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, 2017

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.)

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))

Item 2.02 Results of Operations and Financial Condition.

On February 15, 2017, Targa Resources Corp. (the "Company") issued a press release regarding its financial results for the three months and year ended December 31, 2016. A conference call to discuss these results is scheduled for 10:00 a.m. Eastern time (9:00 a.m. Central time) on Wednesday, February 15, 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 February 15, 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: February 15, 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 February 15, 2017.

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

Targa Resources Corp. Reports
Fourth Quarter and Full Year 2016 Financial Results and Provides 2017 Operational and Financial Guidance

HOUSTON – February 15, 2017 - Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported fourth quarter and full year 2016 results.

Fourth Quarter and Full Year 2016 Financial Results

Fourth quarter 2016 net income (loss) attributable to Targa Resources Corp. was ($150.8) million compared to $27.0 million for the fourth quarter of 2015. For the full year 2016, net income (loss) attributable to Targa Resources Corp. was ($187.3) million compared to $58.3 million for 2015.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $297.6 million for the fourth quarter of 2016 compared to $326.0 million for the fourth quarter of 2015. For the full year 2016, Adjusted EBITDA was $1,064.9 million compared to $1,191.7 million for 2015 (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")).

"2016 was a successful year for Targa as we were able to improve our balance sheet and asset position in a volatile period for our industry," said Joe Bob Perkins, Chief Executive Officer of the Company. "We recently announced the highly strategic acquisition of additional midstream assets in the Delaware and Midland Basins, where we are well-positioned to benefit from continued producer activity. With a healthy balance sheet and a diverse set of assets poised to capture increasing industry activity, we are well positioned looking out at the balance of 2017 and beyond."

On January 19, 2017, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended December 31, 2016, or $3.64 per share on an annualized basis, unchanged from the previous quarter's dividend. Total cash dividends of approximately $176.5 million will be paid on February 15, 2017 on all outstanding shares of common stock to holders of record as of the close of business on February 1, 2017. Also on January 19, 2017, TRC declared a quarterly cash dividend of $23.75 per share of Series A Preferred Stock. Total cash dividends of approximately $22.9 million were paid on February 14, 2017 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on February 1, 2017.

The Company reported distributable cash flow for the fourth quarter of 2016 of $246.2 million compared to total common dividends to be paid of $176.5 million and total Series A Preferred Stock dividends of $22.9 million, resulting in dividend coverage in excess of 1.2x with respect to the fourth quarter of 2016.

For the full year 2016, distributable cash flow of $762.4 million resulted in approximately 1.1x dividend coverage on the common and Series A Stock dividends paid with respect to 2016.

Fourth Quarter 2016 - Capitalization, Liquidity and Financing

Targa's total consolidated debt as of December 31, 2016 was $4,881.0 million including $275.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility due 2020 and $157.8 million, net of unamortized discounts, outstanding on the Company's senior secured term loan due 2022. The consolidated debt also includes $4,452.0 million of Targa Resource Partners LP ("TRP" or "the Partnership") debt, net of $30.3 million of debt issuance costs, including $150.0 million outstanding under TRP's $1.6 billion senior secured revolving credit facility due 2020, $275.0 million outstanding under TRP's accounts receivable securitization facility and $4,057.3 million of TRP senior notes, net of unamortized discounts and premiums.

As of December 31, 2016, TRC had available senior secured revolving credit facility capacity of $395.0 million. TRP had $150.0 million in borrowings outstanding under its $1.6 billion senior secured revolving credit facility and $13.2 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of $1,436.8 million at the Partnership. Total Targa consolidated liquidity as of December 31, 2016, including $73.5 million of cash, was approximately $1.9 billion.

In October 2016, the Partnership issued $500.0 million of 5⅛% Senior Notes due February 2025 and $500.0 million of 5⅜% Senior Notes due February 2027 resulting in total net proceeds of approximately $992.4 million. The net proceeds from the offering along with borrowings under its senior secured revolving credit facility were used to fund concurrent tender offers for other series of senior notes, as described below.

Concurrently with the October 2016 senior notes offering, the Partnership commenced tender offers (the “Tender Offers”) to purchase for cash, subject to certain conditions, its 5% Senior Notes due January 2018 (the “5% Notes”), 6⅝% Senior Notes due October 2020 (the “6⅝% Notes”) and 6⅞% Senior Notes due February 2021 (the “6⅞% Notes” and together with the 5% Notes and 6⅝% Notes, the “Tender Notes”). The total consideration for each series of Tender Notes included a premium for each $1,000 principal amount of notes that was tendered as of the early tender date of October 5, 2016. The Tender Offers were fully subscribed, and the Partnership accepted for purchase all Tender Notes that were validly tendered as of the early tender date.

The results of the Tender Offers, which closed in October 2016, were (in millions):

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer Payments	Note Balance After Tender Offers
5% Senior Notes	$ 733.6	$ 483.1	$ 16.9	$ 5.4	$ 505.4	$ 250.5
6⅝% Senior Notes	309.9	281.7	10.5	0.3	292.5	28.2
6⅞% Senior Notes	478.6	373.5	14.4	4.6	392.5	105.1
	$ 1,522.1	$ 1,138.3	$ 41.8	$ 10.3	$ 1,190.4	$ 383.8

Subsequent to the closing of the Tender Offers, the Partnership issued notices of full redemption to the trustees and noteholders of the 6⅝% Notes and the 6⅞% Notes for the note balances remaining after the Tender Offers. In addition, the Partnership issued notice of full redemption to the trustees and noteholders of the 6⅝% Senior Notes of Targa Pipeline Partners LP (“TPL”) due October 2020 (the “6⅝% TPL Notes”). The redemption price for the 6⅝% Notes and the 6⅝% TPL Notes was 103.313% of the principal amount, while the redemption price for the 6⅞% Notes was 103.438% of the principal amount. The aggregate principal amount outstanding of all three series of notes totaling $146.2 million were redeemed on November 15, 2016 for a total redemption payment of $151.1 million, excluding accrued interest.

In October 2016, the Partnership amended and restated its senior secured revolving credit facility to extend the maturity date from October 2017 to October 2020. The available commitments under the facility of $1.6 billion remained unchanged while the Partnership’s ability to request additional commitments increased from up to $300.0 million to up to $500.0 million.

Outrigger Permian Acquisition

On January 22, 2017, Targa entered into definitive agreements to purchase 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together “Outrigger Delaware”) and Outrigger Midland Operating, LLC (“Outrigger Midland” and together with “Outrigger Delaware”, “Outrigger Permian”) (the “Outrigger Permian Acquisition”).

Targa will pay $475 million in cash at closing and $90 million within 90 days of closing. Subject to certain performance-linked measures and other conditions, additional cash of up to $935 million may be received by the sellers of Outrigger Permian in potential earn-out payments that may occur in 2018 and 2019. The potential earn-out payments will be based upon a multiple of realized gross margin from existing contracts. Targa currently expects to close the transaction during the first quarter of 2017, subject to customary regulatory approvals and closing conditions.

Outrigger Delaware’s gas gathering and processing and crude gathering systems are located in Loving, Winkler and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. Outrigger Delaware’s assets include 70 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Delaware system.

Outrigger Midland’s gas gathering and processing and crude gathering systems are located in Howard, Martin and Borden counties. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 12.5 years. Outrigger Midland currently has 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the Outrigger Midland system.

Targa anticipates connecting Outrigger Delaware to its existing Sand Hills system and Outrigger Midland to its existing WestTX system during 2017, creating operational and capital synergies.

On January 26, 2017, TRC completed a public offering of 9,200,000 shares of common stock (including the underwriters' overallotment option) at a price of $57.65, providing net proceeds of $524.1 million. Targa intends to use the net proceeds from this public offering to fund a portion of the $565 million initial purchase price of the Outrigger Permian Acquisition.

Targa expects that the remaining portion of the purchase price and related fees and expenses will be funded with borrowings under the Partnership's senior secured revolving credit facility or, subject to market conditions, proceeds from the issuance of private or public securities. Prior to funding the Outrigger Permian Acquisition, or if the acquisition is not completed, Targa may use the net proceeds from the equity offering for general corporate purposes, which may include, among other things, repayment of our indebtedness (including the Partnership's indebtedness), acquisitions, capital expenditures, additions to working capital and redeeming or repurchasing some of our outstanding notes.

2017 Operational and Financial Guidance

Given the continued producer activity around its systems, Targa estimates that 2017 Field Gathering and Processing ("G&P") natural gas inlet volumes will average at least 10% higher than 2016 Field G&P average natural gas inlet volumes. In the Permian Basin, Targa anticipates average G&P natural gas inlet volumes will increase by approximately 20% in 2017 compared to 2016. The Permian guidance includes anticipated volumes from the acquisition of assets in the Delaware and Midland Basins announced on January 23, 2017, and subject to customary regulatory approvals and other closing conditions, Targa expects the acquisition will close during the first quarter. In SouthTX and the Badlands, Targa estimates 2017 average natural gas inlet volumes will be higher than average 2016 volumes, and Targa also expects higher average crude volumes in the Badlands year over year. These volume~~s~~ increases will be partially offset by lower volumes in WestOK, SouthOK and North Texas.

In the Downstream business, related to its LPG export business at Galena Park, Targa has approximately two-thirds of its current estimated export capacity of 7 million barrels per month contracted each year at attractive rates through 2022. Some years are slightly higher and some years are slightly lower than two-thirds, but two-thirds is representative of the significant percentage of current LPG export capacity contracted in each year.

In support of the growth Targa is seeing in its G&P business and the additional growth opportunities upstream activity is creating in its Downstream business, Targa expects that 2017 net growth capital expenditures will be at least $700 million, based on currently announced projects and other identified spending. There are a number of other attractive G&P and Downstream projects under development, but not yet announced, that may require additional growth capex spending in 2017. Net maintenance capital expenditures for 2017 are estimated to be approximately $110 million.

For full year 2017, Targa expects dividend coverage to exceed 1.0 times assuming a $3.64 per common share 2017 dividend.

Inclusive of the January 23, 2017 acquisition in the Permian Basin, Targa estimates that it will not pay cash taxes for the next 5 years.

Conference Call

Targa will host a conference call for investors and analysts at 10:00 a.m. Eastern time (9:00 a.m. Central time) on February 15, 2017 to discuss fourth quarter and full year 2016 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 62528053. 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. An updated investor presentation will also be available in the Events and Presentations section of the Company's website following the completion of the conference call.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	2016 vs. 2015	2016 vs. 2015 %	Year Ended December 31, 2016	Year Ended December 31, 2015	2016 vs. 2015	2016 vs. 2015 %
	(in millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,744.1	$ 1,345.8	$ 398.3	30%	$ 5,626.8	$ 5,465.4	$ 161.4	3%
Fees from midstream services	268.5	301.6	(33.1)	(11%)	1,064.1	1,193.2	(129.1)	(11%)
Total revenues	2,012.6	1,647.4	365.2	22%	6,690.9	6,658.6	32.3	0%
Product purchases	1,544.0	1,187.6	356.4	30%	4,922.9	4,837.6	85.3	2%
Gross margin (1)	468.6	459.8	8.8	2%	1,768.0	1,821.0	(53.0)	(3%)
Operating expenses	139.7	130.4	9.3	7%	553.7	540.0	13.7	3%
Operating margin (1)	328.9	329.4	(0.5)	(0%)	1,214.3	1,281.0	(66.7)	(5%)
Depreciation and amortization expenses	194.1	228.8	(34.7)	(15%)	757.7	677.1	80.6	12%
General and administrative expenses	48.9	25.2	23.7	94%	187.2	161.7	25.5	16%
Goodwill impairment	183.0	290.0	(107.0)	(37%)	207.0	290.0	(83.0)	(29%)
Other operating (income) expense	0.5	(7.7)	8.2	106%	6.6	(7.1)	13.7	193%
Income from operations	(97.6)	(206.9)	109.3	53%	55.8	159.3	(103.5)	(65%)
Interest expense, net	(67.2)	(42.5)	(24.7)	58%	(254.2)	(231.9)	(22.3)	10%
Equity earnings (loss)	(2.9)	(1.4)	(1.5)	107%	(14.3)	(2.5)	(11.8)	NM
Gain (loss) from financing activities	(69.6)	3.5	(73.1)	NM	(48.2)	(10.1)	(38.1)	NM
Other income (expense)	(0.1)	0.9	(1.0)	(111%)	1.2	(26.6)	27.8	105%
Income tax (expense) benefit	96.8	14.5	82.3	NM	100.6	(39.6)	140.2	NM
Net income (loss)	(140.6)	(231.9)	91.3	39%	(159.1)	(151.4)	(7.7)	5%
Less: Net income (loss) attributable to noncontrolling interests	10.2	(258.9)	269.1	104%	28.2	(209.7)	237.9	113%
Net income (loss) attributable to Targa Resources Corp.	(150.8)	27.0	(177.8)	NM	(187.3)	58.3	(245.6)	NM
Dividends on Series A preferred stock	22.9	—	22.9	—	72.6	—	72.6	—
Deemed dividends on Series A preferred stock	5.9	—	5.9	—	18.2	—	18.2	—
Net income (loss) attributable to common shareholders	$ (179.6)	$ 27.0	$ (206.6)	NM	$ (278.1)	$ 58.3	$ (336.4)	NM
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 297.6	$ 326.0	$ (28.2)	(9%)	$ 1,064.9	$ 1,191.7	$ (126.8)	(11%)
Distributable cash flow (1)	246.2	216.1	30.3	14%	762.4	830.3	(67.9)	(8%)
Capital expenditures	165.6	206.0	(40.4)	(20%)	592.1	777.2	(185.1)	(24%)
Business acquisitions	—	—	—	—	—	5,024.2	(5,024.2)	(100%)
Operating statistics:								
Crude oil gathered, MBbl/d	103.5	108.8	(5.3)	(5%)	105.2	106.3	(1.1)	(1%)
Plant natural gas inlet, MMcf/d (2) (3) (4)	3,349.5	3,472.1	(122.4)	(4%)	3,411.9	3,241.3	170.6	5%
Gross NGL production, MBbl/d (4)	305.3	294.7	10.6	4%	305.4	265.5	39.9	15%
Export volumes, MBbl/d (5)	206.4	192.0	14.4	8%	181.4	183.0	(1.6)	(1%)
Natural gas sales, BBtu/d (3) (4) (6)	1,925.7	1,917.2	8.5	0%	1,962.9	1,770.7	192.2	11%
NGL sales, MBbl/d (4) (6)	542.5	563.0	(20.5)	(4%)	526.1	517.0	9.1	2%
Condensate sales, MBbl/d (4)	9.6	9.0	0.6	7%	10.1	9.3	0.8	9%

(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) 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.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) 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.
(5) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.
(6) 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, 2016 Compared to Three Months Ended December 31, 2015

The increase in commodity sales was primarily due to higher NGL and natural gas prices ($447.2 million), partially offset by lower NGL volumes ($32.7 million) and the impact of hedge settlements ($17.5 million). Fee-based and other revenues decreased primarily due to lower fractionation and export fees.

The increase in product purchases reflects the same factors as commodity sales, which were the impact of the higher commodity prices, partially offset by lower NGL volumes.

Operating margin was flat while gross margin increased slightly in 2016, which reflects increased Gathering and Processing segment margins, offset by decreased Logistics and Marketing segment margin results. Operating expenses increased compared to 2015 due to higher compensation, benefits and utilities expenses. See "—Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

The decrease in depreciation and amortization expenses is primarily due to the $32.6 million charge in 2015 to reflect an impairment of certain gas processing facilities and associated gathering systems due to market conditions and processing spreads in Louisiana. In 2016, there were no impairments of property, plant and equipment or intangibles assets.

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

The Company recognized an impairment of goodwill of $183.0 million during 2016 as compared with the $290.0 million provisional impairment of goodwill recorded during the fourth quarter of 2015, which was finalized in the first quarter of 2016 with an additional impairment of $24.0 million. These impairment charges relate to goodwill acquired in 2015 in connection with the Company's acquisition of Atlas Energy LP ("ATLS") and Atlas Pipeline Partners, LP ("APL") (collectively, the "Atlas mergers").

Other operating (income) expense in 2016 increased as the Company reported net gains on sales of assets in 2015.

Net interest expense increased primarily due to lower non-cash interest income related to the mandatorily redeemable preferred interest liability that is revalued quarterly at the estimated redemption value as of the reporting date. The estimated redemption value of the mandatorily redeemable preferred interests liability increased during 2016 as compared with a decrease in 2015. Other factors included lower capitalized interest due to decreased capital expenditures in 2016, partially offset by the impact of lower average outstanding borrowings during 2016.

The decrease in equity earnings (loss) was due to lower operating results from Gulf Coast Fractionators LP ("GCF").

During 2016, the Company recorded a $69.6 million loss from financing activities that included the tender of certain senior notes of the Partnership, redemption of certain senior notes of the Partnership and the write-off of debt issuance costs associated with the amendment of the TRP revolving credit facility. In 2015, the Company incurred a net gain from financing activities of $3.5 million from the Partnership's debt repurchases.

The change in income tax (expense) benefit was primarily due to the impact of the TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. Income attributable to noncontrolling interests is not subject to income taxes in our financial statements. Therefore, during most of 2016, we recorded income taxes on the majority of the pre-tax loss generated by TRP due to absence of the large noncontrolling interest in TRP.

Net income (loss) attributable to noncontrolling interests was significantly lower for 2016 due to the absence of the third-party common noncontrolling interest that was acquired in the February 2016 TRC/TRP Merger described above. The impact of the TRP buy-in was most pronounced during the fourth quarter of both years because each included significant losses as a result of the Company's annual goodwill impairment evaluations. The noncontrolling interest bore approximately 89% of the fourth quarter impairment loss in 2015 versus 0% in 2016.

Preferred dividends in 2016 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.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

The increase in commodity sales was primarily due to the favorable impact of the inclusion of two additional months of TPL's operations during 2016 ($270.1 million), partially offset by lower commodity prices ($53.7 million) and the impact of hedge settlements ($42.5 million). Additionally, fee-based and other revenues decreased primarily due to lower fractionation and export fees, partially offset by the impact of an additional two months of TPL's fee revenue in 2016 ($40.9 million).

The increase in product purchases was primarily due to the inclusion of two additional months of operations from TPL in 2016 ($137.5 million), partially offset by the impact of the lower commodity prices.

The lower operating margin and gross margin in 2016 reflects decreased segment margin results for Logistics and Marketing, partially offset by increased Gathering and Processing segment margins. Operating expenses increased slightly compared to 2015 due to the inclusion of TPL's operations for an additional two months in 2016, offset by a continued focused cost reduction effort throughout our operating areas. 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 expenses reflects an additional two months of TPL operations in 2016, growth investments from other system expansions including CBF Train 5, the Buffalo Plant, compressor stations and pipelines, and higher planned amortization of the Badlands intangible assets. Partially offsetting these factors was an additional $32.6 million charge to depreciation in 2015 to reflect an impairment of certain gas processing facilities and associated gathering systems in the Gathering and Processing segment due to market conditions and processing spreads in Louisiana.

General and administrative expenses, which include TPL operations for an additional two months in 2016, increased primarily due to higher compensation and benefits, partially offset by lower property insurance premiums.

The Company recognized impairments of goodwill totaling $207.0 million during 2016, as compared with the $290.0 million provisional impairment of goodwill recorded during the fourth quarter of 2015. Goodwill impairment recorded in 2016 includes $24.0 million recorded in the first quarter to finalize the 2015 provisional charge, as well as an additional $183.0 million associated with the Company's annual impairment evaluation in the fourth quarter of 2016. These impairment charges relate to goodwill acquired in the 2015 Atlas mergers.

Other operating (income) expense in 2016 includes 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, whereas in 2015 the Company reported a net gain on sales of assets.

Net interest expense increased primarily due to lower non-cash interest income related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date. The estimated redemption value of the mandatorily redeemable preferred interests liability decreased in 2016 by a lesser amount than in 2015. Other factors included lower capitalized interest due to decreased capital expenditures in 2016, partially offset by the impact of lower average outstanding borrowings during 2016.

The decrease in equity earnings (loss) was due to lower operating results from GCF and the inclusion of an additional two months of equity losses from the T2 Joint Ventures in 2016.

During 2016, the Company recorded a $48.2 million loss from financing activities that included the tender of $1,138.3 million of certain senior notes of the Partnership, the repurchase of $559.2 million of certain senior notes of the Partnership in open market purchases, and the redemption of $146.2 million of certain senior notes of the Partnership. In 2015, the Company incurred a net loss from financing activities of $10.1 million from the partial repayments of the TRC senior secured term loan and the repurchase of certain senior notes of the Partnership.

Other income (expense) in 2015 was primarily attributable to non-recurring transaction costs related to the Atlas mergers.

The change in income tax (expense) benefit was primarily due to the decrease in income (loss) before income taxes and the impact of the TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. Income attributable to noncontrolling interests is not subject to income taxes in our financial statements. Therefore, during most of 2016, we recorded income taxes on the majority of the pre-tax loss generated by TRP due to absence of the large noncontrolling interest in TRP.

Despite similar amounts of net losses in 2016 and 2015, net income (loss) attributable to noncontrolling interests was significantly lower for 2016 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. The impact of the TRP non-controlling common interest buy-in was most pronounced during the fourth quarter of both years which included significant losses as a result of our annual goodwill impairment evaluations. The noncontrolling interest bore approximately 89% of the fourth quarter impairment loss in 2015 and 0% in 2016. This reduction was partially offset by the impact of a full year of distributions in 2016 for the TRP's Preferred Units issued in October 2015.

Preferred dividends in 2016 represent both cash dividends on Series A Preferred Stock and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. The Series A Preferred Stock was issued on March 16, 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. For all operating statistics presented, the numerator is the total volume or sales during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.

The Company operates in two primary segments (previously referred to as divisions): (i) Gathering and Processing, previously disaggregated into two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing (also referred to as the Downstream Business), previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution.

Concurrent with the TRC/TRP Merger, management reevaluated the Company’s reportable segments and determined that its divisions are the appropriate level of disclosure for the Company’s reportable segments. The increase in activity within Field Gathering and Processing due to the Atlas mergers coupled with the decline in activity in the Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of the Logistics and Marketing division is no longer appropriate due to the integrated nature of the operations within TRC’s Downstream Business and its leadership by a consolidated executive management team.

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, 2016	Three Months Ended December 31, 2015	2016 vs. 2015		Year Ended December 31, 2016	Year Ended December 31, 2015	2016 vs. 2015	
Gross margin	$ 255.6	$ 221.1	$ 34.6	16%	$ 903.6	$ 830.1	$ 73.5	9%
Operating expenses	82.6	77.9	4.6	6%	326.5	315.0	11.5	4%
Operating margin	$ 173.0	$ 143.2	$ 30.0	21%	$ 577.1	$ 515.1	$ 62.0	12%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	271.1	241.3	29.8	12%	259.1	234.0	25.1	11%
WestTX (5)	528.4	462.0	66.4	14%	500.7	374.0	126.7	34%
Sand Hills (4)	130.5	154.0	(23.5)	(15%)	139.5	163.0	(23.5)	(14%)
Versado	196.3	185.9	10.4	6%	181.5	183.2	(1.7)	(1%)
Total Permian	1,126.3	1,043.2	83.1		1,080.8	954.2	126.6	
SouthTX (5)	206.7	140.3	66.4	47%	216.4	120.0	96.4	80%
North Texas	299.3	335.7	(36.4)	(11%)	317.3	347.6	(30.3)	(9%)
SouthOK (5)	450.0	470.7	(20.7)	(4%)	462.1	401.5	60.6	15%
WestOK (5)	413.1	510.3	(97.2)	(19%)	444.9	471.7	(26.8)	(6%)
Total Central	1,369.1	1,457.0	(87.9)		1,440.7	1,340.8	99.9	
Badlands (6)	49.5	56.9	(7.4)	(13%)	52.1	49.2	2.9	6%
Total Field	2,544.9	2,557.1	(12.2)		2,573.6	2,344.2	229.4	
Coastal	804.6	914.9	(110.4)	(12%)	838.4	897.0	(58.6)	(7%)
Total	3,349.5	3,472.0	(122.6)	(4%)	3,412.0	3,241.2	170.8	5%
Gross NGL production, MBbl/d (3)								
SAOU (4)	33.1	27.6	5.5	20%	31.8	27.3	4.5	16%
WestTX (5)	68.6	53.2	15.4	29%	62.7	43.4	19.3	44%
Sand Hills (4)	14.0	16.6	(2.6)	(16%)	14.7	17.4	(2.7)	(16%)
Versado	22.8	23.1	(0.3)	(1%)	21.7	23.4	(1.7)	(7%)
Total Permian	138.5	120.5	18.0		130.9	111.5	19.4	
SouthTX (5)	19.8	15.5	4.3	28%	23.8	13.8	10.0	72%
North Texas	34.2	37.9	(3.7)	(10%)	35.8	39.6	(3.8)	(10%)
SouthOK (5)	39.8	43.3	(3.5)	(8%)	39.4	28.1	11.3	40%
WestOK (5)	24.5	26.6	(2.1)	(8%)	27.1	23.8	3.3	14%
Total Central	118.3	123.3	(5.0)		126.1	105.3	20.8	
Badlands	6.7	8.5	(1.8)	(21%)	7.3	6.8	0.5	7%
Total Field	263.5	252.3	11.2		264.3	223.6	40.7	
Coastal	41.9	44.0	(2.1)	(5%)	41.2	41.8	(0.6)	(1%)
Total	305.4	296.3	9.1	3%	305.5	265.4	40.1	15%
Crude oil gathered, MBbl/d	103.5	108.8	(5.3)	(5%)	105.2	106.3	(1.1)	(1%)
Natural gas sales, BBtu/d (3)	1,584.4	1,690.2	(105.8)	(6%)	1,623.6	1,577.9	45.7	3%
NGL sales, MBbl/d	241.4	237.5	3.9	2%	241.3	208.3	33.0	16%
Condensate sales, MBbl/d	9.6	9.0	0.6	7%	9.9	9.1	0.8	9%
Average realized prices (7):								
Natural gas, $/MMBtu	2.68	2.05	0.63	31%	2.14	2.38	(0.24)	(10%)
NGL, $/gal	0.45	0.31	0.14	45%	0.36	0.35	0.01	3%
Condensate, $/Bbl	42.46	35.34	7.12	20%	36.20	41.86	(5.66)	(14%)

(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, including the volumes related to plants acquired in the APL merger.
(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.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended December 31, 2016 Compared to Three Months Ended December 31, 2015

The increase in gross margin was primarily due to higher commodity prices offset by lower throughput volumes. Total Field inlet volumes were down slightly, with increases at SAOU, WestTX, Versado and SouthTX offsetting decreases at the other areas. The inlet volume decrease for Coastal, which generates significantly lower margins than does Field, accounted for 90% of the overall inlet volume decrease. NGL production and NGL sales increased primarily due to increased plant recoveries due to additional ethane recovery and more efficient plant operations. Natural gas sales decreased due to lower inlet volumes and increased ethane recovery. Badlands natural gas and crude oil volumes decreased primarily due to the timing of producer well completion fracturing and associated shut-in of adjacent wells and to inclement weather.

Excluding the impact of a one-time expense reduction settlement recorded in the fourth quarter of 2015, operating expenses for most areas were lower due to a continued focused cost reduction effort.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for all of 2016 and an increase in NGL prices partially offset by lower natural gas and condensate prices and lower inlet volumes in WestOK and on certain of the Company's other systems. The plant inlet volume increase in SAOU was more than offset by reduced producer activity and volumes at Sand Hills (which also had operational issues), Versado and North Texas. Badlands natural gas volumes increased due to system expansions while crude oil volumes were essentially flat. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of including operating expenses for TPL for an additional two months in 2016 and system expansions, operating expenses for most areas were lower due to a continued focused cost reduction effort.

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, 2016			
Operating statistics: **Plant natural gas inlet, MMcf/d (1),(2)**	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	271.1	100%	271.1	271.1
WestTX (5)(6)	725.8	73%	528.4	528.4
Sand Hills (4)	130.5	100%	130.5	130.5
Versado (7)	196.3	100%	196.3	196.3
Total Permian	1,323.7		1,126.3	1,126.3
SouthTX	206.7	Varies (8)	194.5	206.7
North Texas	299.3	100%	299.3	299.3
SouthOK	450.0	Varies (9)	371.7	450.0
WestOK	413.1	100%	413.1	413.1
Total Central	1,369.1		1,278.6	1,369.1
Badlands (10)	49.5	100%	49.5	49.5
Total Field	2,742.3		2,454.4	2,544.9
Gross NGL production, MBbl/d (2)				
SAOU (4)	33.1	100%	33.1	33.1
WestTX (5)(6)	94.2	73%	68.6	68.6
Sand Hills (4)	14.0	100%	14.0	14.0
Versado (7)	22.8	100%	22.8	22.8
Total Permian	164.1		138.5	138.5
SouthTX	19.8	Varies (8)	18.7	19.8
North Texas	34.2	100%	34.2	34.2
SouthOK	39.8	Varies (9)	33.0	39.8
WestOK	24.5	100%	24.5	24.5
Total Central	118.3		110.4	118.3
Badlands	6.7	100%	6.7	6.7
Total Field	289.1		255.6	263.5

(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 period and the denominator is the number of calendar days during the period.
(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(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. Targa held a 63% interest in Versado until October 31, 2016, when it acquired the remaining 37% interest.
(8) SouthTX includes the Silver Oak II plant, of which TPL has owned a 90% interest since January 2016, and prior to which TPL owned 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) SouthOK includes the Centrahoma joint venture, of which TPL owns 60%, and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(10) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	259.1	100%	259.1	259.1
WestTX (5)(6)	687.8	73%	500.7	500.7
Sand Hills (4)	139.5	100%	139.5	139.5
Versado (7)	181.5	100%	181.5	181.5
Total Permian	1,267.9		1,080.8	1,080.8
SouthTX	216.4	Varies (8)	205.6	216.4
North Texas	317.3	100%	317.3	317.3
SouthOK	462.1	Varies (9)	382.0	462.1
WestOK	444.9	100%	444.9	444.9
Total Central	1,440.7		1,349.8	1,440.7
Badlands (10)	52.1	100%	52.1	52.1
Total Field	2,760.7		2,482.7	2,573.6
Gross NGL production, MBbl/d (2)				
SAOU (4)	31.8	100%	31.8	31.8
WestTX (5)(6)	86.1	73%	62.7	62.7
Sand Hills (4)	14.7	100%	14.7	14.7
Versado (7)	21.7	100%	21.7	21.7
Total Permian	154.3		130.9	130.9
SouthTX	23.8	Varies (8)	22.8	23.8
North Texas	35.8	100%	35.8	35.8
SouthOK	39.4	Varies (9)	32.6	39.4
WestOK	27.1	100%	27.1	27.1
Total Central	126.1		118.3	126.1
Badlands	7.3	100%	7.3	7.3
Total Field	287.7		256.5	264.3

(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 period and the denominator is the number of calendar days during the period.
(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(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. Targa held a 63% interest in Versado until October 31, 2016, when it acquired the remaining 37% interest.
(8) SouthTX includes the Silver Oak II plant, of which TPL has owned a 90% interest since January 2016, and prior to which TPL owned 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) SouthOK includes the Centrahoma joint venture, of which TPL owns 60%, and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company’s reported financials.
(10) 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 December 31,				**Year Ended December 31,**			
	2016	**2015**	**2016 vs. 2015**		**2016**	**2015**	**2016 vs. 2015**	
			(in millions)					
Gross margin	$ 207.0	$ 215.2	$ (8.2)	(4%)	$ 801.8	$ 907.5	$ $ (105.7)	(12%)
Operating expenses	57.1	52.5	4.6	9%	227.4	225.8	1.6	1%
Operating margin	$ 149.9	$ 162.7	$ (12.8)	(8%)	$ 574.4	$ 681.7	$ $ (107.3)	(16%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	298.6	327.7	(29.1)	(9%)	309.3	342.7	(33.4)	(10%)
LSNG treating volumes (2)	29.8	21.5	8.3	39%	24.9	22.4	2.5	11%
Benzene treating volumes (2)	24.1	21.5	2.6	12%	22.1	22.4	(0.3)	(1%)
Export volumes, MBbl/d (4)	206.4	192.0	14.4	8%	181.4	183.0	(1.6)	(1%)
NGL sales, MBbl/d	510.9	450.2	60.7	13%	477.5	422.1	55.4	13%
Average realized prices:								
NGL realized price, $/gal	$ 0.58	$ 0.44	$ 0.14	32%	$ 0.49	$ 0.46	$ $ 0.03	7%

(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 December 31, 2016 Compared to Three Months Ended December 31, 2015

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

Operating expenses increased primarily due to higher compensation and benefits, higher fuel and power and the startup of CBF Train 5, partially offset by lower ad valorem taxes as a result of an adjustment from forecasted to actual.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Logistics and Marketing gross margin decreased primarily due to lower LPG export margin and the realization in 2015 of contract renegotiation fees related to the Company's crude oil and condensate splitter project. Gross margin also decreased due to lower fractionation margin and lower terminaling and storage throughput, partially offset by higher NGL marketing gains. LPG export margin decreased due to lower fees. Fractionation margin decreased primarily due to lower supply volume and lower system product gains, partially offset by higher fees. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above).

Operating expenses were relatively flat. Higher compensation and benefits and higher ad valorem taxes associated with the start-up of CBF Train 5 were largely offset by lower fuel and power, and lower maintenance expense resulting from continued focused cost reductions.

Other

	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	2016 vs. 2015	Year Ended December 31, 2016	Year Ended December 31, 2015	2016 vs. 2015
	(in millions)					
Gross margin	$ 6.0	$ 23.5	$ (17.5)	$ 62.9	$ 84.2	$ (21.3)
Operating margin	$ 6.0	$ 23.5	$ (17.5)	$ 62.9	$ 84.2	$ (21.3)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities 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 Targa's commodity risk management activities is to mitigate a portion of the impact of commodity prices on its operating cash flow. The Company has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes and (ii) NGL and condensate equity volumes in its Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because the Company is essentially forward-selling a portion of its 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, 2016			Three Months Ended December 31, 2015		
	(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)	10.7	$ 0.31	$ 3.3	13.1	$ 1.10	$ 14.4
NGL (MMgal)	16.7	(0.01)	(0.1)	4.1	0.94	3.9
Crude oil (MBbl)	0.3	9.81	3.3	0.3	30.83	9.9
Non-hedge accounting (2)			(0.2)			(4.3)
Ineffectiveness (3)			(0.3)			(0.4)
			$ 6.0			$ 23.5

	Year Ended December 31, 2016			Year Ended December 31, 2015		
	(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)	44.7	$ 0.79	$ 35.2	34.2	$ 1.08	$ 37.0
NGL (MMgal)	31.9	0.21	6.8	28.4	0.77	22.0
Crude oil (MBbl)	1.1	17.14	19.5	0.9	31.81	29.3
Non-hedge accounting (2)			2.3			(5.0)
Ineffectiveness (3)			(0.9)			0.9
			$ 62.9			$ 84.2

(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 APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Company and included in the acquisition date fair value of assets acquired. Derivative settlements of $26.6 million and $67.9 million related to these novated contracts were received during the years ended December 31, 2016 and December 31, 2015, respectively, and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired with 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.

The principal executive offices of Targa are located at 1000 Louisiana, Suite 4300, Houston, TX 77002 and their telephone number is 713-584-1000. For more information please go to 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; 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 APL merger; non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; 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 expenses. 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 the Company's assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to the Company's 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 our 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 adjustments, 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 the Company's 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,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (150.8)	$ 27.0	$ (187.3)	$ 58.3
Impact of TRC/TRP Merger on NCI	—	(212.0)	(3.8)	(180.1)
Income attributable to TRP preferred limited partners	2.9	2.4	11.3	2.4
Interest expense, net	67.2	42.5	254.2	231.9
Income tax expense (benefit)	(96.8)	(14.5)	(100.6)	39.6
Depreciation and amortization expenses	194.1	228.8	757.7	677.1
Goodwill impairment	183.0	290.0	207.0	290.0
(Gain) loss on sale or disposition of assets	0.4	(7.8)	6.1	(8.0)
(Gain) loss from financing activities	69.6	(3.5)	48.2	10.1
(Earnings) loss from unconsolidated affiliates (1)	2.9	1.4	14.3	2.5
Distributions from unconsolidated affiliates and preferred partner interests, net (1)	4.9	3.8	17.5	21.1
Change in contingent consideration	(0.1)	(1.2)	(0.4)	(1.2)
Compensation on equity grants	7.5	6.0	29.7	25.0
Transaction costs related to business acquisitions (1)	—	—	—	27.3
Splitter Agreement (2)	10.8	—	10.8	—
Risk management activities	6.5	18.8	25.2	64.8
Other	—	0.6	—	0.6
Noncontrolling interests adjustments (3)	(4.5)	(56.3)	(25.0)	(69.7)
TRC Adjusted EBITDA	**$ 297.6**	**$ 326.0**	**$ 1,064.9**	**$ 1,191.7**
Distributions to TRP preferred limited partners	(2.9)	(2.4)	(11.3)	(2.4)
Cash received from payments under Splitter Agreement (2)	43.0	—	43.0	—
Splitter Agreement (2)	(10.8)	—	(10.8)	—
Interest expenses on debt obligations (4)	(62.7)	(68.9)	(263.8)	(253.3)
Cash tax (expense) benefit (5)	9.8	(15.0)	20.9	(15.0)
Maintenance capital expenditures	(29.4)	(24.9)	(85.7)	(97.9)
Noncontrolling interests adjustments of maintenance capex	1.6	1.3	5.2	7.2
Distributable Cash Flow	**$ 246.2**	**$ 216.1**	**$ 762.4**	**$ 830.3**

(1) The definition of Adjusted EBITDA was revised in 2015 to exclude earnings from unconsolidated investments net of distribution and transactions costs related to business acquisitions.
(2) In Adjusted EBITDA, the amount reflects the annual cash payment received for the Splitter Agreement recognized over the four quarters following receipt. In distributable cash flow, the amounts reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.
(3) Noncontrolling interest portion of depreciation and amortization expenses.
(4) Excludes amortization of interest expense.
(5) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is recognized over a period of six quarters beginning in Q3 2016.

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 December 31,		Year Ended December 31,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ (150.8)	$ 27.0	$ (187.3)	$ 58.3
Net income (loss) attributable to noncontrolling interests	10.2	(258.9)	28.2	(209.7)
Net income (loss)	(140.6)	(231.9)	(159.1)	(151.4)
Depreciation and amortization expenses	194.1	228.8	757.7	677.1
General and administrative expenses	48.9	25.2	187.2	161.7
Goodwill impairment	183.0	290.0	207.0	290.0
Interest expense, net	67.2	42.5	254.2	231.9
Income tax expense (benefit)	(96.8)	(14.5)	(100.6)	39.6
(Gain) loss on sale or disposition of assets	0.4	(7.8)	6.1	(8.0)
(Gain) loss from financing activities	69.6	(3.5)	48.2	10.1
Other, net	3.1	0.6	13.6	30.0
Operating margin	328.9	329.4	1,214.3	1,281.0
Operating expenses	139.7	130.4	553.7	540.0
Gross margin	**$ 468.6**	**$ 459.8**	**$ 1,768.0**	**$ 1,821.0**

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 Reports on Form 10-K, 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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