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Targa Resources Corp. Reports
First Quarter 2018 Financial Results

HOUSTON – May 3, 2018 - Targa Resources Corp. (NYSE: TRGP) ("TRC", the "Company" or "Targa") today reported first quarter 2018 results.

First Quarter 2018 Financial Results

First quarter 2018 net income (loss) attributable to Targa Resources Corp. was $22.9 million compared to ($119.3) million for the first quarter of 2017.

The Company reported earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("Adjusted EBITDA") of $306.6 million for the first quarter of 2018 compared to $276.7 million for the first quarter of 2017 (see the section of this release entitled "Targa Resources Corp. - Non-GAAP Financial Measures" for a discussion of Adjusted EBITDA, distributable cash flow, gross margin and operating margin, and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP")).

"Our first quarter operational and financial performance was in-line with our expectations, and strong progress continued on our multiple capital projects underway. Our Joyce Plant is now operational providing much needed relief to our Midland Basin system. We also recently announced attractive Delaware Basin and Grand Prix expansions, which further leverage our existing integrated assets and position us to effectively compete for additional volumes," said Joe Bob Perkins, Chief Executive Officer of Targa. "We remain focused on enhancing our attractive long-term outlook through continued execution across all areas of our business."

On April 18, 2018, TRC declared a quarterly dividend of $0.91 per share of its common stock for the three months ended March 31, 2018, or $3.64 per share on an annualized basis. Total cash dividends of approximately $199.7 million will be paid on May 15, 2018 on all outstanding shares of common stock to holders of record as of the close of business on May 1, 2018. Also on April 18, 2018, TRC declared a quarterly cash dividend of $23.75 per share of its Series A Preferred Stock. Total cash dividends of approximately $22.9 million will be paid on May 14, 2018 on all outstanding shares of Series A Preferred Stock to holders of record as of the close of business on May 1, 2018.

The Company reported distributable cash flow for the first quarter of 2018 of $216.4 million compared to total common dividends to be paid of $199.7 million and total Series A Preferred Stock dividends to be paid of $22.9 million.

First quarter 2018 - Capitalization, Liquidity and Financing

The Company's total consolidated debt as of March 31, 2018 was $5,364.2 million including $435.0 million outstanding under TRC's $670.0 million senior secured revolving credit facility due 2020. The consolidated debt included $4,929.2 million of Targa Resources Partners LP ("TRP" or "the Partnership") debt, net of $28.8 million of debt issuance costs, with $380.0 million outstanding under TRP's $1.6 billion senior secured revolving credit facility due 2020, $300.0 million outstanding under TRP's accounts receivable securitization facility and $4,278.0 million of outstanding TRP senior unsecured notes.

Total consolidated liquidity of the Company as of March 31, 2018, including $219.8 million of cash, was approximately $1.7 billion. As of March 31, 2018, TRC had available borrowing capacity under its senior secured revolving credit facility of $235.0 million. TRP had $380.0 million of borrowings and $25.9 million in letters of credit outstanding under its $1.6 billion senior secured revolving credit facility, resulting in available senior secured revolving credit facility capacity of $1,194.1 million. In addition to the availability under its senior secured revolving credit facility, the Partnership also had $50.0 million of availability under its accounts receivable securitization facility.

During the three months ended March 31, 2018, the Company issued 1,162,963 shares of common stock under an equity distribution agreement entered into in December 2016, resulting in net proceeds of $57.7 million.

In April 2018, TRC issued 640,228 shares of common stock under an equity distribution agreement entered into in May 2017, resulting in net proceeds of $29.0 million.

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of 5⅞% senior notes due April 2026. The Partnership used the net proceeds of $992.3 million after costs from the offering to repay borrowings under its credit facilities and for general partnership purposes. Including the April 2018 senior notes issuance, TRC's pro forma consolidated liquidity as of March 31, 2018 was approximately $2.7 billion.

Sale of Inland Marine Barge Business

Targa executed agreements on May 1, 2018 to sell its inland marine barge business to Kirby Corp. (NYSE: KEX) for approximately $69.3 million. Subject to customary regulatory approvals and other closing conditions, the transaction is expected to close during the second quarter, and Targa intends to use the sale proceeds to fund a portion of its capital growth program underway.

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 3, 2018 to discuss first quarter 2018 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 6449338. Please dial in ten minutes prior to the scheduled start time. A replay will be available approximately two hours following the completion of the webcast through the Investors section of the Company's website. Presentation slides will also be available in the Events and Presentations section of the Company's website, or directly at http://ir.targaresources.com/trc/events.cfm.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended March 31,			
	2018	2017	2018 vs. 2017	
	(In millions, except operating statistics and price amounts)			
Revenues				
Sales of commodities	$ 2,173.7	$ 1,858.1	$ 315.6	17%
Fees from midstream services	281.9	254.5	27.4	11%
Total revenues	2,455.6	2,112.6	343.0	16%
Product purchases	1,941.0	1,654.2	286.8	17%
Gross margin (1)	514.6	458.4	56.2	12%
Operating expenses	173.2	151.9	21.3	14%
Operating margin (1)	341.4	306.5	34.9	11%
Depreciation and amortization expense	198.1	191.1	7.0	4%
General and administrative expense	56.7	48.7	8.0	16%
Other operating (income) expense	0.3	16.2	(15.9)	(98%)
Income (loss) from operations	86.3	50.5	35.8	71%
Interest income (expense), net	16.1	(63.0)	79.1	126%
Equity earnings (loss)	1.5	(12.6)	14.1	112%
Gain (loss) from financing activities	—	(5.8)	5.8	100%
Change in contingent considerations	(56.1)	(3.3)	(52.8)	NM
Other income (expense), net	—	(5.2)	5.2	100%
Income tax (expense) benefit	(8.9)	(71.1)	62.2	87%
Net income (loss)	38.9	(110.5)	149.4	135%
Less: Net income (loss) attributable to noncontrolling interests	16.0	8.8	7.2	82%
Net income (loss) attributable to Targa Resources Corp.	22.9	(119.3)	142.2	119%
Dividends on Series A Preferred Stock	22.9	22.9	—	—
Deemed dividends on Series A Preferred Stock	7.0	6.1	0.9	15%
Net income (loss) attributable to common shareholders	$ (7.0)	$ (148.3)	$ 141.3	95%
Financial and operating data:				
Financial data:				
Adjusted EBITDA (1)	$ 306.6	$ 276.7	$ 29.9	11%
Distributable cash flow (1)	216.4	194.0	22.4	12%
Capital expenditures	558.0	174.6	383.4	220%
Business acquisition (2)	—	1,032.4	(1,032.4)	(100%)
Operating statistics: (3)				
Crude oil gathered, Badlands, MBbl/d	117.7	113.5	4.2	4%
Crude oil gathered, Permian, MBbl/d (4)	49.4	9.2	40.2	NM
Plant natural gas inlet, MMcf/d (5) (6)	3,752.3	3,223.6	528.7	16%
Gross NGL production, MBbl/d	386.9	288.7	98.2	34%
Export volumes, MBbl/d (7)	201.9	217.5	(15.6)	(7%)
Natural gas sales, BBtu/d (6) (8)	2,107.1	1,813.3	293.8	16%
NGL sales, MBbl/d (8)	574.9	533.6	41.3	8%
Condensate sales, MBbl/d	16.2	10.7	5.5	51%

(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 $416.3 million acquisition date fair value of the potential earn-out payments.
(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 the Company's 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, 2018 Compared to Three Months Ended March 31, 2017

The increase in commodity sales was primarily due to increased commodity volumes ($244.8 million) and higher NGL and condensate prices ($206.6 million), partially offset by lower natural gas and petroleum product prices ($103.7 million) and the impact of hedges ($32.0 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases was primarily due to increased volumes and higher NGL and condensate prices.

The higher operating margin and gross margin in 2018 reflects increased segment margin results for Gathering and Processing and Logistics and Marketing. Operating expenses increased compared to 2017 primarily due to plant and system expansions in the Permian region, the inclusion of the Permian Acquisition for a full quarter in 2018 as compared with one month in 2017 and the commencement in operations of the Raptor Plant at SouthTX in June 2017. See "—Review of Segment Performance" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased primarily due to the impact of the Permian Acquisition for a full quarter in 2018 and other growth investments.

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

Other operating (income) expense in 2017 includes the loss due to the reduction in the carrying value of the Company's 100% ownership interest in Venice Gathering, L.L.C., which the Company sold in April 2017.

The change in interest income (expense), net was primarily due to higher non-cash interest income related to the mandatorily redeemable preferred interests that is revalued quarterly at the estimated redemption value as of the reporting date, as well as higher capitalized interest. These factors more than offset the impact of higher average outstanding borrowings during 2018. The decrease in the estimated redemption value of the mandatorily redeemable preferred interests is primarily attributable to the February 2018 amendments to the agreements governing the WestTX and WestOK joint ventures.

Equity earnings increased in 2018, which reflects the commencement of operations at the Cayenne Pipeline, LLC joint venture, increased equity earnings at Gulf Coast Fractionators LP, and decreased equity losses from the T2 Joint Ventures, which in 2017 included a $12.0 million loss provision due to the impairment of the Company's investment in the T2 EF Cogen joint venture.

During 2017, the Company recorded a loss from financing activities of $5.8 million on the repayment of the outstanding balance on the Company's senior secured term loan.

During 2018, the Company recorded expense of $56.1 million resulting from the change in the fair value of contingent considerations, substantially all of which was due to the increase in fair value as of March 31, 2018 of the Permian Acquisition contingent consideration liability, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date. The increase in fair value of the contingent consideration during the three months ended March 31, 2018 was primarily related to an increase in underlying forecasted volumes for the remainder of the earn-out period and a shorter term over which such projections are discounted. The fair value of the contingent consideration represents the Company's current view of the future payment amounts, and may decrease or increase until the settlement dates, resulting in the recognition of additional other income (expense). During 2017, the Company recorded other expense of $3.2 million resulting from an increase in the fair value of the Permian Acquisition contingent consideration liability from the acquisition date to March 31, 2017.

Other expense in 2017 was primarily attributable to $5.1 million of non-recurring transaction costs related to the Permian Acquisition.

The income tax expense decreased in 2018 as compared with 2017. In 2017, the first quarter estimate for the full year effective tax rate resulted in a negative tax rate when applied to the first quarter loss. The first quarter 2018 estimate for the full year effective tax rate has normalized and does not have the inverse relationship with first quarter earnings that existed in 2017.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Company's consolidated joint ventures as compared with 2017.

Review of Segment Performance

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

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

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 (including exposure to the SCOOP and STACK plays) 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,						
	2018		2017		2018 vs. 2017		
Gross margin	$	325.6	$	263.0	$	62.6	24%
Operating expenses		104.8		85.6		19.2	22%
Operating margin	$	220.8	$	177.4	$	43.4	24%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Permian Midland (4)		1,014.1		793.6		220.5	28%
Permian Delaware (4)		409.2		338.0		71.2	21%
Total Permian		1,423.3		1,131.6		291.7	
SouthTX		416.3		171.8		244.5	142%
North Texas		235.1		282.5		(47.4)	(17%)
SouthOK		529.9		440.4		89.5	20%
WestOK		350.1		393.1		(43.0)	(11%)
Total Central		1,531.4		1,287.8		243.6	
Badlands (5)		73.3		46.0		27.3	59%
Total Field		3,028.0		2,465.4		562.6	
Coastal		724.3		758.2		(33.9)	(4%)
Total		3,752.3		3,223.6		528.7	16%
Gross NGL production, MBbl/d (3)							
Permian Midland (4)		140.2		99.7		40.5	41%
Permian Delaware (4)		45.7		37.9		7.8	21%
Total Permian		185.9		137.6		48.3	
SouthTX		54.1		16.6		37.5	226%
North Texas		25.9		32.0		(6.1)	(19%)
SouthOK		48.9		40.9		8.0	20%
WestOK		19.4		22.8		(3.4)	(15%)
Total Central		148.3		112.3		36.0	
Badlands		10.2		5.5		4.7	85%
Total Field		344.4		255.4		89.0	
Coastal		42.6		33.3		9.3	28%
Total		387.0		288.7		98.3	34%
Crude oil gathered, Badlands, MBbl/d		117.7		113.5		4.2	4%
Crude oil gathered, Permian, MBbl/d (4)		49.4		9.2		40.2	NM
Natural gas sales, BBtu/d (3)		1,767.3		1,547.4		219.9	14%
NGL sales, MBbl/d		300.4		227.6		72.8	32%
Condensate sales, MBbl/d		16.2		10.7		5.5	51%
Average realized prices (6):							
Natural gas, $/MMBtu		2.37		2.89		(0.52)	(18%)
NGL, $/gal		0.59		0.50		0.09	18%
Condensate, $/Bbl		59.66		44.98		14.68	33%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents the Company's undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware. For the volume statistics presented, the numerator is the total volume sold during the period of the Company’s ownership while the denominator is the number of calendar days during the 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, 2018 Compared to Three Months Ended March 31, 2017

The increase in gross margin was primarily due to higher Permian volumes including those associated with the Permian Acquisition in March 2017, higher Central and Badlands region volumes and higher NGL prices. The overall increase in Gathering and Processing inlet volumes included all areas in the Permian region, SouthTX, SouthOK, and Badlands, partially offset by decreases at WestOK, North Texas and Coastal. The Coastal Gathering and Processing assets generate significantly lower unit margins than the Field Gathering and Processing assets. NGL production, NGL sales and natural gas sales increased primarily due to higher Gathering and Processing inlet volumes and increased NGL recoveries primarily due to reduced ethane rejection. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition and higher production from new wells and system expansions. In Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to higher production from new wells and system expansions.

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

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, 2018			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland	1,257.8	Varies (4)	1,014.1	1,014.1
Permian Delaware	409.2	100%	409.2	409.2
Total Permian	1,667.0		1,423.3	1,423.3
SouthTX	416.3	Varies (5)	294.3	416.3
North Texas	235.1	100%	235.1	235.1
SouthOK	529.9	Varies (6)	429.0	529.9
WestOK	350.1	100%	350.1	350.1
Total Central	1,531.4		1,308.5	1,531.4
Badlands (7)	73.3	100%	73.3	73.3
Total Field	3,271.7		2,805.1	3,028.0
Gross NGL production, MBbl/d (2)				
Permian Midland	174.8	Varies (4)	140.2	140.2
Permian Delaware	45.7	100%	45.7	45.7
Total Permian	220.5		185.9	185.9
SouthTX	54.1	Varies (5)	36.7	54.1
North Texas	25.9	100%	25.9	25.9
SouthOK	48.9	Varies (6)	40.4	48.9
WestOK	19.4	100%	19.4	19.4
Total Central	148.3		122.4	148.3
Badlands	10.2	100%	10.2	10.2
Total Field	379.0		318.5	344.4

(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, other than Badlands.

(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) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants that are owned 100% by the Company. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.

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

(6) SouthOK includes Centrahoma Processing, LLC, a joint venture that the Company operates ("Centrahoma" or the "Centrahoma Joint Venture"), of which the Company owns 60%, and other plants that are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.

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

Operating statistics:	Three Months Ended March 31, 2017			
Plant natural gas inlet, MMcf/d (1),(2)	**Gross Volume (3)**	**Ownership %**	**Net Volume (3)**	**Actual Reported**
Permian Midland (4)	987.1	Varies (5)	793.6	793.6
Permian Delaware (4)	338.0	100%	338.0	338.0
Total Permian	1,325.1		1,131.6	1,131.6
SouthTX	171.8	Varies (6)	161.6	171.8
North Texas	282.5	100%	282.5	282.5
SouthOK	440.4	Varies (7)	366.1	440.4
WestOK	393.1	100%	393.1	393.1
Total Central	1,287.8		1,203.3	1,287.8
Badlands (8)	46.0	100%	46.0	46.0
Total Field	2,658.9		2,380.9	2,465.4
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	124.5	Varies (5)	99.7	99.7
Permian Delaware (4)	37.9	100%	37.9	37.9
Total Permian	162.4		137.6	137.6
SouthTX	16.6	Varies (6)	15.7	16.6
North Texas	32.0	100%	32.0	32.0
SouthOK	40.9	Varies (7)	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 Field	280.2		247.8	255.4

(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, other than Badlands.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which the Company owns 73%, and other plants that are owned 100% by the Company. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in the Company's reported financials.
(6) SouthTX includes the Silver Oak II Plant, of which the Company owned a 90% interest from October 2015 through May 2017, and after which the Company owns a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(7) SouthOK includes the Centrahoma Joint Venture, of which the Company owns 60%, and other plants that are owned 100% by the Company. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in the Company's reported financials.
(8) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

The Logistics and Marketing segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as storing, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to liquefied petroleum gas ("LPG") exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of the Company's other businesses. The Logistics and Marketing segment includes Grand Prix, which is currently under construction. The associated assets are generally connected to and supplied in part by the Company's Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

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

	Three Months Ended March 31,						
	2018		2017		2018 vs. 2017		
			(In millions)				
Gross margin	$	206.9	$	196.4	$	10.5	5%
Operating expenses		68.5		66.3		2.2	3%
Operating margin	$	138.4	$	130.1	$	8.3	6%
Operating statistics MBbl/d (1):							
Fractionation volumes (2)(3)		383.3		304.9		78.6	26%
LSNG treating volumes (2)		30.1		34.5		(4.4)	(13%)
Benzene treating volumes (2)		13.4		23.5		(10.1)	(43%)
Export volumes, MBbl/d (4)		201.9		217.5		(15.6)	(7%)
NGL sales, MBbl/d		514.8		502.0		12.8	3%
Average realized prices:							
NGL realized price, $/gal	$	0.76	$	0.66	$	0.10	15%

(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 quarter and the denominator is the number of calendar days during the quarter.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components that vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
(4) Export volumes represent the quantity of NGL products delivered to third-party customers at the Company's Galena Park Marine Terminal that are destined for international markets.

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017

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

Operating expenses increased due to higher compensation and benefits, higher fuel and power costs that are largely passed through, partially offset by lower maintenance.

Other

	Three Months Ended March 31,					
	2018		2017		2018 vs. 2017	
			(In millions)			
Gross margin	$	(17.8)	$	(1.0)	$	(16.8)
Operating margin	$	(17.8)	$	(1.0)	$	(16.8)

Other contains the results 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 the Company’s 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, 2018			Three Months Ended March 31, 2017			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2018 vs. 2017
Natural gas (BBtu)	17.4	$ 0.33	$ 5.8	10.5	$ 0.02	$ 0.2	$ 5.6
NGL (MMgal)	87.2	(0.11)	(9.4)	43.3	(0.04)	(1.8)	(7.6)
Crude oil (MBbl)	0.4	(10.30)	(4.6)	0.2	5.35	1.2	(5.8)
Non-hedge accounting (2)			(9.6)			(0.8)	(8.8)
Ineffectiveness (3)			-			0.2	(0.2)
			$ (17.8)			$ (1.0)	$ (16.8)

(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) Effective upon the adoption of ASU 2017-12 on January 1, 2018, the Company is no longer required to recognize ineffectiveness through operating margin. Ineffectiveness primarily related to certain crude hedging contracts and certain acquired hedges of Targa Pipeline Partners, L.P. ("TPL") that did 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 us 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. The final settlement was received in December 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

About Targa Resources Corp.

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

For more information, please visit the Company's website at www.targaresources.com.

Targa Resources Corp. - Non-GAAP Financial Measures

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

Adjusted EBITDA

The Company defines Adjusted EBITDA as net income (loss) available to TRC before interest, income taxes, depreciation and amortization, and other items that the Company believes should be adjusted consistent with the Company's core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. Adjusted EBITDA is used as a supplemental financial measure by the Company and by external users of its financial statements such as investors, commercial banks and others. The economic substance behind the Company's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and pay dividends to its investors.

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

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

Distributable Cash Flow

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

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

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

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

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

	Three Months Ended March 31,	
	2018	2017
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow		
Net income (loss) attributable to TRC	$ 22.9	$ (119.3)
Income attributable to TRP preferred limited partners	2.8	2.8
Interest (income) expense, net (1)	(16.1)	63.0
Income tax expense (benefit)	8.9	71.1
Depreciation and amortization expense	198.1	191.1
(Gain) loss on sale or disposition of assets	(0.1)	16.1
(Gain) loss from financing activities (2)	—	5.8
(Earnings) loss from unconsolidated affiliates	(1.5)	12.6
Distributions from unconsolidated affiliates and preferred partner interests, net	6.9	4.2
Change in contingent consideration included in Other expense	56.1	3.3
Compensation on equity grants	13.2	10.8
Transaction costs related to business acquisitions	—	5.1
Splitter Agreement (3)	10.8	10.8
Risk management activities (4)	9.7	3.6
Noncontrolling interests adjustments (5)	(5.1)	(4.3)
TRC Adjusted EBITDA	**$ 306.6**	**$ 276.7**
Distributions to TRP preferred limited partners	(2.8)	(2.8)
Splitter Agreement (3)	(10.8)	(10.8)
Interest expense on debt obligations (6)	(54.8)	(59.0)
Cash tax (expense) benefit (7)	—	15.3
Maintenance capital expenditures	(22.3)	(25.7)
Noncontrolling interests adjustments of maintenance capital expenditures	0.5	0.3
Distributable Cash Flow	**$ 216.4**	**$ 194.0**

(1) Includes the change in estimated redemption value of the mandatorily redeemable preferred interests.

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

(3) 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.

(4) Risk management activities related to derivative instruments including the cash impact of hedges acquired in the 2015 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. The cash impact of the acquired hedges ended at the end of 2017.

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

(6) Excludes amortization in interest expense.

(7) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is recognized over the periods between the third quarter 2016 of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 2017.

Gross Margin

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

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

Logistics and Marketing segment gross margin consists primarily of:

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

The gross margin impacts of the Company's equity volumes hedge settlements are reported in Other.

Operating Margin

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

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

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

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

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

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

	Three Months Ended March 31,	
	2018	**2017**
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:		
Net income (loss) attributable to TRC	$ 22.9	$ (119.3)
Net income (loss) attributable to noncontrolling interests	16.0	8.8
Net income (loss)	38.9	(110.5)
Depreciation and amortization expense	198.1	191.1
General and administrative expense	56.7	48.7
Interest (income) expense, net	(16.1)	63.0
Income tax expense (benefit)	8.9	71.1
(Gain) loss on sale or disposition of assets	(0.1)	16.1
(Gain) loss from financing activities	—	5.8
Other, net	55.0	21.2
Operating margin	341.4	306.5
Operating expenses	173.2	151.9
Gross margin	**$ 514.6**	**$ 458.4**

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 Report on Form 10-K for the year ended December 31, 2017, and any subsequently filed Quarterly Reports on Form 10-Q and Current Reports on Form 8-K. The Company does not undertake an obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Contact the Company's investor relations department by email at InvestorRelations@targaresources.com or by phone at (713) 584-1133.

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