May 4, 2017

Targa Resources Corp. Reports First Quarter 2017 Financial Results

HOUSTON, May 04, 2017 (GLOBE NEWSWIRE) -- Targa Resources Corp. (NYSE:TRGP) ("TRC", the "Company" or "Targa") today reported first quarter 2017 results.

First Quarter 2017 Financial Results

First quarter 2017 net loss attributable to Targa Resources Corp. was ($119.3) million compared to ($2.7) million for the first quarter of 2016.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $276.7 million for the first quarter of 2017 compared to $264.7 million for the first quarter of 2016 (see the section of this release entitled "Targa Resources Corp. - Non-GAAP Financial Measures" for a discussion of Adjusted EBITDA, distributable cash flow, gross margin and operating margin, and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP")).

"The first quarter of 2017 was highlighted by the announcement and closing of the acquisition of additional assets in the Permian Basin, and we are very pleased with the integration. The strength of the outlook for our Midland and Delaware Basin footprints is exemplified by our announcement today that we are moving forward with two additional natural gas processing plants in those Basins representing an additional 450 MMcf/d of natural gas processing capacity," said Joe Bob Perkins, Chief Executive Officer of the Company. "Our first quarter financial results were in-line with our expectations with Adjusted EBITDA 5% higher when compared to the first quarter of 2016, and we expect our financial performance to strengthen further in the second half of this year. Strong long-term market fundamentals underpin the growth trajectory for our Gathering and Processing and Downstream segments and are driving attractive opportunities for additional midstream infrastructure, which provides us with greater visibility for potential cash flow growth in 2018, 2019 and beyond."

On April 19, 2017, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended March 31, 2017, or $3.64 per share on an annualized basis. Total cash dividends of approximately $180.3 million will be paid on May 16, 2017 on all outstanding shares of common stock to holders of record as of the close of business on May 2, 2017. Also on April 19, 2017, TRC declared a quarterly cash dividend of $23.75 per share of its Series A Preferred Stock. Total cash dividends of approximately $22.9 million will be paid on May 15, 2017 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on May 2, 2017.

The Company reported distributable cash flow for the first quarter of 2017 of $194.0 million compared to total common dividends to be paid of $180.3 million and total Series A Preferred Stock dividends to be paid of $22.9 million.

First Quarter 2017 - Capitalization, Liquidity and Financing

On March 14, 2017, TRC used borrowings under its senior secured revolving credit facility ("TRC Revolver") to repay in full the $160.0 million outstanding balance on its senior secured term loan. Targa's total consolidated debt as of March 31, 2017 was $4,748.2 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility due 2020. The consolidated debt included $4,313.2 million of Targa Resource Partners LP ("TRP" or "the Partnership") debt, net of $29.1 million of debt issuance costs, with no amounts outstanding under TRP's $1.6 billion senior secured revolving credit facility due 2020, $285.0 million outstanding under TRP's accounts receivable securitization facility (the "Securitization Facility") and $4,057.3 million of outstanding TRP senior notes, net of unamortized discounts and premiums.

As of March 31, 2017, TRC had available senior secured revolving credit facility capacity of $235.0 million. TRP had no borrowings outstanding under its $1.6 billion senior secured revolving credit facility and $15.8 million in outstanding letters of credit, resulting in available senior secured revolving credit facility capacity of $1,584.2 million at the Partnership. Total Targa consolidated liquidity as of March 31, 2017, including $80.0 million of cash, was approximately $1.9 billion.

On February 23, 2017, the Securitization Facility was amended to increase the facility size to $350.0 million from $275.0 million.

Permian Acquisition

On March 1, 2017, Targa closed the purchase of 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together "New Delaware") and Outrigger Midland Operating, LLC ("New Midland" and together with New Delaware, the "Permian Acquisition").

Targa paid $484.1 million in cash at closing on March 1, 2017 and will pay $90.0 million within 90 days of closing. Subject to certain performance-linked measures and other conditions, additional cash of up to $935.0 million may be payable to the sellers of New Delaware and New Midland 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 contracts that existed on March 1, 2017.

New Delaware's gas gathering and processing and crude gathering assets are located in Loving, Winkler and Ward counties in Texas. 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. The New Delaware assets include 70 MMcf/d of processing capacity and an uninstalled 60 MMcf/d plant, which Targa is in the process of installing in the Delaware Basin with expectations of commencing operations in late 2017. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Delaware system.

New Midland's gas gathering and processing and crude gathering assets are located in Howard, Martin and Borden counties in Texas. 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 13 years. The New Midland assets include 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Midland system.

New Delaware's gas gathering and processing assets were connected to Targa's Sand Hills system in the first quarter of 2017, and the Company expects that New Midland's gas gathering and processing assets will be connected to its existing WestTX system during 2017. Targa believes connecting the acquired assets to its legacy Permian footprint creates operational and capital synergies, and will afford enhanced flexibility in serving its producer customers.

On January 26, 2017, TRC completed a public offering of 9,200,000 shares of its common stock (including the shares sold pursuant to the underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. Targa used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes.

2017 Forecasted Capital Expenditures Update

In addition to the already announced 200 MMcf/d Joyce plant, Targa plans to build an additional plant and expand the gathering and processing footprint of its Permian Midland system in the Midland Basin. This project includes a new 200 MMcf/d cryogenic processing plant, known as the Johnson plant, which is expected to begin operations in the third quarter of 2018. Total net growth capital expenditures (net to the Company's 72.8% interest) for the Johnson plant is expected to approximate $90 million.

In addition to the already announced 60 MMcf/d Oahu plant, Targa plans to build an additional plant and expand the gathering and processing footprint of its Permian Delaware system in the Delaware Basin. This project includes a new 250 MMcf/d cryogenic processing plant, known as the Wildcat plant, which is expected to begin operations in the third quarter of 2018. Total net growth capital expenditures (100% Targa owned) for the Wildcat plant is expected to approximate $130 million.

The Company plans to invest approximately $150 million, an increase of $75 million from its previously disclosed forecast, to expand its crude gathering and natural gas processing business in the Williston Basin, North Dakota. The expansion includes the addition of pipelines, LACT units, compression and other infrastructure to support continued growth in Bakken producer activity.

Including spending related to the Johnson and Wildcat plants and additional growth capital to support increasing activity levels around the Company's assets, Targa now expects 2017 net growth capital expenditures for announced projects will be at least $960.0 million, an increase from the previously disclosed $700.0 million. Targa continues to expect that 2017 net maintenance capital expenditures will be approximately $110.0 million.

Conference Call

The Company will host a conference call for the investment community at 11:00 a.m. Eastern time (10:00 a.m. Central time) on May 4, 2017 to discuss first quarter 2017 results. The conference call can be accessed via webcast through the Events and Presentations section of Targa's website at www.targaresources.com, by going directly to http://ir.targaresources.com/trc/events.cfm or by dialing 877-881-2598. The conference ID number for the dial-in is 10170032. 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, or directly at http://ir.targaresources.com/trc/events.cfm.

Targa Resources Corp. — Consolidated Financial Results of Operations

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	2017 vs. 2016	
	(In millions, except operating statistics and price amounts)			
Revenues				
Sales of commodities	$ 1,858.1	$ 1,171.0	$ 687.1	59 %
Fees from midstream services	254.5	271.4	(16.9)	(6 %)
Total revenues	2,112.6	1,442.4	670.2	46 %
Product purchases	1,654.2	1,011.0	643.2	64 %
Gross margin (1)	458.4	431.4	27.0	6 %
Operating expenses	151.9	132.1	19.8	15 %
Operating margin (1)	306.5	299.3	7.2	2 %
Depreciation and amortization expense	191.1	193.5	(2.4)	(1 %)
General and administrative expense	48.7	45.3	3.4	8 %
Goodwill impairment	—	24.0	(24.0)	(100 %)
Other operating (income) expense	16.2	1.0	15.2	NM
Income from operations	50.5	35.5	15.0	42 %
Interest expense, net	(63.0)	(52.9)	(10.1)	19 %
Equity earnings (loss)	(12.6)	(4.8)	(7.8)	163 %
Gain (loss) from financing activities	(5.8)	24.7	(30.5)	(123 %)
Other income (expense)	(8.5)	(0.1)	(8.4)	NM
Income tax (expense) benefit	(71.1)	(3.1)	(68.0)	NM
Net income (loss)	(110.5)	(0.7)	(109.8)	NM
Less: Net income attributable to noncontrolling interests	8.8	2.0	6.8	NM
Net income (loss) attributable to Targa Resources Corp.	(119.3)	(2.7)	(116.6)	NM
Dividends on Series A preferred stock	22.9	3.8	19.1	NM
Deemed dividends on Series A preferred stock	6.1	—	6.1	—
Net income (loss) attributable to common shareholders	$ (148.3)	$ (6.5)	$ (141.8)	NM
Financial and operating data:				
Financial data:				
Adjusted EBITDA (1)	$ 276.7	$ 264.7	$ 12.0	5 %
Distributable cash flow (1)	194.0	178.0	16.0	9 %
Capital expenditures	174.6	176.9	(2.3)	(1 %)
Business acquisition (2)	1,032.4	—	1,032.4	—
Operating statistics: (3)				
Crude oil gathered, Badlands, MBbl/d	113.5	108.1	5.4	5 %
Crude oil gathered, Permian, MBbl/d (4)	9.2	—	9.2	—
Plant natural gas inlet, MMcf/d (5) (6)	3,242.1	3,406.0	(163.9)	(5 %)
Gross NGL production, MBbl/d	291.8	284.7	7.1	2 %
Export volumes, MBbl/d (7)	217.5	181.0	36.5	20 %
Natural gas sales, BBtu/d (6) (8)	1,870.2	1,974.6	(104.4)	(5 %)
NGL sales, MBbl/d (8)	533.6	547.8	(14.2)	(3 %)
Condensate sales, MBbl/d	10.7	9.5	1.2	13 %

(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 $90.0 million payable which will be settled within 90 days from March 1, 2017, and the preliminary acquisition date fair value of the potential earn-out payments of $461.6 million due in 2018 and 2019.

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

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

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

(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(7) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine Terminal that are destined for international markets.

(8) Includes the impact of intersegment eliminations.

NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

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

The increase in commodity sales was primarily due to higher commodity prices ($757.8 million), partially offset by decreased volumes ($45.4 million) and the impact of hedge settlements ($25.3 million). Additionally, fee-based and other revenues decreased primarily due to lower export fees.

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

The higher operating margin and gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating expenses increased compared to 2016 due to higher maintenance in the Logistics and Marketing segment and plant and system expansions in the Permian region. 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 reflects the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles, partially offset by one month of operations of the Permian Acquisition in 2017 and the impact of growth investments, primarily CBF Train 5 which went into service in June 2016.

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

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

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

Net interest expense increased primarily due to higher non-cash interest expense related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date. The estimated redemption value of the mandatorily redeemable preferred interests increased in 2017, whereas it decreased in 2016. This increase was partially offset by the impact of lower average outstanding borrowings during 2017.

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

During 2017, the Company recorded a loss of $5.8 million on the repayment of the outstanding balance on its senior secured term loan, whereas in 2016 the Company recorded a gain of $24.7 million on open debt market repurchases and other financing activities.

Other expense in 2017 was primarily attributable to $5.1 million of non-recurring transaction costs related to the Permian Acquisition and a $3.2 million increase in the fair value of the Permian Acquisition contingent consideration liability from the acquisition date to March 31, 2017.

Income tax expense for the first quarter of 2017 reflects our current estimates for full-year effective tax rate and full-year earnings. The full-year estimates anticipate a tax benefit, rather than expense, on estimated full year earnings and therefore a negative tax rate to reflect the tax benefit. The negative tax rate that is estimated on a full-year basis is applied to our first quarter loss, so the first quarter reflects income tax expense rather than benefit. We currently estimate that the first quarter income tax expense will be more than offset by income tax benefit over the remainder of the year.

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

Review of Segment Performance

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

The Company operates in two primary segments: (i) Gathering and Processing; and (ii) Logistics and Marketing (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 March 31,		2017 vs. 2016	
	2017	2016		
Gross margin	$ 263.0	$ 194.1	$ 68.9	35%
Operating expenses	85.6	78.5	7.1	9%
Operating margin	$ 177.4	$ 115.6	$ 61.8	53%
Operating statistics (1):				
Plant natural gas inlet, MMcf/d (2),(3)				
SAOU (4)	275.6	243.5	32.1	13%
WestTX	536.5	461.0	75.5	16%
Total Permian Midland	812.1	704.5	107.6	
Sand Hills (4)	139.5	151.1	(11.6)	(8%)
Versado	198.5	180.0	18.5	10%
Total Permian Delaware	338.0	331.1	6.9	
Total Permian	1,150.1	1,035.6	114.5	
SouthTX	171.8	175.7	(3.9)	(2%)

North Texas	282.5	327.5	(45.0)	(14%)
SouthOK	440.4	457.9	(17.5)	(4%)
WestOK	393.1	487.0	(93.9)	(19%)
Total Central	1,287.8	1,448.1	(160.3)	
Badlands (5)	46.0	53.7	(7.7)	(14%)
Total Field	2,483.9	2,537.4	(53.5)	
Coastal	758.2	868.6	(110.4)	(13%)
Total	3,242.1	3,406.0	(163.9)	(5%)
Gross NGL production, MBbl/d (3)				
SAOU (4)	33.3	29.2	4.1	14%
WestTX	69.5	52.4	17.1	33%
Total Permian Midland	102.8	81.6	21.2	
Sand Hills (4)	14.8	15.7	(0.9)	(6%)
Versado	23.1	21.9	1.2	5%
Total Permian Delaware	37.9	37.6	0.3	
Total Permian	140.7	119.2	21.5	
SouthTX	16.6	23.1	(6.5)	(28%)
North Texas	32.0	35.7	(3.7)	(10%)
SouthOK	40.9	28.0	12.9	46%
WestOK	22.8	26.9	(4.1)	(15%)
Total Central	112.3	113.7	(1.4)	
Badlands	5.5	7.6	(2.1)	(28%)
Total Field	258.5	240.5	18.0	
Coastal	33.3	44.2	(10.9)	(25%)
Total	291.8	284.7	7.1	2%
Crude oil gathered, Badlands, MBbl/d	113.5	108.1	5.4	5%
Crude oil gathered, Permian, MBbl/d (4)	9.2	—	9.2	—
Natural gas sales, BBtu/d (3)	1,562.2	1,687.2	(125.0)	(7%)
NGL sales, MBbl/d	227.6	219.3	8.3	4%
Condensate sales, MBbl/d	10.7	9.5	1.2	13%
Average realized prices (6):				
Natural gas, $/MMBtu	2.86	1.75	1.11	63%
NGL, $/gal	0.50	0.28	0.22	79%
Condensate, $/Bbl	44.98	25.65	19.33	75%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

(2) Plant natural gas inlet represents the Company's undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.

(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.

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

(6) Average realized prices exclude the impact of hedging activities presented in Other.

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

The increase in gross margin was primarily due to higher commodity prices and the inclusion of the Permian Acquisition for one month in 2017 partially offset by lower throughput volumes. Inlet volumes for Field Gathering and Processing were slightly lower with increases at WestTX, SAOU and Versado offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing which generates significantly lower margins than does Field Gathering and Processing, accounted for over 67% of the overall inlet volume decrease. Despite overall lower inlet volumes, NGL production and NGL sales increased primarily due to increased plant recoveries including additional ethane recovery. Natural gas sales decreased due to lower inlet volumes and increased ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition and in Badlands due to system expansions. Badlands natural gas volumes decreased primarily due to severe winter weather.

The increase in operating expenses was primarily driven by plant and system expansions in the Permian region and the inclusion of the Permian Acquisition for one month of 2017. Operating expenses in other areas were relatively flat.

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 March 31, 2017			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU (4)	275.6	100%	275.6	275.6
WestTX (5) (6)	736.9	73%	536.5	536.5
Total Permian Midland	1,012.5		812.1	812.1
Sand Hills (4)	139.5	100%	139.5	139.5
Versado (7)	198.5	100%	198.5	198.5
Total Permian Delaware	338.0		338.0	338.0
Total Permian	1,350.5		1,150.1	1,150.1
SouthTX	171.8	Varies (8)	161.6	171.8
North Texas	282.5	100%	282.5	282.5
SouthOK	440.4	Varies (9)	366.1	440.4
WestOK	393.1	100%	393.1	393.1
Total Central	1,287.8		1,203.3	1,287.8
Badlands (10)	46.0	100%	46.0	46.0
Total	2,684.3		2,399.4	2,483.9
Gross NGL production, MBbl/d (2)				
SAOU (4)	33.3	100%	33.3	33.3
WestTX (5) (6)	95.5	73%	69.5	69.5
Total Permian Midland	128.8		102.8	102.8
Sand Hills (4)	14.8	100%	14.8	14.8
Versado (7)	23.1	100%	23.1	23.1
Total Permian Delaware	37.9		37.9	37.9
Total Permian	166.7		140.7	140.7
SouthTX	16.6	Varies (8)	15.7	16.6
North Texas	32.0	100%	32.0	32.0
SouthOK	40.9	Varies (9)	34.2	40.9
WestOK	22.8	100%	22.8	22.8
Total Central	112.3		104.7	112.3

Badlands	5.5	100 %	5.5	5.5
Total	284.5		250.9	258.5

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

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

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

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

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

(8) SouthTX includes the Silver Oak II plant, of which Targa Pipeline Partners, L.P. ("TPL") has owned a 90% interest since October 2015, 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.

	Three Months Ended March 31, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
SAOU	243.5	100 %	243.5	243.5
WestTX (4)	633.2	73 %	461.0	461.0
Total Permian Midland	876.7		704.5	704.5
Sand Hills	151.1	100 %	151.1	151.1
Versado (5)	180.0	63 %	113.4	180.0
Total Permian Delaware	331.1		264.5	331.1
Total Permian	1,207.8		969.0	1,035.6
SouthTX	175.7	100 %	175.7	175.7
North Texas	327.5	100 %	327.5	327.5
SouthOK	457.9	Varies (6)	380.9	457.9
WestOK	487.0	100 %	487.0	487.0
Total Central	1,448.1		1,371.1	1,448.1
Badlands (7)	53.7	100 %	53.7	53.7
Total	2,709.6		2,393.8	2,537.4
Gross NGL production, MBbl/d (2)				
SAOU	29.2	100 %	29.2	29.2
WestTX (4)	72.0	73 %	52.4	52.4
Total Permian Midland	101.2		81.6	81.6
Sand Hills	15.7	100 %	15.7	15.7
Versado (5)	21.9	63 %	13.8	21.9

Total Permian Delaware	37.6		29.5	37.6
Total Permian	138.8		111.1	119.2
SouthTX	23.1	100 %	23.1	23.1
North Texas	35.7	100 %	35.7	35.7
SouthOK	28.0	Varies (6)	24.7	28.0
WestOK	26.9	100 %	26.9	26.9
Total Central	113.7		110.4	113.7
Badlands	7.6	100 %	7.6	7.6
Total	260.1		229.1	240.5

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

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

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

(6) 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.

(7) 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 March 31,			
	2017	**2016**	**2017 vs. 2016**	
	(In millions)			
Gross margin	$ 196.4	$ 210.6	$ (14.2)	(7 %)
Operating expenses	66.3	53.6	12.7	24 %
Operating margin	$ 130.1	$ 157.0	$ (26.9)	(17 %)
Operating statistics MBbl/d (1):				
Fractionation volumes (2)(3)	304.9	295.5	9.4	3 %
LSNG treating volumes (2)	34.5	21.0	13.5	64 %
Benzene treating volumes (2)	23.5	21.0	2.5	12 %
Export volumes, MBbl/d (4)	217.5	181.0	36.5	20 %
NGL sales, MBbl/d	502.0	482.0	20.0	4 %
Average realized prices:				

NGL realized price, $/gal	$ 0.66	$ 0.41	$ 0.25	61 %

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

Logistics and Marketing gross margin decreased due to lower LPG export margin and lower wholesale and marketing margin, partially offset by higher fractionation margin, higher terminaling and storage throughput and higher treating margin. LPG export margin decreased due to lower fees partially offset by higher volumes. Wholesale and marketing margin decreased primarily due to less favorable wholesale supply opportunities in 2017 compared to the same period last year and lower marketing gains. Fractionation margin increased due to higher system product gains, higher fees and higher supply volume. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Treating margin increased slightly due to higher volumes partially offset by lower fees.

Operating expenses increased due to higher maintenance primarily associated with unusual one-time events, higher fuel and power, and higher compensation and benefits.

Other

	Three Months Ended March 31,		
	2017	2016	2017 vs. 2016
		(In millions)	
Gross margin	$ (1.0)	$ 26.8	$ (27.8)
Operating margin	$ (1.0)	$ 26.8	$ (27.8)

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 March 31, 2017			Three Months Ended March 31, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	10.5	$ 0.02	$ 0.2	9.5	$ 1.40	$ 13.2	$ (13.0)
NGL (MMgal)	43.3	(0.04)	(1.8)	14.3	0.27	3.8	(5.6)
Crude oil (MBbl)	0.2	5.35	1.2	0.2	35.22	7.1	(5.9)
Non-hedge accounting (2)			(0.8)			2.7	(3.5)

Ineffectiveness (3)	0.2	—	0.2
	$ (1.0)	$ 26.8	$ (27.8)

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

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

(3) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of TPL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of February 27, 2015 (the "acquisition date"), were novated to the Company and included in the acquisition date fair value of assets acquired. The Company received derivative settlements of $3.0 million for the three months ended March 31, 2017 and $8.7 million for the three months ended March 31, 2016, related to these novated contracts. From the acquisition date through March 31, 2017, the Company has received total derivative settlements of $97.6 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

About Targa Resources Corp.

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

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

Targa Resources Corp. - Non-GAAP Financial Measures

This press release includes the Company's non-GAAP financial measures Adjusted EBITDA, distributable cash flow, gross margin and operating margin. The 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 merger with Atlas Pipeline Partners L.P. in 2015; 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 March 31,	
	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	$ (119.3)	$ (2.7)
Impact of TRC/TRP Merger on NCI	—	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8
Interest expense, net	63.0	52.9
Income tax expense (benefit)	71.1	3.1
Depreciation and amortization expense	191.1	193.5
Goodwill impairment	—	24.0
(Gain) loss on sale or disposition of assets	16.1	0.9
(Gain) loss from financing activities	5.8	(24.7)
(Earnings) loss from unconsolidated affiliates	12.6	4.8
Distributions from unconsolidated affiliates and preferred partner interests, net	4.2	5.8
Change in contingent consideration	3.3	—
Compensation on equity grants	10.8	8.0
Transaction costs related to business acquisitions	5.1	—
Splitter Agreement (1)	10.8	—
Risk management activities	3.6	5.9
Noncontrolling interests adjustments (2)	(4.3)	(5.8)
TRC Adjusted EBITDA	**$ 276.7**	**$ 264.7**
Distributions to TRP preferred limited partners	(2.8)	(2.8)

Splitter Agreement (1)	(10.8)	—
Interest expense on debt obligations (3)	(59.0)	(69.7)
Cash tax (expense) benefit (4)	15.3	—
Maintenance capital expenditures	(25.7)	(15.0)
Noncontrolling interests adjustments of maintenance capex	0.3	0.8
Distributable Cash Flow	**$ 194.0**	**$ 178.0**

(1) 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.

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

(3) Excludes amortization of interest expense.

(4) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is recognized over a period of six quarters beginning in Q3 2016, and a refund of Texas margin tax paid in previous periods and received in 2017.

Gross Margin

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

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

Logistics and Marketing segment gross margin consists primarily of

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

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

Operating Margin

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

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

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

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

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

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

	Three Months Ended March 31,	
	2017	2016
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:		
Net income (loss) attributable to TRC	$ (119.3)	$ (2.7)
Net income (loss) attributable to noncontrolling interests	8.8	2.0
Net income (loss)	(110.5)	(0.7)
Depreciation and amortization expense	191.1	193.5
General and administrative expense	48.7	45.3
Goodwill impairment	—	24.0
Interest expense, net	63.0	52.9
Income tax expense (benefit)	71.1	3.1
(Gain) loss on sale or disposition of assets	16.1	0.9
(Gain) loss from financing activities	5.8	(24.7)
Other, net	21.2	5.0
Operating margin	306.5	299.3
Operating expenses	151.9	132.1
Gross margin	**$ 458.4**	**$ 431.4**

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 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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