TARGA RESOURCES CORP.

FORM 8-K
(Current report filing)

Filed 02/15/18 for the Period Ending 02/15/18

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):
February 15, 2018

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware	**001-34991**	**20-3701075**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(IRS Employer Identification No.)

811 Louisiana, Suite 2100
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 February 15, 2018, Targa Resources Corp. (the "Company") issued a press release regarding its financial results for the three months and year ended December 31, 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, February 15, 2018. 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 February 15, 2018.

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: February 15, 2018

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

TARGA

Exhibit 99.1

811 Louisiana, Suite 2100
Houston, TX 77002
713.584.1000

Targa Resources Corp. Reports
Fourth Quarter and Full Year 2017 Financial Results and Provides 2018 Operational and Financial Guidance

HOUSTON – February 15, 2018 - Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported fourth quarter and full year 2017 results.

Fourth Quarter and Full Year 2017 Financial Results

Fourth quarter 2017 net income (loss) attributable to Targa Resources Corp. was $283.1 million compared to ($150.8) million for the fourth quarter of 2016. The fourth quarter of 2017, in connection with the Company's initial analysis of the impact of the U.S. government's recently enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), included a discrete net deferred tax benefit of $269.5 million. For the full year 2017, net income (loss) attributable to Targa Resources Corp. was $54.0 million compared to ($187.3) million for 2016.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $328.4 million for the fourth quarter of 2017 compared to $297.6 million for the fourth quarter of 2016. For the full year 2017, Adjusted EBITDA was $1,139.8 million compared to $1,064.9 million for 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")).

"We are pleased with our performance during 2017, as increasing system volumes in both our Gathering and Processing and Downstream segments drove Adjusted EBITDA to exceed our previously communicated full year 2017 expectations," said Joe Bob Perkins, Chief Executive Officer of the Company. "Looking forward, we are well positioned to benefit from continued producer activity and the increasing downstream market demand for hydrocarbons. 2018 will be a transitional year for Targa as we continue to invest in attractive opportunities to further integrate and grow our asset footprint, and as we look forward, we remain focused on executing our strategic priorities that are expected to generate significant Adjusted EBITDA growth over the long term."

On January 18, 2018, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended December 31, 2017, or $3.64 per share on an annualized basis. Total cash dividends of approximately $199.1 million will be paid on February 15, 2018 on all outstanding shares of common stock to holders of record as of the close of business on February 1, 2018. Also on January 18, 2018, 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 were paid on February 14, 2018 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on February 1, 2018.

The Company reported distributable cash flow for the fourth quarter of 2017 of $274.6 million compared to total common dividends to be paid of $199.1 million and total Series A Preferred Stock dividends to be paid of $22.9 million, resulting in dividend coverage in excess of 1.2 times with respect to the fourth quarter of 2017.

For the full year 2017, distributable cash flow of $851.8 million resulted in approximately 1.0 times dividend coverage on the common and Series A Stock dividends paid with respect to 2017.

Fourth Quarter 2017 - Capitalization, Liquidity and Financing

The Company's total consolidated debt as of December 31, 2017 was $5,053.0 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility due 2020. The consolidated debt included $4,618.0 million of Targa Resource Partners LP ("TRP" or "the Partnership") debt, net of $30.0 million of debt issuance costs, with $20.0 million outstanding under TRP's $1.6 billion senior secured revolving credit facility due 2020, $350.0 million outstanding under TRP's accounts receivable securitization facility and $4,278.0 million of outstanding TRP senior notes, net of unamortized premiums.

As of December 31, 2017, TRC had available borrowing capacity under its senior secured revolving credit facility of $235.0 million. TRP had $20.0 million of borrowings outstanding under its $1.6 billion senior secured revolving credit facility and $27.2 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of $1,552.8 million at the Partnership. Total consolidated liquidity of the Company as of December 31, 2017, including $137.2 million of cash, was approximately $1.9 billion.

In October 2017, the Partnership issued $750.0 million aggregate principal amount of 5% Senior Notes due January 2028. The Partnership used the net proceeds of $744. 1 million after costs from this offering to redeem its 5% Senior Notes due 2018, reduce borrowings under its credit facilities, and for general partnership purposes.

2018 Financial and Operational Expectations

For 2018, assuming NGL composite barrel prices average $0.67 per gallon, crude oil prices average $58 per barrel and natural gas prices average $2.75 per MMbtu for the year, Targa estimates Adjusted EBITDA to be between $1,225 million and $1,325 million.

Targa estimates 2018 net growth capital expenditures to be approximately $1.6 billion, based on currently announced projects and other identified spending. Targa expects that additional growth capital projects will be identified throughout the year, which would increase 2018 net growth capital expenditures. Net maintenance capital expenditures for 2018 are estimated to be approximately $120 million.

Given the continued producer activity around its systems, Targa estimates that 2018 Field Gathering and Processing ("G&P") natural gas inlet volumes will average between 3,150 million cubic feet per day ("MMcf/d") and 3,350 MMcf/d, with the midpoint representing an 18% increase over 2017 Field G&P average natural gas inlet volumes. In the Permian Basin, Targa estimates average G&P natural gas inlet volumes will be between 1,550 MMcf/d and 1,650 MMcf/d, with the midpoint representing a 25% increase over 2017 Permian G&P average natural gas inlet volumes. In SouthOK, SouthTX and the Badlands, Targa estimates 2018 average natural gas inlet volumes will be higher than average 2017 volumes, and Targa also estimates higher average crude gathered volumes in both the Permian and Badlands year over year. Targa estimates that these volume increases will be partially offset by lower volumes in WestOK and North Texas.

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 February 15, 2018 to discuss fourth quarter 2017 results and its 2018 operational and financial outlook. 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 1389043. 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 December 31, 2017	Three Months Ended December 31, 2016	2017 vs. 2016		Year Ended December 31, 2017	Year Ended December 31, 2016	2017 vs. 2016	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 2,398.0	$ 1,744.1	$ 653.9	37%	$ 7,751.1	$ 5,626.8	$ 2,124.3	38%
Fees from midstream services	304.8	268.5	36.3	14%	1,063.8	1,064.1	(0.3)	—
Total revenues	2,702.8	2,012.6	690.2	34%	8,814.9	6,690.9	2,124.0	32%
Product purchases	2,168.2	1,544.0	624.2	40%	6,906.1	4,922.9	1,983.2	40%
Gross margin (1)	534.6	468.6	66.0	14%	1,908.8	1,768.0	140.8	8%
Operating expenses	160.2	139.7	20.5	15%	622.9	553.7	69.2	12%
Operating margin (1)	374.4	328.9	45.5	14%	1,285.9	1,214.3	71.6	6%
Depreciation and amortization expense	206.7	194.1	12.6	6%	809.5	757.7	51.8	7%
General and administrative expense	54.0	48.9	5.1	10%	203.4	187.2	16.2	9%
Impairment of property, plant and equipment	—	—	—	—	378.0	—	378.0	—
Impairment of goodwill	—	183.0	(183.0)	(100%)	—	207.0	(207.0)	(100%)
Other operating (income) expense	0.2	0.5	(0.3)	(60%)	17.4	6.6	10.8	164%
Income (loss) from operations	113.5	(97.6)	211.1	216%	(122.4)	55.8	(178.2)	NM
Interest expense, net	(52.4)	(67.2)	14.8	22%	(233.7)	(254.2)	20.5	8%
Equity earnings (loss)	(0.3)	(2.9)	2.6	90%	(17.0)	(14.3)	(2.7)	(19%)
Gain (loss) from financing activities	(0.3)	(69.6)	69.3	100%	(16.8)	(48.2)	31.4	65%
Change in contingent considerations	(26.0)	—	(26.0)	—	99.6	0.4	99.2	NM
Other income (expense), net	(0.1)	(0.1)	—	—	(2.6)	0.8	(3.4)	NM
Income tax (expense) benefit	264.8	96.8	168.0	174%	397.1	100.6	296.5	295%
Net income (loss)	299.2	(140.6)	439.8	NM	104.2	(159.1)	263.3	165%
Less: Net income (loss) attributable to noncontrolling interests	16.1	10.2	5.9	58%	50.2	28.2	22.0	78%
Net income (loss) attributable to Targa Resources Corp.	283.1	(150.8)	433.9	288%	54.0	(187.3)	241.3	129%
Dividends on Series A Preferred Stock	22.9	22.9	—	—	91.7	72.6	19.1	26%
Deemed dividends on Series A Preferred Stock	6.7	5.9	0.8	14%	25.7	18.2	7.5	41%
Net income (loss) attributable to common shareholders	$ 253.5	$ (179.6)	$ 433.1	241%	$ (63.4)	$ (278.1)	$ 214.7	77%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 328.4	$ 297.6	$ 30.8	10%	$ 1,139.8	$ 1,064.9	$ 74.9	7%
Distributable cash flow (1)	274.6	246.2	28.4	12%	851.8	762.4	89.4	12%
Capital expenditures	518.9	165.6	353.3	213%	1,506.5	592.1	914.4	154%
Business acquisition (2)	—	—	—	—	987.1	—	987.1	—
Operating statistics: (3)								
Crude oil gathered, Badlands, MBbl/d	119.8	103.5	16.3	16%	113.6	105.2	8.4	8%
Crude oil gathered, Permian, MBbl/d (4)	45.1	—	45.1	—	29.8	—	29.8	—
Plant natural gas inlet, MMcf/d (5) (6)	3,637.3	3,331.9	305.4	9%	3,473.7	3,399.6	74.1	2%
Gross NGL production, MBbl/d	375.6	305.3	70.3	23%	333.2	305.4	27.8	9%
Export volumes, MBbl/d (7)	209.6	206.4	3.2	2%	184.1	181.4	2.7	1%
Natural gas sales, BBtu/d (6) (8)	2,186.6	1,925.7	260.9	14%	2,004.0	1,962.9	41.1	2%
NGL sales, MBbl/d (8)	597.1	542.5	54.6	10%	525.6	526.1	(0.5)	—
Condensate sales, MBbl/d	12.8	9.6	3.2	33%	11.8	10.1	1.7	17%

(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 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 period and the denominator as the number of calendar days during the period.
(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 the Company's ownership while the denominator is the number of calendar days during the period.
(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 December 31, 2017 Compared to Three Months Ended December 31, 2016

The increase in commodity sales was primarily due to higher natural gas liquids ("NGL"), condensate and petroleum products prices ($503.0 million) and increased volumes ($216.0 million), partially offset by the impact of hedge settlements ($37.5 million) and decreased natural gas prices ($27.5 million). Fee-based and other revenues increased due to higher gas processing and crude gathering fees primarily due to the Permian Acquisition, and higher fractionation fees, partially offset by lower export fees.

The increase in product purchases was primarily due to the impact of higher commodity prices and increased volumes.

In the third quarter of 2017, the Company experienced limited impacts to its operations as a result of Hurricane Harvey. As a result of the temporary constraints experienced, approximately $7 million of operating margin shifted to the fourth quarter of 2017 when the additional stored volumes of mixed NGLs were fractionated and sold.

The higher operating margin and gross margin in 2017 reflect increased segment results for both Gathering and Processing and Logistics and Marketing. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the March 2017 Permian Acquisition and the Raptor Plant at SouthTX that went into service in the second quarter of 2017.

General and administrative expense increased primarily due to higher compensation and benefits.

In conjunction with the Company's required annual goodwill assessments, the Company recognized a $183.0 million impairment of goodwill during the fourth quarter of 2016 related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the "Atlas mergers"). There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Net interest expense in 2017 decreased as compared with 2016 primarily due to lower non-cash interest expense related to the decrease in the estimated redemption value of mandatorily redeemable preferred interests and higher capitalized interest related to the Company's growth capital spending.

In 2016, the Company recorded a loss from financing activities of $69.6 million that included the tender and redemption of Partnership Senior Notes.

During 2017, the Company recorded other expense of $26.0 million primarily related to the increase in the year end fair value of the Permian Acquisition contingent consideration liability, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date. The estimated fair value of the contingent consideration may decrease or increase until the settlement dates, resulting in the recognition of additional other income (expense).

The increase in income tax benefit was primarily due to the Tax Act and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of the Company's ending balance sheet deferred tax balances. The resulting $269.5 million reduction of the Company's net deferred tax liability is included in current period earnings. Partially offsetting this increased tax benefit from the lower statutory tax rate is the impact of having pre-tax income in the fourth quarter of 2017 versus a large pre-tax loss in the fourth quarter of 2016 that included a $183.0 million provision for goodwill impairment.

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

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The increase in commodity sales was primarily due to higher commodity prices ($2,124.2 million) and increased petroleum products, natural gas and condensate sales volumes ($100.1 million), partially offset by decreased NGL sales volumes ($13.8 million) and the impact of hedge settlements ($86.2 million). Fee-based and other revenues were flat as a result of lower export fees offset by increases in gas processing and crude gathering fees, which included the impact of the Company's March 2017 Permian Acquisition.

The increase in product purchases was primarily due to the impact of higher commodity prices and increased volumes.

In the third quarter of 2017, the Company experienced limited impacts to its operations from Hurricane Harvey and its operating margin for the full year 2017 was not significantly impacted. No property insurance or business interruption insurance claims were made as a result of the storm.

The higher operating margin and gross margin in 2017 reflect increased segment results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment results. See "Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the March 2017 Permian Acquisition and the impact of other growth investments, including CBF Train 5 that went into service in the second quarter of 2016 and the Raptor Plant at SouthTX that went into service in the second quarter of 2017. These factors were partially offset by lower planned amortization of the Badlands intangible assets.

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

The impairment of property, plant and equipment in 2017 reflects a third quarter impairment of gas processing facilities and gathering systems associated with the Company's North Texas operations in the Gathering and Processing segment. The impairment was the result of the Company's assessment that forecasted undiscounted future net cash flows from operations, while positive, would not be sufficient to recover the total net book value of the underlying assets.

In conjunction with the Company's required annual goodwill assessments, the Company recognized impairments of goodwill totaling $207.0 million during 2016 related to goodwill acquired in the Atlas mergers. There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating expense in 2017 was primarily due to the reduction in the carrying value of the Company's ownership interest in the Venice Gathering System in connection with the April 2017 sale. Other operating expense in 2016 was primarily due to the loss on decommissioning two storage wells at the Company's Hattiesburg facility and an acid gas injection well at the Company's Versado facility.

Net interest expense in 2017 decreased as compared with 2016 primarily due to lower average outstanding borrowings and higher capitalized interest during 2017, partially offset by higher non-cash interest expense related to the increase in the estimated redemption value of mandatorily redeemable preferred interests.

Higher equity losses in 2017 reflect 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 LP.

During 2017, the Company recorded a loss from financing activities of $16.8 million on the redemption of the outstanding 6⅜% Senior Notes and the repayment of the outstanding balance on the Company's senior secured term loan, whereas in 2016 the Company recorded a $48.2 million loss from financing activities that included the tender, open market repurchase and redemption of various series of Partnership Senior Notes.

During 2017, the Company recorded other income for changes in contingent considerations of $99.6 million resulting primarily from a reduction in the estimated fair value of the Permian Acquisition contingent consideration, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date. The estimated fair value of the contingent consideration may decrease or increase until the settlement dates, resulting in the recognition of additional other income (expense).

The increase in income tax benefit was primarily due to the Tax Act and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of the Company's ending balance sheet deferred tax balances. The resulting $269.5 million reduction of the Company's net deferred tax liability is included in current period earnings. Further, in 2017, which is subject to pre-Tax Act rates, a higher pre-tax loss resulted in higher income tax benefits.

Net income attributable to noncontrolling interests was higher in 2017 primarily 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 of 2016, and the Company's October 2016 acquisition of the 37% interest of Versado that the Company 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 a full year in 2017.

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 (also referred to as the Downstream Business).

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 December 31, 2017	Three Months Ended December 31, 2016	2017 vs. 2016		Year Ended December 31, 2017	Year Ended December 31, 2016	2017 vs. 2016	
Gross margin	$ 328.1	$ 255.6	$ 72.5	28%	$ 1,145.5	$ 903.6	$ 241.9	27%
Operating expenses	93.7	82.6	11.1	13%	361.7	326.5	35.2	11%
Operating margin	$ 234.4	$ 173.0	$ 61.4	35%	$ 783.8	$ 577.1	$ 206.7	36%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	978.4	781.8	196.6	25%	893.5	747.4	146.1	20%
Permian Delaware (4)	406.1	326.8	79.3	24%	381.8	321.0	60.8	19%
Total Permian	1,384.5	1,108.6	275.9		1,275.3	1,068.4	206.9	
SouthTX	365.6	206.7	158.9	77%	273.2	216.4	56.8	26%
North Texas	251.5	299.3	(47.8)	(16%)	268.1	317.3	(49.2)	(16%)
SouthOK	540.1	450.0	90.1	20%	494.0	462.1	31.9	7%
WestOK	363.5	413.1	(49.6)	(12%)	377.7	444.9	(67.2)	(15%)
Total Central	1,520.7	1,369.1	151.6		1,413.0	1,440.7	(27.7)	
Badlands (5)	66.5	49.5	17.0	34%	56.5	52.1	4.4	8%
Total Field	2,971.7	2,527.2	444.5		2,744.8	2,561.2	183.6	
Coastal	665.7	804.6	(138.9)	(17%)	728.8	838.4	(109.6)	(13%)
Total	3,637.4	3,331.8	305.6	9%	3,473.6	3,399.6	74.0	2%
Gross NGL production, MBbl/d (3)								
Permian Midland (4)	137.5	101.7	35.8	35%	118.3	94.5	23.8	25%
Permian Delaware (4)	45.2	36.8	8.4	23%	43.1	36.4	6.7	18%
Total Permian	182.7	138.5	44.2		161.4	130.9	30.5	
SouthTX	45.7	19.8	25.9	131%	30.4	23.8	6.6	28%
North Texas	28.6	34.2	(5.6)	(16%)	30.2	35.8	(5.6)	(16%)
SouthOK	48.9	39.8	9.1	23%	42.8	39.4	3.4	9%
WestOK	20.5	24.5	(4.0)	(16%)	21.9	27.1	(5.2)	(19%)
Total Central	143.7	118.3	25.4		125.3	126.1	(0.8)	
Badlands	9.4	6.7	2.7	40%	7.9	7.3	0.6	8%
Total Field	335.8	263.5	72.3		294.6	264.3	30.3	
Coastal	39.8	41.9	(2.1)	(5%)	38.6	41.2	(2.6)	(6%)
Total	375.6	305.4	70.2	23%	333.2	305.5	27.7	9%
Crude oil gathered, Badlands, MBbl/d	119.8	103.5	16.3	16%	113.6	105.2	8.4	8%
Crude oil gathered, Permian, MBbl/d (4)	45.1	—	45.1	—	29.8	—	29.8	—
Natural gas sales, BBtu/d (3)	1,717.7	1,584.4	133.3	8%	1,665.4	1,623.6	41.8	3%
NGL sales, MBbl/d	297.4	241.4	56.0	23%	254.8	241.3	13.5	6%
Condensate sales, MBbl/d	12.8	9.6	3.2	33%	11.8	9.9	1.9	19%
Average realized prices (6):								
Natural gas, $/MMBtu	2.45	2.68	(0.23)	(9%)	2.65	2.14	0.51	24%
NGL, $/gal	0.64	0.45	0.19	42%	0.55	0.36	0.19	53%
Condensate, $/Bbl	51.12	42.46	8.66	20%	45.52	36.20	9.32	26%

(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 period and the denominator is the number of calendar days during the period.

(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 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 Permian Midland and New Delaware volumes are included within Permian Delaware. For the volume statistics presented, the numerator is the total volume sold during the period of the Company's ownership while the denominator is the number of calendar days during the period.

(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 December 31, 2017 Compared to Three Months Ended December 31, 2016

The increase in gross margin was primarily due to higher Permian volumes including those associated with the Permian Acquisition, higher Central region volumes and higher NGL prices. Field Gathering and Processing inlet volumes increased in the Permian region, SouthTX and SouthOK, partially offset by decreases at WestOK and North Texas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower unit margins, partially offset the Field Gathering and Processing inlet volume increase. NGL production and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased plant recoveries including additional ethane recovery. The increase in NGL sales was predominantly due to higher overall inlet volumes and also included the deferral to the fourth quarter of 2017 of NGL sales resulting from operational issues related to Hurricane Harvey. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. In the Badlands, total crude oil gathered volumes and natural gas volumes increased primarily due to higher production from new wells and 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.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes including those associated with the Permian Acquisition. The overall increase in Gathering and Processing inlet volumes included all areas in the Permian region, at SouthTX and SouthOK, partially offset by decreases at WestOK, North Texas and Coastal. The Coastal Gathering and Processing assets generate significantly lower unit margins than the Field Gathering and Processing assets. NGL production, NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased plant recoveries including additional ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. In the Badlands, total crude oil gathered volumes and natural gas volumes increased primarily due to higher production from new wells and 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

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 December 31, 2017			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland (4)	1,218.7	Varies (5)	978.4	978.4
Permian Delaware (4)	406.1	100%	406.1	406.1
Total Permian	1,624.8		1,384.5	1,384.5
SouthTX	365.6	Varies (6) (7)	308.2	365.6
North Texas	251.5	100%	251.5	251.5
SouthOK	540.1	Varies (8)	430.0	540.1
WestOK	363.5	100%	363.5	363.5
Total Central	1,520.7		1,353.2	1,520.7
Badlands (9)	66.5	100%	66.5	66.5
Total Field	3,212.0		2,804.2	2,971.7
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	172.9	Varies (5)	137.5	137.5
Permian Delaware (4)	45.2	100%	45.2	45.2
Total Permian	218.1		182.7	182.7
SouthTX	45.7	Varies (6) (7)	37.8	45.7
North Texas	28.6	100%	28.6	28.6
SouthOK	48.9	Varies (8)	39.3	48.9
WestOK	20.5	100%	20.5	20.5
Total Central	143.7		126.2	143.7
Badlands	9.4	100%	9.4	9.4
Total Field	371.2		318.3	335.8

(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) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants which are owned 100% by the Company. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company’s reported financials.
(6) SouthTX includes the Silver Oak II Plant, of which the Company owned a 90% interest from October 2015 through May 2017, and after which the Company 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) 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.
(8) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants which are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2017			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland (4)	1,110.8	Varies (5)	893.5	893.5
Permian Delaware (4)	381.8	100%	381.8	381.8
Total Permian	1,492.6		1,275.3	1,275.3
SouthTX	273.2	Varies (6) (7)	213.5	273.2
North Texas	268.1	100%	268.1	268.1
SouthOK	494.0	Varies (8)	397.9	494.0
WestOK	377.7	100%	377.7	377.7
Total Central	1,413.0		1,257.2	1,413.0
Badlands (9)	56.5	100%	56.5	56.5
Total Field	2,962.1		2,589.0	2,744.8
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	148.2	Varies (5)	118.3	118.3
Permian Delaware (4)	43.1	100%	43.1	43.1
Total Permian	191.3		161.4	161.4
SouthTX	30.4	Varies (6) (7)	23.4	30.4
North Texas	30.2	100%	30.2	30.2
SouthOK	42.8	Varies (8)	34.9	42.8
WestOK	21.9	100%	21.9	21.9
Total Central	125.3		110.4	125.3
Badlands	7.9	100%	7.9	7.9
Total Field	324.5		279.7	294.6

(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 year and the denominator is the number of calendar days during the year.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants which are owned 100% by the Company. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company’s reported financials.
(6) SouthTX includes the Silver Oak II Plant, of which the Company owned a 90% interest from October 2015 through May 2017, and after which the Company 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) 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.
(8) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants which are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(9) 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 the Company’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. The Logistics and Marketing segment also includes the Grand Prix project.

Logistics and Marketing operations are generally connected to and supplied in part by the Company's Gathering and Processing segment and are predominantly located in Mont Belvieu, Galena Park and Channelview, 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 December 31,				Year Ended December 31,			
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	(In millions)							
Gross margin	$ 220.0	$ 207.0	$ 13.0	6%	$ 773.4	$ 801.8	$ (28.4)	(4%)
Operating expenses	66.5	57.1	9.4	16%	261.6	227.4	34.2	15%
Operating margin	$ 153.5	$ 149.9	$ 3.6	2%	$ 511.8	$ 574.4	$ (62.6)	(11%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	442.6	298.6	144.0	48%	354.2	309.3	44.9	15%
LSNG treating volumes (2)	33.8	29.8	4.0	13%	32.2	24.9	7.3	29%
Benzene treating volumes (2)	24.6	24.1	0.5	2%	21.6	22.1	(0.5)	(2%)
Export volumes, MBbl/d (4)	209.6	206.4	3.2	2%	184.1	181.4	2.7	1%
NGL sales, MBbl/d	554.9	510.9	44.0	9%	490.0	477.5	12.5	3%
Average realized prices:								
NGL realized price, $/gal	$ 0.80	$ 0.58	$ 0.22	38%	$ 0.69	$ 0.49	$ 0.20	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 the Company's Galena Park Marine Terminal that are destined for international markets.

Three Months Ended December 31, 2017 Compared to Three Months Ended December 31, 2016

Logistics and Marketing gross margin increased due to higher fractionation margin and higher terminaling and storage throughput, partially offset by lower LPG export margin. Fractionation margin increased due to higher supply volume, which included 29.3 MBbl/d deferred from the third quarter of 2017 due to temporary operational issues related to Hurricane Harvey, and higher system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). LPG export margin decreased due to lower fees, partially offset by higher volumes, which included 12.5 MBbl/d deferred from the third quarter of 2017 due to the temporary closure of the Houston Ship Channel resulting from Hurricane Harvey.

Operating expenses increased due to higher fuel and power costs which are largely passed through, higher taxes, and higher compensation and benefits associated with Train 5.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

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

Operating expenses increased due to higher fuel and power costs that are largely passed through, higher compensation and benefits related to the operations of CBF Train 5, 2017 repairs and maintenance activities that were not required in 2016 and higher taxes.

Other

	Three Months Ended December 31,			Year Ended December 31,		
	2017	2016	2017 vs. 2016	2017	2016	2017 vs. 2016
	(In millions)					
Gross margin	$ (13.5)	$ 6.0	$ (19.5)	$ (9.6)	$ 62.9	$ (72.5)
Operating margin	$ (13.5)	$ 6.0	$ (19.5)	$ (9.6)	$ 62.9	$ (72.5)

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 December 31, 2017			Three Months Ended December 31, 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)	17.8	$ 0.39	$ 6.9	10.7	$ 0.31	$ 3.3
NGL (MMgal)	85.4	(0.21)	(18.3)	11.7	(0.01)	(0.1)
Crude oil (MBbl)	0.4	(1.31)	(0.5)	0.3	9.81	3.3
Non-hedge accounting (2)			(1.3)			(0.2)
Ineffectiveness (3)			(0.3)			(0.3)
			$ (13.5)			$ 6.0

	Year Ended December 31, 2017			Year Ended December 31, 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)	61.1	$ 0.22	$ 13.5	44.7	$ 0.79	$ 35.2
NGL (MMgal)	262.9	(0.10)	(26.0)	31.9	0.21	6.8
Crude oil (MBbl)	1.3	4.09	5.3	1.1	17.14	19.5
Non-hedge accounting (2)			(2.2)			2.3
Ineffectiveness (3)			(0.2)			(0.9)
			$ (9.6)			$ 62.9

(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 LP ("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 the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $7.6 million, $26.6 million, and $67.9 million for the years ended December 31, 2017, 2016 and 2015, related to these novated contracts. The final settlement was received in December 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. The Company 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, terminaling and selling 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 following tables 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, and other items that the Company believes should be adjusted consistent with the Company's core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. Adjusted EBITDA is used as a supplemental financial measure by the Company and by external users of its 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 the Company's 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, its 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, 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 it (prior to the establishment of any retained cash reserves by the Company's board of directors) to the cash dividends the Company expects to pay its shareholders. Using this metric, management and external users of its 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 the Company's 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 the Company's 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 December 31,		Year Ended December 31,	
	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	$ 283.1	$ (150.8)	$ 54.0	$ (187.3)
Impact of TRC/TRP Merger on NCI	—	—	—	(3.8)
Income attributable to TRP preferred limited partners	2.9	2.9	11.3	11.3
Interest expense, net	52.4	67.2	233.7	254.2
Income tax expense (benefit)	(264.8)	(96.8)	(397.1)	(100.6)
Depreciation and amortization expense	206.7	194.1	809.5	757.7
Impairment of property, plant and equipment	—	—	378.0	—
Impairment of goodwill	—	183.0	—	207.0
(Gain) loss on sale or disposition of assets	(0.7)	0.4	15.9	6.1
(Gain) loss from financing activities (1)	0.3	69.6	16.8	48.2
(Earnings) loss from unconsolidated affiliates	0.3	2.9	17.0	14.3
Distributions from unconsolidated affiliates and preferred partner interests, net	3.0	4.9	18.0	17.5
Change in contingent consideration included in Other expense	26.0	(0.1)	(99.6)	(0.4)
Compensation on equity grants	10.6	7.5	42.3	29.7
Transaction costs related to business acquisitions	—	—	5.6	—
Splitter Agreement (2)	10.8	10.8	43.0	10.8
Risk management activities (3)	2.8	6.5	10.0	25.2
Noncontrolling interests adjustments (4)	(5.0)	(4.5)	(18.6)	(25.0)
TRC Adjusted EBITDA	**$ 328.4**	**$ 297.6**	**$ 1,139.8**	**$ 1,064.9**
Distributions to TRP preferred limited partners	(2.9)	(2.9)	(11.3)	(11.3)
Cash received from payments under Splitter Agreement (2)	43.0	43.0	43.0	43.0
Splitter Agreement (2)	(10.8)	(10.8)	(43.0)	(10.8)
Interest expense on debt obligations (5)	(55.9)	(62.7)	(224.3)	(263.8)
Cash tax (expense) benefit (6)	—	9.8	46.7	20.9
Maintenance capital expenditures	(27.7)	(29.4)	(100.7)	(85.7)
Noncontrolling interests adjustments of maintenance capex	0.5	1.6	1.6	5.2
Distributable Cash Flow	**$ 274.6**	**$ 246.2**	**$ 851.8**	**$ 762.4**

(1) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.

(2) In Adjusted EBITDA, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the condensate splitter agreement 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.

(3) Risk management activities related to derivative instruments including the cash impact of hedges acquired in the Atlas mergers.

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

(5) Excludes amortization of interest expense.

(6) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which was recognized over the periods between the third quarter 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 2017. The year ended December 31, 2017 also includes a refund of Texas margin tax paid in previous periods and received in 2017.

	Twelve Months Ended December 31, 2018	
	Low Range	High Range
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA		
Net income (loss) attributable to TRC	$ 18.0	$ 118.0
Income attributable to TRP preferred limited partners	11.3	11.3
Interest expense, net	260.0	260.0
Income tax expense (benefit)	—	—
Depreciation and amortization expense	890.0	890.0
(Earnings) loss from unconsolidated affiliates	5.0	5.0
Distributions from unconsolidated affiliates and preferred partner interests, net	15.0	15.0
Compensation on TRP equity grants	45.0	45.0
Splitter Agreement	11.0	11.0
Noncontrolling interest adjustment	(30.3)	(30.3)

TRC Adjusted EBITDA	**$ 1,225.0**	**$ 1,325.0**

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 fees 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 fees (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 the Company's equity volumes 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 of the Company to operating margin and gross margin for the periods indicated:

	Three Months Ended December 31,		Year Ended December 31,	
	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	$ 283.1	$ (150.8)	$ 54.0	$ (187.3)
Net income (loss) attributable to noncontrolling interests	16.1	10.2	50.2	28.2
Net income (loss)	299.2	(140.6)	104.2	(159.1)
Depreciation and amortization expense	206.7	194.1	809.5	757.7
General and administrative expense	54.0	48.9	203.4	187.2
Impairment of property, plant and equipment	—	—	378.0	—
Impairment of goodwill	—	183.0	—	207.0
Interest expense, net	52.4	67.2	233.7	254.2
Income tax expense (benefit)	(264.8)	(96.8)	(397.1)	(100.6)
(Gain) loss on sale or disposition of assets	(0.7)	0.4	15.9	6.1
(Gain) loss from financing activities	0.3	69.6	16.8	48.2
Other, net	27.3	3.1	(78.5)	13.6
Operating margin	374.4	328.9	1,285.9	1,214.3
Operating expenses	160.2	139.7	622.9	553.7
Gross margin	**$ 534.6**	**$ 468.6**	**$ 1,908.8**	**$ 1,768.0**

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.

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