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 June 30, 2020
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: 001-33303

TARGA

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
811 Louisiana St, 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**
9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	NGLS/PA	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 July 31, 2020, there were 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units outstanding.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," "TRP" or the "Partnership") 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, the credit ratings for our debt obligations and demand for our senior notes;
- the impact of outbreaks of illnesses, pandemics (like COVID-19) or any other public health crises;
- 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, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- 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; and
- the risks described in our Annual Report on Form 10-K for the year ended December 31, 2019 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Additionally, while we have not been previously materially impacted by prior outbreaks of illnesses, pandemics or other public health crises, there are potential risks to us from the continued impact on global demand for commodities related to the COVID-19 pandemic. The COVID-19 pandemic has reduced economic activity and the related demand for energy commodities, which contributed to a sharp drop in prices in the first half of 2020 and is expected to continue to impact demand over the short-to-medium term.

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 June 30, 2020 ("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
GAAP	Accounting principles generally accepted in the United States of America
gal	U.S. gallons
LIBOR	London Interbank Offered Rate
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
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			June 30, 2020	December 31, 2019
			(Unaudited)	
			(In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 173.6	$ 291.1
Trade receivables, net of allowances of $0.1 and $0.0 million at June 30, 2020 and December 31, 2019			547.3	855.2
Inventories			219.3	161.5
Assets from risk management activities			122.0	103.3
Deposits			95.2	35.4
Held for sale assets			—	137.7
Other current assets			31.5	18.8
Total current assets			1,188.9	1,603.0
Property, plant and equipment, net			12,417.5	14,549.0
Intangible assets, net			1,452.8	1,735.0
Long-term assets from risk management activities			43.3	35.5
Investments in unconsolidated affiliates			724.3	738.7
Other long-term assets			89.5	83.3
Total assets			$ 15,916.3	$ 18,744.5
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable			$ 608.7	$ 977.8
Accrued liabilities			75.0	88.7
Interest payable			144.3	125.4
Distributions payable to noncontrolling interests			89.9	91.8
Accounts payable to Targa Resources Corp.			190.4	193.8
Liabilities from risk management activities			80.5	104.1
Current debt obligations			261.9	382.2
Held for sale liabilities			—	6.4
Total current liabilities			1,450.7	1,970.2
Long-term debt			7,144.6	7,005.2
Long-term liabilities from risk management activities			52.9	40.8
Deferred income taxes, net			23.0	23.0
Other long-term liabilities			266.2	260.0
Contingencies (see Note 11)				
Owners' equity:				
Series A preferred limited partners	Issued	Outstanding	120.6	120.6
June 30, 2020	5,000,000	5,000,000		
December 31, 2019	5,000,000	5,000,000		
Common limited partners	Issued	Outstanding	2,865.2	5,022.7
June 30, 2020	275,168,410	275,168,410		
December 31, 2019	275,168,410	275,168,410		
General partner	Issued	Outstanding	733.8	778.0
June 30, 2020	5,629,136	5,629,136		
December 31, 2019	5,629,136	5,629,136		
Accumulated other comprehensive income (loss)			28.4	122.5
			3,748.0	6,043.8
Noncontrolling interests			3,230.9	3,401.5
Total owners' equity			6,978.9	9,445.3
Total liabilities and owners' equity			$ 15,916.3	$ 18,744.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(Unaudited) (In millions)			
Revenues:				
Sales of commodities	$ 1,280.6	$ 1,684.2	$ 3,060.2	$ 3,660.7
Fees from midstream services	242.9	311.1	512.2	634.0
Total revenues	1,523.5	1,995.3	3,572.4	4,294.7
Costs and expenses:				
Product purchases	860.6	1,361.6	2,043.6	3,087.6
Operating expenses	183.4	210.2	383.3	400.5
Depreciation and amortization expense	204.5	237.2	443.6	474.6
General and administrative expense	58.6	69.3	115.5	146.7
Impairment of long-lived assets	—	—	2,442.8	—
Other operating (income) expense	0.4	(0.2)	1.6	3.3
Income (loss) from operations	216.0	117.2	(1,858.0)	182.0
Other income (expense):				
Interest expense, net	(94.3)	(69.5)	(188.1)	(144.9)
Equity earnings (loss)	14.9	3.2	35.5	5.9
Gain (loss) from financing activities	21.8	—	61.1	(1.4)
Change in contingent considerations	—	0.8	—	(8.9)
Other, net	0.8	—	0.8	—
Income (loss) before income taxes	159.2	51.7	(1,948.7)	32.7
Income tax (expense) benefit	—	—	—	—
Net income (loss)	159.2	51.7	(1,948.7)	32.7
Less: Net income (loss) attributable to noncontrolling interests	93.3	56.3	8.0	67.7
Net income (loss) attributable to Targa Resources Partners LP	$ 65.9	$ (4.6)	$ (1,956.7)	$ (35.0)
Net income attributable to preferred limited partners	$ 2.8	$ 2.8	$ 5.6	$ 5.6
Net income (loss) attributable to general partner	1.2	(0.1)	(39.4)	(0.8)
Net income (loss) attributable to common limited partners	61.9	(7.3)	(1,922.9)	(39.8)
Net income (loss) attributable to Targa Resources Partners LP	$ 65.9	$ (4.6)	$ (1,956.7)	$ (35.0)

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(Unaudited) (In millions)			
Net income (loss)	$ 159.2	$ 51.7	$ (1,948.7)	$ 32.7
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	(132.9)	88.4	26.2	49.6
Settlements reclassified to revenues	(60.2)	(43.3)	(120.3)	(64.6)
Other comprehensive income (loss)	(193.1)	45.1	(94.1)	(15.0)
Comprehensive income (loss)	(33.9)	96.8	(2,042.8)	17.7
Less: Comprehensive income (loss) attributable to noncontrolling interests	93.3	56.3	8.0	67.7
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ (127.2)	$ 40.5	$ (2,050.8)	$ (50.0)

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non- controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
					(Unaudited) (In millions, except units in thousands)				
Balance, March 31, 2020	5,000	$ 120.6	275,168	$ 2,803.6	5,629	$ 732.6	$ 221.5	$ 3,225.6	$ 7,103.9
Contributions from Targa Resources Corp.	—	—	—	49.0	—	1.0	—	—	50.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(103.1)	(103.1)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	15.1	15.1
Other comprehensive income (loss)	—	—	—	—	—	—	(193.1)	—	(193.1)
Net income (loss)	—	2.8	—	61.9	—	1.2	—	93.3	159.2
Distributions	—	(2.8)	—	(49.3)	—	(1.0)	—	—	(53.1)
Balance, June 30, 2020	5,000	$ 120.6	275,168	$ 2,865.2	5,629	$ 733.8	$ 28.4	$ 3,230.9	$ 6,978.9

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non- controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
					(Unaudited) (In millions, except units in thousands)				
Balance, March 31, 2019	5,000	$ 120.6	275,168	$ 5,961.0	5,629	$ 797.1	$ 64.8	$ 1,460.4	$ 8,403.9
Contributions from Targa Resources Corp.	—	—	—	186.2	—	3.8	—	—	190.0
Sale of ownership interests in subsidiaries	—	—	—	(10.5)	—	(0.2)	—	1,619.7	1,609.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(66.9)	(66.9)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	206.7	206.7
Other comprehensive income (loss)	—	—	—	—	—	—	45.1	—	45.1
Net income (loss)	—	2.8	—	(7.3)	—	(0.1)	—	56.3	51.7
Distributions	—	(2.8)	—	(426.3)	—	(8.7)	—	—	(437.8)
Balance, June 30, 2019	5,000	$ 120.6	275,168	$ 5,703.1	5,629	$ 791.9	$ 109.9	$ 3,276.2	$ 10,001.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

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

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non-controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
Balance, December 31, 2019	5,000	$ 120.6	275,168	$ 5,022.7	5,629	$ 778.0	$ 122.5	$ 3,401.5	$ 9,445.3
Contributions from Targa Resources Corp.	—	—	—	49.0	—	1.0	—	—	50.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(204.3)	(204.3)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	25.7	25.7
Other comprehensive income (loss)	—	—	—	—	—	—	(94.1)	—	(94.1)
Net income (loss)	—	5.6	—	(1,922.9)	—	(39.4)	—	8.0	(1,948.7)
Distributions	—	(5.6)	—	(283.6)	—	(5.8)	—	—	(295.0)
Balance, June 30, 2020	5,000	$ 120.6	275,168	$ 2,865.2	5,629	$ 733.8	$ 28.4	$ 3,230.9	$ 6,978.9

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

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non-controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
Balance, December 31, 2018	5,000	$ 120.6	275,168	$ 6,227.2	5,629	$ 802.6	$ 124.9	$ 1,270.8	$ 8,546.1
Contributions from Targa Resources Corp.	—	—	—	186.2	—	3.8	—	—	190.0
Sale of ownership interests in subsidiaries	—	—	—	(10.5)	—	(0.2)	—	1,619.7	1,609.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(85.5)	(85.5)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	403.5	403.5
Other comprehensive income (loss)	—	—	—	—	—	—	(15.0)	—	(15.0)
Net income (loss)	—	5.6	—	(39.8)	—	(0.8)	—	67.7	32.7
Distributions	—	(5.6)	—	(660.0)	—	(13.5)	—	—	(679.1)
Balance, June 30, 2019	5,000	$ 120.6	275,168	$ 5,703.1	5,629	$ 791.9	$ 109.9	$ 3,276.2	$ 10,001.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2020	2019
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income (loss)	$ (1,948.7)	$ 32.7
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	5.0	4.6
Depreciation and amortization expense	443.6	474.6
Impairment of long-lived assets	2,442.8	—
Accretion of asset retirement obligations	1.7	2.3
Equity (earnings) loss of unconsolidated affiliates	(35.5)	(5.9)
Distributions of earnings received from unconsolidated affiliates	44.5	14.4
Risk management activities	(125.9)	0.1
(Gain) loss on sale or disposition of assets	—	3.1
(Gain) loss from financing activities	(61.1)	1.4
Change in contingent considerations	—	8.9
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	240.1	198.2
Inventories	(56.7)	(76.7)
Accounts payable, accrued liabilities and other liabilities	(262.1)	(154.1)
Interest payable	18.9	41.4
Net cash provided by operating activities	706.6	545.0
Cash flows from investing activities		
Outlays for property, plant and equipment	(615.9)	(1,750.5)
Proceeds from sale of business and assets	134.8	2.4
Investments in unconsolidated affiliates	(1.4)	(194.8)
Return of capital from unconsolidated affiliates	6.9	0.1
Other, net	3.5	(19.1)
Net cash used in investing activities	(472.1)	(1,961.9)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facility	1,240.0	1,320.0
Repayments of credit facility	(800.0)	(1,830.0)
Proceeds from borrowings under accounts receivable securitization facility	226.4	742.9
Repayments of accounts receivable securitization facility	(346.4)	(724.6)
Proceeds from issuance of senior notes	—	1,500.0
Redemption of senior notes	(239.8)	(749.4)
Principal payments of finance leases	(6.2)	(5.5)
Costs incurred in connection with financing arrangements	(0.5)	(25.1)
Payment of contingent consideration	—	(317.1)
Sale of ownership interests in subsidiaries	—	1,619.7
Contributions from general partner	1.0	3.8
Contributions from TRC	49.0	186.2
Contributions from noncontrolling interests	25.7	403.5
Distributions to noncontrolling interests	(206.2)	(35.9)
Distributions to unitholders	(295.0)	(679.1)
Net cash provided by (used in) financing activities	(352.0)	1,409.4
Net change in cash and cash equivalents	(117.5)	(7.5)
Cash and cash equivalents, beginning of period	291.1	203.3
Cash and cash equivalents, end of period	$ 173.6	$ 195.8

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 Partners LP is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC" or the "Company" or "Parent"). In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," "TRP," or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Our common units are wholly owned by TRC and no longer publicly traded as a result of TRC's acquisition of our outstanding common units that it and its subsidiaries did not already own in 2016.

The 5,000,000 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") that were issued in October 2015 remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

Our Operations

We are primarily engaged in the business of:

- gathering, compressing, treating, processing, transporting and selling natural gas;
- transporting, storing, fractionating, treating and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling and selling crude oil.

See Note 14 – Segment Information for certain financial information regarding our business segments.

The employees supporting our operations are employed by Targa. Our consolidated financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa's centralized general and administrative services.

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, necessary for a fair statement of the results of the interim periods reported. All significant 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 six months ended June 30, 2020 are not necessarily indicative of the results that may be expected for the year ending December 31, 2020.

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 six months ended June 30, 2020.

Recent Accounting Pronouncements

Recently adopted accounting pronouncements

Measurement of Credit Losses

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The amendments in this update modify the impairment model for financial instruments, including trade and other receivables, held-to-maturity debt securities and other instruments.

The amendments require entities to consider historical information, current conditions, and supportable forecasts to estimate expected credit losses, which may result in earlier recognition of losses. The amendments were effective for us on January 1, 2020 and were adopted by applying the modified retrospective transition approach. The adoption did not result in a cumulative effect adjustment to retained earnings on January 1, 2020. As a result of our adoption, see Accounting Policy Updates – Allowance for Doubtful Accounts below.

Accounting Policy Updates

Allowance for Doubtful Accounts

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. We estimate the allowance for doubtful accounts through various procedures, including extensive review of our trade receivable balances by counterparty, assessing economic events and conditions, our historical experience with counterparties, the counterparty's financial condition and the amount and age of past due accounts.

We continuously evaluate our ability to collect amounts owed to us. Receivables are considered past due if full payment is not received by the contractual due date. These procedures also include performing account reconciliations, dispute resolution and payment confirmation. We may involve our legal counsel to pursue the recovery of defaulted trade receivables.

As the financial condition of any counterparty changes, circumstances develop or additional information becomes available, adjustments to our allowance may be required.

Note 4 — Property, Plant and Equipment and Intangible Assets

	June 30, 2020	December 31, 2019	Estimated Useful Lives (In Years)
Gathering systems	$ 9,117.8	$ 8,976.8	5 to 20
Processing and fractionation facilities	5,666.2	5,137.0	5 to 25
Terminaling and storage facilities	1,498.7	1,495.5	5 to 25
Transportation assets	2,316.3	2,292.4	10 to 50
Other property, plant and equipment	196.2	183.9	3 to 25
Land	159.2	159.7	—
Construction in progress	1,304.2	1,576.5	—
Finance lease right-of-use assets	51.0	48.8	
Property, plant and equipment	20,309.6	19,870.6	
Accumulated depreciation, amortization and impairment	(7,892.1)	(5,321.6)	
Property, plant and equipment, net	$ 12,417.5	$ 14,549.0	
Intangible assets	$ 2,643.5	$ 2,643.5	10 to 20
Accumulated amortization and impairment	(1,190.7)	(908.5)	
Intangible assets, net	$ 1,452.8	$ 1,735.0	

During the preparation of the Company's first quarter 2019 consolidated financial statements, the Company identified an error related to depreciation expense on certain assets that should have been placed in-service during 2018. The Company does not believe this error is material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. The Company recorded the cumulative impact of a one-time $12.5 million overstatement of depreciation expense during the first quarter of 2019.

During the three and six months ended June 30, 2020, depreciation expense was $169.3 million and $370.0 million, respectively. During the three and six months ended June 30, 2019, depreciation expense was $194.3 million and $388.7 million, respectively.

Asset Impairments

We review and evaluate our long-lived assets, including intangible assets, for impairment when events or changes in circumstances indicate that the related carrying amount of such assets may not be recoverable, and changes to our estimates could have an impact on our assessment of asset recoverability.

During the first half of 2020, global commodity prices declined due to factors that significantly impacted both demand and supply. As the COVID-19 pandemic spread, causing travel and other restrictions to be implemented globally, the demand for commodities declined. Additionally, the supply shock late in the first quarter from certain major oil producing nations increasing production also significantly contributed to the sharp drop in commodity prices. While these major oil and gas producing countries subsequently agreed to collectively decrease production, these events, combined with the outbreak of the COVID-19 pandemic, contributed to volatility and depressed commodity prices in the first half of 2020. The drop in commodity prices resulted in prompt reactions from some domestic producers, including significantly reducing capital budgets and resultant drilling activity and shutting-in production. Commodity prices remain weak relative to historical levels and have remained volatile as uncertainty around global commodity supply and demand continues due to the COVID-19 pandemic.

In the first quarter of 2020, we determined that indicators of impairment existed for certain asset groups reported primarily within our Gathering and Processing segment. For each asset group for which undiscounted future net cash flows were not sufficient to recover the net book value, fair value was determined through use of discounted estimated cash flows to measure the impairment loss.

The estimated cash flows used to assess recoverability of our long-lived assets and measure fair value of our asset groups are derived from current business plans, which are developed using near-term price and volume projections reflective of the current environment and management's projections for long-term average prices and volumes. In addition to near and long-term price assumptions, other key assumptions include volume projections, operating costs, timing of incurring such costs and the use of an appropriate discount rate. We believe our estimates and models used to determine fair value are similar to what a market participant would use.

The fair value measurement of our long-lived assets was based, in part, on significant inputs not observable in the market (as discussed above) and thus represents a Level 3 measurement. The significant unobservable inputs used include discount rates and terminal value exit multiples. We utilized a weighted average discount rate of 14.0% when deriving the fair value of the asset groups impaired during the first quarter of 2020. The weighted average discount rate and exit multiples reflect management’s best estimate of inputs a market participant would utilize.

In the first quarter of 2020, we recorded non-cash pre-tax impairments of $2,442.8 million primarily associated with the partial impairment of gas processing facilities and gathering systems associated with our Mid-Continent operations and full impairment of our Coastal operations - all of which are in our Gathering and Processing segment. Our first quarter impairment assessment forecasted further decline in natural gas production across the Mid-Continent and Gulf of Mexico. The carrying value adjustments are included in Impairment of long-lived assets in our Consolidated Statements of Operations. There were no indicators of impairment identified during the second quarter of 2020.

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in prior business combinations. The fair value 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.

As a result of the triggering events and analysis described above, in the first quarter of 2020, we recognized a non-cash pre-tax impairment loss associated with certain intangible customer relationships for which undiscounted future net cash flows were not sufficient to recover the net book value.

The estimated annual amortization expense for intangible assets is approximately $144.0 million, $130.9 million, $122.7 million, $117.5 million and $113.7 million for each of the years 2020 through 2024, respectively.

The changes in our intangible assets are as follows:

Balance at December 31, 2019	$	1,735.0
Impairment		(208.6)
Amortization		(73.6)
Balance at June 30, 2020	$	1,452.8

Note 5 — Debt Obligations

	June 30, 2020	December 31, 2019
Current:		
Accounts receivable securitization facility, due April 2021 (1)	$ 250.0	$ 370.0
Finance lease liabilities	11.9	12.2
Current debt obligations	261.9	382.2
Long-term:		
Senior secured revolving credit facility, variable rate, due June 2023 (2)	440.0	—
Senior unsecured notes:		
5¼% fixed rate, due May 2023	559.6	559.6
4¼% fixed rate, due November 2023	583.9	583.9
6¾% fixed rate, due March 2024	580.1	580.1
5⅛% fixed rate, due February 2025	481.0	500.0
5⅞% fixed rate, due April 2026	963.2	1,000.0
5⅜% fixed rate, due February 2027	468.1	500.0
6½% fixed rate, due July 2027	705.2	750.0
5% fixed rate, due January 2028	700.3	750.0
6⅞% fixed rate, due January 2029	679.3	750.0
5½% fixed rate, due March 2030	949.6	1,000.0
TPL notes, 4¾% fixed rate, due November 2021 (3)	6.5	6.5
TPL notes, 5⅞% fixed rate, due August 2023 (3)	48.1	48.1
Unamortized premium	0.2	0.3
	7,165.1	7,028.5
Debt issuance costs, net of amortization	(43.7)	(49.1)
Finance lease liabilities	23.2	25.8
Long-term debt	7,144.6	7,005.2
Total debt obligations	$ 7,406.5	$ 7,387.4
Irrevocable standby letters of credit outstanding (2)	$ 56.8	$ 88.2

(1) As of June 30, 2020, we had $250.0 million of qualifying receivables under our $250.0 million accounts receivable securitization facility ("Securitization Facility"), resulting in zero availability. During the second quarter of 2020, we amended the Securitization Facility to decrease the facility size from $400.0 million to $250.0 million to more closely align with our expectations for borrowing needs given commodity prices and to extend the facility termination date to April 21, 2021.

(2) As of June 30, 2020, availability under our $2.2 billion senior secured revolving credit facility ("TRP Revolver") was $1,703.2 million.

(3) "TPL" refers to Targa Pipeline Partners LP.

The following table shows the range of interest rates and weighted average interest rate incurred on variable-rate debt obligations during the six months ended June 30, 2020:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRP Revolver	1.9% - 6.0%	2.5%
Securitization Facility	1.5% - 2.7%	2.1%

Compliance with Debt Covenants

As of June 30, 2020, we were in compliance with the covenants contained in our various debt agreements.

Debt Repurchases

During the six months ended June 30, 2020, we repurchased a portion of our outstanding senior notes on the open market as follows:

Debt Repurchased	Book Value	Payment	Gain	Write-off of Debt Issuance Costs	Net Gain
5⅛% Senior Notes due 2025	$ 19.0	$ (14.6)	$ 4.4	$ (0.1)	$ 4.3
5⅞% Senior Notes due 2026	36.8	(29.7)	7.1	(0.2)	6.9
5⅜% Senior Notes due 2027	31.9	(26.6)	5.3	(0.2)	5.1
6½% Senior Notes due 2027	44.8	(35.5)	9.3	(0.4)	8.9
5% Senior Notes due 2028	49.7	(38.0)	11.7	(0.4)	11.3
6⅞% Senior Notes due 2029	70.7	(55.2)	15.5	(0.6)	14.9
5½% Senior Notes due 2030	50.4	(40.2)	10.2	(0.5)	9.7
	$ 303.3	$ (239.8)	$ 63.5	$ (2.4)	$ 61.1

We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such 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.

Contractual Obligations

The following table summarizes payment obligations for debt instruments after giving effect to the debt repurchases detailed above:

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(in millions)				
Long-term debt obligations (1)	$ 7,164.9	$ -	$ 1,006.1	$ 1,693.1	$ 4,465.7
Interest on debt obligations (2)	2,475.0	397.8	792.6	600.7	683.9
	$ 9,639.9	$ 397.8	$ 1,798.7	$ 2,293.8	$ 5,149.6

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.

(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing June 30, 2020 rates for floating debt.

Note 6 — Other Long-term Liabilities

Other long-term liabilities are comprised of deferred revenue, asset retirement obligations and operating lease liabilities.

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 June 30, 2020 and December 31, 2019, was $170.3 million and $172.0 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. Deferred revenue also 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.

Note 7 — Partnership Units and Related Matters

Distributions

TRC is entitled to receive all Partnership distributions after payment of preferred unit distributions each quarter.

The following table details the distributions declared and paid by us for the six months ended June 30, 2020:

Three Months Ended	Date Paid or To Be Paid	Total Distributions	Distributions to Targa Resources Corp.
June 30, 2020	August 13, 2020	$ 51.7	$ 48.9
March 31, 2020	May 13, 2020	53.1	50.3
December 31, 2019	February 13, 2020	241.9	239.1

Contributions

All capital contributions to us continue to be allocated 98% to the limited partner and 2% to our general partner; however, no units will be issued for those contributions. During the second quarter of 2020, TRC made contributions to us of $50.0 million.

Preferred Units

Our Preferred Units rank senior to our common units with respect to the distribution rights. Distributions on our 5,000,000 Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on our Preferred Units are payable out of amounts legally available at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

We paid $2.8 million and $5.6 million of distributions to the holders of Preferred Units ("Preferred Unitholders") for the three and six months ended June 30, 2020.

Subsequent Event

In July 2020, the board of directors of our general partner declared a cash distribution of $0.1875 per Preferred Unit, resulting in approximately $0.9 million in distributions that will be paid on August 17, 2020.

Note 8 — Derivative Instruments and Hedging Activities

The primary purposes of our commodity risk management activities are 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 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. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

At June 30, 2020, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2020	2021	2022	2023	2024	2025
Natural Gas	Swaps	MMBtu/d	167,230	166,216	86,100	20,000	-	-
Natural Gas	Basis Swaps	MMBtu/d	416,374	450,566	295,390	250,000	90,000	5,000
NGL	Swaps	Bbl/d	30,814	23,729	12,371	-	-	-
NGL	Futures	Bbl/d	39,370	12,288	-	-	-	-
Condensate	Swaps	Bbl/d	5,190	5,864	1,610	-	-	-

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 June 30, 2020		Fair Value as of December 31, 2019	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 99.2	$ 74.6	$ 102.1	$ 11.6
	Long-term	36.1	32.6	33.7	6.4
Total derivatives designated as hedging instruments		$ 135.3	$ 107.2	$ 135.8	$ 18.0
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 22.8	$ 5.9	$ 1.2	$ 92.5
	Long-term	7.2	20.3	1.8	34.4
Total derivatives not designated as hedging instruments		$ 30.0	$ 26.2	$ 3.0	$ 126.9
Total current position		$ 122.0	$ 80.5	$ 103.3	$ 104.1
Total long-term position		43.3	52.9	35.5	40.8
Total derivatives		$ 165.3	$ 133.4	$ 138.8	$ 144.9

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

	Gross Presentation			Pro Forma Net Presentation	
June 30, 2020	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 108.9	$ (80.5)	$ 48.2	$ 76.6	$ -
Counterparties without offsetting positions - assets	13.1	-	-	13.1	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	122.0	(80.5)	48.2	89.7	-
Long Term Position					
Counterparties with offsetting positions or collateral	31.5	(49.3)	-	6.6	(24.4)
Counterparties without offsetting positions - assets	11.8	-	-	11.8	-
Counterparties without offsetting positions - liabilities	-	(3.6)	-	-	(3.6)
	43.3	(52.9)	-	18.4	(28.0)
Total Derivatives					
Counterparties with offsetting positions or collateral	140.4	(129.8)	48.2	83.2	(24.4)
Counterparties without offsetting positions - assets	24.9	-	-	24.9	-
Counterparties without offsetting positions - liabilities	-	(3.6)	-	-	(3.6)
	$ 165.3	$ (133.4)	$ 48.2	$ 108.1	$ (28.0)

	Gross Presentation			Pro Forma Net Presentation	
December 31, 2019	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 99.8	$ (85.0)	$ (4.9)	$ 56.0	$ (46.1)
Counterparties without offsetting positions - assets	3.5	-	-	3.5	-
Counterparties without offsetting positions - liabilities	-	(19.1)	-	-	(19.1)
	103.3	(104.1)	(4.9)	59.5	(65.2)
Long Term Position					
Counterparties with offsetting positions or collateral	33.3	(40.5)	-	18.1	(25.3)
Counterparties without offsetting positions - assets	2.2	-	-	2.2	-
Counterparties without offsetting positions - liabilities	-	(0.3)	-	-	(0.3)
	35.5	(40.8)	-	20.3	(25.6)
Total Derivatives					
Counterparties with offsetting positions or collateral	133.1	(125.5)	(4.9)	74.1	(71.4)
Counterparties without offsetting positions - assets	5.7	-	-	5.7	-
Counterparties without offsetting positions - liabilities	-	(19.4)	-	-	(19.4)
	$ 138.8	$ (144.9)	$ (4.9)	$ 79.8	$ (90.8)

Our payment obligations in connection with a majority of these hedging transactions are secured by a first priority lien in the collateral securing the TRP Revolver that ranks equal in right of payment with liens granted in favor of our senior secured lenders. 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 enough to cover the fair value of our open futures positions. The margin deposit is considered collateral, which is located within Deposits on our Consolidated Balance Sheets and is not offset against the fair value of our derivative instruments.

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 asset of $31.9 million as of June 30, 2020. 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:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives in Cash Flow Hedging Relationships	2020	2019	2020	2019
Commodity contracts	$ (132.9)	$ 88.4	$ 26.2	$ 49.6

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2020	2019	2020	2019
Revenues	$ 60.2	$ 43.3	$ 120.3	$ 64.6

Based on valuations as of June 30, 2020, we expect to reclassify commodity hedge-related deferred gains of $29.8 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2023, with $26.3 million of gains 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 instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. For the three and six months ended June 30, 2020, the unrealized mark-to-market gains are primarily attributable to favorable movements in natural gas forward basis prices, as compared to our hedged positions.

		Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	2020	2019	2020	2019
Commodity contracts	Revenue	$ 8.1	$ (1.1)	$ 107.8	$ (10.5)

See Note 9 – Fair Value Measurements and Note 14 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 9 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments and contingent consideration related to business acquisitions 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 June 30, 2020, a net asset position of $31.9 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 $(86.5) 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 $150.7 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 TRP Revolver and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

Contingent consideration liabilities related to business acquisitions are carried at fair value until the end of the related earn-out period.

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 (1) financial instruments measurements included on our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	June 30, 2020				
		Fair Value			
	Carrying 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)	$ 164.0	$ 164.0	$ —	$ 164.0	$ —
Liabilities from commodity derivative contracts (1)	132.1	132.1	—	132.1	—
TPL contingent consideration (2)	2.3	2.3	—	—	2.3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	173.6	173.6	—	—	—
TRP Revolver	440.0	440.0	—	440.0	—
Senior unsecured notes	6,725.1	6,627.2	—	6,627.2	—
Securitization Facility	250.0	250.0	—	250.0	—

	December 31, 2019				
		Fair Value			
	Carrying 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)	$ 136.5	$ 136.5	$ —	$ 136.2	$ 0.3
Liabilities from commodity derivative contracts (1)	142.6	142.6	—	142.0	0.6
TPL contingent consideration (2)	2.3	2.3	—	—	2.3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	291.1	291.1	—	—	—
TRP Revolver	—	—	—	—	—
Senior unsecured notes	7,028.5	7,376.9	—	7,376.9	—
Securitization Facility	370.0	370.0	—	370.0	—

(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 8– 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.
(2) We have a contingent consideration liability for TPL's previous acquisition of a gas gathering system and related assets, which is carried at fair value.

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

We 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 is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

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

The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives were (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable was immaterial. As of June 30, 2020, we had no commodity swap and option contracts categorized as Level 3.

The fair value of the TPL contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. The inputs are not observable; therefore, the entire valuation of the contingent consideration is categorized in 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)	Contingent Consideration
Balance, December 31, 2019	$ (0.3)	$ (2.3)
Transfers out of Level 3 (1)	0.3	—
Balance, June 30, 2020	$ —	$ (2.3)

(1) Transfers relate to long-term over-the-counter swaps for NGL products for which observable market prices became available for substantially their full term.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Nonfinancial assets and liabilities, such as long-lived assets, are measured at fair value on a nonrecurring basis upon impairment. In the first quarter of 2020, we recorded non-cash pre-tax impairments of $2,442.8 million. The impairment charge is primarily associated with the partial impairment of gas processing facilities and gathering systems associated with our Mid-Continent operations and full impairment of our Coastal operations. For disclosures related to valuation techniques, see Note 4 – Property, Plant and Equipment and Intangible Assets.

The techniques described above may produce a fair value calculation that may not be indicative or reflective of future fair values. Furthermore, while we believe our valuation techniques are appropriate and consistent with other market participants, the use of different techniques or assumptions to determine fair value of certain financial and nonfinancial assets and liabilities could result in a different fair value measurement at the reporting date.

Note 10 — Related Party Transactions – Targa

Relationship with Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than costs attributable to Targa's status as a separate reporting company. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
Targa billings of payroll and related costs included in operating expenses	$ 66.6	$ 61.6	$ 132.2	$ 115.7
Targa allocation of general and administrative expense	56.0	61.1	108.5	128.8
Cash distributions to Targa based on general partner and limited partner ownership	50.3	435.0	289.4	673.5
Cash contributions from Targa related to limited partner ownership (1)	49.0	186.2	49.0	186.2
Cash contributions from Targa to maintain its 2% general partner ownership	1.0	3.8	1.0	3.8

(1) The cash contributions from Targa related to limited partner ownership were allocated 98% to the limited partner and 2% to general partner. See Note 7 – Partnership Units and Related Matters.

Note 11 – Contingencies

Legal Proceedings

We are a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business. We are also a party 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.

Note 12 – Revenue

Fixed consideration allocated to remaining performance obligations

The following table includes the estimated minimum revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) at the end of the reporting period and is comprised of fixed consideration primarily attributable to contracts with minimum volume commitments and 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.

	2020	2021	2022 and after
Fixed consideration to be recognized as of June 30, 2020	$ 270.6	$ 515.0	$ 3,202.7

In accordance with the optional exemptions that we elected to apply, the amounts presented in the table above exclude variable consideration for which the allocation exception is met and consideration associated with performance obligations of short-term contracts. In addition, consideration from contracts for which we recognize revenue at the amount that we have the right to invoice for services performed is also excluded from the table above, with the exception of any fixed consideration attributable to such contracts. The nature of the performance obligations for which the consideration has been excluded is consistent with the performance obligations described within our revenue recognition accounting policy; the estimated remaining duration of such contracts primarily ranges from 1 to 19 years. In addition, variability exists in the consideration excluded due to the unknown quantity and composition of volumes to be serviced or sold as well as fluctuations in the market price of commodities to be received as consideration or sold over the applicable remaining contract terms. Such variability is resolved at the end of each future month or quarter.

For disclosures related to disaggregated revenue, see Note 14 – Segment Information.

Note 13 — Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2020	2019
Cash:		
Interest paid, net of capitalized interest (1)	$ 165.3	$ 106.2
Income taxes paid, net of refunds	0.1	(1.7)
Non-cash investing activities:		
Impact of capital expenditure accruals on property, plant and equipment, net	(143.9)	(4.3)
Transfers from materials and supplies inventory to property, plant and equipment	1.8	16.4
Non-cash financing activities:		
Changes in accrued distributions to noncontrolling interests	$ (1.9)	$ 49.6

(1) Interest capitalized on major projects was $22.5 million and $36.1 million for the six months ended June 30, 2020 and 2019.

Note 14 — 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 of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (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. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the 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 June 30, 2020				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 133.5	$ 1,136.3	$ 10.8	$ —	$ 1,280.6
Fees from midstream services	110.0	132.9	—	—	242.9
	243.5	1,269.2	10.8	—	1,523.5
Intersegment revenues					
Sales of commodities	389.2	46.1	—	(435.3)	—
Fees from midstream services	1.5	7.3	—	(8.8)	—
	390.7	53.4	—	(444.1)	—
Revenues	$ 634.2	$ 1,322.6	$ 10.8	$ (444.1)	$ 1,523.5
Operating margin	$ 237.2	$ 231.5	$ 10.8	$ —	$ 479.5
Other financial information:					
Total assets (1)	$ 9,124.2	$ 6,697.2	$ 22.0	$ 72.9	$ 15,916.3
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 37.1	$ 127.9	$ —	$ 4.6	$ 169.6

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Three Months Ended June 30, 2019				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 298.4	$ 1,378.8	$ 7.0	$ —	$ 1,684.2
Fees from midstream services	176.2	134.9	—	—	311.1
	474.6	1,513.7	7.0	—	1,995.3
Intersegment revenues					
Sales of commodities	539.7	43.6	—	(583.3)	—
Fees from midstream services	1.5	7.0	—	(8.5)	—
	541.2	50.6	—	(591.8)	—
Revenues	$ 1,015.8	$ 1,564.3	$ 7.0	$ (591.8)	$ 1,995.3
Operating margin	$ 232.1	$ 184.4	$ 7.0	$ —	$ 423.5
Other financial information:					
Total assets (1)	$ 12,144.4	$ 5,994.7	$ 19.0	$ 94.6	$ 18,252.7
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 420.8	$ 425.5	$ —	$ 10.8	$ 857.1

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Six Months Ended June 30, 2020				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 377.3	$ 2,555.7	$ 127.2	$ —	$ 3,060.2
Fees from midstream services	228.2	284.0	—	—	512.2
	605.5	2,839.7	127.2	—	3,572.4
Intersegment revenues					
Sales of commodities	832.4	102.7	—	(935.1)	—
Fees from midstream services	3.3	15.4	—	(18.7)	—
	835.7	118.1	—	(953.8)	—
Revenues	$ 1,441.2	$ 2,957.8	$ 127.2	$ (953.8)	$ 3,572.4
Operating margin	$ 492.8	$ 525.5	$ 127.2	$ —	$ 1,145.5
Other financial information:					
Total assets (1)	$ 9,124.2	$ 6,697.2	$ 22.0	$ 72.9	$ 15,916.3
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 154.6	$ 306.3	$ —	$ 12.9	$ 473.8

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Six Months Ended June 30, 2019				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 555.1	$ 3,105.6	$ —	$ —	$ 3,660.7
Fees from midstream services	376.1	257.9	—	—	634.0
	931.2	3,363.5	—	—	4,294.7
Intersegment revenues					
Sales of commodities	1,362.5	82.1	—	(1,444.6)	—
Fees from midstream services	3.3	12.5	—	(15.8)	—
	1,365.8	94.6	—	(1,460.4)	—
Revenues	$ 2,297.0	$ 3,458.1	$ —	$ (1,460.4)	$ 4,294.7
Operating margin	$ 470.3	$ 336.3	$ —	$ —	$ 806.6
Other financial information:					
Total assets (1)	$ 12,144.4	$ 5,994.7	$ 19.0	$ 94.6	$ 18,252.7
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 838.5	$ 896.3	$ —	$ 27.8	$ 1,762.6

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
Sales of commodities:				
Revenue recognized from contracts with customers:				
Natural gas	$ 269.7	$ 217.6	$ 542.8	$ 628.9
NGL	908.2	1,195.5	2,069.5	2,591.9
Condensate and crude oil	27.6	172.1	163.3	309.8
Petroleum products	6.8	56.8	56.5	76.0
	1,212.3	1,642.0	2,832.1	3,606.6
Non-customer revenue:				
Derivative activities - Hedge	60.2	43.3	120.3	64.6
Derivative activities - Non-hedge (1)	8.1	(1.1)	107.8	(10.5)
	68.3	42.2	228.1	54.1
Total sales of commodities	1,280.6	1,684.2	3,060.2	3,660.7
Fees from midstream services:				
Revenue recognized from contracts with customers:				
Gathering and processing	107.4	177.5	223.3	371.9
NGL transportation, fractionation and services	32.9	40.1	72.8	76.3
Storage, terminaling and export	89.1	90.4	188.8	170.0
Other	13.5	3.1	27.3	15.8
Total fees from midstream services	242.9	311.1	512.2	634.0
Total revenues	$ 1,523.5	$ 1,995.3	$ 3,572.4	$ 4,294.7

(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 June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
Reconciliation of reportable segment operating margin to income (loss) before income taxes:				
Gathering and Processing operating margin	$ 237.2	$ 232.1	$ 492.8	$ 470.3
Logistics and Transportation operating margin	231.5	184.4	525.5	336.3
Other operating margin	10.8	7.0	127.2	—
Depreciation and amortization expense	(204.5)	(237.2)	(443.6)	(474.6)
General and administrative expense	(58.6)	(69.3)	(115.5)	(146.7)
Impairment of long-lived assets	—	—	(2,442.8)	—
Interest expense, net	(94.3)	(69.5)	(188.1)	(144.9)
Equity earnings (loss)	14.9	3.2	35.5	5.9
Gain (loss) on sale or disposition of business and assets	0.7	0.2	-	(3.1)
Gain (loss) from financing activities	21.8	—	61.1	(1.4)
Change in contingent considerations	—	0.8	—	(8.9)
Other, net	(0.3)	—	(0.8)	(0.2)
Income (loss) before income taxes	$ 159.2	$ 51.7	$ (1,948.7)	$ 32.7

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, 2019 (“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 Partners LP (“we,” “our,” the “Partnership” or “TRP”) is a Delaware limited partnership formed in October 2006 by Targa Resources Corp. (“TRC” or “Targa”). Our common units were listed on the NYSE under the symbol “NGLS” prior to TRC’s acquisition on February 17, 2016 of all our outstanding common units that it and its subsidiaries did not already own. Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) remain outstanding as preferred limited partner interests in us and continue to trade on the NYSE under the symbol “NGLS/PA.”

Targa Resources GP LLC, our general partner, is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa.

Our Operations

We are engaged primarily in the business of:

- gathering, compressing, treating, processing, transporting and selling natural gas;
- transporting, storing, fractionating, treating and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling 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 of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (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”), as well as our equity interest in Gulf Coast Express Pipeline LLC (“GCX”), a natural gas pipeline transporting volumes from West Texas to the Gulf Coast. Grand Prix 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, including these pipelines, 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.

Recent Developments

Response to Current Market Conditions

During the first half of 2020, global commodity prices declined due to factors that significantly impacted both supply and demand. As the COVID-19 pandemic spread and travel and other restrictions were implemented globally, the demand for commodities declined substantially. Additionally, certain major oil producing nations significantly increased their oil and gas production late in the first quarter which further contributed to the surplus production of commodities. Despite these nations subsequently agreeing to reduce global commodity supplies beginning with May 2020 production, commodity prices remain weak relative to historical levels and continue to remain volatile. Reduced economic activity due to the COVID-19 pandemic, combined with uncertainty around global commodity supply and demand, has contributed to depressed crude oil, condensate, NGL and natural gas prices. Furthermore, the recent substantial decline in commodity prices has led many exploration and production companies to reduce planned capital expenditures for drilling and production activities and also led to some companies shutting in wells. Such price and activity declines negatively impact our operations by (i) reducing investments by third parties in the development of new oil and gas reserves, therefore potentially reducing volumes coming onto our systems in the future, (ii) decreasing volumes processed in our facilities and transported on our pipelines and (iii) reducing the prices we receive from the sale of commodities. While commodity prices remain low and uncertainties associated with the impacts of COVID-19 continue, in certain areas of our operations like the Permian Basin, production from wells that were previously shut-in during the second quarter of 2020 has largely resumed.

These circumstances have caused significant market volatility and business disruption. In our Gathering and Processing areas of operation, producers have reduced their drilling activity to varying degrees, which may lead to lower volume growth in the near term and reduced demand for our services. Producer activity also generates demand in our Downstream Business for transportation, fractionation, storage and other fee-based services, which may decrease in the near term.

There has been, and we believe will continue to be, significant volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. Due to the recent volatility in commodity prices, we are uncertain of what pricing and market demand will be throughout 2020, and, as a result, demand for our services may decrease. Across our operations, particularly in our Downstream Business, we benefit from long-term fee-based arrangements for our services, regardless of the actual volumes processed or delivered. The significant level of margin we derive from fee-based arrangements, combined with our hedging arrangements, helps to mitigate our exposure to commodity price movements. For additional information regarding our hedging activities, see "Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Due to the significant decline in commodity prices and the increased volatility in the broader market, the ability of companies in the oil and gas industry to seek financing and access the capital markets on favorable terms or at all has been negatively impacted. In these conditions, investors may be more likely to limit the amounts of their investments as well as seek more restrictive terms and higher costs on any financing. While these effects have increased the costs of debt and equity financing for the Company and others in our industry, we believe we have sufficient access to financial resources and liquidity necessary to meet our requirements for working capital, debt service payments and capital expenditures through the remainder of 2020 and beyond.

In a response to current market conditions, in the first quarter of 2020, we announced that our Board of Directors approved a reduction in the Company's quarterly common dividend to $0.10 per share for the quarter ended March 31, 2020 from $0.91 per share in the previous quarter. This reduction provided for approximately $755 million of additional annual direct cash flow, resulting in significant free cash flow available to reduce debt. We also reduced our estimated 2020 net growth capital expenditures to approximately $700 million to $800 million from our previously disclosed range of $1.2 billion to $1.3 billion, which represents a 40 percent reduction at the midpoint of both ranges. The vast majority of spending is for major ongoing growth capital projects where the capital is already predominantly spent. We continue to work through numerous internal initiatives to respond to current market conditions, including identifying and implementing cost reduction measures such as reducing or deferring non-essential operating and general and administrative expenses.

We believe that our long-term strategy, combined with our high-quality asset portfolio, allows us to generate attractive cash flows even in a low commodity price environment. Geographic, business and customer diversity enhances our ability to generate sufficient cash flows to fund our requirements. Our assets are positioned in strategic oil and gas producing areas across multiple basins and provide services under attractive contract terms to a diverse mix of customers across our operational areas. Our contract portfolio has attractive rates and term characteristics, including a significant fee-based component, especially in our Downstream Business. Our Gathering and Processing segment contract mix also has components of fee-based margin, such as fee floors and other fee-based services which mitigate against low commodity prices.

We are currently experiencing no material issues with potential workforce disruptions, and we remain focused on safeguarding employee health and safety and ensuring safe and reliable operations in response to COVID-19. Additionally, we are currently experiencing no material supply chain disruptions as a result of the COVID-19 pandemic, and our relationships with our major customers continues to be strong. However, if any of these circumstances change, our business could be adversely affected. Further, as there is significant uncertainty around the breadth and duration of the disruptions to global markets related to the aforementioned current events, we are unable to determine the extent that these events could materially impact our future financial position, operations and/or cash flows.

Gathering and Processing Segment Expansion

Permian Midland Processing Expansion

In August 2019, we announced that we began construction of a new 250 MMcf/d cryogenic natural gas processing plant in the Midland Basin, the Gateway Plant, which began operations in the third quarter of 2020.

Permian Delaware Processing Expansions

In March 2018, we announced that we entered into long-term fee-based agreements with an investment grade energy company for natural gas gathering and processing services in the Delaware Basin and for downstream transportation, fractionation and other related services. The agreements are underpinned by the customer's dedication of significant acreage within a large, well-defined area in the Delaware Basin. In addition to high-pressure rich gas gathering pipelines and a natural gas processing plant, the Falcon Plant, which were placed into service in 2019, we commenced operations of a second 250 MMcf/d cryogenic natural gas processing plant, the Peregrine Plant, in the second quarter of 2020.

We provide NGL transportation services on Grand Prix and fractionation services at our Mont Belvieu complex for a majority of the NGLs from the Falcon and Peregrine Plants.

Logistics and Transportation Segment Expansion

Grand Prix NGL Pipeline Extension

In February 2019, we announced an extension to our Grand Prix NGL pipeline system (the “Central Oklahoma Extension”), which will extend from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with The Williams Companies, Inc. (“Williams”) Bluestem Pipeline, linking the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. The Central Oklahoma Extension is expected to be completed in the first quarter of 2021. Transportation volumes on the Central Oklahoma Extension accrue solely to Targa’s benefit and are not included in Grand Prix Pipeline LLC (“Grand Prix Joint Venture”), a consolidated subsidiary of which Targa owns a 56% interest.

Fractionation Expansion

In November 2018, we announced plans to construct two new 110 MBbl/d fractionation trains in Mont Belvieu, Texas (“Train 7” and “Train 8”). Train 7 began operations late in the first quarter of 2020. Train 8 is expected to begin operations at the end of the third quarter of 2020. In January 2019, Williams committed to Targa significant volumes which Targa will transport on Grand Prix and fractionate at Targa’s Mont Belvieu facilities (including Train 7). Williams was also granted an option to purchase a 20% equity interest in the fractionation train, which was originally wholly owned by Targa. Williams exercised its initial option and executed a joint venture agreement with us with respect to Train 7 in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, such as storage caverns and brine handling, will be funded and owned 100% by Targa.

LPG Export Expansion

In February 2019, we announced plans to further expand our LPG export capabilities of propane and butanes at our Galena Park Marine Terminal by increasing refrigeration capacity and associated load rates. With the additional infrastructure, we increased our effective export capacity up to 15 MMBbl per month early in the third quarter of 2020, depending upon the mix of propane and butane demand, vessel size and availability of supply, among other factors.

Asset Sales

In November 2019, we executed agreements to sell our crude gathering and storage business in Permian Delaware for approximately $134 million. The sale closed in the first quarter of 2020.

Financing Activities

During the first half of 2020, we repurchased a portion of our outstanding senior notes on the open market, paying $239.8 million plus accrued interest to repurchase $303.3 million of the notes. The repurchases resulted in a $61.1 million net gain, which included the write-off of $2.4 million in related debt issuance costs.

We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such 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.

In the second quarter of 2020, we amended our accounts receivable securitization facility (the "Securitization Facility") to decrease the facility size from $400.0 million to $250.0 million to more closely align with our expectations for borrowing needs given current commodity prices and to extend the facility termination date to April 21, 2021.

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 in 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 fee-related 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 unit fees due to 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: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses, (3) capital expenditures and (4) the following non-GAAP measures: gross margin, operating margin, and Adjusted EBITDA.

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 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, utilities and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses, other than fuel and power, remain relatively stable and independent of the volumes through our systems, but may increase with system expansions and will fluctuate depending on the scope of the activities performed during a specific period.

Capital Expenditures

Capital projects associated with growth and maintenance projects are 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. Gross margin, operating margin and Adjusted EBITDA are non-GAAP measures. The GAAP measure most directly comparable to these non-GAAP measures is net income (loss) attributable to TRP. These non-GAAP measures should not be considered as an alternative to GAAP net income attributable to TRP 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 net income, 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.

Gross Margin

We define gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program.

Gathering and Processing segment gross 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 payments, other natural gas and crude oil purchases, and our equity volume hedge settlements.

Logistics and Transportation segment gross margin consists primarily of:

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

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

Operating Margin

We define operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of our operations.

Management reviews business segment gross margin and operating margin 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. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by management and by external users of 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 acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) attributable to TRP 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 make distributions to holders of our equity interests.

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 June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(In millions)			
Reconciliation of Net Income (Loss) to Operating Margin and Gross Margin				
Net income (loss)	$ 159.2	$ 51.7	$ (1,948.7)	$ 32.7
Depreciation and amortization expense	204.5	237.2	443.6	474.6
General and administrative expense	58.6	69.3	115.5	146.7
Impairment of long-lived assets	—	—	2,442.8	—
Interest (income) expense, net	94.3	69.5	188.1	144.9
Equity (earnings) loss	(14.9)	(3.2)	(35.5)	(5.9)
(Gain) loss on sale or disposition of assets	(0.7)	(0.2)	—	3.1
(Gain) loss from financing activities	(21.8)	—	(61.1)	1.4
Change in contingent considerations	—	(0.8)	—	8.9
Other, net	0.3	—	0.8	0.2
Operating margin	**479.5**	**423.5**	**1,145.5**	**806.6**
Operating expenses	183.4	210.2	383.3	400.5
Gross margin	**$ 662.9**	**$ 633.7**	**$ 1,528.8**	**$ 1,207.1**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2020	2019	2020	2019
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRP to Adjusted EBITDA				
Net income (loss) attributable to TRP	$ 65.9	$ (4.6)	$ (1,956.7)	$ (35.0)
Interest (income) expense, net	94.3	69.5	188.1	144.9
Depreciation and amortization expense	204.5	237.2	443.6	474.6
Impairment of long-lived assets	—	—	2,442.8	—
(Gain) loss on sale or disposition of assets	(0.7)	(0.2)	—	3.1
(Gain) loss from financing activities (1)	(21.8)	—	(61.1)	1.4
Equity (earnings) loss	(14.9)	(3.2)	(35.5)	(5.9)
Distributions from unconsolidated affiliates and preferred partner interests, net	27.7	12.6	53.4	19.4
Change in contingent considerations	—	(0.8)	—	8.9
Risk management activities	(10.4)	(7.1)	(125.9)	0.1
Severance and related benefits (2)	6.5	—	6.5	—
Noncontrolling interests adjustments (3)	(13.1)	(9.6)	(202.6)	(16.7)
TRP Adjusted EBITDA	**$ 338.0**	**$ 293.8**	**$ 752.6**	**$ 594.8**

(1) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.
(2) Represents one-time severance and related benefit expenses related to our cost reduction measures.
(3) Noncontrolling interest portion of depreciation and amortization expense (including the effects of the impairment of long-lived assets on non-controlling interests).

Consolidated Results of Operations

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2020	2019	2020 vs. 2019		2020	2019	2020 vs. 2019	
	(In millions)							
Revenues:								
Sales of commodities	$ 1,280.6	$ 1,684.2	$ (403.6)	(24%)	$ 3,060.2	$ 3,660.7	$ (600.5)	(16%)
Fees from midstream services	242.9	311.1	(68.2)	(22%)	512.2	634.0	(121.8)	(19%)
Total revenues	1,523.5	1,995.3	(471.8)	(24%)	3,572.4	4,294.7	(722.3)	(17%)
Product purchases	860.6	1,361.6	(501.0)	(37%)	2,043.6	3,087.6	(1,044.0)	(34%)
Gross margin (1)	662.9	633.7	29.2	5%	1,528.8	1,207.1	321.7	27%
Operating expenses	183.4	210.2	(26.8)	(13%)	383.3	400.5	(17.2)	(4%)
Operating margin (1)	479.5	423.5	56.0	13%	1,145.5	806.6	338.9	42%
Depreciation and amortization expense	204.5	237.2	(32.7)	(14%)	443.6	474.6	(31.0)	(7%)
General and administrative expense	58.6	69.3	(10.7)	(15%)	115.5	146.7	(31.2)	(21%)
Impairment of long-lived assets	—	—	—	—	2,442.8	—	2,442.8	—
Other operating (income) expense	0.4	(0.2)	0.6	NM	1.6	3.3	(1.7)	(52%)
Income (loss) from operations	216.0	117.2	98.8	84%	(1,858.0)	182.0	(2,040.0)	NM
Interest expense, net	(94.3)	(69.5)	(24.8)	36%	(188.1)	(144.9)	(43.2)	30%
Equity earnings (loss)	14.9	3.2	11.7	NM	35.5	5.9	29.6	NM
Gain (loss) from financing activities	21.8	—	21.8	—	61.1	(1.4)	62.5	NM
Change in contingent considerations	—	0.8	(0.8)	(100%)	—	(8.9)	8.9	100%
Other, net	0.8	—	0.8	—	0.8	—	0.8	—
Net income (loss)	159.2	51.7	107.5	208%	(1,948.7)	32.7	(1,981.4)	NM
Less: Net income (loss) attributable to noncontrolling interests	93.3	56.3	37.0	66%	8.0	67.7	(59.7)	(88%)
Net income (loss) attributable to Targa Resources Partners LP	$ 65.9	$ (4.6)	$ 70.5	NM	$ (1,956.7)	$ (35.0)	$ (1,921.7)	NM
Financial data:								
Adjusted EBITDA (1)	$ 338.0	$ 293.8	$ 44.2	15%	$ 752.6	$ 594.8	$ 157.8	27%
Growth capital expenditures (2)	142.8	821.4	(678.6)	(83%)	420.1	1,691.5	(1,271.4)	(75%)
Maintenance capital expenditures (3)	26.8	35.5	(8.7)	(25%)	53.7	71.1	(17.4)	(24%)

(1) Gross margin, operating margin, and Adjusted EBITDA 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."

(2) Growth capital expenditures, net of contributions from noncontrolling interest, were $404.2 million and $1,440.5 million for the six months ended June 30, 2020 and 2019. Net contributions to investments in unconsolidated affiliates were $0.3 million and $57.3 million for the six months ended June 30, 2020 and 2019.

(3) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $51.4 million and $67.2 million for the six months ended June 30, 2020 and 2019.

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

Three Months Ended June 30, 2020 Compared to Three Months Ended June 30, 2019

The decrease in commodity sales reflects lower NGL, condensate, and petroleum products prices ($476.2 million) and lower crude marketing, petroleum products, and natural gas volumes ($150.3 million), partially offset by higher NGL and condensate volumes ($137.9 million), higher natural gas prices ($59.5 million) and the favorable impact of hedges ($26.1 million).

The decrease in fees from midstream services is primarily due to new transportation arrangements for Badlands volumes effective in January 2020, which resulted in a change from net presentation as fees from midstream services to gross presentation as sales of commodities and product purchases, partially offset by increased export volumes.

The decrease in product purchases reflects decreased NGL, condensate and petroleum products prices, partially offset by increases in volumes.

Higher operating margin and gross margin in 2020 reflect increased segment results for Gathering and Processing and Logistics and Transportation. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense decreased primarily due to a lower depreciable base associated with assets that were impaired during the first quarter of 2020 and the sale of the Delaware crude gathering system, which was effective December 1, 2019. The decrease in depreciation and amortization expense was partially offset by higher depreciation related to major growth capital projects placed in service, including Train 7 and the additional processing plants and associated infrastructure in the Permian Basin.

General and administrative expense decreased due to cost reduction measures resulting in lower non-labor expenses and reduced compensation and benefits.

Interest expense, net, increased due to higher average borrowings and lower capitalized interest resulting from lower growth capital investments.

The increase in equity earnings is primarily due to higher earnings from our investments in GCX and Little Missouri 4 LLC ("Little Missouri 4"), partially offset by lower earnings from Gulf Coast Fractionators LP ("GCF").

During the three months ended June 30, 2020, we repurchased a portion of our outstanding senior notes on the open market, paying $117.7 million plus accrued interest to repurchase $140.6 million of the notes, resulting in a $21.8 million net gain from financing activities.

Net income attributable to noncontrolling interests was higher in 2020 primarily due to income allocated to noncontrolling interest holders in Targa Badlands LLC ("Targa Badlands"), Targa GCX Pipeline LLC ("GCX DevCo JV"), and the Grand Prix Joint Venture.

Six Months Ended June 30, 2020 Compared to Six Months Ended June 30, 2019

The decrease in commodity sales reflects lower NGL, natural gas, condensate, and petroleum products prices ($1,243.0 million) and lower crude marketing volumes ($131.2 million), partially offset by higher NGL, natural gas, condensate, and petroleum products volumes ($596.5 million) and the favorable impact of hedges ($174.1 million).

The decrease in fees from midstream services is primarily due to new transportation arrangements for Badlands volumes during the six months ended June 30, 2020, which resulted in a change from net presentation as fees from midstream services to gross presentation as sales of commodities and product purchases, partially offset by increased export volumes.

The decrease in product purchases reflects decreased NGL, natural gas, petroleum products and condensate prices, partially offset by increases in volumes.

Higher operating margin and gross margin in 2020 reflect increased segment results for Gathering and Processing and Logistics and Transportation. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense decreased primarily due to lower depreciable base associated with assets that were impaired during the first quarter of 2020 and the sale of the Delaware crude gathering system, which was effective December 1, 2019. The decrease in depreciation and amortization expense was partially offset by higher depreciation related to major growth capital projects placed in service, including Train 7 and the additional processing plants and associated infrastructure in the Permian Basin.

General and administrative expense decreased due to cost reduction measures resulting in reduced compensation and benefits and lower non-labor expenses.

The impairment charge is primarily associated with the partial impairment of gas processing facilities and gathering systems in the first quarter of 2020 associated with our Mid-Continent operations and full impairment of our Coastal operations - all of which are in our Gathering and Processing segment. Based on then-current market conditions, our first quarter impairment assessment projected further decline in natural gas production across the Mid-Continent and Gulf of Mexico. We did not recognize any impairments of long-lived assets during the first quarter of 2019. We may identify additional triggering events in the future, which will require additional evaluations of the recoverability of the carrying value of our long-lived assets and may result in future impairments.

Interest expense, net, increased due to higher average borrowings and lower capitalized interest resulting from lower growth capital investments.

The increase in equity earnings is primarily due to higher earnings from our investments in GCX and Little Missouri 4, partially offset by lower earnings from GCF.

During the six months ended June 30, 2020, the Partnership repurchased a portion of its outstanding senior notes on the open market, paying $239.8 million plus accrued interest to repurchase $303.3 million of the notes, resulting in a $61.1 million net gain from financing activities.

Net income attributable to noncontrolling interests was lower in 2020 primarily due to impairment losses allocated to noncontrolling interest holders, partially offset by income allocated to noncontrolling interest holders in Targa Badlands, GCX DevCo JV, the Grand Prix Joint Venture and Train 6.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Transportation	Other	Consolidated Operating Margin
	(In millions)			
Three Months Ended:				
June 30, 2020	$ 237.2	$ 231.5	$ 10.8	$ 479.5
June 30, 2019	232.1	184.4	7.0	423.5
Six Months Ended:				
June 30, 2020	$ 492.8	$ 525.5	$ 127.2	$ 1,145.5
June 30, 2019	470.3	336.3	—	806.6

Gathering and Processing Segment

	Three Months Ended June 30, 2020	Three Months Ended June 30, 2019	2020 vs. 2019		Six Months Ended June 30, 2020	Six Months Ended June 30, 2019	2020 vs. 2019	
	(In millions, except operating statistics and price amounts)							
Gross margin	$ 338.3	$ 363.8	$ (25.5)	(7%)	$ 708.7	$ 725.1	$ (16.4)	(2%)
Operating expenses	101.1	131.7	(30.6)	(23%)	215.9	254.8	(38.9)	(15%)
Operating margin	$ 237.2	$ 232.1	$ 5.1	2%	$ 492.8	$ 470.3	$ 22.5	5%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	1,698.9	1,425.3	273.6	19%	1,677.0	1,374.2	302.8	22%
Permian Delaware	651.6	545.1	106.5	20%	689.3	513.0	176.3	34%
Total Permian	2,350.5	1,970.4	380.1		2,366.3	1,887.2	479.1	
SouthTX (5)	265.1	313.8	(48.7)	(16%)	275.7	338.7	(63.0)	(19%)
North Texas	197.8	224.0	(26.2)	(12%)	210.6	227.2	(16.6)	(7%)
SouthOK (6)	439.8	607.7	(167.9)	(28%)	501.9	613.8	(111.9)	(18%)
WestOK	251.2	338.2	(87.0)	(26%)	271.4	338.2	(66.8)	(20%)
Total Central	1,153.9	1,483.7	(329.8)		1,259.6	1,517.9	(258.3)	
Badlands (7),(8)	111.6	92.3	19.3	21%	135.6	94.6	41.0	43%
Total Field	3,616.0	3,546.4	69.6		3,761.5	3,499.7	261.8	
Coastal	713.0	804.9	(91.9)	(11%)	748.8	787.5	(38.7)	(5%)
Total	4,329.0	4,351.3	(22.3)	(1%)	4,510.3	4,287.2	223.1	5%
NGL production, MBbl/d (3)								
Permian Midland (4)	245.0	198.0	47.0	24%	245.0	191.3	53.7	28%
Permian Delaware	89.6	71.4	18.2	25%	93.0	65.9	27.1	41%
Total Permian	334.6	269.4	65.2		338.0	257.2	80.8	
SouthTX (5)	28.8	41.7	(12.9)	(31%)	28.5	45.2	(16.7)	(37%)
North Texas	23.5	26.6	(3.1)	(12%)	24.9	26.7	(1.8)	(7%)
SouthOK (6)	51.3	68.3	(17.0)	(25%)	59.0	63.3	(4.3)	(7%)
WestOK	21.0	23.8	(2.8)	(12%)	22.1	24.0	(1.9)	(8%)
Total Central	124.6	160.4	(35.8)		134.5	159.2	(24.7)	
Badlands (8)	13.9	11.3	2.6	23%	16.0	11.3	4.7	42%
Total Field	473.1	441.1	32.0		488.5	427.7	60.8	
Coastal	43.2	47.3	(4.1)	(9%)	46.0	47.8	(1.8)	(4%)
Total	516.3	488.4	27.9	6%	534.5	475.5	59.0	12%
Crude oil gathered, Badlands, MBbl/d	157.9	167.3	(9.4)	(6%)	167.5	168.4	(0.9)	(1%)
Crude oil gathered, Permian, MBbl/d (9)	40.2	86.3	(46.1)	(53%)	45.6	81.4	(35.8)	(44%)
Natural gas sales, BBtu/d (3),(10)	2,048.9	2,049.7	(0.8)	(0%)	2,103.0	1,988.1	114.9	6%
NGL sales, MBbl/d (3),(10)	395.0	389.3	5.7	1%	414.3	374.5	39.8	11%
Condensate sales, MBbl/d	16.1	13.2	2.9	22%	17.3	12.8	4.5	35%
Average realized prices - inclusive of hedges (11):								
Natural gas, $/MMBtu	1.03	0.90	0.13	14%	0.98	1.40	(0.42)	(30%)
NGL, $/gal	0.19	0.34	(0.15)	(44%)	0.21	0.39	(0.18)	(46%)
Condensate, $/Bbl	28.13	49.82	(21.69)	(44%)	36.61	48.49	(11.88)	(24%)

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents 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 72.8%, 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) SouthTX includes the Raptor Plant, of which we own a 50% interest through the Carnero Joint Venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(6) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants that are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(7) Badlands natural gas inlet represents the total wellhead gathered volume and includes the Targa-gathered volumes processed at the Little Missouri 4 Plant.
(8) As of April 3, 2019, Targa owns 55% of Targa Badlands, prior to which we owned a 100% interest. Targa Badlands is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) Permian crude oil gathered volumes reflect the sale of the Delaware crude gathering system, which was effective December 1, 2019.
(10) Natural gas and NGL sales statistics include Badlands starting January 1, 2020. New transportation arrangements for Badlands volumes resulted in a change from net presentation as "Fees from midstream services" to gross presentation as "Sales of commodities" and "Product purchases". This change in presentation did not result in an impact to our operating or gross margin.
(11) Average realized prices include the effect of realized commodity hedge gain/loss attributable to our equity volumes, previously shown in Other. The price is calculated using total commodity sales plus the hedge gain/loss as the numerator and total sales volumes as the denominator.

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

	Three Months Ended June 30, 2020			Three Months Ended June 30, 2019		
	(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)	17.3	$ 0.53	$ 9.2	16.1	$ 1.97	$ 31.8
NGL (MMgal)	100.2	0.22	21.7	72.7	0.12	8.9
Crude oil (MBbl)	0.5	29.85	14.1	0.4	(4.98)	(1.8)
			$ 45.0			$ 38.9

	Six Months Ended June 30, 2020			Six Months Ended June 30, 2019		
	(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)	33.1	$ 0.73	$ 24.1	28.2	$ 1.43	$ 40.4
NGL (MMgal)	195.7	0.20	39.2	142.1	0.07	9.4
Crude oil (MBbl)	0.9	21.24	19.7	0.7	(2.58)	(1.8)
			$ 83.0			$ 48.0

(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 June 30, 2020 Compared to Three Months Ended June 30, 2019

The decrease in gross margin was primarily due to lower volumes in the Central region, attributable to temporary shut-ins and reduced producer activity, and lower realized NGL and condensate prices, partially offset by higher volumes and fee-based margin in the Permian. In the Permian, inlet volumes and NGL production increased due to production from new wells and the addition of the Pembrook and Falcon plants in 2019 and the Peregrine plant in the second quarter of 2020. These increases were partially offset by the impact of temporary shut-ins and reduced producer activity. In the Badlands, natural gas gathered volumes and NGL production increased due to production from new wells and the incremental processing capacity available with the commencement of operations at the Little Missouri 4 Plant in the third quarter of 2019, partially offset by the impact of temporary shut-ins and reduced producer activity. Total crude oil gathered volumes decreased in the Badlands due to temporary shut-ins and reduced producer activity, while the decrease in the Permian was primarily due to the sale of the Delaware crude gathering system in the fourth quarter of 2019.

Despite the addition of new processing facilities in the Permian, operating expenses were lower due to cost reduction measures that resulted in a decrease in expenses from contract labor, chemicals, taxes and supplies.

Six Months Ended June 30, 2020 Compared to Six Months Ended June 30, 2019

The decrease in gross margin was primarily due to lower volumes in the Central region attributable to temporary shut-ins and reduced producer activity, and lower realized commodity prices, partially offset by higher volumes and fee-based margin in the Permian and Badlands. In the Permian, inlet volumes and NGL production increased due to production from new wells and the addition of the Pembrook and Falcon plants in 2019 and the Peregrine plant in the second quarter of 2020. These increases were partially offset by the impact of temporary shut-ins and reduced producer activity. In the Badlands, natural gas gathered volumes and NGL production increased due to production from new wells and the incremental processing capacity available with the commencement of operations at the Little Missouri 4 Plant in the third quarter of 2019, partially offset by the impact of temporary shut-ins and reduced producer activity. Total crude oil gathered volumes were flat in the Badlands, while the decrease in the Permian was primarily due to the sale of the Delaware crude gathering system in the fourth quarter of 2019.

Despite the addition of new processing facilities in the Permian, operating expenses were lower due to cost reduction measures that resulted in a decrease in expenses from contract labor, taxes and chemicals, partially offset by increased compensation and related benefits.

Logistics and Transportation Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2020	2019	2020 vs. 2019		2020	2019	2020 vs. 2019	
	(In millions, except operating statistics and price amounts)							
Gross margin	$ 314.7	$ 262.5	$ 52.2	20%	$ 695.0	$ 482.0	$ 213.0	44%
Operating expenses (1)	83.2	78.1	5.1	7%	169.5	145.7	23.8	16%
Operating margin	$ 231.5	$ 184.4	$ 47.1	26%	$ 525.5	$ 336.3	$ 189.2	56%
Operating statistics MBbl/d (2):								
Fractionation volumes (3)	579.3	512.5	66.8	13%	602.3	484.7	117.6	24%
Export volumes (4)	253.8	231.5	22.3	10%	261.3	222.4	38.9	17%
Pipeline throughput (5)	256.1	—	256.1	—	258.9	—	258.9	—
NGL sales	692.6	605.2	87.4	14%	720.4	594.8	125.6	21%

(1) Effective January 1, 2020, pursuant to amendments to contractual arrangements with our partners, our share of operating expenses associated with GCF, an investment in an unconsolidated affiliate, are included in operating expenses.

(2) 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.

(3) Fractionation contracts include pricing terms composed of base fees and fuel and power components that vary with the cost of energy. As such, the Logistics and Transportation segment results include effects of variable energy costs that impact both gross margin and operating expenses.

(4) 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.

(5) Pipeline throughput represents the total quantity of mixed NGLs delivered by Grand Prix to Mont Belvieu.

Three Months Ended June 30, 2020 Compared to Three Months Ended June 30, 2019

The increase in Logistics and Transportation segment gross margin was primarily due to higher NGL transportation and fractionation margin and higher LPG export margin, partially offset by lower marketing margin. NGL transportation and fractionation margin increased due to volumes delivered on Grand Prix, which began full service into Mont Belvieu during the third quarter of 2019, and higher fractionation volumes, as a result of the commencement of operations of Train 7 in the first quarter of 2020 and operations of Train 6 for a portion of the second quarter of 2019. LPG export margin increased primarily due to higher volumes, driven in part by phased expansions of our LPG export capabilities. Marketing margin decreased due to less optimization margin realized in our marketing businesses.

Operating expenses were higher due to the addition of incremental fractionation capacity, higher taxes primarily attributable to Train 7, and higher compensation and benefits, partially offset by lower fuel and power costs and cost reduction measures.

Six Months Ended June 30, 2020 Compared to Six Months Ended June 30, 2019

The increase in Logistics and Transportation segment gross margin was primarily due to higher NGL transportation and fractionation margin and higher LPG export margin, partially offset by lower marketing margin. NGL transportation and fractionation margin increased due to volumes delivered on Grand Prix, which began full service into Mont Belvieu during the third quarter of 2019, and higher fractionation volumes, as a result of the commencement of operations of Train 7 in the first quarter of 2020 and operations of Train 6 for a portion of the second quarter of 2019. LPG export margin increased primarily due to higher volumes driven in part by phased expansions of our LPG export capabilities, partially offset by lower fees. Marketing margin decreased primarily due to less optimization margin realized in our marketing businesses.

Operating expenses were higher due to the addition of incremental fractionation capacity, higher taxes primarily attributable to Grand Prix and to Train 7, higher compensation and benefits and higher maintenance, partially offset by lower fuel and power costs and cost reduction measures.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2020	2019	2020 vs. 2019	2020	2019	2020 vs. 2019
	(In millions)			(In millions)		
Gross margin	$ 10.8	$ 7.0	$ 3.8	$ 127.2	$ —	$ 127.2
Operating margin	$ 10.8	$ 7.0	$ 3.8	$ 127.2	$ —	$ 127.2

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."

Liquidity and Capital Resources

As of June 30, 2020, we had $173.6 million of "Cash and cash equivalents," on our Consolidated Balance Sheets. We believe our cash position, our cash flows from operating activities 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 ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing or repaying our indebtedness, and meeting our collateral requirements, 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 – Response to Current Market Conditions."

Our main sources of liquidity and capital resources are internally generated cash flows from operations, contributions from TRC that are funded through TRC's access to debt and equity markets, borrowings under the TRP Revolver and the Securitization Facility, and access to debt 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 facility, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity as of August 3, 2020 was:

			August 3, 2020
			(In millions)
Cash on hand		$	189.6
Total availability under the TRP Revolver			2,200.0
Total availability under the Securitization Facility			250.0
			2,639.6
Less:	Outstanding borrowings under the TRP Revolver		(580.0)
	Outstanding borrowings under the Securitization Facility		(250.0)
	Outstanding letters of credit under the TRP Revolver		(56.8)
	Total liquidity	$	1,752.8

Other potential capital resources associated with our existing arrangements include:

- Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on June 29, 2023.

In the second quarter of 2020, we amended the Securitization Facility to decrease the facility size from $400.0 million to $250.0 million to more closely align with our expectations for borrowing needs given current commodity prices and to extend the facility termination date to April 21, 2021.

A portion of our capital resources are allocated to letters of credit to satisfy certain counterparty credit requirements. These letters of credit reflect our non-investment grade status, as assigned to us by Moody's and S&P. They also 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 and valuation, which we closely manage; (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 acquisitions or divestitures and certain organic growth capital projects.

Working capital as of June 30, 2020 increased $105.4 million compared to December 31, 2019. The increase was primarily attributable to lower product purchase payables, partially offset by lower receivables resulting from lower commodity prices and volumes.

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, contributions from TRC, borrowings available under the TRP Revolver and the Securitization Facility and proceeds from debt 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 cash distributions to Targa for at least the next twelve months.

Long-term Financing

In February 2018, we formed three development joint ventures ("DevCo JVs") with investment vehicles affiliated with Stonepeak Infrastructure Partners ("Stonepeak"), which committed a maximum of approximately $960 million of capital to the DevCo JVs.

As of June 30, 2020, total contributions from Stonepeak to the DevCo JVs were $906.5 million. As of June 30, 2020, total contributions from funds managed by Blackstone Energy Partners ("Blackstone") to the Grand Prix Joint Venture were $338.6 million. These contributions from Stonepeak and Blackstone are included in noncontrolling interests.

From time to time, we issue long-term debt securities, which we refer to as senior notes. Our senior notes issued to date, generally have similar terms other than interest rates, maturity dates and redemption premiums. As of June 30, 2020, and December 31, 2019, the aggregate principal amount outstanding of our senior notes and other various long-term debt obligations, including unamortized premiums, debt issuance costs and non-current liabilities of finance leases, was $7,144.6 million and $7,005.2 million, respectively.

The majority of our debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the TRP Revolver and the Securitization Facility. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of June 30, 2020, we did not have any interest rate hedges.

In 2019, we closed on the sale of a 45% interest in Targa Badlands to GSO Capital Partners and Blackstone Tactical Opportunities (collectively, “GSO”) for $1.6 billion in cash. Growth capital of Targa Badlands after the sale is funded on a pro rata ownership basis. Targa Badlands pays a minimum quarterly distribution (“MQD”) to GSO and Targa, with GSO having a priority right on such MQDs. Additionally, GSO’s capital contributions would have a liquidation preference upon a sale of Targa Badlands. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries. As of June 30, 2020, the contributions from GSO were $74.0 million.

During the six months ended June 30, 2020, we repurchased a portion of the outstanding senior notes on the open market, paying $239.8 million plus accrued interest to repurchase $303.3 million of the notes, resulting in a $61.1 million net gain, which included the write-off of $2.4 million in related debt issuance costs. We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such 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.

To date, our 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 5 - 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.”

Distributions on our 5,000,000 Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on our Preferred Units are payable out of amounts legally available at a rate equal to 9.0% per annum.

On and after November 1, 2020, distributions on our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%. At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the Preferred Unitholders have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our Partnership Agreement.

Compliance with Debt Covenants

As of June 30, 2020, we were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

Six Months Ended June 30, 2020	2019	2020 vs. 2019
	(In millions)	
$ 706.6	$ 545.0	$ 161.6

The primary drivers of cash flows from operating activities are (i) the collection of cash from customers from the sale of NGLs, natural gas and other petroleum commodities, as well as fees for gas processing, crude gathering, export, fractionation, terminaling, storage and transportation, (ii) the payment of amounts related to the purchase of NGLs and natural gas, (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.

Net cash provided by operations increased in 2020 compared to 2019 primarily due to higher operating margin and an increase in cash distributions received from unconsolidated affiliates, partially offset by an increase in interest payments as a result of higher average borrowings.

Cash Flows from Investing Activities

Six Months Ended June 30, 2020	Six Months Ended June 30, 2019	2020 vs. 2019
(In millions)		
$ (472.1)	$ (1,961.9)	$ 1,489.8

Cash used in investing activities decreased in 2020 compared to 2019, primarily due to lower outlays for property, plant and equipment of $1,134.6 million, resulting from the completion of construction of Grand Prix, Train 6, and additional processing plants and associated infrastructure in the Permian Basin in 2019. The change is also attributable to proceeds of $134.1 million received from the sale of our Delaware crude gathering system and a $193.4 million decrease in our contributions to unconsolidated affiliates primarily due to the completion of GCX Pipeline in 2019.

Cash Flows from Financing Activities

	Six Months Ended June 30, 2020	Six Months Ended June 30, 2019
Source of Financing Activities, net	(In millions)	
Distributions	$ (295.0)	$ (679.1)
Contributions from (distributions to) noncontrolling interests	(180.5)	367.6
Debt, including financing costs	73.5	239.0
Contributions from TRC and General Partner	50.0	190.0
Sale of ownership interests in subsidiaries	—	1,619.7
Payment of contingent consideration	—	(317.1)
Other	—	(10.7)
Net cash provided by financing activities	$ (352.0)	$ 1,409.4

In 2020, net cash used in financing activities is primarily due to distributions to TRC, and net distributions to noncontrolling interests, partially offset by a net increase of debt outstanding and contributions from TRC and General Partner. Our distributions to noncontrolling interests are higher than our contributions from noncontrolling interests in 2020, primarily due to completion of major growth capital projects in 2019. Our debt outstanding increased due to net borrowings under our credit facility, partially offset by repurchases of a portion of our outstanding senior notes.

In 2019, we realized a net source of cash from financing activities primarily due to the sale of ownership interests in Targa Badlands and Train 7, net contributions from noncontrolling interests and a net increase of debt outstanding. The result was partially offset by payments of distributions, as well as the final contingent consideration payment associated with our 2017 acquisition of gas gathering and processing and crude oil gathering assets in the Permian Basin. The issuance of 6½% Senior Notes due 2027 and 6⅞% Senior Notes due January 2029, partially offset by the redemption of 4⅛% Senior Notes due November 2019 contributed to the net increase of debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth capital projects.

Distributions

TRC is entitled to receive all available Partnership distributions after payments of preferred distributions each quarter.

The following table details the distributions declared and/or paid by us during the six months ended June 30, 2020:

Three Months Ended	Date Paid or To Be Paid	Total Distributions	Distributions to Targa Resources Corp.
June 30, 2020	August 13, 2020	$ 51.7	$ 48.9
March 31, 2020	May 13, 2020	53.1	50.3
December 31, 2019	February 13, 2020	241.9	239.1

Preferred Units

Distributions on our Preferred Units are declared and paid monthly. As of June 30, 2020, we have 5,000,000 Preferred Units outstanding. For the three and six months ended June 30, 2020, $2.8 million and $5.6 million of distributions were paid. We have accrued distributions to Series A Preferred Unitholders of $0.9 million for June, which were paid subsequently on July 15, 2020.

In July 2020, the board of directors of our general partner declared a cash distribution of $0.1875 per Preferred Unit. This distribution will be paid on August 17, 2020.

Capital Expenditures

Our capital expenditures are classified as growth capital expenditures, business acquisitions, 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.

The following table details cash outlays for capital projects for the six months ended June 30, 2020 and 2019:

	Six Months Ended June 30,	
	2020	2019
	(In millions)	
Capital expenditures:		
Growth (1)	$ 420.1	$ 1,691.5
Maintenance (2)	53.7	71.1
Gross capital expenditures	473.8	1,762.6
Transfers from materials and supplies inventory to property, plant and equipment	(1.8)	(16.4)
Change in capital project payables and accruals, net	143.9	4.3
Cash outlays for capital projects	$ 615.9	$ 1,750.5

(1) Growth capital expenditures, net of contributions from noncontrolling interests, were $404.2 million and $1,440.5 million for the six months ended June 30, 2020 and 2019. Net contributions to investments in unconsolidated affiliates were $0.3 million and $57.3 million for the six months ended June 30, 2020 and 2019.

(2) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $51.4 million and $67.2 million for the six months ended June 30, 2020 and 2019.

We currently estimate that in 2020 we will invest approximately $700 million to $800 million in growth capital expenditures, net of noncontrolling interests, and net contributions to investments in unconsolidated affiliates for announced projects. We expect that 2020 maintenance capital expenditures, net of noncontrolling interests, will be approximately $130 million.

Total growth capital expenditures were lower for the six months ended June 30, 2020 as compared to the six months ended June 30, 2019, primarily due to lower spending on growth capital investments, as a significant portion of our major projects began full service in 2019, including Grand Prix, Train 6, and additional processing plants and associated infrastructure in the Permian Basin. Total maintenance capital expenditures were lower for the six months ended June 30, 2020 as compared to the six months ended June 30, 2019, primarily due to timing of maintenance projects.

Off-Balance Sheet Arrangements

As of June 30, 2020, there were $46.0 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. We have all our commodity derivatives 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 also 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 2025. 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 June 30, 2020, 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 by entering into derivative instruments. 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. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs 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 Swap Dealers Association form with customized credit and legal terms. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in commodity prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Act, and as long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. 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 June 30, 2020:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
Natural gas	$ (24.1)	$ 24.1	$ (72.5)
NGLs	12.0	67.5	(43.2)
Crude oil	44.0	59.1	29.2
Total	$ 31.9	$ 150.7	$ (86.5)

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 by $68.3 million and $42.2 million during the three months ended June 30, 2020 and 2019 and $228.1 million and $54.1 million during the six months ended June 30, 2020 and 2019, as a result of transactions accounted for as derivatives. We account for derivatives designated as hedges that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income until the underlying hedged transactions settle. We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net liability position of $6.1 million at December 31, 2019 to a net asset position of $31.9 million at June 30, 2020. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of June 30, 2020, 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 TRP Revolver and the Securitization Facility will also increase. As of June 30, 2020, we had $690.0 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $6.9 million based on our June 30, 2020 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 International Swap Dealers Association 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 $43.9 million as of June 30, 2020. The range of losses attributable to our individual counterparties as of June 30, 2020 would be between $0.4 million and $18.0 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 doubtful accounts was $0.1 million and $0.0 million as of June 30, 2020 and December 31, 2019. Changes in the allowance for doubtful accounts were not material for the three and six months ended June 30, 2020.

During the three and six months ended June 30, 2020, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 13% and 11% of our consolidated revenues. During both the three and six months ended June 30, 2019, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 13% 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 June 30, 2020, 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 that occurred during the quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, during our most recent fiscal quarter.

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, Texas against Targa Channelview LLC, a subsidiary of the Company ("Targa Channelview"), seeking recovery of $129 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.

Additional information required for this item is provided in Note 11 – 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 in addition to the risk factors discussed below. All of these risks and uncertainties, including those risks discussed below, could adversely affect our business, financial condition and/or results of operations.

Our cash flow is affected by supply and demand for natural gas, NGL products and crude oil and by natural gas, NGL, crude oil and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.

Our operations can be affected by the level of natural gas, NGL and crude oil prices and the relationship between these prices. The prices of crude oil, natural gas and NGLs have been volatile, and we expect this volatility to continue. Our future cash flows may be materially adversely affected if we experience significant, prolonged price deterioration. The markets and prices for crude oil, natural gas and NGLs depend upon factors beyond our control. These factors include supply and demand for these commodities, which fluctuates with changes in market and economic conditions, and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting our primary markets;
- the economic conditions of our customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by major foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability of domestic storage for crude oil;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of crude oil and natural gas; and
- the extent of governmental regulation and taxation, including those related to the prorationing of oil and gas production.

Additionally, we have been and may continue to be adversely affected by the continued impact on global demand for commodities related to the COVID-19 pandemic. The COVID-19 pandemic has reduced economic activity and the related demand for energy commodities. These effects, combined with a period of increased production from major oil producing nations and decreasing availability of crude oil storage, has contributed to a sharp drop in prices in the first half of 2020 and is expected to continue to impact demand over the short-term.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under these arrangements, we generally process natural gas from producers and remit to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuate, to the extent our exposure to these prices is unhedged. See "Item 3. Quantitative and Qualitative Disclosures About Market Risk."

As further discussed in Note 4 – Property, Plant and Equipment and Intangible Assets and Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, the global decline in commodity prices due to both demand and supply disruptions was a significant contributing factor to the non-cash impairment charges totaling $2,442.8 million for the six months ended June 30, 2020.

The widespread outbreak of the COVID-19 pandemic or any other public health crisis that impacts the global demand for commodities may have material adverse effects on our business, financial position, results of operations and/or cash flows.

We face risks related to the outbreak of illnesses, pandemics and other public health crises that are outside of our control and could significantly disrupt our operations and adversely affect our financial condition. For example, the recent global spread of COVID-19 has caused business disruption, including disruption to the oil and gas industry. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and gas, and created significant volatility and disruption of financial and commodity markets. The full extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for crude oil, natural gas and natural gas liquids (including the impact that reductions in travel, manufacturing and consumer product demand have had and will have on the demand for commodities), the availability of personnel, equipment and services critical to our ability to operate our assets and the impact of potential governmental restrictions on travel, transportation and operations.

The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will also depend on future developments, which are highly uncertain and cannot be predicted. These developments include, but are not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. Therefore, while we expect this matter will continue to disrupt our operations in some way, the degree of the adverse financial impact cannot be reasonably estimated at this time.

Refer to Note 4 – Property, Plant and Equipment and Intangible Assets and in Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion.

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

Recent Sales of Unregistered Securities.

Not applicable.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers.

Not applicable.

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	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, effective December 1, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2016 (File No. 001-33303)).
3.4	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 12, 2017 (File No. 001-33303)).
3.5	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
10.1	Ninth Amendment to Receivables Purchase Agreement, dated April 22, 2020, by and among Targa Receivables LLC, as seller, Targa Resources Partners LP, 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 Partners LP's Current Report on Form 8-K filed April 24, 2020 (File No. 001-33303)).
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
104*	The cover page from this Quarterly Report on Form 10-Q for the quarter ended June 30, 2020, formatted in Inline XBRL (included with Exhibit 101 attachments).

* Filed herewith

** Furnished herewith

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 Partners LP

By: Targa Resources GP LLC,
its general partner

Date: August 6, 2020

By: */s/ Jennifer R. Kneale*
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

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 Partners LP (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: August 6, 2020

By:	/s/ Matthew J. Meloy
Name:	Matthew J. Meloy
Title:	Chief Executive Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (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 Partners LP (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: August 6, 2020

By:	/s/ Jennifer R. Kneale
Name:	Jennifer R. Kneale
Title:	Chief Financial Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (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 Partners LP (the "Partnership") for the three months ended June 30, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, 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 the Partnership.

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Chief Executive Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: August 6, 2020

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 the Partnership and will be retained by the Partnership 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 Partners LP (the "Partnership") for the three months ended June 30, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Jennifer R. Kneale, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, 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 the Partnership.

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: August 6, 2020

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 the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.