



Targa Resources Corp. Reports Fourth Quarter and Full Year 2022 Financial Results and Provides 2023 Operational, Financial, and Capital Return Outlook

February 22, 2023

HOUSTON, Feb. 22, 2023 (GLOBE NEWSWIRE) -- Targa Resources Corp. (NYSE: TRGP) ("TRGP," the "Company" or "Targa") today reported record results for the fourth quarter and full year 2022.

Fourth Quarter and Full Year 2022 Financial Results

Fourth quarter 2022 net income (loss) attributable to Targa Resources Corp. was \$318.0 million compared to \$(313.6) million (including a non-cash pre-tax impairment loss of \$452.3 million on assets in SouthTX associated with Targa's Central operations) for the fourth quarter of 2021. For full year 2022, net income attributable to Targa Resources Corp. was a record \$1,195.5 million compared to \$71.2 million for 2021.

The Company reported record adjusted earnings before interest, income taxes, depreciation and amortization, and other non-cash items ("adjusted EBITDA") of \$840.4 million for the fourth quarter of 2022 compared to \$570.6 million for the fourth quarter of 2021. For full year 2022, Targa reported record adjusted EBITDA of \$2,901.1 million compared to \$2,052.0 million for the full year 2021.

The Company reported distributable cash flow and adjusted free cash flow for the fourth quarter of 2022 of \$655.5 million and \$103.1 million, respectively. For the full year 2022, the Company reported distributable cash flow and adjusted free cash flow of \$2,278.7 million and \$1,101.5 million, respectively.

On January 19, 2023, Targa declared a quarterly dividend of \$0.35 per share of its common stock for the fourth quarter of 2022, or \$1.40 per share on an annualized basis. Total cash dividends of approximately \$79 million were paid on February 15, 2023 on all outstanding shares of common stock to holders of record as of the close of business on January 31, 2023.

Targa repurchased 395,798 shares of its common stock during the fourth quarter of 2022 at a weighted average price of \$70.75 for a total net cost of \$28.0 million. For the year ended December 31, 2022, Targa repurchased 3,412,354 shares of its common stock at a weighted average price of \$65.87 for a total net cost of \$224.8 million. There was \$143.8 million remaining under the Company's \$500 million common share repurchase program as of December 31, 2022.

Fourth Quarter 2022 - Sequential Quarter over Quarter Commentary

Targa reported fourth quarter 2022 adjusted EBITDA of \$840.4 million, representing a 9 percent increase compared to the third quarter of 2022. In the Gathering & Processing ("G&P") segment, lower sequential adjusted operating margin was driven by lower commodity prices offset by higher natural gas inlet volumes across Targa's Permian systems and a full quarter contribution from the Company's Delaware Basin acquisition, which closed with an accounting effective date of August 1, 2022. Targa's Permian natural gas inlet volumes averaged a record 4.7 billion cubic feet per day ("Bcf/d") in the fourth quarter of 2022 even though volumes were negatively impacted by Winter Storm Elliott. In the Logistics & Transportation ("L&T") segment, the sequential increase in segment adjusted operating margin was attributable to higher marketing margin, higher pipeline transportation and fractionation volumes, and higher LPG export volumes. Marketing margin was higher due to greater optimization opportunities. NGL pipeline transportation and fractionation volumes achieved record levels during the fourth quarter primarily due to higher supply volumes from Targa's Permian G&P systems and third parties, despite the negative impacts of Winter Storm Elliott during the quarter. LPG export volumes were higher sequentially due to improved export market conditions. In the fourth quarter of 2022, lower operating expenses were attributable to lower repairs and maintenance, while higher general and administrative expenses were attributable to higher compensation and benefits.

Capitalization and Liquidity

The Company's total consolidated debt as of December 31, 2022 was \$11,536.4 million, net of \$65.6 million of debt issuance costs and \$8.4 million of unamortized discount, with \$7,784.4 million of outstanding senior notes, \$1.5 billion outstanding under the Company's \$1.5 billion term loan facility, \$290.0 million outstanding under the TRGP Revolver, \$1,008.7 million outstanding under the Commercial Paper Program, \$800.0 million outstanding under the Securitization Facility, and \$227.3 million of finance lease liabilities.

Total consolidated liquidity as of December 31, 2022 was approximately \$1.6 billion, including \$1.4 billion available under the TRGP Revolver and \$219.0 million of cash.

Acquisition and Financing Update

In January 2023, Targa completed the acquisition of Blackstone Energy Partners' 25 percent interest in Targa's Grand Prix NGL Pipeline ("Grand Prix") for aggregate consideration of \$1.05 billion in cash, with an effective date of January 1, 2023 (the "Grand Prix Transaction"). Following the closing of the Grand Prix Transaction, Targa owns 100% of Grand Prix.

In January 2023, Targa completed an underwritten public offering of (i) \$900.0 million in aggregate principal amount of its 6.125% Senior Notes due 2033 and (ii) \$850.0 million in aggregate principal amount of its 6.500% Senior Notes due 2053, resulting in net proceeds of approximately \$1.7 billion. Targa used a portion of the net proceeds from the issuance to fund the Grand Prix Transaction and the remaining net proceeds for general corporate purposes, including to reduce borrowings under the TRGP Revolver and the Commercial Paper Program.

Growth Projects Update

Construction continues on Targa's 275 million cubic feet per day ("MMcf/d") Legacy II plant and 275 MMcf/d Greenwood plant in Permian Midland, its 275 MMcf/d Midway plant and 275 MMcf/d Wildcat II plant in Permian Delaware, its 120 thousand barrels per day ("MBbl/d") fractionation train ("Train 9") in Mont Belvieu, Texas, and its Daytona NGL Pipeline. Targa remains on-track to complete these expansions as previously disclosed.

In response to increasing production and to meet the infrastructure needs of producers, Targa is transferring an existing cryogenic natural gas processing plant acquired in its April 2022 South Texas acquisition to the Permian Delaware. The plant will be installed as a new 230 MMcf/d cryogenic natural gas processing plant (the "Roadrunner II plant"). The Roadrunner II plant is expected to begin operations in the second quarter of 2024.

2023 Operational, Financial, and Capital Return Expectations

Targa's 2023 operational and financial expectations assume Waha natural gas prices average \$2.25 per million British Thermal Units ("MMbtu"), natural gas liquids ("NGL") composite barrel prices average \$0.70 per gallon, and crude oil prices average \$75 per barrel. Targa estimates its 2023 average Permian natural gas inlet volumes will increase 10 percent when compared to its average Permian inlet volumes for the fourth quarter of 2022, which will drive increasing volumes through its L&T systems.

For 2023, Targa estimates full year adjusted EBITDA to be between \$3.5 billion and \$3.7 billion, with the midpoint of the range representing a 24 percent increase over full year 2022 adjusted EBITDA. Targa's estimate for 2023 net growth capital expenditures is between \$1.8 billion to \$1.9 billion, based on announced projects and other identified spending. Net maintenance capital expenditures for 2023 are estimated to be approximately \$175 million. Please see the section of this release entitled "Non-GAAP Financial Measures" for a discussion of forward-looking estimated adjusted EBITDA and a reconciliation of such measure to its most directly comparable GAAP financial measure.

Targa expects to recommend a 43 percent year-over-year increase to its annualized common stock dividend per share for 2023 to \$2.00 per share. The increased dividend will be recommended to Targa's Board of Directors in April for the first quarter of 2023, with payment to shareholders in May 2023. Targa also expects to remain in position to continue to execute opportunistically under its existing \$500 million common share repurchase program and currently plans on recommending that the Board of Directors authorize a new \$1 billion share repurchase program as the Company gets closer to exhausting available capacity under the existing program.

An earnings supplement presentation and an updated investor presentation are available under Events and Presentations in the Investors section of the Company's website at www.targaresources.com/investors/events.

Conference Call

The Company will host a conference call for the investment community at 11:00 a.m. Eastern time (10:00 a.m. Central time) on February 22, 2023 to discuss its fourth quarter results. The conference call can be accessed via webcast under Events and Presentations in the Investors section of the Company's website at www.targaresources.com/investors/events, or by going directly to <https://edge.media-server.com/mmc/p/5awdkn55>. A webcast replay will be available at the link above approximately two hours after the conclusion of the event.

Targa Resources Corp. – Consolidated Financial Results of Operations

	Three Months Ended December 31,				Year Ended December 31,			
	2022	2021	2022 vs. 2021		2022	2021	2022 vs. 2021	
	(In millions)							
Revenues:								
Sales of commodities	\$ 4,075.3	\$ 5,025.1	\$ (949.8)	(19 %)	\$ 19,066.0	\$ 15,602.5	\$ 3,463.5	22 %
Fees from midstream services	479.4	416.5	62.9	15 %	1,863.8	1,347.3	516.5	38 %
Total revenues	4,554.7	5,441.6	(886.9)	(16 %)	20,929.8	16,949.8	3,980.0	23 %
Product purchases and fuel	3,324.2	4,569.7	(1,245.5)	(27 %)	16,882.1	13,729.5	3,152.6	23 %
Operating expenses	252.2	201.7	50.5	25 %	912.8	747.0	165.8	22 %
Depreciation and amortization expense	329.8	219.7	110.1	50 %	1,096.0	870.6	225.4	26 %
General and administrative expense	92.5	80.7	11.8	15 %	309.7	273.2	36.5	13 %
Impairment of long-lived assets	—	452.3	(452.3)	(100 %)	—	452.3	(452.3)	(100 %)
Other operating (income) expense	4.7	9.0	(4.3)	(48 %)	0.2	12.4	(12.2)	(98 %)
Income (loss) from operations	551.3	(91.5)	642.8	NM	1,729.0	864.8	864.2	100 %
Interest expense, net	(145.6)	(103.7)	(41.9)	40 %	(446.1)	(387.9)	(58.2)	15 %
Equity earnings (loss)	0.3	(62.8)	63.1	100 %	9.1	(23.9)	33.0	138 %
Gain (loss) from financing activities	—	—	—	—	(49.6)	(16.6)	(33.0)	199 %
Gain (loss) from sale of equity method investment	—	—	—	—	435.9	—	435.9	100 %
Other, net	(0.3)	0.1	(0.4)	NM	(15.1)	0.5	(15.6)	NM
Income tax (expense) benefit	(9.8)	8.7	(18.5)	(213 %)	(131.8)	(14.8)	(117.0)	NM
Net income (loss)	395.9	(249.2)	645.1	259 %	1,531.4	422.1	1,109.3	263 %
Less: Net income (loss) attributable to noncontrolling interests	77.9	64.4	13.5	21 %	335.9	350.9	(15.0)	(4 %)
Net income (loss) attributable to Targa Resources Corp.	318.0	(313.6)	631.6	201 %	1,195.5	71.2	1,124.3	NM
Premium on repurchase of noncontrolling interests, net of tax	0.1	—	0.1	—	53.2	—	53.2	100 %
Dividends on Series A Preferred Stock	—	21.8	(21.8)	(100 %)	30.0	87.3	(57.3)	(66 %)

Deemed dividends on Series A Preferred Stock	—	—	—	—	215.5	—	215.5	100 %
Net income (loss) attributable to common shareholders	<u>\$ 317.9</u>	<u>\$ (335.4)</u>	<u>\$ 653.3</u>	195 %	<u>\$ 896.8</u>	<u>\$ (16.1)</u>	<u>\$ 912.9</u>	NM
Financial data:								
Adjusted EBITDA (1)	\$ 840.4	\$ 570.6	\$ 269.8	47 %	\$ 2,901.1	\$ 2,052.0	\$ 849.1	41 %
Distributable cash flow (1)	655.5	420.7	234.8	56 %	2,278.7	1,541.4	737.3	48 %
Adjusted free cash flow (1)	103.1	240.8	(137.7)	(57 %)	1,101.5	1,133.7	(32.2)	(3 %)

(1) Adjusted EBITDA, distributable cash flow and adjusted free cash flow are non-GAAP financial measures and are discussed under "Non-GAAP Financial Measures."

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

Three Months Ended December 31, 2022 Compared to Three Months Ended December 31, 2021

The decrease in commodity sales reflects lower NGL prices (\$1,146.7 million) and NGL and natural gas volumes (\$64.8 million), partially offset by higher natural gas prices (\$89.6 million) and condensate volumes (\$15.8 million), and the favorable impact of hedges (\$150.0 million).

The increase in fees from midstream services is primarily due to higher gas gathering and processing fees including the impact of the acquisition of certain assets in the Delaware Basin, and transportation and fractionation volumes, partially offset by lower export fees.

The decrease in product purchases and fuel reflects lower NGL prices and NGL and natural gas volumes, partially offset by higher natural gas prices and condensate volumes.

The increase in operating expenses is primarily due to increased activity and system expansions, the acquisition of certain assets in South Texas and the Delaware Basin, and inflation.

See "—Review of Segment Performance" for additional information on a segment basis.

The increase in depreciation and amortization expense is primarily due to the acquisition of certain assets in the Delaware Basin and the shortening of depreciable lives of certain assets that have been, or will be, idled, partially offset by a lower depreciable base associated with assets that were impaired during the fourth quarter of 2021.

The increase in general and administrative expense is primarily due to higher compensation and benefits, and insurance costs.

In 2021, the Company recognized a non-cash pre-tax impairment loss of \$452.3 million on assets in the South Texas region associated with the Company's Central operations.

The increase in interest expense, net is primarily due to higher net borrowings, partially offset by change in fair value of the mandatorily redeemable preferred interests and higher capitalized interest resulting from higher growth capital investments.

The increase in equity earnings is primarily due to lower losses resulting from the purchase of the Company's remaining interests in the two joint ventures in South Texas that the Company previously held as investments in unconsolidated affiliates, partially offset by lower earnings resulting from the impact of the GCX Sale.

The increase in income tax expense is primarily due to an increase in pre-tax book income, partially offset by a larger release of the valuation allowance in 2022 compared to 2021, the impact of statutory rate changes in Oklahoma and Louisiana in 2021 and the correction of a state tax error in 2021.

The increase in net income (loss) attributable to noncontrolling interests is primarily due to impairment losses in 2021 allocated to noncontrolling interest holders in the Carnero Joint Venture, partially offset by the repurchase of the Company's development company joint ventures in January 2022 (the "DevCo JV Repurchase").

The decrease in dividends on Series A Preferred Stock ("Series A Preferred") is due to the full redemption of all of the Company's issued and outstanding shares of Series A Preferred during 2022.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

The increase in commodity sales reflects higher natural gas, NGL and condensate prices (\$3,116.3 million) and higher NGL, natural gas and condensate volumes (\$615.9 million), partially offset by the unfavorable impact of hedges (\$264.1 million).

The increase in fees from midstream services is primarily due to higher gas gathering and processing fees including the impact of the acquisition of certain assets in the Delaware Basin, and transportation and fractionation volumes, partially offset by lower export fees.

The increase in product purchases and fuel reflects higher natural gas, NGL and condensate prices and higher NGL, natural gas and condensate volumes.

The increase in operating expenses is primarily due to increased activity and system expansions, the acquisition of certain assets in South Texas and the Delaware Basin, and inflation, partially offset by the impact of a major winter storm that affected regions across Texas, New Mexico, Oklahoma and Louisiana during the first quarter of 2021.

See "—Review of Segment Performance" for additional information on a segment basis.

The increase in depreciation and amortization expense is primarily due to the acquisition of certain assets in the Delaware Basin and South Texas, the shortening of depreciable lives of certain assets that have been, or will be, idled and the impact of system expansions on the Company's asset base, partially offset by a lower depreciable base associated with assets that were impaired during the fourth quarter of 2021.

The increase in general and administrative expense is primarily due to higher compensation and benefits, insurance costs and professional fees.

In 2021, the Company recognized a non-cash pre-tax impairment loss of \$452.3 million on assets in the South Texas region associated with the Company's Central operations.

Other operating (income) expense in 2021 consisted primarily of the write-down of certain assets to their recoverable amounts.

The increase in interest expense, net is primarily due to higher net borrowings, partially offset by the change in fair value of the mandatorily redeemable preferred interests, higher capitalized interest resulting from higher growth capital investments, and lower commitment fees.

The increase in equity earnings is primarily due to lower losses resulting from the purchase of the Company's remaining interests in the two joint ventures in South Texas that the Company previously held as investments in unconsolidated affiliates and lower losses from Gulf Coast Fractionators, partially offset by lower earnings resulting from the impact of the GCX Sale and lower earnings from the Company's investment in Little Missouri 4 LLC.

During 2022, the Partnership redeemed the 5.375% Senior Notes due 2027 and the 5.875% Senior Notes due 2026. In addition, the Company terminated the previous TRGP senior secured revolving credit facility (the "Previous TRGP Revolver") and the Partnership's senior secured revolving credit facility (the "Partnership Revolver"). These transactions resulted in a net loss from financing activities. During 2021, the Partnership redeemed the 5.125% Senior Notes due 2025 and the 4.250% Senior Notes due 2023 and Targa Pipeline Partners LP redeemed its TPL 4.750% Senior Notes due 2021 and TPL 5.875% Senior Notes due 2023, resulting in a net loss from financing activities.

During 2022, the Company completed the GCX Sale resulting in a gain from sale of an equity method investment.

The increase in income tax expense is primarily due to an increase in pre-tax book income, partially offset by a larger release of the valuation allowance in 2022 compared to 2021, the impact of statutory rate changes in Oklahoma and Louisiana in 2021 and the correction of a state tax error in 2021.

The decrease in net income (loss) attributable to noncontrolling interests is primarily due to the DevCo JV Repurchase, partially offset by impairment losses in 2021 allocated to noncontrolling interest holders in the Carnero Joint Venture, higher income allocation to noncontrolling interests holders in the Grand Prix Joint Venture and Centrahoma Processing, LLC., and an increase in noncontrolling interest for a joint venture partner in WestTX.

The decrease in dividends on Series A Preferred is due to the full redemption of all of the Company's issued and outstanding shares of Series A Preferred during 2022.

Review of Segment Performance

The following discussion of segment performance includes inter-segment activities. The Company views segment operating margin and adjusted operating margin as important performance measures of the core profitability of its operations. These measures are key components of internal financial reporting and are reviewed for consistency and trend analysis. For a discussion of adjusted operating margin, see "Non-GAAP Financial Measures — Adjusted 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 Transportation.

Gathering and Processing Segment

The Gathering and Processing segment includes assets used in the gathering and/or purchase and sale of natural gas produced from oil and gas wells, removing impurities and processing this raw natural gas into merchantable natural gas by extracting NGLs; and assets used for the gathering and terminaling and/or purchase and sale of crude oil. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland, Central and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota (including the Bakken and Three Forks plays); and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

	Three Months Ended December 31,				Year Ended December 31,			
	2022	2021	2022 vs. 2021		2022	2021	2022 vs. 2021	
	(In millions, except operating statistics and price amounts)							
Operating margin	\$ 544.0	\$ 387.1	\$ 156.9	41 %	\$ 1,981.0	\$ 1,325.3	\$ 655.7	49 %
Operating expenses	177.3	133.1	44.2	33 %	611.8	476.2	135.6	28 %
Adjusted operating margin	<u>\$ 721.3</u>	<u>\$ 520.2</u>	<u>\$ 201.1</u>	39 %	<u>\$ 2,592.8</u>	<u>\$ 1,801.5</u>	<u>\$ 791.3</u>	44 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2) (3)								
Permian Midland (4)	2,376.0	2,075.4	300.6	14 %	2,223.6	1,928.4	295.2	15 %
Permian Delaware (5)	2,371.3	940.5	1,430.8	152 %	1,536.1	839.8	696.3	83 %
Total Permian	4,747.3	3,015.9	1,731.4		3,759.7	2,768.2	991.5	
SouthTX (6)	334.7	159.2	175.5	110 %	276.5	177.7	98.8	56 %
North Texas	219.4	178.2	41.2	23 %	187.0	178.9	8.1	5 %
SouthOK (6)	359.7	415.9	(56.2)	(14 %)	406.8	405.9	0.9	—

WestOK	207.3	215.5	(8.2)	(4 %)	208.7	212.6	(3.9)	(2 %)
Total Central	1,121.1	968.8	152.3		1,079.0	975.1	103.9	
Badlands (6) (7)	140.2	145.9	(5.7)	(4 %)	134.9	139.8	(4.9)	(4 %)
Total Field	6,008.6	4,130.6	1,878.0		4,973.6	3,883.1	1,090.5	
Coastal	457.3	554.3	(97.0)	(17 %)	537.6	587.2	(49.6)	(8 %)
Total	6,465.9	4,684.9	1,781.0	38 %	5,511.2	4,470.3	1,040.9	23 %
NGL production, MBbl/d (3)								
Permian Midland (4)	342.0	300.4	41.6	14 %	321.7	277.9	43.8	16 %
Permian Delaware (5)	289.0	128.1	160.9	126 %	193.9	114.1	79.8	70 %
Total Permian	631.0	428.5	202.5		515.6	392.0	123.6	
SouthTX (6)	34.2	21.0	13.2	63 %	31.2	22.2	9.0	41 %
North Texas	25.2	19.7	5.5	28 %	21.2	20.1	1.1	5 %
SouthOK (6)	36.3	51.5	(15.2)	(30 %)	47.6	49.5	(1.9)	(4 %)
WestOK	12.1	17.3	(5.2)	(30 %)	14.6	16.5	(1.9)	(12 %)
Total Central	107.8	109.5	(1.7)		114.6	108.3	6.3	
Badlands (6)	17.0	17.0	—	—	16.1	16.2	(0.1)	(1 %)
Total Field	755.8	555.0	200.8		646.3	516.5	129.8	
Coastal	22.9	32.2	(9.3)	(29 %)	32.0	33.9	(1.9)	(6 %)
Total	778.7	587.2	191.5	33 %	678.3	550.4	127.9	23 %
Crude oil, Badlands, MBbl/d	113.7	147.6	(33.9)	(23 %)	117.6	140.9	(23.3)	(17 %)
Crude oil, Permian, MBbl/d	28.4	34.4	(6.0)	(17 %)	29.5	35.0	(5.5)	(16 %)
Natural gas sales, BBtu/d (3)	2,416.3	2,341.8	74.5	3 %	2,320.6	2,207.7	112.9	5 %
NGL sales, MBbl/d (3)	453.3	424.1	29.2	7 %	438.7	394.6	44.1	11 %
Condensate sales, MBbl/d	16.3	13.9	2.4	17 %	15.5	14.9	0.6	4 %
Average realized prices - inclusive of hedges (8):								
Natural gas, \$/MMBtu	4.35	4.43	(0.08)	(2 %)	5.35	3.27	2.08	64 %
NGL, \$/gal	0.56	0.76	(0.20)	(26 %)	0.75	0.61	0.14	23 %
Condensate, \$/Bbl	77.21	70.29	6.92	10 %	88.26	60.02	28.24	47 %

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

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

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

(4) Permian Midland includes operations in WestTX, of which the Company owns 72.8% undivided interest, 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) Includes operations from the acquisition of certain assets in the Delaware Basin for the period effective August 1, 2022.

(6) Operations include facilities that are not wholly owned by the Company. SouthTX operating statistics include the impact of the acquisition of certain assets in South Texas for the period effective April 21, 2022.

(7) Badlands natural gas inlet represents the total wellhead volume and includes the Targa volumes processed at the Little Missouri 4 plant.

(8) Average realized prices include the effect of realized commodity hedge gain/loss attributable to the Company's equity volumes. The price is calculated using total commodity sales plus the hedge gain/loss as the numerator and total sales volume as the denominator.

The following table presents the realized commodity hedge gain (loss) attributable to the Company's equity volumes that are included in the adjusted operating margin of the Gathering and Processing segment:

	Three Months Ended December 31, 2022			Three Months Ended December 31, 2021		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	20.2	\$ (0.02)	\$ (0.4)	20.2	\$ (2.51)	\$ (50.8)
NGL (MMgal)	187.9	(0.04)	(7.8)	175.8	(0.31)	(53.9)
Crude oil (MBbl)	0.6	(14.22)	(8.5)	0.5	(23.80)	(11.9)

\$ (16.7)

\$ (116.6)

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

	Year Ended December 31, 2022			Year Ended December 31, 2021		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	74.8	\$ (2.13)	\$ (159.2)	76.8	\$ (1.41)	\$ (108.0)
NGL (MMgal)	717.6	(0.30)	(213.0)	581.5	(0.26)	(153.1)
Crude oil (MBbl)	2.2	(31.73)	(69.8)	2.1	(14.33)	(30.1)
			\$ (442.0)			\$ (291.2)

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

Three Months Ended December 31, 2022 Compared to Three Months Ended December 31, 2021

The increase in adjusted operating margin was due to higher natural gas inlet volumes and higher fees resulting in increased margin predominantly in the Permian, partially offset by lower NGL and natural gas prices. The increase in natural gas inlet volumes in the Permian was attributable to the acquisition of certain assets in the Delaware Basin during the third quarter of 2022, the addition of the Legacy and Red Hills VI plants in the Permian region during the third quarter of 2022 and increased producer activity. Natural gas inlet volumes in the Central region increased due to the acquisition of certain assets in South Texas during the second quarter of 2022. The decrease in volumes in the Coastal region was attributable to lower production.

The increase in operating expenses was predominantly due to the acquisition of certain assets in South Texas and the Delaware Basin in the second and third quarters of 2022. Additionally, higher volumes in the Permian, the addition of the Legacy plant and Red Hills VI plants in the third quarter of 2022 and inflation impacts resulted in increased costs.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

The increase in adjusted operating margin was due to higher realized commodity prices, higher natural gas inlet volumes, and higher fees resulting in increased margin predominantly in the Permian. The increase in natural gas inlet volumes in the Permian was attributable to the acquisition of certain assets in the Delaware Basin during the third quarter of 2022, higher producer activity and the addition of the Legacy and Red Hills VI plants during the third quarter of 2022. The decrease in volumes in the Coastal region was due to lower producer activity.

The increase in operating expenses was predominantly due to the acquisition of certain assets in South Texas and the Delaware Basin in the second and third quarters of 2022, which included one-time acquisition costs. Additionally, higher volumes in the Permian, the addition of the Legacy and Red Hills VI plants during the third quarter of 2022 and the Heim plant in the third quarter of 2021, and inflation impacts, resulted in increased costs.

Logistics and Transportation Segment

The Logistics and Transportation 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 transporting, storing, fractionating, terminaling, and marketing of NGLs and NGL products, including services to LPG exporters and certain natural gas supply and marketing activities in support of the Company's other businesses. The Logistics and Transportation segment also includes Grand Prix NGL Pipeline, which connects the Company's gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with the Company's Downstream facilities in Mont Belvieu, Texas. The associated assets are generally connected to and supplied in part by the Company's Gathering and Processing segment and, except for the pipelines 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 December 31,			Year Ended December 31,		
	2022	2021	2022 vs. 2021	2022	2021	2022 vs. 2021
	(In millions, except operating statistics)					
Operating margin	\$ 441.6	\$ 343.5	\$ 98.1 29%	\$ 1,456.3	\$ 1,264.3	\$ 192.0 15%
Operating expenses	74.4	69.2	5.2 8%	300.2	273.0	27.2 10%
Adjusted operating margin	<u>\$ 516.0</u>	<u>\$ 412.7</u>	<u>\$ 103.3 25%</u>	<u>\$ 1,756.5</u>	<u>\$ 1,537.3</u>	<u>\$ 219.2 14%</u>
Operating statistics Mbbbl/d (1):						
NGL pipeline transportation volumes (2)	502.3	432.8	69.5 16%	488.6	396.2	92.4 23%
Fractionation volumes	744.4	611.6	132.8 22%	731.7	616.0	115.7 19%
Export volumes (3)	299.4	350.3	(50.9) (15%)	314.5	316.9	(2.4) (1%)
NGL sales	861.0	886.3	(25.3) (3%)	866.3	834.9	31.4 4%

(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) Represents the total quantity of mixed NGLs that earn a transportation margin.

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

Three Months Ended December 31, 2022 Compared to Three Months Ended December 31, 2021

The increase in adjusted operating margin was due to higher marketing margin and higher pipeline transportation and fractionation margin, partially offset by lower LPG export margin. Marketing margin increased due to greater optimization opportunities. Pipeline transportation and fractionation volumes benefited from higher supply volumes primarily from the Company's Permian Gathering and Processing systems and higher fees. LPG export margin decreased primarily due to lower volumes.

The increase in operating expenses was due to higher compensation and benefits, higher taxes and higher repairs and maintenance.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

The increase in adjusted operating margin was due to higher pipeline transportation and fractionation margin and higher marketing margin, partially offset by lower LPG export margin. Pipeline transportation and fractionation volumes benefited from higher supply volumes primarily from the Company's Permian Gathering and Processing systems and higher fees. Marketing margin increased due to greater optimization opportunities. LPG export margin decreased primarily due to higher fuel and power costs.

The increase in operating expenses was primarily due to higher repairs and maintenance.

Other

	Three Months Ended December 31,			Year Ended December 31,		
	2022	2021	2022 vs. 2021	2022	2021	2022 vs. 2021
	(In millions)					
Operating margin	\$ (7.5)	\$ (60.3)	\$ 52.8	\$ (302.4)	\$ (115.9)	\$ (186.5)
Adjusted operating margin	\$ (7.5)	\$ (60.3)	\$ 52.8	\$ (302.4)	\$ (115.9)	\$ (186.5)

Other contains the results of commodity derivative activity mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. The Company has entered into derivative instruments to hedge the commodity price associated with a portion of the Company's future commodity purchases and sales and natural gas transportation basis risk within the Company's Logistics and Transportation segment.

About Targa Resources Corp.

Targa Resources Corp. is a leading provider of midstream services and is one of the largest independent midstream infrastructure companies in North America. The Company owns, operates, acquires and develops a diversified portfolio of complementary domestic midstream infrastructure assets and its operations are critical to the efficient, safe and reliable delivery of energy across the United States and increasingly to the world. The Company's assets connect natural gas and NGLs to domestic and international markets with growing demand for cleaner fuels and feedstocks. The Company is primarily engaged in the business of: gathering, compressing, treating, processing, transporting, and purchasing and selling natural gas; transporting, storing, fractionating, treating, and purchasing and selling NGLs and NGL products, including services to LPG exporters; and gathering, storing, terminaling, and purchasing and selling crude oil.

Targa is a FORTUNE 500 company and is included in the S&P 500.

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

Non-GAAP Financial Measures

This press release includes the Company's non-GAAP financial measures: adjusted EBITDA, distributable cash flow, adjusted free cash flow and adjusted operating margin (segment). The following tables provide reconciliations of these non-GAAP financial measures to their most directly comparable GAAP measures.

The Company utilizes non-GAAP measures to analyze the Company's performance. Adjusted EBITDA, distributable cash flow, adjusted free cash flow and adjusted operating margin (segment) are non-GAAP measures. The GAAP measures most directly comparable to these non-GAAP measures are income (loss) from operations, Net income (loss) attributable to Targa Resources Corp. and segment operating margin. These non-GAAP measures should not be considered as an alternative to GAAP measures and have important limitations as analytical tools. Investors should not consider these measures in isolation or as a substitute for analysis of the Company's results as reported under GAAP. Additionally, because the Company's non-GAAP measures exclude some, but not all, items that affect income and segment operating margin, and are defined differently by different companies within the Company's industry, the Company's definitions may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of the Company's non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into the Company's decision-making processes.

Adjusted Operating Margin

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

Gathering and Processing adjusted operating margin consists primarily of:

- service fees related to natural gas and crude oil gathering, treating and processing; and
- revenues from the sale of natural gas, condensate, crude oil and NGLs less producer settlements, fuel and transport and the Company's equity volume hedge settlements.

Logistics and Transportation adjusted operating margin consists primarily of:

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

The adjusted operating margin impacts of mark-to-market hedge unrealized changes in fair value are reported in Other.

Adjusted operating margin for the Company's segments provides useful information to investors because it is used as a supplemental financial measure 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 capital expenditure projects and acquisitions and the overall rates of return on alternative investment opportunities.

Management reviews adjusted operating margin and operating margin for the Company's segments 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 the Company's operating results. The reconciliation of the Company's adjusted operating margin to the most directly comparable GAAP measure is presented under "Review of Segment Performance."

Adjusted EBITDA

The Company defines adjusted EBITDA as Net income (loss) attributable to Targa Resources Corp. 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 the Company's financial statements such as investors, commercial banks and others to measure the ability of the Company's assets to generate cash sufficient to pay interest costs, support the Company's indebtedness and pay dividends to the Company's investors.

Distributable Cash Flow and Adjusted Free Cash Flow

The Company defines distributable cash flow as adjusted EBITDA less cash interest expense on debt obligations, cash tax (expense) benefit and maintenance capital expenditures (net of any reimbursements of project costs). The Company defines adjusted free cash flow as distributable cash flow less growth capital expenditures, net of contributions from noncontrolling interest and net contributions to investments in unconsolidated affiliates. Distributable cash flow and adjusted free cash flow are performance measures used by the Company and by external users of the Company's financial statements, such as investors, commercial banks and research analysts, to assess the Company's ability to generate cash earnings (after servicing the Company's debt and funding capital expenditures) to be used for corporate purposes, such as payment of dividends, retirement of debt or redemption of other financing arrangements.

The following table presents a reconciliation of Net income (loss) attributable to Targa Resources Corp. to adjusted EBITDA, distributable cash flow and adjusted free cash flow for the periods indicated:

	Three Months Ended December 31,		Year Ended December 31,	
	2022	2021	2022	2021
	(In millions)			
Reconciliation of Net income (loss) attributable to Targa Resources Corp. to Adjusted EBITDA, Distributable Cash Flow and Adjusted Free Cash Flow				
Net income (loss) attributable to Targa Resources Corp.	\$ 318.0	\$ (313.6)	\$ 1,195.5	\$ 71.2
Interest (income) expense, net	145.6	103.7	446.1	387.9
Income tax expense (benefit)	9.8	(8.7)	131.8	14.8
Depreciation and amortization expense	329.8	219.7	1,096.0	870.6
Impairment of long-lived assets	—	452.3	—	452.3
(Gain) loss on sale or disposition of assets	(1.5)	3.7	(9.6)	2.0
Write-down of assets	6.2	5.3	9.8	10.3
(Gain) loss from financing activities (1)	—	—	49.6	16.6
(Gain) loss from sale of equity method investment	—	—	(435.9)	—
Transaction costs related to business acquisition (2)	3.6	—	23.9	—
Equity (earnings) loss	(0.3)	62.8	(9.1)	23.9
Distributions from unconsolidated affiliates and preferred partner interests, net	5.5	28.1	27.2	116.5
Change in contingent considerations	—	0.1	—	0.1
Compensation on equity grants	15.7	14.6	57.5	59.2
Risk management activities	7.5	60.4	302.5	116.0
Noncontrolling interests adjustments (3)	0.5	(57.8)	15.8	(89.4)

Adjusted EBITDA	\$ 840.4	\$ 570.6	\$ 2,901.1	\$ 2,052.0
Interest expense on debt obligations (4)	(142.5)	(90.4)	(447.6)	(376.2)
Maintenance capital expenditures, net (5)	(41.3)	(58.8)	(168.1)	(131.7)
Cash taxes	(1.1)	(0.7)	(6.7)	(2.7)
Distributable Cash Flow	\$ 655.5	\$ 420.7	\$ 2,278.7	\$ 1,541.4
Growth capital expenditures, net (5)	(552.4)	(179.9)	(1,177.2)	(407.7)
Adjusted Free Cash Flow	\$ 103.1	\$ 240.8	\$ 1,101.5	\$ 1,133.7

- (1) Gains or losses on debt repurchases or early debt extinguishments.
- (2) Includes financial advisory, legal and other professional fees, and other one-time transaction costs.
- (3) Noncontrolling interest portion of depreciation and amortization expense (including the effects of the impairment of long-lived assets on non-controlling interests).
- (4) Excludes amortization of interest expense.
- (5) Represents capital expenditures, net of contributions from noncontrolling interests and includes net contributions to investments in unconsolidated affiliates.

The following table presents a reconciliation of estimated net income of the Company to estimated adjusted EBITDA for 2023:

	2023E
	(In millions)
Reconciliation of Estimated Net Income Attributable to Targa Resources Corp. to Estimated Adjusted EBITDA	
Net income attributable to Targa Resources Corp.	\$ 1,230.0
Interest expense, net	710.0
Income tax expense	350.0
Depreciation and amortization expense	1,260.0
Equity earnings	(20.0)
Distributions from unconsolidated affiliates	25.0
Compensation on equity grants	60.0
Risk management and other	—
Noncontrolling interests adjustments (1)	(15.0)
Estimated Adjusted EBITDA	\$ 3,600.0

- (1) Noncontrolling interest portion of depreciation and amortization expense.

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 impact of pandemics or any other public health crises, commodity price volatility due to ongoing or new global conflicts, actions by the Organization of the Petroleum Exporting Countries (“OPEC”) and non- OPEC oil producing countries, 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 most recent Annual Report on Form 10-K, 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.

Sanjay Lad
Vice President, Finance & Investor Relations

Jennifer Kneale
Chief Financial Officer



Source: Targa Resources Corp.