

TARGA RESOURCES CORP.

FORM 8-K (Current report filing)

Filed 08/03/17 for the Period Ending 08/03/17

Address	TARGA RESOURCES PARTNERS LP 1000 LOUISIANA STREET, SUITE 4300 HOUSTON, TX 77002
Telephone	713-584-1000
CIK	0001389170
Symbol	TRGP
SIC Code	4922 - Natural Gas Transmission
Industry	Oil & Gas Transportation Services
Sector	Energy
Fiscal Year	12/31

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

FORM 8-K

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

Date of Report (Date of earliest event reported):
August 3, 2017

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction
of incorporation or organization)

001-34991

(Commission
File Number)

20-3701075

(IRS Employer
Identification No.)

1000 Louisiana, Suite 4300

Houston, TX 77002

(Address of principal executive office and Zip Code)

(713) 584-1000

(Registrants' telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter). Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Item 2.02 Results of Operations and Financial Condition.

On August 3, 2017, Targa Resources Corp. (the "Company") issued a press release regarding its financial results for the three months ended June 30, 2017. A conference call to discuss these results is scheduled for 11:00 a.m. Eastern time (10:00 a.m. Central time) on Thursday, August 3, 2017. The conference call will be webcast live and a replay of the webcast will be available through the Investors section of the Company's web site

(<http://www.targaresources.com>). A copy of the earnings press release is furnished as Exhibit 99.1 to this report, which is hereby incorporated by reference into this Item 2.02.

The press release and accompanying schedules and/or the conference call discussions include the non-generally accepted accounting principles (“non-GAAP”) financial measures of distributable cash flow, gross margin, operating margin and adjusted EBITDA. The press release provides reconciliations of these non-GAAP financial measures to their most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles in the United States of America (“GAAP”). Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net cash provided by operating activities, net income (loss) or any other GAAP measure of liquidity or financial performance.

The information furnished pursuant to this Item 2.02, including Exhibit 99.1, shall not be deemed to be “filed” for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any filing under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit Number	Description
Exhibit 99.1	Targa Resources Corp. Press Release dated August 3, 2017.

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.

Targa Resources Corp.

Date: August 3, 2017

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
Exhibit 99.1	Targa Resources Corp. Press Release dated August 3, 2017.



1000 Louisiana, Suite 4300
Houston, TX 77002
713.584.1000
www.targaresources.com

**Targa Resources Corp. Reports
Second Quarter 2017 Financial Results**

HOUSTON – August 3, 2017 - Targa Resources Corp. (NYSE: TRGP) (“TRC”, the “Company” or “Targa”) today reported second quarter 2017 results.

Second Quarter 2017 Financial Results

Second quarter 2017 net income attributable to Targa Resources Corp. was \$57.6 million compared to a net loss of (\$23.2) million for the second quarter of 2016.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items (“Adjusted EBITDA”) of \$257.9 million for the second quarter of 2017 compared to \$257.1 million for the second quarter of 2016 (see the section of this release entitled “Targa Resources Corp. - Non-GAAP Financial Measures” for a discussion of Adjusted EBITDA, distributable cash flow, gross margin and operating margin, and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles (“GAAP”)).

“Our second quarter financial results were in-line with our expectations, and we are confident that our financial performance will meet or exceed our full year 2017 financial expectations,” said Joe Bob Perkins, Chief Executive Officer of the Company. “A pivotal development during the quarter was our announcement to move forward with a 300 thousand barrel per day common carrier NGL Pipeline from the Permian Basin to Mont Belvieu (“Grand Prix”), which is expected to commence operation in the second quarter of 2019. Grand Prix will connect our expansive and growing Permian Basin footprint to our downstream assets at Mont Belvieu. Today, we have approximately 1.7 billion cubic feet per day of processing capacity in the Permian Basin, with another 710 million cubic feet per day under construction that will come online by the third quarter of 2018. Our strong long-term outlook beyond 2017 is supported by our visibility around activity levels and projects coming online, including our Gathering and Processing projects, the addition of Grand Prix and other opportunities in our Downstream segment.”

On July 19, 2017, TRC declared a quarterly dividend of \$0.91 per share of its common stock for the three months ended June 30, 2017, or \$3.64 per share on an annualized basis. Total cash dividends of approximately \$196.2 million will be paid on August 15, 2017 on all outstanding shares of common stock to holders of record as of the close of business on August 1, 2017. Also on July 19, 2017, TRC declared a quarterly cash dividend of \$23.75 per share of its Series A Preferred Stock. Total cash dividends of approximately \$22.9 million will be paid on August 14, 2017 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on August 1, 2017.

The Company reported distributable cash flow for the second quarter of 2017 of \$196.0 million compared to total common dividends to be paid of \$196.2 million and total Series A Preferred Stock dividends to be paid of \$22.9 million.

Second Quarter 2017 - Capitalization, Liquidity and Financing

Targa’s total consolidated debt as of June 30, 2017 was \$4,437.6 million including \$435.0 million outstanding under TRC’s \$670.0 million senior secured revolving credit facility due 2020. The consolidated debt included \$4,002.6 million of Targa Resource Partners LP (“TRP” or “the Partnership”) debt, net of \$25.9 million of debt issuance costs, with no amounts outstanding under TRP’s \$1.6 billion senior secured revolving credit facility due 2020, \$250.0 million outstanding under TRP’s accounts receivable securitization facility and \$3,778.5 million of outstanding TRP senior notes, net of unamortized premiums. In June 2017, the Partnership redeemed its outstanding 6³/₈% Senior Notes due August 2022 (“6³/₈% Senior Notes”), totaling \$278.7 million in aggregate principal amount, at a price of 103.188% plus accrued interest through the redemption date.

As of June 30, 2017, TRC had available senior secured revolving credit facility capacity of \$235.0 million. TRP had no borrowings outstanding under its \$1.6 billion senior secured revolving credit facility and \$20.4 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of \$1,579.6 million at the Partnership. Total Targa consolidated liquidity as of June 30, 2017, including \$98.7 million of cash, was approximately \$1.9 billion.

On June 1, 2017, TRC completed a public offering of 17,000,000 shares of its common stock at a price to the public of \$46.10, providing net proceeds after underwriting discounts, commissions and other expenses of \$777.3 million. Targa used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of Grand Prix, repay outstanding borrowings under its credit facilities, redeem the Partnership's 6% Senior Notes, and for general corporate purposes.

2017 Forecasted Capital Expenditures Update

In May 2017, Targa announced plans to construct a new common carrier NGL pipeline, Grand Prix, which will transport volumes from the Permian Basin, and also from its North Texas system, to its fractionation and storage complex in the NGL market hub at Mont Belvieu. Grand Prix will be supported by Targa plant volumes and other third party customer commitments, and is expected to be in service in the second quarter of 2019. The initial capacity of the pipeline from the Permian Basin will be approximately 300 MBbl/d and will be expandable to 550 MBbl/d with the addition of pump stations. The total net growth capital expenditures for Grand Prix are expected to be approximately \$1.3 billion, with approximately \$330 million of spending in 2017.

Including spending related to Grand Prix and additional growth capital to support increasing activity levels around the Company's assets, Targa now expects 2017 net growth capital expenditures for announced projects will be approximately \$1,375.0 million, an increase from the previously disclosed \$1,210.0 million. Targa continues to expect that 2017 net maintenance capital expenditures will be approximately \$110.0 million.

Conference Call

The Company will host a conference call for the investment community at 11:00 a.m. Eastern time (10:00 a.m. Central time) on August 3, 2017 to discuss second quarter 2017 results. The conference call can be accessed via webcast through the Events and Presentations section of Targa's website at www.targaresources.com, by going directly to <http://ir.targaresources.com/trc/events.cfm> or by dialing 877-881-2598. The conference ID number for the dial-in is 56475709. Please dial in ten minutes prior to the scheduled start time. A replay will be available approximately two hours following the completion of the webcast through the Investors section of the Company's website. Presentation slides will also be available in the Events and Presentations section of the Company's website, or directly at <http://ir.targaresources.com/trc/events.cfm>.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended June 30,		2017 vs. 2016		Six Months Ended June 30,		2017 vs. 2016	
	2017	2016			2017	2016		
(In millions, except operating statistics and price amounts)								
Revenues								
Sales of commodities	\$ 1,623.8	\$ 1,312.9	\$ 310.9	24%	\$ 3,481.7	\$ 2,484.0	\$ 997.7	40%
Fees from midstream services	243.9	270.7	(26.8)	(10%)	498.6	542.0	(43.4)	(8%)
Total revenues	1,867.7	1,583.6	284.1	18%	3,980.3	3,026.0	954.3	32%
Product purchases	1,420.6	1,145.2	275.4	24%	3,074.8	2,156.2	918.6	43%
Gross margin (1)	447.1	438.4	8.7	2%	905.5	869.8	35.7	4%
Operating expenses	155.2	138.9	16.3	12%	307.2	271.0	36.2	13%
Operating margin (1)	291.9	299.5	(7.6)	(3%)	598.3	598.8	(0.5)	—
Depreciation and amortization expense	203.4	186.1	17.3	9%	394.6	379.6	15.0	4%
General and administrative expense	51.0	47.0	4.0	9%	99.6	92.2	7.4	8%
Goodwill impairment	—	—	—	—	—	24.0	(24.0)	(100%)
Other operating (income) expense	0.3	0.1	0.2	200%	16.5	1.1	15.4	NM
Income from operations	37.2	66.3	(29.1)	(44%)	87.6	101.9	(14.3)	(14%)
Interest expense, net	(62.1)	(71.4)	9.3	13%	(125.1)	(124.3)	(0.8)	1%
Equity earnings (loss)	(4.2)	(4.4)	0.2	5%	(16.8)	(9.2)	(7.6)	83%
Gain (loss) from financing activities	(10.7)	(3.3)	(7.4)	224%	(16.5)	21.4	(37.9)	(177%)
Other income (expense), net	4.4	(0.1)	4.5	NM	(4.0)	(0.2)	(3.8)	NM
Income tax (expense) benefit	106.0	(1.7)	107.7	NM	34.9	(4.8)	39.7	NM
Net income (loss)	70.6	(14.6)	85.2	NM	(39.9)	(15.2)	(24.7)	163%
Less: Net income attributable to noncontrolling interests	13.0	8.6	4.4	51%	21.8	10.7	11.1	104%
Net income (loss) attributable to Targa Resources Corp.	57.6	(23.2)	80.8	NM	(61.7)	(25.9)	(35.8)	138%
Dividends on Series A preferred stock	22.9	22.9	—	—	45.8	26.7	19.1	72%
Deemed dividends on Series A preferred stock	6.3	6.5	(0.2)	(3%)	12.5	6.5	6.0	92%
Net income (loss) attributable to common shareholders	\$ 28.4	\$ (52.6)	\$ 81.0	154%	\$ (120.0)	\$ (59.1)	\$ (60.9)	103%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	\$ 257.9	\$ 257.1	\$ 0.8	—	\$ 534.6	\$ 521.8	\$ 12.8	2%
Distributable cash flow (1)	196.0	169.6	26.4	16%	390.2	347.6	42.6	12%
Capital expenditures	434.5	114.9	319.6	278%	609.1	291.8	317.3	109%
Business acquisition (2)	—	—	—	—	987.1	—	987.1	—
Operating statistics: (3)								
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7%	113.0	106.6	6.4	6%
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Plant natural gas inlet, MMcf/d (5) (6)	3,391.2	3,511.4	(120.2)	(3%)	3,304.6	3,452.1	(147.5)	(4%)
Gross NGL production, MBbl/d	321.2	321.0	0.2	—	305.0	302.8	2.2	1%
Export volumes, MBbl/d (7)	155.3	181.3	(26.0)	(14%)	186.2	181.2	5.0	3%
Natural gas sales, BBtu/d (6) (8)	1,957.3	1,958.4	(1.1)	—	1,885.7	1,966.5	(80.8)	(4%)
NGL sales, MBbl/d (8)	473.9	516.8	(42.9)	(8%)	503.6	532.3	(28.7)	(5%)
Condensate sales, MBbl/d	12.1	11.4	0.7	6%	11.5	10.4	1.1	11%

(1) Gross margin, operating margin, adjusted EBITDA, and distributable cash flow are non-GAAP financial measures and are discussed under “Targa Resources Corp. – Non-GAAP Financial Measures.”

(2) Includes the preliminary acquisition date fair value of the potential earn-out payments of \$416.3 million due in 2018 and 2019.

(3) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.

(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.

- (6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
 (7) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine Terminal that are destined for international markets.
 (8) Includes the impact of intersegment eliminations.
 NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The increase in commodity sales was primarily due to higher commodity prices (\$386.8 million) and higher petroleum products and condensate volumes (\$13.7 million), partially offset by decreased NGL sales volumes (\$77.0 million) and the impact of hedge settlements (\$12.6 million). Fee-based and other revenues decreased primarily due to lower export fees and volumes, partially offset by higher crude gathering and gas processing fees.

The increase in product purchases was primarily due to the impact of higher commodity prices, partially offset by decreased volumes.

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin decreased as the increases in operating expenses more than offset the increases in gross margin. Operating expenses increased compared to 2016 due to higher fuel and power and higher maintenance in the Logistics and Marketing segment and the impact of the Permian Acquisition and other plant and system expansions in the Gathering and Processing segment. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expense reflects the impact of the Permian Acquisition and other growth investments, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

Net interest expense decreased primarily due to the impact of lower average outstanding borrowings during 2017.

During 2017, the Company recorded a loss from financing activities of \$10.7 million on the redemption of the outstanding 6% Senior Notes, whereas in 2016 the Company recorded a loss of \$3.3 million on open market debt repurchases.

The income tax benefit for the three months ended June 30, 2017 is the result of the difference between the annual effective tax rate used to calculate income tax (expense) benefit for the three months ended March 31, 2017 and the statutory rate used to calculate income tax (expense) benefit for the six months ended June 30, 2017. For additional discussion of the basis for the calculation of the income tax benefit for the six months ended June 30, 2017, see the income tax explanation under the Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.

Net income attributable to noncontrolling interests was higher in 2017 due to increased earnings at our joint ventures as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in commodity sales was primarily due to higher commodity prices (\$1,148.6 million) and higher petroleum products and condensate volumes (\$18.3 million), partially offset by decreased NGL and natural gas sales volumes (\$131.1 million) and the impact of hedge settlements (\$38.1 million). Fee-based and other revenues decreased primarily due to lower export fees.

The increase in product purchases was primarily due to the impact of higher commodity prices, partially offset by decreased volumes.

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin was relatively flat as compared to 2016 as the increases in gross margin were offset by the increases in operating expenses. Operating expenses increased compared to 2016 due to higher maintenance, higher fuel and power, and higher labor in the Logistics and Marketing segment and plant and system expansions. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expense reflects four months of operations from the Permian Acquisition in 2017 and the impact of other growth investments, primarily CBF Train 5 which went into service in the second quarter of 2016, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

The Company recognized an impairment of goodwill in the first quarter of 2016 of \$24.0 million to finalize the 2015 provisional impairment of goodwill. The impairment charge related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively, the “Atlas mergers”).

Other operating (income) expense in 2017 includes the loss due to the reduction in the carrying value of the Company’s ownership interest in the Venice Gathering System in connection with the April 4, 2017 sale.

Net interest expense in 2017 was flat as compared with 2016. Higher non-cash interest expense related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date was offset by lower average outstanding borrowings during 2017.

Higher equity losses in 2017 reflects a \$12.0 million loss provision due to the impairment of the Company’s investment in the T2 EF Cogen joint venture, partially offset by increased equity earnings at Gulf Coast Fractionators.

During 2017, the Company recorded a loss from financing activities of \$16.5 million on the redemption of the outstanding 6½% Senior Notes and the repayment of the outstanding balance on the Company’s senior secured term loan, whereas in 2016 the Company recorded a gain of \$21.4 million on open market debt repurchases.

The Company has historically calculated the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to ordinary income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period. When calculating the annual estimated effective income tax rate for the six months ended June 30, 2017, the Company was subject to a loss limitation rule because the year-to-date ordinary loss exceeded the full-year expected ordinary loss. The tax benefit for that year-to-date ordinary loss was limited to the amount that would be recognized if the year-to-date ordinary loss were the anticipated ordinary loss for the full year. This requires the Company to use its statutory rate of 37.3% rather than the annual estimated effective tax rate to calculate the benefit for the period.

Net income attributable to noncontrolling interests was higher in 2017 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for a portion of the first quarter 2016, and the Company’s October 2016 acquisition of the 37% interest of Versado that they did not already own. Further, earnings at the Company’s joint ventures increased as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. Preferred dividends increased as the Series A Preferred Stock was outstanding for two full quarters in 2017, as compared to a portion of 2016.

Review of Segment Performance

The following discussion of segment performance includes inter-segment activities. The Company views segment operating margin as an important performance measure of the core profitability of its operations. This measure is a key component of internal financial reporting and is reviewed for consistency and trend analysis. For a discussion of operating margin, see “Targa Resources Corp. - Non-GAAP Financial Measures - Operating Margin.” Segment operating financial results and operating statistics include the effects of intersegment transactions. These intersegment transactions have been eliminated from the consolidated presentation.

The Company operates in two primary segments: (i) Gathering and Processing; and (ii) Logistics and Marketing.

Gathering and Processing Segment

The Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment’s assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

The following table provides summary data regarding results of operations of this segment for the periods indicated:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
Gross margin	\$ 264.2	\$ 222.4	\$ 41.8	19%	\$ 527.4	\$ 416.5	\$ 110.9	27%
Operating expenses	90.7	83.3	7.4	9%	176.3	161.8	14.5	9%
Operating margin	\$ 173.5	\$ 139.1	\$ 34.4	25%	\$ 351.1	\$ 254.7	\$ 96.4	38%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2), (3)								
SAOU (4)	311.6	259.2	52.4	20%	293.7	251.3	42.4	17%
WestTX	541.6	481.4	60.2	13%	526.5	464.7	61.8	13%
Total Permian Midland	853.2	740.6	112.6		820.2	716.0	104.2	
Sand Hills (4)	181.7	135.8	45.9	34%	160.7	143.4	17.3	12%
Versado	196.5	168.8	27.7	16%	197.5	174.4	23.1	13%
Total Permian Delaware	378.2	304.6	73.6		358.2	317.8	40.4	
Total Permian	1,231.4	1,045.2	186.2		1,178.4	1,033.8	144.6	
SouthTX	222.6	265.4	(42.8)	(16%)	197.4	220.5	(23.1)	(10%)
North Texas	277.1	327.5	(50.4)	(15%)	279.8	327.5	(47.7)	(15%)
SouthOK	479.0	470.7	8.3	2%	459.8	464.3	(4.5)	(1%)
WestOK	387.4	445.6	(58.2)	(13%)	390.3	466.3	(76.0)	(16%)
Total Central	1,366.1	1,509.2	(143.1)		1,327.3	1,478.6	(151.3)	
Badlands (5)	52.2	51.2	1.0	2%	49.1	52.5	(3.4)	(6%)
Total Field	2,649.7	2,605.6	44.1		2,554.8	2,564.9	(10.1)	
Coastal	741.6	905.8	(164.2)	(18%)	749.9	887.2	(137.3)	(15%)
Total	3,391.3	3,511.4	(120.1)	(3%)	3,304.7	3,452.1	(147.4)	(4%)
Gross NGL production, MBbl/d (3)								
SAOU (4)	37.9	32.2	5.7	18%	35.6	30.7	4.9	16%
WestTX	74.9	61.9	13.0	21%	70.7	57.2	13.5	24%
Total Permian Midland	112.8	94.1	18.7		106.3	87.9	18.4	
Sand Hills (4)	20.0	14.1	5.9	42%	17.4	14.9	2.5	17%
Versado	22.9	20.2	2.7	13%	23.0	21.1	1.9	9%
Total Permian Delaware	42.9	34.3	8.6		40.4	36.0	4.4	
Total Permian	155.7	128.4	27.3		146.7	123.9	22.8	
SouthTX	23.5	31.4	(7.9)	(25%)	20.1	27.3	(7.2)	(26%)
North Texas	31.1	37.0	(5.9)	(16%)	31.5	36.3	(4.8)	(13%)
SouthOK	38.5	47.3	(8.8)	(19%)	39.7	37.6	2.1	6%
WestOK	23.5	29.7	(6.2)	(21%)	23.1	28.3	(5.2)	(18%)
Total Central	116.6	145.4	(28.8)		114.4	129.5	(15.1)	
Badlands	7.7	7.0	0.7	10%	6.6	7.3	(0.7)	(10%)
Total Field	280.0	280.8	(0.8)		267.7	260.7	7.0	
Coastal	41.2	40.1	1.1	3%	37.3	42.2	(4.9)	(12%)
Total	321.2	320.9	0.3	—	305.0	302.9	2.1	1%
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7%	113.0	106.6	6.4	6%
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Natural gas sales, BBtu/d (3)	1,655.2	1,605.8	49.6	3%	1,601.6	1,646.5	(44.9)	(3%)
NGL sales, MBbl/d	249.2	256.1	(6.9)	(3%)	238.4	237.7	0.7	—
Condensate sales, MBbl/d	12.1	10.9	1.3	12%	11.4	10.2	1.3	13%
Average realized prices (6):								
Natural gas, \$/MMBtu	2.70	1.64	1.06	65%	2.79	1.70	1.09	64%
NGL, \$/gal	0.46	0.36	0.10	28%	0.48	0.32	0.16	50%
Condensate, \$/Bbl	42.74	37.94	4.81	13%	43.79	32.21	11.58	36%

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- (1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
 - (2) Plant natural gas inlet represents the Company's undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than the Badlands.
 - (3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.
 - (4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.
 - (5) Badlands natural gas inlet represents the total wellhead gathered volume.
 - (6) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Inlet volumes for Field Gathering and Processing were higher primarily due to increases at WestTX, SAOU, Sand Hills and Versado, partially offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins, more than offset the Field Gathering and Processing inlet volume increase. Higher NGL production in the Permian region was more than offset by lower NGL production in the other areas. Natural gas sales increased primarily due to increased Field Gathering and Processing inlet volumes. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total Badlands crude oil gathered volumes and natural gas volumes increased primarily due to system expansions.

The increase in operating expenses was primarily driven by the inclusion of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Field Gathering and Processing inlet volume increases in the Permian region, specifically at WestTX, SAOU, Versado and Sand Hills, were offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins than does Field Gathering and Processing, accounted for over 93% of the overall inlet volume decrease. Despite overall lower inlet volumes, NGL production and NGL sales increased slightly primarily due to increased plant recoveries including additional ethane recovery. Natural gas sales decreased due to lower inlet volumes and increased ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total crude oil gathered in the Badlands increased due to system expansions. Badlands natural gas volumes decreased primarily due to the impact of the severe winter weather in the first quarter of 2017.

The increase in operating expenses was primarily driven by plant and system expansions in the Permian region, the inclusion of the Permian Acquisition and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

Gross Operating Statistics Compared to Actual Reported

The table below provides a reconciliation between gross operating statistics and the actual reported operating statistics for the Field portion of the Gathering and Processing segment:

Three Months Ended June 30, 2017

Operating statistics:

Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	311.6	100%	311.6	311.6
WestTX (5) (6)	743.9	73%	541.6	541.6
Total Permian Midland	1,055.5		853.2	853.2
Sand Hills (4)	181.7	100%	181.7	181.7
Versado (7)	196.5	100%	196.5	196.5
Total Permian Delaware	378.2		378.2	378.2
Total Permian	1,433.7		1,231.4	1,231.4
SouthTX	222.6	Varies (8) (9)	199.1	222.6
North Texas	277.1	100%	277.1	277.1
SouthOK	479.0	Varies (10)	382.6	479.0
WestOK	387.4	100%	387.4	387.4
Total Central	1,366.1		1,246.2	1,366.1
Badlands (11)	52.2	100%	52.2	52.2
Total Field	2,852.0		2,529.8	2,649.7
Gross NGL production, MBbl/d (2)				
SAOU (4)	37.9	100%	37.9	37.9
WestTX (5) (6)	102.9	73%	74.9	74.9
Total Permian Midland	140.8		112.8	112.8
Sand Hills (4)	20.0	100%	20.0	20.0
Versado (7)	22.9	100%	22.9	22.9
Total Permian Delaware	42.9		42.9	42.9
Total Permian	183.7		155.7	155.7
SouthTX	23.5	Varies (8) (9)	20.8	23.5
North Texas	31.1	100%	31.1	31.1
SouthOK	38.5	Varies (10)	31.4	38.5
WestOK	23.5	100%	23.5	23.5
Total Central	116.6		106.8	116.6
Badlands	7.7	100%	7.7	7.7
Total Field	308.0		270.2	280.0

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.

(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills.

(5) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.

(6) Includes the Buffalo Plant that commenced commercial operations in April 2016.

(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials. The Company held a 63% interest in Versado until October 31, 2016, when the Company acquired the remaining 37% interest.

(8) SouthTX includes the Silver Oak II Plant, of which Targa owned a 90% interest from October 2015 through May 2017, and after which Targa owns a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

(9) SouthTX also includes the Raptor Plant, which began operations in the second quarter of 2017, of which the Company owns a 50% interest through the Carnero Processing Joint Venture. The Carnero Processing Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

(10) SouthOK includes the Centrahoma Joint Venture, of which Targa owns 60%, and other plants which are owned 100% by Targa. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

(11) Badlands natural gas inlet represents the total wellhead gathered volume.

Three Months Ended June 30, 2016

Operating statistics:

Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU	259.2	100%	259.2	259.2
WestTX (4)	661.2	73%	481.4	481.4
Total Permian Midland	920.4		740.6	740.6
Sand Hills	135.8	100%	135.8	135.8
Versado (5)	168.8	63%	106.3	168.8
Total Permian Delaware	304.6		242.1	304.6
Total Permian	1,225.0		982.7	1,045.2
SouthTX	265.4	Varies (6)	251.9	265.4
North Texas	327.5	100%	327.5	327.5
SouthOK	470.7	Varies (7)	393.7	470.7
WestOK	445.6	100%	445.6	445.6
Total Central	1,509.2		1,418.7	1,509.2
Badlands (8)	51.2	100%	51.2	51.2
Total Field	2,785.4		2,452.6	2,605.6
Gross NGL production, MBbl/d (2)				
SAOU	32.2	100%	32.2	32.2
WestTX (4)	85.0	73%	61.9	61.9
Total Permian Midland	117.2		94.1	94.1
Sand Hills	14.1	100%	14.1	14.1
Versado (5)	20.2	63%	12.7	20.2
Total Permian Delaware	34.3		26.8	34.3
Total Permian	151.5		120.9	128.4
SouthTX	31.4	Varies (6)	30.2	31.4
North Texas	37.0	100%	37.0	37.0
SouthOK	47.3	Varies (7)	44.0	47.3
WestOK	29.7	100%	29.7	29.7
Total Central	145.4		140.9	145.4
Badlands	7.0	100%	7.0	7.0
Total Field	303.9		268.8	280.8

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.

(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

(4) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.

(5) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials. The Company held a 63% interest in Versado until October 31, 2016, when the Company acquired the remaining 37% interest.

(6) SouthTX includes the Silver Oak II Plant, of which Targa owned a 90% interest from October 2015 through May 2017, and after which Targa owns a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

(7) SouthOK includes the Centrahoma Joint Venture, of which Targa owns 60%, and other plants which are owned 100% by Targa. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

(8) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

The Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of Targa's other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of the Company's other operations, as well as transporting natural gas and NGLs.

Logistics and Marketing operations are generally connected to and supplied in part by the Company's Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

The following table provides summary data regarding results of operations of this segment for the periods indicated:

	Three Months Ended June 30,			Six Months Ended June 30,				
	2017	2016	2017 vs. 2016	2017	2016	2017 vs. 2016		
	(In millions)							
Gross margin	\$ 176.9	\$ 197.6	\$ (20.7)	(10%)	\$ 373.2	\$ 407.9	\$ (34.7)	(9%)
Operating expenses	64.5	55.8	8.7	16%	130.8	109.4	21.4	20%
Operating margin	<u>\$ 112.4</u>	<u>\$ 141.8</u>	<u>\$ (29.4)</u>	(21%)	<u>\$ 242.4</u>	<u>\$ 298.5</u>	<u>\$ (56.1)</u>	(19%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	338.5	329.8	8.7	3%	321.8	312.7	9.1	3%
LSNG treating volumes (2)	33.3	23.1	10.2	44%	33.9	22.0	11.9	54%
Benzene treating volumes (2)	22.1	23.1	(1.0)	(4%)	22.8	22.0	0.8	4%
Export volumes, MBbl/d (4)	155.3	181.3	(26.0)	(14%)	186.2	181.2	5.0	3%
NGL sales, MBbl/d	439.4	463.6	(24.2)	(5%)	470.5	472.8	(2.3)	—
Average realized prices:								
NGL realized price, \$/gal	\$ 0.58	\$ 0.48	\$ 0.10	21%	\$ 0.62	\$ 0.44	\$ 0.18	41%

- (1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the period and the denominator is the number of calendar days during the period.
- (2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
- (3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
- (4) Export volumes represent the quantity of NGL products delivered to third-party customers at Targa's Galena Park Marine Terminal that are destined for international markets.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Logistics and Marketing gross margin decreased due to lower LPG export margin partially offset by higher fractionation margin, higher terminaling and storage throughput, and higher treating margin. LPG export margin decreased due to lower fees and volumes. Fractionation margin increased due to higher fees, an increase in system product gains and higher supply volume. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Treating margin increased slightly due to higher volumes partially offset by lower fees.

Operating expenses increased primarily due to higher fuel and power, which are largely passed through, and higher labor primarily associated with Train 5.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The six month gross margin results were impacted by the same factors as discussed above for the quarter except that LPG export volumes were higher.

Operating expenses increased primarily due to higher fuel and power, which are largely passed through, higher maintenance associated with unusual one-time events in the first quarter of 2017, and higher labor associated with Train 5.

Other

	Three Months Ended June 30,			Six Months Ended June 30,				
	2017	2016	2017 vs. 2016	2017	2016	2017 vs. 2016		
	(In millions)							
Gross margin	\$ 6.0	\$ 18.6	\$ (12.6)	\$ 4.9	\$ 45.7	\$ (40.8)		
Operating margin	<u>\$ 6.0</u>	<u>\$ 18.6</u>	<u>\$ (12.6)</u>	<u>\$ 4.9</u>	<u>\$ 45.7</u>	<u>\$ (40.8)</u>		

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. The primary purpose of the Company's commodity risk management activities is to mitigate a portion of the impact of commodity prices on the Company's operating cash flow. The Company has entered into derivative instruments to hedge the commodity price associated with a portion of the Company's expected natural gas, NGL and condensate equity volumes in the Company's Gathering and Processing Operations that result from percent of proceeds/liquids processing arrangements. Because the Company is essentially forward-selling a portion of its future plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

The following table provides a breakdown of the change in Other operating margin:

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016			2017 vs. 2016
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	
Natural gas (BBtu)	15.5	\$ 0.16	\$ 2.5	10.7	\$ 1.27	\$ 13.6	\$ (11.1)
NGL (MMgal)	59.4	0.01	0.8	13.1	0.09	1.0	(0.2)
Crude oil (MBbl)	0.3	6.93	2.3	0.3	15.72	4.4	(2.1)
Non-hedge accounting (2)			0.4			(0.1)	0.5
Ineffectiveness (3)			-			(0.3)	0.3
			\$ 6.0			\$ 18.6	\$ (12.6)

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016			2017 vs. 2016
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	
Natural gas (BBtu)	26.0	\$ 0.09	\$ 2.6	20.2	\$ 1.33	\$ 26.9	\$ (24.3)
NGL (MMgal)	102.7	(0.01)	(1.1)	27.3	0.18	5.0	(6.1)
Crude oil (MBbl)	0.6	6.29	3.5	0.5	23.82	11.5	(8.0)
Non-hedge accounting (2)			(0.3)			2.6	(2.9)
Ineffectiveness (3)			0.2			(0.3)	0.5
			\$ 4.9			\$ 45.7	\$ (40.8)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.

(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

(3) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of Targa Pipeline Partners, L.P. ("TPL") that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of \$102.1 million as of February 27, 2015 (the "acquisition date"), were novated to the Company and included in the acquisition date fair value of assets acquired. The Company received derivative settlements of \$1.9 million and \$4.9 million for the three and six months ended June 30, 2017 and \$6.3 million and \$15.1 million for the three and six months ended June 30, 2016, related to these novated contracts. From the acquisition date through June 30, 2017, the Company has received total derivative settlements of \$99.5 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

About Targa Resources Corp.

Targa Resources Corp. is a leading provider of midstream services and is one of the largest independent midstream energy companies in North America. Targa owns, operates, acquires, and develops a diversified portfolio of complementary midstream energy assets. The Company is primarily engaged in the business of: gathering, compressing, treating, processing, and selling natural gas; storing, fractionating, treating, transporting, and selling NGLs and NGL products, including services to LPG exporters; gathering, storing, and terminaling crude oil; and storing, terminaling, and selling refined petroleum products.

For more information, please visit our website at www.targaresources.com.

Targa Resources Corp. - Non-GAAP Financial Measures

This press release includes the Company's non-GAAP financial measures Adjusted EBITDA, distributable cash flow, gross margin and operating margin. The tables below provide reconciliations of these non-GAAP financial measures to their most directly comparable GAAP measures. The Company's non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, net cash flows provided by operating activities or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA

The Company defines Adjusted EBITDA as net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015; non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment (explained below); net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by the Company and by external users of the Company's financial statements such as investors, commercial banks and others. The economic substance behind the Company's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and pay dividends to its investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRC. Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool. Investors should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in the Company's industry, the Company's definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Distributable Cash Flow

The Company defines distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustment (explained below), cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items.

Distributable cash flow is a significant performance metric used by the Company and by external users of the Company's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Company (prior to the establishment of any retained cash reserves by our board of directors) to the cash dividends the Company expects to pay its shareholders. Using this metric, management and external users of the Company's financial statements can quickly compute the coverage ratio of estimated cash flows to cash dividends. Distributable cash flow is also an important financial measure for the Company's shareholders since it serves as an indicator of the Company's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Company is generating cash flow at a level that can sustain or support an increase in its quarterly dividend rates.

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income (loss) attributable to TRC. Distributable cash flow should not be considered as an alternative to GAAP net income (loss) available to common and preferred shareholders. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in the Company's industry, the Company's definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

The following table presents a reconciliation of net income of the Company to Adjusted EBITDA and Distributable Cash Flow for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(In millions)				
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	\$ 57.6	\$ (23.2)	\$ (61.7)	\$ (25.9)
Impact of TRC/TRP Merger on NCI	—	—	—	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8	5.6	5.6
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
Depreciation and amortization expense	203.4	186.1	394.6	379.6
Goodwill impairment	—	—	—	24.0
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
(Earnings) loss from unconsolidated affiliates	4.2	4.4	16.8	9.2
Distributions from unconsolidated affiliates and preferred partner interests, net	6.2	3.0	10.4	8.8
Change in contingent consideration included in Other expense	(2.1)	—	1.2	—
Compensation on equity grants	10.7	7.2	21.5	15.2
Transaction costs related to business acquisitions	0.1	—	5.2	—
Splitter Agreement (1)	10.8	—	21.5	—
Risk management activities	1.6	6.6	5.2	12.6
Noncontrolling interests adjustments (2)	(4.3)	(6.2)	(8.6)	(12.1)
TRC Adjusted EBITDA	\$ 257.9	\$ 257.1	\$ 534.6	\$ 521.8
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(5.6)	(5.6)
Splitter Agreement (1)	(10.8)	—	(21.5)	—
Interest expense on debt obligations (3)	(56.6)	(65.9)	(115.5)	(135.6)
Cash tax (expense) benefit (4)	31.4	—	46.7	—
Maintenance capital expenditures	(23.3)	(20.2)	(49.0)	(35.2)
Noncontrolling interests adjustments of maintenance capex	0.2	1.4	0.5	2.2
Distributable Cash Flow	\$ 196.0	\$ 169.6	\$ 390.2	\$ 347.6

(1) In Adjusted EBITDA, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the condensate splitter agreement (the "Splitter Agreement") between Targa Terminals, LLC and Noble Americas Corp., a subsidiary of Noble Group, Ltd., over the four quarters following receipt. In Distributable Cash Flow, the Splitter Agreement adjustment represents the amounts necessary to reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.

(2) Noncontrolling interest portion of depreciation and amortization expense.

(3) Excludes amortization of interest expense.

(4) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is being recognized over the periods between the Q3 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before Q4 2017, was received in Q2 2017. The remaining \$20.9 million unamortized balance of the tax refund was therefore included in Distributable Cash Flow in the second quarter of 2017. Also includes a refund of Texas margin tax paid in previous periods and received in 2017.

Gross Margin

The Company defines gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by the Company's contract mix and commodity hedging program.

Gathering and Processing segment gross margin consists primarily of revenues from the sale of natural gas, condensate, crude oil and NGLs and fee revenues related to natural gas and crude oil gathering and services, less producer payments and other natural gas and crude oil purchases.

Logistics and Marketing segment gross margin consists primarily of:

- service fee revenues (including the pass-through of energy costs included in fee rates),
- system product gains and losses, and
- NGL and natural gas sales less NGL and natural gas purchases, transportation costs and the net inventory change.

The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

The Company defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of its operations.

Management reviews business segment gross margin and operating margin monthly as a core internal management process. The Company believes that investors benefit from having access to the same financial measures that management uses in evaluating its operating results. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by management and by external users of the Company's financial statements, including investors and commercial banks, to assess:

- the financial performance of the Company's assets without regard to financing methods, capital structure or historical cost basis;
- the Company's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in the Company's industry, the Company's definitions of gross margin and operating margin may not be comparable with similarly titled measures of other companies, thereby diminishing their utility.

Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

The following table presents a reconciliation of net income to operating margin and gross margin for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(In millions)				
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	\$ 57.6	\$ (23.2)	\$ (61.7)	\$ (25.9)
Net income (loss) attributable to noncontrolling interests	13.0	8.6	21.8	10.7
Net income (loss)	70.6	(14.6)	(39.9)	(15.2)
Depreciation and amortization expense	203.4	186.1	394.6	379.6
General and administrative expense	51.0	47.0	99.6	92.2
Goodwill impairment	—	—	—	24.0
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
Other, net	—	4.6	21.1	9.6
Operating margin	291.9	299.5	598.3	598.8
Operating expenses	155.2	138.9	307.2	271.0
Gross margin	\$ 447.1	\$ 438.4	\$ 905.5	\$ 869.8

Forward-Looking Statements

Certain statements in this release are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future, are forward-looking statements. These forward-looking statements rely on a number of assumptions concerning future events and are subject to a number of uncertainties, factors and risks, many of which are outside the Company's

control, which could cause results to differ materially from those expected by management of the Company. Such risks and uncertainties include, but are not limited to, weather, political, economic and market conditions, including a decline in the price and market demand for natural gas, natural gas liquids and crude oil, the timing and success of business development efforts; and other uncertainties. These and other applicable uncertainties, factors and risks are described more fully in the Company's filings with the Securities and Exchange Commission, including its Annual Report on Form 10-K for the year ended December 31, 2016, and any subsequently filed Quarterly Reports on Form 10-Q and Current Reports on Form 8-K. The Company does not undertake an obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.
Contact investor relations by phone at (713) 584-1133.

Sanjay Lad
Director – Investor Relations

Jennifer Kneale
Vice President – Finance