UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2023

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission File Number: 001-34991

TARGA RESOURCES CORP.
(Exact name of registrant as specified in its charter)

Delaware	**20-3701075**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
811 Louisiana Street, Suite 2100, Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 584-1000
(Registrant’s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock	TRGP	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

As of October 31, 2023, there were 222,975,600 shares of the registrant’s common stock, $0.001 par value, outstanding.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, including Targa Resources Partners LP (the "Partnership"), "we," "us," "our," "Targa," "TRGP," or the "Company") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify 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, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the following risks and uncertainties:

- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and natural gas liquid supplies to our logistics and transportation facilities and our success in connecting our facilities to transportation services and markets;
- the timing and extent of changes in natural gas, natural gas liquids, crude oil and other commodity prices, interest rates and demand for our services;
- our ability to access the capital markets, which will depend on general market conditions, including the impact of increased interest rates and the potential for additional increases, and associated Federal Reserve policies and potential economic recession, our credit ratings and debt obligations, and demand for our common equity, senior notes and commercial paper;
- downside commodity price volatility from a variety of potential factors;
- actions taken by other countries with significant hydrocarbon production;
- the timing and success of business development efforts;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, such as the Inflation Reduction Act of 2022 (the "IRA"), particularly with regard to taxes, safety and the protection of the environment;
- the impact of outbreaks of illnesses, pandemics or any other public health crises;
- weather and other natural phenomena, and related impacts;
- industry changes, including the impact of consolidations, changes in competition and the drive to reduce fossil fuel use and substitute alternative forms of energy for oil and gas;
- our ability to timely obtain and maintain necessary licenses, permits and other approvals;
- our ability to grow through internal growth capital projects or acquisitions and the successful integration and future performance of such assets;
- general economic, market and business conditions;
- the impact of disruptions in the bank and capital markets, including those resulting from lack of access to liquidity for banking and financial services firms; and
- the risks described in our Annual Report on Form 10-K for the year ended December 31, 2022 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2023 ("Quarterly Report") will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Quarterly Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
BBtu	Billion British thermal units
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
/d	Per day
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
gal	U.S. gallons
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMgal	Million U.S. gallons
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCOOP	South Central Oklahoma Oil Province
SOFR	Secured Overnight Financing Rate
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	September 30, 2023	December 31, 2022
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 139.5	$ 219.0
Trade receivables, net of allowances of $2.6 and $2.2 million at September 30, 2023 and December 31, 2022	1,241.1	1,408.4
Inventories	536.2	393.8
Assets from risk management activities	84.2	179.9
Other current assets	138.3	155.5
Total current assets	2,139.3	2,356.6
Property, plant and equipment, net	15,333.5	14,214.6
Intangible assets, net	2,446.6	2,734.6
Long-term assets from risk management activities	17.7	24.5
Investments in unconsolidated affiliates	138.3	131.3
Other long-term assets	114.2	98.4
Total assets	$ 20,189.6	$ 19,560.0
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,581.3	$ 1,448.8
Accrued liabilities	292.0	289.5
Interest payable	101.0	174.0
Liabilities from risk management activities	105.8	320.1
Current debt obligations	602.0	834.3
Total current liabilities	2,682.1	3,066.7
Long-term debt	12,318.4	10,702.1
Long-term liabilities from risk management activities	34.8	140.1
Deferred income taxes, net	418.3	327.7
Other long-term liabilities	358.2	341.2
Contingencies (see Note 12)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference (1,200,000 shares authorized, zero shares issued and outstanding as of September 30, 2023 and December 31, 2022), net of discount	—	—
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 450,000,000 shares authorized as of September 30, 2023 and December 31, 2022)	0.2	0.2
Issued / Outstanding		
September 30, 2023: 240,087,974 / 223,080,697		
December 31, 2022: 237,939,058 / 226,042,229		
Preferred stock ($0.001 par value, after designation of Series A Preferred Stock: 98,800,000 shares authorized, zero shares issued and outstanding)	—	—
Additional paid-in capital	3,061.5	3,702.3
Retained earnings (deficit)	305.5	(626.8)
Accumulated other comprehensive income (loss)	(5.3)	54.7
Treasury stock, at cost (17,007,277 shares as of September 30, 2023 and 11,896,829 shares as of December 31, 2022)	(855.8)	(464.7)
Total Targa Resources Corp. stockholders' equity	2,506.1	2,665.7
Noncontrolling interests	1,871.7	2,316.5
Total owners' equity	4,377.8	4,982.2
Total liabilities, Series A Preferred Stock and owners' equity	$ 20,189.6	$ 19,560.0

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Sales of commodities	$ 3,374.3	$ 4,800.3	$ 10,314.0	$ 14,990.7
Fees from midstream services	522.3	559.8	1,506.8	1,384.3
Total revenues	3,896.6	5,360.1	11,820.8	16,375.0
Costs and expenses:				
Product purchases and fuel	2,690.0	4,306.3	7,777.9	13,557.8
Operating expenses	277.7	261.3	808.4	660.6
Depreciation and amortization expense	331.3	287.2	988.2	766.2
General and administrative expense	90.0	79.1	253.4	217.2
Other operating (income) expense	2.5	(3.8)	2.0	(4.4)
Income (loss) from operations	505.1	430.0	1,990.9	1,177.6
Other income (expense):				
Interest expense, net	(175.1)	(125.8)	(509.8)	(300.5)
Equity earnings (loss)	3.0	1.7	6.2	8.7
Gain (loss) from financing activities	—	—	—	(49.6)
Gain (loss) from sale of equity method investment	—	—	—	435.9
Other, net	(0.1)	(14.6)	(4.9)	(14.6)
Income (loss) before income taxes	332.9	291.3	1,482.4	1,257.5
Income tax (expense) benefit	(53.9)	(12.0)	(260.7)	(122.0)
Net income (loss)	279.0	279.3	1,221.7	1,135.5
Less: Net income (loss) attributable to noncontrolling interests	59.0	86.2	175.4	258.0
Net income (loss) attributable to Targa Resources Corp.	220.0	193.1	1,046.3	877.5
Premium on repurchase of noncontrolling interests, net of tax	—	—	490.7	53.1
Dividends on Series A Preferred Stock	—	—	—	30.0
Deemed dividends on Series A Preferred Stock	—	—	—	215.5
Net income (loss) attributable to common shareholders	$ 220.0	$ 193.1	$ 555.6	$ 578.9
Net income (loss) per common share - basic	$ 0.97	$ 0.85	$ 2.44	$ 2.54
Net income (loss) per common share - diluted	$ 0.97	$ 0.84	$ 2.43	$ 2.50
Weighted average shares outstanding - basic	223.8	226.6	225.2	227.6
Weighted average shares outstanding - diluted	225.1	230.3	226.5	231.5

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended September 30,					
	2023			2022		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss)			$ 279.0			$ 279.3
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ (153.8)	$ 34.9	(118.9)	$ 225.4	$ (50.4)	175.0
Settlements reclassified to revenues	(22.2)	5.0	(17.2)	121.7	(27.0)	94.7
Other comprehensive income (loss)	(176.0)	39.9	(136.1)	347.1	(77.4)	269.7
Comprehensive income (loss)			142.9			549.0
Less: Comprehensive income (loss) attributable to noncontrolling interests			59.0			86.2
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 83.9			$ 462.8

	Nine Months Ended September 30,					
	2023			2022		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss)			$ 1,221.7			$ 1,135.5
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ 39.6	$ (9.0)	30.6	$ (136.7)	$ 30.5	(106.2)
Settlements reclassified to revenues	(117.2)	26.6	(90.6)	425.2	(94.8)	330.4
Other comprehensive income (loss)	(77.6)	17.6	(60.0)	288.5	(64.3)	224.2
Comprehensive income (loss)			1,161.7			1,359.7
Less: Comprehensive income (loss) attributable to noncontrolling interests			175.4			258.0
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 986.3			$ 1,101.7

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional	Retained Earnings (Accumulated	Accumulated Other Comprehensive	Treasury Shares		Noncontrolling	Total	Series A
	Shares	Amount	Paid in Capital	Deficit)	Income (Loss)	Shares	Amount	Interests	Owners' Equity	Preferred Stock
	(Unaudited) (In millions, except shares in thousands)									
Balance, June 30, 2023	**224,052**	**$ 0.2**	**$ 3,045.8**	**$ 199.5**	**$ 130.8**	**15,160**	**$ (701.1)**	**$ 1,865.0**	**$ 4,540.2**	**$ —**
Compensation on equity grants	—	—	15.7	—	—	—	—	—	15.7	—
Dividend equivalent rights	—	—	—	(0.9)	—	—	—	—	(0.9)	—
Shares issued under compensation program	876	—	—	—	—	—	—	—	—	—
Shares tendered for tax withholding obligations	(263)	—	—	—	—	263	(21.6)	—	(21.6)	—
Repurchases of common stock	(1,584)	—	—	—	—	1,584	(132.0)	—	(132.0)	—
Excise tax on repurchases of common stock	—	—	—	—	—	—	(1.1)	—	(1.1)	—
Common stock dividends										
Dividends - $0.50 per share	—	—	—	(113.1)	—	—	—	—	(113.1)	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(56.5)	(56.5)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	4.2	4.2	—
Other comprehensive income (loss)	—	—	—	—	(136.1)	—	—	—	(136.1)	—
Net income (loss)	—	—	—	220.0	—	—	—	59.0	279.0	—
Balance, September 30, 2023	**223,081**	**$ 0.2**	**$ 3,061.5**	**$ 305.5**	**$ (5.3)**	**17,007**	**$ (855.8)**	**$ 1,871.7**	**$ 4,377.8**	**$ —**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

(Unaudited)
(In millions, except shares in thousands)

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owners' Equity	Series A Preferred Stock
	Shares	**Amount**				**Shares**	**Amount**			
Balance, June 30, 2022	**227,062**	**$ 0.2**	**$ 3,834.4**	**$ (1,137.9)**	**$ (276.4)**	**10,142**	**$ (350.4)**	**$ 2,331.0**	**$ 4,400.9**	**$ —**
Compensation on equity grants	—	—	14.4	—	—	—	—	—	14.4	—
Dividend equivalent rights	—	—	(1.7)	—	—	—	—	—	(1.7)	—
Shares issued under compensation program	481	—	—	—	—	—	—	—	—	—
Shares tendered for tax withholding obligations	(128)	—	—	—	—	128	(8.6)	—	(8.6)	—
Repurchases of common stock	(1,157)	—	—	—	—	1,157	(73.0)	—	(73.0)	—
Common stock dividends										
Dividends - $0.35 per share	—	—	—	(79.3)	—	—	—	—	(79.3)	—
Dividends in excess of retained earnings	—	—	(79.3)	79.3	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(75.2)	(75.2)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	4.9	4.9	—
Other comprehensive income (loss)	—	—	—	—	269.7	—	—	—	269.7	—
Net income (loss)	—	—	—	193.1	—	—	—	86.2	279.3	—
Balance, September 30, 2022	**226,258**	**$ 0.2**	**$ 3,767.8**	**$ (944.8)**	**$ (6.7)**	**11,427**	**$ (432.0)**	**$ 2,346.9**	**$ 4,731.4**	**$ —**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owners' Equity	Series A Preferred Stock
	Shares	Amount				Shares	Amount			
	(Unaudited) (In millions, except shares in thousands)									
Balance, December 31, 2022	**226,042**	**$ 0.2**	**$ 3,702.3**	**$ (626.8)**	**$ 54.7**	**11,897**	**$ (464.7)**	**$ 2,316.5**	**$ 4,982.2**	**$ —**
Compensation on equity grants	—	—	45.7	—	—	—	—	—	45.7	—
Dividend equivalent rights	—	—	(2.3)	(0.9)	—	—	—	—	(3.2)	—
Shares issued under compensation program	2,149	—	—	—	—	—	—	—	—	—
Shares tendered for tax withholding obligations	(714)	—	—	—	—	714	(55.4)	—	(55.4)	—
Repurchases of common stock	(4,396)	—	—	—	—	4,396	(333.1)	—	(333.1)	—
Excise tax on repurchases of common stock	—	—	—	—	—	—	(2.6)	—	(2.6)	—
Common stock dividends										
Dividends - $1.35 per share	—	—	—	(306.6)	—	—	—	—	(306.6)	—
Dividends in excess of retained earnings	—	—	(193.5)	193.5	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(170.0)	(170.0)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	7.1	7.1	—
Repurchase of noncontrolling interests, net of tax	—	—	(490.7)	—	—	—	—	(457.3)	(948.0)	—
Other comprehensive income (loss)	—	—	—	—	(60.0)	—	—	—	(60.0)	—
Net income (loss)	—	—	—	1,046.3	—	—	—	175.4	1,221.7	—
Balance, September 30, 2023	**223,081**	**$ 0.2**	**$ 3,061.5**	**$ 305.5**	**$ (5.3)**	**17,007**	**$ (855.8)**	**$ 1,871.7**	**$ 4,377.8**	**$ —**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

(Unaudited)
(In millions, except shares in thousands)

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owners' Equity	Series A Preferred Stock
	Shares	Amount				Shares	Amount			
Balance, December 31, 2021	**228,221**	**$ 0.2**	**$ 4,268.9**	**$ (1,822.3)**	**$ (230.9)**	**7,884**	**$ (204.1)**	**$ 3,166.9**	**$ 5,178.7**	**$ 749.7**
Compensation on equity grants	—	—	41.8	—	—	—	—	—	41.8	—
Dividend equivalent rights	—	—	(5.2)	—	—	—	—	—	(5.2)	—
Shares issued under compensation program	1,580	—	—	—	—	—	—	—	—	—
Shares tendered for tax withholding obligations	(526)	—	—	—	—	526	(31.1)	—	(31.1)	—
Repurchases of common stock	(3,017)	—	—	—	—	3,017	(196.8)	—	(196.8)	—
Series A Preferred Stock dividends										
Dividends - $47.50 per share	—	—	—	(30.0)	—	—	—	—	(30.0)	—
Dividends in excess of retained earnings	—	—	(30.0)	30.0	—	—	—	—	—	—
Deemed dividends - repurchase of Series A Preferred Stock	—	—	(215.5)	—	—	—	—	—	(215.5)	—
Common stock dividends										
Dividends - $1.05 per share	—	—	—	(239.1)	—	—	—	—	(239.1)	—
Dividends in excess of retained earnings	—	—	(239.1)	239.1	—	—	—	—	—	—
Repurchase of Series A Preferred Stock	—	—	—	—	—	—	—	—	—	(749.7)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(234.0)	(234.0)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	13.9	13.9	—
Repurchase of noncontrolling interests, net of tax	—	—	(53.1)	—	—	—	—	(857.9)	(911.0)	—
Other comprehensive income (loss)	—	—	—	—	224.2	—	—	—	224.2	—
Net income (loss)	—	—	—	877.5	—	—	—	258.0	1,135.5	—
Balance, September 30, 2022	**226,258**	**$ 0.2**	**$ 3,767.8**	**$ (944.8)**	**$ (6.7)**	**11,427**	**$ (432.0)**	**$ 2,346.9**	**$ 4,731.4**	**$ —**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2023	2022
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income (loss)	$ 1,221.7	$ 1,135.5
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	9.8	7.2
Compensation on equity grants	45.7	41.8
Depreciation and amortization expense	988.2	766.2
(Gain) loss on sale or disposition of assets	(3.9)	(8.1)
Write-downs of assets	6.0	3.7
Accretion of asset retirement obligations	4.5	3.5
Deferred income tax expense (benefit)	252.1	116.4
Equity (earnings) loss of unconsolidated affiliates	(6.2)	(8.7)
Distributions of earnings received from unconsolidated affiliates	9.6	11.0
Risk management activities	(294.3)	295.0
(Gain) loss from financing activities	—	49.6
(Gain) loss from sale of equity method investment	—	(435.9)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables and other assets	197.2	79.4
Inventories	(134.1)	(320.5)
Accounts payable, accrued liabilities and other liabilities	30.6	144.8
Interest payable	(73.0)	(37.6)
Net cash provided by operating activities	2,253.9	1,843.3
Cash flows from investing activities		
Outlays for property, plant and equipment	(1,665.4)	(815.4)
Outlays for business acquisition, net of cash acquired	—	(3,514.8)
Outlays for asset acquisition, net of cash acquired	—	(203.7)
Proceeds from sale of assets	2.9	18.3
Investments in unconsolidated affiliates	(14.9)	(1.5)
Proceeds from sale of equity method investment	—	857.0
Return of capital from unconsolidated affiliates	4.5	12.5
Other, net	(0.9)	—
Net cash provided by (used in) investing activities	(1,673.8)	(3,647.6)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facilities	—	5,305.0
Repayments of credit facilities	(290.0)	(4,755.0)
Proceeds from borrowings of commercial paper notes	47,077.8	8,584.8
Repayments of commercial paper notes	(46,936.5)	(7,952.8)
Proceeds from borrowings under term loan facility	—	1,500.0
Proceeds from borrowings under accounts receivable securitization facility	103.1	1,180.0
Repayments of accounts receivable securitization facility	(343.1)	(580.0)
Proceeds from issuance of senior notes	1,717.0	2,741.4
Redemption of senior notes	—	(1,473.2)
Principal payments of finance leases	(31.3)	(10.8)
Costs incurred in connection with financing arrangements	(5.0)	(44.4)
Repurchase of shares	(388.5)	(227.9)
Contributions from noncontrolling interests	7.1	13.9
Distributions to noncontrolling interests	(163.5)	(252.0)
Repurchase of noncontrolling interests	(1,091.9)	(926.3)
Redemption of Series A Preferred Stock	—	(965.2)
Dividends paid to common and Series A Preferred shareholders	(314.8)	(298.8)
Net cash provided by (used in) financing activities	(659.6)	1,838.7
Net change in cash and cash equivalents	(79.5)	34.4
Cash and cash equivalents, beginning of period	219.0	158.5
Cash and cash equivalents, end of period	$ 139.5	$ 192.9

See notes to consolidated financial statements.

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization and Operations

Our Organization

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. Targa is a leading provider of midstream services and is one of the largest independent infrastructure companies in North America. We own, operate, acquire, and develop a diversified portfolio of complementary domestic midstream infrastructure assets.

In this Quarterly Report, unless the context requires otherwise, references to “we,” “us,” “our,” “the Company,” “Targa” or “TRGP” are intended to mean our consolidated business and operations. TRGP controls the general partner of and owns all of the outstanding common units representing limited partner interests in Targa Resources Partners LP, referred to herein as the “Partnership”. Targa consolidated the Partnership and its subsidiaries under GAAP, and prepared the accompanying consolidated financial statements under the rules and regulations of the SEC. Targa’s consolidated financial statements include differences from the consolidated financial statements of the Partnership. The most noteworthy differences are:

- the inclusion of the TRGP senior revolving credit facility and term loan facility;
- the inclusion of the TRGP senior notes;
- the inclusion of the TRGP commercial paper notes;
- the inclusion of Series A Preferred Stock (“Series A Preferred”) prior to full redemption in May 2022; and
- the impacts of TRGP’s treatment as a corporation for U.S. federal income tax purposes.

Our Operations

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.

See Note 16 – Segment Information for certain financial information regarding our business segments.

Note 2 — Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and do not include all information and disclosures required by GAAP. Therefore, this information should be read in conjunction with our consolidated financial statements and notes contained in our Annual Report. The information furnished herein reflects all adjustments that are, in the opinion of management, of a normal recurring nature and considered necessary for a fair statement of the results of the interim periods reported. All intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods have been reclassified to conform to the current year presentation. Operating results for the three and nine months ended September 30, 2023 are not necessarily indicative of the results that may be expected for the year ending December 31, 2023.

Note 3 — Significant Accounting Policies

The accounting policies that we follow are set forth in Note 3 – Significant Accounting Policies of the Notes to Consolidated Financial Statements in our Annual Report. Other than the updates noted below, there were no significant updates or revisions to our accounting policies during the nine months ended September 30, 2023.

Recently Adopted Accounting Pronouncements

Supplier Finance Programs

In September 2022, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2022-04, *Liabilities—Supplier Finance Programs (Subtopic 405-50)*. Amendments in this update require annual and interim disclosure of the key terms of outstanding supplier finance programs and a rollforward of the related obligations. These amendments do not affect the recognition, measurement or financial statement presentation of the supplier finance program obligations. These amendments are effective for fiscal years beginning after December 15, 2022, except for the rollforward requirements, which are effective for fiscal years beginning after December 15, 2023. We maintain a supply chain finance program that allows participating suppliers to request early payment from a third-party financial institution of invoices that we confirm as valid. Under this program, we make payments in full to the third-party financial institution for the prior month's outstanding balance within 15 days. The outstanding balance at the end of each reporting period is included in Accounts payable on our Consolidated Balance Sheets. We adopted the amendments on January 1, 2023, with no material impact on our consolidated financial statements.

Note 4 – Acquisitions and Divestitures

In February 2018, we formed three development joint ventures ("DevCo JVs") with investment vehicles affiliated with Stonepeak Infrastructure Partners ("Stonepeak") to fund portions of Grand Prix NGL Pipeline ("Grand Prix"), Gulf Coast Express Pipeline ("GCX") and a 110 MBbl/d fractionator in Mont Belvieu, Texas ("Train 6"). For a four-year period beginning on the date that all three projects commenced commercial operations, we had the option to acquire all or part of Stonepeak's interests in the DevCo JVs (the "DevCo JV Call Right"). The purchase price payable for such partial or full interests was based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs.

In January 2022, we exercised the DevCo JV Call Right and closed on the purchase of all of Stonepeak's interests in the DevCo JVs for $926.3 million (the "DevCo JV Repurchase"). Following the DevCo JV Repurchase, we owned a 75% interest in the Permian region to Mont Belvieu segment of Grand Prix through Grand Prix Pipeline LLC (the "Grand Prix Joint Venture") (prior to the Grand Prix Transaction, as defined below), a 100% interest in Train 6 and a 25% equity interest in GCX (prior to the sale of Targa GCX Pipeline LLC in February 2022 to a third party, with payment received in full in May 2022). The change in our ownership interests was accounted for as an equity transaction representing the acquisition of noncontrolling interests. The amount of the redemption price in excess of the carrying amount, net of tax, was $53.1 million, which was accounted for as a premium on repurchase of noncontrolling interests, and resulted in a reduction to Net income (loss) attributable to common shareholders. In addition, the DevCo JV Repurchase resulted in an $857.9 million reduction of Noncontrolling interests on our Consolidated Balance Sheets.

In January 2023, we completed the acquisition of Blackstone Energy Partners' 25% interest in the Grand Prix Joint Venture (the "Grand Prix Transaction") for aggregate consideration of $1.05 billion in cash and a final closing adjustment of $41.9 million. Following the closing of the Grand Prix Transaction, we own 100% of the interest in Grand Prix. The change in our ownership interests was accounted for as an equity transaction representing the acquisition of noncontrolling interests. The amount of the redemption price in excess of the carrying amount, net of tax, was $490.7 million, which was accounted for as a premium on repurchase of noncontrolling interests, and resulted in a reduction to Net income (loss) attributable to common shareholders. In addition, the Grand Prix Transaction resulted in a $457.3 million reduction of Noncontrolling interests on our Consolidated Balance Sheets.

Delaware Basin Acquisition

In July 2022, we completed the acquisition of all of the interests in Lucid Energy Delaware, LLC ("Lucid") from Riverstone Holdings LLC and Goldman Sachs Asset Management for approximately $3.5 billion in cash (the "Delaware Basin Acquisition"). We received a final net working capital adjustment payment of approximately $11.4 million in the fourth quarter of 2022.

Unaudited Pro Forma Financial Information

The following unaudited pro forma summary presents the consolidated results of operations for the three and nine months ended September 30, 2022 as if the Delaware Basin Acquisition had occurred on January 1, 2021. The unaudited pro forma financial information is presented for informational purposes only and is not necessarily indicative of our results of operations that would have occurred had the transaction been consummated at the beginning of the period presented, nor is it necessarily indicative of future results.

	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2022
Revenues	$ 5,391.1	$ 16,604.0
Net income (loss)	288.3	1,089.7

The summarized unaudited pro forma information has been calculated after applying our accounting policies and reflects adjustments for the following:

- Reflects depreciation and amortization based on the fair values of property, plant and equipment and intangible assets, respectively. Property, plant and equipment are depreciated utilizing a straight-line approach. Intangible assets are amortized in a manner that closely resembles their expected benefit pattern;
- Excludes $14.3 million of acquisition-related costs incurred as of September 30, 2022 from pro forma net income for the three and nine months ended September 30, 2022;
- Excludes the impact of operations previously sold by Lucid, prior to Targa’s acquisition of Lucid;
- Excludes the impact of historical activity between Targa and Lucid, prior to Targa’s acquisition of Lucid;
- Excludes general and administrative expense related to Lucid’s former parent company, which Targa did not acquire;
- Excludes amortization of interest expense and debt issuance costs associated with Lucid’s debt, which was not assumed by Targa;
- Includes interest expense and debt issuance cost amortization associated with Targa’s borrowings to finance the Delaware Basin Acquisition; and
- Reflects the income tax effects of the above pro forma adjustments.

Note 5 — Property, Plant and Equipment and Intangible Assets

	September 30, 2023	December 31, 2022	Estimated Useful Lives (In Years)
Gathering systems	$ 10,698.4	$ 10,403.1	5 to 20
Processing and fractionation facilities	7,783.4	7,421.2	5 to 25
Terminaling and storage facilities	1,369.2	1,341.6	5 to 25
Transportation assets	3,238.7	2,919.3	10 to 50
Other property, plant and equipment	404.8	387.6	3 to 50
Land	178.8	163.3	—
Construction in progress	1,566.3	1,011.0	—
Finance lease right-of-use assets	334.6	266.1	5 to 14
Property, plant and equipment	25,574.2	23,913.2	
Accumulated depreciation, amortization and impairment	(10,240.7)	(9,698.6)	
Property, plant and equipment, net	$ 15,333.5	$ 14,214.6	
Intangible assets	4,378.0	4,379.7	10 to 20
Accumulated amortization and impairment	(1,931.4)	(1,645.1)	
Intangible assets, net	$ 2,446.6	$ 2,734.6	

During the three and nine months ended September 30, 2023, depreciation expense was $235.3 million and $700.2 million, respectively.

During the three and nine months ended September 30, 2022, depreciation expense was $206.5 million and $629.5 million, respectively.

Intangible Assets

Intangible assets consist of customer relationships and customer contracts acquired in prior business combinations. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Amortization expense attributable to these assets is recorded over the periods in which we benefit from services provided to customers.

During the three and nine months ended September 30, 2023, amortization expense was $96.0 million and $288.0 million, respectively.

During the three and nine months ended September 30, 2022, amortization expense was $80.7 million and $136.7 million, respectively.

The estimated annual amortization expense for intangible assets is approximately $384.0 million, $373.2 million, $326.0 million, $279.8 million and $252.2 million for each of the years 2023 through 2027, respectively.

Note 6 — Debt Obligations

	September 30, 2023	December 31, 2022
Current:		
Partnership accounts receivable securitization facility, due August 2024 (1)	$ 560.0	$ 800.0
Finance lease liabilities	42.0	34.3
Current debt obligations	602.0	834.3
Long-term:		
Term loan facility, variable rate, due July 2025	1,500.0	1,500.0
TRGP senior revolving credit facility, variable rate, due February 2027 (2)	1,150.0	1,298.7
Senior unsecured notes issued by TRGP:		
5.200% fixed rate, due July 2027	750.0	750.0
4.200% fixed rate, due February 2033	750.0	750.0
6.125% fixed rate, due March 2033	900.0	—
4.950% fixed rate, due April 2052	750.0	750.0
6.250% fixed rate, due July 2052	500.0	500.0
6.500% fixed rate, due February 2053	850.0	—
Unamortized discount	(40.5)	(8.4)
Senior unsecured notes issued by the Partnership: (3)		
6.500% fixed rate, due July 2027	705.2	705.2
5.000% fixed rate, due January 2028	700.3	700.3
6.875% fixed rate, due January 2029	679.3	679.3
5.500% fixed rate, due March 2030	949.6	949.6
4.875% fixed rate, due February 2031	1,000.0	1,000.0
4.000% fixed rate, due January 2032	1,000.0	1,000.0
	12,143.9	10,574.7
Debt issuance costs, net of amortization	(63.9)	(65.6)
Finance lease liabilities	238.4	193.0
Long-term debt	12,318.4	10,702.1
Total debt obligations	$ 12,920.4	$ 11,536.4
Irrevocable standby letters of credit: (2)		
Letters of credit outstanding under the TRGP senior revolving credit facility	$ 22.3	$ 33.2

(1) In August 2023, the Partnership amended its accounts receivable securitization facility (the "Securitization Facility") to decrease the size of the Securitization Facility from $800.0 million to $600.0 million and to extend the termination date of the Securitization Facility to August 29, 2024. As of September 30, 2023, the Partnership had $560.0 million of qualifying receivables under the Securitization Facility, resulting in $40.0 million availability.

(2) We maintain an unsecured commercial paper note program (the "Commercial Paper Program"), the borrowings of which are supported through maintaining a minimum available borrowing capacity under our $2.75 billion TRGP senior revolving credit facility (the "TRGP Revolver") equal to the aggregate amount outstanding under the Commercial Paper Program. As of September 30, 2023, the TRGP Revolver had no borrowings outstanding and the Commercial Paper Program had $1,150.0 million borrowings outstanding, resulting in approximately $1.6 billion of available liquidity, after accounting for outstanding letters of credit.

(3) We guarantee all of the Partnership's outstanding senior unsecured notes.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the nine months ended September 30, 2023:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRGP Revolver and Commercial Paper Program	5.2% - 6.2%	5.8%
Securitization Facility	5.2% - 6.3%	5.7%
Term Loan Facility	5.8% - 6.8%	6.4%

Compliance with Debt Covenants

As of September 30, 2023, we were in compliance with the covenants contained in our various debt agreements.

In February 2022, we and certain of our subsidiaries entered into a parent guarantee whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of all of the obligations of the Partnership and Targa Resources Partners Finance Corporation (together with the Partnership, the "Partnership Issuers") under the respective indentures governing the Partnership Issuers' senior unsecured notes. As of September 30, 2023, $5.0 billion of the Partnership Issuers' senior unsecured notes was outstanding.

Debt Obligations

Commercial Paper Program

In 2022, we established the Commercial Paper Program. Under the terms of the Commercial Paper Program, we may issue, from time to time, unsecured commercial paper notes with varying maturities of less than one year. Amounts available under the Commercial Paper Program may be issued, repaid and re-issued from time to time, with the maximum aggregate face or principal amount outstanding at any one time not to exceed $2.75 billion. We maintain a minimum available borrowing capacity under the TRGP Revolver equal to the aggregate amount outstanding under the Commercial Paper Program as support. The Commercial Paper Program is guaranteed by each subsidiary that guarantees the TRGP Revolver. The commercial paper notes are presented in Long-term debt on our Consolidated Balance Sheets.

Senior Unsecured Notes Issuances

In January 2023, we completed an underwritten public offering of (i) $900.0 million aggregate principal amount of our 6.125% Senior Notes due 2033 (the "6.125% Notes") and (ii) $850.0 million aggregate principal amount of our 6.500% Senior Notes due 2053 (the "6.500% Notes"), resulting in net proceeds of approximately $1.7 billion. The 6.125% Notes and the 6.500% Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our subsidiaries that guarantee the TRGP Revolver, so long as such subsidiary guarantors satisfy certain conditions. The 6.125% Notes and the 6.500% Notes were issued pursuant to the Indenture, dated as of April 6, 2022, as supplemented by that certain Fifth Supplemental Indenture, dated as of January 3, 2023, among us, each subsidiary guarantor and U.S. Bank Trust Company, National Association, as trustee. We used a portion of the net proceeds from the issuance to fund the Grand Prix Transaction and the remaining proceeds for general corporate purposes, including to reduce borrowings under the TRGP Revolver and the Commercial Paper Program.

In the future, we or the Partnership may redeem, purchase or exchange certain of our and the Partnership's outstanding debt through redemption calls, cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such calls, repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Note 7 — Other Long-term Liabilities

Other long-term liabilities are comprised of the following:

	September 30, 2023	December 31, 2022
Deferred revenue	$ 202.1	$ 198.8
Asset retirement obligations	104.7	97.9
Operating lease liabilities	35.5	28.6
Other liabilities	15.9	15.9
Total other long-term liabilities	$ 358.2	$ 341.2

Deferred Revenue

We have certain long-term contractual arrangements for which we have received consideration that we are not yet able to recognize as revenue. The resulting deferred revenue will be recognized once all conditions for revenue recognition have been met.

Deferred revenue as of September 30, 2023 and December 31, 2022, was $202.1 million and $198.8 million, respectively, which includes $129.0 million of payments received from Vitol Americas Corp. ("Vitol") (formerly known as Noble Americas Corp.), a subsidiary of Vitol US Holding Co., in 2016, 2017, and 2018 as part of an agreement (the "Splitter Agreement") related to the construction and operation of a crude oil and condensate splitter. In December 2018, Vitol elected to terminate the Splitter Agreement. The Splitter Agreement provides that the first three annual payments are ours if Vitol elects to terminate, which Vitol disputes. The timing of revenue recognition related to the Splitter Agreement deferred revenue is dependent on the outcome of current litigation with Vitol. See Note 12 – Contingencies.

Deferred revenue includes nonmonetary consideration received in a 2015 amendment to a gas gathering and processing agreement and consideration received for other construction activities of facilities connected to our systems. Deferred revenue also includes contributions in aid of construction received from customers for which revenue is recognized over the expected contract term.

Note 8 — Common Stock and Related Matters

Common Share Repurchase Program

In October 2020, our Board of Directors approved a share repurchase program (the "2020 Share Repurchase Program") for the repurchase of up to $500.0 million of our outstanding common stock. In May 2023, our Board of Directors approved a new share repurchase program (the "2023 Share Repurchase Program") for the repurchase of up to $1.0 billion of our outstanding common stock. During the second quarter of 2023, we exhausted the 2020 Share Repurchase Program. As of September 30, 2023, there was $810.7 million remaining under the 2023 Share Repurchase Program. We may discontinue the 2023 Share Repurchase Program at any time and are not obligated to repurchase any specific dollar amount or number of shares thereunder.

For the three and nine months ended September 30, 2023, we repurchased 1,583,317 shares and 4,395,519 shares of our common stock at a weighted average per share price of $83.38 and $75.77 for a total net cost of $132.0 million and $333.1 million, respectively. For the three and nine months ended September 30, 2022, we repurchased 1,156,832 shares and 3,016,556 shares of our common stock at a weighted average per share price of $63.06 and $65.23 for a total net cost of $72.9 million and $196.8 million, respectively.

Common Stock Dividends

In April 2023, we declared an increase to our common dividend to $0.50 per common share or $2.00 per common share annualized effective for the first quarter of 2023.

The following table details the dividends declared and/or paid by us to common shareholders for the nine months ended September 30, 2023:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Dividends on Share-Based Awards	Dividends Declared per Share of Common Stock
		(In millions, except per share amounts)			
September 30, 2023	November 15, 2023	$ 113.0	$ 111.5	$ 1.5	$ 0.50000
June 30, 2023	August 15, 2023	113.6	111.8	1.8	0.50000
March 31, 2023	May 15, 2023	114.7	113.0	1.7	0.50000
December 31, 2022	February 15, 2023	80.5	79.3	1.2	0.35000

Note 9 — Earnings per Common Share

In March 2023, the Compensation Committee amended the Restricted Stock Units Grant Agreements that govern the Restricted Stock Unit awards ("RSUs") that vest no later than three years following the RSUs' grant date. The amendment resulted in quarterly cash dividend payments to RSU holders beginning with the common stock dividend paid in May 2023. As the amended RSUs and certain four-year retention awards participate in nonforfeitable dividends with the common equity owners of the Company, they are considered participating securities.

We calculate earnings per share using the two-class method. Earnings are allocated to common stock and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings to the extent that each security participates in earnings.

The following table sets forth a reconciliation of net income and weighted average shares outstanding used in computing basic and diluted net income per common share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(In millions, except per share amounts)			
Net income (loss) attributable to Targa Resources Corp.	$ 220.0	$ 193.1	$ 1,046.3	$ 877.5
Less: Premium on repurchase of noncontrolling interests, net of tax (1)	—	—	490.7	53.1
Less: Dividends on Series A Preferred Stock (2)	—	—	—	30.0
Less: Deemed dividends on Series A Preferred (2)	—	—	—	215.5
Net income (loss) attributable to common shareholders	220.0	193.1	555.6	578.9
Less: Participating share-based earnings (3)	2.2	—	5.1	—
Net income (loss) allocated to common shareholders for basic earnings per share	$ 217.8	$ 193.1	$ 550.5	$ 578.9
Weighted average shares outstanding - basic	223.8	226.6	225.2	227.6
Dilutive effect of unvested stock awards	1.3	3.7	1.3	3.9
Weighted average shares outstanding - diluted	225.1	230.3	226.5	231.5
Net income (loss) available per common share - basic	$ 0.97	$ 0.85	$ 2.44	$ 2.54
Net income (loss) available per common share - diluted	$ 0.97	$ 0.84	$ 2.43	$ 2.50

(1) Represents premium paid on the Grand Prix Transaction and the DevCo JV Repurchase. See Note 4 – Acquisitions and Divestitures.
(2) The Series A Preferred had no mandatory redemption date, but was redeemable at our election for a 5% premium to the liquidation preference subsequent to March 16, 2022. In May 2022, we redeemed all of our issued and outstanding Series A Preferred.
(3) Represents the distributed and undistributed earnings of the Company attributable to the participating securities. The dilutive effect of the reallocation of participating securities to diluted net income attributable to common shareholders was immaterial.

The following potential common stock equivalents are excluded from the determination of diluted earnings per share because the inclusion of such shares would have been anti-dilutive (in millions on a weighted-average basis):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Unvested restricted stock awards	1.4	—	1.6	—
Series A Preferred (1)	—	—	—	19.9

(1) The Series A Preferred had no mandatory redemption date, but was redeemable at our election for a 5% premium to the liquidation preference subsequent to March 16, 2022. In May 2022, we redeemed all of our issued and outstanding Series A Preferred.

Note 10 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have entered into derivative instruments to hedge the commodity price risks associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation segment. The hedge positions associated with (i) and (ii) above will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices and are primarily designated as cash flow hedges for accounting purposes.

The hedges generally match the NGL product composition and the NGL delivery points of our physical equity volumes. Our natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations.

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying condensate equity volumes.

We also enter into derivative instruments to help manage other short-term commodity-related business risks and take advantage of market opportunities. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues as current income.

At September 30, 2023, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2023	2024	2025	2026	2027
Natural Gas	Swaps	MMBtu/d	148,830	103,512	56,856	10,373	—
Natural Gas	Basis Swaps	MMBtu/d	735,435	402,780	256,658	102,500	25,000
NGL	Swaps	Bbl/d	42,072	28,492	18,759	2,646	—
NGL	Futures	Bbl/d	34,467	18,549	4,562	—	—
Condensate	Swaps	Bbl/d	6,379	4,531	3,245	494	—

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty within the same Targa entity. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements.

The following schedules reflect the fair value of our derivative instruments and their location on our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of September 30, 2023		Fair Value as of December 31, 2022	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 61.8	$ (74.4)	$ 158.7	$ (93.8)
	Long-term	12.6	(19.0)	24.2	(30.9)
Total derivatives designated as hedging instruments		$ 74.4	$ (93.4)	$ 182.9	$ (124.7)
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 22.4	$ (31.4)	$ 21.2	$ (226.3)
	Long-term	5.1	(15.8)	0.3	(109.2)
Total derivatives not designated as hedging instruments		$ 27.5	$ (47.2)	$ 21.5	$ (335.5)
Total current position		$ 84.2	$ (105.8)	$ 179.9	$ (320.1)
Total long-term position		17.7	(34.8)	24.5	(140.1)
Total derivatives		$ 101.9	$ (140.6)	$ 204.4	$ (460.2)

The pro forma impact of reporting derivatives on our Consolidated Balance Sheets on a net basis is as follows:

September 30, 2023	Gross Presentation			Pro Forma Net Presentation	
	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 83.2	$ (105.3)	$ 20.7	$ 25.6	$ (27.0)
Counterparties without offsetting positions - assets	1.0	—	—	1.0	—
Counterparties without offsetting positions - liabilities	—	(0.5)	—	—	(0.5)
	84.2	(105.8)	20.7	26.6	(27.5)
Long-Term Position					
Counterparties with offsetting positions or collateral	17.7	(34.8)	2.3	2.1	(16.9)
Counterparties without offsetting positions - assets	—	—	—	—	—
Counterparties without offsetting positions - liabilities	—	—	—	—	—
	17.7	(34.8)	2.3	2.1	(16.9)
Total Derivatives					
Counterparties with offsetting positions or collateral	100.9	(140.1)	23.0	27.7	(43.9)
Counterparties without offsetting positions - assets	1.0	—	—	1.0	—
Counterparties without offsetting positions - liabilities	—	(0.5)	—	—	(0.5)
	$ 101.9	$ (140.6)	$ 23.0	$ 28.7	$ (44.4)

December 31, 2022	Gross Presentation			Pro Forma Net Presentation	
	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 162.2	$ (316.7)	$ 12.2	$ 27.2	$ (169.5)
Counterparties without offsetting positions - assets	17.7	—	—	17.7	—
Counterparties without offsetting positions - liabilities	—	(3.4)	—	—	(3.4)
	179.9	(320.1)	12.2	44.9	(172.9)
Long-Term Position					
Counterparties with offsetting positions or collateral	24.5	(137.4)	22.4	7.3	(97.8)
Counterparties without offsetting positions - assets	—	—	—	—	—
Counterparties without offsetting positions - liabilities	—	(2.7)	—	—	(2.7)
	24.5	(140.1)	22.4	7.3	(100.5)
Total Derivatives					
Counterparties with offsetting positions or collateral	186.7	(454.1)	34.6	34.5	(267.3)
Counterparties without offsetting positions - assets	17.7	—	—	17.7	—
Counterparties without offsetting positions - liabilities	—	(6.1)	—	—	(6.1)
	$ 204.4	$ (460.2)	$ 34.6	$ 52.2	$ (273.4)

Some of our hedges are futures contracts executed through brokers that clear the hedges through an exchange. We maintain a margin deposit with the brokers in an amount sufficient to cover the fair value of our open futures positions. The margin deposit is considered collateral, which is located within Other current assets on our Consolidated Balance Sheets and is not offset against the fair value of our derivative instruments. Our derivative instruments other than our futures contracts are executed under International Swaps and Derivatives Association ("ISDA") agreements, which govern the key terms with our counterparties. Our ISDA agreements contain credit-risk related contingent features. Following the release of the collateral securing our TRGP Revolver, our derivative positions are no longer secured. As of September 30, 2023, we have outstanding net derivative positions that contain credit-risk related contingent features that are in a net liability position of $43.9 million. We have not been required to post any collateral related to these positions due to our credit rating. If our credit rating was to be downgraded one notch below investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Financial Services LLC, as defined in our ISDAs, we estimate that as of September 30, 2023, we would not be required to post collateral to certain counterparties per the terms of our ISDAs.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net liability of $38.7 million as of September 30, 2023. The estimated fair value is net of an adjustment for credit risk based on the default probabilities as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are margined daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other comprehensive income ("OCI") and amounts reclassified from OCI to revenue for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Commodity contracts	$ (153.8)	$ 225.4	$ 39.6	$ (136.7)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Revenues	$ 22.2	$ (121.7)	$ 117.2	$ (425.2)

Based on valuations as of September 30, 2023, we expect to reclassify commodity hedge-related deferred losses of $(14.3) million included in accumulated other comprehensive income (loss) into earnings before income taxes through the end of 2026, with $(7.8) million of losses to be reclassified over the next twelve months.

Our consolidated earnings are also affected by the use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial assets and liabilities (“financial instruments”) can cause non-cash earnings volatility due to changes in the underlying commodity price indices. For the three months ended September 30, 2023, the unrealized mark-to-market losses are primarily attributable to unfavorable movements in natural gas forward prices, as compared to our positions. For the nine months ended September 30, 2023, the unrealized mark-to-market gains are primarily attributable to favorable movements in natural gas forward prices, as compared to our positions.

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2023	2022	2023	2022
Commodity contracts	Revenue	$ (7.0)	$ (121.5)	$ 316.2	$ (317.5)

See Note 11 – Fair Value Measurements and Note 16 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 11 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial instruments. Derivative financial instruments are reported at fair value on our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost on our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps, futures, option contracts and fixed-price forward commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and we believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. The financial position of these derivatives at September 30, 2023, a net liability position of $38.7 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $195.7 million. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $118.2 million.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- the TRGP Revolver, commercial paper notes, Securitization Facility and Term Loan Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- the TRGP senior unsecured notes and the Partnership's senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities at each balance sheet reporting date using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (i) financial instruments measurements included on our Consolidated Balance Sheets at fair value, and (ii) supplemental fair value disclosures for other financial instruments:

	September 30, 2023				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 100.9	$ 100.9	$ —	$ 100.9	$ —
Liabilities from commodity derivative contracts (1)	139.6	139.6	—	139.3	0.3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	139.5	139.5	—	—	—
TRGP Revolver and Commercial Paper Program	1,150.0	1,150.0	—	1,150.0	—
TRGP Senior unsecured notes	4,459.5	4,064.5	—	4,064.5	—
Term Loan Facility	1,500.0	1,500.0	—	1,500.0	—
Partnership's Senior unsecured notes	5,034.4	4,672.7	—	4,672.7	—
Securitization Facility	560.0	560.0	—	560.0	—

	December 31, 2022				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 201.6	$ 201.6	$ —	$ 201.6	$ —
Liabilities from commodity derivative contracts (1)	457.4	457.4	—	457.4	—
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	219.0	219.0	—	—	—
TRGP Revolver and Commercial Paper Program	1,298.7	1,298.7	—	1,298.7	—
TRGP Senior unsecured notes	2,741.6	2,452.6	—	2,452.6	—
Term Loan Facility	1,500.0	1,500.0	—	1,500.0	—
Partnership's Senior unsecured notes	5,034.4	4,711.3	—	4,711.3	—
Securitization Facility	800.0	800.0	—	800.0	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 10 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

Additional Information Regarding Level 3 Fair Value Measurements Included on Our Consolidated Balance Sheets

We have historically reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable market prices or implied volatilities for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input was determined to be significant to the overall inputs, the entire valuation was categorized in Level 3. This included derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these swaps was determined using a discounted cash flow valuation technique based on a commodity forward curve. For these derivatives, the primary input to the valuation model was the commodity forward curve, which was based on observable or public data sources and extrapolated when observable prices were not available.

The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives were the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the commodity forward curve where prices are not observable was immaterial. As of September 30, 2023, we had two derivative contracts categorized as Level 3.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts Asset/(Liability)
Balance, December 31, 2022	$ —
New Level 3 derivative instruments	(0.3)
Balance, September 30, 2023	$ (0.3)

Note 12 — Contingencies

Legal Proceedings

We and the Partnership are parties to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business. We and the Partnership are also parties to various proceedings with governmental environmental agencies, including, but not limited to the U.S. Environmental Protection Agency, Texas Commission on Environmental Quality, Oklahoma Department of Environmental Quality, New Mexico Environment Department, Louisiana Department of Environmental Quality and North Dakota Department of Environmental Quality, which assert monetary sanctions for alleged violations of environmental regulations, including air emissions, discharges into the environment and reporting deficiencies, related to events that have arisen at certain of our facilities in the ordinary course of our business.

On December 26, 2018, Vitol filed a lawsuit in the 80th District Court of Harris County (the "District Court"), Texas against Targa Channelview LLC, then a subsidiary of the Company ("Targa Channelview"), seeking recovery of $129.0 million in payments made to Targa Channelview, additional monetary damages, attorneys' fees and costs. Vitol alleges that Targa Channelview breached the Splitter Agreement, which provided for Targa Channelview to construct a crude oil and condensate splitter (the "Splitter") adjacent to a barge dock owned by Targa Channelview to provide services contemplated by the Splitter Agreement. In January 2018, Vitol acquired Noble Americas Corp. and on December 23, 2018, Vitol voluntarily elected to terminate the Splitter Agreement claiming that Targa Channelview failed to timely achieve start-up of the Splitter. Vitol's lawsuit also alleges Targa Channelview made a series of misrepresentations about the capability of the barge dock that would service crude oil and condensate volumes to be processed by the Splitter and Splitter products. Vitol seeks return of $129.0 million in payments made to Targa Channelview prior to the start-up of the Splitter, as well as additional damages. On the same date that Vitol filed its lawsuit, Targa Channelview filed a lawsuit against Vitol seeking a judicial determination that Vitol's sole and exclusive remedy was Vitol's voluntarily termination of the Splitter Agreement and, as a result, Vitol was not entitled to the return of any prior payments under the Splitter Agreement or other damages as alleged. Targa also seeks recovery of its attorneys' fees and costs in the lawsuit.

On October 15, 2020, the District Court awarded Vitol $129.0 million (plus interest) following a bench trial. In addition, the District Court awarded Vitol $10.5 million in damages for losses and demurrage on crude oil that Vitol purchased for start-up efforts. The Company appealed the award in the Fourteenth Court of Appeals in Houston, Texas. In October 2020, we sold Targa Channelview but, under the agreements governing the sale, we retained the liabilities associated with the Vitol proceedings. On September 13, 2022, the Fourteenth Court of Appeals upheld the trial court's judgment in part with regard to the return of Vitol's prior payments, but modified the judgment to delete Vitol's ability to recover any damages related to losses or demurrage on crude oil. We filed a petition for review with the Supreme Court of Texas which was denied on October 20, 2023, but we are seeking rehearing and the appeal remains pending. The cumulative amount of interest on the award through September 30, 2023, if accrued, would have been approximately $52.3 million.

On July 24, 2023, we received a Notice of Violation from the New Mexico Environment Department, Air Quality Bureau, relating to alleged air permit violations between August 1, 2021 and June 30, 2022 by Lucid Energy Delaware, LLC, an entity we subsequently acquired in July 2022 in the Delaware Basin Acquisition and whose assets are now integrated into Targa Northern Delaware LLC, a wholly-owned subsidiary of the Company. We have been engaging with the New Mexico Environment Department to resolve this matter. Although this matter is ongoing and management cannot predict its ultimate outcome, the resolution of this matter may result in a fine or penalty in excess of $0.3 million. We do not expect that any expenditures related to this matter will be material to our consolidated financial statements.

On October 26, 2023, we received a final judgment in a lawsuit alleging a breach of contract related to the major winter storm in February 2021. The damages awarded against us are approximately $6.9 million, not including pre-judgment interest.

We are also a defendant in three other breach of contract cases related to force majeure events arising during the major winter storm in February 2021. We believe that the likelihood of a partial loss could be reasonably possible, and, while it is not possible to predict the ultimate outcome of these cases on an individual or consolidated basis, we estimate that the total range of potential loss resulting from all of these cases could be between $0 and $10.0 million in the aggregate. We intend to continue to vigorously defend these cases.

Note 13 — Revenue

Fixed consideration allocated to remaining performance obligations

The following table presents the estimated minimum revenue related to unsatisfied performance obligations at the end of the reporting period and is comprised of fixed consideration primarily attributable to contracts with minimum volume commitments, for which a guaranteed amount of revenue can be calculated. These contracts are comprised primarily of gathering and processing, fractionation, export, terminaling and storage agreements, with remaining contract terms ranging from 1 to 16 years.

	2023	2024	2025 and after
Fixed consideration to be recognized as of September 30, 2023	$ 109.7	$ 461.6	$ 2,407.5

Based on the optional exemptions that we elected to apply, the amounts presented in the table above exclude remaining performance obligations for (i) variable consideration for which the allocation exception is met and (ii) contracts with an original expected duration of one year or less.

For disclosures related to disaggregated revenue, see Note 16 – Segment Information.

Note 14 — Income Taxes

We record income taxes using an estimated annual effective tax rate and recognize specific events discretely as they occur. Our effective tax rate for the three and nine months ended September 30, 2023 is lower than the U.S. corporate statutory rate of 21% primarily due to the release of a portion of our state valuation allowances, stock compensation windfall and income allocated to noncontrolling interests that is not taxable to the Company. Our effective tax rate for the three and nine months ended September 30, 2022 was lower than the U.S. corporate statutory rate of 21% primarily due to the release of a portion of our federal valuation allowances in addition to income allocated to noncontrolling interests that is not taxable to the Company.

We regularly evaluate the realizable tax benefits of deferred tax assets and record a valuation allowance, if required, based on an estimate of the amount of deferred tax assets that we believe does not meet the more-likely-than-not criteria of being realized. As of September 30, 2023, our valuation allowance was $9.4 million, a decrease of $27.5 million from December 31, 2022. After the change in valuation allowance, we have a net deferred tax liability of $418.3 million.

We are subject to tax in the U.S. and various state jurisdictions. Additionally, we are subject to periodic audits and reviews by U.S. federal and state taxing authorities. As of September 30, 2023, Internal Revenue Service (“IRS”) examinations are currently in process for the 2019, 2020 and 2021 taxable years of certain wholly-owned and consolidated subsidiaries that are treated as partnerships for U.S. federal income tax purposes. We are responding to information requests from the IRS with respect to these audits. We are not aware of any potential audit findings that would give rise to adjustments to taxable income and do not anticipate material changes related to these audits.

Note 15 — Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2023	2022
Cash:		
Interest paid, net of capitalized interest (1)	$ 574.1	$ 332.6
Income taxes (received) paid, net	9.5	1.1
Non-cash investing activities:		
Impact of capital expenditure accruals on property, plant and equipment, net	$ 76.8	$ (40.1)
Non-cash financing activities:		
Changes in accrued distributions to noncontrolling interests	$ 6.5	$ (18.0)

(1) Interest capitalized on major projects was $29.2 million and $9.5 million for the nine months ended September 30, 2023 and 2022.

Note 16 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business). Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided.

Our 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.

Our 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 our other businesses. The Logistics and Transportation segment also includes Grand Prix, which connects our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our Downstream facilities in Mont Belvieu, Texas. The associated assets are generally connected to and supplied in part by our 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.

Other contains the unrealized mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. Elimination of inter-segment transactions are reflected in the corporate and eliminations column.

Reportable segment information is shown in the following tables:

	Three Months Ended September 30, 2023				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 231.3	$ 3,176.5	$ (33.5)	$ —	$ 3,374.3
Fees from midstream services	337.4	184.9	—	—	522.3
	568.7	3,361.4	(33.5)	—	3,896.6
Intersegment revenues					
Sales of commodities	1,298.8	49.0	—	(1,347.8)	—
Fees from midstream services	0.6	11.5	—	(12.1)	—
	1,299.4	60.5	—	(1,359.9)	—
Revenues	$ 1,868.1	$ 3,421.9	$ (33.5)	$ (1,359.9)	$ 3,896.6
Operating margin (1)	$ 505.0	$ 457.4	$ (33.5)		
Other financial information:					
Total assets (2)	$ 12,405.7	$ 7,568.0	$ 7.8	$ 208.1	$ 20,189.6
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 421.5	$ 229.7	$ —	$ 3.8	$ 655.0

	Three Months Ended September 30, 2022				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 180.7	$ 4,731.8	$ (112.2)	$ —	$ 4,800.3
Fees from midstream services	382.0	177.8	—	—	559.8
	562.7	4,909.6	(112.2)	—	5,360.1
Intersegment revenues					
Sales of commodities	2,768.2	160.7	—	(2,928.9)	—
Fees from midstream services	0.3	11.6	—	(11.9)	—
	2,768.5	172.3	—	(2,940.8)	—
Revenues	$ 3,331.2	$ 5,081.9	$ (112.2)	$ (2,940.8)	$ 5,360.1
Operating margin (1)	$ 564.6	$ 340.2	$ (112.2)		
Other financial information:					
Total assets (2)	$ 12,119.0	$ 7,074.9	$ 1.5	$ 194.5	$ 19,389.9
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 222.0	$ 139.1	$ —	$ 8.0	$ 369.1

	Nine Months Ended September 30, 2023				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 787.1	$ 9,232.6	$ 294.3	$ —	$ 10,314.0
Fees from midstream services	979.7	527.1	—	—	1,506.8
	1,766.8	9,759.7	294.3	—	11,820.8
Intersegment revenues					
Sales of commodities	3,621.8	210.2	—	(3,832.0)	—
Fees from midstream services	1.7	32.9	—	(34.6)	—
	3,623.5	243.1	—	(3,866.6)	—
Revenues	$ 5,390.3	$ 10,002.8	$ 294.3	$ (3,866.6)	$ 11,820.8
Operating margin (1)	$ 1,545.9	$ 1,394.4	$ 294.3		
Other financial information:					
Total assets (2)	$ 12,405.7	$ 7,568.0	$ 7.8	$ 208.1	$ 20,189.6
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 1,081.7	$ 645.0	$ —	$ 15.5	$ 1,742.2

	Nine Months Ended September 30, 2022				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 577.0	$ 14,708.6	$ (294.9)	$ —	$ 14,990.7
Fees from midstream services	844.2	540.1	—	—	1,384.3
	1,421.2	15,248.7	(294.9)	—	16,375.0
Intersegment revenues					
Sales of commodities	7,455.4	416.5	—	(7,871.9)	—
Fees from midstream services	0.1	34.3	—	(34.4)	—
	7,455.5	450.8	—	(7,906.3)	—
Revenues	$ 8,876.7	$ 15,699.5	$ (294.9)	$ (7,906.3)	$ 16,375.0
Operating margin (1)	$ 1,437.0	$ 1,014.6	$ (294.9)		
Other financial information:					
Total assets (2)	$ 12,119.0	$ 7,074.9	$ 1.5	$ 194.5	$ 19,389.9
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 551.7	$ 206.9	$ —	$ 16.7	$ 775.3

(1) Operating margin is calculated by subtracting Product purchases and fuel and Operating expenses from Revenues.
(2) Assets in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

The following table shows our consolidated revenues disaggregated by product and service for the periods presented:

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Sales of commodities:				
Revenue recognized from contracts with customers:				
Natural gas	$ 606.0	$ 1,748.1	$ 1,835.9	$ 4,244.1
NGL	2,635.4	3,145.4	7,651.6	11,048.3
Condensate and crude oil	117.7	150.0	393.1	441.0
	3,359.1	5,043.5	9,880.6	15,733.4
Non-customer revenue:				
Derivative activities - Hedge	22.2	(121.7)	117.2	(425.2)
Derivative activities - Non-hedge (1)	(7.0)	(121.5)	316.2	(317.5)
	15.2	(243.2)	433.4	(742.7)
Total sales of commodities	3,374.3	4,800.3	10,314.0	14,990.7
Fees from midstream services:				
Revenue recognized from contracts with customers:				
Gathering and processing	333.3	376.4	966.3	829.6
NGL transportation, fractionation and services	71.1	82.3	190.5	215.1
Storage, terminaling and export	102.2	82.5	302.3	285.3
Other	15.7	18.6	47.7	54.3
Total fees from midstream services	522.3	559.8	1,506.8	1,384.3
Total revenues	$ 3,896.6	$ 5,360.1	$ 11,820.8	$ 16,375.0

(1) Represents derivative activities that are not designated as hedging instruments under ASC 815.

The following table shows a reconciliation of reportable segment Operating margin to Income (loss) before income taxes for the periods presented:

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Reconciliation of reportable segment operating margin to income (loss) before income taxes:				
Gathering and Processing operating margin	$ 505.0	$ 564.6	$ 1,545.9	$ 1,437.0
Logistics and Transportation operating margin	457.4	340.2	1,394.4	1,014.6
Other operating margin	(33.5)	(112.2)	294.3	(294.9)
Depreciation and amortization expense	(331.3)	(287.2)	(988.2)	(766.2)
General and administrative expense	(90.0)	(79.1)	(253.4)	(217.2)
Other operating income (expense)	(2.5)	3.8	(2.0)	4.4
Interest expense, net	(175.1)	(125.8)	(509.8)	(300.5)
Equity earnings (loss)	3.0	1.7	6.2	8.7
Gain (loss) from financing activities	—	—	—	(49.6)
Gain (loss) from sale of equity method investment	—	—	—	435.9
Other, net	(0.1)	(14.7)	(5.0)	(14.7)
Income (loss) before income taxes	$ 332.9	$ 291.3	$ 1,482.4	$ 1,257.5

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management’s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2022 (“Annual Report”), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. Targa is a leading provider of midstream services and is one of the largest independent midstream infrastructure companies in North America. We own, operate, acquire, and develop a diversified portfolio of complementary domestic midstream infrastructure assets.

Our Operations

We are engaged primarily 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.

To provide these services, we operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business).

Our 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.

Our 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 our other businesses. The Logistics and Transportation segment also includes the Grand Prix NGL Pipeline (“Grand Prix”), which connects our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our Downstream facilities in Mont Belvieu, Texas. Our Downstream facilities are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the unrealized mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges.

Recent Developments

In response to increasing production and to meet the infrastructure needs of producers and our downstream customers, our major expansion projects include the following:

Permian Midland Processing Expansions

- In February 2022, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Midland (the “Legacy II plant”). The Legacy II plant commenced operations late in the first quarter of 2023.
- In August 2022, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Midland (the “Greenwood plant”). The Greenwood plant commenced operations in the fourth quarter of 2023.

- In August 2023, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Midland (the “Greenwood II plant”). The Greenwood II plant is expected to begin operations in the fourth quarter of 2024.

Permian Delaware Processing Expansions

- In February 2022, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Delaware (the “Midway plant”). The Midway plant commenced operations in the second quarter of 2023 and we subsequently idled an existing 165 MMcf/d cryogenic natural gas processing plant in the third quarter of 2023.

- In November 2022, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Delaware (the “Wildcat II plant”). The Wildcat II plant is expected to begin operations in the first quarter of 2024.

- In February 2023, we announced the transfer of an existing cryogenic natural gas processing plant acquired in the purchase of Southcross Energy Operating LLC and its subsidiaries 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.

- In August 2023, we announced the construction of a new 275 MMcf/d cryogenic natural gas processing plant in Permian Delaware (the “Bull Moose plant”). The Bull Moose plant is expected to begin operations in the second quarter of 2025.

Fractionation Expansion

- In August 2022, we announced plans to construct a new 120 MBbl/d fractionation train in Mont Belvieu, Texas (“Train 9”). Train 9 is expected to begin operations in the second quarter of 2024.

- In January 2023, we reached an agreement with our partners in Gulf Coast Fractionators (“GCF”) to reactivate GCF’s 135 MBbl/d fractionation facility. The facility is expected to be operational late in the first quarter of 2024.

- In May 2023, we announced plans to construct a new 120 MBbl/d fractionation train in Mont Belvieu, Texas (“Train 10”). Train 10 is expected to begin operations in the first quarter of 2025.

NGL Pipeline Expansion

- In November 2022, we announced plans to construct a new NGL pipeline (the “Daytona NGL Pipeline”) as an addition to our common carrier Grand Prix system. The pipeline will transport NGLs from the Permian Basin and connect to the 30-inch diameter segment of Grand Prix in North Texas, where volumes will be transported to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. The Daytona NGL Pipeline is expected to be in service by the end of 2024.

Acquisitions

In January 2023, we completed the acquisition of Blackstone Energy Partners’ 25% interest in the Grand Prix Joint Venture (the “Grand Prix Transaction”) for approximately $1.05 billion in cash and paid a final closing adjustment of $41.9 million. Following the closing of the Grand Prix Transaction, we own 100% of Grand Prix, including the Daytona NGL Pipeline. For further details on our acquisitions and divestitures, see Note 4 - Acquisitions and Divestitures to our Consolidated Financial Statements.

Capital Allocation

In April 2023, we declared an increase to our common dividend to $0.50 per common share or $2.00 per common share annualized effective for the first quarter of 2023.

For the three and nine months ended September 30, 2023, we repurchased 1,583,317 shares and 4,395,519 shares of our common stock at a weighted average per share price of $83.38 and $75.77 for a total net cost of $132.0 million and $333.1 million, respectively.

In October 2020, our Board of Directors approved a share repurchase program (the “2020 Share Repurchase Program”) for the repurchase of up to $500.0 million of our outstanding common stock. In May 2023, our Board of Directors authorized a new $1.0 billion common share repurchase program (the “2023 Share Repurchase Program” and, together with the 2020 Share Repurchase Program, the “Share Repurchase Programs”). The amount authorized under the 2023 Share Repurchase Program was in addition to the amount remaining under the 2020 Share Repurchase Program. During the second quarter of 2023, we exhausted the 2020 Share Repurchase

Program. There was $810.7 million remaining under the 2023 Share Repurchase Program as of September 30, 2023. We may discontinue the 2023 Share Repurchase Program at any time and are not obligated to repurchase any specific dollar amount or number of shares thereunder.

Financing Activities

In January 2023, we completed an underwritten public offering of (i) $900.0 million in aggregate principal amount of our 6.125% Senior Notes due 2033 (the “6.125% Notes”) and (ii) $850.0 million in aggregate principal amount of our 6.500% Senior Notes due 2053 (the “6.500% Notes”), resulting in net proceeds of approximately $1.7 billion. We 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 our $2.75 billion TRGP senior revolving credit facility (the “TRGP Revolver”) and our unsecured commercial paper note program (the “Commercial Paper Program”).

In August 2023, the Partnership amended its accounts receivable securitization facility (the “Securitization Facility”) to decrease the size of the Securitization Facility from $800.0 million to $600.0 million and to extend the termination date of the Securitization Facility to August 29, 2024.

For additional information about our recent debt-related transactions, see Note 6 - Debt Obligations to our Consolidated Financial Statements.

Corporation Tax Matters

As of September 30, 2023, Internal Revenue Service (“IRS”) examinations are currently in process for the 2019, 2020 and 2021 taxable years of certain wholly-owned and consolidated subsidiaries that are treated as partnerships for U.S federal income tax purposes. We are responding to the information requests from the IRS with respect to these audits. We are not aware of any potential audit findings that would give rise to adjustments to taxable income and do not anticipate material changes related to these audits.

On August 16, 2022, President Biden signed into law the IRA which, among other things, introduced a corporate alternative minimum tax (the “CAMT”), imposed a 1% excise tax on stock buybacks, and provided tax incentives to promote clean energy. Under the CAMT, a 15% minimum tax will be imposed on certain financial statement income of “applicable corporations.” The IRA treats a corporation as an applicable corporation in any taxable year in which the “average annual adjusted financial statement income” of such corporation for the three taxable year period ending prior to such taxable year exceeds $1.0 billion. The 1% excise tax on stock buybacks is accrued in the current year for payment with the first quarterly excise tax return of the subsequent year.

On December 27, 2022, IRS Notice 2023-7 (the “Notice”) was issued by the U.S. Department of the Treasury and the IRS. The Notice provides guidance on the application of the CAMT which may be relied upon until final regulations are released. Based on our interpretation of the IRA, the CAMT and related guidance, and a number of operational, economic, accounting and regulatory assumptions, including the safe harbor provided for in the Notice, the Company does not qualify as an “applicable corporation” for 2023.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see “Recent Accounting Pronouncements” included within Note 3 – Significant Accounting Policies to our Consolidated Financial Statements.

How We Evaluate Our Operations

The profitability of our business is a function of the difference between: (i) the revenues we receive from our operations, including fee-based revenues from services and revenues from the natural gas, NGLs, crude oil and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of wellhead natural gas, crude oil and mixed NGLs that we purchase as well as operating, general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for crude oil, natural gas and NGLs, the impact of our commodity hedging program and its ability to mitigate exposure to commodity price movements, and the volumes of crude oil, natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services, utilization of our assets and changes in our customer mix.

Our profitability is also impacted by fee-based contracts. Our growing capital expenditures for pipelines and gathering and processing assets underpinned by fee-based margin, expansion of our Downstream facilities, continued focus on adding fee-based margin to our existing and future gathering and processing contracts, as well as third-party acquisitions of businesses and assets, will continue to increase the number of our contracts that are fee-based. Fixed fees for services such as gathering and processing, transportation, fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities. Nevertheless, a change in market dynamics such as available commodity throughput does affect profitability.

Management uses a variety of financial measures and operational measurements to analyze our performance. These include: (i) throughput volumes, facility efficiencies and fuel consumption, (ii) operating expenses, (iii) capital expenditures and (iv) the following non-GAAP measures: adjusted EBITDA, distributable cash flow, adjusted free cash flow and adjusted operating margin (segment).

Throughput Volumes, Facility Efficiencies and Fuel Consumption

Our profitability is impacted by our ability to add new sources of natural gas supply and crude oil supply to offset the natural decline of existing volumes from oil and natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing crude oil and natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, connected by third-party transportation and Grand Prix, to our Downstream Business fractionation facilities and at times to our export facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

In addition, we seek to increase adjusted operating margin by limiting volume losses, reducing fuel consumption and by increasing efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. We also monitor the volumes of NGLs received, stored, fractionated and delivered across our logistics assets. This information is tracked through our processing plants and Downstream Business facilities to determine customer settlements for sales and volume related fees for service and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of our facilities. Similar tracking is performed for our crude oil gathering and logistics assets and our NGL pipelines. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis and safety programs.

Operating Expenses

Operating expenses are costs associated with the operation of specific assets. Labor, contract services, repair and maintenance and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses remain relatively stable and independent of the volumes through our systems, but may increase with system expansions and inflation, and will fluctuate depending on the scope of the activities performed during a specific period.

Capital Expenditures

Our capital expenditures are classified as growth capital expenditures and maintenance capital expenditures. Growth capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, and reduce costs or enhance revenues. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

Capital spending associated with growth and maintenance projects is closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval.

Non-GAAP Measures

We utilize non-GAAP measures to analyze our 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 our results as reported under GAAP. Additionally, because our non-GAAP measures exclude some, but not all, items that affect income and segment operating margin, and are defined differently by different companies within our industry, our definitions may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of our non-GAAP measures as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision-making processes.

Adjusted Operating Margin

We define adjusted operating margin for our segments as revenues less product purchases and fuel. It is impacted by volumes and commodity prices as well as by our 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 our 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 our segments provides useful information to investors because it is used as a supplemental financial measure by management and by external users of our financial statements, including investors and commercial banks, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our 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 our segments monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that management uses in evaluating our operating results. The reconciliation of our adjusted operating margin to the most directly comparable GAAP measure is presented under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – By Reportable Segment.”

Adjusted EBITDA

We define adjusted EBITDA as Net income (loss) attributable to Targa Resources Corp. before interest, income taxes, depreciation and amortization, and other items that we believe should be adjusted consistent with our 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 us and by external users of our financial statements such as investors, commercial banks and others to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

Distributable Cash Flow and Adjusted Free Cash Flow

We define 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). We define 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 us and by external users of our financial statements, such as investors, commercial banks and research analysts, to assess our ability to generate cash earnings (after servicing our 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.

Our Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
	(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.	$ 220.0	$ 193.1	$ 1,046.3	$ 877.5
Interest (income) expense, net	175.1	125.8	509.8	300.5
Income tax expense (benefit)	53.9	12.0	260.7	122.0
Depreciation and amortization expense	331.3	287.2	988.2	766.2
(Gain) loss on sale or disposition of assets	(0.9)	(6.5)	(3.9)	(8.1)
Write-down of assets	3.4	2.7	6.0	3.7
(Gain) loss from financing activities (1)	—	—	—	49.6
(Gain) loss from sale of equity method investment	—	—	—	(435.9)
Transaction costs related to business acquisition (2)	—	20.3	—	20.3
Equity (earnings) loss	(3.0)	(1.7)	(6.2)	(8.7)
Distributions from unconsolidated affiliates and preferred partner interests, net	5.3	2.4	14.1	21.7
Compensation on equity grants	15.7	14.4	45.7	41.8
Risk management activities	33.5	112.2	(294.3)	295.0
Noncontrolling interests adjustments (3)	(1.0)	6.7	(3.2)	15.2
Litigation expense (4)	6.9	—	6.9	—
Adjusted EBITDA	**$ 840.2**	**$ 768.6**	**$ 2,570.1**	**$ 2,060.8**
Interest expense on debt obligations (5)	(172.1)	(123.0)	(500.9)	(305.2)
Maintenance capital expenditures, net (6)	(65.0)	(49.4)	(153.0)	(126.8)
Cash taxes	(0.9)	(1.3)	(8.6)	(5.6)
Distributable Cash Flow	**$ 602.2**	**$ 594.9**	**$ 1,907.6**	**$ 1,623.2**
Growth capital expenditures, net (6)	(593.6)	(304.1)	(1,588.5)	(624.8)
Adjusted Free Cash Flow	**$ 8.6**	**$ 290.8**	**$ 319.1**	**$ 998.4**

(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.
(4) Litigation expense includes charges related to litigation resulting from the major winter storm in February 2021 that we consider outside the ordinary course of our business and/or not reflective of our ongoing core operations. We may incur such charges from time to time, and we believe it is useful to exclude such charges because we do not consider them reflective of our ongoing core operations and because of the generally singular nature of the claims underlying such litigation.
(5) Excludes amortization of debt issuance costs.
(6) Represents capital expenditures, net of contributions from noncontrolling interests and includes net contributions to investments in unconsolidated affiliates.

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2023	2022	2023 vs. 2022		2023	2022	2023 vs. 2022	
			(In millions)					
Revenues:								
Sales of commodities	$ 3,374.3	$ 4,800.3	$ (1,426.0)	(30)%	$ 10,314.0	$ 14,990.7	$ (4,676.7)	(31)%
Fees from midstream services	522.3	559.8	(37.5)	(7)%	1,506.8	1,384.3	122.5	9%
Total revenues	3,896.6	5,360.1	(1,463.5)	(27)%	11,820.8	16,375.0	(4,554.2)	(28)%
Product purchases and fuel	2,690.0	4,306.3	(1,616.3)	(38)%	7,777.9	13,557.8	(5,779.9)	(43)%
Operating expenses	277.7	261.3	16.4	6%	808.4	660.6	147.8	22%
Depreciation and amortization expense	331.3	287.2	44.1	15%	988.2	766.2	222.0	29%
General and administrative expense	90.0	79.1	10.9	14%	253.4	217.2	36.2	17%
Other operating (income) expense	2.5	(3.8)	6.3	166%	2.0	(4.4)	6.4	145%
Income (loss) from operations	505.1	430.0	75.1	17%	1,990.9	1,177.6	813.3	69%
Interest expense, net	(175.1)	(125.8)	(49.3)	39%	(509.8)	(300.5)	(209.3)	70%
Equity earnings (loss)	3.0	1.7	1.3	76%	6.2	8.7	(2.5)	(29)%
Gain (loss) from financing activities	—	—	—	—	—	(49.6)	49.6	100%
Gain (loss) from sale of equity method investment	—	—	—	—	—	435.9	(435.9)	(100)%
Other, net	(0.1)	(14.6)	14.5	99%	(4.9)	(14.6)	9.7	66%
Income tax (expense) benefit	(53.9)	(12.0)	(41.9)	NM	(260.7)	(122.0)	(138.7)	114%
Net income (loss)	279.0	279.3	(0.3)	—	1,221.7	1,135.5	86.2	8%
Less: Net income (loss) attributable to noncontrolling interests	59.0	86.2	(27.2)	(32)%	175.4	258.0	(82.6)	(32)%
Net income (loss) attributable to Targa Resources Corp.	220.0	193.1	26.9	14%	1,046.3	877.5	168.8	19%
Premium on repurchase of noncontrolling interests, net of tax	—	—	—	—	490.7	53.1	437.6	NM
Dividends on Series A Preferred Stock	—	—	—	—	—	30.0	(30.0)	(100)%
Deemed dividends on Series A Preferred Stock	—	—	—	—	—	215.5	(215.5)	(100)%
Net income (loss) attributable to common shareholders	$ 220.0	$ 193.1	$ 26.9	14%	$ 555.6	$ 578.9	$ (23.3)	(4)%
Financial data:								
Adjusted EBITDA (1)	$ 840.2	$ 768.6	$ 71.6	9%	$ 2,570.1	$ 2,060.8	$ 509.3	25%
Distributable cash flow (1)	602.2	594.9	7.3	1%	1,907.6	1,623.2	284.4	18%
Adjusted free cash flow (1)	8.6	290.8	(282.2)	(97)%	319.1	998.4	(679.3)	(68)%

(1) Adjusted EBITDA, distributable cash flow and adjusted free cash flow are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

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

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022

The decrease in commodity sales reflects lower natural gas, NGL and condensate prices ($2,704.1 million), partially offset by higher NGL and natural gas volumes ($1,000.1 million) and the favorable impact of hedges ($258.5 million).

The decrease in fees from midstream services is primarily due to lower gas gathering and processing fees and transportation and fractionation volumes, partially offset by higher export volumes.

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

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

See "—Results of Operations—By Reportable Segment" 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 impact of system expansions on our asset base, partially offset by the shortening of the depreciable lives of certain assets that were idled in 2022.

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

The increase in interest expense, net is due to higher net borrowings primarily for the acquisition of certain assets in the Delaware Basin and the Grand Prix Transaction, and higher interest rates, partially offset by higher capitalized interest resulting from higher growth capital investments.

The increase in income tax expense is primarily due to an increase in pre-tax book income and a smaller release of the valuation allowance in 2023 compared to 2022.

The decrease in net income (loss) attributable to noncontrolling interests is primarily due to the Grand Prix Transaction and lower earnings allocated to our joint venture partner in WestTX.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

The decrease in commodity sales reflects lower NGL, natural gas and condensate prices ($7,920.7 million), partially offset by higher NGL, natural gas and condensate volumes ($2,063.8 million) and the favorable impact of hedges ($1,176.2 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 South Texas, and higher export fees, partially offset by lower transportation and fractionation fees.

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

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

See "—Results of Operations—By Reportable Segment" 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 impact of system expansions on our asset base, partially offset by the shortening of depreciable lives of certain assets that were idled in 2022.

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

The increase in interest expense, net is due to higher net borrowings primarily for the acquisition of certain assets in the Delaware Basin and the Grand Prix Transaction, and higher interest rates, partially offset by higher capitalized interest resulting from higher growth capital investments.

During 2022, we terminated the previous TRGP senior secured revolving credit facility and the Partnership's senior secured revolving credit facility. In addition, the Partnership redeemed its 5.375% Senior Notes due 2027 and its 5.875% Senior Notes due 2026. These transactions resulted in a net loss from financing activities.

During 2022, we completed the sale of Targa GCX Pipeline LLC to a third party (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 and a smaller release of the valuation allowance in 2023 compared to 2022.

The decrease in net income (loss) attributable to noncontrolling interests is primarily due to the Grand Prix Transaction and lower earnings allocated to our joint venture partner in WestTX and Venice Energy Services Company, L.L.C.

The premium on repurchase of noncontrolling interests, net of tax is due to the Grand Prix Transaction in 2023 and the purchase of all of Stonepeak Infrastructure Partners' interests in our development company joint ventures in 2022.

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

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Transportation	Other
		(In millions)	
Three Months Ended:			
September 30, 2023	$ 505.0	$ 457.4	$ (33.5)
September 30, 2022	564.6	340.2	(112.2)
Nine Months Ended:			
September 30, 2023	$ 1,545.9	$ 1,394.4	$ 294.3
September 30, 2022	1,437.0	1,014.6	(294.9)

Gathering and Processing Segment

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	2023 vs. 2022		Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	2023 vs. 2022	
	(In millions, except operating statistics and price amounts)							
Operating margin	$ 505.0	$ 564.6	$ (59.6)	(11 %)	$ 1,545.9	$ 1,437.0	$ 108.9	8 %
Operating expenses	189.6	176.6	13.0	7 %	560.8	434.5	126.3	29 %
Adjusted operating margin	$ 694.6	$ 741.2	$ (46.6)	(6 %)	$ 2,106.7	$ 1,871.5	$ 235.2	13 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2) (3)								
Permian Midland (4)	2,566.9	2,307.2	259.7	11 %	2,474.1	2,172.3	301.8	14 %
Permian Delaware (5)	2,485.4	1,784.8	700.6	39 %	2,513.7	1,254.6	1,259.1	100 %
Total Permian	5,052.3	4,092.0	960.3	23 %	4,987.8	3,426.9	1,560.9	46 %
SouthTX (6)	394.4	335.5	58.9	18 %	373.9	256.9	117.0	46 %
North Texas	212.0	177.7	34.3	19 %	205.2	176.1	29.1	17 %
SouthOK (6)	394.6	400.4	(5.8)	(1 %)	391.2	422.7	(31.5)	(7 %)
WestOK	206.2	212.8	(6.6)	(3 %)	207.1	209.1	(2.0)	(1 %)
Total Central	1,207.2	1,126.4	80.8	7 %	1,177.4	1,064.8	112.6	11 %
Badlands (6) (7)	128.3	144.8	(16.5)	(11 %)	129.6	133.1	(3.5)	(3 %)
Total Field	6,387.8	5,363.2	1,024.6	19 %	6,294.8	4,624.8	1,670.0	36 %
Coastal	535.6	539.1	(3.5)	(1 %)	532.4	564.7	(32.3)	(6 %)
Total	6,923.4	5,902.3	1,021.1	17 %	6,827.2	5,189.5	1,637.7	32 %
NGL production, MBbl/d (3)								
Permian Midland (4)	373.1	332.6	40.5	12 %	357.4	314.8	42.6	14 %
Permian Delaware (5)	322.5	210.9	111.6	53 %	325.3	159.1	166.2	104 %
Total Permian	695.6	543.5	152.1	28 %	682.7	473.9	208.8	44 %
SouthTX (6)	42.3	36.4	5.9	16 %	42.1	30.1	12.0	40 %
North Texas	24.2	20.5	3.7	18 %	23.8	19.8	4.0	20 %
SouthOK (6)	46.4	48.1	(1.7)	(4 %)	44.2	51.4	(7.2)	(14 %)
WestOK	12.3	14.8	(2.5)	(17 %)	12.6	15.4	(2.8)	(18 %)
Total Central	125.2	119.8	5.4	5 %	122.7	116.7	6.0	5 %
Badlands (6)	15.5	18.0	(2.5)	(14 %)	15.5	15.8	(0.3)	(2 %)
Total Field	836.3	681.3	155.0	23 %	820.9	606.4	214.5	35 %
Coastal	40.6	31.7	8.9	28 %	37.9	35.1	2.8	8 %
Total	876.9	713.0	163.9	23 %	858.8	641.5	217.3	34 %
Crude oil, Badlands, MBbl/d	101.6	122.2	(20.6)	(17 %)	105.6	118.9	(13.3)	(11 %)
Crude oil, Permian, MBbl/d	27.2	30.3	(3.1)	(10 %)	27.4	29.9	(2.5)	(8 %)
Natural gas sales, BBtu/d (3)	2,758.2	2,458.1	300.1	12 %	2,668.4	2,288.4	380.0	17 %
NGL sales, MBbl/d (3)	508.8	436.1	72.7	17 %	487.4	433.8	53.6	12 %
Condensate sales, MBbl/d	17.0	15.5	1.5	10 %	18.7	15.2	3.5	23 %
Average realized prices (8):								
Natural gas, $/MMBtu	2.03	6.71	(4.68)	(70 %)	1.97	5.71	(3.74)	(65 %)
NGL, $/gal	0.46	0.77	(0.31)	(40 %)	0.46	0.82	(0.36)	(44 %)
Condensate, $/Bbl	70.07	96.41	(26.34)	(27 %)	74.20	92.25	(18.05)	(20 %)

(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 our 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 we own a 72.8% undivided interest, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our 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 us. 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, net of fees, include the effect of realized commodity hedge gain/loss attributable to our 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, net of fees.

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

	Three Months Ended September 30, 2023			Three Months Ended September 30, 2022		
	(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)	15.0	$ 0.62	$ 9.3	20.3	$ (3.58)	$ (72.7)
NGL (MMgal)	166.0	0.04	7.2	194.9	(0.25)	(49.4)
Crude oil (MBbl)	0.6	(13.17)	(7.9)	0.6	(26.83)	(16.1)
			$ 8.6			$ (138.2)

	Nine Months Ended September 30, 2023			Nine Months Ended September 30, 2022		
	(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)	50.0	$ 1.24	$ 62.2	54.5	$ (2.91)	$ (158.8)
NGL (MMgal)	515.0	0.07	34.4	529.7	(0.39)	(205.2)
Crude oil (MBbl)	1.8	(7.17)	(12.9)	1.6	(38.31)	(61.3)
			$ 83.7			$ (425.3)

(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 September 30, 2023 Compared to Three Months Ended September 30, 2022

The decrease in adjusted operating margin was due to lower commodity prices, partially offset by higher natural gas inlet volumes and higher fees 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, the addition of the Legacy I and Red Hills VI plants during the third quarter of 2022 and the Legacy II plant late in the first quarter of 2023, and continued strong producer activity. The natural gas inlet volumes in the Central region increased primarily due to increased producer activity during the third quarter of 2023.

The increase in operating expenses was predominantly due to the acquisition of certain assets in the Delaware Basin. Additionally, higher volumes in the Permian, the addition of the Legacy I, Red Hills VI, Legacy II and Midway plants, and inflation impacts resulted in increased costs.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

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 commodity 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 I and Red Hills VI plants during the third quarter of 2022 and the Legacy II plant late in the first quarter of 2023, and continued strong 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 and increased producer activity.

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

Logistics and Transportation Segment

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2023	2022	2023 vs. 2022		2023	2022	2023 vs. 2022	
	(In millions, except operating statistics)							
Operating margin	$ 457.4	$ 340.2	$ 117.2	34%	$ 1,394.4	$ 1,014.6	$ 379.8	37%
Operating expenses	88.8	84.5	4.3	5%	247.9	225.8	22.1	10%
Adjusted operating margin	$ 546.2	$ 424.7	$ 121.5	29%	$ 1,642.3	$ 1,240.4	$ 401.9	32%
Operating statistics MBbl/d (1):								
NGL pipeline transportation volumes (2)	660.2	499.5	160.7	32%	606.4	484.0	122.4	25%
Fractionation volumes	793.4	742.1	51.3	7%	782.3	727.5	54.8	8%
Export volumes (3)	349.3	276.1	73.2	27%	341.9	319.6	22.3	7%
NGL sales	997.9	825.0	172.9	21%	984.1	868.1	116.0	13%

(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 our Galena Park Marine Terminal that are destined for international markets.

Three Months Ended September 30, 2023 Compared to Three Months Ended September 30, 2022

The increase in adjusted operating margin was due to higher pipeline transportation and fractionation margin, higher LPG export margin and higher marketing margin. Pipeline transportation and fractionation volumes benefited from higher supply volumes primarily from our Permian Gathering and Processing systems and higher fees. LPG export margin increased due to higher volumes. Marketing margin increased due to greater optimization opportunities.

The increase in operating expenses was primarily due to higher compensation and benefits, and higher costs attributable to inflation.

Nine Months Ended September 30, 2023 Compared to Nine Months Ended September 30, 2022

The increase in adjusted operating margin was due to higher pipeline transportation and fractionation margin, higher marketing margin and higher LPG export margin. Pipeline transportation and fractionation volumes benefited from higher supply volumes primarily from our Permian Gathering and Processing systems and higher fees. Marketing margin increased due to greater optimization opportunities. LPG Export margin increased primarily due to higher volumes and lower fuel and power costs.

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

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	2022	2023 vs. 2022	2023	2022	2023 vs. 2022
			(In millions)			
Operating margin	$ (33.5)	$ (112.2)	$ 78.7	$ 294.3	$ (294.9)	$ 589.2
Adjusted operating margin	$ (33.5)	$ (112.2)	$ 78.7	$ 294.3	$ (294.9)	$ 589.2

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. We have entered into derivative instruments to hedge the commodity price associated with a portion of our future commodity purchases and sales and natural gas transportation basis risk within our Logistics and Transportation segment. See further details of our risk management program in "Item 3. – Quantitative and Qualitative Disclosures About Market Risk."

Our Liquidity and Capital Resources

As of September 30, 2023, inclusive of our consolidated joint venture accounts, we had $139.5 million of Cash and cash equivalents on our Consolidated Balance Sheets. We believe our cash positions, our cash flows from operating activities, our free cash flow after dividends and remaining borrowing capacity on our credit facilities (discussed below in "Short-term Liquidity") are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below. Our liquidity and capital resources are managed on a consolidated basis.

On a consolidated basis, our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing or repaying our indebtedness, meeting our collateral requirements and to pay dividends declared by our Board of Directors will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control. These include commodity prices and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. For additional discussion on recent factors impacting our liquidity and capital resources, please see "Recent Developments."

On a consolidated basis, our main sources of liquidity and capital resources are internally generated cash flows from operations, borrowings under the TRGP Revolver, Commercial Paper Program, the Securitization Facility, and access to debt and equity capital markets. We supplement these sources of liquidity with joint venture arrangements and proceeds from asset sales. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets have experienced and may continue to experience volatility. Our exposure to adverse credit conditions includes our credit facilities, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity on a consolidated basis as of September 30, 2023, was:

	Consolidated Total
	(In millions)
Cash on hand (1)	$ 139.5
Total availability under the Securitization Facility	600.0
Total availability under the TRGP Revolver and Commercial Paper Program	2,750.0
	3,489.5
Less: Outstanding borrowings under the Securitization Facility	(560.0)
Outstanding borrowings under the TRGP Revolver and Commercial Paper Program	(1,150.0)
Outstanding letters of credit under the TRGP Revolver	(22.3)
Total liquidity	$ 1,757.2

(1) Includes cash held in our consolidated joint venture accounts.

Other potential capital resources associated with our existing arrangements includes our right to request an additional $500.0 million in commitment increases under the TRGP Revolver, subject to the terms therein. The TRGP Revolver matures on February 17, 2027.

In August 2023, the Partnership amended the Securitization Facility to decrease the size of the Securitization Facility from $800.0 million to $600.0 million and to extend the termination date of the Securitization Facility to August 29, 2024.

A portion of our capital resources are allocated to letters of credit to satisfy certain counterparty credit requirements. As of September 30, 2023, we had $22.3 million letters of credit outstanding under the TRGP Revolver. They reflect certain counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis, at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced, with receivables from customers being offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (i) our cash position; (ii) liquids inventory levels, which we closely manage, as well as liquids valuations; (iii) changes in payables and accruals related to major growth capital projects; (iv) changes in the fair value of the current portion of derivative contracts; (v) monthly swings in borrowings under the Securitization Facility; and (vi) major structural changes in our asset base or business operations, such as certain organic growth capital projects and acquisitions or divestitures.

Working capital as of September 30, 2023 increased $167.3 million compared to December 31, 2022. The increase was primarily due to lower net borrowings on the Securitization Facility, lower net liabilities for hedging activities and higher NGL inventory, partially offset by lower net receivables resulting from lower commodity prices and higher accounts payable related to capital spending on growth projects.

Based on our anticipated levels of operations and absent any disruptive events, we believe that our internally generated cash flow, borrowings available under the TRGP Revolver, Commercial Paper Program, Securitization Facility, and proceeds from debt and equity offerings, as well as joint ventures and/or asset sales, should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and quarterly cash dividends for at least the next twelve months.

Long-term Financing

Our long-term financing consists of potentially raising funds through long-term debt obligations, the issuance of common stock, preferred stock, or joint venture arrangements.

In January 2023, we, along with certain of our subsidiaries as guarantors thereto, completed an underwritten public offering of the 6.125% Notes and the 6.500% Notes, resulting in net proceeds of approximately $1.7 billion. We used a portion of the net proceeds from the issuance to fund the Grand Prix Transaction and the remaining proceeds for general corporate purposes, including to reduce borrowings under the TRGP Revolver and the Commercial Paper Program.

In the future, we or the Partnership may redeem, purchase or exchange certain of our and the Partnership's outstanding debt through redemption calls, cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such calls, repurchases, exchanges or redemptions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

To date, our debt balances and our subsidiaries' debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness.

For additional information about our debt-related transactions, see Note 6 - Debt Obligations to our Consolidated Financial Statements. For information about our interest rate risk, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

Compliance with Debt Covenants

As of September 30, 2023, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	2023 vs. 2022
(In millions)		
$ 2,253.9	$ 1,843.3	$ 410.6

The primary drivers of cash flows from operating activities are: (i) the collection of cash from customers from the sale of NGLs and natural gas, as well as fees for processing, gathering, export, fractionation, terminaling, storage and transportation; (ii) the payment of amounts related to the purchase of NGLs, natural gas and crude oil; (iii) changes in payables and accruals related to major growth capital projects; and (iv) the payment of other expenses, primarily field operating costs, general and administrative expense and interest expense. In addition, we use derivative instruments to manage our exposure to commodity price risk. Changes in the prices of the commodities we hedge impact our derivative settlements as well as our margin deposit requirements on unsettled futures contracts.

The increase in net cash provided by operations was primarily due to higher settlements for hedge transactions and a decrease in payments for product purchases and fuel, offset by lower collections from customers.

Cash Flows from Investing Activities

Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022	2023 vs. 2022
(In millions)		
$ (1,673.8)	$ (3,647.6)	$ 1,973.8

The decrease in net cash used in investing activities was primarily due to higher outlays for the acquisition of certain assets in the Delaware Basin and South Texas in 2022, partially offset by proceeds from the GCX Sale in 2022 and higher outlays for property, plant and equipment in 2023 primarily related to construction activities in the Permian region and Mont Belvieu, Texas.

Cash Flows from Financing Activities

	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
	(In millions)	
Source of Financing Activities, net		
Debt, including financing costs	$ 1,292.0	$ 4,495.0
Redemption of Series A Preferred Stock	—	(965.2)
Repurchase of noncontrolling interests	(1,091.9)	(926.3)
Dividends	(314.8)	(298.8)
Contributions from (distributions to) noncontrolling interests	(156.4)	(238.1)
Repurchase of shares	(388.5)	(227.9)
Net cash provided by (used in) financing activities	$ (659.6)	$ 1,838.7

The change in net cash provided by (used in) financing activities was primarily due to lower borrowings of debt, higher repurchases of noncontrolling interests and higher repurchases of common stock, partially offset by the redemption of all of our Series A Preferred in 2022 and higher distributions to noncontrolling interests prior to the Grand Prix Transaction.

Summarized Combined Financial Information for Guarantee of Securities of Subsidiaries

Our subsidiaries that guarantee our obligations under the TRGP Revolver (the "Obligated Group") also fully and unconditionally guarantee, jointly and severally, the payment of TRGP's senior notes, subject to certain limited exceptions.

In lieu of providing separate financial statements for the Obligated Group, we have presented the following supplemental summarized Combined Balance Sheet and Statement of Operations information for the Obligated Group based on Rule 13-01 of the SEC's Regulation S-X.

All significant intercompany items among the Obligated Group have been eliminated in the supplemental summarized combined financial information. The Obligated Group's investment balances in our non-guarantor subsidiaries have been excluded from the supplemental summarized combined financial information. Significant intercompany balances and activity for the Obligated Group with other related parties, including our non-guarantor subsidiaries (referred to as "affiliates"), are presented separately in the following supplemental summarized combined financial information.

Summarized Combined Balance Sheet and Statement of Operations information for the Obligated Group as of the end of the most recent period presented follows:

Summarized Combined Balance Sheet Information

	September 30, 2023	December 31, 2022
	(In millions)	
ASSETS		
Current assets	$ 1,127.6	$ 1,425.4
Current assets - affiliates	—	6.0
Long-term assets	14,942.9	14,398.8
Long-term assets - affiliates	—	10.5
Total assets	$ 16,070.5	$ 15,840.7
LIABILITIES AND OWNERS' EQUITY		
Current liabilities	$ 2,017.1	$ 2,169.6
Current liabilities - affiliates	45.5	28.0
Long-term liabilities	13,118.4	11,503.4
Targa Resources Corp. stockholders' equity	889.5	2,139.7
Total liabilities and owners' equity	$ 16,070.5	$ 15,840.7

Summarized Combined Statement of Operations Information

	Nine Months Ended September 30, 2023	Year Ended December 31, 2022
	(In millions)	
Revenues	$ 11,580.7	$ 20,477.0
Operating income (loss)	1,626.7	1,108.3
Net income (loss)	870.0	909.0
Dividends on Series A Preferred	—	30.0

Common Stock Dividends

The following table details the dividends on common stock declared and/or paid by us for the nine months ended September 30, 2023:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Dividends on Share-Based Awards	Dividends Declared per Share of Common Stock
		(In millions, except per share amounts)			
September 30, 2023	November 15, 2023	$ 113.0	$ 111.5	$ 1.5	$ 0.50000
June 30, 2023	August 15, 2023	113.6	111.8	1.8	0.50000
March 31, 2023	May 15, 2023	114.7	113.0	1.7	0.50000
December 31, 2022	February 15, 2023	80.5	79.3	1.2	0.35000

The actual amount we declare as dividends in the future depends on our consolidated financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects, compliance with our debt covenants and any other matters that our Board of Directors deems relevant.

Capital Expenditures

The following table details cash outlays for capital projects for the nine months ended September 30, 2023 and 2022:

	Nine Months Ended September 30,	
	2023	2022
	(In millions)	
Capital expenditures:		
Growth (1)	$ 1,582.7	$ 643.9
Maintenance (2)	159.5	131.4
Gross capital expenditures	1,742.2	775.3
Change in capital project payables and accruals, net	(76.8)	40.1
Cash outlays for capital projects	$ 1,665.4	$ 815.4

(1) Growth capital expenditures, net of contributions from noncontrolling interests and including net contributions to investments in unconsolidated affiliates, were $1,588.5 million and $624.8 million for the nine months ended September 30, 2023 and 2022.
(2) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $153.0 million and $126.8 million for the nine months ended September 30, 2023 and 2022.

The increase in total growth capital expenditures was primarily due to system expansions in the Permian region in response to forecasted production growth and higher activity levels, and expansions in our downstream business. The increase in total maintenance capital expenditures was primarily due to our growing infrastructure footprint.

With our announced natural gas processing additions currently under construction in the Permian region, coupled with the construction of our Daytona NGL Pipeline and Train 9 and Train 10 fractionators in Mont Belvieu, we currently estimate that in 2023 we will invest between $2.0 to $2.2 billion in net growth capital expenditures for announced projects. Future growth capital expenditures may vary based on investment opportunities. We expect that 2023 maintenance capital expenditures, net of noncontrolling interests, will be approximately $200 million.

Off-Balance Sheet Arrangements

As of September 30, 2023, there were $245.8 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers.

Risk Management

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. All of our commodity derivatives are with major financial institutions or major energy companies. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices, which could have a material adverse effect on our results of operations. We sell our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil, NGL and natural gas prices are volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk through 2027. Market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

A portion of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the proceeds from the sale of commodities as payment for services. The prices of natural gas, NGLs and crude oil are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of September 30, 2023, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation segment. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. We also enter into commodity financial instruments to help manage other short-term commodity-related business risks of our ongoing operations and in conjunction with marketing opportunities available to us in the operations of our logistics and transportation assets. With swaps, we typically receive an agreed fixed price for a specified notional quantity of commodities and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

When entering into new hedges, we intend to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. The fair value of our natural gas and NGL hedges are based on published index prices for delivery at various locations, which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

A majority of these commodity price hedges are documented pursuant to a standard International Swaps and Derivatives Association (“ISDA”) form with customized credit and legal terms. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. While we have no current obligation to post cash, letters of credit or other additional collateral to secure these hedges so long as we maintain our current credit rating, we could be obligated to post collateral to secure the hedges in the event of an adverse change in our creditworthiness where a counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices. A purchased put (or floor) transaction does not expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction; however, we are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

We also enter into commodity price hedging transactions using futures contracts on futures exchanges. Exchange traded futures are subject to exchange margin requirements, so we may have to increase our cash deposit due to a rise in natural gas, NGL or crude oil prices. Unlike bilateral hedges, we are not subject to counterparty credit risks when using futures on futures exchanges.

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls).

To analyze the risk associated with our derivative instruments, we utilize a sensitivity analysis. The sensitivity analysis measures the change in fair value of our derivative instruments based on a hypothetical 10% change in the underlying commodity prices, but does not reflect the impact that the same hypothetical price movement would have on the related hedged items. The financial statement impact on the fair value of a derivative instrument resulting from a change in commodity price would normally be offset by a corresponding gain or loss on the hedged item under hedge accounting. The fair values of our derivative instruments are also influenced by changes in market volatility for option contracts and the discount rates used to determine the present values.

The following table shows the effect of hypothetical price movements on the estimated fair value of our derivative instruments as of September 30, 2023:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
		(In millions)	
Natural gas	$ (2.1)	$ 33.3	$ (37.4)
NGLs	(5.4)	88.9	(99.9)
Crude oil	(31.2)	(4.0)	(58.4)
Total	$ (38.7)	$ 118.2	$ (195.7)

The table above contains all derivative instruments outstanding as of the stated date for the purpose of hedging commodity price risk, which we are exposed to due to our equity volumes and future commodity purchases and sales, as well as basis differentials related to our gas transportation arrangements.

Our operating revenues increased (decreased) by $15.2 million and $(243.2) million during the three months ended September 30, 2023 and 2022, respectively, and $433.4 million and $(742.7) million during the nine months ended September 30, 2023 and 2022, respectively, as a result of transactions accounted for as derivatives. The estimated fair value of our risk management position has moved from a net liability position of $255.8 million at December 31, 2022 to a net liability position of $38.7 million at September 30, 2023.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRGP Revolver, the Commercial Paper Program, the Securitization Facility, and the Term Loan Facility. As of September 30, 2023, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRGP Revolver, the Commercial Paper Program, the Securitization Facility and the Term Loan Facility will also increase. As of September 30, 2023, we had $3.2 billion in outstanding variable rate borrowings. A hypothetical change of 100 basis points in the rate of our variable interest rate debt would impact our consolidated annual interest expense by $32.1 million based on our September 30, 2023 debt balances.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the ISDA agreements with our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $24.7 million as of September 30, 2023. The range of losses attributable to our individual counterparties as of September 30, 2023 would be between $0.4 million and $11.0 million, depending on the counterparty in default.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including performing initial and subsequent credit risk analyses, setting maximum credit limits and terms and requiring credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We have an active credit management process, which is focused on controlling loss exposure due to bankruptcies or other liquidity issues of counterparties. Our allowance for credit losses was $2.6 million and $2.2 million as of September 30, 2023 and December 31, 2022, respectively.

During the three and nine months ended September 30, 2023 and 2022, no customer comprised 10% or greater of our consolidated revenues.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered in this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2023, the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended September 30, 2023, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

On December 26, 2018, Vitol Americas Corp. (“Vitol”) filed a lawsuit in the 80th District Court of Harris County (the “District Court”), Texas against Targa Channelview LLC, then a subsidiary of the Company (“Targa Channelview”), seeking recovery of $129.0 million in payments made to Targa Channelview, additional monetary damages, attorneys’ fees and costs. Vitol alleges that Targa Channelview breached an agreement, dated December 27, 2015, for crude oil and condensate between Targa Channelview and Noble Americas Corp. (the “Splitter Agreement”), which provided for Targa Channelview to construct a crude oil and condensate splitter (the “Splitter”) adjacent to a barge dock owned by Targa Channelview to provide services contemplated by the Splitter Agreement. In January 2018, Vitol acquired Noble Americas Corp. and on December 23, 2018, Vitol voluntarily elected to terminate the Splitter Agreement claiming that Targa Channelview failed to timely achieve start-up of the Splitter. Vitol’s lawsuit also alleges Targa Channelview made a series of misrepresentations about the capability of the barge dock that would service crude oil and condensate volumes to be processed by the Splitter and Splitter products. Vitol seeks return of $129.0 million in payments made to Targa Channelview prior to the start-up of the Splitter, as well as additional damages. On the same date that Vitol filed its lawsuit, Targa Channelview filed a lawsuit against Vitol seeking a judicial determination that Vitol’s sole and exclusive remedy was Vitol’s voluntarily termination of the Splitter Agreement and, as a result, Vitol was not entitled to the return of any prior payments under the Splitter Agreement or other damages as alleged. Targa also seeks recovery of its attorneys’ fees and costs in the lawsuit.

On October 15, 2020, the District Court awarded Vitol $129.0 million (plus interest) following a bench trial. In addition, the District Court awarded Vitol $10.5 million in damages for losses and demurrage on crude oil that Vitol purchased for start-up efforts. The Company appealed the award in the Fourteenth Court of Appeals in Houston, Texas. In October 2020, we sold Targa Channelview but, under the agreements governing the sale, we retained the liabilities associated with the Vitol proceedings. On September 13, 2022, the Fourteenth Court of Appeals upheld the trial court’s judgment in part with regard to the return of Vitol’s prior payments, but modified the judgment to delete Vitol’s ability to recover any damages related to losses or demurrage on crude oil. We filed a petition for review with the Supreme Court of Texas which was denied on October 20, 2023, but we are seeking rehearing and the appeal remains pending. The cumulative amount of interest on the award through September 30, 2023, if accrued, would have been approximately $52.3 million.

Additional information required for this item is provided in Note 12 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Part I—Item 1A. Risk Factors” of our Annual Report. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Recent Sales of Unregistered Securities.

None.

Repurchase of Equity by Targa Resources Corp. or Affiliated Purchasers.

Period	Total number of shares purchased (1)	Average price per share	Total number of shares purchased as part of publicly announced plans (2)	Maximum approximate dollar value of shares that may yet be purchased under the plan (in thousands) (2)
July 1, 2023 - July 31, 2023	352,139	$ 77.58	348,105	$ 915,718
August 1, 2023 - August 31, 2023	737,577	$ 83.55	484,959	$ 874,713
September 1, 2023 - September 30, 2023	757,696	$ 85.32	750,253	$ 810,703

(1) Includes 1,583,317 shares repurchased under the Share Repurchase Programs, as well as 264,095 shares that were withheld by us to satisfy tax withholding obligations of certain of our officers, directors and key employees that arose upon the lapse of restrictions on restricted stock.

(2) In the fourth quarter of 2020, our Board of Directors approved the 2020 Share Repurchase Program for the repurchase of up to $500.0 million of our outstanding common stock. In May 2023, our Board of Directors approved the 2023 Share Repurchase Program for the repurchase of up to $1.0 billion of our outstanding common stock. During the second quarter of 2023, we exhausted the 2020 Share Repurchase Program. We may discontinue the 2023 Share Repurchase Program at any time and are not obligated to repurchase any specific dollar amount or number of shares thereunder.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed May 26, 2021 (File No. 001-34991)).
3.3	Certificate of Designations of Series A Preferred Stock of Targa Resources Corp., filed with the Secretary of State of the State of Delaware on March 16, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
3.4	Second Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.4 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed on May 5, 2022 (File No. 001-34991)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	Second Amended and Restated Targa Resources Corp. 2010 Stock Incentive Plan, as amended and restated effective August 1, 2023 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed August 3, 2023 (File No. 001-34991)).
10.2	Fourteenth Amendment to Receivables Purchase Agreement, dated as of August 30, 2023, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed August 31, 2023 (File No. 001-34991)).
22.1*	List of Subsidiary Guarantors.
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	Inline XBRL Instance Document – The instance document does not appear in the interactive data file because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document

Number	Description
104*	The cover page from this Quarterly Report on Form 10-Q for the quarter ended September 30, 2023, formatted in Inline XBRL (included with Exhibit 101 attachments).

* Filed herewith
** Furnished herewith
+ Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Targa Resources Corp. (Registrant)
Date: November 2, 2023	By: *<u>/s/ Jennifer R. Kneale</u>* Jennifer R. Kneale Chief Financial Officer (Principal Financial Officer)

Exhibit 22.1

List of Subsidiary Guarantors

Name	**State of Incorporation or Organization**
Arkoma Newco LLC	Delaware
Delaware-Permian Pipeline LLC	Delaware
FCPP Pipeline, LLC	Delaware
Flag City Processing Partners, LLC	Delaware
Grand Prix Development LLC	Delaware
Grand Prix Pipeline LLC	Delaware
Lasso Acquiror LLC	Delaware
Midland-Permian Pipeline LLC	Delaware
Setting Sun Pipeline Corporation	Delaware
Slider WestOk Gathering, LLC	Delaware
Targa Capital LLC	Delaware
Targa Cayenne LLC	Delaware
Targa Chaney Dell LLC	Delaware
Targa Cogen LLC	Delaware
Targa Condensate Marketing LLC	Delaware
Targa Delaware LLC	Delaware
Targa Delaware QOF LLC	Delaware
Targa Delaware QOZB LLC	Delaware
Targa Downstream LLC	Delaware
Targa Energy GP LLC	Delaware
Targa Energy LP	Delaware
Targa Frio LaSalle GP LLC	Texas
Targa Frio LaSalle Pipeline LP	Texas
Targa Gas Marketing LLC	Delaware
Targa Gas Pipeline LLC	Delaware
Targa Gas Processing LLC	Delaware
Targa GP Inc.	Delaware
Targa Gulf Coast NGL Pipeline LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa LA Holdings LLC	Delaware
Targa LA Operating LLC	Delaware
Targa Liquids Marketing and Trade LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa LP Inc.	Delaware
Targa Midkiff LLC	Delaware
Targa Midland Crude LLC	Delaware
Targa Midland LLC	Delaware
Targa Midstream Services LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa Northern Delaware LLC	Delaware
Targa Permian Condensate Pipeline LLC	Delaware
Targa Pipeline Mid-Continent Holdings LLC	Delaware
Targa Pipeline Mid-Continent LLC	Delaware
Targa Pipeline Mid-Continent WestOk LLC	Delaware
Targa Pipeline Mid-Continent WestTex LLC	Delaware
Targa Pipeline Operating Partnership LP	Delaware
Targa Pipeline Partners GP LLC	Delaware
Targa Pipeline Partners LP	Delaware
Targa Resources Finance Corporation	Delaware
Targa Resources GP LLC	Delaware

Targa Resources LLC	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LLC	Delaware
Targa Resources Partners LP	Delaware
Targa Rich Gas Services GP LLC	Texas
Targa Rich Gas Services LP	Texas
Targa Rich Gas Utility GP LLC	Texas
Targa Rich Gas Utility LP	Texas
Targa Southern Delaware LLC	Delaware
Targa SouthOk NGL Pipeline LLC	Oklahoma
Targa SouthTex CCNG Gathering Ltd.	Texas
Targa SouthTex Energy GP LLC	Delaware
Targa SouthTex Energy LP LLC	Delaware
Targa SouthTex Energy Operating LLC	Delaware
Targa SouthTex Gathering Ltd.	Texas
Targa SouthTex Midstream Company LP	Texas
Targa SouthTex Midstream Marketing Company Ltd.	Texas
Targa SouthTex Midstream T/U GP LLC	Texas
Targa SouthTex Midstream Utility LP	Texas
Targa SouthTex Mustang Transmission Ltd.	Texas
Targa SouthTex NGL Pipeline Ltd.	Texas
Targa SouthTex Processing LLC	Delaware
Targa Train 6 LLC	Delaware
Targa Train 8 LLC	Delaware
Targa Train 9 LLC	Delaware
Targa Transport LLC	Delaware
TPL Arkoma Midstream LLC	Delaware
TPL Gas Treating LLC	Delaware
TPL SouthTex Gas Utility Company LP	Texas
TPL SouthTex Midstream Holding Company LP	Texas
TPL SouthTex Midstream LLC	Delaware
TPL SouthTex Pipeline Company LLC	Texas
TPL SouthTex Processing Company LP	Texas
TPL SouthTex Transmission Company LP	Texas
T2 Eagle Ford Gathering Company LLC	Delaware
T2 Gas Utility LLC	Texas
T2 LaSalle Gas Utility LLC	Texas
T2 LaSalle Gathering Company LLC	Delaware
Velma Gas Processing Company, LLC	Delaware
Velma Intrastate Gas Transmission Company, LLC	Delaware
Versado Gas Processors, L.L.C.	Delaware

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Matthew J. Meloy, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 2, 2023

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Chief Executive Officer of Targa Resources Corp.
(Principal Executive Officer)

Exhibit 31.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Jennifer R. Kneale, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 2, 2023

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer of Targa Resources Corp.
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp., for the three months ended September 30, 2023 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy, as Chief Executive Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Chief Executive Officer of Targa Resources Corp.

Date: November 2, 2023

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Targa and will be retained by Targa and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp., for the three months ended September 30, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Jennifer R. Kneale, as Chief Financial Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to her knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer of Targa Resources Corp.

Date: November 2, 2023

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Targa and will be retained by Targa and furnished to the Securities and Exchange Commission or its staff upon request.