December 31, 2015
ETP Senior Notes	$ 19,439	$ 19,439
Transwestern Senior Notes	782	782
Panhandle Senior Notes	1,085	1,085
Sunoco, Inc. Senior Notes	465	465
Sunoco Logistics Senior Notes	5,350	4,975
Bakken Term Note	1,100	—
Revolving credit facilities and commercial paper:		
ETP $3.75 billion Revolving Credit Facility due November 2019 (1)	1,584	1,362
Sunoco Logistics $2.50 billion Revolving Credit Facility due March 2020 (2)	622	562
Other long-term debt	32	32
Unamortized premiums, net of discounts and fair value adjustments	126	158
Deferred debt issuance costs	(187)	(181)
Total debt	30,398	28,679
Less: Current maturities of long-term debt	1,216	126
Long-term debt, less current maturities	$ 29,182	$ 28,553

(1) Includes $208 million of commercial paper outstanding at September 30, 2016.

(2) Includes $140 million of commercial paper product outstanding at September 30, 2016.

Credit Facilities and Commercial Paper

ETP Credit Facility

The ETP Credit Facility allows for borrowings of up to $3.75 billion and expires in November 2019. The indebtedness under the ETP Credit Facility is unsecured, is not guaranteed by any of the Partnership’s subsidiaries and has equal rights to holders of our current and future unsecured debt. In September 2016, the Partnership initiated a commercial paper program under the borrowing limits established by the $3.75 billion ETP Credit Facility. As of September 30, 2016, the ETP Credit Facility had $1.58 billion of outstanding borrowings, which included $208 million of commercial paper.

Sunoco Logistics Credit Facilities

Sunoco Logistics maintains a $2.50 billion unsecured revolving credit agreement (the “Sunoco Logistics Credit Facility”), which matures in March 2020. The Sunoco Logistics Credit Facility contains an accordion feature, under which the total aggregate commitment may be increased to $3.25 billion under certain conditions. As of September 30, 2016, the Sunoco Logistics Credit Facility had $622 million of outstanding borrowings, which included $140 million of commercial paper.

Sunoco Logistics Senior Notes

Sunoco Logistics had $175 million of 6.125% senior notes which matured and were repaid in May 2016, using borrowings under the $2.50 billion Sunoco Logistics Credit Facility.

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In July 2016, Sunoco Logistics issued $550 million aggregate principal amount of 3.90% senior notes due in July 2026. The net proceeds from this offering were used to repay outstanding credit facility borrowings and for general partnership purposes.

Bakken Financing

In August 2016, ETP, Sunoco Logistics and Phillips 66 announced the completion of the project-level financing of the Dakota Access Pipeline and Energy Transfer Crude Oil Pipeline projects (collectively, the “Bakken Pipeline”). The $2.50 billion credit facility is anticipated to provide substantially all of the remaining capital necessary to complete the projects. As of September 30, 2016, $1.10 billion was outstanding under this credit facility.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2016.

CASH DISTRIBUTIONS

Cash Distributions Paid by ETP

We expect to use substantially all of our cash provided by operating and financing activities from the Operating Companies to provide distributions to our Unitholders. Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash (as defined in our Partnership Agreement) for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

Following are distributions declared and/or paid by us subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 16, 2016	$1.0550
March 31, 2016	May 6, 2016	May 16, 2016	1.0550
June 30, 2016	August 8, 2016	August 15, 2016	1.0550
September 30, 2016	November 7, 2016	November 14, 2016	1.0550

The total amounts of distributions declared for the periods presented (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30,	
	2016	2015
Common Units held by public[(1)]	$1,607	$1,458
Common Units held by ETE	8	51
Class H Units held by ETE	263	186
General Partner interest held by ETE	24	23
Incentive distributions held by ETE	1,012	937
IDR relinquishments net of Class I Unit distributions	(271)	(83)
Total distributions declared to the partners of ETP	$2,643	$2,572

(1) Reflects the impact from Common Units issued in the Regency Merger.

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In July 2016, ETE agreed to relinquish an aggregate amount of $720 million in incentive distributions commencing with the quarter ended June 30, 2016 and ending with the quarter ending December 31, 2017, including a relinquishment of $85 million for the quarter ended September 30, 2016. In connection with the PennTex acquisition in November 2016, discussed in Note 2, ETE has agreed to a perpetual waiver of incentive distributions in the amount of $33 million annually.

ETE has also previously agreed to relinquish additional incentive distributions. In the aggregate, including relinquishment agreed to in July and November 2016, ETE has agreed to relinquish its right to the following amounts of incentive distributions in future periods, including distributions on Class I Units.

Year	Total
2016 (remainder)	$ 138
2017	626
2018	138
2019	128
Each year beyond 2019	33

Cash Distributions Paid by Sunoco Logistics

Sunoco Logistics is required by its partnership agreement to distribute all cash on hand at the end of each quarter, less appropriate reserves determined by its general partner.

Following are distributions declared and/or paid by Sunoco Logistics subsequent to December 31, 2015:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2015	February 8, 2016	February 12, 2016	$ 0.4790
March 31, 2016	May 9, 2016	May 13, 2016	0.4890
June 30, 2016	August 8, 2016	August 12, 2016	0.5000
September 30, 2016	November 9, 2016	November 14, 2016	0.5100

In connection with the acquisition from Vitol, Sunoco Logistics' general partner executed an amendment to its partnership agreement in September 2016 which provides for a reduction to the incentive distributions paid by Sunoco Logistics. The reductions will total $60 million over a two-year period, recognized ratably over eight quarters, beginning with the third quarter 2016 cash distribution. The incentive distribution reduction will reduce the incentive distributions that ETP receives from Sunoco Logistics, as well as the amount of distributions that ETP pays on its Class H units.

The total amounts of Sunoco Logistics distributions declared for the periods presented were as follows (all from Available Cash from Sunoco Logistics' operating surplus and are shown in the period with respect to which they relate):

	Nine Months Ended September 30, 2016	2015
Limited Partners:		
Common units held by public	$ 353	$ 245
Common units held by ETP	100	88
General Partner interest held by ETP	11	9
Incentive distributions held by ETP	289	198
IDR reduction	(8)	—
Total distributions declared	$ 745	$ 540

Cash Distributions Paid by PennTex

PennTex is required by its partnership agreement to distribute a minimum quarterly distribution of $0.2750 per unit at the end of each quarter. For the three months ended September 30, 2016, PennTex declared a quarterly distribution of

$0.2950 per unit to be paid on November 14, 2016 to unitholders of record as of November 7, 2016.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2015, in addition to the accompanying notes and management's discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed for the year ended December 31, 2015. Since December 31, 2015, there have been no material changes to our primary market risk exposures or how those exposures are managed.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values, including derivatives related to our consolidated subsidiaries, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power, barrels for natural gas liquids, crude and refined products and bushels for corn. Dollar amounts are presented in millions.

	September 30, 2016			December 31, 2015		
	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change	Notional Volume	Fair Value Asset (Liability)	Effect of Hypothetical 10% Change
Mark-to-Market Derivatives						
(Trading)						
Natural Gas (MMBtu):						
Fixed Swaps/Futures	1,262,500	$ —	$ —	(602,500)	$ (1)	$ —
Basis Swaps IFERC/NYMEX[1]	60,102,500	—	—	(31,240,000)	(1)	—
Power (Megawatt):						
Forwards	419,824	2	1	357,092	—	2
Futures	99,247	—	—	(109,791)	2	—
Options – Puts	(536,400)	1	—	260,534	—	—
Options – Calls	1,080,400	(2)	2	1,300,647	—	3
Crude (Bbls):						
Futures	(656,000)	—	5	(591,000)	4	3
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	4,762,500	1	—	(6,522,500)	—	—
Swing Swaps IFERC	13,072,500	—	2	71,340,000	(1)	—
Fixed Swaps/Futures	(35,962,500)	—	11	(14,380,000)	(1)	5
Forward Physical Contracts	(6,834,328)	1	2	21,922,484	4	5
Natural Gas Liquid (Bbls) – Forwards/Swaps	(13,519,200)	(29)	42	(8,146,800)	10	13
Refined Products (Bbls) – Futures	(1,970,000)	(9)	20	(993,000)	9	5
Corn (Bushels) – Futures	—	—	—	1,185,000	—	1
Fair Value Hedging Derivatives						
(Non-Trading)						
Natural Gas (MMBtu):						
Basis Swaps IFERC/NYMEX	(30,620,000)	(1)	—	(37,555,000)	—	—
Fixed Swaps/Futures	(30,620,000)	(12)	10	(37,555,000)	73	9

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash

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market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of September 30, 2016, we had $3.86 billion of floating rate debt outstanding. A hypothetical change of 100 basis points would result in a maximum potential change to interest expense of $39 million annually; however, our actual change in interest expense may be less in a given period due to interest rate floors included in our variable rate debt instruments. We manage a portion of our interest rate exposure by utilizing interest rate swaps, including forward-starting interest rate swaps to lock-in the rate on a portion of anticipated debt issuances.

The following table summarizes our interest rate swaps outstanding (dollars in millions), none of which are designated as hedges for accounting purposes:

Term	Type[1]	Notional Amount Outstanding September 30, 2016	Notional Amount Outstanding December 31, 2015
July 2016[2][4]	Forward-starting to pay a fixed rate of 3.80% and receive a floating rate	$ —	$ 200
July 2017[3][4]	Forward-starting to pay a fixed rate of 3.90% and receive a floating rate	500	300
July 2018[3]	Forward-starting to pay a fixed rate of 4.00% and receive a floating rate	200	200
December 2018	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.53%	1,200	1,200
March 2019	Pay a floating rate based on a 3-month LIBOR and receive a fixed rate of 1.42%	300	300
July 2019[3]	Forward-starting to pay a fixed rate of 3.25% and receive a floating rate	200	200

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward-starting swaps have terms of 10 and 30 years with a mandatory termination date the same as the effective date.

(3) Represents the effective date. These forward-starting swaps have terms of 30 years with a mandatory termination date the same as the effective date.

(4) ETP previously had outstanding forward starting interest rate swaps, which were scheduled to expire in July 2016, with a total notional value of $200 million. In June 2016, ETP extended the expiration of those swaps to July 2017.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on interest rate derivatives) of $253 million as of September 30, 2016. For the $1.50 billion of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows of $43 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, 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 SEC’s rules and forms.

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Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2016 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS
For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2015 and Note 10 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2016.
ITEM 1A. RISK FACTORS
There have been no material changes from the risk factors described in Part I, Item 1A in our Annual Report on Form 10-K for our previous fiscal year ended December 31, 2015. The following risk factor, which was previously included in our Form 10-K, has been included herein along with additional quantitative information with respect to the Partnership's revenues, in order to supplement the disclosures previously provided in the Form 10-K.
The profitability of certain activities in our natural gas gathering, processing, transportation and storage operations are largely dependent upon natural gas commodity prices, price spreads between two or more physical locations and market demand for natural gas and NGLs.
For a portion of the natural gas gathered on our systems, we purchase natural gas from producers at the wellhead and then gather and deliver the natural gas to pipelines where we typically resell the natural gas under various arrangements, including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices.
We also enter into percent-of-proceeds arrangements, keep-whole arrangements, and processing fee agreements pursuant to which we agree to gather and process natural gas received from the producers.
Under percent-of-proceeds arrangements, we generally sell the residue gas and NGLs at market prices and remit to the producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGL volumes to the producer and sell the volumes we keep to third parties at market prices. Under these arrangements, our revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have an adverse effect on our revenues and results of operations.
Under keep-whole arrangements, we generally sell the NGLs produced from our gathering and processing operations at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the Btu content of the natural gas, we must either purchase natural gas at market prices for return to producers or make a cash payment to producers equal to the value of this natural gas. Under these arrangements, our gross margins generally decrease when the price of natural gas increases relative to the price of NGLs.
When we process the gas for a fee under processing fee agreements, we may guarantee recoveries to the producer. If recoveries are less than those guaranteed to the producer, we may suffer a loss by having to supply liquids or its cash equivalent to keep the producer whole.
We also receive fees and retain gas in kind from our natural gas transportation and storage customers. Our fuel retention fees and the value of gas that we retain in kind are directly affected by changes in natural gas prices. Decreases in natural gas prices tend to decrease our fuel retention fees and the value of retained gas.
In addition, we receive revenue from our off-gas processing and fractionating system in south Louisiana primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenue is exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.
For our midstream segment, we generally analyze gross margin based on fee-based margin (which includes revenues from processing fee arrangements) and non fee-based margin (which includes gross margin earned on percent-of-proceeds and keep-whole arrangements). For the nine months ended September 30, 2016 and 2015, gross margin from our midstream segment totaled $1.35 billion of which fee-based revenues constituted 87% and 88%, respectively, and non fee-based margin constituted 13% and 12%, respectively. For the years ended December 31, 2015 and 2014, gross margin from our midstream segment totaled $1.81 billion and $1.93 billion, respectively, of

which fee-based revenues constituted 86% and 66%, respectively, and non fee-based margin constituted 14% and 34%, respectively. The amount of gross margin earned by our midstream segment from fee-based and non fee-based arrangements (individually and as a percentage of total revenues) will be impacted by the volumes associated with both types of arrangements, as well as commodity prices; therefore, the dollar amounts and the relative magnitude of gross

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margin from fee-based and non fee-based arrangements in future periods may be significantly different from results reported in previous periods.

Protests and legal actions against our Dakota Access pipeline project have caused construction delays and may further delay the completion of the pipeline project.

During the summer of 2016, individuals affiliated with, or sympathetic to, the Standing Rock Sioux Native American tribe (the “SRST”) began gathering near a construction site on our Dakota Access pipeline project in North Dakota to protest the development of the pipeline project. Some of the protesters eventually trespassed on to the construction site, tampered with equipment, and disrupted construction activity at the site. At this time, we are working with the various authorities to mitigate this unlawful protest. Dakota Access has the necessary permits and approvals to perform all work on the pipeline project, other than a small area under dispute as described below. In response to the protests, Dakota Access filed a lawsuit in federal court in North Dakota to restrain protestors from disrupting construction and also requested a temporary restraining order (“TRO”) against the Chairman of the SRST and the protestors. The U.S. District Court granted Dakota Access’s request for a TRO, and the defendants filed a motion to dismiss the case and dissolve the TRO. The Court later granted the defendants’ motions to dissolve the TRO. Dakota Access filed a response to the defendant’s motion to dismiss, and the Court has yet to rule. At this time, we cannot determine how long the protest will continue, how the legal action will be resolved, or the impact both may have on construction time. Additional protests or legal actions may arise in connection with our Dakota Access project or other projects. Trespass on to construction sites or our physical facilities, or other disruptions, could result in further damage to our assets, safety incidents, potential liability or project delays.

In July 2016, the U.S. Army Corps of Engineers (“USACE”) issued permits to Dakota Access consistent with environmental and historic preservation statutes for the pipeline to make two crossings of the Missouri River in North Dakota, including a crossing of the Missouri River at Lake Oahe. The USACE has also issued an easement to allow the crossing of land owned by the USACE adjacent to the Missouri River at one location, but has not issued an easement to allow the crossing of land owned by the USACE adjacent to Lake Oahe. The SRST filed a lawsuit in the U.S. District Court for the District of Columbia against the USACE challenging the legality of the permits issued for the construction of the Dakota Access pipeline across those waterways and claiming violations of the National Historic Preservation Act (“NHPA”). The SRST also sought a preliminary injunction to rescind the USACE permits while the case is pending. Dakota Access’ moved to intervene in the case and that motion was granted by the Court. The SRST has also sought an emergency TRO to stop construction on the pipeline project. After a hearing on the TRO, the parties agreed to voluntarily stop construction in the relevant geographic area until the Court ruled on the preliminary injunction. Three days later, on September 9, 2016, the Court denied SRST’s motion for a preliminary injunction. After that decision, the Department of the Army, the Department of Justice, and the Department of the Interior released a joint statement stating that the USACE would not grant the easement for the land adjacent to Lake Oahe until the federal departments completed a review of the SRST’s claims in its lawsuit with respect to the USACE’s compliance with certain federal statutes in connection with its activities related to the granting of the permits. The SRST appealed the denial of the preliminary injunction to the U.S. Court of Appeals for the D.C. Circuit and filed an emergency motion for an injunction pending the appeal to the U.S. District Court. The U.S. District Court denied SRST’s emergency motion for an injunction pending the appeal. The SRST filed an amended complaint and added claims based on treaties between the tribes and the United States and statues governing the use of government property. The appeal of the U.S. District Court’s September 9th denial of the SRST’s preliminary injunction is still pending.

In addition, the Cheyenne River Sioux and Yankton Sioux tribes have filed related lawsuits in an effort to prevent construction of the Dakota Access pipeline project.

While we believe that the review process by the federal departments has been completed and that the easement for the land adjacent to Lake Oahe will be granted in a timely manner, we cannot assure this outcome. Any significant delay in receiving this easement will delay the receipt of revenue from this project. In addition, any action or inaction by the federal departments may increase the cost of construction of the pipeline. We cannot determine when or how these lawsuits will be resolved or the impact they may have on the Dakota Access project.

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ITEM 6. EXHIBITS

The exhibits listed below are filed or furnished, as indicated, as part of this report:

Exhibit Number	Description
2.1	Contribution Agreement, dated October 24, 2016 by and among Energy Transfer Partners, L.P. and NGP X US Holdings, LP, PennTex Midstream Partners, LLC, MRD Midstream LLC, WHR Midstream LLC and certain individual investors and managers named therein (incorporated by reference to Exhibit 2.1 to the Registrant’s Form 8-K filed October 25, 2016).
2.2*	Membership Interest Purchase Agreement, dated as of August 2, 2016, by and between Bakken Holdings Company LLC and MarEn Bakken Company LLC.
3.1	Amendment No. 13 to the Second Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P., dated July 27, 2016 (incorporated by reference to Exhibit 3.1 to the Registrant’s Form 8-K filed August 2, 2016).
10.1	Form of Commercial Paper Dealer Agreement between Energy Transfer Partners, L.P., as Issuer, and the Dealer party thereto (incorporated by reference to Exhibit 99.1 to the Registrant’s Form 8-K filed August 22, 2016).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

** Furnished herewith.

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SIGNATURE

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.

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.,
its General Partner

By: Energy Transfer Partners, L.L.C.,
its General Partner

Date: November 9, 2016 By: /s/ A. Troy Sturrock
A. Troy Sturrock
Senior Vice President, Controller and Principal Accounting Officer
(duly authorized to sign on behalf of the registrant)